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Annual Energy Outlook 2011

with Projections to 2035

Independent Statistics & Analysis
U.S. Energy Information Administration

For further information . . .

The *Annual Energy Outlook 2011* was prepared by the U.S. Energy Information Administration (EIA), under the direction of John J. Conti (john.conti@eia.gov, 202-586-2222), Assistant Administrator of Energy Analysis; Paul D. Holtberg (paul.holtberg@eia.gov, 202/586-1284), Co-Acting Director, Office of Integrated and International Energy Analysis, and Team Leader, Analysis Integration Team; Joseph A. Beamon (joseph.beamon@eia.gov, 202/586-2025), Director, Office of Electricity, Coal, Nuclear, and Renewables Analysis; A. Michael Schaal (michael.schaal@eia.gov, 202/586-5590), Director, Office of Petroleum, Gas, and Biofuel Analysis; Joseph C. Ayoub (joseph.ayoub@eia.gov, 202-586-8994), Co-Acting Director, Office of Integrated and International Energy Analysis, and James T. Turnure (james.turnure@eia.gov, 202/586-1762), Director, Office of Energy Consumption and Efficiency Analysis.

For ordering information and questions on other energy statistics available from EIA, please contact the EIA Energy Information Center at:

EIA Energy Information Center, EI-30
U.S. Energy Information Administration
Forrestal Building
Washington, DC 20585

Telephone: 202/586-8800 E-mail: infoctr@eia.gov
FAX: 202/586-0727 Website: www.eia.gov/

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

General questions	Paul D. Holtberg (paul.holtberg@eia.gov, 202-586-1284)
National energy modeling system	Dan H. Skelly (daniel.skelly@eia.gov, 202-586-2222)
Executive summary	Paul D. Holtberg (paul.holtberg@eia.gov, 202/586-1284)
Economic activity	Kay A. Smith (kay.smith@eia.gov, 202/586-1132)
World oil prices	John L. Staub (john.staub@eia.gov, 202-586-3005)
International oil production	Emre M. Yucel (emre.yucel@eia.gov, 202/586-3005)
International oil demand	Linda E. Doman (linda.doman@eia.gov, 202/586-1041)
Residential demand	Owen Comstock (owen.comstock@eia.gov, 202/586-4752)
Commercial demand	Erin E. Boedecker (erin.boedecker@eia.gov, 202/586-4791)
Industrial demand	Elizabeth D. Sendich (elizabeth.sendich@eia.gov, 202/586-7145)
Transportation demand	John D. Maples (john.maples@eia.gov, 202/586-1757)
Electricity generation, capacity	Jeff S. Jones (jeffrey.jones@eia.gov, 202/586-2038)
Electricity generation, emissions	Michael T. Leff (michael.leff@eia.gov, 202/586-1297)
Electricity prices	Lori B. Aniti (lori.aniti@eia.gov, 202/586-2867)
Nuclear energy	Laura K. Martin (laura.martin@eia.gov, 202/586-1494)
Renewable energy	Chris R. Namovicz (chris.namovicz@eia.gov, 202/586-7120)
Oil and natural gas production	Dana Van Wagener (dana.vanwagener@eia.gov, 202/586-4725)
Liquefied natural gas markets	Phyllis D. Martin (phyllis.martin@eia.gov, 202-586-9592)
Oil refining and markets	William S. Brown (william.brown@eia.gov, 202/586-8181)
Ethanol and biodiesel	Mac J. Statton (mac.statton@eia.gov, 202-586-7105)
Coal supply and prices	Michael L. Mellish (michael.mellish@eia.gov, 202/586-2136)
Carbon dioxide emissions	Diane R. Kearney (diane.kearney@eia.gov, 202/586-2415)

The *Annual Energy Outlook 2011* is available on the EIA website at www.eia.gov/forecasts/aeo/. Assumptions underlying the projections, tables of regional results, and other detailed results will also be available, at www.eia.gov/forecasts/aeo/assumptions/. Model documentation reports for the National Energy Modeling System are available at website www.eia.gov/analysis/model-documentation.cfm and will be updated for the *Annual Energy Outlook 2011* during 2011.

Other contributors to the report include Justine Barden, Joseph Benneche, Tina Bowers, Phillip Budzik, Stephen Calopedis, Nicholas Chase, John Cochener, Michael Cole, Margie Daymude, Robert Eynon, Adrian Geagla, Peter Gross, James Hewlett, Behjat Hojjati, Sean Hill, Kevin Jarzomski, Stephanie Kette, Paul Kondis, Andy Kydes, Marie LaRiviere, Thomas Lee, Perry Lindstrom, Lauren Mayne, David Peterson, Chetha Phang, Eugene Reiser, Mark Schipper, Joanne Shore, Robert Smith, John Staub, Russell Tarver, Diwakar Vashishat, Steven Wade, and Peggy Wells.

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U.S. Energy Information Administration
Office of Integrated and International Energy Analysis
U.S. Department of Energy
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Preface

The *Annual Energy Outlook 2011* (*AEO2011*), prepared by the U.S. Energy Information Administration (EIA), presents long-term projections of energy supply, demand, and prices through 2035, based on results from EIA's National Energy Modeling System (NEMS). EIA published an "early release" version of the *AEO2011* Reference case in December 2010.

The report begins with an *Executive summary* that highlights key aspects of the projections. It is followed by a *Legislation and regulations* section that discusses evolving legislative and regulatory issues, including a summary of recently enacted legislation and regulations, such as a recently announced (October 13, 2010) EPA waiver, which allows the use of motor gasoline blends containing 15 percent ethanol in newer vehicles (model year 2007 or later), or the 7-year moratorium on offshore drilling in the Atlantic and Pacific that was announced by the U.S. Department of the Interior on December 1, 2010. The *Issues in focus* section contains discussions of selected energy topics, including a discussion of the results in two cases that adopt different assumptions about the future course of existing policies: one case assumes the extension of a selected group of existing public policies—corporate average fuel economy standards, appliance standards, production tax credits, and the elimination of sunset provisions in existing energy policies; the other case assumes only the elimination of sunset provisions. Other discussions include: a look at evolving environmental regulations that affect the power sector; the economics of carbon capture and storage; prospects for shale gas production, including cost uncertainty and its impact on decisions for new power plant builds, fuel use, and emissions; and the basis for world oil price and production trends in *AEO2011*.

The *Market trends* section summarizes the projections for energy markets. The analysis in *AEO2011* focuses primarily on a Reference case, Low and High Economic Growth cases, and Low and High Oil Price cases. Results from a number of other alternative cases also are 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. Complete tables for all the alternative cases are available on EIA's website in a table browser at www.eia.gov/oiaf/aeo/tablebrowser/.

AEO2011 projections are based generally on Federal, State, and local laws and regulations in effect as of the end of January 2011. 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 certain situations, however, where it is clear that a law or regulation will take effect shortly after the *AEO* is completed, it may be considered in the projection.

AEO2011 is published in accordance with Section 205c of the U.S. 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 by EIA are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular scenario. The Reference case projection is a business-as-usual trend estimate, given known technology and technological and demographic trends. EIA explores the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, and rates of technology progress. The main cases in *AEO2011* generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide policy-neutral baselines that can be used to analyze policy initiatives.

While energy markets are complex, energy 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 *AEO2011* 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.

Updated *Annual Energy Outlook 2011* Reference case (April 2011)

The *AEO2011* Reference case included in the final published report released in April 2011 is updated from the Reference case that was used in the *AEO2011 Early Release Overview* (December 2010). The Reference case was updated to incorporate modeling changes and reflect changes based on recent legislation and regulations that were not available when the *Early Release Overview* was published. Major changes made for the updated Reference include:

- Added a 30-percent investment tax credit for fuel cells, with a 2016 expiration date
- Retired the Oyster Creek nuclear power plant at the end of 2019
- Revised the amount of new wind capacity built in 2012 (7 rather than 10 gigawatts)
- Benchmarked oil production to EIA's January *Short-Term Energy Outlook* (including revision of undiscovered oil drilling schedules)
- Delayed additional deepwater offshore projects
- Forced economic life to be 43 years for coalbed methane play that was deciding on a 16-year life
- Updated carbon-dioxide-enhanced oil recovery
- Updated natural gas reserve reporting
- Updated 2011 cellulosic ethanol subsidy
- Updated ethanol tax credit, biodiesel tax credit, and ethanol tariff through 2011
- Allowed E15 use in 2001-2006 model year light-duty vehicles (in addition to 2007-present)
- Updated battery cost curve
- Updated sales of electric, hybrid electric, microhybrid, and plug-in electric vehicles
- Updated High Technology case assumptions
- Updated historical data for energy-related carbon dioxide emissions and updated carbon dioxide emissions factors for biomass, based on upcoming EIA data reports.

Future analyses using the *AEO2011* Reference case will start from the version released with this complete report.

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Executive summary

The projections in the Energy Information Administration's (EIA) *Annual Energy Outlook 2011 (AEO2011)* focus on the factors that shape the U.S. energy system over the long term. Under the assumption that current laws and regulations remain unchanged throughout the projections, the *AEO2011* Reference case provides the basis for examination and discussion of energy production, consumption, technology, and market trends and the direction they may take in the future. It also serves as a starting point for analysis of potential changes in energy policies. But *AEO2011* is not limited to the Reference case. It also includes 57 sensitivity cases (see Appendix E, Table E1), which explore important areas of uncertainty for markets, technologies, and policies in the U.S. energy economy.

Key results highlighted in *AEO2011* include strong growth in shale gas production, growing use of natural gas and renewables in electric power generation, declining reliance on imported liquid fuels, and projected slow growth in energy-related carbon dioxide (CO_2) emissions even in the absence of new policies designed to mitigate greenhouse gas (GHG) emissions.

AEO2011 also includes in-depth discussions on topics of special interest that may affect the energy outlook. They include: impacts of the continuing renewal and updating of Federal and State laws and regulations; discussion of world oil supply and price trends shaped by changes in demand from countries outside the Organization for Economic Cooperation and Development or in supply available from the Organization of the Petroleum Exporting Countries; an examination of the potential impacts of proposed revisions to Corporate Average Fuel Economy standards for light-duty vehicles and proposed new standards for heavy-duty vehicles; the impact of a series of updates to appliance standard alone or in combination with revised building codes; the potential impact on natural gas and crude oil production of an expanded offshore resource base; prospects for shale gas; the impact of cost uncertainty on construction of new electric power plants; the economics of carbon capture and storage; and the possible impact of regulations on the electric power sector under consideration by the U.S. Environmental Protection Agency (EPA). Some of the highlights from those discussions are mentioned in this Executive Summary. Readers interested in more detailed analyses and discussions should refer to the "Issues in focus" section of this report.

Imports meet a major but declining share of total U.S. energy demand

Real gross domestic product grows by 2.7 percent per year from 2009 to 2035 in the *AEO2011* Reference case, and oil prices grow to about $125 per barrel (2009 dollars) in 2035. In this environment, net imports of energy meet a major, but declining, share of total U.S. energy demand in the Reference case. The need for energy imports is offset by the increased use of biofuels (much of which are produced domestically), demand reductions resulting from the adoption of new vehicle fuel economy standards, and rising energy prices. Rising fuel prices also spur domestic energy production across all fuels—particularly, natural gas from plentiful shale gas resources—and temper the growth of energy imports. The net import share of total U.S. energy consumption in 2035 is 17 percent, compared with 24 percent in 2009. (The share was 29 percent in 2007, but it dropped considerably during the 2008-2009 recession.)

Much of the projected decline in the net import share of energy supply is accounted for by liquids. Although U.S. consumption of liquid fuels continues to grow through 2035 in the Reference case, reliance on petroleum imports as a share of total liquids consumption decreases. Total U.S. consumption of liquid fuels, including both fossil fuels and biofuels, rises from about 18.8 million barrels per day in 2009 to 21.9 million barrels per day in 2035 in the Reference case. The import share, which reached 60 percent in 2005 and 2006 before falling to 51 percent in 2009, falls to 42 percent in 2035 (Figure 1).

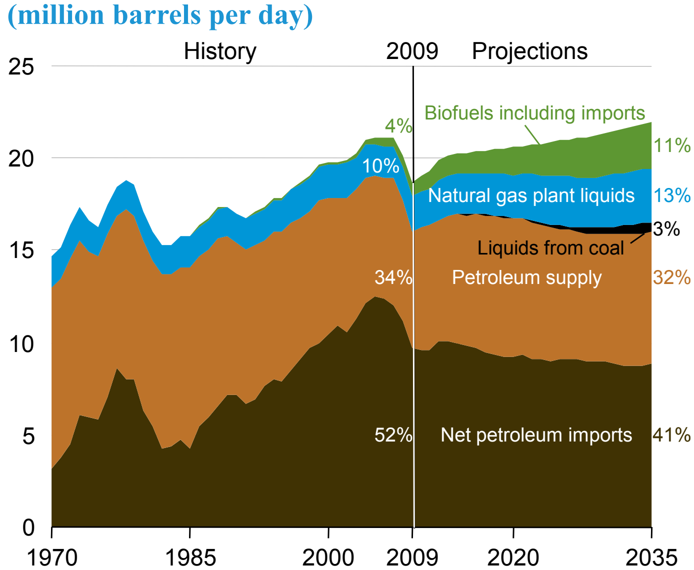
Domestic shale gas resources support increased natural gas production with moderate prices

Shale gas production in the United States grew at an average annual rate of 17 percent between 2000 and 2006. Early success in shale gas production was achieved primarily in the Barnett Shale in Texas. By 2006, the success in the Barnett shale, coupled with high natural gas prices and technological improvements, turned the industry focus to other shale plays. The combination of horizontal drilling and hydraulic fracturing technologies has made it possible to produce shale gas economically, leading to an average annual growth rate of 48 percent over the 2006-2010 period.

Shale gas production continues to increase strongly through 2035 in the *AEO2011* Reference case, growing almost fourfold from 2009 to 2035. While total domestic natural gas production grows from 21.0 trillion cubic feet in 2009 to 26.3 trillion cubic feet in 2035, shale gas production grows to 12.2 trillion cubic feet in 2035, when it makes up 47 percent of total U.S. production—up considerably from the 16-percent share in 2009 (Figure 2).

The estimate for technically recoverable unproved shale gas resources in the Reference case is 827 trillion cubic feet. Although more information has become available as a result of increased drilling activity in developing shale gas plays, estimates of technically recoverable resources and well productivity remain highly uncertain. Estimates of technically

Figure 1. U.S. liquids fuel consumption, 1970-2035 (million barrels per day)



recoverable shale gas are certain to change over time as new information is gained through drilling, production, and technological and managerial development. Over the past decade, as more shale formations have gone into commercial production, the estimate of technically and economically recoverable shale gas resources has skyrocketed. However, the increases in recoverable shale gas resources embody many assumptions that might prove to be incorrect over the long term.

Alternative cases in *AEO2011* examine the potential impacts of variation in the estimated ultimate recovery per shale gas well and the assumed recoverability factor used to estimate how much of the play acreage contains recoverable shale gas. In those cases, overall domestic natural gas production varies from 22.4 trillion cubic feet to 30.1 trillion cubic feet in 2035, compared with 26.3 trillion cubic feet in the Reference case. The Henry Hub spot price for natural gas in 2035 (in 2009 dollars) ranges from $5.35 per thousand cubic feet to $9.26 per thousand cubic feet in the alternative cases, compared with $7.07 per thousand cubic feet in the Reference case.

Despite rapid growth in generation from natural gas and nonhydropower renewable energy sources, coal continues to account for the largest share of electricity generation

Assuming no additional constraints on CO_2 emissions, coal remains the largest source of electricity generation in the *AEO2011* Reference case because of continued reliance on existing coal-fired plants. EIA projects few new central-station coal-fired power plants, however, beyond those already under construction or supported by clean coal incentives. Generation from coal increases by 25 percent from 2009 to 2035, largely as a result of increased use of existing capacity; however, its share of the total generation mix falls from 45 percent to 43 percent as a result of more rapid increases in generation from natural gas and renewables over the same period. The role of natural gas grows due to low natural gas prices and relatively low capital construction costs that make it more attractive than coal. The share of generation from natural gas increases from 23 percent in 2009 to 25 percent in 2035.

Electricity generation from renewable sources grows by 72 percent in the Reference case, raising its share of total generation from 11 percent in 2009 to 14 percent in 2035. Most of the growth in renewable electricity generation in the power sector consists of generation from wind and biomass facilities (Figure 3). The growth in generation from wind plants is driven primarily by State renewable portfolio standard (RPS) requirements and Federal tax credits. Generation from biomass comes from both dedicated biomass plants and co-firing in coal plants. Its growth is driven by State RPS programs, the availability of low-cost feedstocks, and the Federal renewable fuels standard, which results in significant cogeneration of electricity at plants producing biofuels.

Proposed environmental regulations could alter the power generation fuel mix

The EPA is expected to enact several key regulations in the coming decade that will have an impact on the U.S. power sector, particularly the fleet of coal-fired power plants. Because the rules have not yet been finalized, their impacts cannot be fully analyzed, and they are not included in the Reference case. However, *AEO2011* does include several alternative cases that examine the sensitivity of power generation markets to various assumed requirements for environmental retrofits.

The range of coal plant retirements varies considerably across the cases (Table 1), with a low of 9 gigawatts (3 percent of the coal fleet) in the Reference case and a high of 73 gigawatts (over 20 percent of the coal fleet). The higher end of this range is driven by the somewhat extreme assumptions that all plants must have scrubbers to remove sulfur dioxide and selective catalytic reduction to remove nitrogen oxides, that natural gas wellhead prices remain at or below about $5 through 2035, and that environmental

Figure 2. U.S. natural gas production, 1990-2035 (trillion cubic feet per year)

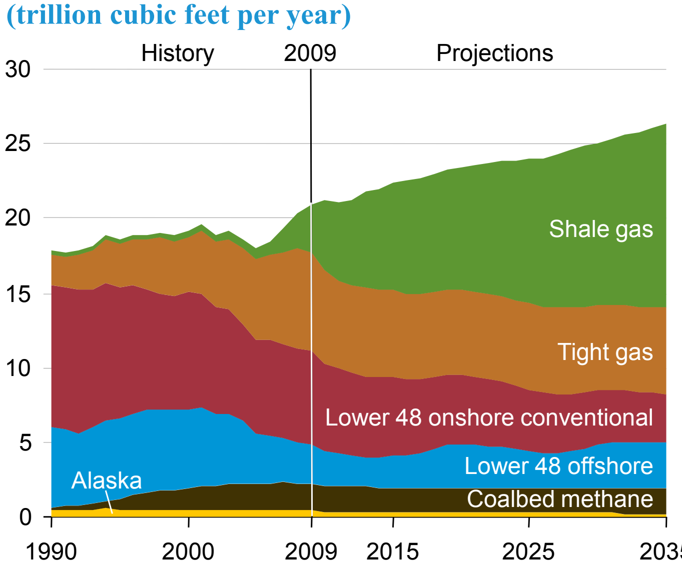
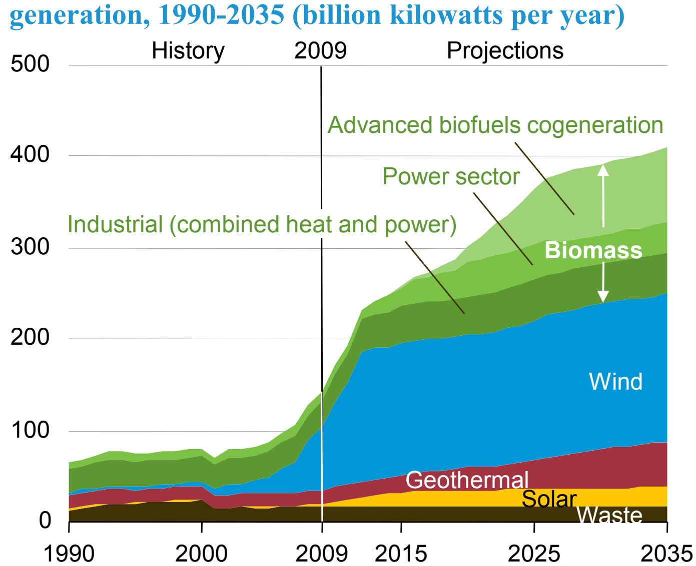


Figure 3. U.S. nonhydropower renewable electricity generation, 1990-2035 (billion kilowatts per year)



retrofit decisions are based on an assumption that retrofits occur only if plant owners can recover their costs within 5 years. The latter quick cost recovery assumption is meant to represent the possibility of future environmental regulation, including for GHGs.

In all these cases, coal continues to account for the largest share of electricity generation through 2035. Many of the coal plants projected to be retired in these cases had relatively low utilization factors and high heat rates historically, and their contribution to overall coal-fired generation was relatively modest.

Electricity generation from natural gas is higher in 2035 in all the environmental regulation sensitivity cases than in the Reference case. The faster growth in electricity generation with natural gas is supported by low natural gas prices and relatively low capital costs for new natural gas plants, which improve the relative economics of gas when regulatory pressure is placed on the existing coal fleet. In the alternative cases, natural gas generation in 2035 varies from 1,323 billion kilowatthours to 1,797 billion kilowatthours, compared with 1,288 billion kilowatthours in the Reference case.

Assuming no changes in policy related to greenhouse gas emissions, carbon dioxide emissions grow slowly and do not return to 2005 levels until 2027

After falling by 3 percent in 2008 and 7 percent in 2009, largely as a result of the economic downturn, energy-related CO_2 emissions grow slowly in the *AEO2011* Reference case due to a combination of modest economic growth, growing use of renewable technologies and fuels, efficiency improvements, slower growth in electricity demand (in part because of the recent recession), and more use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, which assumes no explicit regulations to limit GHG emissions beyond vehicle GHG standards, energy-related CO_2 emissions do not return to 2005 levels (5,996 million metric tons) until 2027, growing by an average of 0.6 percent per year from 2009 to 2027, or a total of 10.6 percent. CO_2 emissions then rise by an additional 5 percent from 2027 to 2035, to 6,311 million metric tons in 2035 (Figure 4).

To put the numbers in perspective, population growth is projected to average 0.9 percent per year, overall economic growth 2.7 percent per year, and growth in energy use 0.7 percent per year over the same period. Although total energy-related CO_2 emissions increase from 5,996 million metric tons in 2005 to 6,311 million metric tons in 2035 in the Reference case, emissions per capita fall by 0.7 percent per year over the same period. Most of the growth in CO_2 emissions in the *AEO2011* Reference case is accounted for by the electric power and transportation sectors.

The projections for CO_2 emissions are sensitive to many factors, including economic growth, policies aimed at stimulating renewable fuel use or low-carbon power sources, and any policies that may be enacted to reduce GHG emissions. In the *AEO2011* Low and High Economic Growth cases, projections for total primary energy consumption in 2035 are 106.4 quadrillion British thermal units (Btu) (6.9 percent below the Reference case) and 122.6 quadrillion Btu (7.4 percent above the Reference case), and projections for energy-related CO_2 emissions in 2035 are 5,864 million metric tons (7.1 percent below the Reference case) and 6,795 million metric tons (7.7 percent above the Reference case), respectively.

Figure 4. U.S. carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)

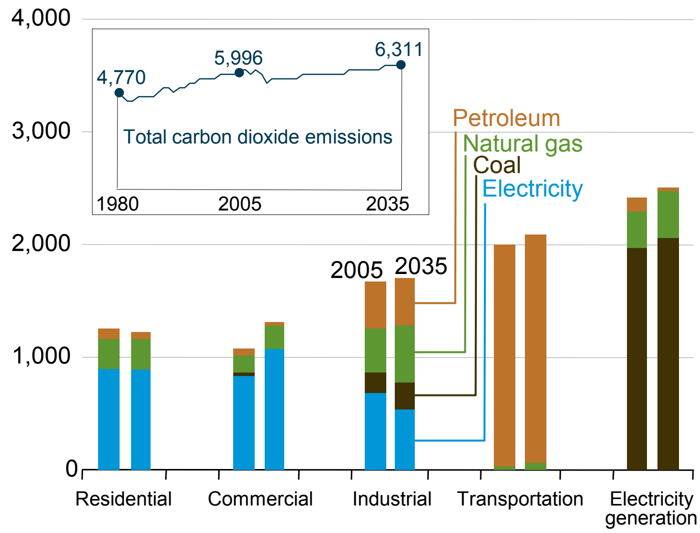


Table 1. Coal-fired plant retirements in alternative cases, 2010-2035

Analysis case	Coal-fired capacity retired (gigawatts)	Average size of plants retired (megawatts)	Average heat rate of plants retired (million Btu per kilowatthour)
Reference	8.8	93.0	12,338
Transport Rule Mercury MACT 20	13.5	91.4	12,053
Transport Rule Mercury MACT 5	17.8	83.3	12,102
Retrofit Required 20	19.2	84.5	12,034
Retrofit Required 5	44.8	91.2	11,579
Low Gas Price	15.6	104	12,098
Low Gas Price Retrofit Required 20	39.5	97.8	11,576
Low Gas Price Retrofit Required 5	72.6	109.6	11,363

Legislation and regulations

Introduction

The *Annual Energy Outlook 2011 (AEO2011)* Reference case generally assumes that current laws and regulations affecting the energy sector remain unchanged throughout the projection (including the implication that laws which include sunset dates do, in fact, become ineffective at the time of those sunset dates). Currently, there are many pieces of legislation and regulation that appear to have some probability of being enacted in the not-too-distant future, and some laws include sunset provisions that may be extended. However, it is difficult to discern the exact forms that the final provisions of pending legislation or regulations will take, and sunset provisions may or may not be extended. Even in situations where existing legislation contains provisions to allow revision of implementing regulations, those provisions may not be exercised consistently. In certain situations, however, where it is clear that a law or regulation will take effect shortly after the *Annual Energy Outlook (AEO)* modeling work is completed, it may be considered in the projection. Sensitivity cases that incorporate alternative assumptions about proposed policies or existing policies subject to periodic updates are also included among the many alternative cases completed as part of the *AEO*. The Federal and State laws and regulations included in *AEO2011* are based on those in effect as of the end of January 2011. In addition, at the request of the Administration and Congress, the U.S. Energy Information Administration (EIA) has regularly examined the potential implications of proposed legislation in Service Reports. Those reports, and others that were completed before 2010, can be found on the EIA website at www.eia.gov/oiaf/service_rpts.htm.

Examples of recently enacted State and Federal legislation incorporated in *AEO2011* include:

- State provisions passed in 2010 in Connecticut [*1*], Maine [*2*], New Jersey [*3*], and New York [*4*] that reduced the maximum allowable sulfur content of heating oil sold, as well as some plans to include mandated percentages of biodiesel content.
- Final regulations promulgated by the California Air Resources Board (CARB) in January 2010 to implement a Low Carbon Fuel Standard (LCFS) [*5*]. The LCFS program aims to reduce the carbon intensity of motor gasoline and diesel fuel sold in California by 10 percent over the years 2012 through 2020 by increasing the volumes of alternative low-carbon fuels being introduced into the marketplace.
- The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, enacted in December 2010 [*6*]. This law includes an extension of the Volumetric Ethanol Excise Tax Credit at $0.45 per gallon through 2011, a retroactive extension of the $1.00 per gallon biodiesel excise tax credit through 2011, and an extension of the $0.54 per gallon tariff on imported ethanol through 2011.
- Updates to State renewable portfolio standard (RPS) programs, representing laws and regulations of 30 States and the District of Columbia that require renewable electricity generation.

Examples of recent Federal and State regulations, as well as provisions considered in earlier *AEO*s that have been affected by subsequent court decisions, include the following:

- Approval of a waiver allowing the use of motor gasoline blends containing up to 15 percent ethanol for vehicles of model year (MY) 2001 and newer by the U.S. Environmental Protection Agency (EPA) in January 2011 [*7*].
- Issuance of new guidelines by the EPA in April 2010 regarding the compliance of surface coal mining operations in Appalachia with the provisions of the Clean Water Act, the National Environmental Policy Act, and the environmental justice Executive Order (E.O. 12898) [*8*]. The guidance explains the approach that the EPA will be following in permit reviews and instructs Regional offices to use clear, consistent, and science-based standards in reviewing the permits.

Detailed information on several Federal and State legislative and regulatory developments considered in *AEO2011* is provided below.

1. Updated State air emissions regulations

Regional Greenhouse Gas Initiative

The Regional Greenhouse Gas Initiative (RGGI) is a program that includes 10 Northeast States that have agreed to curtail and reverse growth in their carbon dioxide (CO_2) emissions. The RGGI program includes all electricity generating units with a capacity of at least 25 megawatts and requires an allowance for each ton of CO_2 emitted [*9*]. The first year of mandatory compliance was in 2009.

Each participating State was provided a CO_2 budget consisting of a history-based baseline with a cushion for emissions growth, so that meeting the cap would be relatively easy initially and become more stringent in subsequent years. The requirements cover 95 percent of CO_2 emissions from the region's electric power sector. Overall, the RGGI States as a whole must maintain covered emissions at or below a level of 188 million tons CO_2 through 2012, after which a mandatory 2.5-percent annual decrease in CO_2 emissions through 2018 reduces the total for covered CO_2 emissions in the RGGI States to 10 percent below the initial calculated budget. Although each State was given its own emissions budget, allowances are auctioned at a uniform price across the entire region.

At the most recent RGGI auction in March 2011, 42 million allowances were offered and sold at a clearing price of $1.89 per ton of CO_2 [*10*], just above the price floor. The previous auction in December 2010 also cleared at the price floor, because total emissions from electricity generators did not grow as anticipated.

RGGI's impact on electricity markets is included in the *AEO2011* Reference case. Its impact on actual emissions, especially in the early years, is minimal because of its relatively modest reduction targets. Also, it is difficult to capture the nuances of initiatives that cover only single States or groups of States that do not correspond to the regions used in the National Energy Modeling System (NEMS). Therefore, EIA estimated generation for the Mid-Atlantic region and capped emissions from those facilities. Pennsylvania's emissions were not restricted, because Pennsylvania is an observing member and is not participating in the cap-and-trade program or subject to any mandatory emission reductions.

California greenhouse gas reduction program

California is moving forward with its plans to cap and then reverse the growth of State greenhouse gas (GHG) emissions. After surviving a challenge on the ballot in November 2010, the mandatory restrictions begin to take effect in January 2012. After the law was passed and signed, a scoping plan was written that outlines the major components of the regulations [*11*]. In all, there are 21 programs in the law that will mitigate GHG emissions through a variety of mechanisms—from landfill methane control to proper tire pressurization programs [*12*]. While *AEO2011* incorporates programs from the law, such as the LCFS and 33-percent RPS—where rules are sufficiently specified to allow modeling in the *AEO*—other programs, such as the carbon cap-and-trade provisions, are not included either because they do not include sufficient specification of implementing regulations or because they include provisions that cannot be modeled in NEMS.

The programs that are expected to generate the highest level of emission reductions are the cap-and-trade system (which is not included in *AEO2011*) and the 33-percent RPS [*13*]. The RPS requires investor-owned electricity providers to meet this mandate by 2020. CARB is in charge of the program, although other agencies still have roles in the implementation. The cap-and-trade program is scheduled to begin its first phase in 2012, covering GHG emissions from electricity (including imports) and large industrial facilities emitting more than 25,000 metric tons CO_2 annually [*14*]. Allowances are given away initially, but it is assumed that a market will develop in which allowances will trade for a price as demand grows and the number of available allowances shrinks. (The number of available allowances is scheduled to decline by 2 percent per year, starting from 165.8 million metric tons in 2012.) In 2015, distributors of fossil fuels will be added to the program, and the cap will increase to 394.5 metric tons. In the subsequent 5-year period, the cap will decrease by 3 percent annually. In addition to CO_2, the six other most common GHGs emitted (methane, nitrous oxide, sulfur hexafluoride, nitrogen trifluoride, hydrofluorocarbons, and perfluorocarbons) will also fall under the program's jurisdiction.

Several issues remain to be resolved, including finalization of the allowance allocation system, implementation of an auction system, and the possibility of a price cap. The exact distribution of the allowance revenue has not been determined nor has the treatment of natural gas as a fuel. This is all information that needs to be defined before the program can be incorporated in the *AEO*. A goal of the program is to link to other State trading programs, although the status of neighboring States' programs is uncertain. A San Francisco superior court judge also recently ruled that CARB did not conduct adequate environmental reviews or thoroughly explore cap-and-trade alternatives for meeting the reduction goal in Assembly Bill (AB) 32. This may also delay the program's implementation [*15*].

2. State renewable energy requirements and goals: Update through 2010

To the extent possible, *AEO2011* incorporates the impacts of State laws requiring the addition of renewable generation or capacity by utilities doing business in the States. Currently, 30 States and the District of Columbia have enforceable RPS or similar laws (Table 2). Under such standards, each State determines its own levels of renewable generation, eligible technologies, and noncompliance penalties. *AEO2011* includes the impacts of all laws in effect in 2010 (with the exception of Hawaii, because NEMS provides electricity market projections for the continental United States only).

In the *AEO2011* Reference case, States generally meet their ultimate RPS targets. RPS compliance in most regions is approximated, because NEMS is not a State-level model, and each State generally represents only a portion of one of the NEMS electricity regions. Compliance costs in each region are tracked, and the projection for total renewable generation is checked for consistency with any State-level cost-control provisions, such as caps on renewable credit prices, limits on State compliance funding, or impacts on consumer electricity prices. In general, EIA has confirmed each State's requirements through original documentation, although the Database of State Incentives for Renewables & Efficiency (DSIRE) also assisted EIA's efforts [*16*].

No States that did not previously have RPS programs have enacted new renewable generation laws over the past year. States that have made significant modifications to existing laws include the following:

California

Through several executive orders, CARB is now charged with implementing a 33-percent RPS by 2020 as part of the carbon-reduction guidelines originally laid out in AB 32 [*17*] (see previous section). This standard is a significant increase from the previous 20-percent version administered by the California Energy Commission and Public Utility Commission. More information can be found in the subsequent section on airborne emission regulations.

Table 2. Renewable portfolio standards in the 30 States with current mandates

State	Program mandate
AZ	Arizona Corporate Commission Decision No. 69127 requires 15 percent of electricity 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 provided to solar generation and systems manufactured in-State.
CA	As a follow-up from AB 32 and Executive Order S-21-09, the CARB now administers a new RPS that requires 33-percent renewable generation by 2020.
CO	Enacted in March 2010, House Bill (HB) 1001 strengthens the State's existing RPS program by requiring 20 percent of electricity generated by investor-owned utilities in 2015 to be renewable, increasing to 30 percent by 2020. There is also a distributed generation requirement. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 mandates a 27-percent renewable sales requirement by 2020, including a 4-percent requirement for sales from higher efficiency or combined heat and power systems. Of the overall total, 3 percent may be met by waste-to-energy and conventional biomass facilities.
DE	Senate Substitute 1 amended Senate Bill 119 to extend the increasing RPS targets to 2025; 25 percent of generation is now required to come from renewable sources in 2025. There is a separate requirement for solar generation (3.5 percent of the total in 2025) and penalty payments for compliance failure. Offshore wind receives 3.5 times the standard credit amount.
HI	HB 1464 sets the renewable mandate at 40 percent by 2030. All existing renewable facilities are eligible to meet 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, with escalating annual targets. In addtion, 75 percent of the required sales must be generated from wind and 6 percent from solar. The plan also includes a cap on incremental costs resulting from the penetration of renewable generation. In 2009, the rule was modified to cover sales outside a utility's home territory.
IA	In 1983, an RPS mandating 105 megawatts of renewable energy capacity was adopted.
KS	In 2009, HB 2369 established a requirement that 20 percent of installed capacity must use renewable resources by 2020.
ME	In 2007, Public Law 403 was added to the State's RPS requirements. The law requires a 10-percent increase from the 2006 level of renewable capacity by 2017, and that level must be maintained in subsequent years. The years leading up to 2017 also have new capacity milestones. Generation from eligible community-owned facilities receives a 10-percent credit premium.
MD	In April 2008, HB 375 revised the preceding RPS to include a target of 20 percent renewable generation by 2022, including a 2-percent solar target. HB 375 also raised penalty payments for "Tier 1" compliance shortfalls to 4 cents per kilowatthour. Senate Bill 277, while preserving 2022 target of 2 percent solar, made the interim solar requirements and penalty payments slightly less stringent.
MA	The State RPS has a goal of a 15-percent renewable share of total sales by 2020 and includes necessary payments for compliance shortfalls. Eligible biomass is restricted to low-carbon life cycle emission sources. A Solar Carve-Out Program was also added, which seeks to establish 400 megawatts (DC) of solar generating capacity.
MI	Public Act 295 established an RPS that will require 10 percent renewable generation by 2015. Bonus credits are given to solar energy.
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 other suppliers. The 30-percent requirement for Xcel consists of 24 percent that must be from wind, 1 percent that can be from wind or solar, and 5 percent that can be from other resources.
MO	In November 2008, Missouri voters approved Proposition C, which mandates a 2-percent renewable energy requirement in 2011, increasing incrementally to 15 percent of generation in 2021. Bonus credits are given to renewable generation within the State.
MT	HB 681, approved in April 2008, expanded the State 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 a renewable energy credit market.
NV	The State has an escalating renewable target, established in 1997 and revised in 2005 and again in 2009 by Senate Bill 358. The most recent requirement mandates a 25-percent renewable generation share of sales by 2025. Up to one-fourth of the 25-percent share may be met through efficiency measures. There is also a minimum requirement for PV systems, which receive bonus credits.
NH	HB 873, passed in May 2007, legislated that 23.8 percent of electricity sales must be met by renewables in 2025. Compliance penalties vary by generation type.
NJ	In 2006, the State RPS was revised to increase renewable energy targets. Renewable generation is to provide 22.5 percent of sales by 2021, with interim targets. AB 3520 requires 5,316 gigawatthours of solar generation by 2026. SB 2036 has a specific offshore wind target of 1,100 megawatts of capacity.

(continued on page 9)

Table 2. Renewable portfolio standards in the 30 States with current mandates (continued)

State	Program mandate
NM	Senate Bill 418, passed in March 2007, directs investor-owned utilities to derive 20 percent of their sales from renewable generation by 2020. The renewable portfolio must consist of diversified technologies, with wind and solar each accounting for 20 percent of the target. There is a separate standard of 10 percent by 2020 for cooperatives.
NY	The Public Service Commission issued updated RPS rules in January of 2010, expanding the program to a 29-percent requirement by 2015. There is also a separate end-use standard. The program is administered and funded by the State.
NC	In 2007, 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 cooperatives and municipals. Through 2018, 25 percent of the target may be met through efficiency standards, increasing to 40 percent in later years.
OH	Senate Bill 221, passed in May 2008, requires 25 percent of electricity sales to be produced from alternative energy resources by 2025, including low-carbon and renewable technologies. One-half of the target must come from renewable sources. Municipals and cooperatives are exempt.
OR	Senate Bill 838, signed into law in June 2007, required renewable targets of 25 percent by 2025 for large utilities and 5 to 10 percent by 2025 for smaller utilities. Renewable electricity on line after 1995 is considered eligible.
PA	The Alternative Energy Portfolio Standard, signed into law in November 2004, has an 18-percent requirement by 2020. Most of the qualifying generation must be renewable, but there is also a provision that allows waste coal resources to receive credits.
RI	The Renewable Energy Standard was signed into law in 2004. The program requires that 16 percent of total sales be renewable by 2019. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must pay an alternative compliance penalty. State utilities must also procure 90 megawatts of new renewable capacity, including 3 megawatts of solar, by 2014.
TX	Senate Bill 20, passed in August 2005, strengthened the State RPS by mandating 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.
WA	In November 2006, Washington 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. Generation from any facility that came on line after 1999 is eligible.
WV	HB 103, passed in June 2009, established a requirement that 25 percent of sales must come from alternative energy resources by 2025. Alternative energy was defined to include various renewables, along with several different fossil energy technologies.
WI	Senate Bill 459, passed in March 2006, strengthened the State RPS with a requirement that, by 2015, each utility must generate 10 percent of its electricity from renewable resources, up from the previous requirement of 2.2 percent in 2011. The renewable share of total generation must be at least 6 percentage points above the average renewable share from 2001 to 2003.

Colorado

The State strengthened its existing RPS by requiring that 30 percent of sales be generated from renewable sources by 2020 [*18*]. Investor-owned qualifying utilities must also provide appropriate incentives so that renewable distributed generation makes up 3 percent of total sales [*19*].

Delaware

Although Delaware's RPS structure remains largely unchanged, Senate Substitute No. 1 for Senate Bill 119 extended the targets by an additional 5 years, to 2025. In 2025, 25 percent of sales must be from renewable sources. The solar provisions also are extended, and 3.5 percent of sales must come from electricity generated by solar photovoltaic cells [*20*].

Massachusetts

After temporarily suspending biomass eligibility on the basis of a study of life-cycle carbon emissions from biomass feedstocks, the Commonwealth changed its RPS to clarify and restrict the sources of biomass that will be eligible to meet its standard [*21*]. Although the changes attempt to prevent excess CO_2 emissions from biomass generation, there still is much uncertainty about the true carbon footprints of various biomass feedstocks, as well as the future of eligible materials. Also, a Solar Carve-Out Program was added to the State's RPS, requiring additional installations to bring total installed photovoltaic capacity to 400 megawatts [*22*].

New Jersey

The State enacted two pieces of legislation affecting its RPS. AB 3520 [*23*] changed and extended its solar target to require a fixed amount of renewable generation rather than a percentage of renewable capacity: 5,316 gigawatthours of generation will be required in 2026. Senate Bill 2036 [*24*] established an offshore wind target of 1,100 megawatts. However, considerable regulatory uncertainties remain to be resolved.

New York

In January 2010, the New York Public Service Commission issued new orders expanding the State-funded RPS program [*25*]. The main-tier program seeks to establish 29 percent renewable generation by 2015, including existing capacity that already meets more than two-thirds of the new mandate. The program will be funded through a limited State fund of $2 billion. Moreover, a supplemental customer-sited tier will increase installations of end-use solar, wind, and anaerobic digester capacity.

3. Updates on liquid fuels taxes and tax credits

Excise taxes on highway fuels

The handling of Federal highway fuel taxes in *AEO2011* is unchanged from *AEO2010*. Gasoline is taxed at 18.4 cents per gallon, diesel fuel is taxed at 24.4 cents per gallon, and jet fuel for use in commercial aviation is taxed at 4.4 cents per gallon, as specified in the 2005 Transportation Equity Act [*26*]. The taxes are not adjusted for inflation and remain at the same nominal values through 2035. Although the highway fuel taxes expire in 2011 under current law, their assumed extension is consistent with Federal budgeting procedures which dictate that excise taxes dedicated to a trust fund, if expiring, are assumed to be extended at current rates [*27*].

Federal fuel taxes are the primary source of funding for the Highway Trust Fund, which is used to maintain the interstate highway system as well as mass transit systems. Recent vehicle efficiency improvements and lower consumer demand have led to shortfalls in the Trust Fund's revenues over the past few years.

State fuel taxes are calculated and allocated by Census Region, based on a volume-weighted average of diesel, gasoline, and jet fuel sales. State fuel taxes in *AEO2011* are updated to their most recent values (as of June 2010) [*28*].

Tax credits and tariffs for biofuels

In December 2010, the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 became law [*29*]. The law includes an extension through 2011 of the $0.45 per gallon Volumetric Ethanol Excise Tax Credit, which was previously set to expire at the end of 2010 as specified in the Food, Conservation, and Energy Act of 2008 [*30*]. The cellulosic biofuels [*31*] production tax credit, also specified in the Food, Conservation, and Energy Act of 2008, remains set to expire in January 2013. The credit is $1.01 per gallon, but if applied to cellulosic ethanol it is reduced by the amount of the excise tax credit available to ethanol blends (assumed to be $0.45 per gallon through 2011).

In addition, the law includes a retroactive extension (through 2011) of the $1.00 per gallon biodiesel excise tax credit, which had been set to expire in December 2009. The credit applies to biodiesel made from recycled vegetable oils or animals fats and to renewable diesel. The tax package also includes an extension through 2011 of the $0.54 per gallon tariff on imported ethanol, which had been set to expire at the end of 2010. Both extensions are included in the *AEO2011* Reference case.

4. California Low Carbon Fuel Standard

California's LCFS will be administered by CARB [*32*]. In general, the regulated parties under the LCFS legislation are fuel producers or importers who sell motor gasoline or diesel fuel in California. The legislation is designed to reduce the carbon intensity of motor gasoline and diesel fuels sold in California by 10 percent between 2012 and 2020 through the increased sale of alternative low-carbon fuels. Each low-carbon fuel has its own carbon intensity, based on life-cycle analyses conducted under the guidance of CARB for a number of approved fuel pathways. The carbon intensities are calculated on an energy-equivalent basis, measured in grams of CO_2-equivalent emissions per megajoule.

The *AEO2011* Reference case incorporates the California LCFS, using CARB's mandated carbon intensities and approved fuel pathways [*33*]. Although NEMS is not a State-level model, CARB-mandated gasoline and diesel are modeled separately from other gasoline and diesel sold in the Pacific Census Division 9 (which also includes Washington, Oregon, Alaska, and Hawaii). In cases where data for California are not available, information from Census Division 9 is used as a proxy. Because CARB has not yet officially quantified penalties for LCFS noncompliance, the Reference case incorporates a monetary penalty estimated to encourage compliance, based on relevant provisions in the California Health and Safety Code [*34*].

Carbon intensities provide a measure of complete well-to-wheels or life-cycle emissions of each fuel pathway, including indirect land-use change (ILUC) penalties where applicable [*35*]. The ILUC penalty is used to account for potential changes in land use as the production of biofuels increases. Because the science behind the ILUC penalty is relatively new and still controversial, potential revisions and updates are expected as the LCFS evolves. For example, *AEO2011* assumes that corn ethanol is treated as having 20 percent lower GHG emissions than gasoline.

The fuel pathways used in EIA's analysis include existing technologies—such as Midwestern corn ethanol, imported sugarcane ethanol, and soy-based biodiesel—as well as a number of "next-generation" technologies, including cellulosic ethanol and biomass-to-liquid (BTL) fuels. Other provisions in the LCFS legislation also allow nonregulated parties, such as electricity and hydrogen producers, to contribute. With the exception of efforts to streamline the development and installation of home charging stations, there does not appear to be any significant effort at present to promote plug-in vehicles or to enhance public charging stations and other infrastructure.

The LCFS results in the transportation into California of additional renewable fuels produced in other regions or countries. To meet the LCFS gasoline mandate, consumption of motor fuel containing up to 85 percent ethanol (E85) in Census Division 9 increases to more than 2.4 billion gallons in 2020, allowing a larger share of ethanol consumption to contribute to lowering the gasoline carbon intensity. For the diesel mandate, every gallon of CARB diesel contains 20 percent biodiesel (the maximum generally recommended by original equipment manufacturers) by 2017.

The largest source of compliant fuel is sugarcane ethanol, imported primarily from Brazil, and biodiesel. Imported sugarcane ethanol has a much lower carbon intensity than domestically produced corn ethanol, primarily as a result of production methods that use fewer fossil fuel inputs. It is assumed that, in the last years of the LCFS program, such next-generation technologies as cellulosic ethanol and BTL will begin to reach the market and make a larger contribution toward meeting the LCFS. The same can be said for LCFS-compliant diesel, which requires the blending of more costly biomass-based diesel fuels.

In the later years of the LCFS, gasoline blends with ethanol content greater than E10, such as E85, will be needed for the gasoline mandate to be met. Even if ethanol with the lowest carbon footprint is used in E10 blends, it will not lower the carbon intensity of gasoline sufficiently for the LCFS to be met. Consequently, the amount of E85 available in California is a key factor in determining the mix of fuels with low carbon pathways, such as sugarcane ethanol and cellulosic ethanol, that can be used in meeting the gasoline mandate. For the diesel mandate, a blend of 20 percent biodiesel is already common today, and with the addition of such next-generation technologies as BTL fuels that are potentially "drop-in" fuels usable in existing distribution channels, the mandate can be met without new infrastructure.

5. Representing impacts of the U.S. EPA's interim permit review guidelines for surface coal mining operations

In April 2010, the EPA issued a set of new guidelines to several of its regional offices for monitoring the compliance of surface coal mining operations in Appalachia with the provisions of the Clean Water Act (CWA), the National Environmental Policy Act, and the environmental justice Executive Order (E.O. 12898) [*36*]. The stated purpose of the guidance was to explain more fully the approach that the EPA will be following in permit reviews and to provide additional assurance that its regional offices use clear, consistent, and science-based standards in reviewing the permits. Although the new guidelines went into effect immediately, they were subjected to review both by the public and by the EPA's Science Advisory Board, with a set of final guidelines to be issued in the spring of 2011.

Issuance of the new EPA guidelines is related primarily to the ongoing controversy over use of the mountaintop removal method at a number of surface coal mining operations in Central Appalachia—primarily in southern West Virginia and eastern Kentucky. Although the guidelines propose a more rigorous review for all new surface coal mines in Appalachia, the EPA indicates that the practice of valley fills, primarily associated with the mountaintop removal method, is the aspect of Appalachian coal mining that will be most scrutinized. In particular, the EPA points to new scientific evidence that dissolved solids in drainage from existing valley fills in Central Appalachia are adversely affecting downstream aquatic systems.

Although the proposed use of valley fills at mining sites will not necessarily preclude the issuance of permits for surface mines under Sections 402 and 404 of the CWA, the EPA guidelines recommend that all practicable efforts be made to minimize their use. Section 402 of the CWA pertains to the issuance of National Pollution Discharge Elimination System permits. Section 404 relates to the issuance of permits for the discharge of dredge or fill material into the waters of the United States, including wetlands. Issuance of Section 404 permits comes under the authority of the U.S. Army Corps of Engineers but is subject to EPA oversight.

Two recent actions by the EPA related to its review of Section 404 permits for proposed mountaintop mining operations in West Virginia indicate the Agency's heightened concern with regard to valley fills. In January 2010, the EPA announced its approval for the issuance of a Section 404 permit for Patriot Coal's proposed Hobet 45 mountaintop mining operation. The EPA indicated that the company was able to eliminate the need for any valley fills and, as a result, reduce the estimated adverse downstream impact by 50 percent.

In contrast, in January 2011, the EPA issued a final determination effectively denying a Section 404 permit for Arch Coal Company's Spruce No. 1 mountaintop mining operation, which would have resulted in the burial of 6.6 miles of headwater streams under the spoil of four separate valley fills [*37*]. Although a Section 404 permit for the mine was approved by the U.S. Army Corps of Engineers in January 2007, the EPA indicated that additional information had been obtained since then about its earlier concerns related to the project. The EPA indicated that its action to deny four of the six valley fills proposed for the Spruce No. 1 mine would protect not only wildlife in the parts of streams directly affected by the proposed mining operation but also the aquatic wildlife communities downstream from the project site. As was the case with the Hobet 45 mine, the EPA requested that Arch Coal submit possible corrective actions to the Spruce No. 1 mine plan to mitigate environmental impacts. Primarily on the basis of economic considerations, Arch Coal declined to offer additional changes to the proposed plan for the mine.

In *AEO2011*, the impact of the EPA's April 2010 guidelines for surface coal mining operations is represented by downward adjustments to the coal mining productivity assumptions for Central Appalachian surface mines (Figure 5), resulting in slightly higher estimated production costs for the region and mine type. The assumed productivity levels for Central Appalachian surface mines are roughly 15 to 20 percent lower than those that would have been used for a case without the EPA's new permit review guidelines. The revised productivity levels are based on the assumption that large surface mining operations will decline gradually toward the productivity levels for smaller surface mines in the region as a result of the more restrictive guidelines for overburden management at large mountaintop mining operations. No adjustments were made to the productivity assumptions for other Appalachian supply regions in response to the new EPA permit review guidelines, because few if any surface mining operations in other regions employ the mountaintop removal method.

6. EPA approval of E15 waiver

In October 2010, the EPA approved a waiver for the use of motor gasoline blends containing up to 15 percent ethanol (E15) in MY 2007 and newer vehicles—an increase over the 10 percent ethanol limit (E10) set in 1978 [*38*]. In January 2011, the EPA extended the waiver to vehicles manufactured in years 2001-2006 [*39*]. That change was incorporated in the modeling for *AEO2011*.

Although the EPA's January 2011 ruling will allow the use of E15 blend in approximately 60 percent of the current vehicle fleet, there are issues that may limit its widespread adoption:

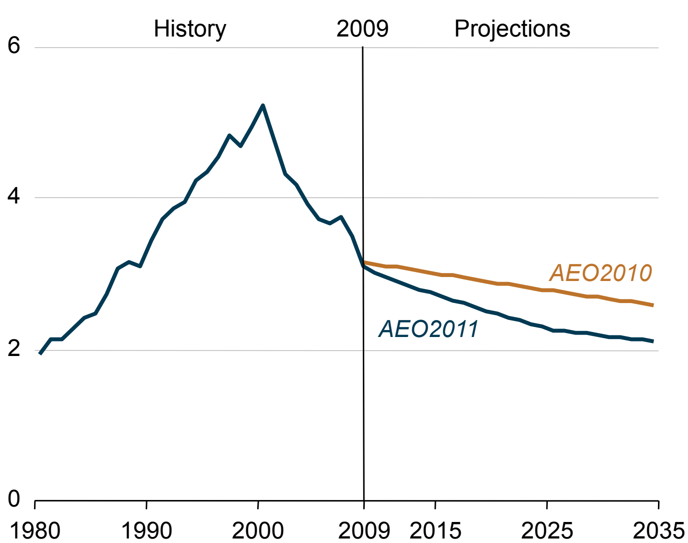
- Retailers must justify the significant costs of upgrading pumps and storage tanks while weighing the prospects for increased liability and uncertain consumer acceptance. Because the majority of U.S. service stations are "pay at the pump," there is concern about potential liability for engine damage resulting from consumer misfueling in motor vehicles not approved for E15 use, as well as in small engine applications. In addition, much of the retail outlet infrastructure for blends containing more than 10 percent ethanol lacks Underwriter Laboratory certification, creating concerns about the costs of any equipment malfunctions.
- In addition to liability issues, infrastructure costs in the form of blender pumps and additional storage tanks could deter retailers from choosing to offer a higher ethanol blend. Most service stations use two storage tanks, one containing a regular E10 blend and the other a premium blend. Adding a higher E15 blend could force service station owners either to add an additional tank and modified pumps or to stop offering E10 gasoline blends or profitable premium-grade fuels.
- Retailers may be unwilling to commit to E15 in the short term, because consumer acceptance is uncertain. Warning labels about possible engine damage could dampen consumer demand, despite educational efforts.

To examine the potential impacts of high and low penetration of E15 fuel in retail markets, two sensitivity cases were compared with the *AEO2011* Reference case. In the High E15 case, ethanol blending above 10 percent occurs earlier in the projection and increases more rapidly than in the Reference case. The High E15 case also assumes that any State which currently has laws or regulations prohibiting ethanol blends above 10 percent or oxygenate content in excess of 3.5 percent will remove those restrictions by 2015. As a result, ethanol use for gasoline blending increases to 18.1 billion gallons in 2015, compared with 15.8 billion gallons in the Reference case, and to 21.2 billion gallons in 2020, compared with 17.8 billion gallons in the Reference case.

Most of the additional ethanol needed to meet increased demand in the High E15 case is corn ethanol produced domestically,with cellulosic ethanol and imported ethanol beginning to make larger contributions after 2020. Ethanol blending increases to 14.5 percent of the motor gasoline pool in 2020—compared with 12.4 percent in the Reference case—and to 14.8 percent in 2035.

In the Low E15 case, the results are similar to those in the Reference case, and many of the infrastructure and regulatory barriers reflected in the Reference case govern the dynamics in the Low E15 case. Ethanol blending in the Low E15 case never rises above 11.5 percent of the motor gasoline pool and is 11.4 percent in 2035. Total ethanol supply in 2020 is almost 2 billion gallons less than in the Reference case, but with E85 consumption increasing at a faster rate after 2020, it reaches levels similar to those in the Reference case. In 2035, E85 use in the Low E15 case totals about 12 billion gallons, or 2 billion gallons more than in the Reference case. In both cases, total ethanol supply in 2035 is approximately 28 billion gallons.

Figure 5. Surface coal mining productivity in Central Appalachia, 1980-2035 (short tons per miner per hour)



Rapid increases in E85 consumption in the Reference, High E15, and Low E15 cases indicate the importance for ethanol producers of E85 availability after the motor gasoline blending pool has been saturated, even with an increase to a 15-percent limit for ethanol blends. Growth in E85 consumption is affected by the level of demand for ethanol in gasoline blends, particularly in the High E15 case. Because most of the growth in ethanol use for blending occurs in the near term in the High E15 case, growth in E85 use begins later (in 2024) than in the Reference and Low E15 cases (2016).

While more ethanol blended into gasoline reduces its energy content and often the miles per gallon of the vehicle using it, *AEO2011* assumes that only E85 will be priced at a discount for its lower energy content. E10 and E15 are assumed to compete for demand on price alone. Nevertheless, the ability to switch out volumes of E85 with E15 can be expected to affect gasoline pricing. When E15 penetration is high, gasoline prices are lower, because more of the less expensive blend stock (ethanol) is used. In addition, there is less need to encourage E85 demand by subsidizing infrastructure cost and E85 prices with higher gasoline prices. With low penetration the opposite is true: gasoline prices are higher, because more cost recovery is needed for E85 marketing and infrastructure, and less ethanol is available for blending.

7. Mandates for low-sulfur heating oil in the Northeast

During 2010, Connecticut [*40*], Maine [*41*], New Jersey [*42*], and New York [*43*] passed legislation to reduce the maximum allowable sulfur content of heating oil sold in their markets. Pennsylvania proposed a similar law, but it was not approved. Connecticut and Maine will begin regulating maximum sulfur content by mid-2011, with Connecticut reducing the maximum to 50 parts per million (ppm) and Maine reducing the maximum to 15 ppm. The Connecticut law includes a second reduction to 15 ppm in 2014. Connecticut and Maine also put in place requirements for 2-percent biodiesel content in heating oil, starting in mid-2011. The New Jersey legislation reduces the maximum sulfur content to 500 ppm in 2014 and includes a second reduction to 15 ppm in 2016. New York reduced the maximum sulfur content to 15 ppm starting in 2012. The new laws in each of the four States are included in *AEO2011*.

On February 1, 2011, the U.S. Department of Energy also announced plans to convert the inventory of almost 2 million barrels in the Northeast Heating Oil Reserve to cleaner burning ultra-low-sulfur distillate. The first phase of this transition was the sale of the 2 million barrels of heating oil in February 2011. The receipts from those sales will be used to purchase ultra-low-sulfur heating oil to refill the reserve before the 2011-2012 heating oil season begins.

Endnotes for legislation and regulations

Links current as of April 2011

1. Connecticut State Senate, Bill 382, "An Act Requiring Biodiesel Blended Heating Oil and Lowering the Sulfur Content of Heating Oil Sold in the State," website www.cga.ct.gov/2010/TOB/S/2010SB-00382-R00-SB.htm.
2. Maine State Legislature, "An Act To Establish Biofuel and Ultra-low Sulfur Requirements for Number 2 Home Heating Oil," website www.mainelegislature.org/legis/bills/bills_124th/billtexts/HP116001.asp.
3. New Jersey State Department of Environmental Protection, Amendment N.J.A.C. 7:27-9.2, "Sulfur in Fuels," website www.nj.gov/dep/rules/adoptions/adopt_100920a.pdf.
4. New York State Senate, Bill S1145C, "S1145C-2009: Requires a Reduction in Sulfur Emissions for All Heating Oil Used in Non-Attainment Areas," website http://open.nysenate.gov/legislation/bill/S1145C-2009#.
5. California Air Resources Board, LCFS Final Regulation Order, "Low Carbon Fuel Standard," website www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf.
6. 111th Congress, Public Law 312, "Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010," Sections 701, 704, and 708, website www.gpo.gov/fdsys/pkg/PLAW-111publ312/html/PLAW-111publ312.htm.
7. U.S. Environmental Protection Agency, "E15 (A Blend of Gasoline and Ethanol)," website www.epa.gov/otaq/regs/fuels/additive/e15.
8. U.S. Environmental Protection Agency, "April 1, 2010 Memorandum: Improving EPA Review of Appalachian Surface Coal Mining Operations Under the Clean Water Act, National Environmental Policy Act, and the Environmental Justice Executive Order," website http://water.epa.gov/lawsregs/guidance/wetlands/mining.cfm#memo20100401.
9. Regional Greenhouse Gas Initiative, "Fact Sheet: The Regional Greenhouse Gas Initiative (RGGI)," website www.rggi.org/docs/RGGI_Fact_Sheet.pdf.
10. Regional Greenhouse Gas Initiative, "Auction Results," website www.rggi.org/market/co2_auctions/results.
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Issues in focus

Introduction

The "Issues in focus" section of the *Annual Energy Outlook (AEO)* provides an in-depth discussion on topics of special interest, including significant changes in assumptions and recent developments in technologies for energy production and consumption. Detailed quantitative results are available in Appendix D. The first topic updates a discussion included in the *Annual Energy Outlook 2010 (AEO2010)* that compared the results of two cases with different assumptions about the future course of existing energy policies. One case assumes the elimination of sunset provisions in existing energy policies; that is, the policies are assumed not to sunset as they would under current law. The other case assumes the extension of a selected group of existing policies—corporate average fuel economy (CAFE) standards, appliance standards, and production tax credits (PTCs)—in addition to the elimination of sunset provisions.

Other topics include (2) a discussion of projected trends in world oil supply and prices based on assumed changes in demand from countries outside the Organization for Economic Cooperation and Development (OECD) or in the availability of oil supply from the Organization of the Petroleum Exporting Countries (OPEC); (3) an examination of the potential impacts of proposed revisions to CAFE standards for light-duty vehicles (LDVs); (4) potential impacts of proposed CAFE standards for heavy-duty trucks; (5) potential impacts of a series of updates to efficiency standards for residential and commercial appliances, alone or in combination with revised building codes; (6) an analysis of potential impacts on natural gas and crude oil production of expanded drilling in U.S. offshore fields; (7) prospects for shale gas; (8) the impacts of cost uncertainty on the construction of new electric power plants; (9) the economics of carbon capture and storage; and (10) the impacts of proposed U.S. Environmental Protection Agency (EPA) regulations in the electric power sector.

The topics explored in this section represent current and emerging issues in energy markets; but many of the topics discussed in *AEO*s published in recent years also remain relevant today. Table 3 provides a list of titles from the 2010, 2009, and 2008 *AEO*s that are likely to be of interest to today's readers—excluding topics that are updated in *AEO2011*. The articles listed in Table 3 can be found on the U.S. Energy Information Administration's (EIA's) website at www.eia.gov/analysis/reports.cfm?t=128.

1. No Sunset and Extended Policies cases

Background

The *Annual Energy Outlook 2011 (AEO2011)* Reference case is best described as a "current laws and regulations" case, because it generally assumes that existing laws and current regulations will remain unchanged throughout the projection period, unless the legislation establishing them sets a sunset date or specifies how they will change. The Reference case often serves as a starting point for the analysis of proposed legislative or regulatory changes. While the definition of the Reference case is relatively straightforward, there may be considerable interest in a variety of alternative cases that reflect the updating or extension of current laws and regulations. In that regard, areas of particular interest include:

- Laws or regulations that have a history of being extended beyond their legislated sunset dates. Examples include the various tax credits for renewable fuels and technologies, which have been extended with or without modifications several times since their initial implementation.
- Laws or regulations that call for the periodic updating of initial specifications. Examples include appliance efficiency standards issued by the U.S. Department of Energy (DOE) and CAFE and greenhouse gas (GHG) emissions standards for vehicles issued by National Highway Traffic Safety Administration (NHTSA) and the EPA.
- Laws or regulations that allow or require the appropriate regulatory agency to issue new or revised regulations under certain conditions. Examples include the numerous provisions of the Clean Air Act (CAA) that require the EPA to issue or revise regulations if it finds that an environmental quality target is not being met.

Table 3. Key analyses of interest from *Issues in focus* in recent *AEO*s

AEO2010	*AEO2009*	*AEO2008*
Energy intensity trends in *AEO2010*	Economics of plug-in hybrid electric vehicles	Impacts of uncertainty in energy project costs
Natural gas as a fuel for heavy trucks: issues and incentives	Impact of limitations on access to oil and natural gas resources in the Federal Outer Continental Shelf	Limited Electricity Generation Supply and Limited Natural Gas Supply cases
Factors affecting the relationship between crude oil and natural gas prices	Expectations for oil shale production	Trends in heating and cooling degree-days: Implications for energy demand
U.S. nuclear power plants: continued life or replacement after 60?	Bringing Alaska North Slope natural gas to market	Liquefied natural gas: Global challenges
Accounting for carbon dioxide emissions from biomass energy combustion	Tax credits and renewable generation	
	Greenhouse gas concerns and power sector planning	

To provide some insight into the sensitivity of results to different characterizations of baseline policies, two alternative cases are discussed in this section. No attempt is made to cover the full range of possible uncertainties in these areas, and readers should not view the cases discussed as EIA projections of how laws or regulations might or should be changed.

Analysis cases

The two cases prepared—the No Sunset case and Extended Policies case—incorporate all the assumptions from the *AEO2011* Reference case, except as identified below. Changes from the Reference case assumptions in these cases include the following.

No Sunset case

- Extension of tax credits for renewable energy sources in the utility, industrial, and buildings sectors and for energy-efficient equipment in the buildings sector, including:
  - The PTC of 2.1 cents per kilowatthour or the 30-percent investment tax credit (ITC) available for wind, geothermal, biomass, hydroelectric, and landfill gas resources, currently set to expire at the end of 2012 for wind and 2013 for the other eligible resources, are assumed to be extended indefinitely.
  - For solar power investment, a 30-percent ITC that is scheduled to revert to a 10-percent credit in 2016 is, instead, assumed to be extended indefinitely at 30 percent.
  - In the buildings sector, tax credits for the purchase of energy-efficient equipment, including PV in new houses, are assumed to be extended indefinitely, as opposed to ending in 2010 or 2016 as prescribed by current law. The business ITCs for commercial-sector generation technologies and geothermal heat pumps are assumed to be extended indefinitely, as opposed to expiring in 2016; and the business ITC for solar systems is assumed to remain at 30 percent instead of reverting to 10 percent.
  - In the industrial sector, the ITC for combined heat and power (CHP) that ends in 2016 in the *AEO2011* Reference case is assumed to be extended through 2035.
- Extension through 2035 of the $0.45 per gallon blender's tax credit for ethanol (set to expire at the end of 2011).
- Extension through 2035 of the $1.00 per gallon biodiesel excise tax credit (set to expire at the end of 2011).
- Extension through 2035 of the $0.54 per gallon tariff on imported ethanol (set to expire at the end of 2011).
- Extension through 2035 of the PTC for cellulosic biofuels of up to $1.01 per gallon (set to expire at the end of 2012).

Extended Policies case

With the exception of the blender's and other biofuel tax credits, the Extended Policies case adopts the same assumptions as in the No Sunset case, plus the following:

- Federal equipment efficiency standards are updated at particular intervals consistent with the provisions in the existing law, with the levels based on ENERGY STAR specifications, or Federal Energy Management Program (FEMP) purchasing guidelines for Federal agencies. Standards are also introduced for products that currently are not subject to Federal efficiency standards.
- Updated Federal residential and commercial building energy codes reach 30-percent improvement in 2020 relative to the 2006 International Energy Conservation Code (IECC) in the residential sector and the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Building Energy Code 90.1-2004 in the commercial sector. Two subsequent rounds in 2023 and 2026 each add an assumed 5-percent incremental improvement to building energy codes.

  The equipment standards and building codes assumed for the Extended Policies case are meant to illustrate the potential effects of these polices on energy consumption for buildings. No cost-benefit analysis or evaluation of impacts on consumer welfare was completed in developing the assumptions. Likewise, no technical feasibility analysis was conducted, although standards were not allowed to exceed "maximum technologically feasible" levels described in DOE's technical support documents.
- The Extended Policies case modifies the Reference case by assuming a 3-percent annual increase in fuel economy standards for new LDVs from model year (MY) 2017 through MY 2025, with subsequent CAFE standards held constant. CAFE standards for LDVs increase from 34.1 miles per gallon (mpg) in MY 2016 to 46.0 mpg in MY 2025.

  The *AEO2011* Reference case and Extended Policies case include both the attribute-based CAFE standards for LDVs for MY 2011 and the joint attribute-based CAFE and vehicle GHG emissions standards for MY 2012 to MY 2016. However, the Reference case assumes that LDV CAFE standards increase to 35 miles per gallon by MY 2020, as called for in the Energy Independence and Security Act of 2007 (EISA2007). CAFE standards are then held constant in subsequent model years, although the fuel economy of new LDVs continues to rise modestly over time.
- The extensions of the blender's and all biofuels excise tax credits and import tariffs through 2035 adopted in the No Sunset case are not included in the Extended Policies case. The renewable fuels standard (RFS) enacted in EISA2007 is an alternative instrument for stimulating demand for biofuels. It already is represented in the *AEO2010* Reference case, and it tends to be the binding driver on biofuels rather than the tax credits.

- In the industrial sector, CHP tax credits are extended to cover all system sizes rather than applying only to systems under 50 megawatts, and the maximum credit (cap) is increased from $15,000 to $25,000 per system. These extensions are consistent with previously proposed or pending legislation.

Analysis results

The changes made to Reference case assumptions in the No Sunset and Extended Policies cases generally lead to lower estimates for overall energy consumption, increased use of renewable fuels, particularly for electricity generation, and reduced energy-related carbon dioxide (CO_2) emissions. Because the Extended Policies case includes most of the assumptions in the No Sunset case but adds others, the impacts in the Extended Policies case tend to be greater than those in the No Sunset case. Although these cases show lower energy prices—because the tax credits and end-use efficiency standards lead to lower energy demand and reduce the cost of renewable fuels—consumers spend more on appliances that are more efficient in order to comply with the tighter appliance standards, and the Government receives lower tax revenues as consumers and businesses take advantage of the tax credits.

Energy consumption

Total energy consumption in the No Sunset case is close to the level in the Reference case (Figure 6). Improvements in energy efficiency lead to slightly reduced consumption in this case, despite somewhat lower energy prices.

Total energy consumption in the Extended Policies case, which assumes the issuance of more stringent efficiency standards for end-use equipment and LDVs in the future, is lower than in the Reference case. In 2035, total energy consumption in the Extended Policies case is nearly 7 percent below the projection in the Reference case. As an example of individual end uses, the assumed future standard for residential electric water heating, which requires installation of heat pumps starting in 2021, has the potential to reduce their electricity use by 50 percent from the Reference case level in 2035. Overall, delivered energy use in the buildings sector in 2035 is 8.5 percent lower in the Extended Policies case than in the Reference case.

Transportation energy consumption

The Extended Policies case modifies the Reference case by assuming a 3-percent annual increase in the stringency of CAFE standards for MY 2017 to MY 2025, with subsequent standards held constant. The LDV CAFE standards in the Extended Policies case increase from 34.1 mpg in 2016 to 46.0 mpg in 2025, as compared with 35.6 mpg in the Reference case. Sales of unconventional vehicles (including those that use diesel, alternative fuels, and/or hybrid electric systems) play a substantial role in meeting the higher fuel economy standards, growing to around 70 percent of new LDV sales in 2035, compared with about 40 percent in the Reference case.

As a result of more stringent CAFE standards, LDV energy consumption declines in the Extended Policies case, from 16.1 quadrillion British thermal units (Btu) (8.6 million barrels per day) in 2009 to 14.8 quadrillion Btu (8.3 million barrels per day) in 2025 and 14.4 quadrillion Btu (8.1 million barrels per day) in 2035—representing a 10-percent reduction from the Reference case in 2025 and a 19-percent reduction in 2035 (Figure 7). Liquid fuel consumption in the transportation sector continues to grow in the Extended Policies case, from 13.6 million barrels per day in 2009 to 14.1 million in 2025 and 14.2 million in 2035, but at a slower rate than in the Reference case. Cumulative consumption of liquid fuel for transportation between 2017 and 2035 drops by 6.5 billion barrels, or 6 percent, in comparison with the Reference case.

Figure 6. Total energy consumption in three cases, 2005-2035 (quadrillion Btu)

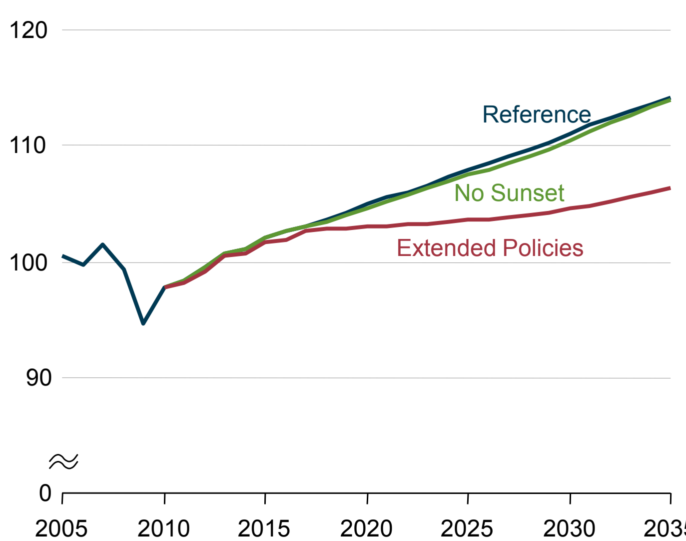
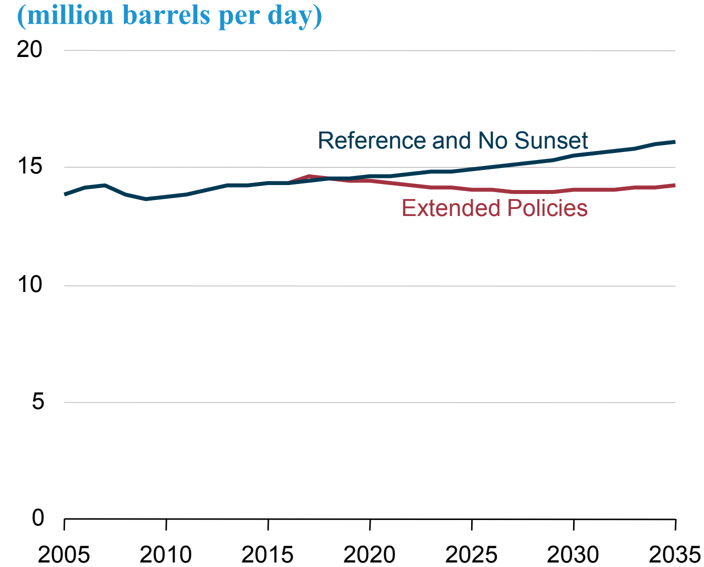


Figure 7. Total liquid fuels consumption for transportation in three cases, 2005-2035 (million barrels per day)



Renewable electricity generation

The extension of tax credits for renewables through 2035 would, over the long run, lead to more rapid growth in renewable generation than projected in the Reference case. When the renewable tax credits are extended without extending energy efficiency standards, as is assumed in the No Sunset case, there is a significant increase in renewable generation in 2035 relative to the Reference case projection (Figure 8). Extending both renewable tax credits and energy efficiency standards results in more modest growth in renewable generation, because renewable generation in the near term is a significant source of new generation to meet load growth, and enhanced energy efficiency standards tend to reduce overall electricity consumption and the need for new generation resources.

In the Reference case, growth in renewable generation accounts for 26 percent of total generation growth from 2009 to 2035. In the No Sunset and Extended Policies cases, growth in renewable generation accounts for 36 to 38 percent of total generation growth. In 2035, the share of total electricity generation accounted for by renewables is 14 percent in the Reference case, as compared with 16 percent in the No Sunset case and the Extended Policies case.

In all three cases, the most rapid growth in renewable capacity occurs in the near term. After that, the growth slows through 2020 before picking up again. Before 2015, ample supplies of renewable energy in relatively favorable resource areas (such as windy lands or accessible geothermal sites), combined with the Federal incentives, make renewable generation competitive with conventional sources. With slow growth in electricity demand and the addition of capacity stimulated by renewable incentives before 2015, little new capacity is needed between 2015 and 2020. In addition, in some regions, attractive low-cost renewable resources already have been exploited, leaving only less favorable sites that may require significant investment in transmission as well as other additional infrastructure costs. Starting around 2020, significant new sources of renewable generation also appear on the market as a result of cogeneration at biorefineries built primarily to produce renewable liquid fuels to meet the Federal RFS, where combustion of waste products to produce electricity is an economically attractive option.

After 2020, renewable generation in the No Sunset and Extended Policies cases increases more rapidly than in the Reference case, and as a result generation from nuclear and fossil fuels is reduced from the levels in the Reference case (Figure 9). Natural gas represents the largest source of displaced generation. In 2035, electricity generation from natural gas is 8 percent lower in the No Sunset case and 16 percent lower in the Extended Policies case than in the Reference case.

Energy-related CO_2 emissions

In the No Sunset and Extended Policies cases, lower overall energy demand leads to lower levels of energy-related CO_2 emissions than in the Reference case. The Extended Policies case shows much larger emissions reductions than the No Sunset and Reference cases, in part, due to the inclusion of a tighter CAFE policy for transportation. From 2012 to 2035, energy-related CO_2 emissions are reduced by a cumulative total of 5.2 billion metric tons (a 3.7-percent reduction over the period) in the Extended Policies case from the Reference case projection, as compared with 0.7 billion metric tons (a 0.5-percent reduction over the period) in the No Sunset case (Figure 10). The increase in fuel economy assumed for new LDVs in the Extended Policies case leads to nearly one-half the total reduction in CO_2 emissions in the Reference case projection by 2035. The balance of the reduction in CO_2 emissions is due to greater efficiency improvement in appliances and increased penetration of renewable of electricity generation.

Figure 8. Renewable electricity generation in three cases, 2005-2035 (billion kilowatthours)

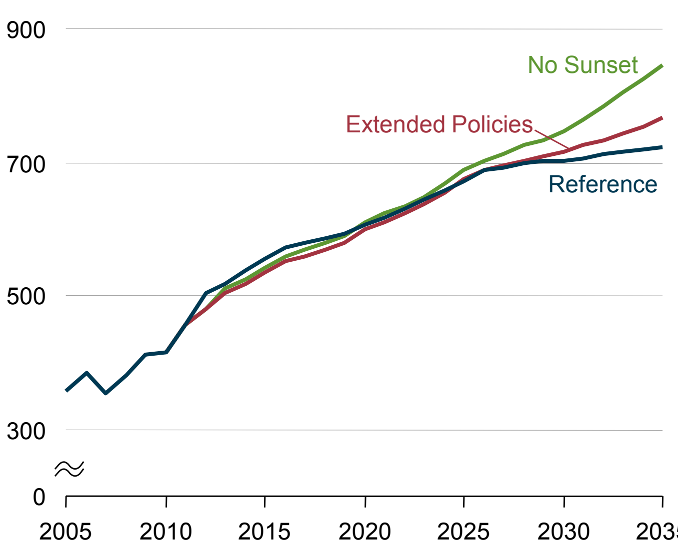
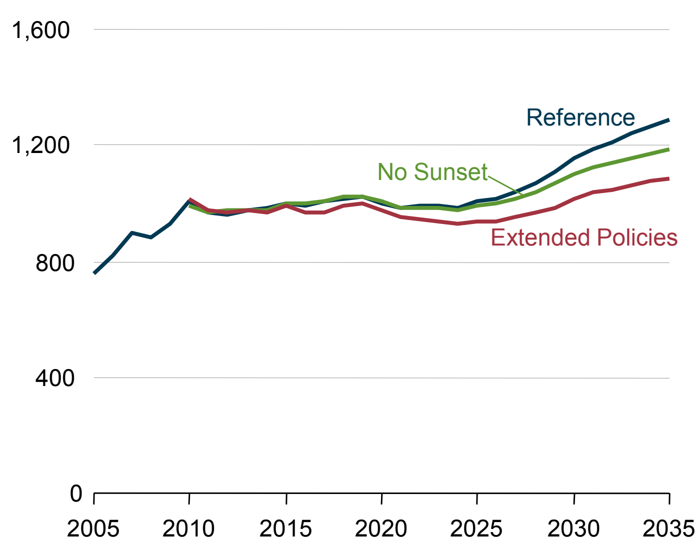


Figure 9. Electricity generation from natural gas in three cases, 2005-2035 (billion kilowatthours)



The majority of the emissions reductions in the No Sunset case are the result of increases in electricity generation from renewable fuels. By convention, emissions associated with the combustion of biomass for electricity generation are not counted, because they are assumed to be balanced by carbon uptake when the feedstock is grown. A small reduction in transportation sector emissions in the No Sunset case is counterbalanced by an increase in emissions from refineries during the production of synthetic fuels that receive tax credits. Relatively small incremental reductions in emissions are attributable to renewables in the Extended Policies case, mainly because electricity demand is lower than in the Reference case, reducing the consumption of all fuels used for generation, including biomass.

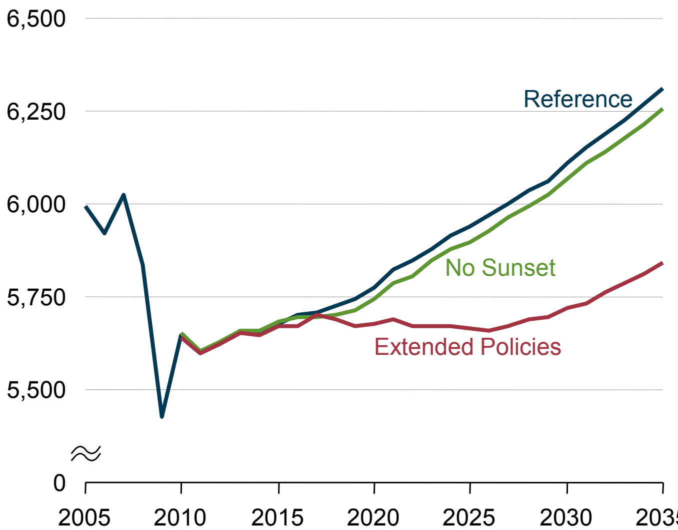
In the residential sector, in both the No Sunset and Extended Policies cases, water heating, space cooling, and space heating together account for most of the emissions reductions from Reference case levels. In the commercial sector, only the Extended Policies case sees substantial emission reductions in those categories.

Energy prices and tax credit payments

With lower levels of overall energy use and more consumption of renewable fuels in the No Sunset and Extended Policies cases, energy prices are lower than in the Reference case. In 2035, natural gas wellhead prices are $0.21 per thousand cubic feet (3 percent) and $0.60 per thousand cubic feet (9 percent) lower in the No Sunset and Extended Policies cases, respectively, than in the Reference case (Figure 11), and electricity prices are 2 percent and 6 percent lower than in the Reference case (Figure 12).

The reductions in energy consumption and CO_2 emissions in the Extended Policies case require additional equipment costs to consumers and revenue reductions for the U.S. Government. From 2011 to 2035, residential and commercial consumers spend an additional $11 billion per year (in real 2009 dollars) on average for newly purchased end-use equipment, distributed generation systems, and residential building shell improvements in the Extended Policies case than in the Reference case. On the other hand, they save an average of $29 billion per year on their energy bills.

Figure 10. Energy-related carbon dioxide emissions in three cases, 2005-2035 (million metric tons)



Tax credits paid to consumers in the buildings sector in the Extended Policies case average $14 billion (real 2009 dollars) more per year than in the Reference case. In comparison, revenue reductions as a result of tax credits in the buildings sector average $1 billion more per year over the same period than in the Reference case. However, 60 percent of the revenue reductions in the Reference case occur by 2016 when most of the tax credits are scheduled to expire.

The largest response to Federal PTC incentives for new renewable generation is seen in the No Sunset case, with extension of the PTC resulting in annual average reductions in Government tax revenues of approximately $730 million over the 2011 to 2035 period, as compared with $230

Figure 11. Natural gas wellhead prices in three cases, 2005-2035 (2009 dollars per thousand cubic feet)

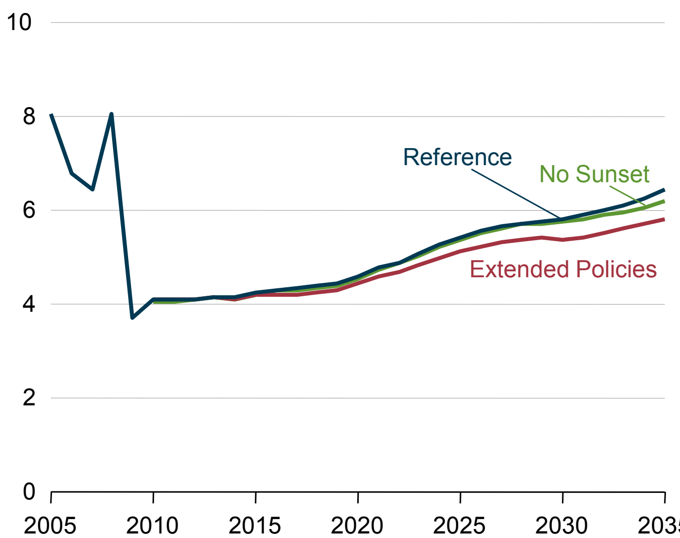
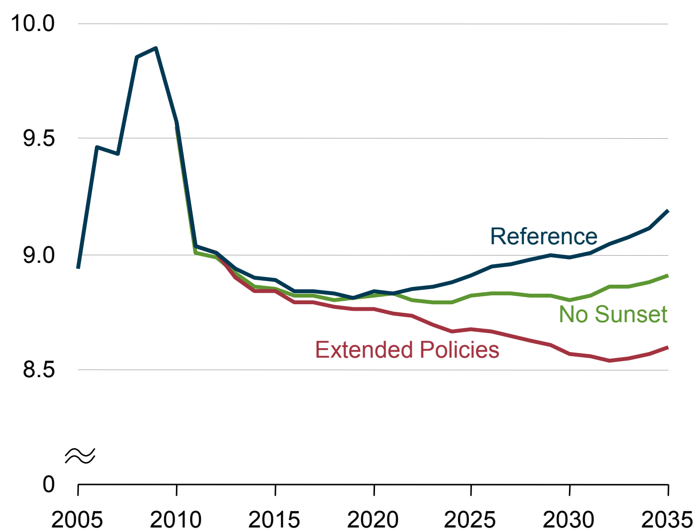


Figure 12. Average electricity prices in three cases, 2005-2035 (2009 cents per kilowatthour)



million per year in the Reference case. Additional reductions in Government tax revenue in the No Sunset case result from extensions of both the ethanol and biodiesel blenders tax credits and the cellulosic biofuels PTC, with annual average tax revenue reductions over the period from 2011 to 2035 of $3.1 billion per year (2009 dollars) in comparison with the Reference case.

2. World oil price and production trends in *AEO2011*

The world oil price is represented in *AEO2011* as the price of light, low-sulfur crude oil delivered at Cushing, Oklahoma. Projections of future supply and demand are made for "liquids." The term "liquids" refers to conventional petroleum liquids, such as conventional crude oil, natural gas plant liquids, and refinery gain, in addition to unconventional liquids, such as biofuels, bitumen, coal-to-liquids (CTL), coal- and biomass-to-liquids, gas-to-liquids (GTL), extra-heavy oils, and oil shale (derived from kerogen).

World oil prices are influenced by a number of factors, some of which have mainly short-term impacts. Others, such as expectations about world oil demand and OPEC production decisions, affect prices in the longer term. Supply and demand in the world oil market are balanced through responses to price movements, and the factors underlying expectations for supply and demand are both numerous and complex. The key factors determining long-term expectations for oil supply, demand, and prices can be summarized in four broad categories: the economics of non-OPEC conventional liquids supply; OPEC investment and production decisions; the economics of unconventional liquids supply; and world demand for liquids.

In 2010, the "prompt month contract" for crude oil (the contract for the nearest month's trading) remained relatively steady from January to November, at a monthly average between $74 and $84 per barrel (2009 dollars), before increasing to just over $89 per barrel in December [*44*].

Long-term prospects

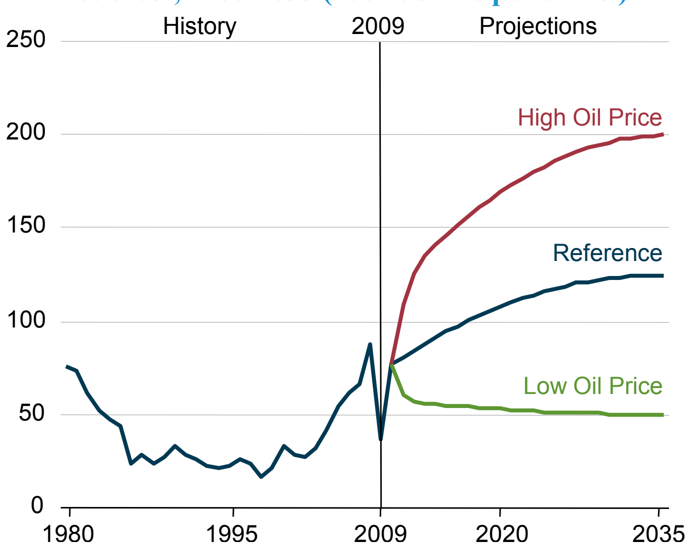
In past *AEO*s, High Oil Price and Low Oil Price cases have been used to explore the potential impacts of changes in world liquids supply on world (and U.S.) oil markets as a result of either OPEC production decisions or changes in economic access to non-OPEC resources. In *AEO2011*, the High Oil Price and Low Oil Price cases have been expanded to incorporate alternative assumptions about liquids supply, economic developments, and liquids demand as key price determinants. The assumed price paths in the *AEO2011* High and Low Oil Price cases bracket a broad range of possible future world oil price paths, with prices in 2035 (in real 2009 dollars) at $200 per barrel in the High Oil Price case and $50 per barrel in the Low Oil Price case, as compared with $125 in the Reference case (Figure 13). This is by no means the full range of possible future oil price paths.

Reference case

The global oil market projections in the *AEO2011* Reference case are based on the assumption that current practices, politics, and levels of access will continue in the near to mid-term. The Reference case assumes that continued robust economic growth in the non-OECD nations, including China, India, and Brazil, will more than offset relatively tepid growth projected for many OECD nations. In the Reference case, non-OECD liquids consumption is about 25 million barrels per day higher in 2035 than it was in 2009, but OECD consumption grows by less than 3 million barrels per day over the same period. Total liquids consumption grows to 103 million barrels per day by 2030 and 111 million barrels per day by 2035.

The *AEO2011* Reference case assumes that limitations on economic access to resources in many areas restrain the growth of non-OPEC conventional liquids production over the projection period and that OPEC production meets a relatively constant share of about 40 percent of total world liquids supply. With those constraining factors, satisfying the growing world demand for liquids in coming decades requires production from higher cost resources, particularly for non-OPEC producers with technically challenging supply projects. In the Reference case, the increased cost of non-OPEC supplies and a constant OPEC market share combine to support average increases in real world oil prices of about 5.2 percent per year from 2009 to 2020 and 1.0 percent from 2020 to 2035. In 2035, the average real price of crude oil in the Reference case is $125 per barrel in 2009 dollars.

Figure 13. Average annual world oil prices in three cases, 1980-2035 (2009 dollars per barrel)



Increases in non-OPEC production in the Reference case come primarily from high-cost conventional projects in areas with inconsistent fiscal or political regimes and from increasingly expensive unconventional liquids projects that are made economical by rising oil prices and advances in production technology (Figure 14). Oil sands production in Canada and biofuels production mostly from the United States and Brazil are the most important components of the world's unconventional resources, accounting for nearly 70 percent of the projected incremental supply between 2009 and 2035 in the Reference case.

Low Oil Price cases

In earlier *AEO*s, the Low Oil Price case assumed that significantly improved access to resources and the willingness of OPEC members to increase their market share would result in low prices and ample supplies, leading to strong increases in demand over the long term. For *AEO2011*, the Low Oil Price case has been changed to one in which relatively low demand for liquids, combined with greater economic access to and production of conventional resources, results in sustained low oil prices. In particular, the new Low Oil Price case focuses on demand in non-OECD countries, where uncertainty about future growth is much higher than in the OECD nations. The *AEO2011* Low Oil Price case assumes that world oil prices fall steadily after 2011 to about $50 per barrel in 2030 and stabilize at that level through 2035, and that relatively low gross domestic product (GDP) growth in the non-OECD countries, compared to the Reference case, keeps their liquids demand at relatively low levels. Average annual GDP growth in the non-OECD nations is assumed to be 1.5 percentage points lower than in the Reference case, or about 3.6 percent on average. The result is that non-OECD demand for liquids in 2035 is 15 million barrels per day lower than would have been projected in previous *AEO*s, as represented in the *AEO2011* Traditional Low Oil Price case. Total world liquids consumption rises to only 108 million barrels per day in 2035 in the *AEO2011* Low Oil Price case.

In both the Low Oil Price case and the Traditional Low Oil Price case, low prices limit the development of relatively expensive unconventional supplies. Thus, the volumes of unconventional production supplied are the same in the two cases (Figure 15). Similarly, there is only a modest difference between the volumes of non-OPEC conventional liquids supplies in the two cases. In contrast, OPEC conventional liquids supplies, which increase by about 28 million barrels per day in the Traditional Low Oil Price case, increase by only about 15 million barrels per day in the Low Oil Price case.

High Oil Price cases

In the *AEO2011* High Oil Price case, high demand for liquids, combined with more constrained supply availability, results in a sharp, continued increase in world oil prices. As in the Low Oil Price case, GDP growth is used as a proxy for liquids demand growth in the non-OECD nations. Annual GDP growth in non-OECD nations is assumed to be 1.0 percentage points higher in the High Oil Price case than in the Reference case, or 5.7 percent on average. Coupled with more constrained supply, oil prices increase to $200 per barrel in 2035 as a consequence. Despite the higher prices, however, total world liquids consumption grows to 115 million barrels per day in the High Oil Price case, or 4 million barrels per day higher than in the Reference case. In contrast, in the Traditional High Oil Price case, only world liquids supply strategies are assumed to result in higher oil prices and tight supplies, which constrain increases in demand over the long term.

In both the High Oil Price case and the Traditional High Oil Price case, high prices and restrictions on the production of lower cost conventional liquids encourage the development of relatively expensive unconventional supplies. The outlook is similar in the two cases, with about 20 million barrels per day of unconventional resources brought to market in 2035. Non-OPEC liquids supplies are slightly higher in the High Oil Price case than in the Traditional High Oil Price case, but the largest difference between the two cases is in conventional OPEC supplies. The High Oil Price case assumes that OPEC will increase production to maximize revenues, because demand in non-OECD nations is not dampened by high prices. In this case, OPEC conventional liquids supplies increase by almost 8 million barrels per day from 2009 to 2035, as compared with a decline of 2 million barrels per day in the Traditional High Oil Price case.

Figure 14. Total liquids production by source in the Reference case, 2000-2035 (million barrels per day)

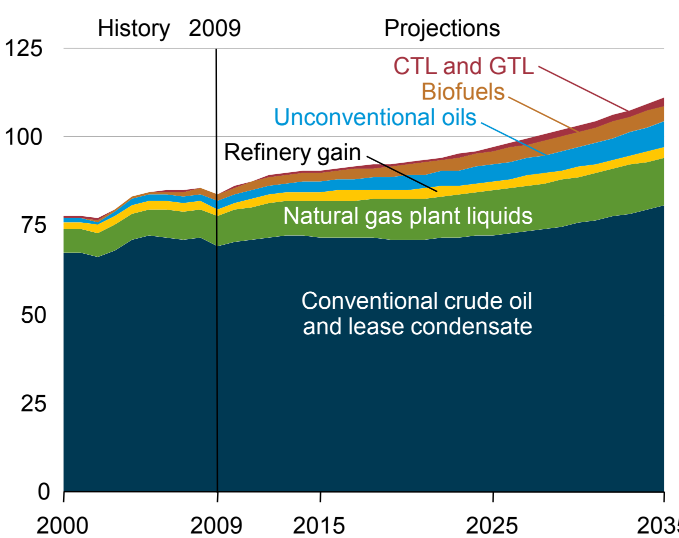
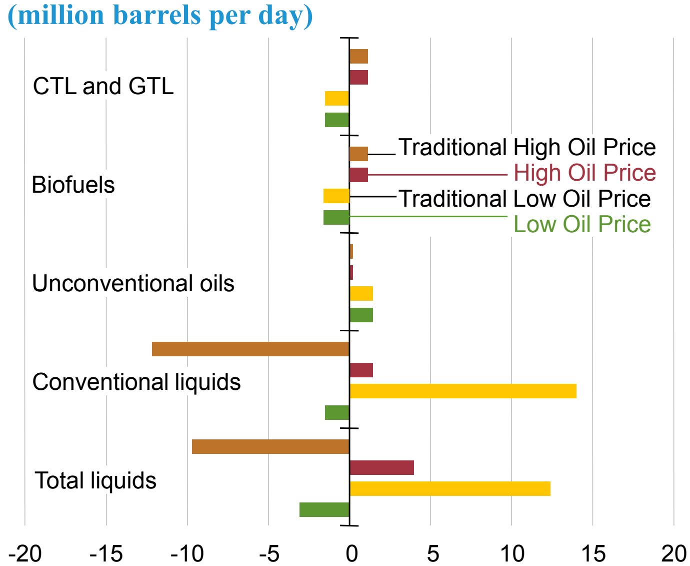


Figure 15. Differences from Reference case liquids production in four Oil Price cases, 2035 (million barrels per day)



3. Increasing light-duty vehicle greenhouse gas and fuel economy standards for model years 2017 to 2025

EPA Notice of Intent to conduct a joint rulemaking

In September 2010, the EPA and NHTSA issued a Notice of Intent to issue a proposed rule that will set GHG emissions and fuel economy standards for LDVs for MY 2017 through MY 2025 [*45*]. The LDV standards cover both passenger cars and light trucks. The notice provides an initial GHG emissions assessment for several potential levels of stringency, representing decreases of 3, 4, 5, and 6 percent per year in GHG emissions and corresponding increases in mpg equivalent fuel efficiency levels from the MY 2016 fleetwide average of 250 grams per mile. For each level of stringency, four technological pathways were analyzed, corresponding to different penetration mixes of advanced gasoline technologies, vehicle mass reductions, and advanced hybrid electric, plug-in hybrid electric, and plug-in electric vehicles.

