DOE/EIA-0383(2008)
June 2008

Annual Energy Outlook 2008

With Projections to 2030

For Further Information . . .

The *Annual Energy Outlook 2008* was prepared by the Energy Information Administration, under the direction of John J. Conti (john.conti@eia.doe.gov, 202-586-2222), Director, Integrated Analysis and Forecasting; Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284), Director, Demand and Integration Division; Joseph A. Beamon (jbeamon@eia.doe.gov, 202/586-2025), Director, Coal and Electric Power Division; A. Michael Schaal (michael.schaal@eia.doe.gov, 202/586-5590), Director, Oil and Gas Division; Glen E. Sweetnam (glen.sweetnam@eia.doe.gov, 202/586-2188), Director, International, Economic, and Greenhouse Gases Division; and Andy S. Kydes (akydes@eia.doe.gov, 202/586-2222), Senior Technical Advisor.

For ordering information and questions on other energy statistics available from the Energy Information Administration, please contact the National Energy Information Center. Addresses, telephone numbers, and hours are as follows:

National Energy Information Center, EI-30
Energy Information Administration
Forrestal Building
Washington, DC 20585

Telephone: 202/586-8800
FAX: 202/586-0727
TTY: 202/586-1181
9 a.m. to 5 p.m., eastern time, M-F

E-mail: infoctr@eia.doe.gov
Web Site: http://www.eia.doe.gov/
FTP Site: ftp://ftp.eia.doe.gov/

Specific questions about the information in this report may be directed to:

Overview	Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284)
Economic Activity	Kay A. Smith (kay.smith@eia.doe.gov, 202/586-1132)
International Oil Production	Lauren Mayne (lauren.mayne@eia.doe.gov, 202/586-3005)
International Oil Demand	Linda Doman (linda.doman@eia.doe.gov, 202/586-1041)
Residential Demand	John H. Cymbalsky (john.cymbalsky@eia.doe.gov, 202/586-4815)
Commercial Demand	Erin E. Boedecker (erin.boedecker@eia.doe.gov, 202/586-4791)
Industrial Demand	Paul D. Holtberg (paul.holtberg@eia.doe.gov, 202/586-1284)
Transportation Demand	John D. Maples (john.maples@eia.doe.gov, 202/586-1757)
Electricity Generation, Capacity	Jeff S. Jones (jjones@eia.doe.gov, 202/586-2038)
Electricity Generation, Emissions	Robert K. Smith (robert.smith@eia.doe.gov, 202/586-9413)
Electricity Prices	Lori B. Aniti (laniti@eia.doe.gov, 202/586-2867)
Nuclear Energy	Laura K. Martin (laura.martin@eia.doe.gov, 202/586-1494)
Renewable Energy	Chris R. Namovicz (chris.namovicz@eia.doe.gov, 202/586-7120)
Oil and Natural Gas Production	Eddie L. Thomas, Jr. (eddie.thomas@eia.doe.gov, 202/586-5877)
Natural Gas Markets	Philip M. Budzik (pbudzik@eia.doe.gov, 202/586-2847)
Oil Refining and Markets	William S. Brown (william.brown@eia.doe.gov, 202/586-8181)
Coal Supply and Prices	Michael L. Mellish (mmellish@eia.doe.gov, 202/586-2136)
Greenhouse Gas Emissions	Daniel H. Skelly (dskelly@eia.doe.gov, 202/586-1722)

The *Annual Energy Outlook 2008* will be available on the EIA web site at www.eia.doe.gov/oiaf/aeo/ in early summer 2008. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available in early summer 2008, at web sites www.eia.doe.gov/oiaf/assumption/ and /supplement/. Model documentation reports for the National Energy Modeling System are available at web site http://tonto.eia.doe.gov/reports/reports_kindD.asp?type=model documentation and will be updated for the *Annual Energy Outlook 2008* during 2008.

Other contributors to the report include Kara Akins, Justine Barden, Joseph Benneche, Michael Bredehoeft, Margie Daymude, Linda Doman, Casey Dunagan, Robert Eynon, Peter Gross, James Hewlett, Sean Hill, Crawford Honeycutt, Diane Kearney, Stephanie Kette, Nasir Khilji, Paul Kondis, Thomas Lee, Phyllis Martin, Lauren Mayne, Ted McCallister, Christina O'Brien, Chetha Phang, Anthony Radich, Eugene Reiser, Sharon Shears, John Staub, Laura Yee, Dana Van Wagener, Steven Wade, and Peggy Wells.

DOE/EIA-0383(2008)

Annual Energy Outlook 2008

With Projections to 2030

June 2008

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

This publication is on the WEB at:
www.eia.doe.gov/oiaf/aeo/

This report was prepared by the Energy Information Administration, the independent statistical and analytical agency within the U.S. Department of Energy. The information contained herein should be attributed to the Energy Information Administration and should not be construed as advocating or reflecting any policy position of the Department of Energy or any other organization.

Preface

The *Annual Energy Outlook 2008* (*AEO2008*), prepared by the Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2030. The projections are based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2008* reference case in December 2007; however, the Energy Independence and Security Act of 2007 (EISA2007), which was enacted later that month, will have a major impact on energy markets, and given the year-long life of *AEO2008* and its use as a baseline for analyses of proposed policy changes, EIA decided to update the reference case to reflect the provisions of EISA2007.

The report begins with an "Overview" summarizing the *AEO2008* reference case and comparing it with the *Annual Energy Outlook 2007* (*AEO2007*) reference case. The Overview also includes a section that provides a comparison between the *AEO2008* released in December and the current version. The next section, "Legislation and Regulations," discusses evolving legislation and regulatory issues, including a summary of recently enacted legislation, such as EISA2007, and provides an update on the handling of aspects of previously enacted legislation, such as the loan guarantee program set up by Title XVII of the Energy Policy Act of 2005 (EPACT2005). This section also provides a summary of State renewable fuel requirements and emissions regulations and a discussion of how selected Federal fuel taxes and tax credits are handled in *AEO2008*.

The "Issues in Focus" section includes discussion of a scenario under which electricity generation options other than natural gas are restricted and natural gas supply is limited; the competitive factors that influence imports of liquefied natural gas (LNG); and the implications of changing the basis for measuring heating and cooling degree-days. It also discusses the implications of uncertainty in energy project costs and the basis of the world oil price and production trends in *AEO2008*.

The "Market Trends" section summarizes the projections for energy markets. The analysis in *AEO2008* focuses primarily on a reference case, low and high economic growth cases, and low and high energy price cases. Results from a number of other alternative cases are also presented, illustrating uncertainties associated with the reference case projections for energy demand, supply, and prices. Complete tables for the five primary cases are provided in Appendixes A through C. Major results from many of the alternative cases are provided in Appendix D.

AEO2008 projections are based on Federal, State, and local laws and regulations in effect on or before December 31, 2007. The potential impacts of pending or proposed legislation, regulations, and standards (and sections of existing legislation that require implementing regulations or funds that have not been appropriated) are not reflected in the projections.

In general, historical data used in the *AEO2008* projections are based on EIA's *Annual Energy Review 2006*, published in June 2007. Other historical data, taken from multiple sources, are presented for comparative purposes; documents referenced in the source notes should be consulted for official data values.

AEO2008 is published in accordance with Section 205c of the Department of Energy (DOE) Organization Act of 1977 (Public Law 95-91), which requires the EIA Administrator to prepare annual reports on trends and projections for energy use and supply.

Projections in *AEO2008* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, given known technology and technological and demographic trends. *AEO2008* assumes that current laws and regulations are maintained throughout the projections. Thus, the projections provide a policy-neutral reference case that can be used to analyze policy initiatives.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2008* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

Contents

Page

Overview **1**
- Energy Trends to 2030 2
- Economic Growth 2
- Energy Prices 4
- Energy Consumption by Sector 6
- Energy Consumption by Primary Fuel 7
- Energy Intensity 8
- Energy Production and Imports 9
- Electricity Generation 10
- Energy-Related Carbon Dioxide Emissions 11

Legislation and Regulations **15**
- Introduction 16
- Energy Independence and Security Act of 2007: Summary of Provisions 16
- Federal Fuels Taxes and Tax Credits 23
- Mobile Source Air Toxics Rule 24
- EPACT2005 Loan Guarantee Program 25
- State Renewable Energy Requirements and Goals: Update Through 2007 25
- State Regulations on Airborne Emissions: Update Through 2007 28

Issues in Focus **31**
- Introduction 32
- Impacts of Uncertainty in Energy Project Costs 32
- Limited Electricity Generation Supply and Limited Natural Gas Supply Cases 38
- Trends in Heating and Cooling Degree-Days: Implications for Energy Demand 44
- Liquefied Natural Gas: Global Challenges 46
- World Oil Prices and Production Trends in *AEO2008* 50

Market Trends **53**
- Trends in Economic Activity 54
- International Oil Markets 56
- Energy Demand 57
- Residential Sector Energy Demand 59
- Commercial Sector Energy Demand 61
- Industrial Sector Energy Demand 63
- Transportation Sector Energy Demand 65
- Electricity Demand 67
- Electricity Supply 68
- Electricity Prices 72
- Natural Gas Demand 73
- Natural Gas Prices 75
- Natural Gas Supply 77
- Oil Production 79
- Liquid Fuels Production and Demand 81
- Liquid Fuel Prices 83
- Coal Production 84
- Coal Prices 85
- Emissions From Energy Use 86

Comparison with Other Projections **89**

List of Acronyms **102**

Notes and Sources **103**

Contents

Page

Appendixes

A. Reference Case 115
B. Economic Growth Case Comparisons 149
C. Price Case Comparisons 157
D. Results from Side Cases 170
E. NEMS Overview and Brief Description of Cases 191
F. Regional Maps 207
G. Conversion Factors 215

Tables

1. Total energy supply and disposition in the *AEO2008* and *AEO2007* reference cases, 2006-2030 13
2. Representative efficiency standards for enclosed motors 20
3. Summary of DOE's August 2006 loan guarantee solicitation 26
4. State renewable portfolio standards 27
5. Key analyses from "Issues in Focus" in recent *AEO*s 32
6. Costs of producing electricity from new plants, 2015 and 2030 69
7. Projections of annual average economic growth rates, 2006-2030 90
8. Projections of world oil prices, 2010-2030 90
9. Projections of average annual growth rates for energy consumption, 2006-2030 91
10. Comparison of electricity projections, 2015 and 2030 92
11. Comparison of natural gas projections, 2015, 2025, and 2030 94
12. Comparison of petroleum projections, 2015, 2025, and 2030 97
13. Comparison of coal projections, 2015, 2025, and 2030 98

Figures

1. Energy prices, 1980-2030 5
2. Delivered energy consumption by sector, 1980-2030 6
3. Energy consumption by fuel, 1980-2030 7
4. Energy use per capita and per dollar of gross domestic product, 1980-2030 8
5. Total energy production and consumption, 1980-2030 9
6. Energy production by fuel, 1980-2030 9
7. Electricity generation by fuel, 1980-2030 11
8. U.S. carbon dioxide emissions by sector and fuel, 1990-2030 12
9. Changes in construction commodity costs, 1973-2007 32
10. Changes in construction commodity costs and electric utility construction costs, 1973-2007 33
11. Additions to U.S. electricity generation capacity by fuel in three cases, 2006-2030 35
12. U.S. natural gas supply by source in three cases, 2030 36
13. U.S. natural gas consumption by sector in three cases, 2030 36
14. U.S. natural gas prices in three cases, 2000-2030 36
15. Electricity generation by fuel in four cases, 2006 and 2030 40
16. New generating capacity additions in four cases, 2006-2030 41
17. Natural gas consumption by sector in four cases, 2030 41
18. Natural gas supply by source in four cases, 2006 and 2030 42
19. Lower 48 wellhead natural gas prices in four cases, 1995-2030 43
20. U.S. average electricity prices in four cases, 1995-2030 44
21. Annual heating and cooling degree-days, 1993-2007 45
22. Heating and cooling degree-days in the *AEO2008* reference case, 2010-2030 45
23. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on energy use for heating and cooling in buildings by fuel type, 2030 46
24. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on peak seasonal electricity demand load, 2030 46
25. U.S. imports of liquefied natural gas, 2001-2007 48
26. OECD Europe natural gas supply by source, 2000-2007 48

Figures (Continued) **Page**

27. Gross U.S. imports of liquefied natural gas in three cases, 1990-2030 49
28. U.S. natural gas supply in three cases, 2006-2030 49
29. Lower 48 wellhead natural gas prices in three cases, 1990-2030 49
30. World oil price in six cases, 2000-2030 50
31. World liquids consumption in the *AEO2008* reference case, 2006-2030 50
32. Average annual growth rates of real GDP, labor force, and productivity, 2006-2030 54
33. Average annual inflation, interest, and unemployment rates, 2006-2030 54
34. Sectoral composition of industrial output growth rates, 2006-2030 55
35. Energy expenditures in the U.S. economy, 1990-2030 55
36. Energy expenditures as a share of gross domestic product, 1970-2030 55
37. World oil prices, 1980-2030 56
38. Unconventional resources as a share of the world liquids market, 1990-2030 56
39. World liquids production shares by region, 2006 and 2030 57
40. Energy use per capita and per dollar of gross domestic product, 1980-2030 57
41. Primary energy use by fuel, 2006-2030 58
42. Delivered energy use by fuel, 1980-2030 58
43. Primary energy consumption by sector, 1980-2030 59
44. Residential delivered energy consumption per capita, 1990-2030 59
45. Residential delivered energy consumption by fuel, 2006, 2015, and 2030 60
46. Efficiency gains for selected residential appliances, 2030 60
47. Electricity consumption for residential lighting, 2006-2030 61
48. Commercial delivered energy consumption per capita, 1980-2030 61
49. Commercial delivered energy consumption by fuel, 2006, 2015, and 2030 62
50. Efficiency gains for selected commercial equipment, 2030 62
51. Industrial delivered energy consumption, 1980-2030 63
52. Industrial energy consumption by fuel, 2000, 2006, and 2030 63
53. Average growth in value of shipments for the manufacturing subsectors, 2006-2030 64
54. Average growth of delivered energy consumption in the manufacturing subsectors, 2006-2030 64
55. Industrial delivered energy intensity, 1990-2030 65
56. Delivered energy consumption for transportation, 1980-2030 65
57. Average fuel economy of new light-duty vehicles, 1980-2030 66
58. Sales of unconventional light-duty vehicles by fuel type, 2006 and 2030 66
59. Energy use for light-duty vehicles by fuel type, 2006 and 2030 67
60. Annual electricity sales by sector, 1980-2030 67
61. Electricity generation by fuel, 2006 and 2030 68
62. Electricity generation capacity additions by fuel type, including combined heat and power, 2007-2030 68
63. Levelized electricity costs for new plants, 2015 and 2030 69
64. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2007-2030 69
65. Electricity generation from nuclear power, 1990-2030 70
66. Nonhydroelectric renewable electricity generation by energy source, 2006-2030 70
67. Grid-connected electricity generation from renewable energy sources, 1990-2030 71
68. Levelized and avoided costs for new renewable plants in the Northwest, 2030 71
69. Regional growth in nonhydroelectric renewable electricity generation, 2006-2030 72
70. Fuel prices to electricity generators, 1995-2030 72
71. Average U.S. retail electricity prices, 1970-2030 73
72. Natural gas consumption by sector, 1990-2030 73
73. Total natural gas consumption, 1990-2030 74
74. Natural gas consumption in the electric power and non-electric power sectors in alternative price cases, 1990-2030 74
75. Natural gas consumption in the electric power and non-electric power sectors in alternative growth cases, 1990-2030 75

Contents

Figures (Continued) **Page**

76. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 75
77. Lower 48 wellhead natural gas prices, 1990-2030 76
78. Natural gas prices by end-use sector, 1990-2030 76
79. Average natural gas transmission and distribution margins, 1990-2030 77
80. Natural gas production by source, 1990-2030 77
81. Total U.S. natural gas production, 1990-2030 78
82. Net U.S. imports of natural gas by source, 1990-2030 78
83. Net U.S. imports of liquefied natural gas, 1990-2030. 79
84. Domestic crude oil production by source, 1990-2030 79
85. Total U.S. crude oil production, 1990-2030. 80
86. Total U.S. unconventional crude oil production, 2006-2030 80
87. Liquid fuels consumption by sector, 1990-2030 81
88. EISA2007 RFS credits earned in selected years, 2006-2030 81
89. Fossil fuel and biofuel content of U.S. motor fuel supply, 2006, 2015, and 2030 82
90. Net import share of U.S. liquid fuels consumption, 1990-2030 82
91. Motor gasoline, diesel fuel, and E85 prices, 2006-2030 83
92. Average U.S. delivered prices for motor gasoline, 1990-2030 83
93. Coal production by region, 1970-2030 84
94. U.S. coal production, 2006, 2015, and 2030. 84
95. Average minemouth price of coal by region, 1990-2030 85
96. Average delivered coal prices, 1990-2030 85
97. Carbon dioxide emissions by sector and fuel, 2006 and 2030 86
98. Carbon dioxide emissions, 1990-2030 86
99. Sulfur dioxide emissions from electricity generation, 1995-2030 87
100. Nitrogen oxide emissions from electricity generation, 1995-2030 87

Overview

Overview

Energy Trends to 2030

In preparing projections for *AEO2008*, EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between today and 2030. This overview focuses on one case, the reference case, which is presented and compared with the *AEO2007* reference case (see Table 1). Readers are encouraged to review the full range of alternative cases included in other sections of *AEO2008*.

As in previous editions of the *Annual Energy Outlook* (*AEO*), the reference case assumes that current policies affecting the energy sector remain unchanged throughout the projection period. The reference case provides a clear basis against which alternative cases and policies can be compared. Although current laws and regulations may change over the next 25 years, and new ones may be created, it is not possible to predict what they will be or how they will be implemented [*1*].

EIA published an "early release" version of the *AEO2008* reference case in December 2007. Later that month, EISA2007 was enacted. The provisions in EISA2007 will have a major impact on energy markets, particularly liquid fuels. Given the year-long life of *AEO2008* and its use as a baseline for analyses of proposed policy changes, EIA decided to update the reference case to reflect the provisions of EISA2007. A short summary of the impact of including EISA-2007 is provided in the box on pages 3 and 4.

Trends in energy supply and demand are affected by many factors that are difficult to predict, including energy prices, U.S. and worldwide economic growth, advances in technologies, and future public policy decisions both in the United States and in other countries. As noted in *AEO2007*, energy markets are changing in response to readily observable factors, which include, among others: higher energy prices; the growing influence of developing countries on worldwide energy requirements; recently enacted legislation and regulations in the United States; changing public perceptions on issues related to emissions of air pollutants and greenhouse gases (GHGs) and the use of alternative fuels and; and the economic viability of various energy technologies.

Projections in the *AEO2008* reference case have been updated to better reflect trends that are expected to persist in the economy and in energy markets. For example, the projection for U.S. economic growth, a key determinant of U.S. energy demand, is lower in *AEO2008* than it was in *AEO2007*, reflecting an updated assumption for productivity improvement. Other key changes in the *AEO2008* projections include:

- Higher price projections for crude oil and natural gas
- Higher projections for delivered energy prices, reflecting both higher wellhead and minemouth prices and higher costs to transport, distribute, and refine fuels per unit supplied
- Slower projected growth in energy demand (particularly for natural gas but also for liquid fuels and coal)
- Faster projected growth in the use of nonhydroelectric renewable energy, resulting from a revised representation of State renewable portfolio standard (RPS) provisions
- Higher projections for domestic oil production, particularly in the near term
- Slower projected growth in energy imports, both natural gas and oil
- Slower projected growth in energy-related emissions of carbon dioxide (CO_2).

Coal, liquid fuels (excluding the biofuels portion of total liquids supply), and natural gas meet 80 percent of total U.S. primary energy supply requirements in 2030—down from an 85-percent share in 2006, reflecting the incorporation of EISA2007 provisions, slower economic growth, higher energy prices, lower total energy demand, and increased use of renewable energy when compared with *AEO2007*.

Economic Growth

The *AEO2008* reference case reflects reduced expectations for economic growth: U.S. gross domestic product (GDP) grows at an average annual rate of 2.4 percent from 2006 to 2030—0.4 percentage points slower than the rate in the *AEO2007* reference case over the same period. The main factor contributing to the slower rate of growth in GDP is a lower estimate of growth in labor productivity. Nonfarm business labor productivity grows by 1.9 percent per year in the *AEO2008* reference case, compared with 2.3 percent per year in *AEO2007*. Nonfarm employment growth is 0.9 percent per year in the *AEO2008* reference case, about the same as in *AEO2007*. From 2006 to 2030, total industrial shipments grow by

Impacts of Updating the AEO2008 Reference Case

EIA's decision to update the *AEO2008* early-release reference case was motivated by the enactment in December 2007 of EISA2007, which contains many provisions that will significantly influence future energy trends. The specific EISA2007 provisions modeled in *AEO2008* include updates to the renewable fuel standard (RFS) and the corporate average fuel economy (CAFE) standard for new light-duty vehicles (LDVs); updated and new appliance energy efficiency standards for boilers, dehumidifiers, dishwashers, clothes washers, and commercial walk-in refrigerators and freezers; lighting energy efficiency standards; provisions to reduce energy consumption in Federal buildings; and efficiency standards for industrial electric motors.

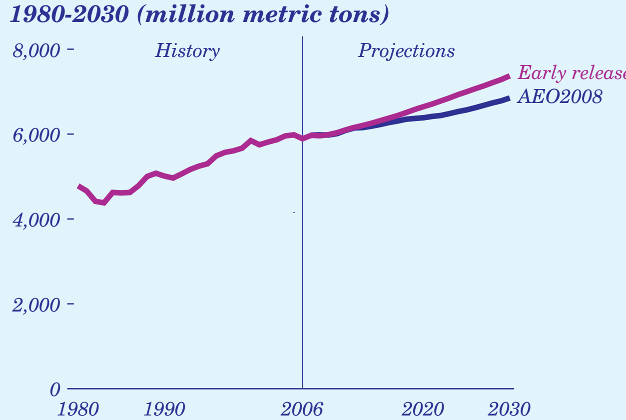
Consistent with the general approach used in past *AEO*s, the reference case does not consider those sections of EISA2007 that require appropriations for implementation or sections with highly uncertain impacts on energy markets. It also includes additional revisions that reflect historical data issued after the *AEO2008* early-release reference case was completed, new data from EIA's January 2008 *Short-Term Energy Outlook* (*STEO*), a more current economic outlook, and technical updates to the earlier version of NEMS.

Total energy consumption and greenhouse gas emissions

EISA2007 has a significant impact on both projected total energy consumption and GHG emissions. Total primary energy consumption in the *AEO2008* reference case grows by 18.5 quadrillion British thermal units (Btu), from 99.5 quadrillion Btu in 2006 to 118.0 quadrillion Btu in 2030—5.3 quadrillion Btu less than in the early-release reference case. Although other changes were also made, the inclusion of EISA2007 is by far the most important. In 2030, the projected consumption levels for liquid fuels, natural gas, and coal all are lower in the *AEO2008* reference case than they were in the early-release case.

Without the application of carbon capture and sequestration (CCS) technology, CO_2 emissions from the combustion of fossil fuels are proportional to the consumption and carbon content of the fuels. Inclusion of EISA2007 provisions in the *AEO2008* reference case both reduces total energy consumption and shifts consumption to fuels that are less carbon-intensive or are carbon-neutral. As a result, the projection for total energy-related CO_2 emissions in 2030 is 6,851 million metric tons in the *AEO2008* reference case, as compared with 7,373 million metric tons in the early-release reference case—a difference of 7 percent or 522 million metric tons (see figure below). The difference between the two cases grows over time, so that cumulative energy-related CO_2 emissions over the period from 2008 to 2030 are 5.3 billion metric tons lower in the *AEO2008* reference case than in the early-release reference case.

Total annual carbon dioxide emissions in the early-release and AEO2008 reference cases, 1980-2030 (million metric tons)



Liquid fuels consumption and imports

The combination of a higher CAFE standard for new LDVs and an updated RFS has a substantial impact on the level and mix of liquids consumption. Total liquids consumption[a] in 2030 in the *AEO2008* reference case, including the impact of EISA2007, is 22.8 million barrels per day—2.1 million barrels per day lower than in the early-release reference case.

Conventional petroleum consumption in 2030, excluding biofuels but including coal-to-liquids (CTL) diesel (a nonrenewable fuel), is 2.9 million barrels per day less in the *AEO2008* reference case. On an energy basis, total liquids consumption is 44.0 quadrillion Btu in 2030 in the *AEO2008* reference case, about 9 percent lower than projected in the early-release case.

(continued on page 4)

[a]Liquid fuels include conventional petroleum products, ethanol, biodiesel, diesel from biomass, CTL, and gas-to-liquids.

1.3 percent per year in the *AEO2008* reference case, as compared with 2.0 percent per year in *AEO2007*.

Energy Prices

EIA raised the reference case path for world oil prices in *AEO2008* (although the upward adjustment is smaller than the last major adjustment, introduced in *AEO2006*). The real world crude oil price (which for the purposes of *AEO2008* is defined as the price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, in 2006 dollars) declines gradually from current levels to $57 per barrel in 2016 ($68 per barrel in nominal dollars), as expanded investment in exploration and development brings new supplies to world markets. After 2016, real prices begin to rise (Figure 1), as demand continues to grow and higher cost supplies are brought to market. In 2030, the average real price of crude oil is $70 per barrel in 2006 dollars, or about $113 per barrel in nominal dollars. Alternative *AEO2008* cases address higher and lower world crude oil prices.

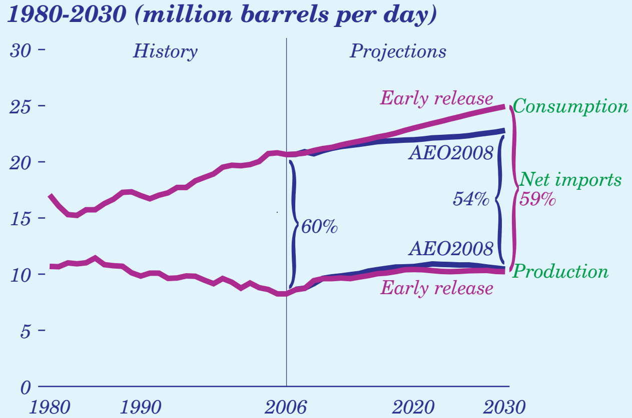
In developing its oil price outlook, EIA explicitly considered four factors: (1) growth in world liquids consumption; (2) the outlook for conventional oil production in countries outside the Organization of the Petroleum Exporting Countries (OPEC); (3) growth

Impacts of Updating the AEO2008 Reference Case (continued)

In the *AEO2008* reference case, because a large share of the biofuels consumed is produced domestically, net imports of liquid fuels (including both crude oil and products) are reduced by more relative to the early-release case than is total liquids consumption. Total net imports of liquids in 2030 are 2.4 million barrels per day lower in the *AEO2008* reference case than in the early-release case. As shown in the figure below, U.S. dependence on net imports of liquid fuels (including crude oil and refined liquids) on a volumetric basis declines in the *AEO2008* reference case from 60 percent in 2006 to 51 percent in 2022, followed by an increase to 54 percent in 2030—as compared with 59 percent in the early-release reference case. Even with the increase in biofuel use and the higher vehicle efficiency standards, however, petroleum products still account for 88 percent of total transportation energy consumption in the *AEO2008* reference case, compared with 96 percent in 2006.

The fuel mix for vehicles also changes between the two cases. The figure below shows the mix of fuels for LDVs in 2030 on an energy basis in the two cases. Biofuel consumption, excluding CTL, reaches 2.0 quadrillion Btu (23.5 billion gallons) in 2030, or about 11 percent of total demand for motor vehicle fuel in the *AEO2008* reference case—an increase of 0.6 quadrillion Btu (7.1 billion gallons) from the early-release reference case and 1.6 quadrillion Btu (18.2 billion gallons) more than in 2006. The increase in the *AEO2008* reference case includes more ethanol consumption—both ethanol blended with gasoline in E10 (gasoline containing up to 10 percent ethanol by volume) and as E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume)—and more biodiesel consumption than in the early-release projection.

U.S. liquids supply, consumption, and net imports in the early-release and AEO2008 reference cases, 1980-2030 (million barrels per day)



Light-duty vehicle energy use by fuel in the early-release and AEO2008 reference cases, 2030 (quadrillion Btu)

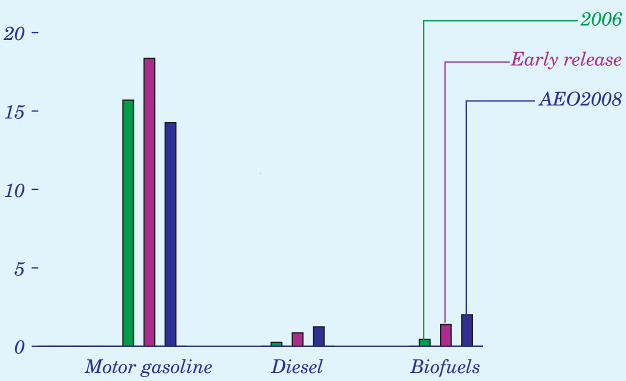
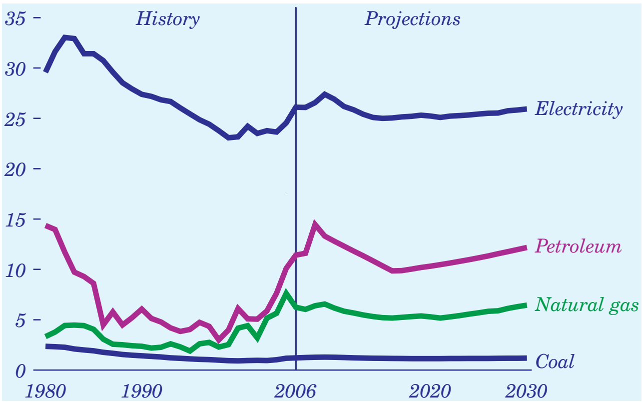


Figure 1. Energy prices, 1980-2030 (2006 dollars per million Btu)



in unconventional liquids production; and (4) OPEC behavior. With the forces driving demand outside the United States as strong as, or stronger than, previously expected but with global supply projections somewhat weaker, oil prices in *AEO2008* are higher than projected in *AEO2007* [*2*].

As a result of recent strong economic growth worldwide, transitory shortages of experienced personnel, equipment, and construction materials in the oil industry, and political instability in some major producing regions, oil prices currently are above EIA's estimate of the long-run equilibrium price. EIA's expectations regarding the ultimate size of both conventional and unconventional liquid resources have not changed since last year's *AEO*.

The *AEO2008* reference case represents EIA's current judgment about the most likely behavior of key OPEC members in the mid-term. In the projection, OPEC countries increase production at a rate that keeps their market share of world liquids production at approximately 40 percent through 2030.

The *AEO2008* reference case also projects significant long-term potential for supply from non-OPEC producers. In several resource-rich regions—including Brazil, Azerbaijan, and Kazakhstan—high oil prices, expanded infrastructure, and new exploration and drilling technologies permit additional non-OPEC oil production. Also, with the economic viability of Canada's oil sands enhanced by higher world oil prices and advances in production technology, oil sands production is expected to reach 4 million barrels per day in 2030.

The price of natural gas also is higher in the *AEO2008* reference case. The real wellhead price of natural gas (in 2006 dollars) declines from current levels through 2016, as new supplies enter the market. After some fluctuations through 2021, real natural gas prices rise to $6.63 per thousand cubic feet in 2030 ($10.64 per thousand cubic feet in nominal dollars). The higher prices in the *AEO2008* reference case reflect an increase in production costs associated with recent trends that were discussed in *AEO2007* but were not reflected fully in the *AEO2007* reference case [*3*]. The higher natural gas prices also are supported by higher oil prices.

Minemouth coal prices in the *AEO2008* reference case, both nationally and regionally, are generally similar to those projected in the *AEO2007* reference case. By region, the largest price difference is for Wyoming's Powder River Basin, where the projected average minemouth price in 2030 is 12.1 percent above the *AEO2007* projection, at $0.66 (2006 dollars) per million Btu, reflecting a less optimistic outlook for improvements in coal mining productivity.

Average real minemouth coal prices (in 2006 dollars) fall from $1.21 per million Btu ($24.63 per short ton) in 2006 to $1.14 per million Btu ($22.45 per short ton) in 2018 in the *AEO2008* reference case, as prices moderate following a substantial run-up over the past few years. After 2020, coal prices rise as demand increases, reaching $1.19 per million Btu ($23.32 per short ton) in 2030. The 2020 and 2030 price projections are 2.6 percent and 0.9 percent higher, respectively, than those in the *AEO2007* reference case. Without adjustment for inflation, the average minemouth price of coal in the *AEO2008* reference case is $1.91 per million Btu ($37.42 per ton) in 2030.

AEO2008 projects higher prices for most energy fuels delivered to consumers. For example, in 2030, the average delivered price of natural gas (in 2006 dollars) is more than $1 per million Btu higher in the *AEO2008* reference case than was projected in *AEO2007*. In part, the higher delivered prices result from higher prices paid to fossil fuel producers at the wellhead or minemouth; but they also result from updates made to assumptions about the costs to transport, distribute, and refine the fuels to make them more consistent with recent trends. For example, as a result of declining use per customer and the growing cost of bringing supplies from new regions to market, margins between the delivered and wellhead prices of natural gas are higher than previously projected. Factors contributing to higher margins for liquid fuels include continued growth in the use of heavier and sourer crudes, growing demand for cleaner products, and the rising cost of refinery safety and emissions abatement.

Increases in diesel fuel prices in recent years have led railroads to implement fuel adjustment surcharges on coal shipments, which are incorporated in the *AEO2008* reference case. The average real delivered price of coal to power plants (in 2006 dollars) increases from $1.69 per million Btu ($33.85 per short ton) in 2006 to $1.78 per million Btu ($35.03 per short ton) in 2030, 2.3 percent higher than in the *AEO2007* reference case. In nominal dollars, the average delivered price of coal to power plants is projected to reach $2.86 per million Btu ($56.22 per short ton) in 2030.

Electricity prices follow trends in the delivered prices of fuels to power plants in the reference case. From a peak of 9.3 cents per kilowatthour (2006 dollars) in 2009, average delivered electricity prices decline to 8.5 cents per kilowatthour in 2015 and then increase to 8.8 cents per kilowatthour in 2030. In the *AEO2007* reference case, with slightly lower expectations for delivered fuel prices and construction costs for all new technologies, electricity prices reached 8.3 cents per kilowatthour (2006 dollars) in 2030. In nominal dollars, the average delivered electricity price in the *AEO2008* reference case reaches 14.1 cents per kilowatthour in 2030.

Energy Consumption by Sector

Total primary energy consumption in the *AEO2008* reference case grows by 19 percent between 2006 and 2030 (an average rate of 0.7 percent per year), from 99.5 quadrillion Btu in 2006 to 118.0 quadrillion Btu in 2030—13.2 quadrillion Btu less than in the *AEO2007* reference case. In 2030, the levels of consumption projected for liquid fuels, natural gas, and coal are lower in the *AEO2008* reference case than they were in the *AEO2007* reference case. Among the most important factors leading to lower total energy demand in the *AEO2008* reference case are lower economic growth, greater use of more efficient appliances and vehicles, higher energy prices, and slower growth in energy-intensive industries.

Residential delivered energy consumption in the *AEO2008* reference case grows from 10.8 quadrillion Btu in 2006 to 12.9 quadrillion Btu in 2030, or by 0.7 percent per year (Figure 2). Higher delivered energy prices, slower growth in the housing stock, increases in lighting efficiency to meet the standards established in EISA2007, and a revised accounting of heating and cooling degree-days to better reflect recent temperature trends contribute to the lower level of residential energy use in the *AEO2008* projection, which is 0.9 quadrillion Btu lower than the *AEO2007* projection.

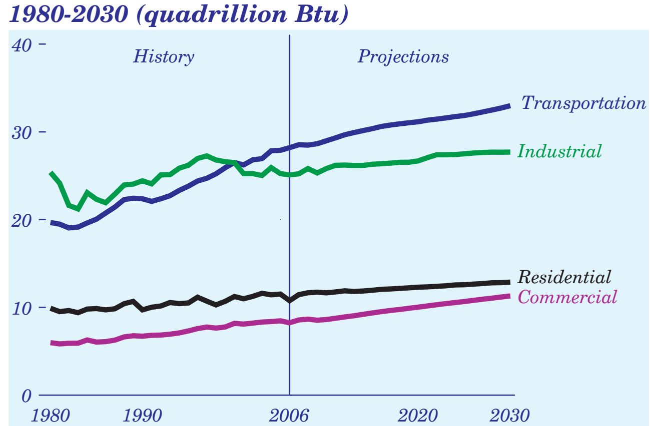
Higher delivered energy prices and slower growth in commercial square footage lead to slower growth in commercial energy consumption in the *AEO2008* reference case than in the *AEO2007* reference case. Delivered commercial energy consumption grows from 8.3 quadrillion Btu in 2006 to 11.3 quadrillion Btu in 2030, over 1 quadrillion Btu less than in the *AEO2007* reference case.

Since 1997, delivered energy consumption in the U.S. industrial sector has trended downward, falling from about 27 quadrillion Btu in 1997 to 25 quadrillion Btu in 2006, despite rising output. A number of factors have worked to reduce industrial energy consumption since 1997: economic weakness between 2000 and 2003, the hurricanes of 2005 that reduced activity in some industrial subsectors, and rising energy prices.

Industrial delivered energy consumption increases to 27.7 quadrillion Btu in 2030. Although the *AEO2008* reference case includes steady economic growth and declining energy prices in the near term, growth in the energy-intensive industries continues to be weak, reflecting increased competition from foreign regions with lower relative energy prices. Growth in the energy-intensive U.S. manufacturing industries averages 0.7 percent per year from 2006 to 2030, slower than the 1.3-percent average growth in *AEO2007*.

Delivered energy consumption in the transportation sector grows to 33.0 quadrillion Btu in 2030 in the *AEO2008* reference case, 6.3 quadrillion Btu less than in *AEO2007*. The lower projected level of consumption predominantly reflects the influence of the new

Figure 2. Delivered energy consumption by sector, 1980-2030 (quadrillion Btu)



CAFE standard for LDVs specified in EISA2007 and slower economic growth, as well as the impact of higher fuel prices.

EISA2007 requires new LDVs, including both cars and trucks, to reach a combined average fuel economy of 35 miles per gallon (mpg) by 2020, based on the U.S. Environmental Protection Agency (EPA) test value used to measure compliance with the CAFE standard. The EPA CAFE test value generally differs from the estimated mpg value on the fuel economy label and, typically, exceeds the actual on-the-road fuel economy of a new vehicle by a significant margin. Despite these differences, the higher fuel economy standards in EISA2007 significantly improve the in-use fuel economy of the LDV stock. In the reference case, the average in-use fuel economy for the stock of LDVs in 2030 increases to 27.9 mpg, almost 40 percent above its 2006 level. To attain these fuel economy levels, the projection reflects increases in the sale of unconventional vehicle technologies [*4*], such as flex-fuel, hybrid, and diesel vehicles, and a slowdown in the growth of new light truck sales.

Energy Consumption by Primary Fuel

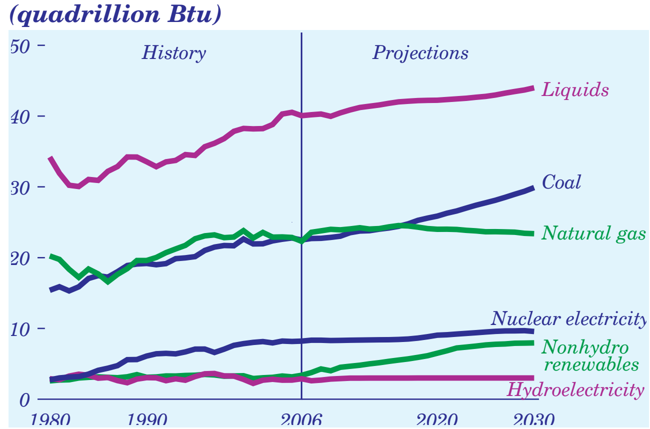
Total consumption of liquid fuels, including both fossil liquids and biofuels, grows from 20.7 million barrels per day in 2006 to 22.8 million barrels per day in 2030 in the *AEO2008* reference case (Figure 3), less than the *AEO2007* reference case projection of 26.9 million barrels per day in 2030. Liquid fuels consumption is lower in all sectors in *AEO2008* than in the *AEO2007* reference case, as a result of incorporation of the new LDV CAFE standard specified in EISA-2007, slower economic growth, and higher delivered prices for liquid fuels. Much of the difference is in the transportation sector.

In *AEO2008*, natural gas consumption increases from 21.7 trillion cubic feet in 2006 to 23.8 trillion cubic feet in 2016, then declines to 22.7 trillion cubic in 2030 (Figure 3). The projection for natural gas consumption in the *AEO2008* reference case is sharply lower than in *AEO2007*, where consumption grew to 26.1 trillion cubic feet in 2030. Consumption is lower in all sectors in *AEO2008*, and particularly in the industrial and electricity power sectors. Industrial natural gas use is 1.7 trillion cubic feet lower in 2030 in the *AEO2008* reference case (8.1 trillion cubic feet, compared with 9.8 trillion cubic feet in *AEO2007*), as a result of higher delivered prices for natural gas, lower economic growth, and a reassessment of natural gas use in the energy-intensive industries. In *AEO2008*, electricity generation accounts for 5.0 trillion cubic feet of natural gas use in 2030, compared with the *AEO2007* projection of 5.9 trillion cubic feet. The lower level of consumption in *AEO2008* results from higher natural gas prices and slower growth in electricity demand.

Total coal consumption increases from 22.5 quadrillion Btu (1,114 million short tons) in 2006 to 29.9 quadrillion Btu (1,545 million short tons) in 2030 in the *AEO2008* reference case. As in the *AEO2007* reference case, coal consumption is projected to grow at a faster rate toward the end of the projection period, particularly after 2020, as coal use for new coal-fired generating capacity grows rapidly. In the *AEO2008* reference case, coal consumption in the electric power sector increases from 23.7 quadrillion Btu in 2020 to 27.5 quadrillion Btu in 2030, and coal use at CTL plants increases from 0.6 quadrillion Btu in 2020 to 1.0 quadrillion Btu in 2030. The projected increase in coal use for CTL plants is lower than in previous *AEO*s as a result of EISA2007, because investment dollars that previously would have gone into CTL capacity now flow to biomass-to-liquids (BTL) capacity; however, there is a great deal of uncertainty around this projection.

The *AEO2008* reference case projects substantially greater use of renewable energy than was projected in *AEO2007*. Total consumption of marketed renewable fuels—including ethanol for gasoline blending, biodiesel [*5*], and diesel from biomass [*6*], of which 2.8 quadrillion Btu in 2030 is included with liquids fuel consumption—grows by 3.0 percent per year in the reference case, from 6.8 quadrillion Btu in 2006 to 13.7 quadrillion Btu in 2030, compared with 9.9 quadrillion Btu in *AEO2007*. About 45 percent of the demand for renewables in 2030 is for grid-related

Figure 3. Energy consumption by fuel, 1980-2030 (quadrillion Btu)



electricity generation (including combined heat and power [CHP]).

The rapid growth in the use of renewable fuels for transportation in *AEO2008* reflects the EISA2007 RFS, which sets a requirement for 21 billion gallons of advanced biofuels and 36 billion gallons of total renewable fuels by 2022. Included are requirements for 1 billion gallons of biodiesel and 16 billion gallons of cellulosic biofuels, both of which count toward the advanced biofuels requirement. The remaining 4 billion gallons of advanced biofuels may come from any source. The difference between advanced biofuels and total renewable fuels may be met by corn ethanol. Diesel fuels derived from biomass feedstocks count for 1.5 times their physical volume in the calculation of credits toward the RFS requirements, because diesel has a higher energy content per gallon than ethanol does.

Although the situation is very uncertain, the current state of the industry and EIA's present view of projected rates of technology development and market penetration of cellulosic biofuel technologies suggest that available quantities of cellulosic biofuels before 2022 will be insufficient to meet the new RFS targets for cellulosic biofuels, triggering both waivers and a modification of applicable volumes, as provided for in Section 211(o) of the Clean Air Act as amended by EISA2007. The modification of volumes reduces the overall target in 2022 from 36 billion gallons to 32.5 billion gallons in the *AEO2008* reference case.

Ethanol use in the *AEO2008* reference case, grows from 5.6 billion gallons in 2006 to 23.9 billion gallons in 2030—about 16 percent of total gasoline consumption by volume and about 65 percent more than in *AEO2007*. Ethanol use for gasoline blending grows to 13.4 billion gallons and E85 consumption to 10.5 billion gallons in 2030. The ethanol supply is expected to be produced from both corn and cellulose feedstocks, with corn accounting for 15.0 billion gallons and cellulose 6.9 billion gallons of ethanol production in 2030. Biodiesel use increases to 1.2 billion gallons in 2030, or about 1.5 percent of total diesel consumption by volume. In addition, consumption of BTL diesel grows to 4.5 billion gallons in 2030, or 5.3 percent of total diesel consumption by volume.

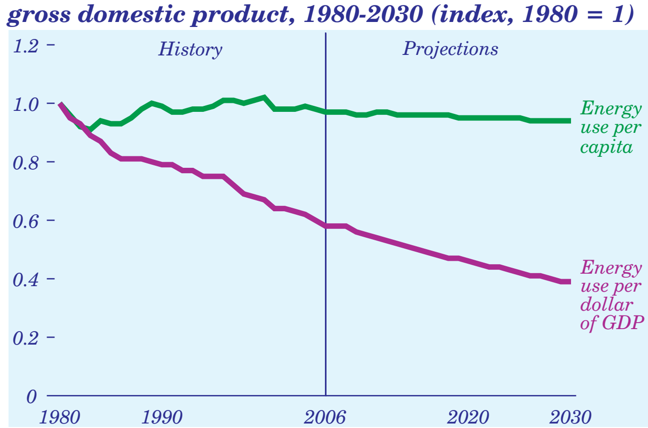
Excluding hydroelectricity, renewable energy consumption for electric power generation grows from 0.9 quadrillion Btu in 2006 to 3.2 quadrillion Btu in 2030, as compared with 2.1 quadrillion Btu in *AEO2007*. The higher level of nonhydroelectric renewable energy consumption in the *AEO2008* reference case reflects primarily a revised representation of State RPS programs, which require that specific and generally increasing shares of electricity sales be supplied by renewable resources, such as wind, solar, geothermal, and sometimes biomass or hydropower. Previous *AEO*s placed more weight on the "escape clauses" incorporated in many State RPS programs, given that the consumer costs of the programs would increase significantly if the Federal production tax credit (PTC) for qualifying renewable energy expired as provided for under current law. The new representation, which assumes that the State RPS goals will be met absent a clear contrary indication, results in significant additional growth of renewable generation from wind, biomass, and geothermal resources.

Energy Intensity

Energy intensity, measured as primary energy use (in thousand Btu) per dollar of GDP (in 2000 dollars), declines by about one-third from 2006 to 2030 in the *AEO2008* reference case (Figure 4). Although energy use generally increases as the economy grows, continuing improvement in the energy efficiency of the U.S. economy and a shift to less energy-intensive activities are projected to keep the rate of energy consumption growth lower than the rate of GDP growth.

Since 1992, the energy intensity of the U.S. economy has declined on average by 2.0 percent per year, in part because the share of industrial shipments accounted for by the energy-intensive industries has fallen from 30 percent in 1992 to 21 percent in 2006. In the *AEO2008* reference case, the energy-intensive industries' share of total industrial shipments continues to decline, although at a slower rate, to 18 percent in 2030.

Figure 4. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



Population is a key determinant of energy consumption, influencing demand for travel, housing, consumer goods, and services. Since 1990, the population has increased by about 20 percent and energy consumption by a comparable 18 percent in the United States, with annual variations in energy use per capita resulting from variations in weather and economic factors. The age, income, and geographic distribution of the population also affect the growth of energy consumption. Aging of the population, a gradual shift from the North to the South, and rising per-capita income will influence future trends. Overall, the U.S. population increases by 22 percent from 2006 to 2030 in the *AEO2008* reference case. Over the same period, energy consumption increases by 19 percent. The result is a decrease in energy consumption per capita at an annual rate of 0.1 percent per year from 2006 to 2030, a drop from the 0.3-percent yearly increase in the *AEO2007* reference case.

Recently, as energy prices have risen, the potential for more energy conservation has received increased attention. Although additional energy conservation is induced by higher energy prices in the *AEO2008* reference case and by the passage of EISA2007, no further policy-induced conservation measures are assumed beyond those in existing legislation and regulation, nor does the reference case assume behavioral changes beyond those observed in the past.

Energy Production and Imports

Net imports of energy are expected to continue meeting a major share of total U.S. energy demand (Figure 5). The increased use of biofuels resulting from EISA2007, much of which is domestically produced, and the reduction in demand for transportation fuels due to the new CAFE standards both serve to moderate growth in energy imports. Higher fuel prices over the projection period also spur increased domestic energy production (Figure 6) and moderate energy demand growth, further tempering growth in imports. The projected net import share of total U.S. energy consumption in 2030 is 27 percent, a decline from the 30-percent share in 2006.

The projection for U.S. crude oil production in the *AEO2008* reference case is higher than in the *AEO2007* reference case, primarily as a result of more production from the expansion of enhanced oil recovery (EOR) operations and, to a lesser extent, higher crude oil prices. U.S. crude oil production in the *AEO2008* reference case increases from 5.1 million barrels per day in 2006 to a peak of 6.3 million barrels per day in 2018, with production increases from the deep waters of the Gulf of Mexico and from onshore EOR projects. Domestic production subsequently declines to 5.6 million barrels per day in 2030, as increased production from new, smaller discoveries is inadequate to offset declines in production from large fields in Alaska and the Gulf of Mexico.

Total domestic liquids supply, including crude oil, natural gas plant liquids, refinery processing gains, and other refinery inputs (including ethanol, biodiesel, BTL, and liquids from coal) generally increase through 2022 in the *AEO2008* reference case, while imports of crude oil and other petroleum products remain flat. Total domestic liquids supply grows from 8.2 million barrels per day in 2006 to 10.4 million barrels per day in 2030.

In the *AEO2008* reference case, the net import share of total liquids supplied, including crude oil and refined products, drops from 60 percent in 2006 to 51 percent in 2022 and then increases to 54 percent in

Figure 5. Total energy production and consumption, 1980-2030 (quadrillion Btu)

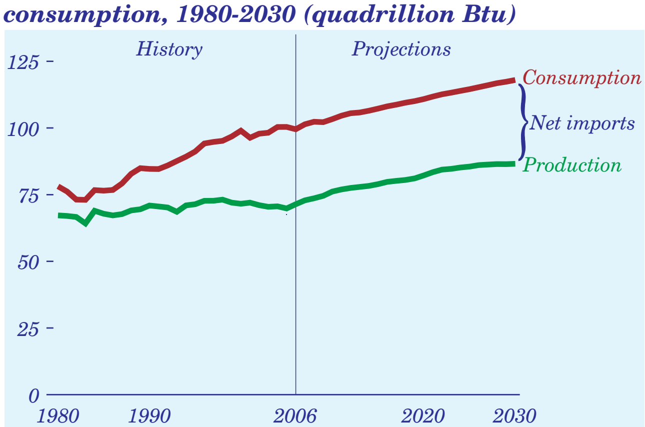
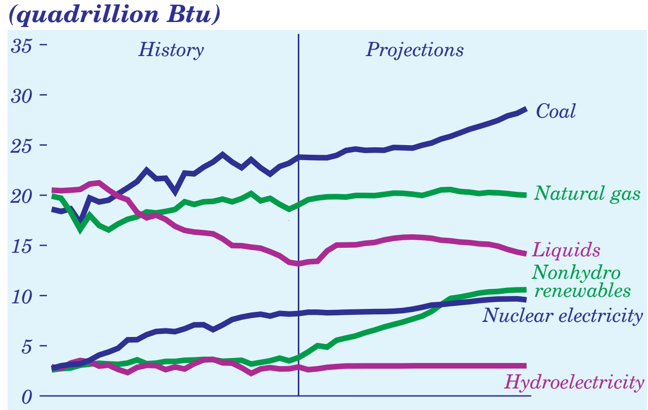


Figure 6. Energy production by fuel, 1980-2030 (quadrillion Btu)



2030. Net imports of crude oil and net imports of petroleum products in 2030 each are about 2.0 million barrels per day lower in the *AEO2008* reference case than in the *AEO2007* reference case. The primary reasons for the difference between the *AEO2008* and *AEO2007* projections for net imports of liquid fuels are a lower level of total liquids consumption and a higher level of biofuels consumption in the transportation sector in the *AEO2008* reference case.

Total domestic production of natural gas (including supplemental natural gas supplies) increases from 18.6 trillion cubic feet in 2006 to 20.0 trillion cubic feet in 2022 before declining to 19.5 trillion cubic feet in 2030 in the *AEO2008* reference case. The projections are lower than in the *AEO2007* reference case, which showed production increasing to 20.6 trillion cubic feet in 2030, primarily because of higher costs associated with exploration and development and, particularly in the last decade of the projection, lower demand for natural gas in *AEO2008*. Onshore production of unconventional natural gas is expected to be a key contributor to the growth in U.S. supply, increasing from 8.5 trillion cubic feet in 2006 to a peak of 9.6 trillion cubic feet in 2018 and generally holding at about that level through 2030.

The Alaska natural gas pipeline is expected to be completed in 2020 (2 years later than in the *AEO2007* reference case, because of delays in the resolution of issues between Alaska's State government and industry participants). After the pipeline goes into operation, Alaska's total natural gas production in the *AEO2008* reference case increases to 2.0 trillion cubic feet in 2021 (from 0.4 trillion cubic feet in 2006) and then remains at that level through 2030.

Net pipeline imports of natural gas from Canada and Mexico fall from 2.9 trillion cubic feet in 2006 to 0.3 trillion cubic feet in 2030 in the *AEO2008* reference case (compared with the *AEO2007* projection of 0.9 trillion cubic feet in 2030). The difference between the 2030 projections in *AEO2008* and *AEO2007* is largely the result of a higher level of exports to Mexico and lower demand in the United States.

Total net imports of LNG to the United States in the *AEO2008* reference case increase from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030, as compared with 4.5 trillion cubic feet in 2030 in *AEO2007*. The lower projection is attributable to two factors: higher costs throughout the LNG industry, especially in the area of liquefaction, and decreased U.S. natural gas consumption due to higher natural gas prices, slower economic growth, and expected greater competition for supplies in the global LNG market.

The future direction of the global LNG market is one of the key uncertainties in the *AEO2008* reference case. With many new international players entering LNG markets, the competition for available supplies is strong, and the amounts available to the U.S. market may vary considerably from year to year. The *AEO2008* reference case has been updated to reflect current market dynamics, which could change considerably as worldwide LNG markets evolve.

As domestic coal demand grows in the *AEO2008* reference case, U.S. coal production (excluding waste coal) increases at an average rate of 0.8 percent per year, from 23.8 quadrillion Btu (1,163 million short tons) in 2006 to 28.6 quadrillion Btu (1,455 million short tons) in 2030—15 percent less than in the *AEO2007* reference case. Production from mines west of the Mississippi River provides the largest share of the incremental coal production. On a Btu basis, 59 percent of domestic coal production originates from States west of the Mississippi River in 2030, up from 49 percent in 2006.

Typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 91 percent of total coal consumption. Coal consumption in the electric power sector in the *AEO2008* reference case, at 27.5 quadrillion Btu in 2030, is less than in the *AEO2007* reference case (31.1 quadrillion Btu in 2030). Slower growth in overall electricity demand, combined with more generation from nuclear and renewable energy, underlies the reduced outlook for electricity sector coal consumption. Another emerging market for coal is CTL. Coal use in CTL plants grows from 0.6 quadrillion Btu (42 million short tons) in 2020 to 1.0 quadrillion Btu (64 million short tons) in 2030.

Electricity Generation

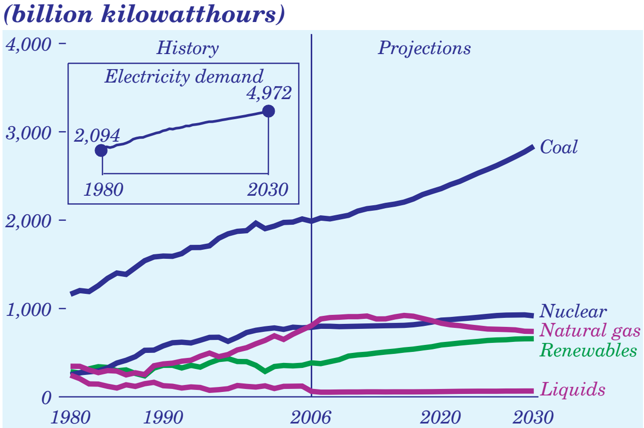
Total electricity consumption, including both purchases from electric power producers and on-site generation, grows from 3,814 billion kilowatthours in 2006 to 4,972 billion kilowatthours in 2030, increasing at an average annual rate of 1.1 percent in the *AEO2008* reference case. In comparison, electricity consumption grew by annual rates of 4.2 percent, 2.6 percent, and 2.3 percent in the 1970s, 1980s, and 1990s, respectively. The growth rate in the *AEO2008* projection is lower than in the *AEO2007* reference case (1.5 percent per year). The reduced rate of growth in *AEO2008* results from slower economic growth, the imposition of new efficiency standards in EISA2007, and higher electricity prices.

In the *AEO2008* reference case, electricity generation from natural-gas-fired power plants increases sharply from 2006 to 2008 and then remains relatively stable for the next decade, growing by 3 percent from 2008 to 2016—less rapidly than in the *AEO2007* reference case. After 2016, however, generation from new coal, nuclear, and renewable plants displaces some natural-gas-fired generation (Figure 7). In the *AEO2008* reference case, 741 billion kilowatthours of electricity is generated from natural gas in 2030, 21 percent less than the 937 billion kilowatthours in 2030 in the *AEO2007* reference case.

In the *AEO2008* reference case, the natural gas share of electricity generation (including generation in the end-use sectors) remains between 20 percent and 21 percent through 2017 before falling to 14 percent in 2030. The coal share remains between 48 percent and 49 percent from 2006 through 2018 before increasing to 54 percent in 2030. Additions to coal-fired generating capacity in the *AEO2008* reference case total 104 gigawatts from 2006 to 2030 (as compared with 156 gigawatts in the *AEO2007* reference case), including 4 gigawatts at CTL plants and 29 gigawatts at integrated gasification combined-cycle plants. Given the assumed continuation of current energy and environmental policies in the reference case, CCS technology does not come into use during the projection period.

Nuclear generating capacity in the *AEO2008* reference case increases from 100.2 gigawatts in 2006 to 114.9 gigawatts in 2030. The increase includes 17 gigawatts of capacity at newly built nuclear power plants (33 percent more than in the *AEO2007* reference case) and 2.7 gigawatts expected from uprates of existing plants, partially offset by 4.5 gigawatts of retirements.

Figure 7. Electricity generation by fuel, 1980-2030 (billion kilowatthours)



Rules issued by the Internal Revenue Service in 2006 for the EPACT2005 PTC for new nuclear plants allow the credits to be shared out on a prorated basis to more than 6 gigawatts of new capacity. In the *AEO2008* reference case the credits are shared out to 8 gigawatts of new nuclear capacity, and another 9 gigawatts of capacity is built without credits.

Total electricity generation from nuclear power plants grows from 787 billion kilowatthours in 2006 to 917 billion kilowatthours in 2030 in the *AEO2008* reference case, accounting for about 18 percent of total generation in 2030. Additional nuclear capacity is built in some of the alternative *AEO2008* cases, particularly those that project higher demand for electricity or higher fossil fuel prices.

The use of renewable technologies for electricity generation is stimulated by improved technology, higher fossil fuel prices, and short-term extensions of the EPACT2005 tax credits. The reference case also includes State RPS programs for which legislation is in place. Total renewable generation in the *AEO2008* reference case, including CHP and end-use generation, grows by 2.2 percent per year, from 385 billion kilowatthours in 2006 to 656 billion kilowatthours in 2030. The projection for renewable generation in the *AEO2008* reference case, which includes State and regional programs, is significantly higher than the *AEO2007* projection.

Energy-Related Carbon Dioxide Emissions

Absent the application of CCS technology (which is not expected to come into use without changes in current policies that are not included in the reference case), CO_2 emissions from the combustion of fossil fuels are proportional to fuel consumption and carbon content, with coal having the highest carbon content, natural gas the lowest, and liquid fuels in between. In the *AEO2008* reference case, the coal share of total energy use increases from 23 percent in 2006 to 25 percent in 2030, while the share of natural gas falls from 22 percent to 20 percent, and the liquids share falls from 40 percent to 37 percent. The combined share of carbon-neutral renewable and nuclear energy grows from 15 percent in 2006 to 17 percent in 2030.

Taken together, projected growth in the absolute level of primary energy consumption and a shift toward a fuel mix with slightly lower average carbon content cause projected energy-related emissions of CO_2 (Figure 8) to grow by 16 percent from 2006 to 2030—slightly lower than the projected 19-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive, because the 16-percent increase in CO_2 emissions is about one-fifth of the projected increase in GDP (79 percent), and emissions per capita decline by 5 percent. In the *AEO2008* reference case, projected energy-related CO_2 emissions grow from 5,890 million metric tons in 2006 to 6,851 million metric tons in 2030. By comparison, in the *AEO2007* reference case, energy-related CO_2 emissions were projected to grow by about 35 percent, to 7,950 million metric tons in 2030, reflecting both a higher projection of overall energy use and, to a lesser extent, a different mix of energy sources.

Figure 8. U.S. carbon dioxide emissions by sector and fuel, 1990-2030 (million metric tons)

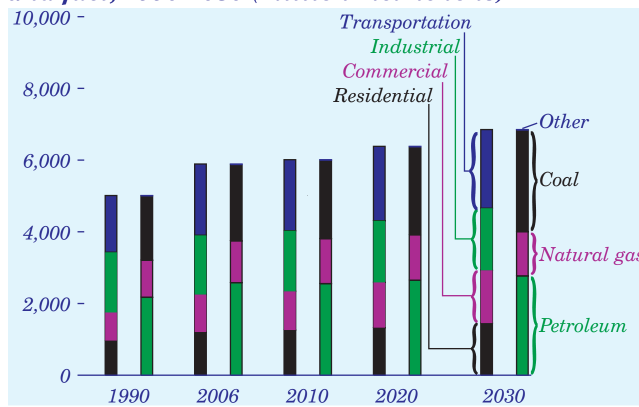


Table 1. Total energy supply and disposition in the *AEO2008* and *AEO2007* reference cases, 2006-2030

Energy and economic factors	2006	2010 *AEO2008*	2010 *AEO2007*	2020 *AEO2008*	2020 *AEO2007*	2030 *AEO2008*	2030 *AEO2007*
Primary energy production (quadrillion Btu)							
Petroleum	13.16	15.03	14.42	15.71	14.85	14.15	13.71
Dry natural gas	19.04	19.85	19.93	20.24	21.41	20.00	21.15
Coal	23.79	23.97	24.47	25.2	26.61	28.63	33.52
Nuclear electricity	8.21	8.31	8.23	9.05	9.23	9.57	9.33
Hydroelectricity	2.89	2.92	3.02	3.00	3.08	3.00	3.09
Biomass	2.94	4.05	4.22	6.42	4.69	8.12	5.26
Other renewable energy	0.88	1.51	1.18	2.00	1.33	2.45	1.44
Other	0.50	0.54	0.67	0.58	0.89	0.64	1.12
Total	**71.41**	**76.17**	**76.13**	**82.21**	**82.09**	**86.56**	**88.63**
Net imports (quadrillion Btu)							
Petroleum	26.69	23.93	25.19	24.03	28.92	26.52	34.74
Natural gas	3.56	3.96	4.67	3.66	5.48	3.28	5.59
Coal/other (- indicates export)	-0.28	-0.84	-0.19	1.06	0.93	1.86	1.57
Total	**29.98**	**27.04**	**29.66**	**28.75**	**35.33**	**31.66**	**41.90**
Consumption (quadrillion Btu)							
Liquid fuels	40.06	40.46	41.76	42.24	46.52	43.99	52.17
Natural gas	22.30	23.93	24.73	24.01	27.04	23.39	26.89
Coal	22.50	23.03	24.24	25.87	27.29	29.90	34.14
Nuclear electricity	8.21	8.31	8.23	9.05	9.23	9.57	9.33
Hydroelectricity	2.89	2.92	3.02	3.00	3.08	3.00	3.09
Biomass	2.50	3.01	3.30	4.50	3.64	5.51	4.06
Other renewable energy	0.88	1.51	1.18	2.00	1.33	2.45	1.44
Net electricity imports	0.19	0.18	0.04	0.17	0.04	0.20	0.04
Total	**99.50**	**103.30**	**106.50**	**110.80**	**118.16**	**118.00**	**131.16**
Liquid fuels (million barrels per day)							
Domestic crude oil production	5.10	5.93	5.67	6.23	5.89	5.59	5.39
Other domestic production	3.19	3.69	4.03	4.46	4.49	4.85	5.08
Net imports	12.45	11.39	11.79	11.36	13.56	12.41	16.37
Consumption	20.65	20.99	21.59	21.96	24.03	22.80	26.95
Natural gas (trillion cubic feet)							
Production	18.57	19.35	19.42	19.73	20.86	19.49	20.61
Net imports	3.46	3.85	4.55	3.55	5.35	3.18	5.45
Consumption	21.66	23.25	24.02	23.33	26.26	22.72	26.12
Coal (million short tons)							
Production	1,177	1,179	1,202	1,281	1,336	1,467	1,704
Net imports	-15	-34	-7	46	41	78	68
Consumption	1,114	1,145	1,195	1,327	1,377	1,545	1,772
Prices (2006 dollars)							
Imported low-sulfur, light crude oil (dollars per barrel)	66.02	74.03	59.23	59.70	53.64	70.45	60.93
Imported crude oil (dollars per barrel)	59.05	65.18	52.76	51.55	47.89	58.66	53.21
Domestic natural gas at wellhead (dollars per thousand cubic feet)	6.42	6.33	5.93	5.44	5.39	6.63	6.16
Domestic coal at minemouth (dollars per short ton)	24.63	26.16	24.94	22.51	22.24	23.32	23.29
Average electricity price (cents per kilowatthour)	8.9	9.2	8.3	8.6	8.1	8.8	8.3
Economic indicators							
Real gross domestic product (billion 2000 dollars)	11,319	12,453	12,790	15,984	17,077	20,219	22,494
GDP chain-type price index (index, 2000=1.000)	1.166	1.26	1.253	1.52	1.495	1.871	1.815
Real disposable personal income (billion 2000 dollars)	8,397	9,472	9,568	12,654	13,000	16,246	17,535
Value of manufacturing shipments (billion 2000 dollars)	5,821	5,997	6,298	7,113	7,779	7,997	9,502
Primary energy intensity (thousand Btu per 2000 dollar of GDP)	**8.79**	**8.30**	**8.33**	**6.93**	**6.92**	**5.84**	**5.83**
Carbon dioxide emissions (million metric tons)	**5,890**	**6,011**	**6,214**	**6,384**	**6,944**	**6,851**	**7,950**

Notes: Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity. For nuclear electricity, both production and consumption numbers are based on its fossil-fuel-equivalent energy content.

Sources: AEO2008 National Energy Modeling System, run AEO2008.D030208F; and AEO2007 National Energy Modeling System, run AEO2007.D112106A.

Legislation and Regulations

Legislation and Regulations

Introduction

Because analyses by EIA are required to be policy-neutral, the projections in *AEO2008* are based on Federal and State laws and regulations in effect on or before December 31, 2007. **The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself—are not reflected in the projections.** Throughout 2007, however, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports (see box on page 17).

Examples of Federal and State legislation incorporated in *AEO2008* include:

- EISA2007, signed into law on December 19, 2007, which (*a*) includes an expanded RFS requiring the use of 36 billion gallons of ethanol by 2022; (*b*) creates an attribute-based minimum CAFE standard of 35 mpg by 2020 for cars and trucks; (*c*) establishes a program of CAFE credit trading and transfer; (*d*) extends and then phases out the CAFE credits established under the Alternative Motor Fuels Act of 1988 (AMFA); (*e*) creates various appliance efficiency standards; (*f*) establishes a lighting efficiency standard starting in 2012; (*g*) requires industrial electric motors to meet the premium motor efficiency standards of the National Electrical Manufacturers Association (NEMA); and (*h*) creates or enhances a number of other programs related to industrial waste heat or natural gas efficiency, energy use in Federal buildings, weatherization assistance, and manufactured housing (see below for more detailed discussion of the provisions in EISA2007 and their handling in *AEO2008*)
- The provisions of EPACT2005 that remain in effect and have not been superseded by EISA2007, including: mandatory energy conservation standards; numerous tax credits for businesses and individuals; elimination of the oxygen content requirement for Federal reformulated gasoline (RFG); extended royalty relief for offshore oil and natural gas producers; authorization for DOE to issue loan guarantees for new or improved technology projects that avoid, reduce, or sequester GHGs; a PTC for new nuclear facilities; and extension and expansion of the PTC for electricity generated from renewable fuels
- The Military Construction Appropriations Act of 2005, which contains provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction
- The Working Families Tax Relief Act of 2004, which includes tax deductions for qualified clean-fuel and electric vehicles and changes in the rules governing oil and natural gas well depletion
- The American Jobs Creation Act of 2004, which includes incentives and tax credits for biodiesel fuels and a modified depreciation schedule for the Alaska natural gas pipeline
- State RPS programs, including the California RPS passed on September 12, 2002
- The Clean Air Act Amendments of 1990 (CAAA-90), which included new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The National Appliance Energy Conservation Act of 1987
- State programs for restructuring of the electricity industry.

Examples of Federal and State regulations incorporated in *AEO2008* include the following:

- The Mobile Source Air Toxics rule released by the EPA on February 9, 2007 (MSAT2), which establishes controls on gasoline, passenger vehicles, and portable fuel containers designed to significantly reduce emissions of benzene and other hazardous air pollutants [*7*]
- New stationary diesel regulations issued by the EPA on July 11, 2006, which limit emissions of nitrogen oxides (NO_x), particulate matter, sulfur dioxide (SO_2), carbon monoxide, and hydrocarbons to the same levels required by the EPA's nonroad diesel engine regulations.

More detailed information on recent legislative and regulatory developments is provided below.

Energy Independence and Security Act of 2007: Summary of Provisions

The Energy Independence and Security Act of 2007 was signed into law on December 19, 2007, and became Public Law 110-140 [*8*]. Provisions in EISA2007

EIA Service Reports on Proposed Legislation Released Since January 2007

The table below summarizes the Service Reports on proposed legislation completed since 2007. Those reports, and others that were completed before 2007, can be found on the EIA web site at www.eia.doe.gov/oiaf/service_rpts.htm.

Title	Date of release	Requestor	Availability on EIA web site (www.eia.doe.gov/oiaf/servicerpt/)	Focus of analysis
Analysis of Crude Oil Production in the Arctic National Wildlife Refuge	*May 2008*	*Senator Ted Stevens*	*anwr/index.html*	*Provides an assessment of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge (ANWR) in Alaska.*
Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007	*April 2008*	*Senators Joseph Lieberman, John Warner, John Barrasso, James Inhofe, and George Voinovich*	*s2191/index.html*	*S. 2191 is a complex bill regulating emissions of GHGs through market-based mechanisms, energy efficiency programs, and economic incentives. This analysis focuses on the impacts of the GHG cap-and-trade program established under Title I of S. 2191.*
Federal Financial Interventions and Subsidies in Energy Markets 2007	*April 2008*	*Senator Lamar Alexander*	*subsidy2/ index.html*	*Update to 1999 to 2000 EIA work on Federal energy subsidies, including any additions or deletions of Federal subsidies based on Administration or Congressional action since 2000, and providing an estimate of the size of each current subsidy. Subsidies directed to electricity production are estimated on the basis of generation by fuel.*
Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007	*January 2008*	*Senators Jeff Bingaman and Arlen Specter*	*lcea/index.html*	*S. 1766 establishes a mandatory GHG allowance program to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.*
Oil and Natural Gas Market Supply and Renewable Portfolio Standard Impact of Selected Provisions of H.R. 3221	*December 2007*	*Representatives Joe Barton, Jim McCrery, and Don Young*	*bmy/index.html*	*Analyze selected provisions of H.R. 3221, the energy bill adopted by the House of Representatives (H.R.) in early August 2007. The analysis focuses on Title VII, dealing with energy on Federal lands; Section 9611, which would establish a Federal renewable portfolio standard for certain electricity sellers; and Section 13001, which would eliminate the eligibility of oil and natural gas producers and refiners to claim deductions under Section 199 of the Internal Revenue Code.*
Supplement to: Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007	*November 2007*	*Senators John Barrasso, James Inhofe, and George Voinovich*	*biv/index.html*	*Further energy and economic analysis to supplement information presented in EIA's recent analysis of S. 280, the Climate Stewardship and Innovation Act of 2007.*
Energy and Economic Impacts of Implementing a 25-Percent Renewable Portfolio Standard and Renewable Fuel Standard by 2025	*September 2007*	*Senator James Inhofe*	*eeim/index.html*	*Analysis of a "25-by-25" proposal that combines a requirement that a 25-percent share of electricity sales be produced from renewable sources by 2025 with a requirement that a 25-percent share of liquid transportation fuel sales also be derived from renewable sources by 2025. The electricity requirement is implemented as a renewable portfolio standard, while the motor fuel standard is implemented as an RFS.*
Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007	*July 2007*	*Senators Joseph Lieberman and John McCain*	*csia/index.html*	*Estimate of the economic impacts of S. 280, the Climate Stewardship and Innovation Act of 2007. S. 280 would establish a series of caps on GHG emissions starting in 2012 followed by increasingly stringent caps beginning in 2020, 2030, and 2050.*

(continued on page 18)

that require funding appropriations to be implemented, whose impact is highly uncertain, or that require further specification by Federal agencies or Congress are not included in *AEO2008*. For example, EIA does not try to anticipate policy responses to the many studies required by EISA2007, nor to predict the impact of research and development (R&D) funding authorizations included in the bill. Moreover, *AEO2008* does not include any provision that addresses a level of detail beyond that modeled in NEMS, which was used to develop the *AEO2008* projections. *AEO2008* addresses only those provisions in EISA2007 that establish specific tax credits, incentives, or standards, including the following:

- RFS requirements for the use of 36 billion gallons of ethanol per year by 2022, with corn ethanol limited to 15 billion gallons. Any other ethanol or biodiesel may be used to fulfill the balance of the mandate, but the balance must include 16 billion gallons per year of cellulosic ethanol by 2022 and 5 billion gallons per year of biodiesel by 2012.
- A new CAFE standard for LDVs (cars and light trucks) of 35 mpg by 2020. The Act also specifies that vehicle attribute-based standards are to be developed separately for cars and light trucks.
- A CAFE credit and transfer program among manufacturers and across a manufacturer's fleet.
- Extension through 2019 of the CAFE credits specified under the AMFA. EISA2007 reduces the maximum credit by 0.2 mpg for each model year after 2014 and phases it out entirely by model year 2020.
- Appliance energy efficiency standards for boilers, dehumidifiers, dishwashers, clothes washers, external power supplies, and commercial walk-in coolers and freezers.
- Lighting energy efficiency standards for general-service incandescent lighting in 2012 and sooner for general-service tubular fluorescent lighting and metal halide lamp fixtures.
- Standards for industrial electric motor efficiency, requiring industrial motors of various sizes to meet the NEMA premium motor efficiency standards.
- Standards for energy use in Federal buildings, requiring a 30-percent reduction by 2015.

The following discussion provides a summary of the EISA2007 provisions included in *AEO2008* and some of the provisions that could be included if more

EIA Service Reports on Proposed Legislation Released Since January 2007 (continued)

Title	Date of release	Requestor	Availability on EIA web site (www.eia.doe.gov/oiaf/servicerpt/)	Focus of analysis
Impacts of a 15-Percent Renewable Portfolio Standard	*June 2007*	*Senator Jeff Bingaman*	*prps/index.html*	*Analysis of a renewable portfolio standard requiring that 15 percent of U.S. electricity sales be derived from qualifying renewable energy resources.*
Analysis of Alternative Extensions of the Existing Production Tax Credit for Wind Generators	*May 2007*	*Ms. Janice Mays, Chief Counsel, Committee on Ways & Means, U.S. House of Representatives*	*ptc/index.html*	*Analysis of alternative extensions of the existing PTC that would apply to wind generators only.*
Energy Market Impacts of a Clean Energy Portfolio Standard - Follow-up	*February 2007*	*Senator Norman Coleman*	*portfolio/index.html*	*Analysis of a proposed clean energy portfolio standard (CEPS). The proposed CEPS requires electricity suppliers to increase their share of electricity sales that is generated using clean energy resources, including: nonhydropower renewable resources, new hydroelectric or nuclear resources, fuel cells, and fossil-fired plants that capture and sequester CO_2 emissions.*
Energy Market and Economic Impacts of a Proposal to Reduce Greenhouse Gas Intensity with a Cap and Trade System	*January 2007*	*Senators Jeff Bingaman, Mary Landrieu, Lisa Murkowski, Arlen Specter, Ken Salazar, and Richard Lugar*	*bllmss/index.html*	*Analysis of the impacts of a proposal that would regulate emissions of GHGs through an allowance cap-and-trade system. The program would set the cap to achieve a reduction in emissions relative to economic output, or GHG intensity.*

complete information were available about their funding and implementation. This discussion is not a complete summary of all the sections of EISA2007. More extensive summaries are available from other sources [*9*].

End-Use Demand

Buildings Sector

EISA2007 affects residential and commercial buildings in three specific areas: appliance and lighting energy efficiency, energy savings in private-sector buildings and industry, and energy savings in government and public institutions.

Appliance and Lighting Energy Efficiency. Subtitles A and B in Title III of EISA2007 include provisions with the potential to affect energy demand in the buildings sector. Many of the provisions give DOE the authority to set new efficiency standards or test procedures for new efficiency standards. Where EISA2007 specifies both efficiency levels and effective dates in the standards, they are implemented directly in the NEMS buildings modules. Where specific appliances and future DOE updates to the standards are not specified, they are not included in *AEO2008*.

Section 301 provides efficiency standards for external power supplies, limiting wattage in both active and no-load mode for units produced after July 1, 2008. DOE is instructed to review the standards in the future, but only the 2008 standard is included in *AEO2008*. Section 303 increases the Federal efficiency standard for residential boiler units manufactured after September 1, 2012, providing a small increase (less than 5 percent) over the current standard. Dehumidifiers, clothes washers, and dishwashers are subject to new standards between 2010 and 2012, as provided in Section 311. Energy conservation standards for walk-in refrigerators and walk-in freezers established in Section 312 require energy-efficient elements in the doors, walls, motors, and lighting of units manufactured in 2009 or later. Section 313 amends electric motor efficiency standards, and Section 314 adds single-package vertical air conditioners and heat pumps to the packaged air conditioning and heating equipment covered by the standards in EPACT2005. These two provisions address a level of detail that is not modeled in NEMS, and they are not included in *AEO2008*.

The largest projected energy savings from EISA2007 are the result of energy conservation standards for efficient light bulbs described in Sections 321, 322, and 324. Section 321 requires significant wattage reductions (approximately 28 percent) in incandescent lamps beginning in 2012, increasing to a reduction of about 65 percent in 2020. Section 322 sets standards for general-service fluorescent lamps and incandescent reflector lamps, and Section 324 imposes minimum ballast efficiency standards for metal halide lamp fixtures beginning in 2009. Section 323 mandates the use of energy-efficient lighting fixtures and bulbs to the maximum extent feasible in all Federal buildings starting in 2009.

Energy Savings in Buildings and Industry. Provisions under EISA2007 Title IV, Subtitle A, address energy efficiency in residential buildings. Section 411 reauthorizes funding for weatherization programs through fiscal year (FY) 2012; however, the program has been targeted for elimination by DOE in its most current budget and therefore is not included in *AEO2008*. Section 413 requires manufactured housing to comply with the most recent version of the International Energy Conservation Code (IECC) starting in 2012. This provision is included in *AEO2008*. The 2006 version of the IECC represents the most recent code.

Provisions under Title IV, Subtitle B, establish an office and a partnership consortium to promote high-performance green building initiatives. Section 422 specifically directs the establishment of a Zero Net Energy Commercial Buildings Initiative, with the eventual goal of having all U.S. commercial buildings use zero net energy by 2050. The provision includes several research, development, and deployment activities and authorizes funding for the initiative through 2018. Because the activities depend on future appropriations, they are not included in *AEO2008*.

Title IV, Subtitle C, addresses Federal energy use, updating energy intensity reduction goals and performance standards for Federal buildings, mandating energy and efficiency management, providing for the development of high-performance green building standards for Federal facilities, and directing the establishment of a program to accelerate Federal use of cost-effective technologies and practices. Federal purchasing requirements for energy intensity reduction and performance standards are represented in *AEO2008* as a result of earlier Executive Orders and legislation. Other aspects of these provisions either address a level of detail that is not modeled in *AEO2008* or are not included because they depend on future appropriations.

Provisions under the other Subtitles of Title IV address data center efficiency, environmental quality in schools, and sustainability and efficiency grants and loans for institutions. These provisions are not included in *AEO2008*, because they depend on future appropriations or address a level of detail that is not modeled in NEMS.

Energy Savings in Government and Public Institutions. Title V contains a variety of provisions, including promotion of efficiency and environmental measures for the Capitol complex; promotion and permanent authorization of energy savings performance contracts; standards for Federal purchase of specific technologies; and authorization for funding of State energy programs, utility efficiency incentives, and local energy efficiency block grants. Federal purchasing requirements governing purchases of cost-effective energy-efficient products are represented in *AEO2008* as a result of earlier Executive Orders and legislation. The provisions in EISA2007 Title V are not included in *AEO2008*, because they depend on future appropriations or address a level of detail that is not modeled in NEMS.

Industrial Sector

EISA2007 includes several provisions in Titles III and IV that could affect energy demand in the U.S. industrial sector; however, provisions in Title VI, Accelerated Research and Development, that may affect industrial energy consumption over the long term are not included in *AEO2008*.

Section 313 of Title III increases or creates minimum efficiency standards for newly manufactured general-purpose electric motors that must be met within 3 years of enactment (Table 2). Efficiency standards for general-purpose, integral-horsepower induction motors are raised, with the exception of fire pump motors. Minimum standards are created for seven types of poly-phase, integral-horsepower induction motors and NEMA design B motors (201 to 500 horsepower) not covered under the previous standards in the Energy Policy Act of 1992 (EPACT1992). These standards are included in *AEO2008* for industrial motor additions.

Table 2. Representative efficiency standards for enclosed motors (percent)

Horsepower	EPACT1992	EISA2007
1	82.5	85.5
5	87.5	89.5
20	91.0	93.0
50	93.0	94.5
100	94.5	95.4
200	95.0	96.2
500	—	96.2

Sections 451, 452, and 453 direct the EPA to survey all major industrial combustion sources and create a registry of the quantity and quality of waste energy at each site. DOE may provide up to 50 percent of the funding for a feasibility study to determine whether the waste heat can be captured with a 5-year payback. In addition, DOE is authorized to provide grants of nearly $200 million per year to industrial partnerships for research on energy savings. Finally, these sections create a program that collects best practices, designs, processes, and innovations for building energy-efficient data centers. These provisions are not funded and are not included in *AEO2008*.

Transportation Sector

EISA2007 Title 1, Section 102, requires that the average manufacturer's fleet fuel economy for cars and light-duty trucks be increased, starting in 2011, to an average of 35 mpg by 2020, based on the EPA test value used to measure compliance with the CAFE standard. The EPA CAFE test value generally differs from the estimated mpg value on the fuel economy label and, typically, exceeds the actual on-the-road fuel economy of a new vehicle by a significant margin. For model years 2021 through 2030, Section 102 specifies that the average fuel economy must be set at the maximum feasible average for each fleet. In *AEO2008*, fuel economy standards for LDVs are assumed to remain at the 2020 level. *AEO2008* includes attribute-based fuel economy standards for light trucks, given vehicle footprint [*10*] and sales share. It uses these fuel economy curves to achieve the overall fleet fuel economy standard of 35 mpg. The fuel economy standards for cars are not attribute-based, but they apply to the manufacturer's fleet of both domestic and imported vehicles. In *AEO2008*, the fuel economy standard for cars is assumed to increase from 27.5 mpg in 2010 to 41.0 mpg in 2020. For light trucks, the footprint-based average fleet fuel economy standard increases from 24.0 mpg in 2011 to 31.0 mpg in 2020.

Section 103 requires the development of fuel economy standards for work trucks—8,500 pounds to less than 10,000 pounds gross vehicle weight rating (GVWR)—and commercial medium- and heavy-duty on-highway vehicles (GVWR 10,000 pounds or more). The new fuel economy standards require consideration of vehicle attributes and duty requirements and can prescribe standards for different vehicle classes, such as buses used in urban operation or semi-trucks used primarily in highway operation. Section 103 provides a minimum lead time of four full model years before the new fuel economy standard is adopted, and a minimum of three full model years after the new fuel economy standard has been established before the fuel economy standards for work trucks can be modified. Because these fuel economy standards are pending, and because NEMS currently does not model fuel economy regulations for work trucks or commercial medium- and heavy-duty vehicles, this aspect of EISA2007 is not included in *AEO2008*.

Section 104 establishes a fuel economy credit trading program. Currently, CAFE credits earned by manufacturers can be banked for up to 3 years and can be applied only to the fleets (car or light truck) from which the credits were earned. Starting in model year 2011, the credit trading program will allow manufacturers whose vehicles exceed the minimum fuel economy standards to earn credits that can be sold to other manufacturers whose vehicles fail to achieve the prescribed standards. The credit trading program is designed to ensure that the total fuel savings for manufacturers exceeding the prescribed standards are preserved when credits are sold to manufacturers not achieving the standards.

The credit trading program begins in 2011, and EISA2007 allows manufacturers to apply credits earned to any of the three model years before the model year for which they are earned and to any of the five model years after the credits are earned. Credit transfers within a manufacturer's fleet are limited to specific maximums: 1.0 mpg for model years 2011 through 2013, 1.5 mpg for model years 2014 through 2017, and 2.0 mpg for model years 2018 and later. NEMS currently allows for sensitivity analysis of CAFE credit banking by manufacturer fleet but does not model the trading of credits among different manufacturers. Consequently, *AEO2008* does not include trading of fuel economy credits.

Section 109 extends the CAFE credits specified under AMFA through 2019. Before the passage of EISA-2007, the CAFE credits under AMFA were scheduled to expire after model year 2010. Currently, 1.2 mpg is the maximum CAFE credit that can be earned for selling alternative-fuel vehicles. EISA2007 extends the 1.2 mpg credit maximum through 2014 and reduces the maximum by 0.2 mpg for each following year until it is phased out by model year 2020. NEMS currently does not model CAFE credits earned from alternative-fuel vehicles sales, and *AEO2008* does not consider this section of EISA2007.

Petroleum, Ethanol, and Biofuels

This section summarizes the numerous provisions of EISA2007 affecting the supply, composition, and refining of petroleum and related products that are included in *AEO2008*.

Renewable Fuels Standard

EISA2007 Title II, in Subtitles A and B, includes an updated RFS that increases the requirement for total U.S. consumption of renewable fuels from the 7.5 billion gallons in 2012 as specified in EPACT2005 to 36 billion gallons in 2022. Mandates are set for specific types of renewable fuels, including both conventional biofuels (corn-based ethanol) and advanced biofuels that are not derived from corn starch (such as cellulosic ethanol, butanol, or diesel products and biomass-based diesel [*11*].

The advanced biofuel requirement comes into effect in 2009 at 0.6 billion gallons and rises to 21 billion gallons in 2022. In 2015 and thereafter, the maximum amount of corn-based ethanol that can be applied to the overall RFS is 15 billion gallons. The cellulosic biofuel requirement starts in 2010 at 0.1 billion gallons and rises to 16 billion gallons in 2022. The biomass-based diesel requirement begins at 0.5 billion gallons in 2009 and rises to 1 billion gallons in 2012, with the remaining years to be determined by the EPA Administrator.

EISA2007 also establishes a life-cycle GHG standard for biofuels. The GHG standard for all biofuels is based on the 2005 emission level for the particular type of transportation fuel. Corn-based ethanol must achieve a 20-percent reduction in life-cycle GHG emissions, which would disqualify future corn ethanol production facilities that use coal for process heat. In addition to being defined as not being derived from corn starch, advanced biofuels are further defined as any renewable fuels that reduce emissions by at least 50 percent. Finally, 60 percent or more of the reduction in emissions must be achieved before any cellulosic biofuel can qualify under that category.

Given uncertainty about whether the new RFS schedule can be achieved, EISA2007 contains a general waiver based on technical, economic, or environmental feasibility. In addition, the cellulosic biofuel mandate includes a credit program that is activated only in years when the mandated level of cellulosic biofuel is judged by the EPA Administrator as unlikely to be met. For all the fuel mandates, if there is a 20-percent deficit in more than two consecutive years or a 50-percent deficit in any one year, regulatory adjustment mechanisms are provided to lower the mandated levels from that point forward. This rule, which could be enacted by the EPA Administrator no sooner than 2016, would modify all applicable volumes (including the overall and advanced biofuel totals) for all subsequent years.

The RFS is included in *AEO2008*, with cellulosic biofuel credit and waiver provisions that are consistent with those in the existing law. Actual renewable fuel supplies in any year are allowed to exceed the minimum RFS requirements, depending on the availability of technology and feedstocks and the relative costs of renewable fuels and competing petroleum products. Because the RFS does not explicitly specify the level of the mandate after 2022, *AEO2008* assumes that it will remain at the 2022 level through 2030.

In order to achieve the biofuel consumption levels mandated in EISA2007, significantly more biofuels must be consumed than can be blended into gasoline as E10. Other than requiring studies involving ethanol pipelines and similar infrastructure issues, EISA2007 does not directly provide for infrastructure improvements that may be necessary. In *AEO2008*, the amount of ethanol in excess of what can be consumed in E10 is assumed to be used in E85. Flexible-fuel vehicles are assumed to be available in sufficient numbers to use the required amounts of E85, and E85 distribution infrastructure is assumed to be built over a technically practicable period. The infrastructure development costs are spread across all transportation fuels.

E85 infrastructure costs potentially could be reduced if biobutanol or ethanol-gasoline blends containing more than 10 percent ethanol (other than E85) were able to meet a significant portion of the RFS; however, *AEO2008* assumes that neither will actually contribute to meeting the EISA2007 mandates. At present there is little commercial activity for biobutanol, and only a few tests are under way [*12*]. Automakers and engine manufacturers are concerned about ethanol-related problems in vehicles built to run on gasoline blends no higher than E10, because higher ethanol blends are corrosive to engines not designed to handle them, and their use could adversely affect performance and cause vehicle warranties to be voided [*13*].

Amortization of Geological and Geophysical Expenditures

EISA2007 extends the 5-year amortization period for geological and geophysical expenditures by major integrated oil companies to 7 years as of the enactment of the bill. Because the NEMS oil and gas supply model does not directly represent geological and geophysical expenditures, this change is not included in *AEO2008*.

Electricity

EISA2007 includes few provisions that affect electricity generation or transmission. Title XIII, Smart Grid, promotes a modernization of the electricity transmission and distribution system to strengthen reliability and energy efficiency. Funding is provided for research and demonstration projects, as well as matching funds for qualifying investments. States are to encourage, but not require, utilities to adopt smart grid technology and allow them to recover their costs through rate increases. The bill does not include enough specific information to support NEMS projections of changes in investment or prices for electricity transmission and distribution, but it is implicitly assumed in *AEO2008* that electricity will be provided reliably.

Coal

Industries that rely on coal could benefit from EISA-2007 Title VII, Carbon Capture and Sequestration, if CO_2 emissions are restricted in the future. Sections 702 through 711 expand authorized funding and provide greater detail on the carbon capture and development program originally established in EPACT2005, Section 963. EISA2007 Sections 702 through 711 are not included in *AEO2008*, because the authorized funds have not been appropriated and the effects of the included research, development, and other projects are uncertain.

Section 702 authorizes $240 million per year from 2008 through 2012 for carbon sequestration projects, an increase from the amount authorized in EPACT-2005. Among the R&D programs supported under Section 702 are the development of a minimum of seven large-scale geologic sequestration projects, with each project capable of injecting at least 1 million tons of CO_2 annually. Geologic formations that potentially could be used for sequestration include operating or depleted oil and natural gas fields, unmineable coal seams, deep saline or basalt formations, and deep geologic resources from which economical geothermal heat is extracted. Monitoring, mitigation, and verification of CO_2 containment are also required under Section 702.

Section 703 authorizes additional funding of $200 million per year from 2009 through 2013 for R&D projects focused on capture, purification, compression, transportation, and injection of CO_2 emitted from industry sources. In the decision to undertake Section 703 projects, the Secretary of Energy may prioritize projects that include sequestration programs described under Section 702; however, integration is not a requirement for funding. As noted above, these R&D provisions are not included in *AEO2008*.

Section 706 recognizes that the CCS program must adhere to the Safe Drinking Water Act. Additional provisions in EISA2007 authorize funds for the education and training of individuals to work in the CCS field. None of these provisions is specifically reflected in *AEO2008*.

Section 711 requires the Secretary of the Interior and the Director of the United States Geological Survey (USGS) to develop an assessment of the potential, including geographical extent and capacity, of geologic formations to sequester carbon. The Secretary of Energy and the Secretary of the Interior are further charged with the responsibility for creating a database of possible sequestration sites, ranked by capacity and risk. Section 711 authorizes total funding of $30 million from 2008 through 2012. This section does not pertain directly to *AEO2008* and is not included.

Renewable Energy

In addition to the renewable energy provisions affecting the transportation, industrial, and buildings sectors, EISA2007 contains provisions authorizing several R&D programs for renewable energy use in the electric power sector. Specifically, Title VI calls for renewed, new, or enhanced R&D, educational, and technology transfer programs in the areas of solar energy (Sections 601-607), geothermal energy (Sections 611-625), and marine and hydrokinetic energy (Sections 631-636). Section 656 authorizes the Renewable Energy Innovation Manufacturing Partnership to advance manufacturing methods that use renewable energy. Appropriations for the authorized programs are not provided in the bill, however, and the programs are not included in *AEO2008*.

Other titles in EISA2007 contain provisions directly related to renewable electricity generation, but they either call for programs to be established or require specific appropriations that have not been made and, therefore, are not included in *AEO2008*. Section 803 authorizes direct grants for eligible renewable energy development projects. Section 806 is a nonbinding “sense of the Congress” statement that the Nation should strive to achieve a 25-percent renewable share of total energy consumption by 2025, while also providing sufficient food, feed, and fiber from agricultural resources. This statement does not contain any enforceable provisions or require any specific policy actions. Section 807 requires the Secretary of Interior to compile a comprehensive assessment of domestic geothermal resources. Section 1002 calls for the establishment of a workforce training program for trades related to renewable and energy efficiency. Section 1201 establishes a loan program for small businesses that want to purchase renewable energy or energy efficiency systems. Section 1207 establishes a program to support venture capital funding for new renewable energy businesses.