The four technological pathways were not meant as requirements but were used to show that the potential levels of stringency examined by the EPA and NHTSA are technically feasible. Although the notice provided an initial evaluation of a potential range of increases in stringency, it recognized that much more technological and economic analysis would be needed before a specific standard could be released. The EPA and NHTSA expect to release a proposed rulemaking in September 2011 and to issue a final rulemaking by July 2012.

Sensitivity cases

Two sensitivity cases were used to analyze the impacts of more stringent GHG emissions and fuel economy standards on LDVs in MY 2017 through MY 2025. Fuel economy and GHG emissions standards for MY 2011 through MY 2016 have been promulgated already as final rulemakings, and are already represented in the Reference case; they were, therefore, not modified in these sensitivity cases.

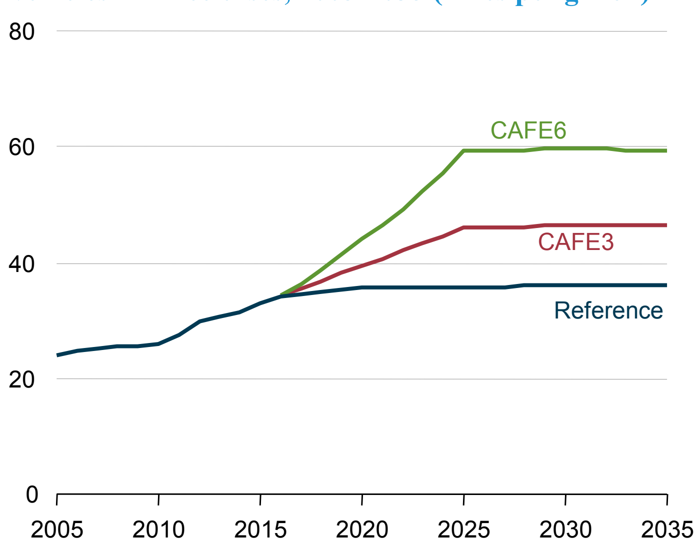
The *CAFE 3% Growth (CAFE3) case* is a modified Reference case that assumes a 3-percent annual increase in fuel economy standards for MY 2017 through MY 2025 LDVs, starting from the levels for MY 2016 LDVs, with the subsequent post-MY 2025 standards held constant. In 2025, the combined LDV fuel economy standard, at 46.1 mpg, is 29 percent higher than the standard assumed in the *AEO2011* Reference case. The *CAFE 6% Growth (CAFE6) case* assumes a 6-percent annual increase in fuel economy standards for new LDVs from MY 2016 levels for MY 2017 through MY 2025, with the subsequent standards held constant. In 2025, the LDV fuel economy standard, at 59.3 mpg, is 66 percent higher than the standard assumed in the Reference case (Figure 16). For new passenger cars, the fuel economy standard in 2025 is 40.4 mpg in the Reference case, 53.5 mpg in the CAFE3 case, and 75.4 mpg in the CAFE6 case. For new light-duty trucks, the fuel economy standard in 2025 is 29.7 mpg in the Reference case, 38.1 mpg in the CAFE3 case, and 45.5 mpg in the CAFE6 case.

The standards enacted for MY 2011 through 2016 are attribute-based, using vehicle footprint, and allow credits for alternative technologies and fuels to be applied toward compliance. The Notice of Intent for MY 2017 through 2025 does not address the type of attribute standard that would be employed or the structure of credits allowed toward compliance. The sensitivity cases examined here assume a continuation of the current footprint-based attribute standards, as well as credit banking.

Results

In view of the substantial rate of fuel economy improvement required, compliance with the more stringent CAFE standards cases would require a rapid increase in sales of unconventional vehicles (those that use diesel, alternative fuels, and/or hybrid electric systems) and significant improvement in the fuel economy of conventional vehicles that continue to rely solely on gasoline spark-ignited engines for motive power (Table 4). Such rapid changes are likely to challenge the financial, engineering, and production capabilities of the automotive industry. In addition, increased costs for vehicles that employ technologies unfamiliar to consumers could result in lower new vehicle sales relative to the Reference case.

Figure 16. Combined CAFE standards for light-duty vehicles in three cases, 2005-2035 (miles per gallon)



Although this analysis does not address those potential issues, it does project the levels of market penetration by unconventional vehicles and advanced technologies that would be needed for compliance with the more stringent standards, and it estimates the costs of compliance given Reference case assumptions for technology efficiency improvement and cost. The resulting impacts on new LDV sales, stocks, energy demand, and CO_2 emissions are discussed below.

Sales of unconventional vehicles, which will be critical to achieving the required fuel economy improvements, are projected to grow to 70 percent of total new LDV sales in 2025 in the CAFE3 case and nearly 90 percent in the CAFE6 case, as compared with 40 percent in the Reference case. In the CAFE3 case, the largest increases in new sales market shares are among hybrid electric, diesel, and micro hybrid systems in conventional gasoline vehicles (Figure 17), all of which are more fuel efficient than their conventional gasoline counterparts. The increase in hybrid and diesel vehicle sales displaces sales of both conventional gasoline and flex-fuel vehicles. The more stringent standards in the CAFE6 case cause an even greater reduction in conventional gasoline and flex-fuel vehicle sales, significantly expanding the market adoption of plug-in hybrid and all-electric vehicles, which are more fuel efficient than their unconventional counterparts, and even greater sales share for hybrid electric and diesel vehicles.

While declining as a share of total new vehicle sales, sales of conventional gasoline vehicles without micro hybrid systems still account for a significant percentage (30 percent) of new vehicles in the CAFE3 case and a less, but still important share (11 percent) in the CAFE6 case. Conventional gasoline vehicle fuel economy increases in both cases through the introduction of new fuel-efficient technologies and improved vehicle designs. In order to meet the increased fuel economy requirements, conventional vehicle subsystems (engine, transmission, aerodynamics, vehicle weight, and horsepower) would have to be modified to ensure compliance. Included in conventional gasoline vehicle technologies but counted separately in the discussion above are micro hybrid systems, which are present in 36 percent of conventional gasoline vehicles in the CAFE3 case and 58 percent in the CAFE6 case in 2025, compared with 12 percent in the Reference case.

The market adoption of unconventional vehicles and inclusion of additional technologies that improve the fuel economy of conventional gasoline vehicles results in higher average prices for new LDVs compared to the Reference case. As a result, while vehicle operating costs would fall (see below), consumers would need to purchase more expensive vehicles (Figure 18). A distribution of vehicle sales by price in 2010, derived from Ward's Automotive data [*46*], shows that 31 percent of the new vehicles purchased by consumers were within a price range of $10,000 to $25,000, 49 percent within $25,000 to $35,000, and 19 percent at prices above $35,000. In the CAFE3 case, the distribution in 2025 shifts to 15 percent within $10,000 to $25,000, 61 percent within $25,000 to $35,000, and 24 percent above $35,000 (all 2009 dollars). The sales distribution in 2025 shifts even more in the CAFE6 case, with 9 percent within $10,000 to $25,000, 56 percent within $25,000 to $35,000, and 35 percent above $35,000 (all 2009 dollars).

The cases estimate a demand response for new vehicle sales as a result of changes in average new vehicle price by employing a price elasticity of demand of -1. While this measure attempts to quantify the potential impact of the increase in vehicle price on sales, it is not intended to be inclusive of all the potential factors that could affect new vehicle purchase decisions made by consumers. As a result of higher vehicle prices, total new LDV sales in 2025 are 8 percent lower in the CAFE3 case and 14 percent lower in the CAFE6 case than in the Reference case.

As vehicle attributes change to meet more stringent CAFE standards, such as decreased average vehicle horsepower and weight, some consumers switch from passenger cars to light-duty trucks, which in the CAFE3 case have average fuel economies in 2025 comparable to those for passenger cars in 2016. The share of total new LDV sales made up by light-duty trucks is 40 percent in the CAFE3 case and 41 percent in the CAFE6 case in 2025, up from 38 percent in the Reference case, but still far lower than their share (more than 50 percent) in 2005. Note, however, that consumer incentives to switch from cars to light trucks are sensitive to the assumed relative stringency of cars versus light truck CAFE.

Although the CAFE sensitivity cases allow for fluctuation in new LDV sales and switching between purchases of passenger cars and light-duty trucks, additional impacts on fuel demand would be associated with the continued use of existing vehicle stocks. As consumers defer new vehicle purchases, the utilization of older, less fuel-efficient vehicles increases relative to the Reference case.

Table 4. Unconventional light-duty vehicle types

Unconventional vehicle type	Description
Micro hybrid	Vehicles with gasoline engines, larger batteries, and electrically powered auxiliary systems that allow the engine to be turned off when the vehicle is coasting or idle and then quickly restarted. Regenerative braking recharges the batteries but does not provide power to the wheels for traction.
Hybrid electric (gasoline or diesel)	Vehicles that combine internal combustion and electric propulsion but have limited all-electric range and batteries that cannot be recharged using grid power.
Diesel	Vehicles that use diesel fuel in a compression-ignition internal combustion engine.
Plug-in hybrid electric (10- and 40-mile all-electric range)	Vehicles that use battery power to drive for some distance, until a minimum level of battery power is reached, at which point they operate on a mixture of battery and internal combustion power. Plug-in hybrids also can be engineered to run in a "blended mode," where an onboard computer determines the most efficient use of battery and internal combustion power. The batteries can be recharged from the grid by plugging a power cord into an electrical outlet.
Plug-in electric (100- and 200-mile range)	Vehicles that operate by electric propulsion from batteries that are recharged either from the grid exclusively or through regenerative breaking.
Flex-fuel	Vehicles that run on gasoline or any gasoline-ethanol blend up to 85 percent ethanol.

The demand for mobility and the stock of vehicles available in the Reference case are maintained over the projection period in the CAFE cases, but the two CAFE cases assume longer vehicle survival rates and more intensive use of older vehicles.

The United States currently has a total LDV stock of around 230 million vehicles. That number grows to over 300 million vehicles by 2035 in the Reference and CAFE cases. Although the introduction of more stringent fuel economy standards in the CAFE cases stimulates sales of more fuel-efficient new vehicles, it takes time for the new vehicles to penetrate the vehicle fleet in significant numbers to affect the average of fuel economy of the entire LDV stock. In the CAFE cases, the trend is even slower, as a result of reduced scrappage and increased travel of older vehicles. Consequently, the average on-road fuel economy of the LDV stock, which represents the fuel economy realized by all vehicles in use, increases from 22.4 mpg in 2016 to 28.6 mpg in 2025 in the CAFE3 case and 30.2 mpg in the CAFE6 case, as compared with 25.7 mpg in the Reference case. In 2035, the average on-road fuel economy of the LDV stock increases to 34.0 mpg in the CAFE3 case and 39.4 mpg in the CAFE6 case, 22 percent and 41 percent higher, respectively, than the Reference case average of 27.9 mpg (Figure 19).

In the two CAFE cases, more stringent fuel economy standards lead to reductions in total delivered energy consumption, including all fuels. Fuel bills fall by a similar amount. Total cumulative delivered energy consumption by LDVs from 2017 to 2035 is 10 percent lower in the CAFE3 case than in the Reference case and 13 percent lower in the CAFE6 case. In 2025, total delivered energy consumption by LDVs is 19 percent lower in the CAFE3 case and 27 percent lower in the CAFE6 case than in the Reference case. Total liquids fuel consumption in 2035 is 1.9 million barrels per day lower in the CAFE3 case and 2.8 million barrels per day lower in the CAFE6 case than in the Reference case (Figure 20). Reductions in total delivered energy consumption and liquids fuel

Figure 17. Model year 2025 light-duty vehicle market shares by technology type in three cases (percent of total sales)

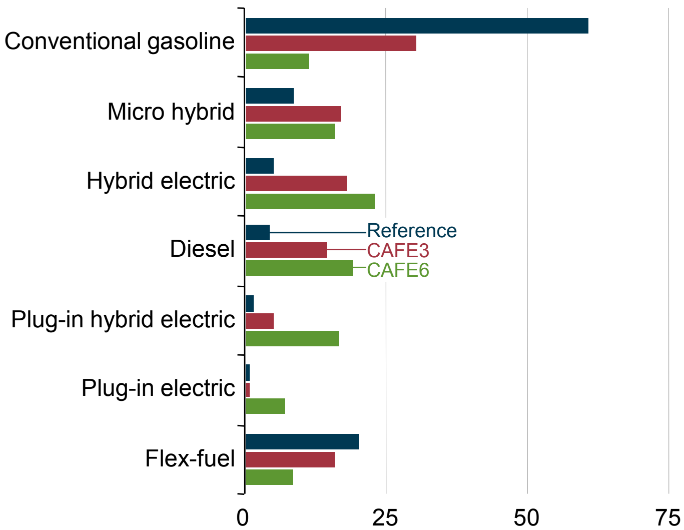


Figure 18. Distribution of new light-duty vehicle sales by vehicle price (2009 dollars) in 2025 in the CAFE3 and CAFE6 cases (percent of total sales compared to 2010)

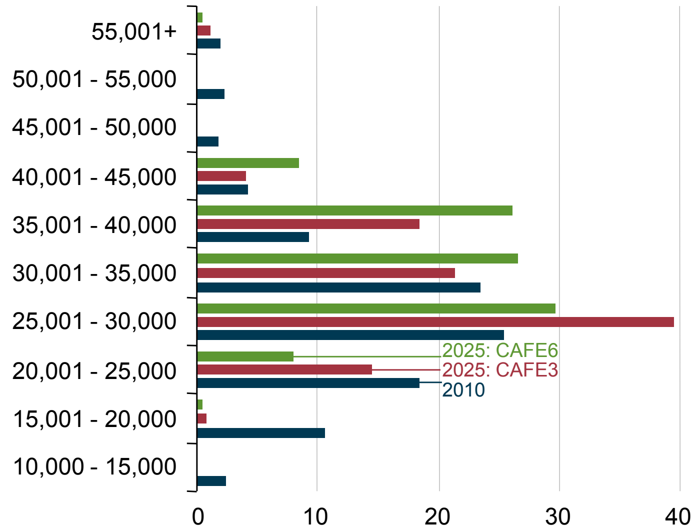


Figure 19. On-road fuel economy of the light-duty vehicle stock in three cases, 2005-2035 (miles per gallon)

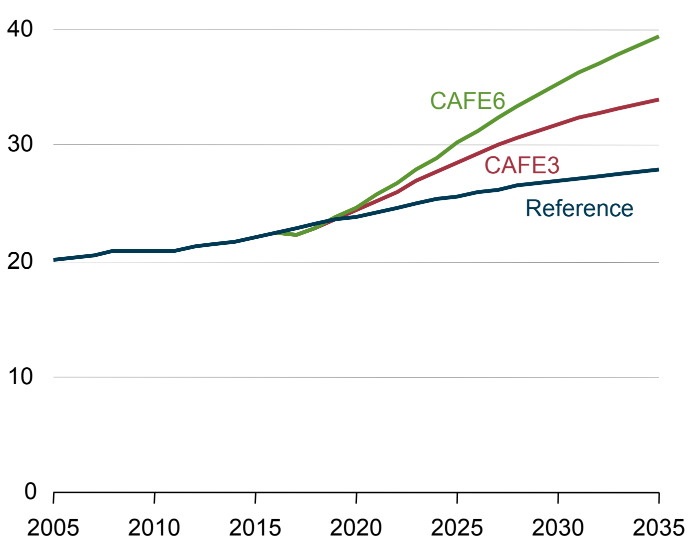
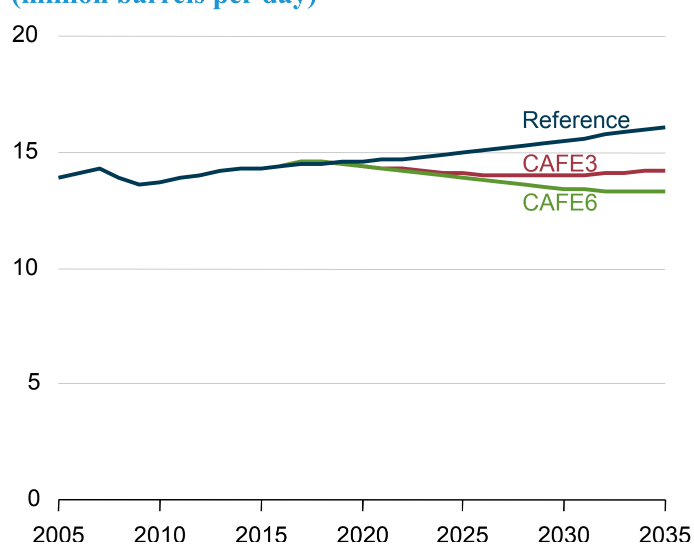


Figure 20. Total liquid fuels consumption by light-duty vehicles in three cases, 2005-2035 (million barrels per day)



consumption are more pronounced later in the projection period, when a greater percentage of the total vehicle stock consists of vehicles with higher fuel economy.

The declines in total LDV energy demand in the CAFE cases lead to large reductions in motor gasoline consumption—from 98 percent of total LDV energy use in 2016 to 84 percent in 2025 and 77 percent in 2035 in the CAFE3 case, as compared with 91 percent in 2025 and 89 percent in 2035 in the Reference case. The more stringent fuel economy standards called for in the CAFE6 case lead to even greater reductions in motor gasoline consumption, to 83 percent of total LDV energy use in 2025 and 69 percent in 2035.

Despite the overall decline in energy consumption by LDVs, the changing composition of the fleet by vehicle fuel type leads to increased consumption of some fuels. Lower demand for motor gasoline reduces the amount of ethanol that can be blended into the motor gasoline pool as either E10 or E15. As a consequence, more fuel containing up to 85 percent ethanol (E85) is sold to meet the RFS. E85 accounts for 11 percent of total LDV energy use in 2035 in the CAFE3 case and 14 percent in the CAFE6 case, compared with 7 percent in the Reference case. Diesel fuel consumption increases to 11 percent and 15 percent of total LDV energy use in 2035 in the CAFE3 and CAFE6 cases, respectively, compared with 4 percent in the Reference case. Electricity use by LDVs remains less than 1 percent of total LDV energy use in both the Reference and CAFE3 cases but reaches 3 percent of the total in the CAFE6 case, where sales of plug-in vehicles and all-electric vehicles expand.

Reductions in LDV delivered energy consumption lead to lower GHG emissions from the transportation sector. Cumulative CO_2 emissions from transportation over the period from 2009 through 2035 are 2.2 billion metric tons lower in the CAFE3 case and 2.6 billion metric tons lower in the CAFE6 case than in the Reference case, reductions of 6 percent and 7 percent, respectively. CO_2 emissions decline from 1,927 million metric tons in 2016 to 1,826 million metric tons in 2025 in the CAFE3 case and to 1,815 million metric tons in the CAFE6 case, as compared with 1,940 million metric tons in the Reference case. In 2035, CO_2 emissions from transportation fuel use total 1,859 million metric tons in the CAFE3 case and 1,788 million metric tons in the CAFE6 case, compared with 2,080 million metric tons in the Reference case (Figure 21).

CO_2 emissions from the electric power and refinery sectors also are affected by increased electricity use for plug-in vehicles. Cumulative emissions from the electric power sector over the period from 2017 to 2035 are 118 million metric tons higher in the CAFE3 case and 416 million metric tons higher in the CAFE6 case than in the Reference case—increases that are equal to 0.3 percent and 0.9 percent of total CO_2 emissions from electricity generation, respectively, over the same period. More stringent fuel economy standards reduce motor gasoline demand by more than they increase demand for diesel and E85 fuels. As a result, cumulative CO_2 emissions from refineries between 2017 and 2035 decline by 359 million metric tons in the CAFE3 case and 471 million metric tons in the CAFE6 case from the Reference case level—declines of 8.8 percent and 11.6 percent, respectively.

Issues

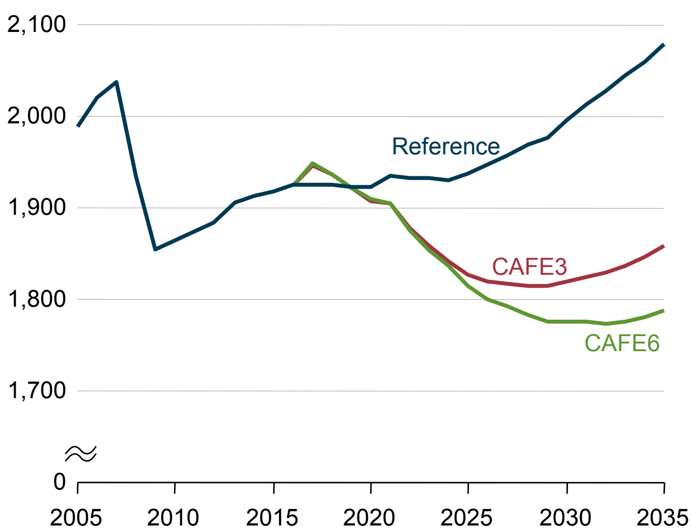
Setting LDV fuel economy standards 6 to 14 years into the future is a difficult undertaking, given the uncertainties associated with technology availability and cost, consumer acceptance and willingness to pay for unfamiliar technology, and fuel prices. The availability and cost of advanced vehicle technologies are critical in determining the ability of manufacturers to meet more stringent standards, but there is a high degree of uncertainty regarding the cost and availability of key technologies so far into the future.

For example, battery technologies used in plug-in vehicles are important in meeting more stringent standards in the CAFE3 case and are critical to compliance in the CAFE6 case. The future cost and performance of battery technologies in 2025 cannot be known with confidence. If there are limited breakthroughs in the cost, safety, or life of batteries, then the ability to meet, for example, the levels of stringency called for in the CAFE6 case, which will very likely necessitate plug-in vehicles, will be extremely challenging. On the other hand, a breakthrough in battery technology or another known technology, or the introduction of a new unforeseen technology, could dramatically lessen the burden on manufacturers of meeting more stringent CAFE standards in terms of both cost and availability.

When manufacturers bring an advanced vehicle technology to market, consumers must be willing to buy it. There is a high level of uncertainty about consumer willingness to pay significantly higher prices for more fuel-efficient vehicles. In recent history, consumers have tended to value upgrades in performance, vehicle size, and other attributes at the expense of fuel economy.

For example, assuming an annual vehicle use of 14,000 miles per year, a fuel price of $4 per gallon, and no discount rate, a consumer would save 117 gallons of fuel worth $467 each year by driving a vehicle with a fuel economy of 40 mpg instead of 30 mpg. However, purchasing a vehicle that gets 70 mpg

Figure 21. Total transportation carbon dioxide emissions (million metric tons carbon dioxide equivalent)



instead of 60 mpg would save only 33 gallons, worth $133 (Figure 22). This is important, because the cost of adding technology to an already fuel-efficient vehicle tends to get increasingly expensive (for example, changing a conventional gasoline vehicle to a plug-in hybrid electric vehicle). As manufacturers strive to improve fuel economy, the least costly technologies that reduce fuel consumption will be incorporated first. Employing additional technology to increase fuel economy further will require the use of more expensive technologies.

Consumer willingness to pay for improved fuel economy changes dramatically with different potential fuel prices, which are highly uncertain. If the price of fuel in 14 years is significantly higher than today's prices, a cost-conscious consumer may be willing to pay much more for a vehicle with higher fuel economy, perhaps even without increases in CAFE and GHG standards. Conversely, if fuel prices in the future are relatively low, it may be difficult to convince consumers to pay for fuel economy improvements if the savings from improving fuel economy have only a small impact on their annual fuel expenditures. The willingness of consumers to purchase vehicles with higher fuel economy could also affect both new vehicle sales and scrappage rates.

4. Fuel consumption and greenhouse gas emissions standards for heavy-duty vehicles

The proposed rulemaking

The EPA and NHTSA in November 2010 jointly issued a proposed rulemaking that would, for the first time, establish greenhouse gas emissions and fuel consumption standards for heavy-duty vehicles (HDVs) [*47*].The proposed standards separately address three discrete vehicle categories: combination tractors, heavy-duty pickup trucks and vans, and vocational vehicles (Table 5). The final regulations are scheduled to be issued by July 2011.

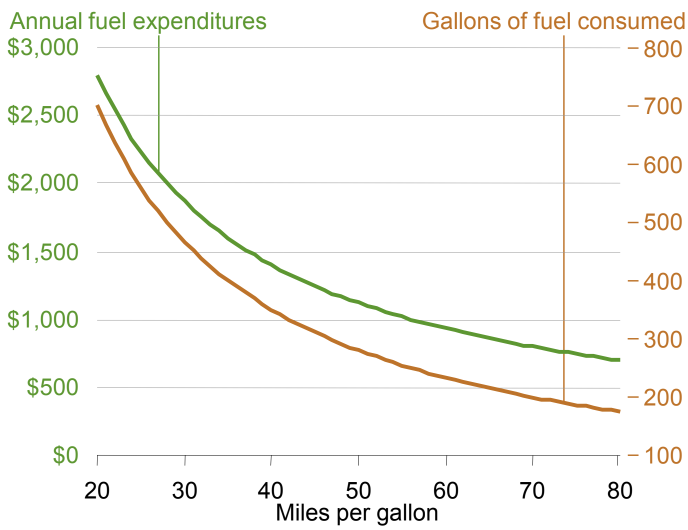
For combination tractors, standards are proposed by cab type, roof type, and engine type. For heavy-duty pickups and vans, the proposed standards are categorized by diesel or gasoline engine and are set as total vehicle gallons per 100 miles, or grams per mile, based on a vehicle's "work factor"—a weighted average of payload and towing capacity. For vocational vehicles, the standards are proposed for different chassis types, according to gross vehicle weight rating (GVWR) and engine type. Standards for combination tractor cabs and vocational vehicles are set as gallons per 1,000 ton-miles or grams per ton-mile, and engine standards are set as gallons per 100 brake horsepower-hours [*48*] or grams per horsepower-hour.

Heavy-duty vehicle fuel economy standards

AEO2011 includes a sensitivity case that analyzes the estimated impacts of the proposed fuel consumption and GHG emissions standards for heavy-duty trucks. However, because of data and modeling limitations, impacts of the standards for specific truck types or engines could not be represented. Instead, the *HDV Fuel Economy Standards case* approximates the proposed fuel consumption and GHG emissions standards by increasing the on-road fuel economy of new heavy-duty trucks by approximately 8.5 percent in MY 2017 from MY 2010 levels.

The increase in on-road fuel economy for heavy-duty trucks in MY 2017 in the sensitivity case is based on estimates developed from the U.S. Census Bureau's 2002 Vehicle Inventory and Use Survey (VIUS) [*49*] and from Ward's Auto [*50*], which together provide data on vehicle body type, tractor cab type, and engine type by GVWR classification. The estimated vehicle distributions were combined with the EPA and NHTSA estimates of reductions in fuel consumption in MY 2017 for combination tractors and vocational vehicles and in MY 2018 for heavy-duty pickups and vans, compared to a MY 2010 baseline [*51*].

Figure 22. Total annual fuel consumption (gallons) for consumers driving 14,000 miles per year and annual fuel expenditures at a $4.00 per gallon fuel price (2009 dollars)



Using data from VIUS and Ward's Automotive, fuel consumption reductions provided by EPA and NHTSA were combined and aggregated into the reported categorization of heavy-duty trucks used in *AEO2011*: medium heavy-duty trucks (includes Class 3 through Class 6 trucks with GVWR 10,001 to 26,000 pounds) and heavy heavy-duty trucks (Class 7 and Class 8 trucks with GVWR greater than 26,001 pounds), regardless of vehicle body or engine type. This weighting and aggregation showed an approximately 10 percent reduction in fuel consumption for both categories of heavy-duty trucks in MY 2017 from MY 2010 levels, relative to a simulated fuel economy estimate. The reduction in fuel consumption was modeled as an increase in on-road new vehicle fuel economy to account for the potential variation of simulation-tested fuel economy from expected on-road performance. Increases in fuel economy begin in MY 2014, the first year that GHG emissions standards are binding (Figure 23).

Between MY 2014 and MY 2017, the new heavy-duty truck standards lead to the adoption of technologies to improve fuel economy that otherwise would not have been purchased.

For new medium heavy-duty trucks, average on-road fuel economy increases from 7.9 mpg (gasoline) in 2013 (the year before imposition of binding GHG emission standards) to 8.5 mpg in 2017—a 7.8-percent increase from the *AEO2011* Reference case projection. On-road fuel economy for heavy heavy-duty trucks increases from 5.7 mpg in 2013 to 6.2 mpg in 2017, a 9.6-percent increase from the Reference case. After 2017 the standards are held constant, but owner-operators have the option of purchasing additional fuel-efficient technology according to their economic choice based on the net present value of fuel savings compared with the incremental cost of the technology. In 2035, the on-road fuel economy of new medium and heavy heavy-duty trucks reaches 8.4 and 6.4 mpg, respectively, as compared with 7.8 and 6.4 mpg in the Reference case.

Results

In the HDV Fuel Economy Standards case, new medium and heavy heavy-duty trucks with higher on-road fuel economy gradually penetrate the market. Progress is limited, however, due to the slow turnover in the stock of heavy trucks, which have a median lifetime of 29 years. Between 2014 and 2035, new heavy-duty truck sales per year are equal to about 6 percent of the total heavy-duty truck stock, ranging between about 600,000 and 900,000 new heavy-duty trucks sales per year out of a total stock that grows from 10 million in 2014 to 17 million in 2035. As new heavy-duty trucks are added to the total stock and older trucks with lower fuel economy are removed from service, the average on-road fuel economy for the total stock of medium and heavy heavy-duty trucks increases in the HDV Fuel Economy Standards case (Figure 24).

For medium heavy-duty trucks average on-road fuel economy increases from 7.9 median mpg in 2013 to 8.0 mpg in 2017 and 8.4 mpg in 2035, as compared with 7.9 mpg and 7.8 mpg, respectively, in the Reference case. For heavy heavy-duty trucks, on-road fuel economy increases from 5.7 mpg in 2013 to 5.9 mpg in 2017 and 6.3 mpg in 2035, as compared with 5.7 mpg and 6.2 mpg, respectively, in the Reference case.

The higher on-road fuel economy of the heavy-duty truck stock reduces total delivered energy consumption in the Fuel Economy Standards case. Total cumulative delivered energy consumption by heavy-duty trucks from 2014 to 2035 is 3 percent lower in the Fuel Economy Standards case than in the Reference case. The difference amounts to a cumulative reduction of slightly less than 1 percent of total delivered transportation energy consumption from 2014 to 2035. Total delivered energy consumption is 0.6 percent lower in 2017, the first year of complete implementation, and 0.5 percent lower in 2035 in the Fuel Economy Standards case than in the Reference case. Total liquids fuel consumption in 2035 is about 75 thousand barrels per day lower in the Fuel Economy Standards case than in the Reference case (Figure 25). However, heavy-duty truck total delivered energy and liquids fuel consumption climbs in both cases, as travel demand increases with growth in industrial output.

Cumulative CO_2 emissions from 2014 to 2035 are lower by 276 million metric tons (about 3 percent) in the HDV Fuel Economy Standards case than in the Reference case, representing a reduction of less than 1 percent in total CO_2 emissions from the transportation sector (Figure 26).

Issues

The HDV Fuel Economy Standards case approximates the proposed rulemaking by aggregating vehicle body type data from the 2002 VIUS. (The survey has not been updated since 2002.) There may be significant differences between the heavy-duty truck market today and the market a decade ago. Further, there are data uncertainties associated with the 2002 VIUS, but the data were used because VIUS is the only source of information on vehicle body type. Also, little if any information is available on other metrics used in the proposed standards.

Numerous limitations in the available data on the types and numbers of heavy trucks sold according to the vehicle classifications specified in the proposed standards make it difficult to estimate the energy impacts that could be expected as heavy-duty trucks begin to comply with the new standards. Without better and more complete data, it is difficult to analyze the composition of the heavy-duty truck market at the level of diversity included in the proposed standards, or the efficiency and fuel economy metrics associated with each classification in the standards. In addition, the lack of data makes it difficult to define an accurate baseline from which to gauge improvement.

Table 5. Vehicle categories for the HDV standards

Vehicle category	Description	Truck classes covered
Combination tractors	Semi trucks that typically pull trailers.	Class 7 and Class 8 (GVWR 26,001 pounds and above)
Heavy-duty pickups and vans	Pickup trucks and vans, such as 3/4-ton or 1-ton pickups used on construction sites or 12- to 15-person passenger vans.	Class 2b and Class 3 (GVWR 8,501 to 14,000 pounds)
Vocational vehicles	Includes a wide range of truck configurations, such as delivery, refuse, utility, dump, cement, school bus, ambulance, and tow trucks. For purposes of the rulemaking, vocational vehicles are defined as all heavy-duty trucks that are not combination tractors or heavy-duty pickups or vans.	Class 2b through Class 8 (GVWR 8,501 pounds and above)

Another issue is how compliance will be measured, and how well compliance testing procedures will replicate the average real-world performance of combination tractors, heavy-duty pickups and vans, and vocational vehicles. For combination tractors, which tend to spend a majority of their operation under steady conditions, such as highway driving, engine manufacturers must demonstrate compliance by using the steady-state Supplemental Engine Test [*52*]. Tractor manufacturers will then be required to install certified engines, with tractor compliance measured by an input-based truck simulation model, the Greenhouse Gas Emissions Model (GEM). GEM uses fixed input values, such as payload and trailer weights. Compliance will vary with the GEM inputs for aerodynamics, weight, tires, and idle reduction and speed limiter technologies.

Compliance for heavy-duty pickups and vans will be determined by a vehicle test procedure similar to the national program for LDVs, using the highway fuel economy test and the Federal test procedure for city driving, weighted 45 percent and 55 percent, respectively. Heavy-duty pickups and vans are assumed to be loaded to one-half of their payload capacity.

Vocational vehicles also use the GEM simulation model to demonstrate chassis compliance, using fixed curb and payload weights for each vehicle category, with tires being the only manufacturer-specific technology that can be input into the model. The proposed rulemaking weights the test drive-cycle as 37 percent at 65 miles per hour cruise, 21 percent at 55 miles per hour cruise, and 42 percent in transient performance, which broadly covers urban conditions. Chassis manufacturers will be allowed to install only certified CO_2 and fuel consumption compliant engines based on the transient Heavy-Duty Federal Test Procedure.

As validation, GEM results for fuel consumption and CO_2 emissions were compared with three SmartWay certified tractors in a chassis testing procedure. The GEM results were within 4 percent of the chassis testing results. Although the testing

Figure 23. On-road fuel economy of new medium and heavy heavy-duty vehicles in two cases, 2005-2035 (miles per gallon gasoline equivalent)

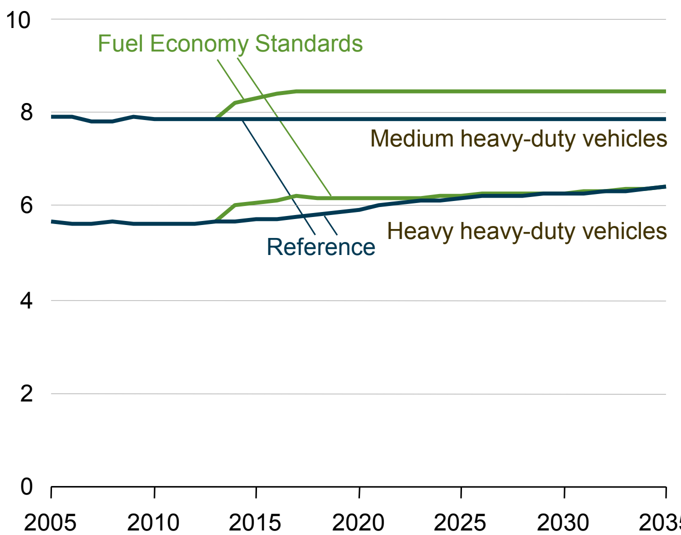


Figure 24. Average on-road fuel economy of medium and heavy heavy-duty vehicles in two cases, 2005-2035 (miles per gallon gasoline equivalent)

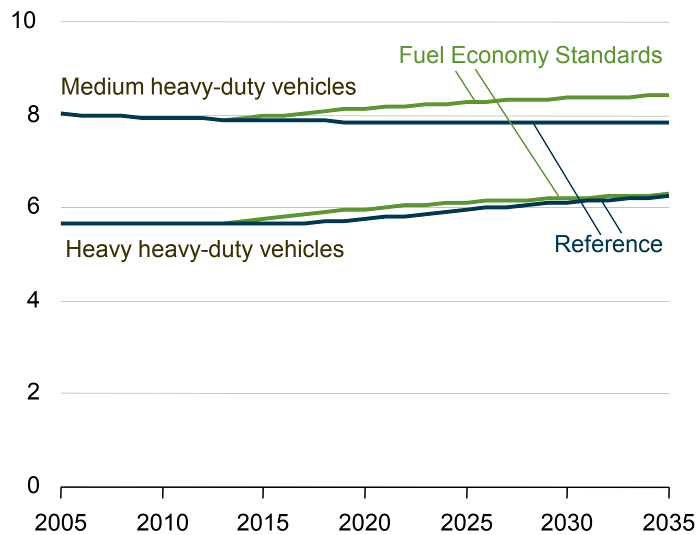


Figure 25. Total liquid fuels consumed by the transportation sector in two cases, 2005-2035 (million barrels per day)

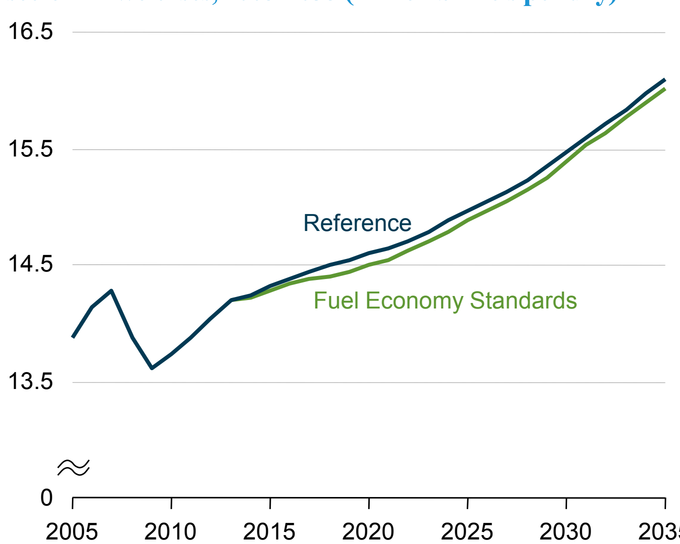
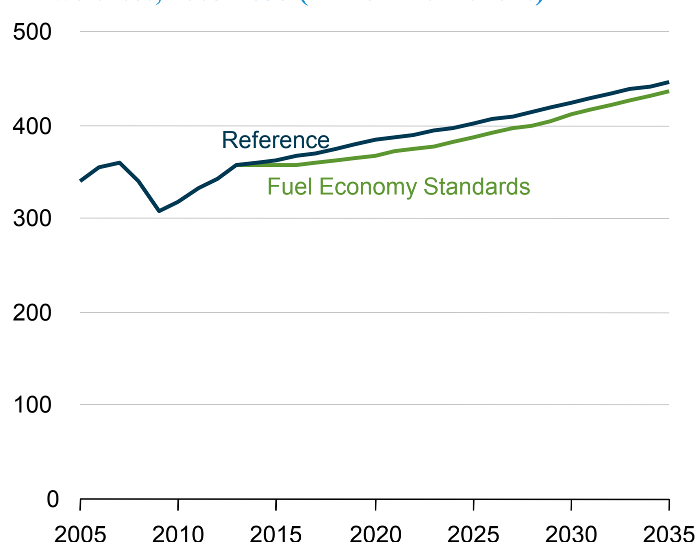


Figure 26. CO_2 emissions from heavy-duty vehicles in two cases, 2005-2035 (million metric tons)



mechanisms may accurately reflect real-world conditions, they may either underestimate or overestimate average fuel consumption and CO_2 emissions by vehicle category. Ultimately, fuel savings will be realized from the new standards; but given data limitations it is difficult to say with certainty the extent to which they will occur.

5. Potential efficiency improvements in alternative cases for appliance standards and building codes

In 2009, the residential and commercial buildings sectors used 19.6 quadrillion Btu of delivered energy, or 21 percent of total U.S. energy consumption. The residential sector accounted for 57 percent of that energy use and the commercial sector 43 percent. In the *AEO2011* Reference case, delivered energy for buildings increases by 16 percent, to 22.8 quadrillion Btu in 2035, which is moderate relative to the rate of increase in the number of buildings and their occupants. Accordingly, energy use in the buildings sector on a per-capita basis declines in the projection. The decline of buildings energy use per capita in past years is attributable in part to improvements in the efficiencies of appliances and building shells, and efficiency improvements continue to play a key role in projections of buildings energy consumption.

Three alternative cases in *AEO2011* illustrate the impacts of appliance standards and building codes on energy delivered to the residential and commercial sectors (Figure 27). The Expanded Standards case assumes multiple rounds of updates to appliance standards for most end uses. The Expanded Standards and Codes case includes the same updates to standards and adds several rounds of updates to national building codes. These cases differ from the Extended Policies case, in that they do not include the tax credit extensions assumed in the No Sunset case. The 2010 Technology case assumes that future equipment purchases are limited to the options available in 2010, and that the 2010 building codes remain unchanged through 2035. The 2010 Technology case includes all current Federal standards, but unlike the Reference case it does not include future efficiency levels established by equipment manufacturers and efficiency advocates through consensus agreements.

Without the benefits of technology improvement, buildings energy use in the 2010 Technology case grows to more than 24 quadrillion Btu in 2035, compared to under 23 quadrillion Btu in the Reference case. In the Expanded Standards and Codes case, energy delivered to the buildings sectors does not exceed 21 quadrillion Btu throughout the projection period.

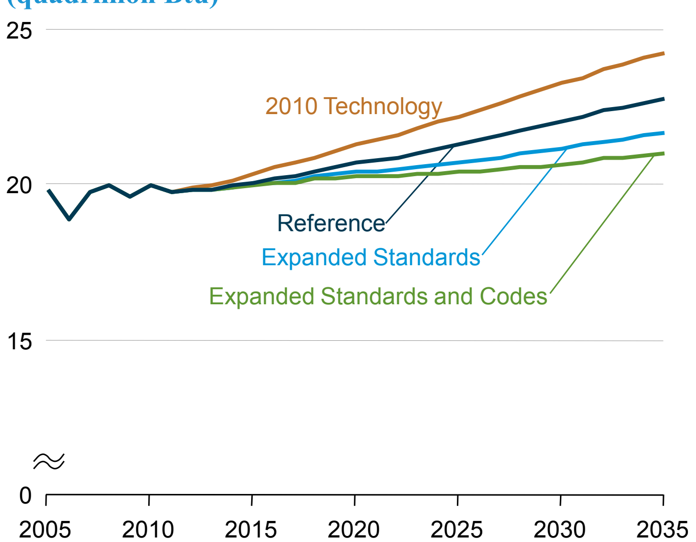
Background

Governments at both the State and Federal levels have used appliance standards and building codes to mandate minimum levels of efficiency in commercially available products and in new construction. California first established standards for selected appliances in the mid-1970s, and the Federal Government followed in 1987 with the National Appliance Energy Conservation Act. Currently, most major end-use devices are covered by Federal standards, and some States have added standards for such products as televisions, audio and video equipment, swimming pool pumps, commercial holding cabinets for hot food, and bottle-type water dispensers.

There are no Federal building codes; rather, codes are set at the State level. For residential buildings, most State codes are some version of the IECC. Commercial building codes are more likely to be based on specifications developed jointly by the American National Standards Institute, the ASHRAE, and the Illuminating Engineering Society of North America. In addition, the States have sole responsibility for compliance monitoring and enforcement of the codes, and efforts vary significantly across States.

Although both contribute to efficiency improvements and reduced energy consumption, building codes and appliance standards achieve those goals in different ways. Appliance standards set efficiency levels and require new equipment to provide a given level of service output (e.g., heat, light, or refrigeration) with a reduced level of energy input.

Figure 27. Residential and commercial delivered energy consumption in four cases, 2005-2035 (quadrillion Btu)



Building codes can reduce energy mainly for heating and cooling equipment by increasing insulation and decreasing air infiltration. Better insulation impedes heat transfer, and better infiltration control reduces air transfer between outdoor elements and indoor conditioned space. Those measures make the work done by heating and cooling equipment more effective, essentially by creating a more robust barrier between outdoor and indoor spaces.

Appliance standards

DOE's thresholds for setting Federal standards include average energy use in excess of 150 kilowatthours (or Btu equivalent) per household for any 12-month period; aggregate household energy use in excess of 4.2 billion kilowatthours (14.3 trillion Btu); and technological feasibility of substantial efficiency improvement for the product. For example, a typical refrigerator under the 2001 DOE standard can use up to 510 kilowatthours per year, and residential refrigeration in aggregate consumed

367 trillion Btu in 2009. Once a product is covered by DOE, the States must seek waivers from Federal preemption in order to implement their own standards.

Assumptions for future efficiency standards in the Extended Policies case and the Expanded Standards case are based on ENERGY STAR specifications or, for some products in the commercial sector, FEMP guidelines. The first round of standards in the Expanded Standards case assumes ENERGY STAR levels, but the improvements assumed for subsequent rounds are only 50 percent of those assumed for the first round (7.5 percent in the case of dehumidifiers). This approach is taken because, for example, an ENERGY STAR dehumidifier uses 15 percent less energy than required by the most recent standard, but it may be unreasonable to assume that future standards for dehumidifiers (or any other equipment) will always be able to achieve improvements of the same magnitude. In addition, the assumed future standards do exceed the "maximum technologically feasible" levels described in technical support documents for DOE's rulemaking.

Future efficiency levels for several products, in addition to standards already promulgated by DOE, are included in the *AEO2011* Reference case. Efficiency advocates and equipment manufacturers have developed consensus agreements on regional standards for electric heat pumps, central air conditioners, and furnaces, and national standards for refrigerators, freezers, clothes washers, clothes dryers, dishwashers, and room air conditioners. In those cases, efficiency levels in additional rounds of standards are limited to one-half the ENERGY STAR improvement increment.

The ENERGY STAR program provides an annual summary of market penetration by qualified products [*53*]. For some product categories with high levels of market penetration, ENERGY STAR specifications are updated more frequently, to encourage greater efficiency. Consequently, ENERGY STAR levels may be the most up-to-date and consistent set of efficiency levels that are plausible for future standards.

The Expanded Standards case includes updated standards for currently covered products as well as new standards for products not yet covered. Updated standards for covered products are introduced according to DOE's rulemaking schedule, which typically staggers rulemakings and revisits standard levels every 6 years. Standards for products not previously covered are assumed to be added to the schedule, with the last standard being introduced in 2019. For most end uses, only one additional round of standards is applied. Exceptions in the residential sector include boilers, geothermal heat pumps, and dehumidifiers, with two rounds of standards. Two additional rounds of standards are also assumed for geothermal heat pumps in the commercial sector.

By law, the DOE rulemaking process requires that efficiency improvements be imposed at neutral cost to consumers. Extensive cost-benefit analysis in the process involves thorough engineering and market analyses of potential impacts on consumers and is subject to scrutiny and input from equipment manufacturers, efficiency advocates, and other stakeholders. The sensitivity cases described here focus on the aggregate energy impacts of additional standards and codes, but do not address the impacts on consumer welfare. Future efficiency levels are based solely on estimations of improvements for currently available products.

Building codes

Residential and commercial building energy codes [*54*] are currently applied at the State level with no consistent schedule for adoption, compliance, or enforcement. Current residential building codes vary widely: some States comply with 2009 IECC or better, while others have codes that predate the 1998 MEC / IECC or have no mandatory codes at all. On the commercial side, the most stringent States have adopted ASHRAE 90.1-2007 or better, while the least stringent States either have no mandatory code or have codes that precede ASHRAE 90.1-1999. The Energy Policy Act of 1992 required certification of building energy code updates from all States, so that residential codes would meet or exceed the (now obsolete) Council of American Building Officials' 1992 Model Energy Code, and commercial codes would meet or exceed ASHRAE 90.1-1989. As of 2010, a State-level scorecard from efficiency advocates identified 12 States that still do not have mandatory energy codes for either residential or commercial buildings [*55*].

The American Recovery and Reinvestment Act of 2009 (ARRA) provides State Energy Program (SEP) funding, contingent on the updating of a State's building codes to ASHRAE 90.1-2007 and the IECC that was most recent when ARRA was passed in 2009, and on the State's providing a plan to achieve at least 90-percent compliance within 8 years. All 50 States applied for and received SEP funds with those conditions. The Reference case assumes that States comply with ARRA. The Expanded Standards and Codes case adds three rounds of building codes, the first of which mandates a 15-percent improvement over IECC 2009 in the residential sector and a 30-percent improvement over ASHRAE 90.1-2004 in the commercial sector by 2020. Two subsequent rounds in 2023 and 2026 each add an assumed 5-percent incremental improvement.

Results for the residential sector

Because many of the products targeted by the appliance standards program are used in the residential sector, about 60 percent of the additional buildings sector efficiency gains in the Expanded Standards and Codes case are realized there. Figure 28 shows cumulative energy savings relative to the 2010 Technology case in three cases for various groups of residential end uses.

The Reference case includes technology improvement in every end use. Also, two consensus agreements among equipment manufacturers and efficiency advocates provide additional significant reductions in consumption. In 2009, a consensus agreement recommended regional standards for some heating and cooling equipment as an alternative to the national standards of the past. In 2010, a consensus agreement recommended standards for refrigerators, freezers, room air conditioners, clothes washers, clothes dryers, and dishwashers. Those consensus agreements are included in the Reference case as *de facto* standards, and they contribute to the cumulative reduction in delivered energy use of 13.4 quadrillion Btu in the Reference case relative to the 2010 Technology case.

The Expanded Standards case shows significant improvement in miscellaneous energy loads, mostly as the result of an assumed standard for standby power in 2014. Standards for televisions and computer monitors are introduced in 2016, as recent improvements in display technology have offered room for energy savings. Products such as home audio equipment and DVD players that have been subject to State standards are assumed to be covered at the Federal level, further contributing to energy savings. Similarly, energy use for personal computers and related equipment, such as printers, modems, and routers, also are affected by the standards for standby power and assumed new DOE rulemakings for peripheral devices. Ultimately, the energy consumption associated with televisions, set-top boxes, personal computers, and related equipment is reduced by 1.8 quadrillion Btu in 2035 in the Expanded Standards case.

Electric water heating, with an assumed standard mandating heat pump water heaters in 2021, is reduced by 2.0 quadrillion Btu in 2035 in the Expanded Standards case relative to the Reference case. Electricity use for large kitchen appliances (refrigeration and cooking) display relatively little improvement in the Expanded Standards case. Refrigeration already is subject to stringent standards in the Reference case, whereas cooking equipment has less room for technological improvement. A lighting standard is assumed to be set in 2026, establishing an efficacy level for general-service bulbs at the level of compact fluorescent lamps; however, that level is not much higher than the standard that already has been promulgated and will go into effect in 2014. Energy use for laundry and dishwashing equipment shows little direct improvement in the Expanded Standards case, because standards for those products are more likely to limit water use than energy use.

The building codes in the Expanded Standards and Codes case provide an additional 2.9 quadrillion Btu of savings for space heating and cooling relative to those in the Expanded Standards case. Space heating accounts for most of the savings. In addition, some features of new building codes could focus on thermal improvements, such as reducing air infiltration or increasing the solar heat gain coefficients of windows, which may be beneficial in winter months but slightly detrimental in summer months.

Results for the commercial sector

Buildings in the commercial sector are less homogeneous than those in the residential sector, in terms of both form and function. The wider range of commercial equipment makes standard-setting more difficult, and although many products have been subject to Federal efficiency standards, FEMP guidelines, and ENERGY STAR specifications, coverage is not as comprehensive as in the residential sector. Figure 29 shows cumulative energy savings relative to the 2010 Technology case in three cases for various groups of commercial end uses.

Like the residential sector, commercial buildings with residential-size equipment were affected by the 2009 consensus agreement for heating and cooling products, which is included in the Reference case. This contributes to a cumulative reduction in delivered energy use for commercial heating, ventilation, and air conditioning of 1.5 quadrillion Btu (2 percent) in the Reference case relative to the 2010 Technology case. Office-related computer equipment sees significant energy savings, primarily because laptops gain market share from desktop computers.

In the Expanded Standards case, office equipment again accounts for a large share of the efficiency gains, because desktop computers and their monitors, laptops, copiers, fax machines, printers, and multi-function devices are assumed to be subject to

Figure 28. Residential delivered energy savings in three cases, 2010-2035 (cumulative differences from the 2010 Technology case, quadrillion Btu)

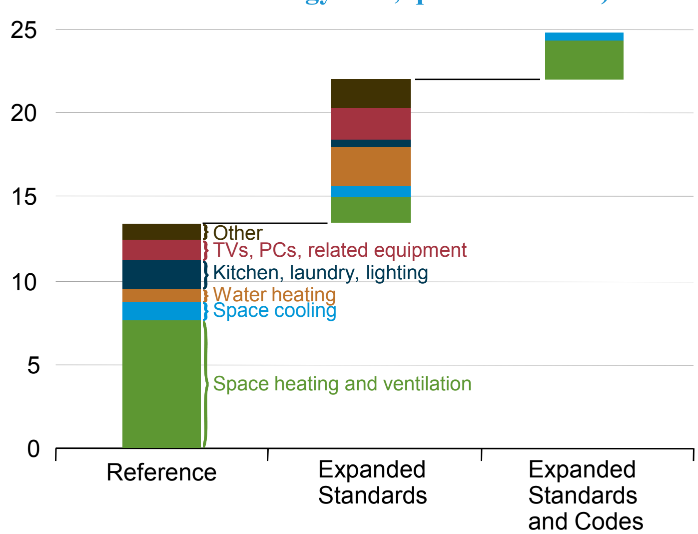
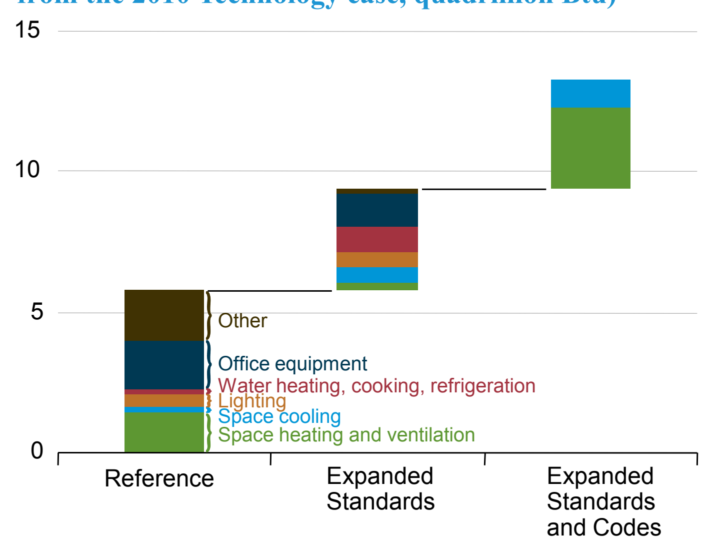


Figure 29. Commercial delivered energy savings in three cases, 2010-2035 (cumulative differences from the 2010 Technology case, quadrillion Btu)



efficiency standards, ultimately saving 1.2 quadrillion Btu over the projection period. Lighting in the commercial sector is subject to a tighter standard in 2017, saving 0.6 quadrillion Btu in total through 2035. In addition, an assumed 2021 standard requiring the use of heat pump water heaters leads to a 29-percent reduction in electricity consumption for water heating in 2035.

Building codes in the Expanded Standards and Codes case have nearly as much impact as the assumed standards in the Expanded Standards case, because the assumed building codes are much more stringent than those in the Reference case. Ultimately, the new codes provide almost 3 quadrillion Btu of savings in energy consumption for space heating savings and about 1 quadrillion Btu of savings for space cooling, beyond the reductions attributable to equipment standards.

Summary

In comparison with a case that restricts future equipment to what was available in 2010, the alternative cases described here show the potential for energy savings from the technological improvement and the application of appliance standards and building codes. In the Reference case, assumed technology improvement in general, and consensus agreements on efficiency improvements for some end uses in particular, save 13.4 quadrillion Btu of residential delivered energy—equivalent to 4.4 percent of total residential energy use—from 2010 to 2035. In the commercial sector, 5.6 quadrillion Btu of energy—equivalent to 2.2 percent of total commercial delivered energy—is saved from 2010 to 2035. Assumed appliance standards in the Expanded Standards case provide additional cumulative energy savings from 2010 to 2035 of 2.8 percent and 1.4 percent in the residential and commercial sectors, respectively. On top of those savings, the tighter building codes assumed in the Expanded Standards and Codes case provide additional cumulative reductions in energy use of 1.0 percent and 1.6 percent in the residential and commercial sectors, respectively. Ultimately, in the Reference case, 19.0 quadrillion Btu of delivered energy consumption is avoided over 25 years relative to projected consumption in the 2010 Technology case. That total is roughly equivalent to the energy that the buildings sectors consumed in 2006. The Expanded Standards and Codes case goes beyond the Reference case to save an additional 19.0 quadrillion Btu of delivered energy from 2010 to 2035.

6. Potential of offshore crude oil and natural gas resources

The 2010 Macondo oil well accident in the Gulf of Mexico heightened awareness of the risks associated with exploration and development of offshore crude oil and natural gas resources, particularly in deep water. In addition, there is significant uncertainty about the offshore resources available in the Gulf of Mexico and Alaska offshore areas. Despite the risks and uncertainties, however, offshore crude oil and natural gas production is expected to remain an important component of U.S. supply through 2035.

In 2009, offshore production accounted for 1.79 million barrels per day or 33 percent of the 5.36 million barrels per day of total U.S. crude oil production and 2.70 trillion cubic feet or 13 percent of the 20.96 trillion cubic feet of U.S. natural gas production. In the *AEO2011* Reference case, offshore production accounts for roughly 32 percent of total domestic crude oil production and 11 percent of total domestic natural gas production over next 25 years.

Analysis cases

Three sensitivity cases were used to evaluate the impacts of key assumptions related to the availability of offshore crude oil and natural gas resources and the costs of exploring and developing them. Specific assumptions in the three cases are discussed below.

High OCS Resource case

Resource estimates for most of the U.S. outer continental shelf (OCS) are uncertain, particularly for resources in undeveloped regions where there has been little or no exploration and development activity, and modern seismic survey data are lacking. In several recent studies prepared for the DOE [*56*] and the National Association of Regulatory Utility Commissioners [*57*], technically recoverable resources in undeveloped areas of the OCS have been estimated at 2 to 5 times the latest (2006) estimates from the U.S. Department of the Interior's Bureau of Ocean Energy Management.

The *AEO2011* High OCS Resource case assumes a technically recoverable undiscovered crude oil resource base in the Atlantic, Pacific, and Alaska OCS and in areas of the eastern and central Gulf of Mexico (which are currently under a statutory drilling moratorium) that is triple the size of the resource base assumed in the Reference case (Table 6), resulting in a total OCS level of technically recoverable resources of 144.0 billion barrels of crude oil, as compared with 69.3 billion barrels in the Reference case. For natural gas, the High OCS Resource case triples the technically recoverable undiscovered resources in some areas, with the exception of the Alaska OCS. Projected natural gas production from the Alaska OCS is not sensitive to the level of technically undiscovered resources, because natural gas prices are not high enough to support investment in a pipeline to bring natural gas from the North Slope area to market.

Reduced OCS Access case

The Reduced OCS Access case assumes leases in the Pacific, Atlantic, Eastern Gulf of Mexico, and Alaska OCS regions are not available until after 2035, as detailed in Table 7.

High OCS Cost case

The High OCS Cost case assumes that costs for exploration and development of offshore oil and natural gas resources are 30 percent higher than those in the Reference case. The higher cost assumption is not intended to be an estimate of the impact of any new regulatory or safety requirements, but is simply used to illustrate the potential impacts of higher costs on the production of OCS crude oil and natural gas resources.

Analysis results

In the High OCS Resource case, the assumed increase in technically recoverable OCS resources in undeveloped areas impacts crude oil and natural gas production through 2035, primarily because of the long lead times required for resource development in the offshore, regardless of the size of the resources discovered. In most areas, depending on location and water depth, a period of 3 to 10 years for exploration, infrastructure development, and developmental drilling is required from lease acquisition to first production. Because the assumed availability of leases in the Pacific, Atlantic, Eastern Gulf of Mexico, and Alaska is the same in the Reference and High OCS Resource cases, crude oil and natural gas production is not affected by the high resource assumption until 2025 and after.

In 2035, offshore crude oil production in the High OCS Resource case is 51 percent higher, at 3.25 million barrels per day, than the Reference case production level of 2.15 million barrels per day (Figure 30). The majority of the increase (65 percent) is from the Alaska OCS, based on the assumed discovery and development of a large field with 2 billion barrels of recoverable crude oil resources. As a result, total domestic crude oil production in 2035 is 1.05 million barrels per day (18 percent) higher in the High OCS Resource case than in the Reference case. Cumulative total domestic crude oil production from 2010 to 2035 in the High OCS Resource case is only 5 percent higher than in the Reference case.

Changes in domestic oil production tend to have only a modest impact on crude oil and petroleum product prices, because any change in domestic oil production is diluted in the world oil market. In 2009, the United States produced 5.36 million barrels per day of crude oil and lease condensate, or 7 percent of the world total of 72.26 million barrels per day. Unlike crude oil supply and prices, domestic natural gas supply and prices are determined largely by supply and demand for natural gas in the North American market, where the development and production of shale gas in the Lower 48 States is largely responsible for current and foreseeable future market conditions.

Natural gas production in U.S. offshore areas in 2035 is 0.7 trillion cubic feet higher in the High OCS Resource case than in the Reference case, putting some downward pressure on natural gas prices (Figure 31). In 2035, the Henry Hub spot price is about 3 percent lower in the High OCS Resource case than in the Reference case. However, the lower price results in only a small increase in natural gas consumption, 0.2 trillion cubic feet. Thus, the increase in OCS natural gas production is offset by a decrease of 0.5 trillion cubic feet in production from onshore domestic supply sources.

In the Reduced OCS Access case, removing the Pacific, Atlantic, Eastern Gulf of Mexico, and Alaska OCS from future leasing consideration lowers projected domestic production of both crude oil and natural gas. The impact on domestic crude oil production starts after 2026 as a result of the lead time between leasing and production and the economics of projects in undeveloped areas. In 2035, offshore crude oil production in the Reduced OCS Access case, at 1.78 million barrels per day, is 17 percent or 0.17 million barrels per day lower than in the Reference case, resulting in a 6 percent decrease in total domestic crude oil production.

Offshore natural gas production in 2035 is 5 percent lower in the Reduced OCS Access case than in the Reference case (2.92 trillion cubic feet compared with 3.05 trillion cubic feet), resulting in a decrease in total U.S. natural gas production of less than 1 percent. Cumulatively, total domestic crude oil and natural gas production from 2010 to 2035 is less than 1 percent lower in the Reduced OCS Access case than in the Reference case.

In the High OCS Cost case, exploration and development costs for crude oil and natural gas resources in all U.S. offshore regions are 30 percent higher than in the Reference case, resulting in lower levels of offshore crude oil and natural gas production throughout the projection period. The largest difference in production levels between the two cases occurs in 2015, when total U.S. offshore crude oil production is 112,000 barrels per day (6 percent) lower and offshore natural gas production is 0.2 trillion cubic feet (9 percent) lower than in the Reference case.

The higher exploration and production costs in the High OCS cost case change the economics of oil and gas development projects and reduce the number of wells drilled annually in offshore areas. Because of the higher costs, exploration and development of some offshore resources occur later, when prices are higher. In 2035, lower 48 offshore crude oil production is 2 percent lower, and lower 48 offshore natural gas production is 3 percent lower, in the High OCS Cost case than in the Reference case. Impacts on crude oil and natural gas

Table 6. Technically recoverable undiscovered U.S. offshore oil and natural gas resources assumed in two cases

	Crude oil (billion barrels)		Natural gas (trillion cubic feet)	
	Reference	High OCS Resource	Reference	High OCS Resource
Developing Gulf of Mexico	32.0	32.0	173.7	173.7
Undeveloped Gulf of Mexico	3.7	11.0	21.5	64.4
Mid- and South Atlantic	1.4	4.1	12.4	37.1
Southern Pacific	5.7	17.1	10.1	30.4
Alaska	26.6	79.8	132.1	132.1
Total undiscovered	**69.3**	**144.0**	**349.8**	**437.7**

prices and consumption are small. In Alaska, however, the increase in costs deters the development of additional offshore resources that are economically viable in the Reference case.

7. Prospects for shale gas

Production of natural gas from large underground shale formations (shale gas) in the United States grew by an average of 17 percent per year from 2000 to 2006. Early successes in shale gas production occurred primarily in the Barnett Shale of north central Texas. By 2006, successful shale gas operations in the Barnett shale, improvements in shale gas recovery technologies, and attractive natural gas prices encouraged the industry to accelerate its development activity in other shale plays. The combination of two technologies—horizontal drilling and hydraulic fracturing—made it possible to produce shale gas economically, and from 2006 to 2010 U.S. shale gas production grew by an average of 48 percent per year. Further increases in shale gas production are expected, with total production growing by almost threefold from 2009 to 2035 in the *AEO2011* Reference case. However, there is a high degree of uncertainty around the projection, starting with the estimated size of the technically recoverable shale gas resource.

Estimates of technically recoverable shale gas are certain to change over time as new information is gained through drilling and production, and through development of shale gas recovery technology. Over the past decade, as more shale formations have been explored and used for commercial production, estimates of technically and economically recoverable shale gas resources have skyrocketed. However, the estimates embody many assumptions that might prove to be untrue in the long term.

In the *AEO2011* Reference case, estimates of shale gas resources are based in part on an assumption that production rates achieved to date in a limited portion of a formation are representative of future production rates across the entire formation—even though experience to date has shown that production rates from neighboring shale gas wells can vary by as much as a factor of 3. Moreover, across a single shale formation, there are significant variations in depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content, and as a result production rates for different wells in the same formation can vary by as much as a factor of 10.

There is also considerable uncertainty about the ultimate size of the technically and economically recoverable shale gas resource base in the onshore lower 48 States and about the amount of gas that can be recovered per well, on average, over the full extent of a shale formation. Uncertainties associated with shale gas formations include, but are not limited to, the following:

- Most shale gas wells are only a few years old, and their long-term productivity is untested. Consequently, reliable data on long-term production profiles and ultimate gas recovery rates for shale gas wells are lacking.
- In emerging shale formations, gas production has been confined largely to "sweet spots" that have the highest known production rates for the formation. When the production rates for the sweet spot are used to infer the productive potential of an entire formation, its resource potential may be overestimated.
- Many shale formations (particularly, the Marcellus shale) are so large that only a portion of the formation has been extensively production tested.
- Technical advances can lead to more productive and less costly well drilling and completion.

Table 7. First year of available offshore leasing in two cases

	Reference	Reduced OCS Access
Eastern Gulf of Mexico	2022	After 2035
North Atlantic	After 2035	After 2035
Mid- and South Atlantic	2018	After 2035
Northern and Central Pacific	After 2035	After 2035
Southern Pacific	2023	After 2035
Alaska	2010	After 2035

Figure 30. Offshore crude oil production in four cases, 2009-2035 (million barrels per day)

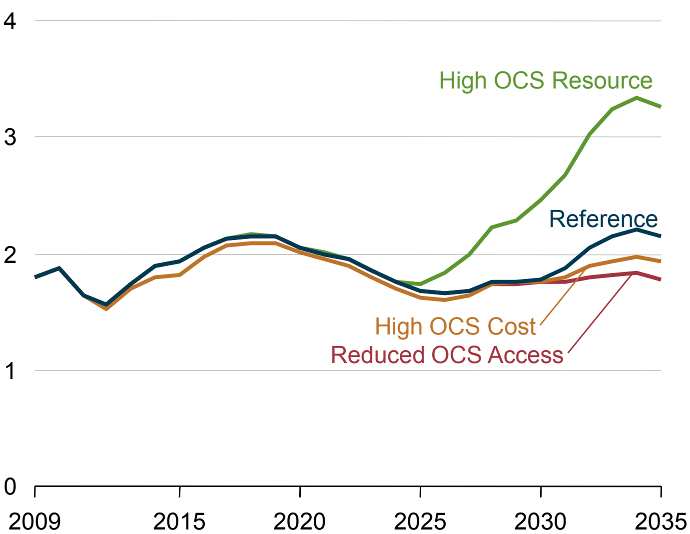
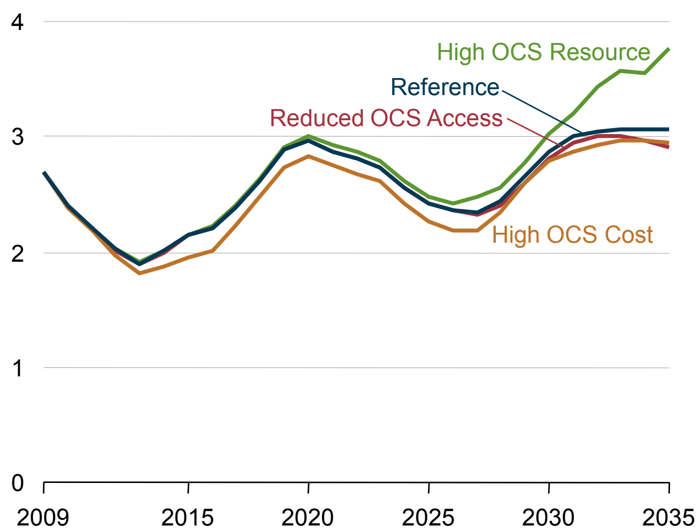


Figure 31. Offshore natural gas production in four cases, 2009-2035 (trillion cubic feet)



- Currently untested shale formations, such as thin seam formations, or untested portions of existing formations, could prove to be highly productive.

Although public estimates of onshore lower 48 shale gas resources, as reported by private institutions, have grown over the past decade as more shale gas plays have been production tested, it is not known what shale formations were included in the estimates or what methodology and data were used to derive them. For example, an estimate relying only on publicly reported costs and performance profiles for shale gas wells would tend to overestimate the size of the economic resource base, because public information is skewed toward high-production and high-profit wells. Given the lack of information about how private institutions have derived their resource estimates, this analysis considers a set of alternative resource estimates that are intended to provide a plausible but not definitive range of potential shale gas resources.

Analysis cases

Two key determinants of the estimated technically recoverable shale gas resource base are (1) estimated ultimate recovery (EUR) per well and (2) an assumed recovery factor that is used to estimate how much of the acreage of shale gas plays contains recoverable natural gas. Four *AEO2011* cases examine the impacts of higher and lower estimates of total recoverable shale gas resources on natural gas prices and production. The four cases are not intended to represent a confidence interval for the resource base, but rather to illustrate how different resource assumptions affect projections of domestic production, prices, and consumption.

High resource cases

Two high shale resource cases were created by increasing two different assumptions underlying the resource estimate. The estimated unproved technically recoverable resource base (excluding 20.1 trillion cubic feet of inferred reserves) is the same in both high shale resource cases and is 50 percent higher than in the Reference case (1,230 trillion cubic feet in the two high shale resource cases, compared with 827 trillion cubic feet in the Reference case).

- In the *High Shale EUR case*, the EUR per shale gas well is assumed to be 50 percent higher than in the Reference case. The higher estimate could result from, for example, better placement of the horizontal lateral within the formation; better completion techniques that allow more of the pore space and absorbed gas to reach the well bore; and/or determination that well recompletions are both productive and economic.
- In the *High Shale Recovery case*, 50 percent more natural gas is assumed to be recovered from each shale formation. The EUR per well is unchanged from the Reference case, and so 50 percent more wells are needed to recover the gas contained in each shale play. Higher recovery could result if a larger portion of each shale formation than originally estimated proves to be productive and economic, and/or if the drilling of more wells, more horizontal laterals, or both closer to each other proves to be productive and economic.

Low shale resource cases

Two low shale resource cases were created by adjusting the same factors described above for the high shale resources cases, but in the opposite direction. The estimated unproved technically recoverable shale gas resources is 423 trillion cubic feet in both of the low shale resource cases, 50 percent lower than the 827 trillion cubic feet level in the Reference case.

- In the *Low Shale EUR case*, the EUR per shale gas well is assumed to be 50 percent lower than in the Reference case. The lower estimate could result, for example, from faster rates of decline in gas production than expected in the Reference case, and/or considerably lower ultimate recovery rates than expected for wells in areas where shale formations have not yet been tested.
- In the *Low Shale Recovery case*, 50 percent less natural gas is recovered from each shale gas play, because, for example, a large number of formations are less productive and less economic than currently anticipated. The EUR per well is unchanged from the Reference case, but the number of wells required to recover the resource is 50 percent lower, because there is 50 percent less natural gas in each shale gas play that can be recovered economically.

The 50-percent variations in the shale gas cases approximate the range of shale gas resource estimates reported by the U.S. Geological Survey for 20 shale gas assessment units in 5 petroleum basins, using the Survey's 95 percent and 5 percent probability resource volumes as indicative of the degree of uncertainty in shale gas resource estimates.

As discussed below, in the High Shale EUR and High Shale Recovery cases, natural gas prices are lower than in the Reference case; however, the energy models used for the *AEO2011* projections do not allow for liquefied natural gas (LNG) exports from domestic facilities. Consequently, net natural gas exports in the Reference, High Shale EUR, and High Shale Recovery cases could be greater if domestic LNG export terminals were represented in the models.

Analysis results

The four shale gas cases illustrate the uncertainties that surround shale gas resources, which could have significant implications for future natural gas prices, production, and consumption (Table 8). They also illustrate that the type of uncertainty involved (EUR or recovery) also bears on the question of how prices, production, and consumption could unfold as uncertainties about the U.S. shale gas resource base are resolved over time.

The largest variations from the Reference case are in the High and Low Shale EUR cases, where lower and higher costs per unit of shale gas production have the effect of increasing and decreasing total production from U.S. shale gas wells. In the Low Shale EUR case, the Henry Hub natural gas price in 2035 is $2.19 per million Btu or 31 percent higher than the Reference case price of $7.07 per million Btu (2009 dollars). Conversely, in the High Shale EUR case, the Henry Hub price in 2035 is $1.72 per million Btu or 24 percent lower than in the Reference case.

In 2035, shale gas production is more than three times as high in the High Shale EUR case as in the Low Shale EUR case, at 17.1 trillion cubic feet and 5.5 trillion cubic feet, respectively, as compared with 12.2 trillion cubic feet in the Reference case. The High and Low Shale EUR cases show the largest variation in shale gas production, as well as the greatest variation in natural gas prices. The High and Low Shale Recovery cases show less variation in production and natural gas prices. In the Low Shale Recovery case, shale gas production totals 8.2 trillion cubic feet in 2035, as compared with 15.1 trillion cubic feet in the High Shale Recovery case. Even in the Low Shale EUR case, however, with the lowest production projections, overall growth in U.S. natural gas production is still primarily the result of an increase in shale gas production from the 2009 level of 3.3 trillion cubic feet.

Price impacts in the High and Low Shale Recovery cases are less pronounced, because the cost per unit of production from each shale formation is the same as in the Reference case. Instead, the recoverable shale gas volume associated with each formation is varied, leading to a corresponding change in the level of drilling required to recover the gas. In the Low Shale Recovery case, the Henry Hub natural gas price in 2035 is $1.10 per million Btu or 16 percent higher than in the Reference case. In the High Shale Recovery case, the Henry Hub price is $1.04 per million Btu or 15 percent lower than in the Reference case. As discussed below, other types of domestic natural gas production and imports are affected by, and reflected in, changes in natural gas prices across the shale gas analysis cases.

In the Low Shale EUR and Low Shale Recovery cases, with higher natural gas prices, total U.S. natural gas consumption in 2035 is 2.4 trillion cubic feet and 1.2 trillion cubic feet lower, respectively, than the Reference case projection of 26.6 trillion cubic feet. Conversely, in the High Shale EUR and High Shale Recovery cases, with lower natural gas prices, total U.S. natural gas consumption in 2035 is 3.1 trillion cubic feet and 1.7 trillion cubic feet higher, respectively, than the Reference case projection.

Natural gas consumption in the specific end-use sectors varies similarly with changes in natural gas prices: higher prices result in less consumption, and lower prices result in more consumption. The electric power sector shows the greatest sensitivity to changes in natural gas prices. In the Low Shale EUR and Low Shale Recovery cases, natural gas use for electric power generation in 2035 is 6.4 trillion cubic feet and 7.1 trillion cubic feet, respectively, compared with 7.9 trillion cubic feet in the Reference case in 2035. In the High Shale EUR and High Shale Recovery cases, total natural gas use for electricity generation in 2035 is 9.6 trillion cubic feet and 8.9 trillion cubic feet, respectively (higher than in the Reference case).

Natural gas consumption in the electric power sector is more responsive to price changes than in the other sectors, because much of the electric power sector's fuel consumption is determined by the dispatching of existing generation units based on the operating cost of each unit, which in turn is determined largely by the costs of competing fuels, such as coal and

Table 8. Natural gas prices, production, imports, and consumption in five cases, 2035

Projection	Low Shale EUR	Low Shale Recovery	Reference	High Shale Recovery	High Shale EUR
Henry Hub spot natural gas prices (2009 dollars per million Btu)	**9.26**	**8.17**	**7.07**	**6.03**	**5.35**
Total U.S. natural gas production (trillion cubic feet)	**22.4**	**24.6**	**26.3**	**28.5**	**30.1**
Onshore lower 48	17.2	19.6	23.1	25.5	27.2
Shale gas	5.5	8.2	12.2	15.1	17.1
Other gas	11.7	11.4	10.8	10.4	10.1
Offshore lower 48	3.5	3.2	3.1	2.8	2.7
Alaska	1.8	1.8	0.2	0.2	0.2
Total net U.S. natural gas imports (trillion cubic feet)	**1.7**	**0.7**	**0.2**	**-0.3**	**-0.5**
Total U.S. natural gas consumption (trillion cubic feet)	**24.1**	**25.4**	**26.6**	**28.3**	**29.6**
Electric power	6.4	7.1	7.9	8.9	9.6
Residential	4.6	4.7	4.8	4.9	4.9
Commercial	3.6	3.7	3.8	3.9	4.1
Industrial	7.5	7.8	8.0	8.4	8.7
Other	2.0	2.1	2.1	2.2	2.3

natural gas. Natural gas use in the end-use consumption sectors is generally less responsive to variations in fuel prices, because opportunities to switch to other fuels typically arise only when a new facility is built, or when an existing facility's equipment is retired or replaced.

Other sources of natural gas supply also respond to changes in shale gas production and natural gas prices across the shale gas analysis cases. Higher shale gas production tends to imply lower production of other natural gas. For example, other onshore lower 48 natural gas production in 2035 varies by 1.6 trillion cubic feet, and offshore lower 48 natural gas production varies by 0.8 trillion cubic feet, between the High and Low Shale EUR cases.

The volume of Alaska natural gas production is determined largely by the presence or absence of an Alaska natural gas pipeline to transport gas into Alberta, Canada, where the gas would be transshipped to the lower 48 States. Whether and when an Alaska gas pipeline is built depends on whether lower 48 natural gas prices are sufficiently high to allow recovery of the pipeline's capital and operating expenses while also providing a sufficient natural gas price at the North Slope wellhead. In the Low Shale EUR and Low Shale Recovery cases, an Alaska gas pipeline begins operation in 2026 and in 2030, respectively, delivering 3.8 billion cubic feet per day into the lower 48 natural gas market.

Just as natural gas prices determine the levels of domestic gas production and consumption, they also determine the level of net natural gas imports, with higher gas prices resulting in higher net natural gas imports. The High Shale EUR and High Shale Recovery cases are particularly noteworthy, because projected natural gas prices in those cases are sufficiently low to cause increases in Mexico's imports of U.S. natural gas that, in 2035, make the United States a net exporter of natural gas, with net exports totaling about 0.5 and 0.3 trillion cubic feet, respectively. U.S. net exports could be even greater if domestic LNG export terminals were developed, but this is not represented in the *AEO* models in the High Shale EUR and High Shale Recovery cases. Under the higher prices associated with the Low Shale EUR and Low Shale Recovery cases, the United States is a net importer of natural gas in 2035, with net imports totaling 1.7 and 0.7 trillion cubic feet year (7 percent and 3 percent of consumption), respectively.

8. Cost uncertainties for new electric power plants

Capital costs are a key consideration in decisions about the type of new generating plant or capacity addition that will be built to meet future demand for electricity. Capital costs for new power plants include materials, skilled labor, and generating equipment. For *AEO2011*, EIA commissioned a study of the cost components for different utility-scale electric power technologies, with the goal of presenting costs for different plant types in a common set of cost categories to facilitate comparison of capital costs. A major change from previous years in assumptions for the cost study included a significant increase in the assumed costs for coal and nuclear power projects [*58*].

There is, however, a great deal of uncertainty about future capital costs for all generating technologies. The completion of initial projects could yield experience that enables costs for future projects to be reduced, through a "learning by doing" process. A slow economic recovery could soften demand for the materials and labor used in building new power plants, which also could lower construction costs. Conversely, a failure to "learn" increases in the costs of labor and key commodities, or an uncertain outlook for the economy in general could increase the costs of future projects.

Because some plant types—coal, nuclear, and most renewables—are more capital-intensive than others (in particular, natural gas), the mix of future capacity installations and consequently the fuels used for power generation depends on both the relative and absolute level of capital costs. If construction costs increase proportionately for plants of all types, leaving relative costs unchanged, natural-gas-fired capacity will be more economical than the more capital-intensive coal and nuclear technologies. Over the longer term, higher construction costs could lead to higher electricity prices, which could slow the growth of electricity consumption.

Case descriptions

Several alternative cases assuming different trends in capital costs for power plant construction were used to examine the implications of different cost paths for new power plant construction. Because there is a correlation between rising power plant construction costs and rising commodity prices, construction costs in *AEO2011* are tied to a producer price index for metals and metal products.

The nominal index is converted to a real annual cost factor, using 2013 as the base year. The resulting cost factor for the Reference case remains nearly flat in the early years of the projection, then declines through the end of the projection, so that the construction cost factors in 2035 are nearly 20 percent lower than in 2011. As a result, future capital costs are lower even before technology learning adjustments are applied. The cost factor remains constant across all technology types.

In the *Frozen Plant Capital Cost case*, base overnight construction costs for all new electricity generating technologies are assumed to remain constant at 2015 levels, when the cost factor peaks in the Reference case. Cost decreases can still occur as a result of technology learning, but overall decreases are slower than in the Reference case. In 2035, capital costs for each technology are roughly 25 percent higher in the Frozen Plant Capital Cost case than in the Reference case.

In the *Decreasing Plant Capital Cost case*, base overnight construction costs for each generating technology in 2010 is 20 percent lower than in the Reference case in 2010, and they decline more rapidly in the projection. In 2035, capital costs for all technologies are about 40 percent lower in the Decreasing Plant Capital Cost case than in the Reference case.

Other alternative cost cases focus on specific technologies to examine the effects of cost reductions that could occur more rapidly for a given technology (for example, as a result of research and development funding or international learning experience).

In the *Low Nuclear Cost case*, capital and operating costs for new nuclear capacity are 20 percent lower than in the Reference case in 2010, and they fall to 40 percent lower in 2035.

In the *Low Fossil Technology Cost case*, capital and operating costs for each new fossil-fired generating technology is 20 percent lower than in the Reference case in 2010, and they fall to 40 percent lower in 2035.

Capacity additions

Overall capacity requirements and the mix of generating types change across the cases. In the Reference case, 223 gigawatts of new generating capacity are added from 2010 to 2035, as compared with 216 gigawatts in the Frozen Capital Cost case and 272 gigawatts in the Decreasing Plant Capital Cost case, where higher and lower electricity prices, respectively, lead to changes in total electricity demand. In addition, slightly more existing capacity is retired in the Decreasing Plant Capital Cost case, because new capacity is less expensive, and some older plants are retired and replaced with new capacity.

In all the cost cases, the majority of new capacity is natural-gas-fired (Figure 32). In the Frozen Plant Capital Cost case, builds of all types drop slightly from the level in the Reference case, but the mix of new generating capacity is similar to that in the Reference case. In the Decreasing Plant Capital Cost case, more new capacity of all types is built than in the Reference case, with nuclear and renewables both capturing slightly higher shares of total capacity builds. The increase in renewable capacity builds the Decreasing Plant Capital Cost case consists primarily of wind capacity.

In the cases that focus on specific technologies, the mix of capacity builds changes to favor those with declining costs. In the Low Fossil Technology Cost case, all coal- and natural-gas fired capacity is less expensive to build than in the Reference case, but the costs for nuclear and renewable capacity are the same as those in the Reference case. As a result, more coal and natural gas capacity is built, and less renewable capacity. Similarly, in the Low Nuclear Cost case, total additions of new nuclear capacity increase to 25 gigawatts, from 6 gigawatts in the Reference case. The new nuclear capacity primarily displaces natural-gas-fired capacity.

Electricity generation and prices

The alternative capital cost cases have smaller impacts on the overall mix of generation by fuel type, because capital cost assumptions do not affect the operation of existing capacity. Coal maintains the largest share of total generation in 2035 in all the cases, varying only from 42 percent to 44 percent across all the cases (Figure 33). The renewable share of generation in 2035 also remains fairly constant at 14 percent to 15 percent in all the cases, because the requirements of different State and regional RPS programs still must be met. In the Decreasing Plant Capital Cost case, generation from biomass co-firing is lower than in the Reference case, and wind generation provides more of the renewable requirement, because generating costs for new technologies, including wind, are lower than the costs for biomass co-firing. The nuclear share of total generation in 2035 is between 17 and 18 percent in all but one of the cases, increasing to 20 percent in the Low Nuclear Cost case. Natural-gas-fired

Figure 32. Additions to U.S. generating capacity by fuel type in five cases, 2009-2035 (gigawatts)

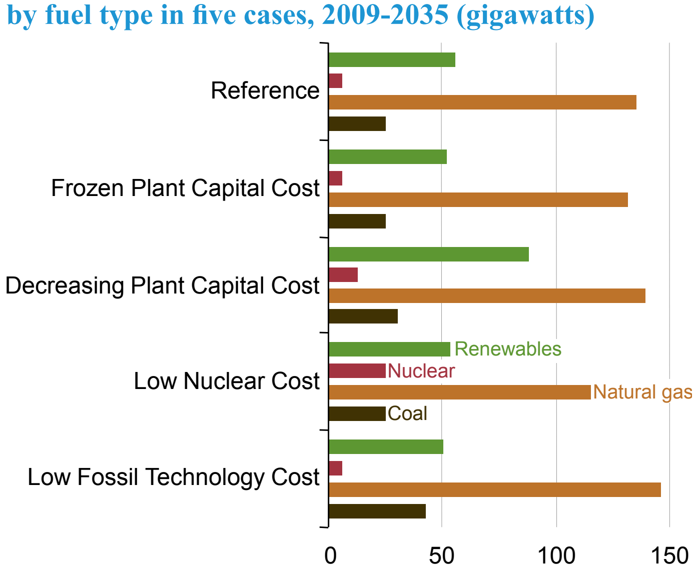
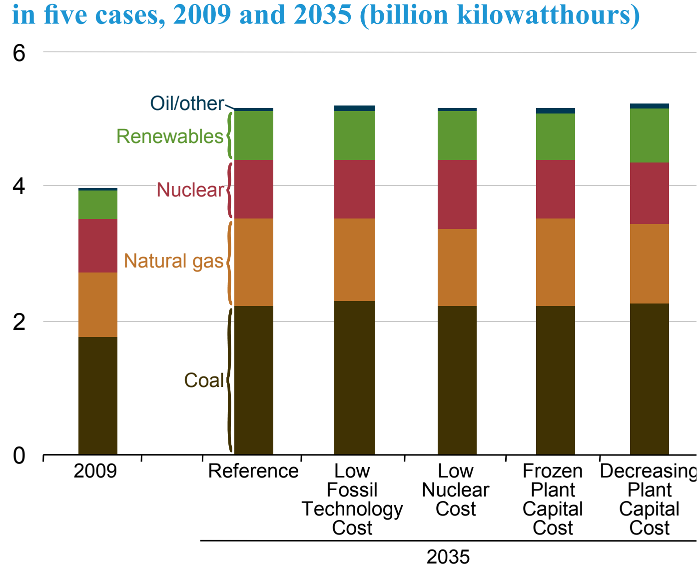


Figure 33. U.S. electricity generation by fuel in five cases, 2009 and 2035 (billion kilowatthours)



generation, typically the marginal generating choice, drops in the Decreasing Plant Capital Cost case, where new capacity of all types is cheaper than in the Reference case.

Electricity prices in 2035 are 1 percent higher in the Frozen Plant Capital Cost case than in the Reference case, because construction costs are higher. In the Decreasing Plant Capital Cost case, electricity prices in 2035 are 4 percent lower than in the Reference case. In the Lower Nuclear Cost and Low Fossil Technology Cost cases, where only those two technologies are affected, price changes are smaller than those in the cases where all technologies were adjusted (Figure 34).

9. Carbon capture and storage: Economics and issues

Background

Carbon capture and storage (CCS) is a process in which CO_2 is separated from emission streams and injected into geologic formations, avoiding its release into the atmosphere. Typically, the captured CO_2 is transported by pipeline from the emissions source to a suitable storage site.

Capturing and storing CO_2 from power plants and industrial processes adds significant capital and operating costs. In some cases, captured CO_2 may have considerable value—for example, it may be sold to oil producers for use in CO_2-enhanced oil recovery (EOR). In some mature oil fields, producers can recover significantly more of the oil in place by injecting CO_2 into a well. CO_2-EOR has been used in the United States for more than 30 years, providing experience in transporting and injecting CO_2 as well as increasing petroleum production [*59*]. However, broad deployment of CCS technology would require additional incentives to be economical, beyond the value added from CO_2-EOR. At present, CCS activity is limited to a few large-scale tests around the world, largely funded by governments.

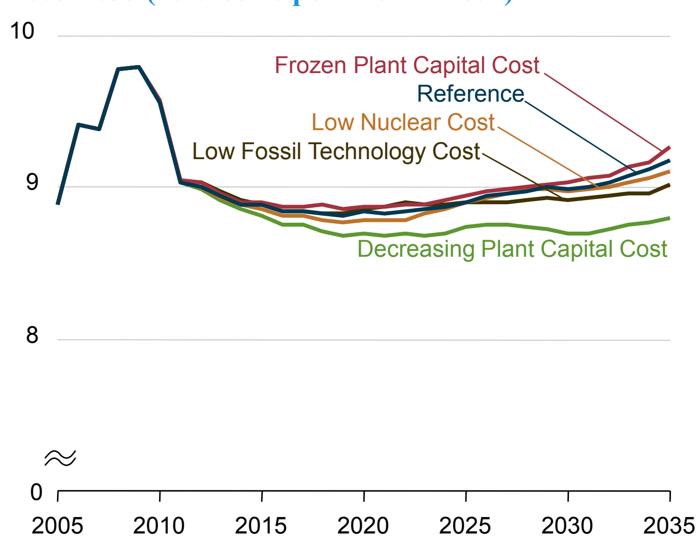
Wide-scale adoption of CCS could allow for continued widespread use of fossil fuels in a low-carbon energy system. Significant barriers to the technology remain, however, such as the cost of building and operating capture-ready industrial facilities, the feasibility of permanently storing CO_2 underground, and the difficulty of constructing significant infrastructure to transport CO_2 to injection sites. Such challenges would have to be overcome in order to enable widespread deployment of CCS. The preponderance of expected costs for CCS deployment are for capturing and compressing the CO_2. However, uncertainty in the cost of permanent storage is also significant.

Current research on CCS is focused on lowering the cost of carbon capture and validating the feasibility of permanent CO_2 storage. The primary goal of the research is to make CCS viable for fossil fuel power plants, which are the largest potential source of CO_2 for CCS and present the most difficult technical hurdles in making CCS economically feasible. A few industrial processes, such as ethanol and ammonia production, yield emissions that are nearly pure CO_2, mitigating the technical challenge and energy intensity of CO_2 capture.

In 2009, CO_2-EOR operators injected nearly 50 million metric tons of CO_2 into operating domestic oil wells, most of which was obtained from natural sources. However, the limited supply of natural CO_2 has provided enough incentive for a few facilities to capture anthropogenic CO_2. This activity has also financed the construction of several pipelines to transport CO_2 to oil fields. There is potential for more early adopters of CCS to continue receiving payments from CO_2-EOR operators, but the quantity of CO_2 that potentially could be used for EOR is small in comparison with the 2.2 billion metric tons emitted in the U.S. power sector in 2009.

Table 9 lists the five commercial-scale CCS projects now in operation worldwide, according to the International Energy Agency. All the projects shown in Table 9 are being monitored over the long term, to ensure that the stored CO_2 does not leak. This is why the Rangely Weber and Weyburn-Midale projects are counted as CCS demonstrations even though they are primarily EOR projects [*60*].

Figure 34. U.S. electricity prices in five cases, 2005-2035 (2009 cents per kilowatthour)



Carbon capture

In order for CO_2 to be transported and stored, it must be isolated from emissions sources and compressed to a supercritical state [*61*]. For fossil fuel power plants, this is the most expensive component of CCS, because the flue gases of existing coal-fired power plants contain only 12 to 14 percent CO_2, and those from existing natural-gas-fired power plants contain only 3 to 4 percent CO_2 [*62*]. Existing technologies for capturing the CO_2 from dilute flue gases are energy-intensive, and consequently their operating costs are high. The National Energy Technology Laboratory is supporting research focused on the development of technologies that can lower the cost of capture, either by developing techniques to lower the cost of purifying dilute CO_2 streams or by increasing the purity of CO_2 in the flue gases of fossil fuel power plants. The goal of the research is to develop and eventually commercialize carbon capture technologies that can be used routinely by power plant operators while adding less than 10 percent to consumers' electricity costs [*63*].

CO_2 emissions from fossil-fuel power plants can be captured through pre-combustion, post-combustion, or oxy-combustion processes. In the near term, the most likely approach for capturing CO_2 from existing coal-fired power plants is to retrofit them with post-combustion capture systems, in which flue gas is treated with a solvent (usually, an amine or chilled ammonia) to separate CO_2 from the flue gas before it is released to the atmosphere. Not all existing fossil fuel power plants can be retrofitted for CCS, however, given the costs, space requirements, and need for access to cooling water, all of which can contribute to making a project infeasible.

CCS technology may be more easily integrated as part of a new fossil-fuel plant, where cost and efficiency savings could be realized by including CCS in the initial design. New coal-fired plants with CCS can be built with post-combustion capture systems, similar to retrofits, or with pre-combustion capture systems that gasify the coal and capture CO_2 from the newly formed syngas before combustion. Retrofitting natural-gas-fired combined-cycle plants with post-combustion technology is also a possibility, as are new natural gas power plants with pre-combustion capture. Carbon capture technologies currently are in the early stages of development, and it is unclear which may be developed on a commercial scale.

CO_2 pipelines

Once captured, CO_2 must be transported to a suitable site for sequestration or EOR. The most cost-effective method is to move CO_2, compressed to a supercritical state, by pipeline. The technology for building pipelines to transport gases over long distances is mature, based on experience with natural gas pipelines, as well as more than 3,000 miles of CO_2 pipelines currently in use to supply CO_2-EOR fields. Large-scale adoption of CCS is likely to require significant construction of new pipelines. Interstate CO_2 pipelines (unlike natural gas pipelines) are not regulated by the Federal Energy Regulatory Commission, and the lack of national eminent domain authority to ease construction [*64*] represents a possible impediment to the development of a national pipeline network.

Geologic sequestration and CO_2-EOR

Several types of geologic formation have been identified as being suitable for permanent carbon sequestration. Key requirements for a formation that can be used for CO_2 storage include being able to store CO_2 cost-effectively, prevent leakage of injected CO_2, and avoiding interference with other valuable geologic formations, such as freshwater aquifers. The largest contributors to the costs of sequestration are the drilling, operating, and monitoring of wells. Cost-effective storage depends largely on the ability of a field to store the CO_2 densely so as to limit the number of injection wells required. Permanent storage capabilities depend on the presence of an impermeable cap rock and lack of faults or uncapped well bores to the surface. Depleted oil and gas fields, deep saline aquifers, and unmineable coal seams all meet these criteria, and all have been identified as good candidates for sequestration. Basalt formations and offshore sediments may also prove to be feasible in the future [*65*].

In the United States, many specific formations have been identified as suitable for sequestration; however, their potential costs and capacities are uncertain. With the exception of depleted oil and gas fields, the geology of sequestration opportunities is not well characterized, and the behavior of injected supercritical CO_2 is not completely understood. It has been estimated that the cost of injection in a saline aquifer can vary by a factor of 3 within a single formation, depending on the geology of the aquifer. Furthermore, injection costs can vary between reservoirs by orders of magnitude [*66*]. Current research is focused on characterizing the geology of sequestration sites and developing methods to estimate capacities and the feasibility of permanently storing CO_2 in specific formations accurately.

Until now, U.S. experience with injecting CO_2 underground has largely been limited to CO_2-EOR. Natural sources of CO_2 comprise a majority of current supply, but some anthropogenic CO_2, largely from natural gas processing plants, is captured and used for CO_2-EOR [*67*]. As long as CO_2 is a valuable commodity, CO_2-EOR operators will maximize oil production to the extent possible and attempt to recover as much injected CO_2 as they can, but there will be little interest in permanent storage. However, CO_2-EOR has helped to establish a market for captured CO_2 and has provided a better understanding of the technical issues involved in injecting CO_2.

Table 9. Commercial-scale CCS projects operating in 2010

Project name	Country	CO_2 source	Quantity injected (million metric tons per year)	Start year
Sleipner	Norway	Natural gas processing	1.0	1996
In Salah	Algeria	Natural gas processing	1.0	2004
Snohvit	Norway	Natural gas processing	0.7	2008
Rangely Weber	United States	Natural gas processing	1.0	1986
Weyburn-Midale	United States/Canada	Coal gasification plant	3.2	2000

Analysis results

Reference case

Without a cost for emitting CO_2 or government support for CCS, there is no reason to add CCS capabilities to facilities other than when oil producers are willing to pay the entire capital and operating costs of capturing and transporting CO_2 for EOR. In the Reference case oil producers are assumed to purchase CO_2 from emitters in several industries at a price that gives emitters sufficient economic incentive to capture their emissions. Interregional CO_2 pipelines may be constructed if oil prices and EOR opportunities make them economical. Pipeline construction is delayed, however, by the time required to get permits and construct such large projects.

In the Reference case, CO_2-EOR plays an increasing role in U.S. petroleum production. Early in the projection period, most CO_2 is obtained from natural sources (Figure 35). As demand for CO_2 increases beyond the capacity of natural sources, industrial emitters with relatively pure streams of CO_2 begin to capture and sell the CO_2 to EOR operators. No anthropogenic CO_2 is captured from power plants beyond the 2 gigawatts of advanced coal with sequestration that is assumed to be supported by Federal incentives, because the cost is too high for oil producers to implicitly fund the construction of a CCS-capable power plant. CO_2-EOR supports more than 1.1 million barrels per day of domestic oil production in 2035 in the Reference case, nearly 4 times the CO_2-EOR production level in 2009. CO_2-EOR provides 19 percent of total U.S. crude oil production in 2035.

Oil prices represent a key uncertainty for future CO_2-EOR projects, because they are the most significant factor in determining the economic feasibility of projects. Other major uncertainties are the amount of CO_2 available to oil producers and the CO_2 emissions cost required to give emitters enough incentive to capture it. In 2035, more than 125 million metric tons CO_2 per year is captured from anthropogenic sources outside the power sector—equivalent to more than 10 percent of the 1,147 million metric tons of direct CO_2 emissions from the industrial sector in 2035. Because not all industrial emissions are sufficiently pure to be captured cheaply, the Reference case results for CO_2-EOR imply that a large proportion of all CO_2 emissions from ethanol fermentation, CTL and BTL plants, hydrogen production in refineries, ammonia plants, and natural gas processing plants will be captured for sale.

GHG Price Economywide case

An additional case, which includes a CO_2 price, illustrates the potential role for CCS in mitigating U.S. CO_2 emissions. In the GHG Price Economywide case, the CO_2 price (in 2009 dollars) rises from $25 per ton in 2013 to $77 per ton in 2035, encouraging the deployment of CCS technology in the power sector. Due to lower capital costs and relatively low natural gas prices, natural gas combined-cycle plants with sequestration are cheaper to build than advanced coal plants with sequestration (Figure 36), although a significant number of existing coal-fired power plants are retrofitted for CCS after 2030. Additional carbon capture capability is constructed for CTL and BTL plants in the refining sector. Commercial-scale CTL and BTL plants with CCS provide a relatively inexpensive source of CO_2 that can be used for EOR.

One factor that could limit future CO_2-EOR activity is the availability of CO_2. In the GHG Price Economywide case, emitters have an economic incentive to capture and store CO_2, given the cost of emitting CO_2 into the atmosphere. In this case, oil producers can purchase CO_2 captured from power plants, with the price to oil producers decreasing as the amount of CO_2 captured increases due to the higher CO_2 supply.

Figure 35. CO_2 injection volumes in the Reference case, 2005-2035 (million metric tons per year)

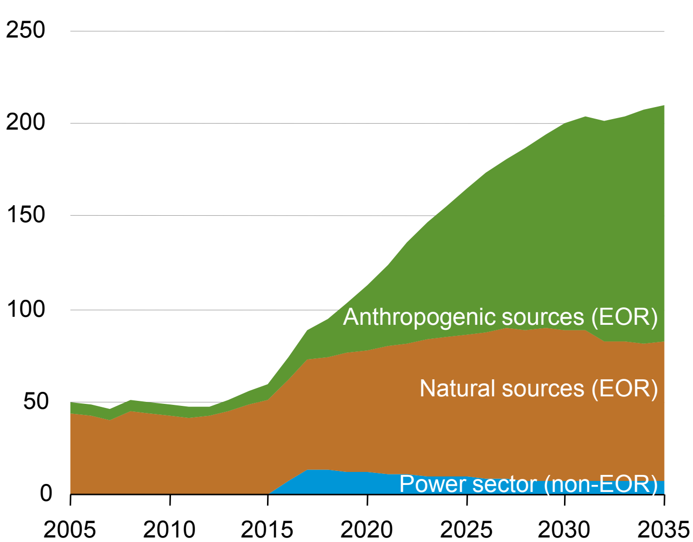
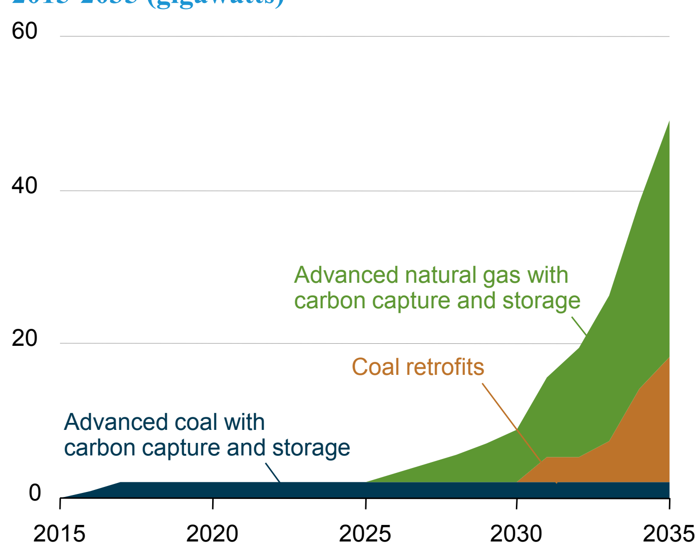


Figure 36. CCS capacity additions in the U.S. electric power sector in the GHG Price Economywide case, 2015-2035 (gigawatts)



Oil producers cannot use all the CO_2 that is captured in the electricity and refining sectors in the GHG Price Economywide case, especially in the later years of the projection period. As a result, significant quantities of CO_2 are sequestered in non-EOR geologic fields (Figure 37). However, despite the low-cost sources of CO_2 for oil producers that come on line after 2015 in the GHG Price Economywide case, there is only a relatively small increase (127,000 barrels per day) in domestic petroleum production, primarily because of the relatively late timing of CCS installations in the power sector and a limit to the number of oil fields suitable for CO_2-EOR that are not already developed in the Reference case.

An alternative viewpoint on the effect that a U.S. carbon mitigation policy could have on CO_2-EOR production is provided in a recent report by Advanced Resources International (ARI) [*68*], which suggests that as much as 3.6 million barrels per day of incremental oil production could have been stimulated if the American Clean Energy and Security Act had passed in 2009. That analysis is not fully comparable with the *AEO2011* projections, however, because the ARI projection was based in part on an earlier version of the National Energy Modeling System that did not fully incorporate a comprehensive framework for developing EOR fields, pipeline infrastructure, and deployment of the technology.

Other sensitivity cases

Two sensitivity cases illustrate the uncertainties in the Reference case projections for CO_2-EOR production. The Low EOR case assumes that the amount of inexpensive, anthropogenic CO_2 that can be accessed by oil producers is lower than in the Reference case. The Low EOR/GHG Price Economywide case adds the GHG Price Economywide case assumptions to those of the Low EOR case.

Figure 38 shows projected CO_2-EOR volumes in the Reference case, GHG Price Economywide case, Low EOR case, and Low EOR/GHG Price Economywide case. The Low EOR case and the Low EOR/GHG Price Economywide case show a stronger response of CO_2-EOR to the increase in availability of CO_2 from carbon capture as a result of the assumed carbon policy. In the Low EOR case, there is significant unsatisfied demand for CO_2 at fields that are suitable for EOR. The GHG price provides a means for that demand to be satisfied.

10. Power sector environmental regulations on the horizon

The EPA is expected to enact several key regulations in the coming decade—pertaining to air emissions, solid waste, and cooling water intake—that will affect the U.S. electric power sector, particularly the fleet of coal-fired power plants. In order to comply with those new regulations, existing coal-fired plants may need extensive environmental control retrofits if they are to remain in operation [*69*]. Because the final makeup of the expected rules is uncertain, *AEO2011* includes alternative cases that assume different variations of possible retrofit requirements. They should be viewed as sensitivity cases, rather than projections of what is likely to happen.

Background on rules

Transport Rule

The Transport Rule, proposed by the EPA in July 2010 [*70*], is designed to reduce emissions of sulfur dioxide (SO_2) and nitrous oxide (NO_x) from electric power plants in the eastern half of the United States. The purpose of the rule is to assist States in complying with the National Ambient Air Quality Standards (NAAQS) for fine particulate matter ($PM_{2.5}$) and ground-level ozone [*71*]. The EPA determined that a major reason many States were not meeting the NAAQS for $PM_{2.5}$ and ozone was emissions from

Figure 37. CO_2 injection volumes in the GHG Price Economywide case, 2005-2035 (million metric tons per year)

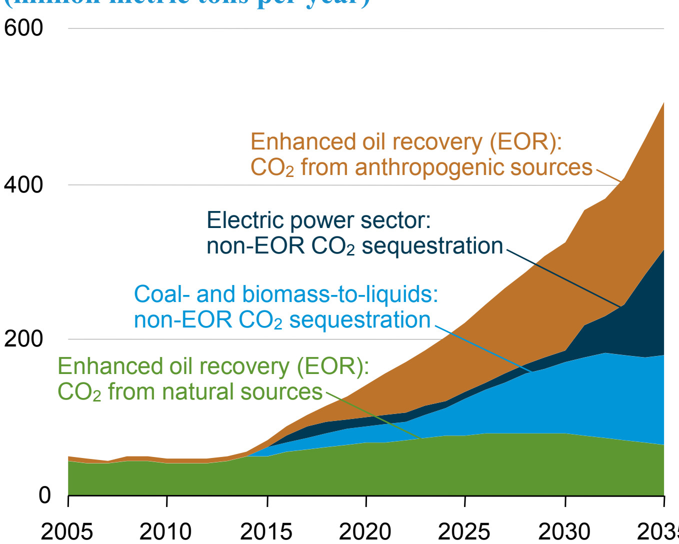
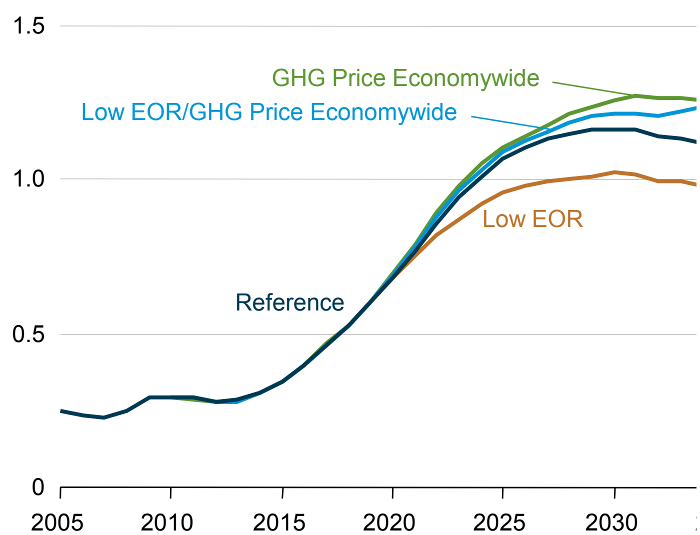


Figure 38. CO_2-EOR oil production in four cases, 2005-2035 (million barrels per day)



power plants in upwind States. Accordingly, the Transport Rule establishes State-level emissions caps designed to limit the effects of power plant emissions on the air quality of neighboring States.

The Transport Rule was developed to address legal flaws in the EPA's Clean Air Interstate Rule (CAIR), which was vacated by the U.S. District Court of Appeals in 2008 [*72*]. First proposed in 2005, CAIR would have established an interstate cap-and-trade system for SO_2 and NO_x emissions in 28 eastern States, designed to meet the same goals as the Transport Rule. The court ruled that CAIR could not be implemented under the Clean Air Act, concluding that a broad regional cap-and-trade system would not guarantee improved air quality in specific local regions, as required by CAA. The court temporarily reinstated CAIR in December 2008, but it ordered the EPA to revise the rule to address the flaws cited. The EPA included limits on interstate trading in the newly proposed Transport Rule specifically for that purpose.

In June 2010, the EPA proposed three versions of the Transport Rule. The EPA's preferred option would cap emissions in each participating State, allow for a limited amount of emissions trading between States, and permit unlimited intrastate trading. A second alternative would prohibit any interstate trading but allow intrastate trading. A third option would disallow all emissions trading. The EPA is expected to announce a final rule in the spring of 2011.

In designing the Transport Rule, the EPA determined that 28 States have SO_2 emissions levels high enough to contribute significantly to $PM_{2.5}$ nonattainment in downwind States, and that 26 States have NO_x emissions levels high enough to contribute to ozone nonattainment. The Transport Rule would require each of those States to reduce emissions to a defined cap by 2012. An additional 15 States would be required to reduce SO_2 emissions further by 2014 (Table 10).

In addition, the EPA is considering lowering the NAAQS for annual ozone concentrations from the current limit of 75 parts per billion. If it does, additional reductions in NO_x emissions from power plants probably will be required beyond the sensitivity case evaluated here. The EPA has hinted that this would be done by increasing the stringency of the Transport Rule for NO_x at some point in the future.

There are several possible strategies for reducing SO_2 emissions from coal-fired power plants: plant owners can use lower sulfur coal in their boilers, retire plants without emissions controls, or install emissions control equipment—primarily, flue gas desulfurization (FGD) scrubbers. There are two key types of FGD scrubbers, wet and dry. Wet scrubbers remove SO_2 from post-combustion flue gas by using a wet alkaline solution, typically containing limestone. Dry scrubbers send the flue gas through a semi-dry alkaline sorbent that removes the SO_2 [*73*]. *AEO2011* assumes that all future SO_2 control systems will consist of wet FGD scrubbers.

For NO_x there are two basic emissions reduction technologies: combustion and post-combustion. Combustion technologies adjust the combustion reaction so that less NO_x is produced. Post-combustion technologies remove NO_x from the exhaust after it is produced. The choice of control technology is based on plant-specific characteristics, such as unit capacity, boiler configuration, and coal type. Combustion retrofits generally are accomplished by modifying existing boilers so that less NO_x is produced in the combustion process—usually a less costly option but also less effective at removing emissions than post-combustion controls.

There are two types of post combustion NO_x controls: selective catalytic converters (SCRs) and selective noncatalytic converters (SNCRs). Both technologies use a reagent (typically ammonia or urea) to react with the flue gas in order to reduce NO_x to nitrogen and water. In SCRs the reaction occurs in the presence of a catalyst bed; in SNCRs the catalyst bed is not included. The catalyst increases the cost and scale of a retrofit project, but it also increases the efficiency of NO_x removal. SCRs also are more easily scaled up, which makes them a more effective option for larger plants. The most stringent pollution control case in *AEO2011* assumes that all plants not currently using NO_x controls will be required to install SCRs.

Utility boiler MACT

In March 2011, the EPA proposed rules to regulate emissions of mercury, other metals, and acid gases from power plants. The rules are intended to enforce Section 112 of the Clean Air Act's limits on emissions of hazardous air pollutants (HAPs) from electric power plants. The rule requires that all power plants larger than 25 megawatts capacity install the MACT needed to reduce emissions of affected pollutants to levels that match the performance of top-performing plants of the same type. Hydrogen chloride (HCl) and $PM_{2.5}$ were used as proxies for all acid gases and for metals other than mercury, respectively, because they would tend to be captured by the same control devices. The rule is intended to result in the removal of 91 percent of mercury and HCl from the emissions of coal-fired power plants and the installation of fabric filters at all plants in order to meet the PM limits.

Table 10. Transport Rule emissions targets, 2012 and 2014 (million metric tons)

	Annual SO_2 (28 States)	Annual NO_x (28 States)	Ozone season NO_x (26 States)	Annual SO_2 (15 additional States)
Actual 2005 emissions	8.9	2.7	0.9	--
Actual 2009 emissions	4.6	1.4	0.6	--
2012 emissions targets	3.4	1.3	0.6	--
2014 emissions targets	3.4	1.3	0.6	2.6

Potential regulation of coal combustion residuals

In June 2010, the EPA released a proposal for regulating coal combustion residuals (CCRs) from electric power plants under the Resource Conservation and Recovery Act (RCRA). Two options given by the EPA were to regulate CCRs under Subtitle C of the RCRA, which would classify CCRs as a hazardous waste pollutant, or Subtitle D, which would classify them as a nonhazardous waste pollutant. By defining CCRs as hazardous, Subtitle C would place more stringent regulations on the storage of coal ash, which probably would result in the closure of surface ash impoundments.

Subtitle D would require the EPA to establish a national criterion for permitting CCR disposal but would leave implementation of such a system to the States. Under Subtitle D, the EPA is considering two options for existing surface impoundments, which are referred to as "Subtitle D" and "Subtitle D Prime." The primary difference between the two options is that, under Subtitle D, existing surface impoundments would either have to be retrofitted with composite liners or cease receiving CCRs within 5 years, while under the Subtitle D Prime, existing surface impoundments could continue to operate to the end of their useful lifetimes without the installation of composite liners. RCRA Subtitle C would require active regulation by the EPA. Under Subtitle D, the main vehicle for enforcement would be citizen lawsuits. As of January 2011, the EPA was reviewing comments on the proposed rule, with a final rule expected to be released in 2011.

In complying with the proposed regulations for CCRs, plants could face increased costs for CCR disposal, depending on specific plant characteristics. Plants with on-site coal ash impounds could incur costs for retrofits or replacements. Plants with wet ash handling systems could be required to switch to dry ash handling systems. The Tennessee Valley Authority (TVA) has already announced that it will replace all wet ash handling systems with dry systems across its entire coal-fired fleet (about 17 gigawatts total capacity). TVA estimates that the investment required for the conversion will be between $1.5 billion and $2.0 billion over the next 10 years [*74*]. However, because of uncertainty about the makeup of the final rule and the difficulty of assessing project costs, which are inherently site-specific, the potential CCR regulations are not included in any *AEO2011* cases.

The EPA has been seeking to regulate mercury emissions from power plants since they were first designated a HAP in December 2000. In 2005, the EPA proposed a cap-and-trade system for mercury under the Clean Air Mercury Rule (CAMR). However, regulating with a cap-and-trade policy required that the EPA first remove mercury from the HAPs list. That action was challenged in court by several States and environmental organizations, and as a result the U.S. Court of Appeals for the District of Columbia Circuit vacated CAMR in 2008 [*75*].

Despite the court's ruling, the EPA still is required by the CAA to regulate mercury emissions from power plants. The utility boiler MACT rules are intended to fulfill that obligation. Currently, there are 189 listed HAPs. In developing the MACT standards, the EPA determines the emissions of each of those pollutants from power plant boilers. In its proposed rule, the EPA has designated certain pollutants as "proxy" pollutants, meaning that the regulation of one substance could serve to cover others. The rule is expected to be finalized by November 2011. After it is issued, power plant owners will have until 2015 to comply, although extensions of up to 2 years may be granted.

Mercury emissions from power plants can be reduced by fabric filters and activated carbon injection (ACI) systems, which work by injecting powdered carbon into flue gases to bind the mercury and then using particulate control equipment, such as fabric filters, to remove it. Mercury can also be removed by equipment designed to reduce other pollutants, such as FGD scrubbers. FGD scrubbers are especially effective in reducing mercury from bituminous coal emissions, due to its particular chemical makeup. ACI systems may be necessary to remove mercury from subbituminous and lignite coal emissions. In the sensitivity cases discussed here, all coal-fired plants are required to reduce mercury emissions by 90 percent.

Acid gas can be removed through the use of FGD scrubbers or direct sorbent injection (DSI). DSI has lower capital costs than FGD scrubbers, but the technology has not yet been widely deployed in the power sector. In its regulatory impact analysis of the Air Toxics Rule, the EPA assumes significant deployment of DSI [*76*]. Because of DSI's relatively low capital costs, the EPA sees it as an attractive, low-cost way for smaller coal plants with lower utilization factors to comply with the rule and continue operating. Other analyses are not as optimistic on the prospect of DSI. For example, a study by the Edison Electric Institute on the impacts of several proposed EPA rules for the power sector shows DSI being installed on only 9 gigawatts of capacity to comply with the utility boiler MACT [*77*]. In order to represent a more stringent case, *AEO2011* assumes that FGDs will be needed for compliance with the rule.

Retrofit or retire?

Several key economic factors can influence owners' decisions as to whether older power plants should be retrofitted or retired. The stringency of regulations, compliance costs, remaining life of a plant, fuel prices, and expectations regarding electricity demand and prices all may be considered. Plant owners must determine whether expected future revenues from their plants over their remaining lives will be sufficient to recover the investment in new equipment needed to comply with environmental regulations. Key variables in the determination are the costs of retrofit equipment and future electricity prices.

Because natural gas often is the marginal fuel for electricity generation, low natural gas prices make it more likely that older coal-fired plants will be retired. Low natural gas prices reduce the overall cost of generating electricity, eventually leading to reduced revenues from coal-fired plants. The updated estimates of capital costs for coal and nuclear power plants in *AEO2011* are 25 to 37 percent higher than those used in *AEO2010*, whereas capital costs for natural gas combined-cycle plants are essentially unchanged

Potential regulation of cooling water intakes

Section 316(b) of the Clean Water Act (CWA) requires facilities with cooling water intake structures to use the best technology available (BTA) to mitigate the environmental impacts of the systems—specifically, damage to aquatic wildlife. In 2004, the EPA originally proposed regulation of existing power plants under Section 316(b), which is intended to apply to all facilities that remove at least 50 million gallons of water per day from the environment and use at least 25 percent of the water for cooling. A typical 500-megawatt plant with once-through cooling uses approximately 500 million gallons of cooling water per day. However, determining BTA as it applies to the CWA has been the subject of extensive legal delays, culminating in a Supreme Court case, which has delayed implementation of the rule [*78*]. Because of the Court's ruling, the EPA is able to consider both the costs and benefits in the design of its final rule. The EPA issued proposed standards for comment on March 28, 2011.

In a once-through system, intake structures withdraw water for use in a thermal power plant's cooling system. Once used, the water is discharged back into the body of water at a higher temperature. Both the water intake and thermal discharge can cause significant damage to local fish populations. In a closed-cycle cooling system, heat from the power plant is removed through evaporation in a nearby cooling tower. Closed-cycle systems require significantly less water intake than once-through systems, mitigating much of the environmental damage associated with the cooling system.

The determination of BTA for cooling water in power plants could have a substantial effect on the entire power sector. New York State and California already have issued rules that essentially require all plants in their States to have closed-loop cooling systems. If the same standard were implemented nationwide, extensive retrofits would be required. The Electric Power Research Institute (EPRI) has estimated that 312 gigawatts of capacity currently in operation (252 gigawatts of fossil fuel capacity and 60 gigawatts of nuclear capacity) would be affected by such a rule. In some cases it may not be possible to install a closed-loop cooling system, and such a requirement could, therefore, cause some plants to be retired.

Closed-loop cooling is considered the most stringent form of compliance with Section 316(b) of the CWA. Other methods of reducing fish mortality, such as wedge wires, variable speed pumps, and traveling water screens, may not be as effective as cooling towers, but they can be installed at much lower cost. In view of that uncertainty, the *AEO2011* cases do not include compliance with Section 316(b).

from *AEO2010*. In addition, projected natural gas prices in the *AEO2011* Reference case are lower than those in *AEO2010*, reducing the levelized costs of generation for new natural gas power plants. Consequently, new combined-cycle plants are an attractive alternative for replacing capacity lost as a result of coal-fired plant retirements.

Uncertainty about future GHG regulations continues to loom in power sector investment decisions. Despite a lack of Congressional action, many utilities include a CO_2 emissions price in their long-term investment decisions [*79*]. A carbon price would increase the cost of generation for all fossil fuel plants, but the largest impact would be on coal-fired generation. Thus, plant owners could be reluctant to retrofit existing coal plants, given the possibility that GHG regulations might be enacted in the near future. This uncertainty may influence the expectations of plant owners about the economic lives of particular facilities.

In the Reference case and most of the alternative cases for *AEO2011*, existing power plants are assumed to continue operating for at least 20 years, allowing the costs of environmental retrofits to be recovered over a 20-year period. In addition, *AEO2011* includes two cases described below, which assume that investors will implement retrofits only if their costs can be recovered over a 5-year period, given their concern that future laws or regulations aimed at limiting GHG emissions present a significant risk to the long-term operation of the affected units.

Analysis cases

Transport Rule Mercury MACT 20 case

The Transport Rule Mercury MACT 20 case assumes that the Transport Rule will be enacted in 2014, placing limits on SO_2 and NO_x emissions. It also assumes a 90-percent MACT for mercury starting in 2015. This case assumes a 20-year capital recovery period for financing FGD scrubbers and SCRs.

Transport Rule Mercury MACT 5 case

This case is identical to the Transport Rule Mercury MACT 20 case, except that it assumes a 5-year capital recovery period for financing FGD scrubbers and SCRs.

Retrofit Required 20 case

The Retrofit Required 20 case assumes more stringent regulation of air emissions from coal-fired plants and utility boilers, requiring the installation of FGD scrubbers and SCRs. It is based on assumptions of more stringent utility boiler MACT requirements and future NO_x emissions limits. Utility boiler MACT regulations are scheduled to be effective in 2015, but this case assumes a lag of several years to account for possible delays in implementation.

Retrofit Required 5 case

This case is identical to the Retrofit Required 20 case, except that it assumes a 5-year capital recovery period for financing FGD scrubbers and SCRs.

Low Gas Price Retrofit Required 20 case

This case is similar to the Transport Rule Mercury MACT 20 case but uses more optimistic assumptions about future volumes of shale gas production, which leads to lower natural gas prices. The domestic shale gas resource assumption in this case comes from the *AEO2011* High Shale EUR case (Figure 39).

Low Gas Price Retrofit Required 5 case

This case is identical to the Low Gas Price Retrofit Required 20 case, except that it assumes a 5-year capital recovery period for financing FGD scrubbers and SCRs.

GHG Price Economywide case

The GHG Price Economywide case assumes a price on CO_2 emissions that rises from $25 per ton (2009 dollars) in 2013 to $77 per ton in 2035. It does not include any specific provisions of the proposed Kerry-Lieberman and Waxman-Markey bills [*80*], such as offsets, bonus allowances, targeted allowance allocations, or increased efficiency mandates. None of the EPA rules described above is included in the GHG Price Economywide case.

Results

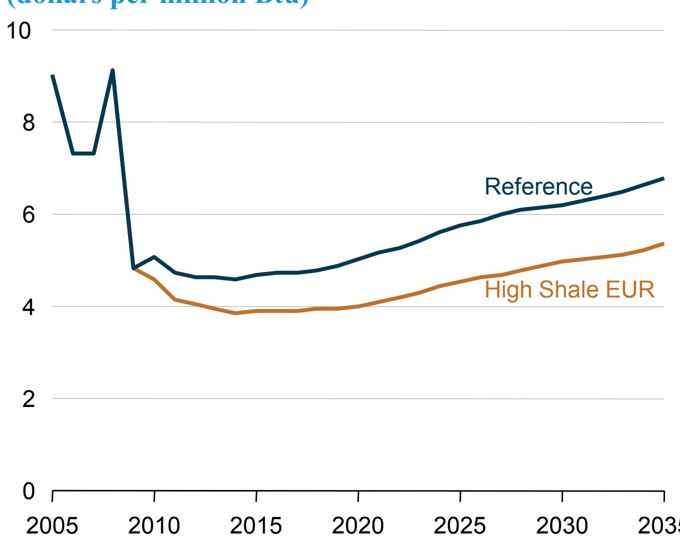
Coal-fired plant retirements

Retirements of coal-fired power plants in the different analysis cases vary with the assumed stringency of environmental rules, the assumed cost recovery period for retrofit investments, natural gas price levels, and assumptions regarding future GHG regulations. Of the 316 gigawatts of coal-fired capacity currently in operation in the United States, 117 gigawatts has no FGD scrubbers installed or currently under construction [*81*]. Lacking some of the controls necessary to comply with potential future regulations, those coal plants may be candidates for retirement if the regulations are enacted. Generally, the poorest performing plants, with the highest heat rates and lowest utilization rates, are the first that might be retired. Table 11 shows the amount of capacity retired along with the retired plants average heat rates and capacity factors in each case.

Projected retirements of coal-fired capacity are higher in each of the analysis cases shown in Table 11 than in the Reference case. Because the emissions reduction requirements in CAIR and the Transport Rule are similar, increased retirements in the Transport Rule Mercury MACT 20 and MACT 5 cases can be attributed to restrictions on allowance trading and to the Mercury MACT. In the Retrofit Required 20 and Retrofit Required 5 cases, explicit mandates are assumed to require the installation of FGDs and SCRs, so that retirement decisions are based on the costs of retrofits. In the Retrofit Required 20 case, most coal-fired plants continue operating beyond 2020. In the Retrofit Required 5 case, with only 5 years to recover the costs of installing retrofits, the amount of coal-fired capacity retired is more than double the amount retired in the Retrofit Required 20 case.

Lower natural gas prices in the Low Gas Price Retrofit Required 20 and Low Gas Price Retrofit Required 5 cases lead to comparatively more retirements of coal-fired capacity—39.5 and 72.6 gigawatts, respectively. Lower natural gas prices reduce the price of electricity in general, lowering power plant revenues. For natural-gas-fired plants, revenue reductions are largely offset by lower fuel costs. For coal-fired plants, assuming that coal prices do not change, there is no offset for the revenue declines, and retrofit projects become uneconomical in some instances. The GHG Price Economywide case assumes a price on CO_2 emissions, which renders many existing coal-fired plants uneconomical. As a result, retirements of coal-fired capacity total 135 gigawatts by 2035.

Figure 39. Natural gas prices in the Reference and High Ultimate Shale Recovery cases, 2005-2035 (dollars per million Btu)



Retrofit equipment installations

In the Retrofit Required 20 and Retrofit Required 5 cases, power plants are required to install FGD scrubbers and SCRs in order to continue operating after 2020, based on the assumption that stringent controls will be required by the EPA for compliance with clean air rules. The combined cost of the two retrofits could range from $500 to $1,000 per kilowatt of capacity, depending on plant size and characteristics [*82*]. More retrofits occur in the Retrofit Required 20 case than in the Retrofit Required 5 case, because the economics of retrofit projects improve with the longer capital recovery period.

The Transport Rule Mercury MACT 20 and Transport Rule Mercury MACT 5 cases mandate emissions reductions, but they do not require the installation of any particular control equipment. Therefore, while there are more retrofit projects in these cases than in the Reference case, there are not nearly as many as in the Retrofit Required 20 and 5 cases, because there are other options for compliance with the rule, such as using more low-sulfur coal and dispatching uncontrolled plants less often—options that are not available in the Retrofit Required 20 and 5 cases. In the Low Gas Price Retrofit Required 20 and 5 cases, lower prices for natural gas lead to lower overall electricity prices and lower plant revenues. There are fewer retrofits in the Low Gas Price cases, because lower revenues make it less likely that plant owners will be able to recover their investments in the equipment.

In the GHG Price Economywide case, 16 gigawatts of existing coal-fired capacity is retrofitted with CCS equipment. CCS is still unproven on a commercial scale, but *AEO2011* assumes that the technology will be available as a carbon mitigation option if a sufficient CO_2 price is in place.

Generation by fuel

Despite the decline in coal-fired capacity in all the analysis cases above, coal remains the largest single source of generation through 2035 in all but one of the cases (Figure 40). Even with more stringent emission caps, once a coal plant has been retrofitted it becomes more economical to run, because SO_2 and NO_x emission allowance costs are no longer incurred. Many of the coal plants that are retired have low utilization factors and high heat rates, and their contribution to overall coal generation is relatively small. In the Retrofit Required 20 and 5 cases, coal-fired generation increases in 2020, as plants that overcome the regulatory hurdle and install retrofits are run more frequently. In the Retrofit Required 20 case, coal-fired generation in 2035 is higher than in the Transport Rule Mercury MACT 20 and 5 cases, as the retrofitted plants are heavily utilized. Other than in the GHG Price Economywide case, electricity generation from coal is lowest in the Low Gas Price Retrofit Required 20 and 5 cases, where low natural gas prices stimulate construction of new natural gas plants to replace retired coal capacity, and existing gas-fired capacity is dispatched more frequently, displacing additional coal-fired generation. In the Low Gas Price Retrofit Required 20 and 5 cases, generation from coal in 2035 is 10 percent and 19 percent below the Reference case level, respectively. In the Low Gas Price Retrofit Required 5 case, the natural gas and coal shares of total generation in 2035 are the same, at 34 percent.

Natural-gas-fired electricity generation in 2035 is higher in all the cases (although it is lower in some earlier years) than in the Reference case. Rapid growth in gas-fired generation is supported by low natural gas prices and relatively low capital costs for new natural gas plants, which improve the relative economics of natural gas when regulatory pressure is placed on the existing coal fleet. Natural gas emits virtually no SO_2 and less NO_x than does coal, making it a more attractive fuel for environmental compliance.

In the Transport Rule Mercury MACT 20 and 5 cases, generation from natural gas grows steadily throughout the projection. In the early years, gas-fired generation is slightly higher than in the Reference case, because fuel switching is used as an option to comply with the flexible requirements of the Transport Rule. In the Retrofit Required 20 case, electricity generation from natural gas increases more slowly, and it is 4 percent lower than the Reference case level in 2025, when retrofitted coal plants no longer incur costs for SO_2 and NO_x emissions allowances (Figure 41). In the Low Gas Price Retrofit Required 20 and 5 cases, utilization of existing combined-cycle natural gas plants is higher throughout the projections, resulting in more gas-fired generation. In all the cases, increases in natural-gas-fired generation after 2025 result predominantly from the construction of new combined-cycle plants to meet growing demand for electricity and replace retired coal capacity.

In the GHG Price Economywide case, coal-fired generation declines steadily throughout the projection. In 2035, generation from coal is approximately 54 percent below the 2009 level, and 11 percent of the electricity generated from coal comes from either new or retrofitted coal plants with CCS. Generation from natural gas increases by more than 90 percent from 2009 to 2035 in the GHG Price Economywide case. Natural gas is a more attractive fuel for complying with a GHG price, because when it is used

Table 11. Coal-fired plant retirements in nine cases, 2010-2035

Analysis case	Coal-fired capacity retired (gigawatts)	Average size of coal-fired plants retired (megawatts)	Average heat rate of coal-fired plants retired (million Btu per kilowatthour)
Reference	8.8	93.0	12,338
Transport Rule Mercury MACT 20	13.5	91.4	12,053
Transport Rule Mercury MACT 5	17.8	83.3	12,102
Retrofit Required 20	19.2	84.5	12,034
Retrofit Required 5	44.8	91.2	11,579
Low Gas Price	15.6	104.0	12,098
Low Gas Price Retrofit Required 20	39.5	97.8	11,576
Low Gas Price Retrofit Required 5	72.6	109.6	11,363
GHG Price Economywide	135.2	157.0	11,454

in an efficient combined-cycle plant, it emits approximately 60 percent less CO_2 per kilowatthour of generation than coal burned in a typical existing plant. Toward the end of the projection, new natural gas plants with CCS are also built in the GHG Price Economywide case, and in 2035 13 percent of gas-fired electricity generation is from plants with CCS.

Generation from nuclear power is the same as in the *AEO2011* Reference case in all cases, with the exception of the GHG Price Economywide and Low Gas Price Retrofit Required 20 cases. In the GHG Price Economywide case, generation from nuclear capacity increases as a result of additional capacity builds. In the Low Gas Price Retrofit Required 20 case, 2.9 gigawatts of nuclear capacity is retired because electricity prices are low. Generation from renewables remains relatively unchanged from the Reference case level through 2035 in all cases.

Fuel use

High levels of electricity generation from natural gas generally mean more natural gas consumption. In all cases examined here, natural gas use in 2035 is higher than in the Reference case (Figure 42). The largest increase in natural gas consumption occurs in the Low Gas Price Retrofit Required 20 and 5 cases, where natural gas consumption in 2035 is 23 percent and 36 percent higher, respectively, than in the Reference case, as well as in the GHG Price Economywide case, where natural gas consumption is 30 percent higher in 2035.

Capacity additions

The retirement of significant amounts of coal-fired capacity, combined with growth in electricity demand, necessitates the construction of additional generation capacity. Natural gas plants with lower generating costs make up the majority of new capacity in all cases, with the largest amount of new natural gas capacity constructed in the Low Gas Price Retrofit Required 20 and 5 cases. Most of the new coal-fired plants that are built have already been announced and are in either planning or construction stages. All new nuclear plants are built as a result of public policies (such as PTCs and the loan guarantee programs). A small amount of new coal-fired capacity is built in the last few years of the Reference case projection, because natural gas prices rise. Renewable capacity additions are similar to the Reference case in all cases.

In the GHG Price Economywide case there is significantly more new capacity construction than in any of the other cases, as coal-fired plants are retired and need to be replaced with low CO_2-emitting technologies (Figure 43). This includes 29 gigawatts of new nuclear capacity added through 2035. In the cases without a CO_2 emissions price, new nuclear power plants are built beyond those explicitly helped by the loan guarantee program. However, a price on CO_2 emissions raises the cost of electricity sufficiently for nuclear power (which releases no CO_2) to become an economically viable option without additional subsidies. Additions of renewable

Figure 40. Electricity generation by fuel in nine cases, 2009 and 2035 (trillion kilowatthours)

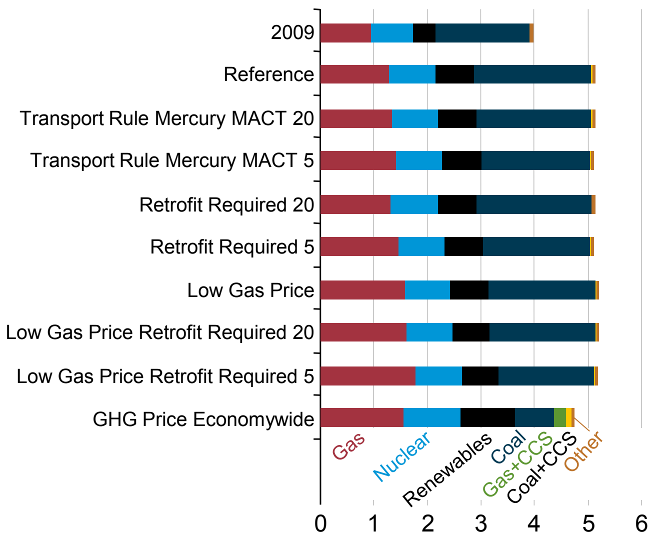


Figure 41. Electricity generation by fuel in nine cases, 2009 and 2025 (trillion kilowatthours)

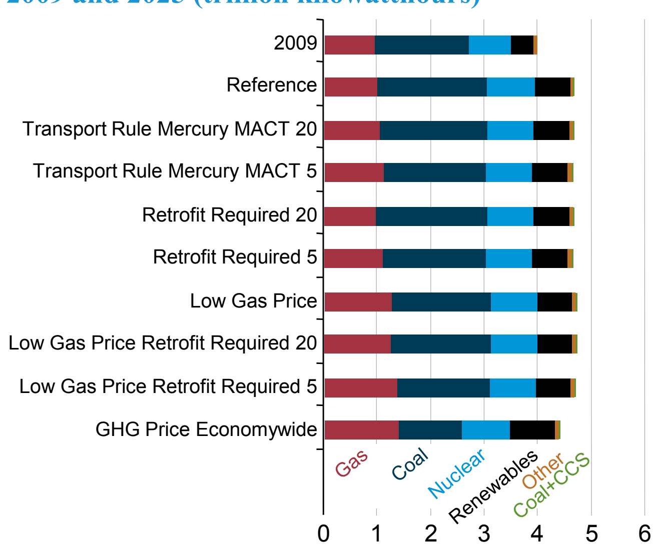
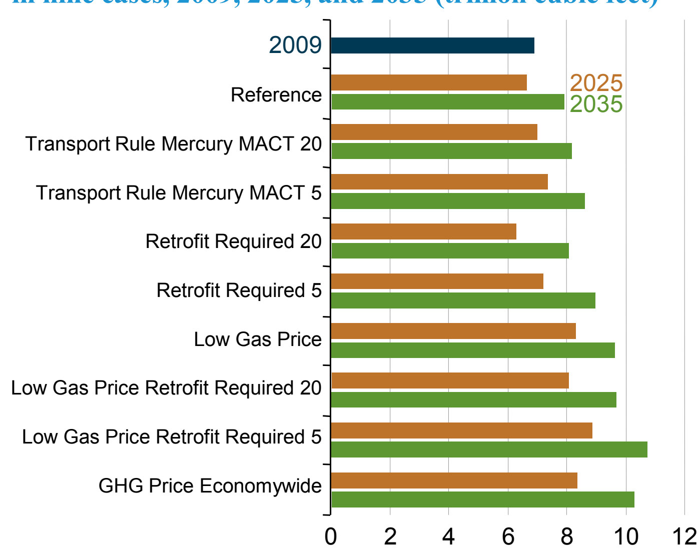


Figure 42. Natural gas consumption in the power sector in nine cases, 2009, 2025, and 2035 (trillion cubic feet)



capacity, also a low-CO_2 source of electricity, are 36 percent higher in the GHG Price Economywide case than in the Reference case in 2035.

Emissions

Emissions of SO_2 decline from Reference case levels in all cases, with more dramatic declines in the Retrofit Required 20 and 5 cases. With the Transport Rule in force, SO_2 emissions decline to levels slightly below the Reference case level. The Reference case already includes CAIR, which remains in effect until the Transport Rule takes effect. CAIR features a flexible trading system and allowance banking, resulting in slightly higher annual emissions toward the end of the projection and more variability in year-to-year emissions levels. Trading is more limited with the Transport Rule because of restrictions on the banking of allowances, which levels out emissions over the projection. NO_x emissions are slightly higher with the Transport Rule than in the Reference case, because fewer NO_x control retrofits are built as a result of the higher NO_x allowance prices under CAIR than under the Transport Rule. There are significant reductions in SO_2 and NO_x emissions in the four Retrofit Required cases, where all coal-fired plants that continue to operate through 2020 are required to be equipped with FGD and SCR. The Retrofit Required 20 and 5 cases are assumed to be implemented nationwide, whereas the Transport Rule Mercury MACT 20 and 5 cases apply only to the targeted States. Except for the Low Gas Price and GHG Price Economywide cases, all cases assume a 90-percent mercury MACT, which reduces mercury emissions significantly from Reference case levels after 2015.

CO_2 emissions from the electric power sector in 2035 are lower in all cases than in the Reference case because of the shift from coal-fired to natural-gas-fired generation, but with electricity demand increasing throughout the projection period they are higher than the 2009 level except in the GHG Price Economywide case (Figure 44). Coal-fired plants that are not retired are used heavily, and natural gas plants still emit CO_2 albeit at a significantly lower rate per kilowatthour than coal plants. In the GHG Price Economywide case, significantly more coal-fired capacity is retired than in the other cases, and more nuclear and renewable capacity, as well as coal and natural gas capacity equipped with CCS, is deployed.

Electricity prices

Electricity prices in 2035 are less than 2 percent above the Reference case level in the Transport Rule Mercury MACT 20, Retrofit Required 20, and Retrofit Required 5 cases. The increase is relatively modest because several low-cost alternatives for complying with the regulations are available. When lower natural gas prices are assumed, the real price of electricity price declines relative to the Reference case price, as lower natural gas prices are reflected in electricity prices. In the GHG Policy case, which assumes that the cost of CO_2 emissions allowances is passed through directly to customers, average electricity prices in 2035 are 38 percent higher than in the Reference case. However, the GHG Price Economywide case does not include any of the consumer rebates from the Waxman-Markey and Kerry-Lieberman bills, which have the effect of significantly lowering electric prices.

Reliability

The possible retirement of significant amounts of coal-fired generating capacity has raised concerns about reliability of the electric power grid. For example, the North American Electric Reliability Council has warned that EPA regulation of emissions from the power sector is a threat to reliability standards. Specific plants may be important to the reliability of a specific region, and if they are shut down before replacement capacity has been constructed, local reliability shortfalls could ensue. However, several safeguards exist to prevent such problems. Merchant plant owners must obtain permission from grid operators before retiring capacity [83],

Figure 43. Cumulative capacity additions in the Reference and GHG Price Economywide cases, 2010-2035 (gigawatts)

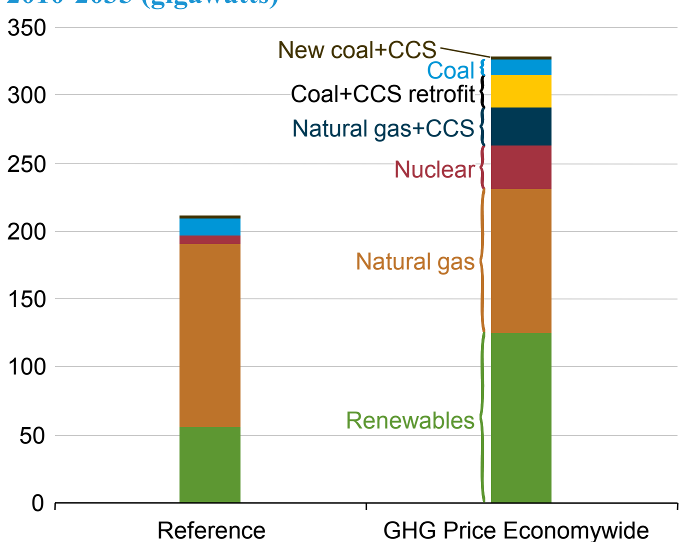
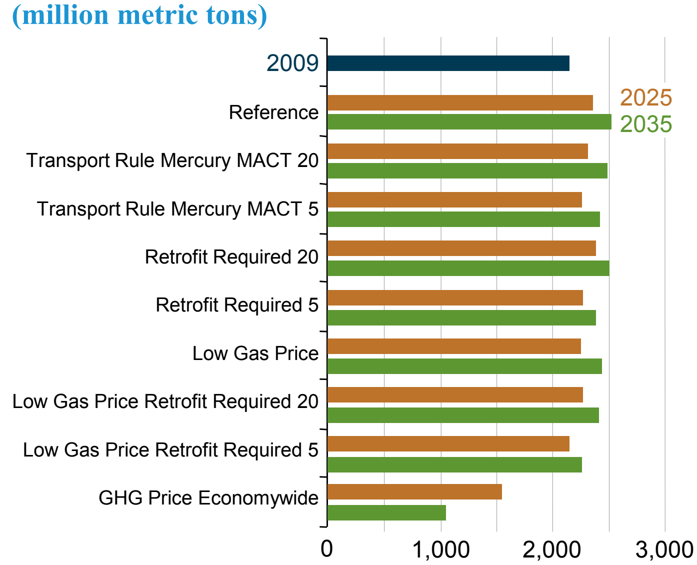


Figure 44. Carbon dioxide emissions from the electric power sector in nine cases, 2009, 2025, and 2035 (million metric tons)



and regulated utilities must demonstrate to their public utility commissions that their fleets meet the reliability standards included in their integrated resource plans.

On a national level, electric reliability shortfalls resulting from the retirement of coal plants can be mitigated both by increasing the utilization of other existing plants and by constructing new capacity. From 2000 to 2009, about 190 gigawatts of natural-gas-fired capacity was added in the U.S. electric power sector. In the *AEO2011* Reference case another 135 gigawatts of natural-gas-fired capacity is added from 2010 to 2035, and in the Low Gas Price case 154 gigawatts of new natural-gas-fired capacity is added. Most of the new capacity is built after 2020 in both cases.

Endnotes for issues in focus

Links current as of April 2011

44. U.S. Energy Information Administration, *Short-Term Energy Outlook* (January 11, 2011), "Table 2. U.S. Energy Prices," website www.eia.doe.gov/emeu/steo/pub/archives/jan11_base.xls#'2tab'!A1.
45. U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "2017 and Later Model Year Light Duty Vehicle GHG Emissions and CAFE Standards," *Federal Register*, Vol. 75, No. 197 (October 13, 2010), pp. 62739-62750, website http://edocket.access.gpo.gov/2010/2010-25444.htm.
46. Data from Ward's Auto, website www.wardsauto.com (subscription site).
47. U.S. Environmental Protection Agency, "Heavy-Duty Regulations," website www.epa.gov/oms/climate/regulations.htm#1-2; and U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles," *Federal Register*, Vol. 75, No. 229 (November 30, 2010), pp. 74451-74456, website http://edocket.access.gpo.gov/2010/2010-28120.htm. For purposes of the proposed rulemaking, heavy-duty vehicles are those with a GVWR of at least 8,501 pounds, except those Class 2b vehicles of 8,501 to 10,000 pounds that are currently covered under LDV fuel economy and GHG emissions standards.
48. Brake horsepower-hour is defined as the horsepower per hour of an engine before the loss in power caused by the gearbox, alternator, water pump, or other auxiliary components, usually determined from the force exerted on a friction brake or dynamometer connected to the drive shaft.
49. U.S. Census Bureau, "Vehicle Inventory and Use Survey," website http://www.census.gov/svsd/www/vius/products.html. Note that the survey has been discontinued.
50. Ward's Auto, "U.S. Factory Sales of Diesel Trucks by GVW, 1965-2010," website www.wardsauto.com (subscription site).
51. See U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles," *Federal Register*, Vol. 75, No. 229 (November 30, 2010), pp. 74451-74456, website http://edocket.access.gpo.gov/2010/2010-28120.htm.
52. For more information on vehicle compliance measurement and engine, cab, chassis, and vehicle test procedures, see *Federal Register*, Vol. 75, No. 229 (November 30, 2010), pp. 74451-74456, website http://edocket.access.gpo.gov/2010/2010-28120.htm.
53. U.S. Environmental Protection Agency, "ENERGY STAR® Unit Shipment and Market Penetration Report Calendar Year 2009 Summary" (2009), website www.energystar.gov/ia/partners/downloads/2009_USD_Summary.pdf.
54. In this article, the term "building code" refers to building energy codes, as opposed to construction or safety codes, such as those from the International Code Council or the International Building Code.
55. American Council for an Energy-Efficient Economy, "The 2010 State Energy Efficiency Scorecard" (October 2010), website www.aceee.org/research-report/e107.
56. Advanced Resources International, *Outer Continental Shelf Moratoria Areas: Impact of Various Assumptions on Oil and Natural Gas Production Potential* (Arlington, VA: January 2009), prepared for the U.S. Department of Energy, Office of Fossil Energy, website http://fossil.energy.gov/programs/oilgas/publications/oilgas_generalpubs/ocs_moratoria_areas_2008analysis.html.
57. J. Ratafia-Brown, R. Irby, and K. Perry, *Analysis of the Social, Economic and Environmental Effects of Maintaining Oil and Gas Exploration and Production Moratoria on and Beneath Federal Lands* (Washington, DC: February 2010), website www.naruc.org/Publications/NARUC_MORATORIA_REPORT_02-17-10.pdf.
58. U.S. Energy Information Administration, *Updated Capital Cost Estimates for Electricity Generation Plants* (Washington, DC: November 2010), website www.eia.gov/oiaf/beck_plantcosts/index.html.
59. National Energy Technology Laboratory, *Carbon Sequestration Atlas of the United States and Canada*, Third Edition (2010), website www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasIII.
60. International Energy Agency, *Carbon Capture and Storage: Progress and Next Steps* (Paris, France: 2010), website www.iea.org/papers/2010/ccs_g8.pdf.
61. A supercritical state is a phase of matter in which a fluid has some of the properties of both a liquid and a solid. The advantage for transporting and injecting CO_2 in a supercritical state is that the density can be fine-tuned to increase process efficiencies.
62. International Energy Agency, "IEA Energy Technology Essentials: CO_2 Capture and Storage" (Paris, France: December 2006), website www.iea.org/techno/essentials1.pdf.
63. National Energy Technology Laboratory, *DOE/NETL Advanced Carbon Dioxide Capture R&D Program: Technology Update* (September 2010), website www.netl.doe.gov/technologies/coalpower/ewr/pubs/CO2%20Capture%20Tech%20Update%20Final.pdf, p. 14, Box 2.

64. U.S. Department of Energy, *Report of the Interagency Task Force on Carbon Capture and Storage* (Washington, DC: August 2010), website www.fe.doe.gov/programs/sequestration/ccs_task_force.html.

65. National Energy Technology Laboratory, *Methodology for Development of Geologic Storage Estimates for Carbon Dioxide* (August 2008), website www.netl.doe.gov/technologies/carbon_seq/refshelf/methodology2008.pdf.

66. J.K. Eccles, L. Pratson, R.G. Newell, and R.B. Jackson, "Physical and Economic Potential of Geological CO_2 Storage in Saline Aquifers," *Environment Science and Technology*, Vol. 43, No. 6 (February 2009), website http://pubs.acs.org/doi/abs/10.1021/es801572e.

67. National Energy Technology Laboratory, *Carbon Dioxide Enhanced Oil Recovery: Untapped Domestic Energy Supply and Long Term Carbon Storage Solution* (March 2010), website www.netl.doe.gov/technologies/oil-gas/publications/EP/CO2_EOR_Primer.pdf.

68. Advanced Resources International, Inc., *U.S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage: White Paper* (Arlington, VA: March 2010).

69. Four key regulations currently being considered by EPA are the Air Transport Rule, Utility Boiler Maximum Available Control Technology (MACT), the Coal Combustion and Residuals Rule, and the Cooling Water Intake Structure Rule. Each proposal is designed to enforce existing sections of the CAA, RCRA, and CWA.

70. U.S. Environmental Protection Agency, "Proposed Air Pollution Transport Rule" (Washington, DC: July 26, 2010), website www.epa.gov/airquality/transport/pdfs/TRPresentationfinal_7-26_webversion.pdf.

71. U.S. Environmental Protection Agency, "Proposed Air Pollution Transport Rule" (Washington, DC: July 26, 2010), website www.epa.gov/airquality/transport/pdfs/TRPresentationfinal_7-26_webversion.pdf.

72. U.S. Court of Appeals for the District of Columbia Circuit, "State of North Carolina v. Environmental Protection Agency," No. 05-1244 (Washington, DC: December 23, 2008), website www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemandOrder.pdf.

74. Tennessee Valley Authority, "Coal Combustion Byproducts" (Oak Ridge, TN: July 2010), website www.tva.gov/news/keytopics/coal_combustion_products.htm.

73. If a wet FGD proves prohibitively expensive for smaller coal plants, other retrofit options exist. Alternative SO_2 control technologies, such as DSI, have lower initial capital cost but higher operating costs than FGD's, making them potentially attractive for smaller to medium size coal plants. While some DSI systems are currently operating, the technology is still in early stages of commercialization. Since it is difficult to assess their long term impact on the coal fleet, they are not included in *AEO2011*.

78. U.S. Supreme Court, "Entergy Corp, v. Riverkeeper, Inc., et al," No. 07-588 (Washington, DC: April 1, 2009), website www.supremecourt.gov/opinions/08pdf/07-588.pdf.

75. U.S. Court of Appeals for the District of Columbia Circuit, "State of New Jersey v. Environmental Protection Agency," No. 05-1097 (Washington, DC: February 8, 2008), website www.cadc.uscourts.gov/internet/opinions.nsf/68822E72677ACBCD8525744000470736/$file/05-1097a.pdf.

76. U.S. Environmental Protection Agency, "Power Plant Mercury and Air Toxics Standards" (Washington, DC: March 16, 2011), website www.epa.gov/airquality/powerplanttoxics/pdfs/overviewfactsheet.pdf.

77. Edison Electric Institute, "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet" (Washington, DC: January 2011), website www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf. DSI is allowed in one of the studies side cases. The side case also assumes that the 316b Cooling Water Intake Rule and the Coal Combustion Residuals Rule are also in effect.

79. Edison Electric Institute, "Potential Impacts of Environmental Regulation on the U.S. Generation Fleet" (Washington, DC: January 2011), website www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEIModelingReportFinal-28January2011.pdf. DSI is allowed in one of the studies side cases. The side case also assumes that the 316b Cooling Water Intake Rule and the Coal Combustion Residuals Rule are also in effect.

80. U.S. Energy Information Administration, "Energy Market and Economic Impacts of H.R. 2454, the American Clean Energy and Security Act of 2009" (Washington, DC: August 4, 2009), website www.eia.doe.gov/oiaf/servicerpt/hr2454/index.html.

81. U.S. Energy Information Administration, "Number and Capacity of Existing Fossil-Fuel Steam-Electric Generators with Environmental Equipment" (Washington, DC: April 2011), website www.eia.doe.gov/cneaf/electricity/epa/epat3p10.html.

82. U.S. Environmental Protection Agency, "Emission Control Technologies," website www.epa.gov/airmarkt/progsregs/epa-ipm/docs/v410/Chapter5.pdf.

83. For example, PJM Interconnection requires that Exelon keep its Eddystone Generating Plant in Pennsylvania open for an additional 2 years in order to support system reliability. See *Daily Times*, "Exelon Postpones Shutdown of Eddystone Plant" (Delaware County, PA: March 4, 2010), website www.delcotimes.com/articles/2010/03/04/business/doc4b8f2a66906bf935574426.txt?viewmode=fullstory.

Market trends

Projections by the U.S. Energy Information Administration (EIA) are not statements of what will happen but of what might happen, given the assumptions and methodologies used for any particular case. The Reference case projection is a business-as-usual estimate, given known technology, technological, market, and demographic trends. The main cases in the *Annual Energy Outlook 2011 (AEO2011)* generally assume that current laws and regulations are maintained throughout the projections. Thus, the projections provide a baseline starting point that can be used to analyze policy initiatives. EIA explores the impacts of alternative assumptions in other cases with different macroeconomic growth rates, world oil prices, rates of technology progress, and policy changes.

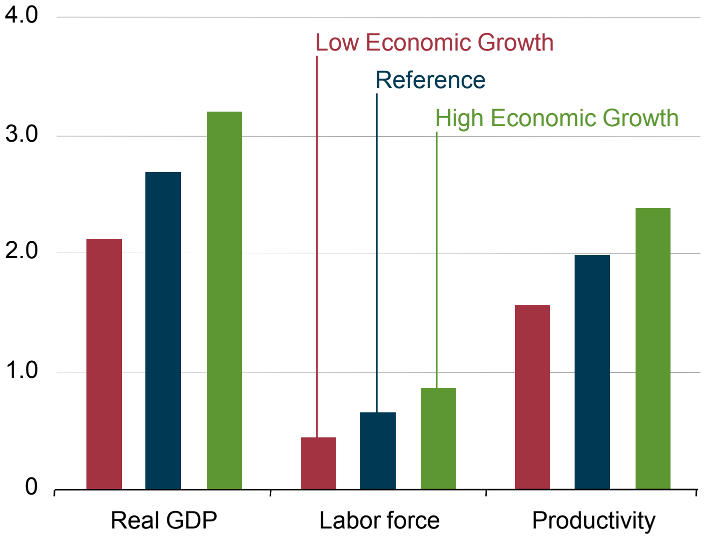
While energy markets are complex, energy models are simplified representations of energy production and consumption, regulations, and producer and consumer behavior. Projections are highly dependent on the data, methodologies, model structures, and assumptions used in their development. Behavioral characteristics 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 *AEO2011* 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.

Real growth in gross domestic product averages 2.1 to 3.2 percent across cases

Figure 45. Average annual growth rates of real GDP, labor force, and productivity in three cases, 2009-2035 (percent per year)



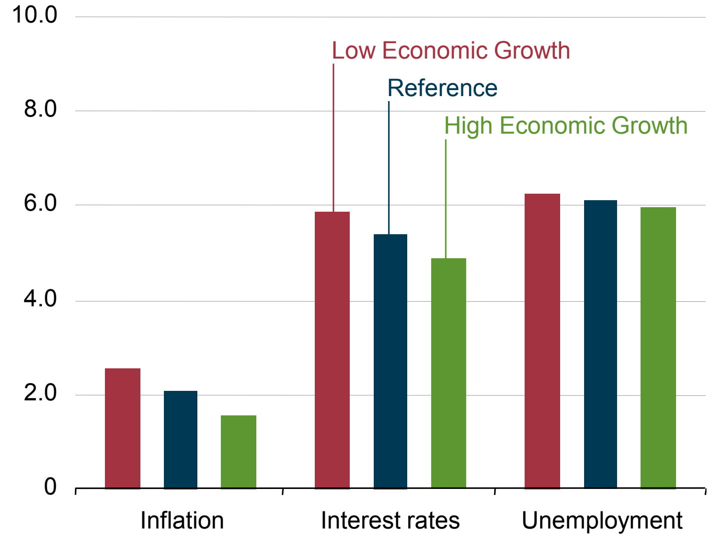
AEO2011 presents three views of economic growth (Figure 45). The rate of growth in real gross domestic product (GDP) depends on assumptions about labor force growth and productivity. In the Reference case, growth in real GDP averages 2.7 percent per year due to a 0.7 percent per year growth in the labor force and a 2.1 percent per year growth in labor productivity.

GDP growth in 2010 partially offsets the decline in 2009, helping GDP to recover to pre-recession levels by 2011. In the *AEO2011* Reference case, economic recovery accelerates in 2012, while employment recovers more slowly. With the percentage losses in employment during the 2007-2009 recession roughly double those of the 1982 recession, the unemployment rate remains elevated for an extended period, returning to its pre-recession 2003 to 2007 average of 5.2 percent by 2022.

The *AEO2011* High and Low Economic Growth cases examine the impacts of alternative assumptions on the economy. The High Economic Growth case includes more rapid expansion of the labor force, nonfarm employment, and productivity, with real GDP growth averaging 3.2 percent per year from 2009 to 2035. With higher productivity gains and employment growth, inflation and interest rates are lower in the High Economic Growth case than in the Reference case. In the Low Economic Growth case, real GDP growth averages 2.1 percent per year from 2009 to 2035, with slower growth rates for the labor force, nonfarm employment, and labor productivity. Consequently, the Low Economic Growth case shows higher inflation and interest rates and slower growth in industrial output.

Inflation, interest rates remain low, unemployment averages about 6 percent

Figure 46. Average annual inflation, interest, and unemployment rates in three cases, 2009-2035 (percent)



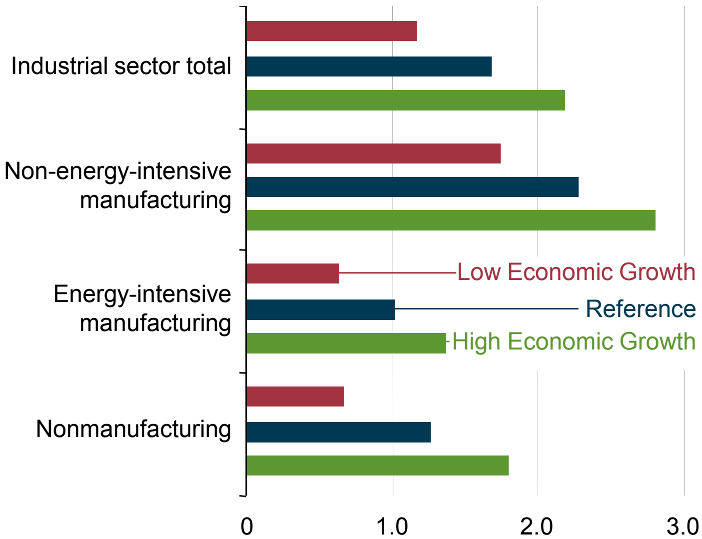
In the *AEO2011* Reference case, annual consumer price inflation averages 2.1 percent from 2009 to 2035, the annual yield on the 10-year Treasury note averages 5.4 percent (nominal), and the unemployment rate averages 6.1 percent (Figure 46). In the High Economic Growth case, population, and labor productivity grow faster than in the Reference case, leading to faster growth in capital stock, labor force, and employment. Potential output growth is faster, and as a result the annual growth rate of real GDP is 0.5 percent higher than in the Reference case. In the Low Economic Growth case, productivity, population, labor force, and capital stock grow more slowly, and real GDP growth is 0.6 percent lower than in the Reference case.

As the economy recovers, real GDP and inflation are expected to grow faster than the average over the past 26 years. By 2020, real GDP and inflation settle into the long-run 26-year average growth rates of 2.7 percent and 2.1 percent, respectively. During the last five years of the projection (2030-2035), real GDP growth slows to 2.5 percent, reflecting slowing growth in population. The Treasury note yield and unemployment rate average 5.8 percent and 5.1 percent, respectively, from 2020 to 2035, with the 10-year Treasury note higher than the 26-year average of 5.4 percent and the unemployment rate lower than the 26-year average of 6.1 percent.

Exports grow more rapidly than imports, as the dollar depreciates and countries in Asia and Latin America with higher economic growth rates develop their domestic markets and pull in more U.S. exports. Export growth supports U.S. employment, leading to lower unemployment rates and an improving trade balance over the projection period.

Output growth for energy-intensive industries slows

Figure 47. Sectoral composition of industrial output growth rates in three cases, 2009-2035 (percent per year)

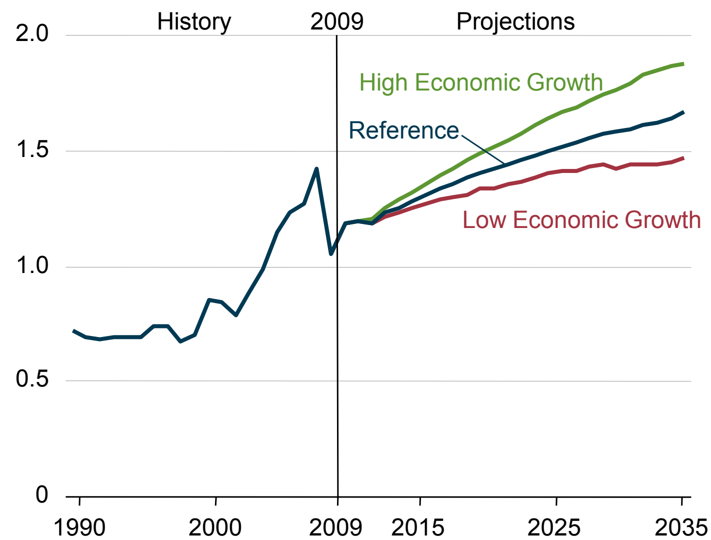


Industrial sector output has grown more slowly than the overall economy in recent decades, as imports have met a growing share of demand for industrial goods, whereas the service sector has grown more rapidly [*84*]. In the *AEO2011* Reference case, real GDP grows at an average annual rate of 2.7 percent from 2009 to 2035, while the industrial sector and its manufacturing component grow by 1.7 percent per year and 1.9 percent per year, respectively (Figure 47). As the economy recovers from the recent recession, growth in U.S. manufacturing output in the Reference case accelerates from 2011 through 2020. After 2020, growth in both GDP and manufacturing output return to rates closer to the historical trend. Increased foreign competition, slow expansion of domestic production capacity, and higher energy prices increase competitive pressure on most manufacturing industries after 2020. These factors weigh particularly heavy on the energy-intensive manufacturing sectors, which taken together grow at a slower rate of about 1.0 percent per year, which reflects projections ranging from a 0.1-percent annual decline for bulk chemicals to a 1.5-percent annual increase for food processing.

A decline in U.S. dollar exchange rates, combined with modest growth in unit labor costs, stimulates U.S. exports, eventually improving the U.S. current account balance. From 2009 to 2035, real exports of goods and services grow at an average annual rate of 6.3 percent, and real imports of goods and services grow by an average of 4.6 percent per year. Strong growth in exports is an important driver for growth projections in the transportation equipment, electronics, and machinery industries.

Energy expenditures rise, but decline relative to gross domestic product

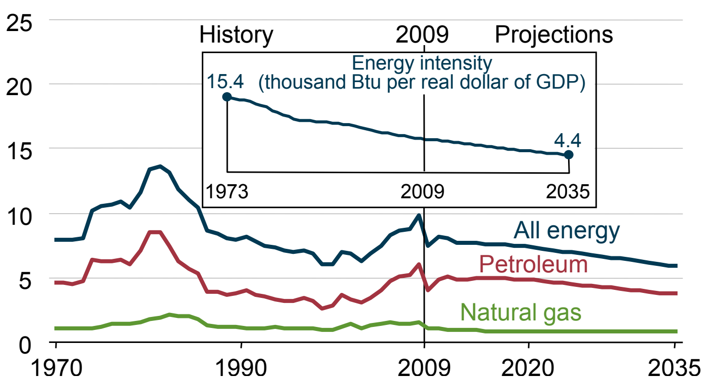
Figure 48. Energy expenditures in the U.S. economy in three cases, 1990-2035 (trillion 2009 dollars)



U.S. energy expenditures totaled $1.1 trillion (2009 dollars) in 2009, lower than the 2007 level of $1.3 trillion. As the economy recovers and energy prices rise, energy expenditures grow to $1.7 trillion in 2035 in the Reference case, $1.9 trillion in the High Growth case, and $1.5 trillion in the Low Growth case (Figure 48). The energy intensity of the economy (thousand British thermal units [Btu] of energy consumed per dollar of real GDP) was 7.4 in 2009. With structural shifts in the economy, improving energy efficiency, and higher real energy prices, U.S. energy intensity falls to 4.4 in 2035.

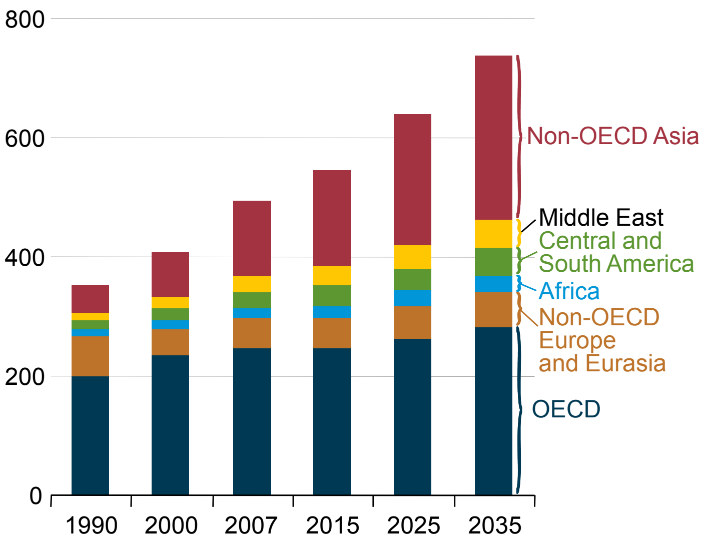
From 2003 to 2008, rising oil and natural gas prices increased the energy expenditure share of nominal GDP; the 9.8-percent share in 2008 was the highest since 1985. In 2009, the average cost of oil to refiners fell to $54 per barrel [*85*], natural gas prices fell by about half, and the energy expenditure share fell to 7.4 percent. The energy expenditure share declines throughout the projection (Figure 49), reflecting economic growth and declines in energy intensity.

Figure 49. Energy end-use expenditures as a share of gross domestic product, 1970-2035 (nominal expenditures as percent of nominal GDP)



Non-OECD nations account for 84 percent of growth in world energy use

Figure 50. World energy consumption by region, 1990-2035 (quadrillion Btu)



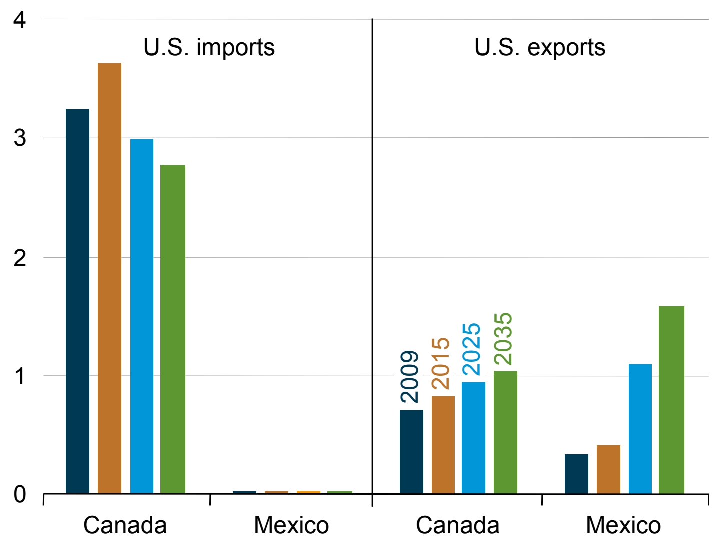
EIA's *International Energy Outlook* shows world marketed energy consumption increasing strongly over the projection period, rising by nearly 50 percent from 2009 through 2035 (Figure 50). Most of the growth occurs in emerging economies outside the Organization for Economic Cooperation and Development (OECD), especially in non-OECD Asia. Total non-OECD energy use increases by 84 percent in the Reference case, compared with a 14-percent increase in the developed OECD nations.

Energy use in non-OECD Asia, led by China and India, shows the most robust growth among the non-OECD regions, rising by 118 percent over the projection period. However, strong growth is also projected for much of the rest of the non-OECD regions: 82 percent growth in the Middle East, 63 percent in Africa, and 63 percent in Central and South America. The slowest growth among the non-OECD regions is projected for non-OECD Europe and Eurasia (including Russia), where substantial gains in energy efficiency are achieved through replacement of inefficient Soviet-era capital equipment.

Worldwide, the use of energy from all sources increases over the projection. Given expectations that oil prices will remain relatively high, petroleum and other liquids are the world's slowest-growing energy sources. High energy prices and concerns about the environmental consequences of greenhouse gas (GHG) emissions lead a number of national governments to provide incentives in support of the development of alternative energy sources, making renewables the world's fastest-growing source of energy in the outlook.

U.S. reliance on imported natural gas falls, and exports rise

Figure 51. North American natural gas trade, 2009-2035 (trillion cubic feet)

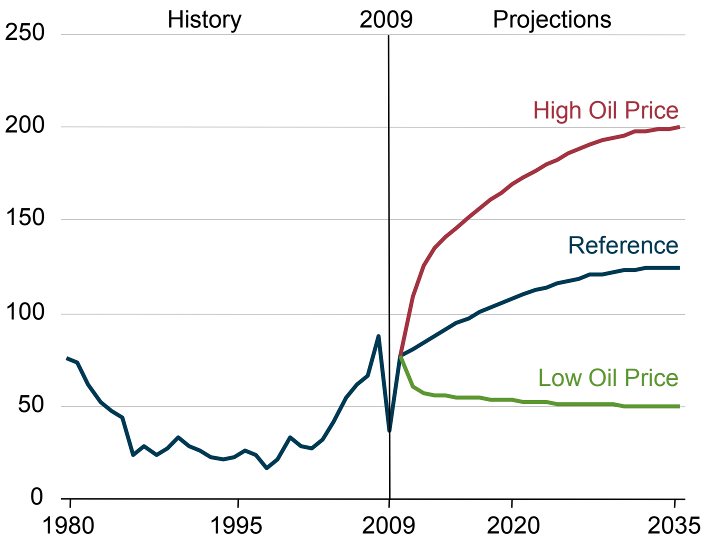


The energy markets of the three North American nations (United States, Canada, and Mexico) are well integrated, with extensive infrastructure that allows cross-border trade between the United States and both Canada and Mexico. The United States, which is by far the region's largest energy consumer, relies on Canada and Mexico for supplies of liquid fuels. Canada and Mexico were the largest suppliers of U.S. liquids imports in 2009, providing 2.5 and 1.2 million barrels per day, respectively. In addition, Canada supplies the United States with substantial natural gas supplies, exporting 3.2 trillion cubic feet to U.S. markets in 2009 (Figure 51).

In the *AEO2011* Reference case, the existing trade relationships between the United States and the two other North American countries continue. In 2035, the United States still imports 2.6 million barrels per day of liquid fuels from Canada and about 1.0 million barrels per day from Mexico. The improving prospects for domestic U.S. natural gas production, however, mean a smaller natural gas import requirement. In 2035, U.S. imports of Canadian natural gas fall to 2.8 trillion cubic feet. On the other hand, U.S. natural gas exports to both Canada and Mexico increase. Canada's imports of U.S. natural gas rise from 0.7 trillion cubic feet in 2009 to 1.0 trillion cubic feet in 2035, and Mexico's imports rise from 0.3 trillion cubic feet in 2009 to 1.6 trillion cubic feet in 2035.

Oil price cases depict uncertainty in world oil markets

Figure 52. Average annual world oil prices in three cases, 1980-2035 (2009 dollars per barrel)



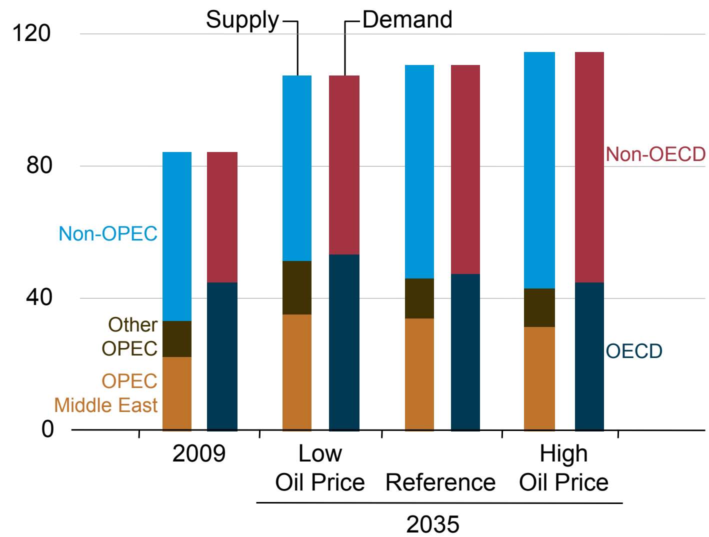
World oil prices in *AEO2011*, defined in terms of the average price of low-sulfur, light crude oil delivered to Cushing, Oklahoma, span a broad range that reflects the inherent volatility and uncertainty of world oil prices (Figure 52). The *AEO2011* price paths are not intended to reflect absolute bounds for future oil prices, but rather to allow analysis of the implications of world oil market conditions that differ from those assumed in the *AEO2011* Reference case. The Reference case assumes a continuation of current trends in terms of economic access to resources outside the Organization of the Petroleum Exporting Countries (OPEC), the OPEC market share of world production, and global economic growth.

The High Oil Price case depicts a world oil market in which total GDP growth in the non-OECD countries is faster than in the Reference case, driving up demand for liquids. On the supply side, conventional production is more restricted by political decisions and limits on economic access to resources (e.g., use of quotas, fiscal regimes, and other approaches that restrict access) compared to the Reference case. Oil production in the major producing countries is reduced (e.g., OPEC share falls to 37 percent), and the consuming countries turn to high-cost unconventional liquids production to satisfy demand.

In the Low Oil Price case, GDP growth in non-OPEC countries is slower than in the Reference case, resulting in lower demand for liquids. Regarding supply, producing countries develop stable fiscal policies and investment regimes directed at encouraging development of their resources. OPEC nations increase production, achieving approximately a 48-percent market share of total liquids production by 2035, up from approximately 40 percent in 2009.

Liquids demand in developing nations is driven by the rate of GDP growth

Figure 53. World liquids supply and demand by region in three cases, 2009 and 2035 (million barrels per day)



Total use of liquids is similar in the Reference, High Oil Price, and Low Oil Price cases, ranging from 108 to 115 million barrels per day in 2035, respectively. This occurs because the alternative oil price cases reflect a shifting of both supply and demand, with a resulting consumption and production level that is similar. Although total GDP growth in the OECD countries is assumed to be the same in all three cases, non-OECD GDP growth is lower in the Low Oil Price case and higher in the High Oil Price case, changing the shares of global liquids use by OECD and non-OECD countries among the three cases (Figure 53). Thus the cases reflect a future where the impact of income growth as a demand driver of oil prices overwhelms any countervailing impact of oil prices as a driver of growth.

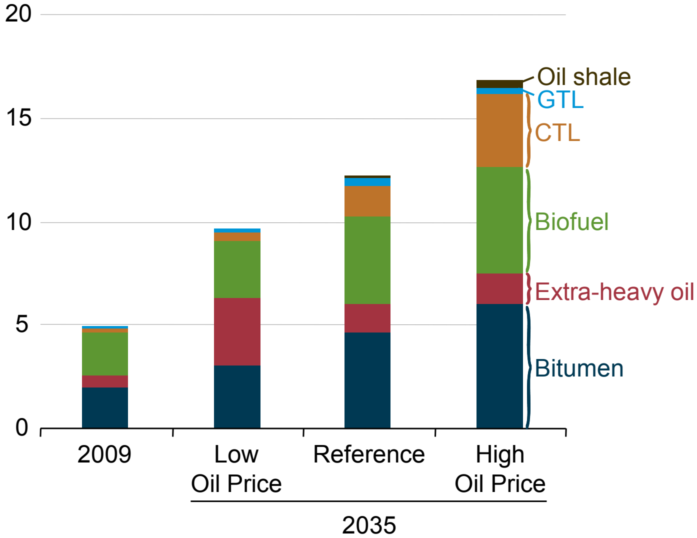
In the Reference case, OECD liquids use grows to 47.9 million barrels per day, while non-OECD liquids use grows to 62.9 million barrels per day, in 2035. In the Low Oil Price case, OECD liquids use in 2035 is higher than in the Reference case, whereas non-OECD use is lower. In the High Oil Price case, OECD use falls to 45.1 million barrels per day in 2035. In contrast, non-OECD use, driven by higher GDP growth, increases to nearly 70 million barrels per day in 2035. Non-OECD Asia and the Middle East account for most of the difference from the Reference case, but liquids use in Central and South America in 2035 is also 1.1 million barrels per day higher than in the Reference case.

Total liquids production is nearly identical in the Reference and High Oil Price cases, with the most significant difference coming from increased unconventional production in the High Oil Price case as some advanced production technologies become economical. In the Low Oil Price case, lower demand and lower prices shutter more expensive conventional liquids projects and reduce unconventional liquids production.

U.S. energy demand

Unconventional liquids gain market share as prices rise

Figure 54. Unconventional resources as a share of total world liquids production in three cases, 2009 and 2035 (percent)



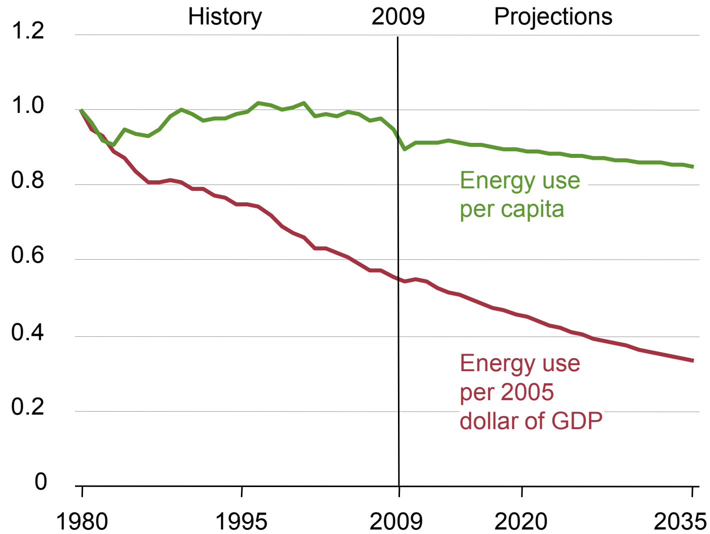
World production of liquid fuels from unconventional resources in 2009 was 4.1 million barrels per day, or about 5 percent of total liquids production. In the *AEO2011* projections, production from unconventional sources grows to about 10.4, 13.5, and 19.4 million barrels per day in 2035 in the Low Oil Price, Reference, and High Oil Price cases, respectively, accounting for about 10, 12, and 17 percent of total world liquids production (Figure 54).

The factors most likely to affect production levels vary for the different types of unconventional liquid. Price is the most important factor for bitumen production from Canadian oil sands, because the fiscal regime and extraction technologies remain relatively constant, regardless of world oil prices. Production of Venezuela's extra-heavy oil depends more on the prevailing investment environment and the assumed government-imposed levels of economic access to resources in the different price cases. In the Low Oil Price case, with more foreign investment in extra-heavy oil, production in 2035 climbs to 3.6 million barrels per day. In the Reference and High Oil Price cases, with growing investment restrictions, extra-heavy oil production is limited to 1.5 million barrels per day and 1.7 million barrels per day, respectively, in 2035.

Production levels for biofuels, coal-to-liquids (CTL), and gas-to-liquids (GTL) are driven largely by the price level and the extent of the need to compensate for restrictions on economic access to conventional liquid resources in other nations. In the Low Oil Price and High Oil Price cases, production from those three sources in 2035 totals 3.6 million barrels per day and 9.0 million barrels per day, respectively.

U.S. average energy use per person and per dollar of GDP declines through 2035

Figure 55. Energy use per capita and per dollar of gross domestic product, 1980-2035 (index, 1980 = 1)

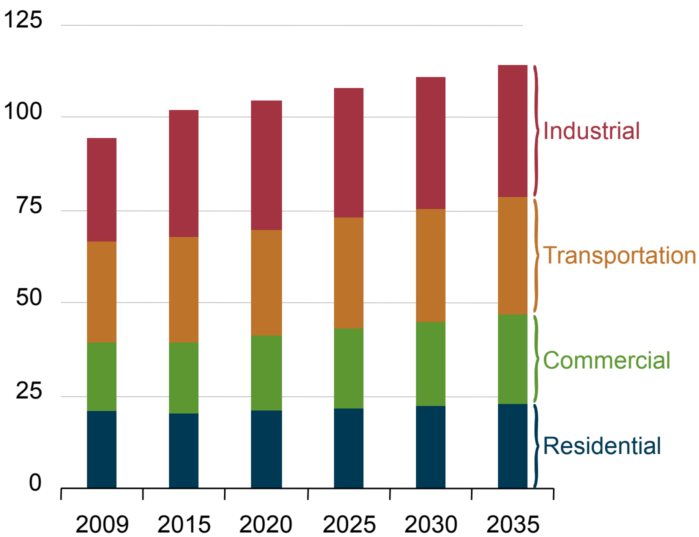


Growth in energy use is linked to population growth through increases in housing, commercial floorspace, transportation, and goods and services. These changes affect not only the level of energy use, but also the mix of fuels used. Energy consumption per capita declined from 337 million Btu in 2007 to 308 million Btu in 2009, the lowest level since 1967. In the *AEO2011* Reference case, energy use per capita increases slightly through 2013, as the economy recovers from the 2008-2009 economic downturn. After 2013, energy use per capita declines by 0.3 percent per year on average, to 293 million Btu in 2035, as higher efficiency standards for vehicles and appliances take effect (Figure 55).

Energy intensity (Btu of energy use per dollar of real GDP) falls as a result of structural changes and efficiency improvements. Since 1990, a growing share of U.S. output has come from less energy-intensive services. In 1990, 68 percent of the total value of output came from services, 8 percent from energy-intensive manufacturing industries, and the balance from non-energy-intensive manufacturing and the nonmanufacturing industries (e.g., agriculture, mining, and construction). In 2009, services accounted for 76 percent of total output and energy-intensive industries only 6 percent. Services continue to play a growing role in the *AEO2011* Reference case, accounting for 79 percent of total output in 2035, with energy-intensive manufacturing accounting for less than 5 percent. In combination with improvements in energy efficiency in all sectors, the shift away from energy-intensive industries pushes overall energy intensity down by an average of 1.9 percent per year from 2009 to 2035.

Industrial and commercial sectors lead growth in primary energy use

Figure 56. Primary energy use by end-use sector, 2009-2035 (quadrillion Btu)



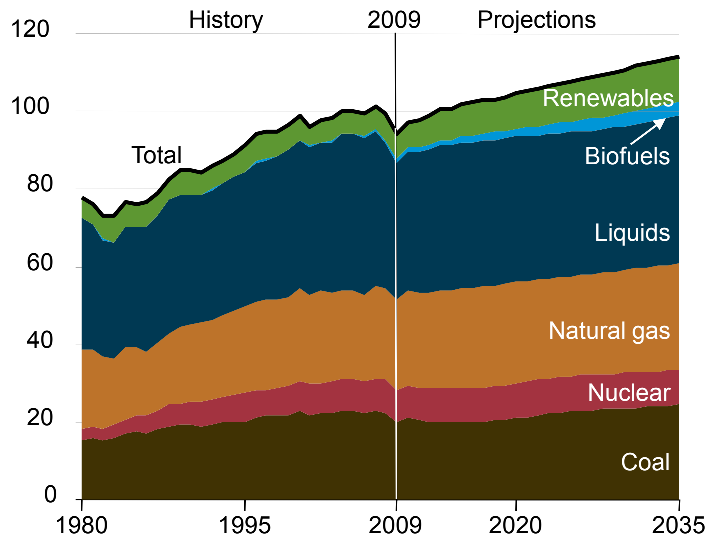
Total primary energy consumption, including fuels used for electricity generation, grows by 0.7 percent per year from 2009 to 2035, to 114.2 quadrillion Btu in 2035 in the *AEO2011* Reference case (Figure 56). The largest increase, 7.2 quadrillion Btu from 2009 to 2035, is in the industrial sector, which was the end-use sector most severely affected by the economic downturn in 2009. When 2008 is used as the base year, the total increase in industrial energy consumption is only about one-half the increase from 2009 to 2035, at 3.3 quadrillion Btu from 2008 to 2035. Factors contributing to the growth in industrial energy consumption include increased use of natural gas for combined heat and power (CHP) generation and increased production of biofuels to meet the renewable fuels standard (RFS) required by EISA2007.

The second-largest increase in total primary energy consumption from 2009 to 2035 (5.8 quadrillion Btu) is in the commercial sector, which currently accounts for the smallest sectoral share of primary energy use. Even as standards for building shells and energy efficiency are being tightened in the commercial sector, the growth rate for commercial energy use, at 1.1 percent per year, is the fastest rate among the end-use sectors, propelled by 1.2-percent average annual projected growth in commercial floorspace.

Primary energy use in the transportation sector grows by 4.7 quadrillion Btu from 2009 to 2035. Light-duty vehicles (LDVs) have accounted for more than 16 percent of total U.S. energy consumption since 2002, and their share declines slightly to 15.5 percent in 2020 as fuel economy standards increase to meet the statutory requirements of EISA2007. Growth in energy consumption by LDVs averages 0.3 percent per year from 2009 to 2035.

Renewable sources lead rise in primary energy consumption

Figure 57. Primary energy use by fuel, 1980-2035 (quadrillion Btu)



Consumption of all fuels increases in the *AEO2011* Reference case, but the aggregate fossil fuel share of total energy use falls from 83 percent in 2009 to 78 percent in 2035 as renewable fuel use grows rapidly (Figure 57). The renewable share of total energy use increases from 8 percent in 2009 to 13 percent in 2035, in response to the Energy Independence and Security Act of 2007 (EISA2007) RFS, availability of Federal tax credits for renewable electricity generation and capacity early in the projection period, and State renewable portfolio standard (RPS) programs.

Consumption of all liquid fuels increases by 0.5 percent per year from 2009 to 2035, with most of the increase accounted for by biofuels. The petroleum share of liquid fuel use declines as consumption of alternative fuels increases and petroleum use is roughly flat. Nearly all use of liquid biofuels occurs in the transportation sector. Biodiesel blended into diesel, motor fuel containing up to 85 percent ethanol (E85), and ethanol blended into motor gasoline account for 54 percent of the growth in liquids fuel consumption from 2009 to 2035.

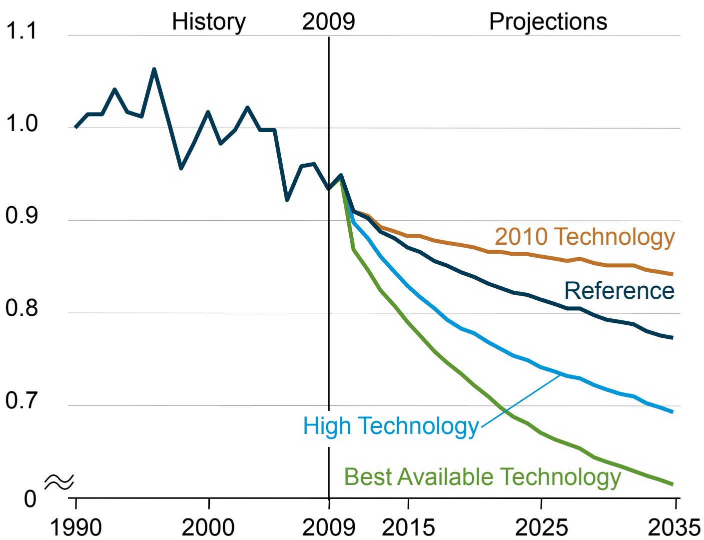
Natural gas consumption grows by about 0.6 percent per year from 2009 to 2035, as the large amount of shale gas resources that can be produced at prices under $7 per thousand cubic feet keeps natural gas prices from 2009 through 2035 below the levels seen from 2005 to 2008.

Coal consumption increases by 0.8 percent per year in the Reference case from 2009 to 2035, or by 0.2 percent per year starting from the 2007 consumption level. Several coal-fired power plants currently under construction, with combined capacity totaling 11.5 gigawatts, come on line by 2012. Nuclear power capacity expands by 9.5 gigawatts, but the nuclear share of primary energy falls from 8.8 percent in 2009 to 8.0 percent in 2035.

Residential sector energy demand

Residential energy use per capita varies with end-use technology assumptions

Figure 58. Residential delivered energy consumption per capita in four cases, 1990-2035 (index, 1990 = 1)



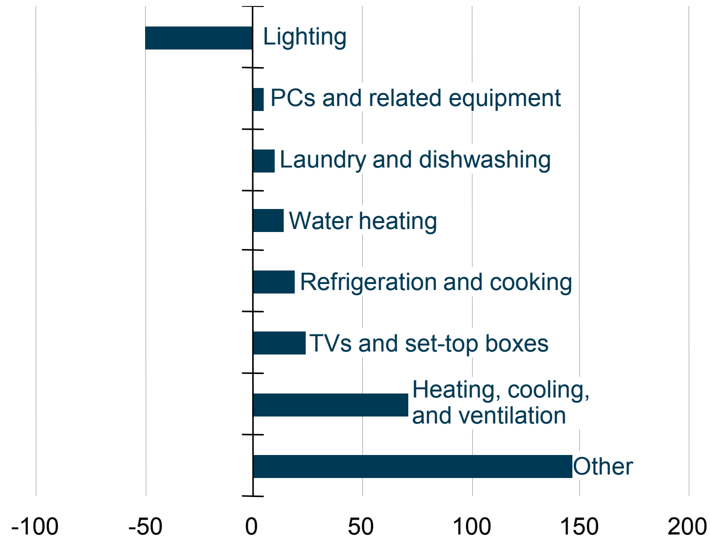
In the *AEO2011* Reference case, residential energy use per capita declines by 17.0 percent from 2009 to 2035 (Figure 58). Delivered energy use stays relatively constant while population grows by 26.7 percent during the period. Growth in the number of homes and in average square footage leads to increased demand for energy services, which is offset in part by efficiency gains in space heating, water heating, and lighting equipment. Population shifts to warmer and drier climates also reduce energy demand for space heating.

Three alternative cases show the potential role of energy-efficient technologies in reducing energy use per capita. The 2010 Technology case assumes no improvement in efficiency for equipment or building shells beyond what is available in 2010. The High Technology case assumes earlier availability, lower cost, higher efficiency, and more energy-efficient consumer purchasing decisions for some advanced equipment. The Best Available Technology case limits purchases of new and replacement appliances to the most efficient available in the year of replacement—regardless of cost—and assumes that new home construction adopts the most energy-efficient components for insulation, windows, and space conditioning equipment.

In the High Technology and Best Available Technology cases, with greater efficiency improvements, household energy use per capita declines by 25.4 percent and 34.1 percent, respectively, from 2009 to 2035. Household energy use per capita falls by 9.6 percent from 2009 to 2035 in the 2010 Technology case, even in the absence of efficiency improvements in commercially available equipment and new building shells, as older equipment is retired and replaced with 2010 vintage equipment.

Electricity use increases despite improved efficiency of electric devices

Figure 59. Change in residential electricity consumption for selected end uses in the Reference case, 2009-2035 (billion kilowatthours)



Electricity use grows 0.7 percent per year, from 42 percent of total residential delivered energy consumption in 2009 to 47 percent in 2035 in the *AEO2011* Reference case. Growing service demand is only partially offset by technological improvements that lead to increased efficiency of electric devices and appliances.