Federal Fuels Taxes and Tax Credits

The *AEO2008* reference case incorporates current regulations that pertain to the energy industry. This section describes the handling of Federal taxes and tax credits in *AEO2008*, focusing primarily on areas where regulations have changed or the handling of taxes or tax credits has been updated.

Excise Taxes on Highway Fuel

The handling of Federal highway fuel taxes remains unchanged from *AEO2007* [*14*]. Gasoline is assumed to be taxed at 18.4 cents per gallon, diesel at 24.4 cents per gallon, and kerosene jet fuel at 4.4 cents per gallon [*15*]. Taxes are not adjusted for inflation and remain at the same nominal values throughout the projections. State fuel taxes are calculated on the basis of a volume-weighted average of gasoline, diesel, and jet fuels sold. The handling of State fuel taxes was updated as of July 2007 [*16*].

Biofuels Tax Credits

The most significant change for *AEO2008* is in the handling of Federal fuels taxes and credits that pertain to biofuels. Several Federal tax credits are available for liquid fuel blenders who blend ethanol into gasoline or biodiesel into diesel fuel or heating oil. Under the Volumetric Ethanol Excise Tax Credit (VEETC) [*17*], blenders are eligible for a tax credit of $0.51 per gallon of ethanol blended. Thus, the tax credit is equal to $0.051 per gallon for E10 and $0.434 per gallon for E85 [*18*]. The credit is scheduled to expire at the end of 2010. Biodiesel also receives a tax credit under VEETC, equal to $1.00 per gallon for "agri-biodiesel" and $0.50 per gallon for "waste-grease biodiesel" made from recycled vegetable oils and animal fats. Currently, the credits are scheduled to expire in 2008 [*19*, *20*]. In *AEO2008*, both tax credits are assumed to expire according to the provisions of existing laws [*21*].

EPACT2005 provides small producers of ethanol, up to 60 million gallons [*22*], with an income tax credit of $0.10 per gallon on production volumes up to 15 million gallons. Because the credit affects only a small portion of the overall ethanol supply and is scheduled to expire on December 31, 2008, it is not included in *AEO2008*.

Ethanol Import Tariff

Two duties currently are imposed on imported ethanol. The first is an *ad valorem* tariff of 2.5 percent; the second is a tariff of $0.54 per gallon, which is applied after the *ad valorem* tariff. The second tariff, which was set to expire in October 2007 but has been extended to January 1, 2009, allows for limited duty-free imports from designated Central American and Caribbean countries, not exceeding 7 percent of domestic production in the previous year. In the *AEO2008* projections, ethanol imports increase after the tariff expires.

Production Tax Credits for Renewable Electricity Production

The handling of the Federal PTC for renewable electricity has been updated for *AEO2008* to be consistent with current legislation. The PTC, which was set to expire on December 31, 2007, was extended to December 31, 2008, by the Tax Relief and Health Care Act of 2006, Public Law (P.L.) 109-432. It provides a benefit of $0.020 per kilowatthour (real 2007 dollars) for the first 10 years of an eligible renewable energy facility's operation, boosting the growth of U.S. wind capacity in the near term. In the *AEO2008* reference case, wind capacity in the electric power sector grows from 15.9 gigawatts in 2007 to 20.2 gigawatts in 2008, as compared with the *AEO2007* projection of 16.6 gigawatts in 2008.

Mobile Source Air Toxics Rule

On February 9, 2007, the EPA released its MSAT2 rule, which will establish controls on gasoline, passenger vehicles, and portable fuel containers. The controls are designed to reduce emissions of benzene and other hazardous air pollutants [*23*]. Benzene is a known carcinogen, and the EPA estimates that mobile sources produced more than 70 percent of all benzene emissions in 1999. Other mobile source air toxics, including 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, and naphthalene, also are thought to increase cancer rates or contribute to other serious health problems. The MSAT2 rule sets a revised specification for benzene, which will take effect in 2011. The regulations on passenger vehicles, which will control hydrocarbon emissions in colder temperatures, will be implemented from 2010 to 2015. The rule also sets more stringent controls on portable fuel containers, beginning in 2009.

The MSAT2 rule has been included in *AEO2008* by modifying the NEMS representation of refinery processing of catalytic reformer feed. Although virtually every refinery will meet the requirement in a different way, most will involve treatment of the feed or product or the operation of the catalytic reformer.

Beginning on January 1, 2011, all gasoline products (including both reformulated and conventional gasoline) produced at refineries will be required to contain no more than 0.62 percent benzene by volume. (This does not apply to gasoline produced or sold in California, which is already covered by the current California Phase 3 Reformulated Gasoline program.) Approved small refineries will be required to conform to the rule by 2015. The second part of the standard requires that the *actual* average benzene levels that each refinery produces be no greater than 1.3 percent by volume by July 1, 2012 (July 1, 2016 for small refiners). The actual level is the level reached without use of any credits.

The published rule for gasoline benzene control includes an averaging, banking, and trading (ABT) program that is consistent with past EPA fuel regulations, allowing refiners to choose the most economical compliance strategy to meet the 0.62-percent annual average standard either by investing in new technology or by buying credits from the ABT program. From 2007 to 2010, the ABT program allows refiners to build “early credits” by making qualifying benzene reductions earlier than required. In 2011 and beyond, refiners and importers can generate “standard credits” by producing or importing gasoline with benzene levels below 0.62 volume percent on an annual average basis. The credits will be interchangeable between refiners and importers nationwide and can be “banked” for future use. The 3-year lag following establishment of the credit program provides the time necessary for small refiners to finish capital projects that are needed to meet the new standards without relying on credits. The rule also establishes a temporary hardship provision, which will provide refiners and importers with temporary relief from the benzene standards under certain rare circumstances (such as a refinery fire or natural disaster).

EPACT2005 Loan Guarantee Program

Title XVII of EPACT2005 authorized DOE to issue loan guarantees for projects involving new or improved technologies to avoid, reduce, or sequester GHGs. The law specified that the amount of the guarantee would be up to 80 percent of a project’s cost. EPACT2005 also specified that DOE must receive funds equal to the “subsidy cost” either through the Federal appropriations process or from the firm receiving the guarantee [*24*]. As discussed in *AEO2007*, this program, by lowering borrowing costs, can have a major impact on the economics of capital-intensive technologies [*25*].

In August 2006, DOE announced its first solicitation for $2 billion in loan guarantees. Even though the entire subsidy costs would be paid by successful applicants, DOE believed that authorization from Congress in an appropriations bill was required, and because there was no such authorization at the time, the requests were considered “pre-applications.” Consequently, the effects of the solicitation were not included in *AEO2007*. In February 2007, DOE did receive authorization to issue a total of $4 billion in guarantees. To codify DOE’s view that authorization is needed, the omnibus appropriations bill for FY 2008 passed by Congress in December 2007 (H.R. 2764) and its accompanying conference report required DOE to submit a loan guarantee implementation plan to both the House and Senate Appropriations Committees for approval 45 days before DOE issues any future solicitations.

The conference report also directed DOE “to make no authority in excess of” $38.5 billion for FY 2008 and FY 2009 [*26*] and allocated the $38.5 billion cap as follows: $18.5 billion for nuclear plants; $6 billion for carbon capture technologies; $2 billion for advanced coal gasification units; $2 billion for “advanced nuclear facilities for the ‘front end’ of the nuclear fuel cycle”; and $10 billion for technologies related to renewables, energy conservation, distributed energy, and electricity generation, transmission, and distribution.

The guidelines that accompanied the August 2006 solicitation—which stated that DOE would only guarantee up to 80 percent of a project’s *debt*—were criticized by some in the investment community and the nuclear industry for failing to take maximum advantage of the loan guarantee provision in EPACT-2005, which allows DOE to guarantee up to 80 percent of a project’s cost [*27*]. The final rule that formalized the guidelines, issued in October 2007, allows for up to 100 percent of the project debt to be guaranteed. This approach was codified in EISA2007.

Because future solicitations have not yet been issued and remain subject to approval of a loan guarantee implementation plan by the Appropriations Committees, only the effects of the August 2006 solicitation are included in *AEO2008*. Table 3 summarizes the number of applications and the requested amounts that could be guaranteed for various technologies in the solicitation. In total, DOE received 143 applications for $27 billion in loan guarantees for projects costing $51 billion [*28*]. In October 2007, DOE released information about the 16 projects and sponsors that will be invited to submit full applications. Because the final approval process will take some time, *AEO2008* assumes that the dollar amount of the approved guarantees will be roughly proportional to the requested guarantees. Accordingly, *AEO2008* includes an additional 1.2 gigawatts of capacity at advanced coal-fired power plants and 250 megawatts at solar power plants that are built as a result of the loan program. (The other projects in the October 2007 announcement were for technologies that are outside the scope of *AEO2008*.)

State Renewable Energy Requirements and Goals: Update Through 2007

In recent years, the *AEO* has tracked the growing number of States that have adopted requirements or goals for renewable energy. While there is no Federal renewable generation mandate, the States have been adopting such standards for some time. *AEO2005* provided a summary of all existing programs in effect at that time [*29*], and subsequent *AEOs* have examined new policies or changes to existing ones [*30,31*]. Since the publication of *AEO2007*, four States have enacted new RPS legislation, and five others have strengthened their existing RPS programs. In total, 25 States and the District of Columbia now have mandatory RPS programs (Table 4). At least four other States—Missouri, North Dakota, Vermont, and Virginia—have voluntary renewable energy programs.

All mandatory State RPS programs enacted as of the end of 2007 are represented in the *AEO2008* reference case. While States differ in aspects such as eligible generation technologies and compliance penalties, a regional representation was created for modeling purposes. With the exception of California and New York, where eligible future renewable generation is uncertain because of funding limitations for State-supported programs, all States were assumed to meet their program targets, consistent with regionally aggregated compliance schedules. EIA estimated compliance generation in California and New York based on regional costs and authorized funding levels. In estimating diverse State mandates on a regional level, some precision is lost; however, including the State RPS programs in the reference case results in a better projection that is more consistent with current legislation and regulation. If recent trends continue, the State RPS programs will exert growing influence over the national energy mix.

Four States enacted new mandatory RPS programs over the past year:

New Hampshire. In May 2007, the State enacted an RPS which requires that the renewable share of energy consumed for electricity generation increase through 2025, reaching nearly 24 percent by 2025 [*32*]. Approximately 16 percent of all electricity sales must be from renewable facilities that begin operation after 2006. New Hampshire will collaborate with the New England control area to establish a renewable energy certificate (REC) program. Eligible generation must occur within New England or be consumed by costumers in the area. In this legislation, different renewable technologies are given distinct classifications with minimum generation requirements and compliance penalties. Solar power, which has the highest compliance penalty, must make up 0.3 percent of total sales by 2015 to reach the mandate.

North Carolina. The State established an RPS in August 2007 with different targets for investor-owned utilities, municipal suppliers, and electric cooperatives [*33*]. Investor-owned utilities must generate 12.5 percent of their total electric sales from renewable generation sources by 2021. Until 2018, one-quarter of this requirement can be met through the implementation of energy efficiency technologies. After 2018, 40 percent of the requirement can be met through the use of energy efficiency technologies. Municipal suppliers and electric cooperatives have a renewable mandate of 10 percent of retail electricity sales by 2018. In addition to the energy efficiency provision, municipal suppliers and electric cooperatives may meet a majority of the mandate through demand-side management and the use of large hydroelectric facilities. North Carolina will use an REC market, and limited out-of-State generation qualifies in meeting the RPS.

Oregon. The State enacted an RPS in June 2007, with standards that vary according to the size of the electricity provider [*34*]. Larger utilities must produce 25 percent of their electricity sales from renewable resources by 2025. Medium-sized suppliers have a 10-percent requirement and small providers a 5-percent requirement. Any renewable power plant coming online after 1995 is considered eligible toward meeting the State renewable energy goal. Oregon will use an REC market exclusive to the State, and credits will be capped at a price yet to be determined.

Washington. Voters approved Initiative 937 in November 2006, enacting the Nation's second ballot

Table 3. Summary of DOE's August 2006 loan guarantee solicitation

Technology	Applications: Number	Applications: Percent of total	Project costs: Amount (billion dollars)	Project costs: Percent of total	Guarantees requested (billion dollars)
Biomass	*70*	*49*	*6*	*11*	*4*
Advanced fossil fuel	*23*	*16*	*35*	*69*	*16*
Solar	*17*	*12*	*3*	*6*	*2*
Energy efficiency	*9*	*6*	*4*	*7*	*3*
Other	*24*	*17*	*4*	*7*	*2*
Total	***143***	***100***	***52***	***100***	***27***

Table 4. State renewable portfolio standards

State	Program mandate
AZ	ACC Decision No. 69127 requires 15 percent of sales to be renewable by 2025, with interim goals increasing annually. A specific percentage of the target must be from distributed generation. Multiple credits may be given for solar generation and in-State manufactured systems.
CA	Public Utilities Code, Section 399.11-399.20, mandates that 20 percent of sales be renewable by 2010. There are also longer-term goals. Renewable projects with above-market costs will be funded by supplemental energy payments from a limited fund, possibly limiting renewable generation below the 20-percent requirement.
CO	House Bill 1281 strengthened the renewable target to 20 percent by 2020 for investor-owned utilities. There is a 10-percent requirement in the same year for cooperative and municipal utilities. Moreover, 2 percent of total sales by investor-owned utilities must be from solar power. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 strengthened the original RPS provisions and mandated a 27-percent renewable sales requirement by 2020. Included in the total is a 4-percent mandate from greater efficiency or CHP systems. Three percent of the overall total may be met from waste-to-energy facilities and conventional biomass.
DE	Senate Bill 19 strengthened the RPS to 20 percent of sales by 2019. There is a separate requirement for solar generation (2 percent of the total), and compliance failure results in higher penalty payments. Solar technologies receive triple credits.
DC	Enacted in 2005, the RPS mandates that 11 percent of sales be renewables by 2022. Some technologies receive bonus credits and awards for early installations of renewable systems.
HI	Senate Bill 3185 amended the RPS to increase the mandate to 20 percent by 2020. All existing renewable facilities are eligible in meeting the target, which has two interim milestones.
IL	Public Act 095-0481 created an agency responsible for overseeing the mandate of 25 percent renewable sales by 2025. There are escalating annual targets, and 75 percent of the requirements must be from wind-generated electricity. The plan also includes a cap on the incremental costs added from renewable penetration.
IA	An RPS mandating 105 megawatts of renewable energy capacity has already been exceeded.
ME	In 2007, Public Law 403 added to the State's RPS requirements. Originally a mandate of 30 percent renewable generation by 2000 was set to be lower than current generation. The new law states that new renewable resource capacity must increase to 10 percent of electricity generation by 2017 and in the subsequent years. The years leading up to 2017 also have new capacity milestones.
MD	Senate Bill 595 revised the RPS to contain a 9.5-percent target by 2022. Moreover, renewable generation technologies are categorized into differing share requirements. Penalty payments for compliance shortfalls were also determined.
MA	The RPS has a 4-percent renewable sales total by 2009 with an optional 1-percent annual increase thereafter (not reflected in AEO2008). The State also imposes penalty payments for compliance shortfalls.
MN	Senate Bill 4 created a 30-percent renewable requirement by 2020 for Xcel, the State's largest supplier, and a 25-percent requirement by 2025 for others. Also specified was the creation of a State cap-and-trade program that will assist the program's implementation.
MT	House Bill 681 expanded the RPS provisions to all suppliers. Initially the law covered only public utilities. A 15-percent share of sales must be renewable by 2015. The State operates an REC market.
NV	Established in 1997 and revised in 2005, the State's escalating target reaches 20 percent by 2015. Up to one-quarter may be met through efficiency measures. There is also a minimum requirement and bonus requirements for solar resources.
NH	House Bill 873 legislated that 23.8 percent of sales must be renewable by 2025. 16.3 percent of total sales must be from renewable facilities that have begun operation after 2006. Compliance penalties vary by generation type.
NJ	In 2006, the RPS was revised to increase renewable energy targets. The current level for renewable generation is 22.5 percent of sales by 2021, with interim targets. There are different requirements for different technologies, including a 2-percent solar mandate.
NM	Senate Bill 418 directs investor-owned utilities to have 20 percent of their sales renewable by 2020. The renewable portfolio must consist of diversified technologies, and wind and solar each must account for 20 percent of the target. There is a separate 10-percent standard by 2020 for cooperatives.
NY	The Public Service Commission issued RPS rules in 2005 that call for renewable sales of 24 percent by 2013, from current levels of 19 percent.
NC	Senate Bill 3 created an RPS of 12.5 percent by 2021 for investor-owned utilities. There is also a 10-percent requirement by 2018 for cooperative and municipal suppliers. Through 2018, one-quarter of the target may be met through efficiency standards; that proportion increases to 40 percent in later years.
OR	In June 2007, Senate Bill 838 required renewable targets of 25 percent by 2025 for large utilities and 5 to 10 percent by 2025 for smaller utilities. Any source of renewable electricity on line after 1995 is considered eligible. Compliance penalty caps have not been determined.
PA	The Alternative Energy Portfolio Standard has an 18-percent requirement by 2020. At least 8 percent of the sales must be renewables, but there is also a provision that allows for certain coal resources to receive credits.
RI	The program requires 16 percent of total sales to be renewable by 2020. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must make an alternative compliance payment.
TX	Senate Bill 20 strengthened the State's RPS to mandate 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.
WA	Voters approved Initiative 937, which specifies that 15 percent of sales from the State's largest generators must come from renewable sources by 2020. There is an administrative penalty of 5 cents per kilowatthour for noncompliance. Any facility on line after 1999 is eligible.
WI	In March 2006, Senate Bill 459 increased the RPS law to 10 percent of renewable sales by 2015. Requirements vary by supplier, and out-of-State generation is eligible.

RPS [*35*]. The law covers 84 percent of Washington's sales, affects the State's 17 largest suppliers, and specifies that 15 percent of their electricity load must be generated from renewable energy by 2020. Eligible generation includes any renewable facility that comes on line after 1999. The 17 suppliers also must identity feasible areas of conservation and publish implementation plans to achieve demand reductions. Failure to comply with the RPS or the conservation measures will result in a penalty to the generator of 5 cents per kilowatthour of generation.

Five States significantly changed their existing RPS requirements:

Delaware. The State enacted Senate Bill (S.B.) 19 in July 2007, increasing the required RPS from 10 percent to 20 percent of electricity by 2019 [*36*]. It also created a solar photovoltaic (PV) provision under which 2 percent of electricity must originate from solar PV by 2019. Both the solar target and the renewable target consist of escalating interim milestones. The existing schedule of alternative compliance payments (ACPs) is not affected [*37*], but the bill does provide for separate solar ACPs with a minimum value of $250 per megawatthour—much higher than the standard ACPs. In-State solar PV generation receives triple credits toward meeting the RPS.

Colorado. House Bill 1281 strengthened the RPS that was approved by voters in 2004 by increasing the amount of renewable energy required in 2015 from 10 percent to 15 percent of sales [*38*]. It also added the requirement that 20 percent of total electricity sales by investor-owned utilities must come from renewable energy by 2020. Investor-owned utilities also are required to generate 2 percent of their sales with solar energy technologies. House Bill 1281 created a less stringent standard for electric cooperatives and municipal utilities, requiring that only 10 percent of sales be from qualifying sources by 2020. It also establishes that generation within Colorado receives 125 percent of the value that out-of-State energy would earn.

Connecticut. The State revised its RPS requirement in June of 2007 as part of Public Act 07-242 [*39*]. The revisions extended the RPS to 2020, with a 27-percent requirement in that year. Most of the standard is to be met through renewable technologies using wind, solar, sustainable biomass, and wave energy. Generation from surrounding States is eligible. There are separate rules requiring CHP systems and efficiency enhancements (4 percent). Three percent of the total may be met from waste-to-heat facilities and conventional biomass. Suppliers that do not comply face a penalty of 5.5 cents that will be used to fund renewable development.

Illinois. In August 2007, the State's voluntary renewable goal was replaced by a mandatory RPS [*40*]. Suppliers with more than 100,000 customers are required to provide 25 percent of their electricity from qualifying facilities by 2025, with several interim requirements. Three-quarters of the facilities must be wind powered. Until 2011, lower cost in-State resources must be used unless they are proven exhausted, in which case out-of-State generation would qualify. After 2011, no preference is given to Illinois resources over others in the region. The costs associated with the mandates are capped and reviewable.

Minnesota. Minnesota's new RPS regulations became effective in February 2007. They created two standards, one for Xcel Energy and another for other suppliers [*41*]. Previously, Minnesota had a voluntary standard. The Xcel milestones are the most significant, with 30 percent of all power required to come from renewable energy by 2020. Approximately 83 percent of the power from renewables must come from wind turbines. Other suppliers, including municipal utilities, have until 2025 to meet a smaller goal of 25 percent. The State Public Utilities Commission is still constructing an REC trading system, and the role that interstate or interregional credits will play is still unknown.

State Regulations on Airborne Emissions: Update Through 2007

Implementation of the Clean Air Interstate Rule

States are moving forward with implementation plans for the Clean Air Interstate Rule (CAIR) [*42*]. The program, promulgated by the EPA in March 2005, is a cap-and-trade system designed to reduce emissions of SO_2 and NO_x. States originally had until March 2007 to submit implementation plans, but the deadline has been extended by another year. CAIR covers 28 eastern States and the District of Columbia. States have the option to participate in the cap-and-trade plan or devise their own plans, which can be more stringent than the Federal requirements. To date, no State has indicated an intent to form NO_x and SO_2 programs with emissions limits stricter than those in CAIR, and it is expected that all States will participate in the EPA-administered cap-and-trade program. CAIR remains on schedule for implementation, and *AEO2008* includes CAIR by assuming that all required States will meet only the Federal requirement and will trade credits.

A similar program, the Clean Air Mercury Rule (CAMR), was promulgated by the EPA in March 2005 to reduce emissions of mercury [*43*]. On February 8, 2008, the U.S. Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proved mercury to be a pollutant eligible for regulation under a less stringent portion of the Clean Air Act. Because the court's ruling came too late for EIA to remove the CAMR provisions from its analysis, *AEO2008* includes consideration of CAMR. Regardless of CAMR, however, some States have implemented plans calling for mandatory 90-percent cuts in mercury emissions from all plants of a certain size. More stringent modeling of mercury emissions limits in some regions may be necessary when State actions have been finalized.

State Greenhouse Gas Initiatives

RGGI. Since the end of 2006, three additional States have joined the Regional Greenhouse Gas Initiative (RGGI) [*44*]. Currently, RGGI includes 10 members: Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Vermont, and Maryland.

Although *AEO2008* does not include RGGI, given the current uncertainty about the program's structure and allowance trading, several States are now moving forward with their draft implementation plans. Massachusetts, Maine, and New York have released public drafts for comment. Each of those plans closely follows the model rules published in August 2006, requiring that 100 percent of the allowances be auctioned. It is thought that all RGGI States are likely to follow the same precedent, with a limited number of giveaway credits. RGGI formally begins in January 2009. Some States will have to enact legislation to make the program legally binding, whereas others have State agencies that already have such authority and do not need to pass new laws. As of late 2007, Vermont was the only RGGI State that had enacted a new law.

WCI. In February 2007, the governors of Arizona, California, New Mexico, Oregon, and Washington established the Western Climate Initiative (WCI). Utah and the Canadian provinces of British Columbia and Manitoba have since joined as full partners. Six additional U.S. States and several Canadian provinces participate as observers. The eight full partners have agreed to the goal of decreasing emissions to 15 percent below 2005 levels by 2020, but little else about the program has been decided. Although the WCI is leaning heavily toward a cap-and-trade system, the specifics of covered emissions, State allowance allocations and trading, emissions accounting, and offsets—among other items—still are being negotiated. *AEO2008* does not include the WCI, because it remains to be seen how the program will function and what the penalties for noncompliance will be.

WCI has a task force that will assemble a program model rule by August 2008. Some WCI partner States already have GHG laws or goals, while others, such as Utah, do not. The agreement does not override the binding GHG laws in California, Oregon, and Washington, but it does require WCI partners to join the Climate Registry, which is a collaboration of 39 U.S. States, Canadian provinces, and Mexican states seeking uniform GHG accounting and reporting.

California. California's S.B. 1368 [*45*] makes it illegal to enter into new long-term contracts to serve the State's electricity demand with power plants that produce GHG emissions in excess of 1,100 pounds per megawatthour of electricity generated—effectively prohibiting the construction of new coal-fired facilities without carbon sequestration, even if they are located in a neighboring State. *AEO2008* includes the impact of S.B. 1368 through limits on coal-fired electricity generation serving California.

California's Assembly Bill (A.B.) 1493, which would establish GHG emissions standards for LDVs, is not considered in the *AEO2008* reference case. A.B. 1493 was signed into law in July 2002, and regulations were released by the California Air Resources Board in August 2004 and approved by California's Office of Administrative Law in September 2005 [*46*]. The emission standards would be applied to light-duty noncommercial passenger vehicles manufactured for model year 2009 and beyond [*47*]. The standards, specified in terms of CO_2-equivalent emissions, would apply to vehicles in two size classes: passenger cars and light-duty trucks with a loaded vehicle weight rating of 3,750 pounds or less; and light-duty trucks with a loaded vehicle weight rating greater than 3,750 pounds and a gross vehicle weight rating less than 8,500 pounds. The

CO_2-equivalent emissions standard for light trucks would include noncommercial passenger trucks between 8,500 pounds and 10,000 pounds. The regulations were to become effective in January 2006 and set near-term emission standards that were to be phased in between 2009 and 2012. The mid-term emission standards were to be phased in between 2013 and 2016. After 2016, the emissions standards would be left unchanged.

Before California can implement the GHG emission standards for vehicles established in A.B. 1493, it must receive a waiver from the U.S. EPA. The EPA, however, has denied California a waiver to regulate GHG emissions from mobile source under the Clean Air Act. Expressing concern about the establishment of regional emissions standards for new motor vehicles, the EPA reasoned that the effects of climate change in California did not support the need for a regional standard.

In October 2003, California, 11 other States, 3 cities, and several environmental groups filed a petition in the U.S. Court of Appeals, arguing that the EPA should regulate GHG emissions from vehicles. In July 2005, a three-judge panel ruled 2 to 1 in the EPA's favor, stating that the agency was not required to regulate GHGs under the Clean Air Act. The decision was overturned in April 2007 by the U.S. Supreme Court, which ruled that the EPA has authority under Section 202 of the Clean Air Act to regulate GHG emissions from automobiles. Nonetheless, on December 19, 2007, the EPA again denied California's request for a waiver [*48*]. On January 2, 2008, California and 15 other States sued the EPA, challenging its decision to deny the wavier [*49*].

AEO2008 also does not include consideration of California A.B. 32, which mandates a 25-percent reduction in California's GHG emissions by 2020. Implementing regulations have not been drafted and are not due to be finalized until January 2012.

Washington and Oregon. Washington and Oregon have joined California in the enactment of State GHG legislation. In May 2007, Washington's Governor Christine Gregoire signed S.B. 6001 [*50*], which mandates cuts in emissions and performance standards for power plants. The legislation targets reductions to 1990 emissions levels in the State by 2020, to 25 percent below the 1990 levels by 2035, and to 50 percent below the 1990 levels by 2050. Washington has not yet mandated the program specifics, such as the type of system that will be used to meet the targets. Additional action from the governor, the utilities, and the State's transportation commission will be required.

Washington State has also adopted the same standards included in California S.B. 1368. Oregon, which has CO_2 regulations for natural-gas-fired plants but not for other fossil-fuel-based power systems, passed its GHG reduction law in August 2007. The law has the same 2020 reduction goal as Washington's and also requires that emissions growth be capped by 2010. It establishes the Oregon Global Warming Commission, a body will have 25 members with various backgrounds who will serve as an advisory board to State and local governments. Like Washington and California, Oregon has not determined the specific procedures to be followed in implementing the required emissions reductions.

Other States. Many other States have goals and other provisions for GHG reductions and accounting of emissions from stationary sources. In May 2007, Montana's Governor Brian Schweitzer signed House Bill 25 [*51*], which requires any new coal-fired generating facility to sequester at least 50 percent of the CO_2 it emits. Florida's Governor Charlie Crist signed three executive orders [*52*] over the summer concerning his State's emissions of heat-trapping gases, including an overall State goal to bring emissions to 80 percent below 1990 levels by 2050. An Energy and Climate Change Action Plan will be developed to determine how the State of Florida can reach those reduction goals.

ICAP. Ten U.S. States, all of which are participants in either RGGI or WCI, have entered the International Carbon Action Partnership (ICAP). ICAP, created in October 2007, seeks collaboration among carbon trading programs. Members include nine European Union countries, the European Commission, Norway, and New Zealand. Several other U.S. States have non-binding goals, carbon registry requirements, or energy plans that include recommendations to limit CO_2 emissions from stationary sources, including those described above.

Issues in Focus

Introduction

Each year, this section of the *AEO* provides in-depth discussions on topics of special interest that may affect annual projections, including significant changes in assumptions and recent developments in technologies for energy production, supply, and consumption. In view of recent increases in construction costs, including the costs of constructing power plants, refineries, and other energy-related facilities, this year's topics include a discussion of cost trends and the implications for energy markets. Other issues discussed this year include the implications of increased reliance on natural gas in the electricity generation sector, warming weather trends and their effects on energy demand, LNG imports, and world oil prices and production trends.

The topics explored in this section represent current, emerging issues in energy markets; but many of the topics discussed in *AEO*s published in recent years are relevant today. Table 5 provides a list of titles from the 2005, 2006, and 2007 *AEO*s that are likely to be of interest to today's readers. They can be found on EIA's web site at www.eia.doe.gov/oiaf/aeo/other analysis/aeo_analyses. html.

Impacts of Uncertainty in Energy Project Costs

From the late 1970s through 2002, steel, cement, and concrete prices followed a general downward trend. Since then, however, iron and steel prices have increased by 8 percent in 2003, 10 percent in 2004, and 31 percent in 2005. Although iron and steel prices declined in 2006, early data for 2007 show another increase. Cement and concrete prices, as well as the composite cost index for all construction commodities, have shown similar trends but with smaller increases in 2004 and 2005 (Figure 9).

Recent increases in the costs of basic commodities and increases in capital costs for energy equipment and facilities could have significant effects on future energy supplies and consumption. Higher capital costs could change both the competition among fuels and technologies and the marginal costs of new energy supplies. In the electric power sector, for example, capital costs are generally lower for generating plants that use fossil fuels than for plants that use nuclear or renewable fuels. If capital costs increased on a proportional basis for plants of all types, then capital-intensive nuclear and renewable power plants would become even less competitive with fossil-fired plants when new capacity is planned. In addition, over the long term, higher capital costs would lead to

Figure 9. Changes in construction commodity costs, 1973-2007 (constant dollar index, 1973=100; 1981=100 for cement costs)

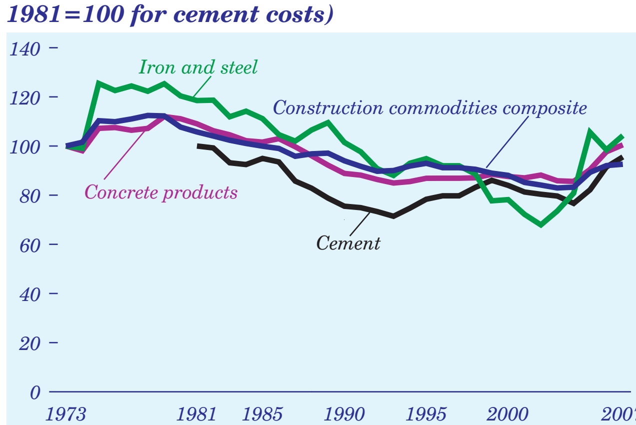


Table 5. Key analyses from "Issues in Focus" in recent AEOs

AEO2007	*AEO2006*	*AEO2005*
Impacts of Rising Construction and Equipment Costs on Energy Industries	*Economic Effects of High Oil Prices*	*Changing Trends in the Bulk Chemicals and Pulp and Paper Industries*
Energy Demand: Limits on the Response to Higher Energy Prices in the End-Use Sectors	*Changing Trends in the Refining Industry*	*Fuel Economy of the Light-Duty Vehicle Fleet*
Miscellaneous Electricity Services in the Buildings Sector	*Energy Technologies on the Horizon*	*Production Tax Credit for Renewable Electricity Generation*
Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing	*Advanced Technologies for Light-Duty Vehicles*	*Distributed Generation in Buildings*
Impacts of Increased Access to Oil and Natural Gas Resources in the Lower 48 Federal Outer Continental Shelf	*Nonconventional Liquid Fuels*	*Restricted Natural Gas Supply Case*
Alaska Natural Gas Pipeline Developments	*Mercury Emissions Control Technologies*	
Coal Transportation Issues	*U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative*	

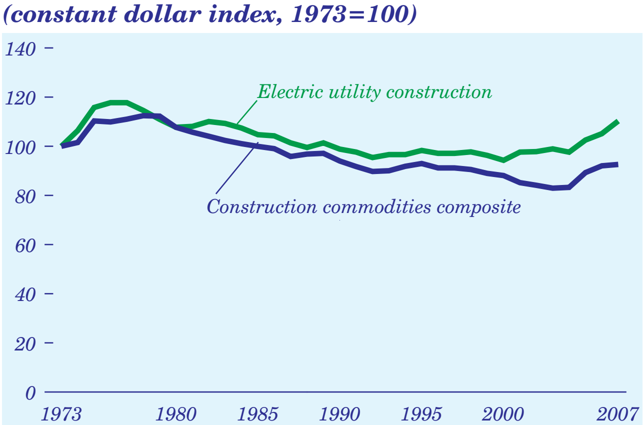
higher energy prices, which in turn could slow the growth of energy consumption.

The *AEO2008* version of NEMS includes updated assumptions about the costs of new power plants, the costs of drilling and pipeline construction in the oil and natural gas industry, refinery costs, and capital costs in the LNG supply chain. In the reference case, energy project costs are assumed to level off over the long term. To examine the effects of different assumptions about future costs, high and low energy project cost cases were developed, assuming higher and lower costs than in the reference case.

Power Plant Construction

In the electric power industry, cost estimates for individual construction projects to be completed over the next decade have increased by 50 percent or more in recent years [*53*]. Increased costs have been reported for power plants of all types, including coal, nuclear, natural gas, and wind. The Handy-Whitman index for electric utility construction (which is used as a proxy for all electric power industry projects) provides an average cost index for six regions in the United States, starting from 1973. A simple average of the regions is used in Figure 10 to show the national trend for power plant construction relative to the cost index for construction materials. The two indexes diverge in the early 2000s, when power plant construction costs began to show a flat to slightly increasing trend, while general construction costs continued to decline. With the sharpest increases in electric utility construction costs occurring over the past 3 years, the electric utility construction cost index for 2007 is 17 percent higher than its low point in 2000.

Figure 10. Changes in construction commodity costs and electric utility construction costs, 1973-2007 (constant dollar index, 1973=100)



Oil and Natural Gas Industry

Exploration and Production

According to the American Petroleum Institute's *Joint Association Survey of Drilling Costs* (JAS), the average real cost of drilling an onshore well almost doubled in 2004 and increased by another 10 percent in 2005. The increases are attributable in part to the increased drilling activity brought on by higher prices for crude oil and natural gas; however, there is a great deal of uncertainty as to whether the recent escalation in drilling costs represents a fundamental shift in the drilling services industry or is a temporary aberration that will be corrected in the near term.

Natural Gas Pipelines

Historical trends in pipeline construction costs are more difficult to identify, because the cost data are not readily available; however, average real capital costs for lower 48 pipeline construction appear to have increased by some 70 percent over the past 3 years. Anecdotal evidence suggests that new estimates for the cost of constructing an Alaska pipeline are 50 percent higher than the estimates published in May 2002, and estimates for a Mackenzie Delta pipeline also are higher than the preliminary estimates from 2003.

LNG Facilities

Construction cost estimates for new natural gas liquefaction facilities scheduled to come on line between 2008 and 2011 increased by 50 percent in 2006 relative to those reported a year earlier for the same period. Some of the increase may be due to strong growth in demand for LNG liquefaction capacity. This cost pressure will not persist as markets adjust and additional projects are announced and completed; however, a portion of the increase is due to increased material costs, shortage of experienced workers, and construction bottlenecks that are likely to persist or take longer to resolve. The costs for regasification facilities and receiving terminals have also increased sharply—by more than 50 percent—over the past few years. Based on contracts signed between 2000 and 2006, LNG shipping costs have also risen by more than 7 percent over the past few years.

Petroleum Refineries and Ethanol Plants

The Nelson-Farrar refinery construction cost indexes, which track overall costs for refinery construction, show a 30-percent increase from 2003 to 2005 in real dollar terms. Similarly, the Chemical Engineering

Plant Cost Index (CEPCI) shows a significant increase in ethanol plant construction costs over recent years. Because there has not been a significant increase in U.S. refining construction activity over the past few years, cost increases in the petroleum refining sector largely reflect higher prices for the various commodities used in the refining industry (steel, nickel, cobalt, etc.) rather than significant increases in demand for refinery services and equipment.

Case Descriptions

Reference Case

The *AEO2008* reference case includes updated information on the current costs of construction and investment in the energy industry, based on recent data and estimates that show higher costs than were assumed for *AEO2007*. In most of the *AEO2008* cases, the higher cost levels are assumed to continue throughout the projections. For the electric power sector, initial costs for all technologies are 15 percent higher than those in *AEO2007* and continue to be higher throughout the projection, although overnight costs fall over time as a result of technology learning.

For the oil and natural gas industry, regional drilling costs are calculated annually from econometrically derived equations, which are based on historical data from the American Petroleum Institute's JAS, and estimates of the number of wells being drilled and the average depth of each well. The cost increases seen after 2003 are represented by an explicit multiplier that captures the combined impacts of various cost factors other than drilling activity and well depth. In the reference case, the cost escalation factor is applied and held constant over the projection, but its effect is partially offset by an annual technology improvement factor that reflects learning and increased efficiency.

Pipeline construction costs are based on average construction cost data filed between 1992 and 2008, and they are assumed to remain constant through 2030. The reference case also assumes that the recent, higher estimates for an Alaska pipeline and a pipeline from the Mackenzie Delta remain constant through 2030.

Construction costs for new natural gas liquefaction facilities were increased by 50 percent in *AEO2008* to match the 2006 cost estimate for facilities scheduled for completion between 2008 and 2011. The construction costs are assumed to remain constant at that level through 2015, then decline to only 15 percent above their pre-2006 levels in 2018 as the market adjusts, after which the costs are assumed to remain constant at the 2018 level through 2030. LNG shipping costs and construction costs for regasification facilities are assumed to be 15 percent and 7 percent higher, respectively, than their 2006 level throughout the *AEO2008* projection.

Construction costs for refineries and for ethanol production plants are assumed to remain constant at 2006 levels through 2030, based on the Nelson-Farr index and CEPCI, respectively.

High Energy Project Cost Case

The high energy project cost case assumes that the cost of construction will continue to rise. For electricity generation plants, the base capital cost for all technologies rises at a rate of 2.5 percent per year—similar to the average increase over the past 3 years—through 2030, offset in part by learning effects.

For the oil and natural gas industry, the escalation factor for drilling costs is assumed to increase to twice its original value by 2010 and remain constant thereafter. It is offset in part by an annual technology improvement factor. Pipeline construction costs are assumed to start at the reference case level but grow to about 25 percent above the reference case level in 2030.

LNG liquefaction costs match the reference case increase through 2008 and add an additional 20 percent thereafter. Construction costs for LNG regasification facilities are 15 percent above the reference case level in 2008 and then held constant through 2030. LNG shipping costs are increased to 7 percent above the reference case level in 2008 and then held constant through 2030.

For the refining sector, construction costs are increased above the reference case level by a factor equal to the percentage difference between the 2004 and 2006 Nelson-Farrar index values and held constant. Construction costs for corn and cellulosic ethanol plants are treated similarly, using the CEPCI.

Low Energy Project Cost Case

The low energy project cost case generally assumes that the cost of construction will decline to the levels of 5 to 10 years ago. For the electricity sector, the 15-percent capital cost escalation factor included in the reference case is phased out over 10 years, so that overnight construction costs for all generating technologies are 15 percent lower than those in the reference case by 2017.

For the oil and natural gas industry, the drilling cost escalation factor applied in the reference case is phased out by 2010. Pipeline construction costs start at the reference case level but decline gradually to about 25 percent below the reference case level in 2030. For LNG liquefaction facilities, construction costs are reduced gradually from those in the reference case, returning to 2006 levels by 2015 and remaining constant thereafter. Similarly, construction costs for LNG regasification facilities and costs for LNG shipping costs decline gradually from reference case levels, return to 2006 levels by 2018, and remain constant thereafter. Refinery construction costs are assumed to return to 2004 levels by 2008 and then remain constant through 2030.

Results

Electricity: Capacity Additions and Generation

The projected mix of generating capacity types added in the electric power sector from 2006 to 2030 does not vary significantly among the reference, high energy project cost, and low energy project cost cases, because increases or decreases in construction costs have similar impacts on new builds for all technology types on a percentage basis. For example, coal-fired technologies provide about 40 percent of all new capacity additions in each of the three cases. More capital-intensive technologies, including nuclear and renewables, are affected somewhat more, however, than those with lower capital costs, including natural-gas- and coal-fired plants.

In the high energy project cost case, coal-fired capacity additions are reduced by 13 gigawatts from the reference case level, but with higher costs leading to higher electricity prices and lower demand, less new generating capacity is needed overall. As a result, the coal share of new builds remains almost the same as in the reference case. The technology most affected is nuclear power: no new nuclear capacity is built before 2030 in the high energy project cost case (Figure 11). Renewable capacity additions are 17 percent lower than in the reference case, but total generation from renewable plants is about the same in order to meet the requirements of State and regional RPS programs. The increase in renewable generation comes primarily from biomass co-firing at existing coal plants.

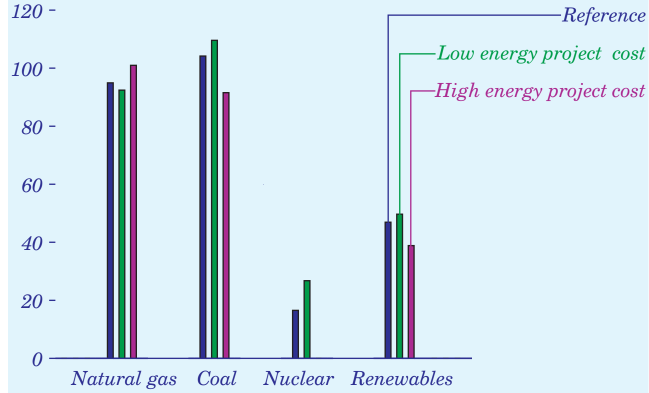
Because they are the least expensive to build, natural gas capacity additions increase in the high energy project cost case relative to the reference case, meeting 43 percent of new capacity needs. As a result, natural-gas-fired generation in 2030 is 22 percent higher than in the reference case. Average electricity prices in 2030 are 9 percent higher in the high energy project cost case than in the reference case.

In the low energy project cost case, more capacity of all types except natural gas is added over the projection period. The largest increase is in nuclear capacity additions, which are 10 gigawatts higher than in the reference case. Because capital costs make up a smaller share of total costs for natural-gas-fired capacity additions than for other technologies, they are slightly less economical in the low energy project cost case and about 3 gigawatts lower than in the reference case. The fuel shares of total generation in 2030 are similar in the low energy project cost case and the reference case, with a small decrease in the natural gas share (to 13 percent, compared with 14 percent in the reference case). The nuclear share of total generation increases from 18 percent in the reference case to 19 percent in the low energy project cost case. Electricity prices in 2030 are 4 percent lower in the low energy project cost case than in the reference case.

Natural Gas: Supply, Consumption, and Prices

Natural gas supply volumes are determined primarily by consumption levels, particularly for electric power generation. Capital costs play a role in determining the relative shares of total supply derived from conventional, unconventional, LNG imports, and other supply categories.

Figure 11. Additions to U.S. electricity generation capacity by fuel in three cases, 2006-2030 (gigawatts)



Total domestic natural gas production in 2030 differs by 1.6 trillion cubic feet between the low and high energy project cost cases (Figure 12). Lower 48 onshore production differs by 1.1 trillion cubic feet between the two cases, with conventional and unconventional production accounting for 0.6 and 0.5 trillion cubic feet of the total difference. Production from Alaska and offshore production differ by 0.4 and 0.2 trillion cubic feet, respectively, between the low and high energy project cost cases.

In 2030, total net natural gas imports are 3.1 trillion cubic feet in the high energy project cost case and 3.4 trillion cubic feet in the low energy project cost case. LNG imports account for more than 80 percent of total net natural gas imports in all the cases, and the capital costs for LNG facilities are by far the largest component of LNG supply costs. Net LNG imports are 2.5 trillion cubic feet in 2030 in the high energy project cost case, compared with 2.8 trillion cubic feet in the low energy project cost case.

The picture for net pipeline imports of natural gas from Canada and Mexico is more complex. In the reference case, because recent cost estimates indicate that a Mackenzie Delta pipeline would not be economical to build [*54*], net pipeline imports total only 0.3 trillion cubic feet in 2030. In the low energy project cost case, a Mackenzie pipeline would begin operation in 2014, providing about 420 billion cubic feet per year through 2030; as a result, net pipeline imports to the United States total 0.5 trillion cubic feet in 2030. In the high energy project cost case, with higher U.S. prices for natural gas inducing more production and exports from Canada, net U.S. pipeline imports total 0.6 trillion cubic feet in 2030.

Differences in total natural gas consumption in the energy project cost cases are determined primarily by the different amounts used for electricity generation. Because coal, nuclear, and renewables are more competitive with natural gas in the low energy project cost case and capture a larger share of new capacity additions, natural gas consumption in the electric power sector in 2030 is 0.4 trillion cubic feet lower than the reference case projection of 5.0 trillion cubic feet (Figure 13).

As a result of the lower level of natural gas use for electricity generation in the low energy project cost case, total domestic natural gas consumption and prices in 2030 are lower than in the reference case: consumption by 0.3 trillion cubic feet (from 22.7 trillion cubic feet in the reference case) and wellhead gas prices by $0.33 (2006 dollars) per thousand cubic feet (from $6.63 in the reference case) (Figure 14).

In the high energy project cost case, new natural-gas-fired electricity generation capacity is considerably less expensive than competing technologies, and the natural gas share of capacity additions increases, resulting in higher total consumption and prices for

Figure 12. U.S. natural gas supply by source in three cases, 2030 (trillion cubic feet)

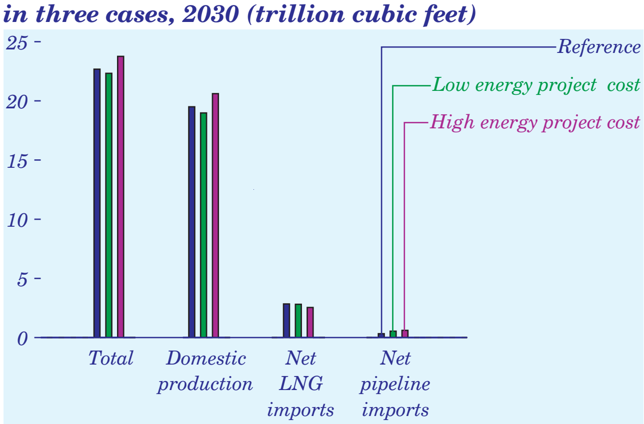


Figure 13. U.S. natural gas consumption by sector in three cases, 2030 (trillion cubic feet)

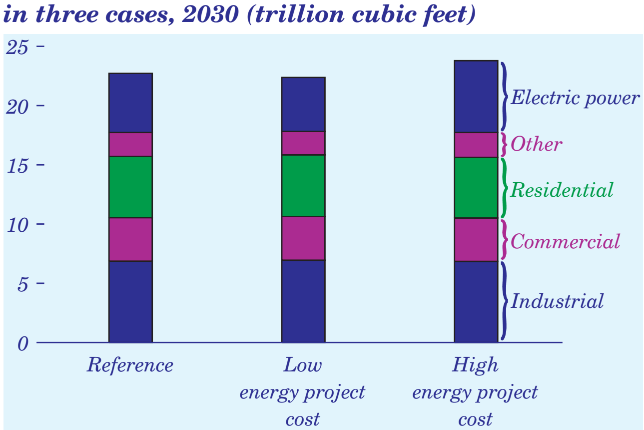
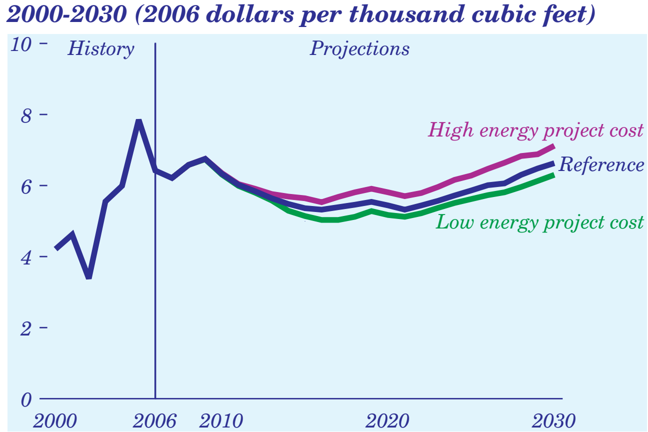


Figure 14. U.S. natural gas prices in three cases, 2000-2030 (2006 dollars per thousand cubic feet)



natural gas than in the reference case. The increase in consumption for electricity generation leads to higher total domestic consumption (by 1.1 trillion cubic feet) and higher price levels (by $0.49 per thousand cubic feet) for natural gas than in the reference case. Because of the higher prices, natural gas consumption in the residential, commercial, and industrial sectors in 2030 is lower than projected in the reference case.

Petroleum Liquids Supply

A large part of the domestic oil resource base has been produced, and new oil reservoir discoveries are expected to be smaller, more remote (offshore deepwater, for example), and more costly to exploit. With a few exceptions—namely, deepwater Gulf of Mexico and offshore Alaska—the remaining domestic petroleum basins have been significantly depleted. Consequently, EOR using miscible CO_2 is the primary extraction technique expected to keep onshore oil production at a relatively high level through 2030. The assumptions in the low and high energy project cost cases were applied only to the domestic resource. Depletion of domestic oil resources constrains the high and low energy project cost assumptions from having a significant impact on domestic oil production. The low and high energy project cost cases would show larger impacts if the assumptions were applied to world liquid supplies.

A slow, continuous decline in oil production is projected for the onshore United States, even with the relatively high oil prices [*55*]. Future domestic onshore oil production is dominated by large oil fields that were discovered decades ago, and EOR only extends their productive life. For example, although the Prudhoe Bay Field started production in 1976, the largest share of Alaska's oil production still comes from Prudhoe Bay. Although large oil fields on Alaska's North Slope came into production more recently [*56*], the long-term trend is for Alaska's oil production to decline as the Prudhoe Bay Field declines. The *AEO2008* reference case and low and high energy project cost cases include constant or declining U.S. oil production, as smaller and smaller new fields come into production while the larger existing fields continue to be depleted [*57*].

In the low energy project cost case, total domestic oil production in 2030 is 18,000 barrels per day higher than projected in the reference case. In the high energy project cost case, higher drilling costs reduce both the rates of return on oil production and the cash flow of oil producers, and as a result total domestic production in 2030 is about 300,000 barrels per day lower than in the reference case.

Because EOR is highly capital-intensive, most of the variation in domestic oil production across the three cases reflects differences in EOR production. In the reference case, CO_2 EOR production in 2030 totals 1.31 million barrels per day, as compared with 1.33 million barrels per day in the low energy project cost case and 980,000 barrels per day in the high energy project cost case.

For deepwater production in the Gulf of Mexico, the reference case projects an increase from about 970,000 barrels per day in 2006 to 2.0 million barrels per day from 2013 through 2019, followed by a decline to 1.6 million barrels per day in 2030. The projections in the low energy project cost case are nearly the same, because the constraints on deepwater development are not prices and costs but long development lead times and limited infrastructure. In the high energy project cost case, the capital intensity of deepwater development constrains oil production in the Gulf in the earlier years, with a peak production level of 1.9 million barrels per day from 2013 through 2019. As oil prices increase later in the projection period, however, small deepwater fields that were uneconomical in earlier years begin to be developed. In 2030, deepwater production in the Gulf is about 30,000 barrels per day higher in the high energy project cost case than projected in the reference case [*58*].

Both CTL and BTL production are also capital-intensive and vary significantly on a percentage basis across the three cases. Combined production from CTL and BTL facilities is about 620,000 barrels per day in 2030 in the low energy project cost case, compared with 510,000 barrels per day in the high energy project cost case.

The only other petroleum supply category significantly affected in the energy project cost cases is natural gas liquids (NGL). In the high energy project cost case, which projects considerably more natural gas production than the low case, NGL production is also higher, at 1.6 million barrels per day, compared with 1.5 million barrels per day in the low case. As a result, the difference in combined CTL and BTL production between two cases is almost completely offset by the difference in NGL production.

Crude oil prices are not projected to vary significantly across the three cases. The reference case projects a price of $70.45 per barrel for low-sulfur light crude oil in 2030 (2006 dollars), compared with $70.33 per barrel in the low energy project cost case and $70.65 per barrel in the high energy project cost case. Accordingly, total domestic consumption of petroleum liquids does not vary by much, at 22.7 million barrels per day in the high energy project cost case and 22.8 million barrels per day in the low energy project cost case. Imports of crude oil and liquid fuels make up the difference between the projections for liquids production and consumption in each case, varying from 55.5 percent of total U.S. supply in 2030 in the high energy project cost case to 54.0 percent in the low energy project cost case. As noted above, the impacts would be more significant if the assumptions in the low and high energy project cost cases were applied to global markets.

Limited Electricity Generation Supply and Limited Natural Gas Supply Cases

Development of U.S. energy resources and the permitting and construction of large energy facilities have become increasingly difficult over the past 20 years, and they could become even more difficult in the future. Growing public concern about global warming and CO_2 emissions also casts doubt on future consumption of fossil fuels—particularly coal, which releases the largest amount of CO_2 per unit of energy produced. Even without regulations to limit greenhouse gas emissions in the United States, the investment community may already be limiting the future use of some energy options. In addition, there is considerable uncertainty about the future availability of, and access to, both domestic and foreign natural gas resources.

To examine the effects of uncertainty about future supplies of electricity and natural gas, three alternative cases were developed for *AEO2008*. The limited electricity generation supply case assumes that higher construction and operating costs together with other factors, such as lack of public acceptance, will limit the use of energy sources other than natural gas for power generation—including coal without CCS technology, nuclear power, and renewable fuels. The limited natural gas supply case assumes that no Arctic natural gas pipeline will be in operation before 2030, the availability of LNG to U.S. regasification terminals will be limited, the U.S. oil and natural gas resource base will be less than in the reference case, access to the resource base will be more limited than assumed in the reference case, and that improvements in oil and natural gas exploration and development technologies will be slower than in the reference case. Finally, a combined limited case includes all the assumptions from the first two cases.

Assumptions

Limited Electricity Generation Supply Case

In the *AEO2008* reference case, based on existing laws and regulations, the use of natural gas for electricity generation continues to increase in the near term, then declines as generators increasingly turn to coal, renewables, and new nuclear power capacity in the longer term. New coal-fired capacity without CCS could be limited, however, by policy changes aimed at limiting CO_2 emissions. Several States already are beginning to implement emission reduction programs, and the U.S. Congress is discussing potential Federal programs. In California and Washington State, recent legislation has set emission standards for electric power plants that would preclude new coal-fired plants without CCS from providing power to those States (see “Legislation and Regulations”). There are also several proposals at the Federal level that would impose caps on CO_2 emissions. The limited electricity generation supply case, in addition to assuming that new coal-fired power plants without CCS cannot be built, also assumes that construction costs for new plants with CCS will be 25 percent higher than in the reference case.

Currently, new nuclear capacity is being proposed in response to incentives provided in EPACT2005, rising fossil fuel prices, and concerns about CO_2 emissions; however, there continue to be concerns about nuclear waste disposal, public acceptance, and the ability to build new plants on time and within budget. It is likely that some new nuclear plants will be built, given current interest levels and financial incentives, but if early builds encounter delays in construction or licensing or significant cost overruns (as occurred with the first generation of nuclear plants), the long-term potential for nuclear electricity in the United States could be reduced.

The limited electricity generation supply case assumes the same amount of new nuclear capacity as in the reference case by 2030; however, in circumstances where the reference case assumes that current capacity factors, averaging over 90 percent nationally, will be maintained throughout each plant’s 60-year lifetime, the limited electricity generation supply case assumes that the national average capacity factor for nuclear power plants will fall to 70 percent in 2030. To date, no nuclear power plant has operated for 40 years, and industry experience in maintaining older nuclear plants is limited. Thus, it is possible that replacement of major components on older plants could cause significant outages, or that gradual breakdowns could lead to lower capacity factors.

Adding large amounts of economical renewable capacity may also face challenges. The reference case projects a large increase in renewable capacity (mostly wind and biomass), mainly to meet the requirements of State RPS programs. There is also some public resistance to the siting of new wind and biomass plants, however, and their costs may increase after the "best" sites have been used. The limited electricity generation supply case assumes the same amounts of new wind and biomass capacity as in the reference case, but the availability of new biomass energy crops is delayed until 2020, compared with 2010 in the reference case. Biomass gasification technology is a new, unproven design that could run into delays and cost overruns, and in addition it could take many years to develop the infrastructure to grow, cultivate, harvest, and transport new energy crops. The costs for all other new renewable capacity (geothermal, landfill gas, solar thermal, and solar PV) are assumed to be 25 percent higher than in the reference case. Again, these technologies are new, and there is considerable uncertainty about initial cost estimates.

Limited Natural Gas Supply Case

The limited natural gas supply case represents an environment in which numerous natural gas supply options are unavailable, less available, or more costly to develop than in the reference case.

Among the most significant uncertainties for future natural gas supply are the development of natural gas pipelines in the Arctic region of North America, the future availability of LNG imports, the size of the domestic natural gas resource base, and the rate of technological improvement in the industry. Currently, two large natural gas pipelines are under consideration for development in the Arctic region: a Mackenzie Delta pipeline in Canada and an Alaska pipeline [*59*], both of which are large, expensive construction projects. It is expected that 6 years will be required to permit, license, design, construct, and open the Mackenzie pipeline and 9 years will be required to do the same for the Alaska pipeline. A number of factors could delay completion of the projects beyond 2030, however, including: higher-than-expected construction costs that would make the pipelines unprofitable throughout the projection period; higher-than-expected State and Provincial taxes and royalties on natural gas production; environmental concerns requiring expensive remediation; delays in regulatory approval and permitting; and difficulties in addressing the concerns of native peoples whose lands are crossed by the pipelines. Accordingly, the limited natural gas supply case assumes that neither pipeline will be opened before 2030.

The future availability of LNG imports depends critically on the development of new LNG supply sources throughout the world, which in turn will require the construction of large, expensive liquefaction facilities and LNG tankers. Typically their financing is supported by multi-decade contract commitments from large natural gas consumers, such as natural gas and electric utilities; however, those large consumers face considerable uncertainty of their own, including whether new nuclear generating capacity will reduce long-term requirements for natural gas supply, whether alternative supplies will be available from other sources at lower prices, and whether suitable pricing mechanisms will be available to ensure that LNG suppliers earn a reasonable rate of return while the consumers pay prices that are reasonable in comparison with the prices of other sources of natural gas supply.

It is possible that potential LNG suppliers could face considerable difficulty in obtaining customer commitments sufficient to support the financing required for development of LNG supplies that are able to satisfy world demand for natural gas. Further, if LNG supplies are scarce relative to world demand, overseas natural gas prices could exceed U.S. domestic prices, drawing LNG supplies away from the U.S. market. Alternatively, new sources of LNG supply could be fully committed to overseas customers under long-term contracts, making spot purchases of LNG either unavailable or prohibitively expensive.

Availability of supplies could also be limited by policies adopted by the countries that produce LNG. For example, LNG producers could operate in concert to limit LNG supplies in order to increase prices or to make more natural gas available to their own consumers. They might also adopt production taxes, excise taxes, and tariffs that would make LNG economically unattractive in the United States.

The LNG assumptions used in the limited natural gas supply case are identical to those used in the low LNG case (discussed later in "Issues in Focus"), with U.S. gross imports of LNG held constant at 1.0 trillion cubic feet per year from 2009 through 2030 [*60*]. The LNG restrictions apply to the United States only; LNG imports to Canada and Mexico remain sensitive to prices, and new LNG import capacity is assumed to be constructed in those countries according to predetermined price triggers.

The actual size of the domestic oil and natural gas resource base is another source of uncertainty. The USGS and Minerals Management Service (MMS) calculate the U.S. undiscovered oil and natural gas resource base on a probabilistic basis, reporting a mean estimate, a 95-percent probability estimate, and a 5-percent probability estimate of technically recoverable oil and natural gas resources in each major U.S. petroleum basin. As an example, for the U.S. lower 48 onshore basins, the USGS mean probability estimate of undiscovered natural gas resources is 483 trillion cubic feet, the 95-percent probability estimate is 291 trillion cubic feet, and the 5-percent probability estimate is 735 trillion cubic feet [*61*], illustrating the wide range of uncertainty with regard to the size of the U.S. oil and natural gas resource base.

The *AEO2008* reference case assumes that the technically recoverable U.S. oil and natural gas resource base is equal to the USGS and MMS mean estimates. Given the uncertainty inherent in those estimates, however, the actual resource base could be considerably smaller. Further, the ability to develop the resource base could be limited by other factors, including the possibility that future laws and regulations could place more Federal and State land off limits to oil and natural gas production. The limited natural gas supply case assumes that the U.S. unproven oil and natural gas resource base and Canada's undiscovered natural gas resource base are 15 percent smaller than the estimates used in the reference case.

Another factor that could reduce available natural gas supplies is a slowdown in the rate of technological progress. Technological progress generally reduces the cost of finding, developing, and producing natural gas resources. In addition to their direct impacts on costs, technology improvements can increase finding and success rates, which have an impact on the average costs of production. A slower rate of progress results in higher capital and operating costs for oil and natural gas exploration and development than would otherwise be the case. The limited natural gas supply case assumes a technological progress rate that is one-half the rate in the reference case.

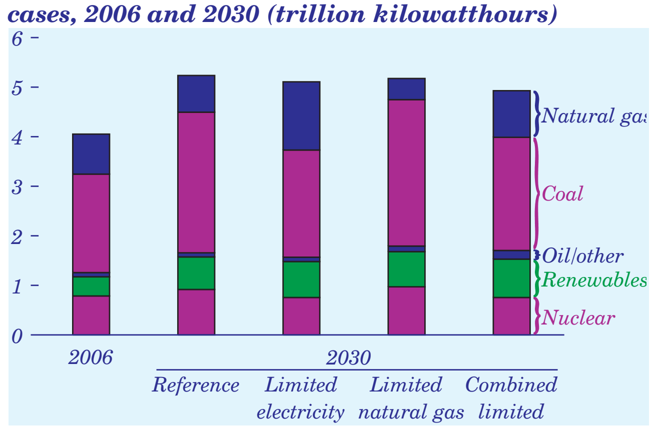
Results

Electricity Generation

In 2006, coal-fired power plants supplied 49 percent of U.S. electricity generation. In the *AEO2008* reference case, coal's market share is maintained through 2020 and grows to 54 percent in 2030, primarily as a result of projected increases in natural gas prices. In the limited electricity generation supply case, natural gas supplies are unchanged from those in the reference case, while generation from other fuels is constrained. As a result, the coal share of total generation drops to 42 percent in 2030, and the natural gas share increases from 20 percent in 2006 to 27 percent in 2030, as compared with 14 percent in 2030 in the reference case (Figure 15). By assumption, nuclear, wind, and biomass remain at or below reference case levels from 2006 through 2030, while generation from other renewables and from oil increases slightly. Although delivered natural gas prices to the electric power sector in 2030 are 16 percent higher in the limited electricity generation supply case than in the reference case because of higher demand, the price increase is not enough to shift generation from natural gas to the competing technologies.

In the limited natural gas supply case, no constraints are assumed for any electricity generation technology relative to the reference case, but natural gas supplies

Figure 15. Electricity generation by fuel in four cases, 2006 and 2030 (trillion kilowatthours)



are limited. As a result, in 2030, delivered natural gas prices to the electric power sector are 39 percent higher than in the reference case, and natural-gas-fired generation is 42 percent less than in the reference case. With no technology restrictions, natural gas is displaced by increases in the use of coal, nuclear, and some renewables (geothermal, biomass, and wind) for electricity generation.

In the combined limited case, all the fuel choices for electricity generation are more expensive than in the reference case. Natural-gas-fired generation in 2030 is higher than in the reference case, but with higher natural gas prices (84 percent higher than those in the reference case) the difference is smaller than in the limited electricity generation supply case. Coal-fired plants with CCS are built, increasing the demand for coal, and investment in new renewable technologies increases, including geothermal and offshore wind. Oil-fired generation also increases substantially, because it is less expensive to use distillate than natural gas even in some newer combined-cycle plants. Total electricity generation is 6 percent lower in the combined limited case than in the reference case, as higher costs for fuel and for plant construction result in higher prices and lower demand for electricity.

The technology mix for new capacity additions differs dramatically among the three limited cases (Figure 16). In the limited electricity generation supply case, the only new coal-fired builds are those currently under construction, and almost all the additional coal-fired plants projected to be built in the reference case are replaced by new natural-gas-fired capacity (an additional 60 gigawatts). Nuclear generating capacity is the same as in the reference case, and renewable capacity additions are 8 gigawatts higher.

In the limited natural gas supply case, higher natural gas prices reduce natural-gas-fired capacity additions, while additions of coal-fired, renewable, and nuclear capacity increase relative to the reference case. Because more older generating units are retired in the limited natural gas supply case (primarily, those using natural gas) more new capacity is added than in the reference case.

In the combined limited case, 17 gigawatts of new coal-fired capacity with CCS is built. Natural-gas-fired capacity also increases relative to the reference case, but by a smaller amount than is projected in the limited electricity generation supply case. More new capacity using renewable technologies that are not constrained by assumption, including geothermal, landfill gas, and offshore wind, is built in the combined case than in the reference case, even though their construction costs are assumed to be higher than in the reference case.

Natural Gas Consumption

Natural gas consumption for electric power generation in 2030 varies widely across the cases, from 43 percent below the reference case level in the limited natural gas supply case to 78 percent above the reference case level in the limited electricity generation supply case (Figure 17). The largest difference from the reference case is in the limited electricity generation supply case, because constraints on competing fuels, such as the CCS requirement for new coal-fired plants, make natural gas the fuel of choice for new capacity.

In the limited electricity generation supply case, natural gas consumption for electricity generation is 3.9 trillion cubic feet above the reference case level in 2030, while total U.S. natural gas consumption in

Figure 16. New generating capacity additions in four cases, 2006-2030 (gigawatts)

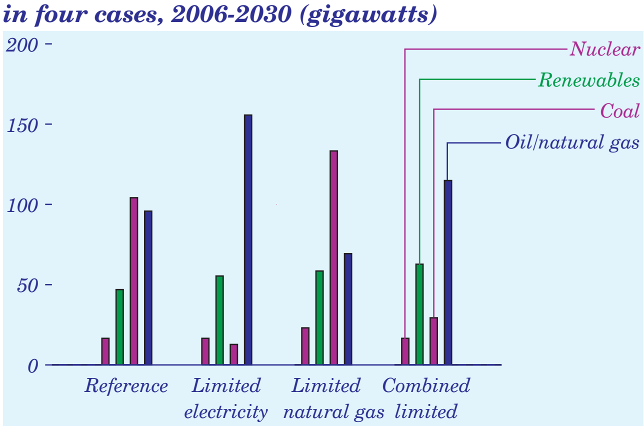
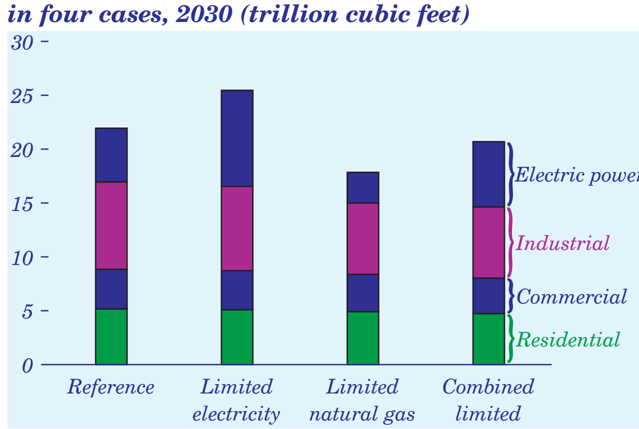


Figure 17. Natural gas consumption by sector in four cases, 2030 (trillion cubic feet)



2030 is only 3.6 trillion cubic feet higher than in the reference case. Higher natural gas prices in the limited electricity generation supply case reduce residential, commercial, and industrial natural gas consumption in 2030 by a total of 0.4 trillion cubic feet from the reference case projection.

In the limited natural gas supply case, where only natural gas supply is constrained, higher natural gas prices cause natural gas to lose market share in all the end-use consumption sectors. In 2030, total natural gas consumption is 3.8 trillion cubic feet less in the limited natural gas supply case than in the reference case. In the electric power sector, which is particularly fuel flexible and price sensitive, natural gas consumption in 2030 is 2.2 trillion feet lower than in the reference case.

In the combined limited case, total natural gas consumption in 2030 is 3 percent lower than projected in the reference case, although natural gas use for electricity generation is 21 percent (1.1 trillion cubic feet) higher than in the reference case. In comparison, natural gas consumption in the electric power sector in 2030 is 3.9 trillion cubic feet higher in the limited electricity generation supply case and 2.2 trillion cubic feet lower in the limited natural gas supply case than in the reference case. The constraints on other sources of electricity generation in the limited electricity generation supply case thus have a much more pronounced effect on natural gas consumption in the electric power sector than do the natural gas supply constraints in the limited natural gas supply case.

In all three cases, higher natural gas prices reduce natural gas consumption in the residential, commercial, and industrial sectors relative to the reference case. In the combined limited case, natural gas consumption in the end-use sectors in 2030 is 14 percent lower than in the reference case. In the short term there is little potential in those sectors for fuel switching, which generally occurs only over the long term as older equipment is retired. In the residential and commercial sectors, most of the reduction in natural gas consumption in the three cases results from conservation and more efficient appliances. In the industrial sector, where there is some fuel-switching capability, part of the decrease is attributable to fuel substitution. In addition, although not quantified here, higher prices could drive some industrial users to either shut down operations or move them outside the United States to locations where fuel and other operating costs are lower.

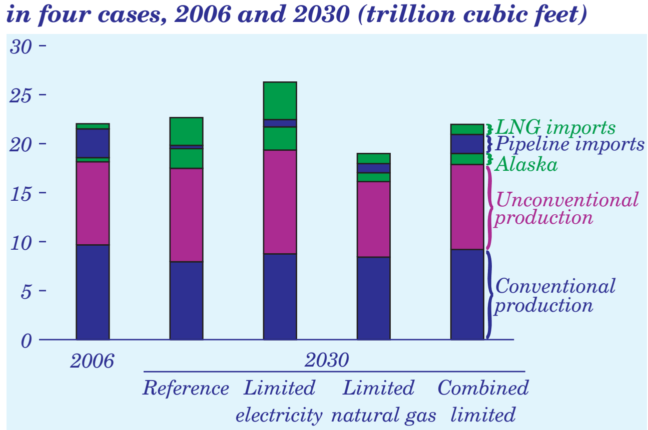
In the end-use sectors, the largest reduction in natural gas consumption occurs in the combined limited case, because the highest natural gas prices are also projected in the combined case. In 2030, natural gas consumption is 19 percent lower in the industrial sector, 8 percent lower in the residential sector, and 10 percent lower in the commercial sector than projected in the reference case.

Natural Gas Supply

As consumption patterns shift across the cases, the mix of natural gas supply sources changes considerably (Figure 18). These changes are dictated largely by the natural gas supply conditions assumed in the limited natural gas supply case and in the combined limited case, which assumes that no Alaska natural gas pipeline is built and that gross LNG imports do not increase after 2009. Consequently, in these two cases, lower 48 sources provide most of the incremental natural gas supply.

In the limited electricity generation supply case, all natural gas sources contribute to incremental supply in 2030. The largest increase is 1.1 trillion cubic feet from unconventional natural gas production, which consists of tight gas, shale gas, and coalbed methane. Unconventional natural gas makes up the bulk of the undiscovered resource base and shows significant growth in the reference case projections. Conventional natural gas production (onshore and offshore) in 2030 is 0.6 trillion cubic feet above the reference case level. Alaskan production and LNG imports, which are not constrained in this case, both respond to higher prices, increasing by 0.4 and 1.0 trillion cubic feet, respectively. Offshore production is slightly higher, by 0.2 trillion cubic feet, and pipeline imports are higher by 0.4 trillion cubic feet.

Figure 18. Natural gas supply by source in four cases, 2006 and 2030 (trillion cubic feet)



In the limited natural gas supply case, where total natural gas consumption in 2030 is 3.8 trillion cubic feet less than in the reference case, the lack of an Alaska pipeline and the constraint on U.S. LNG imports account for 2.9 trillion cubic feet of the reduction in natural gas supply. Unconventional natural gas production is also reduced by 1.8 trillion cubic feet, whereas domestic production from other sources, particularly onshore conventional resources, is increased by 0.4 trillion cubic feet and pipeline imports are increased by 0.6 trillion cubic feet.

The decrease in unconventional natural gas production in the limited natural gas supply case relative to the reference case is a direct result of the changes in supply assumptions. Because the undiscovered unconventional resource base is considerably larger than the conventional resource base, the assumption of a 15-percent smaller resource base has the greatest volumetric impact on unconventional natural gas resources. Technology advances already have made most conventional supplies economically recoverable, and thus a reduced rate of technological progress has a larger impact on the cost of developing unconventional and offshore resources. Deepwater offshore resources are further constrained by infrastructure limitations and long lead times for the construction of new production platforms and pipelines. Thus, conventional production increases, unconventional production decreases, and there is only a small increase in offshore production in the limited natural gas supply case relative to the reference case.

Although the natural gas technology and resource assumptions in the limited natural gas supply case apply to Canada as well as to the United States, LNG imports into Canada and Mexico are not constrained [*62*] and are responsive to higher prices. As a result, both countries are projected to increase their LNG imports and make more natural gas available to the U.S. market by pipeline.

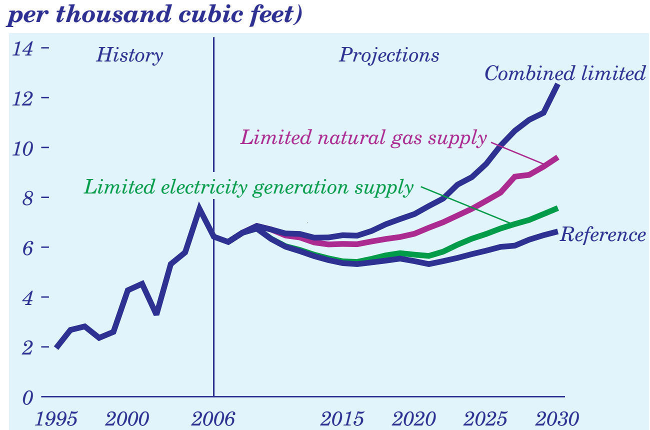
In the combined limited case, net natural gas pipeline imports in 2030 are almost 6 times the reference case level. Although U.S. pipeline imports of natural gas might be expected to increase in the limited electricity generation supply case, the assumed opening of an Alaska natural gas pipeline reduces Canadian exports to the United States.

Before 2025, the largest source of incremental U.S. natural gas supply in the combined limited case is conventional lower 48 natural gas production. In 2030, however, higher natural gas prices cause net pipeline imports to become the largest source of incremental supply. Net pipeline imports in 2030 are 1.6 trillion cubic feet higher and account for slightly more than one-half of the total increase in natural gas supply in the combined limited case relative to the reference case. LNG imports into Canada and Baja California, Mexico, are 1.1 trillion cubic feet higher in the combined limited case than in the reference case in 2030, accounting for more than 50 percent of the increase in net pipeline imports. Other domestic production accounts for the remainder of the difference in incremental supply between the two cases in 2030, with onshore conventional production 1.3 trillion cubic feet higher and offshore production 0.2 trillion cubic feet higher in the combined limited case than in the reference case. The increases in domestic conventional natural gas production and pipeline imports offset declines in unconventional production and Alaska production. They also offset a decline in LNG imports that are eliminated from the combined limited case by assumption but are available in the reference case.

Natural Gas Prices

In each of the three limited cases, natural gas prices are higher than projected in the reference case (Figure 19). The assumptions for the limited natural gas supply case have a more significant impact on price than those for the limited electricity generation supply case, with natural gas wellhead prices 45 percent and 14 percent higher in 2030 than in the reference case, respectively. The largest difference from the reference case is in the combined limited case, with prices 89 percent higher than in the reference case in 2030. End-use prices for natural gas increase in response to the higher wellhead prices and

Figure 19. Lower 48 wellhead natural gas prices in four cases, 1995-2030 (2006 dollars per thousand cubic feet)



moderate consumption, while price increases both result from and contribute to changes in the mix of supply sources.

The reason for the large price variations across the cases is the need to turn to more expensive sources of supply to satisfy the demand for natural gas as consumption increases and available sources of supply diminish. With the exception of Alaska and unconventional natural gas, the domestic conventional natural gas resource base is largely depleted, and only limited production increases are possible in response to consumption increases. Most of the large conventional fields have already been discovered, leaving only the smaller and deeper fields that are more costly to develop.

In the limited electricity generation supply case, which assumes the same resource base and rate of technological progress as in the reference case, unconventional natural gas production increases in response to higher prices. The assumptions for the limited natural gas supply case limit technological progress and reduce the size of the resource base, causing a much greater price increase than in the limited electricity generation supply case. Increased demand for natural gas in the limited electricity generation supply case raises the natural gas wellhead price in 2030 to $7.57 per thousand cubic feet, compared with $6.63 per thousand cubic feet in the reference case. In the limited natural gas supply case, the wellhead price in 2030 is $9.61 per thousand cubic feet, and in the combined limited case it is $12.55 per thousand cubic feet.

Electricity Prices

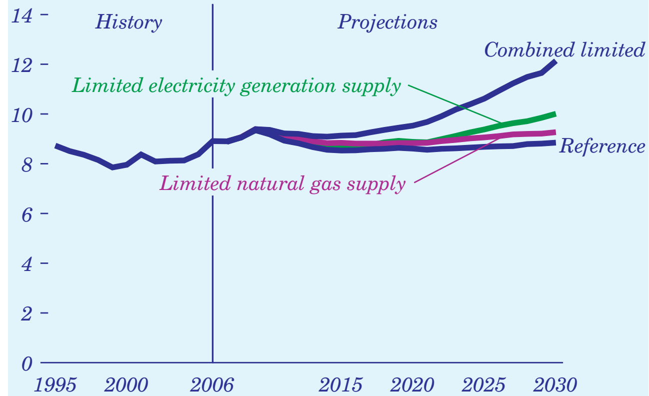
In the *AEO2008* reference case, real electricity prices are projected to remain relatively flat, with the 2030 price slightly below the current price. In the three limited cases, all with higher natural gas prices, electricity prices in 2030 are 4 percent to 36 percent higher than 2006 prices (Figure 20). Electricity prices in 2030 in the limited electricity generation supply case are higher than those in the limited natural gas supply case, even though natural gas prices are lower, because there are more options to change the generation mix in the limited natural gas supply case. In the limited electricity generation supply case, with capacity additions largely restricted to natural gas technologies, electricity prices are more sensitive to changes in natural gas prices and are 13 percent higher in 2030 than projected in the reference case. In comparison, electricity prices in 2030 in the limited natural gas supply case are 5 percent higher than in the reference case. In the combined limited case, electricity prices in 2030 are 37 percent higher than in the reference case.

Trends in Heating and Cooling Degree-Days: Implications for Energy Demand

Weather-related energy use, in the form of heating, cooling, and ventilation, accounted for more than 40 percent of all delivered energy use in residential and commercial buildings in 2006. Given the relatively large amount of energy affected by ambient temperature in the buildings sector, EIA has reevaluated what it considers "normal" weather for purposes of projecting future energy use for heating, cooling, and ventilation. In *AEO2008*, estimates of "normal" heating and cooling degree-days are based on the population-weighted average for the 10-year period from 1997 through 2006.

In previous *AEO*s, EIA used the National Oceanic and Atmospheric Administration (NOAA) 30-year average for heating and cooling degree-days as a benchmark for normal weather. Over the past several years, however, many energy analysts have questioned the use of the 30-year average, given the recent trend toward warmer weather relative to the 30-year average. Figure 21 shows percentage differences from the 30-year average in heating and cooling degree-days for the past 15 years. Over the 15-year period, only two winters have been colder, and all but three summers have been warmer, than the 30-year average; and on average, the winters have been 4 percent warmer and the summers 5 percent warmer than the 30-year average. Five of the 15 summers were more than 10 percent warmer than the 30-year average, whereas only 2 of the 15 winters were 10 percent

Figure 20. U.S. average electricity prices in four cases, 1995-2030 (2006 cents per kilowatthour)



warmer than the average, indicating a larger change for summer than for winter weather over the past 15 years. This suggests that the 30-year average is heavily weighted by years before 1993 and is less representative of heating and cooling degree-days in more recent years.

The recent changes in average heating and cooling degree-days have not only affected the accuracy of *AEO* projections for heating and cooling demand. Underestimating summer demand for cooling—particularly, peak demand—can undermine the plans made by electricity producers for wholesale power purchases and capacity additions. Overestimating winter demand for heating can affect plans for natural gas storage and supply. Consequently, many energy analysts have suggested that shorter time periods provide a more appropriate basis for projecting "normal" weather. For example, Cambridge Energy Research Associates, Inc., now uses a 15-year period (1991-2005) to estimate normal weather in its projections for heating and cooling degree-days [*63*], and NOAA, responding to customer feedback, has undertaken a process to revise its traditional 30-year average by creating "optimal climate normals" that will be more representative of current weather trends [*64*]. EIA decided to use the 10-year average to provide a better match with recent trends in heating and cooling degree-days.

Heating and Cooling Degree-Days in AEO2008

All the *AEO2008* projections use the 1997-2006 average as a proxy for normal weather from 2009 through 2030. The 10-year average is based on heating and cooling degree-day data by State, provided by NOAA, and State population weights provided by the U.S. Census Bureau. The State population projections allow for dynamic estimates of heating and cooling degree-days at the Census Division level. Where State populations are expected to shift within and across Census Divisions, the projections for average heating and cooling degree-days at the national level can vary from year to year.

Figure 22 shows differences in heating and cooling degree-days in the *AEO2008* projection for 2010-2030 from the 1971-2000 30-year average published by NOAA. (It should be noted that the projection is not based on any assumption about global warming. Rather, expected U.S. population shifts cause the numbers of average heating and cooling degree-days to change over the projection period.) In 2010, the number of U.S. cooling degree-days in the *AEO2008* reference case is about 10 percent greater than the NOAA 30-year average with fixed population weights, and the number of heating degree-days is 8 percent less [*65*]. Accordingly, electricity providers are projected to see more peak summer demand, and direct fuel use for heating in buildings is projected to decline through 2030 as a result of State population shifts, all else being equal.

Impacts on the AEO2008 Projections

Fuel Use in Buildings and for Electricity Generation

Because space heating accounts for more direct energy use in buildings than does cooling, use of the 10-year averages for heating and cooling degree-days results in a 2.4-percent net decrease (about 0.6 quadrillion Btu) in buildings sector energy consumption in 2030, as compared with the same projection based on 30-year average heating and cooling degree-days (Figure 23). For electricity providers, on the other hand, the increase in electricity use for

Figure 21. Annual heating and cooling degree-days, 1993-2007 (percent difference from 30-year average)

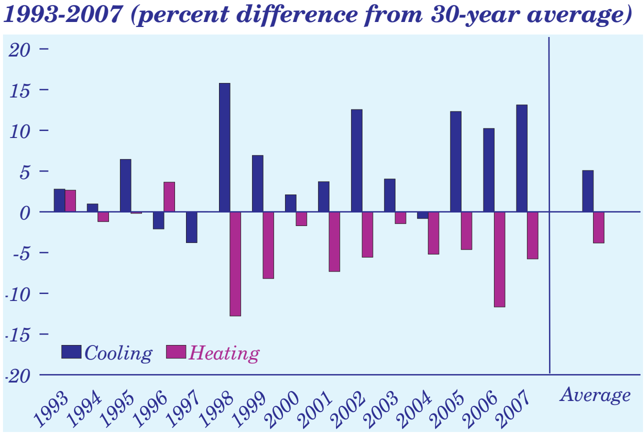
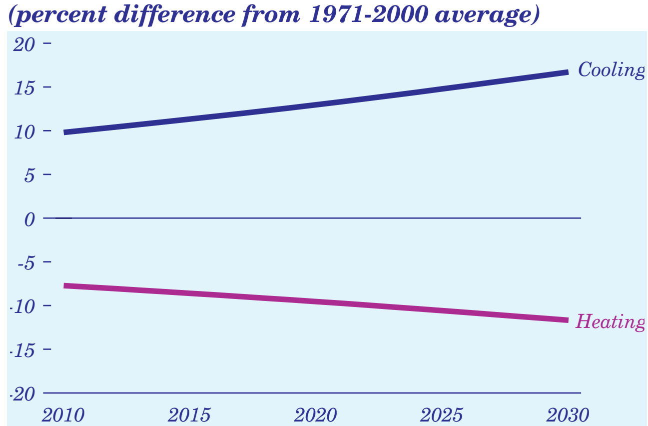


Figure 22. Heating and cooling degree-days in the AEO2008 reference case, 2010-2030 (percent difference from 1971-2000 average)



cooling is more than the decrease in electricity use for heating, and the result is a 0.7-percent net increase (about 0.4 quadrillion Btu) in fuel use for electricity generation. The effect on total net energy consumption in the reference case is small, amounting to a 0.4-percent decrease (about 0.4 quadrillion Btu) in 2030. As a result, expenditures for energy purchases in residential and commercial buildings are 0.4 percent lower in 2030 ($1.8 billion in 2006 dollars), and total CO_2 emissions in 2030 are reduced by 0.1 percent (10 million metric tons).

Electricity Prices

As expected, the additional summer demand for cooling that results from using the 10-year average for cooling degree-days shifts more electricity demand into the summer peak period (Figure 24). In 2030, demand in the summer peak period increases by 4.4 percent, whereas winter demand is reduced by 0.8 percent. The increase in summer peak demand leads to higher real electricity prices, with average increases of 2.3 percent for residential customers and 0.3 percent for commercial customers.

Liquefied Natural Gas: Global Challenges

U.S. imports of LNG in 2007 were more than triple the 2000 total, and they are expected to grow in the long term as North America's conventional natural gas production declines. With U.S. dependence on LNG imports increasing, competitive forces in the international markets for natural gas in general and LNG in particular will play a larger role in shaping the U.S. market for LNG. Key factors currently shaping the future of the global LNG market include the evolution of project economics, worldwide demand for natural gas, government policies that affect the development and use of natural resources in countries with LNG facilities, and changes in seasonal patterns of LNG trade.

Changing Project Economics

From the mid-1990s through 2002, a major factor underlying the growth of global LNG markets was declining costs throughout the LNG supply chain. Since 2003, however, costs have escalated, especially in the area of liquefaction. The result has been a delay in commitments to the construction of new liquefaction capacity, which in turn creates uncertainty about the future availability of LNG supplies.

The cost of liquefaction capacity can vary widely, depending on location, quality of natural gas supplies, and plant design (including whether the planned capacity is an expansion of an existing plant or a new greenfield plant). In general, however, the available data indicate that construction costs for new liquefaction capacity have more than tripled since the early 2000s [*66*]. Some of the reasons for the increase are higher raw material costs for commodities such as nickel and steel, a shortage of experienced workers and contractors, full construction order books, and longer delivery times for key pieces of equipment. Although economies of scale can reduce unit costs, those reductions have not been sufficient to offset increases in other costs.

For regasification facilities and receiving terminals, the available data suggest that the construction costs for new projects have increased by more than 50 percent over the past 5 years [*67*]. In addition, construction costs for LNG tankers have increased by 40 to 50 percent since 2003 [*68*], primarily because of rising

Figure 23. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on energy use for heating and cooling in buildings by fuel type, 2030 (quadrillion Btu)

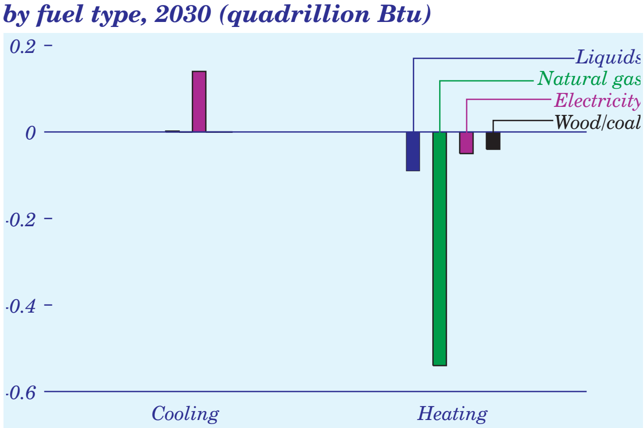
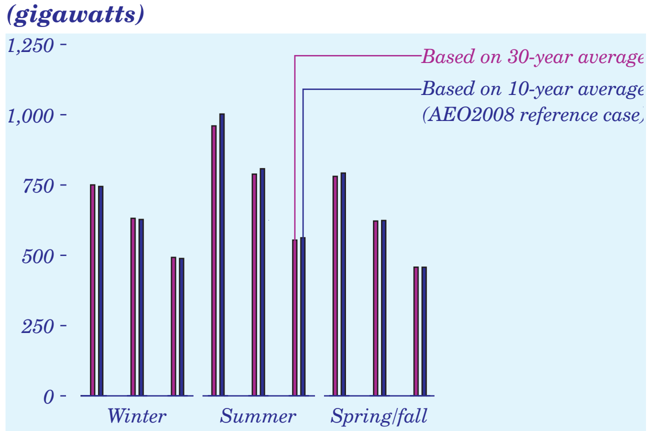


Figure 24. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on peak seasonal electricity demand load, 2030 (gigawatts)



costs for materials and equipment. Wood Mackenzie reports that ship prices remain on "an upward trend driven by a surge in new orders of large tankers, bulk carriers, and containerships, which compete with LNG carriers for berth space" [*69*].

Worldwide Demand for Natural Gas

Contributing to the uncertainty about LNG supply availability is a worldwide increase in natural gas consumption and its effect on prices. In EIA's *International Energy Outlook 2007*, annual worldwide natural gas consumption in 2030 varies by 35 trillion cubic feet between the high and low macroeconomic growth cases, or around plus or minus 11 percent when compared with the reference case [*70*].

For some countries, such as Japan and South Korea, relatively slow growth is expected for natural gas consumption, but because they are almost entirely dependent on LNG imports to meet natural gas demand, any increase is likely to affect LNG markets. For India and China, on the other hand, natural gas consumption has increased much more rapidly. Both countries have been actively searching for new domestic natural gas resources, and both have been pursuing pipeline projects that could bring more imported supplies to domestic consumers. China has been negotiating with Russia to obtain supplies, India has been negotiating with Iran, and both countries have been competing for pipeline supplies from Central Asia and Myanmar. The success or failure of domestic natural gas exploration efforts in India and China and the possible construction of new pipelines is likely to affect their demand for LNG imports and, ultimately, how much LNG will be available to the United States.

Currently, the Organization for Economic Cooperation and Development (OECD) countries account for the majority of LNG imports. In 2006, 12 OECD countries [*71*] were net importers of LNG, and they accounted for just over 90 percent of all LNG imports. Five non-OECD countries [*72*] accounted for the remaining 10 percent. Among the world's net exporters of LNG, however, 11 of 12 were non-OECD countries [*73*], and Australia was the only OECD country with net LNG exports in 2006. At the same time, natural gas consumption has been increasing at a faster rate in the non-OECD countries than in the OECD countries as a whole.

Resource Development Policies

In addition to the uncertainty associated with natural gas demand growth and project costs, many countries that are net LNG exporters have government policies or agreements that promote domestic natural gas consumption. Any expansion (or rollback) of such policies could affect their future domestic consumption of natural gas and the supplies available for export.

Indonesia, Egypt, and Australia have or are considering domestic natural gas supply requirements for projects under development. Indonesia's 2001 Oil and Gas Law imposes a 25-percent domestic market obligation on new contracts for natural gas production sharing, although implementation of the law is still uncertain [*74*]. In 2005, Egypt reduced the portion of natural gas reserves available for export from one-third to one-quarter.

Unlike Egypt and Indonesia, Australia does not have any national regulations that require natural gas resources to be reserved for domestic markets; however, the Western Australia state government has negotiated an agreement with Northwest Shelf LNG developers to reserve 4.7 trillion cubic feet of Northwest shelf natural gas for the domestic market and, more recently, has negotiated a similar agreement with Gorgon LNG developers to set aside 15 percent of reserves for the domestic market. The Western Australia government has also been considering domestic reservation requirements for all future natural gas projects that would liquefy production for export [*75*]. Such a requirement could discourage development of marginal export projects, leaving some resources undeveloped.

Domestic reservation requirements promote natural gas consumption by keeping domestic natural gas prices low. In addition, many countries that are net LNG exporters foster domestic consumption further by directly regulating domestic natural gas prices and keeping them below LNG net-back equivalent prices. Both China and India, two of the world's newest LNG importers, also regulate the prices that electricity generators pay for natural gas. Without below-market prices, generators probably would be unable to use natural gas to generate power profitably for sale to domestic electricity markets, where prices also are regulated.

Seasonal Usage Patterns

The natural gas market in North America, where indigenous production meets much of the demand for natural gas, is a large, liquid market with ample storage capacity. Thus, even during periods of relatively low demand, it can still absorb imports. There is, however, a seasonal element specific to the U.S. market (Figure 25). More LNG is imported by the United States during the summer months, for reasons related as much to conditions in other LNG-importing countries as to conditions in the United States. The conditions that make North America an attractive year-round market are not likely to change, but changing conditions in the rest of the world could reduce the availability of summer LNG imports to the United States.

The natural gas market in OECD Europe is comparable with the North American market in size—about 71 percent as large in 2005. Whereas North America relies almost entirely on storage withdrawals to meet incremental winter demand, OECD Europe employs a variety of sources, with indigenous production, natural gas imports, and storage withdrawals all rising in the winter months to meet increased demand (Figure 26).

The United Kingdom, Belgium, and the Netherlands currently have active market-based systems for natural gas. In addition, European Union regulators are trying to introduce regulatory reform into additional markets and bring more liquidity into continental European markets. Although OECD Europe also has less storage capacity than North America, even when the relative size of annual demand in the two markets is taken into account, it has many geologic structures that could be suitable for seasonal natural gas storage. By 2015, OECD Europe could add almost 1 trillion cubic feet of additional working natural gas capacity in seasonal storage facilities [*76*].

The seasonal LNG supplies available to the North American market could also be affected if new importers of LNG develop in the southern hemisphere, where peak demand for heating occurs during the northern hemisphere's summer. Argentina became the first South American country to import LNG, offloading its first partial cargo in May 2008. Argentina and its neighbors are anticipating a shortage of natural gas this winter (June-August), and Argentina is planning to import LNG on special ships with onboard regasification capability while the construction of onshore regasification terminals is being discussed.