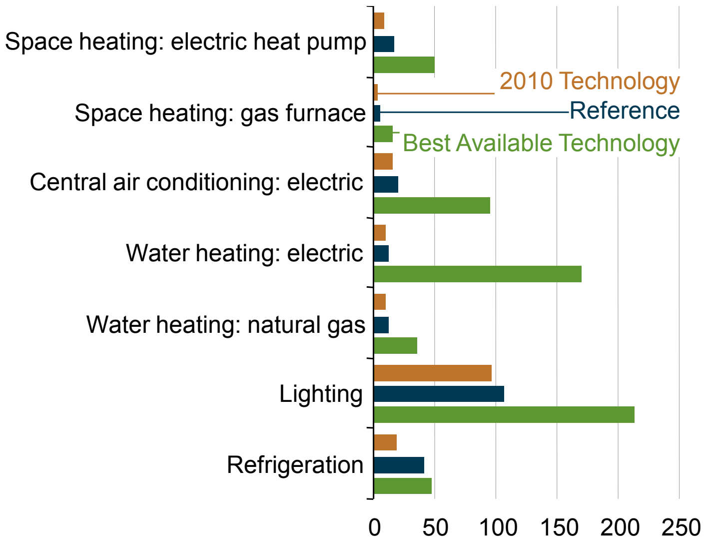
Despite increases in market penetration by ENERGY STAR qualified computers, as well as a general shift from desktop computers to laptops and other portable computing devices, energy use for personal computers (PCs) and related equipment continues to grow slowly, as the number of computers and peripherals per household increases (although at a slower rate than in the past). Contributing to the growth are related electronic devices, such as high-speed internet modems and network routers, which typically lack automatic standby modes and consume full power 24 hours a day.

Increased market penetration is also expected for ENERGY STAR televisions and computer monitors. Flat panel displays capture a growing share of the market and overall stock efficiency improves as light-emitting diodes (LEDs) displace cold cathode fluorescent lamps as a major backlighting technology for liquid crystal displays. Improvements in efficiency are offset to some degree, however, by a trend toward larger screen sizes.

The EISA2007 Federal lighting standards will lead to a decline in energy use for lighting, as low-efficacy incandescent lamps are replaced by compact fluorescent, LED, and high-efficiency incandescent lamps (Figure 59). In 2020, delivered energy use for lighting per household in the Reference case is 33 percent below the 2009 level.

AEO reflects improvement in efficiency standards

Figure 60. Efficiency gains for selected residential equipment in three cases, 2035 (percent change from 2009 installed stock efficiency)



Since their inception in the 1970s, Federal efficiency standards have expanded to cover an extensive range of residential equipment [*86*]. The Reference case captures the continuing effects of the standards, which often are the primary reason for efficiency gains.

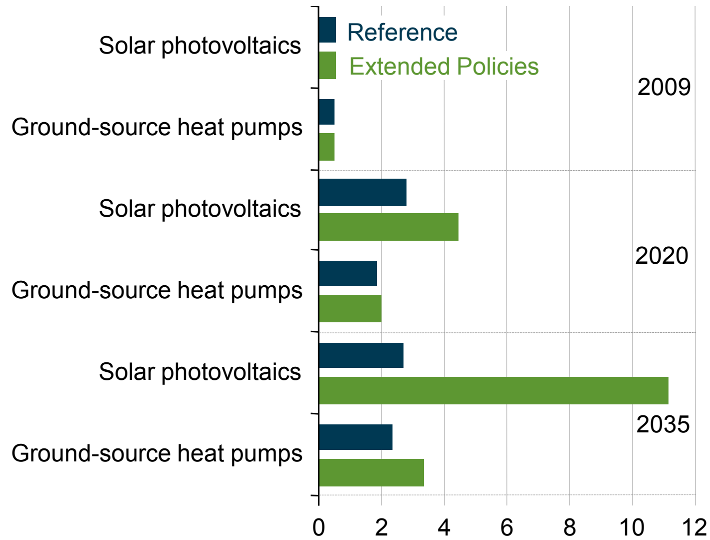
The largest gains in efficiency are expected for lighting, based on EISA2007 standards that require the phased replacement of most incandescent lamps with technologies that by 2020 are roughly three times more efficient than those widely marketed today (Figure 60). Refrigerators and water heaters also have been the subject of recent U.S. Department of Energy rulemakings. Overall, delivered energy use for products covered by the new standards declines by 0.1 percent per year, even as the number of households increase by an average of 1 percent per year.

The Best Available Technology case—which does not consider cost—demonstrates even greater gains in energy efficiency, especially for electric equipment, which has greater potential for improvement. In that case, delivered energy consumption per household declines by 1.7 percent per year from 2009 to 2035, and the total in 2035 is 1.8 quadrillion Btu lower than the 2009 level.

A variety of other products—mostly consumer electronics—are not subject to existing standards, although voluntary programs, such as ENERGY STAR, still lead to some efficiency gains in the *AEO2011* Reference case. Delivered energy use for such products grows faster than the number of households, averaging 1.5 percent per year in the Reference case.

As tax credits expire under current law, gains in residential renewable energy use slow

Figure 61. Residential market saturation by renewable technologies in two cases, 2009, 2020, and 2035 (percent share of single-family homes)



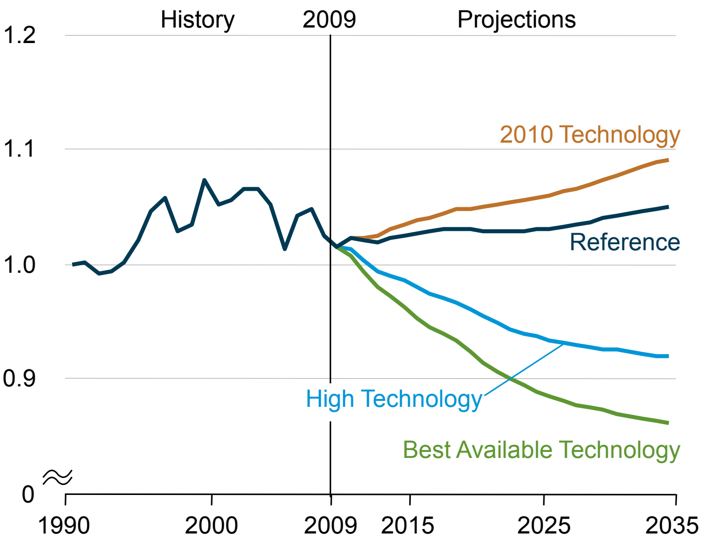
In the residential sector, growth of distributed electricity generation is limited by financial considerations and the interconnection regulations of local electric generators. As technologies improve and policies change, however, the limitations, which vary by State, are assumed to be reduced over time, allowing for faster growth in residential distributed generation (DG).

The current Federal investment tax credit (ITC) for renewable energy installations is available through 2016. When the ITC expires, average growth in solar photovoltaic (PV) capacity in the *AEO2011* Reference case slows from 39 percent per year to less than 1 percent per year. A total of 8.9 gigawatts of photovoltaic capacity is installed by 2035. Likewise, installed wind capacity grows by 48 percent per year from 2009 through 2016, but without the ITC the growth slows to nearly zero percent per year from 2017 to 2035. In the *AEO2011* Extended Policies case, which assumes extension of the ITC through 2035, PV capacity grows by 17 percent per year from 2009 to 2035, and total installed capacity reaches 47.8 gigawatts in 2035.

The number of homes heated by ground-source heat pumps (GSHPs) increases by more than 19 percent per year from 2009 to 2016 in the Reference case, then slows to 3 percent per year after the ITC expires. In 2035, GSHPs account for 2.3 percent of all heating systems installed in single-family homes (Figure 61). In the Extended Policies case, however, sustained tax credits lead to a continued 8.8-percent average annual increase in total installations, from 389,000 units in 2009 to 3,504,000 units in 2035, when GSHPs make up 3.4 percent of all residential heating systems.

End-use efficiency improvements could lower energy consumption per capita

Figure 62. Commercial delivered energy consumption per capita in four cases, 1990-2035 (index, 1990 = 1)



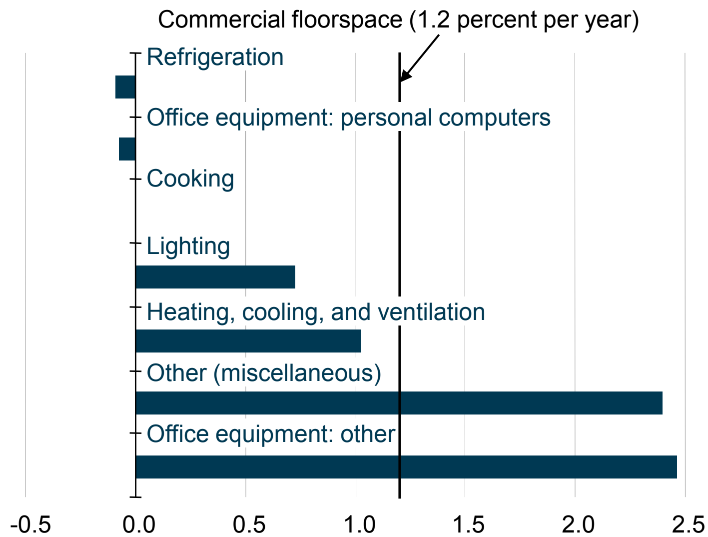
The *AEO2011* Reference case shows minimal change in commercial energy use per capita between 2009 and 2035 (Figure 62). While growth in commercial floorspace (1.2 percent per year) is faster than growth in population (0.9 percent per year), energy use per capita remains relatively steady due to efficiency improvements in equipment and building shells. Efficiency standards and the addition of more efficient technologies account for a large share of the improvement in the efficiency of end-use services, notably in space cooling, refrigeration, and lighting.

Three alternative cases use different assumptions about technology and energy efficiency to examine uncertainty in the projections of commercial energy consumption per capita. The 2010 Technology case limits equipment and building shell technologies to the options available in 2010. The High Technology case assumes lower costs, higher efficiencies for equipment and building shells, and earlier availability of some advanced equipment than in the Reference case, with commercial consumers placing greater importance on the value of future energy savings. The Best Available Technology case limits future equipment choices to the most efficient model for each technology available in the year of replacement and assumes more improvement in the efficiency of building shells for new and existing buildings than in the High Technology case.

Commercial energy consumption per capita in 2035 is 3.9 percent higher in the 2010 Technology case than in the Reference case. In contrast, it is 12.5 percent lower in the High Technology case and 17.9 percent lower in the Best Available Technology case than in the Reference case.

Growth in electricity use dominates the outlook for commercial energy demand

Figure 63. Average annual growth rates for selected electricity end uses in the commercial sector, 2009-2035 (percent per year)



Electricity use increases 1.4 percent per year, from 53 percent of total commercial delivered energy consumption in 2009 to 58 percent in 2035, in the *AEO2011* Reference case. Growth in electricity demand for new electronic equipment more than offsets improvements in equipment and building shell efficiency and growth in CHP.

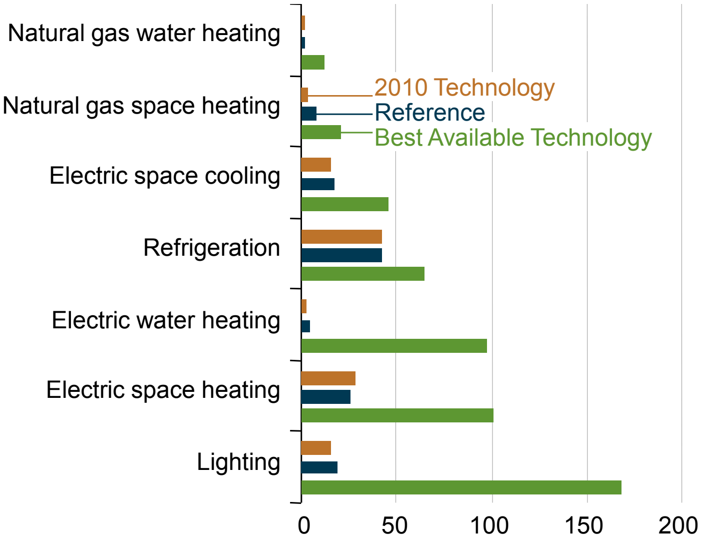
Average annual growth in commercial sector electricity use for PCs and related devices slows between 2009 and 2035, as the market penetration of ENERGY STAR qualified products increases, and laptops gain market share relative to desktop PCs, which use more energy than laptops.

Electricity use for "other" office equipment—including servers and mainframe computers—increases by 2.5 percent per year as demand for high-speed networks and internet connectivity grows, surpassing electricity demand for commercial refrigeration by 2019.

End uses such as space heating and cooling, water heating, and lighting are covered by Federal and State efficiency standards, which have the effect of limiting growth in energy consumption to less than the average of 1.2 percent per year for growth in commercial floorspace (Figure 63). "Other" electric end uses, some of which are not subject to Federal standards, account for much of the growth in commercial electricity consumption. Electricity demand for those other end uses, which include distribution transformers, vertical transport, and medical imaging equipment, increases by an average of 2.4 percent per year and accounts for 39 percent of total commercial electricity consumption in 2035.

Core technologies lead efficiency gains in the commercial sector

Figure 64. Efficiency gains for selected commercial equipment in three cases, 2035 (percent change from 2009 installed stock efficiency)



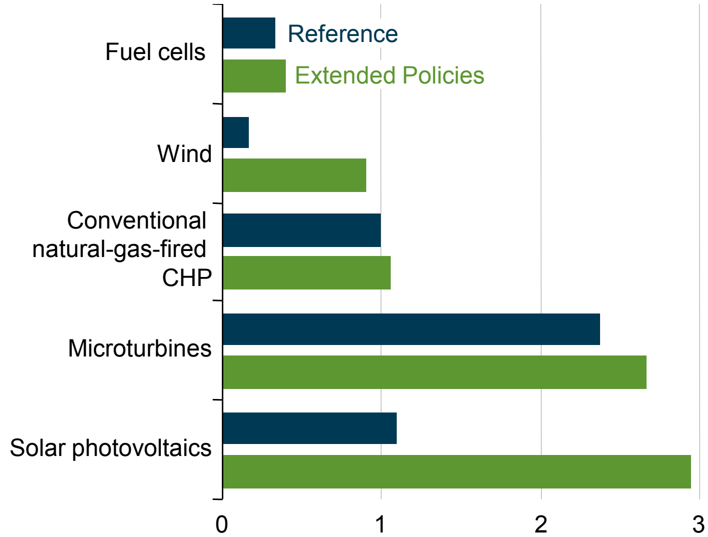
Delivered energy consumption for core space heating, ventilation, air conditioning, water heating, lighting, cooking, and refrigeration uses grows at an average annual rate of 0.6 percent in the *AEO2011* Reference case, compared with 1.2 percent annual growth in commercial floorspace. These core end uses, which frequently have been targets of energy efficiency standards, accounted for just over 60 percent of commercial delivered energy demand in 2009 and are projected to fall to 55 percent of delivered energy in 2035. Energy consumption for the remaining end uses together grows by 1.5 percent per year, led by other electric end uses and by office equipment other than computers.

The percentage gains in efficiency in the Reference case are highest for refrigeration, as a result of provisions in the Energy Policy Act of 2005 (EPACT2005) and EISA2007. Electric space heating shows the next-largest percentage improvement, followed by lighting and cooling (Figure 64).

The Best Available Technology case demonstrates the significant potential for further improvement—especially in electric equipment, led by lighting, space heating, and water heating. In the Best Available Technology case, the share of total commercial delivered energy use accounted for by the core end uses falls to 49 percent in 2035, with significant efficiency gains coming from LED lighting, GSHPs, high-efficiency rooftop heat pumps, centrifugal chillers, and solar water heaters. Those technologies are relatively costly, however, and thus are unlikely to gain wide adoption in commercial applications without improved economics or additional incentives. Additional efficiency improvements could also come from an expansion of standards to include some of the rapidly growing miscellaneous electric applications.

Improved interconnection supports growth in distributed generation

Figure 65. Additions to electricity generation capacity in the commercial sector in two cases, 2009-2035 (gigawatts)



More than 40 States have some form of interconnection standard or guideline that governs the installation of DG capacity and its incorporation into the electricity grid. Current limits on the maximum capacity that can be interconnected are expected to decrease with improvements in technology and the spread of RPS policies and goals over time.

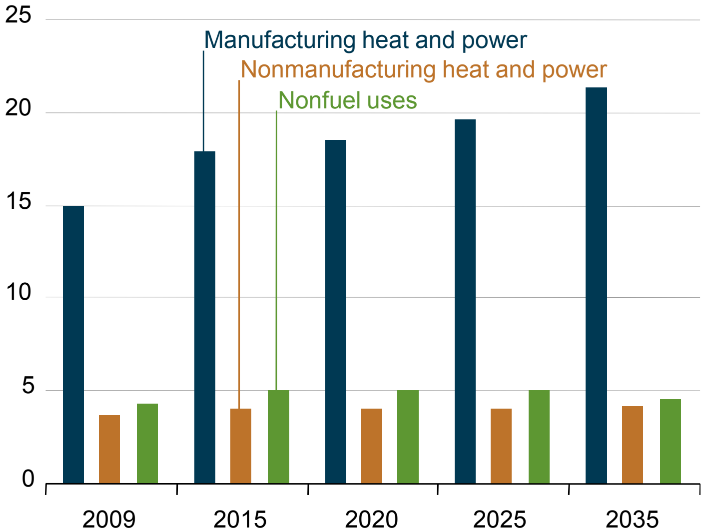
In addition to declining limits on DG interconnection, ITCs for various renewable and nonrenewable DG technologies continue through 2016. With the exception of a permanent 10-percent credit following the expiration of the current 30-percent credit for solar PVs, the *AEO2011* Reference case assumes no ITCs for DG after 2016. The Extended Policies case, on the other hand, assumes that current tax credits continue through 2035.

Total commercial DG capacity in the Reference case increases from 1.9 gigawatts in 2009 to more than 6.8 gigawatts in 2035. In the Extended Policies case, capacity increases to 9.8 gigawatts in 2035. Microturbines show the fastest capacity growth among the DG technologies in the Reference case, averaging 16 percent per year. Commercial sector wind capacity grows by 11 percent per year in the Extended Policies case, more than double the annual growth in the Reference case, as a result of continued tax credits. In 2035, renewable energy accounts for 50 percent of all commercial DG capacity in the Extended Policies case, as compared with less than 35 percent in the Reference case (Figure 65).

Industrial sector energy demand

Heat and power energy consumption increases in manufacturing industries

Figure 66. Industrial delivered energy consumption by application, 2009-2035 (quadrillion Btu)



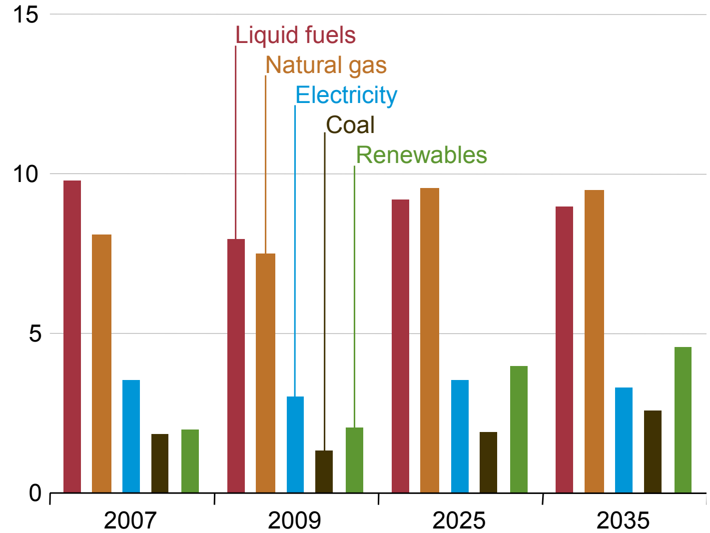
Despite a 54-percent increase in industrial shipments, industrial energy consumption increases by only 19 percent from 2009 to 2035 in the *AEO2011* Reference case. Energy consumption growth is moderated by a shift in the mix of output, as growth in energy-intensive manufacturing output (aluminum, steel, bulk chemicals, paper, and refining) slows and growth in high-value (but less energy-intensive) industries, such as computers and transportation equipment, accelerates.

There is also a relative shift in industrial energy use to manufacturing from nonmanufacturing industries. Manufacturing heat and power as a percentage of total industrial delivered energy consumption grows from 65 percent in 2009 to 71 percent in 2035 (Figure 66). Nonmanufacturing (agriculture, mining, and construction) heat and power energy consumption as a percentage of total energy drops by 2 percent over the projection. The remaining fuel consumption, consisting of nonfuel uses of energy (primarily as feedstocks in chemical manufacturing and asphalt for construction), also declines by about 4 percent.

The rise in manufacturing heat and power consumption in the *AEO2011* Reference case is due primarily to an increase of 1.7 quadrillion Btu in total energy use for production of liquid fuels—both petroleum and nonpetroleum liquids—in the refining industry. From 2009 to 2035, CTL, coal- and biomass-to-liquids (CBTL), and biofuels production accounts for the bulk of the increase, which corresponds to a 48-percent increase in energy consumption for liquid fuels production, although total refinery shipments increase by only 16 percent.

Industrial fuel mix changes as demand increases from low levels in 2009

Figure 67. Industrial energy consumption by fuel, 2007, 2009, 2025 and 2035 (quadrillion Btu)



Demand for all fuels in the industrial sector increases from 2009 levels in the Reference case. As consumption increases, the mix of fuels and their relative shares change slowly, reflecting modest capital spending and limited capability for fuel switching (Figure 67).

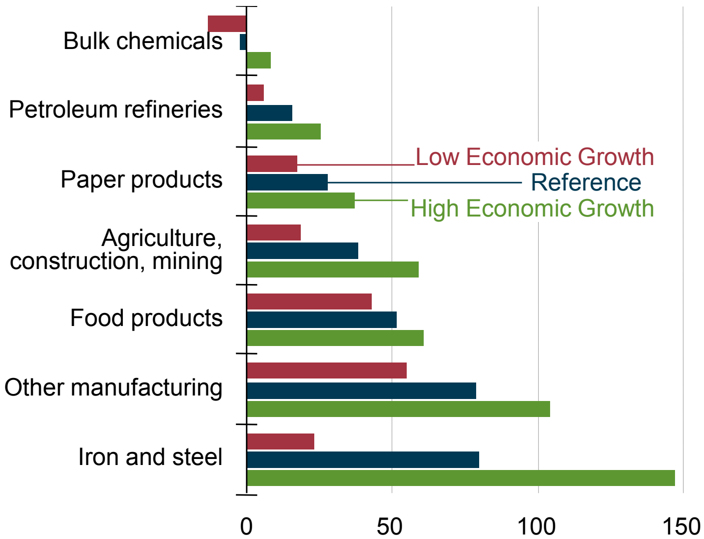
Industrial use of liquid fuels grows by 13 percent from 2009 to 2035, but its share of total liquid fuel consumption declines. Nearly one-half of industrial liquid fuel consumption is for feedstocks in the production of chemicals, and another 20 percent consists of still gas generated and consumed by refineries. Natural gas use in the industrial sector grows by 27 percent from 2009 to 2035, reflecting the recovery in industrial output and relatively low natural gas prices, which spur a large increase in natural gas consumption for CHP generation that offsets a decline in natural gas use for feedstock.

After 2025, increased use of coal for CTL and CBTL production offsets a decline in traditional industrial uses of coal (including steam generation and coke production) as a result of efficiency improvements that reduce the need for process steam. Metallurgical coal use drops, based on an expected decline in smelting and increased use of electric arc furnaces in steel-making.

A decline in the electricity share of industrial energy consumption reflects growth in on-site CHP and efficiency improvements across industries, mostly based on motor efficiency standards. The renewable fuel share expands with growth in lumber, paper, and other industries that consume biomass-based byproducts.

Iron and steel and non-energy-intensive industries show fastest output growth

Figure 68. Cumulative growth in value of shipments by industrial subsector in three cases, 2009-2035 (percent)



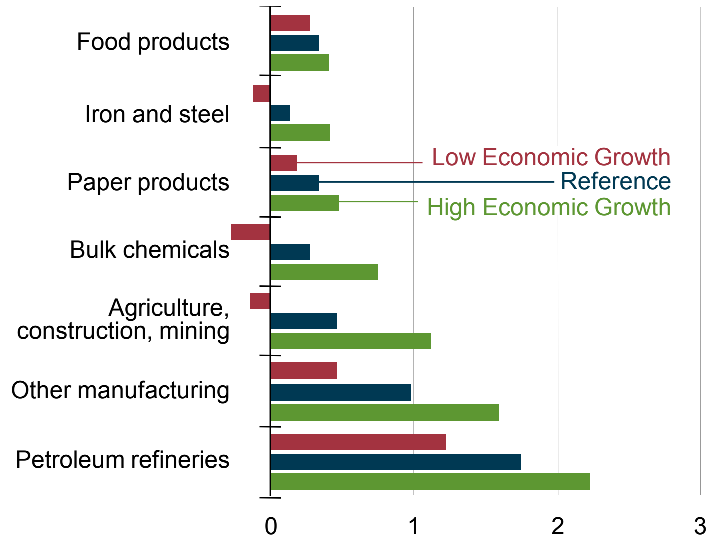
Industrial production recovers from the recent economic downturn and continues to grow over the long term in the *AEO2011* Reference case. The recovery and long-term growth are uneven, however, with the strongest growth in iron and steel and non-energy-intensive manufacturing industries. The remaining industries also recover from the recession, but their production begins to decline after 2025. Over the entire projection, total industrial shipments increase by 54 percent in the Reference case, 35 percent in the Low Economic Growth case, and 75 percent in the High Economic Growth case.

A few energy-intensive manufacturing industries account for the majority of total industrial energy consumption. Ranked by their total energy use, the top five energy-consuming industries—bulk chemicals, refining, paper, steel, and food—accounted for 61 percent of industrial energy consumption and 25 percent of total value of shipments in 2009. With the exception of bulk chemicals, most industries experience overall growth from 2009 to 2035 (Figure 68). Chemical industry output recovers to pre-recession levels by 2015 but then declines by 16 percent from 2015 to 2035.

A rebound in industrial output is being seen already in selected industries, driven by increasing demand based on relative weakness of the U.S. dollar against foreign currencies, which promotes exports of basic commodities [*87*]. Long-term growth in the energy-intensive manufacturing industries is slower, however, as a result of reduced growth in demand for the goods they produce, increased foreign competition, and movement of investment capital to more profitable areas of the economy after the short-term economic rebound from the recession.

Delivered energy use in industry sectors trends upward after recession ends

Figure 69. Change in delivered energy consumption for industrial subsectors in three cases, 2009-2035 (quadrillion Btu)



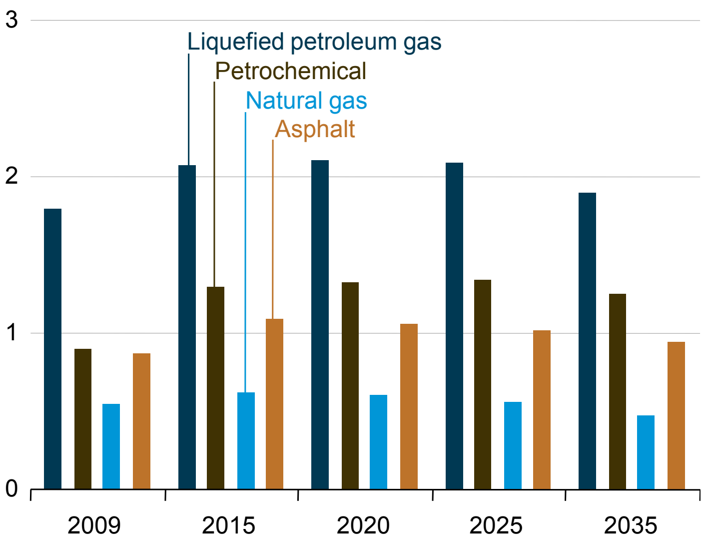
Starting from the low levels of 2009, industrial delivered energy use grows sharply in nearly all the *AEO2011* cases. From 2009 to 2035, industrial energy consumption grows by 7 percent in the Low Economic Growth case, 19 percent in the Reference case, and 31 percent in the High Economic Growth case (Figure 69).

The most significant changes in energy use are in the refining, bulk chemicals, and iron and steel industries. The refining industry (both petroleum and nonpetroleum liquids refineries) shows the strongest growth in the Reference, Low Economic Growth, and High Economic Growth cases. Although total refinery output grows by less than 1 percent per year, the industry's energy use increases modestly in all cases, with continued efforts to remove sulfur from oil inputs, energy-intensive coal liquefaction beginning in 2025, and strong growth in the production of other nonpetroleum liquids. In the Low Economic Growth case, energy use in the bulk chemical industry declines from 2009 to 2035 as its output declines in the face of rising costs for domestic inputs in a globally competitive market. Similarly, energy consumption in the iron and steel industry declines in the Low Economic Growth case as penetration of energy-saving production technologies completely offsets output growth from 2009 to 2035.

Overall energy intensity in the industrial sector declines by 21 percent in the Low Economic Growth case, 23 percent in the Reference case, and 25 percent in the High Economic Growth case. The projections are consistent with the expectation that energy intensity will decline as the economic recovery facilitates investments in more efficient equipment.

Chemical industry use of fuels as feedstocks recovers before declining

Figure 70. Industrial consumption of fuels for use as feedstocks by fuel type, 2009-2035 (quadrillion Btu)



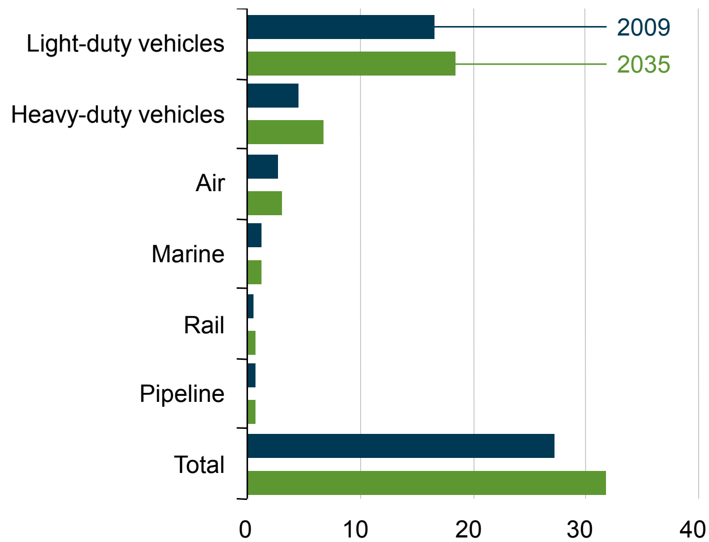
Industrial feedstock consumption includes the use of asphalt and road oil in the construction industry, as well as use of liquid petroleum gas, naphtha, petroleum gas oil, and natural gas as raw materials for the production of various chemicals. The largest share of feedstock energy consumption occurs in the chemical industry, primarily for the production of ethylene and propylene, which are used to make plastics, fertilizers, and a variety of inorganic chemicals.

Industrial energy consumption trends in the *AEO2011* Reference case reflect growth in consumption of all feedstocks after the 2008-2009 economic downturn, followed by a long-term decline as production of basic chemicals falls. Increased use of ethane and propane as alternatives to naphtha and gas oil reflects a recent switch to lighter feedstocks with the rise in crude oil prices relative to natural gas prices. With increasing production of natural gas and natural gas liquids (NGLs), lighter feedstocks become readily available on a continuing basis (Figure 70).

Consumption of all feedstocks is higher in 2035 than in 2009, except for natural gas use, which drops by 14 percent from 2009 to 2035. The use of natural gas as a feedstock falls after 2014, when domestic production of hydrogen, methanol, and ammonia begins a decline that continues through 2035. Ammonia production declines as a result of modest growth in agricultural production and increased foreign competition. Consumption of asphalt and road oil increases through 2016, then declines with slower growth in the construction industry.

Growth in transportation energy use slower than historical trend

Figure 71. Delivered energy consumption for transportation by mode, 2009 and 2035 (quadrillion Btu)



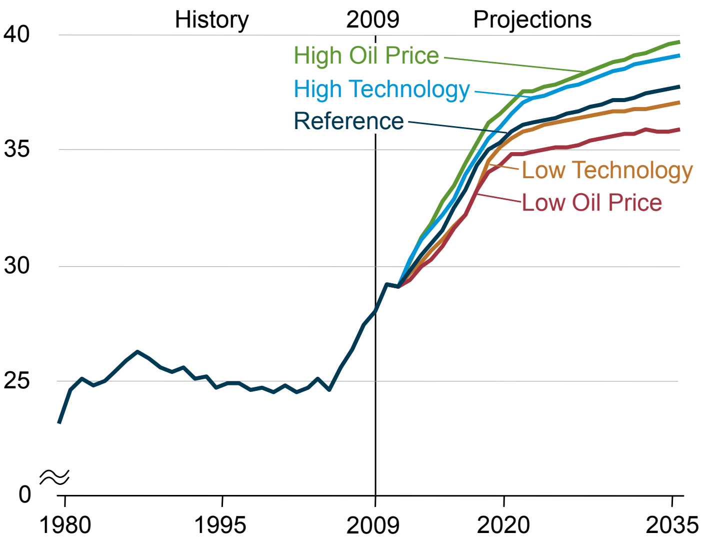
From 2009 to 2035, transportation sector energy consumption grows at an average annual rate of 0.6 percent (from 27.2 quadrillion Btu to 31.8 quadrillion Btu), slower than the 1.2 percent average rate from 1975 to 2009. The slower growth is a result of changing demographics, increased LDV fuel economy, and saturation of personal travel demand.

Energy demand for LDVs increases by 10 percent, or 1.7 quadrillion Btu (1.3 million barrels per day), from 2009 to 2035 (Figure 71). Moderate growth in fuel prices compared with recent history and rising real disposable income combine to increase annual vehicle miles traveled (VMT), although personal travel demand increases at a slower rate than historically. Growth in delivered energy consumption by LDVs is tempered by more stringent standards for vehicle GHG emissions through model year (MY) 2016 and fuel economy through MY 2020. Energy demand for heavy-duty vehicles (including primarily freight trucks but also buses) increases by 48 percent, or 2.2 quadrillion Btu (1.0 million barrels per day), as a result of increased freight travel demand as industrial output grows and the fuel economy of heavy-duty vehicles shows only marginal improvement.

Energy demand for air travel increases by 16 percent, or 0.4 quadrillion Btu (0.2 million barrels per day). Growth in air travel is driven by increases in income and moderate growth in fuel costs, tempered by gains in aircraft fuel efficiency, while growth in air freight movement (caused by export growth) also increases fuel use by aircraft. Energy consumption for marine and rail travel increases as industrial output rises and demand for coal transport grows. Energy use for pipelines stays flat as increasing volumes of natural gas are produced closer to end-use markets.

CAFE and greenhouse gas emissions standards boost vehicle fuel economy

Figure 72. Average fuel economy of new light-duty vehicles in five cases, 1980-2035 (miles per gallon)



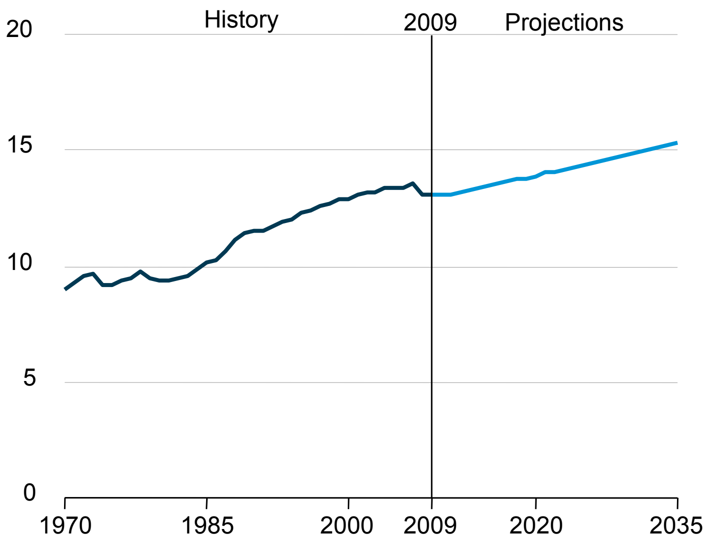
After the introduction of corporate average fuel economy (CAFE) standards in 1978, the fuel economy for all LDVs increased from 19.9 miles per gallon (mpg) in 1978 to 26.2 in 1987. Despite continued technological improvement, fuel economy fell to between 24 and 26 mpg over the next two decades, with sales of light trucks increasing from about 20 percent of new LDV sales in 1980 to 55 percent in 2004 [*88*]. From 2004 to 2008, fuel prices increased, sales of light trucks slowed, and tighter fuel economy standards for light-duty trucks were introduced. As a result, average fuel economy for LDVs rose to 28.0 mpg in 2008.

The National Highway Traffic Safety Administration (NHTSA) introduced new attribute-based CAFE standards for MY 2011 LDVs in 2009, and in 2010 NHTSA and the U.S. Environmental Protection Agency (EPA) jointly announced CAFE and GHG emissions standards for MY 2012 to MY 2016. EISA2007 also requires that LDVs reach an average fuel economy of 35 mpg by MY 2020 [*89*]. In the Reference case, the average fuel economy of new LDVs (including credits for alternative-fuel vehicles and banked credits) rises to 29.8 mpg in 2011, 33.3 mpg in 2016, and 35.8 mpg in 2020 (Figure 72). After 2020, CAFE standards for LDVs remain constant in the Reference case, and LDV fuel economy increases only moderately, to 37.8 mpg in 2035.

In the Reference case, cars represent 65 percent of LDV sales in 2035, compared with 69 percent in the High Oil Price case and 55 percent in the Low Oil Price case. The economics of fuel-saving technologies improve in the High Technology and High Oil Price cases, but the effects on average fuel economy relative to the Reference case are tempered by the fact that CAFE standards already require significant improvement in fuel economy performance and the penetration of advanced technologies.

Travel demand for personal vehicles increases more slowly than in the past

Figure 73. Vehicle miles traveled per licensed driver, 1970-2035 (thousand miles)



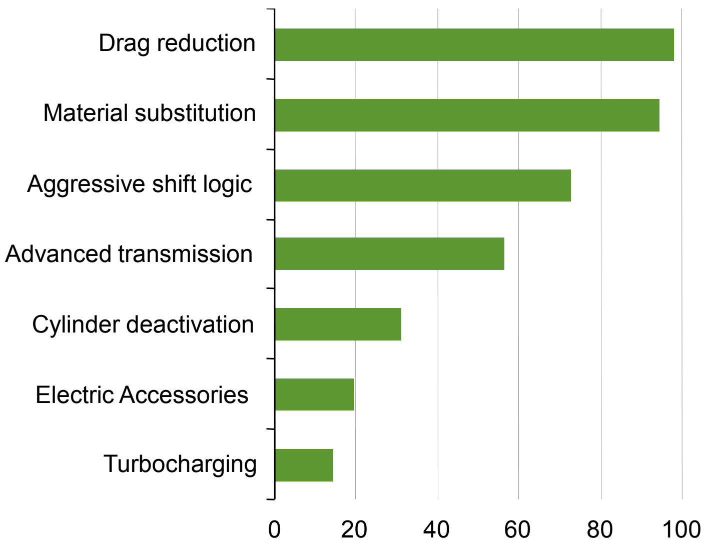
Personal vehicle travel demand, measured as VMT per licensed driver, grew at an average annual rate of 1.1 percent between 1970 to 2007, driven by rising income, a decline in the cost of driving per mile (determined by both fuel economy and fuel price), and demographic changes (such as women fully entering the workforce). Since 2007, VMT per licensed driver has declined slightly because of the sudden spike in the cost of driving per mile followed by the economic downturn. However, VMT per licensed driver begins to grow again in the Reference case, but at a more moderate average annual rate of 0.6 percent, reaching over 15,280 miles in 2035 (Figure 73).

The projected growth in VMT per licensed driver results from a return to rising real disposable personal income, which increases by 90 percent between 2009 and 2035. While motor gasoline prices rise by 60 percent over the period, faster income growth ensures that the impact on travel demand is blunted by a reduction in the percentage of income spent on fuel. In addition, the effect of rising fuel costs is moderated by a 30-percent improvement in new vehicle fuel economy following the implementation of more stringent GHG and CAFE standards for LDVs.

Several demographic forces also play a role in moderating the growth in VMT per licensed driver despite the rise in real disposable income. Although LDV sales increase through 2035, the number of vehicles per licensed driver remains relatively constant (at just over 1). In addition, unemployment remains above pre-recession levels in the Reference case until late in the projection period, further tempering the increase in personal travel demand.

New technologies promise better vehicle fuel efficiency

Figure 74. Market penetration of new technologies for light-duty vehicles, 2035 (percent)



The market adoption of advanced technologies in conventional vehicles facilitates the improvement in fuel economy that is necessary to meet more stringent CAFE standards through MY 2020 and reduce fuel costs thereafter. In the *AEO2011* Reference case, the CAFE compliance of new LDVs rises from 29.1 mpg in 2009 to 35.8 mpg in 2020 and 37.8 mpg in 2035, due in part to greater penetration of unconventionally fueled vehicles and in part to the addition of individual technologies in conventional vehicles (Figure 74).

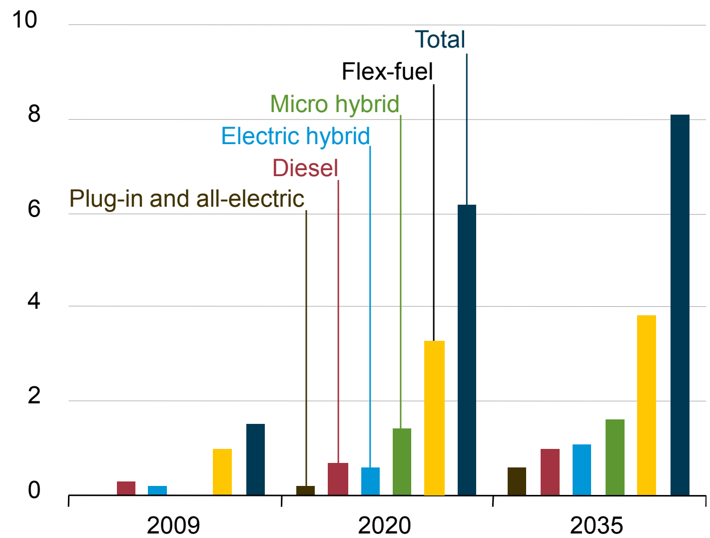
In 2035, advanced drag reduction, which provides fuel economy improvements by reducing vehicle air resistance at higher speeds, is implemented in 98 percent of new LDVs. In addition, with the adoption of light-weight materials through material substitution, the average weights of new cars and light trucks decline by 4.9 percent and 1.5 percent, respectively, from 2009 to 2035, providing additional improvements in fuel economy.

Advanced transmission technologies also improve fuel economy by improving the efficiency of vehicle drive trains. Aggressive shift logic is used in 73 percent of new LDVs in 2035; and other advanced technologies, such as continuously variable, automated manual, and six-speed transmissions, are installed in 56 percent of new conventional vehicles.

Engine technologies that reduce fuel consumption also penetrate the market for new vehicles. Cylinder deactivation and turbocharging reach penetrations of 31 and 14 percent, respectively, in 2035. Electrification of accessories such as pumps and power steering, which also increases fuel economy, is implemented in 19 percent of new LDVs in 2035.

Unconventional vehicle technologies exceed 40 percent of new sales in 2035

Figure 75. Sales of unconventional light-duty vehicles by fuel type, 2009, 2020, and 2035 (million vehicles sold)



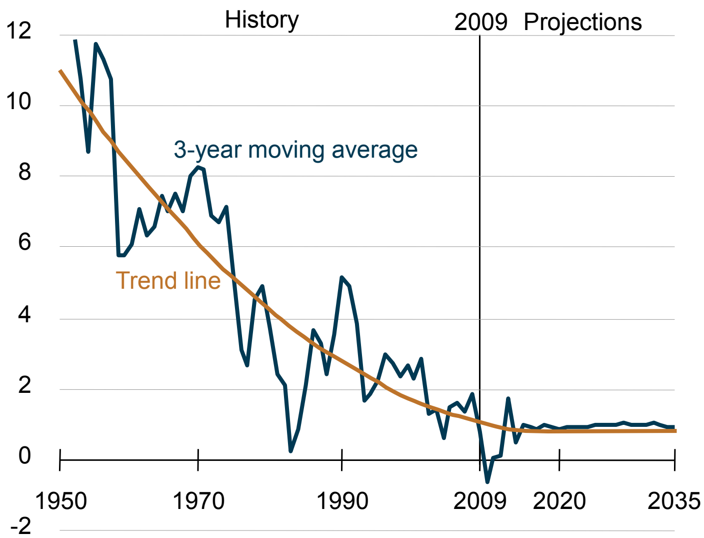
Unconventional vehicles (those that use diesel, alternative fuels, and/or hybrid electric systems) play a significant role in meeting more stringent fuel economy standards and offering fuel savings in the face of relatively higher fuel prices, growing from 15 percent of new vehicle sales in 2009 to 42 percent by 2035 in the *AEO2011* Reference case.

Flex-fuel vehicles (FFVs), which can use blends of ethanol up to 85 percent, represent the largest share of unconventional LDV sales in 2035, at 19 percent of total new vehicle sales and 47 percent of unconventional vehicle sales (Figure 75). Manufacturers selling FFVs currently receive incentives in the form of fuel economy credits earned for CAFE compliance through MY 2016. FFVs also play a critical role in meeting the RFS for biofuels.

Sales of electric and hybrid vehicles that use stored electric energy grow considerably in the Reference case. Micro hybrids, which use start/stop technology to manage engine operation while at idle, account for 8 percent of all conventional gasoline vehicle sales by 2035, the largest share for vehicles that use electric storage. Gasoline-electric and diesel-electric hybrid vehicles account for 5 percent of total LDV sales and 13 percent of unconventional vehicle sales in 2035, and plug-in and all-electric hybrid vehicles account for 3 percent of LDV sales and 8 percent of unconventional vehicle sales. Sales of diesel vehicles also increase, to 5 percent of total LDV sales and 13 percent of unconventional vehicle sales in 2035. Light duty natural gas vehicles account for less than 0.1 percent of new vehicle sales throughout the projection due to their high incremental cost and limited fuel infrastructure.

Residential and commercial sectors dominate electricity demand growth

Figure 76. U.S. electricity demand growth, 1950-2035 (percent, 3-year moving average)



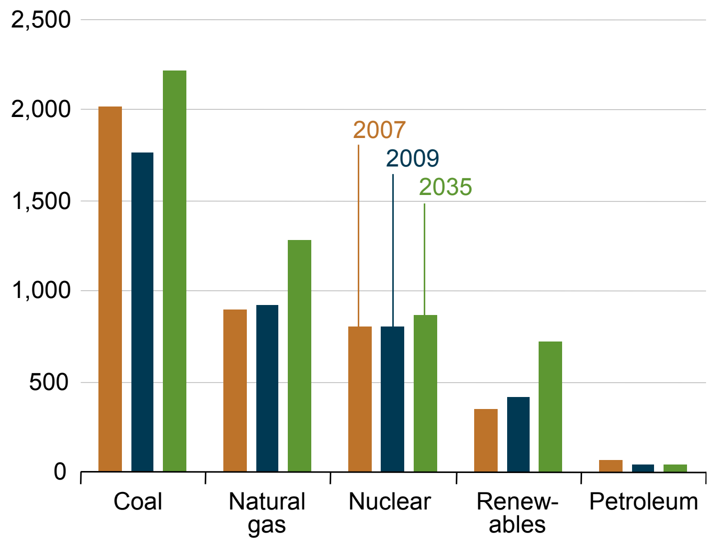
Electricity demand growth has slowed in each decade since the 1950s. After 9.8-percent annual growth in the 1950s, demand (including retail sales and direct use) increased 2.4 percent per year in the 1990s. From 2000 to 2009 (including the 2008-2009 economic downturn) demand grew by 0.5 percent per year. In the Reference case, electricity demand growth rebounds but remains relatively slow, as growing demand for electricity services is offset by efficiency gains from new appliance standards and investments in energy-efficient equipment.

Electricity demand grows by 31 percent in the Reference case (an average of 1.0 percent per year), from 3,745 billion kilowatthours in 2009 to 4,908 billion in 2035 (Figure 76). Residential demand grows by 18 percent over the period, spurred by population growth, rising disposable income, and continued population shifts to warmer regions with greater cooling requirements. Commercial sector electricity demand increases 43 percent, led by the service industries. Industrial electricity demand grows only 9 percent, slowed by increased competition from overseas manufacturers and a shift of U.S. manufacturing toward consumer goods that require less energy to produce.

In the Reference case, average annual electricity prices (2009 dollars) fall 6 percent from 2009 to 2035. Through 2021 prices fall in response to lower coal and natural gas prices, and the phaseout of competitive transition and system upgrade charges included in transmission and distribution costs. After 2021, rising fuel costs more than offset the lower transmission and distribution costs. Economic growth leads to more demand for electricity and the fuels used for generation, raising the prices of both. In the High and Low Economic Growth cases, electricity prices fall by 2 percent and 11 percent, respectively, over the projection period.

Coal-fired plants continue to lead electricity output

Figure 77. Electricity generation by fuel, 2007, 2009, and 2035 (billion kilowatthours)



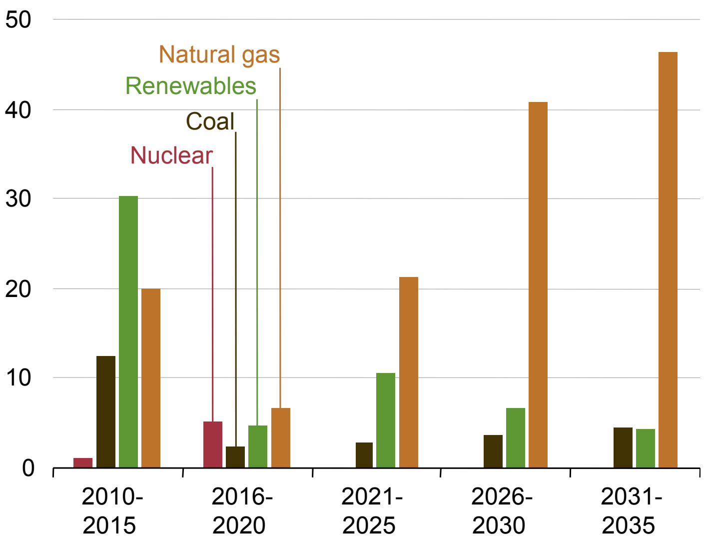
Assuming no additional constraints on carbon emissions, coal remains the dominant source of electricity generation in the *AEO2011* Reference case (Figure 77). Generation from coal increases by 25 percent from 2009 to 2035, but only 10 percent from pre-recession 2007 levels, largely as a result of increased use of existing capacity. Its share of the total generation mix, however, falls from 45 percent to 43 percent as a result of more rapid increases in generation from natural gas and renewables. Growth in gas-fired generation is supported by low natural gas prices and stable capital costs for new plants. Low natural gas prices make the dispatch of existing plants and construction of new natural-gas-fired plants more competitive.

Generation from U.S. nuclear power plants increases by 9 percent from 2009 to 2035, but its share of total generation falls from 20 percent in 2009 to 17 percent in 2035. The Reference case assumes that existing nuclear power plants will continue operating through 2035 (except for retirements already announced); that some plants will be upgraded to higher rated capacities; and that a small number of new nuclear power plants will be built as a result of various incentive programs.

Electricity generation from renewable sources grows by 72 percent in the Reference case, raising its share of total generation from 11 percent in 2009 to 14 percent in 2035. Most of the growth in renewable electricity generation in the power sector consists of generation from wind and biomass facilities. The growth in wind generation is primarily driven by State RPS and Federal tax credits. Generation from biomass comes from both dedicated biomass plants and co-firing in coal plants. Its growth is driven by State RPS, the availability of low-cost feedstocks, and the RFS, which results in significant production of electricity at plants producing biofuels.

Most new capacity additions use natural gas and renewables

Figure 78. Electricity generation capacity additions by fuel type, 2010-2035 (gigawatts)



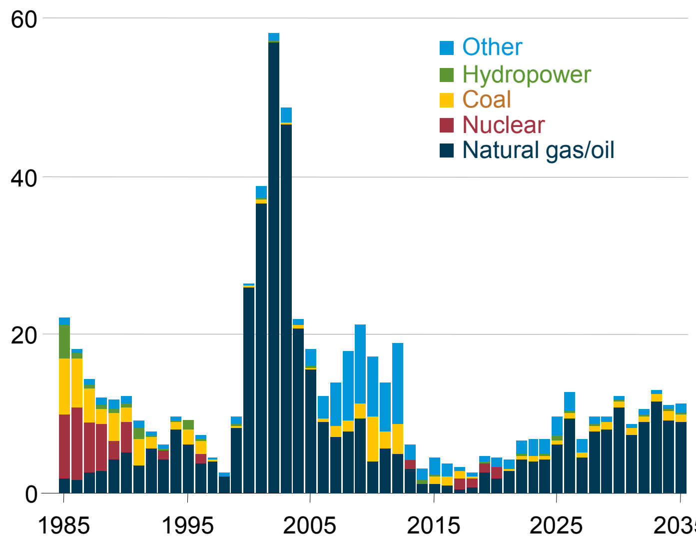
Decisions to add capacity and the choice of fuel depend on a number of factors [*90*]. With growing electricity demand and the retirement of 39 gigawatts of existing capacity, 223 gigawatts of new generating capacity (including end-use combined heat and power) will be needed between 2010 and 2035 (Figure 78).

Natural-gas-fired plants account for 60 percent of capacity additions between 2010 and 2035 in the *AEO2011* Reference case, compared with 25 percent for renewables, 11 percent for coal-fired plants, and 3 percent for nuclear. Escalating construction costs have the largest impact on capital-intensive technologies, including nuclear, coal, and renewables. However, Federal tax incentives, State energy programs, and rising prices for fossil fuels increase the competitiveness of renewable and nuclear capacity. In contrast, uncertainty about future limits on GHG emissions and other possible environmental regulations reduces the competitiveness of coal-fired plants (reflected in the *AEO2011* Reference case by adding 3 percentage points to the cost of capital for new coal-fired capacity).

Capacity additions also are affected by demand growth and by fuel prices, which are uncertain. Total capacity additions from 2010 to 2035 range from 172 gigawatts in the Low Economic Growth case to 290 gigawatts in the High Economic Growth case. With higher natural gas prices, such as in the *AEO2011* Low Shale Estimated Ultimate Recovery (EUR) case, fewer natural-gas-fired plants are added than in the Reference case. In the High Shale EUR case, where delivered natural gas prices are 21 percent lower than in the Reference case by 2035, total gas-fired capacity additions increase to 154 gigawatts between 2009 and 2035 compared to 135 gigawatts in the Reference case. Total capacity additions range from 212 gigawatts in the Low Shale EUR case to 230 gigawatts in the High Shale EUR case.

Annual capacity additions slow significantly after 2012

Figure 79. Additions to electricity generation capacity, 1985-2035 (gigawatts)



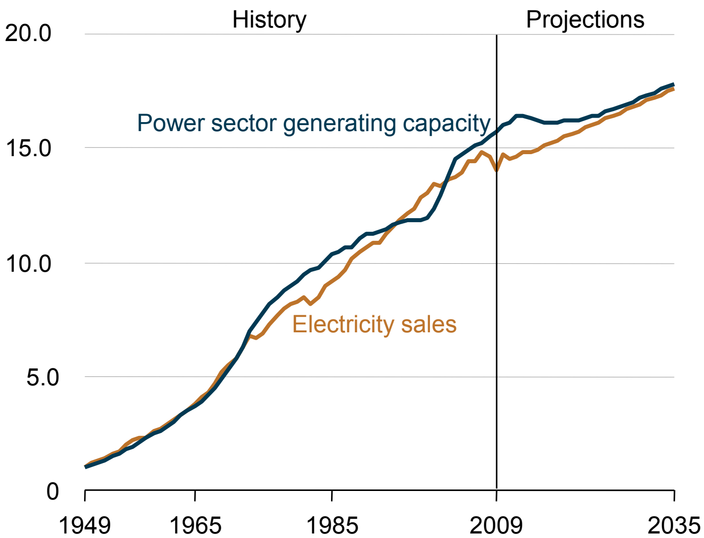
Typically, investments in electricity generation capacity have gone through "boom and bust" cycles, with periods of slower growth followed by strong growth, in response to changing expectations for future electricity demand and fuel prices, as well as changes in the industry, such as restructuring (Figure 79). A construction boom in the early 2000s saw capacity additions averaging 35 gigawatts a year, much higher than had been seen before. More recently, average annual builds have dropped to around 16 gigawatts per year.

In the *AEO2011* Reference case, capacity additions from 2010 to 2035 total 223 gigawatts, including new plants built not only in the power sector but also by end-use generators. Annual additions in 2010, 2011, and 2012 average 17 gigawatts per year, with at least 40 percent of that capacity already under construction. Of those early builds, about 46 percent are renewable capacity built to take advantage of Federal tax incentives and to meet State renewable standards.

Annual builds drop significantly after 2012 and remain below 7 gigawatts per year until 2025. During that period, existing reserves are adequate to meet growth in demand in most regions, given the earlier construction boom and relatively low demand growth following the economic recession. Between 2025 and 2035, average annual builds increase to 11 gigawatts per year, as excess reserves are depleted and total capacity growth is more consistent with demand growth. About 80 percent of the capacity added in the period is natural-gas-fired, due to higher construction costs for other capacity types and uncertain prospects for possible future limitations on GHG emissions.

Growth in generating capacity tracks rising demand for electricity

Figure 80. Electricity sales and power sector generating capacity, 1949-2035 (index, 1949 = 1.0)



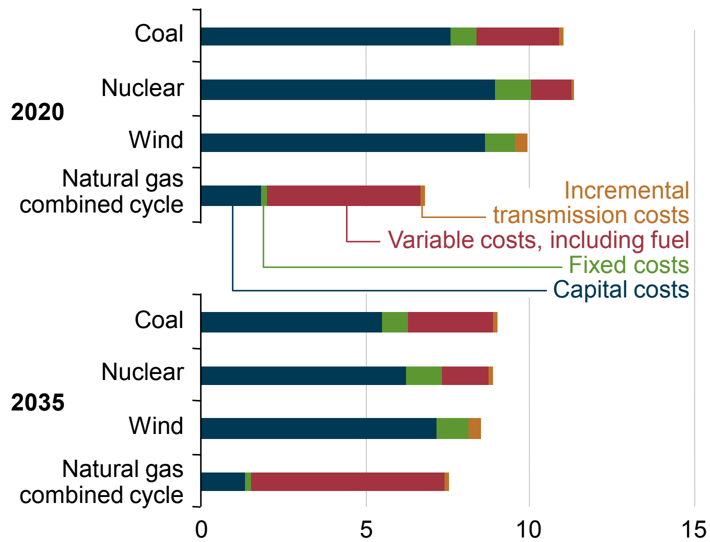
Over the long term, growth in electricity generating capacity and growth in end-use demand for electricity track one another. However, unexpected shifts in demand or dramatic changes affecting capacity investment decisions can cause imbalances for a period of time. Because long-term planning is required for large-scale investments in new capacity, such periods of imbalance can take years to work out.

Figure 80 shows indexes summarizing relative changes in total generating capacity and demand. During the 1950s and 1960s, the capacity and demand indexes tracked very closely. The energy crises of the 1970s and 1980s, together with other factors, slowed electricity demand growth, and capacity growth outpaced demand for more than 10 years afterward, as planned units continued to come on line. Demand and capacity did not align again until the mid-1990s. Then, in the late 1990s, uncertainty about deregulation of the electricity industry caused a downturn in capacity expansion, and another period of imbalance followed, with growth in demand exceeding capacity growth.

In 2000, a boom in construction of new natural-gas-fired plants began, quickly bringing capacity back into balance with demand and, in fact, creating excess capacity. More recently, the economic recession in 2008 and 2009 caused a significant drop in electricity demand. As a result, the lower demand projected for the near term in the *AEO2011* Reference case again results in excess generating capacity. Capacity that is currently under construction is completed in the Reference case, but only a limited amount of additional capacity is built through 2025. In 2025, capacity growth and demand growth are in balance again, and they grow at similar rates through 2035.

Costs and regulatory uncertainties vary across options for new capacity

Figure 81. Levelized electricity costs for new power plants, 2020 and 2035 (2009 cents per kilowatthour)



Technology choices for new generating capacity are based largely on capital, operating, and transmission costs. Coal, nuclear, and renewable plants are capital-intensive (Figure 81), while operating (fuel) expenditures make up most of the costs for gas-fired capacity [*91*]. Capital costs depend on such factors as equipment costs, interest rates, and cost-recovery periods. Fuel costs vary with operating efficiency, fuel price, resource availability, and transportation costs.

In addition to levelized cost considerations [*92*], some technologies and fuels receive subsidies, such as production tax credits (PTCs) and ITCs. Also, new plants must satisfiy local and Federal emissions standards and must be compatible with the utility's load profile.

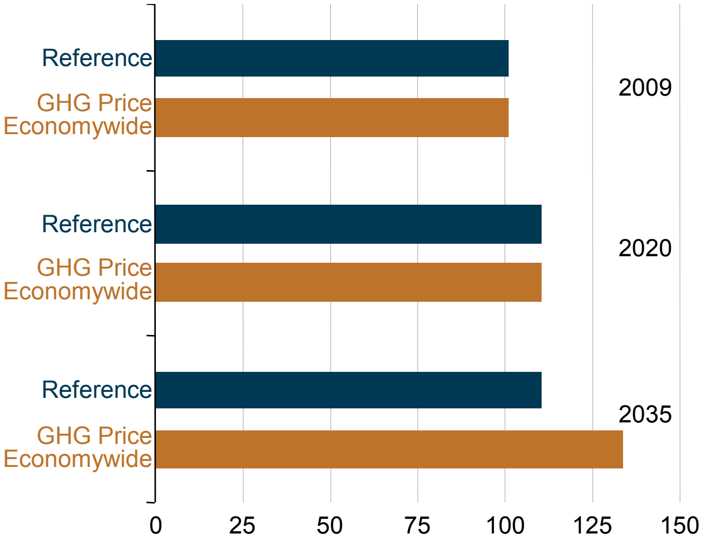
Regulatory uncertainty also affects capacity planning. New coal plants may require carbon control and sequestration equipment, resulting in higher material, labor, and operating costs. Alternatively, coal plants without carbon controls could incur higher costs for siting and permitting. Because nuclear and renewable power plants (including wind plants) do not emit greenhouse gases, their costs are not directly affected by regulatory uncertainty in this area.

Capital costs can decline over time as developers gain technology experience. In the Reference case, the capital costs of new technologies are adjusted upward initially, to reflect the optimism inherent in early estimates of project costs, then decline as project developers gain experience. The decline continues at a progressively slower rate as more units are built. Operating efficiencies also are assumed to improve over time, resulting in reduced variable costs unless increases in fuel costs exceed the savings from efficiency gains.

Renewable generation

EPACT2005 tax credits stimulate some nuclear builds

Figure 82. Electricity generating capacity at U.S. nuclear power plants in two cases, 2009, 2020, and 2035 (gigawatts)

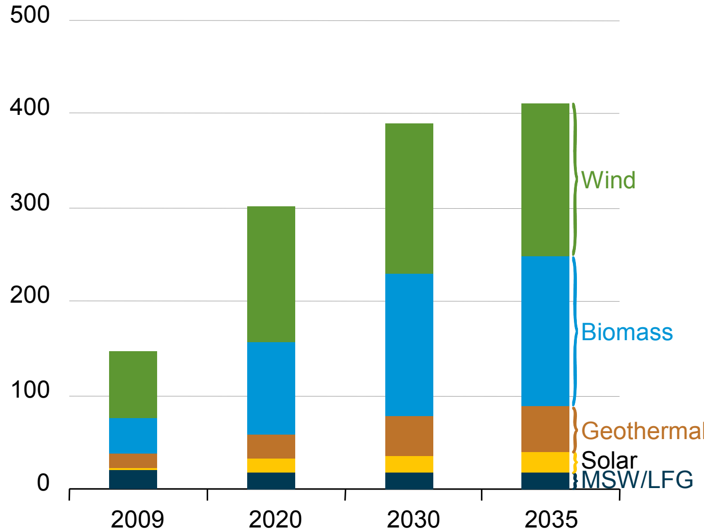


In the *AEO2011* Reference case, nuclear power capacity increases from 101.0 gigawatts in 2009 to 110.5 gigawatts in 2035 (Figure 82), including 3.8 gigawatts of expansion at existing plants and 6.3 gigawatts of new capacity. The new capacity includes completion of a second unit at the Watts Bar site, where construction on a partially completed plant has resumed. Increases in the estimated costs for new nuclear plants make new investments in nuclear power uncertain. Four new nuclear power plants are completed in the Reference case, all of which are brought on line by 2020 to take advantage of Federal financial incentives. High construction costs for nuclear plants, especially relative to natural-gas-fired plants, make other options for new nuclear capacity uneconomical even in the alternative electricity demand and fuel price cases. In the GHG Price Economywide case, which attaches a price to reductions in carbon dioxide, total nuclear capacity additions from 2010 to 2035 increase to 29 gigawatts as a consequence of the higher costs for operating fossil-fueled capacity.

One nuclear unit, Oyster Creek, is expected to be retired at the end of 2019, as announced by Exelon in December 2010. All other existing nuclear units continue to operate through 2035 in the Reference case, which assumes that they will apply for, and receive, operating license renewals, including in some cases a second 20-year extension after they reach 60 years of operation. As discussed in last year's "Issues in focus" section, it will likely be a decade or more before significant insight can be gained regarding what will happen beyond 60 years. With costs for natural-gas-fired generation rising and future regulation of GHG emissions uncertain, the economics of keeping existing nuclear power plants in operation are favorable.

Biomass and wind lead growth in renewable generation

Figure 83. Nonhydropower renewable electricity generation by energy source, 2009-2035 (billion kilowatthours)

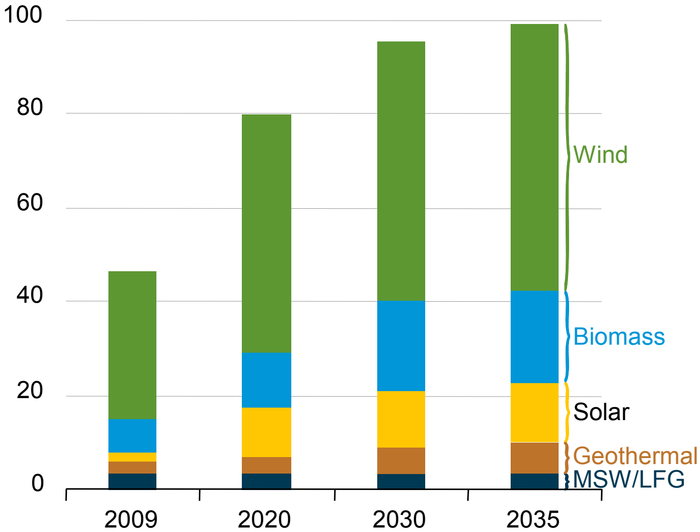


Renewable electricity generation, excluding hydropower, accounts for nearly one-quarter of the growth in electricity generation from 2009 to 2035 in the *AEO2011* Reference case (Figure 83). The increase is supported by RFS, State-level renewable electricity standards, and Federal tax credits. In the Reference case, generation from wind power nearly doubles its share of total generation, while generation from geothermal resources triples as a result of technology advances that make previously marginal sites attractive for development, as well as increasing the resources available at existing geothermal sites.

Renewable electricity generation in the end-use sectors also continues to grow. As a result of the Federal RFS that requires increased use of biofuels, there is an attractive opportunity to use waste heat from biofuel production to generate electricity. Consequently, generation from biomass more than triples from 2009 to 2035, when it accounts for 39 percent of total nonhydroelectric renewable electricity generation. Generation from solar resources increases from 2 percent of nonhydroelectric renewable generation in 2009 to more than 5 percent in 2035, as capital costs, especially for PV technologies in the end-use sectors, decrease over time. End-use solar generation grows from 2.3 billion kilowatthours in 2009 to 16.8 billion kilowatthours in 2035, and additional growth in solar generation comes from utility-scale PV plants, which begin to become competitive in the later years of the projection.

Renewable capacity growth spurred by end-use increases

Figure 84. Nonhydropower renewable electricity generation capacity by source, 2009-2035 (gigawatts)



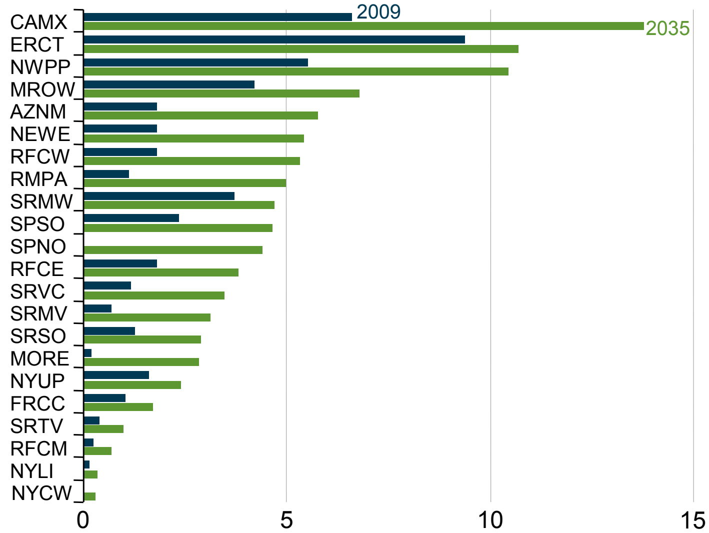
Supported in part by Federal tax credits in the early part of the projection period, the Federal RFS, and State RPS, nonhydropower renewable generating capacity grows at a faster rate than fossil fuel capacity in the *AEO2011* Reference case. Total nonhydropower renewable capacity increases from 47 gigawatts in 2009 to 100 gigawatts in 2035 (Figure 84). The largest increase is in wind-powered generating capacity. Because the Federal PTC expires at the end of 2012, however, 73 percent of the overall increase in wind capacity (18.2 gigawatts) occurs between 2009 and 2012. From 2012 through 2035, only an additional 6.9 gigawatts of wind capacity is added.

Biomass generating capacity grows from 7 gigawatts in 2009 (15 percent of total nonhydropower renewable capacity) to 20.2 gigawatts in 2035 (20 percent). All the growth in biomass capacity occurs in the end-use sectors, mainly at biorefineries, where electricity generation capacity increases as a result of mandates in the Federal RFS that require increased use of biofuels. No growth occurs in dedicated biomass generating capacity, because dedicated open-loop biomass plants remain too expensive to compete successfully with renewable capacity.

Solar generating capacity increases five-fold, with most capacity additions coming in the end-use sectors. The additions are based on a decline in the cost of PV systems over the projection period and the availability of Federal tax credits through 2016. Geothermal capacity also grows as a result of increased site availability, more favorable resource estimates, and lower costs for construction of geothermal facilities.

State portfolio standards increase renewable electricity generation

Figure 85. Regional growth in nonhydroelectric renewable electricity generation capacity, including end-use capacity, 2009-2035 (gigawatts)



Regional growth in renewable generation is based largely on two factors: availability of renewable energy resources and the existence of State RPS programs. After a period of robust RPS enactments in several States, 2010 was a relatively quiet year for RPS expansions. The most prominent change was California's RPS modification, which now requires renewable energy (including hydroelectric plants smaller than 30 megawatts capacity) to make up 33 percent of electricity generation, strengthening the prior 20-percent requirement that was supported by a limited fund.

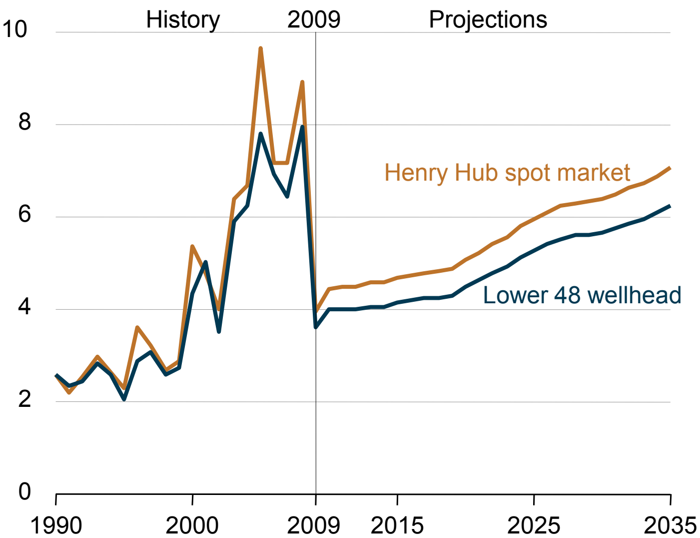
The WECC California region (CAMX), whose area approximates the California State boundaries (for a map of the electricity regions modeled, see Appendix F) has the largest projected nonhydroelectric renewable capacity, at 13.8 gigawatts in 2035 (Figure 85). The vast majority of California's renewable generating plants in 2035 consist of wind and geothermal capacity, each totaling more than 4.5 gigawatts in 2035. The Texas Regional Entity (ERCT) has more wind capacity in 2035 than any other region, at 10.1 gigawatts in 2035, and the second-largest nonhydro renewable capacity overall.

CAMX leads in solar installations, although State RPS programs heavily influence solar growth beyond the Southwest as both the Reliability First Corporation/East (RFCE) and the Reliability First Corporation/West (RFCW) regions have about 1 gigawatt of end-use solar capacity in 2035. Those two regions are not known for a strong solar resource base, and the installations are in response to the ITC in the early years of the projection period and high electricity prices during the later years. Most biomass capacity—confined largely to the end-use sectors—is built at cellulosic ethanol plant sites, most of which are in the Southeast.

Natural gas prices

Price disparity between crude oil and natural gas shifts drilling to liquids-rich shales

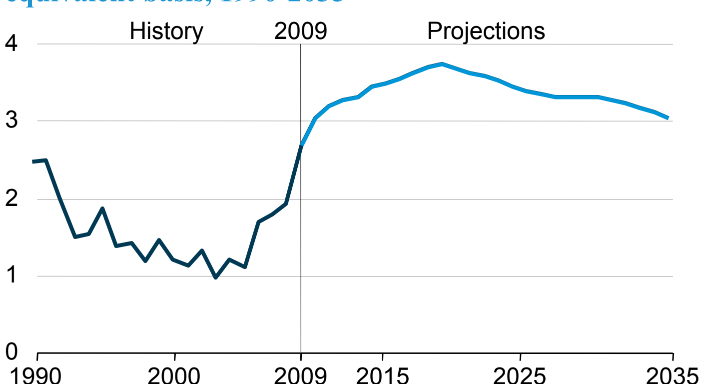
Figure 86. Annual average lower 48 wellhead and Henry Hub spot market prices for natural gas, 1990-2035 (2009 dollars per million Btu)



Unlike crude oil prices, natural gas prices do not return to the higher levels recorded before the 2007-2009 recession (Figure 86). Although some supply factors continue to relate the two markets loosely, the two do not track directly (Figure 87). The large difference between crude oil and natural gas prices results in a shift in drilling toward shale formations with high concentrations of liquids.

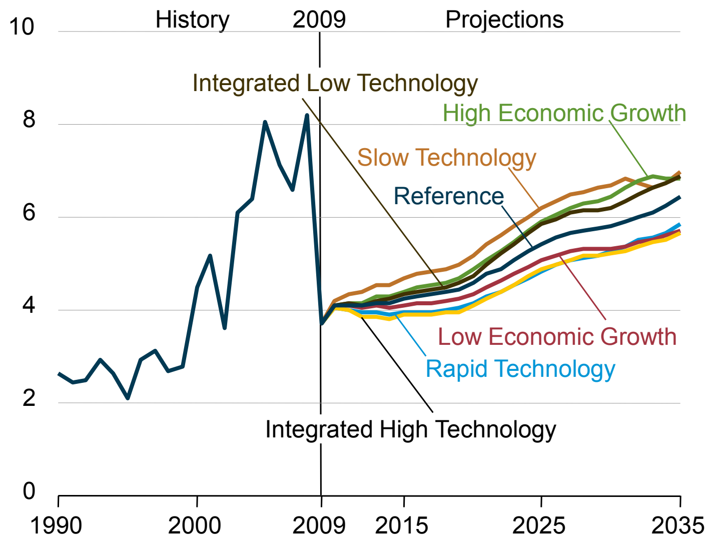
Shale gas continues to have enormous potential. To satisfy consumption levels in the Reference case, the number of lower 48 natural gas wells completed increases by 2.3 percent per year from 2009 to 2035. As a result, the average wellhead price for natural gas increases by an average of 2.1 percent per year, to $6.26 per million Btu in 2035 (2009 dollars). Henry Hub prices increase by 2.3 percent per year, to $7.07 per million Btu in 2035. Nonetheless, the Henry Hub price and average wellhead prices do not pass $5.00 per million Btu until 2020 and 2024, respectively.

Figure 87. Ratio of low-sulfur light crude oil price to Henry Hub natural gas price on an energy equivalent basis, 1990-2035



Natural gas prices vary with economic growth and technology progress

Figure 88. Annual average lower 48 wellhead prices for natural gas in seven cases, 1990-2035 (2009 dollars per thousand cubic feet)



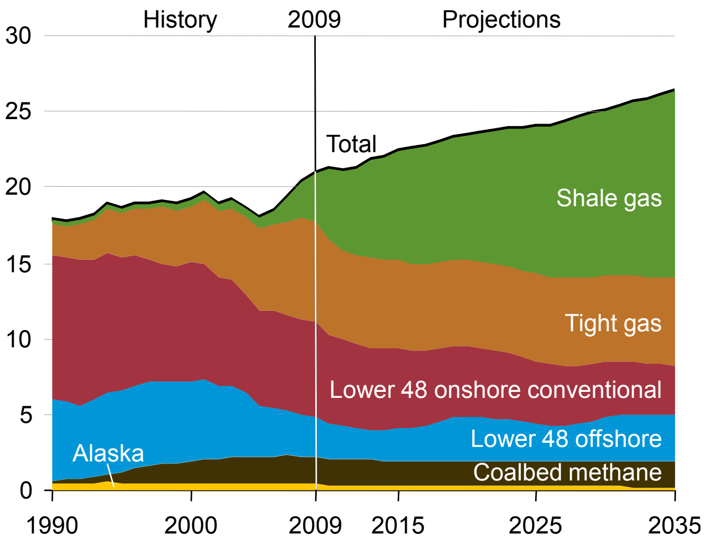
The extent to which natural gas prices in the Rapid and Slow Oil and Gas Technology cases differ from the Reference case depends on assumptions about the rate of improvement in natural gas exploration and production technologies. Technology improvement can reduce drilling and operating costs, expand the economically recoverable resource base, and affect the timing of production increases. It is particularly important to the production of natural gas from shale formations. The Reference case assumes that annual technology improvements follow historical trends. In the Rapid Oil and Gas Technology case, exploration and development costs decline at a faster rate, accelerating growth in production, which puts downward pressure on prices. In the Slow Oil and Gas Technology case, slower respective cost declines lead to higher natural gas prices and lower levels of consumption than in the Reference case (Figure 88).

The same type of impact can be seen from changes in economic growth and demand technologies. In the High Economic Growth and Integrated Low Technology cases, higher levels of demand result in increased production, which puts upward pressure on natural gas prices. In the Low Economic Growth and Integrated High Technology cases, the opposite impact is seen. Lower levels of demand put downward pressure on natural gas prices.

In the High Economic Growth and Slow Oil and Gas Technology cases with faster production growth, prices rise to levels that cause the Alaska pipeline to be completed towards the end of the projection, leading to temporary declines in natural gas prices. In the other cases, natural gas prices remain too low to make the Alaska pipeline economical before 2035.

Shale gas provides largest source of growth in U.S. natural gas supply

Figure 89. Natural gas production by source, 1990-2035 (trillion cubic feet)



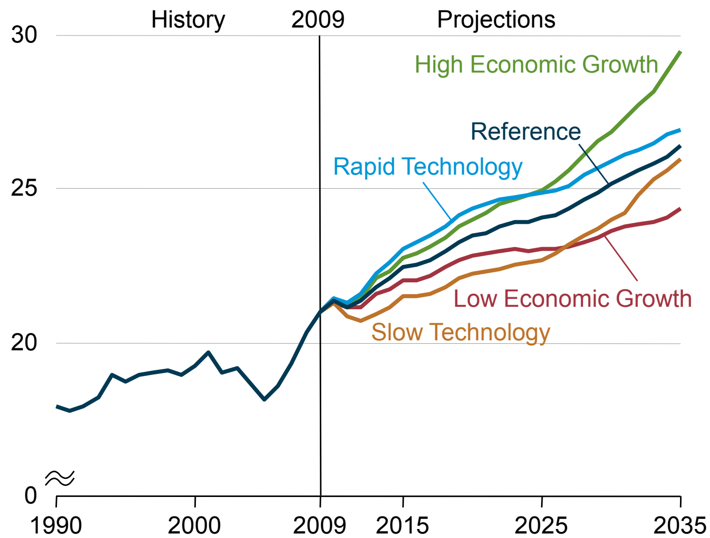
The increase in natural gas production from 2009 to 2035 in the *AEO2011* Reference case results primarily from continued exploration and development of shale gas resources (Figure 89). Shale gas is the largest contributor to production growth, while production from tight sands, coalbed methane deposits, and offshore waters remains stable. Shale gas makes up 47 percent of total U.S. production in 2035, nearly triple its 16-percent share in 2009. The estimate for technically recoverable unproved shale gas resources in the *AEO2011* Reference case is 827 trillion cubic feet. Although more information has become available as a result of increased drilling activity in developing shale gas plays, estimates of technically recoverable resources and well productivity remain highly uncertain. The "Issues in focus" section explores several sensitivity cases that alter the outlook for shale gas resources.

Offshore natural gas production in the Reference case declines initially, reflecting delays in near-term projects in the Gulf of Mexico. According to the latest leasing plan from the Bureau of Ocean Energy Management (BOEM), lease sales in the Mid- and South Atlantic outer continental shelf (OCS) will not occur before 2017. Because the Pacific OCS is considered to have low economic potential, *AEO2011* assumes that leasing in the Pacific will occur only in the southern California offshore and only after 2023.

Production from coalbeds and tight sands does not contribute to total production growth in the Reference case but does remain an important source of natural gas, accounting for 29 to 40 percent of total production from 2009 to 2035.

Economic growth and technology progress affect natural gas supply

Figure 90. Total U.S. natural gas production in five cases, 1990-2035 (trillion cubic feet)



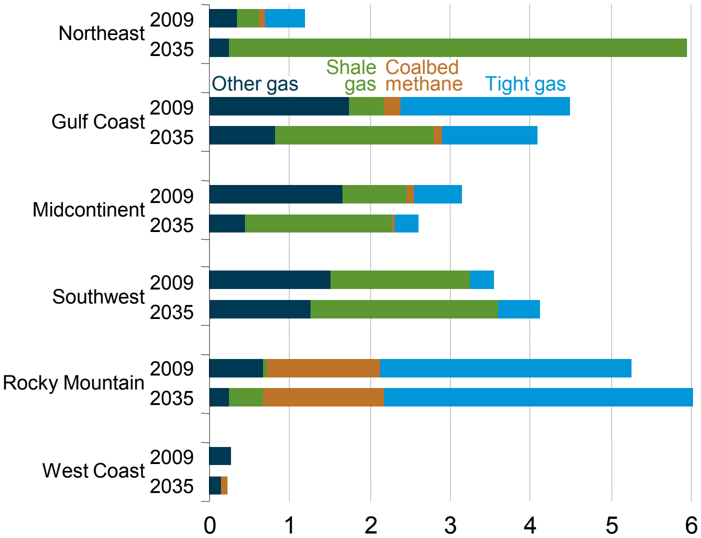
The level of domestic natural gas production is influenced by changes in the rate of economic growth and improvement in exploration and development technologies. The effect of economic growth results from its impact on the level of natural gas consumption. Changes in the rate of technology improvement affect natural gas drilling and production costs, which in turn can affect productive capacity of natural gas wells and change the number of successful wells, resulting in lower or higher production.

From 2009 to 2035, average annual natural gas consumption is 1.1 trillion cubic feet higher in the High Economic Growth case than in the Reference case. Domestic production accounts for 90 percent of this increase, with imports from Canada supplying most of the rest. On average in the High Economic Growth case, 64 percent of the increase in domestic production from 2009 to 2035 comes from shale gas, 15 percent from tight sands, and the remainder from offshore wells, coalbeds, and an Alaska pipeline completed in 2034.

Average annual natural gas production from 2009 to 2035 is 0.7 trillion cubic feet higher and 0.9 trillion cubic feet lower in the Rapid and Slow Technology cases, respectively, than in the Reference case (Figure 90). Shale gas production accounts for most of the difference, increasing by 0.8 trillion cubic feet per year on average from Reference case levels in the High Technology case and decreasing by 0.9 trillion cubic feet per year on average in the Slow Technology case. Higher prices in the Slow Technology case enable the Alaska pipeline to be completed in 2032, displacing more expensive production from tight sands and coalbed methane sources in the Rocky Mountain region, where shale gas is less abundant. Lower production levels in the Slow Technology case result from higher costs, lower resource availability, and, ultimately, reduced consumption in response to higher prices.

Increases in shale gas supply support growth in total natural gas supply production

Figure 91. Lower 48 onshore natural gas production by region, 2009 and 2035 (trillion cubic feet)



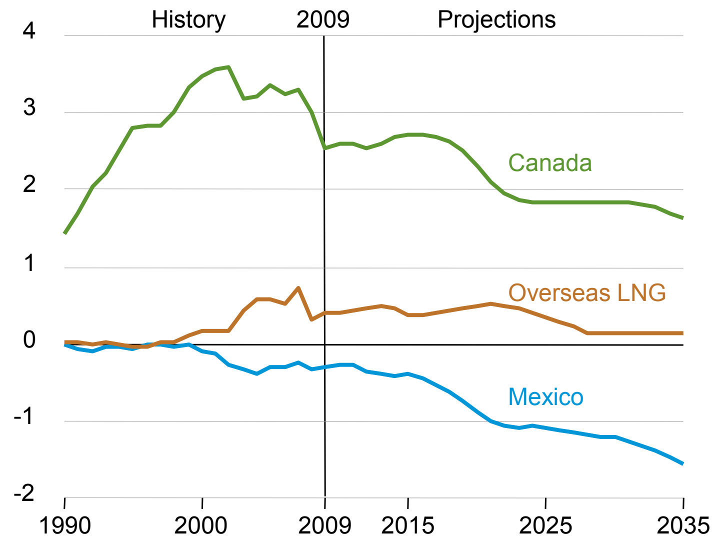
An almost four-fold increase in shale gas production from 2009 to 2035 more than offsets a 26-percent decline in non-shale lower 48 onshore natural gas production in the *AEO2011* Reference case. Significant increases in shale gas production occur in the Northeast and Gulf Coast regions. (See Figure F4 in Appendix F for a map of the regions.) Resource estimates for the Marcellus, Haynesville, and Eagle Ford plays have continued to increase as new information becomes available from exploration and development in those areas.

Dry gas production in the Northeast region increases in the Reference case nearly five-fold from 2009 to 2035 (Figure 91). The majority of the increase comes from the Marcellus shale gas play, which has an estimated technically recoverable resource base of about 400 trillion cubic feet. Because the growth in shale gas production displaces much of the natural gas that currently is supplied to the Northeast from the Gulf Coast and Canada, Gulf Coast gas tends to saturate the Henry Hub market and put downward pressure on natural gas prices.

Even with significant growth in shale gas production, total production in the Gulf Coast and Midcontinent regions falls, reflecting significant declines in sources other than shale formations. In particular, rigs previously used for drilling in tight sands are being moved to shale deposits. In the Southwest, as shale production increases, production from non-shale sources is maintained at a level that allows the region's total production to grow. In the Rocky Mountain region, production increases from tight sands and coalbed methane sources support increases in total production.

U.S. net imports of natural gas decline as domestic production rises

Figure 92. U.S. net imports of natural gas by source, 1990-2035 (trillion cubic feet)



U.S. net imports of natural gas decline in the *AEO2011* Reference case from 11 percent of total supply in 2009 to 1 percent in 2035. The reduction consists primarily of lower imports from Canada and higher net exports to Mexico (Figure 92), as a result of demand growth in both countries that outpace growth in their production.

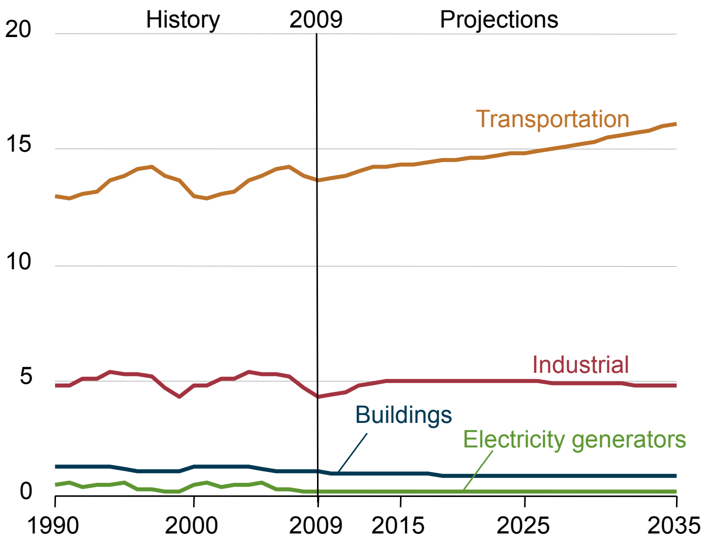
Supplies of natural gas from Canada's conventional sources decline from 2009 to 2035, but those declines are offset by increased production from coalbeds, tight formations, and shale gas deposits, allowing for a relatively constant level of exports to the United States through 2018 before they begin to decline. In addition, net imports to the United States from Canada are offset somewhat by an increase in exports from the United States to eastern Canada.

Mexico's natural gas consumption shows robust growth through 2035, and expected increases in its domestic production are not sufficient to meet demand growth. As a result, Mexico will need to import natural gas to fill the gap. Some of the increased supply to Mexico will be delivered by liquefied natural gas (LNG) tankers, largely to the south of the country, with the remainder coming from the United States.

LNG imports by the United States are minimal in the Reference case and occur largely during periods when world liquefaction capacity exceeds demand. Although U.S. LNG export projects have been proposed, their economic viability remains uncertain in view of the relatively inexpensive sources of natural gas supply available elsewhere in the world. As a result, existing liquefaction capacity in Alaska is the only source for U.S. exports of LNG that is considered in the *AEO2011* Reference case [*93*].

Transportation uses lead growth in liquid fuels consumption

Figure 93. Liquid fuels consumption by sector, 1990-2035 (million barrels per day)



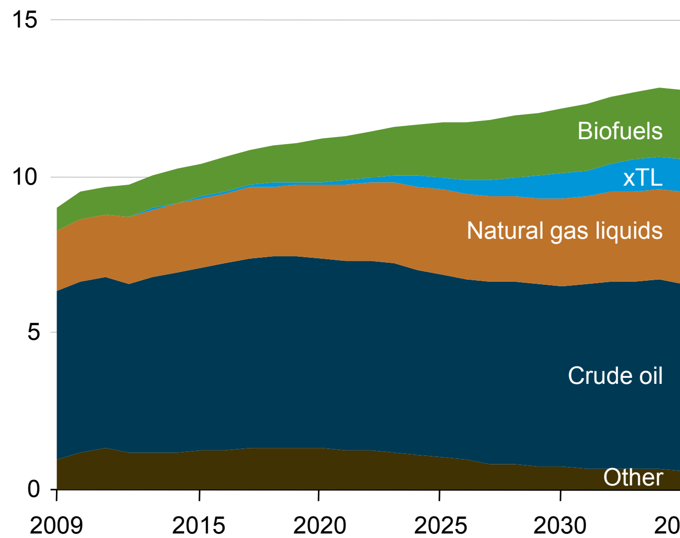
U.S. consumption of liquid fuels—including fuels from petroleum-based sources and, increasingly, those derived from non-petroleum primary fuels such as biomass and natural gas—totals 21.9 million barrels per day in 2035 in the *AEO2011* Reference case, an increase of 2.9 million barrels per day over the 2009 total (Figure 93). In all sectors except transportation, where consumption grows by about 2.5 million barrels per day, liquid fuel consumption remains at about the same level from 2009 to 2035. The transportation sector accounts for 73 percent of total liquid fuels consumption in 2035, up slightly from 71 percent in 2009.

Motor gasoline, ultra-low sulfur diesel, and jet fuel are the primary transportation fuels, supplemented by biofuels such as ethanol and biodiesel. The increase in demand for transportation fuels is met primarily by diesel and biofuels. Motor gasoline consumption increases by approximately 0.3 million barrels per day from 2009 to 2035 in the Reference case, while diesel fuel and E85 consumption increase by 1.3 and 0.8 million barrels per day, respectively, over the period.

Biodiesel and a number of next-generation biofuels account for about 0.6 million barrels per day of the increase in liquid fuels consumption for transportation in 2035. The growth in biofuel use is primarily a result of the RFS mandates in EISA2007, although there is moderate production of corn ethanol beyond that which qualifies for RFS credits. The growth in diesel fuel consumption results from both an expansion of light-duty diesel vehicle sales to meet more stringent CAFE standards and an increase in industrial output that leads to more fuel use by heavy trucks.

Biofuels and natural gas liquids lead growth in total liquids supply

Figure 94. U.S. domestic liquids production by source, 2009-2035 (million barrels per day)



With world oil prices rising in the *AEO2011* Reference case, domestic liquids production grows (Figure 94). From 2009 to 2035, U.S. crude oil production increases by about 600,000 barrels per day.

As a result of the EISA2007 RFS, biofuels production increases by almost 1.5 million barrel per day, with ethanol accounting for the largest share of the increase. Ethanol production increases by more than 800,000 barrels per day from 2009 to 2035, displacing approximately 12 percent of gasoline demand in 2035 on an energy-equivalent basis. In the early years of the projection, ethanol is blended with gasoline and consumed as E10 (motor gasoline blends containing up to 10 percent ethanol) or E15 (motor gasoline blends containing up to 15 percent ethanol). By 2035, however, ethanol is consumed in roughly equal shares as E10, E15, and E85.

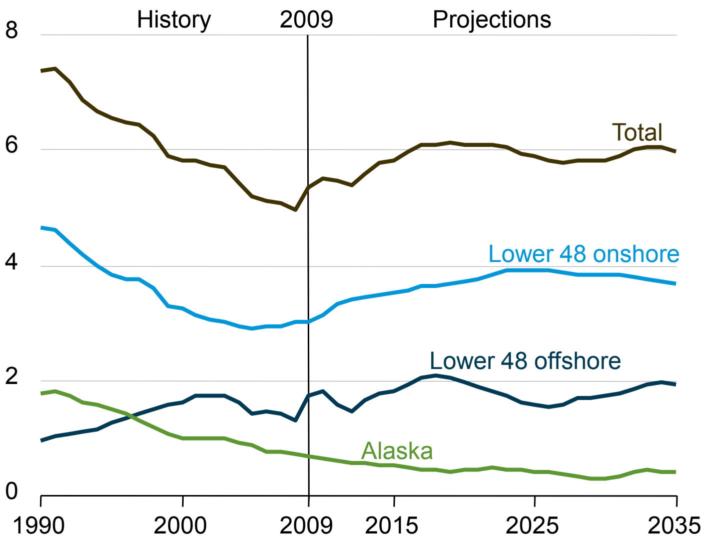
NGL production increases by 1.0 million barrels per day, to 2.9 million barrels per day in 2035, mainly as a result of strong growth in gas shale production, which tends to have relatively large amounts of liquids associated with it. BTL production increases to 516,000 barrels per day, and CTL production increases to 550,000 barrels per day in 2035.

Much of the increased liquids production comes from oil in shale formations (i.e., produced from kerogen, a solid hydrocarbon), CO_2-enhanced oil recovery (EOR), and next-generation "xTL" production, which includes biomass-to-liquids (BTL), GTL, and CTL.

Crude oil supply

U.S. crude oil production increases as projected world oil prices rise

Figure 95. Domestic crude oil production by source, 1990-2035 (million barrels per day)



Rising world oil prices, growing shale oil resources (i.e., liquid oil embedded in non-porous shale rock), and increased production using EOR techniques contribute to increased domestic crude oil production from 2009 to 2035 in the *AEO2011* Reference case (Figure 95). The Bakken shale oil formation contributes to growth in crude oil production in the Rocky Mountain Region, and growth in the Gulf Coast region is spurred by the resources in the Eagle Ford and Austin Chalk formations. Some of the decline in oil production in the Southwest region is offset by production coming from the Avalon shale formation.

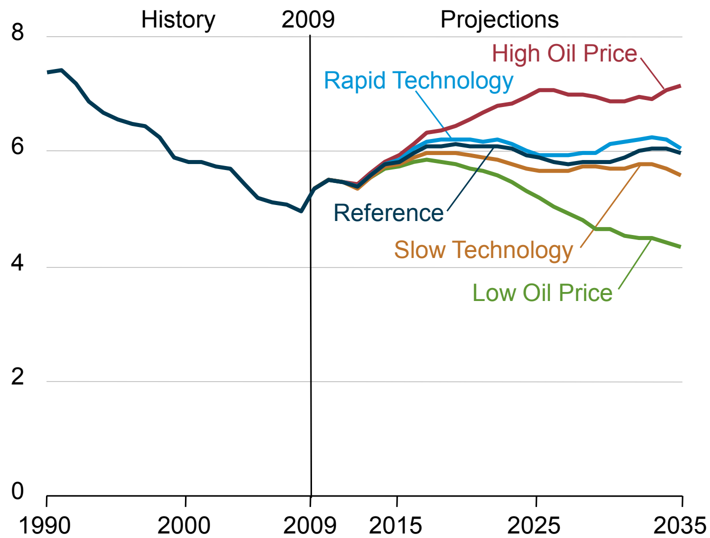
Production with CO_2-EOR increases beginning in 2015 (largely using natural CO_2 sources), continues to grow through 2025 as anthropogenic CO_2 sources increase, and eventually dominates CO_2 production, supporting just over 20 percent of total crude oil production in 2035.

Lower 48 offshore production increases by 13 percent from 2009 to 2035 in the Reference case. According to the recent BOEM leasing plan, lease sales in the Mid- and South-Atlantic OCS will not occur before 2017. In the Pacific OCS, leasing is assumed to occur only off the coast of Southern California and not until after 2023 in the Reference case, because the Pacific OCS is considered to have low potential [*94*].

Oil shale liquid production (i.e., produced from kerogen, a solid hydrocarbon), which comes on line in the Rocky Mountain region in 2029 in the Reference case, accounts for roughly 2 percent of total domestic crude oil production in 2035.

U.S. oil production is more responsive to price changes than to technology gains

Figure 96. Total U.S. crude oil production in five cases, 1990-2035 (million barrels per day)



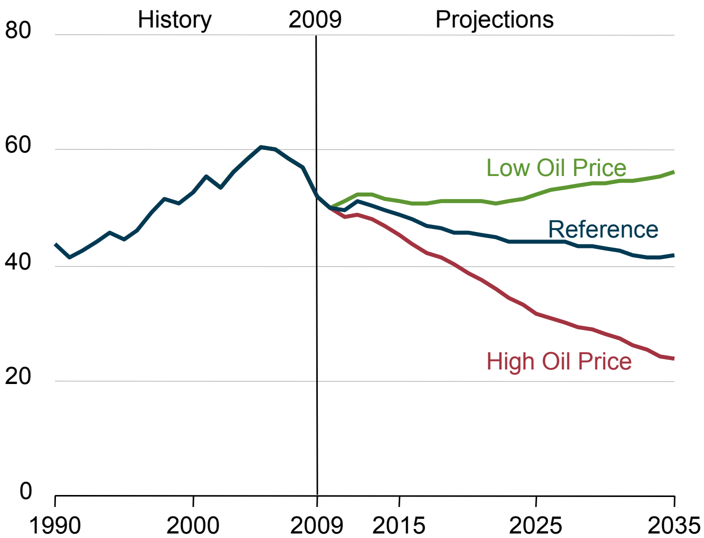
In the *AEO2011* Oil Price and Technology cases, total U.S. crude oil production is more responsive to changes in world oil prices than it is to advances in technology (Figure 96). The most significant difference between the Reference case and the High and Low Oil Price cases is the change in use of CO_2–enhanced EOR in response to the changes in oil price assumptions. From 2015 to 2035, when compared with the Reference case, crude oil production using CO_2 EOR is 17 percent higher on average in the High Oil Price case. In comparison, in the Rapid Technology case, CO_2 EOR technology shows little change, in part because of the limited availability of CO_2 supplies.

Oil production from offshore areas, Alaska, and oil shale deposits also is responsive to changes in world oil prices, because higher or lower prices improve or worsen the economics of those supply sources. For example, production from oil shale in 2035 is nearly threefold higher in the High Oil Price case than in the Reference case, and oil production from offshore drilling is 26 percent higher than in the Reference case.

Advances in horizontal drilling and hydraulic fracturing techniques continue to enhance the development of shale oil formations. Improvements in drilling equipment and monitoring instrumentation are among the key advances that have contributed to the slowdown and subsequent reversal in the decline in U.S. domestic oil production.

Imports of liquid fuels vary with world oil price assumptions

Figure 97. Net import share of U.S. liquid fuels consumption in three cases, 1990-2035 (percent)

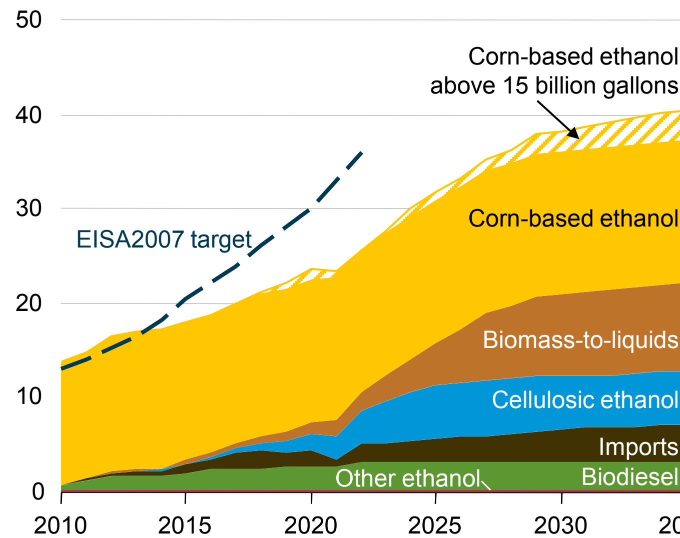


U.S. imports of liquid fuels (including crude oil, petroleum liquids, and liquids derived from nonpetroleum sources), which grew steadily from the mid-1980s to 2005, have been declining since 2005. In the *AEO2011* Reference and High Oil Price cases, imports of liquid fuels continue to decline from 2009 to 2035, although they provide a major part of total U.S. liquids supply over the period. Tighter fuel efficiency standards and higher prices for liquid fuels moderate the growth in liquids demand, even as the combination of higher prices and renewable fuel mandates leads to increased domestic production of both oil and biofuels. Consequently, while consumption of liquid fuels increases steadily in the Reference case from 2009 to 2035, the growth in demand is met by domestic production.

The net import share of U.S. liquid fuels consumption fell from 60 percent in 2005 to 52 percent in 2009. The net import share continues to decline in the Reference case, to 42 percent in 2035 (Figure 97). In the High Oil Price case, the net import share falls to an even lower 24 percent in 2035. Increased penetration of biofuels in the liquids market reduces the need for imports of crude oil and petroleum products in the High Oil Price case. In the Low Oil Price case, the net import share remains flat in the near term, then rises to 56 percent in 2035 as demand increases and imports become cheaper than crude oil produced domestically.

Renewable fuels standard leads to increased production of biofuels

Figure 98. EISA2007 renewable fuels standard, 2010-2035 (billion ethanol equivalent gallons)



The RFS results in a strong increase in renewable fuel production between 2009 to 2022 in the *AEO2011* Reference case (Figure 98). Renewable fuel production, however, does not meet the RFS requirement of 36 billion gallons in 2022 because financial and technological hurdles delay the start of many advanced biofuel projects—particularly, cellulosic biofuel projects.

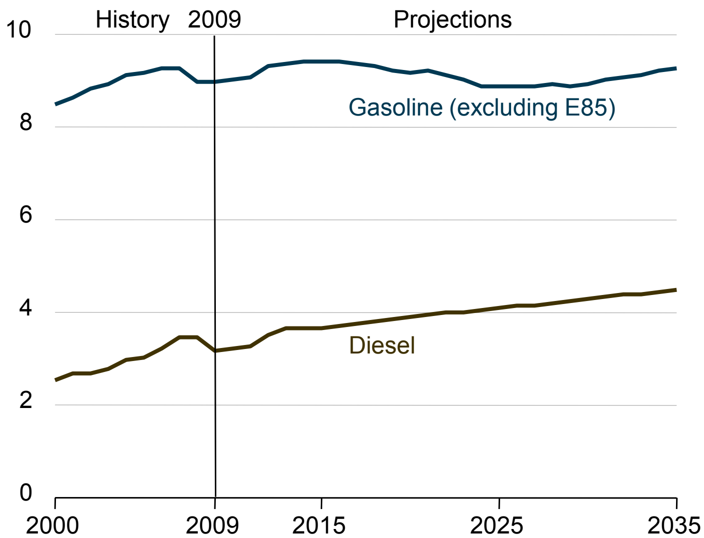
The provisions of the RFS require annual evaluations by the U.S. EPA to determine the status of biofuel production capacity and revise the production mandates for the following year, as needed. The Reference case reflects an EPA reduction in the mandate for cellulosic biofuel production in both 2010 and 2011. Accounting for those modifications and anticipated future changes, only 25.7 billion credits are generated in 2022 in the Reference case, including 15 billion gallons of credits for domestic corn-based ethanol. Corn ethanol consumption grows above the 15 billion gallons that qualifies for the RFS credit to as high as 18 billion gallons by 2035.

The remainder of the biofuel supply in the Reference case consists of cellulosic ethanol, small volumes of next-generation biofuels, and imports of ethanol and biodiesel. In 2022, cellulosic ethanol contributes 3.5 billion gallons of credits towards the RFS mandate, and biodiesel and imported ethanol contribute 2.0 and 2.8 billion gallons of credits, respectively.

The Reference case assumes that the EPA will continue to set RFS targets after 2022, leading to more capacity builds than would have occurred otherwise. The mandate for 36 billion gallons of biofuel is met by 2030, and total biofuel production increases to 37.2 billion ethanol-equivalent gallons in 2035.

Future refinery operations and investments target diesel output

Figure 99. U.S. motor gasoline and diesel fuel consumption, 2000-2035 (million barrels per day)



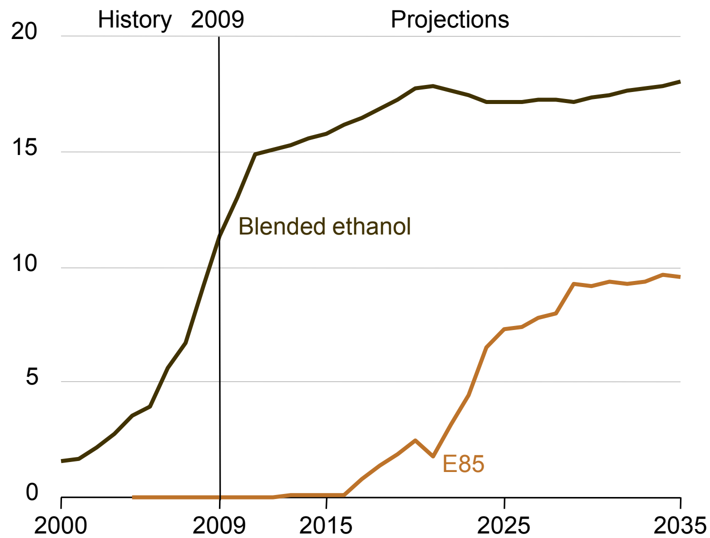
Tighter CAFE standards and increased consumption of ethanol as E85 slow the growth of gasoline consumption in the *AEO2011* Reference case, but diesel consumption increases steadily through 2035 (Figure 99). The resulting increase in diesel output, coupled with a decrease in refinery capacity, causes a shift in the overall slate of refinery outputs.

Although demand for petroleum products declined during the recent economic downturn, new refining capacity that was planned before the downturn comes on line early in the projection, despite lower utilization levels. This new capacity results in the addition of approximately 400,000 barrels per day of new refining distillation capacity by the end of 2012. A portion of the new capacity is configured to process heavier and previously less desirable crudes, capitalizing on their lower costs. The expansions are focused on diesel output for use both domestically and abroad. Given the current economics of refining operations, no additional capacity additions are expected after 2013. As a result, total refining capacity declines gradually after 2013, and more capacity is idled.

Diesel fuel consumption increases by approximately 1.3 million barrels per day from 2009 through 2035 in the Reference case, while motor gasoline consumption increases by 0.3 million barrels per day. The share of total refinery output represented by diesel fuel increases over the projection period.

Higher limit on ethanol blending spurs consumption growth in the near term

Figure 100. U.S. ethanol use in gasoline and E85, 2000-2035 (billion gallons)



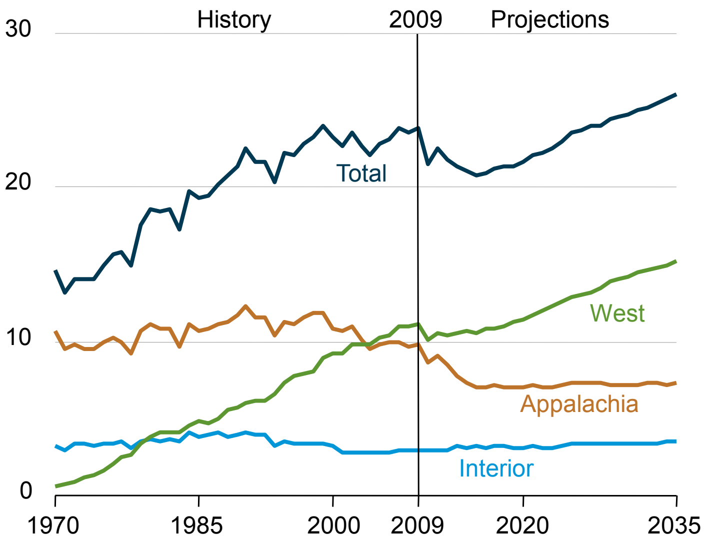
Currently, given the limited retail availability of E85, the primary use of ethanol in the United States is as a blendstock for gasoline. With rapid growth in ethanol capacity and production in recent years, ethanol consumption in 2010 approached the legal gasoline blending limit of 10 percent (E10). Recent EPA actions have increased the blending limit to 15 percent (E15) for vehicles built in 2001 and after. Although the higher blending limit allows ethanol consumption to increase in the near term, a number of issues may constrain its immediate impact.

One of the primary issues expected to slow the widespread adoption of E15 is liability for potential misfueling and infrastructure problems. Retailers will be hesitant to sell E15 if they are not relieved of responsibility for damage to consumer vehicles that may result from misfueling, as well as malfunctions of storage equipment or infrastructure that may be caused by the higher ethanol blend. Consumer acceptance will also play a part; warning labels could deter customers from risking any potential damage from the use of E15.

Given the issues above, ethanol blending in gasoline increases only gradually in the *AEO2011* Reference case (Figure 100), from 13.1 billion gallons in 2010 (about 9 percent of the gasoline pool) to 17.8 billion gallons in 2020 (about 12 percent of the gasoline pool). In 2020, vehicles built in 2001 and after consume E15 primarily, and the remaining growth in ethanol consumption shifts to E85 use, which increases from about 0.8 billion gallons in 2017 to 9.6 billion gallons in 2035.

Early declines in coal production are more than offset by growth after 2014

Figure 101. Coal production by region, 1970-2035 (quadrillion Btu)



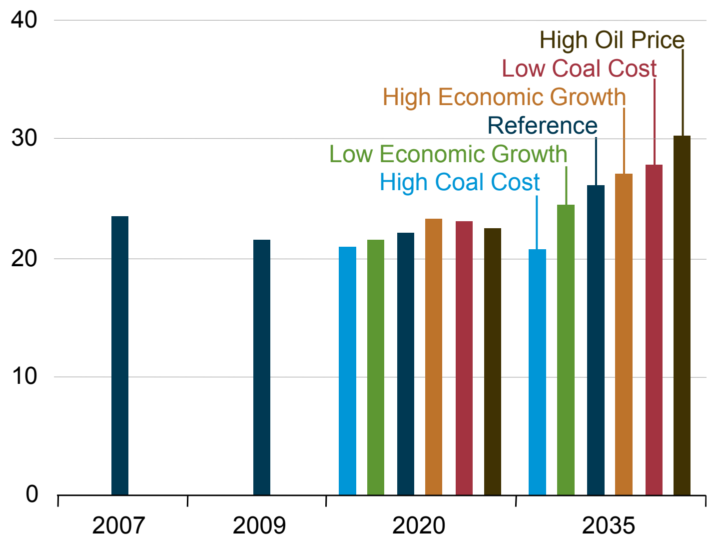
U.S. coal production declined by 2.3 quadrillion Btu in 2009. In the *AEO2011* Reference case, production does not return to its 2008 level until after 2025. Between 2008 and 2014 a potential recovery in coal production is kept in check by continued low natural gas prices and increased generation from renewables and nuclear capacity. After 2014, coal production grows at an average annual rate of 1.1 percent through 2035, with increases in coal use for electricity generation and for the production of synthetic liquids.

Western coal production increases through 2035 (Figure 101) but at a much slower rate than in the past, as demand grows slowly. Low-cost supplies of coal from the West satisfy much of the additional fuel needs at coal-fired power plants east of the Mississippi River and supply most of the coal needed at new CTL and CBTL plants.

Coal production in the Interior region, which has trended slightly downward since the early 1990s, rebounds somewhat in the Reference case, increasing from 2.9 quadrillion Btu in 2009 to 3.5 quadrillion Btu in 2035. Most of the additional production from this region originates from mines tapping into the substantial reserves of mid- and high-sulfur bituminous coal in Illinois, Indiana, and western Kentucky. Appalachian coal production declines substantially from current levels, as coal produced from the extensively mined, higher cost reserves of Central Appalachia is supplanted by lower cost coal from other supply regions. Increasing production in the northern part of the basin, however, does help to moderate the overall production decline in Appalachia.

Long-term outlook for coal production varies considerably across cases

Figure 102. U.S. coal production in six cases, 2007, 2009, 2020, and 2035 (quadrillion Btu)



U.S. coal production varies across the *AEO2011* cases, reflecting different assumptions about the costs of producing and transporting coal, the outlook for economic growth, and the outlook for world oil prices (Figure 102). In addition, although they are not shown in the figure, alternative assumptions about restrictions on GHG emissions could have even larger impacts on coal production over the projection period.

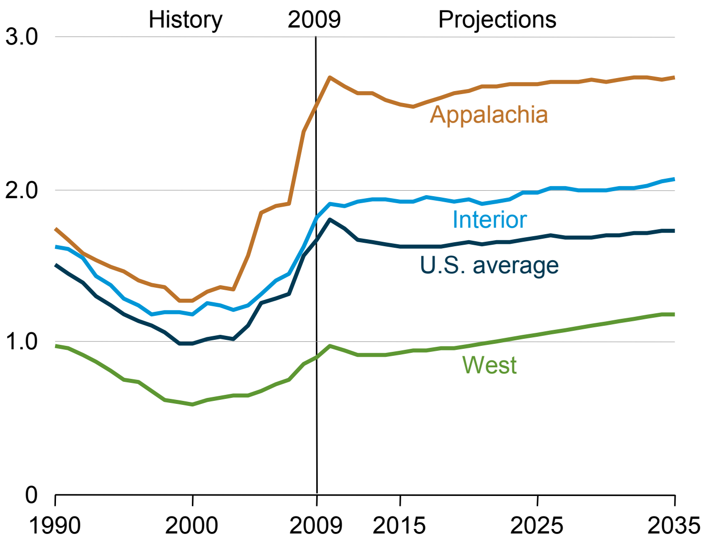
Assumptions about economic growth primarily affect the projections for overall electricity demand, which in turn determine the need for coal-fired generation. In contrast, assumptions about the costs of producing and transporting coal primarily affect the choice of technologies for electricity generation, with coal capturing a larger share of the U.S. electricity market in the Low Coal Cost case and a smaller share in the High Coal Cost case. In the High Oil Price case, higher oil prices stimulate the demand for coal-based synthetic liquids, leading to a substantial expansion of coal use at CTL and CBTL plants. Production of coal-based synthetic liquids totals 1.6 million barrels per day in 2035 in the High Oil Price case, nearly three times the amount in the Reference case.

Coal production in the Reference case increases by 21 percent from 2009 to 2035, whereas the alternative cases show changes ranging from a decrease of 4 percent to an increase of 41 percent. In the earlier years of the projection, from 2009 to 2020, variations in coal production across the cases are smaller, ranging from a decline of 4 percent to an increase of 8 percent, primarily reflecting the smaller changes in overall energy demand over the shorter time frame.

Coal prices

Growth in average minemouth price slows compared to recent history

Figure 103. Average annual minemouth coal prices by region, 1990-2035 (2009 dollars per million Btu)



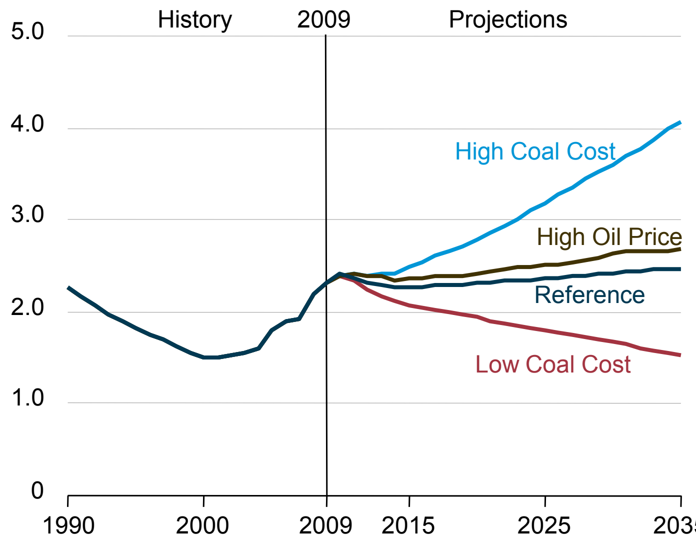
In the Reference case, the average real minemouth price for U.S. coal remains nearly unchanged, declining from $1.67 per million Btu in 2009 to $1.65 in 2020, and then rising to $1.73 in 2035—an increase of 0.2 percent per year over the entire projection period. In contrast, there were sizable increases in coal prices from 2000 to 2009, averaging 6.0 percent per year, and declines from 1990 to 2000 that averaged 4.2 percent per year. The moderation of coal prices in the Reference case results from a variety of factors, including a shift in production from Appalachia to the Interior and Western regions, which have lower costs of production, and a relatively flat outlook for coal mining productivity, which acts to keep mine production costs close to current levels.

In the Western and Interior coal supply regions, slight declines in mining productivity, combined with increased production, result in higher real minemouth prices in the *AEO2011* Reference case, with prices increasing at average annual rates of 1.1 percent in the Western region and 0.5 percent in the Interior region from 2009 to 2035 (Figure 103).

In the Appalachian region, the average real minemouth coal price increases by 0.2 percent per year from 2009 to 2035. The price outlook for Appalachian coal primarily reflects continuing but slower declines in coal mining productivity. Recent increases in the average price of Appalachian coal, from $1.27 per million Btu in 2000 to $2.56 per million Btu in 2009, in part as a result of significant declines in mining productivity over the decade, have substantially reduced the competitiveness of Appalachian coal with coal from other producing regions.

Substantial changes in coal prices would have moderate effects on demand

Figure 104. Average annual delivered coal prices in four cases, 1990-2035 (2009 dollars per million Btu)



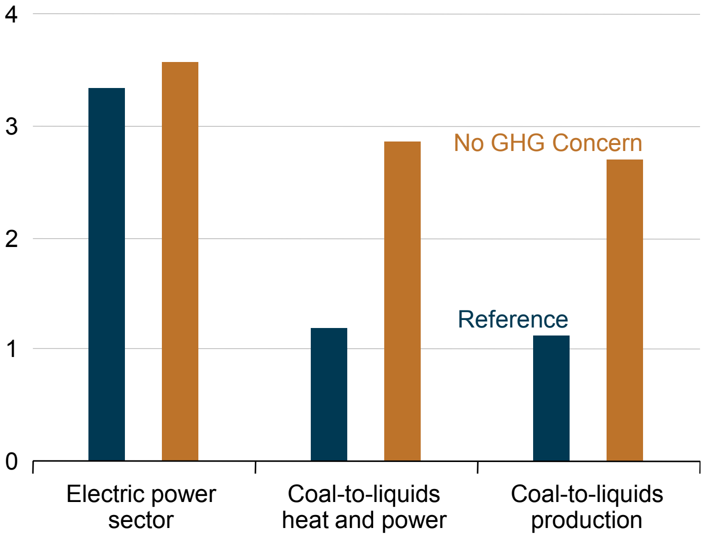
Alternative assumptions for coal mining and transportation costs affect delivered coal prices and demand. Two Coal Cost cases developed for *AEO2011* examine the impacts on U.S. coal markets of alternative assumptions about mining productivity, labor costs, mine equipment costs, and coal transportation rates (Figure 104). Although alternative assumptions about economic growth and world oil prices lead to some variations in the price paths for coal, the differences from the Reference case are relatively small in those cases.

In the High Coal Cost case, the average delivered coal price is $4.08 per million Btu (2009 dollars) in 2035—65 percent higher than in the Reference case, where the average price is $2.47 per million Btu in 2035. Because the higher coal prices result in switching from coal to natural gas and renewables in the electricity sector, U.S. coal consumption in 2035 is 16 percent (3.8 quadrillion Btu) lower in the High Coal Cost case than in the Reference case. In the Low Coal Cost case, delivered coal prices in 2035 average $1.53 per million Btu—38 percent lower than in the Reference case—and total coal consumption is 4 percent (0.9 quadrillion Btu) higher than in the Reference case.

Because the Economic Growth and Oil Price cases use the Reference case assumptions for coal mining and rail transportation costs, they show smaller variations in average delivered coal prices than do the two coal cost cases. Differences in coal price projections in the Economic Growth and Oil Price cases result mainly from higher and lower levels of demand for coal. In the Oil Price cases, higher and lower fuel costs for both coal producers and railroads also contribute to the slight variations in coal prices.

Concerns about GHG legislation affect the long-term outlook for coal

Figure 105. Change in annual U.S. coal consumption by end use in two cases, 2009-2035 (quadrillion Btu)

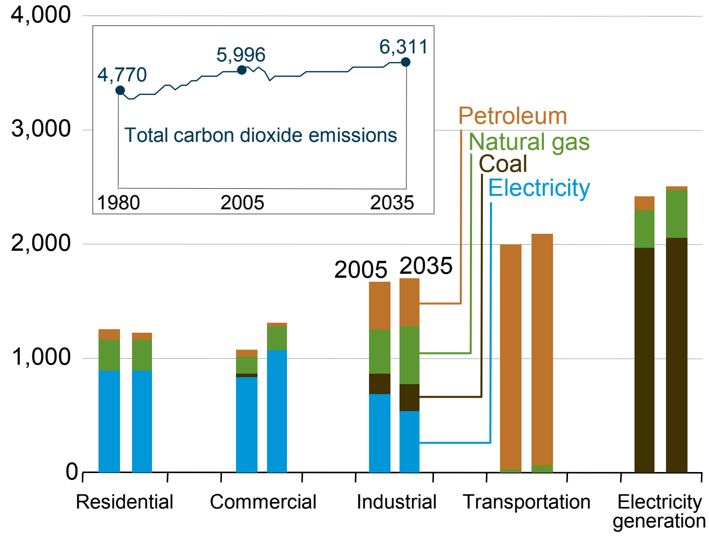


In the Reference case, the cost of capital for investments in GHG-intensive technologies—including conventional coal-fired power plants, CTL plants, CBTL plants, and integrated coal gasification and combined cycle plants without CCS—is increased by 3 percentage points to reflect the behavior of utilities, other energy companies, and regulators concerning the possible enactment of GHG legislation which could mandate that owners purchase allowances, invest in CCS, or invest in other projects to offset their emissions in the future. A No GHG Concern case, in which the additional 3 percentage points for GHG-intensive technologies is removed, is used to evaluate the impact on energy investments.

In the No GHG Concern case, coal use for both electricity generation in the electric power sector and as part of production of coal-based synthetic liquids is 3.5 quadrillion Btu higher than in the Reference case (Figure 105), and 48 gigawatts (including 28 gigawatts at coal-based synthetic liquids plants) of new coal-fired generating capacity is added after 2009, as compared with 26 gigawatts in the Reference case (including about 12 gigawatts currently under construction). Of the 22 gigawatts of additional coal-fired capacity builds in the No GHG Concern case, 16 gigawatts, or 73 percent, are at coal-based synthetic liquids plants and 6 gigawatts are in the electric power sector. As a result, additions of both natural gas and renewable generating capacity are lower in the No GHG Concern case than in the Reference case. The production of coal-based synthetic liquids rises to 1.3 million barrels per day (2.7 quadrillion Btu) in 2035 in the No GHG Concern case, compared with 0.5 million barrels per day (1.1 quadrillion Btu) in the Reference case. Total CO_2 emissions increase to 6,476 million metric tons in 2035 in the No GHG Concern case, about 3 percent higher than in the Reference case and 19 percent higher than in 2009.

Growth of carbon dioxide emissions slows in the projections

Figure 106. U.S. carbon dioxide emissions by sector and fuel, 2005 and 2035 (million metric tons)



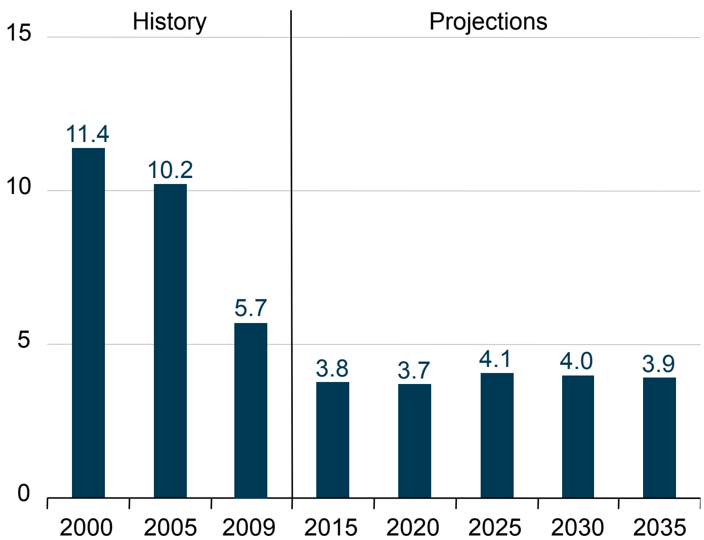
On average, energy-related CO_2 emissions in the *AEO2011* Reference case grow slowly, by an average of 0.2 percent per year from 2005 to 2035 as compared with 0.9 percent per year from 1980 to 2005. Reasons for the slower rate of increase include growing use of renewable technologies and fuels, efficiency improvements, slower growth in electricity demand (in part because of the recent recession), and more use of natural gas, which is less carbon-intensive than other fossil fuels. In the Reference case, energy-related CO_2 emissions do not exceed 2005 levels until 2027, and in 2035 they total 6,311 million metric tons or about 5 percent higher than in 2005 (Figure 106).

Petroleum remains the largest source of CO_2 emissions over the projection period, but its share falls to 41 percent in 2035 from 44 percent in 2005. Although rising from the relatively low levels of 2009, CO_2 emissions from petroleum, used mainly in the transportation sector, vary little from 2013 to 2025, as improvements in fuel economy and the expanded use of ethanol rise more quickly than travel demand. From 2025 to 2035, with little additional improvement in fuel economy and slower growth in biofuels use, petroleum-related CO_2 emissions increase by an average of 0.6 percent per year.

Emissions from coal, the second largest source of CO_2 emissions, do not reach 2005 levels until 2027. Coal's share of CO_2 emissions remains fairly stable through 2035 because of sustained growth in the CTL industry and some growth in the power sector. From 2009 to 2035, the natural gas share of CO_2 emissions increases relative to its 2005 share, because more natural gas is used to fuel electricity generation and industrial applications.

Sulfur dioxide emissions decrease due to the Clean Air Interstate Rule

Figure 107. Sulfur dioxide emissions from electricity generation, 2000-2035 (million short tons)

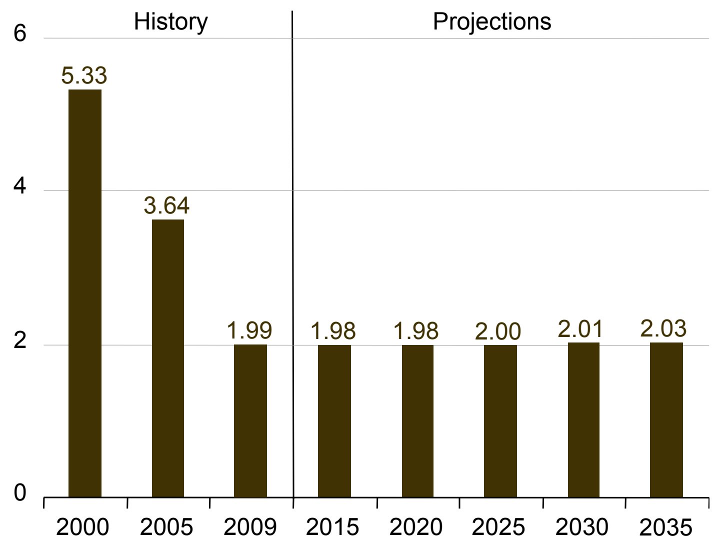


Since the U.S. District Court of Appeals overturned the Clean Air Interstate Rule (CAIR) in July 2008 [*95*], followed by its temporary reinstatement of the rule 6 months later, there has been tremendous uncertainty about regulation of sulfur dioxide (SO_2) emissions from electric power plants. In July 2010, the EPA proposed the Air Transport Rule, which would require emissions reductions similar to those in CAIR, but is designed to address the court's objections to CAIR. Currently, the EPA is reviewing public comments on the Air Transport Rule, and many key details of the regulation have not been determined. Because of the uncertainty about the ultimate makeup of the Air Transport Rule, *AEO2011* assumes that the temporary CAIR rule, which still is the binding rule on SO_2 emissions from power plants, remains in effect through 2035.

In the *AEO2011* Reference case, SO_2 emissions from the U.S. electric power sector fall to between 3.8 and 4.1 million short tons from 2015 to 2035, or an average of about 30 percent below 2009 levels (Figure 107). The reduction occurs as a result of CAIR limits. Emissions fluctuate slightly from year to year after 2020 as a result of allowance banking, which is allowed under CAIR but probably will be more limited under the Air Transport Rule, given its restrictions on allowance trading. In order to meet the emission reduction requirements in CAIR, new flue gas desulfurization (FGD) retrofits are installed on 54 gigawatts of coal capacity from 2009 to 2035, increasing the total amount of generating capacity with FGD equipment installed to approximately 222 gigawatts, or 70 percent of coal-fired generating capacity in the electric power sector, in 2035. In the Reference case, 8.8 gigawatts of coal-fired capacity is retired from 2009 to 2035.

Nitrogen oxide emissions are flat in the Reference case

Figure 108. Nitrogen oxide emissions from electricity generation, 2000-2035 (million short tons)



The Air Transport Rule, released in July 2010, seeks nitrous oxide (NO_x) emissions reductions similar to those in the CAIR. Because key details of the Air Transport Rule have not been finalized, however, it is not included in the *AEO2011* Reference case. A temporary version of CAIR remains binding until the Air Transport Rule can be finalized, and the Reference case assumes that CAIR remains in effect through 2035.

NO_x emissions from electric power plants dropped significantly from 3 million short tons in 2008 to approximately 2 million short tons in 2009, as a result of a reduction in coal-fired electricity generation in 2009. In the Reference case, NO_x emissions stabilize at roughly the 2009 level through 2035 (Figure 108), despite steady increases in coal-fired generation. With a growing number of coal-fired power plants being fitted with NO_x control equipment, NO_x emissions are maintained at the levels needed to meet the CAIR target.

Coal-fired power plants can be retrofitted with any of the three types of NO_x control technologies: selective catalytic converter (SCR), selective noncatalytic converter (SCNR), or low-NO_x burners. The type of retrofit used depends on the specific characteristics of the plant, including the boiler configuration and the type of coal used. From 2009 to 2035, 155 gigawatts of coal-fired capacity is retrofitted with NO_x controls in the Reference case: 61 percent with SCR, 5 percent with SCNR, and 33 percent with low-NO_x burners.

Endnotes for market trends

Links current as of April 2011

84. The industrial sector includes manufacturing, agriculture, construction, and mining. The energy-intensive manufacturing sectors include food, paper, bulk chemicals, petroleum refining, glass, cement, steel, and aluminum.

85. U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC: August 2010), Table 5.21, "Crude Oil Refiner Acquisition Cost, 1968-2009," website www.eia.gov/emeu/aer/txt/stb0521.xls.

86. Products covered include many types of heating and cooling equipment, gas and electric water heaters, refrigerators and freezers, several types of lighting (especially, incandescent lamps and fluorescent ballasts), clothes washers and dryers, dishwashers, ranges and ovens, and swimming pool heaters.

87. Board of Governors of the Federal Reserve System, Federal Reserve Statistical Release G.17, "Industrial Production and Capacity Utilization" (Washington, DC: February 2011), website www.federalreserve.gov/releases/g17/Current/#NOTICE.

88. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Databook: Edition 29*, ORNL-6985 (Oak Ridge, TN: July 2010), Chapter 4, "Light Vehicles and Characteristics."

89. The *AEO2011* Reference case does not include the proposed fuel economy standards for heavy-duty vehicles provided in *Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles*, published by the EPA and the NHTSA in April 2010, nor does it include increases in fuel economy standards for LDVs, based on the September 2010 EPA/NHTSA Notice of Upcoming Joint Rulemaking to Establish 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and CAFE Standards, because the notice of intent does not propose any new vehicle standards.

90. The factors that influence decisionmaking on capacity additions include electricity demand growth, the need to replace inefficient plants, the costs and operating efficiencies of different generation options, fuel prices, State RPS programs, and the availability of Federal tax credits for some technologies.

91. 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.

92. For detailed discussion of levelized costs, see U.S. Energy Administration, "Levelized Cost of New Generation Resources in the Annual Energy Outlook 2011," website www.eia.gov/forecasts/aeo/electricity_generation.html.

93. Conoco Phillips has recently announced plans to shut down its Alaska facility, which has been exporting small amounts of LNG to Japan for over 40 years. They have a license to export through 2013. This is Alaska's only export facility.

94. See "Potential of offshore crude oil and natural gas resources" in the "Issues in focus" section of this report.

95. U.S. Court of Appeals for the District of Columbia Circuit, "State of North Carolina v. Environmental Protection Agency," No. 05-1244 (Washington, DC: December 23, 2008), website www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemandOrder.pdf.

Comparison with other projections

Only IHS Global Insight (IHSGI) produces a comprehensive energy projection with a time horizon similar to that of the *Annual Energy Outlook 2011 (AEO2011)*. Other organizations, however, address one or more aspects of the U.S. energy market. The most recent projection from IHSGI, 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 *AEO2011* Reference case.

1. Economic growth

The range of projected economic growth tends to be wider for the earlier years of the projection period and then narrows in the long run, because the group of concepts—such as population, productivity, and labor force growth—that explain long-run growth trends is smaller than the group of variables that affect projections of short-run growth. From 2009 to 2011, projections for the average annual rate of growth of real gross domestic product (GDP) in the United States range from -0.1 percent to 3.0 percent (Table 12).

In the *AEO2011* Reference case, real GDP grows at a 2.4-percent average annual rate over the 2009-2011 period, lower than projected by the Office of Management and Budget (OMB) and the Interindustry Forecasting Project at the University of Maryland (INFORUM); however, not all of those projections have been updated to take account of the faster pace of economic recovery that became evident late in 2010. The *AEO2011* projection of GDP growth is slightly lower than the projections by IHSGI and higher than projection by the Bureau of Labor Statistics (BLS), although the BLS macroeconomic projections are made only every 2 years. In March 2010, the consensus Blue Chip projection was for 3.0-percent average annual growth in GDP from 2009 to 2011.

The range of GDP growth rates narrows over the period from 2011 to 2015, with projections ranging from 3.0 to 4.0 percent per year. The average annual GDP growth of 3.2 percent in the *AEO2011* Reference case from 2011 to 2015 falls in the middle of the range, with the OMB projecting a stronger recovery from the recession. OMB projects average annual GDP growth of 4.0 percent from 2011 to 2015. INFORUM, IHSGI, and the International Energy Agency (IEA) all project growth rates that are below that in the *AEO2011* Reference case.

There are few public or private projections of GDP growth for the United States that extend to 2035. The *AEO2011* Reference case projects 2.7-percent average annual GDP growth from 2009 to 2035, consistent with trends in labor force and productivity growth. IHSGI projects GDP growth averaging 2.7 percent per year from 2009 to 2035, and INFORUM projects lower GDP growth of 2.5 percent over the same period. INFORUM also projects lower growth in productivity and labor force.

Table 12. Projections of average annual economic growth, 2009-2035

	Average annual percentage growth rates	
Projection	2009-2020	2020-2035
AEO2010 (Reference case)	2.8	2.5
AEO2011 (Reference case)	2.8	2.6
IHSGI (August 2010)	2.8	2.6
OMB (January 2011)[a]	3.2	--
CBO (January 2011)[a]	2.8	--
INFORUM (December 2010)	2.8	2.3
Social Security Administration (May 2010)	2.3	2.1
BLS (December 2009)[a]	2.4	--
IEA (2010)[b]	2.0	2.1
Blue Chip Consensus (March 2010)	2.4	--
ExxonMobil	2.6	2.4
ICF Q4 2010 Integrated Energy Outlook	2.8	2.8

-- = not reported.
[a]CBO and OMB forecasts end in 2021, and growth rates cited are for 2009-2021. BLS forecast ends in 2018. ExxonMobil forecast ends in 2030, and growth rates cited are for 2020-2030.
[b]IEA publishes U.S. growth rates for certain intervals: 2008-2020 growth is 2.0 percent, and 2008-2035 growth rate is 2.1 percent.

2. World oil prices

In the *AEO2011* Reference case, world oil prices rise from $62 per barrel to approximately $95 per barrel in 2015 and $108 per barrel in 2020 (Table 13). From 2020 to 2035, prices increase slowly to $125 per barrel in 2035. This price trend is slightly lower than the trend shown in the *AEO2010* Reference case.

Table 13. Projections of world oil prices, 2015-2035 (2009 dollars per barrel)

Projection	2015	2020	2025	2030	2035
AEO2011 (Reference case)	94.58	108.10	117.54	123.09	124.94
AEO2010 (Reference case)	94.51	109.30	116.12	124.66	134.47
Deutsche Bank	81.06	91.77	99.75	105.39	109.09
ICF Q4 2010 Integrated Energy Outlook	77.86	77.86	77.86	77.86	77.86
INFORUM	90.97	102.25	108.91	117.02	125.07
IEA (current policy scenario)	94.00	110.00	120.00	130.00	135.00
EVA	87.02	91.97	99.71	110.85	--
IHSGI	90.44	86.15	80.17	82.31	--

-- = not reported.

Market volatility and differing assumptions about the future of the world economy are reflected in the range of price projections for both the short term and the long term; however, most projections show prices rising over the entire course of the projection period although slowing after 2025. The other projections range from $78 per barrel to $95 per barrel in 2015, a span of $17 per barrel; and from $78 per barrel to $135 per barrel in 2035, a span of $57 per barrel. The wide range underscores the uncertainty inherent in the projections. The range of the other projections is encompassed in the range of the *AEO2011* Low and High Oil Price cases, from $55 per barrel to $146 per barrel in 2015 and from $50 per barrel to $200 per barrel in 2035.

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) price widely cited in the trade press as a proxy for world oil prices. The only series that do not report projections in WTI terms are IEA's *World Energy Outlook 2010*, where prices are expressed as the IEA crude oil import price, and INFORUM, where prices are expressed as the average U.S. refiner acquisition cost of imported crude oil.

3. Total energy consumption

Three of the projections, IHSGI, INFORUM, and ExxonMobil, feature consumption by sector. However, to allow comparison with the IHSGI projection, the *AEO2011* Reference case was adjusted to remove coal-to-liquids (CTL) heat and power, biofuels heat and co-products, and natural gas feedstock use. The ExxonMobil projections do not include electricity consumption in the sectoral consumption breakout. Both the IHSGI and INFORUM projections feature higher total energy consumption than *AEO2011*, while ExxonMobil features lower consumption (Table 14).

Both INFORUM and IHSGI have significantly higher projections of electricity consumption than *AEO2011*, which explains much of the difference in the levels of energy consumption among the three projections: the generation of electricity uses approximately three times the amount of energy from fuel as the amount of useful energy provided to end users. In both the INFORUM and IHSGI projections, the electric power sector consumes 10 quadrillion Btu more energy than projected in *AEO2011*. The greater use of electricity, predominantly for more conventional applications, results in higher electricity prices.

None of the electricity projections includes more than modest penetration of electric vehicles in the transportation sector by 2035 (IHSGI projects almost 300 trillion Btu of electricity consumed in the transportation sector in 2035). The ExxonMobil projection for electricity does not detail electricity consumption, but the amount of energy used to generate electricity is at the 2008 level in 2025 and 2030, with electricity producers aggressively switching to natural gas from coal (the amount of coal used by electricity generators ranks third behind natural gas and nuclear in 2030).

Projected commercial and transportation sector electricity consumption in INFORUM is comparable to that in *AEO2011*, but electricity consumption in the residential and industrial sectors in the INFORUM projection grows to a level more than 50 percent above consumption in 2009, much greater than the increase in *AEO2011* (about 20 percent in the residential sector and 10 percent in the industrial sector). Residential and industrial sector electricity consumption in the IHSGI projection also grows faster than in *AEO2011*, but at a somewhat slower rate than in the INFORUM projection. However, commercial sector electricity consumption grows more rapidly in the IHSGI projection than in both the INFORUM and *AEO2011* projections. *AEO2011* includes the consensus agreement to implement one round of appliance standard updates that holds down residential electricity growth, as well as growth in industrial natural gas usage for combined heat and power, which shifts some industrial energy demand from electricity to natural gas.

Despite the much higher level of electricity consumption in the IHSGI projection, projected total energy consumption is only about 1.2 quadrillion Btu higher than in *AEO2011*. The difference is moderated by lower growth in motor gasoline consumption in the transportation sector in the IHSGI forecast. Motor gasoline consumption in the IHSGI projection in 2035 is almost 3 quads lower than in *AEO2011*, however, the lower level of gasoline consumption is partially offset by about one quad higher diesel fuel consumption. The IHSGI projection includes about 3 million more light-duty truck sales in 2035 (but comparable numbers of light-duty car sales) than *AEO2011*.

INFORUM projects higher prices for motor gasoline than *AEO2011* (more than $1 higher in 2035), with more efficient light-duty vehicles (the vehicle stock average is about 1.8 mpg higher in 2035). However, the total stock of vehicles is larger (due mainly to a stock difference in 2009), and they are driven more miles, leading to a higher level of consumption in the INFORUM forecast than shown in *AEO2011*. The ExxonMobil projection has energy use in each sector level or declining from the level in 2008, which leads to lower overall energy consumption than in the *AEO2011* Reference case.

4. Electricity

Table 15 provides a summary of the results from the *AEO2011* Reference case and compares them with the other projections. Electricity sales increase on average by 1.1 percent per year through 2015 in *AEO2011*, reaching 3,811 billion kilowatthours, which is lower than the other projections. Electricity sales in 2015 range from a low of 3,811 billion kilowatthours in *AEO2011* to a high of 4,500 billion kilowatthours in INFORUM. The IHSGI projection of electricity sales, at 4,119 billion kilowatthours in 2015, also projects higher sales than *AEO2011* for the residential and commercial sectors, while industrial sector sales are slightly less than in *AEO2011*. Both IHSGI and INFORUM project higher sales in 2035 than *AEO2011*. In 2035, IHSGI projects sales of 5,551 billion kilowatthours, INFORUM projects 5,935 billion kilowatthours, and *AEO2011* projects 4,483 billion kilowatthours. Although INFORUM does not provide sales by sector, IHSGI projects higher sales than *AEO2011* for all sectors in 2035.

The average retail electricity price in *AEO2011* falls from 9.8 cents per kilowatthour in 2009 to 8.9 cents per kilowatthour in 2015. IHSGI projects a higher average retail price of 10.4 cents per kilowatthour in 2015, consistent with the higher level of demand in that projection. The average retail electricity price remains relatively flat after 2015 in *AEO2011*, rising to only 9.2 cents per kilowatthour in 2035. In comparison, the average retail electricity price increases to 12.9 cents per kilowatthour in the IHSGI projection, again reflecting the much higher level of electricity sales in that projection.

Although the average retail electricity price in the residential sector falls in *AEO2011* from 11.5 cents per kilowatthour in 2009 to 10.6 cents per kilowatthour in 2025 before rising to 10.8 cents per kilowatthour in 2035, it rises steadily in the Energy Ventures Analysis (EVA) and IHSGI projections, to 18.5 cents per kilowatthour and 13.2 cents per kilowatthour in 2025, respectively. The average residential retail electricity price in the INFORUM projection is similar to those in *AEO2011*. The relative patterns of change in retail electricity prices in the commercial and industrial sectors in the *AEO2011*, EVA, IHSGI, and INFORUM projections are similar to those in the residential sector.

The change in total generation and imports of electricity in 2015 is consistent with sales, ranging from 4,286 billion kilowatthours in *AEO2011* to 4,522 billion kilowatthours in the IHSGI projection. The level of generation continues to increase with the growth

Table 14. Projections of energy consumption by sector, 2009-2035 (quadrillion Btu)

Sector	*AEO2011* Reference	INFORUM	IHSGI	Exxon-Mobil	*AEO2011* Reference	INFORUM	IHSGI	Exxon-Mobil
	2009				2015			
Residential	11.1	11.6	10.6	--	11.0	12.3	11.2	--
Residential excluding electricity	6.5	6.6	6.0	6.0	6.4	6.4	5.9	6.0
Commercial	8.5	8.4	8.4	--	9.0	9.0	9.0	--
Commercial excluding electricity	4.0	3.9	3.8	3.6	4.2	4.0	3.7	3.5
Industrial	21.8	22.3	--	--	26.7	25.1	--	--
Industrial excluding electricity	18.8	19.3	--	19.0	23.2	21.6	--	18.0
Losses[a]	0.7	--	--	--	0.9	--	--	--
Natural gas feedstocks	0.5	--	--	--	0.6	--	--	--
Industrial removing losses and feedstocks	20.6	--	20.0	--	25.2	--	21.4	--
Transportation	27.2	27.0	26.2	27.0	28.5	28.5	27.1	28.0
Electric power	38.3	40.2	39.7	36.0	39.7	45.4	44.6	37.0
Less: electricity demand[b]	12.2	12.6	12.2	--	13.0	14.5	14.1	--
Total primary energy	**94.8**	**96.9**	**--**	**91.0**	**102.0**	**105.9**	**--**	**92.0**
Excluding: losses and feedstocks[a]	**93.6**	--	**92.7**	--	**100.5**	--	**99.2**	--
	2025				2035			
Residential	11.3	13.8	12.1	--	11.7	14.4	12.8	--
Residential excluding electricity	6.3	6.5	5.8	5.0	6.2	6.5	5.7	--
Commercial	9.9	10.0	9.8	--	11.1	11.0	10.8	--
Commercial excluding electricity	4.4	4.2	3.6	3.5	4.6	4.5	3.5	--
Industrial	28.1	28.6	--	--	28.9	30.8	--	--
Industrial excluding electricity	24.6	24.3	--	17.0	25.6	26.0	--	--
Losses[a]	2.3	--	--	--	3.7	--	--	--
Natural gas feedstocks	0.6	--	--	--	0.5	--	--	--
Industrial removing losses and feedstocks	25.2	--	21.9	--	24.7	--	22.3	--
Transportation	29.6	30.2	27.4	27.0	31.8	32.6	28.2	--
Electric power	43.2	54.0	50.4	38.0	46.0	58.4	56.0	--
Less: electricity demand[b]	14.1	17.5	16.6	--	15.3	19.3	18.9	--
Total primary energy	**108.0**	**119.1**	**--**	**92.0**	**114.2**	**128.0**	**--**	**--**
Excluding: losses and feedstocks[a]	**105.1**	--	**105.1**	--	**110.0**	--	**111.2**	--

-- = not reported.
[a]Losses in CTL and biofuel production.
[b]Energy consumption in the sectors includes electricty demand purchases from the electric power sector, which are subtracted to avoid double counting in deriving total primary energy consumption.

Table 15. Comparison of electricity projections, 2015, 2025, and 2035 (billion kilowatthours, except where noted)

Projection	2009	*AEO2011* Reference case	Other projections EVA	IHSGI	ICF	INFORUM
		2015				
Average end-use price (2009 cents per kilowatthour)	9.8	8.9	--	10.4	--	--
Residential	11.5	10.9	13.4	12.0	--	11.5
Commercial	10.1	9.1	12.1	10.9	--	10.1
Industrial	6.8	6.0	8.4	7.1	--	6.8
Total generation plus imports	**4,015**	**4,286**	**4,072**	**4,522**	**4,380**	**--**
Coal	1,772	1,799	1,748	1,905	--	--
Oil	41	43	--	42	--	--
Natural gas[a]	931	1,000	944	1,159	--	--
Nuclear	799	839	850	831	--	--
Hydroelectric/other[b]	437	572	530	586	--	--
Net imports	34	33	--	23	--	--
Electricity sales	3,574	3,811	3,825	4,119	--	4,500
Residential	1,363	1,348	1,489	1,556	--	--
Commercial/other[c]	1,323	1,416	1,419	1,528	--	--
Industrial	882	1,038	917	1,036	--	--
Capability, including CHP (gigawatts)[d]	1,033	1,075	1,061	1,101	1,009	--
Coal	317	322	296	318	297	--
Oil and natural gas	467	469	505	477	423	--
Nuclear	101	106	106	105	105	--
Hydroelectric/other	149	179	155	200	184	--
		2025				
Average end-use price (2009 cents per kilowatthour)	9.8	8.9	--	11.5	--	--
Residential	11.5	10.6	18.5	13.2	--	11.8
Commercial	10.1	9.1	17.1	12.0	--	10.4
Industrial	6.8	6.1	13.0	7.8	--	7.0
Total generation plus imports	**4,015**	**4,704**	**4,144**	**5,282**	**5,060**	**--**
Coal	1,772	2,069	1,603	1,689	--	--
Oil	41	44	--	43	--	--
Natural gas[a]	931	1,003	942	1,756	--	--
Nuclear	799	877	965	1,000	--	--
Hydroelectric/other[b]	437	689	635	794	--	--
Net imports	34	22	--	23	--	--
Electricity sales	3,574	4,142	3,873	4,856	--	5,390
Residential	1,363	1,461	1,595	1,881	--	--
Commercial/other[c]	1,323	1,636	1,615	1,835	--	--
Industrial	882	1,031	664	1,139	--	--
Capability, including CHP (gigawatts)[d]	1,033	1,119	1,065	1,282	1,173	--
Coal	317	326	278	304	261	--
Oil and natural gas	467	489	479	574	579	--
Nuclear	101	111	120	125	108	--
Hydroelectric/other	149	194	188	279	226	--

-- = not reported.
See notes at end of table.

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in sales. In 2035, the total electricity supply from generation plus imports ranges from 5,181 billion kilowatthours in *AEO2011* to 6,025 billion kilowatthours in the IHSGI projection, over 16 percent higher than in *AEO2011*.

AEO2011 projects more coal-fired generation in 2035 than IHSGI—2,218 billion kilowatthours compared with 1,487 billion kilowatthours. The difference in the IHSGI projection, which includes greater electricity demand, is made up by increased generation primarily from natural gas but also from nuclear and hydroelectric/other energy sources. While *AEO2011* shows 1,288 billion kilowatthours of natural-gas-fired generation in 2035, IHSGI shows 2,261 billion kilowatthours. Nuclear generation in 2035 totals 874 billion kilowatthours in *AEO2011*, compared with 1,163 billion kilowatthours in the IHSGI projection, and hydroelectric/other generation in 2035 is 740 billion kilowatthours in *AEO2011*, compared with 1,069 billion kilowatthours in the IHSGI projection.

The mix of generating capability by fuel is relatively similar across the projections in 2015. By 2025, however, the mix of generating capacity begins to change, due to variations in the projected rates of growth in electricity demand and more aggressive retirements of coal capacity in the EVA and ICF International (ICF) projections. Although little coal-fired capacity is retired in the IHSGI projection by 2025, the greater growth in electricity demand is met by a sharp increase in natural gas and hydroelectric/other capacity. Natural-gas- and oil-fired capacity in 2025 totals 574 gigawatts in the IHSGI projection, compared with 489 gigawatts in *AEO2011*. While the ICF projection shows less growth in demand, it shows more retirements of coal capacity by 2025. As a result, ICF shows the highest level of natural-gas- and oil-fired capacity in 2025, at 579 gigawatts.

The faster growth in natural gas and hydroelectric/other capacity continues through 2035 in the IHSGI and ICF projections. Natural-gas- and oil-fired capacity reaches 675 gigawatts and 655 gigawatts in 2035 in the IHSGI and IFC projections, respectively. By comparison, natural-gas- and oil-fired capacity grows to only 572 gigawatts in *AEO2011* in 2035. Hydroelectric/other capacity continues to grow in each of the three projections after 2025, to 384 gigawatts and 297 gigawatts in the IHSGI and ICF projections,

Table 15. Comparison of electricity projections, 2015, 2025, and 2035 (billion kilowatthours, except where noted) (continued)

Projection	2009	*AEO2011* Reference case	Other projections: EVA	IHSGI	ICF	INFORUM
		2035				
Average end-use price (2009 cents per kilowatthour)	9.8	9.2	--	12.9	--	--
Residential	11.5	10.8	--	14.8	--	12.6
Commercial	10.1	9.2	--	13.5	--	11.1
Industrial	6.8	6.4	--	8.7	--	7.4
Total generation plus imports	**4,015**	**5,181**	**--**	**6,025**	**5,601**	**--**
Coal	1,772	2,218	--	1,487	--	--
Oil	41	46	--	45	--	--
Natural gas[a]	931	1,288	--	2,261	--	--
Nuclear	799	874	--	1,163	--	--
Hydroelectric/other[b]	437	740	--	1,069	--	--
Net imports	34	14	--	23	--	--
Electricity sales	3,574	4,483	--	5,551	--	5,935
Residential	1,363	1,613	--	2,187	--	--
Commercial/other[c]	1,323	1,886	--	2,139	--	--
Industrial	882	962	--	1,225	--	--
Capability, including CHP (gigawatts)[d]	1,033	1,221	--	1,498	1,346	--
Coal	317	334	--	292	287	--
Oil and natural gas	467	572	--	675	655	--
Nuclear	101	111	--	147	108	--
Hydroelectric/other	149	205	--	384	297	--

-- = not reported.
[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. IHSGI capacity is nameplate, excluding cogeneration plants.

respectively, compared with 205 gigawatts in *AEO2011*. The IHSGI projection shows the most growth in U.S. nuclear power capacity, to 147 gigawatts in 2035, compared with 111 gigawatts in *AEO2011*. ICF shows 108 gigawatts of nuclear capacity in 2035.

Environmental regulations are an important factor in the selection of technologies for electricity generation. While complete information on the regulations assumed in each of the projection is not available. *AEO2011* includes only current laws and regulations; it does not assume a cap or tax on carbon dioxide (CO_2) emissions. Restrictions on CO_2 emissions could change the mix of technologies used to generate electricity.

5. Natural gas

The variation among published projections of natural gas consumption, production, imports, and prices (Table 16) can be significant. It results from differences in the assumptions that underlie the projections. For example, the natural gas projection in the *AEO2011* Reference case assumes, for the most part, that current laws and regulations will continue through the projection period, whereas other natural gas projections may include anticipated policy developments over the next 25 years. In particular, *AEO2011* does not assume the implementation of regulations limiting CO_2 emissions or other types of emissions beyond those already in effect.

Each of the projections examined here shows an increase in overall natural gas consumption from 2009 to 2035, with the ICF and IHSGI projections having the most significant increases, at 43 percent and 41 percent, respectively. Total natural gas consumption in the INFORUM and ExxonMobil projections remains flat from 2009 to 2015 but grows to a level comparable with those in the *AEO2011*, Deutsche Bank (DB), and EVA projections in 2025. In the later years of all the projections, total natural gas consumption grows despite increasing natural gas prices, with the exception of the DB projection, which shows a decline in consumption from 2025 to 2035. Total natural gas consumption in 2035 in the ICF and IHSGI projections is about 30 percent higher than in the DB projection, which shows the lowest level of total natural gas consumption.

The ICF, ExxonMobil, and IHSGI projections for natural gas consumption by electricity generators are significantly different from the other projections. In 2035, IHGSI is more than double the lowest projection, the *AEO2011* Reference case. *AEO2011*, DB, EVA, and INFORUM show similar projections of natural gas consumption for the electricity generation sector, with annual growth rates of 1 percent across the projection period; the ICF, ExxonMobil, and IHSGI projections show 3-percent annual growth. The slow growth in *AEO2011* reflects slow growth for electricity generation due to the construction of planned coal, renewable, and nuclear capacity builds.

Industrial natural gas consumption varies greatly across the different projections. ICF, INFORUM, EVA, and the *AEO2011* Reference case show growing industrial natural gas consumption throughout the projection period. Industrial natural gas consumption in *AEO2011*, however, increases by 31 percent from 2009 to 2015 and then levels off for the remainder of the projection, whereas in the other projections it grows more steadily. The growth in industrial natural gas consumption in *AEO2011* is attributable to relatively low industrial natural gas prices, a strong increase in natural gas use in combined heat and power plants, and a significant increase in the use of natural gas as a feedstock in the chemical and hydrogen industries. Industrial natural gas consumption remains constant in the ExxonMobil projection throughout the projection period, while industrial natural gas consumption in the IHSGI and DB projections increases initially, then declines from 2015 to 2035. The projections of industrial natural gas consumption in 2035 range from 36 percent above the 2009 level (INFORUM) to 11 percent below the 2009 level (DB).

The basic consumption patterns and levels of natural gas consumption are relatively similar across the residential sector projections, with the exception of DB. (It should be noted that ExxonMobil's projection for residential consumption includes commercial consumption.) Residential sector natural gas consumption in the DB projection increases steadily, growing to 26 percent above the 2009 level in 2035. Three of the six projections (INFORUM, *AEO2011*, and EVA) show relatively similar growth in commercial consumption in the projection period. The projections of commercial natural gas consumption in the ICF, DB and IHSGI projections are initially similar to the other projections, but demand eventually declines, resulting in 2035 projections of commercial natural gas consumption that are below 2009 levels. (INFORUM's 2009 commercial consumption level is 3.68 trillion cubic feet, significantly higher than the others.) The DB projection includes the most significant decline, falling to 23 percent below 2009 levels in 2035.

With the exception of the DB and INFORUM projections for the period after 2025, all the projections show growing domestic natural gas production throughout the projection period, although at different rates. The greatest growth in natural gas production is in the ICF projection, and the lowest is in the INFORUM projection. Natural gas production in the ICF projection exceeds that in the INFORUM projection by 28 percent in 2025. With significant declines in net pipeline imports, ICF and the *AEO2011* Reference case project strong increases in the domestic production share of total natural gas supply. The rest of the projections show domestic natural gas production maintaining a relatively stable share of total natural gas supply, with the exception of the DB projection, where domestic production drops off notably in 2035 with a big increase in LNG imports. In all the other projections, net LNG imports remain well under 1 trillion cubic feet throughout the projection period. Some of the projections show declines in net pipeline imports relative to the 2009 level. The exception is IHSGI, which shows increasing net pipeline imports after 2015, following an initial dip. In comparison with EVA and DB, the *AEO2011* and ICF projections show severe declines in pipeline imports.

Table 16. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted)

Projection	2009	*AEO2011* Reference case	Other projections: IHSGI	EVA	DB	ICF	ExxonMobil	INFORUM
		2015						
Dry gas production[a]	20.96	22.43	22.70	22.70	21.98	23.75	21.00	21.21
Net imports	**2.64**	**2.69**	**2.19**	**2.60**	**3.01**	**1.68**	**1.60**	**--**
Pipeline	2.23	2.33	1.46	2.20	1.53	1.26	--	--
LNG	0.41	0.36	0.73	0.40	1.48	0.42	--	--
Consumption	**22.71**	**25.11**	**24.89**	**24.70**	**25.17**	**25.30**	**23.00**[b]	**21.20**[c]
Residential	4.75	4.81	4.72	4.90	5.10	5.11	8.00[d]	4.67
Commercial	3.11	3.38	3.05	3.20	3.25	3.20	--	3.86
Industrial[e]	6.14	8.05	6.64	6.90	6.70	6.88	7.00	7.06
Electricity generators[f]	6.89	6.98	8.58	7.60	8.01	7.81	8.00	5.61
Others[g]	1.82	1.90	1.90	2.10	2.11	2.29	0.00[h]	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	4.24	4.74	5.13	4.66	5.29	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	10.39	11.85	--	--	9.76	--	--
Commercial	9.94	8.60	10.00	--	--	8.77	--	--
Industrial[i]	5.39	5.10	7.18	--	--	6.59	--	--
Electricity generators	4.94	4.79	5.49	--	--	6.27	--	--
		2025						
Dry gas production[a]	20.96	23.98	26.22	24.70	23.48	29.04	24.00	22.67
Net imports	**2.64**	**1.08**	**2.74**	**2.00**	**2.20**	**1.31**	**2.00**	**--**
Pipeline	2.23	0.74	2.01	1.60	1.55	0.68	--	--
LNG	0.41	0.34	0.73	0.40	0.66	0.63	--	--
Consumption	**22.71**	**25.07**	**28.87**	**25.70**	**25.69**	**30.28**	**26.10**[b]	**24.84**[c]
Residential	4.75	4.83	4.62	5.00	5.52	5.20	7.00[d]	4.84
Commercial	3.11	3.56	2.98	3.30	3.25	3.04	--	4.13
Industrial[e]	6.14	8.10	6.47	7.50	6.70	7.21	7.00	7.88
Electricity generators[f]	6.89	6.66	12.64	7.70	8.21	12.18	12.00	7.99
Others[g]	1.82	1.92	2.17	2.20	2.01	2.65	0.10[h]	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	5.43	4.73	6.46	7.15	6.10	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	12.15	11.59	--	--	10.47	--	--
Commercial	9.94	10.03	9.81	--	--	9.52	--	--
Industrial[i]	5.39	6.33	7.09	--	--	7.35	--	--
Electricity generators	4.94	5.91	5.43	--	--	7.09	--	--

-- = not reported.
See notes at end of table.

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Table 16. Comparison of natural gas projections, 2015, 2025, and 2035 (trillion cubic feet, except where noted) (continued)

Projection	2009	*AEO2011* Reference case	Other projections: IHSGI	EVA	DB	ICF	ExxonMobil	INFORUM
		2035						
Dry gas production[a]	20.96	26.32	28.67	--	21.02	31.92	--	20.59
Net imports	**2.64**	**0.18**	**3.44**	**--**	**3.71**	**0.75**	**--**	**--**
Pipeline	2.23	0.04	2.70	--	1.57	-0.13	--	--
LNG	0.41	0.14	0.75	--	2.14	0.87	--	--
Consumption	**22.71**	**26.55**	**32.06**	**--**	**24.73**	**32.64**	**--**	**27.50**[c]
Residential	4.75	4.78	4.57	--	5.98	5.13	--	4.92
Commercial	3.11	3.82	2.93	--	2.39	2.85	--	4.44
Industrial[e]	6.14	8.02	6.23	--	5.47	7.61	--	8.06
Electricity generators[f]	6.89	7.88	15.94	--	9.07	14.20	--	10.08
Others[g]	1.82	2.07	2.39	--	1.82	2.84	--	--
Lower 48 wellhead price (2009 dollars per thousand cubic feet)	3.71	6.42	4.88	--	8.59	6.52	--	--
End-use prices (2009 dollars per thousand cubic feet)								
Residential	12.20	13.76	11.53	--	--	10.67	--	--
Commercial	9.94	11.28	9.80	--	--	9.78	--	--
Industrial[i]	5.39	7.40	7.13	--	--	7.77	--	--
Electricity generators	4.94	6.97	5.55	--	--	7.47	--	--

-- = not reported.
[a]Does not include supplemental fuels.
[b]Does not include lease, plant, and pipeline fuel.
[c]Does not include lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[d]Natural gas consumed in the residential and commercial sectors.
[e]Includes consumption for industrial combined heat and power (CHP) plants and a small number of industrial electricity-only plants, and natural gas-to-liquids heat/power and production; excludes consumption by nonutility generators.
[f]Includes consumption of energy by electricity-only and combined heat and power (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.
[g]Includes lease, plant, and pipeline fuel and fuel consumed in natural gas vehicles.
[h]Fuel consumed in natural gas vehicles.
[i]The 2009 industrial natural gas price for IHSGI is $6.62.

The *AEO2011* Reference case, EVA, and ICF all show similar natural gas production and price levels that increase over time. In contrast, DB projects lower but more stable production levels, with greater price increases; and IHSGI projects stronger growth in natural gas production than *AEO2011*, EVA, and ICF, with lower and more stable prices.

Only three of the projections provide delivered natural gas prices for comparison: the *AEO2011* Reference case, ICF, and IHSGI. However, the ICF and IHSGI price projections are difficult to compare with the *AEO2011* prices because of apparent definitional differences. In the ICF projection, end-use sector prices for the 2009 base year are very different from those in the *AEO2011* and IHSGI projections. Further, the IHSGI industrial delivered natural gas price is difficult to compare. The IHSGI industrial delivered natural gas price in 2009 is $1.23 higher than the 2009 price in *AEO2011* and $1.35 higher than the 2009 price in the ICF projection (all prices in 2009 dollars per thousand cubic feet). The *AEO2011* historical delivered industrial natural gas price is based on the Manufacturing-Industrial Energy Production Survey (rather than EIA's *Natural Gas Monthly*, which represents prices paid to local distribution companies by industrial customers). To put the prices on a more common basis, price margins (the difference between delivered prices and average wellhead prices) can be compared.

For the residential and commercial sectors, each of the projections shows an initial decline in natural gas price margins from 2009 levels. The margins in the *AEO2011* Reference case, however, recover 86 percent of the decline from the 2009 level by 2035, while the ICF and IHSGI margins continue declining throughout the projection period at relatively similar rates. The increase in residential and commercial margins in *AEO2011* is attributable to a significant decline in consumption per customer. From 2015 forward, the projected industrial margins are relatively stable in all three projections, although at significantly different levels. The *AEO2011* and IHSGI natural gas price margins for the electricity sector are similar, with IHSGI showing slightly higher margins; however, those in the ICF projection range from 31 to 106 percent higher than the margins in the other projections from 2015 to 2035.

6. Liquid fuels

In the *AEO2011* Reference case, the U.S. imported refiner's acquisition cost (RAC) for crude oil (in 2009 dollars) increases to $86.83 per barrel in 2015, $107.40 barrel in 2025, and $113.70 per barrel in 2035 (Table 17). Prices are lower in all years in the DB, ICF, and IHSGI projections, ranging from $70 per barrel to $106 per barrel in 2035. In fact, the IHSGI price in 2035 is 9 percent lower than the 2015 price. The ICF price remains steady at $70 per barrel over the entire projection. The prices in the INFORUM projection are slightly higher in 2025 and 2035, reaching $125 per barrel in 2035. Purvin & Gertz (P&G) did not provide a projection of RAC prices.

Domestic crude oil production increases by 11 percent from 2009 to 2035 in the *AEO2011* projection. The INFORUM projection shows production varying within a slightly wider band but remaining at a lower overall level than in *AEO2011*. DB, IHSGI, and P&G all project decreasing domestic crude production. DB's projection for 2035 is 40 percent lower than the *AEO2011* projection, and IHSGI's is 43 percent lower. In the *AEO2011* Reference case, total net imports of crude oil and petroleum products in 2035 are 9 percent lower than in 2009, consistent with projected increases in domestic production of crude oil. IHSGI and INFORUM both project higher total net imports in 2035.

Prices for motor gasoline prices and diesel fuel increase steadily through 2035 in the *AEO2011* projection. INFORUM also projects rising prices but at a faster rate than in *AEO2011*. IHSGI projects decreasing prices. Biofuels supply is listed separately only in the *AEO2011* Reference case and in the P&G projection. In *AEO2011*, biofuels supply increases steadily through 2035 in response to the Renewable Fuels Standard mandate. In the P&G projection, biofuel supply remains steady. Total product demand, including both petroleum products and biofuels, is similar in the *AEO2011* and P&G projections.

7. Coal

The coal projections provided by DB, EVA, ICF, INFORUM, and Wood Mackenzie (WM) present interesting contrasts with the *AEO2011* Reference case. Only *AEO2011* and INFORUM show growth in coal consumption; the other projections show declines ranging between 10 percent and 38 percent from 2009 levels by the end of their respective projection horizons.

Of the six coal projections, only ICF and WM explicitly state that they include a price on carbon. In the ICF projection, coal consumption in 2015 (before implementation of the carbon price) is 3 percent higher than projected in *AEO2011*. In 2025, however, coal consumption in the ICF projection is 19 percent lower than ICF's projection for 2015 and 27 percent lower than the *AEO2011* projection for 2025 (on a Btu basis); this difference is most likely attributable to inclusion of the carbon price in 2025 along with other assumed regulations affecting coal use that are specified in the notes for Table 18. In 2030 and 2035, ICF's outlook for coal consumption is the lowest of the projections.

For most years, the WM projection shows less coal consumption and production than in the *AEO2011* projection, consistent with the impact of a carbon price. The WM projection also showed a decline in regional coal production, again consistent with the assumed carbon price. Coal production both east and west of the Mississippi declines in 2025 relative to 2015 in the WM projection. In 2030, total coal production (excluding coking coal) in the WM projection is 27 percent lower than in the *AEO2011* projection. (WM provides projections only for thermal coal, thus excluding coking coal, which is used in steelmaking. In 2009, coking coal production occurred only in the East, and it accounted for 11 percent of eastern coal production.)

Excluding coking coal, the average minemouth price of coal per ton in 2015 in the WM projection is 19 percent higher than the corresponding price in the *AEO2011* projection. The price difference narrows after 2015, however, and in 2030 the *AEO2011* and WM prices are nearly identical, despite very different coal production outlooks. The WM projection has generally lower production levels than the *AEO2011* projection throughout the period, implying that WM includes higher production costs.

The *AEO2011* and WM projections show similar levels of eastern coal production (excluding coking coal) in 2030, differing by only 0.5 percent, which is noteworthy given the carbon price assumption in the WM projection. It appears that production west of the Mississippi falls more (in terms of tonnage) in the WM projection as a result of the carbon price, but the regional shares of total production remain constant over the projection. Coal production east of the Mississippi (excluding coking coal) represents 38 to 39 percent of total production in all years in the WM projection, consistent with the historical share, but in the *AEO2011* projection coal production east of the Mississippi falls to a 28-percent share in 2030. In *AEO2011*, more favorable pricing of western coal than eastern coal facilitates growth in western coal's share of total production.

Steam coal exports fall to only 8 million tons in 2015 in the WM projection, a decline of 63 percent from 2009 levels, and then exceed 2009 levels by 2025. While steam coal exports show modest gains after 2015, they never reach the higher levels seen in 2008. In contrast, steam coal exports in the *AEO2011* projection vary little, ranging between 18 and 20 million tons from 2009 to 2035 and remaining well below the volumes exported in 2008.

In the INFORUM projection, coal exports total 177 million tons in 2035, the equivalent of about 11 percent of total U.S. production in 2035 and 64 million tons higher than the historical record set in 1981. Total coal exports in 2035 in the INFORUM case are more than double the total in the *AEO2011* projection. Imports are also notably higher in the INFORUM projection, at 113 million tons in 2035—triple the highest historical level of U.S. imports.

Although ICF does not explicitly provide a coal export projection, coal consumption (in Btu) declines at a far faster rate than coal production (provided in tons only), implying strong growth in exports. For example, from 2015 to 2025, coal production east of the Mississippi—historically, where most U.S. coal exports originate—rises by nearly 100 million tons; and while total coal production falls by 4 percent (47 million tons), coal consumption (in Btu) declines by a much larger 19 percent. The gap between production and consumption closes somewhat by 2035, with production 29 percent lower and consumption 39 percent lower than ICF's projection for 2015. EVA also projects strong coal exports that remain in the range of 80 million tons, similar to 2008 export levels, for the projection years shown. In the *AEO2011* Reference case, exports hover in the 70 million ton range.

Table 17. Comparison of liquids projections, 2015, 2025, and 2035 (million barrels per day, except where noted)

Projection	2009	*AEO2011* Reference case	Other projections				
			DB	ICF	IHSGI	INFORUM	P&G
		2015					
Average U.S. imported RAC (2009 dollars per barrel)	59.04	86.83	78.22	70.00	85.02	90.97	--
Domestic production	5.36	5.81	5.52	--	4.89	5.33	4.62
Total net imports	**9.72**	**9.85**	**--**	**--**	**10.25**	**10.26**	**11.19**
Crude oil	8.97	8.70	8.30	--	9.61	8.86	11.07
Petroleum products	0.75	1.14	--	--	0.64	1.41	0.12
Liquids demand	18.81	20.44	--	--	--	--	20.63
Net import share of petroleum demand (percent)	52	49	--	--	--	--	54
Biofuel supply	0.76	1.12	--	--	--	--	0.90
Product prices (2009 dollars per gallon)							
Gasoline	2.349	3.13	--	--	3.01	3.74	--
Diesel	2.441	3.08	--	--	3.12	3.55	--
		2025					
Average U.S. imported RAC (2009 dollars per barrel)	59.04	107.40	96.43	70.00	78.36	108.91	--
Domestic production	5.36	5.88	4.48	--	3.68	5.77	3.56
Total net imports	**9.72**	**9.06**	**--**	**--**	**11.27**	**10.47**	**12.06**
Crude oil	8.97	8.25	8.46	--	10.40	8.80	11.63
Petroleum products	0.75	0.81	--	--	0.87	1.66	0.43
Liquids demand	18.81	20.99	--	--	--	--	20.77
Net import share of petroleum demand (percent)	52	44	--	--	--	--	58
Biofuel supply	0.76	1.92	--	--	--	--	0.92
Product prices (2009 dollars per gallon)							
Gasoline	2.349	3.54	--	--	2.69	4.23	--
Diesel	2.441	3.73	--	--	2.83	3.84	--
		2035					
Average U.S. imported RAC (2009 dollars per barrel)	59.04	113.70	106.36	70.00	77.37	125.07	--
Domestic production	5.36	5.95	3.57	--	3.38	5.73	--
Total net imports	**9.72**	**8.89**	**--**	**--**	**11.54**	**10.62**	**--**
Crude oil	8.97	8.25	7.24	--	11.02	8.76	--
Petroleum products	0.75	0.64	--	--	0.52	1.86	--
Liquids demand	18.81	21.93	--	--	--	--	--
Net import share of petroleum demand (percent)	52	42	--	--	--	--	--
Biofuel supply	0.76	2.48	--	--	--	--	--
Product prices (2009 dollars per gallon)							
Gasoline	2.349	3.71	--	--	2.53	4.87	--
Diesel	2.441	3.89	--	--	2.61	4.48	--

-- = not reported.

Table 18. Comparison of coal projections, 2015, 2025, 2030, and 2035 (million short tons, except where noted)

Projection	2009	*AEO2011* Reference case	*AEO2011* Reference case (thermal coal only)[a]	Other projections: DB	EVA	ICF[b, c]	INFORUM	WM (thermal coal only)[b, d]
				2015				
Production	**1,075**	**1,040**	**969**	--	**1,060**	**1,150**	**1,321**	**1,111**
East of the Mississippi	450	387	319	--	413	505	--	423
West of the Mississippi	625	653	650	--	646	645	--	688
Consumption								
Electric power	937	928	928	--	929	--	--	--
Coke plants	15	22	--	--	18	--	--	--
Coal-to-liquids	0	11	11	--	0	--	--	--
Other industrial/buildings	49	52	52	--	49	--	--	--
Total consumption (quadrillion Btu)[e]	**19.69**	**19.73**	**19.14**	**19.66**		**20.33**	--	--
Total consumption (million short tons)	**1,000**	**1,013**	**991**	--	**996**	--	**1,252**[f]	**1,123**[f]
Net coal exports	**38**	**40**	**-9**	--	**73**	--	**69**	**-12**
Exports	59	70	20	--	85	--	107	8
Imports	21	30	29	--	13	--	38	20
Minemouth price								
2009 dollars per ton	33.26	32.36	27.53	--	--	32.14	57.05	32.85
2009 dollars per Btu	1.67	1.62	1.41	--	--	1.48	--	1.67
Average delivered price to electricity generators								
2009 dollars per ton	43.48	40.94	40.94	--	--	--	--	51.64
2009 dollars per Btu	2.20	2.11	2.11	--	--	2.15	--	2.63
				2025				
Production	**1,075**	**1,188**	**1,111**	--	**980**	**1,103**	**1,538**	**985**
East of the Mississippi	450	406	333	--	363	600	--	370
West of the Mississippi	625	782	778	--	616	503	--	615
Consumption								
Electric power	937	1,066	1,066	--	857	--	--	--
Coke plants	15	21	--	--	14	--	--	--
Coal-to-liquids	0	44	44	--	0	--	--	--
Other industrial/buildings	49	51	51	--	40	--	--	--
Total consumption (quadrillion Btu)[e]	**19.69**	**22.61**	**22.06**	**18.7**	--	**16.48**	--	--
Total consumption (million short tons)	**1,000**	**1,182**	**1,161**	--	**910**	--	**1,463**[f]	**978**[f]
Net coal exports	**38**	**19**	**-37**	--	**71**	--	**75**	**7**
Exports	59	75	18	--	83	--	138	33
Imports	21	56	55	--	12	--	63	26
Minemouth price								
2009 dollars per ton	33.26	33.22	27.92	--	--	33.95	63.29	30.09
2009 dollars per Btu	1.67	1.68	1.45	--	--	1.55	--	1.54
Average delivered price to electricity generators								
2009 dollars per ton	43.48	43.33	43.33	--		--	--	50.12
2009 dollars per Btu	2.20	2.24	2.24	--		2.04	--	2.57

-- = not reported.
See notes at end of table.

(continued on page 103)

Table 18. Comparison of coal projections, 2015, 2025, 2030, and 2035 (million short tons, except where noted) (continued)

Projection	2009	*AEO2011* Reference case	*AEO2011* Reference case (thermal coal only)[a]	Other projections: DB	EVA	ICF[b, c]	INFORUM	WM (thermal coal only)[b, d]
				2030				
Production	**1,075**	**1,252**	**1,180**	--	**962**	**916**	**1,591**	**862**
East of the Mississippi	450	402	335	--	353	500	--	337
West of the Mississippi	625	850	845	--	609	416	--	525
Consumption								
Electric power	937	1094	1094	--	847	--	--	--
Coke plants	15	20	--	--	12	--	--	--
Coal-to-liquids	0	82	82	--	0	--	--	--
Other industrial/buildings	49	51	51	--	36	--	--	--
Total consumption (quadrillion Btu)[e]	**19.69**	**23.39**	**22.88**	**18.23**		**13.85**	--	--
Total consumption (million short tons)	**1,000**	**1,247**	**1,227**	--	**895**	--	**1,517**[f]	**855**[f]
Net coal exports	**38**	**20**	**-33**	--	**69**	--	**74**	**7**
Exports	59	74	20	--	81	--	156	33
Imports	21	54	53	--	12	--	82	26
Minemouth price								
2009 dollars per ton	33.26	33.25	28.47	--		34.54	73.37	28.86
2009 dollars per Btu	1.67	1.69	1.48	--		1.58	--	1.48
Average delivered price to electricity generators								
2009 dollars per ton	43.48	44.63	44.63	--		--	--	48.41
2009 dollars per Btu	2.20	2.32	2.32	--		1.99	--	2.48
				2035				
Production	**1,075**	**1,319**	**1,252**	--		**822**	**1,632**	--
East of the Mississippi	450	415	354	--		464	--	--
West of the Mississippi	625	904	898	--		359	--	--
Consumption								
Electric power	937	1119	1119	--		--	--	--
Coke plants	15	18	--	--		--	--	--
Coal-to-liquids	0	128	128	--		--	--	--
Other industrial/buildings	49	50	50	--		--	--	--
Total consumption (quadrillion Btu)[e]	**19.69**	**24.30**	**23.83**	**17.78**		**12.30**	--	--
Total consumption (million short tons)	**1,000**	**1,315**	**1,297**	--		--	**1,568**[f]	--
Net coal exports	**38**	**18**	**-31**	--		--	**64**	--
Exports	59	71	21	--		--	177	--
Imports	21	53	52	--		--	113	--
Minemouth price								
2009 dollars per ton	33.26	33.92	29.68	--		36.73	79.43	--
2009 dollars per Btu	1.67	1.73	1.54	--		1.67	--	--
Average delivered price to electricity generators								
2009 dollars per ton	43.48	46.36	46.36	--		--	--	--
2009 dollars per Btu	2.20	2.40	2.40	--		1.97	--	--

[a]Excludes coking coal for all data items to facilitate comparison with Wood Mackenzie projections.
[b]ICF includes a carbon price beginning in 2018.
WM includes a carbon price beginning in 2016.
[c]Aside from a price on carbon, the ICF projection also differs from *AEO2011* by representing certain proposed regulations, including Maximum Achievable Control Standards for Hazardous Air Pollutants, regulations for cooling water intake structures under Section 316(b) of the Clean Water Act, and regulations for coal combustion residuals under the authority of the Resource Conservation and Recovery Act. ICF represents the Clean Air Transport Rule, whereas *AEO2011* represents the Clean Air Interstate Rule.
[d]Wood Mackenzie projections exclude coking coal for all data items.
[e]For *AEO2011*, excludes coal converted to coal-based synthetic liquids.
[f]Calculated as *consumption* = (*production* – *exports* + *imports*).

In the INFORUM projection, the average minemouth price of coal (in constant 2009 dollars) increases by about 140 percent from 2009 to 2035. The rise may be due in part to higher mining costs and expectations of growth in domestic coal demand, but it may also be due to strong international demand for U.S. coal. Larger exports of coking coal—which typically command higher prices than thermal coal exports—might also explain some of the increase in the average coal minemouth price in the INFORUM projection.

ICF projects a minemouth coal price on 2015 that is 8 percent lower on a Btu basis than the *AEO2011* price in 2015, although coal production in 2015 is 11 percent higher in the ICF projection. All of the increase in production in 2015 relative to *AEO2011* is attributed to production east of the Mississippi, possibly for export. Over the projection, as ICF's total production falls relative to *AEO2011*, its average minemouth price still continues to rise, so that in 2035 it is only 4 percent lower than the corresponding price in *AEO2011*. The rise in minemouth prices in the ICF projection could be the result of strong international demand, a larger share of higher-cost eastern production, or rising mining costs. In contrast, ICF's delivered coal price to the electricity sector falls slightly from 2015 levels, possibly reflecting either a larger proportion of eastern coal production, which would have lower total transport costs, or generally lower transportation rates for all U.S. coal shipments. *AEO2011* projects an increase in the delivered price of coal to the electricity sector, reflecting higher transportation costs for western coal, as well as higher projected minemouth prices for coal from most basins.

The strongest growth in coal production is projected by INFORUM. In 2035, coal production in the INFORUM projection is 24 percent above the *AEO2011* projection. Similarly, coal consumption in the INFORUM projection is the highest among all the projections regardless of the projection year.

Total coal consumption declines at a rate of 0.5 percent per year (on a tonnage basis) from 2009 to 2030 in the EVA projection, as compared with an average increase of 1.1 percent per year in *AEO2011*. For the same period, thermal coal consumption (excluding coking coal) declines by 0.7 percent per year in the WM projection but increases by 1.1 percent per year in the *AEO2011* projection. From 2009 to 2035, coal consumption increases by 1.7 percent per year (on a tonnage basis) in the INFORUM projection and by 1.1 percent per year in the *AEO2011* Reference case. Also over the 2009-2035 period, coal consumption in the DB and ICF projections (on a Btu basis) declines at by 0.4 percent per year and 1.8 percent per year, respectively, compared with an increase of 0.8 percent per year in the *AEO2011* projection.

List of acronyms

AB	Assembly Bill
ACI	Activated carbon injection
AEO	*Annual Energy Outlook*
AEO2011	*Annual Energy Outlook 2011*
ARI	Advanced Resources International
ARRA	American Recovery and Reinvestment Act of 2009
ASHRAE	American Society of Heating, Refrigeration, and Air Conditioning Engineers
BLS	Bureau of Labor Statistics
BOEM	Bureau of Ocean Energy Management
BTA	Best technology available
BTL	Biomass-to-liquid
Btu	British thermal unit
CAA	Clean Air Act
CAAA90	Clean Air Act Amendments of 1990
CAFE	Corporate average fuel economy
CAIR	Clean Air Interstate Rule
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CBO	Congressional Budget Office
CBTL	Coal- and biomass-to-liquids
CCR	Coal combustion residual
CCS	Carbon capture and storage
CHP	Combined heat and power
CMM	Coal Market Module
CO_2	Carbon dioxide
CTL	Coal-to-liquids
CWA	Clean Water Act
DB	Deutsche Bank
DG	Distributed generation
DOE	U.S. Department of Energy
DSI	Direct sorbent injection
DSIRE	Database of State Incentives for Renewables & Efficiency
E10	Motor gasoline blend containing up to 10 percent ethanol
E15	Motor gasoline blend containing up to 15 percent ethanol
E85	Motor fuel containing up to 85 percent ethanol
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EOR	Enhanced oil recovery
EPA	U.S. Environmental Protection Agency
EPACT2005	Energy Policy Act of 2005
EUR	Estimated ultimate recovery
EVA	Energy Ventures Analysis
FEMP	Federal Energy Management Program
FFV	Flex-fuel vehicle
FGD	Flue gas desulfurization
GDP	Gross domestic product
GEM	Greenhouse Gas Emissions Model
GHG	Greenhouse gas
GSHP	Ground-source heat pump
GTL	Gas-to-liquids
GVWR	Gross vehicle weight rating
HAP	Hazardous air pollutant
HB	House Bill

HCl	Hydrogen chloride
HDV	Heavy-duty vehicle
ICF	ICF International
IDM	Industrial Demand Module
IEA	International Energy Agency
IECC	International Energy Conservation Code
IEM	International Energy Module
IHSGI	IHS Global Insight
ILUC	Indirect land-use change
INFORUM	Interindustry Forecasting Project at the University of Maryland
ITC	Investment tax credit
LCFS	Low Carbon Fuel Standard
LDV	Light-duty vehicle
LED	Light-emitting diode
LNG	Liquefied natural gas
MAM	Macroeconomic Activity Module
mpg	Miles per gallon
MY	Model year
NAAQS	National Ambient Air Quality Standards
NEMS	National Energy Modeling System
NERC	North American Electric Reliability Council
NGL	Natural gas liquids
NGTDM	Natural Gas Transmission and Distribution Module
NHTSA	National Highway Traffic Safety Administration
NO_x	Nitrous oxide
OCS	Outer continental shelf
OECD	Organization for Economic Cooperation and Development
OMB	Office of Management and Budget
OPEC	Organization of the Petroleum Exporting Countries
PADD	Petroleum Administration for Defense District
PCs	Personal computers
P&G	Purvin & Gertz
PM	Particulate matter
PMM	Petroleum Market Module
$PM_{2.5}$	Particulate matter less than 2.5 microns diameter
PTC	Production tax credit
PV	Solar photovoltaic
RCRA	Resource Conservation and Recovery Act
RFM	Renewable Fuels Module
RFS	Renewable fuels standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable portfolio standard
SCNR	Selective noncatalytic converter
SCR	Selective catalytic converter
SEP	State Energy Program
SNCR	Selective noncatalytic converter
SO_2	Sulfur dioxide
TVA	Tennessee Valley Authority
VIUS	U.S. Census Bureau's 2002 Vehicle Inventory and Use Survey
VMT	Vehicle miles traveled
WM	Wood Mackenzie
WTI	West Texas Intermediate

Notes and sources

Table notes and sources

Table 1. Coal-fired plant retirements in alternative cases, 2010-2035: AEO2011 National Energy Modeling System, run REF2011.D020911A, TRMA05.D021811A, TRMA20.D021811A, BAMA05.D021811A, BAMA20.D021811A, LGBAMA05.D021811A, LGBAMA20.D021811A, and HSHLEUR.D020911A.

Table 2. Renewable portfolio standards in the 30 States with current mandates: U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting. Based on a review of enabling legislation and regulatory actions from the various States of policies identified by the Database of State Incentives for Renewable Energy as of September 30, 2010, website www.dsireuse.org.

Table 3. Key analyses of interest from Issues in focus in recent *AEO*s: U.S. Energy Information Administration, *Annual Energy Outlook 2010*, DOE/EIA-0383(2010) (Washington, DC, April 2010); U.S. Energy Information Administration, *Annual Energy Outlook 2009*, DOE/EIA-0383(2009) (Washington, DC, March 2009); U.S. Energy Information Administration, *Annual Energy Outlook 2008*, DOE/EIA-0383(2008) (Washington, DC, June 2008).

Table 4. Unconventional light-duty vehicle types: U.S. Energy Information Administration, Office of Energy Analysis.

Table 5. Vehicle categories for the HDV standards: U.S. Environmental Protection Agency, "Heavy-Duty Regulations," website www.epa.gov/oms/climate/regulations.htm#1-2; and U.S. Environmental Protection Agency and National Highway Traffic Safety Administration, "Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles," *Federal Register*, Vol. 75, No. 229 (November 30, 2010), pp. 74451-74456, website http://edocket.access.gpo.gov/2010/2010-28120.htm.

Table 6. Technically recoverable undiscovered U.S. offshore oil and natural gas resources assumed in two cases: AEO2011 National Energy Modeling System, runs REF2011.D020911A and OCSHRES3S.D032911A.

Table 7. First year of available offshore leasing in two cases: U.S. Energy Information Administration, Office of Energy Analysis.

Table 8. Natural gas prices, production, imports, and consumption in five cases, 2035: AEO2011 National Energy Modeling System, runs REF2011.D020911A, HSHLEUR.D020911A, HSHLDRL.D020911A, LSHLEUR.D020911A, and LSHLDRL.D020911A.

Table 9. Commercial-scale CCS projects operating in 2010: International Energy Agency, *Carbon Capture and Storage: Progress and Next Steps*, website www.iea.org/papers/2010/ccs_g8.pdf.

Table 10. Transport Rule emissions targets, 2012 and 2014: "Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone," *Federal Register*, Vol. 75, No. 147 (August 2, 2010), p. 45217, website www.gpo.gov/fdsys/pkg/FR-2010-08-02/pdf/2010-17007.pdf#page=1.

Table 11. Coal-fired plant retirements in nine cases, 2010-2035: AEO2011 National Energy Modeling System, runs REF2011.D020911A, TRMA05.D021811A, TRMA20.D021811A, BAMA05.D021811A, BAMA20.D021811A, LGBAMA05.D021811A, LGBAMA20.D021811A, HSHLEUR.D020911A, and POLMAX.D031411A.

Table 12. Projections of average annual economic growth, 2009-2035: *AEO2010* (Reference case): AEO2010 National Energy Modeling System, run AEO2010R.D111809A. ***AEO2011* (Reference case):** AEO2011 National Energy Modeling System, run AEO2011.D020911A. **IHSGI (August 2010):** IHS/Global Insight, Inc., *U.S. Macroeconomic 30 Year Trend Forecast* (Lexington, MA, August 2010). **OMB (July 2009):** Office of Management and Budget, *Budget of the United States Government Fiscal Year 2012* (Washington, DC, January 2011). **CBO (January 2011):** Congressional Budget Office, *The Budget and Economic Outlook* (Washington, DC, January 2011). **INFORUM (December 2010):** Inforum Long-term Interindustry Forecasting Tool (Lift) Model (2010). **SSA (May 2010):** Social Security Administration, *OASDI Trustees Report* (Washington, DC, May 2010). **BLS (December 2009):** Bureau of Labor Statistics, *Macro Projections 2009*. **IEA (2010):** International Energy Agency, *World Energy Outlook 2010* (Paris, France, September 2010). **Blue Chip Consensus (March 2010):** *Blue Chip Economic Indicators* (Aspen Publishers, March 10, 2010). **Exxon/Mobil 2010**: Exxon Mobil Corporation, *The Outlook for Energy: A View to 2030* (Irving, TX, 2010). **ICF Quarter 4 2010 Integrated Energy Outlook**: ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010).

Table 13. Projections of world oil prices, 2015-2035: *AEO2011* (Reference case): AEO2011 National Energy Modeling System, run REF2011.D020911A. ***AEO2010* (Reference case):** AEO2010 National Energy Modeling System, run AEO2010.D1111809A. **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (January 11, 2011). **ICF Q4 2010 Integrated Energy Outlook:** ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **INFORUM:** INFORUM Long-term Interindustry Forecasting Tool (Lift) Model (2010). **IEA (current policies scenario):** International Energy Agency, *World Energy Outlook 2010* (Paris, France, November 2010), Reference Scenario. **EVA:** Energy Ventures Analysis, Inc., *Fuel Cast Long Term* (February 2010). **IHSGI:** IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2010).

Table 14. Projections of energy consumption by sector, 2009-2035: *AEO2011*: AEO2011 National Energy Modeling System, run REF2011.D020911A. **INFORUM:** INFORUM Long-term Interindustry Forecasting Tool (Lift) Model (2010). **IHSGI:** IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2010). **ExxonMobil**: Exxon Mobil Corporation, *The Outlook for Energy: A View to 2030* (Irving, TX, 2010).

Table 15. Comparison of electricity projections, 2015, 2025, and 2035: ***AEO2011***: AEO2011 National Energy Modeling System, run AEO2011.D020911A. **EVA**: Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2011). **IHSGI**: IHS/Global Insight, Inc., *2010 Energy Outlook* (Lexington, MA, September 2010). **ICF:** ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **INFORUM:** Inforum Long-term Interindustry Forecasting Tool (Lift) Model (2010).

Table 16. Comparison of natural gas projections, 2015, 2025, and 2035: *AEO2011*: AEO2011 National Energy Modeling System, run REF2011.D020911A. **IHSGI**: IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2010). **EVA:** Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2011). **DB:** Deutsche Bank AG, e-mail from Adam Sieminski (January 11, 2011). **ICF**: ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **ExxonMobil**: Exxon Mobil Corporation, *The Outlook for Energy: A View to 2030* (Irving, TX, 2010). **INFORUM:** Inforum Long-term Interindustry Forecasting Tool (Lift) Model (2010).