Brazil and Chile also will soon become LNG importers. Brazil has two floating regasification and storage units on order, the first of which could begin operation on the country's northeast coast during 2008. Chile has at least one regasification terminal in the advanced planning stage, and others are under consideration. The terminal planned for Quinteros, Chile, is expected to enter service in the second quarter of 2009 with a capacity of 2.5 million tons of LNG (116 billion cubic feet of natural gas) per year and a contract with BG Group for supply of 1.7 million tons (79 billion cubic feet) per year [77].

Implications of Uncertainty in LNG Markets

Changing expectations about global LNG demand, supply, and prices are reflected in the *AEO2008* reference case. Demand for natural gas overall is lower in *AEO2008* than in *AEO2007* as a result of expectations for slower economic growth and higher energy prices, including natural gas prices. With the additional assumptions of higher LNG costs, stronger competition for global LNG supplies, and growing constraints on LNG production, U.S. LNG imports in 2030 are 1.7 trillion cubic feet lower in *AEO2008* than the *AEO2007* projection for LNG imports in 2030. There remains, however, considerable uncertainty

Figure 25. U.S. imports of liquefied natural gas, 2001-2007 (billion cubic feet per day, 3-month average)

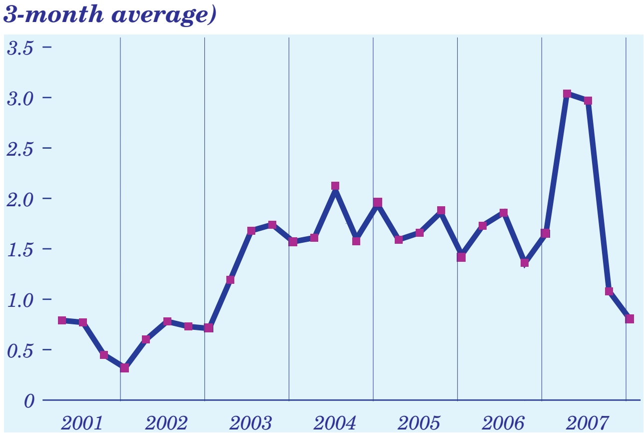
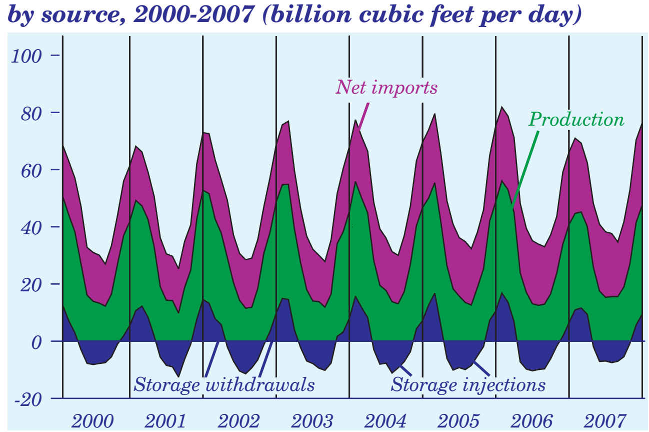


Figure 26. OECD Europe natural gas supply by source, 2000-2007 (billion cubic feet per day)



about the future of the global LNG market, which could lead to higher or lower LNG imports. To quantify the possible effects of that uncertainty, *AEO2008* includes high and low LNG supply cases in which U.S. imports of LNG are assumed to be higher and lower, respectively, than in the reference case.

The high and low LNG supply cases are not based on explicit assumptions about the causes of increased or decreased availability of LNG imports but only examine their potential impacts on natural gas supply, demand, and prices in the United States. Gross U.S. LNG import levels were specified for the high LNG supply case by increasing LNG imports by 10 percent in 2011 relative to the reference case level, followed by a gradual increase to three times the reference case level in 2030. For the low LNG supply case, U.S. LNG imports are held constant at the reference case level in 2009 through the end of the projection. All other assumptions in the LNG supply cases, such as oil prices and domestic resource levels, are the same as in the reference case. In 2030, LNG imports are specified to be 8.5 trillion cubic feet in the high LNG supply case and 1.0 trillion cubic feet in the low LNG supply case (Figure 27).

Varying the amount of LNG imports affects domestic production, consumption, and price levels for natural gas. In general, lower LNG imports result in the use of higher priced domestic production, leading to higher prices and, subsequently, reduced consumption and total supply requirements. In the low LNG supply case, 23 percent of the reduction in LNG imports is made up by a decline in natural gas consumption (primarily in the electricity generation sector, where more than 90 percent of the reduction occurs). The other 77 percent is made up by an increase in supplies from other sources, primarily domestic unconventional natural gas production (26 percent) but also other domestic lower 48 production (20 percent), Alaska production (20 percent), and pipeline imports (11 percent) (Figure 28). The lower supply requirement helps moderate the price increase relative to the reference case (Figure 29). Wellhead natural gas prices in 2030 are 4.4 percent higher in the low LNG supply case than in the reference case.

In the high LNG supply case, the impact on consumption is larger. An increase in natural gas consumption amounts to about 45 percent of the increment in LNG imports relative to the reference case, and the remaining 55 percent offsets declines in domestic natural gas production and pipeline imports. Wellhead prices in 2030 are nearly 17 percent lower in the high LNG supply case than in the reference case.

Figure 27. Gross U.S. imports of liquefied natural gas in three cases, 1990-2030 (trillion cubic feet)

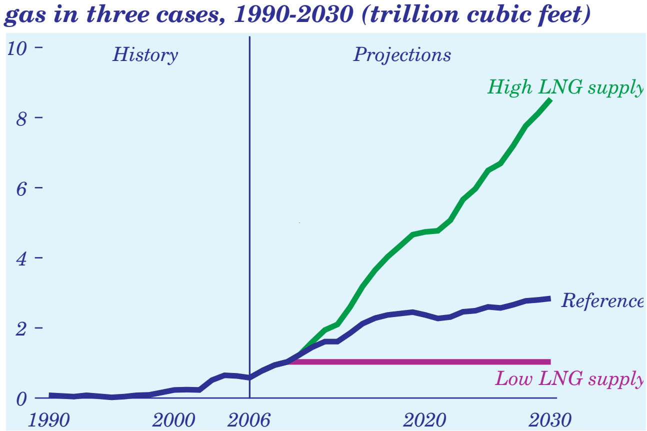


Figure 28. U.S. natural gas supply in three cases, 2006-2030 (trillion cubic feet)

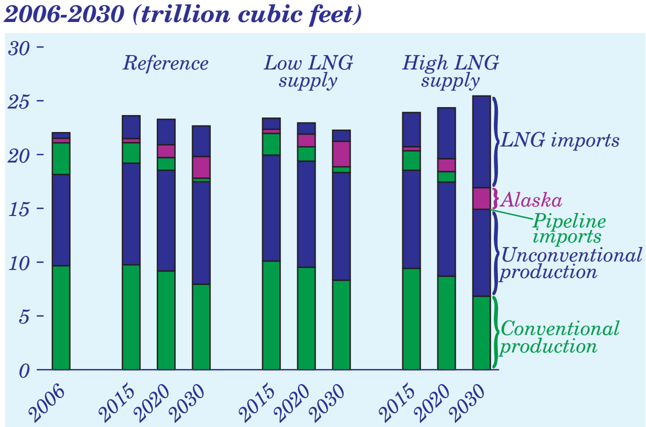
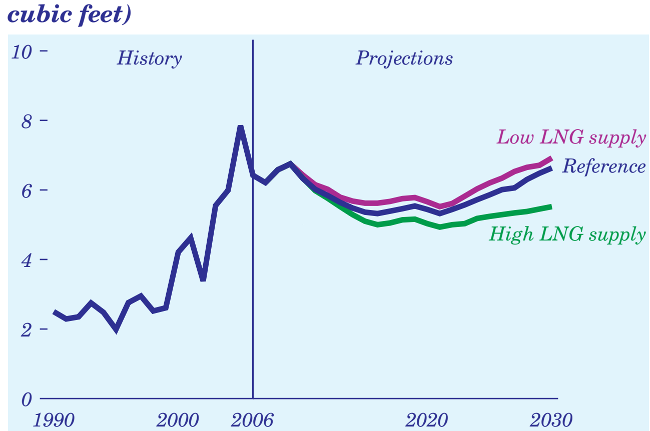


Figure 29. Lower 48 wellhead natural gas prices in three cases, 1990-2030 (2006 dollars per thousand cubic feet)



World Oil Prices and Production Trends in *AEO2008*

AEO2008 defines the world oil price as the price of light, low-sulfur crude oil delivered in Cushing, Oklahoma. Since 2003, both "above ground" and "below ground" factors have contributed to a sustained rise in nominal world oil prices, from $31 per barrel in 2003 to $69 per barrel in 2007. The *AEO2008* reference case outlook for world oil prices is higher than in the *AEO2007* reference case. The main reasons for the adoption of a higher reference case price outlook include continued significant expansion of world demand for liquids, particularly in non-OECD countries, which include China and India; the rising costs of conventional non-OPEC supply and unconventional liquids production; limited growth in non-OPEC supplies despite higher oil prices; and the inability or unwillingness of OPEC member countries to increase conventional crude oil production to levels that would be required for maintaining price stability. EIA will continue to monitor world oil price trends and may need to make further adjustments in future *AEO*s.

In the *AEO2008* reference case, the world oil price in 2030 is approximately 18 percent higher than the *AEO2007* reference case projection. In inflation-adjusted terms (2006 dollars) the world crude oil price reaches $70 per barrel in 2030 in the *AEO2008* reference case, as compared with $61 per barrel in the *AEO2007* reference case (Figure 30).

In *AEO2008*, for both production and consumption, "liquid fuels" include conventional and unconventional liquids. Unconventional liquids include oil sands, biofuels, extra-heavy oils, gas-to-liquids (GTL), and CTL. World consumption of liquid fuels increases from 85 million barrels per day in 2006 to 113 million barrels per day in 2030 in the *AEO2008* reference case. The non-OECD countries, which accounted for 42 percent of world liquids consumption in 2006, are expected to reach 50 percent of the world total in 2022 and 53 percent in 2030, as non-OECD demand for liquid fuels increases from 36 million barrels per day in 2006 to 60 million barrels per day in 2030. Over the same period, OECD consumption increases from 49 million barrels per day to 53 million barrels per day in the reference case (Figure 31).

The OPEC share of world liquids production remains at about 41 percent through 2030, while non-OPEC conventional liquids production increases from 48 million barrels per day in 2006 to 56 million barrels per day in 2030. Unconventional liquids production in both OPEC and non-OPEC countries grows rapidly, but with more substantial increases in the non-OPEC countries (to 11 million barrels per day in 2030, compared with 3 million barrels per day for the OPEC countries in 2030).

Any long-term projection of world oil prices is highly uncertain. Above-ground factors that contribute to price uncertainty include access to oil resources, investment constraints, economic and other objectives of countries where the major reserves and resources are located, cost and availability of substitutes, and economic and policy developments that affect the demand for oil. Below-ground factors include the volumes initially in place in major petroleum basins around the world (including discovered and undiscovered fields) and the fluid and rock characteristics of undiscovered fields. *AEO2008* includes high and low price cases to illustrate the potential impacts of the uncertainties.

Figure 30. World oil price in six cases, 2000-2030 (2006 dollars per barrel)

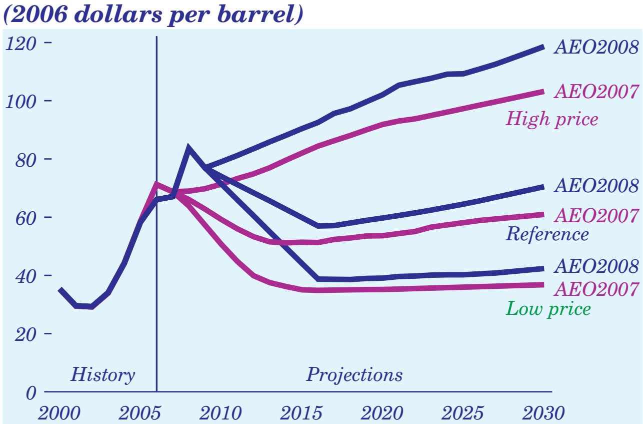
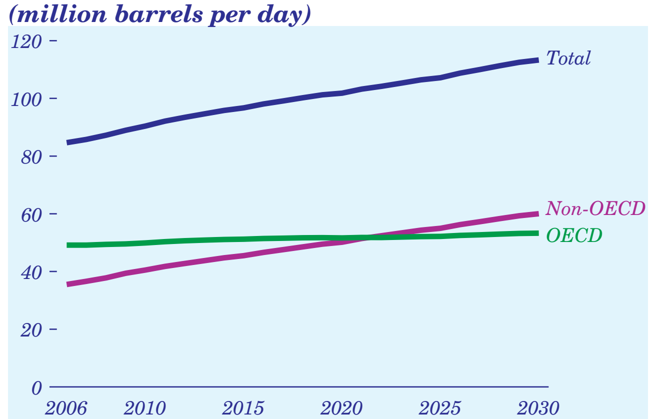


Figure 31. World liquids consumption in the AEO2008 reference case, 2006-2030 (million barrels per day)



The high price case assumes that non-OPEC conventional oil resources are less plentiful, and the overall costs of extraction are higher, than assumed in the reference case. The high price case also assumes that OPEC will choose to allow a decline in its market share to 38 percent of total world liquids production. As a result, the oil price increases steadily to approximately $112 per barrel in 2016 ($93 per barrel in 2006 dollars) and $186 per barrel in 2030 ($119 per barrel in 2006 dollars). World liquids consumption rises from 85 million barrels per day in 2006 to 98 million barrels per day in 2030 in the high price case.

The low price case assumes that non-OPEC conventional oil resources are more plentiful, and the overall costs of extraction are lower, than in the reference case, and that OPEC will choose to increase its market share to 45 percent. In the low price case, the world oil price falls steadily, to approximately $47 per barrel in 2017 ($39 per barrel in 2006 dollars), and then rises gradually to $69 per barrel in 2030 ($42 per barrel in 2006 dollars). World liquids consumption rises to 132 million barrels per day in 2030 in the low price case.

Market Trends

The projections in *AEO2008* are not statements of what will happen but of what might happen, given the assumptions and methodologies used. The projections are business-as-usual trend estimates, given known technology and technological and demographic trends. *AEO2008* assumes that current laws and regulations are maintained throughout the projections. Thus, the projections 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. Unless otherwise noted, laws and regulations are assumed to remain as currently enacted. Further, future laws and regulatory actions are not anticipated.

Because energy markets are complex, models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics are indicative of real-world tendencies rather than representations of specific outcomes.

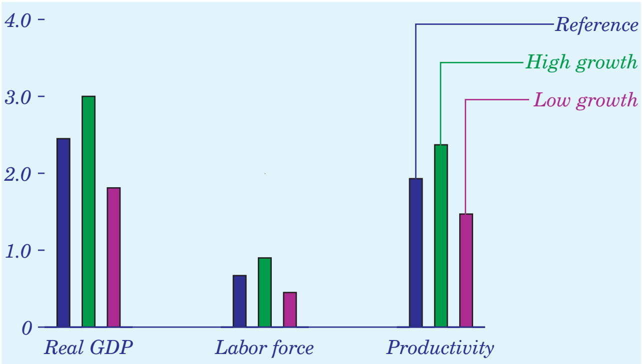
Energy market projections are subject to much uncertainty. Many of the events that shape energy markets are random and cannot be anticipated, including severe weather, political disruptions, strikes, and technological breakthroughs. In addition, future developments in technologies, demographics, and resources cannot be foreseen with certainty. Many key uncertainties in the *AEO2008* projections are addressed through alternative cases.

EIA has endeavored to make these projections as objective, reliable, and useful as possible; however, they should serve as an adjunct to, not a substitute for, a complete and focused analysis of public policy initiatives.

The *AEO* production process was somewhat different this year. After EIA published an early-release version of the *AEO2008* reference case in December 2007, EISA2007 was enacted later that month. EIA decided to update the reference case to reflect the provisions of EISA2007. The *AEO2008* reference case, released in March 2008, also includes additional revisions that reflect historical data issued after the *AEO2008* early-release reference case was completed, as well as new data from EIA's January 2008 *Short-Term Energy Outlook* (*STEO*), a more current economic outlook, and technical updates to the version of NEMS used to produce the early release.

AEO2008 Presents Three Views of Economic Growth

Figure 32. Average annual growth rates of real GDP, labor force, and productivity, 2006-2030 (percent per year)

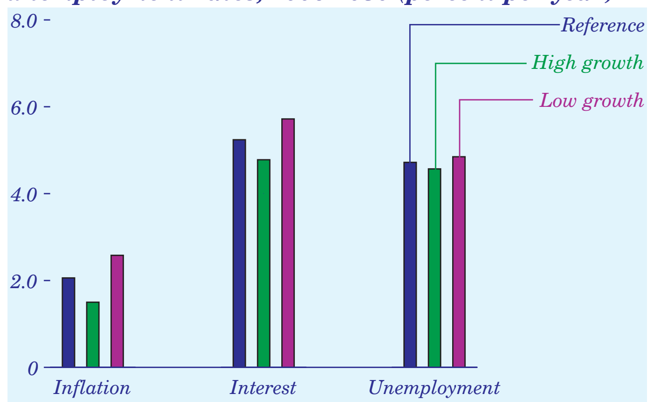


AEO2008 presents three views of economic growth for the 2006-2030 projection period. Economic growth depends mainly on growth in the labor force and productivity. In the reference case, the labor force grows by an average of 0.7 percent per year; labor productivity in the nonfarm business sector grows by 1.9 percent per year; and growth in real GDP averages 2.4 percent per year (Figure 32). In line with the labor and output trends, nonfarm employment grows by 0.9 percent per year, while employment in manufacturing shrinks by 1 percent per year. Investment growth averages 2.8 percent per year in the reference case; disposable income available to households grows by 2.8 percent per year; and disposable income per capita increases by 1.9 percent per year.

The high and low economic growth cases show the effects of alternative economic growth assumptions on the energy market projections (see Appendix E for descriptions of all the alternative cases). In the high growth case, real GDP growth averages 3.0 percent per year, as a result of higher assumed growth rates for the labor force (0.9 percent per year), nonfarm employment (1.2 percent), and nonfarm labor productivity (2.4 percent). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case. In the low growth case, growth in real GDP is 1.8 percent per year, as a result of lower assumed growth rates for the labor force (0.4 percent per year), nonfarm employment (0.5 percent per year), and labor productivity (1.5 percent per year). Consequently, the low growth case shows higher inflation and interest rates and slower growth in industrial output and employment than are projected in the reference case.

Projected Gains in Labor Productivity Are Higher Than Historical Averages

Figure 33. Average annual inflation, interest, and unemployment rates, 2006-2030 (percent per year)

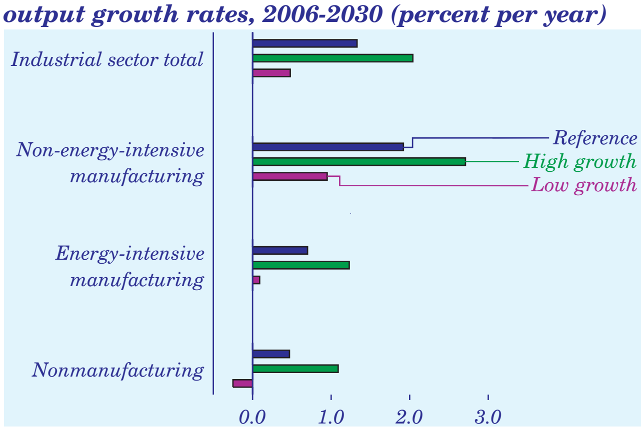


Common indicators for inflation, interest rates and employment are, respectively, the all-urban consumer price index, the interest rate (yield) on 10-year U.S. Treasury notes, and the nonfarm unemployment rate, which are widely viewed as barometers of conditions in the markets for goods and services, credit, and labor, respectively. Historically, from 1982 to 2006, inflation has averaged 3.1 percent per year, the average yield on 10-year Treasury notes has been 7.2 percent per year, and the unemployment rate has averaged 6.1 percent. In the *AEO2008* reference case, as well as in the high and low economic growth cases, projected gains in nonfarm labor productivity—although lower than those seen during the 1990s—are generally higher than the historical averages of the 1980s, leading to more optimistic projections for inflation, interest, and unemployment rates.

In *AEO2008*, the projected average annual inflation rate over the 2006-2030 period is 2.1 percent in the reference case, 1.5 percent in the high economic growth case, and 2.6 percent in the low growth case (Figure 33). Annual yields on the 10-year Treasury note are projected to average 5.2 percent in the reference case, 4.8 percent in the high growth case, and 5.7 percent in the low growth case. The projections for average unemployment rates are 4.7 percent in the reference case, 4.6 percent in the high growth case, and 4.9 percent in the low growth case. Relative to the reference case, the higher inflation, interest, and unemployment rates in the low growth case and the lower rates in the high growth case depend on different assumptions about labor productivity and population growth rates.

Output Growth for Energy-Intensive Industries Is Expected To Slow

Figure 34. Sectoral composition of industrial output growth rates, 2006-2030 (percent per year)



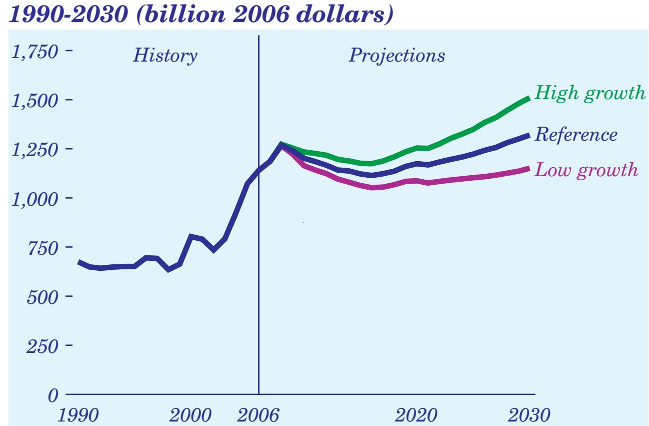
With imports meeting a growing share of demand for industrial goods, the industrial sector has shown slower output growth than the economy as a whole in recent decades. That trend is expected to continue in the *AEO2008* projections. The average annual growth rate for real GDP from 2006 to 2030 is 2.4 percent in the reference case, whereas the industrial sector averages 1.3 percent. With higher energy prices and greater foreign competition, the energy-intensive manufacturing sectors [*78*] grow by only 0.7 percent per year from 2006 through 2030, compared with a 1.9-percent average annual rate of growth for the remaining industrial sectors (Figure 34).

AEO2008 projects relatively slow growth in construction, chemicals, and transportation equipment. High interest rates affect the construction and transportation equipment sectors. Increased foreign competition, slow expansion of domestic production, and higher energy prices exert competitive pressure on the chemicals industry, with growth slowing substantially after 2020.

In the high economic growth case, output from the industrial sector grows by an annual average of 2.0 percent, still below the annual growth of real GDP (3.0 percent). In the low economic growth case, real GDP and industrial output grow by 1.8 and 0.5 percent per year, respectively. In both cases, the non-energy-intensive manufacturing industries show higher growth than the rest of the industrial sector.

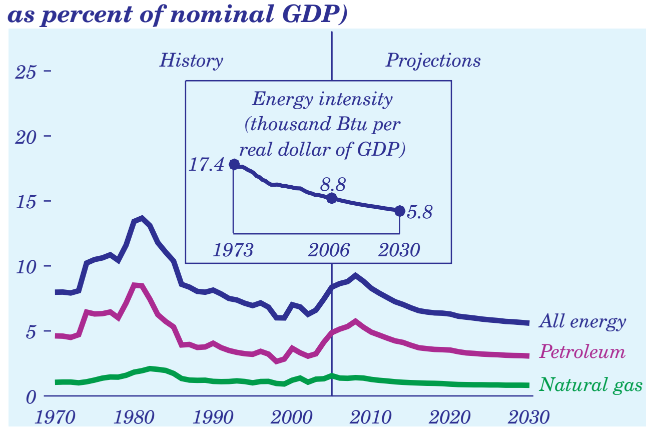
Energy Expenditures Relative to GDP Are Projected To Decline

Figure 35. Energy expenditures in the U.S. economy, 1990-2030 (billion 2006 dollars)



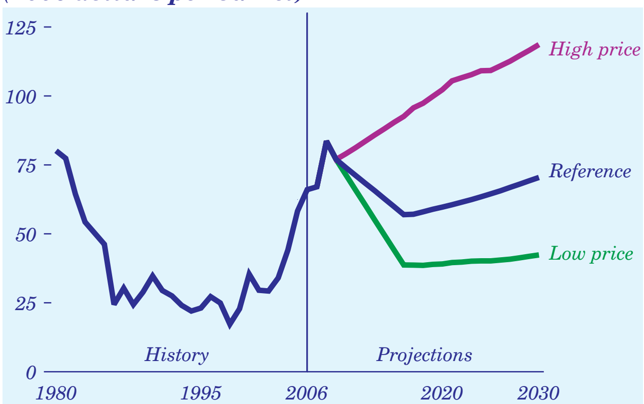
Total U.S. energy expenditures were $1.1 trillion in 2006. Energy expenditures rise to $1.3 trillion (2006 dollars) in 2030 in the *AEO2008* reference case and to $1.5 trillion in the high economic growth case (Figure 35). For the economy as a whole, ratios of energy expenditures to GDP in 2006 were 8.6 percent for all energy, 5.1 percent for petroleum, and 1.4 percent for natural gas. Recent developments in the world oil market have pushed the energy expenditure shares upward, and in the reference case they are expected to increase from current levels until 2010. After 2010 expenditures fall, as the energy intensity of the U.S. economy—measured in terms of energy consumption (thousand Btu) per dollar of real GDP—continues to decline and world oil prices stabilize. Total energy expenditures are projected to equal 5.6 percent of GDP in 2030, petroleum expenditures 3.1 percent, and natural gas expenditures less than 1 percent (Figure 36).

Figure 36. Energy expenditures as a share of gross domestic product, 1970-2030 (nominal expenditures as percent of nominal GDP)



Oil Price Cases Show Uncertainty in Prospects for World Oil Markets

Figure 37. World oil prices, 1980-2030 (2006 dollars per barrel)

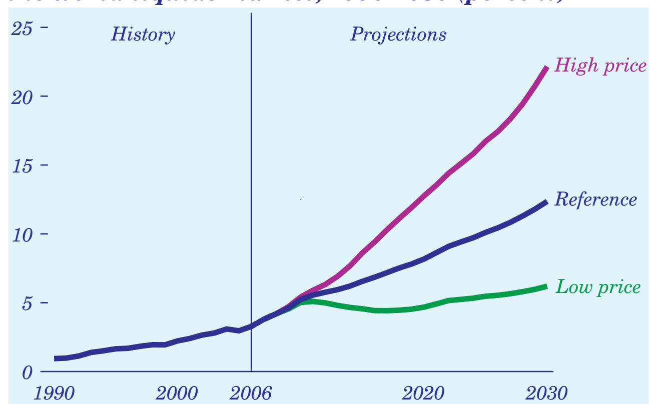


World oil price projections in *AEO2008*, in terms of the average price of imported low-sulfur, light crude oil to U.S. refiners, are higher for 2006-2030 than those presented in *AEO2007*. The higher price path reflects lower estimates of oil consumers' sensitivity to higher prices, an anticipation of lower additions to production capacity in key non-OPEC regions, and a reassessment of OPEC producers' willingness and ability to expand production and production capacity aggressively.

The historical record shows substantial variation in world oil prices, and there is arguably even more uncertainty about future prices when longer time periods are examined. As in previous outlooks, *AEO2008* considers three price cases to illustrate the uncertainty of prospects for future world oil resources. In the reference case, world oil prices moderate from current levels to about $57 per barrel in 2016, start rising again as production in non-OPEC regions peaks, and continue rising to $70 per barrel in 2030 (all prices in 2006 dollars). The low and high price cases reflect a wide band of potential world oil price paths, ranging from $42 to $119 per barrel in 2030 (Figure 37), but they do not bound the set of all possible future outcomes. The high and low oil price cases are predicated on assumptions about access to and costs of non-OPEC oil, OPEC supply decisions, and the supply potential of unconventional liquids. Combining those assumptions with different assumptions about the demand for oil would produce a wider range of oil price paths.

Unconventional Resources Gain Market Share as Prices Rise

Figure 38. Unconventional resources as a share of the world liquids market, 1990-2030 (percent)



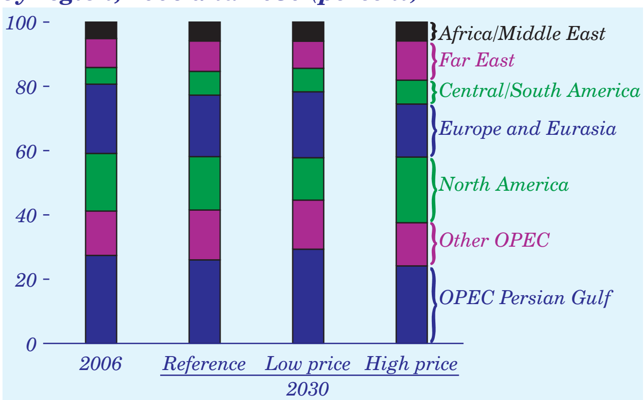
The world's total production of liquid fuels from unconventional resources in 2006 was 2.8 million barrels per day, equal to about 3 percent of total liquids production. Production from unconventional sources included 1.2 million barrels per day from oil sands in Canada, 600,000 barrels per day from very heavy oils in Venezuela, and 320,000 barrels of ethanol per day in the United States. In the *AEO2008* reference case, unconventional production makes up 12 percent (14 million barrels per day) of total liquids production in 2030 (Figure 38).

Depending on price assumptions, world unconventional production is projected to be 5.4 to 18.9 million barrels per day higher in 2030 than it was in 2006, accounting for between 6 and 22 percent of the world's total production of liquids. Production of unconventional liquids depends heavily on prices, being more competitive with conventional sources when market prices are high. Not all unconventional liquids respond to price changes in the same manner, however, because the sources of unconventional liquids differ with regard to resource constraints, political backing, available technologies, and other characteristics.

The composition of world unconventional liquids production does not vary significantly between the reference and low price cases, with biofuels and oil sands combined accounting for about 60 percent of unconventional supply. In the high price case, the economic viability of and need for unconventional liquids supply increase, and 34 percent of total projected unconventional liquids production in 2030 is accounted for by CTL, one-half of which will be produced by China.

World Liquids Supply Is Projected To Remain Diversified in All Cases

Figure 39. World liquids production shares by region, 2006 and 2030 (percent)



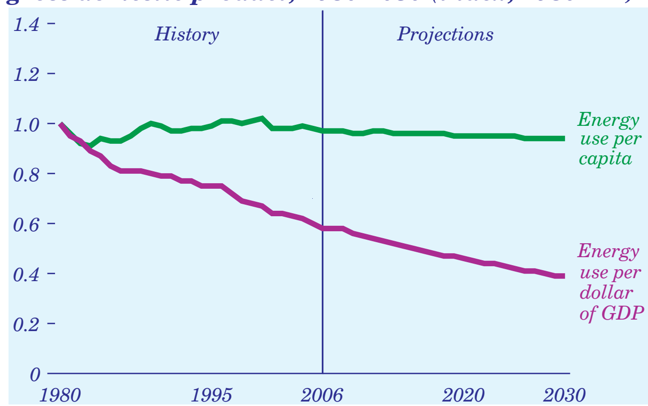
In 2006, OPEC producers in the Persian Gulf accounted for 28 percent of the world's conventional liquids supply, and other OPEC producers accounted for 14 percent. Europe and Eurasia produced 22 percent of conventional supply, North America 17 percent, and the rest of the world 19 percent (Figure 39).

In the reference case, OPEC conventional production maintains approximately a 40-percent share of world total liquids supply through 2030, which is consistent with recent historical trends and reflects an expectation that OPEC suppliers will vary their production levels to influence world oil prices. In all the *AEO2008* cases, OECD liquids production is between 23 and 24 million barrels per day in 2030, constrained by resource availability rather than price or political concerns.

In the high price case, several resource-rich countries, including Saudi Arabia, Mexico, and Russia, limit production, lowering both total world liquids supply and their own shares of the supply. In the high price case, the largest increases in liquids production occur in the United States, China, Canada, Brazil, and India, where substantial increases in unconventional production are expected, underscoring the rising importance of unconventional fuels to the world's supply of liquids. In the low price case, resource-rich countries either maintain current production behavior or increase their openness to foreign capital investment. As a result, the largest increases in world liquids supply shares in the low price case occur in Iraq and the Caspian Sea Basin.

Average Energy Use per Person Levels Off Through 2030

Figure 40. Energy use per capita and per dollar of gross domestic product, 1980-2030 (index, 1980 = 1)



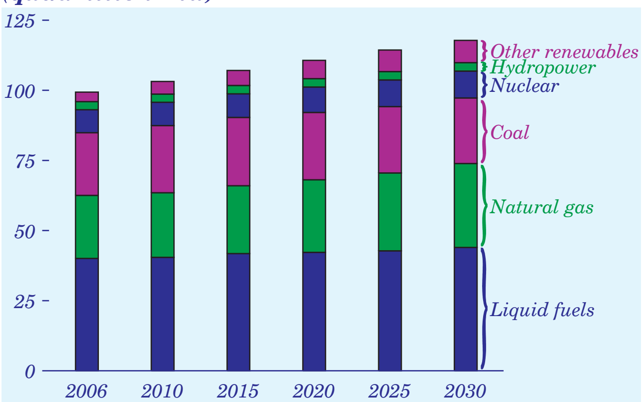
Because energy use for housing, services, and travel in the United States is closely linked to population levels, energy use per capita is relatively stable (Figure 40). In addition, the economy is becoming less dependent on energy in general.

Energy intensity (energy use per 2000 dollar of GDP) declines by an average of 1.4 percent per year in the low growth case, 1.7 percent in the reference case, and 1.9 percent in the high growth case. Efficiency gains and faster growth in less energy-intensive industries account for most of the projected decline, more than offsetting growth in demand for energy services in buildings, transportation, and electricity generation. The decline is more rapid in the high economic growth case, because with higher economic growth the number of new, more efficient systems grows faster, and the additional growth is concentrated in less energy-intensive industries. As energy prices moderate over the longer term, energy intensity declines at a slower rate in the reference, high growth, and low growth cases.

The *AEO2008* cases developed to illustrate the uncertainties associated with those factors include low and high growth cases, low and high price cases, and alternative technology cases (see Appendixes B, C, D, and E).

Coal and Liquid Fuels Lead Increases in Primary Energy Use

Figure 41. Primary energy use by fuel, 2006-2030 (quadrillion Btu)



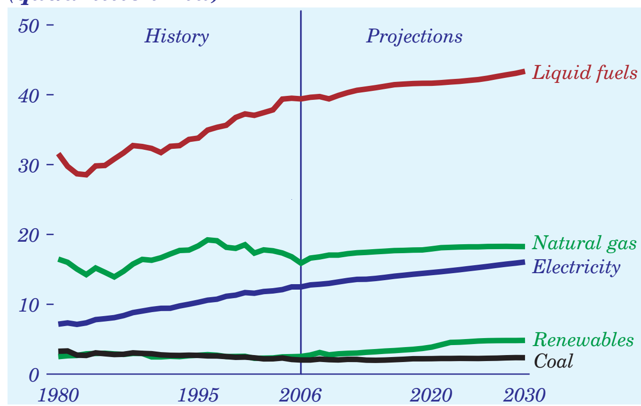
Total primary energy consumption, including energy for electricity generation, grows by 0.7 percent per year from 2006 to 2030 in the reference case (Figure 41). Fossil fuels account for 55 percent of the increase. Coal use increases in the electric power sector, where electricity demand growth and current environmental policies favor coal-fired capacity additions. About 54 percent of the projected increase in coal consumption occurs after 2020, when higher natural gas prices make coal the fuel of choice for most new power plants under current laws and regulations, which do not limit greenhouse gas emissions. Increasing demand for natural gas in the buildings and industrial sectors offsets the decline in natural gas use in the electricity sector after 2016, resulting in a net increase of 5 percent from 2006 to 2030.

The transportation sector accounted for more than two-thirds of all liquid fuel consumption in 2006, and 60 percent of that share went to LDVs. Demand for liquid transportation fuels increases by 17 percent from 2006 to 2030, dominated by growing fuel use for LDVs, trucking, and air travel. The industrial sector accounted for 25 percent of total liquid fuel use in 2006, but its share declines to 21 percent in 2030.

AEO2008 also projects rapid percentage growth in renewable energy production, as a result of the EISA2007 RFS and the various State mandates for renewable electricity generation. Additions of new nuclear power plants are also projected, spurred by improving economics relative to plants fired with fossil fuels and by the EPACT2005 PTCs.

Electricity and Liquid Fuels Lead Rise in Delivered Energy Consumption

Figure 42. Delivered energy use by fuel, 1980-2030 (quadrillion Btu)



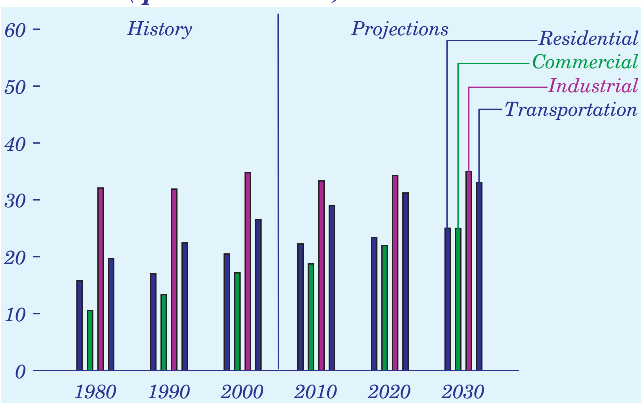
Delivered energy use (excluding losses in electricity generation) grows by 0.7 percent per year from 2006 to 2030 in the reference case. The growth in electricity use is driven by growing demand in the residential and commercial sectors. With the growing market penetration of electric appliances, residential electricity use increases slightly faster than the total number of households, and commercial electricity use outpaces the growth in commercial floorspace. With different assumptions about population and economic growth, average annual growth in delivered energy use from 2006 to 2030 ranges from 0.3 percent in the low growth case to 1.0 percent in the high growth case.

Growth in demand for liquid fuels is led by the transportation sector, as rising population, incomes, and economic output boost demand for travel, partially offsetting improvements in vehicle efficiency (Figure 42). Natural gas use grows more slowly than overall delivered energy demand, reflecting its relatively higher cost, particularly in the industrial sector.

Industrial biomass accounts for the largest share of end-use consumption of renewable energy. Currently it is used mostly as a byproduct fuel in the pulp and paper industry, but that use will be surpassed by consumption of biomass heat and co-products from ethanol manufacture when the biofuel mandate under EISA2007 reaches 36 billion gallons in 2022. Consumption of nonmarketed solar, geothermal, and wind energy also increases dramatically in the projections; however, it continues to account for less than 1 percent of all delivered energy use in the residential and commercial sectors.

U.S. Primary Energy Use Climbs to 118 Quadrillion Btu in 2030

Figure 43. Primary energy consumption by sector, 1980-2030 (quadrillion Btu)



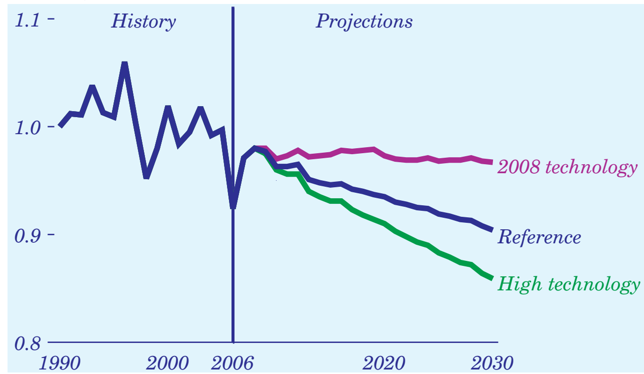
The most significant impact of EISA2007 is in the transportation sector, where the CAFE standard for LDVs is raised to 35 mpg in 2020. Still, from 2006 to 2030 the transportation sector sees the second-largest increase in energy consumption, at 5 quadrillion Btu (Figure 43), as a result of increases in vehicle miles traveled, jet fuel consumption, and demand for fuels such as E10, E85, and diesel to displace motor gasoline.

EISA2007 has little effect on the commercial sector, where energy demand continues to expand more rapidly than the economy as a whole. Dependence on natural gas and electricity, already heavy in the residential and commercial sectors, increases over time. Demand for electricity grows faster than demand for natural gas in both sectors, however, because electricity is used for a wider diversity of applications (including the fastest growing end uses, office equipment, personal computers, and televisions), whereas natural gas is used mainly for space heating, cooking, and water heating, which grow more slowly than households and floorspace.

The variation in residential and commercial energy demand between the high and low price cases is relatively small, and natural gas consumption accounts for most of the difference. In the industrial sector, fuel use in 2030 is higher in the high price case than in the reference case, reflecting differences in CTL, ethanol, and biodiesel production. Different growth rates for manufacturing output in the low and high macroeconomic growth cases account for most of the difference in industrial energy consumption between the two cases.

Residential Energy Use per Capita Varies With Technology Assumptions

Figure 44. Residential delivered energy consumption per capita, 1990-2030 (index, 1990 = 1)

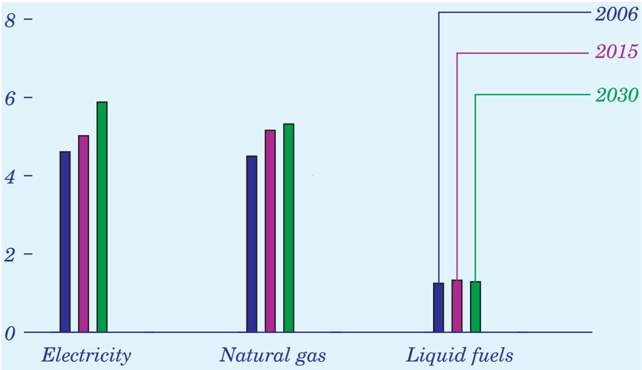


Residential energy use per person has remained fairly constant since 1990 (taking into account year-to-year fluctuations in weather), with increases in energy efficiency offset by consumer preference for larger homes and by new residential uses for energy. Over the past 10 years, the weather has generally been warmer than the 30-year average, causing energy use per person to remain mostly below its 1990 level. Given the preponderance of warmer winters and summers, the *AEO2008* projections define normal weather as the average of the most recent 10 years of historical data, which decreases the need for heating fuels, such as natural gas and fuel oil, and increases the need for electricity used for air conditioning, all else being equal [*79*].

In the *AEO2008* projections, residential energy use per capita changes with assumptions about the rate at which more efficient technologies are adopted. The 2008 technology case assumes no increase in the efficiency of equipment or building shells beyond those available in 2008. The high technology case assumes lower costs, higher efficiencies, and earlier availability of some advanced equipment. In the reference case, residential energy use per capita is projected to fall below the 2006 level after 2024. The 2008 technology case approximates an upper bound on residential energy use per capita in the future: delivered energy use per capita in the residential sector remains above the 2006 level through 2030, when it is 7 percent higher than projected in the reference case (Figure 44). The high technology case provides a lower bound, falling below the 2006 level after 2016 and reaching a 2030 level that is 5 percent below the reference case projection.

Household Uses for Electricity Continue To Expand

Figure 45. Residential delivered energy consumption by fuel, 2006, 2015, and 2030 (quadrillion Btu)



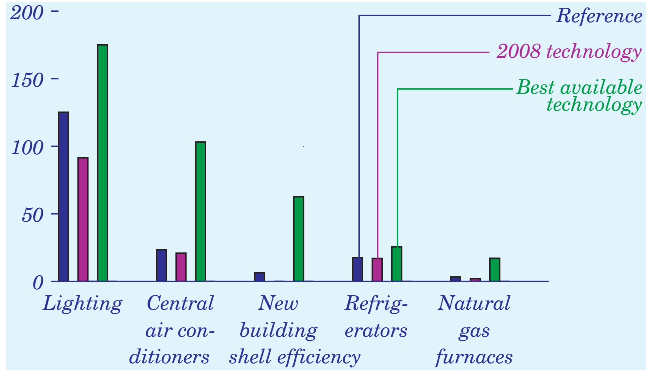
In 2006, households consumed more electricity than natural gas for the first time, as warmer winter temperatures reduced the need for natural gas heating. Over the past decade, residential electricity use has grown steadily, as a result of the increase in air conditioning use and the introduction of new applications. That trend is expected to continue in *AEO2008* (Figure 45). In 2030, electricity use for home cooling is 38 percent higher than the 2006 level in the reference case, as the U.S. population continues to migrate to the South and West, and older homes convert from room air conditioning to central air conditioning. A projected 25-percent increase in the number of households also increases the demand for appliances, and total electricity use in the residential sector increases by 27 percent from 2006 to 2030 in the reference case.

Natural gas and liquid fuels are used in the residential sector primarily for space and water heating. Few new uses have emerged over the past decade, and few are expected in the future. Thus, natural gas and liquids consumption per household decreases as the energy efficiency of furnaces and building components continues to improve.

The 2008 technology and high technology cases provide high and low ranges for the projections. In the high technology case, for example, high-efficiency air conditioners and condensing gas furnaces become more prevalent. Recent developments in solid-state lighting technologies, such as light-emitting diodes (LEDs), are reflected in the reference case as a reduction of up to 85 percent in the amount of electricity needed to provide a given amount of useful light.

Increases in Energy Efficiency Are Projected To Continue

Figure 46. Efficiency gains for selected residential appliances, 2030 (percent change from 2006 installed stock efficiency)



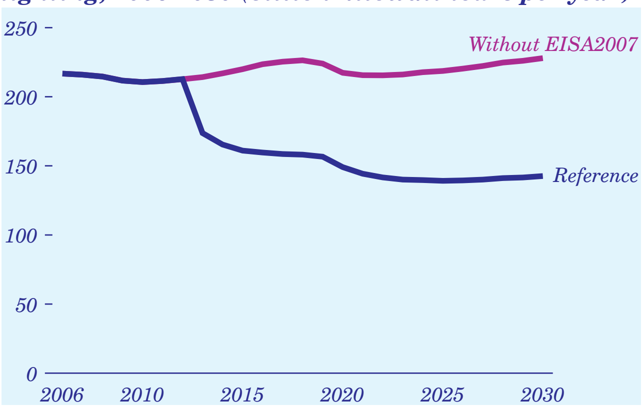
The energy efficiency of new household appliances plays a key role in determining the types and amounts of energy used in residential buildings. As a result of stock turnover and purchases of more efficient equipment, energy use by residential consumers, both per household and per capita, has fallen over time. In the 2008 technology case, which assumes no efficiency improvement of available appliances beyond 2008 levels, normal stock turnover results in higher average energy efficiency for most end uses in 2030, as older appliances are replaced with more efficient models from the existing stock of appliances (Figure 46).

The largest gains in residential energy efficiency are projected in the best available technology case, which assumes that consumers purchase the most efficient products available at normal replacement intervals regardless of cost, and that new buildings are built to the most energy-efficient specifications available, starting in 2009. In this case, residential delivered energy consumption in 2030 is 27 percent less than in the 2008 technology case and 22 percent less than in the reference case. Purchases of new energy-efficient products, especially compact fluorescent and solid-state lighting and condensing gas furnaces, reduce energy use without lowering service levels.

Several current Federal programs, including Zero Energy Homes and ENERGY STAR Homes, promote the use of efficient appliances and building envelope components, such as windows and insulation. In the best available technology case, use of the most efficient building envelope components available can reduce heating requirements in an average new home by more than 60 percent.

Residential Electricity Use for Lighting Is Expected To Decline

Figure 47. Electricity consumption for residential lighting, 2006-2030 (billion kilowatthours per year)



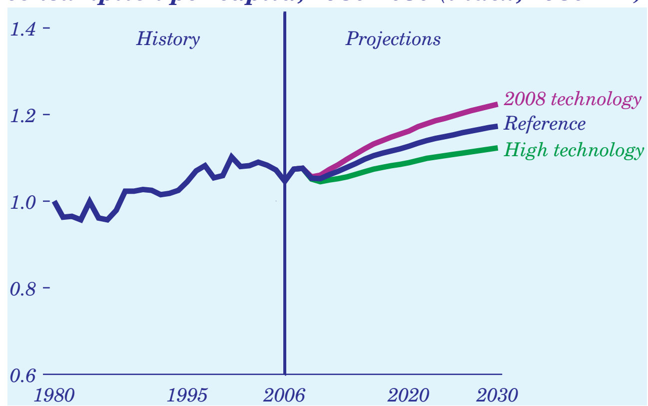
Residential electricity use for lighting accounted for about 16 percent of the sector's total electricity consumption in 2006, making it the second largest use for electricity in households. In the *AEO2008* reference case, electricity use for lighting declines as a result of the lighting efficiency standards in EISA2007, which require general-service incandescent light bulbs to reduce wattage by about 28 percent by 2014, increasing to 65 percent in 2020. DOE is required to examine the potential for tighter standards after 2020, but the details are uncertain and are not included in the *AEO2008* reference case.

Figure 47 summarizes residential lighting use in the *AEO2008* reference case and a case without EISA-2007. Given the relatively rapid turnover in incandescent lighting, EISA2007 achieves electricity savings immediately, reducing lighting demand by 27 percent (59 billion kilowatthours) in 2015. With continued tightening of the standard through 2020, demand for lighting is reduced by 85 billion kilowatthours in 2030, as efficient lighting options, mainly LEDs, gain market share.

In 2007, roughly 200 million compact fluorescent light (CFL) bulbs were sold in the United States, accounting for about 10 percent of total sales. Even without the new standards, CFL sales in the residential market were expected to continue growing in the coming years. LED lamps, which are just now being introduced in the general-service residential lighting market, reach nearly 20 percent of sales in 2020 without the EISA2007 standards. With the EISA2007 standards, the market share for LED bulbs in 2020 doubles.

Rise in Commercial Energy Use per Capita Is Projected To Continue

Figure 48. Commercial delivered energy consumption per capita, 1980-2030 (index, 1980 = 1)

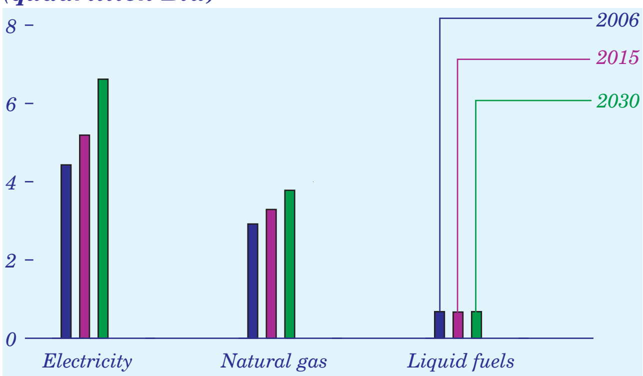


Assumptions about the availability and adoption of energy-efficient technologies define the range for delivered commercial energy use per person in the *AEO2008* projections. Commercial energy consumption per capita increases by a total of 12 percent from 2006 to 2030 in the reference case, primarily as a result of rising electricity use as the Nation continues to move to a service economy. The size of the projected increase varies from a low of 7 percent in the high technology case to a high of 17 percent in the 2008 technology case (Figure 48).

In terms of floorspace, growth in the commercial sector averages 1.2 percent per year from 2006 to 2030, driven by trends in economic and population growth. The reference case assumes future improvements in efficiency for commercial equipment and building shells, as well as increased demand for services. Consequently, commercial energy use increases at about the same rate as floorspace in the reference case, and commercial energy intensity (delivered energy consumption per square foot of floorspace) shows little change, increasing by less than 2 percent. The 2008 technology case assumes no increase in the energy efficiency of commercial equipment and building shells beyond those available in 2008. The result is a 4-percent increase in commercial delivered energy use in 2030 relative to the reference case. In the high technology case, assuming earlier availability, lower costs, and higher efficiencies for more advanced equipment and building shells, delivered energy consumption in 2030 is 4 percent below the reference case projection.

Electricity Leads Expected Growth in Commercial Energy Use

Figure 49. Commercial delivered energy consumption by fuel, 2006, 2015, and 2030 (quadrillion Btu)

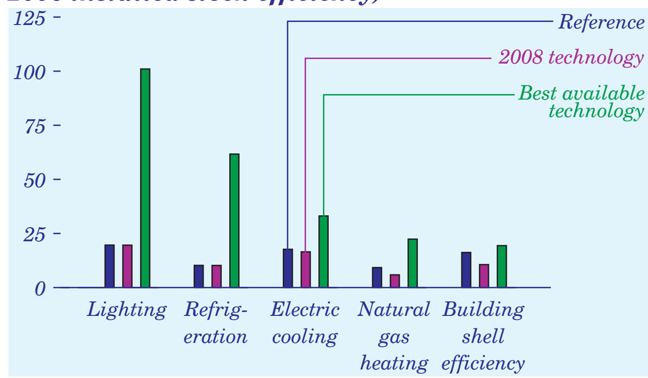


In the *AEO2008* projections, growth in disposable income leads to increased demand for services from hotels, restaurants, stores, theaters, galleries, arenas, and other commercial establishments, which in turn are increasingly dependent on computers and other electronic office equipment both for basic services and for business services and customer transactions. In addition, the growing share of the population over age 65 increases demand for health care and assisted-living facilities and for electricity to power medical and monitoring equipment at those facilities. The reference case projects increases in commercial electricity use averaging 1.7 percent per year from 2006 to 2030 (Figure 49). The high technology and 2008 technology cases provide low and high ranges for the average annual growth rate of commercial electricity consumption from 2006 to 2030, at 1.4 percent and 2.0 percent, respectively.

Use of natural gas and liquids for heating shows limited growth, as commercial activity reflects the U.S. population shift to the South and West and the efficiency of building and equipment stocks improves. Commercial natural gas use grows by 1.1 percent per year on average from 2006 to 2030 in the reference case, including more use of CHP in the later years. While there is little change in liquid fuel consumption, the projections for natural gas use in 2030 range from 3.8 quadrillion Btu in the reference case to 4.0 quadrillion Btu in the high growth case and 3.5 in the low growth case. The high and low oil price cases show the widest range for liquid fuels use, varying from 7 percent below to 12 percent above the reference case projection of 0.7 quadrillion Btu in 2030.

Technology Provides Potential Energy Savings in the Commercial Sector

Figure 50. Efficiency gains for selected commercial equipment, 2030 (percent change from 2006 installed stock efficiency)



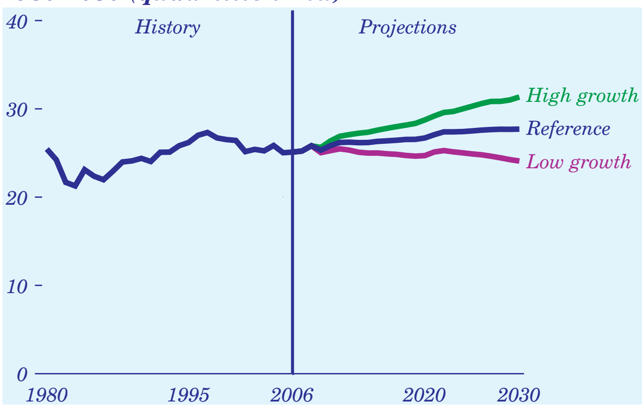
The stock efficiency of energy-using equipment in the commercial sector increases in the *AEO2008* reference case. Adoption of more energy-efficient equipment moderates the growth in demand, in part because of existing building codes for new construction and minimum efficiency standards, including those in EPACT2005 and EISA2007; however, the long service lives of many kinds of energy-using equipment limit the pace of efficiency improvements.

The most rapid increase in overall energy efficiency for the commercial sector occurs in the best available technology case, which assumes that only the most efficient technologies are chosen, regardless of cost, and that new building shells in 2030 are 19 percent more efficient than the commercial buildings stock in 2006. With the adoption of improved heat exchangers for space heating and cooling equipment, solid-state lighting, and more efficient compressors for commercial refrigeration, commercial delivered energy consumption in 2030 in the best technology case is 12 percent less than in the reference case and 16 percent less than in the 2008 technology case.

In the 2008 technology case, which assumes equipment and building shell efficiencies limited to those available in 2008, energy efficiency in the commercial sector still improves from 2006 to 2030 (Figure 50), because the technologies available in 2008 can provide savings relative to equipment currently in place. When businesses consider equipment purchases, however, the additional capital investment needed to buy the most efficient technologies often carries more weight than do future energy savings.

Economic Growth Cases Show Range for Projected Industrial Energy Use

Figure 51. Industrial delivered energy consumption, 1980-2030 (quadrillion Btu)

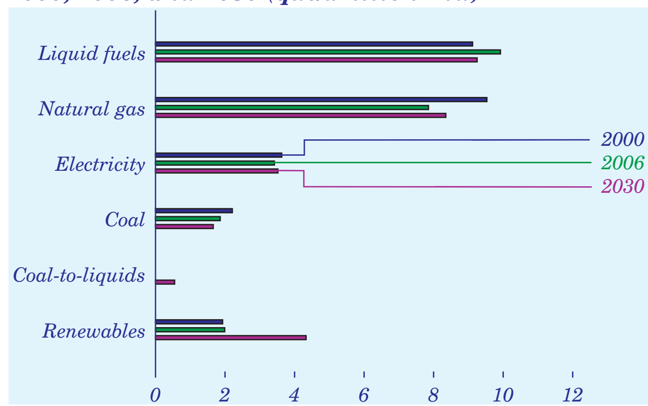


In the *AEO2008* reference case, industrial value of shipments grows at an annual rate of 1.3 percent from 2006 to 2030. Industrial delivered energy consumption increases by just 0.4 percent per year, from 25.1 quadrillion Btu in 2006 to 27.7 quadrillion Btu in 2030, as increased efficiency and changes in the composition of output partially offset growth. In the low economic growth case, industrial value of shipments grows by 0.5 percent per year, and delivered energy consumption falls to 24.2 quadrillion Btu in 2030. In the high growth case, industrial value of shipments grows by 2.0 percent per year, and energy consumption rises to 31.7 quadrillion Btu in 2030, 14 percent higher than in the reference case (Figure 51). The variation in industrial output growth among the three cases is well within the typical range over the past 16 years, when output grew by 1.7 percent per year on average from 1990 to 2007, and annual growth rates ranged from 5.7 percent to a decline of 4.7 percent.

The construction and chemical industries were particularly affected by the recent economic slowdown, and their future growth is expected to be modest (averaging 0.5 percent per year for the construction industry from 2006 to 2030 in the reference case). As a result, energy consumption in the construction sector declines from 2.4 quadrillion Btu in 2006 to 2.2 quadrillion Btu in 2030, with about 70 percent of the decrease attributed to reduced use of asphalt. The bulk chemical industry shows little growth from 2006 to 2030, and its fuel consumption for energy and feedstock totals only 5.6 quadrillion Btu in 2030, as compared with an estimated 6.8 quadrillion Btu in 2006.

Industrial Fuel Choices Vary Over Time

Figure 52. Industrial energy consumption by fuel, 2000, 2006, and 2030 (quadrillion Btu)

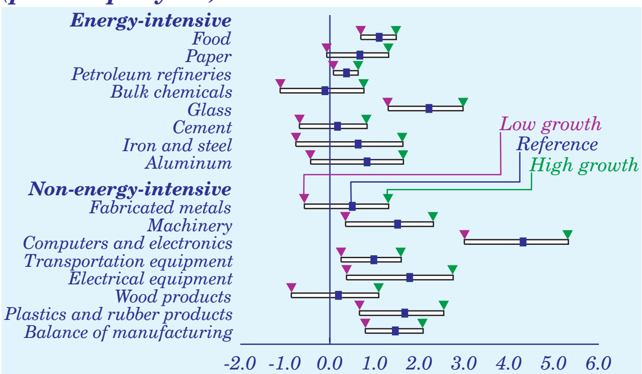


Industries adjust their fuel and product mixes over time to respond to changing markets, as indicated by the falling share of industrial coal use for process steam and the rapid increase in coal use for production of liquid fuels in the *AEO2008* reference case (Figure 52). Traditional coal use falls slightly as the use of metallurgical coal in steelmaking declines, reflecting the difficulty of building additional coke ovens in the United States. Industrial demand for steam coal as a boiler fuel also declines, as industrial processes become more efficient and use less steam, and as the growth of energy- and steam-intensive industries slows. As a result, consumption of steam coal in the industrial sector declines by 0.3 percent per year in the reference case projection.

Natural gas consumption, excluding lease and plant use, increases from 6.7 quadrillion Btu in 2006 to 7.1 quadrillion Btu in 2030—only slightly less than in 1990 (7.2 quadrillion Btu). Consumption of liquid fuels falls slightly, from 9.9 quadrillion Btu in 2006 to 9.3 quadrillion Btu in 2030, but remains the largest category of industrial energy consumption. About three-quarters of industrial liquids consumption is for nonfuel uses or as a byproduct in the refining industry. Industrial consumption of purchased electricity grows by just 0.1 percent per year. The only industrial fuels for which significant increases are projected are coal used in CTL plants and biofuel for ethanol production. From no commercial production in 2006, coal use for CTL grows to 0.6 quadrillion Btu in 2030 in the reference case, and biofuel use for ethanol production increases eightfold, to 2.3 quadrillion Btu in 2030.

Energy-Intensive Industries Grow Less Rapidly Than Industrial Average

Figure 53. Average growth in value of shipments for the manufacturing subsectors, 2006-2030 (percent per year)



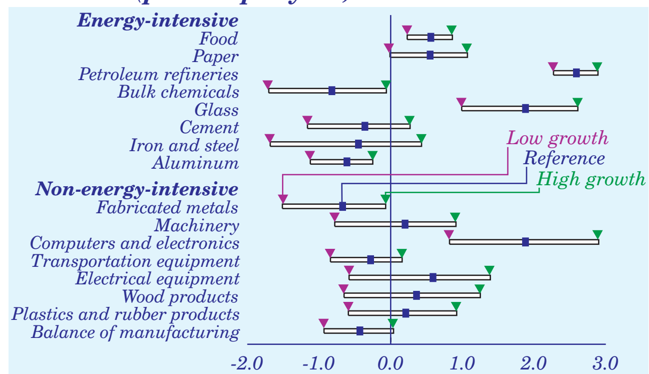
In the *AEO2008* reference case, average annual growth in value of shipments for the manufacturing sectors ranges from a decline of 0.1 percent per year (bulk chemicals) to an increase of 4.3 percent per year (computers). The pattern is similar in the economic growth cases (Figure 53).

For the bulk chemical industry, value of shipments grows slowly for several years and then falls slightly over the last decade of the projection, as export demand falls and other countries increase production. The annual rate of growth in the energy-intensive manufacturing group (0.7 percent) is lower than in the non-energy-intensive group (1.9 percent). Glass is the only energy-intensive subsector with a growth rate above 2 percent per year in the reference case. The growth rate for the industrial sector as a whole in the final 10 years of the projection is slightly lower than in the earlier years (1.2 percent compared with 1.4 percent). Growth rates for the individual subsectors vary considerably, with about one-quarter of them growing more rapidly in the final decade.

The projected growth rates for value of shipments in the industrial subsectors in the high and low economic growth cases generally are symmetrical around the reference case. Industries with the most rapid projected growth in the reference case also have relatively more rapid growth in the high and low economic growth cases. The range across economic growth cases and subsectors is substantial, from a decline of 1.1 percent per year for bulk chemicals in the low economic growth case to an increase of 5.3 percent per year for computer manufacturing in the high economic growth case.

Energy Consumption Growth Varies Widely Across Industry Sectors

Figure 54. Average growth of delivered energy consumption in the manufacturing subsectors, 2006-2030 (percent per year)

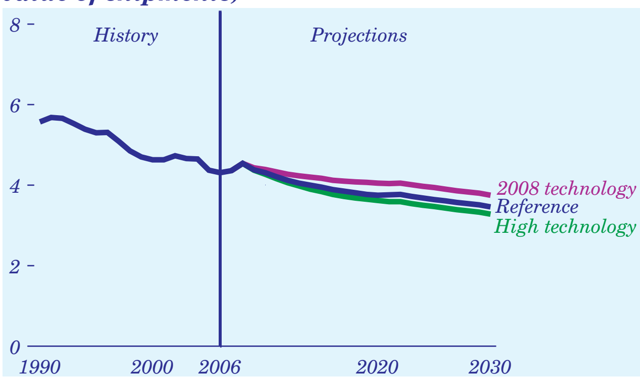


The range of projections for industrial energy consumption in *AEO2008* largely reflects uncertainty about the rate of economic growth. Average annual growth in total delivered energy consumption in the industrial sector from 2006 to 2030 ranges from a decline of 0.1 percent in the low economic growth case to an increase of 1.0 percent in the high economic growth case. In 2030, consumption is 3.5 quadrillion Btu lower in the low economic growth case and 4.0 quadrillion Btu higher in the high economic growth case when compared with the reference case. Thus, across the cases, the range for industrial energy consumption in 2030 is 7.5 quadrillion Btu.

In the reference case, energy consumption growth varies substantially among industry subsectors (Figure 54). Delivered energy consumption falls over the projection period for one-half of the energy-intensive industries (bulk chemicals, cement, iron and steel, and aluminum) as a result of relatively slow output growth rates, combined with expected changes in production technology over the projection period. The declines are reinforced by modest increases in energy prices after 2020. In general, the subsectors with the highest growth rates in energy consumption are those with the highest growth rates in value of shipments (computers and glass). The petroleum refining sector is an exception. As refineries shift to alternative feedstocks for liquids production (biofuels, coal, heavier crude oil), more energy is required per unit of output than is used for traditional petroleum-based refining. Energy consumption at refineries increases from 3.9 quadrillion Btu in 2006 to 7.3 quadrillion Btu in 2030—more than the total growth in industrial sector energy consumption.

Energy Intensity in the Industrial Sector Continues To Decline

Figure 55. Industrial delivered energy intensity, 1990-2030 (thousand Btu per 2000 dollar value of shipments)



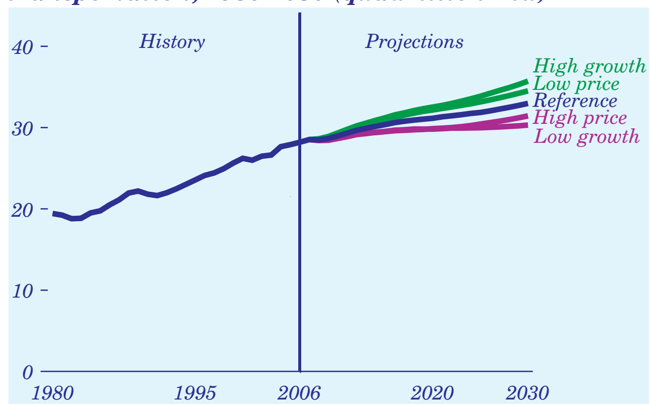
From 1990 to 2006, energy consumption in the industrial sector increased by only 0.5 quadrillion Btu (3 percent), while the value of shipments increased by 33 percent. Thus, industrial delivered energy use per dollar of industrial value of shipments declined by an average of 1.6 percent per year from 1990 to 2006 (Figure 55). Factors contributing to the drop in energy intensity include continued restructuring that reduced the industrial sector share of the most energy-intensive industries; higher petroleum and natural gas prices since 1998, which stimulated greater improvements in energy efficiency; and hurricane-related shutdowns in 2005.

The energy-intensive industries' share of industrial output fell from 23 percent in 1990 to 21 percent in 2006; and in 2030 their share is projected to be 18 percent. Consequently, even if no specific industry showed a reduction in energy intensity, the aggregate energy intensity of the industrial sector would decline. The shift in output share to less energy-intensive industries accounts for 84 percent of the projected change in industrial energy intensity in the reference case [*80*].

The technology cases represent alternative views of the evolution and adoption of energy-saving technologies in the industrial sector. In the high technology case, industrial energy intensity falls by 1.1 percent per year, compared with 0.9 percent per year in the reference case. In the 2008 technology case, energy intensity improves by only 0.5 percent per year. Across the technology cases, industrial energy consumption in 2030 varies over a range from 26.5 to 30.3 quadrillion Btu.

Growth in Transportation Energy Use Is Expected To Slow

Figure 56. Delivered energy consumption for transportation, 1980-2030 (quadrillion Btu)



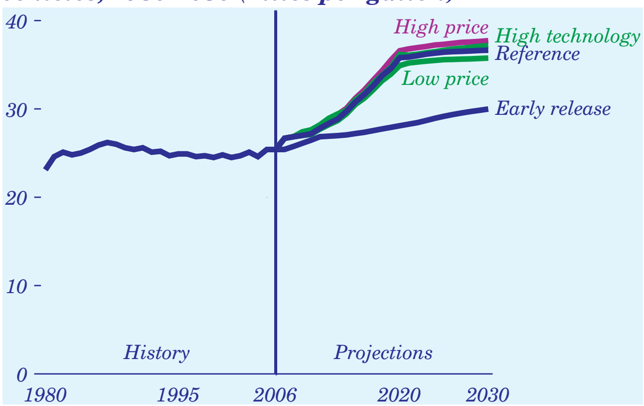
Delivered energy consumption in the transportation sector grows at an average annual rate of 0.7 percent in the *AEO2008* reference case, from 28.2 quadrillion Btu in 2006 to 33.0 quadrillion Btu in 2030 (Figure 56). That rate is less than the historical rate of 1.4 percent per year from 1980 to 2006, because the new EISA2007 fuel economy standards, slower economic growth, and higher fuel prices lead to efficiency improvements and slower growth in travel demand.

Transportation energy consumption is influenced by a variety of factors, including economic growth, population growth, fuel prices, and vehicle fuel efficiency. *AEO2008* includes cases that examine the impacts of those factors on delivered energy consumption. In 2030, transportation sector energy consumption is about 8 percent higher in the high economic growth case and 8 percent lower in the low economic growth case than in the reference case, and it is about 5 percent lower in the high price case and 5 percent higher in the low price case than in the reference case.

By mode, the largest share of total transportation energy consumption is for travel by LDVs (cars, pickup trucks, sport utility vehicles, and vans). The modes with the largest increases in energy demand are heavy trucks (medium and large—classes 3 through 8—freight trucks and buses) and aircraft. Heavy vehicles, which accounted for 18 percent of the sector's total energy use in 2006, account for 20 percent in 2030 in the reference case. With expected strong growth in demand for air travel and more investment in infrastructure, air travel also accounts for a growing portion of total energy consumption (13 percent in 2030, up from 9 percent in 2006).

EISA2007 Improves Fuel Economy of Light-Duty Vehicles

Figure 57. Average fuel economy of new light-duty vehicles, 1980-2030 (miles per gallon)



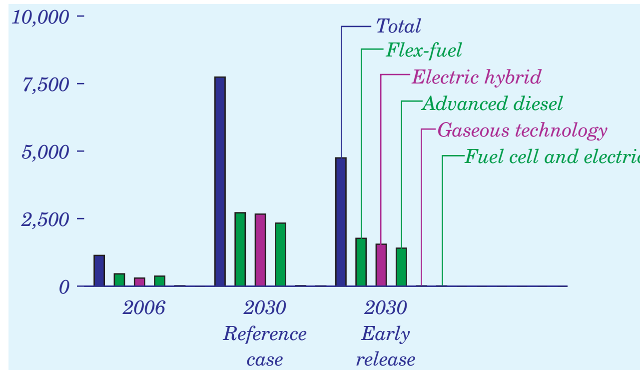
Light trucks have made up a steadily growing share of U.S. LDV sales in recent years, accounting for more than 50 percent of all new LDVs in 2006, compared with 21 percent in 1980 [*81*]. Consequently, despite fuel economy improvements, the average fuel economy of new LDVs declined from a 1987 peak of 26.2 mpg to a low of 25.4 mpg in 2005 and remained at roughly that level in 2006 (Figure 57).

EISA2007, enacted in December 2007, sets a new CAFE standard of 35 mpg for LDVs in 2020. Without EISA2007 (in the early release case), some advanced vehicle technologies are adopted, and the average fuel economy for new LDVs increases to 30.0 mpg in 2030. In the *AEO2008* reference case, with the EISA2007 provisions included, the fuel economy of new LDVs increases to 36.6 mpg in 2030.

The economics of fuel-saving technologies improve further in the high technology and high price cases, and consumers buy more fuel-efficient cars and trucks. In both cases, however, average fuel economy improves only modestly from the reference case level, because meeting the CAFE standards in EISA2007 already requires significant penetration of advanced technologies, pushing fuel economy improvements to the limit of current economic feasibility. In the low price case there is little or no economic incentive for consumers to purchase more fuel-efficient vehicles, and LDV fuel economy in 2030 is slightly lower than in the reference case.

Unconventional Vehicle Technologies Exceed 25 Percent of Sales in 2030

Figure 58. Sales of unconventional light-duty vehicles by fuel type, 2006 and 2030 (thousand vehicles sold)



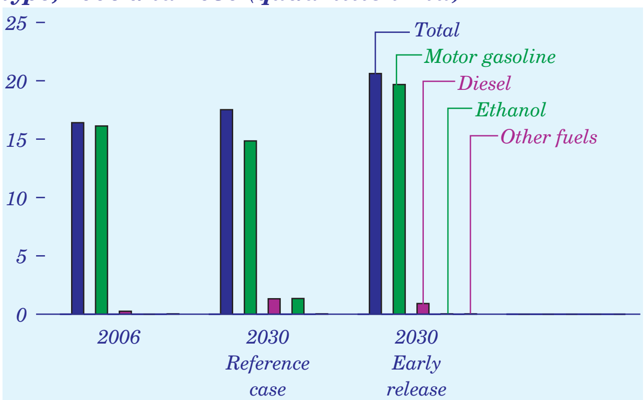
Concerns about oil supply, fuel prices, and emissions have driven the development and market penetration of unconventional vehicles (which can use alternative fuels, electric motors and advanced electricity storage, advanced engine controls, or other new technologies). Unconventional technologies are expected to play an even greater role in meeting the LDV CAFE standards in EISA2007. In the reference case (with EISA2007), unconventional vehicle sales total 7.7 million units (42 percent of new LDV sales) in 2030. Without EISA2007, only 4.7 million units are sold in 2030, making up 25 percent of total new LDV sales (Figure 58).

Sales of hybrid vehicles grow to 2.7 million units in 2030 in the reference case, compared with 1.6 million units without EISA2007. Light-duty diesel engines with advanced direct injection, which can significantly reduce exhaust emissions and improve efficiency, capture 13 percent of the market for new LDVs in 2030. The availability of ultra-low-sulfur diesel (ULSD) and biodiesel fuels, along with advances in emission control technologies that reduce criteria pollutants, increase the sales of unconventional diesel vehicles.

Currently, manufacturers have an incentive to sell flex-fuel vehicles (FFVs), because they receive fuel economy credits that count toward CAFE compliance. Although the credits are phased out by 2020 under EISA2007, FFV sales increase from 454,600 units in 2006 to 2.7 million units in 2030 in the reference case as a result of the growing use of E85 that is needed to satisfy the EISA2007 RFS.

EISA2007 Reduces Light-Duty Vehicle Fuel Use by 3 Quadrillion Btu in 2030

Figure 59. Energy use for light-duty vehicles by fuel type, 2006 and 2030 (quadrillion Btu)



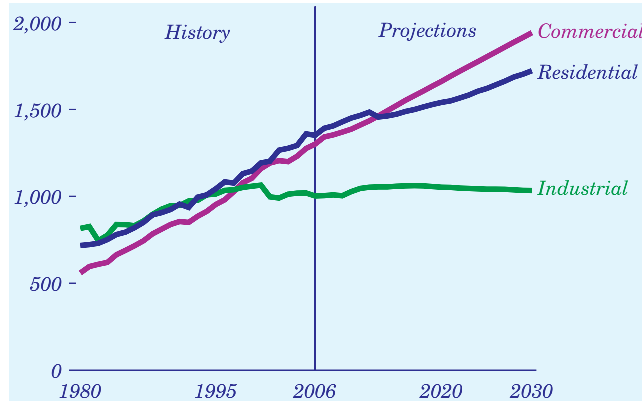
In the reference case, EISA2007 reduces energy consumption for LDVs by more than 3 quadrillion Btu in 2030, from 20.6 quadrillion Btu without EISA2007 to 17.5 quadrillion Btu with the bill (Figure 59). Although total vehicle sales are approximately the same in 2030 with and without EISA2007, higher CAFE standards lead to the savings in energy consumption.

With EISA2007, LDV motor gasoline consumption drops by 4.9 quadrillion Btu in 2030, from 19.7 quadrillion Btu to 14.8 quadrillion Btu. Much of the decline results from switching to unconventional technologies. Diesel fuel consumption in 2030, including biodiesel and BTL diesel, is 1.3 quadrillion Btu, 0.4 quadrillion Btu higher than without EISA2007; and E85 consumption is 1.3 quadrillion Btu in 2030, up from almost zero without EISA2007. The amount of ethanol used in blending is about the same in both cases because of EPA restrictions on ethanol fuel blending.

As a result of EISA2007, the motor gasoline share of fuel use for new LDVs in 2030 declines, and the shares of diesel and ethanol increase. In the reference case, motor gasoline accounts for 84.7 percent of the total, down from 95.4 percent without EISA2007. The diesel fuel share increases to 7.5 percent of total consumption, and the ethanol share increases to 7.7 percent [*82*].

Residential and Commercial Sectors Dominate Electricity Demand Growth

Figure 60. Annual electricity sales by sector, 1980-2030 (billion kilowatthours)

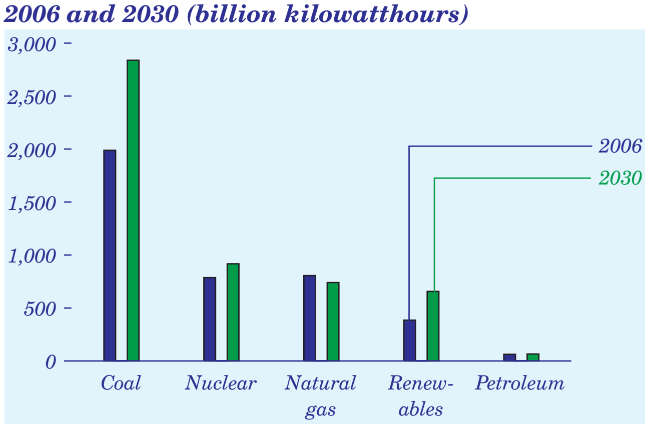


Total electricity sales increase by 29 percent in the *AEO2008* reference case, from 3,659 billion kilowatthours in 2006 to 4,705 billion in 2030, at an average rate of 1.1 percent per year. The relatively slow growth follows the historical trend, with the growth rate slowing in each succeeding decade. Electricity sales, which are strongly affected by economic growth, increase by 39 percent in the high growth case, to 5,089 billion kilowatthours in 2030, but by only 18 percent in the low growth case, to 4,319 billion kilowatthours in 2030. In the reference case, the largest increase is in the commercial sector, at 49 percent from 2006 to 2030 (Figure 60), as service industries continue to drive growth. Electricity demand grows by 27 percent in the residential sector and by only 3 percent in the industrial sector. Growth in population and disposable income leads to increased demand for products, services, and floorspace. Population shifts to warmer regions also increase the need for cooling.

Efficiency gains offset growth in electricity demand, as higher energy prices encourage investment in energy-efficient equipment. In both the residential and commercial sectors, continuing efficiency gains in electric heat pumps, air conditioners, refrigerators, lighting (notably LED lighting), cooking appliances, and computer screens slow the growth of electricity demand. The new standards set in EISA2007 for lighting and other appliances (such as boilers, dehumidifiers, dishwashers, and clothes washers) further dampen electricity demand throughout the projection. Slow growth in industrial production, particularly in the energy-intensive industries, limits electricity demand growth in the industrial sector.

Coal-Fired Power Plants Provide Largest Share of Electricity Supply

Figure 61. Electricity generation by fuel, 2006 and 2030 (billion kilowatthours)



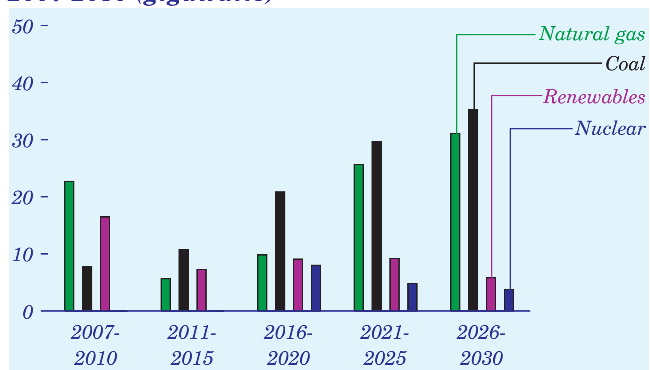
Coal-fired power plants (including utilities, independent power producers, and end-use CHP) continue to be the dominant source of electricity generation through 2030 (Figure 61). Although natural-gas-fired plants with lower capital costs make up most of the capacity additions over the next 10 years, more coal-fired plants are built in the later years as natural gas fuel costs increase. The natural gas share of generation falls from 20 percent in 2006 to 14 percent in 2030, while the coal share increases from 49 percent to 54 percent.

Federal tax incentives, State renewable energy programs, and rising fossil fuel prices lead to increases in renewable and nuclear capacity and generation, as new plants are built. The generation share from renewable capacity increases by 32 percent from 2006 to 2030 and represents 13 percent of total electricity supply in 2030. With capacity additions and improvements in performance at existing nuclear facilities, nuclear generation also increases; however, the nuclear share of total generation falls slightly, from 19 percent in 2006 to 18 percent in 2030.

Technology choices for new plants and utilization of existing capacity are affected by relative fuel costs and changes in environmental policies. For example, natural-gas-fired plants are projected to supply 21 percent of total electricity supply in 2030 in the low price case but only 10 percent in the high price case, but coal-fired plants supply 49 percent of the total in the low price case and 57 percent in the high price case. Changes in environmental policies could also have a significant effect on the fuel shares of total generation.

Early Capacity Additions Use Natural Gas, Coal Plants Are Added Later

Figure 62. Electricity generation capacity additions by fuel type, including combined heat and power, 2007-2030 (gigawatts)



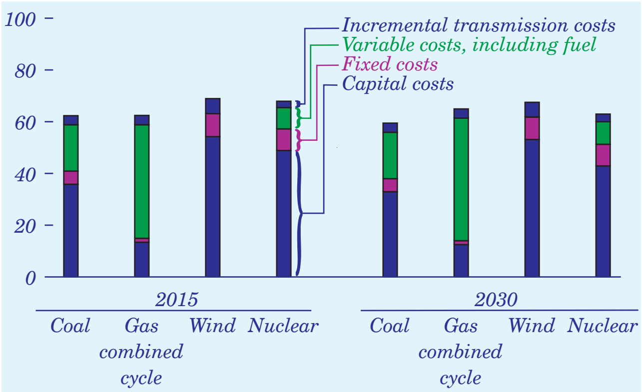
Decisions to add capacity and the choice of fuel type depend on electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different options, fuel prices, and the availability of Federal tax credits for some technologies. With growing electricity demand and the retirement of 45 gigawatts of capacity, 263 gigawatts of new generating capacity (including end-use CHP) will be needed by 2030.

Natural-gas-fired plants generally have lower capacity costs but higher fuel costs than coal-fired plants. As a result, coal-fired plants typically are more economical, and they account for 40 percent of total capacity additions from 2006 to 2030, compared with a 36-percent share for natural gas (Figure 62). Renewable and nuclear plants tend to have high investment costs and relatively low operating costs. EPACT2005 and State RPS programs are expected to stimulate generation from renewable and nuclear plants, which represent 18 percent and 6 percent of total additions, respectively.

The quantity and mix of capacity additions can also be affected by different fuel price paths or growth rates for electricity demand. Because fuel costs are a larger share of total expenditures for new natural-gas-fired capacity, the higher fuel costs in the high price case lead to more coal-fired additions. In the economic growth cases, capacity additions range from 182 gigawatts in the low growth case to 349 gigawatts in the high growth case, although the generation shares for different technologies are similar in the two cases.

Least Expensive Technology Options Are Likely Choices for New Capacity

Figure 63. Levelized electricity costs for new plants, 2015 and 2030 (2006 mills per kilowatthour)



Technology choices for new generating capacity are made to minimize cost while meeting local and Federal emissions constraints. The choice of technology for capacity additions is based on the least expensive option available (Figure 63) [*83*]. The *AEO2008* reference case assumes a capital recovery period of 20 years, with the cost of capital based on competitive market rates.

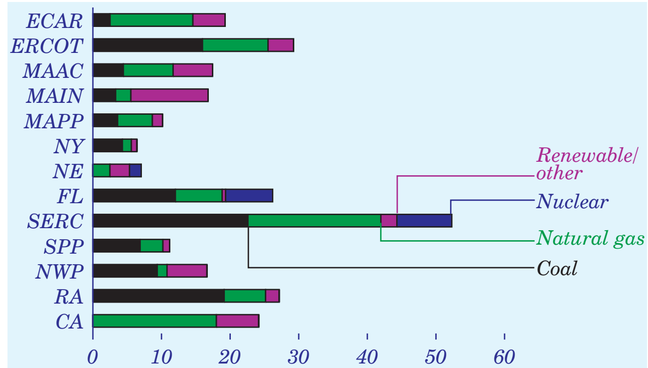
Real capital costs decline over time (Table 6) at rates that depend on the current stage of development for each technology. For the newest technologies, capital costs are initially adjusted upward to reflect the optimism inherent in early estimates of project costs. As project developers gain experience, the costs are assumed to decline. The decline continues at a progressively slower rate as more units are built. The efficiency of new plants is also assumed to improve through 2025, with heat rates for advanced combined cycle and coal gasification units declining from 6,752 and 8,765 Btu per kilowatthour in 2006 to 6,333 and 7,450 Btu per kilowatthour, respectively, in 2025.

Table 6. Costs of producing electricity from new plants, 2015 and 2030

Costs	2015 Advanced coal	2015 Advanced combined cycle	2030 Advanced coal	2030 Advanced combined cycle
	2006 mills per kilowatthour			
Capital	35.83	13.44	32.91	12.50
Fixed	5.05	1.49	5.05	1.49
Variable	17.93	43.87	17.94	47.41
Incremental transmission	3.50	3.62	3.54	3.54
Total	**62.31**	**62.42**	**59.44**	**64.94**

Largest Capacity Additions Expected in the Southeast and the West

Figure 64. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2007-2030 (gigawatts)



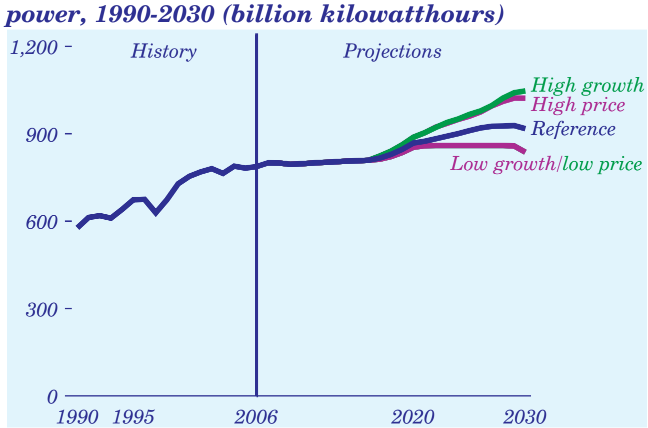
Most areas of the United States currently have excess generation capacity, but all electricity demand regions (see Appendix F for definitions) are expected to need additional, currently unplanned, capacity by 2030. The largest amount of new capacity is expected in the Southeast (FL and SERC), which represents a relatively large and growing share of total U.S. electricity sales and thus requires more capacity than other regions (Figure 64). The growth in demand for electricity in the Southeast is well above the national average.

With natural gas prices rising in the reference case, coal-fired plants account for the largest share of capacity additions through 2030, given the assumption that current environmental policies are maintained indefinitely. The largest concentration of new coal-fired capacity is in the Southeast, where new coal-fired plants are built to accommodate growth in the electricity market and the corresponding need for additional capacity.

Natural gas, renewable, and nuclear plants represent the remaining capacity additions. Natural-gas-fired plants are built to maintain a diverse capacity mix, to serve as reserve capacity, or to meet environmental regulations. About three-fourths of the additions are located in the Southeast, the West (NWP, RA, and CA), and the Midwest (ECAR, MAIN, and MAPP). Renewable capacity is also needed because of State and Federal renewable energy policies, and the Midwest accounts for the largest share of renewable capacity additions. Most nuclear additions are expected in the Southeast, where suppliers have expressed interest in building new nuclear plants.

EPACT2005 Tax Credits Are Expected To Stimulate New Nuclear Builds

Figure 65. Electricity generation from nuclear power, 1990-2030 (billion kilowatthours)

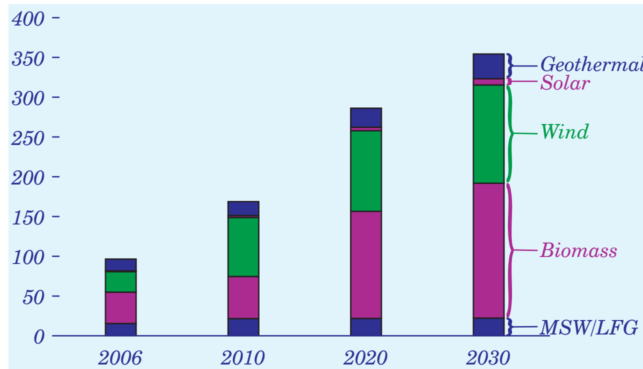


In the *AEO2008* reference case, nuclear capacity grows from 100.2 gigawatts in 2006 to 114.9 gigawatts in 2030, including 2.7 gigawatts of expansion at existing plants, 16.6 gigawatts of new capacity, and 4.5 gigawatts of retirements. EPACT2005 provides an 8-year PTC of 1.8 cents per kilowatthour for up to 6 gigawatts of new nuclear capacity built before 2021. The credit also can be shared for additional capacity but at a lower credit value. The reference case projects 8.0 gigawatts of new nuclear capacity (which will receive the tax credits) by 2020. Early builds are expected to bring down the cost of nuclear capacity and, when combined with rising fossil fuel costs, to result in additional nuclear builds after 2020. All uprates approved, pending, or expected by the NRC at existing units are assumed to be carried out. Most existing nuclear units are expected to continue operating through 2030, based on the assumption that they will apply for and receive license renewals. Seven units, totaling 4.5 gigawatts, are projected to be retired after 2028, when the end date of their original licenses plus a 20-year renewal is reached.

Projected nuclear capacity additions vary, depending on overall demand for electricity and the prices of other fuels. In the five main *AEO2008* cases, nuclear generation grows from 787 billion kilowatthours in 2006 to between 837 and 1,047 billion kilowatthours in 2030 (Figure 65). In the low price case, the delivered price of natural gas in 2030 is 15 percent lower than in the reference case, and new nuclear plants become less economical. In the high price and high growth cases, respectively, 30 and 33 gigawatts of new nuclear capacity are projected, because more capacity is needed and the cost of alternatives is higher.

Biomass and Wind Lead Projected Growth in Renewable Generation

Figure 66. Nonhydroelectric renewable electricity generation by energy source, 2006-2030 (billion kilowatthours)

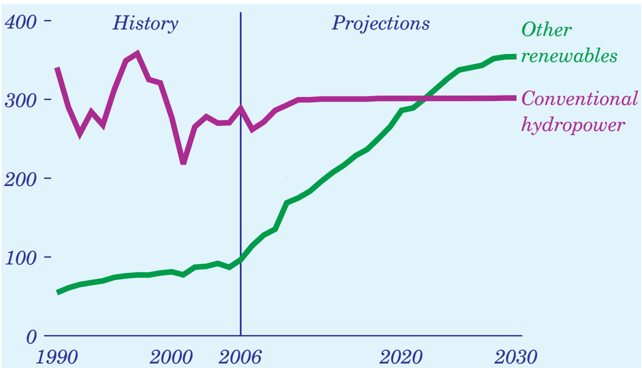


There is considerable uncertainty about the growth potential of wind power, which depends on a variety of factors, including fossil fuel costs, State renewable energy programs, technology improvements, access to transmission grids, public concerns about environmental and other impacts, and the future of the Federal PTC, which is expected to expire at the end of 2008. In the *AEO2008* reference case, generation from wind power increases from 0.6 percent of total generation in 2006 to 2.4 percent in 2030 (Figure 66). Biomass, both dedicated and co-firing, grows from 39 billion kilowatthours in 2006 (1.0 percent of the total) to 170 billion kilowatthours (3.2 percent). Generation from geothermal facilities also grows, but at a slower rate, increasing from 0.4 percent of total generation in 2006 to 0.6 percent in 2030. Current assessments show limited potential for expansion at conventional geothermal sites.

For consistency in reporting, nonbiogenic municipal solid waste (MSW) is separated from renewable generation. Nonrenewable materials, such as plastics, have made up an increasing proportion of MSW, and 44 percent of the energy value of MSW in 2005 was from nonbiogenic sources; in the *AEO2008* reference case, that share is held constant over the projection period. (All growth in generation from MSW and landfill gas facilities is attributed to landfill gas only.) Solar technologies in general remain too costly for grid-connected applications, but demonstration programs and State policies support some growth in central-station solar PV, and small-scale customer-sited PV applications grow rapidly [*84*].

Technology Advances, Tax Provisions Increase Renewable Generation

Figure 67. Grid-connected electricity generation from renewable energy sources, 1990-2030 (billion kilowatthours)

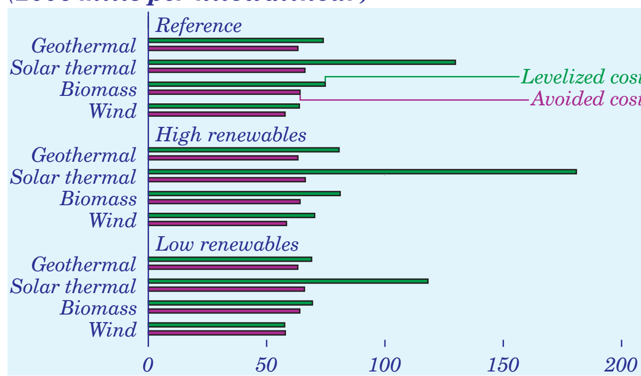


With State RPS programs included in the reference case, renewable electricity generation grows by more than 270 billion kilowatthours. In 2030, total renewable generation is 656 billion kilowatthours or 12.5 percent of total domestic power production. Although conventional hydropower remains the largest source of renewable generation through 2030 (Figure 67), environmental concerns and the scarcity of untapped large-scale sites limit its growth, and its share of total generation falls from 7.1 percent in 2006 to 5.8 percent in 2030. Electricity generation from nonhydroelectric alternative fuels increases, bolstered by legislatively mandated State RPS programs, technology advances and State and Federal supports, although the Federal PTC is assumed to expire at the end of 2008 per existing law. The share of nonhydropower renewable generation increases from 2.4 percent of total generation in 2006 to 6.8 percent in 2030.