Table 17. Comparison of liquids projections, 2015, 2025, and 2035: ***AEO2011***: AEO2011 National Energy Modeling System, run AEO2011.D0209A. **DB:** Deutsche Bank AG, email from Adam Sieminski (January 11, 2011). **ICF:** ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **IHSGI:** IHS/Global Insight, Inc., *U.S. Energy Outlook* (Lexington, MA, September 2010). **INFORUM:** Inforum Long-term Interindustry Forecasting Tool (Lift) Model (2010).**P&G:** Purvin and Gertz, Inc., *2010 Global Petroleum Market Outlook*, Vol. 2, Table III-2 (2010).

Table 18. Comparison of coal projections, 2015, 2025, 2030, and 2035: ***AEO2011***: AEO2011 National Energy Modeling System, run REF2011.D020911A. **DB**: Deutsche Bank AG, email from Adam Sieminski (January 11, 2011). **EVA**: Energy Ventures Analysis, Inc., *FUELCAST: Long-Term Outlook* (February 2011). **ICF**: ICF International, ICD Integrated Energy Outlook (Fourth Quarter, 2010). **INFORUM**: INFORUM Long-term Interindustry Forecasting Tool (Lift) Model (2010). **WM**: Wood Mackenzie, *Fall 2010 Long-Term US Thermal Coal Outlook.*

Figure notes and sources

Figure 1. U.S. liquids fuel consumption, 1970-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011. D020911A.

Figure 2. U.S. natural gas production, 1990-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011. D020911A.

Figure 3. U.S. nonhydropower renewable electricity generation, 1990-2035: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

Figure 4. U.S. carbon dioxide emissions by sector and fuel, 2005 and 2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

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U.S. Energy Information Administration, *Petroleum Supply Annual 2009, Volume 1*, DOE/EIA-0340(2010) (Washington, DC, July 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

Figure 100. U.S. ethanol use in gasoline and E85, 2000-2035: History: U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

Figure 101. Coal production by region, 1970-2035: History (short tons): 1970-1990: U.S. Energy Information Administration, *The U.S. Coal Industry, 1970-1990: Two Decades of Change*, DOE/EIA-0559 (Washington, DC, November 2002). **1991-2000:** U.S. Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2009:** U.S. Energy Information Administration, *Annual Coal Report 2009*, DOE/EIA-0584(2009) (Washington, DC, February 2011), and previous issues. **History (conversion to quadrillion Btu): 1970-2009: Estimation Procedure:** U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis. Estimates of average heat content by region and year are based on coal quality data collected through 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:** U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010), 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"; Form EIA-923, "Power Plant Operations 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:** AEO2011 National Energy Modeling System, run REF2011.D020911A. **Note:** For 1989-2035, coal production includes waste coal.

Figure 102. U.S. coal production in six cases, 2007, 2009, 2020, and 2035: AEO2011 National Energy Modeling System, runs REF2011.D020911A, LCCST11.D020911A, HCCST11.D020911A, LM2011.D020911A, HM2011.D020911A, and HP2011HNO.D022511A. **Note:** Coal production includes waste coal.

Figure 103. Average annual minemouth coal prices by region, 1990-2035: History (dollars per short ton): 1990-2000: U.S. Energy Information Administration, *Coal Industry Annual*, DOE/EIA-0584 (various years). **2001-2009:** U.S. Energy Information Administration, *Annual Coal Report 2009*, DOE/EIA-0584(2009) (Washington, DC, February 2011), and previous issues. **History (conversion to dollars per million Btu): 1970-2009: Estimation Procedure:** U.S. Energy Information Administration, Office of Integrated Analysis and Forecasting. Estimates of average heat content by region and year based on coal quality data collected through 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:** U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010), 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"; and Form EIA-920, "Combined Heat and Power Plant Report"; Form EIA-923, "Power Plant Operations 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:** AEO2011 National Energy Modeling System, run REF2011.D020911A. **Note:** Includes reported prices for both open-market and captive mines.

Figure 104. Average annual delivered coal prices in four cases, 1990-2035: History: **1990-2009:** U.S. Energy Information Administration, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010), and previous issues; *Electric Power Monthly, October 2010*, DOE/EIA-0226(2009/10) (Washington, DC, October 2010); and *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections**: AEO2011 National Energy Modeling System, runs REF2011.D020911A, LCCST11.D020911A, HCCST11.D020911A, and HP2011HNO.D022511A.

Figure 105. Change in annual U.S. coal consumption by end use in two cases, 2009-2035: AEO2011 National Energy Modeling System, run REF2011.D020911A and NORSK2011.D020911A.

Figure 106. U.S. carbon dioxide emissions by sector and fuel, 2005 and 2035: AEO2011 National Energy Modeling System, run REF2011.D020911A.

Figure 107. Sulfur dioxide emissions from electricity generation, 2000-2035: 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*, website www.epa.gov/airmarkets/emissions/prelimarp/index.html. **2009 and Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

Figure 108. Nitrogen oxide emissions from electricity generation, 2000-2035: 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. **2009 and Projections:** AEO2011 National Energy Modeling System, run REF2011.D020911A.

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Table A1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Production								
Crude Oil and Lease Condensate	10.51	11.34	12.51	13.07	12.64	12.49	12.80	0.5%
Natural Gas Plant Liquids	2.41	2.57	2.86	3.06	3.55	3.71	3.92	1.6%
Dry Natural Gas	20.83	21.50	23.01	24.04	24.60	25.75	27.00	0.9%
Coal[1]	23.85	21.58	20.94	22.05	23.64	24.77	26.01	0.7%
Nuclear Power	8.43	8.35	8.77	9.17	9.17	9.17	9.14	0.3%
Hydropower	2.53	2.69	2.92	3.00	3.04	3.07	3.09	0.5%
Biomass[2]	3.94	3.52	4.70	5.77	7.20	8.15	8.63	3.5%
Other Renewable Energy[3]	1.12	1.29	2.14	2.30	2.58	2.97	3.22	3.6%
Other[4]	0.19	0.34	0.78	0.96	0.88	0.81	0.78	3.2%
Total	**73.80**	**73.18**	**78.63**	**83.42**	**87.29**	**90.88**	**94.59**	**1.0%**
Imports								
Crude Oil	21.39	19.70	19.25	18.46	18.35	18.30	18.44	-0.3%
Liquid Fuels and Other Petroleum[5]	6.32	5.40	5.33	5.34	5.18	5.26	5.33	-0.1%
Natural Gas	4.08	3.82	4.01	3.80	3.20	3.07	2.87	-1.1%
Other Imports[6]	0.96	0.61	0.82	0.98	1.39	1.30	1.27	2.9%
Total	**32.76**	**29.53**	**29.41**	**28.57**	**28.13**	**27.93**	**27.92**	**-0.2%**
Exports								
Petroleum[7]	3.78	4.17	3.27	3.54	3.62	3.75	3.92	-0.2%
Natural Gas	1.01	1.09	1.24	1.82	2.07	2.24	2.64	3.5%
Coal	2.07	1.51	1.76	1.92	1.89	1.86	1.78	0.6%
Total	**6.86**	**6.77**	**6.27**	**7.28**	**7.58**	**7.85**	**8.34**	**0.8%**
Discrepancy[8]	**-0.44**	**1.16**	**-0.24**	**-0.21**	**-0.12**	**-0.07**	**-0.02**	**- -**
Consumption								
Liquid Fuels and Other Petroleum[9]	38.46	36.62	39.10	39.38	39.84	40.55	41.70	0.5%
Natural Gas	23.85	23.31	25.77	26.00	25.73	26.58	27.24	0.6%
Coal[10]	22.38	19.69	19.73	20.85	22.61	23.39	24.30	0.8%
Nuclear Power	8.43	8.35	8.77	9.17	9.17	9.17	9.14	0.3%
Hydropower	2.53	2.69	2.92	3.00	3.04	3.07	3.09	0.5%
Biomass[11]	3.07	2.52	3.27	3.93	4.71	5.05	5.25	2.9%
Other Renewable Energy[3]	1.12	1.29	2.14	2.30	2.58	2.97	3.22	3.6%
Other[12]	0.31	0.32	0.31	0.29	0.27	0.24	0.25	-0.9%
Total	**100.14**	**94.79**	**102.02**	**104.92**	**107.95**	**111.03**	**114.19**	**0.7%**
Prices (2009 dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	100.51	61.66	94.58	108.10	117.54	123.09	124.94	2.8%
Imported Crude Oil Price[13]	93.44	59.04	86.83	98.65	107.40	112.38	113.70	2.6%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	8.94	3.95	4.66	5.05	5.97	6.40	7.07	2.3%
Wellhead Price[14]	7.96	3.62	4.13	4.47	5.29	5.66	6.26	2.1%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	8.18	3.71	4.24	4.59	5.43	5.81	6.42	2.1%
Coal (dollars per ton)								
Minemouth Price[15]	31.54	33.26	32.36	32.85	33.22	33.25	33.92	0.1%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.56	1.67	1.62	1.65	1.68	1.69	1.73	0.2%
Average Delivered Price[16]	2.18	2.31	2.26	2.30	2.36	2.42	2.47	0.3%
Average Electricity Price (cents per kilowatthour)	9.8	9.8	8.9	8.8	8.9	9.0	9.2	-0.2%

Table A1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Prices (nominal dollars per unit)								
Petroleum (dollars per barrel)								
Imported Low Sulfur Light Crude Oil Price[13]	99.57	61.66	103.24	130.60	155.46	178.45	199.37	4.6%
Imported Crude Oil Price[13]	92.57	59.04	94.78	119.18	142.05	162.92	181.43	4.4%
Natural Gas (dollars per million Btu)								
Price at Henry Hub	8.86	3.95	5.09	6.10	7.90	9.28	11.28	4.1%
Wellhead Price[14]	7.89	3.62	4.51	5.40	6.99	8.21	9.99	4.0%
Natural Gas (dollars per thousand cubic feet)								
Wellhead Price[14]	8.10	3.71	4.63	5.55	7.18	8.43	10.24	4.0%
Coal (dollars per ton)								
Minemouth Price[15]	31.25	33.26	35.32	39.69	43.93	48.21	54.13	1.9%
Coal (dollars per million Btu)								
Minemouth Price[15]	1.55	1.67	1.77	1.99	2.22	2.45	2.76	2.0%
Average Delivered Price[16]	2.16	2.31	2.47	2.78	3.12	3.50	3.95	2.1%
Average Electricity Price (cents per kilowatthour)	9.7	9.8	9.7	10.7	11.8	13.0	14.7	1.6%

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and wood 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, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids and natural gas.
[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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 natural gas supply values: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 natural gas supply values and natural gas wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 natural gas wellhead price: Bureau of Energy Management, Regulation and Enforcement; and EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2008 and 2009 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2009*, DOE/EIA-0584(2009) (Washington, DC, October 2010). 2009 petroleum supply values and 2008 crude oil and lease condensate production: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). Other 2008 petroleum supply values: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). 2008 and 2009 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2008 and 2009 coal values: *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010). Other 2008 and 2009 values: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Energy Consumption								
Residential								
Liquefied Petroleum Gases	0.52	0.53	0.49	0.48	0.48	0.48	0.48	-0.4%
Kerosene	0.02	0.03	0.02	0.02	0.02	0.02	0.02	-1.5%
Distillate Fuel Oil	0.66	0.61	0.56	0.50	0.44	0.40	0.37	-1.9%
Liquid Fuels and Other Petroleum Subtotal	1.20	1.16	1.07	0.99	0.94	0.90	0.86	-1.1%
Natural Gas	5.00	4.87	4.94	4.98	4.96	4.95	4.90	0.0%
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	-1.1%
Renewable Energy[1]	0.44	0.43	0.40	0.42	0.42	0.42	0.42	-0.1%
Electricity	4.71	4.65	4.60	4.75	4.98	5.25	5.51	0.7%
Delivered Energy	**11.36**	**11.12**	**11.02**	**11.15**	**11.32**	**11.53**	**11.70**	**0.2%**
Electricity Related Losses	10.17	9.96	9.46	9.80	10.24	10.67	11.06	0.4%
Total	**21.53**	**21.08**	**20.48**	**20.95**	**21.56**	**22.20**	**22.76**	**0.3%**
Commercial								
Liquefied Petroleum Gases	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.2%
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.3%
Kerosene	0.00	0.01	0.01	0.01	0.01	0.01	0.01	2.8%
Distillate Fuel Oil	0.37	0.34	0.28	0.27	0.26	0.25	0.25	-1.2%
Residual Fuel Oil	0.07	0.06	0.06	0.06	0.07	0.07	0.07	0.3%
Liquid Fuels and Other Petroleum Subtotal	0.64	0.60	0.55	0.54	0.53	0.53	0.53	-0.5%
Natural Gas	3.22	3.20	3.47	3.59	3.66	3.78	3.92	0.8%
Coal	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.0%
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Electricity	4.56	4.51	4.83	5.21	5.58	6.01	6.43	1.4%
Delivered Energy	**8.60**	**8.49**	**9.02**	**9.50**	**9.94**	**10.49**	**11.05**	**1.0%**
Electricity Related Losses	9.85	9.66	9.94	10.73	11.47	12.21	12.93	1.1%
Total	**18.44**	**18.15**	**18.96**	**20.24**	**21.41**	**22.70**	**23.98**	**1.1%**
Industrial[4]								
Liquefied Petroleum Gases	2.08	2.01	2.36	2.39	2.38	2.29	2.18	0.3%
Motor Gasoline[2]	0.25	0.25	0.33	0.33	0.33	0.32	0.32	1.0%
Distillate Fuel Oil	1.27	1.16	1.16	1.16	1.16	1.14	1.13	-0.1%
Residual Fuel Oil	0.20	0.17	0.17	0.17	0.17	0.16	0.16	-0.3%
Petrochemical Feedstocks	1.12	0.90	1.29	1.33	1.34	1.30	1.26	1.3%
Other Petroleum[5]	3.98	3.45	3.97	3.82	3.79	3.77	3.88	0.5%
Liquid Fuels and Other Petroleum Subtotal	8.91	7.94	9.29	9.20	9.16	8.98	8.94	0.5%
Natural Gas	6.83	6.31	8.27	8.46	8.32	8.30	8.23	1.0%
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]	1.26	1.19	1.24	1.24	1.22	1.24	1.28	0.3%
Natural Gas Subtotal	8.09	7.50	9.51	9.70	9.54	9.53	9.51	0.9%
Metallurgical Coal	0.58	0.40	0.58	0.58	0.55	0.51	0.47	0.6%
Other Industrial Coal	1.16	0.94	0.98	0.98	0.97	0.96	0.94	0.0%
Coal-to-Liquids Heat and Power	0.00	0.00	0.10	0.13	0.40	0.77	1.19	- -
Net Coal Coke Imports	0.04	-0.02	0.01	0.01	0.00	-0.00	-0.00	-7.2%
Coal Subtotal	1.78	1.32	1.67	1.69	1.93	2.24	2.60	2.6%
Biofuels Heat and Coproducts	0.98	0.66	0.85	1.19	1.90	2.33	2.52	5.3%
Renewable Energy[7]	1.52	1.42	1.89	1.98	2.05	2.06	2.04	1.4%
Electricity	3.44	3.01	3.54	3.57	3.52	3.40	3.28	0.3%
Delivered Energy	**24.72**	**21.85**	**26.75**	**27.34**	**28.11**	**28.54**	**28.89**	**1.1%**
Electricity Related Losses	7.44	6.44	7.28	7.36	7.23	6.92	6.59	0.1%
Total	**32.16**	**28.29**	**34.03**	**34.70**	**35.33**	**35.46**	**35.49**	**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 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Transportation								
Liquefied Petroleum Gases	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.4%
E85[8]	0.00	0.00	0.01	0.32	0.93	1.18	1.23	26.3%
Motor Gasoline[2]	16.87	16.82	17.02	16.53	15.93	16.08	16.69	-0.0%
Jet Fuel[9]	3.21	3.20	3.20	3.34	3.47	3.56	3.62	0.5%
Distillate Fuel Oil[10]	6.04	5.54	6.57	7.04	7.45	7.88	8.35	1.6%
Residual Fuel Oil	0.92	0.78	0.79	0.80	0.81	0.81	0.82	0.2%
Other Petroleum[11]	0.17	0.16	0.16	0.16	0.16	0.16	0.16	0.1%
Liquid Fuels and Other Petroleum Subtotal	27.24	26.52	27.76	28.20	28.76	29.69	30.89	0.6%
Pipeline Fuel Natural Gas	0.67	0.65	0.67	0.65	0.64	0.65	0.67	0.1%
Compressed Natural Gas	0.03	0.03	0.04	0.07	0.10	0.14	0.16	7.4%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	0.02	0.02	0.03	0.04	0.05	0.06	0.07	4.6%
Delivered Energy	**27.95**	**27.23**	**28.50**	**28.96**	**29.56**	**30.54**	**31.80**	**0.6%**
Electricity Related Losses	0.05	0.05	0.06	0.07	0.09	0.12	0.15	4.4%
Total	**28.00**	**27.28**	**28.56**	**29.04**	**29.65**	**30.66**	**31.95**	**0.6%**
Delivered Energy Consumption for All Sectors								
Liquefied Petroleum Gases	2.77	2.71	3.02	3.04	3.03	2.94	2.84	0.2%
E85[8]	0.00	0.00	0.01	0.32	0.93	1.18	1.23	26.3%
Motor Gasoline[2]	17.17	17.11	17.39	16.91	16.31	16.45	17.06	-0.0%
Jet Fuel[9]	3.21	3.20	3.20	3.34	3.47	3.56	3.62	0.5%
Kerosene	0.03	0.04	0.03	0.03	0.03	0.03	0.03	-0.4%
Distillate Fuel Oil	8.34	7.65	8.57	8.96	9.31	9.67	10.10	1.1%
Residual Fuel Oil	1.19	1.02	1.03	1.03	1.04	1.04	1.05	0.1%
Petrochemical Feedstocks	1.12	0.90	1.29	1.33	1.34	1.30	1.26	1.3%
Other Petroleum[12]	4.15	3.60	4.13	3.98	3.94	3.92	4.04	0.4%
Liquid Fuels and Other Petroleum Subtotal	37.99	36.23	38.67	38.94	39.39	40.10	41.22	0.5%
Natural Gas	15.07	14.41	16.72	17.10	17.05	17.17	17.22	0.7%
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]	1.26	1.19	1.24	1.24	1.22	1.24	1.28	0.3%
Pipeline Natural Gas	0.67	0.65	0.67	0.65	0.64	0.65	0.67	0.1%
Natural Gas Subtotal	17.00	16.25	18.62	18.99	18.91	19.05	19.17	0.6%
Metallurgical Coal	0.58	0.40	0.58	0.58	0.55	0.51	0.47	0.6%
Other Coal	1.24	1.01	1.05	1.05	1.04	1.03	1.01	-0.0%
Coal-to-Liquids Heat and Power	0.00	0.00	0.10	0.13	0.40	0.77	1.19	- -
Net Coal Coke Imports	0.04	-0.02	0.01	0.01	0.00	-0.00	-0.00	-7.2%
Coal Subtotal	1.86	1.39	1.74	1.76	2.00	2.31	2.66	2.5%
Biofuels Heat and Coproducts	0.98	0.66	0.85	1.19	1.90	2.33	2.52	5.3%
Renewable Energy[13]	2.07	1.96	2.41	2.51	2.59	2.59	2.58	1.1%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity	12.73	12.20	13.00	13.57	14.13	14.72	15.29	0.9%
Delivered Energy	**72.63**	**68.68**	**75.29**	**76.96**	**78.92**	**81.10**	**83.45**	**0.8%**
Electricity Related Losses	27.51	26.11	26.73	27.97	29.03	29.93	30.74	0.6%
Total	**100.14**	**94.79**	**102.02**	**104.92**	**107.95**	**111.03**	**114.19**	**0.7%**
Electric Power[14]								
Distillate Fuel Oil	0.11	0.10	0.09	0.10	0.10	0.10	0.10	0.4%
Residual Fuel Oil	0.37	0.30	0.34	0.35	0.35	0.36	0.37	0.8%
Liquid Fuels and Other Petroleum Subtotal	0.47	0.40	0.43	0.45	0.45	0.46	0.47	0.7%
Natural Gas	6.85	7.06	7.15	7.02	6.82	7.53	8.07	0.5%
Steam Coal	20.51	18.30	17.99	19.09	20.61	21.09	21.64	0.6%
Nuclear Power	8.43	8.35	8.77	9.17	9.17	9.17	9.14	0.3%
Renewable Energy[15]	3.67	3.89	5.08	5.52	5.84	6.16	6.47	2.0%
Electricity Imports	0.11	0.12	0.11	0.09	0.07	0.04	0.05	-3.4%
Total[16]	**40.24**	**38.31**	**39.73**	**41.53**	**43.17**	**44.64**	**46.03**	**0.7%**

Table A2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Total Energy Consumption								
Liquefied Petroleum Gases	2.77	2.71	3.02	3.04	3.03	2.94	2.84	0.2%
E85[8]	0.00	0.00	0.01	0.32	0.93	1.18	1.23	26.3%
Motor Gasoline[2]	17.17	17.11	17.39	16.91	16.31	16.45	17.06	-0.0%
Jet Fuel[9]	3.21	3.20	3.20	3.34	3.47	3.56	3.62	0.5%
Kerosene	0.03	0.04	0.03	0.03	0.03	0.03	0.03	-0.4%
Distillate Fuel Oil	8.45	7.75	8.66	9.06	9.40	9.76	10.20	1.1%
Residual Fuel Oil	1.56	1.32	1.37	1.38	1.40	1.40	1.41	0.3%
Petrochemical Feedstocks	1.12	0.90	1.29	1.33	1.34	1.30	1.26	1.3%
Other Petroleum[12]	4.15	3.60	4.13	3.98	3.94	3.92	4.04	0.4%
Liquid Fuels and Other Petroleum Subtotal	38.46	36.62	39.10	39.38	39.84	40.55	41.70	0.5%
Natural Gas	21.92	21.47	23.87	24.11	23.87	24.69	25.29	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]	1.26	1.19	1.24	1.24	1.22	1.24	1.28	0.3%
Pipeline Natural Gas	0.67	0.65	0.67	0.65	0.64	0.65	0.67	0.1%
Natural Gas Subtotal	23.85	23.31	25.77	26.00	25.73	26.58	27.24	0.6%
Metallurgical Coal	0.58	0.40	0.58	0.58	0.55	0.51	0.47	0.6%
Other Coal	21.75	19.31	19.04	20.13	21.65	22.12	22.64	0.6%
Coal-to-Liquids Heat and Power	0.00	0.00	0.10	0.13	0.40	0.77	1.19	- -
Net Coal Coke Imports	0.04	-0.02	0.01	0.01	0.00	-0.00	-0.00	-7.2%
Coal Subtotal	22.38	19.69	19.73	20.85	22.61	23.39	24.30	0.8%
Nuclear Power	8.43	8.35	8.77	9.17	9.17	9.17	9.14	0.3%
Biofuels Heat and Coproducts	0.98	0.66	0.85	1.19	1.90	2.33	2.52	5.3%
Renewable Energy[17]	5.74	5.85	7.49	8.04	8.43	8.76	9.04	1.7%
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Electricity Imports	0.11	0.12	0.11	0.09	0.07	0.04	0.05	-3.4%
Total	**100.14**	**94.79**	**102.02**	**104.92**	**107.95**	**111.03**	**114.19**	**0.7%**
Energy Use and Related Statistics								
Delivered Energy Use	72.63	68.68	75.29	76.96	78.92	81.10	83.45	0.8%
Total Energy Use	100.14	94.79	102.02	104.92	107.95	111.03	114.19	0.7%
Ethanol Consumed in Motor Gasoline and E85	0.77	0.95	1.33	1.70	2.07	2.26	2.37	3.6%
Population (millions)	305.17	307.84	326.16	342.01	358.06	374.08	390.09	0.9%
Gross Domestic Product (billion 2005 dollars)	13229	12881	15336	17421	20020	22731	25692	2.7%
Carbon Dioxide Emissions (million metric tons)	5838.0	5425.5	5679.9	5776.7	5937.8	6107.5	6310.8	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 electricity generation from wind and solar photovoltaic sources.
[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 electricity generation from wind and solar photovoltaic sources.
[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, 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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 population and gross domestic product: IHS Global Insight Industry and Employment models, September 2010. 2008 and 2009 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2009,* DOE/EIA-0573(2009) (Washington, DC, December 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Residential								
Liquefied Petroleum Gases	29.18	24.63	32.51	38.92	44.84	50.56	55.86	3.2%
Distillate Fuel Oil	24.52	18.12	23.07	29.32	34.28	39.05	43.93	3.5%
Natural Gas	13.49	11.88	11.05	13.13	15.65	18.14	21.37	2.3%
Electricity	32.85	33.62	34.72	37.89	41.27	45.25	50.54	1.6%
Commercial								
Liquefied Petroleum Gases	26.45	21.49	28.73	34.72	40.22	45.46	50.23	3.3%
Distillate Fuel Oil	21.61	15.97	21.04	26.98	31.77	36.23	40.72	3.7%
Residual Fuel Oil	15.66	13.45	14.47	18.35	22.55	25.62	28.93	3.0%
Natural Gas	11.88	9.68	9.14	10.81	12.92	14.92	17.52	2.3%
Electricity	30.22	29.51	29.12	32.04	35.25	38.56	43.06	1.5%
Industrial[1]								
Liquefied Petroleum Gases	24.72	20.59	25.45	31.19	36.40	41.18	45.52	3.1%
Distillate Fuel Oil	22.36	16.56	21.12	27.10	32.01	36.45	40.95	3.5%
Residual Fuel Oil	16.11	12.05	16.15	20.11	24.05	26.98	29.88	3.6%
Natural Gas[2]	9.00	5.25	5.42	6.47	8.15	9.54	11.50	3.1%
Metallurgical Coal	4.49	5.43	6.56	7.65	8.54	9.44	10.50	2.6%
Other Industrial Coal	2.90	3.05	3.17	3.55	3.96	4.43	5.01	1.9%
Coal to Liquids	- -	- -	1.96	2.30	2.36	2.87	3.27	- -
Electricity	19.79	19.79	19.30	21.43	23.79	26.45	29.88	1.6%
Transportation								
Liquefied Petroleum Gases[3]	29.95	25.52	33.36	39.83	45.80	51.56	56.90	3.1%
E85[4]	35.03	20.50	28.80	34.79	39.01	43.98	49.35	3.4%
Motor Gasoline[5]	26.81	19.28	28.35	34.01	39.01	43.98	49.31	3.7%
Jet Fuel[6]	23.09	12.59	20.76	26.62	31.16	35.80	40.35	4.6%
Diesel Fuel (distillate fuel oil)[7]	27.71	17.79	24.56	31.04	35.96	40.57	45.30	3.7%
Residual Fuel Oil	14.43	10.57	13.80	17.57	21.19	24.21	26.24	3.6%
Natural Gas[8]	17.04	12.71	13.06	14.80	16.98	19.05	21.66	2.1%
Electricity	34.36	34.92	31.83	33.91	39.01	44.74	51.66	1.5%
Electric Power[9]								
Distillate Fuel Oil	19.38	14.33	18.38	23.89	28.04	32.34	36.45	3.7%
Residual Fuel Oil	14.61	8.96	14.37	17.83	21.50	24.46	26.66	4.3%
Natural Gas	9.02	4.82	5.10	6.05	7.62	9.00	10.86	3.2%
Steam Coal	2.05	2.20	2.31	2.60	2.96	3.36	3.83	2.2%

Table A3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Average Price to All Users[10]								
Liquefied Petroleum Gases	20.51	17.43	23.65	28.84	33.64	38.28	42.49	3.5%
E85[4]	35.03	20.50	28.80	34.79	39.01	43.98	49.35	3.4%
Motor Gasoline[5]	26.63	19.23	28.35	34.00	39.01	43.98	49.31	3.7%
Jet Fuel	23.09	12.59	20.76	26.62	31.16	35.80	40.35	4.6%
Distillate Fuel Oil	26.28	17.51	23.83	30.24	35.20	39.83	44.57	3.7%
Residual Fuel Oil	14.75	10.53	14.27	17.98	21.67	24.66	26.88	3.7%
Natural Gas	10.46	7.28	7.04	8.39	10.33	11.98	14.21	2.6%
Metallurgical Coal	4.49	5.43	6.56	7.65	8.54	9.44	10.50	2.6%
Other Coal	2.10	2.25	2.36	2.66	3.02	3.41	3.89	2.1%
Coal to Liquids	- -	- -	1.96	2.30	2.36	2.87	3.27	- -
Electricity	28.38	28.69	28.43	31.30	34.53	38.17	42.97	1.6%
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)								
Residential	253.79	238.63	243.63	279.35	320.68	367.88	426.84	2.3%
Commercial	190.06	174.64	185.21	221.24	262.27	308.62	368.78	2.9%
Industrial	247.19	179.22	244.72	295.03	341.84	377.94	417.29	3.3%
Transportation	710.71	474.91	725.73	889.64	1022.56	1184.56	1382.69	4.2%
Total Non-Renewable Expenditures	1401.75	1067.41	1399.29	1685.26	1947.34	2239.00	2595.61	3.5%
Transportation Renewable Expenditures	0.04	0.06	0.25	11.06	36.34	51.81	60.53	30.6%
Total Expenditures	**1401.79**	**1067.47**	**1399.54**	**1696.32**	**1983.68**	**2290.81**	**2656.14**	**3.6%**

[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 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2008 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 and 2009 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2009 transportation sector natural gas delivered prices are model results. 2008 and 2009 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2010/09) (Washington, DC, September 2010). 2008 and 2009 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2009 and April 2010, Table 4.2. 2008 and 2009 coal prices based on: EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010) and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. 2008 and 2009 electricity prices: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A3. Energy prices by sector and source (continued)
(2009 dollars per million Btu, unless otherwise noted)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Average Price to All Users[10]								
Liquefied Petroleum Gases	20.51	17.43	23.65	28.84	33.64	38.28	42.49	3.5%
E85[4]	35.03	20.50	28.80	34.79	39.01	43.98	49.35	3.4%
Motor Gasoline[5]	26.63	19.23	28.35	34.00	39.01	43.98	49.31	3.7%
Jet Fuel	23.09	12.59	20.76	26.62	31.16	35.80	40.35	4.6%
Distillate Fuel Oil	26.28	17.51	23.83	30.24	35.20	39.83	44.57	3.7%
Residual Fuel Oil	14.75	10.53	14.27	17.98	21.67	24.66	26.88	3.7%
Natural Gas	10.46	7.28	7.04	8.39	10.33	11.98	14.21	2.6%
Metallurgical Coal	4.49	5.43	6.56	7.65	8.54	9.44	10.50	2.6%
Other Coal	2.10	2.25	2.36	2.66	3.02	3.41	3.89	2.1%
Coal to Liquids	- -	- -	1.96	2.30	2.36	2.87	3.27	- -
Electricity	28.38	28.69	28.43	31.30	34.53	38.17	42.97	1.6%
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)								
Residential	253.79	238.63	243.63	279.35	320.68	367.88	426.84	2.3%
Commercial	190.06	174.64	185.21	221.24	262.27	308.62	368.78	2.9%
Industrial	247.19	179.22	244.72	295.03	341.84	377.94	417.29	3.3%
Transportation	710.71	474.91	725.73	889.64	1022.56	1184.56	1382.69	4.2%
Total Non-Renewable Expenditures	1401.75	1067.41	1399.29	1685.26	1947.34	2239.00	2595.61	3.5%
Transportation Renewable Expenditures	0.04	0.06	0.25	11.06	36.34	51.81	60.53	30.6%
Total Expenditures	**1401.79**	**1067.47**	**1399.54**	**1696.32**	**1983.68**	**2290.81**	**2656.14**	**3.6%**

[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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2008 residential and commercial natural gas delivered prices: EIA,*Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 and 2009 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 transportation sector natural gas delivered prices are based on: EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and estimated State taxes, Federal taxes, and dispensing costs or charges. 2009 transportation sector natural gas delivered prices are model results. 2008 and 2009 electric power sector distillate and residual fuel oil prices: EIA, *Monthly Energy Review*, DOE/EIA-0035(2010/09) (Washington, DC, September 2010). 2008 and 2009 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2009 and April 2010, Table 4.2. 2008 and 2009 coal prices based on: EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010) and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. 2008 and 2009 electricity prices: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A4. Residential sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Key Indicators								
Households (millions)								
Single-Family	80.95	81.48	87.91	92.69	97.10	101.16	104.70	1.0%
Multifamily	25.12	25.32	26.87	28.65	30.69	32.77	34.81	1.2%
Mobile Homes	6.69	6.63	6.53	6.78	7.04	7.25	7.39	0.4%
Total	**112.76**	**113.43**	**121.32**	**128.12**	**134.83**	**141.18**	**146.90**	**1.0%**
Average House Square Footage	**1656**	**1669**	**1765**	**1831**	**1888**	**1938**	**1981**	**0.7%**
Energy Intensity								
(million Btu per household)								
Delivered Energy Consumption	100.8	98.0	90.8	87.0	83.9	81.7	79.7	-0.8%
Total Energy Consumption	191.0	185.8	168.8	163.5	159.9	157.3	155.0	-0.7%
(thousand Btu per square foot)								
Delivered Energy Consumption	60.9	58.7	51.5	47.5	44.5	42.1	40.2	-1.4%
Total Energy Consumption	115.3	111.3	95.6	89.3	84.7	81.2	78.2	-1.3%
Delivered Energy Consumption by Fuel								
Electricity								
Space Heating	0.28	0.28	0.28	0.30	0.30	0.31	0.31	0.4%
Space Cooling	0.87	0.83	0.82	0.86	0.90	0.95	0.99	0.7%
Water Heating	0.43	0.43	0.47	0.49	0.50	0.49	0.48	0.4%
Refrigeration	0.37	0.37	0.35	0.35	0.35	0.36	0.38	0.1%
Cooking	0.10	0.11	0.12	0.12	0.13	0.14	0.15	1.3%
Clothes Dryers	0.19	0.19	0.18	0.18	0.18	0.19	0.20	0.3%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.4%
Lighting	0.72	0.71	0.57	0.54	0.52	0.53	0.54	-1.0%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.4%
Dishwashers[1]	0.09	0.09	0.09	0.09	0.10	0.11	0.11	0.8%
Color Televisions and Set-Top Boxes	0.33	0.34	0.33	0.34	0.36	0.39	0.42	0.8%
Personal Computers and Related Equipment	0.17	0.18	0.17	0.17	0.18	0.19	0.19	0.3%
Furnace Fans and Boiler Circulation Pumps	0.14	0.14	0.15	0.17	0.18	0.19	0.20	1.3%
Other Uses[2]	0.89	0.88	0.95	1.05	1.17	1.30	1.42	1.9%
Delivered Energy	**4.71**	**4.65**	**4.60**	**4.75**	**4.98**	**5.25**	**5.51**	**0.7%**
Natural Gas								
Space Heating	3.40	3.28	3.28	3.30	3.29	3.29	3.28	0.0%
Space Cooling	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Water Heating	1.33	1.33	1.38	1.40	1.39	1.37	1.33	-0.0%
Cooking	0.22	0.22	0.22	0.23	0.23	0.24	0.24	0.5%
Clothes Dryers	0.05	0.05	0.05	0.05	0.05	0.06	0.06	0.3%
Delivered Energy	**5.00**	**4.87**	**4.94**	**4.98**	**4.96**	**4.95**	**4.90**	**0.0%**
Distillate Fuel Oil								
Space Heating	0.56	0.50	0.48	0.43	0.39	0.36	0.33	-1.7%
Water Heating	0.11	0.10	0.08	0.06	0.05	0.05	0.04	-3.4%
Delivered Energy	**0.66**	**0.61**	**0.56**	**0.50**	**0.44**	**0.40**	**0.37**	**-1.9%**
Liquefied Petroleum Gases								
Space Heating	0.26	0.26	0.23	0.22	0.21	0.20	0.19	-1.1%
Water Heating	0.09	0.08	0.06	0.05	0.04	0.04	0.03	-3.5%
Cooking	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.7%
Other Uses[3]	0.14	0.16	0.17	0.18	0.20	0.21	0.23	1.5%
Delivered Energy	**0.52**	**0.53**	**0.49**	**0.48**	**0.48**	**0.48**	**0.48**	**-0.4%**
Marketed Renewables (wood)[4]	0.44	0.43	0.40	0.42	0.42	0.42	0.42	-0.1%
Other Fuels[5]	0.03	0.03	0.03	0.03	0.02	0.02	0.02	-1.4%

Table A4. Residential sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Delivered Energy Consumption by End Use								
Space Heating	4.97	4.78	4.71	4.69	4.64	4.61	4.55	-0.2%
Space Cooling	0.87	0.83	0.82	0.86	0.90	0.95	0.99	0.7%
Water Heating	1.96	1.95	1.99	2.00	1.99	1.94	1.88	-0.1%
Refrigeration	0.37	0.37	0.35	0.35	0.35	0.36	0.38	0.1%
Cooking	0.35	0.35	0.36	0.38	0.39	0.40	0.41	0.6%
Clothes Dryers	0.24	0.24	0.24	0.23	0.24	0.25	0.26	0.3%
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.4%
Lighting	0.72	0.71	0.57	0.54	0.52	0.53	0.54	-1.0%
Clothes Washers[1]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	-0.4%
Dishwashers[1]	0.09	0.09	0.09	0.09	0.10	0.11	0.11	0.8%
Color Televisions and Set-Top Boxes	0.33	0.34	0.33	0.34	0.36	0.39	0.42	0.8%
Personal Computers and Related Equipment	0.17	0.18	0.17	0.17	0.18	0.19	0.19	0.3%
Furnace Fans and Boiler Circulation Pumps	0.14	0.14	0.15	0.17	0.18	0.19	0.20	1.3%
Other Uses[6]	1.03	1.03	1.12	1.23	1.37	1.51	1.65	1.8%
Delivered Energy	**11.36**	**11.12**	**11.02**	**11.15**	**11.32**	**11.53**	**11.70**	**0.2%**
Electricity Related Losses	**10.17**	**9.96**	**9.46**	**9.80**	**10.24**	**10.67**	**11.06**	**0.4%**
Total Energy Consumption by End Use								
Space Heating	5.59	5.39	5.30	5.30	5.26	5.23	5.18	-0.2%
Space Cooling	2.75	2.62	2.52	2.62	2.75	2.88	2.99	0.5%
Water Heating	2.89	2.88	2.96	3.01	3.01	2.94	2.84	-0.1%
Refrigeration	1.18	1.15	1.08	1.06	1.07	1.10	1.15	-0.0%
Cooking	0.58	0.58	0.60	0.63	0.66	0.69	0.71	0.8%
Clothes Dryers	0.65	0.64	0.62	0.60	0.61	0.63	0.66	0.1%
Freezers	0.25	0.25	0.24	0.25	0.25	0.26	0.26	0.2%
Lighting	2.28	2.23	1.74	1.64	1.59	1.60	1.63	-1.2%
Clothes Washers[1]	0.11	0.10	0.09	0.08	0.08	0.09	0.09	-0.6%
Dishwashers[1]	0.29	0.29	0.28	0.28	0.30	0.32	0.34	0.7%
Color Televisions and Set-Top Boxes	1.05	1.05	1.01	1.03	1.10	1.17	1.25	0.7%
Personal Computers and Related Equipment	0.55	0.56	0.52	0.53	0.54	0.56	0.58	0.2%
Furnace Fans and Boiler Circulation Pumps	0.43	0.44	0.47	0.51	0.55	0.58	0.59	1.1%
Other Uses[6]	2.94	2.91	3.06	3.40	3.78	4.16	4.50	1.7%
Total	**21.53**	**21.08**	**20.48**	**20.95**	**21.56**	**22.20**	**22.76**	**0.3%**
Nonmarketed Renewables[7]								
Geothermal Heat Pumps	0.00	0.01	0.02	0.03	0.04	0.04	0.05	8.7%
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.0%
Solar Photovoltaic	0.00	0.00	0.04	0.04	0.04	0.05	0.05	9.7%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	11.1%
Total	**0.01**	**0.01**	**0.07**	**0.09**	**0.09**	**0.10**	**0.11**	**8.3%**

[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 2005*.
[5]Includes kerosene and coal.
[6]Includes all other uses listed above.
[7]Represents delivered energy displaced.
Btu = British thermal unit.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A5. Commercial sector key indicators and consumption
(quadrillion Btu per year, unless otherwise noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Key Indicators								
Total Floorspace (billion square feet)								
Surviving	76.4	77.9	83.4	89.3	95.1	101.1	107.3	1.2%
New Additions	2.4	2.3	2.0	2.2	2.3	2.4	2.5	0.4%
Total	**78.8**	**80.2**	**85.4**	**91.5**	**97.4**	**103.5**	**109.8**	**1.2%**
Energy Consumption Intensity (thousand Btu per square foot)								
Delivered Energy Consumption	109.1	105.9	105.6	103.9	102.1	101.3	100.7	-0.2%
Electricity Related Losses	125.0	120.6	116.3	117.3	117.8	118.0	117.8	-0.1%
Total Energy Consumption	234.1	226.4	221.8	221.2	219.9	219.2	218.4	-0.1%
Delivered Energy Consumption by Fuel								
Purchased Electricity								
Space Heating[1]	0.18	0.18	0.17	0.17	0.17	0.17	0.18	-0.0%
Space Cooling[1]	0.49	0.47	0.53	0.54	0.56	0.59	0.61	1.0%
Water Heating[1]	0.09	0.09	0.09	0.09	0.09	0.10	0.09	0.1%
Ventilation	0.50	0.50	0.56	0.60	0.64	0.68	0.71	1.4%
Cooking	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.0%
Lighting	1.04	1.03	1.04	1.09	1.14	1.20	1.25	0.7%
Refrigeration	0.40	0.40	0.36	0.36	0.36	0.37	0.39	-0.1%
Office Equipment (PC)	0.22	0.22	0.19	0.19	0.19	0.21	0.21	-0.1%
Office Equipment (non-PC)	0.24	0.25	0.32	0.37	0.40	0.44	0.47	2.5%
Other Uses[2]	1.37	1.35	1.55	1.77	1.99	2.23	2.49	2.4%
Delivered Energy	**4.56**	**4.51**	**4.83**	**5.21**	**5.58**	**6.01**	**6.43**	**1.4%**
Natural Gas								
Space Heating[1]	1.56	1.61	1.72	1.76	1.76	1.77	1.77	0.4%
Space Cooling[1]	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.6%
Water Heating[1]	0.44	0.45	0.51	0.56	0.58	0.62	0.64	1.4%
Cooking	0.17	0.17	0.20	0.21	0.22	0.23	0.25	1.4%
Other Uses[3]	1.02	0.94	1.00	1.02	1.05	1.12	1.23	1.0%
Delivered Energy	**3.22**	**3.20**	**3.47**	**3.59**	**3.66**	**3.78**	**3.92**	**0.8%**
Distillate Fuel Oil								
Space Heating[1]	0.15	0.16	0.13	0.12	0.11	0.11	0.10	-1.6%
Water Heating[1]	0.02	0.02	0.02	0.02	0.02	0.02	0.02	-0.3%
Other Uses[4]	0.20	0.16	0.13	0.13	0.13	0.13	0.13	-1.0%
Delivered Energy	**0.37**	**0.34**	**0.28**	**0.27**	**0.26**	**0.25**	**0.25**	**-1.2%**
Marketed Renewables (biomass)	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.0%
Other Fuels[5]	0.34	0.33	0.33	0.33	0.34	0.34	0.35	0.2%
Delivered Energy Consumption by End Use								
Space Heating[1]	1.89	1.94	2.02	2.05	2.04	2.05	2.05	0.2%
Space Cooling[1]	0.52	0.51	0.56	0.58	0.60	0.62	0.65	1.0%
Water Heating[1]	0.55	0.56	0.63	0.67	0.70	0.73	0.75	1.1%
Ventilation	0.50	0.50	0.56	0.60	0.64	0.68	0.71	1.4%
Cooking	0.19	0.20	0.22	0.24	0.25	0.26	0.27	1.2%
Lighting	1.04	1.03	1.04	1.09	1.14	1.20	1.25	0.7%
Refrigeration	0.40	0.40	0.36	0.36	0.36	0.37	0.39	-0.1%
Office Equipment (PC)	0.22	0.22	0.19	0.19	0.19	0.21	0.21	-0.1%
Office Equipment (non-PC)	0.24	0.25	0.32	0.37	0.40	0.44	0.47	2.5%
Other Uses[6]	3.04	2.89	3.12	3.36	3.62	3.93	4.31	1.6%
Delivered Energy	**8.60**	**8.49**	**9.02**	**9.50**	**9.94**	**10.49**	**11.05**	**1.0%**

Table A5. Commercial sector key indicators and consumption (continued)
(quadrillion Btu per year, unless otherwise noted)

Key Indicators and Consumption	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Electricity Related Losses	**9.85**	**9.66**	**9.94**	**10.73**	**11.47**	**12.21**	**12.93**	**1.1%**
Total Energy Consumption by End Use								
Space Heating[1]	2.28	2.32	2.37	2.41	2.40	2.41	2.40	0.1%
Space Cooling[1]	1.58	1.52	1.65	1.70	1.76	1.82	1.89	0.8%
Water Heating[1]	0.75	0.76	0.82	0.86	0.89	0.92	0.94	0.8%
Ventilation	1.57	1.58	1.70	1.84	1.96	2.06	2.15	1.2%
Cooking	0.24	0.25	0.27	0.28	0.29	0.30	0.32	1.0%
Lighting	3.29	3.24	3.18	3.34	3.49	3.63	3.75	0.6%
Refrigeration	1.28	1.25	1.11	1.09	1.10	1.13	1.17	-0.3%
Office Equipment (PC)	0.70	0.68	0.58	0.58	0.60	0.62	0.64	-0.2%
Office Equipment (non-PC)	0.75	0.78	0.97	1.12	1.23	1.34	1.41	2.3%
Other Uses[6]	6.00	5.77	6.32	7.00	7.70	8.47	9.32	1.9%
Total	**18.44**	**18.15**	**18.96**	**20.24**	**21.41**	**22.70**	**23.98**	**1.1%**
Nonmarketed Renewable Fuels[7]								
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.6%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	3.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8%
Total	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**1.3%**

[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 gases, 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 delivered 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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A6. Industrial sector key indicators and consumption

Key Indicators and Consumption	Reference Case 2008	2009	2015	2020	2025	2030	2035	Annual Growth 2009-2035 (percent)
Key Indicators								
Value of Shipments (billion 2005 dollars)								
Manufacturing	4680	4197	5279	5643	6016	6393	6770	1.9%
Nonmanufacturing	2039	1821	2193	2308	2381	2433	2521	1.3%
Total	**6720**	**6017**	**7472**	**7951**	**8396**	**8826**	**9292**	**1.7%**
Energy Prices								
(2009 dollars per million Btu)								
Liquefied Petroleum Gases	24.95	20.59	23.31	25.82	27.52	28.41	28.52	1.3%
Motor Gasoline	16.48	16.59	25.95	28.10	29.48	30.32	30.89	2.4%
Distillate Fuel Oil	22.57	16.56	19.34	22.43	24.20	25.14	25.66	1.7%
Residual Fuel Oil	16.26	12.05	14.80	16.65	18.19	18.61	18.73	1.7%
Asphalt and Road Oil	8.35	6.52	7.40	8.40	9.04	9.24	9.14	1.3%
Natural Gas Heat and Power	8.17	4.48	4.17	4.60	5.45	5.93	6.60	1.5%
Natural Gas Feedstocks	9.86	6.03	5.74	6.14	6.93	7.33	7.95	1.1%
Metallurgical Coal	4.53	5.43	6.01	6.33	6.46	6.51	6.58	0.7%
Other Industrial Coal	2.93	3.05	2.91	2.94	2.99	3.05	3.14	0.1%
Coal for Liquids	- -	- -	1.79	1.91	1.78	1.98	2.05	- -
Electricity	19.97	19.79	17.68	17.74	17.99	18.25	18.73	-0.2%
(nominal dollars per million Btu)								
Liquefied Petroleum Gases	24.72	20.59	25.45	31.19	36.40	41.18	45.52	3.1%
Motor Gasoline	16.33	16.59	28.33	33.95	38.99	43.96	49.30	4.3%
Distillate Fuel Oil	22.36	16.56	21.12	27.10	32.01	36.45	40.95	3.5%
Residual Fuel Oil	16.11	12.05	16.15	20.11	24.05	26.98	29.88	3.6%
Asphalt and Road Oil	8.27	6.52	8.08	10.15	11.96	13.39	14.59	3.1%
Natural Gas Heat and Power	8.10	4.48	4.55	5.56	7.21	8.60	10.53	3.3%
Natural Gas Feedstocks	9.77	6.03	6.27	7.42	9.16	10.62	12.68	2.9%
Metallurgical Coal	4.49	5.43	6.56	7.65	8.54	9.44	10.50	2.6%
Other Industrial Coal	2.90	3.05	3.17	3.55	3.96	4.43	5.01	1.9%
Coal for Liquids	- -	- -	1.96	2.30	2.36	2.87	3.27	- -
Electricity	19.79	19.79	19.30	21.43	23.79	26.45	29.88	1.6%
Energy Consumption (quadrillion Btu)[1]								
Industrial Consumption Excluding Refining								
Liquefied Petroleum Gases Heat and Power	0.23	0.21	0.25	0.25	0.25	0.24	0.24	0.5%
Liquefied Petroleum Gases Feedstocks	1.85	1.79	2.07	2.10	2.09	2.00	1.90	0.2%
Motor Gasoline	0.25	0.25	0.33	0.33	0.33	0.32	0.32	1.0%
Distillate Fuel Oil	1.26	1.16	1.16	1.16	1.16	1.14	1.13	-0.1%
Residual Fuel Oil	0.19	0.16	0.17	0.17	0.17	0.16	0.16	-0.1%
Petrochemical Feedstocks	1.12	0.90	1.29	1.33	1.34	1.30	1.26	1.3%
Petroleum Coke	0.35	0.28	0.22	0.21	0.21	0.21	0.20	-1.3%
Asphalt and Road Oil	1.01	0.87	1.08	1.05	1.01	0.96	0.94	0.3%
Miscellaneous Petroleum[2]	0.48	0.27	0.36	0.35	0.35	0.33	0.31	0.6%
Petroleum Subtotal	6.74	5.88	6.93	6.96	6.90	6.66	6.46	0.4%
Natural Gas Heat and Power	4.99	4.43	6.24	6.34	6.30	6.29	6.29	1.4%
Natural Gas Feedstocks	0.59	0.55	0.61	0.60	0.56	0.51	0.47	-0.6%
Lease and Plant Fuel[3]	1.26	1.19	1.24	1.24	1.22	1.24	1.28	0.3%
Natural Gas Subtotal	6.84	6.16	8.09	8.18	8.08	8.03	8.04	1.0%
Metallurgical Coal and Coke[4]	0.62	0.38	0.59	0.58	0.56	0.51	0.47	0.8%
Other Industrial Coal	1.10	0.88	0.92	0.92	0.91	0.90	0.88	0.0%
Coal Subtotal	1.72	1.26	1.51	1.50	1.47	1.41	1.35	0.3%
Renewables[5]	1.52	1.42	1.89	1.98	2.05	2.06	2.04	1.4%
Purchased Electricity	3.27	2.82	3.37	3.39	3.34	3.22	3.09	0.3%
Delivered Energy	**20.09**	**17.55**	**21.79**	**22.01**	**21.84**	**21.38**	**20.98**	**0.7%**
Electricity Related Losses	7.06	6.04	6.93	6.99	6.86	6.54	6.20	0.1%
Total	**27.15**	**23.59**	**28.73**	**29.00**	**28.70**	**27.92**	**27.19**	**0.5%**

Table A6. Industrial sector key indicators and consumption (continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Refining Consumption								
Liquefied Petroleum Gases Heat and Power	0.01	0.01	0.04	0.04	0.04	0.05	0.05	6.0%
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	0.00	0.00	0.00	0.00	- -
Petroleum Coke	0.51	0.52	0.59	0.55	0.55	0.57	0.58	0.4%
Still Gas	1.60	1.50	1.70	1.63	1.64	1.68	1.82	0.7%
Miscellaneous Petroleum[2]	0.02	0.02	0.02	0.02	0.02	0.02	0.03	1.5%
Petroleum Subtotal	2.16	2.05	2.36	2.25	2.26	2.32	2.47	0.7%
Natural Gas Heat and Power	1.25	1.34	1.42	1.52	1.46	1.50	1.47	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 Subtotal	1.25	1.34	1.42	1.52	1.46	1.50	1.47	0.4%
Other Industrial Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.0%
Coal-to-Liquids Heat and Power	0.00	0.00	0.10	0.13	0.40	0.77	1.19	32.7%
Coal Subtotal	0.06	0.06	0.16	0.19	0.46	0.83	1.25	12.4%
Biofuels Heat and Coproducts	0.98	0.66	0.85	1.19	1.90	2.33	2.52	5.3%
Purchased Electricity	0.17	0.19	0.17	0.18	0.18	0.19	0.19	0.2%
Delivered Energy	**4.63**	**4.30**	**4.96**	**5.33**	**6.26**	**7.16**	**7.91**	**2.4%**
Electricity Related Losses	0.38	0.40	0.35	0.37	0.37	0.38	0.39	-0.1%
Total	**5.00**	**4.69**	**5.30**	**5.70**	**6.63**	**7.54**	**8.30**	**2.2%**
Total Industrial Sector Consumption								
Liquefied Petroleum Gases Heat and Power	0.24	0.22	0.30	0.29	0.29	0.29	0.28	1.1%
Liquefied Petroleum Gases Feedstocks	1.85	1.79	2.07	2.10	2.09	2.00	1.90	0.2%
Motor Gasoline	0.25	0.25	0.33	0.33	0.33	0.32	0.32	1.0%
Distillate Fuel Oil	1.27	1.16	1.16	1.16	1.16	1.14	1.13	-0.1%
Residual Fuel Oil	0.20	0.17	0.17	0.17	0.17	0.16	0.16	-0.3%
Petrochemical Feedstocks	1.12	0.90	1.29	1.33	1.34	1.30	1.26	1.3%
Petroleum Coke	0.87	0.80	0.81	0.77	0.76	0.78	0.78	-0.1%
Asphalt and Road Oil	1.01	0.87	1.08	1.05	1.01	0.96	0.94	0.3%
Still Gas	1.60	1.50	1.70	1.63	1.64	1.68	1.82	0.7%
Miscellaneous Petroleum[2]	0.50	0.28	0.38	0.37	0.37	0.35	0.34	0.7%
Petroleum Subtotal	8.91	7.94	9.29	9.20	9.16	8.98	8.94	0.5%
Natural Gas Heat and Power	6.24	5.76	7.66	7.86	7.76	7.79	7.76	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 Feedstocks	0.59	0.55	0.61	0.60	0.56	0.51	0.47	-0.6%
Lease and Plant Fuel[3]	1.26	1.19	1.24	1.24	1.22	1.24	1.28	0.3%
Natural Gas Subtotal	8.09	7.50	9.51	9.70	9.54	9.53	9.51	0.9%
Metallurgical Coal and Coke[4]	0.62	0.38	0.59	0.58	0.56	0.51	0.47	0.8%
Other Industrial Coal	1.16	0.94	0.98	0.98	0.97	0.96	0.94	0.0%
Coal-to-Liquids Heat and Power	0.00	0.00	0.10	0.13	0.40	0.77	1.19	32.7%
Coal Subtotal	1.78	1.32	1.67	1.69	1.93	2.24	2.60	2.6%
Biofuels Heat and Coproducts	0.98	0.66	0.85	1.19	1.90	2.33	2.52	5.3%
Renewables[5]	1.52	1.42	1.89	1.98	2.05	2.06	2.04	1.4%
Purchased Electricity	3.44	3.01	3.54	3.57	3.52	3.40	3.28	0.3%
Delivered Energy	**24.72**	**21.85**	**26.75**	**27.34**	**28.11**	**28.54**	**28.89**	**1.1%**
Electricity Related Losses	7.44	6.44	7.28	7.36	7.23	6.92	6.59	0.1%
Total	**32.16**	**28.29**	**34.03**	**34.70**	**35.33**	**35.46**	**35.49**	**0.9%**

Table A6. Industrial sector key indicators and consumption (continued)

Key Indicators and Consumption	Reference Case 2008	2009	2015	2020	2025	2030	2035	Annual Growth 2009-2035 (percent)
Energy Consumption per dollar of Shipment (thousand Btu per 2005 dollars)								
Liquefied Petroleum Gases Heat and Power	0.04	0.04	0.04	0.04	0.03	0.03	0.03	-0.6%
Liquefied Petroleum Gases Feedstocks	0.27	0.30	0.28	0.26	0.25	0.23	0.20	-1.4%
Motor Gasoline	0.04	0.04	0.04	0.04	0.04	0.04	0.03	-0.7%
Distillate Fuel Oil	0.19	0.19	0.15	0.15	0.14	0.13	0.12	-1.8%
Residual Fuel Oil	0.03	0.03	0.02	0.02	0.02	0.02	0.02	-1.9%
Petrochemical Feedstocks	0.17	0.15	0.17	0.17	0.16	0.15	0.14	-0.4%
Petroleum Coke	0.13	0.13	0.11	0.10	0.09	0.09	0.08	-1.7%
Asphalt and Road Oil	0.15	0.14	0.14	0.13	0.12	0.11	0.10	-1.3%
Still Gas	0.24	0.25	0.23	0.21	0.20	0.19	0.20	-0.9%
Miscellaneous Petroleum[2]	0.07	0.05	0.05	0.05	0.04	0.04	0.04	-1.0%
Petroleum Subtotal	1.33	1.32	1.24	1.16	1.09	1.02	0.96	-1.2%
Natural Gas Heat and Power	0.93	0.96	1.03	0.99	0.92	0.88	0.84	-0.5%
Natural-Gas-to-Liquids Heat and Power	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Natural Gas Feedstocks	0.09	0.09	0.08	0.08	0.07	0.06	0.05	-2.2%
Lease and Plant Fuel[3]	0.19	0.20	0.17	0.16	0.15	0.14	0.14	-1.4%
Natural Gas Subtotal	1.20	1.25	1.27	1.22	1.14	1.08	1.02	-0.8%
Metallurgical Coal and Coke[4]	0.09	0.06	0.08	0.07	0.07	0.06	0.05	-0.9%
Other Industrial Coal	0.17	0.16	0.13	0.12	0.12	0.11	0.10	-1.7%
Coal-to-Liquids Heat and Power	0.00	0.00	0.01	0.02	0.05	0.09	0.13	30.5%
Coal Subtotal	0.27	0.22	0.22	0.21	0.23	0.25	0.28	0.9%
Biofuels Heat and Coproducts	0.15	0.11	0.11	0.15	0.23	0.26	0.27	3.6%
Renewables[5]	0.23	0.24	0.25	0.25	0.24	0.23	0.22	-0.3%
Purchased Electricity	0.51	0.50	0.47	0.45	0.42	0.39	0.35	-1.3%
Delivered Energy	**3.68**	**3.63**	**3.58**	**3.44**	**3.35**	**3.23**	**3.11**	**-0.6%**
Electricity Related Losses	1.11	1.07	0.97	0.93	0.86	0.78	0.71	-1.6%
Total	**4.79**	**4.70**	**4.55**	**4.36**	**4.21**	**4.02**	**3.82**	**-0.8%**
Industrial Combined Heat and Power								
Capacity (gigawatts)	25.73	27.99	38.78	43.54	54.01	63.20	71.40	3.7%
Generation (billion kilowatthours)	135.57	152.63	227.87	263.44	344.91	413.49	475.49	4.5%

[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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 prices for motor gasoline and distillate fuel oil are based on: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2008 and 2009 petrochemical feedstock and asphalt and road oil prices are based on: EIA, *State Energy Data Report 2008*, DOE/EIA-0214(2008) (Washington, DC, June 2010). 2008 and 2009 coal prices are based on: EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010) and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. 2008 and 2009 electricity prices: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 natural gas prices are based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 refining consumption values are based on: *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). 2009 refining consumption based on: *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). Other 2008 and 2009 consumption values are based on: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 shipments: IHS Global Insight Industry model, September 2010. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A7. Transportation sector key indicators and delivered energy consumption

Key Indicators and Consumption	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Key Indicators								
Travel Indicators								
(billion vehicle miles traveled)								
Light-Duty Vehicles less than 8,500 pounds	2690	2707	2947	3199	3467	3755	4043	1.6%
Commercial Light Trucks[1]	72	67	81	86	92	98	104	1.7%
Freight Trucks greater than 10,000 pounds	228	207	250	269	291	313	335	1.9%
(billion seat miles available)								
Air	1014	960	1059	1122	1180	1234	1282	1.1%
(billion ton miles traveled)								
Rail	1777	1677	1886	2025	2143	2255	2328	1.3%
Domestic Shipping	521	486	521	544	559	577	596	0.8%
Energy Efficiency Indicators								
(miles per gallon)								
New Light-Duty Vehicle CAFE Standard[2]	25.2	25.4	32.6	35.4	35.6	35.8	35.9	1.3%
New Car[2]	28.4	28.4	37.9	40.4	40.4	40.4	40.4	1.4%
New Light Truck[2]	22.4	23.0	28.0	29.7	29.7	29.7	29.7	1.0%
Compliance New Light-Duty Vehicle[3]	28.0	29.1	32.5	35.8	36.6	37.2	37.8	1.0%
New Car[3]	32.5	33.7	37.8	40.7	41.2	41.6	42.0	0.9%
New Light Truck[3]	24.2	25.5	27.8	30.3	30.8	31.3	31.8	0.9%
Tested New Light-Duty Vehicle[4]	28.0	28.0	31.3	34.5	35.3	36.0	36.5	1.0%
New Car[4]	32.5	32.7	36.5	39.4	40.0	40.4	40.8	0.9%
New Light Truck[4]	24.2	24.3	26.6	29.1	29.6	30.1	30.6	0.9%
On-Road New Light-Duty Vehicle[5]	23.2	23.2	26.0	28.8	29.5	30.2	30.6	1.1%
New Car[5]	26.5	26.7	30.1	32.6	33.3	33.8	34.2	1.0%
New Light Truck[5]	20.3	20.4	22.3	24.4	24.8	25.3	25.7	0.9%
Light-Duty Stock[6]	20.8	20.8	22.1	23.9	25.7	27.0	27.9	1.1%
New Commercial Light Truck[1]	15.4	15.6	16.4	17.7	17.9	18.0	18.1	0.6%
Stock Commercial Light Truck[1]	14.3	14.4	15.2	16.3	17.2	17.7	18.0	0.9%
Freight Truck	6.1	6.1	6.1	6.2	6.4	6.5	6.6	0.3%
(seat miles per gallon)								
Aircraft	61.8	62.0	62.8	64.1	65.6	67.5	69.9	0.5%
(ton miles per thousand Btu)								
Rail	3.3	3.3	3.3	3.3	3.3	3.4	3.4	0.1%
Domestic Shipping	2.4	2.4	2.4	2.5	2.5	2.5	2.5	0.2%
Energy Use by Mode								
(quadrillion Btu)								
Light-Duty Vehicles	16.14	16.13	16.36	16.29	16.40	16.89	17.66	0.3%
Commercial Light Trucks[1]	0.63	0.58	0.66	0.66	0.67	0.69	0.73	0.8%
Bus Transportation	0.27	0.27	0.28	0.29	0.30	0.32	0.33	0.8%
Freight Trucks	4.70	4.26	5.11	5.43	5.73	6.02	6.35	1.5%
Rail, Passenger	0.05	0.05	0.05	0.06	0.06	0.06	0.07	1.1%
Rail, Freight	0.58	0.51	0.57	0.61	0.64	0.67	0.69	1.2%
Shipping, Domestic	0.23	0.20	0.22	0.22	0.23	0.23	0.24	0.6%
Shipping, International	0.90	0.78	0.78	0.79	0.79	0.80	0.80	0.1%
Recreational Boats	0.25	0.26	0.27	0.28	0.29	0.30	0.31	0.6%
Air	2.70	2.66	2.71	2.84	2.95	3.03	3.07	0.6%
Military Use	0.71	0.75	0.69	0.70	0.72	0.74	0.76	0.0%
Lubricants	0.14	0.13	0.12	0.12	0.13	0.13	0.13	0.1%
Pipeline Fuel	0.67	0.65	0.67	0.65	0.64	0.65	0.67	0.1%
Total	**27.95**	**27.23**	**28.50**	**28.96**	**29.55**	**30.54**	**31.80**	**0.6%**

Table A7. Transportation sector key indicators and delivered energy consumption (continued)

Key Indicators and Consumption	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Energy Use by Mode (million barrels per day oil equivalent)								
Light-Duty Vehicles	8.55	8.62	8.83	8.90	9.10	9.41	9.83	0.5%
Commercial Light Trucks[1]	0.32	0.30	0.34	0.34	0.34	0.36	0.37	0.9%
Bus Transportation	0.13	0.13	0.14	0.14	0.15	0.15	0.16	0.8%
Freight Trucks	2.26	2.05	2.46	2.61	2.75	2.90	3.05	1.5%
Rail, Passenger	0.02	0.02	0.03	0.03	0.03	0.03	0.03	1.1%
Rail, Freight	0.27	0.24	0.27	0.29	0.31	0.32	0.33	1.2%
Shipping, Domestic	0.11	0.09	0.10	0.10	0.11	0.11	0.11	0.6%
Shipping, International	0.39	0.34	0.34	0.35	0.35	0.35	0.35	0.1%
Recreational Boats	0.13	0.14	0.15	0.15	0.16	0.16	0.17	0.7%
Air	1.31	1.29	1.31	1.38	1.43	1.47	1.49	0.6%
Military Use	0.34	0.36	0.33	0.34	0.34	0.35	0.36	0.1%
Lubricants	0.07	0.06	0.06	0.06	0.06	0.06	0.06	0.1%
Pipeline Fuel	0.31	0.31	0.31	0.31	0.30	0.31	0.32	0.1%
Total	**14.22**	**13.95**	**14.67**	**15.00**	**15.42**	**15.98**	**16.64**	**0.7%**

[1]Commercial trucks 8,500 to 10,000 pounds.
[2]CAFE standard based on projected new vehicle sales.
[3]Includes CAFE credits for alternative fueled vehicle sales, but does not include banked credits used for compliance.
[4]Environmental Protection Agency rated miles per gallon.
[5]Tested new vehicle efficiency revised for on-road performance.
[6]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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010); EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010); Federal Highway Administration, *Highway Statistics 2008* (Washington, DC, April 2010); Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 29 and Annual* (Oak Ridge, TN, 2010); National Highway Traffic and Safety Administration, *Summary of Fuel Economy Performance* (Washington, DC, December 9, 2009); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); EIA, Alternatives to Traditional Transportation Fuels 2008 (Part II - User and Fuel Data), April 2010; EIA, *State Energy Data Report 2008*, DOE/EIA-0214(2008) (Washington, DC, June 2010); U.S. Department of Transportation, Research and Special Programs Administration, *Air Carrier Statistics Monthly, December 2009/2008* (Washington, DC, December ; EIA, *Fuel Oil and Kerosene Sales 2008*, DOE/EIA-0535(2008) (Washington, DC, December 2009); and United States Department of Defense, Defense Fuel Supply Center, Fact Book (January, 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A8. Electricity supply, disposition, prices, and emissions
(billion kilowatthours, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Generation by Fuel Type								
Electric Power Sector[1]								
Power Only[2]								
Coal	1932	1719	1746	1849	1987	2028	2076	0.7%
Petroleum	39	32	37	39	39	40	41	1.0%
Natural Gas[3]	683	722	729	716	701	817	921	0.9%
Nuclear Power	806	799	839	877	877	877	874	0.3%
Pumped Storage/Other[4]	0	2	-0	-0	-0	-0	-0	- -
Renewable Sources[5]	347	380	491	521	541	554	569	1.6%
Distributed Generation (Natural Gas)	0	0	1	2	3	4	5	- -
Total	**3807**	**3653**	**3843**	**4004**	**4148**	**4319**	**4485**	**0.8%**
Combined Heat and Power[6]								
Coal	37	30	23	26	29	30	31	0.1%
Petroleum	4	4	0	0	0	0	0	-9.1%
Natural Gas	119	119	129	125	119	120	113	-0.2%
Renewable Sources	4	4	3	4	4	3	3	-1.0%
Total	**167**	**161**	**155**	**155**	**153**	**153**	**148**	**-0.3%**
Total Net Generation	**3974**	**3814**	**3998**	**4158**	**4300**	**4472**	**4633**	**0.8%**
Less Direct Use	35	35	33	33	33	33	33	-0.2%
Net Available to the Grid	**3939**	**3779**	**3965**	**4125**	**4267**	**4439**	**4600**	**0.8%**
End-Use Generation[7]								
Coal	19	23	30	32	52	79	111	6.3%
Petroleum	3	5	5	5	5	5	5	-0.3%
Natural Gas	80	90	141	160	180	211	250	4.0%
Other Gaseous Fuels[8]	11	11	15	15	15	15	15	1.4%
Renewable Sources[9]	34	36	63	82	128	147	152	5.7%
Other[10]	2	2	1	1	1	1	1	-1.8%
Total	**149**	**167**	**255**	**295**	**381**	**458**	**533**	**4.6%**
Less Direct Use	120	135	205	230	276	334	392	4.2%
Total Sales to the Grid	**29**	**31**	**49**	**65**	**105**	**124**	**142**	**6.0%**
Total Electricity Generation by Fuel								
Coal	1987	1772	1799	1907	2069	2137	2218	0.9%
Petroleum	46	41	43	44	44	45	46	0.5%
Natural Gas	882	931	1000	1002	1003	1152	1288	1.3%
Nuclear Power	806	799	839	877	877	877	874	0.3%
Renewable Sources[5,9]	385	420	556	608	673	703	724	2.1%
Other[11]	16	18	16	16	16	16	16	-0.3%
Total Electricity Generation	**4123**	**3981**	**4253**	**4453**	**4682**	**4930**	**5167**	**1.0%**
Total Net Generation to the Grid	**3968**	**3810**	**4014**	**4190**	**4372**	**4563**	**4742**	**0.8%**
Net Imports	**33**	**34**	**33**	**27**	**22**	**13**	**14**	**-3.4%**
Electricity Sales by Sector								
Residential	1380	1363	1348	1394	1461	1538	1613	0.7%
Commercial	1336	1323	1416	1526	1636	1761	1886	1.4%
Industrial	1009	882	1038	1046	1031	997	962	0.3%
Transportation	7	7	8	10	13	18	22	4.6%
Total	**3732**	**3574**	**3811**	**3976**	**4142**	**4314**	**4483**	**0.9%**
Direct Use	154	170	239	263	309	367	425	3.6%
Total Electricity Use	**3886**	**3745**	**4049**	**4240**	**4451**	**4681**	**4908**	**1.0%**

Table A8. Electricity supply, disposition, prices, and emissions (continued)
(billion kilowatthours, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
End-Use Prices								
(2009 cents per kilowatthour)								
Residential	11.3	11.5	10.9	10.7	10.6	10.6	10.8	-0.2%
Commercial	10.4	10.1	9.1	9.0	9.1	9.1	9.2	-0.3%
Industrial	6.8	6.8	6.0	6.1	6.1	6.2	6.4	-0.2%
Transportation	11.8	11.9	10.0	9.6	10.1	10.5	11.0	-0.3%
All Sectors Average	**9.8**	**9.8**	**8.9**	**8.8**	**8.9**	**9.0**	**9.2**	**-0.2%**
(nominal cents per kilowatthour)								
Residential	11.2	11.5	11.8	12.9	14.1	15.4	17.2	1.6%
Commercial	10.3	10.1	9.9	10.9	12.0	13.2	14.7	1.5%
Industrial	6.8	6.8	6.6	7.3	8.1	9.0	10.2	1.6%
Transportation	11.7	11.9	10.9	11.6	13.3	15.3	17.6	1.5%
All Sectors Average	**9.7**	**9.8**	**9.7**	**10.7**	**11.8**	**13.0**	**14.7**	**1.6%**
Prices by Service Category								
(2009 cents per kilowatthour)								
Generation	6.1	6.0	5.0	5.3	5.6	5.8	6.0	0.0%
Transmission	0.7	0.7	0.8	0.8	0.8	0.8	0.9	0.5%
Distribution	2.9	3.0	3.0	2.8	2.6	2.4	2.3	-1.0%
(nominal cents per kilowatthour)								
Generation	6.1	6.0	5.5	6.4	7.4	8.4	9.6	1.8%
Transmission	0.7	0.7	0.9	1.0	1.1	1.2	1.4	2.3%
Distribution	2.9	3.0	3.3	3.4	3.4	3.5	3.7	0.8%
Electric Power Sector Emissions[1]								
Sulfur Dioxide (million tons)	7.62	5.72	3.77	3.68	4.09	3.97	3.94	-1.4%
Nitrogen Oxide (million tons)	3.01	1.99	1.99	1.98	2.00	2.03	2.05	0.1%
Mercury (tons)	45.27	40.66	26.88	26.82	28.21	29.08	29.91	-1.2%

[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 U.S. Energy Information Administration estimates approximately 7 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. 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.
[11]Includes pumped storage, non-biogenic municipal waste, refinery gas, still gas, 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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 electric power sector generation; sales to utilities; net imports; electricity sales; electricity end-use prices; and emissions: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010), and supporting databases. 2008 and 2009 prices: EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. **Projections**: EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A9. Electricity generating capacity
(gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Electric Power Sector[2]								
Power Only[3]								
Coal	304.4	308.2	312.5	313.1	313.1	313.1	313.4	0.1%
Oil and Natural Gas Steam[4]	114.6	114.0	99.5	92.6	92.4	92.4	88.4	-1.0%
Combined Cycle	157.1	165.4	170.7	170.9	177.2	202.7	226.8	1.2%
Combustion Turbine/Diesel	131.7	134.6	137.6	140.4	152.3	162.5	178.6	1.1%
Nuclear Power[5]	100.6	101.0	105.7	110.5	110.5	110.5	110.5	0.3%
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	0.0%
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Renewable Sources[6]	109.7	116.3	135.7	136.6	141.1	144.9	147.9	0.9%
Distributed Generation[7]	0.0	0.0	0.5	0.8	1.3	2.0	3.1	- -
Total	**939.8**	**961.5**	**984.0**	**986.8**	**1009.7**	**1050.0**	**1090.4**	**0.5%**
Combined Heat and Power[8]								
Coal	4.7	4.7	4.5	4.5	4.5	4.5	4.5	-0.1%
Oil and Natural Gas Steam[4]	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.0%
Combined Cycle	31.8	31.8	32.8	32.8	32.8	32.8	32.8	0.1%
Combustion Turbine/Diesel	2.8	2.9	3.0	3.0	3.0	3.0	3.0	0.2%
Renewable Sources[6]	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Total	**40.4**	**40.4**	**41.3**	**41.3**	**41.3**	**41.3**	**41.3**	**0.1%**
Cumulative Planned Additions[9]								
Coal	0.0	0.0	11.5	11.5	11.5	11.5	11.5	- -
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	6.4	6.4	6.4	6.4	6.4	- -
Combustion Turbine/Diesel	0.0	0.0	2.0	2.0	2.0	2.0	2.0	- -
Nuclear Power	0.0	0.0	1.1	1.1	1.1	1.1	1.1	- -
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	0.7	0.8	1.0	1.1	1.1	- -
Distributed Generation[7]	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -
Total	**0.0**	**0.0**	**21.7**	**21.8**	**21.9**	**22.0**	**22.1**	**- -**
Cumulative Unplanned Additions[9]								
Coal	0.0	0.0	0.0	2.0	2.0	2.0	2.3	- -
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	0.3	0.4	6.7	32.3	56.3	- -
Combustion Turbine/Diesel	0.0	0.0	4.1	7.7	19.6	29.9	45.9	- -
Nuclear Power	0.0	0.0	0.0	5.2	5.2	5.2	5.2	- -
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	18.7	19.5	23.9	27.6	30.5	- -
Distributed Generation[7]	0.0	0.0	0.5	0.8	1.3	2.0	3.1	- -
Total	**0.0**	**0.0**	**23.5**	**35.7**	**58.7**	**98.9**	**143.3**	**- -**
Cumulative Electric Power Sector Additions	**0.0**	**0.0**	**45.2**	**57.5**	**80.6**	**120.9**	**165.4**	**- -**
Cumulative Retirements[10]								
Coal	0.0	0.0	7.4	8.8	8.8	8.8	8.8	- -
Oil and Natural Gas Steam[4]	0.0	0.0	14.5	21.4	21.6	21.6	25.7	- -
Combined Cycle	0.0	0.0	0.4	0.4	0.4	0.4	0.4	- -
Combustion Turbine/Diesel	0.0	0.0	2.9	3.8	3.8	3.8	3.8	- -
Nuclear Power	0.0	0.0	0.0	0.6	0.6	0.6	0.6	- -
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	0.1	0.1	0.1	0.1	0.1	- -
Total	**0.0**	**0.0**	**25.4**	**35.0**	**35.2**	**35.2**	**39.3**	**- -**
Total Electric Power Sector Capacity	**980.2**	**1001.9**	**1025.3**	**1028.2**	**1051.0**	**1091.3**	**1131.7**	**0.5%**

Table A9. Electricity generating capacity (continued)
(gigawatts)

Net Summer Capacity[1]	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
End-Use Generators[11]								
Coal	3.5	4.0	4.9	5.2	7.9	11.5	15.7	5.4%
Petroleum	0.9	1.2	1.2	1.2	1.2	1.2	1.2	0.2%
Natural Gas	14.8	16.1	23.0	25.5	28.2	32.4	37.5	3.3%
Other Gaseous Fuels	1.9	1.9	2.7	2.7	2.7	2.7	2.7	1.3%
Renewable Sources[6]	6.7	7.5	17.5	21.3	27.4	30.3	31.6	5.7%
Other	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.0%
Total	**28.4**	**31.5**	**50.0**	**56.6**	**68.1**	**78.9**	**89.5**	**4.1%**
Cumulative Capacity Additions[9]	**0.0**	**0.0**	**18.5**	**25.1**	**36.6**	**47.4**	**58.0**	**- -**

[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 3.8 gigawatts of uprates through 2035.
[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, 2009.
[10]Cumulative retirements after December 31, 2009.
[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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 capacity and projected planned additions: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A10. Electricity trade
(billion kilowatthours, unless otherwise noted)

Electricity Trade	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Interregional Electricity Trade								
Gross Domestic Sales								
Firm Power	181.3	185.6	172.7	123.5	65.6	54.1	54.1	-4.6%
Economy	303.1	279.2	290.0	241.3	286.6	287.1	301.1	0.3%
Total	**484.4**	**464.7**	**462.7**	**364.7**	**352.2**	**341.1**	**355.2**	**-1.0%**
Gross Domestic Sales (million 2009 dollars)								
Firm Power	10738.4	10992.8	10232.4	7313.8	3888.3	3203.2	3203.2	-4.6%
Economy	24158.0	11225.8	11949.4	11042.4	15126.4	15068.1	17376.4	1.7%
Total	**34896.4**	**22218.6**	**22181.8**	**18356.2**	**19014.6**	**18271.3**	**20579.6**	**-0.3%**
International Electricity Trade								
Imports from Canada and Mexico								
Firm Power	19.9	19.3	28.4	16.9	3.1	0.4	0.4	-14.0%
Economy	37.1	33.1	24.4	29.1	36.0	29.2	30.0	-0.4%
Total	**57.0**	**52.4**	**52.8**	**46.0**	**39.2**	**29.6**	**30.4**	**-2.1%**
Exports to Canada and Mexico								
Firm Power	3.3	3.3	0.9	0.5	0.1	0.0	0.0	- -
Economy	20.7	14.7	18.7	18.1	17.5	17.0	16.4	0.4%
Total	**24.1**	**18.1**	**19.6**	**18.6**	**17.6**	**17.0**	**16.4**	**-0.4%**

- - = Not applicable.

Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 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: 2008 and 2009 interregional firm electricity trade data: North American Electric Reliability Council (NERC), Electricity Sales and Demand Database 2007. 2008 and 2009 Mexican electricity trade data: U.S. Energy Information Administration (EIA), *Electric Power Annual 2009* DOE/EIA-0348(2009) (Washington, DC, January 2011). 2008 Canadian international electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2008*. 2009 Canadian electricity trade data: National Energy Board, *Electricity Exports and Imports Statistics, 2009*. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A11. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

Supply and Disposition	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Crude Oil								
Domestic Crude Production[1]	4.96	5.36	5.81	6.08	5.88	5.82	5.95	0.4%
Alaska	0.69	0.65	0.49	0.42	0.41	0.27	0.39	-1.9%
Lower 48 States	4.28	4.71	5.32	5.66	5.47	5.54	5.56	0.6%
Net Imports	9.75	8.97	8.70	8.30	8.25	8.21	8.25	-0.3%
Gross Imports	9.78	9.01	8.74	8.34	8.28	8.24	8.28	-0.3%
Exports	0.03	0.04	0.03	0.03	0.03	0.03	0.03	-1.2%
Other Crude Supply[2]	-0.06	0.01	0.00	0.00	0.00	0.00	0.00	- -
Total Crude Supply	**14.66**	**14.33**	**14.52**	**14.38**	**14.13**	**14.02**	**14.20**	**-0.0%**
Other Petroleum Supply	**4.10**	**3.59**	**4.38**	**4.34**	**4.41**	**4.40**	**4.46**	**0.8%**
Natural Gas Plant Liquids	1.78	1.91	2.23	2.36	2.68	2.79	2.94	1.7%
Net Product Imports	1.39	0.75	1.14	0.96	0.81	0.73	0.64	-0.6%
Gross Refined Product Imports[3]	1.54	1.27	1.04	0.99	0.92	0.90	0.84	-1.6%
Unfinished Oil Imports	0.76	0.68	0.80	0.78	0.75	0.74	0.76	0.5%
Blending Component Imports	0.79	0.72	0.81	0.81	0.80	0.81	0.83	0.6%
Exports	1.71	1.91	1.50	1.62	1.67	1.72	1.80	-0.2%
Refinery Processing Gain[4]	1.00	0.98	1.01	1.02	0.92	0.88	0.88	-0.4%
Product Stock Withdrawal	-0.07	-0.04	0.00	0.00	0.00	0.00	0.00	- -
Other Non-petroleum Supply	**0.76**	**0.81**	**1.42**	**1.86**	**2.40**	**2.92**	**3.28**	**5.5%**
Supply from Renewable Sources	0.66	0.76	1.12	1.47	1.92	2.30	2.48	4.7%
Ethanol	0.64	0.73	1.03	1.32	1.60	1.75	1.83	3.6%
Domestic Production	0.61	0.72	0.97	1.20	1.44	1.52	1.58	3.1%
Net Imports	0.03	0.01	0.06	0.11	0.16	0.23	0.26	12.2%
Biodiesel	0.02	0.02	0.08	0.10	0.12	0.13	0.13	7.1%
Domestic Production	0.04	0.03	0.07	0.10	0.12	0.12	0.13	5.2%
Net Imports	-0.02	-0.01	0.00	0.00	0.00	0.00	0.00	- -
Other Biomass-derived Liquids[5]	0.00	0.00	0.02	0.05	0.19	0.42	0.52	- -
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Liquids from Coal	0.00	0.00	0.05	0.06	0.19	0.35	0.55	- -
Other[6]	0.10	0.05	0.25	0.33	0.30	0.27	0.25	6.3%
Total Primary Supply[7]	**19.51**	**18.73**	**20.32**	**20.58**	**20.94**	**21.34**	**21.94**	**0.6%**
Liquid Fuels Consumption								
by Fuel								
Liquefied Petroleum Gases	2.04	2.13	2.32	2.34	2.33	2.26	2.19	0.1%
E85[8]	0.00	0.00	0.01	0.22	0.64	0.81	0.84	26.3%
Motor Gasoline[9]	8.99	9.00	9.40	9.19	8.87	8.95	9.28	0.1%
Jet Fuel[10]	1.54	1.39	1.55	1.62	1.68	1.72	1.75	0.9%
Distillate Fuel Oil[11]	3.94	3.63	4.13	4.32	4.49	4.66	4.87	1.1%
Diesel	3.44	3.18	3.68	3.90	4.09	4.29	4.51	1.4%
Residual Fuel Oil	0.62	0.51	0.60	0.60	0.61	0.61	0.62	0.7%
Other[12]	2.38	2.15	2.43	2.39	2.38	2.35	2.38	0.4%
by Sector								
Residential and Commercial	1.06	1.04	0.95	0.91	0.88	0.86	0.85	-0.8%
Industrial[13]	4.69	4.25	4.99	4.96	4.94	4.83	4.77	0.5%
Transportation	13.87	13.61	14.31	14.61	14.96	15.47	16.10	0.6%
Electric Power[14]	0.21	0.18	0.19	0.20	0.20	0.20	0.21	0.7%
Total	**19.52**	**18.81**	**20.44**	**20.68**	**20.99**	**21.36**	**21.93**	**0.6%**
Discrepancy[15]	**-0.01**	**-0.08**	**-0.12**	**-0.10**	**-0.04**	**-0.02**	**0.01**	**- -**

Table A11. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and Disposition	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Domestic Refinery Distillation Capacity[16]	17.6	17.7	17.5	16.5	16.0	15.8	15.8	-0.4%
Capacity Utilization Rate (percent)[17]	85.0	83.0	84.9	89.0	90.1	90.6	91.9	0.4%
Net Import Share of Product Supplied (percent)	57.2	51.9	48.8	45.6	44.0	43.0	41.7	-0.8%
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2009 dollars)	272.65	203.65	296.22	325.04	347.74	363.62	370.10	2.3%

[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 pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the production of green diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[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 fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, 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]End-of-year operable capacity.
[17]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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 petroleum product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). Other 2008 data: EIA, *Petroleum Supply Annual 2008,* DOE/EIA-0340(2008)/1 (Washington, DC, June 2009). Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A12. Petroleum product prices
(2009 dollars per gallon, unless otherwise noted)

Sector and Fuel	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Crude Oil Prices (2009 dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	100.51	61.66	94.58	108.10	117.54	123.09	124.94	2.8%
Imported Crude Oil[1]	93.44	59.04	86.83	98.65	107.40	112.38	113.70	2.6%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	2.525	2.087	2.523	2.729	2.872	2.954	2.965	1.4%
Distillate Fuel Oil	3.432	2.514	2.931	3.366	3.595	3.736	3.818	1.6%
Commercial								
Distillate Fuel Oil	3.010	2.205	2.654	3.074	3.306	3.440	3.512	1.8%
Residual Fuel Oil	2.366	2.013	1.984	2.274	2.552	2.646	2.714	1.2%
Residual Fuel Oil (2009 dollars per barrel)	99.36	84.54	83.33	95.50	107.19	111.12	113.99	1.2%
Industrial[2]								
Liquefied Petroleum Gases	2.139	1.744	1.975	2.187	2.331	2.406	2.416	1.3%
Distillate Fuel Oil	3.108	2.281	2.656	3.079	3.322	3.452	3.523	1.7%
Residual Fuel Oil	2.434	1.804	2.215	2.492	2.722	2.786	2.803	1.7%
Residual Fuel Oil (2009 dollars per barrel)	102.24	75.79	93.04	104.68	114.34	117.02	117.73	1.7%
Transportation								
Liquefied Petroleum Gases	2.591	2.161	2.589	2.792	2.933	3.012	3.021	1.3%
Ethanol (E85)[3]	3.355	1.945	2.503	2.732	2.798	2.878	2.934	1.6%
Ethanol Wholesale Price	2.475	2.028	2.448	2.484	2.369	2.095	2.073	0.1%
Motor Gasoline[4]	3.327	2.349	3.134	3.378	3.539	3.640	3.707	1.8%
Jet Fuel[5]	3.146	1.700	2.568	2.974	3.181	3.334	3.413	2.7%
Diesel Fuel (distillate fuel oil)[6]	3.837	2.441	3.084	3.521	3.726	3.834	3.890	1.8%
Residual Fuel Oil	2.181	1.582	1.893	2.176	2.398	2.500	2.461	1.7%
Residual Fuel Oil (2009 dollars per barrel)	91.59	66.44	79.51	91.41	100.70	105.01	103.37	1.7%
Electric Power[7]								
Distillate Fuel Oil	2.713	1.988	2.336	2.743	2.940	3.094	3.168	1.8%
Residual Fuel Oil	2.208	1.342	1.971	2.209	2.433	2.525	2.501	2.4%
Residual Fuel Oil (2009 dollars per barrel)	92.73	56.36	82.79	92.77	102.20	106.05	105.03	2.4%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	1.774	1.477	1.836	2.022	2.154	2.237	2.255	1.6%
Motor Gasoline[4]	3.305	2.344	3.134	3.378	3.539	3.640	3.707	1.8%
Jet Fuel[5]	3.146	1.700	2.568	2.974	3.181	3.334	3.413	2.7%
Distillate Fuel Oil	3.648	2.408	2.995	3.434	3.651	3.769	3.831	1.8%
Residual Fuel Oil	2.228	1.576	1.957	2.227	2.453	2.547	2.522	1.8%
Residual Fuel Oil (2009 dollars per barrel)	93.58	66.20	82.19	93.55	103.03	106.96	105.92	1.8%
Average	**3.098**	**2.155**	**2.822**	**3.114**	**3.289**	**3.406**	**3.478**	**1.9%**

Table A12. Petroleum product prices (continued)
(nominal dollars per gallon, unless otherwise noted)

Sector and Fuel	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Crude Oil Prices (nominal dollars per barrel)								
Imported Low Sulfur Light Crude Oil[1]	99.57	61.66	103.24	130.60	155.46	178.45	199.37	4.6%
Imported Crude Oil[1]	92.57	59.04	94.78	119.18	142.05	162.92	181.43	4.4%
Delivered Sector Product Prices								
Residential								
Liquefied Petroleum Gases	2.501	2.087	2.754	3.297	3.798	4.283	4.732	3.2%
Distillate Fuel Oil	3.400	2.514	3.200	4.067	4.754	5.416	6.092	3.5%
Commercial								
Distillate Fuel Oil	2.982	2.205	2.897	3.713	4.373	4.987	5.605	3.7%
Residual Fuel Oil	2.344	2.013	2.166	2.747	3.376	3.836	4.331	3.0%
Residual Fuel Oil (nominal dollars per barrel)	98.43	84.54	90.96	115.37	141.78	161.10	181.90	3.0%
Industrial[2]								
Liquefied Petroleum Gases	2.119	1.744	2.155	2.642	3.083	3.489	3.855	3.1%
Distillate Fuel Oil	3.079	2.281	2.899	3.720	4.394	5.004	5.621	3.5%
Residual Fuel Oil	2.412	1.804	2.418	3.011	3.601	4.039	4.473	3.6%
Residual Fuel Oil (nominal dollars per barrel)	101.29	75.79	101.55	126.46	151.23	169.65	187.86	3.6%
Transportation								
Liquefied Petroleum Gases	2.567	2.161	2.826	3.373	3.879	4.367	4.820	3.1%
Ethanol (E85)[3]	3.323	1.945	2.732	3.300	3.701	4.173	4.682	3.4%
Ethanol Wholesale Price	2.451	2.028	2.672	3.001	3.133	3.037	3.308	1.9%
Motor Gasoline[4]	3.297	2.349	3.421	4.081	4.681	5.277	5.915	3.6%
Jet Fuel[5]	3.116	1.700	2.803	3.594	4.207	4.833	5.447	4.6%
Diesel Fuel (distillate fuel oil)[6]	3.801	2.441	3.366	4.253	4.928	5.559	6.207	3.7%
Residual Fuel Oil	2.161	1.582	2.066	2.629	3.171	3.625	3.928	3.6%
Residual Fuel Oil (nominal dollars per barrel)	90.74	66.44	86.79	110.43	133.20	152.24	164.96	3.6%
Electric Power[7]								
Distillate Fuel Oil	2.688	1.988	2.550	3.314	3.889	4.486	5.055	3.7%
Residual Fuel Oil	2.187	1.342	2.152	2.669	3.219	3.661	3.990	4.3%
Residual Fuel Oil (nominal dollars per barrel)	91.87	56.36	90.37	112.08	135.18	153.75	167.60	4.3%
Refined Petroleum Product Prices[8]								
Liquefied Petroleum Gases	1.758	1.477	2.004	2.443	2.849	3.242	3.599	3.5%
Motor Gasoline[4]	3.274	2.344	3.421	4.081	4.681	5.277	5.915	3.6%
Jet Fuel[5]	3.116	1.700	2.803	3.594	4.207	4.833	5.447	4.6%
Distillate Fuel Oil	3.614	2.408	3.269	4.149	4.829	5.464	6.113	3.6%
Residual Fuel Oil	2.207	1.576	2.136	2.691	3.245	3.692	4.024	3.7%
Residual Fuel Oil (nominal dollars per barrel)	92.71	66.20	89.71	113.02	136.27	155.06	169.02	3.7%
Average	**3.069**	**2.155**	**3.080**	**3.762**	**4.350**	**4.938**	**5.550**	**3.7%**

[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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 imported low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2008 and 2009 imported crude oil price: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2008 and 2009 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.” 2008 and 2009 electric power prices based on: EIA, *Monthly Energy Review*, DOE/EIA-0035(2010/09) (Washington, DC, September 2010). 2008 and 2009 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2008 and 2009 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A13. Natural gas supply, disposition, and prices
(trillion cubic feet per year, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Production								
Dry Gas Production[1]	20.29	20.96	22.43	23.43	23.98	25.10	26.32	0.9%
Supplemental Natural Gas[2]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	-0.0%
Net Imports	**2.98**	**2.64**	**2.69**	**1.90**	**1.08**	**0.78**	**0.18**	**-9.7%**
Pipeline[3]	2.68	2.23	2.33	1.40	0.74	0.64	0.04	-14.0%
Liquefied Natural Gas	0.30	0.41	0.36	0.50	0.34	0.14	0.14	-4.1%
Total Supply	**23.33**	**23.66**	**25.18**	**25.40**	**25.12**	**25.94**	**26.57**	**0.4%**
Consumption by Sector								
Residential	4.87	4.75	4.81	4.85	4.83	4.82	4.78	0.0%
Commercial	3.13	3.11	3.38	3.49	3.56	3.68	3.82	0.8%
Industrial[4]	6.65	6.14	8.05	8.24	8.10	8.08	8.02	1.0%
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]	6.67	6.89	6.98	6.84	6.66	7.34	7.88	0.5%
Transportation[8]	0.03	0.03	0.04	0.07	0.10	0.14	0.16	7.5%
Pipeline Fuel	0.65	0.64	0.65	0.64	0.62	0.64	0.65	0.1%
Lease and Plant Fuel[9]	1.22	1.16	1.20	1.21	1.19	1.20	1.25	0.3%
Total	**23.22**	**22.71**	**25.11**	**25.34**	**25.07**	**25.90**	**26.55**	**0.6%**
Discrepancy[10]	**0.11**	**0.95**	**0.07**	**0.06**	**0.05**	**0.04**	**0.02**	**- -**
Natural Gas Prices								
(2009 dollars per million Btu)								
Henry Hub Spot Price	8.94	3.95	4.66	5.05	5.97	6.40	7.07	2.3%
Average Lower 48 Wellhead Price[11]	7.96	3.62	4.13	4.47	5.29	5.66	6.26	2.1%
(2009 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	8.18	3.71	4.24	4.59	5.43	5.81	6.42	2.1%
Delivered Prices								
(2009 dollars per thousand cubic feet)								
Residential	13.99	12.20	10.39	11.16	12.15	12.85	13.76	0.5%
Commercial	12.32	9.94	8.60	9.19	10.03	10.57	11.28	0.5%
Industrial[4]	9.32	5.39	5.10	5.50	6.33	6.76	7.40	1.2%
Electric Power[7]	9.35	4.94	4.79	5.13	5.91	6.36	6.97	1.3%
Transportation[12]	17.67	13.05	12.29	12.58	13.19	13.49	13.94	0.3%
Average[13]	**10.84**	**7.47**	**6.62**	**7.13**	**8.01**	**8.48**	**9.14**	**0.8%**

Table A13. Natural gas supply, disposition, and prices (continued)
(trillion cubic feet per year, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Natural Gas Prices								
(nominal dollars per million Btu)								
Henry Hub Spot Price	8.86	3.95	5.09	6.10	7.90	9.28	11.28	4.1%
Average Lower 48 Wellhead Price[11]	7.89	3.62	4.51	5.40	6.99	8.21	9.99	4.0%
(nominal dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[11]	8.10	3.71	4.63	5.55	7.18	8.43	10.24	4.0%
Delivered Prices								
(nominal dollars per thousand cubic feet)								
Residential	13.86	12.20	11.34	13.48	16.08	18.63	21.95	2.3%
Commercial	12.20	9.94	9.38	11.10	13.27	15.32	18.00	2.3%
Industrial[4]	9.24	5.39	5.56	6.65	8.38	9.80	11.82	3.1%
Electric Power[7]	9.26	4.94	5.23	6.20	7.81	9.22	11.13	3.2%
Transportation[12]	17.50	13.05	13.42	15.20	17.44	19.56	22.25	2.1%
Average[13]	**10.74**	**7.47**	**7.22**	**8.61**	**10.60**	**12.29**	**14.58**	**2.6%**

[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. In addition, 2008 and 2009 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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 supply values; and lease, plant, and pipeline fuel consumption: U.S. Energy Information Administration (EIA), *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 supply values; and lease, plant, and pipeline fuel consumption; and wellhead price: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). Other 2008 and 2009 consumption based on: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 wellhead price: Bureau of Energy Management, Regulation and Enforcement; and EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2008 residential and commercial delivered prices: EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 residential and commercial delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 and 2009 electric power prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2009 and April 2010, Table 4.2. 2008 and 2009 industrial delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2008 transportation sector delivered prices are based on: EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and estimated state taxes, federal taxes, and dispensing costs or charges. 2009 transportation sector delivered prices are model results. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A14. Oil and gas supply

Production and Supply	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Crude Oil								
Lower 48 Average Wellhead Price[1] (2009 dollars per barrel)	**96.13**	**89.64**	**94.99**	**107.36**	**115.15**	**119.56**	**119.45**	**1.1%**
Production (million barrels per day)[2]								
United States Total	4.96	5.36	5.81	6.08	5.88	5.82	5.95	0.4%
Lower 48 Onshore	3.01	3.00	3.51	3.72	3.92	3.83	3.65	0.8%
Lower 48 Offshore	1.27	1.71	1.81	1.94	1.55	1.71	1.91	0.4%
Alaska	0.69	0.64	0.49	0.42	0.41	0.27	0.39	-1.9%
Lower 48 End of Year Reserves[2] (billion barrels)	**17.05**	**17.88**	**19.69**	**21.57**	**21.89**	**22.32**	**22.76**	**0.9%**
Natural Gas								
Lower 48 Average Wellhead Price[1]								
(2009 dollars per million Btu)								
Henry Hub Spot Price	8.94	3.95	4.66	5.05	5.97	6.40	7.07	2.3%
Average Lower 48 Wellhead Price[1]	7.96	3.62	4.13	4.47	5.29	5.66	6.26	2.1%
(2009 dollars per thousand cubic feet)								
Average Lower 48 Wellhead Price[1]	8.18	3.71	4.24	4.59	5.43	5.81	6.42	2.1%
Dry Production (trillion cubic feet)[3]								
United States Total	20.29	20.96	22.43	23.43	23.98	25.10	26.32	0.9%
Lower 48 Onshore	17.22	17.88	20.00	20.21	21.31	22.01	23.05	1.0%
Associated-Dissolved[4]	1.42	1.40	1.48	1.43	1.36	1.20	1.02	-1.2%
Non-Associated	15.81	16.48	18.51	18.78	19.95	20.81	22.04	1.1%
Tight gas	6.75	6.59	5.90	5.72	5.74	5.71	5.84	-0.5%
Shale Gas	2.23	3.28	7.20	8.21	9.69	10.94	12.25	5.2%
Coalbed Methane	1.87	1.80	1.67	1.66	1.72	1.71	1.72	-0.2%
Other	4.95	4.80	3.74	3.19	2.81	2.44	2.23	-2.9%
Lower 48 Offshore	2.69	2.70	2.15	2.96	2.42	2.86	3.05	0.5%
Associated-Dissolved[4]	0.62	0.64	0.64	0.87	0.68	0.71	0.80	0.8%
Non-Associated	2.07	2.05	1.51	2.09	1.74	2.15	2.26	0.4%
Alaska	0.37	0.37	0.28	0.26	0.24	0.22	0.21	-2.1%
Lower 48 End of Year Dry Reserves[3] (trillion cubic feet)	**236.96**	**261.37**	**279.40**	**293.61**	**299.51**	**308.52**	**314.16**	**0.7%**
Supplemental Gas Supplies (trillion cubic feet)[5]	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**-0.0%**
Total Lower 48 Wells Drilled (thousands)	**56.20**	**35.06**	**37.10**	**40.23**	**45.34**	**49.05**	**53.63**	**1.6%**

[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 2008 and 2009 are model results and may differ slightly from official EIA data reports.