Wind is the largest source of renewable generation among the nonhydropower renewable fuels, with 124 billion kilowatthours of generation in 2030, up from 26 billion kilowatthours in 2006. Initially helped by the Federal PTC, its growth continues as States meet their RPS requirements. Biomass also grows strongly, as generation from both dedicated facilities and co-firing applications increases to 83 billion kilowatthours in 2030, with an additional 87 billion kilowatthours generated in end-use systems. In the near term, market penetration by the unproven biomass gasification technology is slow, while co-firing expands more rapidly. The strong growth in end-use generation is led by the renewable fuels mandate. Facilities producing BTL fuels also use the feedstocks for electricity production.

Renewables Are Expected To Become More Competitive Over Time

Figure 68. Levelized and avoided costs for new renewable plants in the Northwest, 2030 (2006 mills per kilowatthour)

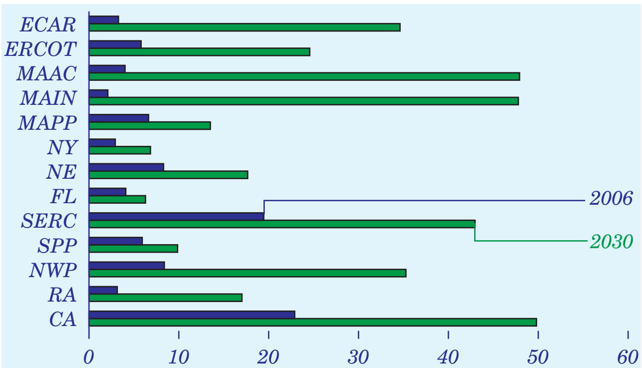


The projected cost of renewable generation in *AEO2008* is significantly higher than projected in previous *AEO*s, primarily as a result of increases in the installation cost of new generating capacity observed throughout the electric power industry. Broad indexes of utility construction costs suggest increases of approximately 15 percent over previous EIA estimates. Available data for specific renewable capacity markets, such as wind power, confirm both the direction and general magnitude of the cost increases when applied more narrowly to renewable generation. For *AEO2008*, the cost increases are applied to all power-sector installations, and they are expected to be persistent rather than short-term cost spikes. In general, renewable generation is expected to remain more expensive than the generation it would displace, that is, its avoided cost (Figure 68).

In addition to the increase in capital costs, EIA reassessed the cost and performance of dedicated biomass generation technology. According to an independent expert review, previous EIA estimates for biomass gasification technology understated its cost even before the industry-wide increase in capital costs. Although higher installation costs make biomass more expensive, significant growth in dedicated biomass capacity is expected in regions with stringent RPS requirements and limited supplies of lower cost resources, such as wind. In the near term, growth in renewable generation in those regions is met largely by biomass co-firing in existing coal plants—an option with relatively low capital costs. The higher efficiency of dedicated plants makes them increasingly attractive, however, as biomass fuels with higher energy value are used to meet RPS mandates.

State Portfolio Standards Increase Generation from Renewable Fuels

Figure 69. Regional growth in nonhydroelectric renewable electricity generation, 2006-2030 (billion kilowatthours)

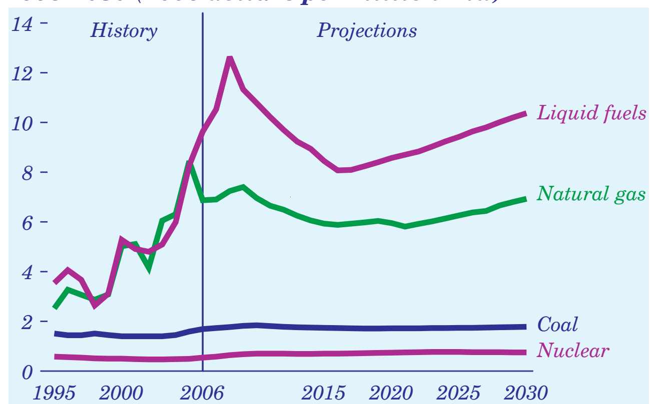


In October 2007, 25 States and the District of Columbia had legislatively mandated RPS programs. The mandatory programs were modeled in the *AEO2008* reference case [*85*], but States with voluntary goals were assumed not to have any impact on the national energy mix. Because NEMS does not provide projections at the State level, the reference case assumes that all States will reach their goals within each program's legislative framework, and the results are aggregated at the regional level. In some States, however, compliance could be limited by authorized funding levels for the programs. For example, California is not expected to meet its renewable energy targets because of limits to authorized funding for its RPS program.

In the reference case, wind capacity grows much more rapidly than projected in previous *AEO*s, to 40 gigawatts in 2030 [*86*]. Much of the qualifying capacity in the Midwest, Northeast, Southwest, and Pacific Northwest is expected to consist of wind farms. In one midwestern region (MAIN), 11 gigawatts of wind turbine capacity is projected to be on line in 2030, as compared with 220 megawatts in 2006. In the Mid-Atlantic region, State RPS programs are the driving force behind additional dedicated biomass gasification plants. Approximately 3 gigawatts of new capacity, along with co-firing, provides 37 billion kilowatthours of generation annually. Most of the new biomass capacity is projected to come on line in the Mid-Atlantic region from 2006 to 2030 (Figure 69). While the growth in wind capacity is the most dramatic, biomass co-firing and geothermal power plants also contribute to the baseload generation needed to satisfy State RPS requirements.

Fuel Costs Drop from Recent Highs, Then Increase Gradually

Figure 70. Fuel prices to electricity generators, 1995-2030 (2006 dollars per million Btu)



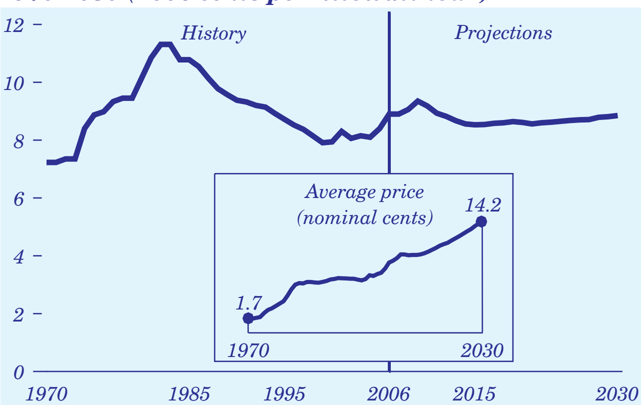
Fuel costs account for about two-thirds of the generating costs of new natural-gas-fired plants, less than one-third for new coal-fired plants, and less than one-tenth for new nuclear power plants in 2030. For many renewable fuels, such as wind and solar, fuel is free. Capital and operations and maintenance expenses make up the balance of the costs. As a result, natural-gas-fired generation tends to be the most sensitive—and wind and solar the least sensitive—to changes in fuel costs.

In the reference case, prices for fossil fuels delivered to electricity generators peak between 2005 and 2010, as the result of a boom in U.S. and foreign demand, combined with constraints on supply growth and political instability in oil- and gas-producing nations. Fossil fuel prices fall in the middle years of the projection, however, as new supplies come on line to meet growing demand. Prices then increase steadily as demand once again starts to outpace supply (Figure 70). Nuclear and biomass fuel prices rise gradually throughout the projection, as a result of worldwide growth in the demand for nuclear fuel and depletion of local biomass stocks.

Electricity generation from relatively low-cost, low-polluting, natural-gas-fired plants increased significantly in the early years of this decade. More recently, higher costs and increasing volatility of supply and prices have characterized natural gas markets. Consequently, in the reference case, the natural gas share of total electricity generation drops after 2016, and both coal-fired and renewable generation increase.

Electricity Prices Moderate in the Near Term, Then Rise Gradually

Figure 71. Average U.S. retail electricity prices, 1970-2030 (2006 cents per kilowatthour)



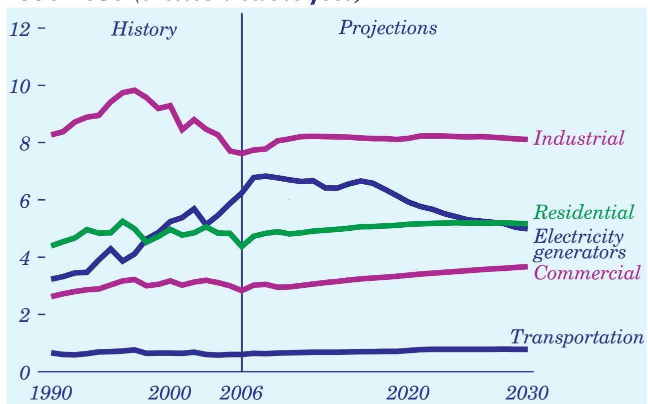
In the *AEO2008* reference case, continuing high fuel prices and escalating capital costs for new generating capacity lead to a jump in real electricity prices, peaking in 2009 at an annual average of 9.3 cents per kilowatthour (2006 dollars). Electricity prices fall to 8.5 cents per kilowatthour in 2015, as new sources of natural gas and coal are brought on line. From 2016 on, generally rising prices for natural gas and petroleum (in addition to the impact of State renewable fuel mandates) encourage power producers to increase their use of less expensive coal and renewable fuels. Retail electricity prices rise gradually after 2016, to 8.8 cents per kilowatthour in 2030 (Figure 71).

Customers in States with competitive retail markets for electricity experience the effects of changes in natural gas prices more rapidly than customers in States with regulated markets, because competitive prices are determined by the marginal cost of energy, and natural-gas-fired plants, with their higher operating costs, often set hourly marginal prices. After 2016, as other plant types set hourly prices more often, the price of natural gas has less influence on competitive retail markets. In the low and high oil and natural gas price cases, electricity prices range from 8.5 to 9.1 cents per kilowatthour in 2030.

Electricity distribution costs decline by 5 percent from 2006 to 2030, as technology improvements and a growing customer base lower the cost of the distribution infrastructure. Transmission costs increase by 30 percent, as additional investments are made in the grid to alleviate current constraints, facilitate competitive markets, and meet growing consumer demand for electricity.

Fastest Increase in Natural Gas Use Is Expected for the Buildings Sectors

Figure 72. Natural gas consumption by sector, 1990-2030 (trillion cubic feet)



In the reference case, total natural gas consumption increases from 21.7 trillion cubic feet in 2006 to a peak value of 23.8 trillion cubic feet in 2016, followed by a decline to 22.7 trillion cubic feet in 2030. The natural gas share of total energy consumption drops from 22 percent in 2006 to 20 percent in 2030.

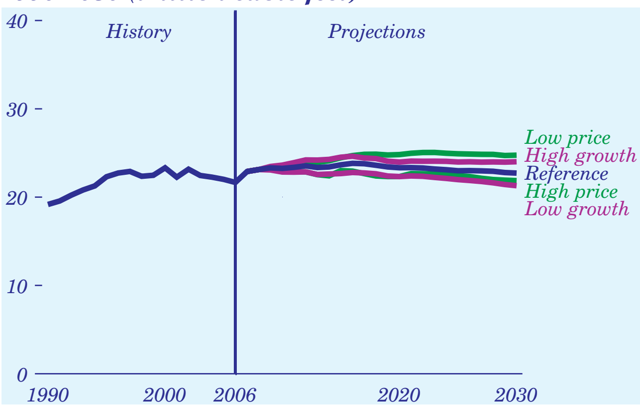
The projected path of total natural gas consumption depends almost entirely on the amount consumed in the electric power sector. Natural gas consumption for electricity generation in the power sector declines from current levels to 5.0 trillion cubic feet in 2030 in the reference case (Figure 72), as a result of a projected increase in natural gas prices that begins after 2016.

Natural gas consumption in the electric power sector is highly responsive to price changes, because electricity producers can choose among different fuels on an ongoing basis. In contrast, consumption of natural gas in the residential, commercial, and industrial sectors is influenced not only by fuel prices but also by economic trends. In those sectors, natural gas consumption increases steadily from 2006 through 2030.

In the industrial sector, natural gas consumption is projected to grow from 7.6 trillion cubic feet in 2006 to 8.1 trillion cubic feet in 2030. In the residential and commercial sectors (the buildings sectors), consumption increases from a combined total of 7.2 trillion cubic feet in 2006 to 8.8 trillion cubic feet in 2030. As a result, the buildings sectors show the greatest overall increase in natural gas consumption, in both percentage and absolute terms.

Natural Gas Consumption Varies With Fuel Prices and Economic Growth

Figure 73. Total natural gas consumption, 1990-2030 (trillion cubic feet)



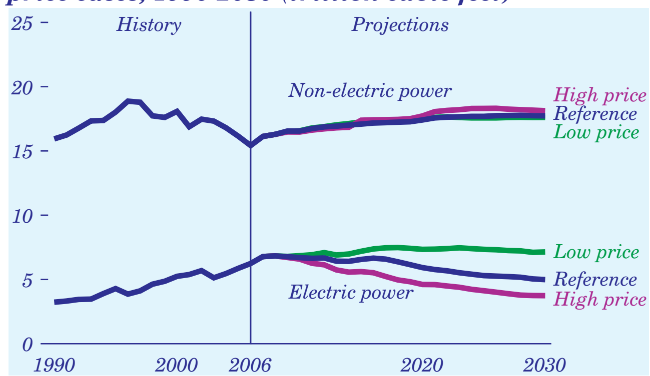
In the *AEO2008* projections, natural gas consumption varies with natural gas prices and economic growth rates. Higher natural gas prices reduce demand, and higher economic growth rates increase demand.

In the high and low price cases, natural gas consumption in 2030 ranges from 24.8 trillion cubic feet in the low case to 21.9 trillion cubic feet in the high case (Figure 73). High natural gas prices provide direct economic incentives for reducing natural gas consumption, whereas low prices encourage more consumption; however, the strength of the relationship depends on short- and long-term fuel substitution capabilities and equipment options within each consumption sector.

In the economic growth cases, consumption in 2030 varies from 24.0 trillion cubic feet in the high growth case to 21.3 trillion cubic feet in the low growth case. With faster economic growth, disposable income increases more rapidly, and consumers increase their energy purchases either by buying products that consume additional energy (such as larger homes), being less energy-efficient in using products they already own (for example, by setting thermostats higher in the winter and lower in the summer), or both.

Natural Gas Use in the Electric Power Sector Is Sensitive to Prices

Figure 74. Natural gas consumption in the electric power and non-electric power sectors in alternative price cases, 1990-2030 (trillion cubic feet)



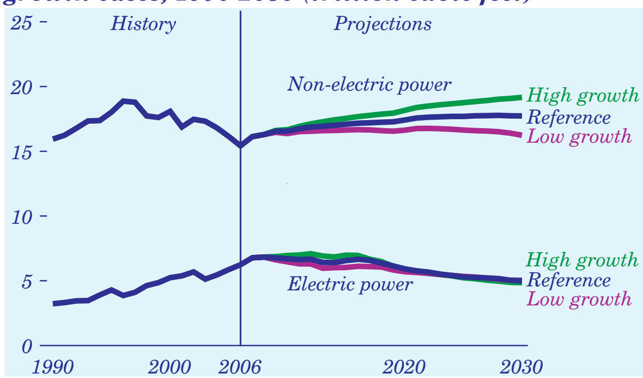
In the *AEO2008* projections, the largest variation in sectoral demand for natural gas in response to high and low price assumptions occurs in the electric power sector (Figure 74). Natural gas consumption by electricity producers in 2030, projected at 5.0 trillion cubic feet in the reference case, increases to 7.1 trillion cubic feet in the low price case but falls to 3.7 trillion cubic feet in the high price case.

Much of the variation in projected natural gas demand in the electric power sector between the low and high price cases is the result of different projections for the amount of natural-gas-fired generating capacity built—and consequently the amount of electricity generated from natural gas—from 2007 to 2030. In the high price case, a cumulative 65.4 gigawatts of new natural-gas-fired generating capacity is added in the electric power sector between 2007 and 2030. In the low price case, cumulative natural-gas-fired capacity additions in the electric power sector total 131.1 gigawatts over the same period.

When natural gas prices are high, electric power producers can quickly substitute generation from coal and other fuels for power generated from natural gas. In contrast, in the residential, commercial, industrial, and transportation sectors, fuel price assumptions have a considerably smaller effect on natural gas consumption, because fuel substitution options are limited and the stocks of equipment that use natural gas have relatively slow turnover rates. In 2030, total natural gas consumption in those sectors ranges from 18.1 trillion cubic feet in the high price case to 17.6 trillion cubic feet in the low price case.

Natural Gas Use in Other Sectors Is More Sensitive to Economic Growth

Figure 75. Natural gas consumption in the electric power and non-electric power sectors in alternative growth cases, 1990-2030 (trillion cubic feet)

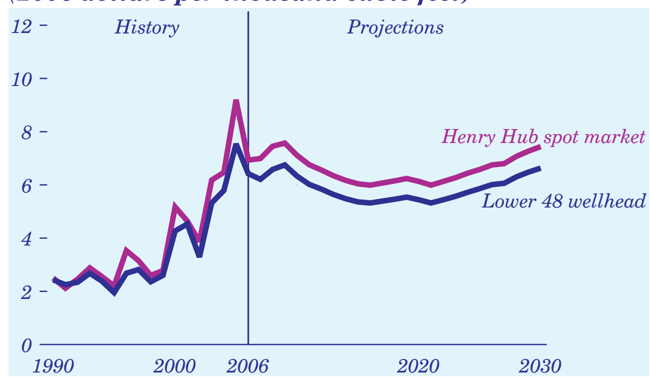


The largest variation in natural gas consumption in the residential, commercial, industrial, and transportation end-use sectors results from different assumptions about economic growth rates. In the high economic growth case, natural gas consumption in those end-use sectors is projected to total 19.2 trillion cubic feet in 2030. In the low growth case, the projected total in 2030 is 16.2 trillion cubic feet (Figure 75). Most of the difference between the projections in the two cases is attributable to the industrial sector, where growth in economic output has a greater impact on natural gas consumption than it does in the residential, commercial, and transportation sectors. In the industrial sector, projected natural gas consumption in 2030 varies from 7.2 trillion cubic feet in the low growth case to 9.0 trillion cubic feet in the high growth case.

Natural gas consumption in the electric power sector is sensitive to natural gas prices because other fuels, such as coal, can be substituted directly for natural gas in generating electricity. In the high and low economic growth cases, however, natural gas consumption in the electric power sector shows little variation from the reference case projection. Natural gas use for electricity generation in 2030 varies from 5.0 trillion cubic feet in the low growth case to 4.9 trillion cubic feet in the high growth case. In the high economic growth case, when natural gas consumption in the electric power sector begins to rise, natural gas prices increase significantly, and in response coal and nuclear power are substituted for natural gas.

Projected Natural Gas Prices Fall from Current Levels Before Rising

Figure 76. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030 (2006 dollars per thousand cubic feet)



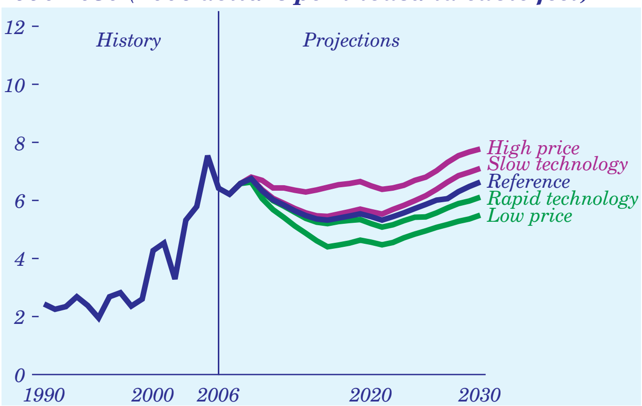
In the *AEO2008* reference case, lower 48 wellhead prices for natural gas are projected to decline from current levels to an average of $5.32 per thousand cubic feet (2006 dollars) in 2016, then rise to $6.63 per thousand cubic feet in 2030. Henry Hub spot market prices are projected to decline to $5.82 per million Btu ($5.99 per thousand cubic feet) in 2016 and then rise to $7.22 per million Btu ($7.43 per thousand cubic feet) in 2030 (Figure 76).

Current high natural gas prices are expected to stimulate the development of new gas supplies and constrain growth in natural gas consumption. Greater availability of natural gas supplies leads to a decline in prices through 2016. After 2016, wellhead natural gas prices increase largely as a result of the increased cost of developing the remaining U.S. natural gas resource base.

Natural gas prices in the reference case are determined largely by the cost of supplying natural gas from the remaining U.S. and Canadian resource base. In the future, however, the U.S. natural gas market is expected to become more integrated with natural gas markets worldwide, as a result of increased U.S. access to, and reliance on, LNG supplies from foreign sources. As a consequence, international market conditions will have a stronger influence on domestic natural gas prices in the United States, causing even greater uncertainty in future U.S. natural gas prices than would be the case if the United States relied exclusively on natural gas supplies from North America.

Prices Vary With Resource Size and Technology Progress Assumptions

Figure 77. Lower 48 wellhead natural gas prices, 1990-2030 (2006 dollars per thousand cubic feet)

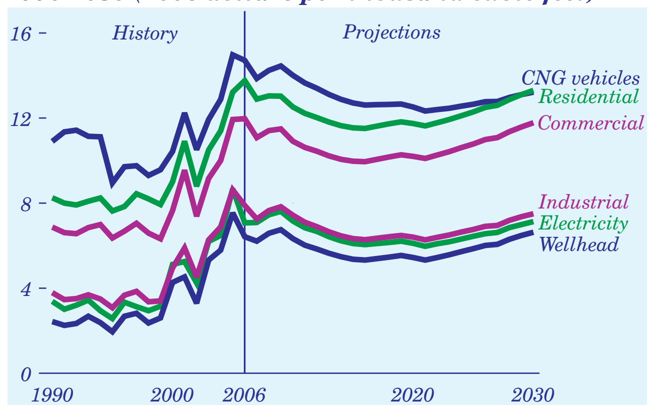


In the high price case, oil prices are assumed to be higher and the unproven natural gas resource base is assumed to be 15 percent smaller than the estimates used in the reference case. The low price case assumes lower oil prices and a 15-percent larger unproven resource base than in the reference case. A smaller domestic natural gas resource base increases exploration and production (E&P) costs, leading to higher natural gas prices. As a result, U.S. wellhead prices (and the price of LNG worldwide) are higher in the high price case and lower in the low price case than in the reference case (Figure 77). In 2030, domestic wellhead natural gas prices are projected to average $7.77 (2006 dollars) per thousand cubic feet in the high price case, compared with $5.49 per thousand cubic feet in the low price case.

Technological progress affects the future production of natural gas by reducing production costs and expanding the economically recoverable resource base. In the *AEO2008* reference case, the rate of improvement in natural gas production technology is based on the historical rate. The slow oil and natural gas technology case assumes an improvement rate 50 percent lower than in the reference case. As a result, future capital and operating costs are higher, causing the projected average wellhead price of natural gas to increase to $7.10 per thousand cubic feet in 2030. The rapid technology case assumes a rate of technology improvement 50 percent higher than in the reference case, reducing natural gas development and production costs. In the rapid technology case, wellhead natural gas prices are projected to average $6.11 per thousand cubic feet in 2030.

Delivered Natural Gas Prices Follow Trends in Wellhead Prices

Figure 78. Natural gas prices by end-use sector, 1990-2030 (2006 dollars per thousand cubic feet)



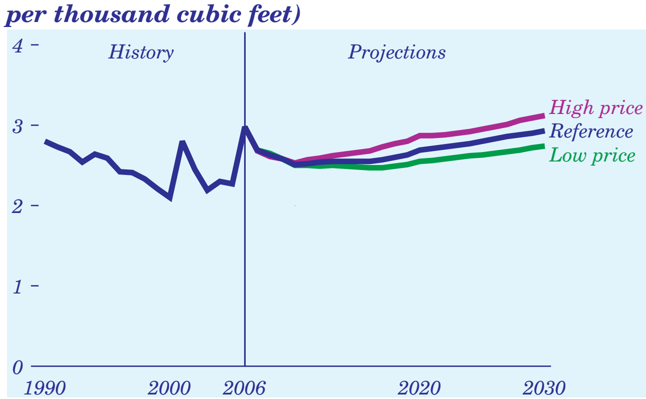
Trends in delivered natural gas prices largely reflect changes in projected wellhead prices. In the *AEO2008* reference case, prices for natural gas delivered to the end-use sectors decline through 2016 as wellhead natural gas prices decline, then increase along with wellhead prices over the rest of the projection period (Figure 78).

Natural gas transmission and distribution margins in the industrial and electric power sectors fall over time, because production facilities in those sectors typically are connected directly to transmission pipelines, and pipeline rates are projected to fall as their depreciation expenses decline more rapidly than their costs increase. In the residential and commercial sectors, in contrast, transmission and distribution rates for natural gas rise over time, because increases in building efficiency reduce natural gas consumption at each building site, and distribution expenses thus are spread over a lower total volume of system throughput. As a result, average U.S. transmission and distribution margins increase slowly from 2006 to 2030 in the reference case.

All the *AEO2008* cases assume that sufficient transmission and distribution capacity will be built to accommodate the projected growth in natural gas consumption. If public opposition were to prevent infrastructure expansion, however, delivered prices could be higher than projected.

Transmission and Distribution Margins Vary Inversely With Volumes

Figure 79. Average natural gas transmission and distribution margins, 1990-2030 (2006 dollars per thousand cubic feet)

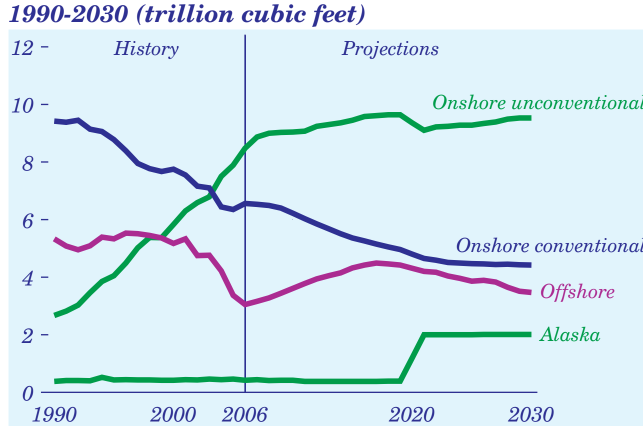


The transmission and distribution margin for natural gas delivered to end users is the difference between the average delivered price and the average source price, which is the quantity-weighted average of the lower 48 wellhead price and the average import price. It reflects both the capital and operating costs for pipelines and the volume of natural gas transported. Although operating costs vary with the level of pipeline utilization, capital costs are fixed for the most part. Variations in pipeline throughput result in higher or lower transmission and distribution costs per thousand cubic feet of natural gas transported. Thus, because the high and low price case projections show the greatest variation in total natural gas consumption, the greatest variation in transmission and distribution margins is also seen in those cases.

In the high price case, total natural gas consumption in 2030 is projected to be only 21.9 trillion cubic feet. As a result, the average transmission and distribution margin for delivered natural gas is projected to increase from $2.98 per thousand cubic feet in 2006 to $3.12 per thousand cubic feet in 2030 (2006 dollars). In the low price case, total natural gas consumption in 2030 grows to 24.8 trillion cubic feet, and the average transmission and distribution margin in 2030 drops to $2.74 per thousand cubic feet as the existing pipeline system is used at a higher capacity factor. In the reference case, with projected natural gas consumption of 22.7 trillion cubic feet in 2030, the projected average transmission and distribution margin in 2030 is $2.93 per thousand cubic feet (Figure 79).

Unconventional Production Is a Growing Source of U.S. Gas Supply

Figure 80. Natural gas production by source, 1990-2030 (trillion cubic feet)



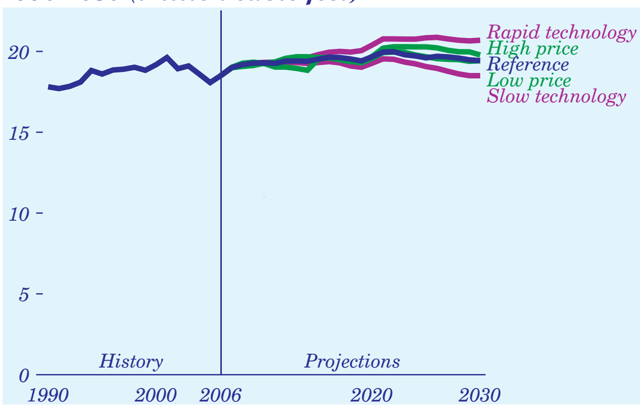
Total U.S. natural gas production grows modestly in the reference case, from 18.5 trillion cubic feet in 2006 to 19.4 trillion cubic feet in 2030, as depletion of the onshore lower 48 conventional resource base is offset by increased production from unconventional sources and from Alaska. Offshore production increases from 3.0 trillion cubic feet in 2006 to 4.5 trillion cubic feet in 2017, then declines to 3.5 trillion cubic feet in 2030. Production in shallow waters declines slowly through 2030. Production in deeper waters rises to 3.0 trillion cubic feet in 2019 and then declines through 2030.

A large proportion of the onshore lower 48 conventional natural gas resource base has been discovered. Discoveries of new conventional natural gas reservoirs are expected to be smaller and deeper, and thus more expensive and riskier to develop and produce. Accordingly, total lower 48 onshore conventional natural gas production declines in the *AEO2008* reference case from 6.6 trillion cubic feet in 2006 to 4.4 trillion cubic feet in 2030 (Figure 80). Incremental production of lower 48 onshore natural gas comes primarily from unconventional resources, including coalbed methane, tight sandstones, and gas shales. Lower 48 unconventional production increases in the reference case from 8.5 trillion cubic feet in 2006 to 9.5 trillion cubic feet in 2030.

The Alaska natural gas pipeline is expected to begin transporting natural gas to the lower 48 States in 2020. As a result, Alaska's natural gas production increases from 0.4 trillion cubic feet in 2006 to 2.0 trillion cubic feet in 2030 in the reference case.

Natural Gas Supply Projections Reflect Rates of Technology Progress

Figure 81. Total U.S. natural gas production, 1990-2030 (trillion cubic feet)



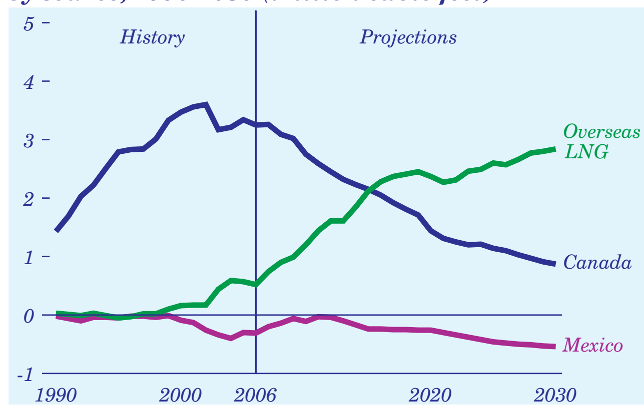
Exploration for and production of natural gas becomes more profitable when prices increase and when exploration and development costs decline. The rapid and slow technology cases show the effects of different assumed rates of technology improvement in the oil and natural gas industries, which directly affect exploration and development costs. The high and low price cases show the effects of different assumptions about oil price levels and the availability of unproved oil and natural gas resources.

Technological progress generally reduces the cost of natural gas production, leading to lower wellhead prices, more end-use consumption, and more production. More rapid progress works to increase domestic natural gas production and slower progress works to reduce production in the technology cases. U.S. natural gas production in 2030 is 6.4 percent higher in the rapid technology case and 4.8 percent lower in the slow technology case than in the reference case (Figure 81).

The high and low price cases show smaller effects on total production than do the technology cases. The high and low price cases include higher and lower oil prices and assume an unproven natural gas resource base that is 15 percent smaller (in the high price case) or 15 percent larger (in the low price case) than assumed in the reference case. In the high price case, the stimulative effect that higher natural gas prices normally would have on natural gas production is offset by an increase in E&P costs as a result of the smaller resource base.

Net Imports of Liquefied Natural Gas Grow in the Projection

Figure 82. Net U.S. imports of natural gas by source, 1990-2030 (trillion cubic feet)

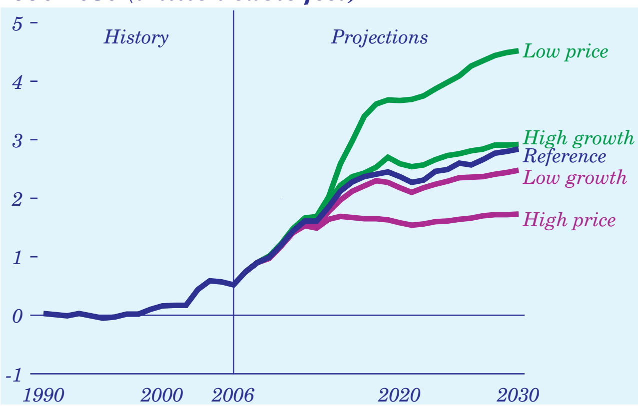


Net U.S. imports of natural gas from Canada are projected to decline, and net imports of LNG are projected to grow, from 2006 through 2030. Most of the expected growth in U.S. natural gas imports is in the form of LNG. The total capacity of U.S. LNG receiving terminals increases from 1.5 trillion cubic feet in 2006 to 5.2 trillion cubic feet in 2009 in the reference case (with no further increase through 2030), and net LNG imports grow from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030 (Figure 82). The U.S. market is expected to be tight throughout the projection because of competition for LNG supplies across the world. Although U.S. imports rise over time, they are expected to vary significantly from year to year, depending on domestic and worldwide natural gas prices. When international natural gas prices are higher than U.S. prices, LNG imports are expected to be lower, and vice versa. Thus, LNG imports in the *AEO2008* cases reflect the expected long-term trend rather than actual import levels in any particular year.

Over the past year, reported costs for development of the Mackenzie Delta natural gas pipeline, including development costs for the three anchor natural gas fields, have increased substantially [*87*]. Therefore, the pipeline is not expected to be built with natural gas prices at the levels projected in the *AEO2008* reference case. Canada still is expected to export natural gas to the United States in the reference case, however, with U.S. net imports from Canada declining from 3.2 trillion cubic feet in 2006 to 0.9 trillion cubic feet in 2030. Natural gas prices in the reference case are adequate to support that level of imports despite the absence of the Mackenzie Delta pipeline.

LNG Imports Are the Source of Supply Most Affected in the Price Cases

Figure 83. Net U.S. imports of liquefied natural gas, 1990-2030 (trillion cubic feet)



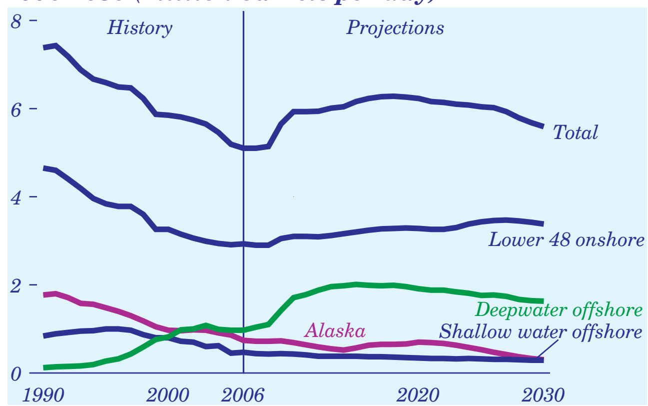
Net U.S. imports of LNG are expected to vary considerably from year to year, depending on both the level of U.S. natural gas prices and whether those prices are higher or lower than prices elsewhere in the world. Higher prices overseas are expected to reduce U.S. LNG imports, and lower prices overseas are expected to increase U.S. imports. U.S. LNG imports are much less sensitive to economic growth rates, which determine the level of domestic natural gas consumption. Given the uncertainty in future domestic and overseas natural gas prices, the level of future U.S. LNG imports is highly uncertain.

In the high price case, the higher world crude oil price is expected to result in increased natural gas consumption in overseas energy markets, exerting upward pressure on LNG prices. In addition, some LNG contract prices are tied directly to crude oil prices. Higher crude oil prices will also spur greater GTL production, placing additional pressure on world natural gas supplies. Collectively, these activities are expected to increase overseas wellhead natural gas prices and worldwide LNG prices, reducing both domestic natural gas consumption and LNG imports in the United States.

Net U.S. imports of LNG in 2030 are projected to total 2.8 trillion cubic feet in the reference case, 4.5 trillion cubic feet in the low price case, 1.7 trillion cubic feet in the high price case, 2.9 trillion cubic feet in the high economic growth case, and 2.5 trillion cubic feet in the low economic growth case (Figure 83).

U.S. Crude Oil Production Increases Slightly Through 2030

Figure 84. Domestic crude oil production by source, 1990-2030 (million barrels per day)

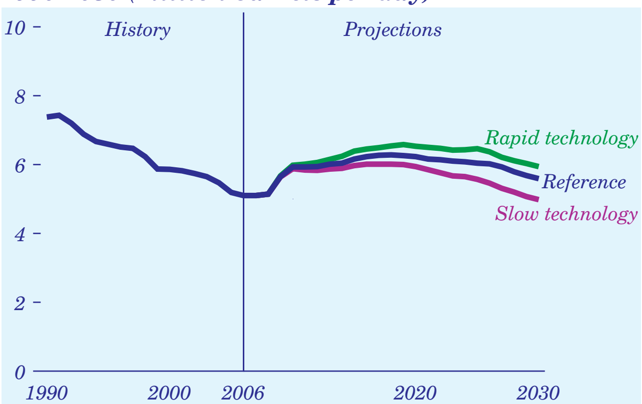


In the reference case, U.S. conventional oil production grows from 5.1 million barrels per day in 2006 to a peak of 6.3 million barrels per day in 2018, then declines to 5.6 million barrels per day in 2030 (Figure 84). The shape of the U.S. production profile is determined largely by lower 48 offshore oil production, which rises from 1.4 million barrels per day in 2006 to 2.4 million barrels per day in 2015 and then falls to 1.9 million barrels per day in 2030. Deepwater oil production in the Gulf of Mexico increases from 970,000 barrels per day in 2006 to a peak of 2.0 million barrels per day between 2013 through 2019, which is followed by a decline to 1.6 million barrels per day in 2030. Production in the shallower Gulf waters (at depths less than 1,000 feet) declines from 350,000 barrels per day in 2006 to 230,000 barrels per day in 2030. The decline in total offshore oil production during the later years of the reference case reflects depletion of the largest offshore oil fields and the fact that the remaining offshore oil resource base is composed of smaller and smaller fields.

Because a large portion of the U.S. onshore conventional oil resource base already has been produced, newly discovered oil reservoirs are expected to be smaller, more remote (e.g., Alaska), and more costly to exploit. Onshore oil production in the lower 48 States increases slightly, however, as higher crude oil prices stimulate production by EOR techniques using CO_2 injection, which increases from 350,000 barrels per day in 2006 to 1.3 million barrels per day in 2030. Excluding the increase in EOR production, lower 48 onshore oil production declines slowly, from 2.6 million barrels per day in 2006 to 2.1 million barrels per day in 2030.

More Rapid Technology Advances Could Raise U.S. Oil Production

Figure 85. Total U.S. crude oil production, 1990-2030 (million barrels per day)



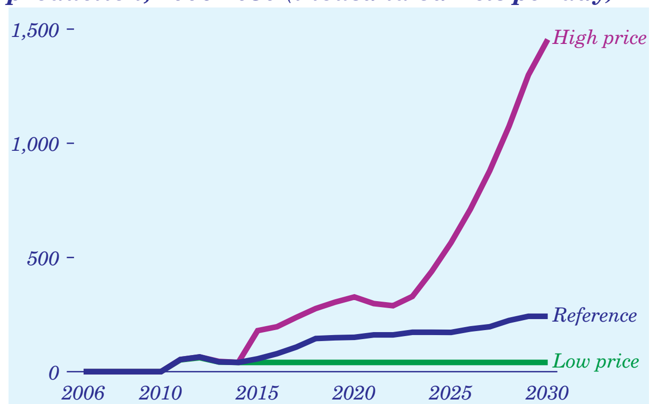
The rapid and slow oil and gas technology cases assume rates of technological progress in the petroleum industry that are 50 percent higher and 50 percent lower than in the reference case. The rate of technological progress determines the cost of developing and producing the remaining domestic oil resource base. Higher (or lower) rates of technological progress result in lower (or higher) oil development and production costs, which in turn allow more (or less) oil production. In 2030, domestic crude oil production is 5.6 million barrels per day in the reference case, 5.9 million barrels per day in the rapid technology case, and 5.0 million barrels per day in the slow technology case (Figure 85).

Domestic oil consumption, which is determined largely by oil prices and economic growth rates, does not vary significantly across the technology cases; however, imports of crude oil and petroleum products do vary, depending on domestic oil production levels. In 2030, net imports of crude oil and liquid fuels total 12.4 million barrels per day in the reference case, as compared with 12.0 million barrels per day in the rapid technology case and 13.0 million barrels per day in the slow technology case.

Higher rates of technological progress result in higher oil production rates and more rapid depletion of the domestic resource base. Cumulative U.S. crude oil production from 2006 through 2030 is 2.0 billion barrels (3.9 percent) higher in the rapid technology case and 2.6 billion barrels (4.9 percent) lower in the slow technology case than in the reference case.

Unconventional Liquids Production Increases With Higher Oil Prices

Figure 86. Total U.S. unconventional crude oil production, 2006-2030 (thousand barrels per day)

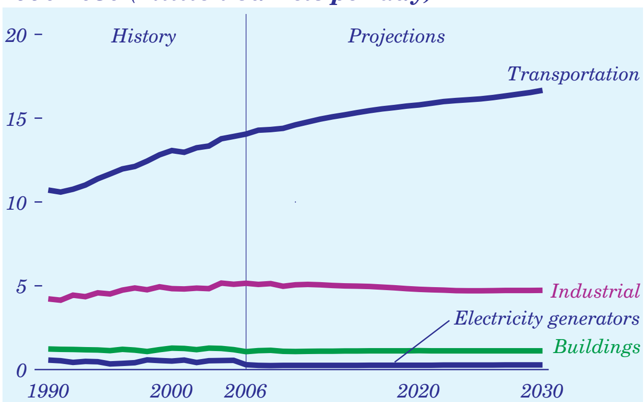


Crude oil prices are the primary determining factor for future levels of domestic unconventional oil production (such as oil shale, CTL, and GTL). In the *AEO2008* low price case, CTL production begins in 2011, using only U.S. facilities now under construction, and remains at 40,000 barrels per day through 2030. With the higher oil price in the reference case, CTL production starts in 2011 at about 50,000 barrels per day and increases to about 240,000 barrels per day in 2030 (Figure 86). In the high price case, both GTL and oil shale production become economical, and total domestic unconventional oil production increases to 1.5 million barrels per day in 2030—1.2 million barrels per day from CTL, 130,000 barrels per day from GTL, and 140,000 barrels per day from oil shale. In the high price case, both oil and natural gas prices are sufficiently high to encourage both the construction of an Alaska natural gas pipeline and GTL production on Alaska's North Slope.

There is considerable uncertainty surrounding the future of unconventional crude oil production in the United States. Environmental regulations could either preclude unconventional production or raise its cost significantly. If future U.S. laws limited and/or taxed greenhouse gas emissions, they could lead to substantial increases in the costs of unconventional production, which emits significant volumes of CO_2. Restrictions on access to water also could prove costly, especially in the arid West. In addition, environmental restrictions on land use could preclude unconventional oil production in some areas of the United States.

Transportation Uses Lead Growth in Liquid Fuels Consumption

Figure 87. Liquid fuels consumption by sector, 1990-2030 (million barrels per day)



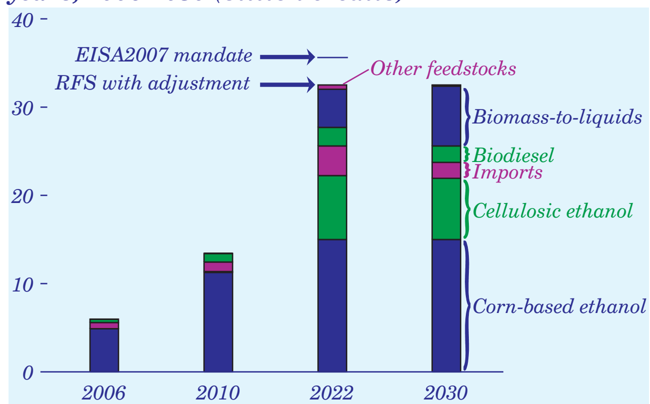
U.S. consumption of liquid fuels—including fuels from petroleum-based sources and, increasingly, those derived from nonpetroleum primary fuels such as coal, biomass, and natural gas—totals 22.8 million barrels per day in 2030 in the reference case, an increase of 2.1 million barrels per day over the 2006 total (Figure 87). All of the increase is in the transportation sector, which accounts for 73 percent of total liquid fuels consumption in 2030, up from 68 percent in 2006.

Gasoline, ULSD, and jet fuel are the main transportation fuels. The reference case includes the effects of technology improvements that are expected to increase the efficiency of motor vehicles and aircraft, but the projected growth in demand for each mode outpaces those improvements as the demand for transportation services grows in proportion to increases in population and GDP. With the new CAFE standards in EISA2007, transportation use of liquid fuels increases by 2.6 million barrels per day in the reference case, 3.9 million barrels per day in the high economic growth case, and 1.8 million barrels per day in the high price case from 2006 to 2030.

Consumption of liquid fuels from nonpetroleum sources increases substantially over the projection period. Ethanol, which made up 4 percent of the motor gasoline pool in 2006, increases to 15.8 percent of the total motor gasoline pool in 2030. Total production of liquid fuels from CTL and BTL plants, which are expected to commence operation in 2011, increases in the reference case to 540,000 barrels per day in 2030, equivalent to 9.7 percent of the total pool of distillate fuel.

RFS Is Defined by Multiple Biofuel Categories in EISA2007

Figure 88. EISA2007 RFS credits earned in selected years, 2006-2030 (billion credits)



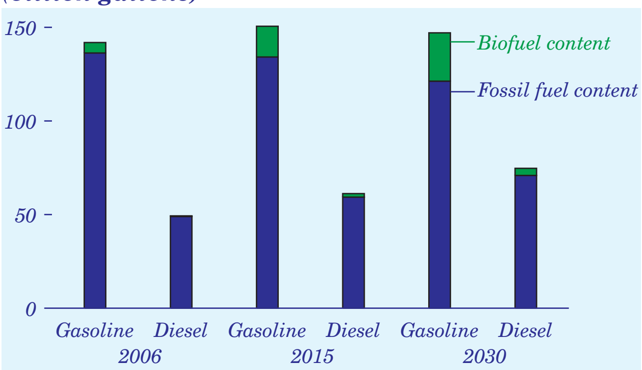
EISA2007 mandates a total RFS credit requirement of 36 billion gallons in 2022. Credits are equal to gallons produced, except for fatty acid methyl ester biodiesel and BTL diesel, which receive a 1.5-gallon credit for each gallon produced. The renewable fuels can be grouped into two categories: conventional biofuels (ethanol produced from corn starch) and advanced biofuels (including cellulosic ethanol, biodiesel, and BTL diesel). In total, 15 billion gallons of credits from conventional biofuels and 21 billion gallons from advanced biofuels are required in 2022.

In the *AEO2008* reference case, however, only 32.5 billion gallons of RFS credits are generated in 2022, because cellulosic biofuel production is not expected to increase rapidly enough to provide the credits that would be needed to meet the advanced biofuels requirement. If the available quantities of biofuels are inadequate to meet the initial targets, EISA2007 provides for both the application of waivers and modification of applicable credit volumes (Figure 88).

Corn ethanol is projected to make the largest contribution toward the RFS mandate, providing up to 15 billion credits. Cellulosic ethanol contributes 7.2 billion credits to the advanced and cellulosic biofuel requirement in 2022, and BTL diesel contributes 4.3 billion credits. BTL production continues to increase in the later years of the projection, to 6.8 billion gallons in 2030. The remainder of the credits for advanced biofuels in 2022 include credits for approximately 3 billion gallons of ethanol imports, 2 billion gallons of biodiesel, and 0.5 billion gallons of ethanol from wheat and other feedstocks.

EISA2007 Increases U.S. Supply of Renewable Transportation Fuels

Figure 89. Fossil fuel and biofuel content of U.S. motor fuel supply, 2006, 2015, and 2030 (billion gallons)

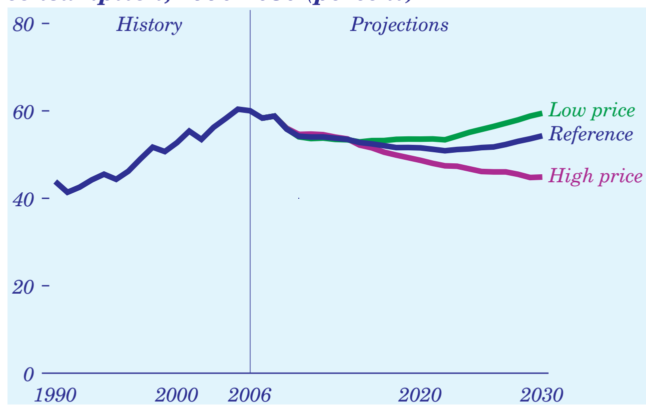


As a result of the EISA2007 RFS, the biofuel component of motor fuels in the transportation sector is projected to grow substantially, as the fossil fuel content of gasoline and diesel declines from 136 billion gallons (96 percent) in 2006 to 125 billion gallons (83 percent) in 2030 (Figure 89). The biofuel content of all gasoline and E85 consumed in the United States, which totaled about 5.6 billion gallons in 2006, increases to 25.8 billion gallons in 2030. In addition, a smaller increase in biofuel content is projected for diesel fuel, from 0.3 billion gallons in 2006 to 3.8 billion gallons in 2030.

Adding to the decline in U.S. consumption of fossil-fuel-based gasoline is a projected increase in diesel fuel use for passenger vehicles—a shift that is likely to require significant adjustments in the refining industry. Crude oil processing typically yields a sizable portion of product in the naphtha range, which frequently is used in motor gasoline. Historically, there has been a mutually beneficial relationship between U.S. and European refiners, with surplus diesel being shipped from the United States to Europe and surplus gasoline shipped from Europe to the United States. A significant increase in U.S. demand for diesel while the demand for gasoline is falling is likely to require significant investment by refiners in both the United States and Europe in order to maximize diesel yields.

Imports of Liquid Fuels Are Expected To Decline

Figure 90. Net import share of U.S. liquid fuels consumption, 1990-2030 (percent)



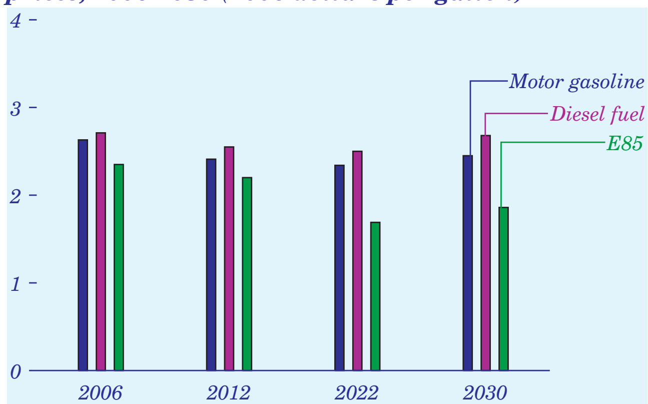
In 2006, net imports of liquid fuels, primarily petroleum, accounted for 60 percent of domestic consumption. In the reference case, U.S. dependence on liquid fuel imports declines to 51 percent in 2022, before climbing to 54 percent in 2030 (Figure 90). In the high price case, net imports as a share of domestic consumption of liquid fuels fall to 45 percent in 2030. In the low price case, dependence on petroleum imports remains roughly constant, with an import share of 59 percent in 2030.

In the reference case, demand for refined products continues to increase more rapidly than refining capacity. Historically, the availability of product imports has been limited by a lack of foreign refineries capable of meeting the stringent U.S. standards for liquids products. One example is provided by the U.S. ban on use of methyl tertiary butyl ether as an oxygenate in RFG. Since the ban took effect in January 2007, U.S. refiners have switched to using ethanol as the oxygenate in RFG, and the New York Mercantile Exchange (NYMEX) market has stopped offering imports of RFG and switched to imports of reformulated blendstock for oxygenate blending.

In recent years, however, liquids demand has grown rapidly in some countries of Eastern Europe and Asia, and those nations are moving to adopt the same fuel quality standards as the developed world. As a result, refineries throughout the world are becoming more sophisticated, and in the future more of them will be able to provide products suitable for the U.S. market, which they may do if it is profitable.

Ethanol Prices Compete on a Btu Basis To Meet the EISA2007 RFS

Figure 91. Motor gasoline, diesel fuel, and E85 prices, 2006-2030 (2006 dollars per gallon)

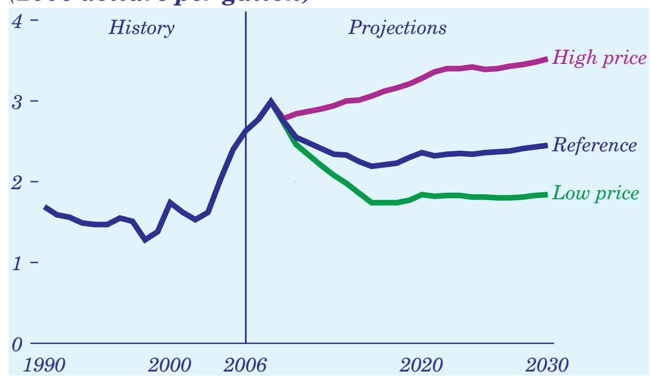


In the *AEO2008* reference case, with the EISA2007 renewable fuels mandate in effect, the U.S. market for E10 is saturated by 2014, after which the ethanol requirement is met by increased consumption of E85. To encourage the use of E85, its price is discounted to make it competitive with motor gasoline on an energy-equivalent basis. The E85 price discounts are funded by premiums placed on the petroleum content of other motor fuels. As E85 consumption increases, the price drops from $2.35 per gallon in 2006 to a low of $1.57 (2006 dollars) in 2017 before rising to $1.86 in 2030. In comparison, the price of motor gasoline is $2.63 per gallon in 2006 and $2.45 in 2030 (Figure 91).

In the low price case, E85 follows the same general price path, falling to $1.44 per gallon in 2030. In contrast, in the high price case, the price of E85 rises to $2.73 per gallon in 2030, although it is still discounted relative to motor gasoline, which increases to $3.52 per gallon in 2030. In the *AEO2008* early release, which excluded the impact of EISA2007, the price of E85 remained closer to the price of motor gasoline throughout the projection period, increasing to $2.29 per gallon in 2030, while the price of gasoline increased to $2.49 in 2030.

U.S. Motor Gasoline Prices Rise and Fall With Changes in World Oil Price

Figure 92. Average U.S. delivered prices for motor gasoline, 1990-2030 (2006 dollars per gallon)



Retail prices for petroleum products largely follow changes in crude oil prices. In the *AEO2008* reference case, the world oil price path reaches a low of $57 per barrel in 2016 and then increases to about $70 in 2030 (2006 dollars). The U.S. average motor gasoline price follows the same trend, falling to $2.19 per gallon in 2016 before rising to $2.45 in 2030.

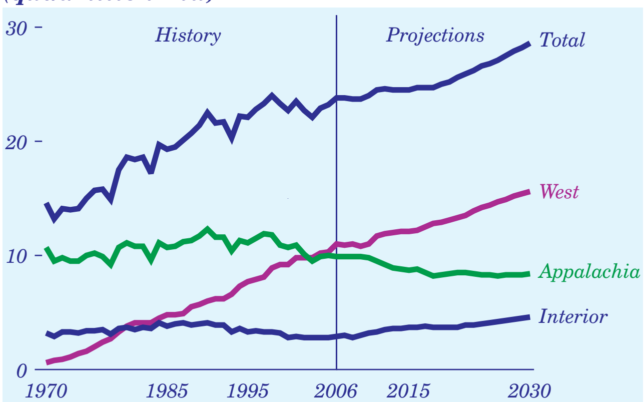
In the high price case, with the price of imported crude oil rising to $119 per barrel (2006 dollars) in 2030, the average price of U.S. motor gasoline increases rapidly, to $3.06 per gallon in 2016 and $3.52 per gallon in 2030. In the low price case, gasoline prices decline to a low of $1.74 per gallon in 2016, increase slowly through the early 2020s, and level off at about $1.84 per gallon through 2030 (Figure 92).

Because changes from the reference case assumptions for economic growth rates have less pronounced effects on motor gasoline prices than do changes in oil price assumptions, the average prices for U.S. motor gasoline in the high and low economic growth cases are close to those in the reference case. In the high growth case, the average gasoline price falls to a low of $2.24 per gallon in 2016 and then rises to $2.59 per gallon in 2030. In the low growth case, the average price reaches a low of $2.16 per gallon in 2017, followed by an increase to $2.32 per gallon in 2030.

In all the *AEO2008* cases, increases in motor gasoline prices as a result of the EISA2007 biofuel mandates are more than offset by erosion of the real dollar value of the Federal excise taxes. By assumption, the Federal gasoline tax is fixed at its 2007 nominal level of 18.4 cents per gallon.

Western Coal Production Continues To Increase Through 2030

Figure 93. Coal production by region, 1970-2030 (quadrillion Btu)



In the *AEO2008* reference case, increasing coal use for electricity generation at existing plants and construction of a few new coal-fired plants lead to annual production increases that average 0.3 percent per year from 2006 to 2015, when total production is 24.5 quadrillion Btu. In the absence of restrictions on CO_2 emissions, the growth in coal production is even stronger from 2015 to 2030, averaging 1.0 percent per year, as a substantial number of new coal-fired power plants and several CTL plants are brought on line.

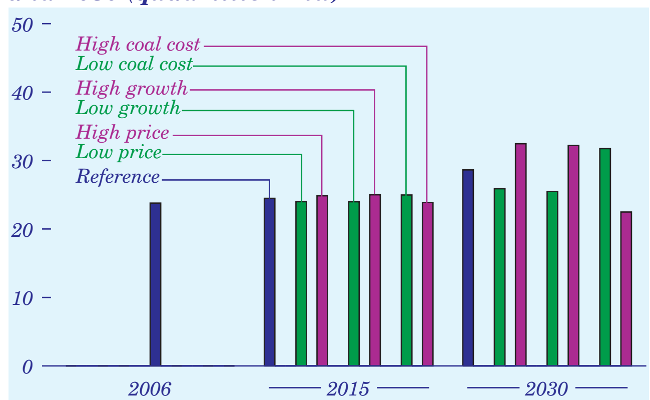
Western coal production, which has grown steadily since 1970, continues to increase through 2030 (Figure 93). Much of the projected growth is in output from the Powder River Basin, where producers are well positioned to increase production from the vast remaining surface-minable reserves.

Appalachian coal production declines slightly in the reference case. Although producers in Central Appalachia are well situated to supply coal to new generating capacity in the Southeast, that portion of the Appalachian basin has been mined extensively, and production costs have been increasing more rapidly than in other regions. The eastern portion of the Interior coal basin (Illinois, Indiana, and western Kentucky), with extensive reserves of mid- and high-sulfur bituminous coals, benefits from the new coal-fired generating capacity in the Southeast.

Production of low-Btu lignite in the Interior and Western supply regions also increases substantially, primarily to meet the energy and feedstock requirements of new coal-fired power plants and CTL plants in Texas, Montana, and North Dakota.

Long-Term Production Outlook Varies Considerably Across Cases

Figure 94. U.S. coal production, 2006, 2015, and 2030 (quadrillion Btu)

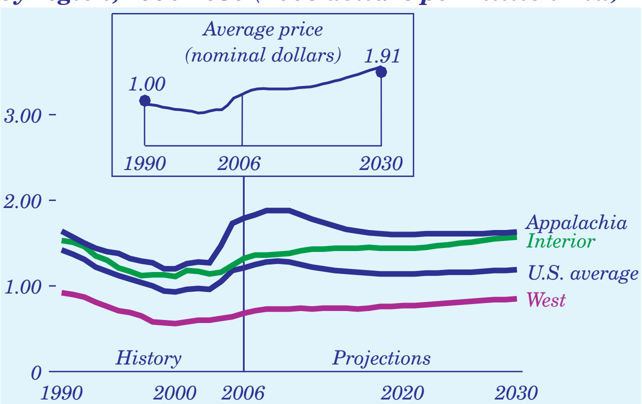


In most of the *AEO2008* cases, U.S. coal production is projected to increase from 2006 to 2030; however, different assumptions about economic growth (which mainly affect overall electricity demand) and about the costs of producing fossil fuels (which primarily determine the mix of supply sources for generation and petroleum products) lead to different results. The reference case projects a 20-percent increase from 2006 to 2030, whereas the alternative cases show changes that range from a decrease of 5 percent to an increase of 36 percent (Figure 94). Because the level of uncertainty is lower in the near term, the projected changes in coal production from 2006 to 2015 show significantly less variation, ranging from virtually no change to an increase of 5 percent.

Across the cases, regional coal production trends generally follow the national trend. As a result, the projected regional shares of total coal production in 2030 (from the Appalachian, Interior, and Western supply regions) do not vary by much among the reference, high and low price, and high and low economic growth cases. In the high coal cost case, however, the combination of higher mining and transportation costs and slow growth in total U.S. coal demand leads to a sizable drop in projected output from Wyoming's Powder River Basin, which is by far the most important coal-producing area in the West. As a result, the Western share of total U.S. coal production declines slightly in the high coal cost case, from 46 percent in 2006 to 45 percent in 2030. In the other cases, the West's share of total coal production in 2030 ranges from a low of 54 percent to a high of 60 percent.

Minemouth Coal Prices in the Western and Interior Regions Rise Steadily

Figure 95. Average minemouth price of coal by region, 1990-2030 (2006 dollars per million Btu)



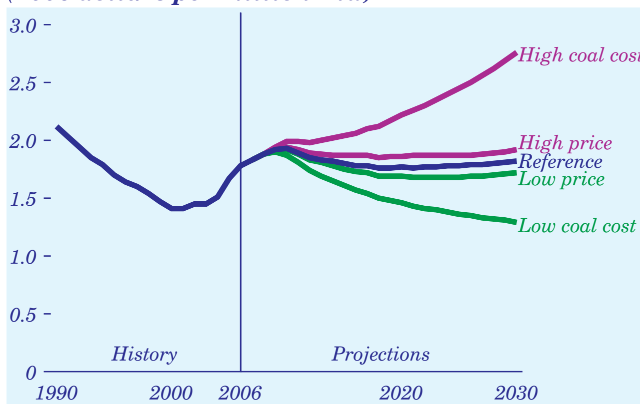
Strong growth in production in the Interior and Western supply regions, combined with limited improvement in coal mining productivity, results in minemouth price increases of 0.7 and 0.9 percent per year, respectively, for the two regions from 2006 through 2030. Average minemouth prices in Appalachia decline by 0.4 percent per year over the same period, as a result of falling output levels and a shift to lower cost production in the northern part of the basin.

The U.S. average minemouth price for coal drops slightly between 2006 and 2020, from $1.21 to $1.14 per million Btu (2006 dollars), as mine capacity utilization declines and production shifts away from the higher cost mines of Central Appalachia. After 2020, rising natural gas prices and requirements for additional generating capacity result in the construction of 65 gigawatts of new coal-fired generating capacity. The combination of new investment in mining capacity to meet the demand growth, a continued low rate of productivity improvement, and rising utilization of mining capacity leads to an increase in the average minemouth price, to $1.19 per million Btu in 2030.

From 1990 to 1999, the average minemouth price of coal declined by 4.5 percent per year (Figure 95). Increases in U.S. coal mining productivity of 6.3 percent per year helped to reduce mining costs and contributed to the price decline. Since 1999, U.S. coal mining productivity has declined by 0.8 percent per year, and the average minemouth coal price has increased by 3.7 percent per year. In the *AEO2008* reference case, coal mining productivity rises at an average rate of 0.6 percent per year from 2006 to 2030, more closely reflecting the trend of the past several years.

Higher Mining and Transportation Costs Raise Delivered Coal Prices

Figure 96. Average delivered coal prices, 1990-2030 (2006 dollars per million Btu)



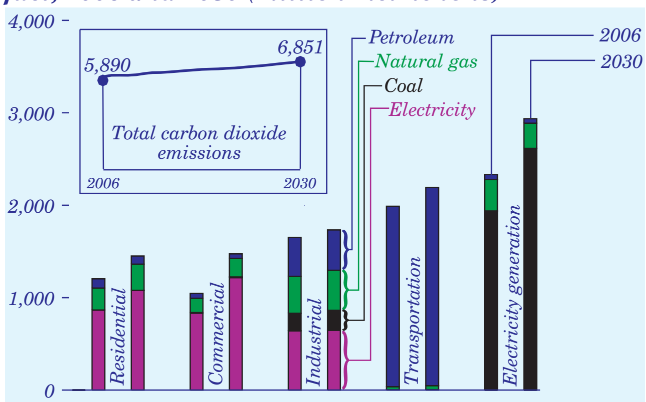
Alternative assumptions for coal mining and transportation costs affect delivered coal prices and demand. Two alternative coal cost cases developed for *AEO2008* examine the impacts on U.S. coal markets of alternative assumptions about mining productivity, labor costs, and mine equipment costs on the production side, and about railroad productivity and rail equipment costs on the transportation side.

In the high coal cost case, the average delivered coal price in 2006 dollars is $2.76 per million Btu in 2030—52 percent higher than in the reference case (Figure 96). As a result, U.S. coal consumption is 4.8 quadrillion Btu (16 percent) lower than in the reference case in 2030, reflecting both a switch from coal to natural gas, nuclear, and renewables in the electricity sector and reduced CTL production. In the low coal cost case, the average delivered price in 2030 is $1.29 per million Btu—29 percent lower than in the reference case—and total coal consumption is 2.1 quadrillion Btu (7 percent) higher than in the reference case.

Because the high and low economic growth cases and the high and low price cases use the reference case assumptions for coal mining and rail transportation productivity and equipment costs, they show smaller variations in average delivered coal prices than do the two coal cost cases. Different coal price projections in the high and low economic growth cases (with price paths very close to the reference case) and high and low price cases result mainly from higher and lower projected levels of demand for coal. In the price cases, higher and lower fuel costs for both coal producers and railroads contribute to the variations in projected coal prices.

Rising Energy Consumption Increases Carbon Dioxide Emissions

Figure 97. Carbon dioxide emissions by sector and fuel, 2006 and 2030 (million metric tons)

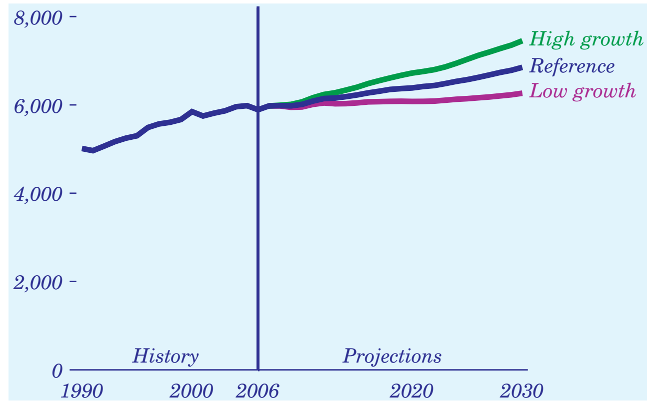


Without capture and sequestration, CO_2 emissions from the combustion of fossil fuels are proportional to the carbon content of the fuel. Coal has the highest carbon content and natural gas the lowest, with petroleum in between. In the *AEO2008* reference case, the shares of these fuels change slightly from 2006 to 2030, with more coal and less oil and natural gas. The combined share of renewable and nuclear energy grow from 15 percent in 2006 to 20 percent in 2030. As a result, CO_2 emissions increase by 16 percent over the period, as compared with a 19-percent increase in total energy use (Figure 97). At the same time, the economy becomes less carbon intensive: the percentage increase in CO_2 emissions is one-fifth the increase in GDP, and emissions per capita decline by 5 percent over the 24-year period.

The factors that influence growth in CO_2 emissions are the same as those that drive increases in fossil energy demand. Among the most significant are population and economic growth; increased penetration of computers, electronics, appliances, and office equipment; increases in commercial floorspace; increases in highway, rail, and air travel; and continued reliance on coal for electric power generation. The increases in demand for energy services are partially offset by efficiency improvements and shifts toward less energy-intensive industries. New CO_2 mitigation programs, more rapid improvements in technology, or more rapid adoption of voluntary CO_2 emissions reduction programs could result in lower CO_2 emissions levels than projected here.

Emissions Projections Change With Economic Growth Assumptions

Figure 98. Carbon dioxide emissions, 1990-2030 (million metric tons)



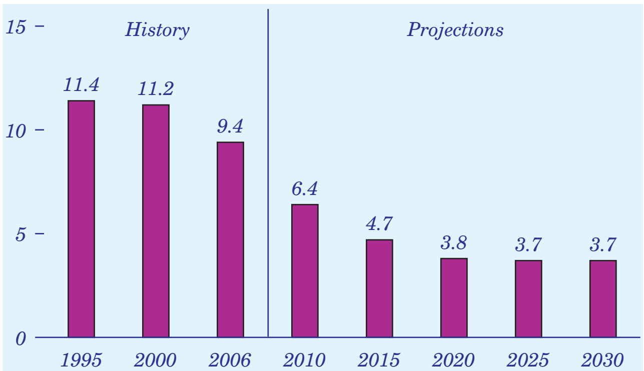
Higher growth in population, labor force, and productivity is assumed in the high growth case than in the reference case, leading to higher industrial output, higher disposable income, lower inflation, and lower interest rates. The low growth case assumes the reverse. In the high and low growth cases, GDP varies by about 14 percent and population by about 8 percent from the reference case projections for 2030.

Alternative projections for industrial output, commercial floorspace, housing, and transportation in the population and economic growth cases influence the demand for energy and result in variations in CO_2 emissions (Figure 98). Emissions in 2030 are 9 percent lower in the low growth case and 9 percent higher in the high growth case than in the reference case. The strength of the relationship between economic growth and emissions varies by end-use sector. It is strongest for the industrial sector and, to a lesser extent, the transportation sector, where economic activity strongly influences energy use and emissions, and where fuel choices are limited. It is weaker in the commercial and residential sectors, where population and building characteristics have large influences and vary less across the three cases.

Changes in electricity sales across the cases affect the amount of new, more efficient generating capacity required, reducing somewhat the sensitivity of energy use to GDP. However, the choice of coal for most new baseload capacity increases CO_2 intensity in the high growth case while decreasing it in the low growth case, offsetting the effects of changes in efficiency across the cases.

Clean Air Interstate Rule Reduces Sulfur Dioxide Emissions

Figure 99. Sulfur dioxide emissions from electricity generation, 1995-2030 (million short tons)



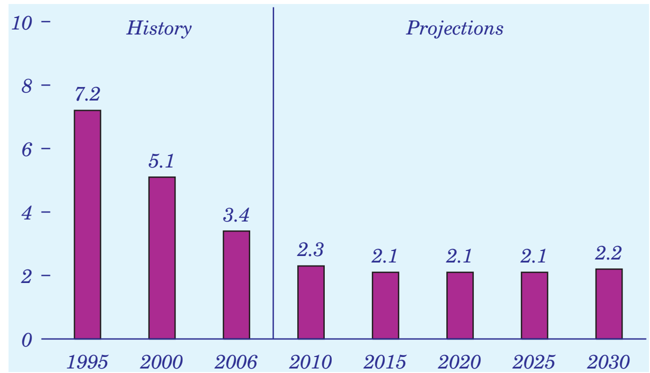
SO_2 emissions are expected to fall as CAIR takes effect [*88*]. States can achieve mandated emissions reductions in two ways: by requiring power plants to participate in the EPA's national cap and trade program or by requiring them to meet State-specific emissions milestones through more stringent measures chosen by the State.

In the *AEO2008* reference case, national SO_2 emissions from electricity generation fall from 9.4 million short tons in 2006 to 3.7 million short tons in 2030 (Figure 99). The reduction results from both the use of lower sulfur coal and the addition of flue gas desulfurization equipment on 125 gigawatts of existing capacity. SO_2 allowance prices rise steadily throughout the early years of the projection, to more than $1,000 per ton in 2020. After 2020, allowance prices slowly decline, settling below $500 in 2030.

SO_2 emissions are not greatly affected by economic growth, as shown in the *AEO2008* high economic growth case. Because many new coal-fired power plants are equipped to remove SO_2 before beginning operation, the allowance prices are no higher than in the reference case. Fuel price assumptions have a greater effect on SO_2 allowance prices. With more CTL plants expected to be constructed in the high price case, potential emissions from coal combustion increase; however, CTL plants are expected to have SO_2 capture equipment that is more efficient than the equipment on advanced pulverized coal plants. Thus, in the later years of the projection, SO_2 allowance prices are slightly lower in the high price case than in the reference case.

Nitrogen Oxide Emissions Also Fall As CAIR Takes Effect

Figure 100. Nitrogen oxide emissions from electricity generation, 1995-2030 (million short tons)



CAIR also mandates NO_x emission reductions in 28 States and the District of Columbia [*89*]. The required reductions are intended to reduce the formation of ground-level ozone, for which NO_x emissions are a major precursor. As with the CAIR-mandated SO_2 reductions, each State can determine a preferred method for reducing NO_x emissions. *AEO2008* assumes that all the States covered by CAIR will participate in interstate trading of allowances.

In the *AEO2008* reference case, national NO_x emissions from the electric power sector fall from 3.4 million short tons in 2006 to 2.2 million short tons in 2030 (Figure 100). Because the CAIR caps are inflexible, different assumptions in the high and low economic growth and high and low price cases have little affect on cumulative NO_x emissions. The projections for cumulative NO_x emissions over the projection period are lowest in the low economic growth case—0.5 percent lower than in the reference case.

After mandatory compliance begins, NO_x allowance prices range between $2,500 and $3,400 per ton emitted in the reference case, tending to rise as the emission caps tighten. In 2030, selective catalytic reduction equipment is projected to have been added on an additional 98 gigawatts of coal-fired generating capacity in the reference case. In the high economic growth case, NO_x allowances are more costly. The construction of more coal-fired power plants to meet a higher level of demand for electricity, and the resulting need for additional retrofits, pushes allowance prices to approximately $3,800 in 2025, after which the price stabilizes.

Comparison With Other Projections

Comparison with Other Projections

Only Global Insights, Inc. (GII) produces a comprehensive energy projection with a time horizon similar to that of *AEO2008*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from GII, as well as others that concentrate on economic growth, international oil prices, energy consumption, electricity, natural gas, petroleum, and coal, are compared here with the *AEO2008* projections.

Economic Growth

Projections of the average annual GDP growth rate for the United States from 2006 through 2010 range from 2.4 percent to 2.8 percent (Table 7). GDP grows at an annual rate of 2.4 percent in the *AEO2008* reference case over the period, significantly lower than the projections made by the Office of Management and Budget (OMB), the Congressional Budget Office (CBO), the Interindustry Forecasting Project at the University of Maryland (INFORUM), the Social Security Administration (SSA), and Energy Ventures Analysis, Inc. (EVA). The *AEO2008* projection is slightly lower than the projections by the International Energy Agency (IEA) and GII. The consensus Blue Chip projection is for 2.5-percent average annual growth from 2006 to 2010.

The range of GDP growth rates is wider for the period from 2010 to 2015, with projections ranging from 2.3 to 2.9 percent per year. The average annual GDP growth of 2.7 percent in the *AEO2008* reference case from 2010 to 2015 is around the middle of the range. The Blue Chip consensus projection is 2.9 percent, CBO projects 2.8 percent, and EVA projects 2.7 percent for the annual rate of GDP growth from 2010 to 2015. The GII, INFORUM, SSA, and IEA projections all are below the *AEO2008* reference case projection.

Table 7. Projections of annual average economic growth rates, 2006-2030

	Average annual percentage growth rates			
Projection	2006-2010	2010-2015	2015-2020	2020-2030
AEO2007 (reference case)	2.9	2.8	3.0	2.8
AEO2008 (reference case)	2.4	2.7	2.4	2.4
GII	2.5	2.5	2.5	2.4
OMB	2.7	NA	NA	NA
CBO	2.6	2.8	NA	NA
Blue Chip	2.5	2.9	NA	NA
INFORUM	2.6	2.5	2.3	2.3
SSA	2.7	2.3	2.1	2.0
EVA	2.8	2.7	2.4	2.1
IEA	2.6	2.6	2.2	2.2

NA = not available.

There are few public or private projections of GDP growth rates for the United States that extend to 2030. The *AEO2008* reference case reflects a GDP growth rate after 2015 that is consistent with the trend in expected labor force and productivity growth.

World Oil Prices

Comparisons of the *AEO2008* cases with other oil price projections are shown in Table 8. In the *AEO2008* reference case, world oil prices fall from current levels through 2016 and then gradually rise to about $70 in real terms (2006 dollars). Given current prices, this pattern of falling and then rising oil prices is seen in all the long-term projections, with the exception of GII's, which consistently declines. The world oil price measures are, by and large, comparable across projections. EIA reports the price of imported low-sulfur, light crude oil, approximately the same as the West Texas Intermediate (WTI) prices that are widely cited as a proxy for world oil prices in the trade press. The only series that does not report projections in WTI terms is IEA's *World Energy Outlook 2007*, where prices are expressed as the IEA crude oil import price.

Recent volatility in crude oil prices demonstrates the uncertainty inherent in the projections. GII and Deutsche Bank AG (DB) define the range of crude oil price projections for 2030, from a low of about $46 per barrel (GII) to a high of $80 per barrel (DB). The *AEO2008* reference case projects a world oil price of about $70 per barrel in 2030.

Total Energy Consumption

The *AEO2008* reference case projects growth in end-use consumption of natural gas and coal, in contrast to the decline that occurred from 1980 to 2006 (Table 9). Natural gas consumption increases in the residential, commercial, and industrial sectors, despite relatively high prices. Natural gas is cleaner than other fuels, does not require on-site storage, and has tended to be priced competitively with oil for

Table 8. Projections of world oil prices, 2010-2030 (2006 dollars per barrel)

Projection	2010	2015	2020	2025	2030
AEO2007 (reference case)	59.21	51.37	53.61	58.07	60.91
AEO2008 (reference case)	74.03	59.85	59.70	64.49	70.45
GII	68.25	61.40	54.80	48.20	45.70
IEA (reference)	59.03	57.30	58.87	60.43	62.00
DB	56.65	60.00	66.00	72.00	80.00
SEER	69.41	58.85	60.83	62.88	65.00

heating. Coal consumption as a boiler fuel in the commercial and industrial sectors declines slightly, with potential use in new boilers limited by environmental restrictions; however, the projections for industrial coal consumption include its use in CTL plants, a technology that becomes competitive at the level of oil prices in the *AEO2008* reference case.

The projected growth in consumption of liquids, including ethanol blends and biodiesel, from 2006 to 2030 is about one-half the average from 1980 to 2006. Transportation is the only sector for which liquids consumption grows significantly, offsetting a moderate decline in the industrial sector. Continued growth in fuel use for transportation is expected despite high prices and newly tightened fuel economy standards. With economic growth, an increasing population, and rising per capita income, demand for personal and freight travel increases. Although the average fuel efficiency of vehicles and airplanes continues to improve, the changes under currently enacted laws and regulations are insufficient to offset the projected increase in transportation demand.

Growth in electricity use continues in the *AEO2008* reference case, but the pace slows to one-half the historical rate. Some rapidly growing applications, such as air conditioning and computers, slow as penetration approaches saturation levels. Electrical efficiency also continues to improve, due in large part to efficiency standards, and the impacts tend to accumulate with the gradual turnover of appliance stocks.

The *AEO2008* reference case includes higher growth in primary and delivered energy from 2006 to 2030 than is shown in the outlook from GII. GII projects little growth in end-use natural gas consumption, whereas the *AEO2008* reference case projects continued growth in the industrial and buildings sectors (see Table 11). GII's projected growth rates for liquids consumption are somewhat higher than those in the *AEO2008* reference case, which includes the impacts of EISA2007 on vehicle fuel economy (see Table 12). Differences between the *AEO2008* reference case and the GII projections for end-use coal consumption result from a projected increase in coal use for CTL in the *AEO2008* reference case (see Table 13).

Electricity

Table 10 provides a summary of the results from the *AEO2008* cases and compares them with other projections. Electricity sales in 2015 range from a low of 4,059 billion kilowatthours in the *AEO2008* reference case to a high of 4,319 billion kilowatthours in the EVA projection. EVA shows higher sales in the commercial and residential sectors and somewhat less growth in industrial sales than do the *AEO2008* reference case and GII. The projections for total electricity sales in 2030 are about the same (4,705 billion kilowatthours) in the *AEO2008* reference case and GII, which are the only projections available that include 2030. The annual rate of demand growth in both projections is about 1.1 percent per year from 2006 to 2030. In 2030, GII includes lower growth in the commercial sector and higher growth in the residential and industrial sectors compared with the *AEO2008* reference case.

The *AEO2008* reference case shows a decline in real electricity prices early in the projection period and then rising prices at the end of the period because of increases in the cost of fuels used for generation and increases in capital expenditures for construction of new capacity. The higher fossil fuel prices and capital expenditures in the *AEO2008* reference case result in an increase in the average electricity price, from 8.5 cents per kilowatthour in 2015 to 8.8 cents per kilowatthour in 2030. GII shows slightly declining prices over the projection period.

Total generation and imports of electricity in 2015 are similar in the *AEO2008* reference case, EVA, and GII. In contrast, the IEA projection for electricity generation in its *World Energy Outlook 2007* is higher than the other projections. Generation in the IEA projection for the United States (which exclude imports of electricity) are higher than in any of the *AEO2008* cases. Consistent with higher total electricity generation, the IEA projection includes higher

Table 9. Projections of average annual growth rates for energy consumption, 2006-2030 (percent)

Energy use	History 1980-2006	Projections AEO2008	GII
*Delivered energy**			
*Petroleum liquids***	0.9	0.4	0.6
Natural gas	-0.1	0.6	0.3
Coal	-1.7	0.6	-0.1
Electricity	2.2	1.1	1.0
Total	0.7	0.7	0.6
Electricity losses	1.8	0.8	0.4
Primary energy	0.9	0.7	0.6

**Excludes consumption by electricity generators in the electric power sector; includes consumption for end-use combined heat and power generation.*

***Includes ethanol and biodiesel used as transportation fuels.*

Table 10. Comparison of electricity projections, 2015 and 2030 (billion kilowatthours, except where noted)

Projection	2006	AEO2008 reference case	Other projections: GII	EVA	IEA
		2015			
Average end-use price (2006 cents per kilowatthour)	**8.9**	**8.5**	**8.8**	**NA**	**NA**
Residential	10.4	10.2	10.2	10.98	NA
Commercial	9.5	8.7	9.3	9.82	NA
Industrial	6.1	5.9	6.0	6.37	NA
Total generation plus imports	**4,069**	**4,496**	**4,531**	**4,547**	**4,959**
Coal	1,988	2,182	2,171	2,219	2,552
Oil	63	57	64	66	133
Natural gas [a]	811	909	920	936	858
Nuclear	787	807	827	825	849
Hydroelectric/other [b]	403	529	533	486	567
Net imports	18	11	17	15	NA
Electricity sales	**3,659**	**4,059**	**4,116**	**4,319**	**NA**
Residential	1,351	1,472	1,553	1,625	NA
Commercial/other [c]	1,306	1,529	1,489	1,683	NA
Industrial	1,002	1,058	1,074	1,011	NA
Capability, including CHP (gigawatts) [d]	**983**	**1,016**	**1,019**	**1,050**	**NA**
Coal	314	329	326	341	NA
Oil and natural gas	444	437	430	482	NA
Nuclear	100	102	104	104	NA
Hydroelectric/other	125	148	160	123	NA
		2030			
Average end-use price (2006 cents per kilowatthour)	**8.9**	**8.8**	**8.7**	**NA**	**NA**
Residential	10.4	10.5	10.1	NA	NA
Commercial	9.5	8.9	9.2	NA	NA
Industrial	6.1	6.0	5.8	NA	NA
Total generation plus imports	**4,069**	**5,258**	**5,180**	**NA**	**5,947**
Coal	1,988	2,836	2,557	NA	3,148
Oil	63	66	55	NA	102
Natural gas [a]	811	745	905	NA	896
Nuclear	787	917	888	NA	933
Hydroelectric/other [b]	403	670	761	NA	869
Net imports	18	23	14	NA	NA
Electricity sales	**3,659**	**4,705**	**4,706**	**NA**	**NA**
Residential	1,351	1,722	1,793	NA	NA
Commercial/other [c]	1,306	1,950	1,724	NA	NA
Industrial	1,002	1,033	1,189	NA	NA
Capability, including CHP (gigawatts) [d]	**983**	**1,204**	**1,086**	**NA**	**NA**
Coal	314	414	378	NA	NA
Oil and natural gas	444	504	375	NA	NA
Nuclear	100	115	115	NA	NA
Hydroelectric/other	125	172	218	NA	NA

[a]Includes supplemental gaseous fuels. For EVA, represents total oil and natural gas. [b]"Other" includes conventional hydroelectric, pumped storage, geothermal, wood, wood waste, municipal waste, other biomass, solar and wind power, batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, petroleum coke, and miscellaneous technologies. [c]"Other" includes sales of electricity to government, railways, and street lighting authorities. [d]EIA capacity is net summer capability, including CHP plants. GII capacity is nameplate, excluding cogeneration plants.

CHP = combined heat and power. NA = not available.

Sources: ***2006 and AEO2008:*** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *Global Petroleum Outlook, Fall 2007* (Lexington, MA, November 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007). **IEA:** International Energy Agency, *World Energy Outlook 2007* (Paris, France, November 2007).

levels of generation from fossil and renewable technologies in 2030 than do the *AEO2008* cases. The requirements for generating capacity are driven by growth in electricity sales and the need to replace existing units that are uneconomical or are being retired for other reasons. Consistent with its projections of electricity sales, EVA shows higher growth in fossil-based generating capacity through 2015 compared with the *AEO2008* reference case and GII; however, EVA projects considerably less renewable capacity in 2015 than do *AEO2008* and GII.

Renewable generating capacity in 2030 is higher in the GII projection than in the *AEO2008* reference case. Nuclear capacity in 2030 is 115 gigawatts in both *AEO2008* and GII, as a result of the incentives included in EPACT2005. The *AEO2008* reference case includes 2.7 gigawatts of uprates for nuclear capacity and 4.5 gigawatts of nuclear plant retirements by 2030 as their operating licenses expire. Environmental regulations are important determinants in the selection of the technologies used for electricity generation. In addition to existing environmental program requirements for electric utilities, EVA assumes that new, stricter national emissions limits will be adopted for emissions of SO_2 and NO_x by 2015. EVA also includes an escalating penalty on CO_2 emissions, starting at $6 per ton in 2013.

The *AEO2008* cases include the impact of the EPA's CAIR regulation [*90*]. Because *AEO2008* includes only current laws and regulations, however, it does not assume any tax on CO_2 emissions. Restrictions on CO_2 emissions could change the mix of technologies used to generate electricity.

Natural Gas

In the *AEO2008* reference case, total natural gas consumption increases through 2016 and then declines through 2030 as higher natural gas prices cause natural gas to lose market share to coal for electricity generation. With the exception of the Altos and Strategic Energy and Economic Research, Inc. (SEER) projections, all the other projections show total natural gas consumption increasing throughout the projection period (Table 11). Altos shows a slight decline in natural gas consumption after 2025, and SEER shows almost the same level of natural gas consumption in 2025 and 2030.

The *AEO2008* reference case projects the lowest level of natural gas consumption in 2030, followed by GII (about 1.0 trillion cubic feet more than in the *AEO2008* reference case). The Altos projection includes the highest growth rate for natural gas consumption, reaching 31.4 trillion cubic feet in 2030 (8.7 trillion cubic feet more than in the *AEO2008* reference case). The DB and SEER projections show natural gas consumption in 2030 exceeding the *AEO2008* reference case projection by 1.8 and 2.6 trillion cubic feet, respectively. Although GII projects lower natural gas consumption in 2030 in the residential and commercial sectors than is projected in the *AEO2008* reference case, natural gas consumption for electricity generation in the GII projection is much greater, resulting in higher aggregate natural gas demand than in the *AEO2008* reference case, highlighting a fundamental difference between the *AEO2008* reference case and GII projections. This difference can also be seen in a comparison of the *AEO2008* reference case with the Altos and SEER projections.

Natural gas consumption in the electricity generation sector grows from 2006 to 2015 in all the projections. (DB does not include projections by sector.) Growth in natural gas consumption in the electricity generation sector is projected to continue through 2025 in the EVA and Altos projections. The *AEO2008* reference case shows the lowest level of natural gas consumption for electric power in 2025, at 5.3 trillion cubic feet, followed by GII at 6.9 trillion cubic feet.

All the projections show a decline in natural gas consumption in the electric power sector between 2025 and 2030, with the largest decline in the Altos projection (0.8 trillion cubic feet). Despite the large decline in natural gas consumption in the power sector in the Altos projection, it remains the most optimistic, with 2030 consumption projected to be 13.6 trillion cubic feet—almost three times higher than that in the *AEO2008* reference case. The SEER and GII projections for natural gas consumption in the electric power sector in 2030 are higher than the *AEO2008* reference case projection by 2.0 trillion cubic feet and 1.8 trillion cubic feet, respectively.

Each of the projections—with the exception of GII, which expects a slight decline between 2015 and 2030—shows steady growth in natural gas consumption in the combined residential and commercial sectors. Altos projects the highest level of natural gas consumption in the residential and commercial sectors in 2030 (9.3 trillion cubic feet), followed by SEER (9.0 trillion cubic feet) and the *AEO2008* reference case (8.8 trillion cubic feet). Each of the projections shows an increase in natural gas consumption in the industrial sector between 2006 and 2015. That growth is projected to continue through 2025 in each of the projections except for the *AEO2008* reference case. The *AEO2008* projection shows a decline in industrial sector natural gas consumption between 2025 and 2030, whereas the other projections show increases.

Domestic natural gas production increases through 2015 in each of the projections, with Altos showing the highest production level in 2015, at 21.9 trillion cubic feet. The *AEO2008* reference case and GII show domestic natural gas production continuing to increase through 2025, whereas DB, SEER, and Altos show production declines over the same period. For example, DB shows domestic natural gas production declining by 3.0 trillion cubic feet from 2015 to 2025. All the projections show a decline in production from 2025 to 2030, with DB projecting the lowest level of production in 2030 (3.0 trillion cubic feet lower than in the *AEO2008*

Table 11. Comparison of natural gas projections, 2015, 2025, and 2030 (trillion cubic feet, except where noted)

Projection	2006	AEO2008 reference case	Other projections				
			GII	EVA	DB	SEER	Altos
		2015					
Dry gas production [a]	**18.51**	**19.52**	**18.66**	**NA**	**19.66**	**20.33**	**21.90**
Net imports	**3.46**	**4.03**	**4.55**	**7.81**	**NA**	**4.71**	**6.75**
Pipeline	2.94	1.91	1.90	3.05	NA	1.68	2.03
LNG	0.52	2.12	2.65	4.75	3.04	3.03	4.72
Consumption	**21.66**	**23.66**	**23.36**	**25.56**	**23.74**	**25.79**	**26.98**
Residential	4.37	5.01	4.98	5.06	NA	5.08	5.05
Commercial	2.83	3.20	3.03	3.23	NA	3.12	3.44
Industrial [b]	6.49	7.00	6.65	7.09	NA	6.66	7.54 [c]
Electricity generators [d]	6.24	6.56	6.97	8.24	NA	9.03	10.95
Other [e]	1.73	1.88	1.73	1.94	NA	1.89	NA
Lower 48 wellhead price (2006 dollars per thousand cubic feet) [f]							
	6.42	**5.36**	**6.54**	**5.49**	**7.75**	**6.89**	**6.07**
End-use prices (2006 dollars per thousand cubic feet)							
Residential	13.80	11.54	11.98	NA	NA	11.45	NA
Commercial	11.85	9.97	10.69	NA	NA	9.97	NA
Industrial [g]	7.89	6.33	8.38	NA	NA	6.97	NA
Electricity generators	7.07	6.10	7.15	NA	NA	7.61	NA
		2025					
Dry gas production [a]	**18.51**	**19.60**	**18.73**	**NA**	**16.68**	**19.43**	**19.60**
Net imports	**3.46**	**3.28**	**4.64**	**9.49**	**NA**	**5.48**	**13.86**
Pipeline	2.94	0.68	1.28	2.44	NA	0.44	2.76
LNG	0.52	2.60	3.36	7.05	8.77	5.04	11.10
Consumption	**21.66**	**22.99**	**23.52**	**28.21**	**24.26**	**25.27**	**31.70**
Residential	4.37	5.19	4.98	5.09	NA	5.31	5.15
Commercial	2.83	3.53	2.98	3.51	NA	3.40	3.87
Industrial [b]	6.49	6.96	6.96	7.99	NA	7.08	8.29 [c]
Electricity generators [d]	6.24	5.30	6.90	9.45	NA	7.49	14.39
Other [e]	1.73	2.02	1.71	2.17	NA	2.00	NA
Lower 48 wellhead price (2006 dollars per thousand cubic feet) [f]							
	6.42	**5.86**	**6.63**	**5.40**	**7.75**	**6.40**	**7.00**
End-use prices (2006 dollars per thousand cubic feet)							
Residential	13.80	12.29	11.89	NA	NA	11.13	NA
Commercial	11.85	10.78	10.63	NA	NA	9.40	NA
Industrial [g]	7.89	6.76	8.42	NA	NA	6.47	NA
Electricity generators	7.07	6.44	7.20	NA	NA	7.03	NA

NA = not available. See notes and sources at end of table.

reference case). The *AEO2008* reference case shows domestic natural gas production of 19.4 trillion cubic feet in 2030—the highest of all the projections.

Net imports of natural gas are projected to increase between 2006 and 2015 in each of the projections. EVA projects the highest level of net imports at 7.8 trillion cubic feet, followed by Altos at 6.8 trillion cubic feet. The *AEO2008* reference case shows a drop in net imports between 2015 and 2030. Each of the other projections shows net imports increasing steadily from 2006 to 2030 (Altos expects an increase of 12.1 trillion cubic feet over the period). In addition, all the projections show the increases in net imports coming primarily from LNG. Altos projects LNG net import levels in 2030 that are more than four times higher than in the *AEO2008* reference case, at 12.6 trillion cubic feet. The projections have LNG imports accounting for between 13 and 40 percent of consumption in 2030.

Given that the average wellhead price for natural gas in 2006 was $6.42 per thousand cubic feet, each of the projections shows a decline in natural gas prices between 2006 and 2015, except GII, DB, and SEER. The *AEO2008* reference case projects the lowest average wellhead prices in 2015, at $5.36 per thousand cubic feet. EVA's natural gas price projection for 2025 is lower than that in the *AEO2008* reference case, by about $0.46 per thousand cubic feet. DB consistently projects relatively high average wellhead prices between 2006 and 2030. Among the other projections, only GII and SEER project an average natural gas wellhead price below that in the *AEO2008* reference case in 2030. In the GII and SEER projections, natural gas wellhead prices in 2030 are below the *AEO2008* reference case projection by $0.15 and $0.13 per thousand cubic feet, respectively, and wellhead prices in the DB and Altos projections exceed the *AEO2008* reference case projection by $1.12 and $0.82 per thousand cubic feet, respectively.

Table 11. Comparison of natural gas projections, 2015, 2025, and 2030 (continued)
(trillion cubic feet, except where noted)

Projection	2006	AEO2008 reference case	Other projections				
			GII	EVA	DB	SEER	Altos
		2030					
Dry gas production [a]	**18.51**	**19.43**	**18.68**	**NA**	**16.44**	**18.63**	**18.90**
Net imports	**3.46**	**3.18**	**4.86**	**NA**	**NA**	**6.33**	**15.57**
Pipeline	2.94	0.33	0.76	NA	NA	0.20	2.95
LNG	0.52	2.84	4.10	NA	9.84	6.13	12.62
Consumption	**21.66**	**22.72**	**23.69**	**NA**	**24.53**	**25.29**	**31.42**
Residential	4.37	5.17	4.94	NA	NA	5.44	5.17
Commercial	2.83	3.67	2.97	NA	NA	3.57	4.12
Industrial [b]	6.49	6.87	7.18	NA	NA	7.29	8.50 [c]
Electricity generators [d]	6.24	4.99	6.83	NA	NA	6.98	13.63
Other [e]	1.73	2.02	1.76	NA	NA	2.01	NA
Lower 48 wellhead price (2006 dollars per thousand cubic feet) [f]							
	6.42	**6.63**	**6.48**	**NA**	**7.75**	**6.50**	**7.45**
End-use prices (2006 dollars per thousand cubic feet)							
Residential	13.80	13.30	11.67	NA	NA	11.30	NA
Commercial	11.85	11.78	10.42	NA	NA	9.44	NA
Industrial [g]	7.89	7.50	8.26	NA	NA	6.53	NA
Electricity generators	7.07	7.13	7.05	NA	NA	6.28	NA

NA = not available.

[a]Does not include supplemental fuels. [b]Includes consumption for industrial CHP plants, a small number of electricity-only plants, and GTL plants for heat and power production; excludes consumption by nonutility generators. [c]Includes lease and plant fuel. [d]Includes consumption of energy by electricity-only and CHP plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes electric utilities, small power producers, and exempt wholesale generators. [e]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles. [f]2006 wellhead natural gas prices for GII, DB, and SEER are $6.41, $6.42, and $6.24 per thousand cubic feet, respectively. [g]The 2006 industrial natural gas price for GII is $8.89 per thousand cubic feet.

Sources: **2006 and *AEO2008*:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *2007 U.S. Energy Outlook* (October 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 18, 2007. **SEER:** Strategic Energy and Economic Research, Inc., *Natural Gas Scenarios* (March 2008). **Altos:** Altos World Gas Trade (September 2007).

The price margins for delivered natural gas can vary significantly from year to year. In 2006, margins in the residential, commercial, industrial, and transportation sectors were notably higher than the historical average, and margins in the electricity generation sector were somewhat lower than the historical average. Starting from a level more representative of the historical average, margins in the electricity generation and industrial sectors generally decline in the *AEO2008* reference case. In contrast, margins in the residential and commercial sectors increase, because the fixed costs are spread over lower per-customer volumes as consumption is reduced by efficiency improvements.

End-use prices in the GII and SEER projections imply declining margins in all sectors, with the exception of the residential and electricity generation sectors in the SEER projection, which increase from 2025 to 2030. As a result, the GII and SEER margins in the residential and commercial sectors are lower than those in the *AEO2008* reference case projection by between \$1.20 and \$2.20 per thousand cubic feet in 2030. The industrial margin in the GII projection remains appreciably higher throughout the projection period, whereas the industrial margin in the SEER projection is between \$0.83 and \$0.90 per thousand cubic feet lower than the margins in the *AEO2008* reference case projection from 2015 to 2030. In fact, the SEER industrial margins appear to be only a few pennies in all years.

Petroleum

In the DB projection, real crude oil prices increase from \$57 per barrel in 2010 to \$80 per barrel in 2030. In the *AEO2008* reference case, real prices decline from current levels to a low of \$57 per barrel in 2016 before recovering to \$70 per barrel in 2030 (Table 8).

Despite the higher crude oil prices in 2030, the import share of product supplied is much higher in the DB projection than in the *AEO2008* reference case (74 percent and 54 percent, respectively). Although this may seem counterintuitive given the relative price projections, it makes sense in terms of the projections for domestic crude oil production. In the DB projection, U.S. crude oil production declines sharply after 2015, to 4.8 million barrels per day in 2030 (as compared with 7.2 million barrels per day in 2030 in the *AEO2008* reference case) (Table 12). In fact, U.S. crude oil production is lower in all the other projections than in the *AEO2008* reference case.

It is clear that expectations about U.S. crude oil production potential are among the main factors accounting for the differences between the *AEO2008* reference case and the other projections. In addition, unlike the DB analysis, the *AEO2008* reference case incorporates the effects of the new RFS mandate under EISA2007, which was signed into law in December 2007. With the new RFS mandate, biofuel consumption is projected to increase significantly through 2022, with more than 23 billion gallons of ethanol and almost 4 billion gallons of biomass-based diesel consumed in 2030, which would displace a significant amount of fossil fuel use in the transportation sector and, thereby, further reduce imports.

GII's long-term projections for the crude oil price in 2025 (\$48 per barrel) and 2030 (\$46 per barrel) are much lower than those in the *AEO2008* reference case (see Table 8). The GII projection for import share of product supplied is therefore higher than the *AEO2008* reference case projection.

In contrast with crude oil production, projections for NGL production are similar (remaining relatively constant) in the EVA, GII, and *AEO2008* reference case projections through 2030. The exception is DB, which projects a 26-percent decrease in domestic NGL production from 2015 to 2030.

Based on expectations of continued economic growth, all the petroleum projections show continued growth in product demand; however, growth in demand for individual petroleum products varies considerably. In particular, motor gasoline demand, which in the DB projections increases to 11.2 million barrels per day in 2030, is much lower in the GII and *AEO2008* reference case projections. Motor gasoline demand declines over time in the GII and *AEO2008* reference case projections (although it increases slightly from 2025 to 2030 in the *AEO2008* reference case). The GII projection includes a substantial increase in ethanol use (not shown in the Table 12) stemming from new, unspecified motor fuel policies, with ethanol making up more than 30 percent of total U.S. motor gasoline sales in 2030. A 30-percent share is in excess of even the new RFS mandate incorporated in *AEO2008*.

Looking at other petroleum products, the GII projections for jet fuel and distillate demand are higher than those in the DB and *AEO2008* reference case projections. The most likely explanation is that, although long-term GDP growth rates are similar in

Table 12. Comparison of petroleum projections, 2015, 2025, and 2030 (million barrels per day, except where noted)

Projection	2006	AEO2008 reference case	Other projections: GII	EVA	DB	IEA
		2015				
Crude oil and NGL production	**6.84**	**7.86**	**6.37**	**7.40**	**6.47**	**6.70**
Crude oil	5.10	6.16	4.63	5.60	4.92	NA
Natural gas liquids	1.74	1.70	1.75	1.80	1.55	NA
Total net imports	**12.45**	**11.36**	**13.79**	**NA**	**14.00**	**NA**
Crude oil	10.09	9.89	12.02	NA	NA	NA
Petroleum products	2.36	1.47	1.77	NA	NA	NA
Petroleum demand	**20.65**	**21.68**	**22.36**	**NA**	**22.07**	**22.45**
Motor gasoline	9.25	9.73	9.83	NA	9.84	NA
Jet fuel	1.63	1.85	1.92	NA	1.71	NA
Distillate fuel	4.17	4.68	4.79	NA	4.63	NA
Residual fuel	0.69	0.69	0.68	NA	0.71	NA
Other	4.91	4.73	5.14	NA	5.18	NA
Import share of product supplied (percent)	**60**	**52**	**62**	**NA**	**63**	**NA**
		2025				
Crude oil and NGL production	**6.84**	**7.65**	**5.47**	**5.80**	**5.28**	**NA**
Crude oil	5.10	6.04	3.71	4.10	4.01	NA
Natural gas liquids	1.74	1.61	1.75	1.70	1.27	NA
Total net imports	**12.45**	**11.38**	**15.13**	**NA**	**17.25**	**NA**
Crude oil	10.09	10.11	13.70	NA	NA	NA
Petroleum products	2.36	1.27	1.43	NA	NA	NA
Petroleum demand	**20.65**	**22.25**	**23.54**	**NA**	**24.25**	**NA**
Motor gasoline	9.25	8.84	9.08	NA	10.77	NA
Jet fuel	1.63	2.16	2.36	NA	1.90	NA
Distillate fuel	4.17	5.19	5.98	NA	5.16	NA
Residual fuel	0.69	0.69	0.65	NA	0.75	NA
Other	4.91	5.37	5.47	NA	5.67	NA
Import share of product supplied (percent)	**60**	**51**	**64**	**NA**	**71**	**NA**
		2030				
Crude oil and NGL production	**6.84**	**7.16**	**5.05**	**NA**	**4.78**	**6.30**
Crude oil	5.10	5.59	3.30	NA	3.63	NA
Natural gas liquids	1.74	1.57	1.75	NA	1.15	NA
Total net imports	**12.45**	**12.29**	**15.63**	**NA**	**18.75**	**NA**
Crude oil	10.09	11.03	14.51	NA	NA	NA
Petroleum products	2.36	1.26	1.12	NA	NA	NA
Petroleum demand	**20.65**	**22.80**	**24.04**	**NA**	**25.30**	**23.87**
Motor gasoline	9.25	8.91	8.47	NA	11.20	NA
Jet fuel	1.63	2.31	2.61	NA	2.00	NA
Distillate fuel	4.17	5.53	6.69	NA	5.43	NA
Residual fuel	0.69	0.70	0.63	NA	0.77	NA
Other	4.91	5.35	3.35	NA	5.90	NA
Import share of product supplied (percent)	**60**	**54**	**65**	**NA**	**74**	**NA**

NA = Not available.

Sources: ***2006 and AEO2008:*** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *2007 U.S. Energy Outlook* (October 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski on November 18, 2007. **IEA:** International Energy Agency, *World Energy Outlook 2007* (Paris, France, November 2007).

the GII and *AEO2008* projections, the long-term cost of crude oil, as noted above, is much lower in the GII projection, leading to cheaper refined products and therefore higher demand. Finally, among the outside projections, IEA projects the lowest level of U.S. petroleum demand in 2030—probably as a result of IEA's assumption of slower U.S. economic growth. Further, although IEA's projection for U.S. petroleum demand in 2030 (23.9 million barrels per day) is higher than in the *AEO2008* reference case (22.8 million barrels per day), it would in fact be about 1 million barrels per day *lower* if *AEO2008* had not included the EISA2007 RFS mandate.

Coal

Coal production, trade, and price projections vary considerably across the three projections shown in Table 13. The coal projection in the *AEO2008* reference case reflects existing environmental laws that regulate SO_2, NO_x, and mercury emissions. The *AEO2008* reference case projections for coal consumption, production, and imports are generally higher than the projections from other sources.

All the projections show increases in total coal consumption over their projection periods. In the *AEO2008* reference case, total coal consumption

Table 13. Comparison of coal projections, 2015, 2025, and 2030 (million short tons, except where noted)

Projection	2006	AEO2008 reference case	Other projections: GII	Other projections: EVA
		2015		
Production	**1,163**	**1,215**	**1,135**	**1,225**
Consumption by sector				
Electric power	1,026	1,125	1,055	1,121
Coke plants	23	21	23	23
Coal-to-liquids	0	16	NA	NA
Other industrial/buildings	65	64	65	71
Total	**1,114**	**1,225**	**1,143**	**1,216**
Net coal exports	**15.3**	**3.3**	**-8.0**	**13.2**
Exports	49.6	45.3	31.8	45.9
Imports	34.3	42.0	39.7	32.7
Minemouth price				
(2006 dollars per short ton)	24.63	23.38	19.68	25.14
(2006 dollars per million Btu)	1.21	1.17	0.94 [a]	1.23
Average delivered price to electricity generators				
(2006 dollars per short ton)	33.85	34.24	31.92	NA
(2006 dollars per million Btu)	1.69	1.74	1.52 [a]	NA
		2025		
Production	**1,163**	**1,363**	**1,140**	**1,311**
Consumption by sector				
Electric power	1,026	1,303	1,058	1,224
Coke plants	23	20	22	21
Coal-to-liquids	0	46	NA	NA
Other industrial/buildings	65	62	66	67
Total	**1,114**	**1,431**	**1,146**	**1,311**
Net coal exports	**15.3**	**-57.3**	**-5.9**	**-1.9**
Exports	49.6	35.5	31.1	43.3
Imports	34.3	92.8	36.9	45.2
Minemouth price				
(2006 dollars per short ton)	24.63	22.75	18.75	26.49
(2006 dollars per million Btu)	1.21	1.16	0.89 [a]	1.31
Average delivered price to electricity generators				
(2006 dollars per short ton)	33.85	34.03	30.61	NA
(2006 dollars per million Btu)	1.69	1.74	1.46 [a]	NA

Btu = British thermal unit. NA = Not available. See notes and sources at end of table.

grows by an average of 1.1 percent annually from 2006 to 2015, to 1,225 million tons in 2015. Although the reference case projection is 82 million tons higher than the corresponding projection from GII, it is similar to the EVA projection for total coal consumption in 2015. For 2025, both EVA and GII project lower levels of total coal consumption than the *AEO2008* reference case (8 percent and 20 percent lower, respectively). For 2030, GII projects total coal consumption of 1,175 million tons, 370 million tons less than in the *AEO2008* reference case.

Coal use in the electricity sector accounts for a large percentage of total coal consumption in all years across all the projections. Relative to the *AEO2008* reference case, both EVA and GII project slower growth in coal consumption for the electric power sector over the entire projection period. EVA projects total coal consumption in the electricity sector of 1,224 million tons in 2025, 79 million tons less than in the *AEO2008* reference case. The GII projection for coal consumption in the electric power sector is 1,088 million tons in 2030, 313 million tons less than in the *AEO2008* reference case.

The *AEO2008* reference case includes the introduction of CTL production before 2015, with coal use at CTL plants increasing to 64 million tons (4 percent of total coal consumption) in 2030. Projections for CTL production from the other organizations are not available for comparison [*91*].

The *AEO2008* reference case, GII, and EVA projections show relatively constant coal consumption levels both at coke plants and in the other industrial/buildings sector. The EVA projections do not extend to 2030. GII shows 21 million tons of coal consumption at coke plants and 66 million tons in the other industrial/buildings sector in 2030, both somewhat higher than in the *AEO2008* reference case (18 and 62 million tons, respectively).

In the *AEO2008* reference case, minemouth coal prices are generally flat over the projection period. EVA projects an increase to $26.49 in 2025, the highest among the projections compared, whereas the *AEO2008* reference case projection for 2025 is $22.75 per ton. In GII's projection, the minemouth coal price falls to $18.42 per ton in 2030. GII also projects a decline in delivered coal prices to the electric power sector through 2030, from $31.92 per ton in 2015 to $30.42 per ton in 2030—$4.61 per ton less than in the *AEO2008* reference case.

Table 13. Comparison of coal projections, 2015, 2025, and 2030 (continued)
(million short tons, except where noted)

Projection	2006	AEO2008 reference case	Other projections: GII	Other projections: EVA
		2030		
Production	1,163	1,455	1,168	NA
Consumption by sector				
Electric power	1,026	1,401	1,088	NA
Coke plants	23	18	21	NA
Coal-to-liquids	0	64	NA	NA
Other industrial/buildings	65	62	66	NA
Total	1,114	1,545	1,175	NA
Net coal exports	15.3	-77.7	-7.0	NA
Exports	49.6	34.6	30.8	NA
Imports	34.3	112.3	37.8	NA
Minemouth price				
(2006 dollars per short ton)	24.63	23.32	18.42	NA
(2006 dollars per million Btu)	1.21	1.19	0.88 [a]	NA
Average delivered price to electricity generators				
(2006 dollars per short ton)	33.85	35.03	30.42	NA
(2006 dollars per million Btu)	1.69	1.78	1.45 [a]	NA

Btu = British thermal unit. NA = Not available.
[a]Imputed using heat conversion factor implied by US steam coal consumption figures for the electricity sector.
Sources: ***2006 and AEO2008:*** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **GII:** Global Insight, Inc., *2007 U.S. Energy Outlook* (October 2007). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (August 2007).

Comparison with Other Projections

In the *AEO2008* and EVA projections, domestic coal production increases to meet rising demand. Production grows most rapidly in the *AEO2008* reference case, averaging 0.9 percent per year from 2006 to 2030. The EVA projection through 2025 closely resembles that in the *AEO2008* reference case, and the GII projection is significantly lower. In the GII projection, coal production totals 1,168 million tons in 2030, 20 percent less than in the *AEO2008* reference case (1,455 million tons).

U.S. coal exports represent a small percentage of domestic coal production in all the projections. Coal exports decline to less than 35 million tons in 2030 in the *AEO2008* reference case and GII projections, and the United States is represented as a net importer of coal after 2015 in all the projections. In the EVA projection, U.S. coal imports increase to 45 million tons in 2025, and exports are 43 million tons in 2025. In the *AEO2008* reference case, U.S. coal imports in 2015, 2025, and 2030 are higher than in the other projections.

List of Acronyms

A.B.	Assembly Bill
ABT	Averaging, banking, and trading
ACP	Alternative compliance payment
AEO	*Annual Energy Outlook*
AEO2007	*Annual Energy Outlook 2007*
AEO2008	*Annual Energy Outlook 2008*
AMFA	Alternative Motor Fuels Act of 1988
ANWR	Arctic National Wildlife Refuge
BTL	Biomass-to-liquids
Btu	British thermal unit
CAAA90	Clean Air Act Amendments of 1990
CAFE	Corporate Average Fuel Economy
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CBO	Congressional Budget Office
CCS	Carbon capture and sequestration
CEPCI	Chemical Engineering Plant Cost Index
CEPS	Clean energy portfolio standard
CFL	Compact fluorescent light bulb
CHP	Combined heat and power
CO_2	Carbon dioxide
CTL	Coal-to-liquids
DB	Deutsche Bank AG
DOE	U.S. Department of Energy
E&P	Exploration and production
E10	Gasoline containing up to 10 percent ethanol by volume
E85	Fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume
EIA	Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT1992	Energy Policy Act of 1992
EPACT2005	Energy Policy Act of 2005
EVA	Energy Ventures Analysis, Inc.
FFV	Flex-fuel vehicle
FY	Fiscal year
GDP	Gross domestic product
GHGs	Greenhouse gases
GII	Global Insights, Inc.
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
H.R.	House of Representatives
ICAP	International Carbon Action Partnership
IEA	International Energy Agency
IECC	International Energy Conservation Code
INFORUM	Interindustry Forecasting Project at the University of Maryland
JAS	Joint Association Survey of Drilling Costs
LDV	Light-duty vehicle
LED	Light-emitting diode
LNG	Liquefied natural gas
MMS	Minerals Management Service
mpg	Miles per gallon
MSAT2	Mobile Source Air Toxics Rule (February 2007)
MSW	Municipal solid waste
NEMA	National Electrical Manufacturers Association
NEMS	National Energy Modeling System (EIA)
NGL	Natural gas liquids
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen oxides
NRC	U.S. Nuclear Regulatory Commission
NYMEX	New York Mercantile Exchange
OECD	Organization for Economic Cooperation and Development
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
P.L.	Public Law
PTC	Production tax credit
PV	Solar photovoltaic
R&D	Research and development
REC	Renewable energy certificate
RFG	Reformulated gasoline
RFS	Renewable Fuels Standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SEER	Strategic Energy and Economic Research, Inc.
S.B.	Senate Bill
SO_2	Sulfur dioxide
SSA	Social Security Administration
STEO	*Short-Term Energy Outlook* (EIA)
ULSD	Ultra-low-sulfur diesel
USGS	U.S. Geological Survey
VEETC	Volumetric Ethanol Excise Tax Credit
WCI	Western Climate Initiative
WTI	West Texas Intermediate (crude oil)

Text Notes

Overview

1. Some possible policy changes—notably, the adoption of policies to limit or reduce greenhouse gas emissions—could change the reference case projections significantly. EIA has examined many of the proposed greenhouse gas policies at the request of Congress; the reports are available on EIA's web site (see "Responses to Congressional and Other Requests," web site www.eia.doe.gov/oiaf/service_rpts.htm).
2. The comparison of production levels was adjusted for the entry of Angola into OPEC in late 2007.
3. See Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "Impact of Rising Construction and Equipment Costs on Energy Industries," pp. 36-41.
4. Vehicles that can use alternative fuels or employ electric motors and advanced electricity storage, advanced engine controls, or other new technologies.
5. Biodiesel is defined as the monoalkyl esters of fatty acids derived from plant or animal matter and suitable for use in a diesel engine.
6. BTL is defined as diesel fuel and other liquid hydrocarbons produced by a Fischer-Tropsch process using cellulosic biomass as feedstock.

Legislation and Regulations

7. U.S. Environmental Protection Agency, 40 CFR Parts 59, 80, 85 and 86 [EPA-HQ-OAR-2005-0036; FRL-8278-4], RIN 2060-AK70, "Control of Hazardous Air Pollutants from Mobile Sources; Final Rule," *Federal Register*, Vol. 72, No. 37 (February 26, 2007), web site http://edocket.access.gpo.gov/2007/pdf/E7-2667.pdf. Most of the data cited here were taken from this source.
8. For the complete text of the Energy Independence and Security Act of 2007, see web site http:// frwebgate.acess.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_public_laws&docid=f:publ140.110.pdf.
9. See, for example, web site http://energy.senate.gov/public/_files/HR6EnergyBillSummary.pdf.
10. Footprint is the product of track width and wheelbase, measured in square feet.
11. Energy Policy Act of 2005, Section 1501.
12. "DuPont and BP Reveal Biobutanol Test Results" *Ethanol & Biodiesel News* (April 23, 2007).
13. DuPont, "Alternative Fuels and Potential Material Compatibility Issues," DuPont Automobile Annual Fuel Luncheon (April 16, 2008).
14. Energy Information Administration, *Annual Energy Outlook 2007*, DOE-EIA-0383(2007) (Washington, DC, February 2007), "Legislation and Regulations: Excise Taxes on Highway Fuels," p. 25, web site www.eia.doe.gov/oiaf/archive/aeo07.
15. U.S. Department of the Treasury, Internal Revenue Service, *Excise Taxes for 2007*, Publication 510 (1/2007) (Washington, DC, Revised January 2007), web site www.irs.gov/publications/p510.
16. Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees, and Environmental Taxes and Fees" (June 29, 2007).
17. U.S. Department of Energy, Energy Efficiency and Renewable Energy, Alternative Fuels & Advanced Vehicles Data Center, "Volumetric Ethanol Excise Tax Credit (VEETC)," web site www.eere.energy.gov/afdc/progs/view_ind_fed.php/afdc/399/0.
18. E85 is a fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume.
19. VEETC was established by the American Jobs Creation Act of 2004, Section 301. Before VEETC, gasoline blended with 5.7 percent, 7.7 percent, or 10 percent ethanol received an excise tax reduction equivalent to 51 cents per gallon of ethanol; however, the applicable excise tax reduction for blends with any other ethanol percentage was equivalent to less than 51 cents per gallon of ethanol. This was an especially serious impediment to blenders of E85.
20. VEETC provided biodiesel tax credits for 2005 and 2006. EPACT2005, Section 1344, extended the biodiesel tax credits through 2007 and 2008.
21. The Food, Conservation, and Energy Act of 2008 (Public Law 110-234), which was enacted in May 2008, contains several tax provisions related to biofuels. The bill reduces the ethanol blending tax credit from 51 cents to 45 cents per gallon once annual ethanol production or import volumes reach 7.5 billion gallons; extends the ethanol import tariff through 2010; and establishes a tax credit for cellulosic biofuels of up to $1.01 per gallon produced. The *AEO2008* reference case projects ethanol production of 8.5 billion gallons in 2008, which would trigger the blending tax credit reduction in 2009. *AEO2008* does not include consideration of the Food, Conservation, and Energy Act of 2008, which was enacted too late for inclusion.
22. EPACT2005, Section 1347, increased the production volume for small producers from 30 million to 60 million gallons, starting in 2006.
23. Most of the data cited in this section are taken from U.S. Environmental Protection Agency, 40 CFR Parts 59, 80, 85, and 86, "Control of Hazardous Air Pollutants From Mobile Sources; Final Rule," *Federal Register*, Vol. 72, No. 37 (February 26, 2007), pp. 8428-8570, web site http://edocket.access.gpo.gov/2007/pdf/E7-2667.pdf.
24. The subsidy cost—essentially the expected cost of the program, excluding administrative expenditures—generally equals the amount of the loan multiplied by the probability of default. The actual computation of the "subsidy cost" and whether it represents the true cost of the program are complex issues far beyond the scope of this section of *AEO2008*. For more details on government loan guarantee programs, see Energy Information Administration, *Federal Financial Interventions and Subsidies in Energy Markets 2007*, SR/CNEAF/2008-01 (Washington, DC, April 2008), web site www.eia.doe.gov/oiaf/servicerpt/subsidy2/index.html.
25. Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "Loan Guarantees and the Economics of Electricity Generating Technologies," pp. 48-49,

web site www.eia.doe.gov/oiaf/archive/aeo07/pdf/issues.pdf.

26. U.S. House of Representatives, 110th Congress, "Energy and Water Development Appropriations Bill, 2008" (House Report 110-185, June 11, 2007); and U.S. Senate, 110th Congress, "Energy and Water Appropriations Bill, 2008" (Senate Report 110-127, July 9, 2007), web site www.access.gpo.gov/congress/legislation/08appro.html.
27. See, for example, testimony of Christopher Crane, Senior Vice President, Exelon Corporation, and President and Chief Nuclear Officer, Exelon Nuclear, before the Subcommittee on Energy and Air Quality, Committee on Energy and Commerce, U.S. House of Representatives (April 24, 2007), web site http://energycommerce.house.gov/cmte_mtgs/110-eaq-hrg.042407.Crane-testimony.pdf.
28. U.S. Department of Energy, Loan Guarantee Program, "DOE Releases Information on Loan Guarantee Pre-Applications" (March 6, 2007), web site www.lgprogram.energy.gov/press/030607.html.
29. Energy Information Administration, *Annual Energy Outlook 2005*, DOE/EIA-0383(2005) (Washington, DC, February 2005), "State Renewable Energy Requirements and Goals: Status Through 2003," pp. 20-22, web site www.eia.doe.gov/oiaf/archive/aeo05/leg_reg.html.
30. Energy Information Administration, *Annual Energy Outlook 2006*, DOE/EIA-0383(2006) (Washington, DC, February 2006), "State Renewable Energy Requirements and Goals: Update Through 2005," pp. 24-27, web site www.eia.doe.gov/oiaf/archive/aeo06/leg_reg.html.
31. Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "State Renewable Energy Requirements and Goals: Update Through 2006," pp. 28-30, web site www.eia.doe.gov/oiaf/archive/aeo07/leg_reg.html.
32. State of New Hampshire, H.B. 873, web site www.gencourt.state.nh.us/legislation/2007/HB0873.html.
33. General Assembly of North Carolina, S.B. 3, web site www.ncleg.net/Sessions/2007/Bills/Senate/PDF/S3v6.pdf.
34. Oregon Legislative Assembly, S.B. 838, signed into law by Governor Theodore R. Kulongoski on June 6, 2007, defines a large supplier as any generator that provides at least 3 percent of the State's electric load, a medium-sized supplier as one that provides between 1.5 and 3 percent of the State's load, and a small supplier as one that provides less than 1.5 percent of the State's load. See web site www.oregon.gov/ENERGY/RENEW/docs/sb0838.en.pdf.
35. Revised Code of Washington, Chapter 19.285, web site http://apps.leg.wa.gov/RCW/default.aspx?cite=19.285.
36. State of Delaware, S.B. 19, web site http://depsc.delaware.gov/electric/delrps.shtml.
37. An alternative compliance payment is a payment to the State for not meeting their renewable energy goal. In some instances, there are different compliance payments (or penalties) for unique generation technologies.
38. State of Colorado, H.B. 07-1281, web site www.leg.state.co.us/clics/clics2007a/csl.nsf/fsbillcont3/C9B0B62160D242CA87257251007C4F7A?open&file=1281_enr.pdf.
39. State of Connecticut, House Bill 7432, Public Act 07-242, web site www.cga.ct.gov/2007/ACT/PA/2007PA-00242-R00HB-07432-PA.htm.
40. State of Illinois, Public Act 095-0481, web site www.ilga.gov/legislation/publicacts/95/PDF/095-0481.pdf.
41. "Minnesota - Renewable Portfolio Standard," web site www.dsireusa.org/library/includes/tabsrch.cfm?state=MN0type=RPS&CurrentPageID=7&EE=1&RE=1.
42. U.S. Environmental Protection Agency, "Clean Air Interstate Rule," web site www.epa.gov/cair.
43. U.S. Environmental Protection Agency, "Clean Air Mercury Rule," web site www.epa.gov/camr.
44. *AEO2007* included a summary of the RGGI provisions in the original model rule. See Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007), "State Regulations on Airborne Emissions: Update Through 2006," pp. 30-32, web site www.eia.doe.gov/oiaf/archive/aeo07/leg_reg.html.
45. State of California, "Senate Bill 1368," web site www.energy.ca.gov/ghgstandards/documents/sb_1368_bill_20060929_chaptered.pdf.
46. California Environmental Protection Agency, Air Resources Board, "Proposed Regulations to Control Greenhouse Gas Emissions from Motor Vehicles," web site www.arb.ca.gov/regact/grnhsgas/grnhsgas.htm (September 19, 2005).
47. State of California, "Assembly Bill No. 1493," web site www.calcleancars.org/ab1493.pdf.
48. U.S. Environmental Protection Agency, "California Greenhouse-Gas Waiver Request," web site www.epa.gov/otaq/ca-waiver.htm.
49. Office of the New York State Attorney General Andrew M. Cuomo, "Cuomo Leads Coalition of 15 States Against EPA in Battle for States' Right To Fight Global Warming" (January 2, 2008), web site www.oag.state.ny.us/press/2008/jan/jan02a_08.html.
50. State of Washington, "Mitigating the impacts of climate change," SB 6001 – 2007-08, web site http://apps.leg.wa.gov/billinfo/summary.aspx?bill=6001.
51. State of Montana, House Bill No. 25, web site http://data.opi.mt.gov/bills/2007/billpdf/HB0025.pdf.
52. State of Florida, Executive Order 07-126, "Leadership by Example: Immediate Actions to Reduce Greenhouse Gas Emissions from Florida State Government"; Executive Order 07-127, "Immediate Actions to Reduce Greenhouse Gas Emissions within Florida"; and Executive Order 07-128, "Florida Governor's Action Team on Energy and Climate Change"; web site www.dep.state.fl.us/climatechange/eo.htm.

Issues in Focus

53. M.L. Wald, "Costs Surge for Building Power Plants," *New York Times* (July 10, 2007), web site www.nytimes.com/2007/07/10/business/worldbusiness/10energy.html.
54. Imperial Oil Resources Ventures, Ltd., "Mackenzie Gas Project: Supplemental Information Project Update," National Energy Board Submission IPRCC.PR.07.08 (Calgary, Alberta, Canada, May 2007).
55. Rising oil prices do not necessarily lead to rising oil production from existing fields. Reservoir characteristics and the properties of the oil in the reservoirs primarily determine the maximum efficient recovery rate for a particular oil reservoir. Aggregate incremental rates of improvement in oil recovery diminish rapidly as oil prices rise. For example, a recent analysis of Alaska's North Slope oil fields indicates that very little incremental recovery is achievable once oil prices exceed $60 per barrel. See National Energy Technology Laboratory, Arctic Energy Office, *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline? Summary Report*, DOE/NETL-2007/1280 (Fairbanks, AK, August 2007), web site www.netl.doe.gov/technologies/oil-gas/publications/EPreports/ANSSummaryReportFinalAugust2007.pdf. Technological progress is more likely to affect the ultimate oil recovery rate than oil prices or drilling costs.
56. Production began in 2000 at the Alpine Field, which has an estimated ultimate recoverable reserve of about 540 million barrels. Source: National Energy Technology Laboratory, *Alaska North Slope Oil and Gas: A Promising Future or an Area in Decline? Summary Report*, DOE/NETL-2007/1280.
57. A higher or lower level of future U.S. oil industry activity primarily affects the rate at which future U.S. oil production declines. High levels of activity can stabilize oil production for an extended period of time, especially through the application of EOR techniques, but eventually the depletion of the resource base causes production to decline. Lower levels of activity accelerate the rate of decline in future oil production.
58. Oil production in the shallow waters of the Gulf of Mexico declines slowly in all the cases.
59. The reference case assumes that pipelines from Canada and Alaska will be connected to natural gas markets in the lower 48 States. If no Arctic pipelines were built, however, there would be no pipeline to move natural gas from Alaska's North Slope to southern Alaska, where it would otherwise be converted to LNG and shipped to foreign and domestic customers. As an alternative, natural gas from the North Slope could be converted to petroleum liquids and transported through the existing Alyeska oil pipelines (also known as the TransAlaska Pipeline System).
60. Net LNG imports are slightly lower than gross LNG imports before 2011, because LNG exports to Japan from Alaska are expected to continue through 2011, at about 65 billion cubic feet per year.
61. U.S. Geological Survey, "USGS National Assessment of Oil and Gas Resources Update (December, 2006)," web site http://certmapper.cr.usgs.gov/data/noga00/natl/tabular/total.xls. The estimates cited in this discussion are rough approximations. The actual probability spread of the estimates is considerably larger.
62. If LNG imports into Canada and Mexico were constrained to the same degree as assumed for the lower 48 States, natural gas prices would be even higher, causing both a larger decrease in domestic natural gas consumption and a larger increase in lower 48 production.
63. CERA Advisory Service, "Monthly Natural Gas Briefing" (April 20, 2007).
64. NOAA Webcast, "Improving Climate Normals" (September 26, 2007).
65. A small amount of the difference is due to the use of dynamic population weights in *AEO2008*.
66. James T. Jensen of Jensen Associates in Weston, MA, stated in a presentation on "Increasing Global LNG Investments" to the LNG North America Summit 2007 in Houston, TX, June 20, 2007, that, "At the turn of the decade, LNG plant construction costs were approaching $200/ton of capacity but current costs are a multiple of that level and there have been several 'problem trains' that have been quoted at $1,200/ton and above."
67. Zeus Development Corporation of Houston, TX, has reported that costs for the Gros Cacouna terminal on the St. Lawrence River have nearly doubled from initial estimates and that the terminal is being put on hold while cost-cutting options to reduce costs to under $1 billion are studied. See "Spiraling Costs Impact Petro-Canada's LNG Terminal, Delay Decision," *LNG Express* (August 1, 2007), web site www.lngexpress.com (subscription site).
68. According to Keith Bainbridge of London-based LNG Shipping Solutions, the price of a standard sized ship, estimated at around $155 million in late 2003, has risen to between $215 and $230 million in 2007.
69. Wood Mackenzie Research and Consulting, "Global LNG Online," web site www.woodmacresearch.com/cgi-bin/wmprod/portal/energy/productMicrosite.jsp?productOID=664070 (available to subscribers only).
70. Energy Information Administration, *International Energy Outlook 2007*, DOE/EIA-0484(2007) (Washington, DC, May 2007), web site www.eia.doe.gov/oiaf/ ieo.
71. Japan, South Korea, Spain, United States, France, Turkey, Belgium, United Kingdom, Italy, Mexico, Portugal, and Greece.
72. Taiwan, India, China, Puerto Rico, and Dominican Republic.
73. Indonesia, Malaysia, Qatar, Algeria, Trinidad and Tobago, Nigeria, Oman, Brunei, United Arab Emirates, Egypt, and Libya.
74. Embassy of the United States, Jakarta, Indonesia, *Country Commercial Guide – Indonesia Fiscal Year 2003*, Chapter 7, "Investment Climate Statement," p. 61, web site www.usembassyjakarta.org/ccg/ccg.html.
75. Government of Western Australia, Department of the Premier and Cabinet, *WA Government Policy on Securing Domestic Gas Supplies* (October 2006), web site www.doir.wa.gov.au/documents/DomGas_Policy(1).pdf.
76. Gas Infrastructure Europe's "Storage Investment Database" for November 2007 listed new storage projects

in Europe with a total of 1.47 trillion cubic feet of working capacity—including 0.96 trillion cubic feet in OECD countries—that had planned operational dates before 2016 and were designated as either aquifer or depleted reservoir types (commonly used for seasonal storage). The database included projects placed in operation after June 2007, under construction, committed (evaluated by the company with detailed studies and possibly undergoing planning and permitting stages), or planned (at an early evaluation stage). Four types of capacity were included: aquifer, LNG peak shaving, reservoir, and salt cavity. See Gas Infrastructure Europe, "Storage Investment Database," web site www.gie.eu.com/maps_data/database.html.

77. BG Group, "BG Group Finalises Agreement To Meet Natural Gas Demand in Chile," Press Release (June 4, 2007), web site www.bg-group.com/MediaCentre/PressArchive/2007/Pages/060407-sx.aspx.

Market Trends

78. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.
79. This change in methodology is discussed in the Issues In Focus section, pages 44-46.
80. A Divisia index is used for this calculation. A discussion of the index can be found in G. Boyd, J.F. McDonald, M. Ross, and D.A. Hansont, "Separating the Changing Composition of U.S. Manufacturing Production from Energy Efficiency Improvements: A Divisia Index Approach," *Energy Journal*, Vol. 8, No. 2 (1987).
81. S.C. Davis and S.W. Diegel, *Transportation Energy Data Book: Edition 25*, ORNL-6974 (Oak Ridge, TN, May 2006), Chapter 4, "Light Vehicles and Characteristics," web site http://cta.ornl.gov/data/chapter4.shtml.
82. The fuel shares are calculated in terms of energy content. Because of the differences in energy content per gallon of gasoline, diesel, and ethanol, the percentage share would be different on a volumetric basis. For example, it takes about 1.3 gallons of E85 to replace the energy in 1 gallon of gasoline.
83. Unless otherwise noted, the term "capacity" in the discussion of electricity generation indicates utility, nonutility, and CHP capacity. Costs reflect the average of regional costs, except for wind, which uses a representative region.
84. Does not include off-grid PV. Based on annual PV shipments from 1989 through 2005, EIA estimates that as much as 192 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2005, plus an additional 481 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 10.8 (annual PV shipments, 1989-2005). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
85. Previous *AEO*s did not consider State RPS requirements.
86. Wind capacity is more than double the 2030 level projected in *AEO2007*.
87. Imperial Oil Resources Ventures, Ltd., "Mackenzie Gas Project: Supplemental Information Project Update," National Energy Board Submission IPRCC. PR.07.08 (Calgary, Alberta, Canada, May 2007).
88. CAIR mandates SO_2 emissions caps in 28 eastern and midwestern States and the District of Columbia. The first compliance period begins in 2010, and a second, more stringent cap takes effect in 2015.
89. The first milestone for reducing NO_x emissions from electric power generation becomes effective in 2009. A lower limit is mandated for 2015.

Comparison with Other Projections

90. *AEO2008* also includes the CAMR regulations. On February 8, 2008, the U.S. Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proved that mercury was a pollutant eligible for regulation under a less stringent portion of the Clean Air Act; however, EIA did not have time to revise *AEO2008* before publication to remove the impact of CAMR.
91. Although neither EVA nor GII provided projections for coal consumption at CTL plants, the lack of growth in coal consumption in non-electricity sectors indicates that this technology is either not represented explicitly by the models or, alternatively, that very little CTL capacity is projected to come on line.

Table Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and D of this report.

Table 1. Total energy supply and disposition in the *AEO2008* and *AEO2007* reference cases, 2006-2030: *AEO2007*: AEO2007 National Energy Modeling System, run AEO2007.D112106A. ***AEO2008*:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **Notes:** Quantities are derived from historical volumes and assumed thermal conversion factors. Other production includes liquid hydrogen, methanol, and some inputs to refineries. Net imports of petroleum include crude oil, petroleum products, unfinished oils, alcohols, ethers, and blending components. Other net imports include coal coke and electricity.

Table 2. Representative efficiency standards for enclosed motors: National Electrical Manufacturers Association, *NEMA Summary and Analysis of Energy Independence and Secrurity Act of 2007*, Appendix II, Section 313—Electrical Motor Efficiency, web site www.nema.org/gov/energy/upload/NEMA-Summary-and-Analysis-of-the-Energy-Independence-and-Security-Act-of-2007.pdf.

Table 3. Summary of DOE's August 2006 loan guarantee solicitation: U.S. Department of Energy, *DOE Releases Information on Loan Guarantee Pre-Applications*

(March 6, 2007), web site www.lgprogram.energy.gov/press/030607.html.

Table 4. State renewable portfolio standards: Energy Information Administration, Office of Integrated Analysis and Forecasting.

Table 5. Key analyses from "Issues in Focus" in recent *AEOs*: Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (Washington, DC, February 2007); Energy Information Administration, *Annual Energy Outlook 2006*, DOE/EIA-0383(2006) (Washington, DC, February 2006); Energy Information Administration, *Annual Energy Outlook 2005*, DOE/EIA-0383 (2005) (Washington, DC, February 2005).

Table 6. Costs of producing electricity from new plants, 2015 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure Notes and Sources

Note: Tables indicated as sources in these notes refer to the tables in Appendixes A, B, C, and D of this report.

Figure 1. Energy prices, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A1.

Figure 2. Delivered energy consumption by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A2.

Figure 3. Energy consumption by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Tables A1 and A17.

Figure 4. Energy use per capita and per dollar of gross domestic product, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections: Energy use per capita:** Calculated from data in Table A2. **Energy use per dollar of GDP:** Table A19.

Figure 5. Total energy production and consumption, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A1.

Figure 6. Energy production by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Tables A1 and A17.

Figure 7. Electricity generation by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A8.

Figure 8. U.S. carbon dioxide emissions by sector and fuel, 1990-2030: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** Table A18.

Figure 9. Changes in construction commodity costs, 1973-2007: U.S. Department of Labor, Bureau of Labor Statistics, Producer Price Index for WPU112 (construction), WPU101 (iron and steel), WPU133 (concrete), and WPU1322 (cement).

Figure 10. Changes in construction commodity costs and electric utility construction costs, 1973-2007: *Handy-Whitman Bulletin*, No. 165, "Cost Trends of Electric Utility Construction"; and U.S. Department of Labor, Bureau of Labor Statistics, Producer Price Index, Series ID WPU112.

Figure 11. Additions to U.S. electricity generation capacity by fuel in three cases, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 12. U.S. natural gas supply by source in three cases, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 13. U.S. natural gas consumption by sector in three cases, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 14. U.S. natural gas prices in three cases, 2000-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LC2008.D030308A, and HC2008.D030308A.

Figure 15. Electricity generation by fuel in four cases, 2006 and 2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 16. New generating capacity additions in four cases, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 17. Natural gas consumption by sector in four cases, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 18. Natural gas supply by source in four cases, 2006 and 2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 19. Lower 48 wellhead natural gas prices in four cases, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 20. U.S. average electricity prices in four cases, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F,

HIGASDEM.D030408A, LOGASSUP.D030408A, and HDEMLSUP.D030408A.

Figure 21. Annual heating and cooling degree-days, 1993-2007: Energy Information Administration, Short-Term Energy Outlook On-Line Table Browser (February 26, 2007).

Figure 22. Heating and cooling degree-days in the *AEO2008* reference case, 2010-2030: National Energy Modeling System runs AEO2008.D030208F and WEATHER.D030408A, based on weather data from NOAA and State population projections from the Census Bureau.

Figure 23. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on energy use for heating and cooling in buildings by fuel type, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F and WEATHER.D030408A.

Figure 24. Impacts of change from 30-year to 10-year average for heating and cooling degree-days on peak seasonal electricity demand load, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F and WEATHER.D030408A.

Figure 25. U.S. imports of liquefied natural gas, 2001-2007: Energy Information Administration, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007).

Figure 26. OECD Europe natural gas supply by source, 2000-2007: International Energy Agency, Monthly Gas Data Service.

Figure 27. Gross U.S. imports of liquefied natural gas in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LOLNG08.D030508A, and HILNG08.D030508A.

Figure 28. U.S. natural gas supply in three cases, 2006-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LOLNG08.D030508A, and HILNG08.D030508A.

Figure 29. Lower 48 wellhead natural gas prices in three cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LOLNG08.D030508A, and HILNG08.D030508A.

Figure 30. World oil price in six cases, 2000-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LP2008.D031608A, HP2008.D031808A, AEO2007.D112106A, LP2007.D112106A, and HP2008.D112106A.

Figure 31. World liquids consumption in the *AEO2008* reference case, 2006-2030: Table A20.

Figure 32. Average annual growth rates of real GDP, labor force, and productivity, 2006-2030: Table B4.

Figure 33. Average annual inflation, interest, and unemployment rates, 2006-2030: Table B4.

Figure 34. Sectoral composition of industrial output growth rates, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 35. Energy expenditures in the U.S. economy, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 36. Energy expenditures as share of gross domestic product, 1970-2030: History: U.S. Department of Commerce, Bureau of Economic Analysis; and Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 37. World oil prices, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table C1.

Figure 38. Unconventional resources as a share of the world liquids market, 1990-2030: History: Derived from Energy Information Administration, *International Energy Annual 2005* (June-October 2007), Table G.4, web site www.eia.doe.gov/iea. **Projections:** Table A20. **Note:** Data from Table G.4 are used as a proxy for historical unconventional oil production, because international data are limited. In addition, estimates of historical production from Canadian oil sands and Venezuelan ultra-heavy oil were added to Table G.4. Assumptions about future unconventional oil production are based on current investment reports, published production targets, resource availabilities, and marketplace competition.

Figure 39. World liquids production shares by region, 2006 and 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, and LP2008.D031608A.

Figure 40. Energy use per capita and per dollar of gross domestic product, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections: Energy use per capita:** Calculated from data in Table A2. **Energy use per dollar of GDP:** Table A19.

Figure 41. Primary energy use by fuel, 2006-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Tables A1 and A17.

Figure 42. Delivered energy use by fuel, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A2.

Figure 43. Primary energy consumption by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A2.

Figure 44. Residential delivered energy consumption per capita, 1990-2030: History: Energy Information Administration, "State Energy Consumption, Price, and Expenditure Estimates (SEDS)," (Washington, DC, October 2007), web site www.eia.doe.gov/emeu/states/_seds.html, and *Annual Energy Review 2006*, DOE/EIA-0384

(2006) (Washington, DC, June 2007). **Projections:** AEO-2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDHIGH.D030408A.

Figure 45. Residential delivered energy consumption by fuel, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 46. Efficiency gains for selected residential appliances, 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004); and AEO-2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDBEST.D030408A.

Figure 47. Electricity consumption for residential lighting, 2006-2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004); and AEO-2008 National Energy Modeling System, runs AEO2008.D030208F and AEO2008.D112607A.

Figure 48. Commercial delivered energy consumption per capita, 1980-2030: History: Energy Information Administration, "State Energy Consumption, Price, and Expenditure Estimates (SEDS)" (Washington, DC, October 2007), web site www.eia.doe.gov/emeu/states/_seds.html, and *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO-2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDHIGH.D030408A.

Figure 49. Commercial delivered energy consumption by fuel, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 50. Efficiency gains for selected commercial equipment, 2006 and 2030: Energy Information Administration, *Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004); and AEO2008 National Energy Modeling System, runs AEO2008.D030208F, BLDFRZN.D030408A, and BLDBEST.D030408A.

Figure 51. Industrial delivered energy consumption, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 52. Industrial energy consumption by fuel, 2000, 2006, and 2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO-2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 53. Average growth in value of shipments for the manufacturing subsectors, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 54. Average growth of delivered energy consumption in the manufacturing subsectors, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 55. Industrial delivered energy intensity, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007); and Global Insight, Inc., *2007 U.S. Energy Outlook* (November 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, INDFRZN.D030608A, and INDHIGH.D032208A.

Figure 56. Delivered energy consumption for transportation, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** Tables B2 and C2.

Figure 57. Average fuel economy of new light-duty vehicles, 1980-2030: History: U.S. Department of Transportation, National Highway Traffic Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2006), web site www.nhtsa.dot.gov/staticfiles/DOT/NHTSA/Vehicle%20Safety/Articles/Associated%20Files/SummaryFuelEconomyPerformance-2006.pdf. **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, AEO2008.D112607A, TRNHIGH.D031408A, HP2008.D031808A, and LP2008.D031608A.

Figure 58. Sales of unconventional light-duty vehicles by fuel type, 2006 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 59. Energy use for light-duty vehicles by fuel type, 2006 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 60. Annual electricity sales by sector, 1980-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A8.

Figure 61. Electricity generation by fuel, 2006 and 2030: Table A8.

Figure 62. Electricity generation capacity additions by fuel type, including combined heat and power, 2007-2030: Table A9.

Figure 63. Levelized electricity costs for new plants, 2015 and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 64. Electricity generation capacity additions, including combined heat and power, by region and fuel, 2007-2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 65. Electricity generation from nuclear power, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, LM2008.D031608A, HP2008.D031808A, and LP2008.D031608A.

Figure 66. Nonhydroelectric renewable electricity generation by energy source, 2006-2030: Table A16.

Figure 67. Grid-connected electricity generation from renewable energy sources, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A16.

Figure 68. Levelized and avoided costs for new renewable plants in the Northwest, 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HIRENCST08.D030408A, and LORENCST08.D030408A.

Figure 69. Regional growth in nonhydroelectic renewable electricity generation, 2006-2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 70. Fuel prices to electricity generators, 1995-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 71. Average U.S. retail electricity prices, 1970-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A8.

Figure 72. Natural gas consumption by sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2004) (Washington, DC, June 2007). **Projections:** Table A13.

Figure 73. Total natural gas consumption, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, HM2008.D031608A, and LM2008.D031608A.

Figure 74. Natural gas consumption in the electric power and non-electric power sectors in alternative price cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, and LP2008.D031608A.

Figure 75. Natural gas consumption in the electric power and non-electric power sectors in alternative growth cases, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HM2008.D031608A, and LM2008.D031608A.

Figure 76. Lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2030: History: For lower 48 wellhead prices: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). For Henry Hub natural gas prices: Energy Information Administration, *Short-Term Energy Outlook* Query System, Monthly Natural Gas Data, Variable NGHHMCF. **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 77. Lower 48 wellhead natural gas prices, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, OGHTEC08.D030508A, and OGLTEC08.D030508A.

Figure 78. Natural gas prices by end-use sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A13.

Figure 79. Average natural gas transmission and distribution margins, 1990-2030: History: Calculated as the difference between natural gas end-use prices and lower 48 wellhead natural gas prices; Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** AEO-2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, and LP2008.D031608A.

Figure 80. Natural gas production by source, 1990-2030: History: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** Table A14.

Figure 81. Total U.S. natural gas production, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, OGHTEC08.D030508A, and OGLTEC08.D030508A.

Figure 82. Net U.S. imports of natural gas by source, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 83. Net U.S. imports of liquefied natural gas, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, LP2008.D031608A, HM2008.D031608A, and LM2008.D031608A.

Figure 84. Domestic crude oil production by source, 1990-2030: History: Energy Information Administration, Office of Integrated Analysis and Forecasting. **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 85. Total U.S. crude oil production, 1990-2030: History: Energy Information Administration, Annual Energy Review 2006, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, OGHTEC08.D030508A, and OGLTEC08.D030508A.

Figure 86. Total U.S. unconventional crude oil production, 2006-2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, HP2008.D031808A, and LP2008.D031608A.

Figure 87. Liquid fuels consumption by sector, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** Table A11.

Figure 88. EISA2007 RFS credits earned in selected years, 2006-2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 89. Fossil fuel and biofuel content of U.S. motor fuel supply, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 90. Net import share of U.S. liquid fuels consumption, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384

(2006) (Washington, DC, June 2007). **Projections:** Table C4.

Figure 91. Motor gasoline, diesel fuel, and E85 prices, 2006-2030: Table A12.

Figure 92. Average U.S. delivered prices for motor gasoline, 1990-2030: History: Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384 (2006) (Washington, DC, June 2007). **Projections:** Table C5.

Figure 93. Coal production by region, 1970-2030: History (short tons): 1970-1990: Energy Information Administration (EIA), *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** EIA, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2006:** EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, October 2007), and previous issues. **History: Conversion to quadrillion Btu), 1970-2006:** Estimation Procedure: EIA, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year are based on coal quality data for 2006, collected in various energy surveys (see sources), and national-level estimates of U.S. coal production by year in units of quadrillion Btu, published in EIA's *Annual Energy Review*. **Sources:** EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **Note:** For 1989-2030, coal production includes waste coal.

Figure 94. U.S. coal production, 2006, 2015, and 2030: AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LP2008.D031608A, HP2008.D031808A, LM2008.D031608A, HM2008.D031608A, LCCST08.D030508A, and HCCST08.D030508A. **Note:** Coal production includes waste coal.

Figure 95. Average minemouth price of coal by region, 1990-2030: History: Dollars per short ton: 1990-2000: Energy Information Administration (EIA), *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2006:** EIA, *Annual Coal Report 2006*, DOE/EIA-0584 (2006) (Washington, DC, October 2007), and previous issues. **Conversion to dollars per million Btu): 1990-2006:** Estimation Procedure: EIA, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year are based on coal quality data for 2006, collected in various energy surveys (see sources), and national-level estimates of U.S. coal production by year in units of quadrillion Btu published in EIA's *Annual Energy Review*. **Sources:** EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 1.2; Form EIA-3, "Quarterly Coal Consumption and Quality Report, Manufacturing Plants"; Form EIA-5, "Quarterly Coal Consumption and Quality Report, Coke Plants"; Form EIA-6A, "Coal Distribution Report"; Form EIA-7A, "Coal Production Report"; Form EIA-423, "Monthly Cost and Quality of Fuels for Electric Plants Report"; Form EIA-906, "Power Plant Report"; Form EIA-920, "Combined Heat and Power Plant Report"; U.S. Department of Commerce, Bureau of the Census, "Monthly Report EM 545"; and Federal Energy Regulatory Commission, Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." **Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F. **Note:** Includes reported prices for both open market and captive mines.

Figure 96. Average delivered coal prices, 1990-2030: History: Energy Information Administration (EIA), *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121 (2006/4Q) (Washington, DC, March 2007), and previous issues; EIA, *Electric Power Monthly*, October 2007, DOE/EIA-0226(2007/10) (Washington, DC, October 2007); and EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** AEO2008 National Energy Modeling System, runs AEO2008.D030208F, LP2008.D031608A, HP2008.D031808A, LCCST08.D030508A, and HCCST08.D030508A. **Note:** Historical prices are weighted by consumption but exclude residential/commercial prices and export free-alongside-ship (f.a.s.) prices.

Figure 97. Carbon dioxide emissions by sector and fuel, 2006 and 2030: 2006: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **2030:** Table A18.

Figure 98. Carbon dioxide emissions, 1990-2030: History: Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** Table B2.

Figure 99. Sulfur dioxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2006 and Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Figure 100. Nitrogen oxide emissions from electricity generation, 1995-2030: History: 1995: U.S. Environmental Protection Agency, *National Air Pollutant Emissions Trends, 1990-1998*, EPA-454/R-00-002 (Washington, DC, March 2000). **2000:** U.S. Environmental Protection Agency, *Acid Rain Program Preliminary Summary Emissions Report, Fourth Quarter 2004*, web site www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2006 and Projections:** AEO2008 National Energy Modeling System, run AEO2008.D030208F.

Appendixes

Table A1. Total Energy Supply and Disposition Summary
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Production								
Crude Oil and Lease Condensate	10.99	10.80	12.76	13.25	13.40	12.99	12.04	0.5%
Natural Gas Plant Liquids	2.33	2.36	2.27	2.29	2.31	2.17	2.11	-0.5%
Dry Natural Gas	18.60	19.04	19.85	20.08	20.24	20.17	20.00	0.2%
Coal[1]	23.19	23.79	23.97	24.48	25.20	26.85	28.63	0.8%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Hydropower	2.70	2.89	2.92	2.99	3.00	3.00	3.00	0.2%
Biomass[2]	2.79	2.94	4.05	5.12	6.42	8.00	8.12	4.3%
Other Renewable Energy[3]	0.67	0.88	1.51	1.75	2.00	2.25	2.45	4.4%
Other[4]	0.36	0.50	0.54	0.58	0.58	0.61	0.64	1.1%
Total	**69.80**	**71.41**	**76.17**	**78.96**	**82.21**	**85.53**	**86.56**	**0.8%**
Imports								
Crude Oil	22.09	22.08	21.14	21.80	21.58	22.38	24.41	0.4%
Liquid Fuels and Other Petroleum[5]	7.23	7.21	5.61	5.34	5.43	5.28	5.44	-1.2%
Natural Gas	4.45	4.29	4.80	5.12	4.68	4.63	4.64	0.3%
Other Imports[6]	0.85	0.98	0.95	1.04	1.93	2.23	2.74	4.4%
Total	**34.62**	**34.57**	**32.49**	**33.31**	**33.62**	**34.52**	**37.22**	**0.3%**
Exports								
Petroleum[7]	2.32	2.60	2.82	2.91	2.98	3.17	3.33	1.0%
Natural Gas	0.74	0.73	0.84	0.97	1.02	1.25	1.36	2.6%
Coal	1.27	1.26	1.79	1.14	0.87	0.90	0.88	-1.5%
Total	**4.32**	**4.59**	**5.45**	**5.03**	**4.87**	**5.32**	**5.56**	**0.8%**
Discrepancy[8]	**0.01**	**1.87**	**-0.13**	**-0.01**	**0.12**	**0.19**	**0.21**	**- -**
Consumption								
Liquid Fuels and Other Petroleum[9]	40.47	40.06	40.46	41.80	42.24	42.78	43.99	0.4%
Natural Gas	22.65	22.30	23.93	24.35	24.01	23.66	23.39	0.2%
Coal[10]	22.78	22.50	23.03	24.19	25.87	27.75	29.90	1.2%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Hydropower	2.70	2.89	2.92	2.99	3.00	3.00	3.00	0.2%
Biomass[11]	2.45	2.50	3.01	3.60	4.50	5.42	5.51	3.3%
Other Renewable Energy[3]	0.67	0.88	1.51	1.75	2.00	2.25	2.45	4.4%
Other[12]	0.21	0.19	0.18	0.17	0.17	0.18	0.20	0.3%
Total	**100.08**	**99.52**	**103.34**	**107.26**	**110.85**	**114.54**	**118.01**	**0.7%**

Table A1. Total Energy Supply and Disposition Summary (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Prices (2006 dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price	58.28	66.02	74.03	59.85	59.70	64.49	70.45	0.3%
Imported Crude Oil Price[13]	50.40	59.05	65.18	52.03	51.55	55.68	58.66	-0.0%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	8.93	6.73	6.90	5.87	5.95	6.39	7.22	0.3%
Wellhead Price[14]	7.62	6.24	6.16	5.21	5.29	5.69	6.45	0.1%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	7.85	6.42	6.33	5.36	5.44	5.86	6.63	0.1%
Coal (dollars per ton)								
Minemouth Price[15]	24.08	24.63	26.16	23.38	22.51	22.75	23.32	-0.2%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.18	1.21	1.28	1.17	1.14	1.16	1.19	-0.1%
Average Delivered Price[16]	1.67	1.78	1.93	1.80	1.77	1.78	1.82	0.1%
Average Electricity Price (cents per kilowatthour)	8.4	8.9	9.2	8.5	8.6	8.7	8.8	-0.0%

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol, biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 natural gas supply values: Energy Information Administration (EIA), *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 natural gas wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2005 and 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values and 2005 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). Other 2005 petroleum supply values: EIA, *Petroleum Supply Annual 2005,* DOE/EIA-0340(2005)/1 (Washington, DC, October 2006). 2005 and 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2005 and 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2005 and 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

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

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Energy Consumption								
Residential								
Liquefied Petroleum Gases	0.50	0.47	0.48	0.50	0.52	0.54	0.55	0.7%
Kerosene	0.09	0.07	0.08	0.08	0.08	0.08	0.08	0.5%
Distillate Fuel Oil	0.85	0.70	0.75	0.75	0.73	0.69	0.65	-0.3%
Liquid Fuels and Other Petroleum Subtotal	1.45	1.25	1.31	1.33	1.33	1.31	1.29	0.1%
Natural Gas	4.97	4.50	4.95	5.16	5.30	5.35	5.32	0.7%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-0.4%
Renewable Energy[1]	0.45	0.41	0.44	0.42	0.40	0.39	0.38	-0.3%
Electricity	4.64	4.61	4.95	5.02	5.25	5.53	5.88	1.0%
Delivered Energy	**11.52**	**10.77**	**11.66**	**11.95**	**12.30**	**12.58**	**12.88**	**0.7%**
Electricity Related Losses	10.12	10.04	10.59	10.61	11.08	11.57	12.14	0.8%
Total	**21.64**	**20.82**	**22.25**	**22.56**	**23.39**	**24.15**	**25.01**	**0.8%**
Commercial								
Liquefied Petroleum Gases	0.09	0.08	0.09	0.09	0.09	0.09	0.09	0.6%
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.4%
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.2%
Distillate Fuel Oil	0.45	0.42	0.38	0.41	0.41	0.42	0.41	-0.0%
Residual Fuel Oil	0.12	0.11	0.10	0.10	0.10	0.10	0.10	-0.4%
Liquid Fuels and Other Petroleum Subtotal	0.72	0.68	0.63	0.67	0.68	0.68	0.68	0.0%
Natural Gas	3.09	2.92	3.04	3.29	3.47	3.63	3.78	1.1%
Coal	0.09	0.08	0.08	0.08	0.08	0.08	0.08	-0.1%
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	- -
Electricity	4.35	4.43	4.73	5.19	5.67	6.15	6.62	1.7%
Delivered Energy	**8.38**	**8.25**	**8.62**	**9.37**	**10.03**	**10.67**	**11.30**	**1.3%**
Electricity Related Losses	9.50	9.66	10.12	10.98	11.96	12.87	13.68	1.5%
Total	**17.87**	**17.91**	**18.74**	**20.34**	**21.98**	**23.54**	**24.98**	**1.4%**
Industrial[4]								
Liquefied Petroleum Gases	2.07	2.09	2.12	1.97	1.83	1.74	1.71	-0.8%
Motor Gasoline[2]	0.37	0.38	0.38	0.37	0.37	0.38	0.38	0.1%
Distillate Fuel Oil	1.26	1.28	1.29	1.25	1.23	1.22	1.23	-0.2%
Residual Fuel Oil	0.28	0.28	0.28	0.25	0.23	0.23	0.23	-0.9%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Other Petroleum[5]	4.39	4.48	4.25	4.30	4.22	4.25	4.41	-0.1%
Liquid Fuels and Other Petroleum Subtotal	9.79	9.92	9.67	9.60	9.27	9.15	9.25	-0.3%
Natural Gas	6.79	6.68	7.16	7.21	7.14	7.17	7.08	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Natural Gas Subtotal	7.93	7.85	8.37	8.43	8.39	8.44	8.35	0.3%
Metallurgical Coal	0.62	0.60	0.60	0.54	0.54	0.52	0.48	-0.9%
Other Industrial Coal	1.28	1.26	1.31	1.22	1.20	1.19	1.18	-0.3%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	- -
Net Coal Coke Imports	0.04	0.06	0.03	0.03	0.04	0.04	0.04	-1.8%
Coal Subtotal	1.94	1.92	1.93	1.92	2.11	2.14	2.26	0.7%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewable Energy[7]	1.64	1.69	1.66	1.75	1.83	1.93	2.02	0.7%
Electricity	3.48	3.42	3.50	3.61	3.59	3.55	3.52	0.1%
Delivered Energy	**25.03**	**25.10**	**25.82**	**26.31**	**26.70**	**27.50**	**27.70**	**0.4%**
Electricity Related Losses	7.59	7.45	7.50	7.63	7.57	7.43	7.28	-0.1%
Total	**32.62**	**32.55**	**33.32**	**33.93**	**34.27**	**34.93**	**34.98**	**0.3%**

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

Sector and Source	Reference Case 2005	2006	2010	2015	2020	2025	2030	Annual Growth 2006-2030 (percent)
Transportation								
Liquefied Petroleum Gases	0.01	0.02	0.02	0.01	0.01	0.01	0.01	-1.0%
E85[8]	0.00	0.00	0.00	0.18	0.97	1.42	1.34	33.5%
Motor Gasoline[2]	17.02	17.20	17.25	17.46	16.56	15.83	15.97	-0.3%
Jet Fuel[9]	3.22	3.16	3.44	3.82	4.15	4.48	4.79	1.8%
Distillate Fuel Oil[10]	5.99	6.18	6.54	7.13	7.63	8.25	8.98	1.6%
Residual Fuel Oil	0.83	0.83	0.85	0.85	0.86	0.86	0.87	0.2%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.8%
Other Petroleum[11]	0.19	0.18	0.17	0.18	0.18	0.18	0.18	0.0%
Liquid Fuels and Other Petroleum Subtotal	27.26	27.57	28.29	29.63	30.37	31.03	32.15	0.6%
Pipeline Fuel Natural Gas	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Compressed Natural Gas	0.02	0.02	0.04	0.06	0.07	0.08	0.08	6.0%
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	1.3%
Delivered Energy	**27.90**	**28.20**	**28.98**	**30.37**	**31.15**	**31.86**	**32.98**	**0.7%**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.06	0.06	1.1%
Total	**27.95**	**28.25**	**29.03**	**30.42**	**31.21**	**31.92**	**33.04**	**0.7%**
Delivered Energy Consumption for All Sectors								
Liquefied Petroleum Gases	2.68	2.65	2.70	2.57	2.45	2.39	2.37	-0.5%
E85[8]	0.00	0.00	0.00	0.18	0.97	1.42	1.34	33.5%
Motor Gasoline[2]	17.44	17.62	17.68	17.89	16.99	16.26	16.40	-0.3%
Jet Fuel[9]	3.22	3.16	3.44	3.82	4.15	4.48	4.79	1.8%
Kerosene	0.14	0.11	0.12	0.12	0.13	0.13	0.13	0.4%
Distillate Fuel Oil	8.56	8.59	8.97	9.55	10.00	10.58	11.28	1.1%
Residual Fuel Oil	1.22	1.23	1.23	1.21	1.19	1.19	1.20	-0.1%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.8%
Other Petroleum[12]	4.55	4.64	4.40	4.45	4.38	4.41	4.56	-0.1%
Liquid Fuels and Other Petroleum Subtotal	39.23	39.41	39.90	41.23	41.65	42.17	43.37	0.4%
Natural Gas	14.86	14.12	15.19	15.72	15.98	16.22	16.27	0.6%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Pipeline Natural Gas	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Natural Gas Subtotal	16.61	15.88	17.04	17.60	17.93	18.22	18.26	0.6%
Metallurgical Coal	0.62	0.60	0.60	0.54	0.54	0.52	0.48	-0.9%
Other Coal	1.38	1.35	1.40	1.31	1.29	1.28	1.27	-0.3%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	- -
Net Coal Coke Imports	0.04	0.06	0.03	0.03	0.04	0.04	0.04	-1.8%
Coal Subtotal	2.04	2.01	2.03	2.01	2.21	2.23	2.35	0.6%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewable Energy[13]	2.22	2.23	2.23	2.29	2.37	2.45	2.52	0.5%
Electricity	12.49	12.49	13.20	13.85	14.54	15.26	16.05	1.1%
Delivered Energy	**72.82**	**72.32**	**75.08**	**77.99**	**80.18**	**82.61**	**84.86**	**0.7%**
Electricity Related Losses	27.26	27.19	28.26	29.27	30.67	31.93	33.16	0.8%
Total	**100.08**	**99.52**	**103.34**	**107.26**	**110.85**	**114.54**	**118.01**	**0.7%**
Electric Power[14]								
Distillate Fuel Oil	0.21	0.18	0.18	0.18	0.20	0.21	0.23	0.9%
Residual Fuel Oil	1.03	0.46	0.38	0.39	0.39	0.40	0.40	-0.6%
Liquid Fuels and Other Petroleum Subtotal	1.24	0.64	0.56	0.57	0.59	0.61	0.63	-0.1%
Natural Gas	6.04	6.42	6.89	6.75	6.09	5.45	5.13	-0.9%
Steam Coal	20.74	20.48	21.01	22.18	23.67	25.51	27.55	1.2%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Renewable Energy[15]	3.49	3.74	4.53	5.05	5.64	5.94	6.13	2.1%
Electricity Imports	0.08	0.06	0.05	0.04	0.04	0.05	0.08	1.0%
Total[16]	**39.73**	**39.68**	**41.46**	**43.12**	**45.21**	**47.19**	**49.21**	**0.9%**

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

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Total Energy Consumption								
Liquefied Petroleum Gases	2.68	2.65	2.70	2.57	2.45	2.39	2.37	-0.5%
E85[8]	0.00	0.00	0.00	0.18	0.97	1.42	1.34	33.5%
Motor Gasoline[2]	17.44	17.62	17.68	17.89	16.99	16.26	16.40	-0.3%
Jet Fuel[9]	3.22	3.16	3.44	3.82	4.15	4.48	4.79	1.8%
Kerosene	0.14	0.11	0.12	0.12	0.13	0.13	0.13	0.4%
Distillate Fuel Oil	8.76	8.77	9.15	9.73	10.20	10.79	11.51	1.1%
Residual Fuel Oil	2.26	1.69	1.60	1.59	1.58	1.59	1.60	-0.2%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.8%
Other Petroleum[12]	4.55	4.64	4.40	4.45	4.38	4.41	4.56	-0.1%
Liquid Fuels and Other Petroleum Subtotal	40.47	40.06	40.46	41.80	42.24	42.78	43.99	0.4%
Natural Gas	20.90	20.54	22.08	22.47	22.07	21.67	21.40	0.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Lease and Plant Fuel[6]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Pipeline Natural Gas	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Natural Gas Subtotal	22.65	22.30	23.93	24.35	24.01	23.66	23.39	0.2%
Metallurgical Coal	0.62	0.60	0.60	0.54	0.54	0.52	0.48	-0.9%
Other Coal	22.12	21.83	22.41	23.49	24.96	26.79	28.82	1.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	- -
Net Coal Coke Imports	0.04	0.06	0.03	0.03	0.04	0.04	0.04	-1.8%
Coal Subtotal	22.78	22.49	23.03	24.19	25.87	27.75	29.90	1.2%
Nuclear Power	8.16	8.21	8.31	8.41	9.05	9.50	9.57	0.6%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewable Energy[17]	5.71	5.97	6.76	7.34	8.01	8.39	8.66	1.6%
Electricity Imports	0.08	0.06	0.05	0.04	0.04	0.05	0.08	1.0%
Total	**100.08**	**99.52**	**103.34**	**107.26**	**110.85**	**114.54**	**118.01**	**0.7%**
Energy Use and Related Statistics								
Delivered Energy Use	72.82	72.32	75.08	77.99	80.18	82.61	84.86	0.7%
Total Energy Use	100.08	99.52	103.34	107.26	110.85	114.54	118.01	0.7%
Ethanol Consumed in Motor Gasoline and E85	0.34	0.47	1.05	1.34	1.82	2.06	2.01	6.2%
Population (millions)	297.34	300.13	310.85	324.29	337.74	351.41	365.59	0.8%
Gross Domestic Product (billion 2000 dollars)	11004	11319	12453	14199	15984	17951	20219	2.4%
Carbon Dioxide Emissions (million metric tons)	5981.5	5890.3	6010.6	6226.2	6384.1	6570.6	6851.0	0.6%

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, 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 ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic and solar thermal sources. Includes petroleum coke used in the electric power sector. Excludes ethanol, 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.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 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: 2005 and 2006 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 population and gross domestic product: Global Insight, Global Insight Industry and Employment models, July 2007. 2005 and 2006 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2006,* DOE/EIA-0573(2006) (Washington, DC, November 2007).
Projections: EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A3. Energy Prices by Sector and Source
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Residential								
Liquefied Petroleum Gases	18.83	23.08	25.21	24.15	24.23	24.63	25.43	0.4%
Distillate Fuel Oil	16.98	17.94	17.21	14.27	14.27	15.14	16.27	-0.4%
Natural Gas	12.85	13.40	12.15	11.20	11.39	11.94	12.91	-0.2%
Electricity	28.52	30.52	31.37	30.04	30.20	30.33	30.63	0.0%
Commercial								
Distillate Fuel Oil	13.82	14.59	15.24	12.88	13.24	13.88	15.00	0.1%
Residual Fuel Oil	11.21	8.60	10.06	7.95	7.95	8.62	9.22	0.3%
Natural Gas	11.53	11.50	10.59	9.68	9.91	10.47	11.43	-0.0%
Electricity	26.12	27.75	27.89	25.52	25.64	25.71	26.17	-0.2%
Industrial[1]								
Liquefied Petroleum Gases	17.54	19.71	17.74	16.65	16.79	17.10	17.79	-0.4%
Distillate Fuel Oil	14.50	15.33	15.72	13.95	14.62	15.10	16.26	0.2%
Residual Fuel Oil	10.43	9.06	10.86	8.24	8.29	9.00	9.62	0.2%
Natural Gas[2]	8.37	7.66	7.21	6.15	6.21	6.56	7.29	-0.2%
Metallurgical Coal	3.29	3.54	4.07	3.53	3.42	3.51	3.60	0.1%
Other Industrial Coal	2.22	2.34	2.42	2.31	2.28	2.30	2.33	-0.0%
Coal for Liquids	- -	- -	- -	0.96	1.09	1.17	1.30	- -
Electricity	17.25	17.97	19.21	17.22	17.27	17.30	17.63	-0.1%
Transportation								
Liquefied Petroleum Gases[3]	20.49	21.72	26.03	24.93	24.94	25.28	26.03	0.8%
E85[4]	23.89	24.81	23.58	17.61	18.15	18.50	19.62	-1.0%
Motor Gasoline[5]	19.28	21.19	21.23	18.80	19.64	19.67	20.37	-0.2%
Jet Fuel[6]	13.30	14.83	15.77	13.16	13.27	14.15	15.37	0.1%
Diesel Fuel (distillate fuel oil)[7]	18.09	19.72	19.68	17.65	18.26	18.54	19.59	-0.0%
Residual Fuel Oil	8.68	7.89	10.53	8.56	8.69	9.50	10.39	1.2%
Natural Gas[8]	14.55	14.28	13.60	12.34	12.15	12.28	12.83	-0.4%
Electricity	30.79	29.73	30.95	28.95	29.05	28.95	29.65	-0.0%
Electric Power[9]								
Distillate Fuel Oil	12.62	13.35	13.62	10.67	10.69	11.59	12.71	-0.2%
Residual Fuel Oil	7.40	8.17	9.45	7.41	7.50	8.25	9.04	0.4%
Natural Gas	8.44	6.87	6.96	5.93	5.95	6.26	6.93	0.0%
Steam Coal	1.59	1.69	1.84	1.74	1.72	1.74	1.78	0.2%
Average Price to All Users[10]								
Liquefied Petroleum Gases	17.75	20.35	19.27	18.32	18.59	19.03	19.82	-0.1%
E85[4]	23.89	24.81	23.58	17.61	18.15	18.50	19.62	-1.0%
Motor Gasoline[5]	19.18	21.06	21.23	18.80	19.64	19.67	20.37	-0.1%
Jet Fuel	13.30	14.83	15.77	13.16	13.27	14.15	15.37	0.1%
Distillate Fuel Oil	17.11	18.56	18.48	16.57	17.20	17.62	18.74	0.0%
Residual Fuel Oil	8.44	8.21	10.31	8.19	8.29	9.06	9.87	0.8%
Natural Gas	9.93	9.22	8.72	7.78	7.98	8.49	9.36	0.1%
Metallurgical Coal	3.29	3.54	4.07	3.53	3.42	3.51	3.60	0.1%
Other Coal	1.63	1.73	1.88	1.77	1.75	1.77	1.81	0.2%
Coal for Liquids	- -	- -	- -	0.96	1.09	1.17	1.30	- -
Electricity	24.55	26.10	26.90	25.00	25.23	25.43	25.93	-0.0%

Table A3. Energy Prices by Sector and Source (Continued)
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Non-Renewable Energy Expenditures by Sector (billion 2006 dollars)								
Residential	221.30	225.38	241.71	232.60	243.22	256.33	274.70	0.8%
Commercial	159.35	166.54	174.38	173.76	189.37	206.24	227.37	1.3%
Industrial	203.06	205.11	224.65	197.41	193.16	194.97	203.93	-0.0%
Transportation	489.23	542.63	560.74	514.93	530.80	539.68	587.86	0.3%
Total Non-Renewable Expenditures	1072.94	1139.66	1201.48	1118.69	1156.54	1197.22	1293.86	0.5%
Transportation Renewable Expenditures	0.03	0.03	0.06	3.14	17.64	26.21	26.35	32.2%
Total Expenditures	**1072.96**	**1139.70**	**1201.54**	**1121.83**	**1174.18**	**1223.43**	**1320.22**	**0.6%**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]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.
- - = Not applicable.
Note: Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 and 2006 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and estimated state taxes, federal taxes, and dispensing costs or charges. 2006 transportation sector natural gas delivered prices are model results. 2005 and 2006 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2003 through April 2004, Table 4.11.A. 2005 and 2006 coal prices based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2005 and 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A4. Residential Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Households (millions)								
Single-Family	79.65	80.81	83.48	88.66	93.38	97.49	101.28	0.9%
Multifamily	24.49	24.81	25.86	27.42	29.05	30.69	32.44	1.1%
Mobile Homes	6.94	6.89	6.67	6.65	6.73	6.78	6.86	-0.0%
Total	**111.09**	**112.51**	**116.00**	**122.73**	**129.15**	**134.96**	**140.58**	**0.9%**
Average House Square Footage	**1802**	**1815**	**1858**	**1916**	**1965**	**2008**	**2046**	**0.5%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	103.7	95.8	100.5	97.3	95.3	93.2	91.6	-0.2%
Total Energy Consumption	194.8	185.0	191.8	183.8	181.1	179.0	177.9	-0.2%
(thousand Btu per square foot)								
Delivered Energy Consumption	57.5	52.8	54.1	50.8	48.5	46.4	44.8	-0.7%
Total Energy Consumption	108.1	101.9	103.2	95.9	92.1	89.1	87.0	-0.7%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.31	0.27	0.30	0.32	0.32	0.33	0.33	0.8%
Space Cooling	0.82	0.75	0.79	0.85	0.91	0.97	1.04	1.4%
Water Heating	0.38	0.38	0.38	0.40	0.42	0.43	0.43	0.5%
Refrigeration	0.39	0.39	0.37	0.36	0.37	0.38	0.39	0.0%
Cooking	0.10	0.10	0.11	0.12	0.12	0.13	0.14	1.2%
Clothes Dryers	0.25	0.25	0.25	0.26	0.27	0.28	0.30	0.6%
Freezers	0.08	0.08	0.08	0.08	0.09	0.10	0.11	1.3%
Lighting	0.73	0.74	0.72	0.55	0.51	0.47	0.49	-1.7%
Clothes Washers[1]	0.03	0.04	0.03	0.03	0.03	0.03	0.03	-1.1%
Dishwashers[1]	0.10	0.10	0.09	0.09	0.10	0.10	0.11	0.4%
Color Televisions and Set-Top Boxes	0.30	0.33	0.39	0.40	0.43	0.48	0.55	2.2%
Personal Computers	0.07	0.07	0.10	0.11	0.12	0.14	0.16	3.6%
Furnace Fans	0.06	0.05	0.06	0.07	0.07	0.08	0.08	1.6%
Other Uses[2]	1.01	1.05	1.26	1.37	1.49	1.61	1.73	2.1%
Delivered Energy	**4.64**	**4.61**	**4.95**	**5.02**	**5.25**	**5.53**	**5.88**	**1.0%**
Natural Gas								
Space Heating	3.59	3.13	3.57	3.73	3.83	3.87	3.88	0.9%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.1%
Water Heating	1.09	1.08	1.08	1.12	1.15	1.14	1.09	0.1%
Cooking	0.22	0.22	0.22	0.24	0.25	0.26	0.26	0.8%
Clothes Dryers	0.07	0.07	0.07	0.08	0.08	0.08	0.08	0.6%
Delivered Energy	**4.97**	**4.50**	**4.95**	**5.16**	**5.30**	**5.35**	**5.32**	**0.7%**
Distillate Fuel Oil								
Space Heating	0.75	0.60	0.66	0.66	0.65	0.62	0.59	-0.1%
Water Heating	0.11	0.10	0.09	0.09	0.08	0.08	0.07	-1.8%
Delivered Energy	**0.85**	**0.70**	**0.75**	**0.75**	**0.73**	**0.69**	**0.65**	**-0.3%**
Liquefied Petroleum Gases								
Space Heating	0.26	0.23	0.24	0.24	0.24	0.23	0.23	0.0%
Water Heating	0.06	0.06	0.05	0.05	0.05	0.04	0.04	-1.1%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.3%
Other Uses[3]	0.15	0.15	0.16	0.18	0.20	0.22	0.25	2.0%
Delivered Energy	**0.50**	**0.47**	**0.48**	**0.50**	**0.52**	**0.54**	**0.55**	**0.7%**
Marketed Renewables (wood)[4]	0.45	0.41	0.44	0.42	0.40	0.39	0.38	-0.3%
Other Fuels[5]	0.10	0.08	0.09	0.09	0.09	0.09	0.09	0.4%

Table A4. Residential Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Delivered Energy Consumption by End Use								
Space Heating	5.46	4.72	5.30	5.46	5.53	5.53	5.50	0.6%
Space Cooling	0.82	0.75	0.79	0.85	0.91	0.97	1.04	1.4%
Water Heating	1.64	1.62	1.61	1.66	1.70	1.69	1.63	0.0%
Refrigeration	0.39	0.39	0.37	0.36	0.37	0.38	0.39	0.0%
Cooking	0.35	0.35	0.36	0.38	0.41	0.42	0.43	0.9%
Clothes Dryers	0.32	0.33	0.33	0.34	0.35	0.36	0.38	0.6%
Freezers	0.08	0.08	0.08	0.08	0.09	0.10	0.11	1.3%
Lighting	0.73	0.74	0.72	0.55	0.51	0.47	0.49	-1.7%
Clothes Washers	0.03	0.04	0.03	0.03	0.03	0.03	0.03	-1.1%
Dishwashers	0.10	0.10	0.09	0.09	0.10	0.10	0.11	0.4%
Color Televisions and Set-Top Boxes	0.30	0.33	0.39	0.40	0.43	0.48	0.55	2.2%
Personal Computers	0.07	0.07	0.10	0.11	0.12	0.14	0.16	3.6%
Furnace Fans	0.06	0.05	0.06	0.07	0.07	0.08	0.08	1.6%
Other Uses[6]	1.16	1.21	1.42	1.56	1.69	1.83	1.98	2.1%
Delivered Energy	**11.52**	**10.77**	**11.66**	**11.95**	**12.30**	**12.58**	**12.88**	**0.7%**
Electricity Related Losses	**10.12**	**10.04**	**10.59**	**10.61**	**11.08**	**11.57**	**12.14**	**0.8%**
Total Energy Consumption by End Use								
Space Heating	6.14	5.31	5.95	6.13	6.21	6.22	6.18	0.6%
Space Cooling	2.61	2.39	2.48	2.64	2.83	3.01	3.19	1.2%
Water Heating	2.47	2.44	2.43	2.51	2.59	2.59	2.52	0.1%
Refrigeration	1.26	1.24	1.15	1.12	1.14	1.16	1.20	-0.1%
Cooking	0.57	0.58	0.60	0.63	0.67	0.70	0.72	0.9%
Clothes Dryers	0.88	0.88	0.87	0.90	0.92	0.95	0.99	0.5%
Freezers	0.27	0.26	0.25	0.26	0.29	0.31	0.34	1.1%
Lighting	2.31	2.35	2.26	1.71	1.58	1.47	1.49	-1.9%
Clothes Washers	0.11	0.11	0.10	0.09	0.08	0.08	0.08	-1.2%
Dishwashers	0.31	0.30	0.29	0.29	0.30	0.31	0.33	0.3%
Color Televisions and Set-Top Boxes	0.95	1.05	1.23	1.26	1.33	1.49	1.69	2.0%
Personal Computers	0.21	0.21	0.30	0.34	0.38	0.43	0.48	3.5%
Furnace Fans	0.19	0.17	0.20	0.21	0.23	0.24	0.24	1.5%
Other Uses[6]	3.37	3.50	4.13	4.46	4.84	5.19	5.55	1.9%
Total	**21.64**	**20.82**	**22.25**	**22.56**	**23.39**	**24.15**	**25.01**	**0.8%**
Nonmarketed Renewables[7]								
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.01	0.01	6.1%
Solar Hot Water Heating	0.01	0.01	0.02	0.02	0.03	0.04	0.05	5.3%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.01	16.9%
Total	**0.01**	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.07**	**5.9%**

[1]Does not include water heating portion of load.
[2]Includes small electric devices, heating elements, and motors not listed above.
[3]Includes such appliances as outdoor grills and mosquito traps.
[4]Includes wood used for primary and secondary heating in wood stoves or fireplaces as reported in the *Residential Energy Consumption Survey 2001*.
[5]Includes kerosene and coal.
[6]Includes all other uses listed above.
[7]Represents primary energy displaced.
Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2005 and 2006 based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A5. Commercial Sector Key Indicators and Consumption
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	72.1	73.2	77.2	82.2	87.4	92.9	98.7	1.3%
New Additions	1.6	1.6	1.6	1.8	1.8	2.0	2.1	0.9%
Total	**73.8**	**74.8**	**78.8**	**83.9**	**89.3**	**94.8**	**100.8**	**1.2%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	113.5	110.3	109.3	111.6	112.3	112.6	112.2	0.1%
Electricity Related Losses	128.8	129.1	128.4	130.8	134.0	135.7	135.8	0.2%
Total Energy Consumption	242.3	239.4	237.8	242.4	246.3	248.3	247.9	0.1%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.14	0.13	0.14	0.14	0.14	0.15	0.15	0.5%
Space Cooling[1]	0.52	0.51	0.50	0.52	0.55	0.58	0.61	0.8%
Water Heating[1]	0.16	0.16	0.15	0.16	0.16	0.16	0.16	0.1%
Ventilation	0.19	0.19	0.19	0.20	0.21	0.22	0.23	0.9%
Cooking	0.04	0.04	0.04	0.04	0.04	0.04	0.04	-0.4%
Lighting	1.16	1.15	1.12	1.17	1.22	1.28	1.34	0.7%
Refrigeration	0.23	0.23	0.23	0.24	0.25	0.27	0.28	0.8%
Office Equipment (PC)	0.17	0.21	0.25	0.28	0.30	0.33	0.35	2.1%
Office Equipment (non-PC)	0.39	0.42	0.55	0.68	0.79	0.87	0.92	3.3%
Other Uses[2]	1.34	1.39	1.55	1.77	2.01	2.26	2.54	2.5%
Delivered Energy	**4.35**	**4.43**	**4.73**	**5.19**	**5.67**	**6.15**	**6.62**	**1.7%**
Natural Gas								
Space Heating[1]	1.30	1.18	1.29	1.37	1.40	1.41	1.42	0.8%
Space Cooling[1]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.2%
Water Heating[1]	0.56	0.55	0.54	0.60	0.65	0.70	0.73	1.2%
Cooking	0.23	0.23	0.24	0.27	0.29	0.31	0.33	1.5%
Other Uses[3]	0.97	0.94	0.95	1.03	1.10	1.19	1.29	1.3%
Delivered Energy	**3.09**	**2.92**	**3.04**	**3.29**	**3.47**	**3.63**	**3.78**	**1.1%**
Distillate Fuel Oil								
Space Heating[1]	0.15	0.13	0.13	0.14	0.15	0.15	0.15	0.8%
Water Heating[1]	0.05	0.05	0.04	0.05	0.05	0.05	0.05	0.3%
Other Uses[4]	0.25	0.25	0.20	0.22	0.22	0.21	0.21	-0.6%
Delivered Energy	**0.45**	**0.42**	**0.38**	**0.41**	**0.41**	**0.42**	**0.41**	**-0.0%**
Marketed Renewables (biomass)	0.13	0.13	0.13	0.13	0.13	0.13	0.13	- -
Other Fuels[5]	0.36	0.34	0.33	0.34	0.35	0.35	0.35	0.1%
Delivered Energy Consumption by End Use								
Space Heating[1]	1.59	1.44	1.56	1.65	1.69	1.71	1.71	0.7%
Space Cooling[1]	0.55	0.53	0.52	0.54	0.57	0.60	0.63	0.8%
Water Heating[1]	0.77	0.75	0.74	0.81	0.86	0.91	0.94	0.9%
Ventilation	0.19	0.19	0.19	0.20	0.21	0.22	0.23	0.9%
Cooking	0.27	0.27	0.28	0.31	0.33	0.35	0.36	1.2%
Lighting	1.16	1.15	1.12	1.17	1.22	1.28	1.34	0.7%
Refrigeration	0.23	0.23	0.23	0.24	0.25	0.27	0.28	0.8%
Office Equipment (PC)	0.17	0.21	0.25	0.28	0.30	0.33	0.35	2.1%
Office Equipment (non-PC)	0.39	0.42	0.55	0.68	0.79	0.87	0.92	3.3%
Other Uses[6]	3.05	3.05	3.17	3.49	3.81	4.15	4.53	1.7%
Delivered Energy	**8.38**	**8.25**	**8.62**	**9.37**	**10.03**	**10.67**	**11.30**	**1.3%**

Table A5. Commercial Sector Key Indicators and Consumption (Continued)
(Quadrillion Btu per Year, Unless Otherwise Noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Electricity Related Losses	**9.50**	**9.66**	**10.12**	**10.98**	**11.96**	**12.87**	**13.68**	**1.5%**
Total Energy Consumption by End Use								
Space Heating[1]	1.90	1.73	1.86	1.95	1.99	2.02	2.02	0.7%
Space Cooling[1]	1.69	1.63	1.58	1.65	1.72	1.81	1.90	0.6%
Water Heating[1]	1.12	1.10	1.06	1.14	1.20	1.25	1.28	0.6%
Ventilation	0.60	0.60	0.60	0.62	0.65	0.68	0.71	0.7%
Cooking	0.36	0.35	0.36	0.39	0.41	0.42	0.43	0.9%
Lighting	3.69	3.66	3.52	3.63	3.79	3.96	4.12	0.5%
Refrigeration	0.73	0.73	0.73	0.75	0.79	0.82	0.86	0.6%
Office Equipment (PC)	0.56	0.68	0.80	0.86	0.93	1.02	1.08	1.9%
Office Equipment (non-PC)	1.24	1.34	1.73	2.11	2.46	2.68	2.81	3.1%
Other Uses[6]	5.97	6.08	6.49	7.23	8.05	8.89	9.77	2.0%
Total	**17.87**	**17.91**	**18.74**	**20.34**	**21.98**	**23.54**	**24.98**	**1.4%**
Nonmarketed Renewable Fuels[7]								
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.7%
Total	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**1.6%**