Sources: 2008 and 2009 crude oil lower 48 average wellhead price: U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2008 and 2009 lower 48 onshore, lower 48 offshore, and Alaska crude oil production: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2008 U.S. crude oil and natural gas reserves: EIA, *U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves*, DOE/EIA-0216(2009) (Washington, DC, October 2010). 2008 Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2008 natural gas lower 48 average wellhead price: Bureau of Energy Management, Regulation and Enforcement; and EIA, *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010). 2009 natural gas lower 48 average wellhead price, Alaska and total natural gas production, and supplemental gas supplies: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). Other 2008 and 2009 values: EIA, Office of Energy Analysis. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A15. Coal supply, disposition, and prices
(million short tons per year, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case 2008	2009	2015	2020	2025	2030	2035	Annual Growth 2009-2035 (percent)
Production[1]								
Appalachia	391	343	274	279	282	278	282	-0.8%
Interior	147	147	156	160	166	167	177	0.7%
West	634	585	610	661	739	807	860	1.5%
East of the Mississippi	493	450	387	396	406	402	415	-0.3%
West of the Mississippi	678	625	653	704	782	850	904	1.4%
Total	**1172**	**1075**	**1040**	**1100**	**1188**	**1252**	**1319**	**0.8%**
Waste Coal Supplied[2]	**14**	**12**	**14**	**14**	**14**	**14**	**14**	**0.6%**
Net Imports								
Imports[3]	32	21	30	38	56	54	53	3.6%
Exports	82	59	70	76	75	74	71	0.7%
Total	**-49**	**-38**	**-40**	**-38**	**-19**	**-20**	**-18**	**-2.8%**
Total Supply[4]	**1136**	**1049**	**1014**	**1076**	**1183**	**1247**	**1315**	**0.9%**
Consumption by Sector								
Residential and Commercial	4	3	3	3	3	3	3	-0.2%
Coke Plants	22	15	22	22	21	20	18	0.6%
Other Industrial[5]	54	45	49	49	48	48	47	0.1%
Coal-to-Liquids Heat and Power	0	0	6	7	23	42	66	- -
Coal to Liquids Production	0	0	5	6	21	40	62	- -
Electric Power[6]	1041	937	928	989	1066	1094	1119	0.7%
Total	**1121**	**1000**	**1013**	**1076**	**1182**	**1247**	**1315**	**1.1%**
Discrepancy and Stock Change[7]	**16**	**49**	**1**	**0**	**1**	**0**	**-0**	**- -**
Average Minemouth Price[8]								
(2009 dollars per short ton)	31.54	33.26	32.36	32.85	33.22	33.25	33.92	0.1%
(2009 dollars per million Btu)	1.56	1.67	1.62	1.65	1.68	1.69	1.73	0.2%
Delivered Prices (2009 dollars per short ton)[9]								
Coke Plants	119.20	143.01	157.51	165.95	169.26	170.64	172.38	0.7%
Other Industrial[5]	64.03	64.87	61.78	62.45	63.58	64.89	66.89	0.1%
Coal to Liquids	- -	- -	30.96	35.63	31.66	35.84	36.68	- -
Electric Power								
(2009 dollars per short ton)	41.07	43.48	40.94	41.57	43.33	44.63	46.36	0.2%
(2009 dollars per million Btu)	2.07	2.20	2.11	2.15	2.24	2.32	2.40	0.3%
Average	**43.77**	**46.03**	**44.40**	**45.00**	**45.97**	**46.81**	**47.87**	**0.2%**
Exports[10]	98.60	101.44	123.13	132.67	136.16	134.51	133.36	1.1%

Table A15. Coal supply, disposition, and prices (continued)
(million short tons per year, unless otherwise noted)

Supply, Disposition, and Prices	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Average Minemouth Price[8]								
(nominal dollars per short ton)	31.25	33.26	35.32	39.69	43.93	48.21	54.13	1.9%
(nominal dollars per million Btu)	1.55	1.67	1.77	1.99	2.22	2.45	2.76	2.0%
Delivered Prices (nominal dollars per short ton)[9]								
Coke Plants	118.09	143.01	171.93	200.49	223.88	247.39	275.08	2.5%
Other Industrial[5]	63.44	64.87	67.44	75.45	84.09	94.08	106.75	1.9%
Coal to Liquids	- -	- -	33.79	43.05	41.88	51.96	58.54	- -
Electric Power								
(nominal dollars per short ton)	40.69	43.48	44.69	50.23	57.30	64.71	73.98	2.1%
(nominal dollars per million Btu)	2.05	2.20	2.31	2.60	2.96	3.36	3.83	2.2%
Average	**43.37**	**46.03**	**48.47**	**54.37**	**60.80**	**67.86**	**76.40**	**2.0%**
Exports[10]	97.68	101.44	134.40	160.28	180.10	195.00	212.81	2.9%

[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]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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2009*, DOE/EIA-0584(2009) (Washington, DC, October 2010); EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010); and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A16. Renewable energy generating capacity and generation
(gigawatts, unless otherwise noted)

Capacity and Generation	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Electric Power Sector[1]								
Net Summer Capacity								
Conventional Hydropower	76.87	76.87	77.52	77.61	78.59	79.28	79.85	0.1%
Geothermal[2]	2.42	2.42	2.75	3.38	4.21	5.58	6.42	3.8%
Municipal Waste[3]	3.37	3.37	3.37	3.37	3.37	3.37	3.37	-0.0%
Wood and Other Biomass[4]	2.19	2.19	2.19	2.19	2.19	2.19	2.19	0.0%
Solar Thermal	0.53	0.61	1.26	1.28	1.30	1.32	1.35	3.1%
Solar Photovoltaic[5]	0.05	0.07	0.15	0.23	0.32	0.43	0.52	7.9%
Wind	24.89	31.45	48.90	49.01	51.56	53.17	54.63	2.1%
Offshore Wind	0.00	0.00	0.20	0.20	0.20	0.20	0.20	- -
Total	**110.31**	**116.98**	**136.33**	**137.27**	**141.75**	**145.53**	**148.53**	**0.9%**
Generation (billion kilowatthours)								
Conventional Hydropower	253.09	270.20	293.22	301.20	305.17	308.11	310.59	0.5%
Geothermal[2]	14.95	15.21	19.63	24.68	31.36	42.34	49.19	4.6%
Biogenic Municipal Waste[6]	15.68	16.39	14.80	14.80	14.80	14.80	14.80	-0.4%
Wood and Other Biomass	10.46	10.39	20.51	38.57	38.41	30.86	32.64	4.5%
Dedicated Plants	8.58	8.73	7.06	10.13	8.54	7.07	8.15	-0.3%
Cofiring	1.88	1.66	13.45	28.45	29.87	23.79	24.49	10.9%
Solar Thermal	0.83	0.76	2.49	2.52	2.56	2.60	2.66	4.9%
Solar Photovoltaic[5]	0.04	0.04	0.36	0.56	0.80	1.06	1.31	13.9%
Wind	55.42	70.82	141.77	142.16	150.73	155.92	160.13	3.2%
Offshore Wind	0.00	0.00	0.75	0.75	0.75	0.75	0.75	- -
Total	**350.47**	**383.82**	**493.52**	**525.25**	**544.58**	**556.44**	**572.06**	**1.5%**
End-Use Generators[7]								
Net Summer Capacity								
Conventional Hydropower[8]	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.0%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[9]	0.29	0.30	0.30	0.30	0.30	0.30	0.30	0.0%
Biomass	4.86	4.86	7.26	9.46	15.14	17.50	18.06	5.2%
Solar Photovoltaic[5]	0.77	1.50	7.73	9.14	9.51	10.05	10.68	7.8%
Wind	0.08	0.18	1.45	1.68	1.70	1.76	1.83	9.2%
Total	**6.70**	**7.55**	**17.46**	**21.29**	**27.36**	**30.31**	**31.58**	**5.7%**
Generation (billion kilowatthours)								
Conventional Hydropower[8]	3.33	3.34	3.49	3.49	3.49	3.49	3.49	0.2%
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	- -
Municipal Waste[9]	1.94	1.96	2.56	2.56	2.56	2.56	2.56	1.0%
Biomass	27.88	27.88	42.60	59.73	104.98	122.36	126.57	6.0%
Solar Photovoltaic[5]	1.22	2.34	11.99	14.25	14.86	15.75	16.79	7.9%
Wind	0.10	0.24	1.97	2.30	2.34	2.42	2.53	9.5%
Total	**34.47**	**35.76**	**62.61**	**82.34**	**128.22**	**146.57**	**151.94**	**5.7%**

Table A16. Renewable energy generating capacity and generation (continued)
(gigawatts, unless otherwise noted)

Capacity and Generation	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Total, All Sectors								
Net Summer Capacity								
Conventional Hydropower	77.58	77.57	78.23	78.32	79.30	79.99	80.56	0.1%
Geothermal	2.42	2.42	2.75	3.38	4.21	5.58	6.42	3.8%
Municipal Waste	3.66	3.67	3.67	3.67	3.67	3.67	3.67	-0.0%
Wood and Other Biomass[4]	7.04	7.04	9.45	11.64	17.33	19.68	20.24	4.1%
Solar[5]	1.35	2.18	9.14	10.65	11.13	11.80	12.56	7.0%
Wind	24.96	31.64	50.55	50.89	53.46	55.13	56.66	2.3%
Total	**117.02**	**124.53**	**153.79**	**158.55**	**169.11**	**175.84**	**180.11**	**1.4%**
Generation (billion kilowatthours)								
Conventional Hydropower	256.42	273.54	296.71	304.69	308.66	311.59	314.08	0.5%
Geothermal	14.95	15.21	19.63	24.68	31.36	42.34	49.19	4.6%
Municipal Waste	17.62	18.36	17.36	17.36	17.36	17.36	17.36	-0.2%
Wood and Other Biomass	38.34	38.27	63.11	98.30	143.39	153.22	159.21	5.6%
Solar[5]	2.08	3.15	14.84	17.34	18.21	19.41	20.76	7.5%
Wind	55.52	71.06	144.49	145.22	153.82	159.09	163.41	3.3%
Total	**384.94**	**419.59**	**556.13**	**607.59**	**672.80**	**703.01**	**724.00**	**2.1%**

[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 both hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems (EGS). Near-field EGS potential occurs on known hydrothermal sites, however this potential requires the addition of external fluids for electricity generation and is only available after 2025.
[3]Includes 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]Does not include off-grid photovoltaics (PV). Based on annual PV shipments from 1989 through 2008, EIA estimates that as much as 237 megawatts of remote electricity generation PV applications (i.e., off-grid power systems) were in service in 2008, plus an additional 550 megawatts in communications, transportation, and assorted other non-grid-connected, specialized applications. See U.S. Energy Information Administration, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010), Table 10.9 (annual PV shipments, 1989-2008). 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.
[6]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 U.S. Energy Information Administration estimates that in 2007 approximately 6 billion kilowatthours of electricity were generated from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. Energy Information Administration, *Methodology for Allocating Municipal Solid Waste to Biogenic and Non-Biogenic Energy* (Washington, DC, May 2007).
[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]Represents own-use industrial hydroelectric power.
[9]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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 capacity: U.S. Energy Information Administration (EIA), Form EIA-860, "Annual Electric Generator Report" (preliminary). 2008 and 2009 generation: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A17. Renewable energy consumption by sector and source
(quadrillion Btu per year)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Marketed Renewable Energy[1]								
Residential (wood)	**0.44**	**0.43**	**0.40**	**0.42**	**0.42**	**0.42**	**0.42**	**-0.1%**
Commercial (biomass)	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.11**	**0.0%**
Industrial[2]	**2.50**	**2.08**	**2.74**	**3.18**	**3.96**	**4.39**	**4.57**	**3.1%**
Conventional Hydroelectric	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.0%
Municipal Waste[3]	0.16	0.17	0.18	0.18	0.18	0.18	0.18	0.1%
Biomass	1.33	1.22	1.68	1.77	1.84	1.85	1.83	1.6%
Biofuels Heat and Coproducts	0.98	0.66	0.85	1.19	1.90	2.33	2.52	5.3%
Transportation	**0.87**	**0.99**	**1.51**	**2.00**	**2.72**	**3.41**	**3.73**	**5.2%**
Ethanol used in E85[4]	0.00	0.00	0.01	0.21	0.61	0.77	0.81	26.3%
Ethanol used in Gasoline Blending	0.83	0.95	1.33	1.49	1.46	1.48	1.56	1.9%
Biodiesel used in Distillate Blending	0.04	0.04	0.15	0.20	0.24	0.25	0.25	7.1%
Liquids from Biomass	0.00	0.00	0.02	0.09	0.39	0.89	1.10	- -
Renewable Diesel and Gasoline[5]	0.00	0.00	0.01	0.01	0.02	0.02	0.02	- -
Electric Power[6]	**3.67**	**3.89**	**5.08**	**5.52**	**5.84**	**6.16**	**6.47**	**2.0%**
Conventional Hydroelectric	2.49	2.66	2.89	2.97	3.01	3.04	3.06	0.5%
Geothermal	0.31	0.32	0.44	0.59	0.79	1.12	1.32	5.6%
Biogenic Municipal Waste[7]	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.0%
Biomass	0.21	0.11	0.23	0.43	0.43	0.34	0.37	4.8%
Dedicated Plants	0.13	0.12	0.10	0.15	0.13	0.10	0.11	-0.2%
Cofiring	0.08	-0.01	0.13	0.29	0.30	0.24	0.25	- -
Solar Thermal	0.01	0.01	0.02	0.02	0.03	0.03	0.03	4.9%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	13.9%
Wind	0.55	0.70	1.40	1.41	1.49	1.54	1.59	3.2%
Total Marketed Renewable Energy	**7.58**	**7.50**	**9.85**	**11.23**	**13.05**	**14.50**	**15.29**	**2.8%**
Sources of Ethanol								
From Corn and Other Starch	0.78	0.93	1.24	1.40	1.38	1.49	1.56	2.0%
From Cellulose	0.00	0.00	0.01	0.15	0.48	0.47	0.47	48.6%
Net Imports	0.04	0.02	0.07	0.15	0.21	0.30	0.33	12.2%
Total	**0.83**	**0.95**	**1.33**	**1.70**	**2.07**	**2.26**	**2.37**	**3.6%**

Table A17. Renewable energy consumption by sector and source (continued)
(quadrillion Btu per year)

Sector and Source	Reference Case 2008	2009	2015	2020	2025	2030	2035	Annual Growth 2009-2035 (percent)
Nonmarketed Renewable Energy[8] Selected Consumption								
Residential	**0.01**	**0.01**	**0.07**	**0.09**	**0.09**	**0.10**	**0.11**	**8.3%**
Solar Hot Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.01	2.0%
Geothermal Heat Pumps	0.00	0.01	0.02	0.03	0.04	0.04	0.05	8.7%
Solar Photovoltaic	0.00	0.00	0.04	0.04	0.04	0.05	0.05	9.7%
Wind	0.00	0.00	0.01	0.01	0.01	0.01	0.01	11.1%
Commercial	**0.03**	**0.03**	**0.03**	**0.03**	**0.04**	**0.04**	**0.04**	**1.3%**
Solar Thermal	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.6%
Solar Photovoltaic	0.00	0.00	0.00	0.01	0.01	0.01	0.01	3.9%
Wind	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.8%

[1]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.
[2]Includes all electricity production by industrial and other combined heat and power for the grid and for own use.
[3]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.
[4]Excludes motor gasoline component of E85.
[5]Renewable feedstocks for the on-site production of diesel and gasoline.
[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. 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 9,854 Btu per kilowatthour.
[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 U.S. Energy Information Administration estimates that in 2007 approximately 0.3 quadrillion Btus were consumed from a municipal waste stream containing petroleum-derived plastics and other non-renewable sources. See U.S. 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 U.S. 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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 ethanol: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 and 2009 electric power sector: EIA, Form EIA-860, "Annual Electric Generator Report" (preliminary). Other 2008 and 2009 values: EIA, Office of Energy Analysis.
Projections: EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A18. Carbon dioxide emissions by sector and source
(million metric tons, unless otherwise noted)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Residential								
Petroleum	85	83	73	68	64	61	58	-1.3%
Natural Gas	266	259	262	264	263	263	260	0.0%
Coal	1	1	1	1	1	1	0	-1.1%
Electricity[1]	878	824	757	780	833	872	909	0.4%
Total	**1229**	**1166**	**1092**	**1112**	**1160**	**1196**	**1228**	**0.2%**
Commercial								
Petroleum	46	44	39	38	38	37	37	-0.6%
Natural Gas	171	169	184	190	194	200	208	0.8%
Coal	7	6	6	6	6	6	6	0.0%
Electricity[1]	850	800	795	854	933	998	1063	1.1%
Total	**1074**	**1018**	**1023**	**1088**	**1170**	**1241**	**1314**	**1.0%**
Industrial[2]								
Petroleum	376	343	410	402	402	400	405	0.6%
Natural Gas[3]	407	383	489	500	492	493	493	1.0%
Coal	173	128	162	164	187	215	249	2.6%
Electricity[1]	642	533	582	586	588	565	542	0.1%
Total	**1598**	**1387**	**1643**	**1651**	**1668**	**1673**	**1689**	**0.8%**
Transportation								
Petroleum[4]	1896	1816	1878	1881	1892	1945	2023	0.4%
Natural Gas[5]	37	34	38	38	40	42	44	1.0%
Electricity[1]	4	4	5	6	8	10	12	4.3%
Total	**1937**	**1854**	**1921**	**1925**	**1940**	**1997**	**2080**	**0.4%**
Electric Power[6]								
Petroleum	40	34	33	35	35	35	37	0.3%
Natural Gas	362	373	379	372	362	399	428	0.5%
Coal	1959	1742	1714	1806	1951	1998	2049	0.6%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**2374**	**2160**	**2138**	**2225**	**2360**	**2444**	**2526**	**0.6%**
Total by Fuel								
Petroleum[3]	2444	2319	2434	2423	2430	2478	2561	0.4%
Natural Gas	1243	1218	1352	1365	1351	1398	1434	0.6%
Coal	2139	1877	1882	1977	2144	2219	2304	0.8%
Other[7]	12	12	12	12	12	12	12	0.0%
Total	**5838**	**5426**	**5680**	**5777**	**5938**	**6107**	**6311**	**0.6%**
Carbon Dioxide Emissions (tons per person)	**19.1**	**17.6**	**17.4**	**16.9**	**16.6**	**16.3**	**16.2**	**-0.3%**

[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, 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 2008, international bunker fuels accounted for 86 to 130 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 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 emissions and emission factors: U.S. Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2009,* DOE/EIA-0573(2009) (Washington, DC, December 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A19. Energy-related carbon dioxide emissions by end use
(million metric tons)

Sector and Source	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Residential								
Space Heating	292.69	279.60	272.85	270.86	268.47	266.39	263.11	-0.2%
Space Cooling	162.47	147.72	135.39	140.24	150.37	157.54	164.20	0.4%
Water Heating	164.41	160.32	160.36	162.26	163.49	159.75	154.66	-0.1%
Refrigeration	69.77	65.09	58.06	56.92	58.36	60.38	62.88	-0.1%
Cooking	32.95	32.03	32.51	34.07	35.91	37.39	38.70	0.7%
Clothes Dryers	37.79	35.69	33.17	32.37	33.23	34.56	35.96	0.0%
Freezers	14.84	13.90	12.91	13.13	13.71	14.06	14.43	0.1%
Lighting	134.22	125.70	93.51	88.06	87.22	87.55	89.23	-1.3%
Clothes Washers[1]	6.31	5.85	4.91	4.41	4.48	4.70	4.89	-0.7%
Dishwashers[1]	17.17	16.09	14.89	15.25	16.50	17.58	18.65	0.6%
Color Televisions and Set-Top Boxes	62.03	59.44	54.35	55.38	59.93	64.15	68.61	0.6%
Personal Computers and Related Equipment	32.17	31.33	27.80	28.37	29.72	30.85	31.71	0.0%
Furnace Fans and Boiler Circulation Pumps	25.57	24.67	25.43	27.38	30.24	31.49	32.26	1.0%
Other Uses	174.01	165.12	166.34	183.70	208.58	229.34	249.04	1.6%
Discrepancy[2]	2.85	3.79	-0.00	0.00	0.00	0.00	0.00	-28.5%
Total Residential	**1229.24**	**1166.35**	**1092.49**	**1112.42**	**1160.21**	**1195.73**	**1228.32**	**0.2%**
Commercial								
Space Heating[3]	127.32	128.25	128.76	130.33	130.33	130.73	130.54	0.1%
Space Cooling[3]	92.96	85.70	88.59	91.17	95.98	99.38	103.41	0.7%
Water Heating[3]	42.12	41.58	44.00	46.26	48.12	49.69	50.80	0.8%
Ventilation	92.45	89.19	91.42	98.49	106.96	112.72	118.04	1.1%
Cooking	13.16	13.28	14.38	15.09	15.71	16.30	16.87	0.9%
Lighting	194.26	182.85	171.08	179.04	190.65	198.63	206.01	0.5%
Refrigeration	75.47	70.56	59.86	58.46	60.25	61.96	64.22	-0.4%
Office Equipment (PC)	41.33	38.12	30.95	31.31	32.55	34.14	34.85	-0.3%
Office Equipment (non-PC)	44.27	44.13	51.94	60.16	67.37	73.13	77.41	2.2%
Other Uses[4]	350.35	324.36	342.43	377.83	422.03	464.68	511.60	1.8%
Total Commercial	**1073.69**	**1018.02**	**1023.40**	**1088.13**	**1169.96**	**1241.34**	**1313.74**	**1.0%**
Industrial								
Manufacturing								
Refining								
Food Products	260.03	258.29	288.28	290.06	314.11	356.19	405.68	1.8%
Paper Products	107.09	102.49	105.47	110.03	116.18	119.76	122.70	0.7%
Bulk Chemicals	100.00	89.65	95.56	93.28	90.78	87.05	82.98	-0.3%
Glass	282.56	263.03	296.76	296.24	290.00	269.58	250.33	-0.2%
Cement Manufacturing	24.31	20.02	22.83	24.06	25.94	26.14	26.04	1.0%
Iron and Steel	36.59	28.55	32.98	33.48	33.83	32.75	30.04	0.2%
Aluminum	118.67	75.90	107.58	110.31	107.52	99.37	91.23	0.7%
Fabricated Metal Products	31.20	30.82	29.30	28.22	26.72	24.94	23.17	-1.1%
Machinery	43.03	38.34	45.61	45.86	47.05	45.89	45.03	0.6%
Computers and Electronics	26.22	22.37	28.08	29.54	31.97	31.88	32.02	1.4%
Transportation Equipment	37.33	32.51	39.99	42.57	45.67	47.67	48.93	1.6%
Electrical Equipment	52.05	45.41	63.50	59.55	59.07	61.20	63.60	1.3%
Wood Products	8.42	7.45	9.31	9.15	9.90	10.16	10.49	1.3%
Plastics	19.15	17.64	23.03	22.59	21.92	20.77	19.55	0.4%
Balance of Manufacturing	42.80	37.75	41.50	42.12	42.41	41.02	40.40	0.3%
Total Manufacturing	159.81	143.04	152.19	156.28	153.93	150.44	146.27	0.1%
Nonmanufacturing	1349.26	1213.26	1381.97	1393.31	1416.98	1424.82	1438.46	0.7%
Agriculture								
Construction	76.78	74.57	74.55	74.39	74.88	74.74	74.38	-0.0%
Mining	94.04	78.52	96.81	97.43	96.54	94.14	93.58	0.7%
Total Nonmanufacturing	56.28	49.39	50.85	50.28	50.19	50.26	50.44	0.1%
Discrepancy[2]	227.10	202.47	222.21	222.09	221.61	219.13	218.40	0.3%
Total Industrial	**21.41**	**-28.42**	**39.28**	**35.75**	**29.52**	**29.47**	**31.76**	**- -**
	1597.78	**1387.31**	**1643.46**	**1651.16**	**1668.11**	**1673.42**	**1688.61**	**0.8%**

Table A19. Energy-related carbon dioxide emissions by end use (continued)
(million metric tons)

Sector and Source	Reference Case 2008	2009	2015	2020	2025	2030	2035	Annual Growth 2009-2035 (percent)
Transportation								
Light-Duty Vehicles	1100.28	1072.82	1070.91	1040.63	1023.05	1045.89	1094.14	0.1%
Commercial Light Trucks[5]	44.05	40.28	45.08	44.73	45.06	46.60	48.85	0.7%
Bus Transportation	18.85	18.92	18.92	18.94	18.98	19.08	19.28	0.1%
Freight Trucks	339.28	306.68	362.87	383.43	402.21	423.36	446.65	1.5%
Rail, Passenger	6.19	5.96	6.15	6.49	6.93	7.25	7.55	0.9%
Rail, Freight	41.80	37.09	40.84	43.41	45.53	47.72	49.09	1.1%
Shipping, Domestic	17.11	15.14	15.85	16.32	16.55	16.95	17.35	0.5%
Shipping, International	70.20	60.78	61.39	61.78	62.14	62.52	62.90	0.1%
Recreational Boats	17.54	17.86	18.30	18.65	19.21	19.80	20.47	0.5%
Air	191.53	188.34	191.86	201.45	209.37	214.62	217.94	0.6%
Military Use	50.75	53.27	48.79	49.61	50.96	52.34	53.69	0.0%
Lubricants	5.20	4.75	4.58	4.64	4.72	4.81	4.88	0.1%
Pipeline Fuel	35.31	34.65	35.34	34.73	34.02	34.63	35.42	0.1%
Discrepancy[2]	-0.74	-2.69	-0.35	0.20	0.79	1.39	1.96	- -
Total Transportation	**1937.33**	**1853.85**	**1920.52**	**1924.99**	**1939.51**	**1996.96**	**2080.16**	**0.4%**
Biogenic Energy Combustion[6]								
Biomass	196.75	174.96	227.61	256.86	262.92	255.30	256.31	1.5%
Biogenic Waste	8.26	8.27	8.27	8.27	8.27	8.27	8.27	0.0%
Biofuels Heat and Coproducts	91.62	61.59	79.61	111.90	178.58	218.60	236.59	5.3%
Ethanol	56.60	64.87	91.11	116.47	141.63	154.48	161.98	3.6%
Biodiesel	2.93	3.07	10.88	14.41	17.46	17.96	18.18	7.1%
Liquids from Biomass	0.00	0.00	1.51	6.33	28.66	65.12	80.22	- -
Renewable Diesel and Gasoline	0.00	0.00	0.90	1.01	1.12	1.12	1.11	- -
Total	**356.17**	**312.75**	**419.88**	**515.25**	**638.65**	**720.84**	**762.66**	**3.5%**

[1]Does not include water heating portion of load.
[2]Represents differences between total emissions by end-use and total emissions by fuel as reported in Table A18. Emissions by fuel may reflect benchmarking and other modeling adjustments to energy use and the associated emissions that are not assigned to specific end uses.
[3]Includes emissions related to fuel consumption for district services.
[4]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 emissions from residual fuel oil, liquefied petroleum gases, coal, motor gasoline, and kerosene.
[5]Commercial trucks 8,500 to 10,000 pounds.
[6]By convention, the direct emissions from biogenic energy sources are excluded from energy-related CO_2 emissions. The release of carbon from these sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net emissions over some period of time. If, however, increased use of biomass energy results in a decline in terrestrial carbon stocks, a net positive release of carbon may occur. Accordingly, the emissions from biogenic energy sources are reported here as an indication of the potential net release of carbon dioxide in the absence of offsetting sequestration.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 emissions and emission factors: U.S. Energy Information Administration (EIA), *Emissions of Greenhouse Gases in the United States 2009,* DOE/EIA-0573(2009) (Washington, DC, December 2010). **Projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A20. Macroeconomic indicators

(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Real Gross Domestic Product	**13229**	**12881**	**15336**	**17421**	**20020**	**22731**	**25692**	**2.7%**
Components of Real Gross Domestic Product								
Real Consumption	9265	9154	10443	11669	13280	15046	16976	2.4%
Real Investment	1957	1516	2592	2992	3548	4128	4849	4.6%
Real Government Spending	2503	2543	2555	2664	2796	2934	3069	0.7%
Real Exports	1648	1491	2437	3382	4485	5761	7334	6.3%
Real Imports	2152	1854	2624	3153	3840	4730	5902	4.6%
Energy Intensity								
(thousand Btu per 2005 dollar of GDP)								
Delivered Energy	5.49	5.33	4.91	4.42	3.94	3.57	3.25	-1.9%
Total Energy	7.57	7.36	6.65	6.02	5.39	4.88	4.44	-1.9%
Price Indices								
GDP Chain-type Price Index (2005=1.000)	1.086	1.096	1.197	1.324	1.450	1.589	1.749	1.8%
Consumer Price Index (1982-4=1.00)								
All-urban	2.15	2.15	2.39	2.69	2.97	3.29	3.66	2.1%
Energy Commodities and Services	2.36	1.93	2.44	2.86	3.25	3.64	4.10	2.9%
Wholesale Price Index (1982=1.00)								
All Commodities	1.90	1.73	2.00	2.19	2.38	2.54	2.74	1.8%
Fuel and Power	2.14	1.59	2.05	2.43	2.84	3.22	3.68	3.3%
Metals and Metal Products	2.13	1.87	2.48	2.68	2.77	2.83	2.87	1.7%
Industrial Commodities excluding Energy	1.81	1.76	2.00	2.14	2.25	2.34	2.43	1.2%
Interest Rates (percent, nominal)								
Federal Funds Rate	1.93	0.16	5.15	4.96	4.86	4.94	5.04	- -
10-Year Treasury Note	3.67	3.26	5.76	5.88	5.78	5.76	5.89	- -
AA Utility Bond Rate	6.19	5.75	7.41	7.69	7.69	7.73	7.93	- -
Value of Shipments (billion 2005 dollars)								
Service Sectors	20737	19555	23155	25591	28648	31685	34664	2.2%
Total Industrial	6720	6017	7472	7951	8396	8826	9292	1.7%
Nonmanufacturing	2039	1821	2193	2308	2381	2433	2521	1.3%
Manufacturing	4680	4197	5279	5643	6016	6393	6770	1.9%
Energy-Intensive	1635	1551	1792	1875	1940	1977	2015	1.0%
Non-energy Intensive	3046	2646	3487	3768	4075	4416	4756	2.3%
Total Shipments	**27456**	**25573**	**30627**	**33542**	**37044**	**40510**	**43956**	**2.1%**
Population and Employment (millions)								
Population, with Armed Forces Overseas	305.2	307.8	326.2	342.0	358.1	374.1	390.1	0.9%
Population, aged 16 and over	239.4	241.8	256.5	269.4	282.6	296.2	309.6	1.0%
Population, over age 65	38.9	39.7	47.1	55.1	64.2	72.3	77.7	2.6%
Employment, Nonfarm	136.7	130.9	142.2	148.7	156.2	164.2	170.8	1.0%
Employment, Manufacturing	13.4	11.9	17.4	17.1	15.8	14.3	13.1	0.4%
Key Labor Indicators								
Labor Force (millions)	154.3	154.2	160.7	166.2	170.6	175.8	182.6	0.7%
Nonfarm Labor Productivity (1992=1.00)	1.04	1.07	1.18	1.31	1.47	1.62	1.79	2.0%
Unemployment Rate (percent)	5.82	9.27	6.87	5.47	4.98	4.94	5.20	- -
Key Indicators for Energy Demand								
Real Disposable Personal Income	10043	10100	11533	13181	15118	17123	19224	2.5%
Housing Starts (millions)	0.98	0.60	1.85	1.90	1.93	1.83	1.74	4.2%
Commercial Floorspace (billion square feet)	78.8	80.2	85.4	91.5	97.4	103.5	109.8	1.2%
Unit Sales of Light-Duty Vehicles (millions)	13.19	10.40	17.03	16.81	18.24	19.64	20.64	2.7%

GDP = Gross domestic product.
Btu = British thermal unit.
- - = Not applicable.
Sources: 2008 and 2009: IHS Global Insight Industry and Employment models, September 2010. **Projections:** U.S. Energy Information Administration, AEO2011 National Energy Modeling System run REF2011.D020911A.

Table A21. International liquids supply and disposition summary
(million barrels per day, unless otherwise noted)

Supply and Disposition	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Crude Oil Prices (2009 dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	100.51	61.66	94.58	108.10	117.54	123.09	124.94	2.8%
Imported Crude Oil	93.44	59.04	86.83	98.65	107.40	112.38	113.70	2.6%
Crude Oil Prices (nominal dollars per barrel)[1]								
Imported Low Sulfur Light Crude Oil	99.57	61.66	103.24	130.60	155.46	178.45	199.37	4.6%
Imported Crude Oil	92.57	59.04	94.78	119.18	142.05	162.92	181.43	4.4%
Conventional Production (Conventional)[2]								
OPEC[3]								
Middle East	24.24	22.61	25.66	26.96	28.64	30.93	33.87	1.6%
North Africa	4.05	3.92	4.32	3.96	3.84	3.85	3.98	0.1%
West Africa	4.18	4.06	5.10	5.18	5.10	5.10	5.31	1.0%
South America	2.50	2.31	2.00	1.80	1.73	1.65	1.64	-1.3%
Total OPEC	**34.98**	**32.91**	**37.08**	**37.91**	**39.32**	**41.53**	**44.80**	**1.2%**
Non-OPEC								
OECD								
United States (50 states)	7.71	8.26	9.30	9.79	9.78	9.70	9.89	0.7%
Canada	1.84	1.96	1.80	1.78	1.78	1.79	1.78	-0.4%
Mexico and Chile	3.19	2.90	2.05	1.52	1.22	1.30	1.48	-2.6%
OECD Europe[4]	4.96	4.62	3.36	2.83	2.67	2.62	2.66	-2.1%
Japan	0.13	0.13	0.14	0.14	0.14	0.15	0.15	0.6%
Australia and New Zealand	0.65	0.65	0.56	0.53	0.52	0.52	0.54	-0.8%
Total OECD	**18.48**	**18.52**	**17.20**	**16.58**	**16.13**	**16.08**	**16.49**	**-0.4%**
Non-OECD								
Russia	9.79	9.66	10.02	10.34	10.86	11.64	12.64	1.0%
Other Europe and Eurasia[5]	2.88	3.08	3.54	3.72	3.97	4.22	4.47	1.4%
China	3.97	3.93	3.80	3.81	4.02	4.22	4.22	0.3%
Other Asia[6]	3.75	3.70	3.47	3.17	2.99	2.87	2.85	-1.0%
Middle East	1.54	1.54	1.57	1.40	1.24	1.14	1.10	-1.3%
Africa	2.39	2.34	2.71	2.76	2.85	2.96	3.16	1.2%
Brazil	1.95	2.05	2.76	3.34	3.87	4.38	4.93	3.4%
Other Central and South America	1.82	1.87	2.10	2.10	2.24	2.49	2.59	1.3%
Total Non-OECD	**28.09**	**28.17**	**29.96**	**30.64**	**32.03**	**33.92**	**35.95**	**0.9%**
Total Conventional Production	**81.55**	**79.60**	**84.24**	**85.14**	**87.47**	**91.53**	**97.24**	**0.8%**
Unconventional Production[7]								
United States (50 states)	0.65	0.75	1.11	1.41	1.94	2.47	2.90	5.3%
Other North America	1.54	1.68	2.39	2.93	3.57	4.35	5.27	4.5%
OECD Europe[4]	0.21	0.22	0.23	0.24	0.26	0.27	0.28	1.0%
Middle East	0.00	0.01	0.17	0.21	0.24	0.24	0.24	14.0%
Africa.	0.21	0.21	0.28	0.37	0.39	0.44	0.44	2.9%
Central and South America	1.18	1.14	1.78	2.31	2.61	2.90	3.17	4.0%
Other	0.11	0.12	0.17	0.30	0.64	0.98	1.22	9.4%
Total Unconventional Production	**3.91**	**4.14**	**6.13**	**7.77**	**9.66**	**11.65**	**13.54**	**4.7%**
Total Production	**85.45**	**83.74**	**90.37**	**92.91**	**97.13**	**103.18**	**110.78**	**1.1%**

Table A21. International liquids supply and disposition summary (continued)
(million barrels per day, unless otherwise noted)

Supply and Disposition	Reference Case							Annual Growth 2009-2035 (percent)
	2008	2009	2015	2020	2025	2030	2035	
Consumption[8]								
OECD								
United States (50 states)	19.52	18.81	20.44	20.68	20.99	21.36	21.93	0.6%
United States Territories	0.28	0.27	0.31	0.30	0.30	0.31	0.32	0.7%
Canada	2.24	2.15	2.24	2.14	2.14	2.18	2.24	0.2%
Mexico and Chile	2.21	2.13	2.17	2.19	2.30	2.46	2.63	0.8%
OECD Europe[4]	15.36	14.49	13.55	13.03	12.82	12.85	12.95	-0.4%
Japan	4.79	4.37	4.18	4.07	3.98	3.91	3.88	-0.5%
South Korea	2.35	2.32	2.44	2.49	2.63	2.85	3.13	1.1%
Australia and New Zealand	1.14	1.19	1.18	1.14	1.13	1.14	1.17	-0.1%
Total OECD	**47.89**	**45.73**	**46.50**	**46.03**	**46.29**	**47.07**	**48.25**	**0.2%**
Non-OECD								
Russia	2.91	2.83	2.90	2.75	2.66	2.66	2.78	-0.1%
Other Europe and Eurasia[5]	2.23	2.16	2.25	2.20	2.25	2.35	2.48	0.5%
China	7.83	8.32	11.10	12.60	14.36	16.55	19.13	3.3%
India	2.97	3.06	3.68	4.13	4.54	5.05	5.64	2.4%
Other Non-OECD Asia[6]	6.35	6.13	6.72	7.27	7.98	8.77	9.75	1.8%
Middle East	6.55	6.64	7.47	8.06	8.76	9.76	11.02	2.0%
Africa	3.15	3.31	3.50	3.56	3.76	4.07	4.45	1.2%
Brazil	2.49	2.46	2.82	3.00	3.20	3.49	3.79	1.7%
Other Central and South America	3.10	3.09	3.41	3.32	3.33	3.41	3.51	0.5%
Total Non-OECD	**37.59**	**38.01**	**43.87**	**46.88**	**50.84**	**56.11**	**62.54**	**1.9%**
Total Consumption	**85.48**	**83.74**	**90.37**	**92.91**	**97.13**	**103.19**	**110.79**	**1.1%**
OPEC Production[9]	35.63	33.45	38.08	39.23	40.77	43.10	46.50	1.3%
Non-OPEC Production[9]	49.82	50.29	52.30	53.68	56.37	60.08	64.28	0.9%
Net Eurasia Exports	9.48	9.80	11.16	12.45	13.80	15.22	16.78	2.1%
OPEC Market Share (percent)	41.7	39.9	42.1	42.2	42.0	41.8	42.0	- -

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate), 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, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[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, Slovenia, Spain, Sweden, Switzerland, Turkey, and the United Kingdom.
[5]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, 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]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both conventional and unconventional liquids production.
- - = Not applicable.
Note: Totals may not equal sum of components due to independent rounding. Data for 2008 and 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2008 and 2009 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2008 and 2009 imported crude oil price: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2008 quantities derived from: EIA, International Energy Statistics database as of November 2009. **2009 quantities and projections:** EIA, AEO2011 National Energy Modeling System run REF2011.D020911A and EIA, Generate World Oil Balance Model.

Economic growth case comparisons

Table B1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	Projections								
		2015			2025			2035		
		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	11.34	12.53	12.51	12.55	12.44	12.64	12.62	12.13	12.80	12.87
Natural Gas Plant Liquids	2.57	2.79	2.86	2.89	3.39	3.55	3.70	3.59	3.92	4.11
Dry Natural Gas	21.50	22.50	23.01	23.30	23.58	24.60	25.54	24.92	27.00	30.16
Coal[1]	21.58	20.87	20.94	21.35	22.73	23.64	25.07	24.57	26.01	27.02
Nuclear Power	8.35	8.77	8.77	8.77	9.02	9.17	9.17	8.99	9.14	9.14
Hydropower	2.69	2.92	2.92	2.93	3.00	3.04	3.06	3.03	3.09	3.10
Biomass[2]	3.52	4.67	4.70	4.79	6.99	7.20	7.40	8.28	8.63	9.58
Other Renewable Energy[3]	1.29	2.03	2.14	2.18	2.36	2.58	2.74	2.79	3.22	3.46
Other[4]	0.34	0.79	0.78	0.75	0.81	0.88	0.88	0.77	0.78	0.88
Total	**73.18**	**77.87**	**78.63**	**79.51**	**84.32**	**87.29**	**90.17**	**89.07**	**94.59**	**100.33**
Imports										
Crude Oil	19.70	18.75	19.25	19.84	17.24	18.35	19.70	16.92	18.44	20.43
Liquid Fuels and Other Petroleum[5]	5.40	5.21	5.33	5.52	4.87	5.18	5.65	4.78	5.33	6.22
Natural Gas	3.82	3.97	4.01	4.09	3.10	3.20	3.33	2.79	2.87	2.79
Other Imports[6]	0.61	0.82	0.82	0.83	1.04	1.39	1.40	1.14	1.27	1.25
Total	**29.53**	**28.75**	**29.41**	**30.28**	**26.25**	**28.13**	**30.09**	**25.63**	**27.92**	**30.69**
Exports										
Petroleum[7]	4.17	3.26	3.27	3.29	3.55	3.62	3.70	3.79	3.92	4.05
Natural Gas	1.09	1.25	1.24	1.23	2.12	2.07	2.03	2.74	2.64	2.55
Coal	1.51	1.76	1.76	1.76	1.89	1.89	1.89	1.79	1.78	1.77
Total	**6.77**	**6.26**	**6.27**	**6.28**	**7.56**	**7.58**	**7.62**	**8.32**	**8.34**	**8.37**
Discrepancy[8]	**1.16**	**-0.23**	**-0.24**	**-0.29**	**-0.13**	**-0.12**	**-0.18**	**0.03**	**-0.02**	**0.01**
Consumption										
Liquid Fuels and Other Petroleum[9]	36.62	38.46	39.10	39.94	37.91	39.84	41.96	38.41	41.70	45.43
Natural Gas	23.31	25.21	25.77	26.14	24.55	25.73	26.84	24.97	27.24	30.41
Coal[10]	19.69	19.65	19.73	20.16	21.47	22.61	23.91	22.92	24.30	25.12
Nuclear Power	8.35	8.77	8.77	8.77	9.02	9.17	9.17	8.99	9.14	9.14
Hydropower	2.69	2.92	2.92	2.93	3.00	3.04	3.06	3.03	3.09	3.10
Biomass[11]	2.52	3.24	3.27	3.35	4.57	4.71	4.86	5.00	5.25	5.73
Other Renewable Energy[3]	1.29	2.03	2.14	2.18	2.36	2.58	2.74	2.79	3.22	3.46
Other[12]	0.32	0.31	0.31	0.31	0.27	0.27	0.28	0.24	0.25	0.25
Total	**94.79**	**100.59**	**102.02**	**103.79**	**103.15**	**107.95**	**112.82**	**106.35**	**114.19**	**122.64**
Prices (2009 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	61.66	93.59	94.58	95.66	115.30	117.54	120.09	122.17	124.94	128.52
Imported Crude Oil Price[13]	59.04	86.00	86.83	88.20	104.56	107.40	110.70	110.20	113.70	118.34
Natural Gas (dollars per million Btu)										
Price at Henry Hub	3.95	4.52	4.66	4.84	5.59	5.97	6.50	6.29	7.07	7.50
Wellhead Price[14]	3.62	4.00	4.13	4.29	4.95	5.29	5.76	5.57	6.26	6.64
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	3.71	4.11	4.24	4.40	5.07	5.43	5.91	5.71	6.42	6.81
Coal (dollars per ton)										
Minemouth Price[15]	33.26	32.25	32.36	32.87	32.95	33.22	34.20	33.12	33.92	34.82
Coal (dollars per million Btu)										
Minemouth Price[15]	1.67	1.61	1.62	1.64	1.66	1.68	1.73	1.69	1.73	1.77
Average Delivered Price[16]	2.31	2.25	2.26	2.30	2.32	2.36	2.42	2.39	2.47	2.52
Average Electricity Price (cents per kilowatthour)	9.8	8.8	8.9	9.0	8.6	8.9	9.3	8.7	9.2	9.6

Table B1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	Projections								
		2015			2025			2035		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	61.66	104.03	103.24	101.79	165.41	155.46	144.96	220.15	199.37	178.52
Imported Crude Oil Price[13]	59.04	95.59	94.78	93.85	149.99	142.05	133.62	198.58	181.43	164.38
Natural Gas (dollars per million Btu)										
Price at Henry Hub	3.95	5.02	5.09	5.15	8.01	7.90	7.85	11.33	11.28	10.41
Wellhead Price[14]	3.62	4.45	4.51	4.56	7.10	6.99	6.95	10.03	9.99	9.22
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	3.71	4.56	4.63	4.68	7.28	7.18	7.13	10.30	10.24	9.46
Coal (dollars per ton)										
Minemouth Price[15]	33.26	35.85	35.32	34.98	47.27	43.93	41.29	59.67	54.13	48.37
Coal (dollars per million Btu)										
Minemouth Price[15]	1.67	1.79	1.77	1.75	2.38	2.22	2.09	3.04	2.76	2.46
Average Delivered Price[16]	2.31	2.50	2.47	2.44	3.33	3.12	2.93	4.30	3.95	3.50
Average Electricity Price (cents per kilowatthour)	9.8	9.8	9.7	9.6	12.4	11.8	11.2	15.7	14.7	13.3

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and wood 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, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids and natural gas.
[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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 natural gas supply values and natural gas wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 coal minemouth and delivered coal prices: EIA, *Annual Coal Report 2009*, DOE/EIA-0584(2009) (Washington, DC, October 2010). 2009 petroleum supply values: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2009 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2009 coal values: *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010). Other 2009 values: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs LM2011.D020911A, REF2011.D020911A, and HM2011.D020911A.

Table B2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		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	0.53	0.49	0.49	0.49	0.47	0.48	0.48	0.46	0.48	0.50
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.61	0.56	0.56	0.56	0.44	0.44	0.44	0.36	0.37	0.37
Liquid Fuels and Other Petroleum Subtotal	1.16	1.07	1.07	1.07	0.93	0.94	0.95	0.84	0.86	0.89
Natural Gas	4.87	4.92	4.94	4.96	4.84	4.96	5.09	4.64	4.90	5.19
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.40	0.40	0.41	0.41	0.42	0.44	0.40	0.42	0.45
Electricity	4.65	4.55	4.60	4.65	4.78	4.98	5.18	5.09	5.51	5.93
Delivered Energy	**11.12**	**10.95**	**11.02**	**11.10**	**10.97**	**11.32**	**11.66**	**10.98**	**11.70**	**12.47**
Electricity Related Losses	9.96	9.39	9.46	9.55	9.87	10.24	10.57	10.38	11.06	11.61
Total	**21.08**	**20.33**	**20.48**	**20.65**	**20.83**	**21.56**	**22.22**	**21.36**	**22.76**	**24.08**
Commercial										
Liquefied Petroleum Gases	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16
Motor Gasoline[2]	0.05	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.34	0.28	0.28	0.28	0.25	0.26	0.26	0.24	0.25	0.25
Residual Fuel Oil	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07	0.07
Liquid Fuels and Other Petroleum Subtotal	0.60	0.55	0.55	0.55	0.53	0.53	0.54	0.52	0.53	0.54
Natural Gas	3.20	3.45	3.47	3.48	3.59	3.66	3.70	3.82	3.92	4.05
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.51	4.80	4.83	4.87	5.41	5.58	5.74	6.16	6.43	6.74
Delivered Energy	**8.49**	**8.97**	**9.02**	**9.07**	**9.70**	**9.94**	**10.15**	**10.68**	**11.05**	**11.50**
Electricity Related Losses	9.66	9.89	9.94	10.01	11.16	11.47	11.73	12.57	12.93	13.20
Total	**18.15**	**18.86**	**18.96**	**19.07**	**20.87**	**21.41**	**21.88**	**23.25**	**23.98**	**24.70**
Industrial[4]										
Liquefied Petroleum Gases	2.01	2.35	2.36	2.39	2.26	2.38	2.48	1.99	2.18	2.35
Motor Gasoline[2]	0.25	0.32	0.33	0.35	0.31	0.33	0.35	0.29	0.32	0.36
Distillate Fuel Oil	1.16	1.09	1.16	1.23	1.05	1.16	1.27	0.99	1.13	1.28
Residual Fuel Oil	0.17	0.17	0.17	0.18	0.16	0.17	0.18	0.14	0.16	0.17
Petrochemical Feedstocks	0.90	1.28	1.29	1.30	1.27	1.34	1.39	1.15	1.26	1.35
Other Petroleum[5]	3.45	3.82	3.97	4.16	3.48	3.79	4.11	3.44	3.88	4.35
Liquid Fuels and Other Petroleum Subtotal	7.94	9.03	9.29	9.60	8.53	9.16	9.79	8.00	8.94	9.86
Natural Gas	6.31	8.11	8.27	8.48	7.88	8.32	8.81	7.55	8.23	9.01
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]	1.19	1.21	1.24	1.25	1.18	1.22	1.26	1.18	1.28	1.44
Natural Gas Subtotal	7.50	9.32	9.51	9.72	9.06	9.54	10.06	8.73	9.51	10.45
Metallurgical Coal	0.40	0.56	0.58	0.62	0.48	0.55	0.63	0.38	0.47	0.58
Other Industrial Coal	0.94	0.97	0.98	1.00	0.94	0.97	1.01	0.90	0.94	0.98
Coal-to-Liquids Heat and Power	0.00	0.10	0.10	0.10	0.28	0.40	0.56	0.97	1.19	1.37
Net Coal Coke Imports	-0.02	0.00	0.01	0.01	-0.00	0.00	0.01	-0.01	-0.00	0.01
Coal Subtotal	1.32	1.63	1.67	1.73	1.70	1.93	2.21	2.23	2.60	2.95
Biofuels Heat and Coproducts	0.66	0.84	0.85	0.86	1.86	1.90	1.93	2.45	2.52	2.80
Renewable Energy[7]	1.42	1.86	1.89	1.94	1.95	2.05	2.15	1.89	2.04	2.19
Electricity	3.01	3.45	3.54	3.65	3.27	3.52	3.75	2.92	3.28	3.64
Delivered Energy	**21.85**	**26.13**	**26.75**	**27.49**	**26.37**	**28.11**	**29.90**	**26.22**	**28.89**	**31.88**
Electricity Related Losses	6.44	7.11	7.28	7.49	6.75	7.23	7.66	5.96	6.59	7.13
Total	**28.29**	**33.24**	**34.03**	**34.97**	**33.12**	**35.33**	**37.56**	**32.18**	**35.49**	**39.01**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		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	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.03
E85[8]	0.00	0.01	0.01	0.01	0.99	0.93	0.87	1.23	1.23	1.01
Motor Gasoline[2]	16.82	16.84	17.02	17.28	15.19	15.93	16.77	15.33	16.69	18.43
Jet Fuel[9]	3.20	3.17	3.20	3.24	3.34	3.47	3.62	3.37	3.62	3.89
Distillate Fuel Oil[10]	5.54	6.39	6.57	6.79	6.98	7.45	7.98	7.66	8.35	9.29
Residual Fuel Oil	0.78	0.79	0.79	0.80	0.80	0.81	0.81	0.81	0.82	0.83
Other Petroleum[11]	0.16	0.15	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17
Liquid Fuels and Other Petroleum Subtotal	26.52	27.38	27.76	28.29	27.48	28.76	30.23	28.57	30.89	33.64
Pipeline Fuel Natural Gas	0.65	0.65	0.67	0.68	0.62	0.64	0.66	0.62	0.67	0.78
Compressed Natural Gas	0.03	0.04	0.04	0.04	0.10	0.10	0.11	0.15	0.16	0.18
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.05	0.05	0.07	0.07	0.08
Delivered Energy	**27.23**	**28.10**	**28.50**	**29.03**	**28.23**	**29.56**	**31.05**	**29.42**	**31.80**	**34.69**
Electricity Related Losses	0.05	0.06	0.06	0.06	0.09	0.09	0.10	0.14	0.15	0.16
Total	**27.28**	**28.16**	**28.56**	**29.09**	**28.32**	**29.65**	**31.15**	**29.56**	**31.95**	**34.85**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.71	3.00	3.02	3.04	2.89	3.03	3.14	2.62	2.84	3.04
E85[8]	0.00	0.01	0.01	0.01	0.99	0.93	0.87	1.23	1.23	1.01
Motor Gasoline[2]	17.11	17.21	17.39	17.67	15.54	16.31	17.17	15.66	17.06	18.84
Jet Fuel[9]	3.20	3.17	3.20	3.24	3.34	3.47	3.62	3.37	3.62	3.89
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate Fuel Oil	7.65	8.33	8.57	8.86	8.73	9.31	9.95	9.25	10.10	11.19
Residual Fuel Oil	1.02	1.02	1.03	1.04	1.03	1.04	1.06	1.02	1.05	1.07
Petrochemical Feedstocks	0.90	1.28	1.29	1.30	1.27	1.34	1.39	1.15	1.26	1.35
Other Petroleum[12]	3.60	3.97	4.13	4.31	3.64	3.94	4.27	3.59	4.04	4.51
Liquid Fuels and Other Petroleum Subtotal	36.23	38.03	38.67	39.50	37.45	39.39	41.50	37.94	41.22	44.93
Natural Gas	14.41	16.52	16.72	16.96	16.41	17.05	17.71	16.16	17.22	18.44
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]	1.19	1.21	1.24	1.25	1.18	1.22	1.26	1.18	1.28	1.44
Pipeline Natural Gas	0.65	0.65	0.67	0.68	0.62	0.64	0.66	0.62	0.67	0.78
Natural Gas Subtotal	16.25	18.39	18.62	18.89	18.20	18.91	19.63	17.96	19.17	20.66
Metallurgical Coal	0.40	0.56	0.58	0.62	0.48	0.55	0.63	0.38	0.47	0.58
Other Coal	1.01	1.03	1.05	1.07	1.01	1.04	1.08	0.97	1.01	1.05
Coal-to-Liquids Heat and Power	0.00	0.10	0.10	0.10	0.28	0.40	0.56	0.97	1.19	1.37
Net Coal Coke Imports	-0.02	0.00	0.01	0.01	-0.00	0.00	0.01	-0.01	-0.00	0.01
Coal Subtotal	1.39	1.69	1.74	1.80	1.76	2.00	2.28	2.30	2.66	3.01
Biofuels Heat and Coproducts	0.66	0.84	0.85	0.86	1.86	1.90	1.93	2.45	2.52	2.80
Renewable Energy[13]	1.96	2.37	2.41	2.46	2.48	2.59	2.70	2.40	2.58	2.74
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.20	12.83	13.00	13.19	13.51	14.13	14.72	14.25	15.29	16.40
Delivered Energy	**68.68**	**74.15**	**75.29**	**76.69**	**75.27**	**78.92**	**82.77**	**77.30**	**83.45**	**90.55**
Electricity Related Losses	26.11	26.44	26.73	27.10	27.87	29.03	30.05	29.05	30.74	32.09
Total	**94.79**	**100.59**	**102.02**	**103.79**	**103.15**	**107.95**	**112.82**	**106.35**	**114.19**	**122.64**
Electric Power[14]										
Distillate Fuel Oil	0.10	0.09	0.09	0.10	0.10	0.10	0.10	0.11	0.10	0.12
Residual Fuel Oil	0.30	0.34	0.34	0.35	0.35	0.35	0.36	0.36	0.37	0.38
Liquid Fuels and Other Petroleum Subtotal	0.40	0.43	0.43	0.44	0.46	0.45	0.46	0.47	0.47	0.50
Natural Gas	7.06	6.82	7.15	7.25	6.35	6.82	7.21	7.01	8.07	9.75
Steam Coal	18.30	17.96	17.99	18.37	19.71	20.61	21.63	20.62	21.64	22.11
Nuclear Power	8.35	8.77	8.77	8.77	9.02	9.17	9.17	8.99	9.14	9.14
Renewable Energy[15]	3.89	4.98	5.08	5.15	5.59	5.84	6.02	5.98	6.47	6.74
Electricity Imports	0.12	0.11	0.11	0.11	0.07	0.07	0.08	0.03	0.05	0.05
Total[16]	**38.31**	**39.27**	**39.73**	**40.29**	**41.39**	**43.17**	**44.77**	**43.29**	**46.03**	**48.49**

Table B2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Total Energy Consumption										
Liquefied Petroleum Gases	2.71	3.00	3.02	3.04	2.89	3.03	3.14	2.62	2.84	3.04
E85[8]	0.00	0.01	0.01	0.01	0.99	0.93	0.87	1.23	1.23	1.01
Motor Gasoline[2]	17.11	17.21	17.39	17.67	15.54	16.31	17.17	15.66	17.06	18.84
Jet Fuel[9]	3.20	3.17	3.20	3.24	3.34	3.47	3.62	3.37	3.62	3.89
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate Fuel Oil	7.75	8.42	8.66	8.95	8.83	9.40	10.05	9.36	10.20	11.31
Residual Fuel Oil	1.32	1.36	1.37	1.38	1.38	1.40	1.42	1.39	1.41	1.45
Petrochemical Feedstocks	0.90	1.28	1.29	1.30	1.27	1.34	1.39	1.15	1.26	1.35
Other Petroleum[12]	3.60	3.97	4.13	4.31	3.64	3.94	4.27	3.59	4.04	4.51
Liquid Fuels and Other Petroleum Subtotal	36.62	38.46	39.10	39.94	37.91	39.84	41.96	38.41	41.70	45.43
Natural Gas	21.47	23.34	23.87	24.21	22.76	23.87	24.92	23.17	25.29	28.19
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]	1.19	1.21	1.24	1.25	1.18	1.22	1.26	1.18	1.28	1.44
Pipeline Natural Gas	0.65	0.65	0.67	0.68	0.62	0.64	0.66	0.62	0.67	0.78
Natural Gas Subtotal	23.31	25.21	25.77	26.14	24.55	25.73	26.84	24.97	27.24	30.41
Metallurgical Coal	0.40	0.56	0.58	0.62	0.48	0.55	0.63	0.38	0.47	0.58
Other Coal	19.31	18.99	19.04	19.43	20.72	21.65	22.70	21.59	22.64	23.16
Coal-to-Liquids Heat and Power	0.00	0.10	0.10	0.10	0.28	0.40	0.56	0.97	1.19	1.37
Net Coal Coke Imports	-0.02	0.00	0.01	0.01	-0.00	0.00	0.01	-0.01	-0.00	0.01
Coal Subtotal	19.69	19.65	19.73	20.16	21.47	22.61	23.91	22.92	24.30	25.12
Nuclear Power	8.35	8.77	8.77	8.77	9.02	9.17	9.17	8.99	9.14	9.14
Biofuels Heat and Coproducts	0.66	0.84	0.85	0.86	1.86	1.90	1.93	2.45	2.52	2.80
Renewable Energy[17]	5.85	7.35	7.49	7.60	8.06	8.43	8.72	8.38	9.04	9.49
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.12	0.11	0.11	0.11	0.07	0.07	0.08	0.03	0.05	0.05
Total	**94.79**	**100.59**	**102.02**	**103.79**	**103.15**	**107.95**	**112.82**	**106.35**	**114.19**	**122.64**
Energy Use and Related Statistics										
Delivered Energy Use	68.68	74.15	75.29	76.69	75.27	78.92	82.77	77.30	83.45	90.55
Total Energy Use	94.79	100.59	102.02	103.79	103.15	107.95	112.82	106.35	114.19	122.64
Ethanol Consumed in Motor Gasoline and E85	0.95	1.32	1.33	1.35	2.04	2.07	2.11	2.24	2.37	2.40
Population (millions)	307.84	324.28	326.16	330.09	343.66	358.06	374.90	359.21	390.09	422.90
Gross Domestic Product (billion 2005 dollars)	12881	14820	15336	15941	18388	20020	21728	22163	25692	29231
Carbon Dioxide Emissions (million metric tons)	5425.5	5605.0	5679.9	5789.0	5652.0	5937.8	6248.7	5863.8	6310.8	6794.9

[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 electricity generation from wind and solar photovoltaic sources.
[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 electricity generation from wind and solar photovoltaic sources.
[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, 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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 population and gross domestic product: IHS Global Insight Industry and Employment models, September 2010. 2009 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2009,* DOE/EIA-0573(2009) (Washington, DC, December 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs LM2011.D020911A, REF2011.D020911A, and HM2011.D020911A.

Table B3. Energy prices by sector and source

(2009 dollars per million Btu, unless otherwise noted)

Sector and Source	2009	2015 Low Economic Growth	2015 Reference	2015 High Economic Growth	2025 Low Economic Growth	2025 Reference	2025 High Economic Growth	2035 Low Economic Growth	2035 Reference	2035 High Economic Growth
Residential										
Liquefied Petroleum Gases	24.63	29.63	29.79	30.04	33.37	33.90	34.49	34.42	35.01	35.91
Distillate Fuel Oil	18.12	20.81	21.14	21.63	25.42	25.92	27.03	26.28	27.53	28.76
Natural Gas	11.88	9.97	10.12	10.31	11.40	11.83	12.42	12.51	13.39	13.83
Electricity	33.62	31.52	31.80	32.12	30.43	31.20	32.37	30.25	31.67	32.89
Commercial										
Liquefied Petroleum Gases	21.49	26.17	26.32	26.58	29.88	30.41	30.98	30.91	31.48	32.35
Distillate Fuel Oil	15.97	18.98	19.28	19.74	23.54	24.02	25.13	24.32	25.52	26.74
Residual Fuel Oil	13.45	13.09	13.25	13.41	16.79	17.05	17.45	17.81	18.13	18.68
Natural Gas	9.68	8.22	8.37	8.56	9.34	9.77	10.34	10.15	10.98	11.41
Electricity	29.51	26.27	26.67	27.11	25.69	26.65	27.91	25.28	26.99	28.36
Industrial[1]										
Liquefied Petroleum Gases	20.59	23.14	23.31	23.60	26.97	27.52	28.15	27.90	28.52	29.43
Distillate Fuel Oil	16.56	19.06	19.34	19.80	23.73	24.20	25.31	24.45	25.66	26.91
Residual Fuel Oil	12.05	14.64	14.80	14.98	17.79	18.19	18.93	18.18	18.73	19.37
Natural Gas[2]	5.25	4.84	4.96	5.12	5.84	6.17	6.65	6.52	7.21	7.61
Metallurgical Coal	5.43	6.00	6.01	6.07	6.42	6.46	6.50	6.51	6.58	6.65
Other Industrial Coal	3.05	2.90	2.91	2.93	2.96	2.99	3.05	3.06	3.14	3.18
Coal to Liquids	- -	1.79	1.79	1.81	1.85	1.78	1.90	1.93	2.05	2.08
Electricity	19.79	17.35	17.68	18.01	17.33	17.99	18.91	17.46	18.73	19.85
Transportation										
Liquefied Petroleum Gases[3]	25.52	30.40	30.56	30.82	34.08	34.62	35.22	35.08	35.66	36.56
E85[4]	20.50	26.19	26.38	26.53	29.05	29.49	30.71	29.52	30.93	32.31
Motor Gasoline[5]	19.28	25.79	25.97	26.12	29.07	29.49	30.71	29.57	30.90	32.12
Jet Fuel[6]	12.59	18.70	19.02	19.51	22.97	23.56	24.72	24.05	25.28	26.57
Diesel Fuel (distillate fuel oil)[7]	17.79	22.21	22.50	23.00	26.63	27.19	28.45	27.05	28.39	29.82
Residual Fuel Oil	10.57	12.53	12.65	12.83	15.61	16.02	16.84	16.01	16.44	17.18
Natural Gas[8]	12.71	11.80	11.97	12.19	12.36	12.84	13.49	12.71	13.57	14.13
Electricity	34.92	28.84	29.16	29.39	28.19	29.49	31.15	30.07	32.37	34.49
Electric Power[9]										
Distillate Fuel Oil	14.33	16.55	16.84	17.32	20.73	21.20	22.18	21.71	22.84	24.00
Residual Fuel Oil	8.96	13.05	13.17	13.35	15.86	16.26	16.98	16.35	16.71	17.31
Natural Gas	4.82	4.51	4.67	4.84	5.36	5.76	6.28	6.02	6.80	7.32
Steam Coal	2.20	2.10	2.11	2.14	2.20	2.24	2.30	2.32	2.40	2.43
Average Price to All Users[10]										
Liquefied Petroleum Gases	17.43	21.53	21.67	21.90	24.99	25.43	25.93	26.19	26.62	27.39
E85[4]	20.50	26.19	26.38	26.53	29.05	29.49	30.71	29.52	30.93	32.31
Motor Gasoline[5]	19.23	25.79	25.97	26.12	29.07	29.49	30.71	29.57	30.90	32.12
Jet Fuel	12.59	18.70	19.02	19.51	22.97	23.56	24.72	24.05	25.28	26.57
Distillate Fuel Oil	17.51	21.53	21.83	22.31	26.07	26.61	27.84	26.62	27.93	29.33
Residual Fuel Oil	10.53	12.94	13.07	13.26	15.98	16.39	17.17	16.41	16.85	17.54
Natural Gas	7.28	6.34	6.45	6.61	7.47	7.81	8.30	8.21	8.91	9.24
Metallurgical Coal	5.43	6.00	6.01	6.07	6.42	6.46	6.50	6.51	6.58	6.65
Other Coal	2.25	2.15	2.16	2.18	2.24	2.28	2.34	2.36	2.43	2.47
Coal to Liquids	- -	1.79	1.79	1.81	1.85	1.78	1.90	1.93	2.05	2.08
Electricity	28.69	25.74	26.04	26.37	25.35	26.11	27.20	25.47	26.93	28.14
Non-Renewable Energy Expenditures by Sector (billion 2009 dollars)										
Residential	238.63	219.18	223.20	227.80	228.09	242.45	259.97	237.98	267.49	296.15
Commercial	174.64	166.09	169.68	173.77	185.95	198.28	212.97	208.42	231.11	252.68
Industrial	179.22	215.61	224.19	234.84	233.84	258.44	288.83	221.28	261.51	302.29
Transportation	474.91	649.53	664.86	685.06	722.46	773.10	851.85	761.88	866.49	996.25
Total Non-Renewable Expenditures	1067.41	1250.40	1281.92	1321.47	1370.34	1472.27	1613.61	1429.57	1626.60	1847.37
Transportation Renewable Expenditures	0.06	0.22	0.23	0.24	28.63	27.48	26.58	36.43	37.93	32.69
Total Expenditures	**1067.47**	**1250.63**	**1282.15**	**1321.71**	**1398.97**	**1499.75**	**1640.20**	**1466.00**	**1664.53**	**1880.05**

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		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	24.63	32.94	32.51	31.97	47.87	44.84	41.63	62.02	55.86	49.88
Distillate Fuel Oil	18.12	23.13	23.07	23.02	36.46	34.28	32.63	47.36	43.93	39.96
Natural Gas	11.88	11.09	11.05	10.97	16.36	15.65	14.99	22.54	21.37	19.21
Electricity	33.62	35.04	34.72	34.18	43.66	41.27	39.07	54.51	50.54	45.69
Commercial										
Liquefied Petroleum Gases	21.49	29.09	28.73	28.28	42.87	40.22	37.39	55.70	50.23	44.94
Distillate Fuel Oil	15.97	21.10	21.04	21.01	33.76	31.77	30.33	43.82	40.72	37.15
Residual Fuel Oil	13.45	14.55	14.47	14.27	24.09	22.55	21.07	32.09	28.93	25.94
Natural Gas	9.68	9.14	9.14	9.11	13.40	12.92	12.48	18.29	17.52	15.85
Electricity	29.51	29.21	29.12	28.85	36.85	35.25	33.69	45.55	43.06	39.39
Industrial[1]										
Liquefied Petroleum Gases	20.59	25.72	25.45	25.12	38.69	36.40	33.98	50.27	45.52	40.88
Distillate Fuel Oil	16.56	21.19	21.12	21.07	34.05	32.01	30.55	44.06	40.95	37.38
Residual Fuel Oil	12.05	16.28	16.15	15.94	25.52	24.05	22.85	32.76	29.88	26.90
Natural Gas[2]	5.25	5.38	5.42	5.45	8.37	8.15	8.03	11.74	11.50	10.57
Metallurgical Coal	5.43	6.66	6.56	6.46	9.20	8.54	7.84	11.73	10.50	9.24
Other Industrial Coal	3.05	3.23	3.17	3.12	4.25	3.96	3.68	5.52	5.01	4.41
Coal to Liquids	- -	1.99	1.96	1.93	2.65	2.36	2.29	3.49	3.27	2.90
Electricity	19.79	19.29	19.30	19.17	24.86	23.79	22.83	31.46	29.88	27.58
Transportation										
Liquefied Petroleum Gases[3]	25.52	33.80	33.36	32.80	48.89	45.80	42.51	63.21	56.90	50.79
E85[4]	20.50	29.12	28.80	28.23	41.68	39.01	37.07	53.20	49.35	44.87
Motor Gasoline[5]	19.28	28.66	28.35	27.79	41.70	39.01	37.07	53.28	49.31	44.61
Jet Fuel[6]	12.59	20.78	20.76	20.76	32.95	31.16	29.83	43.33	40.35	36.91
Diesel Fuel (distillate fuel oil)[7]	17.79	24.68	24.56	24.47	38.20	35.96	34.34	48.75	45.30	41.42
Residual Fuel Oil	10.57	13.93	13.80	13.65	22.39	21.19	20.33	28.85	26.24	23.86
Natural Gas[8]	12.71	13.12	13.06	12.97	17.73	16.98	16.29	22.90	21.66	19.63
Electricity	34.92	32.06	31.83	31.27	40.45	39.01	37.61	54.18	51.66	47.91
Electric Power[9]										
Distillate Fuel Oil	14.33	18.39	18.38	18.43	29.74	28.04	26.77	39.12	36.45	33.34
Residual Fuel Oil	8.96	14.50	14.37	14.21	22.76	21.50	20.50	29.46	26.66	24.04
Natural Gas	4.82	5.01	5.10	5.15	7.69	7.62	7.58	10.85	10.86	10.16
Steam Coal	2.20	2.33	2.31	2.27	3.16	2.96	2.78	4.19	3.83	3.38

Table B3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth	Low Economic Growth	Reference	High Economic Growth
Average Price to All Users[10]										
Liquefied Petroleum Gases	17.43	23.93	23.65	23.31	35.85	33.64	31.30	47.19	42.49	38.05
E85[4]	20.50	29.12	28.80	28.23	41.68	39.01	37.07	53.20	49.35	44.87
Motor Gasoline[5]	19.23	28.66	28.35	27.79	41.70	39.01	37.07	53.28	49.31	44.61
Jet Fuel	12.59	20.78	20.76	20.76	32.95	31.16	29.83	43.33	40.35	36.91
Distillate Fuel Oil	17.51	23.94	23.83	23.74	37.40	35.20	33.60	47.96	44.57	40.74
Residual Fuel Oil	10.53	14.39	14.27	14.11	22.92	21.67	20.73	29.57	26.88	24.36
Natural Gas	7.28	7.05	7.04	7.03	10.71	10.33	10.02	14.79	14.21	12.84
Metallurgical Coal	5.43	6.66	6.56	6.46	9.20	8.54	7.84	11.73	10.50	9.24
Other Coal	2.25	2.39	2.36	2.32	3.22	3.02	2.82	4.25	3.89	3.43
Coal to Liquids	- -	1.99	1.96	1.93	2.65	2.36	2.29	3.49	3.27	2.90
Electricity	28.69	28.61	28.43	28.06	36.37	34.53	32.83	45.90	42.97	39.09
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	238.63	243.64	243.63	242.40	327.21	320.68	313.80	428.83	426.84	411.36
Commercial	174.64	184.62	185.21	184.91	266.76	262.27	257.06	375.56	368.78	350.97
Industrial	179.22	239.67	244.72	249.89	335.45	341.84	348.63	398.73	417.29	419.90
Transportation	474.91	722.01	725.73	728.96	1036.41	1022.56	1028.23	1372.86	1382.69	1383.82
Total Non-Renewable Expenditures	1067.41	1389.94	1399.29	1406.16	1965.83	1947.34	1947.72	2575.99	2595.61	2566.06
Transportation Renewable Expenditures	0.06	0.25	0.25	0.25	41.08	36.34	32.09	65.64	60.53	45.40
Total Expenditures	**1067.47**	**1390.19**	**1399.54**	**1406.41**	**2006.91**	**1983.68**	**1979.81**	**2641.63**	**2656.14**	**2611.46**

[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 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 transportation sector natural gas delivered prices are model results. 2009 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2009 and April 2010, Table 4.2. 2009 coal prices based on: EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010) and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. 2009 electricity prices: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2011 National Energy Modeling System runs LM2011.D020911A, REF2011.D020911A, and HM2011.D020911A.

Table B4. Macroeconomic indicators
(billion 2005 chain-weighted dollars, unless otherwise noted)

Indicators	2009	Projections								
		2015			2025			2035		
		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	**12881**	**14820**	**15336**	**15941**	**18388**	**20020**	**21728**	**22163**	**25692**	**29231**
Components of Real Gross Domestic Product										
Real Consumption	9154	10165	10443	10787	12313	13280	14276	14940	16976	19034
Real Investment	1516	2346	2592	2850	3110	3548	4018	3881	4849	5816
Real Government Spending	2543	2503	2555	2619	2610	2796	2996	2691	3069	3445
Real Exports	1491	2403	2437	2490	4008	4485	5020	6194	7334	8502
Real Imports	1854	2552	2624	2703	3658	3840	3982	5533	5902	6241
Energy Intensity										
(thousand Btu per 2005 dollar of GDP)										
Delivered Energy	5.33	5.00	4.91	4.81	4.09	3.94	3.81	3.49	3.25	3.10
Total Energy	7.36	6.79	6.65	6.51	5.61	5.39	5.19	4.80	4.44	4.20
Price Indices										
GDP Chain-Type Price Index (2005=1.000)	1.096	1.219	1.197	1.166	1.573	1.450	1.323	1.975	1.749	1.523
Consumer Price Index (1982-4=1)										
All-urban	2.15	2.44	2.39	2.33	3.23	2.97	2.72	4.12	3.66	3.19
Energy Commodities and Services	1.93	2.46	2.44	2.40	3.46	3.25	3.10	4.42	4.10	3.71
Wholesale Price Index (1982=1.00)										
All Commodities	1.73	2.05	2.00	1.94	2.63	2.38	2.14	3.16	2.74	2.30
Fuel and Power	1.59	2.06	2.05	2.03	3.00	2.84	2.72	3.93	3.68	3.33
Metals and Metal Products	1.87	2.51	2.48	2.43	2.97	2.77	2.56	3.19	2.87	2.54
Industrial Commodities excluding Energy	**1.76**	**2.04**	**2.00**	**1.95**	**2.44**	**2.25**	**2.05**	**2.74**	**2.43**	**2.11**
Interest Rates (percent, nominal)										
Federal Funds Rate	0.16	5.50	5.15	4.76	5.37	4.86	4.38	5.53	5.04	4.40
10-Year Treasury Note	3.26	6.21	5.76	5.23	6.37	5.78	5.23	6.46	5.89	5.20
AA Utility Bond Rate	5.75	7.71	7.41	7.04	8.39	7.69	7.07	8.62	7.93	7.16
Value of Shipments (billion 2005 dollars)										
Service Sectors	19555	22738	23155	23669	27266	28648	30049	32411	34664	36924
Total Industrial	6017	7186	7472	7796	7702	8396	9103	8128	9292	10535
Non-manufacturing	1821	2038	2193	2361	2117	2381	2651	2161	2521	2896
Manufacturing	4197	5148	5279	5435	5585	6016	6452	5967	6770	7639
Energy-Intensive	1551	1760	1792	1833	1827	1940	2056	1829	2015	2205
Non-Energy Intensive	2646	3388	3487	3602	3758	4075	4395	4138	4756	5434
Total Shipments	**25573**	**29924**	**30627**	**31465**	**34967**	**37044**	**39152**	**40539**	**43956**	**47459**
Population and Employment (millions)										
Population with Armed Forces Overseas	307.8	324.3	326.2	330.1	343.7	358.1	374.9	359.2	390.1	422.9
Population, aged 16 and over	241.8	254.7	256.5	260.1	272.9	282.6	293.6	289.4	309.6	331.1
Population, over age 65	39.7	46.9	47.1	47.4	63.1	64.2	65.4	75.2	77.7	80.4
Employment, Nonfarm	130.9	136.1	142.2	149.1	145.1	156.2	166.9	155.4	170.8	186.0
Employment, Manufacturing	11.9	17.2	17.4	17.7	15.4	15.8	15.9	12.7	13.1	13.4
Key Labor Indicators										
Labor Force (millions)	154.2	158.7	160.7	163.5	164.7	170.6	177.3	172.9	182.6	192.5
Non-farm Labor Productivity (1992=1.00)	1.07	1.16	1.18	1.20	1.38	1.47	1.57	1.60	1.79	1.98
Unemployment Rate (percent)	9.27	7.02	6.87	6.70	5.18	4.98	4.84	5.34	5.20	5.07
Key Indicators for Energy Demand										
Real Disposable Personal Income	10100	11235	11533	11891	14171	15118	16080	17306	19224	21138
Housing Starts (millions)	0.60	1.54	1.85	2.16	1.50	1.93	2.37	1.20	1.74	2.29
Commercial Floorspace (billion square feet)	80.2	84.5	85.4	86.5	93.3	97.4	101.5	103.3	109.8	116.9
Unit Sales of Light-Duty Vehicles (millions)	10.40	16.51	17.03	17.86	16.92	18.24	19.70	18.37	20.64	23.26

GDP = Gross domestic product.
Btu = British thermal unit.
Sources: 2009: IHS Global Insight Industry and Employment models, September 2010. **Projections:** U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs LM2011.D020911A, REF2011.D020911A, and HM2011.D020911A.

Appendix C

Price case comparisons

Table C1. Total energy supply, disposition, and price summary
(quadrillion Btu per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Production										
Crude Oil and Lease Condensate	11.34	12.35	12.51	12.76	11.19	12.64	15.18	9.32	12.80	15.31
Natural Gas Plant Liquids	2.57	2.88	2.86	2.90	3.50	3.55	3.62	3.85	3.92	3.86
Dry Natural Gas	21.50	23.05	23.01	23.23	24.24	24.60	25.20	26.91	27.00	27.63
Coal[1]	21.58	20.63	20.94	20.83	23.30	23.64	24.98	23.82	26.01	30.33
Nuclear Power	8.35	8.77	8.77	8.77	9.08	9.17	9.17	9.05	9.14	9.14
Hydropower	2.69	2.92	2.92	2.92	3.01	3.04	3.03	3.06	3.09	3.09
Biomass[2]	3.52	4.71	4.70	4.95	6.46	7.20	8.55	7.97	8.63	11.88
Other Renewable Energy[3]	1.29	2.09	2.14	2.14	2.52	2.58	2.61	3.01	3.22	3.22
Other[4]	0.34	0.59	0.78	0.92	0.65	0.88	0.90	0.62	0.78	1.02
Total	**73.18**	**77.99**	**78.63**	**79.43**	**83.95**	**87.29**	**93.24**	**87.62**	**94.59**	**105.48**
Imports										
Crude Oil	19.70	20.90	19.25	17.61	22.46	18.35	12.86	25.74	18.44	10.15
Liquid Fuels and Other Petroleum[5]	5.40	5.58	5.33	5.01	6.09	5.18	4.56	6.77	5.33	4.42
Natural Gas	3.82	4.21	4.01	3.98	3.60	3.20	2.77	3.04	2.87	2.46
Other Imports[6]	0.61	0.82	0.82	0.82	1.22	1.39	1.39	1.05	1.27	1.38
Total	**29.53**	**31.51**	**29.41**	**27.42**	**33.37**	**28.13**	**21.58**	**36.61**	**27.92**	**18.41**
Exports										
Petroleum[7]	4.17	3.23	3.27	3.38	3.45	3.62	3.64	3.73	3.92	3.93
Natural Gas	1.09	1.24	1.24	1.24	2.10	2.07	2.06	2.71	2.64	2.62
Coal	1.51	1.76	1.76	1.76	1.89	1.89	1.86	1.65	1.78	1.92
Total	**6.77**	**6.23**	**6.27**	**6.37**	**7.45**	**7.58**	**7.57**	**8.09**	**8.34**	**8.47**
Discrepancy[8]	**1.16**	**-0.27**	**-0.24**	**-0.18**	**-0.11**	**-0.12**	**-0.05**	**-0.05**	**-0.02**	**0.19**
Consumption										
Liquid Fuels and Other Petroleum[9]	36.62	40.72	39.10	37.62	42.67	39.84	37.88	45.61	41.70	39.11
Natural Gas	23.31	25.99	25.77	25.97	25.70	25.73	25.93	27.21	27.24	27.33
Coal[10]	19.69	19.44	19.73	19.59	22.34	22.61	23.12	22.95	24.30	26.46
Nuclear Power	8.35	8.77	8.77	8.77	9.08	9.17	9.17	9.05	9.14	9.14
Hydropower	2.69	2.92	2.92	2.92	3.01	3.04	3.03	3.06	3.09	3.09
Biomass[11]	2.52	3.30	3.27	3.33	4.39	4.71	5.29	5.05	5.25	6.62
Other Renewable Energy[3]	1.29	2.09	2.14	2.14	2.52	2.58	2.61	3.01	3.22	3.22
Other[12]	0.32	0.31	0.31	0.31	0.27	0.27	0.28	0.24	0.25	0.25
Total	**94.79**	**103.55**	**102.02**	**100.66**	**109.98**	**107.95**	**107.30**	**116.19**	**114.19**	**115.23**
Prices (2009 dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	61.66	55.00	94.58	146.10	51.28	117.54	185.87	50.07	124.94	199.95
Imported Crude Oil Price[13]	59.04	48.46	86.83	136.84	41.36	107.40	175.09	39.66	113.70	187.79
Natural Gas (dollars per million Btu)										
Price at Henry Hub	3.95	4.60	4.66	4.74	5.63	5.97	6.19	6.66	7.07	7.20
Wellhead Price[14]	3.62	4.07	4.13	4.20	4.98	5.29	5.48	5.90	6.26	6.37
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	3.71	4.18	4.24	4.31	5.11	5.43	5.62	6.05	6.42	6.54
Coal (dollars per ton)										
Minemouth Price[15]	33.26	31.65	32.36	33.61	31.30	33.22	35.10	31.42	33.92	36.56
Coal (dollars per million Btu)										
Minemouth Price[15]	1.67	1.58	1.62	1.68	1.59	1.68	1.77	1.60	1.73	1.87
Average Delivered Price[16]	2.31	2.20	2.26	2.37	2.22	2.36	2.52	2.29	2.47	2.68
Average Electricity Price (cents per kilowatthour)	9.8	8.8	8.9	9.0	8.7	8.9	9.1	8.8	9.2	9.3

Table C1. Total energy supply, disposition, and price summary (continued)
(quadrillion Btu per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Prices (nominal dollars per unit)										
Petroleum (dollars per barrel)										
Imported Low Sulfur Light Crude Oil Price[13]	61.66	59.99	103.24	159.83	68.94	155.46	246.11	81.59	199.37	321.76
Imported Crude Oil Price[13]	59.04	52.86	94.78	149.70	55.61	142.05	231.84	64.62	181.43	302.20
Natural Gas (dollars per million Btu)										
Price at Henry Hub	3.95	5.01	5.09	5.19	7.56	7.90	8.19	10.85	11.28	11.58
Wellhead Price[14]	3.62	4.44	4.51	4.59	6.70	6.99	7.25	9.61	9.99	10.25
Natural Gas (dollars per thousand cubic feet)										
Wellhead Price[14]	3.71	4.56	4.63	4.71	6.87	7.18	7.44	9.86	10.24	10.52
Coal (dollars per ton)										
Minemouth Price[15]	33.26	34.52	35.32	36.77	42.08	43.93	46.48	51.20	54.13	58.83
Coal (dollars per million Btu)										
Minemouth Price[15]	1.67	1.73	1.77	1.84	2.13	2.22	2.35	2.61	2.76	3.01
Average Delivered Price[16]	2.31	2.40	2.47	2.60	2.98	3.12	3.33	3.72	3.95	4.31
Average Electricity Price (cents per kilowatthour)	9.8	9.5	9.7	9.9	11.7	11.8	12.1	14.4	14.7	15.0

[1]Includes waste coal.
[2]Includes grid-connected electricity from wood and wood 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, and coal-based synthetic liquids. Petroleum coke, which is a solid, is included. Also included are natural gas plant liquids and crude oil consumed as a fuel. Refer to Table A17 for detailed renewable liquid fuels consumption.
[10]Excludes coal converted to coal-based synthetic liquids and natural gas.
[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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 natural gas supply values and natural gas wellhead price: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 coal minemouth and delivered coal prices: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 petroleum supply values: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). 2009 low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2009 coal values: *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010). Other 2009 values: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs LP2011LNO.D022511A, REF2011.D020911A, and HP2011HNO.D022511A.

Table C2. Energy consumption by sector and source
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	2009	2015 Low Oil Price	2015 Reference	2015 High Oil Price	2025 Low Oil Price	2025 Reference	2025 High Oil Price	2035 Low Oil Price	2035 Reference	2035 High Oil Price
Energy Consumption										
Residential										
Liquefied Petroleum Gases	0.53	0.52	0.49	0.46	0.53	0.48	0.44	0.54	0.48	0.43
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.61	0.61	0.56	0.51	0.52	0.44	0.40	0.45	0.37	0.32
Liquid Fuels and Other Petroleum Subtotal	1.16	1.15	1.07	0.99	1.07	0.94	0.85	1.01	0.86	0.77
Natural Gas	4.87	4.95	4.94	4.93	4.98	4.96	4.95	4.91	4.90	4.91
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.36	0.40	0.45	0.35	0.42	0.48	0.34	0.42	0.48
Electricity	4.65	4.62	4.60	4.57	5.03	4.98	4.95	5.57	5.51	5.48
Delivered Energy	**11.12**	**11.08**	**11.02**	**10.95**	**11.43**	**11.32**	**11.24**	**11.83**	**11.70**	**11.65**
Electricity Related Losses	9.96	9.45	9.46	9.39	10.38	10.24	10.05	11.21	11.06	10.85
Total	**21.08**	**20.53**	**20.48**	**20.35**	**21.81**	**21.56**	**21.29**	**23.04**	**22.76**	**22.50**
Commercial										
Liquefied Petroleum Gases	0.15	0.15	0.15	0.15	0.16	0.15	0.15	0.16	0.16	0.15
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.34	0.32	0.28	0.25	0.31	0.26	0.23	0.30	0.25	0.22
Residual Fuel Oil	0.06	0.07	0.06	0.06	0.07	0.07	0.06	0.07	0.07	0.07
Liquid Fuels and Other Petroleum Subtotal	0.60	0.58	0.55	0.52	0.59	0.53	0.50	0.59	0.53	0.50
Natural Gas	3.20	3.48	3.47	3.46	3.69	3.66	3.63	3.95	3.92	3.91
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.51	4.85	4.83	4.80	5.63	5.58	5.54	6.51	6.43	6.41
Delivered Energy	**8.49**	**9.08**	**9.02**	**8.96**	**10.07**	**9.94**	**9.85**	**11.22**	**11.05**	**10.99**
Electricity Related Losses	9.66	9.91	9.94	9.87	11.62	11.47	11.25	13.12	12.93	12.68
Total	**18.15**	**19.00**	**18.96**	**18.82**	**21.69**	**21.41**	**21.10**	**24.34**	**23.98**	**23.67**
Industrial[4]										
Liquefied Petroleum Gases	2.01	2.46	2.36	2.32	2.50	2.38	2.31	2.29	2.18	2.11
Motor Gasoline[2]	0.25	0.34	0.33	0.33	0.34	0.33	0.33	0.34	0.32	0.32
Distillate Fuel Oil	1.16	1.19	1.16	1.13	1.20	1.16	1.14	1.20	1.13	1.11
Residual Fuel Oil	0.17	0.20	0.17	0.15	0.21	0.17	0.15	0.24	0.16	0.14
Petrochemical Feedstocks	0.90	1.21	1.29	1.28	1.26	1.34	1.32	1.19	1.26	1.25
Other Petroleum[5]	3.45	4.31	3.97	3.63	4.41	3.79	3.35	4.73	3.88	3.27
Liquid Fuels and Other Petroleum Subtotal	7.94	9.71	9.29	8.84	9.92	9.16	8.59	9.99	8.94	8.20
Natural Gas	6.31	8.19	8.27	8.48	8.12	8.32	8.59	7.98	8.23	8.54
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	0.11
Lease and Plant Fuel[6]	1.19	1.24	1.24	1.25	1.21	1.22	1.26	1.25	1.28	1.34
Natural Gas Subtotal	7.50	9.43	9.51	9.73	9.33	9.54	9.86	9.23	9.51	9.99
Metallurgical Coal	0.40	0.59	0.58	0.58	0.55	0.55	0.55	0.46	0.47	0.46
Other Industrial Coal	0.94	0.99	0.98	0.97	0.98	0.97	0.97	0.94	0.94	0.93
Coal-to-Liquids Heat and Power	0.00	0.10	0.10	0.15	0.16	0.40	1.33	0.20	1.19	3.45
Net Coal Coke Imports	-0.02	0.01	0.01	0.01	0.00	0.00	0.00	-0.00	-0.00	-0.00
Coal Subtotal	1.32	1.68	1.67	1.71	1.69	1.93	2.85	1.60	2.60	4.84
Biofuels Heat and Coproducts	0.66	0.87	0.85	0.91	1.47	1.90	2.49	2.11	2.52	3.87
Renewable Energy[7]	1.42	1.91	1.89	1.88	2.09	2.05	2.02	2.12	2.04	2.00
Electricity	3.01	3.60	3.54	3.52	3.53	3.52	3.49	3.29	3.28	3.25
Delivered Energy	**21.85**	**27.18**	**26.75**	**26.57**	**28.02**	**28.11**	**29.30**	**28.34**	**28.89**	**32.15**
Electricity Related Losses	6.44	7.36	7.28	7.22	7.28	7.23	7.08	6.63	6.59	6.44
Total	**28.29**	**34.54**	**34.03**	**33.80**	**35.31**	**35.33**	**36.38**	**34.97**	**35.49**	**38.59**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Transportation										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
E85[8]	0.00	0.01	0.01	0.33	0.19	0.93	2.55	0.19	1.23	3.61
Motor Gasoline[2]	16.82	17.87	17.02	15.86	18.21	15.93	13.00	19.76	16.69	12.55
Jet Fuel[9]	3.20	3.22	3.20	3.18	3.49	3.47	3.46	3.64	3.62	3.61
Distillate Fuel Oil[10]	5.54	6.63	6.57	6.51	7.53	7.45	7.48	8.40	8.35	8.38
Residual Fuel Oil	0.78	0.79	0.79	0.79	0.81	0.81	0.81	0.82	0.82	0.82
Other Petroleum[11]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Liquid Fuels and Other Petroleum Subtotal	26.52	28.70	27.76	26.85	30.39	28.76	27.48	32.98	30.89	29.16
Pipeline Fuel Natural Gas	0.65	0.67	0.67	0.67	0.64	0.64	0.65	0.65	0.67	0.66
Compressed Natural Gas	0.03	0.03	0.04	0.06	0.04	0.10	0.19	0.04	0.16	0.30
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.04	0.04	0.05	0.07	0.06	0.07	0.11
Delivered Energy	**27.23**	**29.43**	**28.50**	**27.62**	**31.11**	**29.56**	**28.39**	**33.73**	**31.80**	**30.24**
Electricity Related Losses	0.05	0.05	0.06	0.08	0.07	0.09	0.14	0.11	0.15	0.22
Total	**27.28**	**29.48**	**28.56**	**27.69**	**31.18**	**29.65**	**28.53**	**33.84**	**31.95**	**30.46**
Delivered Energy Consumption for All Sectors										
Liquefied Petroleum Gases	2.71	3.14	3.02	2.94	3.20	3.03	2.91	3.01	2.84	2.72
E85[8]	0.00	0.01	0.01	0.33	0.19	0.93	2.55	0.19	1.23	3.61
Motor Gasoline[2]	17.11	18.26	17.39	16.24	18.59	16.31	13.38	20.15	17.06	12.92
Jet Fuel[9]	3.20	3.22	3.20	3.18	3.49	3.47	3.46	3.64	3.62	3.61
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate Fuel Oil	7.65	8.75	8.57	8.40	9.56	9.31	9.25	10.34	10.10	10.03
Residual Fuel Oil	1.02	1.06	1.03	1.01	1.09	1.04	1.02	1.12	1.05	1.03
Petrochemical Feedstocks	0.90	1.21	1.29	1.28	1.26	1.34	1.32	1.19	1.26	1.25
Other Petroleum[12]	3.60	4.46	4.13	3.78	4.56	3.94	3.50	4.89	4.04	3.43
Liquid Fuels and Other Petroleum Subtotal	36.23	40.13	38.67	37.19	41.96	39.39	37.42	44.57	41.22	38.63
Natural Gas	14.41	16.64	16.72	16.94	16.82	17.05	17.37	16.89	17.22	17.66
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	0.11
Lease and Plant Fuel[6]	1.19	1.24	1.24	1.25	1.21	1.22	1.26	1.25	1.28	1.34
Pipeline Natural Gas	0.65	0.67	0.67	0.67	0.64	0.64	0.65	0.65	0.67	0.66
Natural Gas Subtotal	16.25	18.56	18.62	18.85	18.67	18.91	19.28	18.78	19.17	19.77
Metallurgical Coal	0.40	0.59	0.58	0.58	0.55	0.55	0.55	0.46	0.47	0.46
Other Coal	1.01	1.05	1.05	1.04	1.05	1.04	1.04	1.01	1.01	1.00
Coal-to-Liquids Heat and Power	0.00	0.10	0.10	0.15	0.16	0.40	1.33	0.20	1.19	3.45
Net Coal Coke Imports	-0.02	0.01	0.01	0.01	0.00	0.00	0.00	-0.00	-0.00	-0.00
Coal Subtotal	1.39	1.75	1.74	1.77	1.76	2.00	2.92	1.67	2.66	4.90
Biofuels Heat and Coproducts	0.66	0.87	0.85	0.91	1.47	1.90	2.49	2.11	2.52	3.87
Renewable Energy[13]	1.96	2.38	2.41	2.45	2.55	2.59	2.61	2.58	2.58	2.59
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	12.20	13.09	13.00	12.93	14.22	14.13	14.06	15.42	15.29	15.26
Delivered Energy	**68.68**	**76.77**	**75.29**	**74.10**	**80.63**	**78.92**	**78.78**	**85.13**	**83.45**	**85.03**
Electricity Related Losses	26.11	26.77	26.73	26.56	29.35	29.03	28.52	31.07	30.74	30.19
Total	**94.79**	**103.55**	**102.02**	**100.66**	**109.98**	**107.95**	**107.30**	**116.19**	**114.19**	**115.23**
Electric Power[14]										
Distillate Fuel Oil	0.10	0.11	0.09	0.09	0.11	0.10	0.10	0.12	0.10	0.11
Residual Fuel Oil	0.30	0.48	0.34	0.34	0.59	0.35	0.36	0.93	0.37	0.37
Liquid Fuels and Other Petroleum Subtotal	0.40	0.59	0.43	0.43	0.70	0.45	0.46	1.05	0.47	0.48
Natural Gas	7.06	7.44	7.15	7.12	7.04	6.82	6.65	8.43	8.07	7.56
Steam Coal	18.30	17.69	17.99	17.82	20.58	20.61	20.20	21.28	21.64	21.55
Nuclear Power	8.35	8.77	8.77	8.77	9.08	9.17	9.17	9.05	9.14	9.14
Renewable Energy[15]	3.89	5.06	5.08	5.03	5.90	5.84	5.82	6.44	6.47	6.47
Electricity Imports	0.12	0.11	0.11	0.11	0.07	0.07	0.08	0.04	0.05	0.05
Total[16]	**38.31**	**39.87**	**39.73**	**39.49**	**43.57**	**43.17**	**42.58**	**46.49**	**46.03**	**45.45**

Table C2. Energy consumption by sector and source (continued)
(quadrillion Btu per year, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Total Energy Consumption										
Liquefied Petroleum Gases	2.71	3.14	3.02	2.94	3.20	3.03	2.91	3.01	2.84	2.72
E85[8]	0.00	0.01	0.01	0.33	0.19	0.93	2.55	0.19	1.23	3.61
Motor Gasoline[2]	17.11	18.26	17.39	16.24	18.59	16.31	13.38	20.15	17.06	12.92
Jet Fuel[9]	3.20	3.22	3.20	3.18	3.49	3.47	3.46	3.64	3.62	3.61
Kerosene	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Distillate Fuel Oil	7.75	8.85	8.66	8.49	9.68	9.40	9.35	10.47	10.20	10.14
Residual Fuel Oil	1.32	1.54	1.37	1.35	1.67	1.40	1.38	2.05	1.41	1.40
Petrochemical Feedstocks	0.90	1.21	1.29	1.28	1.26	1.34	1.32	1.19	1.26	1.25
Other Petroleum[12]	3.60	4.46	4.13	3.78	4.56	3.94	3.50	4.89	4.04	3.43
Liquid Fuels and Other Petroleum Subtotal	36.62	40.72	39.10	37.62	42.67	39.84	37.88	45.61	41.70	39.11
Natural Gas	21.47	24.08	23.87	24.05	23.86	23.87	24.02	25.31	25.29	25.22
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	0.11
Lease and Plant Fuel[6]	1.19	1.24	1.24	1.25	1.21	1.22	1.26	1.25	1.28	1.34
Pipeline Natural Gas	0.65	0.67	0.67	0.67	0.64	0.64	0.65	0.65	0.67	0.66
Natural Gas Subtotal	23.31	25.99	25.77	25.97	25.70	25.73	25.93	27.21	27.24	27.33
Metallurgical Coal	0.40	0.59	0.58	0.58	0.55	0.55	0.55	0.46	0.47	0.46
Other Coal	19.31	18.74	19.04	18.86	21.62	21.65	21.23	22.29	22.64	22.56
Coal-to-Liquids Heat and Power	0.00	0.10	0.10	0.15	0.16	0.40	1.33	0.20	1.19	3.45
Net Coal Coke Imports	-0.02	0.01	0.01	0.01	0.00	0.00	0.00	-0.00	-0.00	-0.00
Coal Subtotal	19.69	19.44	19.73	19.59	22.34	22.61	23.12	22.95	24.30	26.46
Nuclear Power	8.35	8.77	8.77	8.77	9.08	9.17	9.17	9.05	9.14	9.14
Biofuels Heat and Coproducts	0.66	0.87	0.85	0.91	1.47	1.90	2.49	2.11	2.52	3.87
Renewable Energy[17]	5.85	7.44	7.49	7.48	8.45	8.43	8.43	9.01	9.04	9.06
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Imports	0.12	0.11	0.11	0.11	0.07	0.07	0.08	0.04	0.05	0.05
Total	**94.79**	**103.55**	**102.02**	**100.66**	**109.98**	**107.95**	**107.30**	**116.19**	**114.19**	**115.23**
Energy Use and Related Statistics										
Delivered Energy Use	68.68	76.77	75.29	74.10	80.63	78.92	78.78	85.13	83.45	85.03
Total Energy Use	94.79	103.55	102.02	100.66	109.98	107.95	107.30	116.19	114.19	115.23
Ethanol Consumed in Motor Gasoline and E85	0.95	1.36	1.33	1.46	1.77	2.07	2.83	1.89	2.37	3.54
Population (millions)	307.84	326.16	326.16	326.16	358.06	358.06	358.06	390.09	390.09	390.09
Gross Domestic Product (billion 2005 dollars)	12881	15411	15336	15260	20029	20020	20122	25735	25692	25813
Carbon Dioxide Emissions (million metric tons)	5425.5	5777.8	5679.9	5557.7	6136.1	5937.8	5799.7	6497.0	6310.8	6243.9

[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 electricity generation from wind and solar photovoltaic sources.
[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 electricity generation from wind and solar photovoltaic sources.
[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, 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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 consumption based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 population and gross domestic product: IHS Global Insight Industry and Employment models, September 2010. 2009 carbon dioxide emissions: EIA, *Emissions of Greenhouse Gases in the United States 2009,* DOE/EIA-0573(2009) (Washington, DC, December 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs LP2011LNO.D022511A, REF2011.D020911A, and HP2011HNO.D022511A.