[1]Includes fuel consumption for district services.
[2]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, and medical equipment.
[3]Includes miscellaneous uses, such as pumps, emergency generators, combined heat and power in commercial buildings, and manufacturing performed in commercial buildings.
[4]Includes miscellaneous uses, such as cooking, emergency generators, and combined heat and power in commercial buildings.
[5]Includes residual fuel oil, liquefied petroleum gas, coal, motor gasoline, and kerosene.
[6]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generators, combined heat and power in commercial buildings, manufacturing performed in commercial buildings, and cooking (distillate), plus residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[7]Represents primary energy displaced by solar thermal space heating and water heating, and electricity generation by solar photovoltaic systems.
Btu = British thermal unit.
PC = Personal computer.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A6. Industrial Sector Key Indicators and Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Value of Shipments (billion 2000 dollars)								
Manufacturing	4208	4290	4577	5076	5493	5883	6283	1.6%
Nonmanufacturing	1525	1531	1419	1583	1619	1663	1715	0.5%
Total	**5732**	**5821**	**5997**	**6659**	**7113**	**7546**	**7997**	**1.3%**
Energy Prices (2006 dollars per million Btu)								
Liquefied Petroleum Gases	17.54	19.71	17.74	16.65	16.79	17.10	17.79	-0.4%
Motor Gasoline	15.48	15.48	21.18	18.72	19.63	19.62	20.32	1.1%
Distillate Fuel Oil	14.50	15.33	15.72	13.95	14.62	15.10	16.26	0.2%
Residual Fuel Oil	10.43	9.06	10.86	8.24	8.29	9.00	9.62	0.2%
Petrochemical Feedstocks	9.01	9.01	9.22	8.32	8.25	8.53	8.94	-0.0%
Asphalt and Road Oil	5.49	4.63	9.66	7.28	5.74	5.93	6.35	1.3%
Natural Gas Heat and Power	7.43	6.69	6.38	5.26	5.35	5.71	6.45	-0.2%
Natural Gas Feedstocks	9.07	8.37	7.95	6.90	6.96	7.31	8.04	-0.2%
Metallurgical Coal	3.29	3.54	4.07	3.53	3.42	3.51	3.60	0.1%
Other Industrial Coal	2.22	2.34	2.42	2.31	2.28	2.30	2.33	-0.0%
Coal for Liquids	- -	- -	- -	0.96	1.09	1.17	1.30	- -
Electricity	17.25	17.97	19.21	17.22	17.27	17.30	17.63	-0.1%
Energy Consumption (quadrillion Btu)[1]								
Industrial Consumption Excluding Refining								
Liquefied Petroleum Gases Heat and Power	0.17	0.16	0.17	0.17	0.16	0.16	0.16	-0.1%
Liquefied Petroleum Gases Feedstocks	1.89	1.91	1.92	1.77	1.64	1.59	1.55	-0.9%
Motor Gasoline	0.37	0.38	0.38	0.37	0.37	0.38	0.38	0.1%
Distillate Fuel Oil	1.26	1.28	1.29	1.25	1.23	1.22	1.23	-0.2%
Residual Fuel Oil	0.27	0.27	0.28	0.23	0.22	0.21	0.21	-1.0%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Petroleum Coke	0.33	0.36	0.34	0.32	0.31	0.31	0.30	-0.8%
Asphalt and Road Oil	1.32	1.26	1.22	1.11	1.08	1.10	1.13	-0.5%
Miscellaneous Petroleum[2]	0.52	0.56	0.39	0.36	0.33	0.30	0.29	-2.7%
Petroleum Subtotal	7.53	7.60	7.34	7.04	6.73	6.59	6.55	-0.6%
Natural Gas Heat and Power	5.14	5.01	5.12	5.24	5.22	5.25	5.22	0.2%
Natural Gas Feedstocks	0.59	0.57	0.54	0.50	0.46	0.43	0.39	-1.5%
Lease and Plant Fuel[3]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Natural Gas Subtotal	6.88	6.74	6.86	6.97	6.93	6.95	6.88	0.1%
Metallurgical Coal and Coke[4]	0.66	0.66	0.63	0.57	0.57	0.56	0.52	-1.0%
Other Industrial Coal	1.22	1.20	1.25	1.16	1.14	1.13	1.12	-0.3%
Coal Subtotal	1.88	1.86	1.87	1.73	1.71	1.69	1.64	-0.5%
Renewables[5]	1.64	1.69	1.66	1.75	1.83	1.93	2.02	0.7%
Purchased Electricity	3.34	3.27	3.35	3.44	3.42	3.39	3.35	0.1%
Delivered Energy	**21.28**	**21.17**	**21.09**	**20.92**	**20.62**	**20.55**	**20.44**	**-0.1%**
Electricity Related Losses	7.30	7.13	7.17	7.26	7.22	7.09	6.92	-0.1%
Total	**28.58**	**28.29**	**28.27**	**28.18**	**27.84**	**27.64**	**27.35**	**-0.1%**
Refining Consumption								
Liquefied Petroleum Gases Heat and Power	0.02	0.01	0.03	0.03	0.03	0.00	0.00	-3.4%
Distillate Fuel Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Residual Fuel Oil	0.01	0.01	0.00	0.03	0.01	0.01	0.01	0.1%
Petroleum Coke	0.56	0.57	0.57	0.63	0.65	0.68	0.70	0.9%
Still Gas	1.64	1.69	1.72	1.87	1.85	1.87	1.98	0.7%
Miscellaneous Petroleum[2]	0.03	0.04	0.00	0.00	0.00	0.00	0.00	-10.1%
Petroleum Subtotal	2.26	2.32	2.33	2.56	2.55	2.56	2.70	0.6%
Natural Gas Heat and Power	1.05	1.10	1.51	1.46	1.47	1.49	1.47	1.2%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Subtotal	1.05	1.10	1.51	1.46	1.47	1.49	1.47	1.2%
Other Industrial Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.2%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	- -
Coal Subtotal	0.06	0.06	0.06	0.19	0.40	0.45	0.61	10.0%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Purchased Electricity	0.13	0.15	0.15	0.17	0.17	0.17	0.17	0.7%
Delivered Energy	**3.75**	**3.94**	**4.72**	**5.38**	**6.07**	**6.95**	**7.27**	**2.6%**
Electricity Related Losses	0.29	0.32	0.33	0.37	0.36	0.35	0.36	0.5%
Total	**4.04**	**4.26**	**5.05**	**5.75**	**6.43**	**7.29**	**7.63**	**2.5%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Total Industrial Sector Consumption								
Liquefied Petroleum Gases Heat and Power	0.18	0.17	0.20	0.20	0.19	0.16	0.16	-0.3%
Liquefied Petroleum Gases Feedstocks	1.89	1.91	1.92	1.77	1.64	1.59	1.55	-0.9%
Motor Gasoline	0.37	0.38	0.38	0.37	0.37	0.38	0.38	0.1%
Distillate Fuel Oil	1.26	1.28	1.29	1.25	1.23	1.22	1.23	-0.2%
Residual Fuel Oil	0.28	0.28	0.28	0.25	0.23	0.23	0.23	-0.9%
Petrochemical Feedstocks	1.41	1.41	1.36	1.45	1.39	1.33	1.29	-0.4%
Petroleum Coke	0.89	0.93	0.91	0.95	0.97	0.98	1.00	0.3%
Asphalt and Road Oil	1.32	1.26	1.22	1.11	1.08	1.10	1.13	-0.5%
Still Gas	1.64	1.69	1.72	1.87	1.85	1.87	1.98	0.7%
Miscellaneous Petroleum[2]	0.55	0.60	0.39	0.36	0.33	0.30	0.29	-3.0%
Petroleum Subtotal	9.79	9.92	9.67	9.60	9.27	9.15	9.25	-0.3%
Natural Gas Heat and Power	6.20	6.11	6.62	6.70	6.68	6.74	6.69	0.4%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.59	0.57	0.54	0.50	0.46	0.43	0.39	-1.5%
Lease and Plant Fuel[3]	1.14	1.17	1.21	1.22	1.25	1.27	1.27	0.3%
Natural Gas Subtotal	7.93	7.85	8.37	8.43	8.39	8.44	8.35	0.3%
Metallurgical Coal and Coke[4]	0.66	0.66	0.63	0.57	0.57	0.56	0.52	-1.0%
Other Industrial Coal	1.28	1.26	1.31	1.22	1.20	1.19	1.18	-0.3%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.13	0.34	0.39	0.55	- -
Coal Subtotal	1.95	1.92	1.93	1.92	2.11	2.14	2.26	0.7%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Renewables[5]	1.64	1.69	1.66	1.75	1.83	1.93	2.02	0.7%
Purchased Electricity	3.48	3.42	3.50	3.61	3.59	3.55	3.52	0.1%
Delivered Energy	**25.03**	**25.10**	**25.82**	**26.31**	**26.70**	**27.50**	**27.70**	**0.4%**
Electricity Related Losses	7.59	7.45	7.50	7.63	7.57	7.43	7.28	-0.1%
Total	**32.62**	**32.55**	**33.32**	**33.93**	**34.27**	**34.93**	**34.98**	**0.3%**
Energy Consumption per dollar of Shipment (thousand Btu per 2000 dollars)								
Liquefied Petroleum Gases Heat and Power	0.03	0.03	0.03	0.03	0.03	0.02	0.02	-1.6%
Liquefied Petroleum Gases Feedstocks	0.33	0.33	0.32	0.27	0.23	0.21	0.19	-2.2%
Motor Gasoline	0.07	0.06	0.06	0.06	0.05	0.05	0.05	-1.2%
Distillate Fuel Oil	0.22	0.22	0.22	0.19	0.17	0.16	0.15	-1.5%
Residual Fuel Oil	0.05	0.05	0.05	0.04	0.03	0.03	0.03	-2.3%
Petrochemical Feedstocks	0.25	0.24	0.23	0.22	0.19	0.18	0.16	-1.7%
Petroleum Coke	0.16	0.16	0.15	0.14	0.14	0.13	0.13	-1.0%
Asphalt and Road Oil	0.23	0.22	0.20	0.17	0.15	0.15	0.14	-1.8%
Still Gas	0.29	0.29	0.29	0.28	0.26	0.25	0.25	-0.7%
Miscellaneous Petroleum[2]	0.10	0.10	0.06	0.05	0.05	0.04	0.04	-4.2%
Petroleum Subtotal	1.71	1.70	1.61	1.44	1.30	1.21	1.16	-1.6%
Natural Gas Heat and Power	1.08	1.05	1.10	1.01	0.94	0.89	0.84	-0.9%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.10	0.10	0.09	0.08	0.06	0.06	0.05	-2.8%
Lease and Plant Fuel[3]	0.20	0.20	0.20	0.18	0.18	0.17	0.16	-1.0%
Natural Gas Subtotal	1.38	1.35	1.40	1.27	1.18	1.12	1.04	-1.1%
Metallurgical Coal and Coke[4]	0.12	0.11	0.10	0.09	0.08	0.07	0.07	-2.3%
Other Industrial Coal	0.22	0.22	0.22	0.18	0.17	0.16	0.15	-1.6%
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.02	0.05	0.05	0.07	- -
Coal Subtotal	0.34	0.33	0.32	0.29	0.30	0.28	0.28	-0.7%
Biofuels Heat and Coproducts	0.04	0.05	0.11	0.15	0.21	0.30	0.29	7.4%
Renewables[5]	0.29	0.29	0.28	0.26	0.26	0.26	0.25	-0.6%
Purchased Electricity	0.61	0.59	0.58	0.54	0.50	0.47	0.44	-1.2%
Delivered Energy	**4.37**	**4.31**	**4.31**	**3.95**	**3.75**	**3.64**	**3.46**	**-0.9%**
Electricity Related Losses	1.32	1.28	1.25	1.15	1.06	0.99	0.91	-1.4%
Total	**5.69**	**5.59**	**5.56**	**5.10**	**4.82**	**4.63**	**4.37**	**-1.0%**

Table A6. Industrial Sector Key Indicators and Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Industrial Combined Heat and Power								
Capacity (gigawatts)	26.87	25.69	28.11	31.79	36.84	42.15	44.85	2.3%
Generation (billion kilowatthours)	139.95	139.50	155.59	182.91	220.78	261.90	281.41	3.0%

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2005 and 2006 prices for motor gasoline and distillate fuel oil are based on: Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 and 2006 petrochemical feedstock and asphalt and road oil prices are based on: *State Energy Data Report 2005*, DOE/EIA-0214(2005) (Washington, DC, June 2007). 2005 and 2006 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2005 and 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 refining consumption based on: *Petroleum Supply Annual 2005,* DOE/EIA-0340(2005)/1 (Washington, DC, October 2006). 2006 refining consumption based on: *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). Other 2005 and 2006 consumption values are based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 industrial shipments: Global Insight, Global Insight Industry model, July 2007. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Key Indicators								
Travel Indicators								
(billion vehicle miles traveled)								
Light-Duty Vehicles less than 8,500 pounds	2687	2693	2777	3058	3375	3717	4069	1.7%
Commercial Light Trucks[1]	69	70	73	81	87	94	101	1.5%
Freight Trucks greater than 10,000 pounds	228	235	250	279	304	328	351	1.7%
(billion seat miles available)								
Air	1029	994	1130	1318	1457	1576	1665	2.2%
(billion ton miles traveled)								
Rail	1588	1656	1702	1827	1932	2043	2147	1.1%
Domestic Shipping	610	619	643	677	701	713	721	0.6%
Energy Efficiency Indicators								
(miles per gallon)								
Tested New Light-Duty Vehicle[2]	25.5	26.5	27.2	30.8	35.8	36.4	36.6	1.4%
New Car[2]	30.2	31.1	31.5	34.9	42.0	42.1	42.1	1.3%
New Light Truck[2]	22.4	23.2	23.7	27.7	31.4	32.2	32.4	1.4%
On-Road New Light-Duty Vehicle[3]	20.6	21.5	22.1	25.2	29.4	30.1	30.5	1.5%
New Car[3]	24.5	25.3	25.7	28.7	34.7	35.1	35.3	1.4%
New Light Truck[3]	18.0	18.7	19.2	22.5	25.7	26.5	26.9	1.5%
Light-Duty Stock[4]	19.9	20.3	20.3	21.5	23.7	26.1	27.9	1.3%
New Commercial Light Truck[1]	15.0	15.6	15.7	18.1	19.8	20.2	20.2	1.1%
Stock Commercial Light Truck[1]	14.1	14.3	14.9	15.9	17.4	18.9	19.8	1.4%
Freight Truck	6.0	6.0	6.0	6.2	6.5	6.7	6.8	0.5%
(seat miles per gallon)								
Aircraft	60.9	62.2	63.5	65.3	67.2	68.7	70.0	0.5%
(ton miles per thousand Btu)								
Rail	2.9	2.9	2.9	2.9	3.0	3.0	3.0	0.1%
Domestic Shipping	2.0	2.0	2.0	2.0	2.0	2.0	2.0	0.1%
Energy Use by Mode (quadrillion Btu)								
Light-Duty Vehicles	16.23	16.41	16.52	17.01	17.10	17.11	17.52	0.3%
Commercial Light Trucks[1]	0.61	0.62	0.62	0.64	0.63	0.63	0.64	0.2%
Bus Transportation	0.26	0.26	0.26	0.27	0.27	0.28	0.29	0.3%
Freight Trucks	4.74	4.89	5.18	5.60	5.85	6.13	6.44	1.2%
Rail, Passenger	0.04	0.04	0.05	0.05	0.05	0.05	0.06	1.1%
Rail, Freight	0.55	0.57	0.58	0.62	0.65	0.69	0.72	1.0%
Shipping, Domestic	0.31	0.32	0.33	0.34	0.35	0.36	0.36	0.5%
Shipping, International	0.77	0.78	0.79	0.78	0.79	0.80	0.80	0.1%
Recreational Boats	0.24	0.24	0.25	0.26	0.28	0.29	0.30	0.9%
Air	2.72	2.65	2.90	3.29	3.61	3.92	4.22	2.0%
Military Use	0.68	0.69	0.73	0.71	0.73	0.75	0.76	0.4%
Lubricants	0.15	0.15	0.14	0.14	0.14	0.15	0.15	0.1%
Pipeline Fuel	0.60	0.59	0.64	0.66	0.69	0.72	0.72	0.8%
Total	**27.90**	**28.20**	**28.98**	**30.37**	**31.15**	**31.86**	**32.98**	**0.7%**

Table A7. Transportation Sector Key Indicators and Delivered Energy Consumption (Continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Energy Use by Mode (million barrels per day oil equivalent)								
Light-Duty Vehicles	8.51	8.60	8.94	9.26	9.48	9.56	9.74	0.5%
Commercial Light Trucks[1]	0.32	0.32	0.33	0.35	0.34	0.34	0.35	0.3%
Bus Transportation	0.12	0.13	0.13	0.13	0.13	0.13	0.14	0.4%
Freight Trucks	2.26	2.33	2.48	2.69	2.80	2.94	3.09	1.2%
Rail, Passenger	0.02	0.02	0.02	0.02	0.02	0.03	0.03	1.1%
Rail, Freight	0.26	0.27	0.28	0.30	0.31	0.33	0.34	1.0%
Shipping, Domestic	0.14	0.15	0.15	0.16	0.16	0.17	0.17	0.5%
Shipping, International	0.34	0.34	0.35	0.34	0.35	0.35	0.35	0.1%
Recreational Boats	0.13	0.13	0.14	0.14	0.15	0.16	0.16	1.1%
Air	1.32	1.28	1.40	1.59	1.75	1.89	2.04	2.0%
Military Use	0.33	0.33	0.35	0.34	0.35	0.36	0.37	0.4%
Lubricants	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.1%
Pipeline Fuel	0.30	0.30	0.32	0.33	0.35	0.36	0.36	0.8%
Total	**14.11**	**14.27**	**14.96**	**15.72**	**16.27**	**16.69**	**17.20**	**0.8%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Tested new vehicle efficiency revised for on-road performance.
[4]Combined car and light truck "on-the-road" estimate.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006: Energy Information Administration (EIA), *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006); EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007); Federal Highway Administration, *Highway Statistics 2005* (Washington, DC, December 2006); Oak Ridge National Laboratory, Transportation Energy Data Book: Edition 26 and Annual (Oak Ridge, TN, 2007); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, March 2004); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC97TV (Washington, DC, October 1999); EIA, *State Energy Data Report 2005*, DOE/EIA-0214(2005) (Washington, DC, June 2007); EIA, *Alternatives to Traditional Transportation Fuels 2005 (Part II-User and Fuel Data)*, November 2007; U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2006/2005* (Washington, DC, 2006); EIA, *Fuel Oil and Kerosene Sales 2004*, DOE/EIA-0535(2004) (Washington, DC, November 2005); and United States Department of Defense, Defense Fuel Supply Center. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A8. Electricity Supply, Disposition, Prices, and Emissions
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1956	1930	2002	2122	2287	2502	2756	1.5%
Petroleum	111	55	49	50	52	54	56	0.1%
Natural Gas[3]	554	608	695	682	614	543	503	-0.8%
Nuclear Power	782	787	797	807	868	911	917	0.6%
Pumped Storage/Other[4]	1	0	1	1	1	1	1	5.4%
Renewable Sources[5]	319	347	421	465	518	540	553	2.0%
Distributed Generation (Natural Gas)	0	0	0	1	1	2	4	- -
Total	**3722**	**3727**	**3965**	**4128**	**4340**	**4552**	**4790**	**1.1%**
Combined Heat and Power[6]								
Coal	37	36	32	32	32	32	31	-0.6%
Petroleum	6	4	1	1	1	1	1	-6.7%
Natural Gas	130	124	124	123	108	99	96	-1.1%
Renewable Sources	4	4	4	4	5	5	5	0.5%
Total	**180**	**173**	**160**	**160**	**145**	**136**	**133**	**-1.1%**
Total Net Generation	**3902**	**3900**	**4125**	**4288**	**4485**	**4688**	**4923**	**1.0%**
Less Direct Use	33	33	34	34	34	34	34	0.1%
Net Available to the Grid	**3869**	**3866**	**4091**	**4254**	**4451**	**4654**	**4889**	**1.0%**
End-Use Generation[7]								
Coal	22	22	21	28	39	41	51	3.6%
Petroleum	6	4	6	6	7	9	9	3.6%
Natural Gas	73	74	88	99	111	124	138	2.6%
Other Gaseous Fuels[8]	5	5	4	4	4	4	4	-0.7%
Renewable Sources[9]	34	34	37	48	65	94	98	4.5%
Other[10]	14	13	12	12	12	12	12	-0.4%
Total	**152**	**152**	**169**	**197**	**238**	**285**	**313**	**3.1%**
Less Direct Use	123	121	134	155	182	211	234	2.8%
Total Sales to the Grid	**30**	**31**	**34**	**42**	**56**	**74**	**79**	**4.0%**
Total Electricity Generation	**4054**	**4051**	**4294**	**4485**	**4723**	**4973**	**5235**	**1.1%**
Total Net Generation to the Grid	**3899**	**3897**	**4126**	**4296**	**4507**	**4728**	**4968**	**1.0%**
Net Imports	**25**	**18**	**15**	**11**	**13**	**16**	**23**	**1.0%**
Electricity Sales by Sector								
Residential	1359	1351	1450	1472	1540	1620	1722	1.0%
Commercial	1275	1300	1386	1522	1661	1802	1941	1.7%
Industrial	1019	1002	1027	1058	1052	1041	1033	0.1%
Transportation	6	6	7	7	8	8	9	1.3%
Total	**3660**	**3659**	**3869**	**4059**	**4261**	**4472**	**4705**	**1.1%**
Direct Use	156	154	168	189	216	245	267	2.3%
Total Electricity Use	**3815**	**3814**	**4037**	**4248**	**4477**	**4717**	**4972**	**1.1%**
End-Use Prices (2006 cents per kilowatthour)								
Residential	9.7	10.4	10.7	10.2	10.3	10.3	10.5	0.0%
Commercial	8.9	9.5	9.5	8.7	8.7	8.8	8.9	-0.2%
Industrial	5.9	6.1	6.6	5.9	5.9	5.9	6.0	-0.1%
Transportation	10.5	10.1	10.6	9.9	9.9	9.9	10.1	-0.0%
All Sectors Average	**8.4**	**8.9**	**9.2**	**8.5**	**8.6**	**8.7**	**8.8**	**-0.0%**
Prices by Service Category (2006 cents per kilowatthour)								
Generation	5.4	5.9	6.2	5.5	5.6	5.7	5.9	-0.1%
Transmission	0.6	0.6	0.7	0.8	0.8	0.8	0.8	1.1%
Distribution	2.3	2.3	2.3	2.3	2.3	2.2	2.2	-0.2%

Table A8. Electricity Supply, Disposition, Prices, and Emissions (Continued)
(Billion Kilowatthours, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Electric Power Sector Emissions[1]								
Sulfur Dioxide (million tons)	10.22	9.39	6.43	4.67	3.77	3.66	3.71	-3.8%
Nitrogen Oxide (million tons)	3.64	3.41	2.33	2.11	2.11	2.14	2.16	-1.9%
Mercury (tons)	51.72	50.37	37.24	24.75	19.23	16.88	14.95	-4.9%

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes plants that only produce electricity.
[3]Includes electricity generation from fuel cells.
[4]Includes non-biogenic municipal waste. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity was generated from this material in 2005. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[5]Includes conventional hydroelectric, geothermal, wood, wood waste, biogenic municipal waste, landfill gas, other biomass, solar, and wind power.
[6]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[7]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and 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]Includes refinery gas and still gas.
[9]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power.
[10]Includes batteries, chemicals, hydrogen, pitch, purchased steam, sulfur, and miscellaneous technologies.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 electric power sector generation; sales to utilities; net imports; electricity sales; and emissions: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), and supporting databases. 2005 and 2006 prices: EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. **Projections**: EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A9. Electricity Generating Capacity
(Gigawatts)

Net Summer Capacity[1]	Reference Case 2005	2006	2010	2015	2020	2025	2030	Annual Growth 2006-2030 (percent)
Electric Power Sector[2]								
Power Only[3]								
Coal	305.1	305.2	311.4	319.3	338.5	367.6	401.5	1.1%
Oil and Natural Gas Steam[4]	120.8	119.3	118.0	93.2	93.0	92.6	92.6	-1.1%
Combined Cycle	137.4	144.7	158.2	159.9	164.2	173.3	177.5	0.9%
Combustion Turbine/Diesel	127.4	128.1	134.5	127.1	129.2	140.9	161.8	1.0%
Nuclear Power[5]	100.2	100.2	100.9	102.1	110.9	115.7	114.9	0.6%
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	92.8	95.7	110.9	116.6	122.9	127.5	131.8	1.3%
Distributed Generation[7]	0.0	0.0	0.3	0.9	2.7	5.9	9.8	- -
Total	**905.2**	**914.7**	**955.7**	**940.6**	**982.8**	**1045.0**	**1111.4**	**0.8%**
Combined Heat and Power[8]								
Coal	4.6	4.6	4.6	4.6	4.6	4.6	4.6	0.0%
Oil and Natural Gas Steam[4]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
Combined Cycle	31.9	31.8	31.8	32.5	32.5	32.5	32.5	0.1%
Combustion Turbine/Diesel	2.9	2.9	2.9	2.9	2.9	2.9	2.9	-0.0%
Renewable Sources[6]	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.2%
Total	**40.4**	**40.3**	**40.3**	**41.0**	**41.0**	**41.0**	**41.0**	**0.1%**
Cumulative Planned Additions[9]								
Coal	0.0	0.0	7.7	10.7	10.7	10.7	10.7	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined Cycle	0.0	0.0	13.5	15.5	15.5	15.5	15.5	- -
Combustion Turbine/Diesel	0.0	0.0	3.9	3.9	3.9	3.9	3.9	- -
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	0.0	0.0	9.5	9.5	9.6	9.8	9.9	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**34.5**	**39.6**	**39.7**	**39.9**	**40.0**	**- -**
Cumulative Unplanned Additions[9]								
Coal	0.0	0.0	0.0	6.8	26.3	55.6	89.5	- -
Oil and Natural Gas Steam[4]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combined Cycle	0.0	0.0	0.0	0.3	4.6	13.7	17.9	- -
Combustion Turbine/Diesel	0.0	0.0	3.3	4.6	6.7	18.4	39.5	- -
Nuclear Power	0.0	0.0	0.0	0.0	8.0	12.8	16.6	- -
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[6]	0.0	0.0	5.8	11.5	17.6	22.2	26.3	- -
Distributed Generation[7]	0.0	0.0	0.3	0.9	2.7	5.9	9.8	- -
Total	**0.0**	**0.0**	**9.5**	**24.1**	**65.9**	**128.5**	**199.6**	**- -**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**44.0**	**63.7**	**105.7**	**168.4**	**239.6**	**- -**
Cumulative Retirements[10]								
Coal	0.0	0.0	1.5	3.4	3.7	3.9	3.9	- -
Oil and Natural Gas Steam[4]	0.0	0.0	1.4	26.1	26.4	26.7	26.8	- -
Combined Cycle	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Combustion Turbine/Diesel	0.0	0.0	0.7	9.4	9.4	9.4	9.7	- -
Nuclear Power	0.0	0.0	0.0	0.0	0.0	0.0	4.5	- -
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[6]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**3.6**	**38.9**	**39.5**	**40.0**	**44.8**	**- -**
Total Electric Power Sector Capacity	**945.6**	**955.0**	**996.0**	**981.6**	**1023.8**	**1086.0**	**1152.4**	**0.8%**

Table A9. Electricity Generating Capacity (Continued)
(Gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
End-Use Generators[11]								
Coal	4.1	4.0	4.0	4.9	6.3	6.6	8.0	2.9%
Petroleum	1.2	1.2	1.7	1.7	1.9	2.1	2.1	2.4%
Natural Gas	14.7	14.1	15.8	17.2	18.8	20.6	22.4	2.0%
Other Gaseous Fuels	2.2	1.8	1.7	1.7	1.7	1.7	1.7	-0.1%
Renewable Sources[6]	6.0	6.0	6.7	8.2	10.8	15.2	16.7	4.4%
Other	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.0%
Total	**29.0**	**27.9**	**30.7**	**34.6**	**40.4**	**47.0**	**51.8**	**2.6%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**2.9**	**6.8**	**12.5**	**19.1**	**23.9**	**- -**

[1]Net summer capacity 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 electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes plants that only produce electricity. Includes capacity increases (uprates) at existing units.
[4]Includes oil-, gas-, and dual-fired capacity.
[5]Nuclear capacity includes 2.7 gigawatts of uprates through 2030.
[6]Includes conventional hydroelectric, geothermal, wood, wood waste, all municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
[7]Primarily peak load capacity fueled by natural gas.
[8]Includes combined heat and power plants whose primary business is to sell electricity and heat to the public (i.e., those that report North American Industry Classification System code 22).
[9]Cumulative additions after December 31, 2006.
[10]Cumulative retirements after December 31, 2006.
[11]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and 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.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Interregional Electricity Trade								
Gross Domestic Sales								
Firm Power	127.0	119.4	105.5	82.4	50.6	37.9	37.9	-4.7%
Economy	177.3	169.7	207.2	260.7	220.3	229.5	222.6	1.1%
Total	**304.3**	**289.1**	**312.7**	**343.1**	**270.9**	**267.4**	**260.4**	**-0.4%**
Gross Domestic Sales (million 2006 dollars)								
Firm Power	7077.5	6656.0	5877.2	4592.5	2820.0	2111.0	2111.0	-4.7%
Economy	12274.8	9907.5	12125.3	12861.2	10709.6	10964.4	11182.2	0.5%
Total	**19352.3**	**16563.4**	**18002.5**	**17453.6**	**13529.6**	**13075.4**	**13293.2**	**-0.9%**
International Electricity Trade								
Imports from Canada and Mexico								
Firm Power	13.1	13.7	2.5	1.9	0.8	0.4	0.4	-13.8%
Economy	31.4	28.8	28.9	24.7	26.6	27.5	34.3	0.7%
Total	**44.5**	**42.4**	**31.4**	**26.6**	**27.4**	**27.9**	**34.7**	**-0.8%**
Exports to Canada and Mexico								
Firm Power	2.9	3.2	1.0	0.7	0.2	0.0	0.0	- -
Economy	16.9	21.4	15.5	15.0	14.0	12.1	12.1	-2.3%
Total	**19.8**	**24.6**	**16.5**	**15.6**	**14.2**	**12.1**	**12.1**	**-2.9%**

- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 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.
Sources: 2005 and 2006 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2004. 2005 and 2006 Mexican electricity trade data: Energy Information Administration (EIA), *Electric Power Annual 2006* DOE/EIA-0348(2006) (Washington, DC, November 2007). 2005 Canadian international electricity trade data: National Energy Board, *Annual Report 2005*. 2006 Canadian electricity trade data: National Energy Board, *Annual Report 2006*. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A11. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil								
Domestic Crude Production[1]	5.19	5.10	5.93	6.16	6.23	6.04	5.59	0.4%
Alaska	0.86	0.74	0.69	0.57	0.70	0.53	0.30	-3.7%
Lower 48 States	4.33	4.36	5.24	5.59	5.53	5.51	5.30	0.8%
Net Imports	10.09	10.09	9.60	9.89	9.75	10.11	11.03	0.4%
Gross Imports	10.12	10.12	9.63	9.92	9.79	10.14	11.06	0.4%
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.4%
Other Crude Supply[2]	-0.05	0.05	0.00	0.00	0.00	0.00	0.00	- -
Total Crude Supply	**15.23**	**15.24**	**15.53**	**16.04**	**15.98**	**16.15**	**16.63**	**0.4%**
Other Supply								
Natural Gas Plant Liquids	1.72	1.74	1.68	1.70	1.72	1.61	1.57	-0.4%
Net Product Imports	2.47	2.31	1.72	1.47	1.37	1.27	1.26	-2.5%
Gross Refined Product Imports[3]	2.45	2.17	1.61	1.34	1.41	1.50	1.56	-1.4%
Unfinished Oil Imports	0.58	0.69	0.67	0.67	0.64	0.62	0.70	0.1%
Blending Component Imports	0.54	0.68	0.74	0.79	0.67	0.59	0.52	-1.1%
Exports	1.07	1.22	1.30	1.33	1.36	1.45	1.52	0.9%
Refinery Processing Gain[4]	0.99	0.99	1.05	1.06	1.00	0.97	0.99	0.0%
Other Inputs	0.41	0.45	1.04	1.46	1.97	2.34	2.41	7.2%
Ethanol	0.26	0.36	0.81	1.04	1.41	1.59	1.56	6.2%
Domestic Production	0.25	0.32	0.74	0.93	1.17	1.45	1.44	6.5%
Net Imports	0.01	0.05	0.07	0.11	0.24	0.15	0.12	4.0%
Biodiesel	0.01	0.02	0.04	0.08	0.07	0.07	0.08	6.9%
Domestic Production	0.01	0.02	0.04	0.08	0.07	0.07	0.08	6.9%
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Coal	0.00	0.00	0.00	0.06	0.15	0.17	0.24	- -
Liquids from Biomass	0.00	0.00	0.00	0.07	0.14	0.28	0.29	- -
Other[5]	0.14	0.07	0.18	0.21	0.21	0.22	0.24	5.0%
Total Primary Supply[6]	**20.82**	**20.74**	**21.02**	**21.74**	**22.04**	**22.34**	**22.86**	**0.4%**
Liquid Fuels Consumption								
by Fuel								
Liquefied Petroleum Gases	2.03	2.05	2.05	1.96	1.86	1.81	1.80	-0.5%
E85[7]	0.00	0.00	0.00	0.12	0.67	0.97	0.92	33.5%
Motor Gasoline[8]	9.16	9.25	9.59	9.73	9.24	8.84	8.91	-0.2%
Jet Fuel[9]	1.68	1.63	1.66	1.85	2.01	2.16	2.31	1.5%
Distillate Fuel Oil[10]	4.12	4.17	4.40	4.68	4.91	5.19	5.53	1.2%
Diesel	3.04	3.21	3.72	4.00	4.23	4.52	4.87	1.8%
Residual Fuel Oil	0.92	0.69	0.70	0.69	0.69	0.69	0.70	0.0%
Other[11]	2.89	2.86	2.58	2.65	2.58	2.57	2.62	-0.4%
by Sector								
Residential and Commercial	1.19	1.07	1.08	1.11	1.13	1.12	1.12	0.2%
Industrial[12]	5.09	5.15	5.06	4.98	4.79	4.70	4.73	-0.4%
Transportation	13.91	14.05	14.60	15.33	15.79	16.15	16.66	0.7%
Electric Power[13]	0.55	0.29	0.25	0.25	0.26	0.27	0.28	-0.1%
Total	**20.80**	**20.65**	**20.99**	**21.68**	**21.96**	**22.25**	**22.80**	**0.4%**
Discrepancy[14]	**0.02**	**0.09**	**0.03**	**0.06**	**0.08**	**0.09**	**0.06**	**- -**

Table A11. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Domestic Refinery Distillation Capacity[15]	17.1	17.3	18.3	18.3	18.3	18.3	18.4	0.3%
Capacity Utilization Rate (percent)[16]	91.0	90.0	86.8	89.6	89.3	90.1	92.0	0.1%
Net Import Share of Product Supplied (percent)	60.4	60.0	54.2	52.8	51.6	51.6	54.3	-0.4%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2006 dollars)	251.73	264.86	254.07	203.53	207.19	228.18	261.91	-0.0%

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, and ethers.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2005 data: EIA, *Petroleum Supply Annual 2005,* DOE/EIA-0340(2005)/1 (Washington, DC, October 2006). Other 2006 data: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A12. Petroleum Product Prices
(2006 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil Prices (2006 dollars per barrel)								
Imported Low Sulfur Light Crude Oil	58.28	66.02	74.03	59.85	59.70	64.49	70.45	0.3%
Imported Crude Oil[1]	50.40	59.05	65.18	52.03	51.55	55.68	58.66	-0.0%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	162.3	198.1	216.3	207.3	207.9	211.4	218.3	0.4%
Distillate Fuel Oil	235.6	248.8	238.6	197.9	198.0	209.9	225.7	-0.4%
Commercial								
Distillate Fuel Oil	191.2	201.8	210.2	177.5	182.5	191.3	206.7	0.1%
Residual Fuel Oil	167.8	128.8	150.7	119.0	118.9	129.1	138.0	0.3%
Residual Fuel Oil (2006 dollars per barrel)	70.46	54.09	63.27	49.97	49.95	54.21	57.97	0.3%
Industrial[2]								
Liquefied Petroleum Gases	151.1	169.2	152.3	142.9	144.1	146.8	152.7	-0.4%
Distillate Fuel Oil	200.8	212.1	216.2	191.6	200.7	207.3	223.1	0.2%
Residual Fuel Oil	156.2	135.6	162.6	123.4	124.0	134.7	144.0	0.2%
Residual Fuel Oil (2006 dollars per barrel)	65.60	56.96	68.29	51.82	52.10	56.57	60.48	0.2%
Transportation								
Liquefied Petroleum Gases	176.6	186.4	223.4	214.0	214.0	216.9	223.4	0.8%
Ethanol (E85)[3]	226.6	235.4	223.7	167.0	172.2	175.5	186.1	-1.0%
Ethanol Wholesale Price	196.8	250.0	180.8	171.3	200.7	164.6	152.2	-2.0%
Motor Gasoline[4]	239.5	263.3	255.4	225.4	235.5	236.0	244.6	-0.3%
Jet Fuel[5]	179.6	200.2	212.8	177.6	179.2	191.0	207.5	0.1%
Diesel Fuel (distillate fuel oil)[6]	249.1	271.0	269.8	241.8	250.2	254.1	268.5	-0.0%
Residual Fuel Oil	129.9	118.1	157.7	128.2	130.1	142.1	155.5	1.2%
Residual Fuel Oil (2006 dollars per barrel)	54.56	49.62	66.22	53.84	54.64	59.70	65.32	1.2%
Electric Power[7]								
Distillate Fuel Oil	175.1	185.1	189.0	148.0	148.3	160.8	176.2	-0.2%
Residual Fuel Oil	110.8	122.3	141.5	110.9	112.3	123.4	135.3	0.4%
Residual Fuel Oil (2006 dollars per barrel)	46.52	51.37	59.43	46.56	47.18	51.85	56.84	0.4%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	153.0	174.6	165.4	157.2	159.5	163.3	170.1	-0.1%
Motor Gasoline[4]	238.4	261.6	255.4	225.4	235.5	236.0	244.6	-0.3%
Jet Fuel[5]	179.6	200.2	212.8	177.6	179.2	191.0	207.5	0.1%
Distillate Fuel Oil	236.3	255.9	253.9	227.4	236.1	241.9	257.1	0.0%
Residual Fuel Oil	126.4	122.9	154.3	122.6	124.1	135.6	147.7	0.8%
Residual Fuel Oil (2006 dollars per barrel)	53.07	51.63	64.80	51.50	52.12	56.94	62.04	0.8%
Average	**213.0**	**234.5**	**233.1**	**206.6**	**214.1**	**218.0**	**229.6**	**-0.1%**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2005 and 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 and 2006 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2005 and 2006 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2005 and 2006 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2005 and 2006 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A13. Natural Gas Supply, Disposition, and Prices
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Production								
Dry Gas Production[1]	18.07	18.51	19.29	19.52	19.67	19.60	19.43	0.2%
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Net Imports	**3.61**	**3.46**	**3.85**	**4.03**	**3.55**	**3.28**	**3.18**	**-0.4%**
Pipeline[3]	3.05	2.94	2.64	1.91	1.18	0.68	0.33	-8.7%
Liquefied Natural Gas	0.57	0.52	1.20	2.12	2.37	2.60	2.84	7.3%
Total Supply	**21.75**	**22.03**	**23.20**	**23.61**	**23.28**	**22.94**	**22.68**	**0.1%**
Consumption by Sector								
Residential	4.83	4.37	4.81	5.01	5.15	5.19	5.17	0.7%
Commercial	3.00	2.83	2.96	3.20	3.37	3.53	3.67	1.1%
Industrial[4]	6.60	6.49	6.95	7.00	6.93	6.96	6.87	0.2%
Natural-Gas-to-Liquids Heat and Power[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas to Liquids Production[6]	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electric Power[7]	5.87	6.24	6.70	6.56	5.92	5.30	4.99	-0.9%
Transportation[8]	0.01	0.02	0.03	0.06	0.07	0.08	0.09	6.2%
Pipeline Fuel	0.58	0.58	0.62	0.64	0.67	0.70	0.70	0.8%
Lease and Plant Fuel[9]	1.11	1.14	1.18	1.19	1.22	1.24	1.23	0.3%
Total	**22.01**	**21.66**	**23.25**	**23.66**	**23.33**	**22.99**	**22.72**	**0.2%**
Discrepancy[10]	**-0.26**	**0.37**	**-0.05**	**-0.05**	**-0.05**	**-0.04**	**-0.05**	**- -**
Natural Gas Prices								
(2006 dollars per million Btu)								
Henry Hub Spot Price	8.93	6.73	6.90	5.87	5.95	6.39	7.22	0.3%
Average Lower 48 Wellhead Price[11]	7.62	6.24	6.16	5.21	5.29	5.69	6.45	0.1%
(2006 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	7.85	6.42	6.33	5.36	5.44	5.86	6.63	0.1%
Delivered Prices								
Residential	13.23	13.80	12.52	11.54	11.74	12.29	13.30	-0.2%
Commercial	11.86	11.85	10.91	9.97	10.20	10.78	11.78	-0.0%
Industrial[4]	8.62	7.89	7.43	6.33	6.40	6.76	7.50	-0.2%
Electric Power[7]	8.67	7.07	7.16	6.10	6.11	6.44	7.13	0.0%
Transportation[12]	14.97	14.71	14.01	12.71	12.52	12.65	13.22	-0.4%
Average[13]	**10.22**	**9.49**	**8.97**	**8.00**	**8.22**	**8.73**	**9.63**	**0.1%**

[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 any natural gas regasified in the Bahamas and transported via pipeline to Florida, as well as gas from Canada and Mexico.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[6]Includes any natural gas that is converted into liquid fuel.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Compressed natural gas used as vehicle fuel.
[9]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[10]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. 2005 and 2006 values include net storage injections.
[11]Represents lower 48 onshore and offshore supplies.
[12]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[13]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 supply values; lease, plant, and pipeline fuel consumption; and residential and commercial delivered prices: Energy Information Administration (EIA), *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 supply values; lease, plant, and pipeline fuel consumption; wellhead price; and residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). Other 2005 and 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2005 and 2006 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2006 through April 2007, Table 4.11.A. 2005 and 2006 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2005 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and estimated state taxes, federal taxes, and dispensing costs or charges. 2006 transportation sector delivered prices are model results. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A14. Oil and Gas Supply

Production and Supply	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil								
Lower 48 Average Wellhead Price[1]								
(2006 dollars per barrel)	**52.37**	**60.18**	**78.45**	**57.71**	**52.54**	**55.77**	**60.59**	**0.0%**
Production (million barrels per day)[2]								
United States Total	5.19	5.10	5.93	6.16	6.23	6.04	5.59	0.4%
Lower 48 Onshore	2.91	2.93	3.10	3.20	3.28	3.43	3.38	0.6%
Lower 48 Offshore	1.41	1.43	2.14	2.38	2.25	2.08	1.92	1.2%
Alaska	0.86	0.74	0.69	0.57	0.70	0.53	0.30	-3.7%
Lower 48 End of Year Reserves[2]								
(billion barrels)	**18.85**	**19.02**	**19.89**	**20.93**	**20.78**	**20.72**	**19.89**	**0.2%**
Natural Gas								
Prices (2006 dollars per million Btu)								
Henry Hub Spot Price	8.93	6.73	6.90	5.87	5.95	6.39	7.22	0.3%
Average Lower 48 Wellhead Price[1]	7.62	6.24	6.16	5.21	5.29	5.69	6.45	0.1%
Prices (2006 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	7.85	6.42	6.33	5.36	5.44	5.86	6.63	0.1%
Dry Production (trillion cubic feet)[3]								
United States Total	18.07	18.51	19.29	19.52	19.67	19.60	19.44	0.2%
Lower 48 Onshore	14.24	15.04	15.26	14.81	14.16	13.74	13.95	-0.3%
Associated-Dissolved[4]	1.35	1.42	1.41	1.40	1.33	1.29	1.20	-0.7%
Non-Associated	12.90	13.62	13.85	13.41	12.83	12.45	12.76	-0.3%
Conventional	5.00	5.14	4.81	3.96	3.47	3.18	3.23	-1.9%
Unconventional	7.89	8.48	9.04	9.45	9.36	9.28	9.53	0.5%
Lower 48 Offshore	3.37	3.05	3.61	4.32	4.31	3.86	3.47	0.5%
Associated-Dissolved[4]	0.68	0.62	0.73	0.95	0.97	0.87	0.77	0.9%
Non-Associated	2.69	2.43	2.88	3.37	3.35	2.99	2.69	0.4%
Alaska	0.46	0.42	0.42	0.38	1.19	2.00	2.01	6.7%
Lower 48 End of Year Dry Reserves								
(trillion cubic feet)	**196.22**	**202.99**	**220.62**	**227.01**	**219.31**	**207.16**	**200.42**	**-0.1%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.1%**
Total Lower 48 Wells Drilled (thousands)	**41.54**	**49.72**	**62.33**	**42.40**	**37.19**	**34.02**	**35.78**	**-1.4%**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Marketed production (wet) minus extraction losses.
[4]Gas which occurs in crude oil reservoirs 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.

Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2005 and 2006 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2005 and 2006 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2005 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2005) (Washington, DC, November 2006). 2005 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2005 natural gas lower 48 average wellhead price: Minerals Management Service and EIA, *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006). 2006 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). Other 2005 and 2006 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A15. Coal Supply, Disposition, and Prices
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Production[1]								
Appalachia	397	392	381	340	327	324	328	-0.7%
Interior	149	151	166	193	199	219	241	2.0%
West	585	619	619	682	745	820	885	1.5%
East of the Mississippi	494	491	488	460	447	457	481	-0.1%
West of the Mississippi	638	672	678	755	823	906	974	1.6%
Total	**1131**	**1163**	**1166**	**1215**	**1270**	**1363**	**1455**	**0.9%**
Waste Coal Supplied[2]	**13**	**14**	**13**	**14**	**11**	**11**	**12**	**-0.4%**
Net Imports								
Imports[3]	29	34	37	42	80	93	112	5.1%
Exports	50	50	71	45	34	35	35	-1.5%
Total	**-21**	**-15**	**-34**	**-3**	**46**	**57**	**78**	**- -**
Total Supply[4]	**1124**	**1161**	**1144**	**1225**	**1326**	**1431**	**1545**	**1.2%**
Consumption by Sector								
Residential and Commercial	4	4	4	4	4	4	4	-0.2%
Coke Plants	23	23	23	21	20	20	18	-0.9%
Other Industrial[5]	60	61	64	60	59	58	58	-0.2%
Coal-to-Liquids Heat and Power	0	0	0	9	23	25	35	- -
Coal to Liquids Production	0	0	0	7	19	21	29	- -
Electric Power[6]	1037	1026	1054	1125	1202	1303	1401	1.3%
Total	**1125**	**1114**	**1145**	**1225**	**1327**	**1431**	**1545**	**1.4%**
Discrepancy and Stock Change[7]	**-2**	**47**	**-0**	**-0**	**-0**	**-0**	**-0**	**- -**
Average Minemouth Price[8]								
(2006 dollars per short ton)	24.08	24.63	26.16	23.38	22.51	22.75	23.32	-0.2%
(2006 dollars per million Btu)	1.18	1.21	1.28	1.17	1.14	1.16	1.19	-0.1%
Delivered Prices (2006 dollars per short ton)[9]								
Coke Plants	86.43	92.87	107.02	92.85	89.86	92.16	94.68	0.1%
Other Industrial[5]	49.13	51.67	51.64	49.16	48.82	49.21	49.91	-0.1%
Coal to Liquids	- -	- -	- -	14.44	16.54	18.07	20.60	- -
Electric Power								
(2006 dollars per short ton)	32.01	33.85	36.62	34.24	33.84	34.03	35.03	0.1%
(2006 dollars per million Btu)	1.59	1.69	1.84	1.74	1.72	1.74	1.78	0.2%
Average	**34.08**	**36.03**	**38.87**	**35.71**	**34.83**	**34.94**	**35.70**	**-0.0%**
Exports[10]	69.22	70.93	80.99	71.83	74.00	76.33	79.44	0.5%

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Excludes imports to Puerto Rico and the U.S. Virgin Islands.
[4]Production plus waste coal supplied plus net imports.
[5]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal-to-liquids process.
[6]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Balancing item: the sum of production, net imports, and waste coal supplied minus total consumption.
[8]Includes reported prices for both open market and captive mines.
[9]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[10]F.a.s. price at U.S. port of exit.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 data based on: Energy Information Administration (EIA), *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007); EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007); and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A16. Renewable Energy Generating Capacity and Generation
(Gigawatts, Unless Otherwise Noted)

Capacity and Generation	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	76.72	76.72	76.73	77.15	77.26	77.26	77.32	0.0%
Geothermal[2]	2.23	2.29	2.50	2.88	3.28	3.77	4.18	2.5%
Municipal Waste[3]	3.21	3.39	3.99	3.99	4.02	4.06	4.06	0.8%
Wood and Other Biomass[4,5]	1.96	2.01	2.20	2.74	4.39	4.84	5.58	4.3%
Solar Thermal	0.40	0.40	0.54	0.80	0.82	0.84	0.86	3.2%
Solar Photovoltaic[6]	0.03	0.03	0.07	0.14	0.22	0.30	0.39	11.2%
Wind	8.92	11.50	25.61	29.63	33.64	37.18	40.15	5.3%
Total	**93.46**	**96.34**	**111.63**	**117.32**	**123.62**	**128.26**	**132.54**	**1.3%**
Generation (billion kilowatthours)								
Conventional Hydropower	266.91	285.07	289.47	297.22	298.00	298.09	298.53	0.2%
Geothermal[2]	14.69	14.84	17.52	20.79	23.96	27.84	31.05	3.1%
Biogenic Municipal Waste[7]	12.70	13.46	18.85	18.85	19.08	19.46	19.47	1.6%
Wood and Other Biomass[5]	10.57	10.97	22.98	42.96	77.53	83.30	82.55	8.8%
Dedicated Plants	8.60	9.06	11.06	15.46	27.74	30.98	36.64	6.0%
Cofiring	1.97	1.91	11.92	27.51	49.79	52.32	45.91	14.2%
Solar Thermal	0.54	0.49	1.15	1.97	2.04	2.11	2.18	6.4%
Solar Photovoltaic[6]	0.02	0.01	0.16	0.32	0.52	0.74	0.96	19.6%
Wind	17.81	25.78	74.13	87.19	101.23	113.14	123.18	6.7%
Total	**323.23**	**350.62**	**424.27**	**469.30**	**522.35**	**544.68**	**557.91**	**2.0%**
End-Use Generators[8]								
Net Summer Capacity								
Conventional Hydropower[9]	0.71	0.70	0.70	0.70	0.70	0.70	0.70	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	0.34	0.35	0.35	0.35	0.35	0.35	0.35	0.0%
Biomass	4.72	4.64	4.89	6.37	8.57	12.21	12.60	4.3%
Solar Photovoltaic[6]	0.18	0.27	0.67	0.77	1.13	1.77	2.80	10.2%
Wind	0.01	0.04	0.04	0.05	0.09	0.17	0.26	8.0%
Total	**5.96**	**6.00**	**6.65**	**8.24**	**10.85**	**15.20**	**16.72**	**4.4%**
Generation (billion kilowatthours)								
Conventional Hydropower[9]	3.46	3.24	3.24	3.24	3.24	3.24	3.24	-0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[10]	1.95	2.06	2.82	2.82	2.82	2.82	2.82	1.3%
Biomass	28.33	28.44	29.98	40.50	57.00	84.74	86.99	4.8%
Solar Photovoltaic[6]	0.28	0.43	1.07	1.25	1.85	2.97	4.76	10.6%
Wind	0.02	0.06	0.06	0.06	0.13	0.24	0.38	8.3%
Total	**34.03**	**34.22**	**37.17**	**47.88**	**65.05**	**94.02**	**98.19**	**4.5%**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes all municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[4]Facilities co-firing biomass and coal are classified as coal.
[5]Includes projections for energy crops after 2012.
[6]Does not include off-grid PV. Based on annual PV shipments from 1989 through 2005, EIA estimates that as much as 192 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2005, plus an additional 481 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), Table 10.8 (annual PV shipments, 1989-2005). The approach used to develop the estimate, based on shipment data, provides an upper estimate of the size of the PV stock, including both grid-based and off-grid PV. It will overestimate the size of the stock, because shipments include a substantial number of units that are exported, and each year some of the PV units installed earlier will be retired from service or abandoned.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates approximately 7 billion kilowatthours of electricity was generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[8]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and 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.
[9]Represents own-use industrial hydroelectric power.
[10]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 capacity: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2005 and 2006 generation: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A17. Renewable Energy, Consumption by Sector and Source[1]
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Marketed Renewable Energy[2]								
Residential (wood)	**0.45**	**0.41**	**0.44**	**0.42**	**0.40**	**0.39**	**0.38**	**-0.3%**
Commercial (biomass)	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.13**	**0.0%**
Industrial[3]	**1.88**	**1.99**	**2.34**	**2.75**	**3.32**	**4.21**	**4.33**	**3.3%**
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.0%
Municipal Waste[4]	0.16	0.15	0.15	0.15	0.15	0.15	0.15	0.0%
Biomass	1.45	1.51	1.48	1.57	1.65	1.75	1.83	0.8%
Biofuels Heat and Coproducts	0.24	0.30	0.67	1.00	1.49	2.28	2.31	8.9%
Transportation	**0.35**	**0.50**	**1.13**	**1.66**	**2.24**	**2.77**	**2.77**	**7.4%**
Ethanol used in E85[5]	0.00	0.00	0.00	0.12	0.64	0.93	0.88	33.5%
Ethanol used in Gasoline Blending	0.34	0.47	1.05	1.22	1.18	1.13	1.13	3.7%
Biodiesel used in Distillate Blending	0.01	0.03	0.08	0.17	0.13	0.14	0.16	6.9%
Liquids from Biomass	0.00	0.00	0.00	0.15	0.29	0.56	0.60	- -
Electric Power[6]	**3.49**	**3.74**	**4.53**	**5.05**	**5.64**	**5.94**	**6.13**	**2.1%**
Conventional Hydroelectric	2.67	2.86	2.89	2.96	2.97	2.97	2.97	0.2%
Geothermal	0.31	0.31	0.37	0.48	0.58	0.70	0.80	4.0%
Biogenic Municipal Waste[7]	0.20	0.15	0.23	0.23	0.23	0.23	0.23	1.8%
Biomass	0.18	0.16	0.28	0.48	0.82	0.87	0.86	7.4%
Dedicated Plants	0.14	0.12	0.12	0.16	0.27	0.30	0.36	4.6%
Cofiring	0.04	0.03	0.16	0.33	0.55	0.57	0.49	11.9%
Solar Thermal	0.01	0.00	0.01	0.02	0.02	0.02	0.02	6.4%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.01	0.01	0.01	19.6%
Wind	0.12	0.26	0.74	0.87	1.02	1.13	1.24	6.7%
Total Marketed Renewable Energy	**6.30**	**6.77**	**8.56**	**10.00**	**11.74**	**13.44**	**13.73**	**3.0%**
Sources of Ethanol								
From Corn	0.33	0.41	0.95	1.18	1.26	1.26	1.26	4.8%
From Cellulose	0.00	0.00	0.01	0.03	0.23	0.58	0.58	- -
From Other Feedstocks	0.00	0.00	0.00	0.00	0.01	0.02	0.01	- -
Net Imports	0.01	0.06	0.09	0.14	0.31	0.19	0.15	4.0%
Total	**0.34**	**0.47**	**1.05**	**1.34**	**1.82**	**2.06**	**2.01**	**6.2%**

Table A17. Renewable Energy, Consumption by Sector and Source[1] (Continued)
(Quadrillion Btu per Year)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Nonmarketed Renewable Energy[8] Selected Consumption								
Residential	**0.01**	**0.02**	**0.02**	**0.03**	**0.04**	**0.05**	**0.07**	**5.9%**
Solar Hot Water Heating	0.01	0.01	0.02	0.02	0.03	0.04	0.05	5.3%
Geothermal Heat Pumps	0.00	0.00	0.00	0.01	0.01	0.01	0.01	6.1%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.00	0.01	16.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.0%
Commercial	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**1.7%**
Solar Thermal	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.5%
Solar Photovoltaic	0.00	0.00	0.00	0.00	0.00	0.01	0.01	8.7%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.9%

[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 10,022 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; see Table A2.
[3]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[4]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[5]Excludes motor gasoline component of E85.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities. Only biogenic municipal waste is included. The Energy Information Administration estimates approximately .38 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy*, (Washington, DC, May 2007).
[8]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.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 ethanol: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 and 2006 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2005 and 2006 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A18. Carbon Dioxide Emissions by Sector and Source
(Million Metric Tons, Unless Otherwise Noted)

Sector and Source	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Residential								
Petroleum	101	100	91	92	92	90	88	-0.5%
Natural Gas	262	237	263	274	281	284	282	0.7%
Coal	1	1	1	1	1	1	1	0.9%
Electricity[1]	890	866	904	913	949	1004	1079	0.9%
Total	**1253**	**1204**	**1259**	**1280**	**1324**	**1379**	**1451**	**0.8%**
Commercial								
Petroleum	52	53	46	48	49	49	49	-0.3%
Natural Gas	169	155	162	175	184	193	201	1.1%
Coal	9	6	8	8	8	8	8	1.0%
Electricity[1]	835	832	864	945	1024	1117	1216	1.6%
Total	**1066**	**1046**	**1079**	**1176**	**1265**	**1367**	**1474**	**1.4%**
Industrial[2]								
Petroleum	412	421	435	442	432	428	436	0.1%
Natural Gas[3]	409	399	430	435	434	437	433	0.3%
Coal	189	189	186	185	204	206	217	0.6%
Electricity[1]	668	642	640	656	649	645	647	0.0%
Total	**1677**	**1652**	**1693**	**1718**	**1718**	**1716**	**1733**	**0.2%**
Transportation								
Petroleum[4]	1948	1952	1940	2010	2032	2062	2145	0.4%
Natural Gas[5]	33	33	36	38	40	43	43	1.2%
Electricity[1]	4	4	4	5	5	5	5	1.2%
Total	**1985**	**1989**	**1980**	**2052**	**2077**	**2110**	**2193**	**0.4%**
Electric Power[6]								
Petroleum	101	55	43	44	45	47	48	-0.5%
Natural Gas	321	340	365	358	323	289	272	-0.9%
Coal	1964	1938	1993	2105	2247	2423	2615	1.3%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**2397**	**2344**	**2413**	**2519**	**2627**	**2771**	**2948**	**1.0%**
Total by Fuel								
Petroleum[3]	2615	2581	2555	2636	2650	2676	2767	0.3%
Natural Gas	1193	1163	1256	1279	1262	1245	1231	0.2%
Coal	2162	2134	2188	2299	2459	2638	2841	1.2%
Other[7]	12	12	12	12	12	12	12	0.1%
Total	**5982**	**5890**	**6011**	**6226**	**6384**	**6571**	**6851**	**0.6%**
Carbon Dioxide Emissions (tons per person)	**20.1**	**19.6**	**19.3**	**19.2**	**18.9**	**18.7**	**18.7**	**-0.2%**

[1]Emissions from the electric power sector are distributed to the end-use sectors.
[2]Fuel consumption includes energy for combined heat and power plants (CHP), except those plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes lease and plant fuel.
[4]This includes carbon dioxide from international bunker fuels, both civilian and military, which are excluded from the accounting of carbon dioxide emissions under the United Nations convention. From 1990 through 2006, international bunker fuels accounted for 84 to 126 million metric tons annually.
[5]Includes pipeline fuel natural gas and compressed natural gas used as vehicle fuel.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 emissions and emission factors: Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2006,* DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A19. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	Reference Case 2005	2006	2010	2015	2020	2025	2030	Annual Growth 2006-2030 (percent)
Real Gross Domestic Product	**11004**	**11319**	**12453**	**14199**	**15984**	**17951**	**20219**	**2.4%**
Components of Real Gross Domestic Product								
Real Consumption	7804	8044	8845	10151	11362	12628	13999	2.3%
Real Investment	1869	1920	1939	2307	2614	3088	3743	2.8%
Real Government Spending	1946	1981	2087	2164	2258	2352	2471	0.9%
Real Exports	1203	1304	1797	2455	3387	4582	6191	6.7%
Real Imports	1821	1929	2190	2796	3474	4415	5723	4.6%
Energy Intensity (thousand Btu per 2000 dollar of GDP)								
Delivered Energy	6.62	6.39	6.03	5.48	5.00	4.57	4.16	-1.8%
Total Energy	9.09	8.79	8.30	7.54	6.91	6.35	5.80	-1.7%
Price Indices								
GDP Chain-type Price Index (2000=1.000)	1.130	1.166	1.260	1.375	1.520	1.686	1.871	2.0%
Consumer Price Index (1982-4=1.00)								
All-urban	1.95	2.02	2.20	2.38	2.64	2.94	3.29	2.1%
Energy Commodities and Services	1.77	1.97	2.15	2.15	2.43	2.73	3.14	2.0%
Wholesale Price Index (1982=1.00)								
All Commodities	1.57	1.65	1.80	1.84	1.96	2.10	2.26	1.3%
Fuel and Power	1.56	1.67	1.88	1.82	2.04	2.34	2.75	2.1%
Interest Rates (percent, nominal)								
Federal Funds Rate	3.21	4.96	4.69	4.71	4.92	4.85	4.91	- -
10-Year Treasury Note	4.29	4.79	5.24	5.20	5.44	5.41	5.46	- -
AA Utility Bond Rate	5.44	5.84	6.65	6.71	6.98	7.01	7.13	- -
Value of Shipments (billion 2000 dollars)								
Total Industrial	5732	5821	5997	6659	7113	7546	7997	1.3%
Nonmanufacturing	1525	1531	1419	1583	1619	1663	1715	0.5%
Manufacturing	4208	4290	4577	5076	5493	5883	6283	1.6%
Energy-Intensive	1207	1225	1283	1351	1387	1418	1447	0.7%
Non-energy Intensive	3001	3065	3295	3725	4107	4465	4836	1.9%
Population and Employment (millions)								
Population, with Armed Forces Overseas	297.3	300.1	310.9	324.3	337.7	351.4	365.6	0.8%
Population, aged 16 and over	232.2	235.0	244.9	255.3	266.0	277.3	289.3	0.9%
Population, over age 65	36.9	37.3	40.4	47.0	54.9	63.8	71.6	2.8%
Employment, Nonfarm	133.6	136.1	142.4	149.7	154.5	160.9	168.1	0.9%
Employment, Manufacturing	14.2	14.2	14.2	14.4	13.8	12.5	11.2	-1.0%
Key Labor Indicators								
Labor Force (millions)	149.3	151.4	156.8	162.1	165.6	171.0	177.9	0.7%
Nonfarm Labor Productivity (1992=1.00)	1.34	1.35	1.45	1.60	1.77	1.95	2.14	1.9%
Unemployment Rate (percent)	5.07	4.63	5.03	4.58	4.62	4.79	4.80	- -
Key Indicators for Energy Demand								
Real Disposable Personal Income	8148	8397	9472	11055	12654	14349	16246	2.8%
Housing Starts (millions)	2.22	1.93	1.68	1.88	1.78	1.74	1.70	-0.5%
Commercial Floorspace (billion square feet)	73.8	74.8	78.8	83.9	89.3	94.8	100.8	1.2%
Unit Sales of Light-Duty Vehicles (millions)	16.95	16.50	16.38	17.75	17.47	18.35	19.39	0.7%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2005 and 2006: Global Insight, Global Insight Industry and Employment models, July 2007. **Projections:** Energy Information Administration, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Table A20. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Crude Oil Prices (2006 dollars per barrel)								
Imported Low Sulfur Light Crude Oil	58.28	66.02	74.03	59.85	59.70	64.49	70.45	0.3%
Imported Crude Oil[1]	50.40	59.05	65.18	52.03	51.55	55.68	58.66	-0.0%
Conventional Production (Conventional)[2]								
OPEC[3]								
Asia	1.15	1.11	1.03	0.99	0.98	0.99	0.94	-0.7%
Middle East	22.50	23.21	22.41	23.40	24.09	25.24	27.35	0.7%
North Africa	3.81	3.90	4.28	4.63	4.78	4.84	4.82	0.9%
West Africa	4.03	4.02	5.77	6.88	7.41	7.80	8.23	3.0%
South America	2.21	2.06	1.99	2.20	2.18	2.17	2.16	0.2%
Total OPEC	**33.71**	**34.30**	**35.48**	**38.09**	**39.45**	**41.04**	**43.50**	**1.0%**
Non-OPEC								
OECD								
United States (50 states)	8.04	7.91	8.84	9.12	9.15	8.84	8.39	0.2%
Canada	1.99	2.00	1.85	1.56	1.32	1.16	1.05	-2.7%
Mexico	3.79	3.74	3.37	3.29	3.25	3.24	3.35	-0.5%
OECD Europe[4]	5.94	5.52	4.89	4.05	3.59	3.43	3.39	-2.0%
Japan	0.13	0.13	0.12	0.13	0.14	0.15	0.15	0.8%
Australia and New Zealand	0.59	0.57	0.62	0.64	0.65	0.66	0.66	0.6%
Total OECD	**20.48**	**19.85**	**19.69**	**18.78**	**18.10**	**17.48**	**16.99**	**-0.6%**
Non-OECD								
Russia	9.58	9.82	10.34	10.60	10.90	11.37	11.69	0.7%
Other Eurasia[5]	2.65	2.85	3.77	4.83	5.46	5.88	6.36	3.4%
China	3.74	3.80	3.83	3.87	3.87	3.70	3.53	-0.3%
Other Asia[6]	2.77	2.89	2.92	3.22	3.40	3.43	3.17	0.4%
Middle East[7]	1.67	1.69	2.00	2.20	2.40	2.70	2.90	2.3%
Africa	2.47	2.49	2.92	3.35	3.83	4.04	3.99	2.0%
Brazil	1.75	1.84	2.40	2.94	3.39	3.65	3.66	2.9%
Other Central and South America	2.36	2.36	2.32	2.49	2.67	3.03	3.51	1.7%
Total Non-OECD	**26.98**	**27.73**	**30.51**	**33.49**	**35.94**	**37.80**	**38.81**	**1.4%**
Total Conventional Production	**81.17**	**81.88**	**85.67**	**90.37**	**93.48**	**96.31**	**99.30**	**0.8%**
Unconventional Production[8]								
United States (50 states)	0.26	0.34	0.78	1.15	1.53	1.97	2.06	7.9%
Other North America	1.09	1.23	1.91	2.34	2.85	3.41	3.96	5.0%
OECD Europe[3]	0.03	0.04	0.07	0.10	0.15	0.19	0.26	8.4%
Middle East[7]	0.00	0.00	0.03	0.18	0.31	0.62	1.24	25.8%
Africa.	0.15	0.17	0.31	0.36	0.44	0.59	0.83	6.9%
Central and South America	0.79	0.80	1.18	1.45	1.76	2.09	2.51	4.9%
Other	0.16	0.20	0.44	0.76	1.28	1.96	3.15	12.1%
Total Unconventional Production	**2.48**	**2.78**	**4.73**	**6.34**	**8.32**	**10.83**	**14.00**	**7.0%**
Total Production	**83.65**	**84.66**	**90.40**	**96.70**	**101.80**	**107.14**	**113.31**	**1.2%**

Table A20. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	Reference Case							Annual Growth 2006-2030 (percent)
	2005	2006	2010	2015	2020	2025	2030	
Consumption[9]								
OECD								
United States (50 states)	20.80	20.65	20.99	21.59	21.47	21.52	22.11	0.3%
United States Territories	0.37	0.38	0.43	0.47	0.51	0.55	0.59	1.9%
Canada	2.26	2.27	2.32	2.34	2.36	2.38	2.40	0.2%
Mexico	2.03	2.06	2.19	2.36	2.61	2.75	2.95	1.5%
OECD Europe[3]	15.42	15.42	15.47	15.63	15.71	15.79	15.86	0.1%
Japan	5.16	5.16	5.18	5.21	5.22	5.24	5.26	0.1%
South Korea	2.17	2.18	2.25	2.47	2.57	2.68	2.81	1.1%
Australia and New Zealand	1.03	1.03	1.07	1.13	1.19	1.25	1.28	0.9%
Total OECD	**49.24**	**49.16**	**49.90**	**51.20**	**51.64**	**52.16**	**53.28**	**0.3%**
Non-OECD								
Russia	2.77	2.79	2.89	3.03	3.13	3.25	3.32	0.7%
Other Non-OECD Eurasia[5]	2.05	2.09	2.26	2.43	2.64	2.79	2.96	1.5%
China	6.73	7.26	9.44	10.55	11.96	13.63	15.69	3.3%
India	2.44	2.49	2.68	3.25	3.62	4.03	4.37	2.4%
Other Non-OECD Asia	6.02	6.14	6.67	7.64	8.35	9.08	9.86	2.0%
Middle East[7]	5.91	6.15	7.13	7.79	8.46	9.18	9.84	2.0%
Africa	2.90	2.99	3.36	3.88	4.35	4.62	4.93	2.1%
Brazil	2.40	2.34	2.57	2.87	3.15	3.42	3.68	1.9%
Other Central and South America	3.17	3.26	3.51	4.05	4.51	4.98	5.37	2.1%
Total Non-OECD	**34.41**	**35.51**	**40.51**	**45.50**	**50.16**	**54.98**	**60.02**	**2.2%**
Total Consumption	**83.65**	**84.66**	**90.40**	**96.70**	**101.80**	**107.14**	**113.30**	**1.2%**
OPEC Production[10]	34.31	34.90	36.40	39.26	40.87	42.91	46.16	1.2%
Non-OPEC Production[10]	49.34	49.76	54.00	57.44	60.94	64.23	67.15	1.3%
Net Eurasia Exports	9.15	9.63	11.37	12.91	13.98	14.86	15.43	2.0%
OPEC Market Share (percent)	41.0	41.2	40.3	40.6	40.1	40.0	40.7	-0.0%

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela. Does not include Ecuador, which was admitted to OPEC as a full member on November 17, 2007.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Eurasia consists of Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2005 and 2006 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2005 and 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2005 quantities derived from: EIA, *International Energy Annual 2005*, DOE/EIA-0219(2005) (Washington, DC, June-October 2007). **2006 quantities and projections:** EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.

Economic Growth Case Comparisons

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

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Production										
Crude Oil and Lease Condensate	10.80	12.75	12.76	12.77	13.38	13.40	13.52	11.87	12.04	12.18
Natural Gas Plant Liquids	2.36	2.26	2.27	2.29	2.25	2.31	2.36	2.01	2.11	2.20
Dry Natural Gas	19.04	19.53	19.85	20.13	19.50	20.24	20.63	19.07	20.00	21.10
Coal[1]	23.79	23.95	23.97	24.00	23.63	25.20	27.23	25.47	28.63	32.20
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Hydropower	2.89	2.92	2.92	2.92	2.99	3.00	3.00	2.99	3.00	3.00
Biomass[2]	2.94	4.02	4.05	4.10	6.29	6.42	6.61	7.84	8.12	8.53
Other Renewable Energy[3]	0.88	1.46	1.51	1.51	1.78	2.00	2.08	2.09	2.45	2.61
Other[4]	0.50	0.53	0.54	0.54	0.59	0.58	0.58	0.64	0.64	0.65
Total	**71.41**	**75.71**	**76.17**	**76.56**	**79.31**	**82.21**	**85.27**	**80.71**	**86.56**	**93.39**
Imports										
Crude Oil	22.08	20.76	21.14	21.33	20.61	21.58	22.36	22.66	24.41	25.77
Liquid Fuels and Other Petroleum[5]	7.21	5.44	5.61	6.02	4.61	5.43	6.41	3.90	5.44	6.93
Natural Gas	4.29	4.70	4.80	4.89	4.42	4.68	4.93	4.16	4.64	4.80
Other Imports[6]	0.98	0.94	0.95	0.95	1.96	1.93	1.95	2.80	2.74	2.85
Total	**34.57**	**31.84**	**32.49**	**33.20**	**31.60**	**33.62**	**35.65**	**33.52**	**37.22**	**40.36**
Exports										
Petroleum[7]	2.60	2.83	2.82	2.84	3.00	2.98	3.00	3.42	3.33	3.11
Natural Gas	0.73	0.85	0.84	0.84	1.05	1.02	1.00	1.43	1.36	1.30
Coal	1.26	1.79	1.79	1.79	0.88	0.87	0.86	0.88	0.88	0.88
Total	**4.59**	**5.47**	**5.45**	**5.47**	**4.93**	**4.87**	**4.86**	**5.73**	**5.56**	**5.29**
Discrepancy[8]	**1.87**	**-0.10**	**-0.13**	**-0.17**	**0.17**	**0.12**	**0.02**	**0.29**	**0.21**	**0.07**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.06	39.85	40.46	41.12	40.15	42.24	44.43	40.08	43.99	48.01
Natural Gas	22.30	23.51	23.93	24.31	22.99	24.01	24.68	21.91	23.39	24.71
Coal[10]	22.50	23.00	23.03	23.06	24.48	25.87	27.74	27.00	29.90	32.99
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Hydropower	2.89	2.92	2.92	2.92	2.99	3.00	3.00	2.99	3.00	3.00
Biomass[11]	2.50	2.97	3.01	3.06	4.35	4.50	4.69	5.23	5.51	5.94
Other Renewable Energy[3]	0.88	1.46	1.51	1.51	1.78	2.00	2.08	2.09	2.45	2.61
Other[12]	0.19	0.18	0.18	0.18	0.17	0.17	0.17	0.18	0.20	0.20
Total	**99.52**	**102.19**	**103.34**	**104.46**	**105.82**	**110.85**	**116.04**	**108.21**	**118.01**	**128.38**

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

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Prices (2006 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price	66.02	73.52	74.03	74.56	58.73	59.70	60.62	68.43	70.45	72.15
Imported Crude Oil Price[13]	59.05	64.48	65.18	66.21	50.37	51.55	52.42	55.52	58.66	62.27
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.73	6.69	6.90	7.11	5.72	5.95	5.93	6.84	7.22	7.61
Wellhead Price[14]	6.24	5.96	6.16	6.35	5.08	5.29	5.27	6.10	6.45	6.80
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.42	6.13	6.33	6.53	5.22	5.44	5.43	6.27	6.63	7.00
Coal (dollars per ton)										
Minemouth Price[15]	24.63	26.02	26.16	26.33	22.24	22.51	23.16	22.15	23.32	24.09
Coal (dollars per million Btu)										
Minemouth Price[15]	1.21	1.27	1.28	1.29	1.12	1.14	1.18	1.13	1.19	1.24
Average Delivered Price[16]	1.78	1.92	1.93	1.94	1.74	1.77	1.81	1.76	1.82	1.87
Average Electricity Price (cents per kilowatthour)	8.9	9.1	9.2	9.3	8.3	8.6	8.7	8.6	8.8	9.1

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

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

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.47	0.48	0.48	0.48	0.51	0.52	0.53	0.52	0.55	0.58
Kerosene	0.07	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08	0.09
Distillate Fuel Oil	0.70	0.76	0.75	0.75	0.73	0.73	0.73	0.65	0.65	0.65
Liquid Fuels and Other Petroleum Subtotal	1.25	1.31	1.31	1.32	1.32	1.33	1.35	1.26	1.29	1.32
Natural Gas	4.50	4.94	4.95	4.96	5.18	5.30	5.44	5.07	5.32	5.57
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.44	0.44	0.44	0.40	0.40	0.41	0.36	0.38	0.39
Electricity	4.61	4.93	4.95	4.97	5.10	5.25	5.41	5.52	5.88	6.22
Delivered Energy	**10.77**	**11.63**	**11.66**	**11.69**	**12.01**	**12.30**	**12.63**	**12.23**	**12.88**	**13.52**
Electricity Related Losses	10.04	10.58	10.59	10.60	10.81	11.08	11.36	11.54	12.14	12.74
Total	**20.82**	**22.22**	**22.25**	**22.29**	**22.82**	**23.39**	**23.99**	**23.77**	**25.01**	**26.25**
Commercial										
Liquefied Petroleum Gases	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.10
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.42	0.38	0.38	0.38	0.41	0.41	0.42	0.40	0.41	0.42
Residual Fuel Oil	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Liquid Fuels and Other Petroleum Subtotal	0.68	0.63	0.63	0.63	0.67	0.68	0.69	0.67	0.68	0.70
Natural Gas	2.92	3.02	3.04	3.06	3.34	3.47	3.60	3.54	3.78	4.03
Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.43	4.69	4.73	4.75	5.49	5.67	5.84	6.24	6.62	7.01
Delivered Energy	**8.25**	**8.56**	**8.62**	**8.65**	**9.71**	**10.03**	**10.34**	**10.66**	**11.30**	**11.95**
Electricity Related Losses	9.66	10.07	10.12	10.14	11.63	11.96	12.26	13.04	13.68	14.34
Total	**17.91**	**18.63**	**18.74**	**18.80**	**21.34**	**21.98**	**22.60**	**23.70**	**24.98**	**26.29**
Industrial[4]										
Liquefied Petroleum Gases	2.09	2.07	2.12	2.18	1.65	1.83	2.04	1.40	1.71	2.05
Motor Gasoline[2]	0.38	0.36	0.38	0.39	0.34	0.37	0.41	0.33	0.38	0.43
Distillate Fuel Oil	1.28	1.24	1.29	1.34	1.12	1.23	1.34	1.07	1.23	1.40
Residual Fuel Oil	0.28	0.27	0.28	0.29	0.22	0.23	0.24	0.20	0.23	0.25
Petrochemical Feedstocks	1.41	1.32	1.36	1.41	1.22	1.39	1.57	1.01	1.29	1.60
Other Petroleum[5]	4.48	4.11	4.25	4.38	3.99	4.22	4.48	4.02	4.41	4.79
Liquid Fuels and Other Petroleum Subtotal	9.92	9.38	9.67	9.98	8.53	9.27	10.07	8.03	9.25	10.53
Natural Gas	6.68	7.03	7.16	7.24	6.67	7.14	7.60	6.14	7.08	7.94
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.17	1.20	1.21	1.22	1.22	1.25	1.27	1.23	1.27	1.32
Natural Gas Subtotal	7.85	8.23	8.37	8.47	7.89	8.39	8.87	7.37	8.35	9.26
Metallurgical Coal	0.60	0.59	0.60	0.61	0.49	0.54	0.58	0.39	0.48	0.57
Other Industrial Coal	1.26	1.29	1.31	1.32	1.15	1.20	1.24	1.10	1.18	1.25
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.15	0.34	0.58	0.34	0.55	1.27
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.02	0.04	0.06
Coal Subtotal	1.92	1.91	1.93	1.96	1.82	2.11	2.45	1.84	2.26	3.15
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.67	1.50	1.49	1.49	2.34	2.31	2.29
Renewable Energy[7]	1.69	1.62	1.66	1.71	1.70	1.83	1.98	1.71	2.02	2.33
Electricity	3.42	3.44	3.50	3.57	3.32	3.59	3.87	2.94	3.52	4.10
Delivered Energy	**25.10**	**25.26**	**25.82**	**26.36**	**24.75**	**26.70**	**28.73**	**24.23**	**27.70**	**31.67**
Electricity Related Losses	7.45	7.38	7.50	7.62	7.03	7.57	8.13	6.14	7.28	8.39
Total	**32.55**	**32.64**	**33.32**	**33.98**	**31.78**	**34.27**	**36.86**	**30.37**	**34.98**	**40.06**

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

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Transportation										
Liquefied Petroleum Gases	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.02
E85[8]	0.00	0.00	0.00	0.00	1.07	0.97	0.95	1.53	1.34	1.26
Motor Gasoline[2]	17.20	17.13	17.25	17.40	15.81	16.56	17.32	14.66	15.97	17.34
Jet Fuel[9]	3.16	3.41	3.44	3.47	4.10	4.15	4.13	4.62	4.79	4.83
Distillate Fuel Oil[10]	6.18	6.38	6.54	6.72	7.05	7.63	8.26	7.67	8.98	10.30
Residual Fuel Oil	0.83	0.85	0.85	0.86	0.85	0.86	0.87	0.86	0.87	0.88
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.18	0.17	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.19
Liquid Fuels and Other Petroleum Subtotal	27.57	27.97	28.29	28.63	29.06	30.37	31.72	29.53	32.15	34.82
Pipeline Fuel Natural Gas	0.59	0.63	0.64	0.65	0.66	0.69	0.71	0.68	0.72	0.76
Compressed Natural Gas	0.02	0.03	0.04	0.04	0.06	0.07	0.08	0.07	0.08	0.10
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Delivered Energy	**28.20**	**28.66**	**28.98**	**29.34**	**29.81**	**31.15**	**32.53**	**30.31**	**32.98**	**35.71**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Total	**28.25**	**28.70**	**29.03**	**29.39**	**29.87**	**31.21**	**32.59**	**30.38**	**33.04**	**35.77**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.65	2.65	2.70	2.76	2.26	2.45	2.68	2.03	2.37	2.75
E85[8]	0.00	0.00	0.00	0.00	1.07	0.97	0.95	1.53	1.34	1.26
Motor Gasoline[2]	17.62	17.54	17.68	17.84	16.20	16.99	17.78	15.04	16.40	17.83
Jet Fuel[9]	3.16	3.41	3.44	3.47	4.10	4.15	4.13	4.62	4.79	4.83
Kerosene	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13
Distillate Fuel Oil	8.59	8.76	8.97	9.19	9.31	10.00	10.74	9.80	11.28	12.77
Residual Fuel Oil	1.23	1.22	1.23	1.24	1.17	1.19	1.21	1.15	1.20	1.24
Petrochemical Feedstocks	1.41	1.32	1.36	1.41	1.22	1.39	1.57	1.01	1.29	1.60
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.27	4.40	4.54	4.14	4.38	4.64	4.18	4.56	4.96
Liquid Fuels and Other Petroleum Subtotal	39.41	39.30	39.90	40.56	39.58	41.65	43.83	39.49	43.37	47.37
Natural Gas	14.12	15.03	15.19	15.30	15.25	15.98	16.72	14.82	16.27	17.64
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.17	1.20	1.21	1.22	1.22	1.25	1.27	1.23	1.27	1.32
Pipeline Natural Gas	0.59	0.63	0.64	0.65	0.66	0.69	0.71	0.68	0.72	0.76
Natural Gas Subtotal	15.88	16.86	17.04	17.17	17.13	17.93	18.70	16.73	18.26	19.73
Metallurgical Coal	0.60	0.59	0.60	0.61	0.49	0.54	0.58	0.39	0.48	0.57
Other Coal	1.35	1.38	1.40	1.41	1.24	1.29	1.33	1.19	1.27	1.34
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.15	0.34	0.58	0.34	0.55	1.27
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.02	0.04	0.06
Coal Subtotal	2.02	2.00	2.03	2.05	1.92	2.21	2.54	1.93	2.35	3.25
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.67	1.50	1.49	1.49	2.34	2.31	2.29
Renewable Energy[13]	2.23	2.19	2.23	2.28	2.22	2.37	2.52	2.21	2.52	2.85
Electricity	12.49	13.08	13.20	13.31	13.93	14.54	15.16	14.74	16.05	17.36
Delivered Energy	**72.32**	**74.10**	**75.08**	**76.05**	**76.28**	**80.18**	**84.23**	**77.43**	**84.86**	**92.85**
Electricity Related Losses	27.19	28.08	28.26	28.41	29.54	30.67	31.81	30.78	33.16	35.54
Total	**99.52**	**102.19**	**103.34**	**104.46**	**105.82**	**110.85**	**116.04**	**108.21**	**118.01**	**128.38**
Electric Power[14]										
Distillate Fuel Oil	0.18	0.18	0.18	0.18	0.18	0.20	0.21	0.20	0.23	0.24
Residual Fuel Oil	0.46	0.38	0.38	0.38	0.38	0.39	0.39	0.39	0.40	0.41
Liquid Fuels and Other Petroleum Subtotal	0.64	0.55	0.56	0.56	0.56	0.59	0.60	0.59	0.63	0.64
Natural Gas	6.42	6.64	6.89	7.14	5.86	6.09	5.97	5.18	5.13	4.99
Steam Coal	20.48	21.00	21.01	21.01	22.57	23.67	25.20	25.07	27.55	29.75
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Renewable Energy[15]	3.74	4.48	4.53	4.52	5.41	5.64	5.75	5.77	6.13	6.40
Electricity Imports	0.06	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.08	0.07
Total[16]	**39.68**	**41.16**	**41.46**	**41.72**	**43.47**	**45.21**	**46.96**	**45.52**	**49.21**	**52.90**

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

Sector and Source	2006	Projections 2010 Low Economic Growth	2010 Reference	2010 High Economic Growth	2020 Low Economic Growth	2020 Reference	2020 High Economic Growth	2030 Low Economic Growth	2030 Reference	2030 High Economic Growth
Total Energy Consumption										
Liquefied Petroleum Gases	2.65	2.65	2.70	2.76	2.26	2.45	2.68	2.03	2.37	2.75
E85[8]	0.00	0.00	0.00	0.00	1.07	0.97	0.95	1.53	1.34	1.26
Motor Gasoline[2]	17.62	17.54	17.68	17.84	16.20	16.99	17.78	15.04	16.40	17.83
Jet Fuel[9]	3.16	3.41	3.44	3.47	4.10	4.15	4.13	4.62	4.79	4.83
Kerosene	0.11	0.12	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13
Distillate Fuel Oil	8.77	8.94	9.15	9.37	9.49	10.20	10.96	10.01	11.51	13.01
Residual Fuel Oil	1.69	1.60	1.60	1.62	1.55	1.58	1.60	1.54	1.60	1.65
Petrochemical Feedstocks	1.41	1.32	1.36	1.41	1.22	1.39	1.57	1.01	1.29	1.60
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.27	4.40	4.54	4.14	4.38	4.64	4.18	4.56	4.96
Liquid Fuels and Other Petroleum Subtotal	40.06	39.85	40.46	41.12	40.15	42.24	44.43	40.08	43.99	48.01
Natural Gas	20.54	21.68	22.08	22.44	21.10	22.07	22.70	20.00	21.40	22.63
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lease and Plant Fuel[6]	1.17	1.20	1.21	1.22	1.22	1.25	1.27	1.23	1.27	1.32
Pipeline Natural Gas	0.59	0.63	0.64	0.65	0.66	0.69	0.71	0.68	0.72	0.76
Natural Gas Subtotal	22.30	23.51	23.93	24.31	22.99	24.01	24.68	21.91	23.39	24.71
Metallurgical Coal	0.60	0.59	0.60	0.61	0.49	0.54	0.58	0.39	0.48	0.57
Other Coal	21.83	22.38	22.41	22.42	23.81	24.96	26.53	26.26	28.82	31.09
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.15	0.34	0.58	0.34	0.55	1.27
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.02	0.04	0.06
Coal Subtotal	22.50	23.00	23.03	23.06	24.48	25.87	27.74	27.00	29.90	32.99
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.92
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.67	1.50	1.49	1.49	2.34	2.31	2.29
Renewable Energy[17]	5.97	6.67	6.76	6.81	7.63	8.01	8.27	7.98	8.66	9.25
Electricity Imports	0.06	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.08	0.07
Total	**99.52**	**102.19**	**103.34**	**104.46**	**105.82**	**110.85**	**116.04**	**108.21**	**118.01**	**128.38**
Energy Use and Related Statistics										
Delivered Energy Use	72.32	74.10	75.08	76.05	76.28	80.18	84.23	77.43	84.86	92.85
Total Energy Use	99.52	102.19	103.34	104.46	105.82	110.85	116.04	108.21	118.01	128.38
Ethanol Consumed in Motor Gasoline and E85	0.47	1.04	1.05	1.05	1.82	1.82	1.82	2.04	2.01	2.01
Population (millions)	300.13	309.46	310.85	312.64	325.45	337.74	351.32	336.65	365.59	396.34
Gross Domestic Product (billion 2000 dollars)	11319	12110	12453	12797	14743	15984	17239	17429	20219	23002
Carbon Dioxide Emissions (million metric tons)	5890.3	5953.4	6010.6	6068.7	6076.9	6384.1	6720.8	6263.6	6851.0	7452.0

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, 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 ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic and solar thermal sources. Excludes ethanol, 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.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 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: 2006 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 population and gross domestic product: Global Insight, Global Insight Industry and Employment models, July 2007. 2006 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2006,* DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

Table B3. Energy Prices by Sector and Source
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Residential										
Liquefied Petroleum Gases	23.08	25.00	25.21	25.41	23.99	24.23	24.25	25.03	25.43	25.85
Distillate Fuel Oil	17.94	16.74	17.21	17.48	13.96	14.27	14.71	15.20	16.27	17.12
Natural Gas	13.40	11.95	12.15	12.36	11.14	11.39	11.44	12.47	12.91	13.36
Electricity	30.52	30.99	31.37	31.75	29.19	30.20	30.75	29.59	30.63	31.72
Commercial										
Distillate Fuel Oil	14.59	14.78	15.24	15.51	12.88	13.24	13.81	13.96	15.00	16.08
Residual Fuel Oil	8.60	9.95	10.06	10.17	7.73	7.95	8.11	8.52	9.22	9.80
Natural Gas	11.50	10.41	10.59	10.79	9.72	9.91	9.89	11.13	11.43	11.75
Electricity	27.75	27.46	27.89	28.32	24.63	25.64	26.14	25.22	26.17	27.20
Industrial[1]										
Liquefied Petroleum Gases	19.71	17.58	17.74	17.93	16.65	16.79	16.71	17.60	17.79	18.16
Distillate Fuel Oil	15.33	15.27	15.72	15.99	14.21	14.62	15.23	15.21	16.26	17.47
Residual Fuel Oil	9.06	10.51	10.86	11.10	7.96	8.29	8.65	8.84	9.62	10.61
Natural Gas[2]	7.66	7.02	7.21	7.41	6.00	6.21	6.20	6.95	7.29	7.65
Metallurgical Coal	3.54	4.06	4.07	4.09	3.38	3.42	3.45	3.54	3.60	3.67
Other Industrial Coal	2.34	2.41	2.42	2.43	2.24	2.28	2.34	2.26	2.33	2.41
Coal to Liquids	- -	- -	- -	- -	0.94	1.09	1.27	1.20	1.30	1.39
Electricity	17.97	18.88	19.21	19.56	16.49	17.27	17.59	16.93	17.63	18.24
Transportation										
Liquefied Petroleum Gases[3]	21.72	25.82	26.03	26.24	24.70	24.94	24.95	25.64	26.03	26.44
E85[4]	24.81	22.26	23.58	23.84	18.66	18.15	19.83	18.85	19.62	21.43
Motor Gasoline[5]	21.19	20.80	21.23	21.47	18.98	19.64	19.96	19.29	20.37	21.58
Jet Fuel[6]	14.83	15.33	15.77	16.03	13.02	13.27	13.54	14.37	15.37	16.36
Distillate Fuel Oil[7]	19.72	19.21	19.68	19.96	17.74	18.26	19.03	18.43	19.59	21.01
Residual Fuel Oil	7.89	10.22	10.53	10.81	8.30	8.69	9.04	9.55	10.39	11.21
Natural Gas[8]	14.28	13.37	13.60	13.83	11.79	12.15	12.32	12.27	12.83	13.45
Electricity	29.73	30.39	30.95	31.46	27.97	29.05	29.40	28.89	29.65	30.46
Electric Power[9]										
Distillate Fuel Oil	13.35	13.16	13.62	13.91	10.37	10.69	11.16	11.66	12.71	13.54
Residual Fuel Oil	8.17	9.18	9.45	9.70	7.14	7.50	7.83	8.25	9.04	9.90
Natural Gas	6.87	6.76	6.96	7.17	5.73	5.95	5.93	6.64	6.93	7.27
Steam Coal	1.69	1.83	1.84	1.84	1.69	1.72	1.76	1.72	1.78	1.85
Average Price to All Users[10]										
Liquefied Petroleum Gases	20.35	19.13	19.27	19.44	18.53	18.59	18.42	19.77	19.82	20.01
E85[4]	24.81	22.26	23.58	23.84	18.66	18.15	19.83	18.85	19.62	21.43
Motor Gasoline[5]	21.06	20.79	21.23	21.47	18.98	19.64	19.96	19.29	20.37	21.57
Jet Fuel	14.83	15.33	15.77	16.03	13.02	13.27	13.54	14.37	15.37	16.36
Distillate Fuel Oil	18.56	18.00	18.48	18.77	16.69	17.20	17.92	17.55	18.74	20.15
Residual Fuel Oil	8.21	10.01	10.31	10.57	7.93	8.29	8.62	9.06	9.87	10.71
Natural Gas	9.22	8.55	8.72	8.89	7.80	7.98	7.99	9.03	9.36	9.73
Metallurgical Coal	3.54	4.06	4.07	4.09	3.38	3.42	3.45	3.54	3.60	3.67
Other Coal	1.73	1.87	1.88	1.88	1.72	1.75	1.79	1.74	1.81	1.87
Coal to Liquids	- -	- -	- -	- -	0.94	1.09	1.27	1.20	1.30	1.39
Electricity	26.10	26.54	26.90	27.25	24.37	25.23	25.61	25.21	25.93	26.71

Table B3. Energy Prices by Sector and Source (Continued)
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Non-Renewable Energy Expenditures by Sector (billion 2006 dollars)										
Residential	225.38	237.66	241.71	245.66	230.03	243.22	253.57	250.85	274.70	299.44
Commercial	166.54	170.25	174.38	177.99	176.99	189.37	198.43	206.78	227.37	249.73
Industrial	205.11	214.18	224.65	235.03	170.98	193.16	213.17	161.83	203.93	249.45
Transportation	542.63	542.10	560.74	574.98	488.82	530.80	570.19	502.22	587.86	684.41
Total Non-Renewable Expenditures	1139.66	1164.20	1201.48	1233.66	1066.82	1156.54	1235.36	1121.67	1293.86	1483.04
Transportation Renewable Expenditures	0.03	0.07	0.06	0.07	19.95	17.64	18.92	28.91	26.35	26.92
Total Expenditures	**1139.70**	**1164.27**	**1201.54**	**1233.72**	**1086.77**	**1174.18**	**1254.28**	**1150.58**	**1320.22**	**1509.95**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]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.
- - = Not applicable.
Note: Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 transportation sector natural gas delivered prices are model results. 2006 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2006 through April 2007. 2006 coal prices based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

Table B4. Macroeconomic Indicators
(Billion 2000 Chain-Weighted Dollars, Unless Otherwise Noted)

Indicators	2006	Projections								
		2010			2020			2030		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Real Gross Domestic Product	**11319**	**12110**	**12453**	**12797**	**14743**	**15984**	**17239**	**17429**	**20219**	**23002**
Components of Real Gross Domestic Product										
Real Consumption	8044	8670	8845	9021	10568	11362	12169	12323	13999	15679
Real Investment	1920	1763	1939	2114	2314	2614	2914	3000	3743	4477
Real Government Spending	1981	2055	2087	2118	2118	2258	2398	2167	2471	2772
Real Exports	1304	1784	1797	1809	3059	3387	3720	5218	6191	7170
Real Imports	1929	2143	2190	2246	3326	3474	3589	5386	5723	6008
Energy Intensity (thousand Btu per 2000 dollar of GDP)										
Delivered Energy	6.39	6.12	6.03	5.94	5.15	5.00	4.87	4.41	4.16	4.01
Total Energy	8.79	8.44	8.30	8.16	7.16	6.91	6.71	6.17	5.80	5.55
Price Indices										
GDP Chain-Type Price Index (2000=1.000)	1.166	1.274	1.260	1.245	1.642	1.520	1.400	2.122	1.871	1.630
Consumer Price Index (1982-4=1)										
All-Urban	2.02	2.22	2.20	2.17	2.86	2.64	2.43	3.72	3.29	2.88
Energy Commodities and Services	1.97	2.14	2.15	2.15	2.54	2.43	2.29	3.40	3.14	2.88
Wholesale Price Index (1982=1.00)										
All Commodities	1.65	1.82	1.80	1.77	2.15	1.96	1.78	2.64	2.26	1.91
Fuel and Power	1.67	1.86	1.88	1.89	2.14	2.04	1.92	2.98	2.75	2.51
Interest Rates (percent, nominal)										
Federal Funds Rate	4.96	4.96	4.69	4.40	5.42	4.92	4.45	5.46	4.91	4.37
10-Year Treasury Note	4.79	5.56	5.24	4.89	5.99	5.44	4.90	6.08	5.46	4.89
AA Utility Bond Rate	5.84	6.84	6.65	6.44	7.52	6.98	6.45	7.76	7.13	6.54
Value of Shipments (billion 2000 dollars)										
Total Industrial	5821	5788	5997	6202	6447	7113	7768	6533	7997	9450
Non-manufacturing	1531	1324	1419	1515	1427	1619	1814	1440	1715	1988
Manufacturing	4290	4464	4577	4687	5020	5493	5953	5092	6283	7462
Energy-Intensive	1225	1257	1283	1309	1287	1387	1487	1251	1447	1643
Non-Energy Intensive	3065	3207	3295	3378	3733	4107	4466	3842	4836	5819
Population and Employment (millions)										
Population with Armed Forces Overseas	300.1	309.5	310.9	312.6	325.4	337.7	351.3	336.7	365.6	396.3
Population (aged 16 and over)	235.0	243.5	244.9	246.7	257.6	266.0	275.2	270.4	289.3	309.4
Population, over age 65	37.3	40.3	40.4	40.6	54.0	54.9	55.8	69.3	71.6	74.1
Employment, Nonfarm	136.1	137.3	142.4	147.6	143.5	154.5	165.7	152.9	168.1	183.2
Employment, Manufacturing	14.2	14.0	14.2	14.3	13.3	13.8	14.2	10.1	11.2	12.0
Key Labor Indicators										
Labor Force (millions)	151.4	155.1	156.8	158.3	160.3	165.6	171.6	168.5	177.9	187.6
Non-farm Labor Productivity (1992=1.00)	1.35	1.44	1.45	1.47	1.68	1.77	1.87	1.92	2.14	2.37
Unemployment Rate (percent)	4.63	5.12	5.03	4.93	4.80	4.62	4.41	4.99	4.80	4.68
Key Indicators for Energy Demand										
Real Disposable Personal Income	8397	9284	9472	9661	11888	12654	13436	14627	16246	17874
Housing Starts (millions)	1.93	1.42	1.68	1.93	1.39	1.78	2.17	1.15	1.70	2.24
Commercial Floorspace (billion square feet)	74.8	78.0	78.8	79.4	85.6	89.3	92.6	93.8	100.8	108.0
Unit Sales of Light-Duty Vehicles (millions)	16.50	16.05	16.38	17.09	16.36	17.47	18.88	17.16	19.39	21.86

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2006: Global Insight, Global Insight Industry and Employment models, July 2007. **Projections:** Energy Information Administration, AEO2008 National Energy Modeling System runs LM2008.D031608A, AEO2008.D030208F, and HM2008.D031608A.

Appendix C

Price Case Comparisons

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

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Production										
Crude Oil and Lease Condensate	10.80	12.85	12.76	12.64	13.67	13.40	13.57	11.15	12.04	13.71
Natural Gas Plant Liquids	2.36	2.27	2.27	2.26	2.32	2.31	2.28	2.09	2.11	2.11
Dry Natural Gas	19.04	19.83	19.85	19.81	20.14	20.24	20.26	19.98	20.00	20.36
Coal[1]	23.79	23.97	23.97	23.97	23.33	25.20	26.13	25.88	28.63	32.46
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Hydropower	2.89	2.92	2.92	2.92	3.00	3.00	3.01	3.01	3.00	3.01
Biomass[2]	2.94	4.08	4.05	4.02	6.48	6.42	6.48	8.28	8.12	7.88
Other Renewable Energy[3]	0.88	1.39	1.51	1.51	1.77	2.00	2.10	2.11	2.45	2.45
Other[4]	0.50	0.53	0.54	0.55	0.60	0.58	0.57	0.65	0.64	0.63
Total	**71.41**	**76.16**	**76.17**	**75.99**	**80.21**	**82.21**	**83.66**	**81.87**	**86.56**	**93.27**
Imports										
Crude Oil	22.08	21.40	21.14	20.42	22.41	21.58	19.62	26.43	24.41	18.93
Liquid Fuels and Other Petroleum[5]	7.21	5.48	5.61	6.27	6.72	5.43	4.94	7.46	5.44	4.71
Natural Gas	4.29	5.00	4.80	4.63	6.40	4.68	3.52	6.98	4.64	3.17
Other Imports[6]	0.98	0.95	0.95	0.96	1.89	1.93	2.00	2.60	2.74	2.92
Total	**34.57**	**32.83**	**32.49**	**32.27**	**37.43**	**33.62**	**30.08**	**43.47**	**37.22**	**29.73**
Exports										
Petroleum[7]	2.60	2.87	2.82	2.88	3.03	2.98	3.08	3.07	3.33	3.25
Natural Gas	0.73	0.85	0.84	0.84	1.12	1.02	0.91	1.60	1.36	1.08
Coal	1.26	1.79	1.79	1.79	0.87	0.87	0.82	0.91	0.88	0.88
Total	**4.59**	**5.50**	**5.45**	**5.51**	**5.02**	**4.87**	**4.82**	**5.58**	**5.56**	**5.21**
Discrepancy[8]	**1.87**	**-0.08**	**-0.13**	**-0.10**	**0.22**	**0.12**	**0.14**	**0.37**	**0.21**	**0.25**
Consumption										
Liquid Fuels and Other Petroleum[9]	40.06	40.61	40.46	40.19	44.30	42.24	40.20	46.89	43.99	41.48
Natural Gas	22.30	24.11	23.93	23.72	25.55	24.01	22.71	25.47	23.39	22.24
Coal[10]	22.50	23.03	23.03	23.03	24.18	25.87	26.81	27.38	29.90	32.11
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Hydropower	2.89	2.92	2.92	2.92	3.00	3.00	3.01	3.01	3.00	3.01
Biomass[11]	2.50	3.02	3.01	2.99	4.53	4.50	4.49	5.63	5.51	5.36
Other Renewable Energy[3]	0.88	1.39	1.51	1.51	1.77	2.00	2.10	2.11	2.45	2.45
Other[12]	0.19	0.18	0.18	0.19	0.17	0.17	0.19	0.18	0.20	0.22
Total	**99.52**	**103.57**	**103.34**	**102.87**	**112.39**	**110.85**	**108.78**	**119.39**	**118.01**	**117.54**

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

Supply, Disposition, and Prices	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Prices (2006 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price	66.02	71.45	74.03	79.02	39.07	59.70	102.07	42.35	70.45	118.65
Imported Crude Oil Price[13]	59.05	62.64	65.18	69.19	33.46	51.55	88.31	34.61	58.66	96.42
Natural Gas (dollars per million Btu)										
Price at Henry Hub	6.73	6.61	6.90	7.28	5.01	5.95	7.08	6.00	7.22	8.43
Wellhead Price[14]	6.24	5.89	6.16	6.50	4.43	5.29	6.32	5.33	6.45	7.55
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	6.42	6.06	6.33	6.69	4.56	5.44	6.50	5.49	6.63	7.77
Coal (dollars per ton)										
Minemouth Price[15]	24.63	25.88	26.16	26.17	21.68	22.51	23.62	22.06	23.32	24.79
Coal (dollars per million Btu)										
Minemouth Price[15]	1.21	1.27	1.28	1.28	1.09	1.14	1.20	1.12	1.19	1.28
Average Delivered Price[16]	1.78	1.92	1.93	1.94	1.69	1.77	1.86	1.72	1.82	1.92
Average Electricity Price (cents per kilowatthour)	8.9	9.1	9.2	9.3	8.3	8.6	8.9	8.5	8.8	9.1

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes imports of finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke (net), and electricity (net).
[7]Includes crude oil and petroleum products.
[8]Balancing item. Includes unaccounted for supply, losses, gains, and net storage withdrawals.
[9]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids.
[11]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[12]Includes non-biogenic municipal waste and net electricity imports.
[13]Weighted average price delivered to U.S. refiners.
[14]Represents lower 48 onshore and offshore supplies.
[15]Includes reported prices for both open market and captive mines.
[16]Prices weighted by consumption; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

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

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.47	0.48	0.48	0.48	0.52	0.52	0.51	0.56	0.55	0.55
Kerosene	0.07	0.08	0.08	0.08	0.09	0.08	0.08	0.09	0.08	0.07
Distillate Fuel Oil	0.70	0.76	0.75	0.75	0.78	0.73	0.65	0.72	0.65	0.56
Liquid Fuels and Other Petroleum Subtotal	1.25	1.32	1.31	1.31	1.40	1.33	1.24	1.37	1.29	1.18
Natural Gas	4.50	4.97	4.95	4.93	5.41	5.30	5.20	5.44	5.32	5.23
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.44	0.44	0.44	0.39	0.40	0.42	0.36	0.38	0.40
Electricity	4.61	4.95	4.95	4.94	5.29	5.25	5.22	5.90	5.88	5.85
Delivered Energy	**10.77**	**11.69**	**11.66**	**11.63**	**12.49**	**12.30**	**12.09**	**13.08**	**12.88**	**12.66**
Electricity Related Losses	10.04	10.58	10.59	10.58	10.98	11.08	11.12	11.91	12.14	12.10
Total	**20.82**	**22.27**	**22.25**	**22.21**	**23.47**	**23.39**	**23.21**	**24.99**	**25.01**	**24.76**
Commercial										
Liquefied Petroleum Gases	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.42	0.38	0.38	0.38	0.45	0.41	0.37	0.49	0.41	0.38
Residual Fuel Oil	0.11	0.10	0.10	0.09	0.11	0.10	0.10	0.11	0.10	0.10
Liquid Fuels and Other Petroleum Subtotal	0.68	0.64	0.63	0.63	0.73	0.68	0.63	0.76	0.68	0.64
Natural Gas	2.92	3.06	3.04	3.03	3.56	3.47	3.37	3.87	3.78	3.67
Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.43	4.74	4.73	4.72	5.72	5.67	5.62	6.68	6.62	6.57
Delivered Energy	**8.25**	**8.64**	**8.62**	**8.59**	**10.22**	**10.03**	**9.83**	**11.52**	**11.30**	**11.09**
Electricity Related Losses	9.66	10.12	10.12	10.12	11.87	11.96	11.99	13.47	13.68	13.59
Total	**17.91**	**18.76**	**18.74**	**18.70**	**22.08**	**21.98**	**21.82**	**24.99**	**24.98**	**24.68**
Industrial[4]										
Liquefied Petroleum Gases	2.09	2.13	2.12	2.12	1.87	1.83	1.78	1.75	1.71	1.71
Motor Gasoline[2]	0.38	0.38	0.38	0.37	0.37	0.37	0.37	0.38	0.38	0.37
Distillate Fuel Oil	1.28	1.29	1.29	1.28	1.26	1.23	1.22	1.29	1.23	1.23
Residual Fuel Oil	0.28	0.28	0.28	0.28	0.30	0.23	0.19	0.37	0.23	0.19
Petrochemical Feedstocks	1.41	1.37	1.36	1.36	1.41	1.39	1.36	1.30	1.29	1.30
Other Petroleum[5]	4.48	4.31	4.25	4.14	4.67	4.22	3.73	4.93	4.41	3.62
Liquid Fuels and Other Petroleum Subtotal	9.92	9.76	9.67	9.57	9.89	9.27	8.65	10.02	9.25	8.42
Natural Gas	6.68	7.15	7.16	7.12	7.00	7.14	7.21	6.73	7.08	7.21
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.20
Lease and Plant Fuel[6]	1.17	1.21	1.21	1.21	1.25	1.25	1.26	1.27	1.27	1.30
Natural Gas Subtotal	7.85	8.36	8.37	8.33	8.25	8.39	8.68	8.00	8.35	8.71
Metallurgical Coal	0.60	0.60	0.60	0.59	0.56	0.54	0.51	0.50	0.48	0.47
Other Industrial Coal	1.26	1.31	1.31	1.30	1.19	1.20	1.19	1.16	1.18	1.18
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.09	0.34	0.45	0.09	0.55	2.69
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Coal Subtotal	1.92	1.94	1.93	1.92	1.87	2.11	2.19	1.80	2.26	4.39
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.66	1.51	1.49	1.49	2.41	2.31	2.09
Renewable Energy[7]	1.69	1.67	1.66	1.66	1.86	1.83	1.80	2.04	2.02	2.00
Electricity	3.42	3.52	3.50	3.48	3.65	3.59	3.52	3.51	3.52	3.58
Delivered Energy	**25.10**	**25.93**	**25.82**	**25.62**	**27.04**	**26.70**	**26.32**	**27.77**	**27.70**	**29.19**
Electricity Related Losses	7.45	7.52	7.50	7.45	7.57	7.57	7.51	7.07	7.28	7.40
Total	**32.55**	**33.45**	**33.32**	**33.07**	**34.61**	**34.27**	**33.83**	**34.84**	**34.98**	**36.59**

Table C2. Energy Consumption by Sector and Source (Continued)

(Quadrillion Btu per Year, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Transportation										
Liquefied Petroleum Gases	0.02	0.02	0.02	0.02	0.01	0.01	0.02	0.01	0.01	0.02
E85[8]	0.00	0.00	0.00	0.00	0.95	0.97	0.91	1.17	1.34	1.65
Motor Gasoline[2]	17.20	17.28	17.25	17.14	17.46	16.56	15.36	17.54	15.97	13.83
Jet Fuel[9]	3.16	3.45	3.44	3.43	4.16	4.15	4.14	4.79	4.79	4.79
Distillate Fuel Oil[10]	6.18	6.56	6.54	6.52	7.75	7.63	7.64	9.09	8.98	9.29
Residual Fuel Oil	0.83	0.85	0.85	0.85	0.86	0.86	0.86	0.87	0.87	0.87
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[11]	0.18	0.17	0.17	0.17	0.18	0.18	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum Subtotal	27.57	28.34	28.29	28.14	31.36	30.37	29.11	33.65	32.15	30.62
Pipeline Fuel Natural Gas	0.59	0.64	0.64	0.64	0.71	0.69	0.66	0.76	0.72	0.70
Compressed Natural Gas	0.02	0.04	0.04	0.04	0.07	0.07	0.07	0.08	0.08	0.09
Electricity	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
Delivered Energy	**28.20**	**29.04**	**28.98**	**28.84**	**32.17**	**31.15**	**29.87**	**34.51**	**32.98**	**31.44**
Electricity Related Losses	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06
Total	**28.25**	**29.09**	**29.03**	**28.89**	**32.23**	**31.21**	**29.92**	**34.57**	**33.04**	**31.50**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.65	2.72	2.70	2.71	2.50	2.45	2.40	2.41	2.37	2.37
E85[8]	0.00	0.00	0.00	0.00	0.95	0.97	0.91	1.17	1.34	1.65
Motor Gasoline[2]	17.62	17.71	17.68	17.56	17.88	16.99	15.78	17.97	16.40	14.25
Jet Fuel[9]	3.16	3.45	3.44	3.43	4.16	4.15	4.14	4.79	4.79	4.79
Kerosene	0.11	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13	0.11
Distillate Fuel Oil	8.59	8.99	8.97	8.93	10.25	10.00	9.89	11.59	11.28	11.46
Residual Fuel Oil	1.23	1.23	1.23	1.23	1.27	1.19	1.15	1.35	1.20	1.16
Petrochemical Feedstocks	1.41	1.37	1.36	1.36	1.41	1.39	1.36	1.30	1.29	1.30
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.47	4.40	4.29	4.83	4.38	3.88	5.09	4.56	3.77
Liquid Fuels and Other Petroleum Subtotal	39.41	40.06	39.90	39.64	43.38	41.65	39.63	45.80	43.37	40.87
Natural Gas	14.12	15.21	15.19	15.11	16.04	15.98	15.85	16.11	16.27	16.19
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.20
Lease and Plant Fuel[6]	1.17	1.21	1.21	1.21	1.25	1.25	1.26	1.27	1.27	1.30
Pipeline Natural Gas	0.59	0.64	0.64	0.64	0.71	0.69	0.66	0.76	0.72	0.70
Natural Gas Subtotal	15.88	17.06	17.04	16.96	18.00	17.93	17.97	18.14	18.26	18.39
Metallurgical Coal	0.60	0.60	0.60	0.59	0.56	0.54	0.51	0.50	0.48	0.47
Other Coal	1.35	1.40	1.40	1.40	1.28	1.29	1.28	1.25	1.27	1.27
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.09	0.34	0.45	0.09	0.55	2.69
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Coal Subtotal	2.02	2.03	2.03	2.02	1.96	2.21	2.28	1.89	2.35	4.48
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.66	1.51	1.49	1.49	2.41	2.31	2.09
Renewable Energy[13]	2.23	2.24	2.23	2.23	2.38	2.37	2.35	2.53	2.52	2.53
Electricity	12.49	13.23	13.20	13.16	14.68	14.54	14.38	16.12	16.05	16.03
Delivered Energy	**72.32**	**75.30**	**75.08**	**74.67**	**81.92**	**80.18**	**78.10**	**86.88**	**84.86**	**84.38**
Electricity Related Losses	27.19	28.27	28.26	28.20	30.47	30.67	30.68	32.51	33.16	33.15
Total	**99.52**	**103.57**	**103.34**	**102.87**	**112.39**	**110.85**	**108.78**	**119.39**	**118.01**	**117.54**
Electric Power[14]										
Distillate Fuel Oil	0.18	0.18	0.18	0.18	0.20	0.20	0.20	0.22	0.23	0.22
Residual Fuel Oil	0.46	0.38	0.38	0.38	0.72	0.39	0.37	0.87	0.40	0.39
Liquid Fuels and Other Petroleum Subtotal	0.64	0.56	0.56	0.56	0.92	0.59	0.57	1.09	0.63	0.61
Natural Gas	6.42	7.05	6.89	6.76	7.55	6.09	4.74	7.34	5.13	3.85
Steam Coal	20.48	21.00	21.01	21.01	22.21	23.67	24.54	25.50	27.55	27.63
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Renewable Energy[15]	3.74	4.41	4.53	4.53	5.40	5.64	5.76	5.80	6.13	6.21
Electricity Imports	0.06	0.05	0.05	0.06	0.04	0.04	0.07	0.05	0.08	0.09
Total[16]	**39.68**	**41.50**	**41.46**	**41.36**	**45.16**	**45.21**	**45.06**	**48.63**	**49.21**	**49.18**

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

Sector and Source	2006	2010 Low Price	2010 Reference	2010 High Price	2020 Low Price	2020 Reference	2020 High Price	2030 Low Price	2030 Reference	2030 High Price
Total Energy Consumption										
Liquefied Petroleum Gases	2.65	2.72	2.70	2.71	2.50	2.45	2.40	2.41	2.37	2.37
E85[8]	0.00	0.00	0.00	0.00	0.95	0.97	0.91	1.17	1.34	1.65
Motor Gasoline[2]	17.62	17.71	17.68	17.56	17.88	16.99	15.78	17.97	16.40	14.25
Jet Fuel[9]	3.16	3.45	3.44	3.43	4.16	4.15	4.14	4.79	4.79	4.79
Kerosene	0.11	0.12	0.12	0.12	0.13	0.13	0.12	0.13	0.13	0.11
Distillate Fuel Oil	8.77	9.17	9.15	9.11	10.45	10.20	10.09	11.81	11.51	11.68
Residual Fuel Oil	1.69	1.61	1.60	1.61	1.99	1.58	1.52	2.22	1.60	1.55
Petrochemical Feedstocks	1.41	1.37	1.36	1.36	1.41	1.39	1.36	1.30	1.29	1.30
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[12]	4.64	4.47	4.40	4.29	4.83	4.38	3.88	5.09	4.56	3.77
Liquid Fuels and Other Petroleum Subtotal	40.06	40.61	40.46	40.19	44.30	42.24	40.20	46.89	43.99	41.48
Natural Gas	20.54	22.26	22.08	21.88	23.59	22.07	20.58	23.45	21.40	20.04
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.20
Lease and Plant Fuel[6]	1.17	1.21	1.21	1.21	1.25	1.25	1.26	1.27	1.27	1.30
Pipeline Natural Gas	0.59	0.64	0.64	0.64	0.71	0.69	0.66	0.76	0.72	0.70
Natural Gas Subtotal	22.30	24.11	23.93	23.72	25.55	24.01	22.71	25.47	23.39	22.24
Metallurgical Coal	0.60	0.60	0.60	0.59	0.56	0.54	0.51	0.50	0.48	0.47
Other Coal	21.83	22.40	22.41	22.41	23.49	24.96	25.82	26.75	28.82	28.90
Coal-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.09	0.34	0.45	0.09	0.55	2.69
Net Coal Coke Imports	0.06	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Coal Subtotal	22.50	23.03	23.03	23.03	24.18	25.87	26.81	27.38	29.90	32.11
Nuclear Power	8.21	8.31	8.31	8.31	8.90	9.05	9.26	8.72	9.57	10.66
Biofuels Heat and Coproducts	0.30	0.68	0.67	0.66	1.51	1.49	1.49	2.41	2.31	2.09
Renewable Energy[17]	5.97	6.65	6.76	6.76	7.79	8.01	8.11	8.34	8.66	8.74
Electricity Imports	0.06	0.05	0.05	0.06	0.04	0.04	0.07	0.05	0.08	0.09
Total	**99.52**	**103.57**	**103.34**	**102.87**	**112.39**	**110.85**	**108.78**	**119.39**	**118.01**	**117.54**
Energy Use and Related Statistics										
Delivered Energy Use	72.32	75.30	75.08	74.67	81.92	80.18	78.10	86.88	84.86	84.38
Total Energy Use	99.52	103.57	103.34	102.87	112.39	110.85	108.78	119.39	118.01	117.54
Ethanol Consumed in Motor Gasoline and E85	0.47	1.05	1.05	1.03	1.82	1.82	1.68	1.97	2.01	2.07
Population (millions)	300.13	310.85	310.85	310.85	337.74	337.74	337.74	365.59	365.59	365.59
Gross Domestic Product (billion 2000 dollars)	11319	12465	12453	12426	16030	15984	15944	20228	20219	20258
Carbon Dioxide Emissions (million metric tons)	5890.3	6030.9	6010.6	5983.0	6450.0	6384.1	6258.9	6941.2	6851.0	6799.2

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Excludes ethanol. Includes commercial sector consumption of wood and wood waste, landfill gas, municipal waste, and other biomass for combined heat and power. See Table A5 and/or Table A17 for estimates of nonmarketed renewable energy consumption for solar thermal hot water heating and solar photovoltaic electricity generation.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes petroleum coke, asphalt, road oil, lubricants, still gas, and miscellaneous petroleum products.
[6]Represents natural gas used in well, field, and lease operations, and in natural gas processing plant machinery.
[7]Includes consumption of energy produced from hydroelectric, wood and wood waste, municipal waste, and other biomass sources. Excludes ethanol blends (10 percent or less) in motor gasoline.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes only kerosene type.
[10]Diesel fuel for on- and off- road use.
[11]Includes aviation gasoline and lubricants.
[12]Includes unfinished oils, natural gasoline, motor gasoline blending components, 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 ethanol and nonmarketed renewable energy consumption for geothermal heat pumps, buildings photovoltaic systems, and solar thermal hot water heaters.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, petroleum coke, wind, photovoltaic and solar thermal sources. Excludes net electricity imports.
[16]Includes non-biogenic municipal waste not included above.
[17]Includes conventional hydroelectric, geothermal, wood and wood waste, biogenic municipal waste, other biomass, wind, photovoltaic and solar thermal sources. Excludes ethanol, 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.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 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: 2006 consumption based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 population and gross domestic product: Global Insight, Global Insight Industry and Employment models, July 2007. 2006 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2006,* DOE/EIA-0573(2006) (Washington, DC, November 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C3. Energy Prices by Sector and Source
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections 2010 Low Price	2010 Reference	2010 High Price	2020 Low Price	2020 Reference	2020 High Price	2030 Low Price	2030 Reference	2030 High Price
Residential										
Liquefied Petroleum Gases	23.08	24.91	25.21	25.59	23.30	24.23	25.36	24.26	25.43	26.63
Distillate Fuel Oil	17.94	16.45	17.21	18.25	10.60	14.27	22.09	11.54	16.27	24.45
Natural Gas	13.40	11.85	12.15	12.55	10.43	11.39	12.57	11.71	12.91	14.10
Electricity	30.52	31.02	31.37	31.79	29.21	30.20	31.09	29.82	30.63	31.48
Commercial										
Distillate Fuel Oil	14.59	14.51	15.24	16.12	9.51	13.24	20.37	10.27	15.00	23.16
Residual Fuel Oil	8.60	9.64	10.06	10.69	5.03	7.95	13.09	5.50	9.22	15.41
Natural Gas	11.50	10.30	10.59	10.98	8.97	9.91	11.04	10.26	11.43	12.61
Electricity	27.75	27.52	27.89	28.35	24.45	25.64	26.90	25.01	26.17	27.33
Industrial[1]										
Liquefied Petroleum Gases	19.71	17.49	17.74	18.12	15.94	16.79	17.75	16.77	17.79	19.02
Distillate Fuel Oil	15.33	15.02	15.72	16.46	10.85	14.62	21.23	11.56	16.26	24.32
Residual Fuel Oil	9.06	10.10	10.86	11.00	5.48	8.29	12.92	6.20	9.62	15.20
Natural Gas[2]	7.66	6.94	7.21	7.58	5.35	6.21	7.29	6.22	7.29	8.44
Metallurgical Coal	3.54	4.06	4.07	4.08	3.39	3.42	3.48	3.56	3.60	3.67
Other Industrial Coal	2.34	2.41	2.42	2.43	2.20	2.28	2.38	2.23	2.33	2.48
Coal to Liquids	- -	- -	- -	- -	0.86	1.09	1.26	0.95	1.30	1.57
Electricity	17.97	18.90	19.21	19.60	16.47	17.27	17.89	16.98	17.63	18.11
Transportation										
Liquefied Petroleum Gases[3]	21.72	25.74	26.03	26.35	24.02	24.94	26.04	24.87	26.03	27.21
E85[4]	24.81	21.86	23.58	26.14	15.25	18.15	27.14	15.22	19.62	28.81
Motor Gasoline[5]	21.19	20.43	21.23	23.66	15.35	19.64	27.35	15.35	20.37	29.37
Jet Fuel[6]	14.83	15.13	15.77	17.13	9.18	13.27	21.13	10.22	15.37	23.87
Distillate Fuel Oil[7]	19.72	19.00	19.68	20.45	14.47	18.26	24.74	14.87	19.59	27.72
Residual Fuel Oil	7.89	9.93	10.53	10.83	5.68	8.69	14.02	6.50	10.39	16.44
Natural Gas[8]	14.28	13.33	13.60	13.99	11.22	12.15	13.37	11.64	12.83	14.12
Electricity	29.73	30.48	30.95	31.53	27.77	29.05	30.29	28.56	29.65	30.43
Electric Power[9]										
Distillate Fuel Oil	13.35	12.88	13.62	14.64	7.07	10.69	18.33	8.02	12.71	20.66
Residual Fuel Oil	8.17	8.87	9.45	9.79	4.43	7.50	12.73	5.09	9.04	15.14
Natural Gas	6.87	6.71	6.96	7.31	5.11	5.95	6.96	5.90	6.93	8.06
Steam Coal	1.69	1.83	1.84	1.85	1.62	1.72	1.82	1.66	1.78	1.93
Average Price to All Users[10]										
Liquefied Petroleum Gases	20.35	19.01	19.27	19.65	17.70	18.59	19.63	18.72	19.82	21.03
E85[4]	24.81	21.86	23.58	26.14	15.25	18.15	27.14	15.22	19.62	28.81
Motor Gasoline[5]	21.06	20.43	21.23	23.66	15.35	19.64	27.35	15.35	20.37	29.37
Jet Fuel	14.83	15.13	15.77	17.13	9.18	13.27	21.13	10.22	15.37	23.87
Distillate Fuel Oil	18.56	17.78	18.48	19.25	13.39	17.20	23.84	13.99	18.74	26.92
Residual Fuel Oil	8.21	9.69	10.31	10.61	5.16	8.29	13.50	5.84	9.87	15.90
Natural Gas	9.22	8.43	8.72	9.10	7.00	7.98	9.18	8.07	9.36	10.63
Metallurgical Coal	3.54	4.06	4.07	4.08	3.39	3.42	3.48	3.56	3.60	3.67
Other Coal	1.73	1.86	1.88	1.89	1.66	1.75	1.85	1.69	1.81	1.95
Coal to Liquids	- -	- -	- -	- -	0.86	1.09	1.26	0.95	1.30	1.57
Electricity	26.10	26.54	26.90	27.34	24.19	25.23	26.22	25.03	25.93	26.79

Table C3. Energy Prices by Sector and Source (Continued)
(2006 Dollars per Million Btu, Unless Otherwise Noted)

Sector and Source	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Non-Renewable Energy Expenditures by Sector (billion 2006 dollars)										
Residential	225.38	238.17	241.71	246.28	232.30	243.22	256.49	262.54	274.70	287.88
Commercial	166.54	171.75	174.38	177.84	179.61	189.37	201.22	215.50	227.37	240.45
Industrial	205.11	218.32	224.65	230.83	171.15	193.16	221.31	177.82	203.93	235.22
Transportation	542.63	540.60	560.74	608.98	426.17	530.80	712.89	462.11	587.86	797.19
Total Non-Renewable Expenditures	1139.66	1168.84	1201.48	1263.94	1009.23	1156.54	1391.91	1117.96	1293.86	1560.74
Transportation Renewable Expenditures	0.03	0.07	0.06	0.07	14.43	17.64	24.80	17.78	26.35	47.45
Total Expenditures	**1139.70**	**1168.91**	**1201.54**	**1264.00**	**1023.66**	**1174.18**	**1416.71**	**1135.74**	**1320.22**	**1608.20**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Excludes use for lease and plant fuel.
[3]Includes Federal and State taxes while excluding county and local taxes.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[6]Kerosene-type jet fuel. Includes Federal and State taxes while excluding county and local taxes.
[7]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[8]Compressed natural gas used as a vehicle fuel. Includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[9]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[10]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.
- - = Not applicable.
Note: Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the Energy Information Administration (EIA), *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey 1994* and industrial and wellhead prices from the *Natural Gas Annual 2005*, DOE/EIA-0131(2005) (Washington, DC, November 2006) and the *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 transportation sector natural gas delivered prices are model results. 2006 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, May 2006 through April 2007. 2006 coal prices based on: EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007) and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. 2006 electricity prices: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C4. Liquid Fuels Supply and Disposition
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil										
Domestic Crude Production[1]	5.10	5.97	5.93	5.87	6.35	6.23	6.31	5.18	5.59	6.37
Alaska	0.74	0.69	0.69	0.68	0.77	0.70	0.65	0.32	0.30	0.41
Lower 48 States	4.36	5.29	5.24	5.19	5.59	5.53	5.66	4.86	5.30	5.96
Net Imports	10.09	9.72	9.60	9.27	10.12	9.75	8.87	11.93	11.03	8.54
Gross Imports	10.12	9.75	9.63	9.30	10.15	9.79	8.90	11.95	11.06	8.57
Exports	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other Crude Supply[2]	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.24**	**15.69**	**15.53**	**15.15**	**16.47**	**15.98**	**15.17**	**17.11**	**16.63**	**14.91**
Other Supply										
Natural Gas Plant Liquids	1.74	1.69	1.68	1.68	1.72	1.72	1.69	1.56	1.57	1.56
Net Product Imports	2.31	1.63	1.72	2.07	2.00	1.37	1.15	2.41	1.26	0.88
Gross Refined Product Imports[3]	2.17	1.48	1.61	1.72	1.74	1.41	1.22	2.11	1.56	1.16
Unfinished Oil Imports	0.69	0.70	0.67	0.58	0.79	0.64	0.57	0.87	0.70	0.54
Blending Component Imports	0.68	0.77	0.74	1.09	0.85	0.67	0.78	0.81	0.52	0.68
Exports	1.22	1.31	1.30	1.32	1.38	1.36	1.41	1.38	1.52	1.50
Refinery Processing Gain[4]	0.99	1.06	1.05	0.96	0.99	1.00	0.86	0.99	0.99	0.68
Other Inputs	0.45	1.03	1.04	1.02	1.87	1.97	2.11	2.20	2.41	3.53
Ethanol	0.36	0.81	0.81	0.80	1.41	1.41	1.30	1.53	1.56	1.61
Domestic Production	0.32	0.76	0.74	0.73	1.19	1.17	1.10	1.44	1.44	1.35
Net Imports	0.05	0.06	0.07	0.06	0.22	0.24	0.20	0.09	0.12	0.26
Biodiesel	0.02	0.04	0.04	0.04	0.07	0.07	0.08	0.07	0.08	0.10
Domestic Production	0.02	0.04	0.04	0.04	0.07	0.07	0.08	0.07	0.08	0.10
Net Imports	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.00	0.00	0.13
Liquids from Coal	0.00	0.00	0.00	0.00	0.04	0.15	0.20	0.04	0.24	1.18
Liquids from Biomass	0.00	0.00	0.00	0.00	0.14	0.14	0.20	0.33	0.29	0.28
Other[5]	0.07	0.18	0.18	0.19	0.21	0.21	0.20	0.24	0.24	0.23
Total Primary Supply[6]	**20.74**	**21.10**	**21.02**	**20.87**	**23.06**	**22.04**	**20.99**	**24.26**	**22.86**	**21.57**
Liquid Fuels Consumption										
by Fuel										
Liquefied Petroleum Gases	2.05	2.06	2.05	2.06	1.90	1.86	1.82	1.83	1.80	1.80
E85[7]	0.00	0.00	0.00	0.00	0.65	0.67	0.63	0.80	0.92	1.13
Motor Gasoline[8]	9.25	9.60	9.59	9.54	9.73	9.24	8.60	9.77	8.91	7.75
Jet Fuel[9]	1.63	1.67	1.66	1.66	2.01	2.01	2.00	2.31	2.31	2.31
Distillate Fuel Oil[10]	4.17	4.41	4.40	4.38	5.03	4.91	4.85	5.68	5.53	5.61
Diesel	3.21	3.73	3.72	3.71	4.31	4.23	4.22	4.96	4.87	5.01
Residual Fuel Oil	0.69	0.70	0.70	0.70	0.87	0.69	0.66	0.97	0.70	0.67
Other[11]	2.86	2.61	2.58	2.53	2.80	2.58	2.35	2.85	2.62	2.28
by Sector										
Residential and Commercial	1.07	1.09	1.08	1.08	1.18	1.13	1.06	1.20	1.12	1.05
Industrial[12]	5.15	5.10	5.06	5.01	5.08	4.79	4.50	5.09	4.73	4.37
Transportation	14.05	14.63	14.60	14.54	16.31	15.79	15.11	17.46	16.66	15.87
Electric Power[13]	0.29	0.25	0.25	0.25	0.41	0.26	0.26	0.48	0.28	0.27
Total	**20.65**	**21.06**	**20.99**	**20.87**	**22.99**	**21.96**	**20.92**	**24.22**	**22.80**	**21.57**
Discrepancy[14]	**0.09**	**0.04**	**0.03**	**-0.00**	**0.07**	**0.08**	**0.08**	**0.04**	**0.06**	**0.00**

Table C4. Liquid Fuels Supply and Disposition (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Domestic Refinery Distillation Capacity[15]	17.3	18.3	18.3	18.3	18.3	18.3	18.3	18.6	18.4	18.3
Capacity Utilization Rate (percent)[16]	90.0	87.6	86.8	84.6	92.0	89.3	84.7	93.8	92.0	83.2
Net Import Share of Product Supplied (percent)	60.0	54.1	54.2	54.6	53.5	51.6	48.7	59.5	54.3	44.9
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2006 dollars)	264.86	243.47	254.07	266.30	148.06	207.19	311.47	178.98	261.91	324.14

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, and ethers.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[8]Includes ethanol and ethers blended into gasoline.
[9]Includes only kerosene type.
[10]Includes distillate fuel oil and kerosene from petroleum and biomass feedstocks.
[11]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, liquid hydrogen,and miscellaneous petroleum products.
[12]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[13]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[14]Balancing item. Includes unaccounted for supply, losses, and gains.
[15]End-of-year operable capacity.
[16]Rate is calculated by dividing the gross annual input to atmospheric crude oil distillation units by their operable refining capacity in barrels per calendar day.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2006 data: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C5. Petroleum Product Prices
(2006 Cents per Gallon, Unless Otherwise Noted)

Sector and Fuel	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil Prices (2006 dollars per barrel)										
Imported Low Sulfur Light Crude Oil	66.02	71.45	74.03	79.02	39.07	59.70	102.07	42.35	70.45	118.65
Imported Crude Oil[1]	59.05	62.64	65.18	69.19	33.46	51.55	88.31	34.61	58.66	96.42
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	198.1	213.8	216.3	219.6	200.0	207.9	217.7	208.2	218.3	228.6
Distillate Fuel Oil	248.8	228.1	238.6	253.1	147.0	198.0	306.3	160.1	225.7	339.0
Commercial										
Distillate Fuel Oil	201.8	200.2	210.2	222.4	131.1	182.5	280.9	141.5	206.7	319.3
Residual Fuel Oil	128.8	144.3	150.7	160.0	75.3	118.9	196.0	82.3	138.0	230.6
Residual Fuel Oil (2006 dollars per barrel)	54.09	60.60	63.27	67.19	31.64	49.95	82.32	34.55	57.97	96.87
Industrial[2]										
Liquefied Petroleum Gases	169.2	150.1	152.3	155.5	136.8	144.1	152.4	144.0	152.7	163.2
Distillate Fuel Oil	212.1	206.6	216.2	226.4	149.0	200.7	291.4	158.7	223.1	333.9
Residual Fuel Oil	135.6	151.1	162.6	164.7	82.1	124.0	193.3	92.7	144.0	227.6
Residual Fuel Oil (2006 dollars per barrel)	56.96	63.48	68.29	69.16	34.47	52.10	81.20	38.95	60.48	95.58
Transportation										
Liquefied Petroleum Gases	186.4	220.9	223.4	226.1	206.2	214.0	223.5	213.4	223.4	233.5
Ethanol (E85)[3]	235.4	207.4	223.7	248.0	144.6	172.2	257.5	144.4	186.1	273.4
Ethanol Wholesale Price	250.0	179.5	180.8	203.5	196.5	200.7	194.1	145.9	152.2	179.6
Motor Gasoline[4]	263.3	245.8	255.4	284.1	184.1	235.5	327.5	184.2	244.6	352.3
Jet Fuel[5]	200.2	204.3	212.8	231.2	123.9	179.2	285.2	137.9	207.5	322.3
Diesel Fuel (distillate fuel oil)[6]	271.0	260.5	269.8	280.3	198.3	250.2	339.0	203.8	268.5	379.9
Residual Fuel Oil	118.1	148.6	157.7	162.1	85.1	130.1	209.9	97.3	155.5	246.1
Residual Fuel Oil (2006 dollars per barrel)	49.62	62.41	66.22	68.09	35.73	54.64	88.14	40.86	65.32	103.38
Electric Power[7]										
Distillate Fuel Oil	185.1	178.6	189.0	203.1	98.1	148.3	254.3	111.2	176.2	286.5
Residual Fuel Oil	122.3	132.8	141.5	146.6	66.4	112.3	190.5	76.1	135.3	226.6
Residual Fuel Oil (2006 dollars per barrel)	51.37	55.80	59.43	61.56	27.87	47.18	80.02	31.98	56.84	95.17
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	174.6	163.2	165.4	168.7	151.9	159.5	168.5	160.7	170.1	180.5
Motor Gasoline[4]	261.6	245.7	255.4	284.1	184.0	235.5	327.5	184.2	244.6	352.2
Jet Fuel[5]	200.2	204.3	212.8	231.2	123.9	179.2	285.2	137.9	207.5	322.3
Distillate Fuel Oil	255.9	244.4	253.9	264.5	183.8	236.1	327.2	191.9	257.1	369.4
Residual Fuel Oil	122.9	145.1	154.3	158.8	77.3	124.1	202.1	87.5	147.7	238.0
Residual Fuel Oil (2006 dollars per barrel)	51.63	60.93	64.80	66.69	32.47	52.12	84.89	36.74	62.04	99.95
Average	**234.5**	**224.3**	**233.1**	**252.3**	**166.4**	**214.1**	**296.3**	**171.4**	**229.6**	**326.4**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[3]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[4]Sales weighted-average price for all grades. Includes Federal, State and local taxes.
[5]Includes only kerosene type.
[6]Diesel fuel for on-road use. Includes Federal and State taxes while excluding county and local taxes.
[7]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Weighted averages of end-use fuel prices are derived from the prices in each sector and the corresponding sectoral consumption.
Note: Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 imported low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2006*, DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 residential, commercial, industrial, and transportation sector petroleum product prices are derived from: EIA, Form EIA-782A, "Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report." 2006 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2006 ethanol prices derived from weekly spot prices in the Oxy Fuel News. 2006 wholesale ethanol prices derived from Bloomburg U.S. average rack price. **Projections:** EIA, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Table C6. International Liquids Supply and Disposition Summary
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections								
		2010			2020			2030		
		Low Price	Reference	High Price	Low Price	Reference	High Price	Low Price	Reference	High Price
Crude Oil Prices (2006 dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price	66.02	71.45	74.03	79.02	39.07	59.70	102.07	42.35	70.45	118.65
Imported Crude Oil Price[1]	59.05	62.64	65.18	69.19	33.46	51.55	88.31	34.61	58.66	96.42
Conventional Production (Conventional)[2]										
OPEC[3]										
Asia	1.11	1.04	1.03	1.03	1.03	0.98	0.82	1.14	0.94	0.67
Middle East	23.21	25.67	22.41	20.69	30.59	24.09	21.58	38.17	27.35	22.18
North Africa	3.90	4.28	4.28	4.24	4.98	4.78	3.99	5.80	4.82	3.40
West Africa	4.02	5.78	5.77	5.73	7.71	7.41	6.19	9.89	8.23	5.79
South America	2.06	1.99	1.99	1.97	2.27	2.18	1.82	2.60	2.16	1.52
Total OPEC	**34.30**	**38.76**	**35.48**	**33.67**	**46.58**	**39.45**	**34.40**	**57.59**	**43.50**	**33.55**
Non-OPEC										
OECD										
United States (50 states)	7.91	8.89	8.84	8.70	9.28	9.15	9.06	7.96	8.39	8.70
Canada	2.00	1.86	1.85	1.84	1.66	1.32	1.05	1.32	1.05	0.76
Mexico	3.74	3.39	3.37	3.34	4.12	3.25	2.59	4.21	3.35	2.44
OECD Europe[4]	5.52	4.93	4.89	4.85	4.51	3.59	2.86	4.25	3.39	2.47
Japan	0.13	0.12	0.12	0.12	0.16	0.14	0.11	0.19	0.15	0.11
Australia and New Zealand	0.57	0.62	0.62	0.61	0.83	0.65	0.52	0.83	0.66	0.48
Total OECD	**19.85**	**19.81**	**19.69**	**19.46**	**20.57**	**18.10**	**16.19**	**18.76**	**16.99**	**14.96**
Non-OECD										
Russia	9.82	10.40	10.34	10.27	13.82	10.90	8.69	14.71	11.69	8.50
Other Eurasia[5]	2.85	3.80	3.77	3.75	6.92	5.46	4.35	8.01	6.36	4.63
China	3.80	3.86	3.83	3.80	4.90	3.87	3.09	4.43	3.53	2.57
Other Asia[6]	2.89	2.94	2.92	2.90	4.30	3.40	2.71	3.99	3.17	2.31
Middle East[7]	1.69	1.61	2.00	1.59	2.36	2.40	1.48	2.45	2.90	1.42
Africa	2.49	2.93	2.92	2.90	4.86	3.83	3.06	5.03	3.99	2.91
Brazil	1.84	2.42	2.40	2.39	4.30	3.39	2.71	4.61	3.66	2.67
Other Central and South America	2.36	2.33	2.32	2.30	3.39	2.67	2.13	4.41	3.51	2.55
Total Non-OECD	**27.73**	**30.28**	**30.51**	**29.89**	**44.83**	**35.94**	**28.23**	**47.64**	**38.81**	**27.55**
Total Conventional Production	**81.88**	**88.85**	**85.67**	**83.02**	**111.98**	**93.48**	**78.82**	**123.99**	**99.30**	**76.07**
Unconventional Production[8]										
United States (50 states)	0.34	0.80	0.78	0.78	1.44	1.53	1.71	1.87	2.06	3.19
Other North America	1.23	1.89	1.91	1.92	1.71	2.85	3.48	2.10	3.96	4.88
OECD Europe[3]	0.04	0.07	0.07	0.07	0.09	0.15	0.27	0.14	0.26	0.51
Middle East[7]	0.00	0.03	0.03	0.03	0.18	0.31	0.36	0.66	1.24	1.45
Africa.	0.17	0.31	0.31	0.31	0.27	0.44	0.79	0.44	0.83	1.51
Central and South America	0.80	1.17	1.18	1.19	1.05	1.76	2.46	1.33	2.51	3.64
Other	0.20	0.43	0.44	0.44	0.76	1.28	2.46	1.66	3.15	6.47
Total Unconventional Production	**2.78**	**4.70**	**4.73**	**4.75**	**5.49**	**8.32**	**11.52**	**8.19**	**14.00**	**21.65**
Total Production	**84.66**	**93.55**	**90.40**	**87.76**	**117.47**	**101.80**	**90.34**	**132.18**	**113.31**	**97.71**

Table C6. International Liquids Supply and Disposition Summary (Continued)
(Million Barrels per Day, Unless Otherwise Noted)

Supply and Disposition	2006	Projections 2010 Low Price	2010 Reference	2010 High Price	2020 Low Price	2020 Reference	2020 High Price	2030 Low Price	2030 Reference	2030 High Price
Consumption[8]										
OECD										
United States (50 states)	20.65	21.06	20.99	20.87	22.51	21.47	20.45	23.62	22.11	20.73
United States Territories	0.38	0.46	0.43	0.39	0.62	0.51	0.48	0.70	0.59	0.54
Canada	2.27	2.43	2.32	2.23	2.82	2.36	2.04	2.87	2.40	2.01
Mexico	2.06	2.29	2.19	2.10	3.09	2.61	2.24	3.53	2.95	2.48
OECD Europe[3]	15.42	16.22	15.47	14.85	18.69	15.71	13.59	18.99	15.86	13.27
Japan	5.16	5.41	5.18	4.98	6.18	5.22	4.54	6.26	5.26	4.44
South Korea	2.18	2.36	2.25	2.16	3.07	2.57	2.23	3.37	2.81	2.36
Australia and New Zealand	1.03	1.12	1.07	1.03	1.41	1.19	1.03	1.54	1.28	1.08
Total OECD	**49.16**	**51.36**	**49.90**	**48.61**	**58.38**	**51.64**	**46.60**	**60.88**	**53.28**	**46.89**
Non-OECD										
Russia	2.79	3.00	2.89	2.80	3.65	3.13	2.77	3.90	3.32	2.84
Other Non-OECD Eurasia[5]	2.09	2.37	2.26	2.17	3.11	2.64	2.29	3.50	2.96	2.50
China	7.26	9.86	9.44	9.08	14.21	11.96	10.39	18.73	15.69	13.20
India	2.49	2.81	2.68	2.57	4.30	3.62	3.14	5.23	4.37	3.67
Other Non-OECD Asia	6.14	6.97	6.67	6.40	9.86	8.35	7.20	11.74	9.86	8.29
Middle East[7]	6.15	7.30	7.13	7.05	9.65	8.46	7.61	11.36	9.84	8.61
Africa	2.99	3.53	3.36	3.20	5.20	4.35	3.71	5.94	4.93	4.09
Brazil	2.34	2.69	2.57	2.47	3.75	3.15	2.72	4.42	3.68	3.08
Other Central and South America	3.26	3.68	3.51	3.41	5.37	4.51	3.90	6.48	5.37	4.53
Total Non-OECD	**35.51**	**42.20**	**40.51**	**39.16**	**59.09**	**50.16**	**43.73**	**71.30**	**60.02**	**50.81**
Total Consumption	**84.66**	**93.55**	**90.40**	**87.76**	**117.48**	**101.80**	**90.34**	**132.18**	**113.30**	**97.70**
OPEC Production[10]	34.90	39.67	36.40	34.59	47.42	40.87	36.12	59.00	46.16	36.75
Non-OPEC Production[10]	49.76	53.88	54.00	53.17	70.05	60.94	54.22	73.19	67.15	60.96
Net Eurasia Exports	9.63	11.25	11.37	11.44	18.28	13.98	10.70	19.92	15.43	10.46
OPEC Market Share	41.2	42.4	40.3	39.4	40.4	40.1	40.0	44.6	40.7	37.6

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensates), natural gas plant liquids, other hydrogen and hydrocarbons for refinery feedstocks, alcohol and other sources, and refinery gains.
[3]OPEC = Organization of Petroleum Exporting Countries - Algeria, Angola, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela. Does not include Ecuador, which was admitted to OPEC as a full member on November 17, 2007.
[4]OECD Europe = Organization for Economic Cooperation and Development - Austria, Belgium, Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Eurasia consists of Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Tajikistan, Turkmenistan, Ukraine, and Uzbekistan.
[6]Other Asia = Afghanistan, Bangladesh, Bhutan, Brunei, Cambodia (Kampuchea), Fiji, French Polynesia, Guam, Hong Kong, Indonesia, Kiribati, Laos, Malaysia, Macau, Maldives, Mongolia, Myanmar (Burma), Nauru, Nepal, New Caledonia, Niue, North Korea, Pakistan, Papua New Guinea, Philippines, Samoa, Singapore, Solomon Islands, Sri Lanka, Taiwan, Thailand, Tonga, Vanuatu, and Vietnam.
[7]Non-OPEC Middle East includes Turkey.
[8]Includes liquids produced from energy crops, natural gas, coal, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[9]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[10]Includes both conventional and nonconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 low sulfur light crude oil price: Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2006 imported crude oil price: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **2006 quantities and projections:** Energy Information Administration, AEO2008 National Energy Modeling System runs LP2008.D031608A, AEO2008.D030208F, and HP2008.D031808A.

Appendix D

Results from Side Cases

Table D1. Key Results for Residential and Commercial Sector Technology Cases

Energy Consumption	2006	2010				2020			
		2008 Technology	Reference	High Technology	Best Available Technology	2008 Technology	Reference	High Technology	Best Available Technology
Residential									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.47	0.48	0.48	0.48	0.47	0.53	0.52	0.51	0.49
Kerosene	0.07	0.08	0.08	0.08	0.08	0.09	0.08	0.08	0.07
Distillate Fuel Oil	0.70	0.75	0.75	0.75	0.74	0.74	0.73	0.72	0.65
Liquid Fuels and Other Petroleum	1.25	1.32	1.31	1.31	1.28	1.36	1.33	1.31	1.20
Natural Gas	4.50	4.97	4.95	4.93	4.78	5.49	5.30	5.18	4.46
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.41	0.44	0.44	0.44	0.43	0.42	0.40	0.40	0.37
Electricity	4.61	5.00	4.95	4.94	4.40	5.53	5.25	5.08	4.30
Delivered Energy	**10.77**	**11.74**	**11.66**	**11.63**	**10.91**	**12.81**	**12.30**	**11.97**	**10.34**
Electricity Related Losses	10.04	10.70	10.59	10.57	9.42	11.66	11.08	10.72	9.06
Total	**20.82**	**22.45**	**22.25**	**22.20**	**20.33**	**24.47**	**23.39**	**22.69**	**19.41**
Delivered Energy Intensity (million Btu per household)	**95.8**	**101.2**	**100.5**	**100.2**	**94.0**	**99.2**	**95.3**	**92.7**	**80.1**
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.02**	**0.02**	**0.02**	**0.02**	**0.02**	**0.03**	**0.04**	**0.04**	**0.03**
Commercial									
Energy Consumption (quadrillion Btu)									
Liquefied Petroleum Gases	0.08	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.42	0.38	0.38	0.38	0.38	0.42	0.41	0.41	0.45
Residual Fuel Oil	0.11	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
Liquid Fuels and Other Petroleum	0.68	0.63	0.63	0.63	0.64	0.68	0.68	0.67	0.71
Natural Gas	2.92	3.05	3.04	3.03	3.00	3.50	3.47	3.41	3.29
Coal	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08
Renewable Energy[3]	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13	0.13
Electricity	4.43	4.78	4.73	4.69	4.58	5.95	5.67	5.39	4.90
Delivered Energy	**8.25**	**8.68**	**8.62**	**8.56**	**8.43**	**10.34**	**10.03**	**9.69**	**9.11**
Electricity Related Losses	9.66	10.24	10.12	10.03	9.80	12.56	11.96	11.38	10.34
Total	**17.91**	**18.92**	**18.74**	**18.59**	**18.23**	**22.90**	**21.98**	**21.06**	**19.45**
Delivered Energy Intensity (thousand Btu per square foot)	**110.3**	**110.1**	**109.3**	**108.6**	**107.0**	**115.9**	**112.3**	**108.5**	**102.1**
Commercial Sector Generation									
Net Summer Generation Capacity (megawatts)									
Natural Gas	630	662	665	671	672	908	1106	1325	1452
Solar Photovoltaic	243	505	505	505	506	789	860	902	1013
Wind	18	18	18	19	21	45	71	118	254
Electricity Generation (billion kilowatthours)									
Natural Gas	4.54	4.76	4.79	4.83	4.84	6.53	8.00	9.59	10.52
Solar Photovoltaic	0.38	0.81	0.81	0.81	0.81	1.27	1.41	1.48	1.66
Wind	0.02	0.02	0.02	0.03	0.03	0.06	0.10	0.17	0.36
Nonmarketed Renewables Consumption (quadrillion Btu)	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**	**0.03**

[1]Includes wood used for residential heating. See Table A4 and/or Table A17 for estimates of nonmarketed renewable energy consumption for geothermal heat pumps, solar thermal hot water heating, and solar photovoltaic electricity generation.
[2]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[3]Includes commercial sector consumption of wood and wood waste, landfill gas, biogenic municipal waste, and other biomass for combined heat and power.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all feedbacks are captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2008 National Energy Modeling System, runs BLDFRZN.D030408A, AEO2008.D030208F, BLDHIGH.D030408A, and BLDBEST.D030408A.

2030				Annual Growth 2006-2030 (percent)			
2008 Technology	Reference	High Technology	Best Available Technology	2008 Technology	Reference	High Technology	Best Available Technology
0.58	0.55	0.54	0.50	0.9%	0.7%	0.6%	0.3%
0.09	0.08	0.08	0.05	0.7%	0.5%	0.1%	-1.4%
0.69	0.65	0.63	0.55	-0.1%	-0.3%	-0.5%	-1.1%
1.35	1.29	1.24	1.10	0.3%	0.1%	-0.0%	-0.5%
5.72	5.32	5.04	3.96	1.0%	0.7%	0.5%	-0.5%
0.01	0.01	0.01	0.01	-0.1%	-0.4%	-0.5%	-0.6%
0.40	0.38	0.36	0.33	-0.1%	-0.3%	-0.5%	-0.9%
6.30	5.88	5.58	4.59	1.3%	1.0%	0.8%	-0.0%
13.78	**12.88**	**12.24**	**9.99**	**1.0%**	**0.7%**	**0.5%**	**-0.3%**
13.01	12.14	11.53	9.49	1.1%	0.8%	0.6%	-0.2%
26.78	**25.01**	**23.77**	**19.48**	**1.1%**	**0.8%**	**0.6%**	**-0.3%**
98.0	**91.6**	**87.0**	**71.1**	**0.1%**	**-0.2%**	**-0.4%**	**-1.2%**
0.05	**0.07**	**0.07**	**0.08**	**4.2%**	**5.9%**	**6.2%**	**6.7%**
0.09	0.09	0.09	0.09	0.6%	0.6%	0.6%	0.6%
0.05	0.05	0.05	0.05	0.4%	0.4%	0.4%	0.4%
0.02	0.02	0.02	0.02	0.2%	0.2%	0.2%	0.2%
0.42	0.41	0.41	0.48	0.0%	-0.0%	-0.1%	0.6%
0.10	0.10	0.10	0.10	-0.4%	-0.4%	-0.4%	-0.4%
0.69	0.68	0.68	0.75	0.1%	0.0%	-0.0%	0.4%
3.81	3.78	3.75	3.62	1.1%	1.1%	1.1%	0.9%
0.08	0.08	0.08	0.08	-0.1%	-0.1%	-0.1%	-0.1%
0.13	0.13	0.13	0.13	0.0%	0.0%	-0.0%	0.0%
7.07	6.62	6.17	5.38	2.0%	1.7%	1.4%	0.8%
11.79	**11.30**	**10.81**	**9.95**	**1.5%**	**1.3%**	**1.1%**	**0.8%**
14.61	13.68	12.73	11.11	1.7%	1.5%	1.2%	0.6%
26.40	**24.98**	**23.55**	**21.06**	**1.6%**	**1.4%**	**1.1%**	**0.7%**
117.0	**112.2**	**107.3**	**98.8**	**0.2%**	**0.1%**	**-0.1%**	**-0.5%**
1462	2621	3631	4720	3.6%	6.1%	7.6%	8.8%
1098	1700	2235	4628	6.5%	8.4%	9.7%	13.1%
168	239	588	2249	9.8%	11.4%	15.7%	22.3%
10.53	19.02	26.37	34.29	3.6%	6.2%	7.6%	8.8%
1.75	2.84	3.73	7.73	6.6%	8.7%	10.0%	13.4%
0.24	0.35	0.84	3.08	10.2%	11.9%	16.0%	22.5%
0.03	**0.04**	**0.04**	**0.07**	**1.1%**	**1.7%**	**2.2%**	**4.0%**

Table D2. Key Results for Industrial Sector Technology Cases, Excluding Refining

Consumption	2006	2010 2008 Technology	2010 Reference	2010 High Technology	2020 2008 Technology	2020 Reference	2020 High Technology	2030 2008 Technology	2030 Reference	2030 High Technology
Value of Shipments (billion 2000 dollars)										
Manufacturing	4290	4577	4577	4577	5493	5493	5493	6283	6283	6283
Nonmanufacturing	1531	1419	1419	1419	1619	1619	1619	1715	1715	1715
Total	**5821**	**5997**	**5997**	**5997**	**7113**	**7113**	**7113**	**7997**	**7997**	**7997**
Energy Consumption excluding Refining[1] (quadrillion Btu)										
Liquefied Petroleum Gases	2.08	2.15	2.08	2.02	2.07	1.80	1.59	1.99	1.70	1.48
Heat and Power	0.16	0.17	0.17	0.17	0.18	0.16	0.16	0.18	0.16	0.15
Feedstocks	1.91	1.98	1.92	1.86	1.90	1.64	1.43	1.82	1.55	1.34
Motor Gasoline	0.38	0.38	0.38	0.37	0.40	0.37	0.34	0.42	0.38	0.35
Distillate Fuel Oil	1.28	1.31	1.29	1.27	1.34	1.23	1.14	1.39	1.23	1.11
Residual Fuel Oil	0.27	0.29	0.28	0.27	0.27	0.22	0.21	0.27	0.21	0.20
Petrochemical Feedstocks	1.41	1.38	1.36	1.35	1.45	1.39	1.34	1.37	1.29	1.23
Petroleum Coke	0.36	0.35	0.34	0.34	0.38	0.31	0.29	0.39	0.30	0.27
Asphalt and Road Oil	1.26	1.26	1.22	1.19	1.27	1.08	0.93	1.36	1.13	0.92
Miscellaneous Petroleum[2]	0.56	0.41	0.39	0.38	0.46	0.33	0.31	0.44	0.29	0.26
Petroleum Subtotal	7.60	7.53	7.34	7.20	7.65	6.73	6.14	7.63	6.55	5.82
Natural Gas Heat and Power	5.01	5.30	5.12	5.10	6.05	5.22	5.13	6.16	5.22	5.07
Natural Gas Feedstocks	0.57	0.56	0.54	0.52	0.55	0.46	0.40	0.48	0.39	0.33
Lease and Plant Fuel[3]	1.17	1.21	1.21	1.21	1.25	1.25	1.25	1.27	1.27	1.27
Natural Gas Subtotal	6.74	7.08	6.86	6.83	7.85	6.93	6.78	7.90	6.88	6.66
Metallurgical Coal and Coke[4]	0.66	0.64	0.63	0.61	0.63	0.57	0.49	0.60	0.52	0.42
Other Industrial Coal	1.20	1.26	1.25	1.24	1.23	1.14	1.10	1.23	1.12	1.07
Coal Subtotal	1.86	1.90	1.87	1.85	1.86	1.71	1.59	1.82	1.64	1.49
Renewables[5]	1.69	1.66	1.66	1.68	1.79	1.83	1.91	1.92	2.02	2.17
Purchased Electricity	3.27	3.40	3.35	3.30	3.67	3.42	3.26	3.73	3.35	3.08
Delivered Energy	**21.17**	**21.57**	**21.09**	**20.86**	**22.81**	**20.62**	**19.68**	**23.00**	**20.44**	**19.22**
Electricity Related Losses	7.13	7.28	7.17	7.06	7.73	7.22	6.87	7.70	6.92	6.36
Total	**28.29**	**28.85**	**28.27**	**27.92**	**30.54**	**27.84**	**26.55**	**30.70**	**27.35**	**25.58**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 2000 dollar)	**4.31**	**4.38**	**4.31**	**4.27**	**4.06**	**3.75**	**3.62**	**3.79**	**3.46**	**3.31**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	25.69	28.05	28.11	28.28	36.43	36.84	37.90	43.57	44.85	47.23
Generation (billion kilowatthours)	139.50	155.16	155.59	156.67	218.02	220.78	227.59	272.50	281.41	296.46

[1]Fuel consumption includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes lubricants and miscellaneous petroleum products.
[3]Represents natural gas used in the field gathering and processing plant machinery.
[4]Includes net coal coke imports.
[5]Includes consumption of energy from hydroelectric, wood and wood waste, biogenic municipal waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs INDFRZN.D030608A, AEO2008.D030208F, and INDHIGH.D032208A.

Table D3. Key Results for Transportation Sector Technology Cases

Consumption and Indicators	2006	2010		2020		2030	
		Reference	High Technology	Reference	High Technology	Reference	High Technology
Level of Travel							
(billion vehicle miles traveled)							
Light-Duty Vehicles less than 8,500	2693	2777	2777	3375	3379	4069	4074
Commercial Light Trucks[1]	70	73	73	87	87	101	101
Freight Trucks greater than 10,000	235	250	250	304	304	351	351
(billion seat miles available)							
Air	994	1130	1130	1457	1457	1665	1665
(billion ton miles traveled)							
Rail	1656	1702	1703	1932	1933	2147	2148
Domestic Shipping	619	643	643	701	701	721	721
Energy Efficiency Indicators							
(miles per gallon)							
New Light-Duty Vehicle[2]	26.5	27.2	27.6	35.8	36.1	36.6	37.2
New Car[2]	31.1	31.5	32.2	42.0	42.2	42.1	42.6
New Light Truck[2]	23.2	23.7	24.1	31.4	32.2	32.4	33.4
Light-Duty Stock[3]	20.3	20.3	20.3	23.7	23.9	27.9	28.2
New Commercial Light Truck[1]	15.6	15.7	16.0	19.8	20.7	20.2	21.4
Stock Commercial Light Truck[1]	14.3	14.9	14.9	17.4	17.8	19.8	20.6
Freight Truck	6.0	6.0	6.1	6.5	6.7	6.8	7.2
(seat miles per gallon)							
Aircraft	62.2	63.5	63.5	67.2	67.4	70.0	70.6
(ton miles per thousand Btu)							
Rail	2.9	2.9	2.9	3.0	3.1	3.0	3.2
Domestic Shipping	2.0	2.0	2.0	2.0	2.1	2.0	2.2
Energy Use (quadrillion Btu)							
by Mode							
Light-Duty Vehicles	16.41	16.52	16.48	17.10	16.98	17.52	17.37
Commercial Light Trucks[1]	0.62	0.62	0.61	0.63	0.62	0.64	0.62
Bus Transportation	0.26	0.26	0.26	0.27	0.26	0.29	0.27
Freight Trucks	4.89	5.18	5.15	5.85	5.66	6.44	6.14
Rail, Passenger	0.04	0.05	0.05	0.05	0.05	0.06	0.06
Rail, Freight	0.57	0.58	0.58	0.65	0.63	0.72	0.67
Shipping, Domestic	0.32	0.33	0.32	0.35	0.33	0.36	0.33
Shipping, International	0.78	0.79	0.79	0.79	0.79	0.80	0.80
Recreational Boats	0.24	0.25	0.25	0.28	0.28	0.30	0.30
Air	2.65	2.90	2.90	3.61	3.60	4.22	4.18
Military Use	0.69	0.73	0.73	0.73	0.73	0.76	0.76
Lubricants	0.15	0.14	0.14	0.14	0.14	0.15	0.15
Pipeline Fuel	0.59	0.64	0.64	0.69	0.69	0.72	0.72
Total	**28.20**	**28.98**	**28.91**	**31.15**	**30.77**	**32.98**	**32.37**
by Fuel							
Liquefied Petroleum Gases	0.02	0.02	0.02	0.01	0.01	0.01	0.01
E85[4]	0.00	0.00	0.00	0.97	0.98	1.34	1.35
Motor Gasoline[5]	17.20	17.25	17.21	16.56	16.42	15.97	15.78
Jet Fuel[6]	3.16	3.44	3.44	4.15	4.14	4.79	4.75
Distillate Fuel Oil[7]	6.18	6.54	6.51	7.63	7.39	8.98	8.60
Residual Fuel Oil	0.83	0.85	0.85	0.86	0.85	0.87	0.86
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Petroleum[8]	0.18	0.17	0.17	0.18	0.18	0.18	0.18
Liquid Fuels and Other Petroleum	27.57	28.29	28.21	30.37	29.98	32.15	31.54
Pipeline Fuel Natural Gas	0.59	0.64	0.64	0.69	0.69	0.72	0.72
Compressed Natural Gas	0.02	0.04	0.04	0.07	0.07	0.08	0.08
Electricity	0.02	0.02	0.02	0.03	0.03	0.03	0.03
Delivered Energy	**28.20**	**28.98**	**28.91**	**31.15**	**30.76**	**32.98**	**32.37**
Electricity Related Losses	0.05	0.05	0.05	0.06	0.06	0.06	0.06
Total	**28.25**	**29.03**	**28.96**	**31.21**	**30.82**	**33.04**	**32.43**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]Environmental Protection Agency rated miles per gallon.
[3]Combined car and light truck "on-the-road" estimate.
[4]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[5]Includes ethanol (blends of 10 percent or less) and ethers blended into gasoline.
[6]Includes only kerosene type.
[7]Diesel fuel for on- and off- road use.
[8]Includes aviation gasoline and lubricants.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports. Side cases were run without the fully integrated modeling system, so not all potential feedbacks were captured. The reference case ratio of electricity losses to electricity use was used to compute electricity losses for the technology cases.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and TRNHIGH.D031408A.

Table D4. Key Results for Integrated Technology Cases

Consumption and Emissions	2006	2010			2020			2030		
		2008 Technology	Reference	High Technology	2008 Technology	Reference	High Technology	2008 Technology	Reference	High Technology
Energy Consumption by Sector (quadrillion Btu)										
Residential	10.77	11.73	11.66	11.64	12.79	12.30	12.00	13.73	12.88	12.29
Commercial	8.25	8.66	8.62	8.57	10.30	10.03	9.73	11.69	11.30	10.88
Industrial[1]	25.10	26.30	25.82	25.58	28.96	26.70	25.79	30.15	27.70	26.57
Transportation	28.20	28.98	28.98	28.92	31.18	31.15	30.80	33.00	32.98	32.44
Electric Power[2]	39.68	41.77	41.46	41.23	47.34	45.21	43.63	52.40	49.21	45.79
Total	**99.52**	**104.11**	**103.34**	**102.82**	**115.28**	**110.85**	**107.94**	**123.83**	**118.01**	**112.79**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	40.06	40.69	40.46	40.24	43.25	42.24	41.30	45.16	43.99	42.68
Natural Gas	22.30	24.44	23.93	23.68	25.24	24.01	23.10	24.96	23.39	22.19
Coal	22.50	23.06	23.03	23.01	28.11	25.87	24.82	33.61	29.90	28.00
Nuclear Power	8.21	8.31	8.31	8.31	8.98	9.05	9.15	8.85	9.57	8.99
Renewable Energy[4]	6.27	7.42	7.43	7.39	9.52	9.50	9.39	11.02	10.97	10.75
Other [5]	0.19	0.19	0.18	0.18	0.18	0.17	0.17	0.23	0.20	0.18
Total	**99.52**	**104.11**	**103.34**	**102.82**	**115.28**	**110.85**	**107.94**	**123.83**	**118.01**	**112.79**
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.79**	**8.37**	**8.30**	**8.25**	**7.22**	**6.93**	**6.74**	**6.14**	**5.84**	**5.57**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	338	356	355	354	385	374	367	396	372	354
Commercial	213	215	215	215	242	241	238	259	258	257
Industrial[1]	1010	1074	1052	1044	1173	1069	1032	1193	1086	1038
Transportation	1985	1975	1976	1971	2074	2072	2047	2188	2188	2149
Electric Power[6]	2344	2429	2413	2404	2827	2627	2509	3299	2948	2746
Total	**5890**	**6049**	**6011**	**5987**	**6701**	**6384**	**6193**	**7335**	**6851**	**6543**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2581	2565	2555	2546	2692	2650	2607	2816	2767	2701
Natural Gas	1163	1282	1256	1243	1325	1262	1216	1312	1231	1169
Coal	2134	2190	2188	2186	2671	2459	2359	3194	2841	2661
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5890**	**6049**	**6011**	**5987**	**6701**	**6384**	**6193**	**7335**	**6851**	**6543**
Carbon Dioxide Emissions (tons per person)	**19.6**	**19.5**	**19.3**	**19.3**	**19.8**	**18.9**	**18.3**	**20.1**	**18.7**	**17.9**

[1]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[3]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol and biodiesel. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; municipal waste; other biomass; wind; photovoltaic and solar thermal sources; and 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 component of blends less than 85 percent. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[5]Includes non-biogenic municipal waste and net electricity imports.
[6]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Does not include emissions from the nonbiogenic component of municipal waste because under international guidelines these are accounted for as waste, not energy.
[7]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Includes end-use, fossil electricity, and renewable technology assumptions. Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HTECHCOST.D031408A, AEO2008.D030208F, and LTECHCOST.D032208A.

Table D5. Key Results for Advanced Nuclear Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2006	2010			2020			2030		
		High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost
Capacity										
Coal	309.8	316.0	316.0	316.0	343.8	343.1	341.5	415.1	406.1	389.8
Oil and Natural Gas Steam	119.7	118.4	118.4	118.4	92.8	93.3	91.4	92.4	92.9	89.9
Combined Cycle	176.5	190.0	190.0	190.0	196.8	196.7	196.8	213.5	210.0	208.4
Combustion Turbine/Diesel	130.9	137.4	137.4	137.4	132.1	132.1	132.0	162.9	164.7	162.3
Nuclear Power	100.2	100.9	100.9	100.9	108.9	110.9	113.6	104.4	114.9	136.6
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	96.3	111.6	111.6	111.6	123.6	123.6	123.5	133.1	132.5	131.2
Distributed Generation (Natural Gas)	0.0	0.3	0.3	0.3	2.6	2.7	2.7	9.1	9.8	9.7
Combined Heat and Power[1]	27.9	30.7	30.7	30.7	40.5	40.4	40.5	51.8	51.8	52.4
Total	**982.9**	**1026.7**	**1026.7**	**1026.7**	**1062.5**	**1064.2**	**1063.5**	**1203.8**	**1204.2**	**1201.8**
Cumulative Additions										
Coal	0.0	7.7	7.7	7.7	37.7	37.0	35.5	109.2	100.2	83.8
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	13.5	13.5	13.5	20.3	20.2	20.3	36.9	33.4	31.8
Combustion Turbine/Diesel	0.0	7.2	7.2	7.2	10.5	10.5	10.3	42.0	43.4	41.9
Nuclear Power	0.0	0.0	0.0	0.0	6.0	8.0	10.7	6.0	16.6	38.2
Pumped Storage	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	15.2	15.3	15.3	27.3	27.3	27.2	36.8	36.2	34.9
Distributed Generation	0.0	0.3	0.3	0.3	2.6	2.7	2.7	9.1	9.8	9.7
Combined Heat and Power[1]	0.0	2.9	2.9	2.9	12.6	12.5	12.7	23.9	23.9	24.5
Total	**0.0**	**46.7**	**46.8**	**46.8**	**117.0**	**118.2**	**119.3**	**264.0**	**263.5**	**264.8**
Cumulative Retirements	**0.0**	**3.6**	**3.6**	**3.6**	**40.0**	**39.5**	**41.4**	**45.7**	**44.8**	**48.6**
Generation by Fuel (billion kilowatthours)										
Coal	1966	2034	2034	2034	2332	2319	2310	2856	2787	2656
Petroleum	59	50	50	50	53	53	53	57	57	56
Natural Gas	732	821	820	820	724	722	710	610	599	574
Nuclear Power	787	797	797	797	854	868	888	837	917	1082
Pumped Storage	0	1	1	1	1	1	1	1	1	1
Renewable Sources	351	424	424	424	521	522	523	557	558	554
Distributed Generation	0	0	0	0	1	1	1	3	4	4
Combined Heat and Power[1]	152	169	169	169	238	238	239	313	313	317
Total	**4047**	**4294**	**4294**	**4294**	**4723**	**4723**	**4724**	**5234**	**5235**	**5243**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	55	43	43	43	45	45	45	48	48	47
Natural Gas	340	366	365	366	324	323	318	275	272	263
Coal	1938	1992	1993	1992	2259	2247	2241	2675	2615	2515
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2413**	**2413**	**2413**	**2641**	**2627**	**2616**	**3010**	**2948**	**2837**
Prices to the Electric Power Sector[2] (2006 dollars per million Btu)										
Petroleum	9.63	10.80	10.79	10.79	8.58	8.57	8.57	10.38	10.37	10.29
Natural Gas	6.87	6.97	6.96	6.97	5.95	5.95	5.92	6.95	6.93	6.85
Coal	1.69	1.84	1.84	1.84	1.72	1.72	1.72	1.80	1.78	1.76

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. 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.

[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.

[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.

Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HCNUC08.D030308A, AEO2008.D030208F, and LCNUC08.D030308A.

Table D6. Key Results for Electric Power Sector Fossil Technology Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation Consumption, and Emissions	2006	2010			2020			2030		
		High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost	High Fossil Cost	Reference	Low Fossil Cost
Capacity										
Pulverized Coal	309.3	315.5	315.5	315.5	341.5	338.2	325.3	397.5	376.1	331.7
Coal Gasification Combined-Cycle	0.5	0.5	0.5	0.5	3.1	4.8	17.6	4.7	30.0	94.6
Conventional Natural Gas Combined-Cycle	176.5	190.0	190.0	190.0	192.3	192.1	192.1	194.5	192.1	192.1
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	0.5	4.6	8.7	0.9	17.9	37.4
Conventional Combustion Turbine	130.9	136.6	136.5	136.5	128.2	127.9	127.7	132.1	128.4	125.7
Advanced Combustion Turbine	0.0	0.8	0.9	0.9	7.9	4.2	3.1	37.9	36.3	25.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	100.2	100.9	100.9	100.9	111.2	110.9	109.9	121.5	114.9	105.4
Oil and Natural Gas Steam	119.7	118.4	118.4	118.4	91.3	93.3	94.6	90.9	92.9	92.6
Renewable Sources/Pumped Storage	117.8	133.1	133.1	133.1	145.5	145.1	144.4	154.1	154.0	150.8
Distributed Generation	0.0	0.3	0.3	0.3	2.7	2.7	1.5	12.6	9.8	5.7
Combined Heat and Power[1]	27.9	30.7	30.7	30.7	40.6	40.4	40.5	52.1	51.8	51.0
Total	**982.9**	**1026.7**	**1026.7**	**1026.7**	**1065.0**	**1064.2**	**1065.4**	**1198.9**	**1204.2**	**1212.8**
Cumulative Additions										
Pulverized Coal	0.0	7.7	7.7	7.7	36.0	32.7	19.8	92.2	70.7	26.4
Coal Gasification Combined-Cycle	0.0	0.0	0.0	0.0	2.5	4.3	17.1	4.2	29.5	94.1
Conventional Natural Gas Combined-Cycle	0.0	13.5	13.5	13.5	15.8	15.5	15.5	17.9	15.5	15.5
Advanced Natural Gas Combined-Cycle	0.0	0.0	0.0	0.0	0.5	4.6	8.7	0.9	17.9	37.4
Conventional Combustion Turbine	0.0	6.4	6.3	6.3	6.9	6.4	6.3	10.7	7.1	6.3
Advanced Combustion Turbine	0.0	0.8	0.9	0.9	7.9	4.2	3.1	37.9	36.3	25.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	0.0	0.0	0.0	0.0	8.4	8.0	7.0	23.1	16.6	7.0
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	0.0	15.3	15.3	15.3	27.7	27.3	26.6	36.3	36.2	33.0
Distributed Generation	0.0	0.3	0.3	0.3	2.7	2.7	1.5	12.6	9.8	5.7
Combined Heat and Power[1]	0.0	2.9	2.9	2.9	12.8	12.5	12.6	24.2	23.9	23.1
Total	**0.0**	**46.8**	**46.8**	**46.8**	**121.2**	**118.2**	**118.2**	**260.1**	**263.5**	**274.4**
Cumulative Retirements	**0.0**	**3.6**	**3.6**	**3.6**	**41.8**	**39.5**	**38.3**	**46.8**	**44.8**	**47.0**
Generation by Fuel (billion kilowatthours)										
Coal	1966	2034	2034	2034	2334	2319	2319	2749	2787	2917
Petroleum	59	50	50	50	53	53	51	58	57	52
Natural Gas	732	820	820	820	704	722	733	575	599	588
Nuclear Power	787	797	797	797	871	868	861	967	917	845
Renewable Sources/Pumped Storage	351	425	425	425	523	523	524	558	559	553
Distributed Generation	0	0	0	0	1	1	1	4	4	2
Combined Heat and Power[1]	152	169	169	169	240	238	238	315	313	308
Total	**4047**	**4294**	**4294**	**4294**	**4727**	**4723**	**4727**	**5225**	**5235**	**5266**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	20.48	21.01	21.01	21.01	23.84	23.67	23.54	27.45	27.55	27.62
Petroleum	0.64	0.56	0.56	0.56	0.59	0.59	0.57	0.63	0.63	0.59
Natural Gas	6.42	6.89	6.89	6.89	5.99	6.09	6.12	5.06	5.13	4.83
Nuclear Power	8.21	8.31	8.31	8.31	9.08	9.05	8.98	10.08	9.57	8.81
Renewable Sources	3.74	4.52	4.53	4.52	5.66	5.64	5.66	6.10	6.13	6.06
Total	**39.62**	**41.42**	**41.41**	**41.41**	**45.29**	**45.16**	**45.00**	**49.46**	**49.13**	**48.04**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1938	1992	1993	1992	2263	2247	2235	2608	2615	2623
Petroleum	55	43	43	43	45	45	44	49	48	45
Natural Gas	340	366	365	366	318	323	325	268	272	256
Other[1]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2413**	**2413**	**2413**	**2639**	**2627**	**2616**	**2938**	**2948**	**2937**

[1]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors. 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.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HCFOSS08.D030308A, AEO2008.D030208F, and LCFOSS08.D030308A.

Table D7. Key Results for Renewable Technology Cases

Capacity, Generation, and Emissions	2006	2010 High Renewable Cost	2010 Reference	2010 Low Renewable Cost	2020 High Renewable Cost	2020 Reference	2020 Low Renewable Cost	2030 High Renewable Cost	2030 Reference	2030 Low Renewable Cost
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	76.72	76.73	76.73	76.73	77.35	77.26	77.13	77.35	77.32	77.32
Geothermal[2]	2.29	2.50	2.50	2.50	3.15	3.28	3.26	4.06	4.18	3.96
Municipal Waste[3]	3.39	3.99	3.99	3.92	4.06	4.02	3.96	4.07	4.06	3.97
Wood and Other Biomass[4]	2.01	2.20	2.20	2.20	4.56	4.39	4.53	5.33	5.58	6.48
Solar Thermal	0.40	0.54	0.54	0.54	0.82	0.82	0.82	0.86	0.86	0.86
Solar Photovoltaic	0.03	0.07	0.07	0.07	0.22	0.22	0.22	0.39	0.39	0.39
Wind	11.50	25.61	25.61	25.61	31.53	33.64	36.92	36.57	40.15	43.80
Total	**96.34**	**111.63**	**111.63**	**111.57**	**121.68**	**123.62**	**126.83**	**128.63**	**132.54**	**136.77**
End-Use Sector[5]										
Conventional Hydropower	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70	0.70
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Wood and Other Biomass	4.64	4.87	4.89	4.95	8.32	8.57	8.95	11.97	12.60	13.13
Solar Photovoltaic	0.27	0.67	0.67	0.70	1.01	1.13	1.23	1.39	2.80	3.97
Wind	0.04	0.04	0.04	0.04	0.07	0.09	0.11	0.19	0.26	0.33
Total	**6.00**	**6.63**	**6.65**	**6.74**	**10.45**	**10.85**	**11.33**	**14.60**	**16.72**	**18.48**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	1966	2035	2034	2035	2316	2319	2315	2784	2787	2777
Petroleum	59	50	50	50	52	53	53	56	57	56
Natural Gas	732	821	820	820	728	722	720	606	599	593
Total Fossil	**2757**	**2905**	**2903**	**2904**	**3097**	**3093**	**3088**	**3447**	**3443**	**3426**
Conventional Hydropower	285.07	289.47	289.47	289.47	298.51	298.00	297.16	298.72	298.53	298.35
Geothermal	14.84	17.52	17.52	17.52	22.95	23.96	23.80	30.13	31.05	29.32
Municipal Waste[3]	13.46	18.85	18.85	18.30	19.44	19.08	18.67	19.48	19.47	18.70
Wood and Other Biomass[4]	10.97	21.75	22.98	22.42	86.48	77.53	68.58	92.57	82.55	71.51
Dedicated Plants	9.06	10.94	11.06	11.21	28.80	27.74	28.50	34.54	36.64	42.84
Cofiring	1.91	10.80	11.92	11.22	57.68	49.79	40.07	58.03	45.91	28.68
Solar Thermal	0.49	1.15	1.15	1.15	2.04	2.04	2.04	2.18	2.18	2.18
Solar Photovoltaic	0.01	0.16	0.16	0.16	0.52	0.52	0.52	0.96	0.96	0.96
Wind	25.78	72.85	74.13	73.50	89.99	101.23	113.36	105.86	123.18	137.80
Total Renewable	**350.62**	**421.75**	**424.27**	**422.53**	**519.94**	**522.35**	**524.12**	**549.91**	**557.91**	**558.82**
End-Use Sector[5]										
Total Fossil	99	115	115	115	156	157	158	201	198	200
Conventional Hydropower[7]	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24	3.24
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	2.06	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82	2.82
Wood and Other Biomass	28.44	29.83	29.98	30.29	55.52	57.00	59.20	83.13	86.99	89.54
Solar Photovoltaic	0.43	1.07	1.07	1.12	1.61	1.85	2.01	2.22	4.76	6.75
Wind	0.06	0.06	0.06	0.06	0.09	0.13	0.15	0.27	0.38	0.48
Total Renewable	**34.22**	**37.02**	**37.17**	**37.53**	**63.30**	**65.05**	**67.43**	**91.69**	**98.19**	**102.84**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Coal	1938	1994	1993	1993	2243	2247	2246	2610	2615	2609
Petroleum	55	43	43	43	45	45	45	48	48	47
Natural Gas	340	366	365	366	326	323	323	275	272	270
Other[8]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2414**	**2413**	**2414**	**2625**	**2627**	**2626**	**2945**	**2948**	**2938**

[1]Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[2]Includes hydrothermal resources only (hot water and steam).
[3]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[4]Includes projections for energy crops after 2010.
[5]Includes combined heat and power plants and electricity-only plants in the commercial and industrial sectors; and 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.
[6]Includes municipal waste, landfill gas, and municipal sewage sludge. All municipal waste is included, although a portion of the municipal waste stream contains petroleum-derived plastics and other non-renewable sources.
[7]Represents own-use industrial hydroelectric power.
[8]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs HIRENCST08.D030408A, AEO2008.D030208F, and LORENCST08.D030408A.

Table D8. Natural Gas Supply and Disposition, Oil and Gas Technological Progress Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Natural Gas Prices										
(2006 dollars per million Btu)										
Henry Hub Spot Price	6.73	6.94	6.90	6.86	6.13	5.95	5.69	7.72	7.22	6.66
Average Lower 48 Wellhead Price[1]	6.24	6.19	6.16	6.12	5.45	5.29	5.05	6.90	6.45	5.94
(2006 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[1]	6.42	6.37	6.33	6.30	5.61	5.44	5.20	7.10	6.63	6.11
Dry Gas Production[2]	**18.51**	**19.27**	**19.29**	**19.32**	**19.27**	**19.67**	**20.40**	**18.50**	**19.44**	**20.69**
Lower 48 Onshore	15.04	15.27	15.26	15.26	13.90	14.16	14.70	12.82	13.95	15.21
Associated-Dissolved	1.42	1.41	1.41	1.41	1.29	1.33	1.38	1.10	1.20	1.24
Non-Associated	13.62	13.86	13.85	13.84	12.61	12.83	13.32	11.72	12.76	13.97
Conventional	5.14	4.82	4.81	4.80	3.59	3.47	3.31	3.57	3.23	2.83
Unconventional	8.48	9.04	9.04	9.05	9.02	9.36	10.01	8.15	9.53	11.14
Lower 48 Offshore	3.05	3.58	3.61	3.65	4.18	4.31	4.51	3.32	3.47	3.47
Associated-Dissolved	0.62	0.72	0.73	0.74	0.93	0.97	1.02	0.73	0.77	0.83
Non-Associated	2.43	2.86	2.88	2.91	3.25	3.35	3.49	2.59	2.69	2.64
Alaska	0.42	0.42	0.42	0.42	1.19	1.19	1.19	2.37	2.01	2.01
Supplemental Natural Gas[3]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.46**	**3.85**	**3.85**	**3.85**	**3.60**	**3.55**	**3.41**	**3.23**	**3.18**	**2.73**
Pipeline[4]	2.94	2.64	2.64	2.65	1.14	1.18	1.22	0.23	0.33	0.44
Liquefied Natural Gas	0.52	1.21	1.20	1.20	2.46	2.37	2.19	3.00	2.84	2.29
Total Supply	**22.03**	**23.18**	**23.20**	**23.23**	**22.93**	**23.28**	**23.87**	**21.80**	**22.68**	**23.48**
Consumption by Sector										
Residential	4.37	4.80	4.81	4.81	5.13	5.15	5.17	5.12	5.17	5.22
Commercial	2.83	2.95	2.96	2.96	3.35	3.37	3.39	3.63	3.67	3.72
Industrial[5]	6.49	6.94	6.95	6.96	6.88	6.93	6.99	6.76	6.87	7.02
Electric Power[6]	6.24	6.69	6.70	6.72	5.69	5.92	6.36	4.37	4.99	5.49
Transportation[7]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.08	0.09	0.09
Pipeline Fuel	0.58	0.62	0.62	0.62	0.66	0.67	0.69	0.68	0.70	0.72
Lease and Plant Fuel[8]	1.14	1.18	1.18	1.18	1.20	1.22	1.25	1.20	1.23	1.28
Total	**21.66**	**23.23**	**23.25**	**23.28**	**22.98**	**23.33**	**23.92**	**21.85**	**22.72**	**23.53**
Discrepancy[9]	**0.37**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.04**
Lower 48 End of Year Reserves	**202.99**	**219.82**	**220.62**	**221.61**	**209.51**	**219.31**	**237.64**	**176.29**	**200.42**	**233.48**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]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.
[4]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[5]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]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, 2006 values include net storage injections.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs OGLTEC08.D030508A, AEO2008.D030208F, and OGHTEC08.D030508A.

Table D9. Liquid Fuels Supply and Disposition, Oil and Gas Technological Progress Cases
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010			2020			2030		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Prices (2006 dollars per barrel)										
Imported Low Sulfur Light Crude Oil	**66.02**	**74.11**	**74.03**	**73.96**	**60.00**	**59.70**	**59.39**	**71.11**	**70.45**	**70.03**
Imported Crude Oil[1]	**59.05**	**65.25**	**65.18**	**65.02**	**51.85**	**51.55**	**51.08**	**61.36**	**58.66**	**57.97**
Crude Oil Supply										
Domestic Crude Oil Production[2]	5.10	5.88	5.93	5.98	5.94	6.23	6.53	4.98	5.59	5.94
Alaska	0.74	0.69	0.69	0.69	0.69	0.70	0.70	0.29	0.30	0.30
Lower 48 Onshore	2.93	3.08	3.10	3.13	3.08	3.28	3.46	2.88	3.38	3.58
Lower 48 Offshore	1.43	2.12	2.14	2.16	2.17	2.25	2.37	1.80	1.92	2.06
Net Crude Oil Imports	10.09	9.61	9.60	9.58	10.01	9.75	9.53	11.50	11.03	10.78
Other Crude Oil Supply	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**15.24**	**15.49**	**15.53**	**15.56**	**15.95**	**15.98**	**16.06**	**16.48**	**16.63**	**16.72**
Other Supply										
Natural Gas Plant Liquids	1.74	1.68	1.68	1.68	1.70	1.72	1.74	1.50	1.57	1.61
Net Product Imports[3]	2.31	1.76	1.72	1.70	1.39	1.37	1.29	1.38	1.26	1.13
Refinery Processing Gain[4]	0.99	1.05	1.05	1.05	1.00	1.00	1.01	0.98	0.99	0.99
Other Supply[5]	0.45	1.04	1.04	1.04	2.00	1.97	1.98	2.44	2.41	2.44
Total Primary Supply[6]	**20.74**	**21.01**	**21.02**	**21.03**	**22.05**	**22.04**	**22.08**	**22.79**	**22.86**	**22.89**
Liquid Fuels Consumption by Sector										
Residential and Commercial	1.07	1.08	1.08	1.08	1.12	1.13	1.13	1.11	1.12	1.12
Industrial[7]	5.15	5.06	5.06	5.06	4.79	4.79	4.80	4.71	4.73	4.73
Transportation	14.05	14.59	14.60	14.60	15.79	15.79	15.81	16.63	16.66	16.69
Electric Power[8]	0.29	0.25	0.25	0.25	0.26	0.26	0.26	0.28	0.28	0.28
Total	**20.65**	**20.98**	**20.99**	**21.00**	**21.96**	**21.96**	**21.99**	**22.74**	**22.80**	**22.83**
Discrepancy[9]	**0.09**	**0.03**	**0.03**	**0.03**	**0.08**	**0.08**	**0.09**	**0.05**	**0.06**	**0.06**
Lower 48 End of Year Reserves (billion barrels)[2]	**19.02**	**19.59**	**19.89**	**20.20**	**19.68**	**20.78**	**21.91**	**17.69**	**19.89**	**20.98**

[1]Weighted average price delivered to U.S. refiners.
[2]Includes lease condensate.
[3]Includes net imports of finished petroleum products, unfinished oils, other hydrocarbons, alcohols, ethers, and blending components.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes ethanol (including imports), alcohols, ethers, petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, biodiesel (including imports), natural gas converted to liquid fuel, coal converted to liquid fuel, and biomass converted to liquid fuel.
[6]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[7]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[8]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[9]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 product supplied data based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 data: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs OGLTEC08.D030508A, AEO2008.D030208F, and OGHTEC08.D030508A.

Table D10. Natural Gas Supply and Disposition, Liquefied Natural Gas Supply Cases

(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010			2020			2030		
		Low LNG Supply	Reference	High LNG Supply	Low LNG Supply	Reference	High LNG Supply	Low LNG Supply	Reference	High LNG Supply
Dry Gas Production[1]	**18.51**	**19.46**	**19.29**	**19.30**	**20.52**	**19.67**	**18.57**	**20.63**	**19.44**	**16.86**
Lower 48 Onshore	15.04	15.39	15.26	15.26	14.94	14.16	13.19	14.74	13.95	11.75
Associated-Dissolved	1.42	1.41	1.41	1.41	1.34	1.33	1.33	1.20	1.20	1.19
Non-Associated	13.62	13.98	13.85	13.85	13.61	12.83	11.86	13.54	12.76	10.55
Conventional	5.14	4.87	4.81	4.81	3.74	3.47	3.11	3.53	3.23	2.48
Unconventional	8.48	9.11	9.04	9.04	9.87	9.36	8.75	10.01	9.53	8.08
Lower 48 Offshore	3.05	3.65	3.61	3.61	4.38	4.31	4.19	3.53	3.47	3.10
Associated-Dissolved	0.62	0.73	0.73	0.73	0.97	0.97	0.97	0.78	0.77	0.76
Non-Associated	2.43	2.92	2.88	2.88	3.41	3.35	3.23	2.75	2.69	2.34
Alaska	0.42	0.42	0.42	0.42	1.19	1.19	1.19	2.37	2.01	2.01
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.46**	**3.67**	**3.85**	**3.85**	**2.36**	**3.55**	**5.71**	**1.56**	**3.18**	**8.33**
Pipeline[3]	2.94	2.67	2.64	2.64	1.33	1.18	0.97	0.53	0.33	-0.19
Liquefied Natural Gas	0.52	0.99	1.20	1.20	1.03	2.37	4.74	1.03	2.84	8.53
Total Supply	**22.03**	**23.19**	**23.20**	**23.20**	**22.94**	**23.28**	**24.35**	**22.26**	**22.68**	**25.25**
Consumption by Sector										
Residential	4.37	4.80	4.81	4.81	5.13	5.15	5.19	5.14	5.17	5.27
Commercial	2.83	2.95	2.96	2.96	3.35	3.37	3.40	3.65	3.67	3.77
Industrial[4]	6.49	6.95	6.95	6.95	6.87	6.93	7.04	6.82	6.87	7.19
Electric Power[5]	6.24	6.69	6.70	6.70	5.65	5.92	6.84	4.61	4.99	7.13
Transportation[6]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.08	0.09	0.09
Pipeline Fuel	0.58	0.62	0.62	0.62	0.67	0.67	0.68	0.70	0.70	0.73
Lease and Plant Fuel[7]	1.14	1.19	1.18	1.18	1.25	1.22	1.17	1.29	1.23	1.12
Total	**21.66**	**23.23**	**23.25**	**23.25**	**22.98**	**23.33**	**24.39**	**22.30**	**22.72**	**25.30**
Discrepancy[8]	**0.37**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.05**	**-0.04**
Lower 48 End of Year Reserves	**202.99**	**221.15**	**220.62**	**220.63**	**226.28**	**219.31**	**212.07**	**207.46**	**200.42**	**183.11**
Natural Gas Prices										
(2006 dollars per million Btu)										
Henry Hub Spot Price	6.73	7.00	6.90	6.90	6.18	5.95	5.51	7.52	7.22	6.03
Average Lower 48 Wellhead Price[9]	6.24	6.25	6.16	6.16	5.50	5.29	4.89	6.72	6.45	5.37
(2006 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[9]	6.42	6.43	6.33	6.34	5.66	5.44	5.03	6.92	6.63	5.52
Delivered Prices										
(2006 dollars per thousand cubic feet)										
Residential	13.80	12.61	12.52	12.52	11.97	11.74	11.30	13.59	13.30	12.09
Commercial	11.85	11.00	10.91	10.91	10.43	10.20	9.77	12.07	11.78	10.59
Industrial[4]	7.89	7.52	7.43	7.43	6.62	6.40	5.98	7.80	7.50	6.35
Electric Power[5]	7.07	7.25	7.16	7.16	6.33	6.11	5.74	7.41	7.13	6.05
Transportation[10]	14.71	14.09	14.01	14.01	12.74	12.52	12.12	13.49	13.22	12.13
Average[11]	**9.49**	**9.06**	**8.97**	**8.97**	**8.47**	**8.22**	**7.72**	**9.96**	**9.63**	**8.25**

[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 any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[4]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[5]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[6]Compressed natural gas used as vehicle fuel.
[7]Represents natural gas used in field gathering and processing plant machinery.
[8]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, 2006 values include net storage injections.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
LNG = Liquefied natural gas.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs LOLNG08.D0305086A, AEO2008.D030208F, and HILNG08.D030508A.

Table D11. Liquid Fuels Supply and Disposition, ANWR Drilling Case
(Million Barrels per Day, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2010		2020		2030	
		Reference	ANWR	Reference	ANWR	Reference	ANWR
Crude Oil							
Domestic Crude Production[1]	5.10	5.93	5.93	6.23	6.48	5.59	6.28
Alaska	0.74	0.69	0.69	0.70	0.95	0.30	1.01
Lower 48 States	4.36	5.24	5.24	5.53	5.53	5.30	5.27
Net Imports	10.09	9.60	9.60	9.75	9.53	11.03	10.58
Other Crude Supply[2]	0.05	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**15.24**	**15.53**	**15.53**	**15.98**	**16.00**	**16.63**	**16.86**
Other Supply							
Natural Gas Plant Liquids	1.74	1.68	1.68	1.72	1.73	1.57	1.60
Net Product Imports[3]	2.31	1.72	1.72	1.37	1.37	1.26	1.09
Refinery Processing Gain[4]	0.99	1.05	1.05	1.00	1.01	0.99	1.04
Ethanol[5]	0.36	0.81	0.81	1.41	1.41	1.56	1.54
Biodiesel[5]	0.02	0.04	0.04	0.07	0.07	0.08	0.08
Liquids from Coal	0.00	0.00	0.00	0.15	0.13	0.24	0.20
Liquids from Biomass	0.00	0.00	0.00	0.14	0.14	0.29	0.30
Other[6]	0.07	0.18	0.18	0.21	0.21	0.24	0.25
Total Primary Supply[7]	**20.74**	**21.02**	**21.02**	**22.04**	**22.08**	**22.86**	**22.97**
Liquid Fuels Consumption							
by Fuel							
Liquefied Petroleum Gases	2.05	2.05	2.05	1.86	1.86	1.80	1.80
E85[8]	0.00	0.00	0.00	0.67	0.67	0.92	0.90
Motor Gasoline[9]	9.25	9.59	9.59	9.24	9.24	8.91	8.96
Jet Fuel[10]	1.63	1.66	1.66	2.01	2.01	2.31	2.31
Distillate Fuel Oil[11]	4.17	4.40	4.40	4.91	4.91	5.53	5.53
Residual Fuel Oil	0.69	0.70	0.70	0.69	0.69	0.70	0.70
Other[12]	2.86	2.58	2.58	2.58	2.60	2.62	2.67
by Sector							
Residential and Commercial	1.07	1.08	1.08	1.13	1.13	1.12	1.12
Industrial[13]	5.15	5.06	5.06	4.79	4.80	4.73	4.78
Transportation	14.05	14.60	14.60	15.79	15.80	16.66	16.68
Electric Power[14]	0.29	0.25	0.25	0.26	0.26	0.28	0.28
Total	**20.65**	**20.99**	**20.99**	**21.96**	**21.98**	**22.80**	**22.86**
Discrepancy[15]	**0.09**	**0.03**	**0.03**	**0.08**	**0.10**	**0.06**	**0.11**
Imported Low Sulfur Light Crude Oil Price							
(2006 dollars per barrel)	66.02	74.03	74.03	59.70	59.46	70.45	69.78
Imported Crude Oil Price[16]							
(2006 dollars per barrel)	59.05	65.18	65.18	51.55	51.00	58.66	57.32
Import Share of Product Supplied (percent)	60.0	54.2	54.2	51.6	50.5	54.3	51.3
Net Expenditures for Imported Crude Oil and							
Petroleum Products (billion 2006 dollars)	264.86	254.07	254.07	207.19	200.42	261.91	241.11

[1]Includes lease condensate.
[2]Strategic petroleum reserve stock additions plus unaccounted for crude oil and crude stock withdrawals minus crude product supplied.
[3]Includes other hydrocarbons and alcohols.
[4]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[5]Includes net imports.
[6]Includes petroleum product stock withdrawals; domestic sources of blending components, other hydrocarbons, alcohols, and ethers.
[7]Total crude supply plus all components of Other Supply.
[8]E85 refers to a blend of 85 percent ethanol (renewable) and 15 percent motor gasoline (nonrenewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74 percent is used for this forecast.
[9]Includes ethanol and ethers blended into gasoline.
[10]Includes only kerosene type.
[11]Includes distillate and kerosene.
[12]Includes aviation gasoline, liquefied petroleum gas, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power (CHP), which produces electricity and other useful thermal energy.
[14]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[15]Balancing item. Includes unaccounted for supply, losses, and gains.
[16]Weighted average price delivered to U.S. refiners.
ANWR = Arctic National Wildlife Refuge.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 imported crude oil price and petroleum product supplied based on: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). 2006 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 data: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F and ANWR2008.D031008A.

Table D12. Key Results for Coal Cost Cases
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2015			2030			Growth Rate, 2006-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Supply										
Production[1]	1163	1240	1215	1180	1620	1455	1110	1.4%	0.9%	-0.2%
Appalachia	392	347	340	335	365	328	309	-0.3%	-0.7%	-1.0%
Interior	151	189	193	186	241	241	236	2.0%	2.0%	1.9%
West	619	703	682	659	1015	885	565	2.1%	1.5%	-0.4%
Waste Coal Supplied[2]	14	11	14	16	8	12	18	-2.0%	-0.4%	1.1%
Net Imports	-15	-5	-3	0	52	78	118	- -	- -	- -
Total Supply[3]	**1161**	**1245**	**1225**	**1197**	**1681**	**1545**	**1246**	**1.6%**	**1.2%**	**0.3%**
Consumption by Sector										
Residential and Commercial	4	4	4	4	4	4	4	-0.2%	-0.2%	-0.2%
Coke Plants	23	21	21	21	19	18	18	-0.8%	-0.9%	-1.0%
Other Industrial[4]	61	60	60	59	57	58	56	-0.2%	-0.2%	-0.3%
Coal-to-Liquids Heat and Power	0	14	9	6	63	35	8	- -	- -	- -
Coal-to-Liquids Liquids Production	0	12	7	5	53	29	6	- -	- -	- -
Electric Power[5]	1026	1135	1125	1102	1485	1401	1155	1.5%	1.3%	0.5%
Total Coal Use	**1114**	**1245**	**1225**	**1197**	**1681**	**1545**	**1246**	**1.7%**	**1.4%**	**0.5%**
Average Minemouth Price[6]										
(2006 dollars per short ton)	24.63	19.64	23.38	28.25	13.13	23.32	44.23	-2.6%	-0.2%	2.5%
(2006 dollars per million Btu)	1.21	0.98	1.17	1.41	0.67	1.19	2.21	-2.4%	-0.1%	2.5%
Delivered Prices[7]										
(2006 dollars per short ton)										
Coke Plants	92.87	82.67	92.85	105.20	65.65	94.68	131.91	-1.4%	0.1%	1.5%
Other Industrial[4]	51.67	45.43	49.16	54.03	38.70	49.91	69.85	-1.2%	-0.1%	1.3%
Coal to Liquids	- -	15.03	14.44	17.29	12.42	20.60	32.23	- -	- -	- -
Electric Power[5]										
(2006 dollars per short ton)	33.85	30.75	34.24	38.95	25.22	35.03	54.10	-1.2%	0.1%	2.0%
(2006 dollars per million Btu)	1.69	1.56	1.74	1.97	1.28	1.78	2.69	-1.1%	0.2%	2.0%
Average	**36.03**	**32.00**	**35.71**	**40.63**	**25.24**	**35.70**	**55.68**	**-1.5%**	**-0.0%**	**1.8%**
Exports[8]	70.93	64.55	71.83	79.72	55.19	79.44	95.10	-1.0%	0.5%	1.2%
Cumulative Electricity Generating Capacity Additions (gigawatts)[9]										
Coal	0.0	22.7	18.4	14.2	134.8	104.2	40.1	- -	- -	- -
Conventional: Pulverized Coal	0.0	18.0	15.8	11.9	99.8	70.7	33.5	- -	- -	- -
Advanced: IGCC	0.0	4.8	2.6	2.3	34.9	33.5	6.6	- -	- -	- -
Petroleum	0.0	0.5	0.5	0.5	0.9	0.9	1.0	- -	- -	- -
Natural Gas	0.0	28.0	28.3	29.8	91.7	94.9	97.6	- -	- -	- -
Nuclear	0.0	0.0	0.0	0.0	6.0	16.6	59.8	- -	- -	- -
Renewables[10]	0.0	22.9	23.2	22.6	47.8	46.9	44.9	- -	- -	- -
Other	0.0	-0.0	-0.0	-0.0	-0.0	-0.0	-0.0	- -	- -	- -
Total	**0.0**	**74.1**	**70.5**	**67.1**	**281.0**	**263.5**	**243.4**	**- -**	**- -**	**- -**
Liquids from Coal (million barrels per day)	0.00	0.10	0.06	0.04	0.43	0.24	0.05	- -	- -	- -
Labor Productivity										
Coal Mining (short tons per miner per hour)	6.26	8.36	6.71	5.29	14.93	7.25	2.98	3.7%	0.6%	-3.0%
Rail: Eastern Railroads (billion freight ton-miles per employee per year)	8.58	15.09	12.49	10.29	29.86	17.20	9.77	5.3%	2.9%	0.5%
Rail: Western Railroads (billion freight ton-miles per employee per year)	12.49	18.87	15.56	12.77	33.35	19.08	10.77	4.2%	1.8%	-0.6%

Table D12. Key Results for Coal Cost Cases (Continued)
(Million Short Tons per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2015			2030			Growth Rate, 2006-2030		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Cost Indices										
(constant dollar index, 2006=1.000)										
Transportation Rate Multipliers										
Eastern Railroads	1.000	1.013	1.031	1.048	0.936	1.006	1.080	-0.3%	0.0%	0.3%
Western Railroads	1.000	1.016	1.031	1.045	0.962	1.018	1.077	-0.2%	0.1%	0.3%
Equipment Costs										
Mining										
Underground	1.000	0.954	1.024	1.098	0.821	1.024	1.275	-0.8%	0.1%	1.0%
Surface	1.000	0.933	1.001	1.073	0.803	1.001	1.246	-0.9%	0.0%	0.9%
Railroads	1.000	0.893	0.967	1.047	0.785	0.987	1.238	-1.0%	-0.1%	0.9%
Average Coal Miner Wage										
(2006 dollars per hour)	**22.08**	**20.58**	**22.08**	**23.67**	**17.71**	**22.08**	**27.49**	**-0.9%**	**0.0%**	**0.9%**

[1]Includes anthracite, bituminous coal, subbituminous coal, and lignite.
[2]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
[3]Production plus waste coal supplied plus net imports.
[4]Includes consumption for combined heat and power plants, except those plants whose primary business is to sell electricity, or electricity and heat, to the public. Excludes all coal use in the coal to liquids process.
[5]Includes all electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.
[6]Includes reported prices for both open market and captive mines.
[7]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[8]F.a.s. price at U.S. port of exit.
[9]Cumulative additions after December 31, 2006. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[10]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal solid waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
Btu = British thermal unit.
IGCC = Integrated gasification combined cycle.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 data based on: Energy Information Administration (EIA), *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007); EIA, *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007); Securities and Exchange Commission Form 10K filings (BNSF, Norfolk Southern, and Union Pacific), web site www.sec.gov; CSX Corporation, web site www.csx.com; U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F. **Projections:** EIA, AEO2008 National Energy Modeling System runs LCCST08.D030508A, AEO2008.D030208F, and HCCST08.D030508A.

Table D13. Energy Supply, Disposition, Prices, and Emissions, Natural Gas Cases

Supply, Disposition, and Prices	2006	2015				2030			
		Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply	Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply
Production (quadrillion Btu)									
Crude Oil and Lease Condensate	10.80	13.25	12.21	13.27	12.23	12.04	10.17	12.10	10.24
Natural Gas Plant Liquids	2.36	2.29	2.28	2.30	2.28	2.11	2.05	2.32	2.26
Dry Natural Gas	19.04	20.08	19.97	20.30	20.53	20.00	17.46	22.26	19.48
Coal[1]	23.79	24.48	25.22	23.99	24.05	28.63	29.38	21.39	22.33
Nuclear Power	8.21	8.41	8.41	8.29	8.29	9.57	10.12	7.88	7.88
Hydropower	2.89	2.99	3.00	2.99	3.02	3.00	3.01	3.07	3.10
Biomass[2]	2.94	5.12	5.18	5.05	5.04	8.12	8.04	8.46	8.59
Other Renewable Energy[3]	0.88	1.75	1.82	1.74	1.88	2.45	3.05	2.96	3.94
Other[4]	0.50	0.58	0.59	0.58	0.59	0.64	0.64	0.66	0.63
Total	**71.41**	**78.96**	**78.67**	**78.50**	**77.92**	**86.56**	**83.92**	**81.09**	**78.44**
Net Imports (quadrillion Btu)									
Liquid Fuels and Other Petroleum[5]	26.70	24.23	25.26	24.24	25.34	26.52	28.82	26.62	28.96
Natural Gas	3.56	4.15	2.95	4.25	3.05	3.28	2.03	4.70	3.06
Other[6]	-0.28	-0.09	-0.09	-0.01	0.02	1.86	1.98	2.80	2.90
Total	**29.99**	**28.29**	**28.12**	**28.49**	**28.41**	**31.66**	**32.83**	**34.12**	**34.92**
Consumption (quadrillion Btu)									
Liquid Fuels and Other Petroleum[7]	40.06	41.80	41.81	41.80	41.88	43.99	44.79	44.05	44.90
Natural Gas	22.30	24.35	23.05	24.67	23.70	23.39	19.20	27.08	22.26
Coal[8]	22.50	24.19	24.92	23.81	23.88	29.90	30.74	23.91	24.90
Nuclear Power	8.21	8.41	8.41	8.29	8.29	9.57	10.12	7.88	7.88
Hydropower	2.89	2.99	3.00	2.99	3.02	3.00	3.01	3.07	3.10
Biomass[9]	2.50	3.60	3.66	3.53	3.53	5.51	5.47	5.84	5.98
Other Renewable Energy[3]	0.88	1.75	1.82	1.74	1.88	2.45	3.05	2.96	3.94
Other[10]	0.19	0.17	0.17	0.17	0.18	0.20	0.23	0.27	0.33
Total	**99.52**	**107.26**	**106.83**	**107.00**	**106.36**	**118.01**	**116.60**	**115.05**	**113.28**
Prices (2006 dollars per unit)									
Imported Low Sulfur Light Crude Oil (dollars per barrel)	66.02	59.85	60.44	59.86	60.49	70.45	71.62	70.57	71.79
Natural Gas Wellhead Price[11] (dollars per thousand cubic feet)	6.42	5.36	6.13	5.43	6.48	6.63	9.61	7.57	12.55
Coal Minemouth Price[12] (dollars per ton)	24.63	23.38	23.72	28.29	28.43	23.32	23.88	44.35	45.27
Average Electricity Price (cents per kilowatthour)	8.9	8.5	8.8	8.7	9.1	8.8	9.3	10.0	12.1
Carbon Dioxide Emissions by Fuel (million metric tons)									
Petroleum	2581	2636	2638	2637	2644	2767	2837	2787	2862
Natural Gas	1163	1279	1210	1296	1245	1231	999	1427	1157
Coal	2134	2299	2369	2262	2270	2841	2921	2264	2271
Total	**5890**	**6226**	**6229**	**6207**	**6171**	**6851**	**6769**	**6490**	**6303**

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood.
[3]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy.
[4]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[5]Includes crude oil, finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[6]Includes coal, coal coke, and electricity.
[7]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol, biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen.
[8]Excludes coal converted to coal-based synthetic liquids.
[9]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[10]Includes non-biogenic municipal waste and net electricity imports.
[11]Represents lower 48 onshore and offshore supplies.
[12]Includes reported prices for both open market and captive mines.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth price: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and LOGASSUP.D030408A, HIGASDEM.D030408A, and HDEMLSUP.D030408A.

Table D14. Natural Gas Supply and Disposition, Natural Gas Cases
(Trillion Cubic Feet per Year, Unless Otherwise Noted)

Supply, Disposition, and Prices	2006	2015				2030			
		Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply	Reference	Restricted Natural Gas Supply	Restricted Non-Natural Gas Electricity Generation	Combined High Demand/Low Natural Gas Supply
Dry Gas Production[1]	**18.51**	**19.52**	**19.41**	**19.73**	**19.95**	**19.44**	**16.97**	**21.64**	**18.93**
Lower 48 Onshore	15.04	14.81	14.83	14.98	15.30	13.95	12.57	15.65	14.17
Associated-Dissolved	1.42	1.40	1.32	1.40	1.32	1.20	1.00	1.20	1.01
Non-Associated	13.62	13.41	13.51	13.59	13.98	12.76	11.57	14.45	13.16
Conventional	5.14	3.96	4.25	4.02	4.44	3.23	3.86	3.86	4.48
Unconventional	8.48	9.45	9.26	9.56	9.53	9.53	7.71	10.59	8.68
Lower 48 Offshore	3.05	4.32	4.20	4.36	4.27	3.47	3.50	3.62	3.65
Associated-Dissolved	0.62	0.95	0.90	0.95	0.90	0.77	0.72	0.78	0.74
Non-Associated	2.43	3.37	3.30	3.41	3.37	2.69	2.77	2.84	2.90
Alaska	0.42	0.38	0.38	0.38	0.38	2.01	0.90	2.37	1.12
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**3.46**	**4.03**	**2.87**	**4.13**	**2.96**	**3.18**	**1.97**	**4.57**	**2.97**
Pipeline	2.94	1.91	1.83	1.95	1.93	0.33	0.93	0.74	1.94
Liquefied Natural Gas	0.52	2.12	1.03	2.18	1.03	2.84	1.03	3.83	1.03
Total Supply	**22.03**	**23.61**	**22.34**	**23.92**	**22.98**	**22.68**	**19.00**	**26.27**	**21.96**
Consumption by Sector									
Residential	4.37	5.01	4.95	5.01	4.92	5.17	4.92	5.09	4.74
Commercial	2.83	3.20	3.14	3.19	3.12	3.67	3.46	3.63	3.30
Industrial[3]	6.49	7.00	6.80	6.99	6.74	6.87	5.53	6.49	5.40
Natural Gas-to-Liquids Heat and Power[4]	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.28
Natural Gas-to-Liquids Production[5]	0.00	0.00	0.00	0.00	0.00	0.00	0.27	0.00	0.38
Electric Power[6]	6.24	6.56	5.65	6.88	6.35	4.99	2.84	8.91	6.06
Transportation[7]	0.02	0.06	0.05	0.06	0.05	0.09	0.08	0.08	0.07
Pipeline Fuel	0.58	0.64	0.61	0.64	0.62	0.70	0.53	0.78	0.58
Lease and Plant Fuel[8]	1.14	1.19	1.19	1.20	1.21	1.23	1.10	1.34	1.19
Total	**21.66**	**23.66**	**22.39**	**23.97**	**23.02**	**22.72**	**18.92**	**26.31**	**22.01**
Lower 48 End of Year Reserves	**202.99**	**227.01**	**209.85**	**228.55**	**212.55**	**200.42**	**156.39**	**214.14**	**165.54**
Natural Gas Prices									
(2006 dollars per million Btu)									
Henry Hub Spot Price	6.73	5.87	6.69	5.94	7.06	7.22	10.37	8.21	13.47
Average Lower 48 Wellhead Price[9]	6.24	5.21	5.96	5.28	6.30	6.45	9.34	7.35	12.20
(2006 dollars per thousand cubic feet)									
Average Lower 48 Wellhead Price[9]	6.42	5.36	6.13	5.43	6.48	6.63	9.61	7.57	12.55
Delivered Prices									
(2006 dollars per thousand cubic feet)									
Residential	13.80	11.54	12.39	11.61	12.74	13.30	16.53	14.26	19.61
Commercial	11.85	9.97	10.80	10.04	11.13	11.78	14.93	12.72	17.94
Industrial[5]	7.89	6.33	7.12	6.41	7.48	7.50	10.61	8.51	13.63
Electric Power[6]	7.07	6.10	6.84	6.19	7.23	7.13	9.90	8.24	13.14
Transportation[10]	14.71	12.71	13.46	12.78	13.80	13.22	16.24	14.17	19.16
Average[11]	**9.49**	**8.00**	**8.89**	**8.06**	**9.18**	**9.63**	**13.13**	**10.27**	**15.67**

[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 energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[4]Includes any natural gas used in the process of converting natural gas to liquid fuel that is not actually converted.
[5]Includes any natural gas that is converted into liquid fuel.
[6]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[7]Compressed natural gas used as vehicle fuel.
[8]Represents natural gas used in field gathering and processing plant machinery.
[9]Represents lower 48 onshore and offshore supplies.
[10]Compressed natural gas used as a vehicle fuel. Price includes estimated motor vehicle fuel taxes and estimated dispensing costs or charges.
[11]Weighted average prices. Weights used are the sectoral consumption values excluding lease, plant, and pipeline fuel.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 supply values: Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 consumption based on: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and LOGASSUP.D030408A, HIGASDEM.D030408A, and HDEMLSUP.D030408A.

Table D15. Electricity Generating Capacity, Natural Gas Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity[1]	2006	2015 Reference	2015 Restricted Natural Gas Supply	2015 Restricted Non-Natural Gas Electricity Generation	2015 Combined High Demand/Low Natural Gas Supply	2030 Reference	2030 Restricted Natural Gas Supply	2030 Restricted Non-Natural Gas Electricity Generation	2030 Combined High Demand/Low Natural Gas Supply
Capacity									
Coal	309.8	323.9	336.0	318.3	319.0	406.1	436.3	319.1	336.3
Oil and Natural Gas Steam	119.7	93.6	84.7	99.0	94.5	92.9	83.3	97.6	92.5
Combined Cycle	176.5	192.4	192.3	195.0	194.8	210.0	195.2	289.1	255.3
Combustion Turbine/Diesel	130.9	130.0	123.7	130.8	129.8	164.7	153.3	145.3	144.2
Nuclear Power	100.2	102.1	102.1	102.1	102.1	114.9	121.5	114.9	114.9
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	96.3	117.3	119.1	117.4	118.6	132.5	142.4	138.4	142.6
Distributed Generation (Natural Gas)	0.0	0.9	0.5	1.0	0.4	9.8	5.1	6.0	3.1
Combined Heat and Power[1]	27.9	34.6	34.1	34.6	34.1	51.8	49.9	53.1	53.0
Total	**982.9**	**1016.3**	**1013.8**	**1019.6**	**1014.7**	**1204.2**	**1208.4**	**1185.0**	**1163.4**
Cumulative Additions									
Coal	0.0	17.5	28.3	11.3	11.3	100.2	129.4	12.1	28.6
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	15.8	15.8	18.5	18.3	33.4	18.7	112.6	78.8
Combustion Turbine/Diesel	0.0	8.4	8.1	10.1	9.2	43.4	39.9	25.7	25.1
Nuclear Power	0.0	0.0	0.0	0.0	0.0	16.6	23.1	16.6	16.6
Pumped Storage	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
Renewable Sources	0.0	21.0	22.8	21.1	22.3	36.2	46.1	42.1	46.2
Distributed Generation	0.0	0.9	0.5	1.0	0.4	9.8	5.1	6.0	3.1
Combined Heat and Power[1]	0.0	6.8	6.2	6.7	6.2	23.9	22.0	25.2	25.1
Total	**0.0**	**70.5**	**81.5**	**68.7**	**67.6**	**263.5**	**284.2**	**240.3**	**223.6**
Cumulative Retirements	**0.0**	**38.9**	**52.4**	**33.8**	**37.7**	**44.8**	**61.4**	**40.9**	**45.7**
Generation by Fuel (billion kilowatthours)									
Coal	1966	2154	2235	2115	2122	2787	2904	2136	2256
Petroleum	59	51	52	51	59	57	90	61	152
Natural Gas	732	806	684	848	785	599	310	1218	809
Nuclear Power	787	807	807	795	795	917	970	756	756
Pumped Storage	0	1	1	1	1	1	1	1	1
Renewable Sources	351	469	482	464	474	558	602	613	652
Distributed Generation	0	1	0	2	0	4	2	5	1
Combined Heat and Power[1]	152	197	193	197	193	313	294	318	301
Total	**4047**	**4485**	**4455**	**4473**	**4429**	**5235**	**5174**	**5107**	**4928**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]									
Petroleum	55	44	45	44	51	48	78	54	116
Natural Gas	340	358	308	375	347	272	155	486	331
Coal	1938	2105	2176	2072	2080	2615	2698	2088	2097
Other[3]	12	12	12	12	12	12	12	13	13
Total	**2344**	**2519**	**2541**	**2503**	**2490**	**2948**	**2943**	**2640**	**2557**
Prices to the Electric Power Sector[2] (2006 dollars per million Btu)									
Petroleum	9.63	8.45	8.55	8.47	8.36	10.37	10.10	9.91	10.55
Natural Gas	6.87	5.93	6.66	6.02	7.03	6.93	9.63	8.02	12.78
Coal	1.69	1.74	1.76	1.97	1.98	1.78	1.81	2.69	2.76

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. 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.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 capacity and projected planned additions: Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F, and LOGASSUP.D030408A, HIGASDEM.D030408A, and HDEMLSUP.D030408A.

Table D16. Electricity Generating Capacity, Commodity Cost Cases
(Gigawatts, Unless Otherwise Noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2006	2010			2020			2030		
		Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost
Capacity										
Coal	309.8	316.0	316.0	316.0	344.4	343.1	337.3	410.9	406.1	393.2
Oil and Natural Gas Steam	119.7	118.4	118.4	118.4	95.6	93.3	92.7	93.4	92.9	92.6
Combined Cycle	176.5	190.0	190.0	190.0	197.6	196.7	193.5	208.9	210.0	209.8
Combustion Turbine/Diesel	130.9	137.4	137.4	137.4	132.1	132.1	140.1	155.8	164.7	176.9
Nuclear Power	100.2	100.9	100.9	100.9	113.6	110.9	102.9	125.2	114.9	98.4
Pumped Storage	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5	21.5
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	96.3	111.6	111.6	111.9	125.4	123.6	120.3	135.2	132.5	124.1
Distributed Generation (Natural Gas)	0.0	0.3	0.3	0.2	4.0	2.7	0.5	16.5	9.8	0.5
Combined Heat and Power[1]	27.9	30.8	30.7	30.8	41.1	40.4	40.0	52.5	51.8	54.1
Total	**982.9**	**1026.7**	**1026.7**	**1026.8**	**1075.4**	**1064.2**	**1048.8**	**1219.7**	**1204.2**	**1171.0**
Cumulative Additions										
Coal	0.0	7.7	7.7	7.7	38.2	37.0	31.5	104.7	100.2	87.6
Oil and Natural Gas Steam	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Combined Cycle	0.0	13.5	13.5	13.5	21.1	20.2	16.9	32.4	33.4	33.3
Combustion Turbine/Diesel	0.0	7.2	7.2	7.1	10.1	10.5	20.1	35.6	43.4	56.9
Nuclear Power	0.0	0.0	0.0	0.0	10.7	8.0	0.0	26.8	16.6	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	0.0	15.2	15.3	15.5	29.1	27.3	24.0	38.9	36.2	27.8
Distributed Generation	0.0	0.3	0.3	0.2	4.0	2.7	0.5	16.5	9.8	0.5
Combined Heat and Power[1]	0.0	2.9	2.9	2.9	13.3	12.5	12.2	24.6	23.9	26.2
Total	**0.0**	**46.8**	**46.8**	**46.9**	**126.6**	**118.2**	**105.2**	**279.4**	**263.5**	**232.3**
Cumulative Retirements	**0.0**	**3.6**	**3.6**	**3.6**	**36.7**	**39.5**	**42.0**	**45.2**	**44.8**	**46.8**
Generation by Fuel (billion kilowatthours)										
Coal	1966	2034	2034	2033	2343	2319	2235	2809	2787	2664
Petroleum	59	50	50	49	53	53	51	55	57	53
Natural Gas	732	823	820	813	698	722	814	533	599	749
Nuclear Power	787	797	797	797	888	868	812	999	917	789
Pumped Storage	0	1	1	1	1	1	1	1	1	1
Renewable Sources	351	423	424	427	522	522	534	559	558	563
Distributed Generation	0	0	0	0	2	1	1	6	4	1
Combined Heat and Power[1]	152	169	169	169	244	238	235	320	313	325
Total	**4047**	**4296**	**4294**	**4289**	**4750**	**4723**	**4683**	**5282**	**5235**	**5146**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	55	43	43	43	45	45	44	47	48	46
Natural Gas	340	367	365	363	314	323	362	248	272	331
Coal	1938	1993	1993	1991	2269	2247	2164	2623	2615	2502
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2344**	**2414**	**2413**	**2408**	**2640**	**2627**	**2582**	**2931**	**2948**	**2890**
Prices to the Electric Power Sector[2] (2006 dollars per million Btu)										
Petroleum	9.63	10.81	10.79	10.81	8.60	8.57	8.57	10.39	10.37	10.44
Natural Gas	6.87	6.93	6.96	6.99	5.66	5.95	6.34	6.58	6.93	7.55
Coal	1.69	1.84	1.84	1.84	1.72	1.72	1.73	1.77	1.78	1.79
Average Electricity Price (2006 cents per kilowatthour)	**8.9**	**9.1**	**9.2**	**9.2**	**8.4**	**8.6**	**9.0**	**8.5**	**8.8**	**9.7**

[1]Includes combined heat and power plants and electricity-only plants in commercial and industrial sectors. 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.
[2]Includes electricity-only and combined heat and power plants whose primary business to sell electricity, or electricity and heat, to the public.
[3]Includes emissions from geothermal power and nonbiogenic emissions from municipal waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Source: Energy Information Administration, AEO2008 National Energy Modeling System runs LC2008.D030308A, AEO2008.D030208F, and HC2008.D030308A.

Table D17. Oil and Gas Supply, Commodity Cost Cases

Production and Prices	2006	2010			2020			2030		
		Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost	Low Commodity Cost	Reference	High Commodity Cost
Crude Oil										
Lower 48 Average Wellhead Price[1] (2006 dollars per barrel)	**60.18**	**79.17**	**78.45**	**78.00**	**52.26**	**52.54**	**52.85**	**60.77**	**60.59**	**62.05**
Production (million barrels per day)[2]										
United States Total	5.10	5.93	5.93	5.89	6.25	6.23	6.18	5.61	5.59	5.29
Lower 48 Onshore	2.93	3.11	3.10	3.10	3.30	3.28	3.23	3.40	3.38	3.05
Lower 48 Offshore	1.43	2.14	2.14	2.10	2.25	2.25	2.25	1.92	1.92	1.95
Alaska	0.74	0.69	0.69	0.69	0.70	0.70	0.70	0.30	0.30	0.30
Lower 48 End of Year Reserves[2] (billion barrels)	**19.02**	**19.91**	**19.89**	**19.79**	**20.86**	**20.78**	**20.60**	**19.94**	**19.89**	**18.79**
Natural Gas										
Prices (2006 dollars per million Btu)										
Henry Hub Spot Price	6.73	6.88	6.90	6.92	5.66	5.95	6.34	6.87	7.22	7.74
Average Lower 48 Wellhead Price[3]	6.24	6.13	6.16	6.17	5.02	5.29	5.65	6.13	6.45	6.92
Prices (2006 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[3]	6.42	6.31	6.33	6.35	5.17	5.44	5.81	6.30	6.63	7.12
Production (trillion cubic feet)	**18.57**	**19.37**	**19.36**	**19.28**	**19.25**	**19.73**	**20.36**	**18.98**	**19.50**	**20.61**
Dry Gas Production[4]	18.51	19.30	19.29	19.21	19.19	19.67	20.29	18.91	19.44	20.55
Lower 48 Onshore	15.04	15.27	15.26	15.23	13.78	14.16	14.66	13.50	13.95	14.62
Lower 48 Offshore	3.05	3.61	3.61	3.56	4.22	4.31	4.44	3.40	3.47	3.56
Alaska	0.42	0.42	0.42	0.42	1.19	1.19	1.19	2.01	2.01	2.37
Supplemental Gaseous Supplies[5]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports (trillion cubic feet)	**3.46**	**3.88**	**3.85**	**3.83**	**3.98**	**3.55**	**3.53**	**3.35**	**3.18**	**3.14**
Pipeline	2.94	2.64	2.64	2.65	1.41	1.18	1.41	0.54	0.33	0.61
Liquefied Natural Gas	0.52	1.24	1.20	1.18	2.57	2.37	2.12	2.81	2.84	2.54
Total Supply (trillion cubic feet)	**22.03**	**23.25**	**23.20**	**23.11**	**23.23**	**23.28**	**23.89**	**22.33**	**22.68**	**23.76**
Consumption by Sector (trillion cubic feet)										
Residential	4.37	4.81	4.81	4.80	5.18	5.15	5.11	5.20	5.17	5.12
Commercial	2.83	2.96	2.96	2.96	3.39	3.37	3.34	3.69	3.67	3.66
Industrial[6]	6.49	6.97	6.95	6.91	7.02	6.93	6.85	6.95	6.87	6.85
Electric Power[7]	6.24	6.72	6.70	6.65	5.75	5.92	6.63	4.55	4.99	6.06
Transportation[8]	0.02	0.03	0.03	0.03	0.07	0.07	0.07	0.09	0.09	0.08
Pipeline Fuel	0.58	0.62	0.62	0.62	0.67	0.67	0.68	0.69	0.70	0.73
Lease and Plant Fuel[9]	1.14	1.18	1.18	1.17	1.20	1.22	1.25	1.21	1.23	1.29
Total	**21.66**	**23.30**	**23.25**	**23.15**	**23.28**	**23.33**	**23.93**	**22.37**	**22.72**	**23.80**
Lower 48 End of Year Dry Reserves (trillion cubic feet)	**202.99**	**221.43**	**220.62**	**219.40**	**219.15**	**219.31**	**218.76**	**197.47**	**200.42**	**204.82**
Total Lower 48 Wells Drilled (thousands)	**49.72**	**64.60**	**62.33**	**60.72**	**36.07**	**37.19**	**40.30**	**35.80**	**35.78**	**38.59**

[1]Represents lower 48 onshore and offshore supplies.
[2]Includes lease condensate.
[3]Represents lower 48 onshore and offshore supplies.
[4]Marketed production (wet) minus extraction losses.
[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.
[6]Includes energy for combined heat and power plants, except those whose primary business is to sell electricity, or electricity and heat, to the public.
[7]Includes consumption of energy by electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public. Includes small power producers and exempt wholesale generators.
[8]Compressed natural gas used as vehicle fuel.
[9]Represents natural gas used in field gathering and processing plant machinery.

Note: Totals may not equal sum of components due to independent rounding. Data for 2005 and 2006 are model results and may differ slightly from official EIA data reports.

Sources: 2006 crude oil lower 48 average wellhead price: Energy Information Administration (EIA), *Petroleum Marketing Annual 2006,* DOE/EIA-0487(2006) (Washington, DC, August 2007). 2006 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2006,* DOE/EIA-0340(2006)/1 (Washington, DC, September 2007). 2006 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). Other 2006 values: EIA, Office of Integrated Analysis and Forecasting. **Projections:** EIA, AEO2008 National Energy Modeling System runs LC2008.D030308A, AEO2008.D030208F, and HC2008.D030308A.

Table D18. Energy Supply, Disposition, and Prices
AEO2008 Reference Case Compared to the Early Release

Supply, Disposition, and Prices	2006	2010		2020		2030	
		Reference	Early-Release Reference	Reference	Early-Release Reference	Reference	Early-Release Reference
Production (quadrillion Btu)							
Petroleum[1]	13.16	15.03	14.92	15.71	16.02	14.15	14.30
Dry Natural Gas	19.04	19.85	19.61	20.24	20.28	20.00	20.41
Coal[2]	23.79	23.97	23.31	25.20	25.61	28.63	31.16
Nuclear Power	8.21	8.31	8.31	9.05	9.15	9.57	9.89
Hydropower	2.89	2.92	2.92	3.00	3.00	3.00	3.00
Biomass[3]	2.94	4.05	4.11	6.42	4.93	8.12	5.52
Other Renewable Energy[4]	0.88	1.51	1.50	2.00	1.99	2.45	2.49
Other[5]	0.50	0.54	0.55	0.58	0.64	0.64	0.72
Total	71.41	76.17	75.22	82.21	81.62	86.56	87.48
Net Imports (quadrillion Btu)							
Petroleum[6]	26.70	23.93	24.49	24.03	26.72	26.52	31.20
Natural Gas	3.56	3.96	4.13	3.66	4.40	3.28	3.51
Other Imports[7]	-0.28	-0.84	-0.26	1.06	1.03	1.86	1.79
Total	29.99	27.04	28.36	28.75	32.15	31.66	36.50
Consumption (quadrillion Btu)							
Liquid Fuels and Other Petroleum[8]	40.06	40.46	40.82	42.24	44.41	43.99	48.23
Natural Gas	22.30	23.93	23.90	24.01	24.83	23.39	24.07
Coal[9]	22.50	23.03	22.94	25.87	26.23	29.90	31.71
Nuclear Power	8.21	8.31	8.31	9.05	9.15	9.57	9.89
Hydropower	2.89	2.92	2.92	3.00	3.00	3.00	3.00
Biomass[10]	2.50	3.01	3.08	4.50	3.83	5.51	4.17
Other Renewable Energy[4]	0.88	1.51	1.50	2.00	1.99	2.45	2.49
Other[11]	0.19	0.18	0.18	0.17	0.18	0.20	0.20
Total	99.52	103.34	103.64	110.85	113.61	118.01	123.76
Prices (2006 dollars per unit)							
Imported Low Sulfur Light Crude Oil Price (dollars per barrel)	66.02	74.03	66.89	59.70	61.05	70.45	71.87
Natural Gas Wellhead Price[12] (dollars per thousand cubic feet)	6.42	6.33	6.09	5.44	5.42	6.63	6.60
Coal Minemouth Price[13] (dollars per ton)	24.63	26.16	24.53	22.51	22.63	23.32	23.45
Average Electricity Price (cents per kilowatthour)	8.9	9.2	9.1	8.6	8.6	8.8	8.8
Liquids Supply and Disposition (million barrels per day)							
Domestic Crude Oil Production[14]	5.10	5.93	5.91	6.23	6.39	5.59	5.63
Net Petroleum Imports	12.41	11.32	11.60	11.12	12.50	12.29	14.46
Natural Gas Plant Liquids	1.74	1.68	1.64	1.72	1.68	1.57	1.61
Refinery Processing Gain[15]	0.99	1.05	1.08	1.00	1.10	0.99	1.14
Biofuels[16]	0.38	0.85	0.84	1.62	1.04	1.93	1.33
of which: Ethanol[17]	0.36	0.81	0.83	1.41	0.96	1.56	1.11
Liquids from Coal	0.00	0.00	0.00	0.15	0.16	0.24	0.58
Other[18]	0.12	0.18	0.18	0.21	0.23	0.24	0.27
Total Primary Supply	20.74	21.02	21.24	22.04	23.10	22.86	25.03
Liquid Fuels Consumption	20.65	20.99	21.18	21.96	23.01	22.80	24.93
Net Import Share of Product Supplied (percent)	60.0	54.2	54.8	51.6	55.0	54.3	59.2
Natural Gas Supply and Disposition (trillion cubic feet)							
Dry Gas Production[19]	18.51	19.29	19.06	19.67	19.70	19.43	19.84
Supplemental Natural Gas[20]	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	3.46	3.85	4.01	3.55	4.28	3.18	3.41
Total Supply	22.03	23.20	23.14	23.28	24.04	22.68	23.31
Total Consumption	21.66	23.25	23.22	23.33	24.12	22.72	23.39

Table D18. Energy Supply, Disposition, and Prices (Continued)
AEO2008 Reference Case Compared to the Early Release

Supply, Disposition, Indicators and Emissions	2006	2010		2020		2030	
		Reference	Early-Release Reference	Reference	Early-Release Reference	Reference	Early-Release Reference
Coal Supply and Disposition (million tons)							
Production	1163	1166	1139	1270	1289	1455	1595
Waste Coal Supplied[21]	14	13	13	11	11	12	13
Net Imports	-15	-34	-11	46	45	78	75
Total Supply	1161	1144	1141	1326	1345	1545	1683
Total Consumption	1114	1145	1141	1327	1344	1545	1682
Macroeconomic Indicators							
Real Gross Domestic Product (billion 2000 chain-weighted dollars)	11319	12453	12555	15984	16177	20219	20832
GDP Chain-type Price Index (2000=1.000)	1.166	1.260	1.267	1.520	1.509	1.871	1.838
Industrial Value of Shipments (billion 2000 dollars)	5821	5997	5882	7113	7044	7997	8226
Nonmanufacturing	1531	1419	1494	1619	1672	1715	1804
Manufacturing	4290	4577	4389	5493	5372	6283	6422
Energy-Intensive	1225	1283	1204	1387	1338	1447	1442
Non-energy Intensive	3065	3295	3185	4107	4034	4836	4980
Real Disposable Personal Income (billion 2000 dollars)	8397	9472	9594	12654	12811	16246	16916
Housing Starts (millions)	1.93	1.68	1.85	1.78	1.84	1.70	1.72
Commercial Floorspace (billion square feet)	74.8	78.8	78.7	89.3	89.3	100.8	100.9
Unit Sales of Light-Duty Vehicles (millions)	16.50	16.38	16.92	17.47	18.72	19.39	20.04
Energy Intensity (thousand Btu per 2000 dollar of GDP)	**8.79**	**8.30**	**8.25**	**6.91**	**7.02**	**5.80**	**5.94**
Carbon Dioxide Emissions (million metric tons)	**5890**	**6011**	**6034**	**6384**	**6646**	**6851**	**7373**

[1]Includes crude oil, lease condensate, and natural gas plant liquids.
[2]Includes waste coal.
[3]Includes grid-connected electricity from wood and waste; biomass, such as corn, used for liquid fuels production; and non-electric energy demand from wood. Refer to Table A17 for details.
[4]Includes grid-connected electricity from landfill gas; biogenic municipal waste; wind; photovoltaic and solar thermal sources; and non-electric energy from renewable sources, such as active and passive solar systems. Excludes electricity imports using renewable sources and nonmarketed renewable energy. See Table A17 for selected nonmarketed residential and commercial renewable energy.
[5]Includes non-biogenic municipal waste, liquid hydrogen, methanol, and some domestic inputs to refineries.
[6]Includes crude oil, finished petroleum products, unfinished oils, alcohols, ethers, blending components, and renewable fuels such as ethanol.
[7]Includes coal, coal coke, and electricity.
[8]Includes petroleum-derived fuels and non-petroleum derived fuels, such as ethanol, biodiesel, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids, crude oil consumed as a fuel, and liquid hydrogen. Refer to Table A17 for detailed renewable liquid fuels consumption.
[9]Excludes coal converted to coal-based synthetic liquids.
[10]Includes grid-connected electricity from wood and wood waste, non-electric energy from wood, and biofuels heat and coproducts used in the production of liquid fuels, but excludes the energy content of the liquid fuels.
[11]Includes non-biogenic municipal waste and net electricity imports.
[12]Represents lower 48 onshore and offshore supplies.
[13]Includes reported prices for both open market and captive mines.
[14]Includes lease condensate.
[15]The volumetric amount by which total output is greater than input due to the processing of crude oil into products which, in total, have a lower specific gravity than the crude oil processed.
[16]Domestic production and net imports of ethanol, biodiesel, and liquids from biomass.
[17]Includes net imports.
[18]Includes petroleum product stock withdrawals, domestic sources of blending components, other hydrocarbons, ethers, and renewable fuels such as biodiesel.
[19]Marketed production (wet) minus extraction losses.
[20]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.
[21]Includes waste coal consumed by the electric power and industrial sectors. Waste coal supplied is counted as a supply-side item to balance the same amount of waste coal included in the consumption data.
Btu = British thermal unit.
GDP = Gross domestic product.
Note: Totals may not equal sum of components due to independent rounding. Data for 2006 are model results and may differ slightly from official EIA data reports.
Sources: 2006 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2007/04) (Washington, DC, April 2007). 2006 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2006*, DOE/EIA-0584(2006) (Washington, DC, November 2007). 2006 petroleum supply values: EIA, #PSA#. 2006 low sulfur light crude oil price: EIA, Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” Other 2006 coal values: *Quarterly Coal Report, October-December 2006*, DOE/EIA-0121(2006/4Q) (Washington, DC, March 2007). Other 2006 values: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007). **Projections:** EIA, AEO2008 National Energy Modeling System runs AEO2008.D030208F and AEO2008.D112607A.

NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2008* (*AEO2008*) are generated from the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *Annual Energy Outlook* (*AEO*) projections, NEMS is also used in analytical studies for the U.S. Congress, the White House, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. The *AEO* projections are also used by analysts and planners in other government agencies and nongovernment organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the long-term period through 2030, approximately 25 years into the future. In order to represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, natural gas, and coal supply and distribution; the North American Electric Reliability Council regions and subregions for electricity; and the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information among the modules are the delivered prices of energy to end users and the quantities consumed by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to end users. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply.

The Integrating Module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data structure. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules. The modular design also permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. A solution is reached annually through the long-term horizon. Other variables, such as petroleum product imports, crude oil imports, and several macroeconomic indicators, also are evaluated for convergence.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector. NEMS accounts for all combustion-related carbon dioxide (CO_2) emissions, as well as emissions of sulfur dioxide, nitrogen oxides, and mercury from the electricity generation sector. The version of NEMS used for *AEO2008* represents current legislation and environmental regulations as of December 31, 2007 (such as the Energy Independence and Security Act of 2007 [EISA2007], which was signed into law on December 19, 2007; the Energy Policy Acts of 2005 [EPACT2005]; the Working Families Tax Relief Act of 2004; and the American Jobs Creation Act of 2004) and the costs of compliance with regulations (such as the Clean Air Interstate Rule and Clean Air Mercury Rule [CAMR], both of which were finalized and published in 2005, and the new stationary diesel regulations issued by the U.S. Environmental Protection Agency [EPA] in July 2006 [*2*].) The potential impacts of pending or proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but that require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS.

In general, the historical data used for the *AEO2008* projections were based on EIA's *Annual Energy Review 2006*, published in June 2007 [*3*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2006. CO_2 emissions were calculated by using CO_2 coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2006*, published in November 2007 [*4*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2008* appendix tables indicate the definitions and sources of historical data.

The *AEO2008* projections for years 2007 and 2008 incorporate short-term projections from EIA's January 2008 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to monthly updates of the *STEO* [*5*].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices or expenditures of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of macroeconomic drivers to the energy modules, and there is a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables used in the energy modules include gross domestic product (GDP), disposable income, value of industrial shipments, new housing starts, new light-duty vehicle sales, interest rates, and employment. The module uses the following models from Global Insight, Inc.: Macroeconomic Model of the U.S. Economy, National Industry Model, and National Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial value of shipments uses the North American Industry Classification System (NAICS).

International Module

The International Module represents the response of world oil markets (supply and demand) to assumed world oil prices. The results/outputs of the module are a set of crude oil and product supply curves that are available to U.S. markets for each case/scenario analyzed. The petroleum import supply curves are made available to U.S. markets through the Petroleum Market Module (PMM) of NEMS in the form of 5 categories of imported crude oil and 17 international petroleum products, including supply curves for oxygenates and unfinished oils. The supply-curve calculations are based on historical market data and a world oil supply/demand balance, which is developed from reduced-form models of international liquids supply and demand (new to *AEO2008*), current investment trends in exploration and development, and long-term resource economics for 221 countries/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and nonbuilding uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies, and the effects of both building shell and appliance standards, including the recently enacted provisions of the EISA2007. The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on a 10-year average and on State-level population projections. The Residential Demand Module projects an increase in the average square footage of both new construction and existing structures, based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module projects the consumption of energy for heat and power and for feedstocks and raw materials in each of 21 industries, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the Macroeconomic Activity Module, the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the eight energy-intensive industries, seven are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Bulk chemicals are further disaggregated to organic, inorganic, resins, and agricultural chemicals. A generalized representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the PMM, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and industrial shipments. Fleet vehicles are represented separately to allow analysis of the Energy Policy Act of 1992 (EPACT1992) and other legislation and legislative proposals. EPACT2005 is used to assess the impact of tax credits on the purchase of hybrid gas-electric, alternative-fuel, and fuel-cell vehicles. The module also includes a component to assess the penetration of alternative-fuel vehicles. The corporate average fuel economy and biofuel representation in the module reflect the provisions in EISA2007.

The air transportation component explicitly represents air travel in domestic and foreign markets and includes the industry practice of parking aircraft in both domestic and international markets to reduce operating costs, as well as the movement of aging aircraft from passenger to cargo markets [*6*]. For air freight shipments, the model represents regional fuel use in narrow-body and wide-body aircraft. An infrastructure constraint limits overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs and macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing.

All specifically identified options promulgated by the EPA for compliance with the Clean Air Act Amendments of 1990 (CAAA90) are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated (e.g., fine particulate proposals) are not incorporated. All financial incentives for power generation expansion and dispatch specifically identified in EPACT2005 have been implemented. Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, the regulations are represented in *AEO2008*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics (PV), and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in EPACT1992 and EPACT2005. EPACT1992 provides a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power; those credits have no expiration date. EPACT2005 increases the tax credit to 30 percent for solar energy systems installed before January 1, 2009.

Production tax credits for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants are also represented. They provide a tax credit of up to 1.9 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2008*, new plants coming on line before January 1, 2009, are eligible to receive the credit. Significant changes made for *AEO2008* in the accounting of new renewable energy capacity resulting from State renewable portfolio standard programs, mandates, and goals will be described in *Assumptions to the Annual Energy Outlook 2008* [7].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and unconventional techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. The framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and natural gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. The module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and imports and exports of liquefied natural gas (LNG).

Crude oil production quantities are used as inputs to the PMM in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are used as inputs to the Natural Gas Transmission and Distribution Module for determining natural gas prices and quantities. International LNG supply sources and options for construction of new regasification terminals in Canada, Mexico, and the United States, as well as expansions of existing U.S. regasification terminals, are represented, based on the projected regional costs associated with international natural gas supply, liquefaction, transportation, and regasification and world natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas and determines the associated capacity expansion requirements in an aggregate pipeline network, connecting the domestic and foreign supply regions with 12 U.S. demand regions. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and biofuels (ethanol, biodiesel, biobutanol, etc.). The module represents refining activities in the five PADDs. It explicitly models the requirements of EISA2007 and CAAA90 and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes the production of biofuels for blending in gasoline and diesel.

AEO2008 represents regulations that limit the sulfur content of all nonroad and locomotive/marine diesel to 15 parts per million (ppm) by mid-2012. The module also reflects the renewable fuels standard (RFS) in EISA2007 that requires the use of 36 billion gallons per year of biofuels by 2022, with corn ethanol limited to 15 billion gallons per year. Demand growth and regulatory changes necessitate capacity expansion for refinery processing units. End-use prices are based on the marginal costs of production, plus markups representing the costs of product marketing and distribution and State and Federal taxes [*8*]. Refinery capacity expansion at existing sites is permitted in each of the five refining regions modeled.

Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent by volume or less (E10), as well as E85, a blend of up to 85 percent ethanol by volume. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and in the future it may also be produced from cellulosic material, such as switchgrass and poplar. Biodiesel is produced from seed oil, imported palm oil, animal fats, or yellow grease (primarily, recycled cooking oil).

Both domestic and imported ethanol count toward the RFS. Domestic ethanol production is modeled from two feedstocks: corn and cellulosic materials. Corn-based ethanol plants are numerous (more than 100 are now in operation, producing more than 5 billion gallons annually) and are based on a well-known technology that converts sugar into ethanol. Ethanol from cellulosic sources is a new technology with no pilot plants in operation; however, DOE awarded grants (up to $385 million) in 2007 to construct capacity totaling 147 million gallons per year, which *AEO2008* assumes will be operational in 2012. Imported ethanol may be produced from cane sugar or bagasse, the cellulosic byproduct of sugar milling. The sources of ethanol are modeled to compete on an economic basis and to meet the EISA2007 renewable fuels mandate.

Fuels produced by gasification and Fischer-Tropsch synthesis are modeled in the PMM, based on their economics relative to competing feedstocks and products. The three processes modeled are coal-to-liquids (CTL), gas-to-liquids (GTL), and biomass-to-liquids (BTL). CTL facilities are likely to be built at locations close to coal supplies and water sources, where liquid products and surplus electricity could also be distributed to nearby demand regions. GTL facilities may be built in Alaska, but they would compete with the Alaska Natural Gas Transportation System for available natural gas resources. BTL facilities are likely to be built where there are large supplies of biomass, such as crop residues and forestry waste. Because the BTL process uses cellulosic feedstocks, it is also modeled as a choice to meet the EISA2007 cellulosic biofuels requirement.

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM by 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined by minimizing the cost of coal supplied, given coal demands by demand region and sector, accounting for minemouth prices, transportation costs, existing coal supply contracts, and sulfur and mercury allowance costs. Over the projection horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the cost of rail transportation equipment and diesel fuel.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports, in the context of world coal trade. The CMM determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 17 export and 20 import regions. U.S. coal production and distribution are computed for 14 supply and 14 demand regions.

Annual Energy Outlook 2008 Cases

Table E1 provides a summary of the cases used to derive the *AEO2008* projections. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed. The following sections describe the cases listed in Table E1. The reference case assumptions for each sector will be described in *Assumptions to the Annual Energy Outlook 2008* [*9*].at web site www.eia.doe.gov/oiaf/aeo/assumption. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement.

Macroeconomic Growth Cases

In addition to the *AEO2008* reference case, the low economic growth and high economic growth cases were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- The *low economic growth case* assumes lower growth rates for population (0.5 percent per year), nonfarm employment (0.5 percent per year), and labor productivity (1.5 percent per year), resulting in higher prices and interest rates and lower growth in industrial output. In the low economic growth case, economic output as measured by real GDP increases by 1.8 percent per year from 2006 through 2030, and growth in real GDP per capita averages 1.3 percent per year.
- The *high economic growth case* assumes higher growth rates for population (1.2 percent per year), nonfarm employment (1.2 percent per year), and labor productivity (2.4 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case, and consequently economic

Table E1. Summary of the *AEO2008* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.4 percent per year from 2006 through 2030), world oil price, and technology assumptions. Complete projection tables in Appendix A.	Fully integrated	-	-
Early-Release Reference	Released in 12/2007, this case excludes EISA2007 and other changes in the reference case. Partial projection tables in Appendix D.	Fully Integrated	p. 3	-
Low Economic Growth	GDP grows at an average annual rate of 1.8 percent from 2006 through 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 54	p. 195
High Economic Growth	GDP grows at an average annual rate of 3.0 percent from 2006 through 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix B.	Fully integrated	p. 54	p. 195
Low Price	More optimistic assumptions for worldwide crude oil and natural gas resources and the behavior of the Organization of the Petroleum Exporting Countries (OPEC) than in the reference case. World light, sweet crude oil prices are $42 per barrel in 2030, compared with $70 per barrel in the reference case (2006 dollars). Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 50	p. 199
High Price	More pessimistic assumptions for worldwide crude oil and natural gas resources and OPEC behavior than in the reference case. World light, sweet crude oil prices are about $119 per barrel (2006 dollars) in 2030. Other assumptions are the same as in the reference case. Partial projection tables in Appendix C.	Fully integrated	p. 50	p. 199
Residential: 2008 Technology	Future equipment purchases based on equipment available in 2008. Existing building shell efficiencies fixed at 2008 levels. Partial projection tables in Appendix D.	With commercial	p. 59	p. 199
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new construction meet ENERGY STAR requirements after 2016. Partial projection tables in Appendix D.	With commercial	p. 59	p. 199
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available by fuel. Building shell efficiencies for new construction meet the criteria for most efficient components after 2008. Partial projection tables in Appendix D.	With commercial	p. 60	p. 199
Commercial: 2008 Technology	Future equipment purchases based on equipment available in 2008. Building shell efficiencies fixed at 2008 levels. Partial projection tables in Appendix D.	With residential	p. 61	p. 199
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new and existing buildings increase by 8.75 and 6.25 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 61	p. 200

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available by fuel. Building shell efficiencies for new and existing buildings increase by 10.5 and 7.5 percent, respectively, from 2003 values by 2030. Partial projection tables in Appendix D.	With residential	p. 62	p. 200
Industrial: 2008 Technology	Efficiency of plant and equipment fixed at 2008 levels. Partial projection tables in Appendix D.	Standalone	p. 65	p. 200
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 65	p. 200
Transportation: High Technology	Reduced costs and improved efficiencies assumed for advanced technologies. Partial projection tables in Appendix D.	Standalone	p. 66	p. 200
Electricity: Low Nuclear Cost	New nuclear capacity assumed to have 10 percent lower capital and operating costs in 2030 than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 177	p. 201
Electricity: High Nuclear Cost	Costs for new nuclear technology assumed not to improve from 2008 levels in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 177	p. 201
Electricity: Low Fossil Cost	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 178	p. 201
Electricity: High Fossil Cost	New advanced fossil generating technologies assumed not to improve over time from 2008. Partial projection tables in Appendix D.	Fully integrated	p. 178	p. 201
Renewable Fuels: High Renewable Cost	New renewable generating technologies assumed not to improve over time from 2008. Partial projection tables in Appendix D.	Fully integrated	p. 71	p. 201
Renewable Fuels: Low Renewable Cost	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 71	p. 201
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent more rapid improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 76	p. 202
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent slower improvement than in the reference case. Partial projection tables in Appendix D.	Fully Integrated	p. 76	p. 202
Oil and Gas: High LNG Supply	LNG imports exogenously set to a factor times the reference case levels from 2010 forward, with remaining assumptions from the reference case. The factor starts at 1.0 in 2010 and increases linearly to 3.0 by 2030. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 202
Oil and Gas: Low LNG Supply	LNG imports held constant at 2009 levels, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 202
Oil and Gas: ANWR	The Arctic National Wildlife Refuge (ANWR) in Alaska is opened to Federal oil and natural gas leasing, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 183	p. 202

Table E1. Summary of the *AEO2008* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Coal: Low Coal Cost	Productivity for coal mining and coal transportation assumed to increase more rapidly than in the reference case. Coal mining wages, mine equipment, and coal transportation equipment costs assumed to be lower than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 202
Coal: High Coal Cost	Productivity for coal mining and coal transportation assumed to increase more slowly than in the reference case. Coal mining wages, mine equipment, and coal transportation equipment costs assumed to be higher than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 203
Integrated 2008 Technology	Combination of the residential, commercial, and industrial 2008 technology cases; and the electricity high fossil cost, high renewable cost, and high nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 203
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases; and the electricity low fossil cost, low renewable cost, and low nuclear cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 176	p. 203
Integrated Alternative Weather	Assumes future weather resembles 30-year average, as opposed to 10-year average.	Fully integrated	p. 45	p. 203
High Energy Project Cost	Recent cost increases are assumed to continue. Base costs for new electricity generation capacity increase throughout the projection. Capital costs for oil and gas exploration and production (E&P) activities remain at increased levels, as experienced since 2003. Refining costs increase from current costs.	Fully integrated	p. 34	p. 203
Low Energy Project Cost	Recent cost increases are assumed to revert back to lower levels of a few years ago. Base costs for new electricity generation capacity decrease by 15 percent over 10 years, then remain flat. Capital costs for oil and gas E&P fall back toward their pre-2003 levels over time. Refining costs are set to 2004 levels.	Fully integrated	p. 34	p. 203
Limited Electricity Generation Supply	New coal-fired plants are not built unless they include sequestration. Other non-natural-gas capacity restricted to reference case levels or assumed to have higher costs. Existing nuclear units assumed to have lower output than in the reference case.	Fully integrated	p. 38	p. 203
Limited Natural Gas Supply	No Arctic natural gas pipelines are in operation by 2030. LNG import values are held constant at 2009 levels from 2010 forward. Oil and gas resources are 15 percent lower, and the technological progress rate is 50 percent below the rate in the reference case.	Fully integrated	p. 38	p. 204
Combined Limited	Combines all the assumptions of the limited electricity generation supply and limited natural gas supply cases.	Fully integrated	p. 38	p. 204

output grows at a higher rate (3.0 percent per year) than in the reference case (2.4 percent). GDP per capita grows by 1.8 percent per year, compared with 1.6 percent in the reference case.

Price Cases

The world oil price in *AEO2008* is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price for light sweet crude oil traded on the New York Mercantile Exchange. *AEO2008* also includes a projection of the U.S. annual average refiners' acquisition cost of imported crude oil, which is more representative of the average cost of all crude oils used by refiners.

The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2008* considers three price cases (reference, low price, and high price) to allow an assessment of alternative views on the course of future oil and natural gas prices. In the reference case, world oil prices moderate from 2006 levels through 2016 before beginning to rise to $70 per barrel in 2030 (2006 dollars). The low and high price cases define a wide range of potential price paths (from $42 to $119 per barrel in 2030). The two cases reflect different assumptions about decisions by OPEC members regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources in non-OPEC countries. Because the low and high price cases are not fully integrated with a world economic model, the impact of world oil prices on international economies is not accounted for directly.

- The *reference case* represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources in non-OPEC countries. It also assumes that OPEC producers will choose to maintain their share of the market and will schedule investments in incremental production capacity so that OPEC's conventional oil production will represent about 40 percent of the world's total liquids production.

- The *low price case* assumes that OPEC countries will increase their conventional oil production to obtain approximately a 44-percent share of total world liquids production, and that conventional oil resources in non-OPEC countries will be more accessible and/or less costly to produce (as a result of technology advances, more attractive fiscal regimes, or both) than in the reference case. With these assumptions, non-OPEC conventional oil production is higher in the low price case than in the reference case.

- The *high price case* assumes that OPEC countries will continue to hold their production at approximately the current rate, sacrificing market share as global liquids production increases. It also assumes that oil resources in non-OPEC countries will be less accessible and/or more costly to produce than assumed in the reference case.

Buildings Sector Cases

In addition to the *AEO2008* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes to equipment and building shell efficiencies.

For the residential sector, the three technology-focused cases are as follows:

- The *2008 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2008. Existing building shell efficiencies are assumed to be fixed at 2008 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2008.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*10*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2016.

- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. For new construction, building shell efficiencies are assumed to meet the criteria for the most efficient components after 2008.

For the commercial sector, the three technology-focused cases are as follows:

- The *2008 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2008. Building shell efficiencies are assumed to be fixed at 2008 levels.

- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*11*]. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 8.75 percent and 6.25 percent higher, respectively, than their 2003 levels—a 25-percent improvement relative to the reference case.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year for each fuel, regardless of cost. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 10.5 percent and 7.5 percent higher, respectively, than their 2003 values—a 50-percent improvement relative to the reference case.

The Residential and Commercial Demand Modules of NEMS were also used to complete the high renewable and low renewable cost cases, which are discussed in more detail as part of the Renewable Fuels Cases section below. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, these sensitivities analyze the impact of changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The *low renewable cost case* assumes greater improvements in residential and commercial PV and wind systems than in the reference case. The low renewable cost assumptions result in capital cost estimates for 2030 that are approximately 10 percent lower than reference case costs for distributed PV technologies.
- The *high renewable cost case* assumes that costs and performance levels for residential and commercial PV and wind systems remain constant at 2008 levels through 2030.

Industrial Sector Cases

In addition to the *AEO2008* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid and more rapid technology change and adoption. Because these are standalone cases, the energy intensity changes discussed in this section exclude the refining industry. Energy use in the refining industry is estimated as part of the PMM in NEMS. The Industrial Demand Module was also used as part of the integrated low and high renewable cost cases. For the industrial sector:

- The *2008 technology case* holds the energy efficiency of plant and equipment constant at the 2008 level over the projection period. In this case, delivered energy intensity falls by 1.1 percent annually between 2006 and 2030, as compared with 1.6 percent annually in the reference case. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of industrial output. Because the level and composition of industrial output are the same in the reference, 2008 technology, and high technology cases, any change in energy intensity in the two technology cases is attributable to efficiency changes.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*12*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes (0.7 percent per year, as compared with 0.4 percent per year in the reference case). The same assumption is incorporated in the integrated low renewable cost case, which focuses on electricity generation. Although the choice of 0.7-percent annual rate of improvement in byproduct recovery is an assumption of the high technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Delivered energy intensity falls by 1.9 percent annually in the high technology case.

The 2008 technology case was run with only the Industrial Demand Module, rather than in fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured, and energy consumption and production in the refining industry, which are modeled in the PMM, were excluded.

Transportation Sector Cases

In addition to the *AEO2008* reference case, one standalone case using the Transportation Demand Module of NEMS was developed to examine the effect of more rapid technology change and adoption. For the transportation sector:

- In the *high technology case*, the characteristics of conventional and alternative-fuel light-duty vehicles reflect more optimistic assumptions about incremental improvements in fuel economy and costs [13]. In the freight truck sector, the high technology case assumes more incremental improvement in fuel efficiency for engine and emissions control technologies [14]. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail and shipping sectors.

The high technology case was run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices incorporated.

Electricity Sector Cases

In addition to the reference case, four integrated cases with alternative electric power assumptions were developed to analyze uncertainties about the future costs and performance of new generating technologies. Two of the cases examine alternative assumptions for nuclear power technologies, and two examine alternative assumptions for fossil fuel technologies. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding newer, untested designs. The electricity cases analyze what could happen if costs of advanced designs were either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cases

- The cost assumptions for the *low nuclear cost case* reflect a 10-percent reduction in the capital and operating costs for advanced nuclear technology in 2030, relative to the reference case. The reference case projects an 18-percent reduction in the capital costs of nuclear power plants from 2007 to 2030. The low nuclear cost case assumes a 26-percent reduction between 2007 and 2030.

- The *high nuclear cost case* assumes that capital costs for the advanced nuclear technology do not decline during the projection period but remain fixed at the 2008 levels assumed in the reference case.

Fossil Technology Cases

- In the *low fossil cost case*, capital costs, heat rates, and operating costs for advanced coal and natural gas generating technologies are assumed to be 10 percent lower than reference case levels in 2030. Because learning occurs in the reference case, costs and performance in the low fossil cost case are reduced from initial levels by more than 10 percent. Heat rates in the low fossil cost case fall to between 16 and 31 percent below initial levels, and capital costs are reduced by 19 to 25 percent between 2007 and 2030, depending on the technology.

- In the *high fossil cost case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the projection period but remain fixed at the 2008 values assumed in the reference case.

Additional details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cases will be provided in *Assumptions to the Annual Energy Outlook 2008* [15].

Renewable Fuels Cases

In addition to the *AEO2008* reference case, two integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less aggressive and more aggressive improvement in renewable technologies. The cases are as follows:

- In the *high renewable cost case*, capital costs, operating and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2008 levels through 2030.

- In the *low renewable cost case*, the levelized costs of energy for generating technologies using renewable resources are assumed to decline to 10 percent below the reference case costs for the same resources in 2030. For most renewable resources, lower costs are represented by reducing the capital costs of new plant construction. To reflect recent trends in wind energy cost reductions, however, it is assumed that wind plants ultimately achieve the 10-percent cost reduction through a combination of performance improvement (increased capacity factor) and capital cost reductions. Biomass supplies also are assumed to be 10 percent greater for each supply step. Other generating technologies and projection assumptions remain unchanged from those in the reference case. In the low renewable cost case, the rate of improvement in recovery of biomass byproducts from industrial processes is also increased.

Oil and Gas Supply Cases

Two alternative technology cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. In addition, high and low LNG supply cases were developed to examine the impacts of variations in LNG imports on the domestic natural gas market.

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the reference case are increased by 50 percent. A number of key E&P technologies for unconventional natural gas also are increased by 50 percent in the rapid technology case. Key supply parameters for Canadian oil and natural gas are also modified to simulate the assumed impacts of more rapid oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Specific detail by region and fuel category will be provided in *Assumptions to the Annual Energy Outlook 2008* [*16*].

- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the *AEO2008* reference case are reduced by 50 percent. A number of key E&P technologies for unconventional natural gas also are reduced by 50 percent in the slow technology case. Key Canadian supply parameters are also modified to simulate the assumed impacts of slow oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model are kept at the reference case values.

- The *high LNG supply case* exogenously specifies LNG import levels for 2010 through 2030 equal to a factor times the reference case levels. The factor starts at 1.0 in 2010 and linearly increases to 3.0 by 2030. The intent is to project the potential impact on domestic markets if LNG imports turn out to be higher than projected in the reference case.

- The *low LNG supply case* exogenously specifies LNG imports at the 2009 levels projected in the reference case for 2010 through 2030. The intent is to project the potential impact on domestic markets if LNG imports turn out to be lower than projected in the reference case.

- The *ANWR case* assumes that Federal legislation is passed during 2008, which permits Federal oil and gas leasing in ANWR. This case also assumes that oil and natural gas leasing will commence after 2008 in the State and Native lands, which are either in or adjoining ANWR.

Coal Market Cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, and mine equipment costs on the production side, and railroad productivity and rail equipment costs on the transportation side. The alternative productivity and cost assumptions are applied in every year from 2009 through 2030. For the coal cost cases, adjustments to the reference case assumptions for coal mining and railroad productivity are based on variations in growth rates observed in the data for those industries since 1980. The variations in annual productivity growth rates over the historical period are estimated at 3.3 percent for coal mining and 2.5 percent for rail transportation. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the *low coal cost case*, the average annual growth rates for coal mining and railroad productivity are higher than those in the reference case. On the mining side, adjustments to mine productivity are applied at the supply curve level, and adjustments to railroad productivity are made at the regional (East and West) level. As an example, the average growth rate for western railroad productivity is increased from 1.8 percent per year in the reference case to 4.2 percent per year in the low coal cost case. Coal mining wages and mine equipment costs, which remain constant in real dollars in the reference case, are assumed to decline by approximately 1.0 percent per year in real terms in the low coal cost case. Railroad equipment costs, which remain constant in real dollars in the reference case, are assumed to decrease at a rate of 1.0 percent per year in the low coal cost case.

- In the *high coal cost case*, the average annual productivity growth rates for coal mining and railroad productivity are lower than those in the reference case. Coal mining wages and mine equipment costs are assumed to increase by approximately 1.0 percent per year in real terms. Railroad equipment costs also are assumed to increase by 1.0 percent per year.

Additional details about the productivity, wage, and equipment cost assumptions for the reference and alternative coal cost cases are provided in Appendix D.

Cross-Cutting Integrated Cases

In addition to the sector-specific cases described above, a series of cross-cutting integrated cases were used to analyze specific scenarios with broader sectoral impacts. For example, two integrated technology progress cases were formed by combining the assumptions from the other technology progress cases to analyze the broader impact of more rapid and slower technology improvement rates. Another case examined the implications of assuming different levels of heating and cooling degree-days than in the reference case. Two sets of additional cases were analyzed: one set examines the potential impact of uncertainty in energy project costs, and the other set examines the implications of severe demand pressure on the natural gas industry.

Integrated Technology Cases

The *integrated 2008 technology case* combines the assumptions from the residential, commercial, and industrial 2008 technology cases and the electricity high fossil cost, high renewable cost, and high nuclear cost cases. The *integrated high technology case* combines the assumptions from the residential, commercial, industrial, and transportation high technology cases, the electricity high fossil technology case, the low renewables cost case, and the low nuclear cost case.

Integrated Alternative Weather Case

The main cases in *AEO2008* assume a 10-year average for heating and cooling degree-days. The *integrated alternative weather case* assumes a 30-year average for heating and cooling degree-days, in order to examine the impacts of a smaller number of heating and cooling degree-days on energy consumption in the residential, commercial, and electricity generation sectors, as well as on energy prices and CO_2 emissions. Results from this case are summarized in the Issues in Focus section of this report.

Energy Project Cost Cases

Investment in new power plants and new refining and drilling activities depend on the price of certain commodities, such as steel and concrete, that have increased significantly in recent years, as well as other factors such as capital costs for energy equipment and facilities and labor costs. The reference case assumes that investment costs are based on the latest cost data, including any commodity price increases over the past few years, and that they will remain at those levels through 2030; however, there is considerable uncertainty surrounding the future path of commodity prices.

The *high energy project cost case* assumes that costs will continue to rise, leading to increasing investment costs in the energy industry, which are assumed to grow at the historical rate of the past 5 years. Drilling costs in the oil and gas industry are assumed to double from 2006 to 2030, and the costs of steel and other materials are assumed to increase the cost of construction for LNG liquefaction facilities and the cost of the Alaska pipeline.

The *low energy project cost case* assumes that costs will decline gradually, back to the levels of the early 2000s. Results from these two case are summarized in the Issues in Focus section of this report. Additional details will be provided in *Assumptions to the Annual Energy Outlook 2008* [*17*].

Limited Electricity Generation Supply, Limited Natural Gas Supply, and Combined Limited Cases

Considerable uncertainty surrounds the types of new generating capacity that will be built in the electricity generation sector, depending on potential environmental legislation and technological hurdles for new designs and alternative fuel sources. The volume of recoverable undiscovered natural gas resources, the costs associated with producing those resources, and the potential for bringing new sources of supply to markets in the lower 48 States, either by Arctic pipeline or as LNG, also are uncertain. Three cases were developed to analyze these uncertainties.

The *limited electricity generation supply case* focuses only on the potential challenges facing non-natural-gas generating technologies. This case assumes that, due to the uncertainty of future environmental requirements, no new coal-fired plants will be built unless they include carbon sequestration. It also assumes that new builds of nuclear, wind and biomass will be restricted to reference case levels. New non-gas capacity, including sequestration and other renewables, is assumed to cost 25 percent more than in the reference case. Output from existing nuclear capacity is also assumed to decline after plants reach 40 years of age due to uncertainties surrounding the ability of older plants to maintain high capacity factors.

The *limited natural gas supply case* examines the impacts of constraints on the development of new natural gas resources. This case assumes that the two large gas pipelines under consideration for development in the Arctic region of North America, to transport gas from the North Slope of Alaska and the MacKenzie Delta to market, will not be in operation by 2030. In the reference case, only the Alaska pipeline is economical, coming on-line in 2020. The *limited natural gas supply case* also assumes that LNG import volumes will remain at 2009 levels through 2030, reflecting the potential inability of the U.S. market to attract significant volumes from the world market. This case also uses an assumption consistent with the *high price case*—a 15-percent reduction in U.S. oil and natural gas resources—and an assumption consistent with the *oil and gas slow technology case*—a 50-percent reduction in the rate of technological progress related to costs, finding rates, and success rates. Like the reference case, the *limited natural gas supply case* also assumes that no additional capacity will be built to produce pipeline-quality natural gas from coal.

The *combined limited case* combines the assumptions of the limited electricity generation supply and limited natural gas supply cases. Results from these three case are summarized in the "Issues in Focus" section of this report. Additional details will be provided in *Assumptions to the Annual Energy Outlook 2008* [*18*].

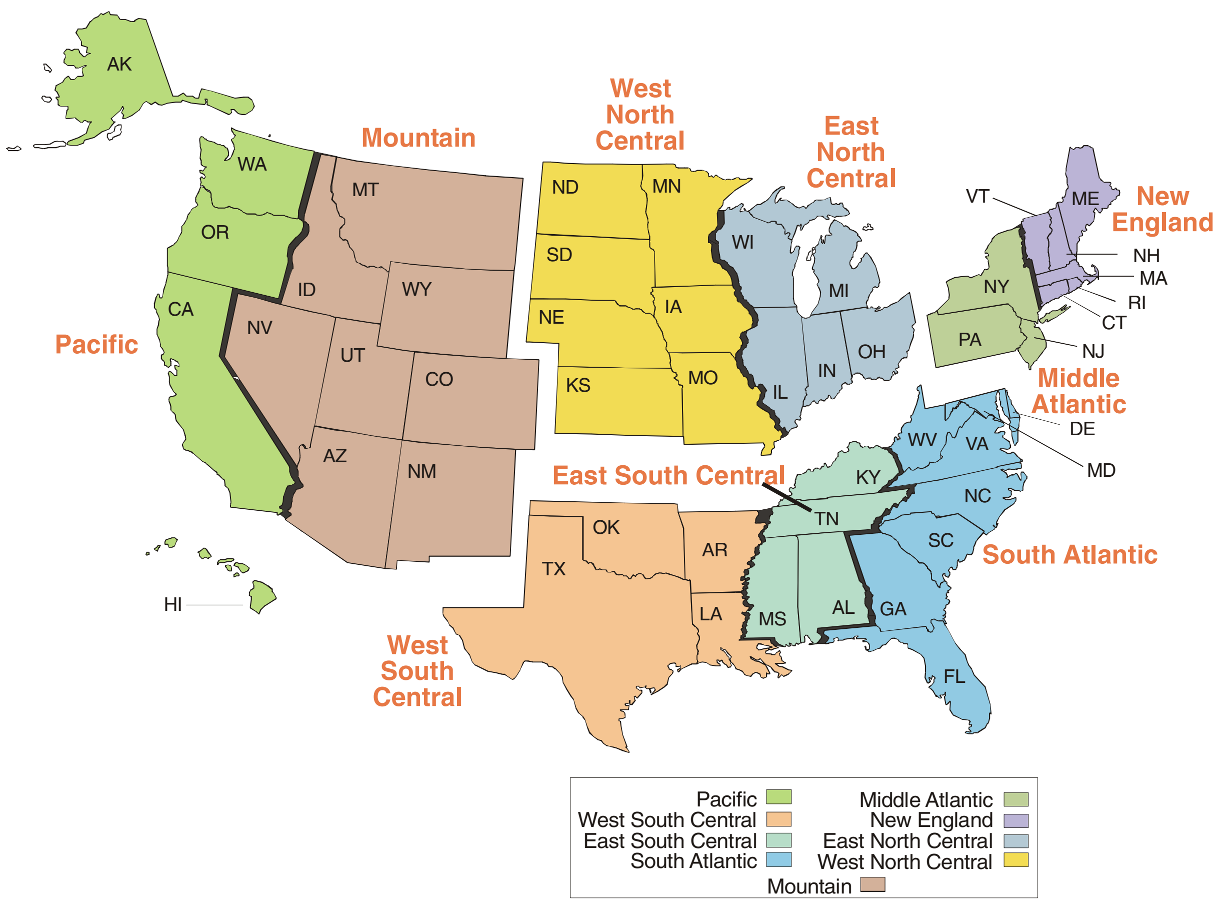
Endnotes

1. Energy Information Administration, *The National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003) (Washington, DC, March 2003).
2. On February 8, 2008, the U.S. Court of Appeals found CAMR to be unlawful and voided it, ruling that the EPA had not proved that mercury was a pollutant eligible for regulation under a less stringent portion of the Clean Air Act; however, EIA did not have time to revise *AEO2008* before publication to remove the impact of CAMR.
3. Energy Information Administration, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007).
4. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2006*, DOE/EIA-0573(2006) (Washington, DC, November 2007).
5. Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.
6. Jet Information Services, Inc., *World Jet Inventory Year-End 2006* (Utica, NY, March 2007); and personal communication from Stuart Miller (Jet Information Services).
7. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554(2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
8. For gasoline blended with ethanol, the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be available through 2010. It is assumed to expire after 2010 under current law.
9. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554(2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
10. High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., January 2006).
11. High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Case Second Edition (Revised)* (Navigant Consulting, Inc., September 2007), and *EIA—Technology Forecast—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., January 2006).
12. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
13. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).

14. Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).
15. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
16. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
17. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.
18. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2008*, DOE/EIA-0554 (2008) (Washington, DC, to be published), web site www.eia.doe.gov/oiaf/aeo/assumption.

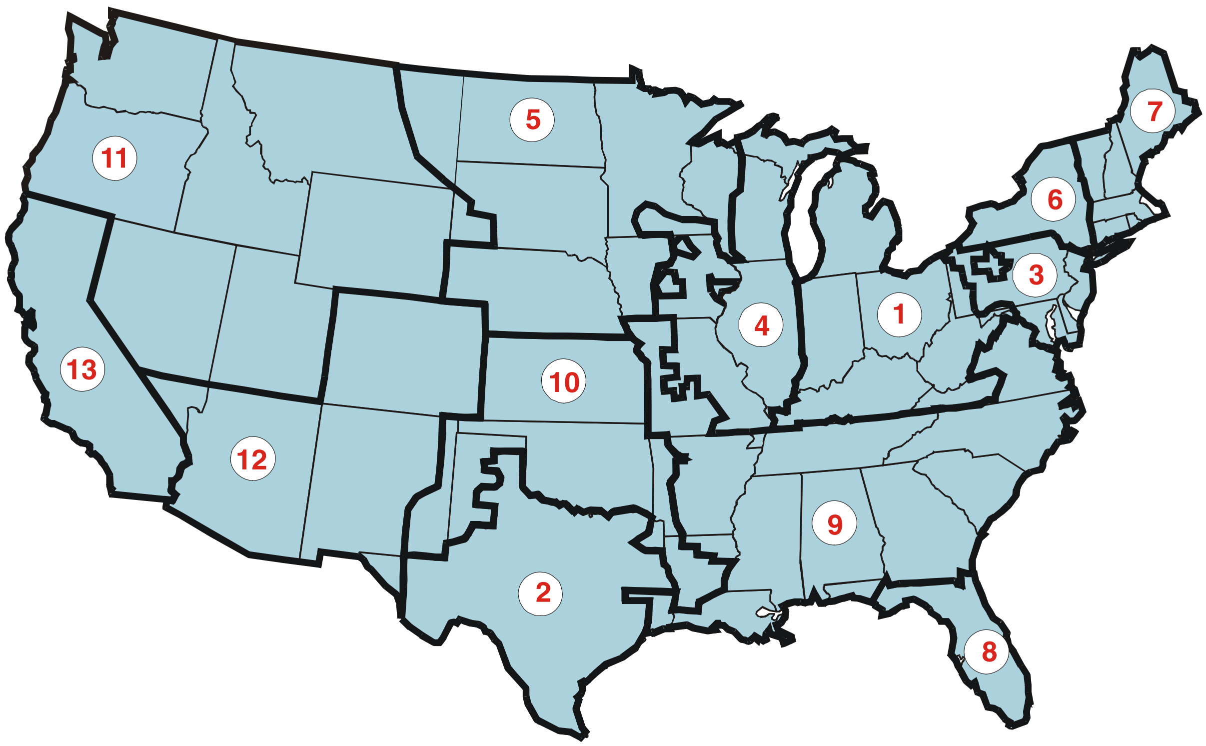
Regional Maps

F1. United States Census Divisions



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

F2. Electricity Market Module Regions



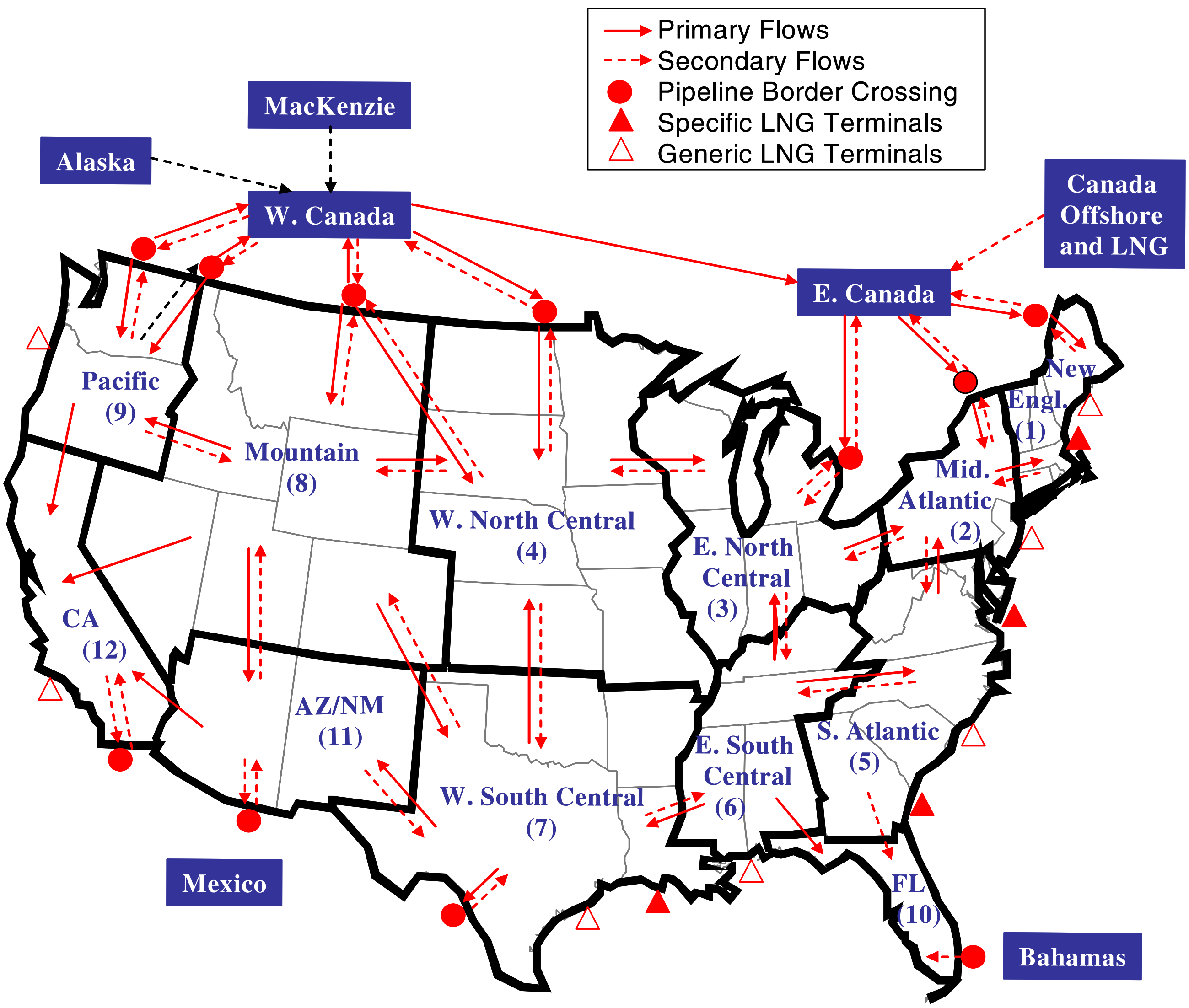
1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8. Florida Reliability Coordinating Council (FL)
9. Southeastern Electric Reliability Council (SER
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13. California (CA)

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

F3. Oil and Gas Supply Model Regions

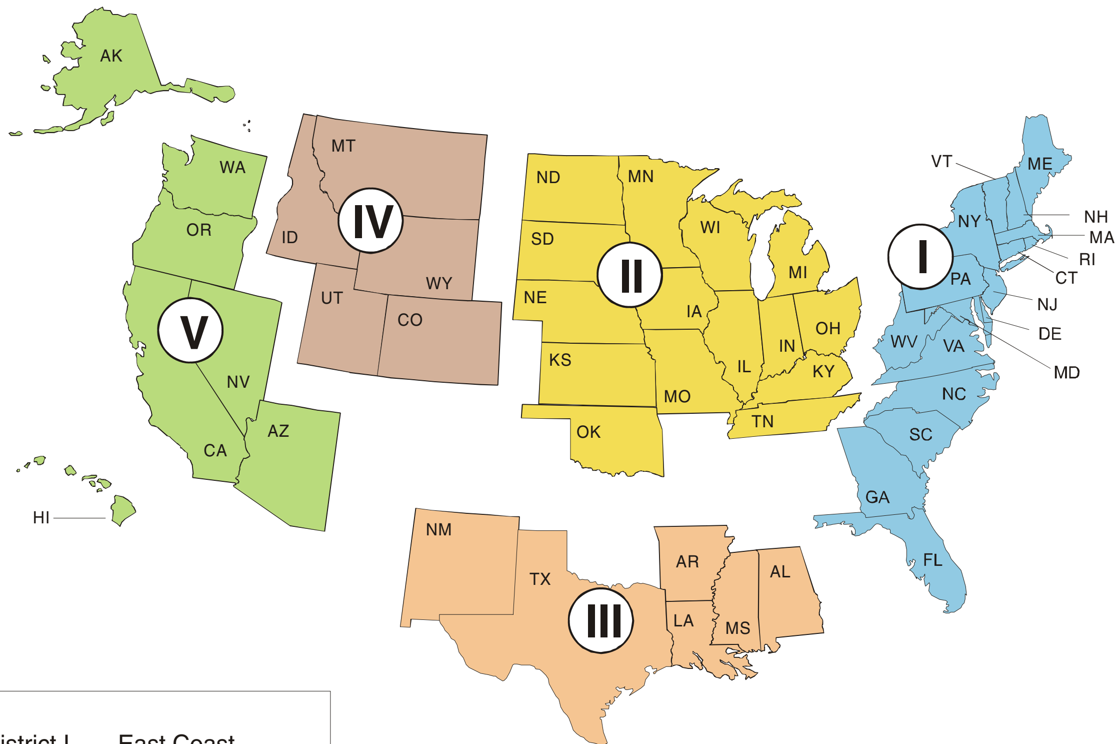
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F4. Natural Gas Transmission and Distribution Model Regions



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

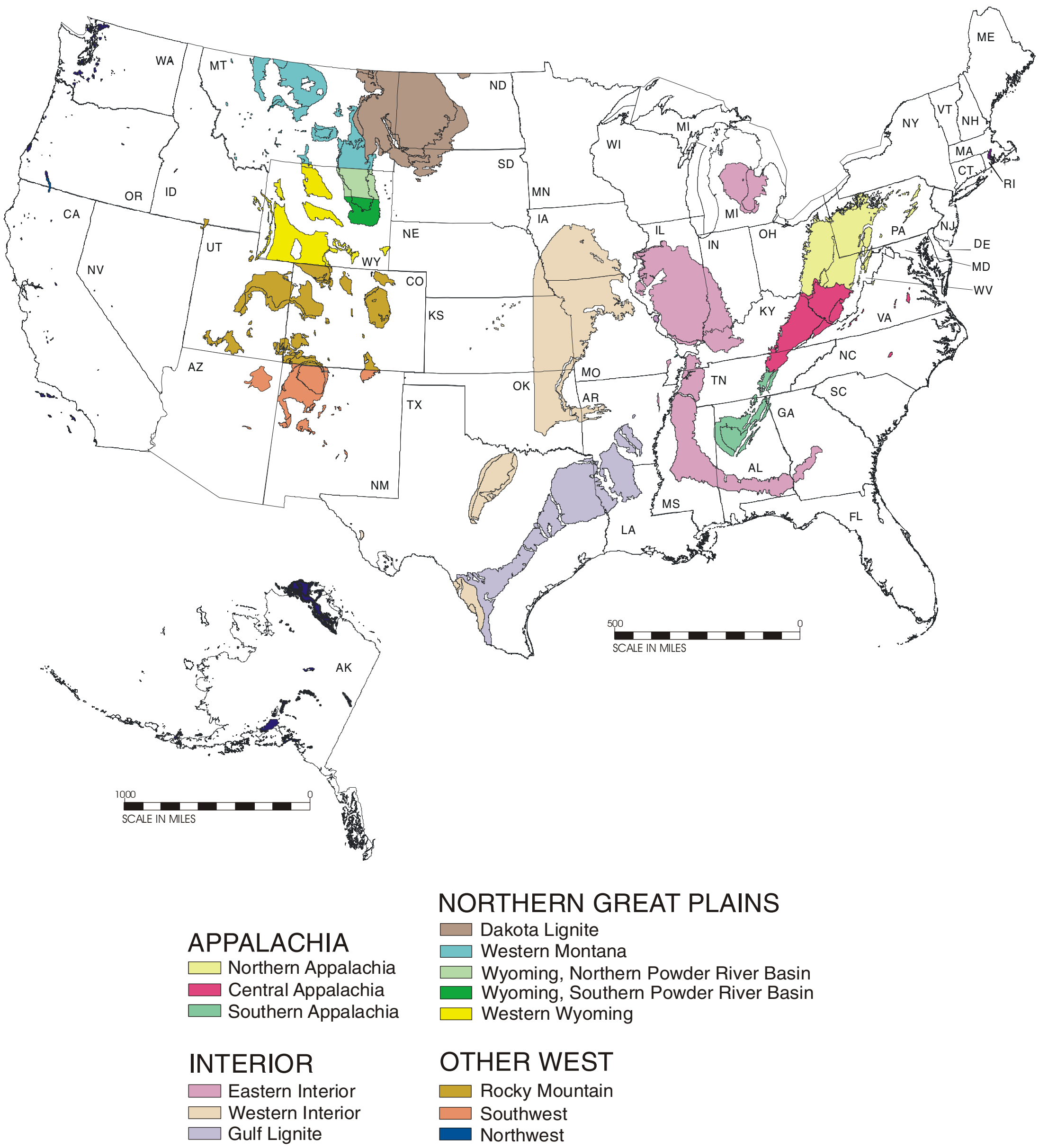
F5. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

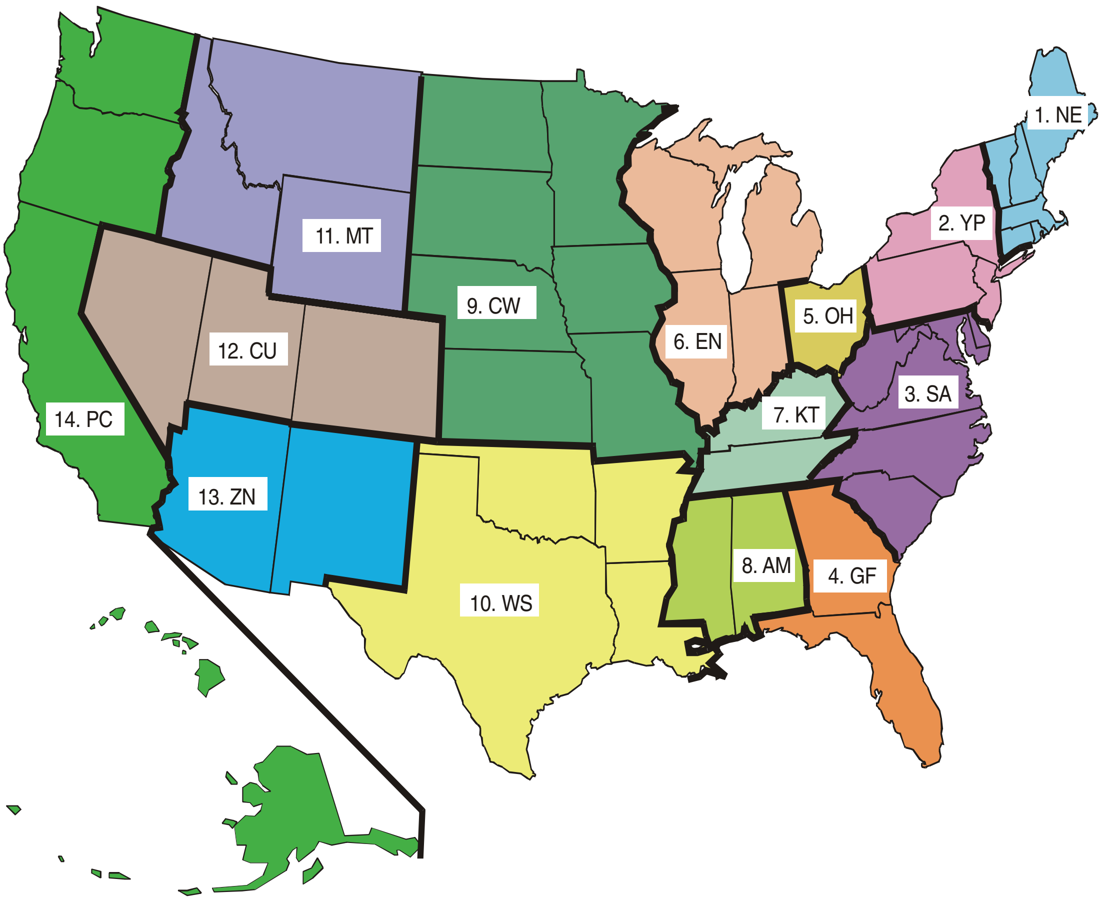
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F6. Coal Supply Regions



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

F7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN

Region Code	Region Content
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

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

Conversion Factors

Table G1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal		
Production	million Btu per short ton	20.310
Consumption	million Btu per short ton	20.183
Coke Plants	million Btu per short ton	26.263
Industrial	million Btu per short ton	21.652
Residential and Commercial	million Btu per short ton	22.016
Electric Power Sector	million Btu per short ton	19.952
Imports	million Btu per short ton	25.073
Exports	million Btu per short ton	25.378
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports	million Btu per barrel	5.980
Liquids		
Consumption	million Btu per barrel	5.338
Motor Gasoline	million Btu per barrel	5.218
Jet Fuel, Kerosene Type	million Btu per barrel	5.670
Distillate Fuel Oil	million Btu per barrel	5.790
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas	million Btu per barrel	3.605
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks	million Btu per barrel	5.554
Unfinished Oils	million Btu per barrel	6.118
Imports	million Btu per barrel	5.450
Exports	million Btu per barrel	5.727
Ethanol	million Btu per barrel	3.539
Biodiesel	million Btu per barrel	5.376
Natural Gas Plant Liquids		
Production	million Btu per barrel	3.712
Natural Gas		
Production, Dry	Btu per cubic foot	1,029
Consumption	Btu per cubic foot	1,029
End-Use Sectors	Btu per cubic foot	1,030
Electric Power Sector	Btu per cubic foot	1,028
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.
Note: Conversion factors vary from year to year. Values correspond to those published by EIA for 2006 and may differ slightly from model results.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2006*, DOE/EIA-0384(2006) (Washington, DC, June 2007), and EIA, AEO2008 National Energy Modeling System run AEO2008.D030208F.