Table C3. Energy prices by sector and source

(2009 dollars per million Btu, unless otherwise noted)

Sector and Source	2009	2015 Low Oil Price	2015 Reference	2015 High Oil Price	2025 Low Oil Price	2025 Reference	2025 High Oil Price	2035 Low Oil Price	2035 Reference	2035 High Oil Price
Residential										
Liquefied Petroleum Gases	24.63	22.24	29.79	40.74	21.24	33.90	48.64	21.22	35.01	51.15
Distillate Fuel Oil	18.12	14.62	21.14	30.42	14.75	25.92	37.19	15.51	27.53	39.66
Natural Gas	11.88	10.04	10.12	10.21	11.49	11.83	12.11	12.91	13.39	13.52
Electricity	33.62	31.38	31.80	32.28	30.45	31.20	31.88	30.66	31.67	32.04
Commercial										
Liquefied Petroleum Gases	21.49	18.79	26.32	37.27	17.77	30.41	45.14	17.73	31.48	47.62
Distillate Fuel Oil	15.97	13.05	19.28	28.36	13.20	24.02	35.23	13.77	25.52	37.59
Residual Fuel Oil	13.45	6.19	13.25	22.12	5.72	17.05	28.17	5.50	18.13	29.29
Natural Gas	9.68	8.29	8.37	8.45	9.45	9.77	10.02	10.52	10.98	11.09
Electricity	29.51	26.25	26.67	27.24	25.82	26.65	27.40	25.81	26.99	27.37
Industrial[1]										
Liquefied Petroleum Gases	20.59	16.02	23.31	34.44	14.99	27.52	42.49	15.00	28.52	45.04
Distillate Fuel Oil	16.56	13.34	19.34	28.33	13.66	24.20	35.46	14.18	25.66	37.78
Residual Fuel Oil	12.05	8.24	14.80	23.52	7.62	18.19	28.51	6.99	18.73	29.90
Natural Gas[2]	5.25	4.89	4.96	5.00	5.84	6.17	6.36	6.92	7.21	7.32
Metallurgical Coal	5.43	5.98	6.01	6.14	6.32	6.46	6.59	6.36	6.58	6.76
Other Industrial Coal	3.05	2.84	2.91	3.02	2.85	2.99	3.16	2.93	3.14	3.38
Coal to Liquids	- -	1.70	1.79	1.86	1.83	1.78	2.23	1.67	2.05	2.41
Electricity	19.79	17.47	17.68	17.98	17.52	17.99	18.43	18.04	18.73	18.87
Transportation										
Liquefied Petroleum Gases[3]	25.52	23.03	30.56	41.52	21.99	34.62	49.36	21.91	35.66	51.81
E85[4]	20.50	18.30	26.38	32.25	19.64	29.49	40.12	19.81	30.93	41.77
Motor Gasoline[5]	19.28	17.94	25.97	35.39	17.65	29.49	42.68	17.64	30.90	44.69
Jet Fuel[6]	12.59	11.85	19.02	28.84	11.45	23.56	35.38	12.43	25.28	38.31
Diesel Fuel (distillate fuel oil)[7]	17.79	16.60	22.50	31.48	16.70	27.19	38.58	16.83	28.39	40.67
Residual Fuel Oil	10.57	6.11	12.65	21.30	5.45	16.02	25.93	4.47	16.44	27.74
Natural Gas[8]	12.71	11.82	11.97	12.10	12.34	12.84	13.12	12.97	13.57	13.69
Electricity	34.92	29.92	29.16	29.64	27.32	29.49	32.92	29.35	32.37	35.04
Electric Power[9]										
Distillate Fuel Oil	14.33	9.97	16.84	26.07	9.74	21.20	32.26	10.41	22.84	34.70
Residual Fuel Oil	8.96	5.72	13.17	21.87	4.91	16.26	26.11	4.13	16.71	27.49
Natural Gas	4.82	4.62	4.67	4.73	5.47	5.76	5.95	6.44	6.80	6.90
Steam Coal	2.20	2.04	2.11	2.22	2.08	2.24	2.41	2.18	2.40	2.64
Average Price to All Users[10]										
Liquefied Petroleum Gases	17.43	14.69	21.67	31.69	13.75	25.43	38.99	13.92	26.62	41.50
E85[4]	20.50	18.30	26.38	32.25	19.64	29.49	40.12	19.81	30.93	41.77
Motor Gasoline[5]	19.23	17.94	25.97	35.39	17.65	29.49	42.68	17.63	30.90	44.69
Jet Fuel	12.59	11.85	19.02	28.84	11.45	23.56	35.38	12.43	25.28	38.31
Distillate Fuel Oil	17.51	15.82	21.83	30.85	16.03	26.61	37.98	16.40	27.93	40.19
Residual Fuel Oil	10.53	6.27	13.07	21.73	5.55	16.39	26.36	4.64	16.85	27.96
Natural Gas	7.28	6.36	6.45	6.50	7.48	7.81	8.04	8.50	8.91	9.07
Metallurgical Coal	5.43	5.98	6.01	6.14	6.32	6.46	6.59	6.36	6.58	6.76
Other Coal	2.25	2.09	2.16	2.27	2.12	2.28	2.45	2.22	2.43	2.68
Coal to Liquids	- -	1.70	1.79	1.86	1.83	1.78	2.23	1.67	2.05	2.41
Electricity	28.69	25.65	26.04	26.51	25.40	26.11	26.78	25.91	26.93	27.29
Non-Renewable Energy Expenditures by Sector (billion 2009 dollars)										
Residential	238.63	215.39	223.20	232.94	229.49	242.45	254.58	252.80	267.49	277.66
Commercial	174.64	164.57	169.68	176.23	188.46	198.28	207.60	218.12	231.11	239.14
Industrial	179.22	182.20	224.19	280.05	185.38	258.44	333.95	184.42	261.51	336.85
Transportation	474.91	476.48	664.86	880.88	494.49	773.10	997.03	543.73	866.49	1076.77
Total Non-Renewable Expenditures	1067.41	1038.64	1281.92	1570.10	1097.82	1472.27	1793.16	1199.08	1626.60	1930.42
Transportation Renewable Expenditures	0.06	0.17	0.23	10.75	3.67	27.48	102.20	3.69	37.93	150.74
Total Expenditures	**1067.47**	**1038.82**	**1282.15**	**1580.85**	**1101.49**	**1499.75**	**1895.36**	**1202.77**	**1664.53**	**2081.17**

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Residential										
Liquefied Petroleum Gases	24.63	24.25	32.51	44.57	28.55	44.84	64.40	34.58	55.86	82.31
Distillate Fuel Oil	18.12	15.95	23.07	33.28	19.84	34.28	49.25	25.27	43.93	63.83
Natural Gas	11.88	10.94	11.05	11.16	15.45	15.65	16.04	21.04	21.37	21.76
Electricity	33.62	34.22	34.72	35.32	40.94	41.27	42.22	49.95	50.54	51.55
Commercial										
Liquefied Petroleum Gases	21.49	20.50	28.73	40.77	23.90	40.22	59.76	28.89	50.23	76.63
Distillate Fuel Oil	15.97	14.23	21.04	31.02	17.75	31.77	46.65	22.43	40.72	60.49
Residual Fuel Oil	13.45	6.76	14.47	24.20	7.70	22.55	37.29	8.97	28.93	47.13
Natural Gas	9.68	9.04	9.14	9.24	12.71	12.92	13.27	17.14	17.52	17.84
Electricity	29.51	28.63	29.12	29.79	34.71	35.25	36.28	42.05	43.06	44.05
Industrial[1]										
Liquefied Petroleum Gases	20.59	17.47	25.45	37.68	20.16	36.40	56.27	24.43	45.52	72.48
Distillate Fuel Oil	16.56	14.55	21.12	30.99	18.37	32.01	46.95	23.11	40.95	60.80
Residual Fuel Oil	12.05	8.98	16.15	25.73	10.24	24.05	37.75	11.39	29.88	48.11
Natural Gas[2]	5.25	5.33	5.42	5.47	7.85	8.15	8.42	11.27	11.50	11.79
Metallurgical Coal	5.43	6.53	6.56	6.71	8.50	8.54	8.72	10.36	10.50	10.88
Other Industrial Coal	3.05	3.10	3.17	3.30	3.84	3.96	4.18	4.77	5.01	5.44
Coal to Liquids	- -	1.85	1.96	2.04	2.46	2.36	2.95	2.72	3.27	3.89
Electricity	19.79	19.05	19.30	19.67	23.55	23.79	24.40	29.39	29.88	30.36
Transportation										
Liquefied Petroleum Gases[3]	25.52	25.12	33.36	45.42	29.56	45.80	65.36	35.70	56.90	83.37
E85[4]	20.50	19.96	28.80	35.28	26.41	39.01	53.12	32.28	49.35	67.22
Motor Gasoline[5]	19.28	19.57	28.35	38.71	23.73	39.01	56.52	28.74	49.31	71.92
Jet Fuel[6]	12.59	12.92	20.76	31.55	15.40	31.16	46.85	20.25	40.35	61.65
Diesel Fuel (distillate fuel oil)[7]	17.79	18.11	24.56	34.44	22.46	35.96	51.08	27.42	45.30	65.44
Residual Fuel Oil	10.57	6.66	13.80	23.30	7.33	21.19	34.33	7.28	26.24	44.64
Natural Gas[8]	12.71	12.89	13.06	13.24	16.58	16.98	17.38	21.14	21.66	22.03
Electricity	34.92	32.63	31.83	32.42	36.73	39.01	43.59	47.82	51.66	56.39
Electric Power[9]										
Distillate Fuel Oil	14.33	10.88	18.38	28.52	13.09	28.04	42.71	16.96	36.45	55.84
Residual Fuel Oil	8.96	6.24	14.37	23.93	6.61	21.50	34.58	6.73	26.66	44.25
Natural Gas	4.82	5.04	5.10	5.17	7.35	7.62	7.88	10.50	10.86	11.11
Steam Coal	2.20	2.22	2.31	2.43	2.80	2.96	3.19	3.55	3.83	4.25

Table C3. Energy prices by sector and source (continued)
(nominal dollars per million Btu, unless otherwise noted)

Sector and Source	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Average Price to All Users[10]										
Liquefied Petroleum Gases	17.43	16.02	23.65	34.67	18.48	33.64	51.63	22.68	42.49	66.79
E85[4]	20.50	19.96	28.80	35.28	26.41	39.01	53.12	32.28	49.35	67.22
Motor Gasoline[5]	19.23	19.57	28.35	38.71	23.72	39.01	56.52	28.73	49.31	71.92
Jet Fuel	12.59	12.92	20.76	31.55	15.40	31.16	46.85	20.25	40.35	61.65
Distillate Fuel Oil	17.51	17.26	23.83	33.75	21.55	35.20	50.29	26.72	44.57	64.67
Residual Fuel Oil	10.53	6.84	14.27	23.77	7.46	21.67	34.90	7.56	26.88	45.00
Natural Gas	7.28	6.94	7.04	7.11	10.05	10.33	10.65	13.84	14.21	14.59
Metallurgical Coal	5.43	6.53	6.56	6.71	8.50	8.54	8.72	10.36	10.50	10.88
Other Coal	2.25	2.28	2.36	2.48	2.86	3.02	3.24	3.61	3.89	4.31
Coal to Liquids	- -	1.85	1.96	2.04	2.46	2.36	2.95	2.72	3.27	3.89
Electricity	28.69	27.98	28.43	29.00	34.15	34.53	35.46	42.22	42.97	43.92
Non-Renewable Energy Expenditures by Sector (billion nominal dollars)										
Residential	238.63	234.91	243.63	254.83	308.53	320.68	337.10	411.91	426.84	446.82
Commercial	174.64	179.48	185.21	192.79	253.37	262.27	274.89	355.41	368.78	384.83
Industrial	179.22	198.71	244.72	306.36	249.23	341.84	442.19	300.50	417.29	542.07
Transportation	474.91	519.66	725.73	963.65	664.79	1022.56	1320.19	885.96	1382.69	1732.75
Total Non-Renewable Expenditures	1067.41	1132.76	1399.29	1717.63	1475.92	1947.34	2374.37	1953.78	2595.61	3106.48
Transportation Renewable Expenditures	0.06	0.19	0.25	11.76	4.93	36.34	135.33	6.01	60.53	242.58
Total Expenditures	**1067.47**	**1132.95**	**1399.54**	**1729.39**	**1480.85**	**1983.68**	**2509.69**	**1959.79**	**2656.14**	**3349.05**

[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 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 residential and commercial natural gas delivered prices: EIA, *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 industrial natural gas delivered prices are estimated based on: EIA, *Manufacturing Energy Consumption Survey* and industrial and wellhead prices from the *Natural Gas Annual 2008*, DOE/EIA-0131(2008) (Washington, DC, March 2010) and the *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 transportation sector natural gas delivered prices are model results. 2009 electric power sector natural gas prices: EIA, *Electric Power Monthly*, DOE/EIA-0226, April 2009 and April 2010, Table 4.2. 2009 coal prices based on: EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010) and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. 2009 electricity prices: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. **Projections:** EIA, AEO2011 National Energy Modeling System runs LP2011LNO.D022511A, REF2011.D020911A, and HP2011HNO.D022511A.

Table C4. Liquid fuels supply and disposition
(million barrels per day, unless otherwise noted)

Supply and Disposition	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil										
Domestic Crude Production[1]	5.36	5.74	5.81	5.93	5.20	5.88	7.06	4.33	5.95	7.13
Alaska	0.65	0.49	0.49	0.49	0.41	0.41	0.79	0.19	0.39	0.48
Lower 48 States	4.71	5.25	5.32	5.44	4.79	5.47	6.27	4.14	5.56	6.65
Net Imports	8.97	9.46	8.70	7.93	10.12	8.25	5.69	11.59	8.25	4.45
Gross Imports	9.01	9.49	8.74	7.96	10.15	8.28	5.73	11.62	8.28	4.49
Exports	0.04	0.03	0.03	0.03	0.03	0.03	0.04	0.02	0.03	0.04
Other Crude Supply[2]	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Supply	**14.33**	**15.20**	**14.52**	**13.86**	**15.32**	**14.13**	**12.75**	**15.92**	**14.20**	**11.58**
Other Petroleum Supply	**3.59**	**4.57**	**4.38**	**4.19**	**4.97**	**4.41**	**4.07**	**5.33**	**4.46**	**3.65**
Natural Gas Plant Liquids	1.91	2.24	2.23	2.25	2.65	2.68	2.74	2.89	2.94	2.90
Net Product Imports	0.75	1.26	1.14	0.92	1.29	0.81	0.46	1.40	0.64	0.06
Gross Refined Product Imports[3]	1.27	1.03	1.04	0.97	1.12	0.92	0.80	1.24	0.84	0.68
Unfinished Oil Imports	0.68	0.89	0.80	0.72	0.90	0.75	0.59	0.97	0.76	0.44
Blending Component Imports	0.72	0.82	0.81	0.77	0.86	0.80	0.74	0.92	0.83	0.75
Exports	1.91	1.47	1.50	1.54	1.59	1.67	1.66	1.73	1.80	1.81
Refinery Processing Gain[4]	0.98	1.07	1.01	1.02	1.03	0.92	0.87	1.04	0.88	0.69
Product Stock Withdrawal	-0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.81**	**1.35**	**1.42**	**1.66**	**1.90**	**2.40**	**3.51**	**2.40**	**3.28**	**5.88**
Supply from Renewable Sources	0.76	1.13	1.12	1.27	1.63	1.92	2.59	2.12	2.48	3.84
Ethanol	0.73	1.06	1.03	1.13	1.37	1.60	2.19	1.46	1.83	2.74
Domestic Production	0.72	1.00	0.97	1.05	1.21	1.44	1.91	1.21	1.58	2.26
Net Imports	0.01	0.06	0.06	0.08	0.16	0.16	0.28	0.26	0.26	0.49
Biodiesel	0.02	0.06	0.08	0.12	0.11	0.12	0.13	0.12	0.13	0.14
Domestic Production	0.03	0.05	0.07	0.12	0.11	0.12	0.13	0.12	0.13	0.14
Net Imports	-0.01	0.00	0.00	-0.00	0.00	0.00	0.00	0.00	0.00	-0.00
Other Biomass-derived Liquids[5]	0.00	0.02	0.02	0.02	0.15	0.19	0.26	0.54	0.52	0.95
Liquids from Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09
Liquids from Coal	0.00	0.05	0.05	0.07	0.08	0.19	0.62	0.09	0.55	1.60
Other[6]	0.05	0.17	0.25	0.32	0.19	0.30	0.31	0.18	0.25	0.36
Total Primary Supply[7]	**18.73**	**21.12**	**20.32**	**19.70**	**22.19**	**20.94**	**20.33**	**23.65**	**21.94**	**21.11**
Liquid Fuels Consumption										
by Fuel										
Liquefied Petroleum Gases	2.13	2.42	2.32	2.27	2.46	2.33	2.24	2.32	2.19	2.09
E85[8]	0.00	0.01	0.01	0.23	0.13	0.64	1.75	0.13	0.84	2.48
Motor Gasoline[9]	9.00	9.86	9.40	8.78	10.11	8.87	7.28	10.95	9.28	7.04
Jet Fuel[10]	1.39	1.55	1.55	1.54	1.69	1.68	1.67	1.76	1.75	1.74
Distillate Fuel Oil[11]	3.63	4.22	4.13	4.05	4.62	4.49	4.46	4.99	4.87	4.84
Diesel	3.18	3.73	3.68	3.63	4.17	4.09	4.09	4.57	4.51	4.50
Residual Fuel Oil	0.51	0.67	0.60	0.59	0.73	0.61	0.60	0.89	0.62	0.61
Other[12]	2.15	2.54	2.43	2.28	2.61	2.38	2.18	2.72	2.38	2.11
by Sector										
Residential and Commercial	1.04	1.02	0.95	0.89	0.98	0.88	0.81	0.96	0.85	0.78
Industrial[13]	4.25	5.20	4.99	4.77	5.31	4.94	4.67	5.27	4.77	4.43
Transportation	13.61	14.80	14.31	13.87	15.74	14.96	14.49	17.07	16.10	15.49
Electric Power[14]	0.18	0.26	0.19	0.19	0.31	0.20	0.20	0.46	0.21	0.21
Total	**18.81**	**21.28**	**20.44**	**19.73**	**22.34**	**20.99**	**20.18**	**23.76**	**21.93**	**20.91**
Discrepancy[15]	**-0.08**	**-0.16**	**-0.12**	**-0.02**	**-0.15**	**-0.04**	**0.15**	**-0.11**	**0.01**	**0.19**

Table C4. Liquid fuels supply and disposition (continued)
(million barrels per day, unless otherwise noted)

Supply and Disposition	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Domestic Refinery Distillation Capacity[16]	17.7	17.5	17.5	17.4	16.8	16.0	14.9	17.3	15.8	14.2
Capacity Utilization Rate (percent)[17]	83.0	88.8	84.9	81.5	93.4	90.1	87.6	93.8	91.9	83.8
Net Import Share of Product Supplied (percent)	51.9	51.1	48.8	45.3	52.2	44.0	31.7	56.0	41.7	23.7
Net Expenditures for Imported Crude Oil and Petroleum Products (billion 2009 dollars)	203.65	183.33	296.22	424.15	178.54	347.74	400.15	192.05	370.10	348.26

[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 pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the production of green diesel and gasoline.
[6]Includes domestic sources of other blending components, other hydrocarbons, and ethers.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[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 fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Includes consumption for combined heat and power, 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]End-of-year operable capacity.
[17]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.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 petroleum product supplied based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs LP2011LNO.D022511A, REF2011.D020911A, and HP2011HNO.D022511A.

Table C5. Petroleum product prices
(2009 dollars per gallon, unless otherwise noted)

Sector and Fuel	2009	2015 Low Oil Price	2015 Reference	2015 High Oil Price	2025 Low Oil Price	2025 Reference	2025 High Oil Price	2035 Low Oil Price	2035 Reference	2035 High Oil Price
Crude Oil Prices (2009 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	61.66	55.00	94.58	146.10	51.28	117.54	185.87	50.07	124.94	199.95
Imported Crude Oil[1]	59.04	48.46	86.83	136.84	41.36	107.40	175.09	39.66	113.70	187.79
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	2.087	1.884	2.523	3.451	1.799	2.872	4.120	1.798	2.965	4.333
Distillate Fuel Oil	2.514	2.028	2.931	4.219	2.046	3.595	5.158	2.151	3.818	5.501
Commercial										
Distillate Fuel Oil	2.205	1.796	2.654	3.904	1.817	3.306	4.849	1.895	3.512	5.174
Residual Fuel Oil	2.013	0.927	1.984	3.311	0.857	2.552	4.216	0.824	2.714	4.384
Residual Fuel Oil (2009 dollars per barrel)	84.54	38.94	83.33	139.07	35.99	107.19	177.07	34.60	113.99	184.12
Industrial[2]										
Liquefied Petroleum Gases	1.744	1.357	1.975	2.917	1.270	2.331	3.599	1.270	2.416	3.815
Distillate Fuel Oil	2.281	1.831	2.656	3.889	1.876	3.322	4.867	1.947	3.523	5.187
Residual Fuel Oil	1.804	1.233	2.215	3.520	1.140	2.722	4.267	1.046	2.803	4.475
Residual Fuel Oil (2009 dollars per barrel)	75.79	51.78	93.04	147.85	47.89	114.34	179.22	43.94	117.73	187.97
Transportation										
Liquefied Petroleum Gases	2.161	1.951	2.589	3.517	1.863	2.933	4.181	1.856	3.021	4.388
Ethanol (E85)[3]	1.945	1.736	2.503	3.060	1.863	2.798	3.806	1.880	2.934	3.963
Ethanol Wholesale Price	2.028	2.345	2.448	2.689	2.230	2.369	2.645	2.013	2.073	2.698
Motor Gasoline[4]	2.349	2.167	3.134	4.271	2.118	3.539	5.123	2.117	3.707	5.362
Jet Fuel[5]	1.700	1.599	2.568	3.894	1.546	3.181	4.777	1.678	3.413	5.172
Diesel Fuel (distillate fuel oil)[6]	2.441	2.275	3.084	4.314	2.289	3.726	5.286	2.306	3.890	5.573
Residual Fuel Oil	1.582	0.914	1.893	3.188	0.816	2.398	3.881	0.669	2.461	4.152
Residual Fuel Oil (2009 dollars per barrel)	66.44	38.38	79.51	133.90	34.28	100.70	163.02	28.10	103.37	174.39
Electric Power[7]										
Distillate Fuel Oil	1.988	1.383	2.336	3.615	1.350	2.940	4.474	1.444	3.168	4.812
Residual Fuel Oil	1.342	0.856	1.971	3.274	0.735	2.433	3.909	0.618	2.501	4.116
Residual Fuel Oil (2009 dollars per barrel)	56.36	35.97	82.79	137.52	30.89	102.20	164.18	25.96	105.03	172.86
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	1.477	1.244	1.836	2.684	1.164	2.154	3.303	1.179	2.255	3.516
Motor Gasoline[4]	2.344	2.167	3.134	4.271	2.118	3.539	5.123	2.117	3.707	5.362
Jet Fuel[5]	1.700	1.599	2.568	3.894	1.546	3.181	4.777	1.678	3.413	5.172
Distillate Fuel Oil	2.408	2.171	2.995	4.233	2.199	3.651	5.210	2.250	3.831	5.511
Residual Fuel Oil	1.576	0.938	1.957	3.253	0.830	2.453	3.946	0.695	2.522	4.186
Residual Fuel Oil (2009 dollars per barrel)	66.20	39.40	82.19	136.61	34.88	103.03	165.72	29.18	105.92	175.81
Average	**2.155**	**1.933**	**2.822**	**3.956**	**1.894**	**3.289**	**4.783**	**1.920**	**3.478**	**5.072**

Table C5. Petroleum product prices (continued)
(2009 dollars per gallon, unless otherwise noted)

Sector and Fuel	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (nominal dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	61.66	59.99	103.24	159.83	68.94	155.46	246.11	81.59	199.37	321.76
Imported Crude Oil[1]	59.04	52.86	94.78	149.70	55.61	142.05	231.84	64.62	181.43	302.20
Delivered Sector Product Prices										
Residential										
Liquefied Petroleum Gases	2.087	2.054	2.754	3.775	2.419	3.798	5.455	2.929	4.732	6.972
Distillate Fuel Oil	2.514	2.212	3.200	4.615	2.751	4.754	6.830	3.505	6.092	8.852
Commercial										
Distillate Fuel Oil	2.205	1.959	2.897	4.270	2.443	4.373	6.420	3.087	5.605	8.326
Residual Fuel Oil	2.013	1.011	2.166	3.622	1.152	3.376	5.583	1.342	4.331	7.055
Industrial[2]										
Liquefied Petroleum Gases	1.744	1.480	2.155	3.191	1.707	3.083	4.766	2.070	3.855	6.140
Distillate Fuel Oil	2.281	1.997	2.899	4.254	2.522	4.394	6.445	3.172	5.621	8.346
Residual Fuel Oil	1.804	1.345	2.418	3.851	1.533	3.601	5.650	1.705	4.473	7.202
Transportation										
Liquefied Petroleum Gases	2.161	2.128	2.826	3.847	2.504	3.879	5.536	3.024	4.820	7.062
Ethanol (E85)[3]	1.945	1.893	2.732	3.348	2.505	3.701	5.040	3.063	4.682	6.378
Ethanol Wholesale Price	2.028	2.557	2.672	2.942	2.998	3.133	3.502	3.279	3.308	4.342
Motor Gasoline[4]	2.349	2.363	3.421	4.672	2.847	4.681	6.784	3.449	5.915	8.629
Jet Fuel[5]	1.700	1.744	2.803	4.260	2.079	4.207	6.325	2.734	5.447	8.323
Diesel Fuel (distillate fuel oil)[6]	2.441	2.481	3.366	4.719	3.077	4.928	7.000	3.758	6.207	8.968
Residual Fuel Oil	1.582	0.997	2.066	3.488	1.097	3.171	5.139	1.090	3.928	6.682
Electric Power[7]										
Distillate Fuel Oil	1.988	1.508	2.550	3.955	1.815	3.889	5.924	2.352	5.055	7.744
Residual Fuel Oil	1.342	0.934	2.152	3.582	0.989	3.219	5.176	1.007	3.990	6.623
Refined Petroleum Product Prices[8]										
Liquefied Petroleum Gases	1.477	1.357	2.004	2.937	1.565	2.849	4.373	1.921	3.599	5.657
Motor Gasoline[4]	2.344	2.363	3.421	4.672	2.847	4.681	6.784	3.449	5.915	8.629
Jet Fuel[5]	1.700	1.744	2.803	4.260	2.079	4.207	6.325	2.734	5.447	8.323
Distillate Fuel Oil	2.408	2.368	3.269	4.631	2.957	4.829	6.899	3.666	6.113	8.869
Residual Fuel Oil (nominal dollars per barrel)	66.20	42.97	89.71	149.44	46.89	136.27	219.43	47.55	169.02	282.92
Average	**2.155**	**2.108**	**3.080**	**4.328**	**2.547**	**4.350**	**6.333**	**3.128**	**5.550**	**8.162**

[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 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 imported low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2009 imported crude oil price: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 prices for motor gasoline, distillate fuel oil, and jet fuel are based on: EIA, *Petroleum Marketing Annual 2009*, DOE/EIA-0487(2009) (Washington, DC, August 2010). 2009 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." 2009 electric power prices based on: Federal Energy Regulatory Commission, FERC Form 423, "Monthly Report of Cost and Quality of Fuels for Electric Plants." 2009 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report. 2009 wholesale ethanol prices derived from Bloomberg U.S. average rack price. **Projections:** EIA, AEO2011 National Energy Modeling System runs LP2011LNO.D022511A, REF2011.D020911A, and HP2011HNO.D022511A.

Table C6. International liquids supply and disposition summary
(million barrels per day, unless otherwise noted)

Supply and Disposition	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Crude Oil Prices (2009 dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	61.66	55.00	94.58	146.10	51.28	117.54	185.87	50.07	124.94	199.95
Imported Crude Oil Price	59.04	48.46	86.83	136.84	41.36	107.40	175.09	39.66	113.70	187.79
Crude Oil Prices (nominal dollars per barrel)[1]										
Imported Low Sulfur Light Crude Oil Price	61.66	59.99	103.24	159.83	68.94	155.46	246.11	81.59	199.37	321.76
Imported Crude Oil Price	59.04	52.86	94.78	149.70	55.61	142.05	231.84	64.62	181.43	302.20
Conventional Production (Conventional)[2]										
OPEC[3]										
Middle East	22.61	28.19	25.66	23.16	31.81	28.64	27.48	34.74	33.87	30.24
North Africa	3.92	4.70	4.32	3.83	4.15	3.84	3.72	3.94	3.98	3.70
West Africa	4.06	5.80	5.10	4.44	6.54	5.10	4.90	6.81	5.31	4.86
South America	2.31	2.18	2.00	1.77	1.86	1.73	1.68	1.62	1.64	1.54
Total OPEC	**32.91**	**40.87**	**37.08**	**33.20**	**44.35**	**39.32**	**37.78**	**47.10**	**44.80**	**40.33**
Non-OPEC										
OECD										
United States (50 states)	8.26	9.22	9.30	9.52	9.07	9.78	10.89	8.45	9.89	10.70
Canada	1.96	1.83	1.80	1.82	1.78	1.78	1.84	1.71	1.78	1.94
Mexico	2.90	2.17	2.05	2.00	1.35	1.22	1.19	1.50	1.48	1.52
OECD Europe[4]	4.62	3.49	3.36	3.30	2.73	2.67	2.61	2.48	2.66	2.73
Japan	0.13	0.14	0.14	0.13	0.15	0.14	0.14	0.16	0.15	0.14
Australia and New Zealand	0.65	0.58	0.56	0.55	0.53	0.52	0.51	0.49	0.54	0.55
Total OECD	**18.52**	**17.43**	**17.20**	**17.33**	**15.62**	**16.13**	**17.18**	**14.79**	**16.49**	**17.59**
Non-OECD										
Russia	9.66	10.71	10.02	9.74	12.43	10.86	10.41	12.90	12.64	13.15
Other Europe and Eurasia[5]	3.08	3.77	3.54	3.44	4.47	3.97	3.81	4.48	4.47	4.64
China	3.93	3.96	3.80	3.72	4.10	4.02	3.89	3.83	4.22	4.40
Other Asia[6]	3.70	3.59	3.47	3.41	3.03	2.99	2.91	2.63	2.85	2.94
Middle East	1.54	1.63	1.57	1.54	1.26	1.24	1.20	0.98	1.10	1.15
Africa	2.34	2.82	2.71	2.65	2.89	2.85	2.75	2.82	3.16	3.32
Brazil	2.05	2.95	2.76	2.68	4.41	3.87	3.72	5.02	4.93	5.11
Other Central and South America	1.87	2.17	2.10	2.06	2.27	2.24	2.17	2.35	2.59	2.70
Total Non-OECD	**28.17**	**31.60**	**29.96**	**29.24**	**34.86**	**32.03**	**30.85**	**35.00**	**35.95**	**37.41**
Total Conventional Production	**79.60**	**89.89**	**84.24**	**79.76**	**94.83**	**87.47**	**85.81**	**96.89**	**97.24**	**95.33**
Unconventional Production[7]										
United States (50 states)	0.75	1.11	1.11	1.26	1.55	1.94	3.01	1.95	2.90	5.42
Other North America	1.68	2.21	2.39	3.68	2.70	3.57	5.38	3.32	5.27	7.11
OECD Europe[3]	0.22	0.10	0.23	0.22	0.11	0.26	0.29	0.18	0.28	0.33
Middle East	0.01	0.14	0.17	0.14	0.19	0.24	0.21	0.19	0.24	0.21
Africa.	0.21	0.16	0.28	0.28	0.16	0.39	0.40	0.16	0.44	0.46
Central and South America	1.14	1.82	1.78	1.86	3.28	2.61	2.98	4.70	3.17	3.60
Other	0.12	0.08	0.17	0.17	0.25	0.64	0.88	0.50	1.22	2.61
Total Unconventional Production	**4.14**	**5.63**	**6.13**	**7.61**	**8.23**	**9.66**	**13.15**	**11.00**	**13.54**	**19.72**
Total Production	**83.74**	**95.52**	**90.37**	**87.38**	**103.06**	**97.13**	**98.96**	**107.90**	**110.78**	**115.06**

Table C6. International liquids supply and disposition summary (continued)
(million barrels per day, unless otherwise noted)

Supply and Disposition	2009	Projections								
		2015			2025			2035		
		Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price	Low Oil Price	Reference	High Oil Price
Consumption[8]										
OECD										
United States (50 states)	18.81	21.28	20.44	19.73	22.34	20.99	20.18	23.76	21.93	20.91
United States Territories	0.27	0.32	0.31	0.30	0.30	0.30	0.32	0.28	0.32	0.36
Canada	2.15	2.40	2.24	2.13	2.48	2.14	2.01	2.64	2.24	2.08
Mexico	2.13	2.29	2.17	2.09	2.57	2.30	2.20	3.02	2.63	2.51
OECD Europe[3]	14.49	14.47	13.55	12.95	14.61	12.82	12.14	14.91	12.95	12.11
Japan	4.37	4.47	4.18	4.03	4.49	3.98	3.75	4.37	3.88	3.55
South Korea	2.32	2.59	2.44	2.34	3.01	2.63	2.54	3.45	3.13	2.89
Australia and New Zealand	1.19	1.25	1.18	1.14	1.26	1.13	1.08	1.30	1.17	1.10
Total OECD	**45.73**	**49.07**	**46.50**	**44.70**	**51.06**	**46.29**	**44.23**	**53.72**	**48.25**	**45.51**
Non-OECD										
Russia	2.83	3.05	2.90	2.80	2.73	2.66	2.71	2.59	2.78	3.01
Other Europe and Eurasia[5]	2.16	2.43	2.25	2.18	2.41	2.25	2.36	2.33	2.48	2.70
China	8.32	11.99	11.10	10.80	15.60	14.36	15.97	16.50	19.13	20.68
India	3.06	3.97	3.68	3.55	4.80	4.54	4.82	4.96	5.64	6.12
Other Asia	6.13	7.11	6.72	6.51	8.01	7.98	8.46	8.69	9.75	10.94
Middle East	6.64	7.69	7.47	7.38	8.27	8.76	9.50	9.01	11.02	12.81
Africa	3.31	3.71	3.50	3.39	3.82	3.76	3.97	3.96	4.45	4.94
Brazil	2.46	2.96	2.82	2.74	3.10	3.20	3.42	3.16	3.79	4.40
Other Central and South America	3.09	3.55	3.41	3.33	3.27	3.33	3.52	3.00	3.51	3.94
Total Non-OECD	**38.01**	**46.45**	**43.87**	**42.67**	**52.00**	**50.84**	**54.73**	**54.20**	**62.54**	**69.54**
Total Consumption	**83.74**	**95.52**	**90.37**	**87.38**	**103.06**	**97.13**	**98.95**	**107.92**	**110.79**	**115.06**
OPEC Production[9]	33.45	42.41	38.08	34.29	47.25	40.77	39.34	50.88	46.50	42.14
Non-OPEC Production[9]	50.29	53.11	52.30	53.09	55.81	56.37	59.62	57.02	64.28	72.92
Net Eurasia Exports	9.80	11.95	11.16	10.90	16.17	13.80	12.87	17.48	16.78	17.18
OPEC Market Share (percent)	39.9	44.4	42.1	39.2	45.8	42.0	39.8	47.2	42.0	36.6

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate), 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, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[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]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, 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]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both conventional and unconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, “Monthly Foreign Crude Oil Acquisition Report.” 2009 imported crude oil price: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **2009 quantities and projections:** EIA, AEO2011 National Energy Modeling System runs LP2011LNO.D022511A, REF2011.D020911A, and HP2011HNO.D022511A and EIA, Generate World Oil Balance Model.

Results from side cases

Table D1. Key results for residential and commercial sector technology cases

Energy Consumption	2009	2015 2010 Technology	2015 Reference	2015 High Technology	2015 Best Available Technology	2025 2010 Technology	2025 Reference	2025 High Technology	2025 Best Available Technology
Residential									
Energy Consumption									
(quadrillion Btu)									
Liquefied Petroleum Gases	0.53	0.50	0.49	0.48	0.48	0.49	0.48	0.45	0.45
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Distillate Fuel Oil	0.61	0.57	0.56	0.55	0.52	0.48	0.44	0.41	0.37
Liquid Fuels and Other Petroleum	1.16	1.09	1.07	1.05	1.02	0.99	0.94	0.88	0.83
Natural Gas	4.87	5.00	4.94	4.79	4.57	5.23	4.96	4.62	4.18
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.41	0.40	0.40	0.38	0.46	0.42	0.40	0.36
Electricity	4.65	4.69	4.60	4.26	4.02	5.27	4.98	4.42	3.96
Delivered Energy	**11.12**	**11.19**	**11.02**	**10.50**	**10.00**	**11.96**	**11.32**	**10.32**	**9.34**
Electricity Related Losses	9.96	9.64	9.46	8.75	8.27	10.83	10.24	9.07	8.14
Total	**21.08**	**20.83**	**20.48**	**19.25**	**18.27**	**22.79**	**21.56**	**19.39**	**17.48**
Delivered Energy Intensity									
(million Btu per household)	**98.0**	**92.2**	**90.8**	**86.5**	**82.4**	**88.7**	**83.9**	**76.5**	**69.3**
Nonmarketed Renewables									
Consumption (quadrillion Btu)	**0.01**	**0.07**	**0.07**	**0.07**	**0.08**	**0.10**	**0.09**	**0.10**	**0.11**
Commercial									
Energy Consumption									
(quadrillion Btu)									
Liquefied Petroleum Gases	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Motor Gasoline[2]	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Kerosene	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Distillate Fuel Oil	0.34	0.28	0.28	0.28	0.28	0.26	0.26	0.25	0.25
Residual Fuel Oil	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.07	0.07
Liquid Fuels and Other Petroleum	0.60	0.55	0.55	0.54	0.54	0.53	0.53	0.52	0.52
Natural Gas	3.20	3.47	3.47	3.35	3.34	3.68	3.66	3.42	3.41
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[3]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.51	4.90	4.83	4.60	4.41	5.83	5.58	4.93	4.47
Delivered Energy	**8.49**	**9.10**	**9.02**	**8.67**	**8.47**	**10.21**	**9.94**	**9.05**	**8.58**
Electricity Related Losses	9.66	10.08	9.94	9.46	9.07	11.97	11.47	10.13	9.19
Total	**18.15**	**19.18**	**18.96**	**18.13**	**17.54**	**22.18**	**21.41**	**19.18**	**17.77**
Delivered Energy Intensity									
(thousand Btu per square foot)	**105.9**	**106.5**	**105.6**	**101.4**	**99.1**	**104.9**	**102.1**	**92.9**	**88.1**
Commercial Sector Generation									
Net Summer Generation Capacity									
(megawatts)									
Natural Gas	653	781	809	842	842	1257	1702	2166	2263
Solar Photovoltaic	693	908	910	914	923	1159	1163	1355	1819
Wind	79	84	85	85	100	89	113	118	170
Electricity Generation									
(billion kilowatthours)									
Natural Gas	4.70	5.63	5.84	6.08	6.08	9.10	12.33	15.71	16.42
Solar Photovoltaic	1.09	1.44	1.45	1.46	1.47	1.84	1.88	2.20	2.96
Wind	0.10	0.11	0.11	0.11	0.13	0.11	0.15	0.16	0.23
Nonmarketed Renewables									
Consumption (quadrillion Btu)	**0.03**	**0.03**	**0.03**	**0.05**	**0.05**	**0.04**	**0.04**	**0.07**	**0.07**

[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, municipal solid 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 2009 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: U.S. Energy Information Administration, AEO2011 National Energy Modeling System, runs BLDFRZN.D021011A, REF2011.D020911A, BLDHIGH.D021011A, and BLDBEST.D021011A.

2035				Annual Growth 2009-2035 (percent)			
2010 Technology	Reference	High Technology	Best Available Technology	2010 Technology	Reference	High Technology	Best Available Technology
0.50	0.48	0.45	0.44	-0.2%	-0.4%	-0.6%	-0.7%
0.02	0.02	0.01	0.01	-1.0%	-1.5%	-2.1%	-2.4%
0.43	0.37	0.32	0.27	-1.4%	-1.9%	-2.4%	-3.0%
0.94	0.86	0.79	0.73	-0.8%	-1.1%	-1.5%	-1.8%
5.34	4.90	4.48	3.98	0.4%	0.0%	-0.3%	-0.8%
0.01	0.01	0.00	0.00	-0.5%	-1.1%	-1.4%	-1.8%
0.48	0.42	0.38	0.33	0.4%	-0.1%	-0.5%	-1.0%
5.96	5.51	4.85	4.25	1.0%	0.7%	0.2%	-0.3%
12.74	**11.70**	**10.51**	**9.29**	**0.5%**	**0.2%**	**-0.2%**	**-0.7%**
11.99	11.06	9.76	8.54	0.7%	0.4%	-0.1%	-0.6%
24.72	**22.76**	**20.26**	**17.83**	**0.6%**	**0.3%**	**-0.2%**	**-0.6%**
86.7	**79.7**	**71.5**	**63.2**	**-0.5%**	**-0.8%**	**-1.2%**	**-1.7%**
0.13	**0.11**	**0.13**	**0.16**	**9.0%**	**8.3%**	**9.0%**	**10.0%**
0.16	0.16	0.16	0.16	0.2%	0.2%	0.2%	0.2%
0.05	0.05	0.05	0.05	0.3%	0.3%	0.3%	0.3%
0.01	0.01	0.01	0.01	2.8%	2.8%	2.8%	2.8%
0.25	0.25	0.23	0.23	-1.2%	-1.2%	-1.4%	-1.4%
0.07	0.07	0.07	0.07	0.3%	0.3%	0.3%	0.3%
0.53	0.53	0.52	0.52	-0.5%	-0.5%	-0.6%	-0.6%
3.91	3.92	3.62	3.63	0.8%	0.8%	0.5%	0.5%
0.06	0.06	0.06	0.06	0.0%	0.0%	0.0%	0.0%
0.11	0.11	0.11	0.11	0.0%	0.0%	0.0%	0.0%
6.87	6.43	5.36	4.75	1.6%	1.4%	0.7%	0.2%
11.48	**11.05**	**9.67**	**9.07**	**1.2%**	**1.0%**	**0.5%**	**0.3%**
13.80	12.93	10.77	9.54	1.4%	1.1%	0.4%	-0.0%
25.28	**23.98**	**20.43**	**18.61**	**1.3%**	**1.1%**	**0.5%**	**0.1%**
104.6	**100.7**	**88.0**	**82.6**	**-0.0%**	**-0.2%**	**-0.7%**	**-0.9%**
2157	4361	5970	6187	4.7%	7.6%	8.9%	9.0%
1564	1789	2895	5943	3.2%	3.7%	5.7%	8.6%
131	240	260	335	2.0%	4.4%	4.7%	5.7%
15.64	31.68	43.39	44.96	4.7%	7.6%	8.9%	9.1%
2.47	2.93	4.74	9.74	3.2%	3.9%	5.8%	8.8%
0.18	0.34	0.37	0.47	2.2%	4.8%	5.1%	6.1%
0.04	**0.04**	**0.10**	**0.12**	**1.0%**	**1.3%**	**4.8%**	**5.5%**

Table D2. Key results for industrial sector technology cases

Consumption and Indicators	2009	2015			2025			2035		
		2010 Technology	Reference	High Technology	2010 Technology	Reference	High Technology	2010 Technology	Reference	High Technology
Value of Shipments (billion 2005 dollars)										
Manufacturing	4197	5279	5279	5279	6016	6016	6016	6770	6770	6770
Nonmanufacturing	1821	2193	2193	2193	2381	2381	2381	2521	2521	2521
Total	**6017**	**7472**	**7472**	**7472**	**8396**	**8396**	**8396**	**9292**	**9292**	**9292**
Energy Consumption excluding Refining[1] (quadrillion Btu)										
Liquefied Petroleum Gases	2.00	2.33	2.32	2.29	2.36	2.34	2.25	2.17	2.14	2.00
Heat and Power	0.21	0.26	0.25	0.25	0.26	0.25	0.24	0.26	0.24	0.22
Feedstocks	1.79	2.07	2.07	2.04	2.10	2.09	2.01	1.91	1.90	1.78
Motor Gasoline	0.25	0.34	0.33	0.32	0.37	0.33	0.30	0.38	0.32	0.28
Distillate Fuel Oil	1.16	1.19	1.16	1.13	1.27	1.16	1.07	1.32	1.13	0.99
Residual Fuel Oil	0.16	0.18	0.17	0.17	0.18	0.17	0.16	0.18	0.16	0.15
Petrochemical Feedstocks	0.90	1.29	1.29	1.27	1.34	1.34	1.28	1.26	1.26	1.17
Petroleum Coke	0.28	0.23	0.22	0.21	0.24	0.21	0.19	0.26	0.20	0.17
Asphalt and Road Oil	0.87	1.17	1.08	1.00	1.27	1.01	0.82	1.32	0.94	0.70
Miscellaneous Petroleum[2]	0.27	0.36	0.36	0.34	0.37	0.35	0.32	0.34	0.31	0.26
Petroleum Subtotal	5.88	7.10	6.93	6.74	7.40	6.90	6.38	7.22	6.46	5.72
Natural Gas Heat and Power	4.43	6.55	6.24	6.36	7.16	6.30	6.62	7.28	6.29	6.63
Natural Gas Feedstocks	0.55	0.61	0.61	0.60	0.57	0.56	0.54	0.47	0.47	0.43
Lease and Plant Fuel[3]	1.19	1.24	1.24	1.24	1.22	1.22	1.22	1.28	1.28	1.28
Natural Gas Subtotal	6.16	8.39	8.09	8.19	8.95	8.08	8.38	9.04	8.04	8.34
Metallurgical Coal and Coke[4]	0.38	0.62	0.59	0.56	0.63	0.56	0.47	0.56	0.47	0.37
Other Industrial Coal	0.88	0.94	0.92	0.92	0.97	0.91	0.90	0.95	0.88	0.86
Coal Subtotal	1.26	1.56	1.51	1.48	1.60	1.47	1.37	1.51	1.35	1.23
Renewables[5]	1.42	1.87	1.89	1.92	1.99	2.05	2.15	1.94	2.04	2.21
Purchased Electricity	2.82	3.40	3.37	3.27	3.44	3.34	3.03	3.37	3.09	2.71
Delivered Energy	**17.55**	**22.33**	**21.79**	**21.59**	**23.38**	**21.84**	**21.31**	**23.08**	**20.98**	**20.22**
Electricity Related Losses	6.04	7.00	6.93	6.72	7.07	6.86	6.23	6.77	6.20	5.46
Total	**23.59**	**29.33**	**28.73**	**28.31**	**30.45**	**28.70**	**27.54**	**29.85**	**27.19**	**25.67**
Delivered Energy Use per Dollar of Shipments (thousand Btu per 2005 dollar)	**3.63**	**3.65**	**3.58**	**3.55**	**3.53**	**3.35**	**3.28**	**3.33**	**3.11**	**3.03**
Onsite Industrial Combined Heat and Power										
Capacity (gigawatts)	23.07	33.91	32.07	35.95	42.07	37.14	48.54	45.61	43.77	57.17
Generation (billion kilowatthours)	123.62	201.42	186.37	215.73	262.97	222.04	308.82	290.17	271.90	373.87

[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, municipal solid waste, and other biomass.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 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: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs INDFRZN.D021011A, REF2011.D020911A, and INDHIGH.D021011A.

Table D3. Key results for transportation sector technology cases

Consumption and Indicators	2009	2015			2025			2035		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500	2707	2946	2947	2949	3462	3467	3475	4036	4043	4056
Commercial Light Trucks[1]	67	81	81	81	92	92	92	104	104	105
Freight Trucks greater than 10,000	207	250	250	250	291	291	291	335	335	335
(billion seat miles available)										
Air	960	1059	1059	1059	1180	1180	1180	1282	1282	1282
(billion ton miles traveled)										
Rail	1677	1886	1886	1886	2143	2143	2143	2328	2328	2328
Domestic Shipping	486	521	521	521	559	559	559	596	596	596
Energy Efficiency Indicators										
(miles per gallon)										
Tested New Light-Duty Vehicle[2]	28.0	30.4	31.3	31.6	35.0	35.3	36.5	35.8	36.5	37.9
New Car[2]	32.7	35.5	36.5	37.2	39.7	40.0	41.6	40.1	40.8	42.7
New Light Truck[2]	24.3	25.9	26.6	26.9	29.0	29.6	30.4	29.5	30.6	31.7
Light-Duty Stock[3]	20.8	21.9	22.1	22.2	25.4	25.7	26.2	27.5	27.9	28.8
New Commercial Light Truck[1]	15.6	16.1	16.4	16.5	17.6	17.9	18.2	17.5	18.1	18.5
Stock Commercial Light Truck[1]	14.4	15.2	15.2	15.3	17.0	17.2	17.4	17.5	18.0	18.3
Freight Truck	6.1	6.0	6.1	6.2	6.1	6.4	6.6	6.3	6.6	6.9
(seat miles per gallon)										
Aircraft	62.0	62.8	62.8	63.0	64.8	65.6	66.7	67.7	69.9	71.7
(ton miles per thousand Btu)										
Rail	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.3	3.4	3.5
Domestic Shipping	2.4	2.4	2.4	2.4	2.4	2.5	2.5	2.4	2.5	2.6
Energy Use (quadrillion Btu)										
by Mode										
Light-Duty Vehicles	16.13	16.44	16.36	16.25	16.56	16.40	16.10	17.89	17.66	17.14
Commercial Light Trucks[1]	0.58	0.66	0.66	0.66	0.68	0.67	0.66	0.75	0.73	0.71
Bus Transportation	0.27	0.28	0.28	0.28	0.30	0.30	0.30	0.33	0.33	0.33
Freight Trucks	4.26	5.21	5.11	5.02	5.96	5.73	5.52	6.67	6.35	6.06
Rail, Passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.07
Rail, Freight	0.51	0.57	0.57	0.57	0.65	0.64	0.63	0.71	0.69	0.67
Shipping, Domestic	0.20	0.22	0.22	0.21	0.23	0.23	0.22	0.25	0.24	0.23
Shipping, International	0.78	0.79	0.78	0.78	0.80	0.79	0.79	0.81	0.80	0.80
Recreational Boats	0.26	0.27	0.27	0.27	0.29	0.29	0.29	0.31	0.31	0.31
Air	2.66	2.71	2.71	2.70	2.99	2.95	2.91	3.17	3.07	3.00
Military Use	0.75	0.69	0.69	0.69	0.72	0.72	0.72	0.76	0.76	0.76
Lubricants	0.13	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.13	0.13
Pipeline Fuel	0.65	0.67	0.67	0.67	0.64	0.64	0.64	0.67	0.67	0.67
Total	**27.23**	**28.68**	**28.50**	**28.28**	**30.01**	**29.55**	**28.98**	**32.50**	**31.80**	**30.86**
by Fuel										
Liquefied Petroleum Gases	0.02	0.02	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
E85[4]	0.00	0.01	0.01	0.01	0.95	0.93	0.94	1.25	1.23	1.30
Motor Gasoline[5]	16.82	17.09	17.02	16.91	16.06	15.93	15.66	16.86	16.69	16.21
Jet Fuel[6]	3.20	3.20	3.20	3.19	3.50	3.47	3.43	3.71	3.62	3.54
Distillate Fuel Oil[7]	5.54	6.68	6.57	6.47	7.69	7.45	7.19	8.68	8.35	7.92
Residual Fuel Oil	0.78	0.80	0.79	0.79	0.81	0.81	0.80	0.83	0.82	0.81
Other Petroleum[8]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Liquid Fuels and Other Petroleum	26.52	27.95	27.76	27.54	29.19	28.76	28.19	31.52	30.89	29.97
Pipeline Fuel Natural Gas	0.65	0.67	0.67	0.67	0.64	0.64	0.64	0.67	0.67	0.67
Compressed Natural Gas	0.03	0.04	0.04	0.04	0.14	0.10	0.10	0.23	0.16	0.16
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.04	0.05	0.05	0.08	0.07	0.07
Delivered Energy	**27.23**	**28.68**	**28.50**	**28.28**	**30.01**	**29.56**	**28.98**	**32.50**	**31.80**	**30.87**
Electricity Related Losses	0.05	0.06	0.06	0.06	0.09	0.09	0.09	0.16	0.15	0.14
Total	**27.28**	**28.74**	**28.56**	**28.34**	**30.10**	**29.65**	**29.07**	**32.66**	**31.95**	**31.01**

[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 2009 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: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs TRNLOW.D021011A, REF2011.D020911A, and TRNHIGH.D021011A.

Table D4. Key results for integrated technology cases

Consumption and Emissions	2009	2015			2025			2035		
		Low Technology	Reference	High Technology	Low Technology	Reference	High Technology	Low Technology	Reference	High Technology
Energy Consumption by Sector (quadrillion Btu)										
Residential	11.12	11.18	11.02	10.52	11.91	11.32	10.37	12.67	11.70	10.63
Commercial	8.49	9.08	9.02	8.73	10.13	9.94	9.14	11.36	11.05	9.83
Industrial[1]	21.85	26.75	26.75	26.81	27.47	28.11	28.45	28.07	28.89	29.92
Transportation	27.23	28.70	28.50	28.25	29.94	29.56	28.98	32.46	31.80	30.85
Electric Power[2]	38.31	40.15	39.73	38.15	44.46	43.17	39.74	47.68	46.03	41.72
Total	**94.79**	**102.71**	**102.02**	**100.00**	**109.35**	**107.95**	**103.68**	**116.23**	**114.19**	**109.15**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	36.62	39.33	39.10	38.81	40.27	39.84	39.16	42.33	41.70	40.60
Natural Gas	23.31	25.97	25.77	24.94	26.52	25.73	24.05	28.94	27.24	24.85
Coal	19.69	19.91	19.73	18.72	22.98	22.61	21.01	24.43	24.30	22.27
Nuclear Power	8.35	8.77	8.77	8.77	9.17	9.17	8.54	9.14	9.14	8.60
Renewable Energy[4]	6.51	8.41	8.34	8.45	10.14	10.33	10.66	11.15	11.56	12.59
Other[5]	0.32	0.31	0.31	0.31	0.28	0.27	0.27	0.25	0.25	0.23
Total	**94.79**	**102.71**	**102.02**	**100.00**	**109.35**	**107.95**	**103.68**	**116.23**	**114.19**	**109.15**
Energy Intensity (thousand Btu per 2005 dollar of GDP)	**7.36**	**6.70**	**6.65**	**6.53**	**5.47**	**5.39**	**5.18**	**4.52**	**4.44**	**4.25**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	343	340	336	328	345	328	307	348	319	293
Commercial	218	229	229	224	236	237	227	248	251	237
Industrial[1]	854	1063	1061	1058	1084	1080	1076	1150	1147	1136
Transportation	1850	1930	1916	1898	1980	1932	1891	2137	2068	1997
Electric Power[6]	2160	2163	2138	2008	2425	2360	2144	2606	2526	2245
Total	**5426**	**5724**	**5680**	**5516**	**6070**	**5938**	**5645**	**6489**	**6311**	**5908**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2319	2450	2434	2412	2485	2430	2380	2633	2561	2478
Natural Gas	1218	1363	1352	1308	1393	1351	1262	1524	1434	1307
Coal	1877	1899	1882	1785	2180	2144	1991	2320	2304	2111
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5426**	**5724**	**5680**	**5516**	**6070**	**5938**	**5645**	**6489**	**6311**	**5908**
Carbon Dioxide Emissions (tons per person)	**17.6**	**17.5**	**17.4**	**16.9**	**17.0**	**16.6**	**15.8**	**16.6**	**16.2**	**15.1**

[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, 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.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid 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.
[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 2009 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs LTRKITEN.D030111A, REF2011.D020911A, and HTRKITEN.D030111A.

Table D5. Key results for expanded standards cases
(quadrillion Btu, unless otherwise noted)

Energy Consumption	2009	2015 Reference	2015 Expanded Standards	2015 Expanded Standards and Codes	2025 Reference	2025 Expanded Standards	2025 Expanded Standards and Codes	2035 Reference	2035 Expanded Standards	2035 Expanded Standards and Codes
Residential Energy Consumption										
by Fuel										
Liquefied Petroleum Gases	0.53	0.49	0.49	0.49	0.48	0.47	0.47	0.48	0.48	0.47
Kerosene	0.03	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01
Distillate Fuel Oil	0.61	0.56	0.56	0.56	0.44	0.44	0.43	0.37	0.35	0.34
Natural Gas	4.87	4.94	4.94	4.92	4.96	4.89	4.81	4.90	4.73	4.58
Coal	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Renewable Energy[1]	0.43	0.40	0.40	0.40	0.42	0.42	0.42	0.42	0.42	0.41
Electricity	4.65	4.60	4.57	4.56	4.98	4.69	4.65	5.51	4.91	4.85
by End Use										
Space Heating	4.78	4.71	4.71	4.69	4.64	4.57	4.46	4.55	4.39	4.20
Space Cooling	0.83	0.82	0.82	0.82	0.90	0.88	0.86	0.99	0.93	0.88
Water Heating	1.95	1.99	1.99	1.99	1.99	1.88	1.88	1.88	1.61	1.61
Refrigeration	0.37	0.35	0.35	0.35	0.35	0.34	0.34	0.38	0.36	0.36
Cooking	0.35	0.36	0.36	0.36	0.39	0.39	0.39	0.41	0.41	0.41
Clothes Dryers	0.24	0.24	0.24	0.24	0.24	0.23	0.23	0.26	0.25	0.25
Freezers	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.09	0.08	0.08
Lighting	0.71	0.57	0.57	0.57	0.52	0.52	0.52	0.54	0.52	0.52
Clothes Washers[2]	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Dishwashers[2]	0.09	0.09	0.09	0.09	0.10	0.10	0.10	0.11	0.10	0.10
Color Televisions and Set-Top Boxes	0.34	0.33	0.33	0.33	0.36	0.32	0.32	0.42	0.35	0.35
Personal Computers and Related Equipment	0.18	0.17	0.16	0.16	0.18	0.13	0.13	0.19	0.14	0.14
Furnace Fans and Boiler Circulation Pumps	0.14	0.15	0.15	0.15	0.18	0.18	0.18	0.20	0.20	0.20
Other Uses[3]	1.03	1.12	1.09	1.09	1.37	1.29	1.29	1.65	1.56	1.56
Delivered Energy	**11.12**	**11.02**	**10.99**	**10.96**	**11.32**	**10.94**	**10.80**	**11.70**	**10.91**	**10.68**
Residential Delivered Energy Intensity										
(million Btu per household)	98.0	90.8	90.6	90.3	83.9	81.1	80.1	79.7	74.3	72.7
(thousand Btu per square foot)	58.7	51.5	51.3	51.2	44.5	43.0	42.4	40.2	37.5	36.7
Commercial Energy Consumption										
by Fuel										
Distillate Fuel Oil	0.34	0.28	0.28	0.28	0.26	0.26	0.25	0.25	0.25	0.23
Other Liquid Fuels[4]	0.26	0.27	0.27	0.27	0.27	0.27	0.27	0.28	0.28	0.28
Natural Gas	3.20	3.47	3.47	3.46	3.66	3.62	3.50	3.92	3.86	3.59
Coal	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Renewable Energy[5]	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11	0.11
Electricity	4.51	4.83	4.83	4.83	5.58	5.42	5.37	6.43	6.18	6.05
by End Use										
Space Heating[6]	1.94	2.02	2.02	2.01	2.04	2.03	1.90	2.05	2.02	1.71
Space Cooling[6]	0.51	0.56	0.56	0.56	0.60	0.57	0.53	0.65	0.60	0.49
Water Heating[6]	0.56	0.63	0.63	0.63	0.70	0.66	0.66	0.75	0.69	0.69
Ventilation	0.50	0.56	0.56	0.56	0.64	0.64	0.64	0.71	0.71	0.71
Cooking	0.20	0.22	0.22	0.22	0.25	0.25	0.25	0.27	0.27	0.27
Lighting	1.03	1.04	1.04	1.04	1.14	1.11	1.11	1.25	1.20	1.20
Refrigeration	0.40	0.36	0.36	0.36	0.36	0.35	0.35	0.39	0.37	0.37
Office Equipment (Personal Computers)	0.22	0.19	0.19	0.19	0.19	0.14	0.14	0.21	0.15	0.15
Office Equipment (non-PC)	0.25	0.32	0.32	0.32	0.40	0.39	0.39	0.47	0.45	0.45
Other Uses[7]	2.89	3.12	3.12	3.12	3.62	3.61	3.61	4.31	4.29	4.29
Total Delivered Energy	**8.49**	**9.02**	**9.02**	**9.01**	**9.94**	**9.74**	**9.57**	**11.05**	**10.74**	**10.33**
Commercial Delivered Energy Intensity										
(thousand Btu per square foot)	105.9	105.6	105.5	105.4	102.1	100.0	98.2	100.7	97.8	94.0

[1]Includes wood used for residential heating.
[2]Does not include water heating portion of load..
[3]Includes small electric devices, heating elements, such outdoor appliances as grills and mosquito traps, motors not included above, and kerosene and coal.
[4]Includes liquefied petroleum gases, motor gasoline, kerosene, and residual fuel oil.
[5]Includes commercial sector consumption of wood and wood waste, landfill gas, municipal solid waste, and other biomass for combined heat and power.
[6]Includes fuel consumption for district services.
[7]Includes miscellaneous uses, such as service station equipment, automated teller machines, telecommunications equipment, medical equipment, pumps, emergency generation, 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.

Btu = British thermal unit.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 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.

Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System, runs REF2011.D020911A, BLDEXPAND.D022811A, and BLDEXPANDCS.D022811A.

Table D6. Key results for transportation sector light-duty vehicle efficiency cases

Consumption and Indicators	2009	2015			2025			2035		
		Reference	CAFE 3% Growth	CAFE 6% Growth	Reference	CAFE 3% Growth	CAFE 6% Growth	Reference	CAFE 3% Growth	CAFE 6% Growth
Level of Travel										
(billion vehicle miles traveled)										
Light-Duty Vehicles less than 8,500	2707	2947	2944	2944	3467	3457	3490	4043	4035	4084
Commercial Light Trucks[1]	67	81	81	81	92	92	92	104	104	105
Freight Trucks greater than 10,000	207	250	250	250	291	291	291	335	335	336
(billion seat miles available)										
Air	960	1059	1059	1059	1180	1180	1180	1282	1282	1282
(billion ton miles traveled)										
Rail	1677	1886	1884	1881	2143	2142	2151	2328	2322	2337
Domestic Shipping	486	521	522	521	559	558	558	596	592	593
Energy Efficiency Indicators										
(miles per gallon)										
Tested New Light-Duty Vehicle[2]	28.0	31.3	31.4	31.4	35.3	44.6	55.0	36.5	46.4	58.5
New Car[2]	32.7	36.5	36.7	36.7	40.0	52.1	70.8	40.8	54.2	75.8
New Light Truck[2]	24.3	26.6	26.7	26.7	29.6	36.7	41.8	30.6	37.4	43.8
Light-Duty Stock[3]	20.8	22.1	22.1	22.1	25.7	28.6	30.2	27.9	34.0	39.4
New Commercial Light Truck[1]	15.6	16.4	16.4	16.4	17.9	20.7	22.2	18.1	20.8	22.8
Stock Commercial Light Truck[1]	14.4	15.2	15.2	15.2	17.2	18.2	18.8	18.0	20.5	22.2
Freight Truck	6.1	6.1	6.1	6.1	6.4	6.4	6.4	6.6	6.6	6.6
(seat miles per gallon)										
Aircraft	62.0	62.8	62.8	62.8	65.6	65.6	65.6	69.9	69.9	69.9
(ton miles per thousand Btu)										
Rail	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4
Domestic Shipping	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5
Energy Use (quadrillion Btu)										
by Mode										
Light-Duty Vehicles	16.13	16.36	16.34	16.34	16.40	14.79	14.53	17.66	14.37	12.90
Commercial Light Trucks[1]	0.58	0.66	0.66	0.66	0.67	0.63	0.61	0.73	0.63	0.59
Bus Transportation	0.27	0.28	0.28	0.28	0.30	0.30	0.30	0.33	0.33	0.33
Freight Trucks	4.26	5.11	5.11	5.11	5.73	5.73	5.72	6.35	6.35	6.38
Rail, Passenger	0.05	0.05	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.06
Rail, Freight	0.51	0.57	0.57	0.57	0.64	0.64	0.64	0.69	0.69	0.69
Shipping, Domestic	0.20	0.22	0.22	0.22	0.23	0.23	0.23	0.24	0.24	0.24
Shipping, International	0.78	0.78	0.78	0.78	0.79	0.79	0.79	0.80	0.80	0.80
Recreational Boats	0.26	0.27	0.27	0.27	0.29	0.29	0.29	0.31	0.31	0.32
Air	2.66	2.71	2.71	2.71	2.95	2.96	2.96	3.07	3.08	3.08
Military Use	0.75	0.69	0.69	0.69	0.72	0.72	0.72	0.76	0.76	0.76
Lubricants	0.13	0.12	0.12	0.12	0.13	0.13	0.13	0.13	0.14	0.14
Pipeline Fuel	0.65	0.67	0.66	0.66	0.64	0.64	0.64	0.67	0.66	0.67
Total	**27.23**	**28.50**	**28.48**	**28.48**	**29.55**	**27.92**	**27.63**	**31.80**	**28.42**	**26.95**
by Fuel										
Liquefied Petroleum Gases	0.02	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02
E85[4]	0.00	0.01	0.01	0.01	0.93	1.22	1.25	1.23	1.56	1.74
Motor Gasoline[5]	16.82	17.02	16.97	16.97	15.93	13.39	12.93	16.69	12.03	9.82
Jet Fuel[6]	3.20	3.20	3.20	3.20	3.47	3.47	3.47	3.62	3.62	3.62
Distillate Fuel Oil[7]	5.54	6.57	6.60	6.60	7.45	8.06	8.13	8.35	9.28	9.56
Residual Fuel Oil	0.78	0.79	0.79	0.79	0.81	0.81	0.81	0.82	0.82	0.82
Other Petroleum[8]	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.17	0.17
Liquid Fuels and Other Petroleum	26.52	27.76	27.74	27.74	28.76	27.13	26.76	30.89	27.50	25.76
Pipeline Fuel Natural Gas	0.65	0.67	0.66	0.66	0.64	0.64	0.64	0.67	0.66	0.67
Compressed Natural Gas	0.03	0.04	0.04	0.04	0.10	0.10	0.10	0.16	0.16	0.16
Liquid Hydrogen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity	0.02	0.03	0.03	0.03	0.05	0.05	0.13	0.07	0.10	0.36
Delivered Energy	**27.23**	**28.50**	**28.48**	**28.48**	**29.56**	**27.92**	**27.63**	**31.80**	**28.42**	**26.95**
Electricity Related Losses	0.05	0.06	0.06	0.06	0.09	0.11	0.27	0.15	0.20	0.73
Total	**27.28**	**28.56**	**28.53**	**28.53**	**29.65**	**28.03**	**27.91**	**31.95**	**28.62**	**27.68**

[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 2009 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: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs REF2011.D020911A, CAFE3.D022211A, and CAFE6.D022211A.

Table D7. Key results for the transportation sector Heavy-Duty Vehicle Fuel Economy Standards case

Sales, Consumption, Supply, and Prices	2009	2015		2025		2035	
		Reference	Heavy-duty Vehicle Fuel Economy Standards	Reference	Heavy-duty Vehicle Fuel Economy Standards	Reference	Heavy-duty Vehicle Fuel Economy Standards
Truck Sales by Size Class (millions)	**0.31**	**0.62**	**0.62**	**0.75**	**0.76**	**0.93**	**0.93**
Medium	0.18	0.31	0.31	0.37	0.37	0.46	0.46
Diesel	0.13	0.22	0.22	0.26	0.27	0.32	0.33
Motor Gasoline	0.05	0.09	0.09	0.09	0.09	0.11	0.11
Liquefied Petroleum Gases	0.00	0.00	0.00	0.00	0.00	0.01	0.01
Natural Gas	0.00	0.00	0.00	0.01	0.01	0.02	0.01
Heavy	0.13	0.31	0.31	0.38	0.38	0.47	0.47
Diesel	0.13	0.29	0.29	0.36	0.36	0.44	0.44
Motor Gasoline	0.01	0.01	0.01	0.02	0.02	0.02	0.02
Liquefied Petroleum Gases	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Natural Gas	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Consumption by Size Class (quadrillion Btu)	**4.26**	**5.11**	**5.02**	**5.72**	**5.52**	**6.34**	**6.19**
Medium	0.81	1.05	1.03	1.23	1.14	1.42	1.30
Diesel	0.56	0.76	0.75	0.91	0.86	1.06	0.98
Motor Gasoline	0.24	0.27	0.27	0.28	0.26	0.29	0.27
Liquefied Petroleum Gases	0.00	0.01	0.01	0.01	0.01	0.02	0.01
Natural Gas	0.00	0.01	0.01	0.03	0.02	0.05	0.04
Heavy	3.45	4.06	3.99	4.49	4.38	4.93	4.88
Diesel	3.34	3.97	3.91	4.42	4.30	4.84	4.80
Motor Gasoline	0.09	0.07	0.07	0.05	0.05	0.05	0.05
Liquefied Petroleum Gases	0.01	0.01	0.01	0.00	0.00	0.01	0.01
Natural Gas	0.00	0.01	0.01	0.02	0.02	0.03	0.03
New Truck Fuel Efficiency by Size Class (gasoline equivalent miles per gallon)	**6.14**	**6.12**	**6.53**	**6.53**	**6.70**	**6.71**	**6.85**
Medium	7.89	7.85	8.31	7.84	8.46	7.84	8.45
Diesel	7.96	7.95	8.37	7.95	8.63	7.95	8.63
Motor Gasoline	7.60	7.64	8.16	7.79	8.26	7.84	8.26
Liquefied Petroleum Gases	7.60	7.63	8.13	7.63	8.19	7.63	8.16
Natural Gas	5.94	5.96	6.02	5.96	6.02	5.96	6.02
Heavy	5.60	5.70	6.06	6.18	6.24	6.40	6.42
Diesel	5.59	5.68	6.05	6.17	6.23	6.39	6.41
Motor Gasoline	8.41	8.40	8.45	8.40	8.45	8.40	8.45
Liquefied Petroleum Gases	5.30	5.30	5.51	5.33	5.51	5.33	5.51
Natural Gas	5.64	5.63	5.73	5.62	5.73	5.62	5.73
Stock Fuel Efficiency by Size Class (gasoline equivalent miles per gallon)	**6.09**	**6.12**	**6.23**	**6.36**	**6.60**	**6.61**	**6.78**
Medium	7.95	7.88	7.96	7.83	8.27	7.83	8.41
Diesel	8.05	7.99	8.07	7.96	8.45	7.95	8.60
Motor Gasoline	7.85	7.72	7.77	7.68	8.00	7.78	8.21
Liquefied Petroleum Gases	7.03	7.47	7.57	7.61	8.08	7.63	8.17
Natural Gas	6.00	5.97	5.98	5.96	6.02	5.96	6.02
Heavy	5.65	5.66	5.76	5.95	6.11	6.24	6.29
Diesel	5.58	5.62	5.71	5.92	6.09	6.22	6.28
Motor Gasoline	8.14	8.25	8.25	8.37	8.40	8.40	8.44
Liquefied Petroleum Gases	5.28	5.29	5.31	5.31	5.45	5.33	5.49
Natural Gas	5.63	5.63	5.70	5.62	5.73	5.62	5.73

[1]Includes lease condensate.
[2]Includes natural gas plant liquids, refinery processing gain, other crude oil supply, and stock withdrawals.
[3]Includes liquids, such as ethanol and biodiesel, derived from biomass, natural gas, and coal. Includes net imports of ethanol and biodiesel.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 data based on: Oak Ridge National Laboratory, *Transportation Energy Data Book: Edition 28 and Annual* (Oak Ridge, TN, 2009); U.S. Department of Commerce, Bureau of the Census, "Vehicle Inventory and Use Survey," EC02TV (Washington, DC, December 2004); Federal Highway Administration, *Highway Statistics 2007* (Washington, DC, October 2008); U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010); and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. **Projections:** EIA, AEO2011 National Energy Modeling System runs REF2011.D020911A and HDVCAFE.D030411A.

Table D8. Energy consumption and carbon dioxide emissions, extended policy cases

Consumption and Emissions	2009	2015			2025			2035		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Energy Consumption by Sector (quadrillion Btu)										
Residential	11.12	11.02	10.94	10.88	11.32	10.99	10.55	11.70	11.20	10.36
Commercial	8.49	9.02	9.03	9.02	9.94	9.95	9.61	11.05	11.08	10.45
Industrial[1]	21.85	26.75	26.81	26.65	28.11	28.36	28.01	28.89	29.51	28.49
Transportation	27.23	28.50	28.52	28.47	29.56	29.54	27.90	31.80	31.81	28.39
Electric Power[2]	38.31	39.73	39.66	39.50	43.17	42.52	40.92	46.03	45.28	42.70
Total	**94.79**	**102.02**	**101.99**	**101.60**	**107.95**	**107.43**	**103.60**	**114.19**	**113.93**	**106.35**
Energy Consumption by Fuel (quadrillion Btu)										
Liquid Fuels and Other Petroleum[3]	36.62	39.10	39.11	38.99	39.84	39.80	37.91	41.70	41.69	37.83
Natural Gas	23.31	25.77	25.78	25.61	25.73	25.66	24.86	27.24	26.70	25.28
Coal	19.69	19.73	19.80	19.81	22.61	22.39	21.64	24.30	24.09	23.22
Nuclear Power	8.35	8.77	8.77	8.77	9.17	9.17	8.97	9.14	9.14	8.94
Renewable Energy[4]	6.51	8.34	8.21	8.10	10.33	10.13	9.93	11.56	12.07	10.83
Other[5]	0.32	0.31	0.31	0.31	0.27	0.27	0.27	0.25	0.24	0.23
Total	**94.79**	**102.02**	**101.99**	**101.60**	**107.95**	**107.43**	**103.60**	**114.19**	**113.93**	**106.35**
Energy Intensity (thousand Btu per 2005 dollar of GDP)	**7.36**	**6.65**	**6.65**	**6.63**	**5.39**	**5.37**	**5.18**	**4.44**	**4.43**	**4.14**
Carbon Dioxide Emissions by Sector (million metric tons)										
Residential	343	336	333	332	328	320	313	319	308	294
Commercial	218	229	229	229	237	238	230	251	253	235
Industrial[1]	854	1061	1063	1056	1080	1092	1071	1147	1164	1128
Transportation	1850	1916	1912	1914	1932	1918	1815	2068	2062	1841
Electric Power[6]	2160	2138	2145	2141	2360	2329	2233	2526	2468	2346
Total	**5426**	**5680**	**5682**	**5671**	**5938**	**5897**	**5663**	**6311**	**6255**	**5843**
Carbon Dioxide Emissions by Fuel (million metric tons)										
Petroleum	2319	2434	2429	2427	2430	2414	2294	2561	2553	2300
Natural Gas	1218	1352	1352	1343	1351	1347	1305	1434	1405	1330
Coal	1877	1882	1889	1889	2144	2123	2052	2304	2285	2201
Other[7]	12	12	12	12	12	12	12	12	12	12
Total	**5426**	**5680**	**5682**	**5671**	**5938**	**5897**	**5663**	**6311**	**6255**	**5843**
Carbon Dioxide Emissions (tons per person)	**17.6**	**17.4**	**17.4**	**17.4**	**16.6**	**16.5**	**15.8**	**16.2**	**16.0**	**15.0**

[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 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, 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.
[4]Includes grid-connected electricity from conventional hydroelectric; wood and wood waste; landfill gas; biogenic municipal solid 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.
[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 2009 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs REF2011.D020911A, NOSUNSET.D030711A, and EXTENDED.D031011A.

Table D9. Electricity generation and generating capacity, extended policy cases
(gigawatts, unless otherwise noted)

Net Summer Capacity, Generation Consumption, and Emissions	2009	2015			2025			2035		
		Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies	Reference	No Sunset	Extended Policies
Capacity	**1033.4**	**1075.0**	**1069.7**	**1056.4**	**1118.9**	**1117.9**	**1086.3**	**1221.0**	**1239.1**	**1155.5**
Electric Power Sector[1]	1001.9	1025.1	1019.6	1005.9	1050.8	1029.2	994.8	1131.5	1099.4	1014.2
Pulverized Coal	312.9	316.4	314.6	308.7	315.0	312.2	304.5	315.3	312.2	304.5
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	2.6	2.6	2.6	2.6	2.6	2.6
Conventional Natural Gas Combined-Cycle	197.2	203.2	203.2	203.2	203.9	203.5	203.2	205.0	204.8	203.3
Advanced Natural Gas Combined-Cycle	0.0	0.3	0.0	0.0	6.0	2.3	0.0	54.6	27.9	4.0
Conventional Combustion Turbine	137.5	136.7	136.2	134.6	135.8	135.4	131.1	135.8	135.4	131.1
Advanced Combustion Turbine	0.0	3.9	3.7	3.4	19.5	9.5	4.2	45.8	26.0	11.0
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	101.0	105.7	105.7	105.7	110.5	110.5	108.1	110.5	110.5	108.1
Oil and Natural Gas Steam	114.4	99.9	100.3	96.3	92.8	88.4	82.6	88.7	88.3	82.6
Renewable Sources	117.0	136.1	133.2	131.5	141.5	142.3	136.5	148.3	167.9	144.2
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Distributed Generation	0.0	0.5	0.3	0.2	1.3	0.5	0.2	3.1	2.0	0.9
Combined Heat and Power[2]	31.5	50.0	50.1	50.5	68.1	88.7	91.5	89.5	139.7	141.3
Fossil Fuels/Other	24.0	32.5	32.7	33.1	40.7	43.2	44.7	57.9	62.3	64.4
Renewable Fuels	7.5	17.5	17.5	17.4	27.4	45.5	46.8	31.6	77.4	76.9
Cumulative Additions	**0.0**	**63.7**	**60.1**	**58.2**	**117.2**	**123.7**	**112.3**	**223.4**	**245.0**	**181.5**
Electric Power Sector[1]	0.0	45.3	41.4	39.3	80.6	66.5	52.4	165.4	136.8	71.8
Pulverized Coal	0.0	10.9	10.9	10.9	12.9	12.9	12.9	13.2	12.9	12.9
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Conventional Natural Gas Combined-Cycle	0.0	6.4	6.4	6.4	7.0	6.7	6.4	8.1	7.9	6.5
Advanced Natural Gas Combined-Cycle	0.0	0.3	0.0	0.0	6.0	2.3	0.0	54.6	27.9	4.0
Conventional Combustion Turbine	0.0	2.1	2.0	2.0	2.1	2.0	2.0	2.1	2.0	2.0
Advanced Combustion Turbine	0.0	3.9	3.7	3.4	19.5	9.5	4.2	45.8	26.0	11.0
Nuclear	0.0	1.1	1.1	1.1	6.3	6.3	6.3	6.3	6.3	6.3
Renewable Sources	0.0	19.4	16.5	14.8	24.8	25.6	19.8	31.6	51.2	27.5
Distributed Generation	0.0	0.5	0.3	0.2	1.3	0.5	0.2	3.1	2.0	0.9
Combined Heat and Power[2]	0.0	18.5	18.6	18.9	36.6	57.2	59.9	58.0	108.2	109.7
Fossil Fuels/Other	0.0	8.5	8.7	9.1	16.8	19.2	20.6	33.9	38.4	40.4
Renewable Fuels	0.0	9.9	9.9	9.8	19.8	38.0	39.3	24.0	69.8	69.3
Cumulative Retirements	**0.0**	**25.4**	**27.1**	**38.6**	**35.2**	**42.8**	**63.0**	**39.3**	**42.8**	**63.0**
Generation by Fuel (billion kilowatthours)	**3978**	**4253**	**4246**	**4230**	**4682**	**4661**	**4504**	**5167**	**5168**	**4886**
Electric Power Sector[1]	3811	3998	3991	3972	4300	4239	4063	4633	4529	4236
Coal	1749	1769	1775	1776	2016	1996	1925	2107	2090	2009
Petroleum	36	38	38	38	40	41	40	42	42	41
Natural Gas	841	858	858	846	820	788	727	1033	901	787
Nuclear Power	799	839	839	839	877	877	858	874	874	855
Renewable Sources	384	494	480	473	545	537	513	572	618	541
Pumped Storage	2	-0	-0	-0	-0	-0	-0	-0	-0	-0
Distributed Generation	0	1	0	0	3	1	0	5	4	2
Combined Heat and Power[2]	167	255	256	257	381	422	440	533	639	650
Fossil Fuels/Other	36	63	63	62	128	152	161	152	226	224
Renewable Fuels	131	192	193	195	253	270	279	381	413	426
Average Electricity Price (cents per kilowatthour)	**9.8**	**8.9**	**8.8**	**8.8**	**8.9**	**8.8**	**8.7**	**9.2**	**8.9**	**8.6**

[1]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.

[2]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.

Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.

Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs REF2011.D020911A, NOSUNSET.D030711A, and EXTENDED.D031011A.

Table D10. Key results for advanced nuclear cost cases
(gigawatts, unless otherwise noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2009	2015			2025			2035		
		High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost	High Nuclear Cost	Reference	Low Nuclear Cost
Capacity										
Coal Steam	312.9	317.4	317.0	316.5	317.6	317.6	317.4	317.9	317.9	317.4
Oil and Natural Gas Steam	114.4	101.0	99.9	101.3	93.9	92.8	94.4	89.7	88.7	93.7
Combined Cycle	197.2	203.5	203.5	203.4	211.6	209.9	208.3	262.5	259.5	238.4
Combustion Turbine/Diesel	137.5	140.4	140.6	140.6	154.8	155.3	156.1	177.0	181.6	181.7
Nuclear Power	101.0	105.7	105.7	105.7	110.5	110.5	111.3	110.5	110.5	129.1
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Renewable Sources	117.0	136.2	136.3	136.2	142.2	141.7	142.0	148.7	148.5	146.6
Distributed Generation (Natural Gas)	0.0	0.8	0.5	0.8	1.7	1.3	1.7	4.3	3.1	4.7
Combined Heat and Power[1]	31.5	50.0	50.0	50.0	68.8	68.1	68.0	90.3	89.5	89.5
Total	**1033.4**	**1076.9**	**1075.2**	**1076.3**	**1123.0**	**1119.1**	**1120.9**	**1222.5**	**1221.2**	**1222.8**
Cumulative Additions										
Coal Steam	0.0	11.5	11.5	11.5	13.5	13.5	13.5	13.8	13.8	13.5
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	6.6	6.6	6.5	14.8	13.1	11.5	65.6	62.7	41.5
Combustion Turbine/Diesel	0.0	5.9	6.1	6.0	21.1	21.6	22.4	43.3	47.9	48.0
Nuclear Power	0.0	1.1	1.1	1.1	6.3	6.3	7.1	6.3	6.3	25.0
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	19.3	19.4	19.3	25.3	24.8	25.1	31.8	31.6	29.7
Distributed Generation	0.0	0.8	0.5	0.8	1.7	1.3	1.7	4.3	3.1	4.7
Combined Heat and Power[1]	0.0	18.5	18.5	18.4	37.3	36.6	36.5	58.8	58.0	58.0
Total	**0.0**	**63.7**	**63.7**	**63.8**	**120.0**	**117.2**	**117.7**	**223.9**	**223.4**	**220.3**
Cumulative Retirements	**0.0**	**23.7**	**25.4**	**24.4**	**34.2**	**35.2**	**33.9**	**38.5**	**39.3**	**34.6**
Generation by Fuel (billion kilowatthours)										
Coal	1749	1754	1769	1783	2005	2016	2030	2104	2107	2087
Petroleum	36	38	38	38	40	40	40	42	42	42
Natural Gas	841	870	858	847	826	820	809	1034	1033	922
Nuclear Power	799	839	839	839	877	877	882	874	874	1019
Pumped Storage	2	-0	-0	-0	-0	-0	-0	-0	-0	-0
Renewable Sources	384	493	494	491	545	545	542	572	572	569
Distributed Generation	0	1	1	1	3	3	3	4	5	4
Combined Heat and Power[1]	167	255	255	254	387	381	380	540	533	534
Total	**3978**	**4250**	**4253**	**4254**	**4683**	**4682**	**4685**	**5171**	**5167**	**5176**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Petroleum	34	33	33	33	36	35	35	37	37	37
Natural Gas	373	384	379	375	364	362	358	427	428	393
Coal	1742	1698	1714	1727	1939	1951	1967	2047	2049	2030
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2160**	**2128**	**2138**	**2147**	**2351**	**2360**	**2372**	**2524**	**2526**	**2472**
Prices to the Electric Power Sector[2] (2009 dollars per million Btu)										
Petroleum	10.26	13.98	13.96	13.97	17.39	17.31	17.74	18.29	18.06	18.27
Natural Gas	4.82	4.72	4.67	4.65	5.79	5.76	5.77	6.83	6.80	6.52
Coal	2.20	2.12	2.11	2.12	2.26	2.24	2.24	2.40	2.40	2.38

[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 solid waste.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs HCNUC11.D020911A, REF2011.D020911A, and LCNUC11.D020911A.

Table D11. Key results for electric power sector fossil technology cases
(gigawatts, unless otherwise noted)

Net Summer Capacity, Generation Consumption, and Emissions	2009	2015			2025			2035		
		High Fossil Technology Cost	Reference	Low Fossil Technology Cost	High Fossil Technology Cost	Reference	Low Fossil Technology Cost	High Fossil Technology Cost	Reference	Low Fossil Technology Cost
Capacity										
Pulverized Coal	312.9	315.3	316.4	316.6	314.7	315.0	314.7	314.7	315.3	330.3
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	2.6	2.6	2.6	2.6	2.6	5.0
Conventional Natural Gas Combined-Cycle	197.2	203.3	203.2	203.3	204.0	203.9	204.9	205.9	205.0	205.6
Advanced Natural Gas Combined-Cycle	0.0	0.6	0.3	0.7	5.2	6.0	18.5	49.7	54.6	65.7
Conventional Combustion Turbine	137.5	136.7	136.7	137.3	135.9	135.8	136.6	135.9	135.8	135.7
Advanced Combustion Turbine	0.0	3.6	3.9	4.7	19.2	19.5	18.3	44.3	45.8	31.9
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	101.0	105.7	105.7	105.7	110.5	110.5	110.5	110.5	110.5	110.5
Oil and Natural Gas Steam	114.4	100.6	99.9	100.9	93.4	92.8	88.5	91.0	88.7	85.2
Renewable Sources/Pumped Storage	138.8	157.8	158.0	157.9	163.9	163.4	161.3	170.6	170.2	165.3
Distributed Generation	0.0	0.3	0.5	1.4	0.6	1.3	4.7	1.4	3.1	16.0
Combined Heat and Power[1]	31.5	50.0	50.0	50.0	68.1	68.1	67.4	90.1	89.5	88.1
Total	**1033.4**	**1074.4**	**1075.0**	**1079.0**	**1118.1**	**1118.9**	**1127.9**	**1216.6**	**1221.0**	**1239.3**
Cumulative Additions										
Pulverized Coal	0.0	10.9	10.9	10.9	12.9	12.9	12.9	12.9	13.2	28.5
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	3.0
Conventional Natural Gas Combined-Cycle	0.0	6.5	6.4	6.5	7.2	7.0	8.0	9.1	8.1	8.7
Advanced Natural Gas Combined-Cycle	0.0	0.6	0.3	0.7	5.2	6.0	18.5	49.7	54.6	65.7
Conventional Combustion Turbine	0.0	2.1	2.1	3.1	2.1	2.1	3.1	2.1	2.1	3.1
Advanced Combustion Turbine	0.0	3.6	3.9	4.7	19.2	19.5	18.3	44.3	45.8	31.9
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	1.1	1.1	1.1	6.3	6.3	6.3	6.3	6.3	6.3
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	19.2	19.4	19.3	25.4	24.8	22.7	32.1	31.6	26.7
Distributed Generation	0.0	0.3	0.5	1.4	0.6	1.3	4.7	1.4	3.1	16.0
Combined Heat and Power[1]	0.0	18.5	18.5	18.5	36.6	36.6	35.9	58.6	58.0	56.6
Total	**0.0**	**63.4**	**63.7**	**66.7**	**116.1**	**117.2**	**131.0**	**217.0**	**223.4**	**246.6**
Cumulative Retirements	**0.0**	**25.7**	**25.4**	**24.4**	**34.9**	**35.2**	**40.0**	**37.3**	**39.3**	**44.3**
Generation by Fuel (billion kilowatthours)										
Coal	1749	1792	1769	1763	2002	2016	1990	2083	2107	2179
Petroleum	36	37	38	38	40	40	41	42	42	42
Natural Gas	841	838	858	861	822	820	840	1035	1033	983
Nuclear Power	799	839	839	839	877	877	877	874	874	874
Renewable Sources/Pumped Storage	386	491	493	493	550	544	541	581	572	565
Distributed Generation	0	0	1	2	1	3	8	4	5	14
Combined Heat and Power[1]	167	255	255	255	381	381	377	537	533	526
Total	**3978**	**4253**	**4253**	**4252**	**4674**	**4682**	**4675**	**5155**	**5167**	**5183**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	18.30	18.21	17.99	17.92	20.44	20.61	20.33	21.35	21.64	22.11
Petroleum	0.40	0.43	0.43	0.44	0.45	0.45	0.46	0.47	0.47	0.48
Natural Gas	7.06	6.99	7.15	7.18	6.84	6.82	6.92	8.11	8.07	7.69
Nuclear Power	8.35	8.77	8.77	8.77	9.17	9.17	9.17	9.14	9.14	9.14
Renewable Sources	3.89	5.03	5.08	5.06	5.87	5.84	5.76	6.52	6.47	6.20
Total	**38.19**	**39.63**	**39.62**	**39.57**	**42.97**	**43.09**	**42.84**	**45.79**	**45.99**	**45.82**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1742	1734	1714	1706	1935	1951	1925	2023	2049	2096
Petroleum	34	33	33	34	35	35	36	37	37	37
Natural Gas	373	371	379	381	363	362	367	430	428	408
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2160**	**2150**	**2138**	**2133**	**2345**	**2360**	**2340**	**2502**	**2526**	**2553**

[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 solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs HCFOSS11.D020911A, REF2011.D020911A, and LCFOSS11.D020911A.

Table D12. Key results for electric power sector capital cost cases
(gigawatts, unless otherwise noted)

Net Summer Capacity, Generation Consumption, and Emissions	2009	2015			2025			2035		
		Frozen Plant Capital Costs	Reference	Decreasing Plant Capital Costs	Frozen Plant Capital Costs	Reference	Decreasing Plant Capital Costs	Frozen Plant Capital Costs	Reference	Decreasing Plant Capital Costs
Capacity										
Pulverized Coal	312.9	316.4	316.4	316.7	314.5	315.0	315.4	314.5	315.3	320.5
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	2.6	2.6	2.6	2.6	2.6	2.6
Conventional Natural Gas Combined-Cycle	197.2	203.2	203.2	203.2	203.7	203.9	204.1	205.2	205.0	204.4
Advanced Natural Gas Combined-Cycle	0.0	0.4	0.3	0.2	4.5	6.0	14.4	53.1	54.6	52.3
Conventional Combustion Turbine	137.5	136.5	136.7	138.6	135.6	135.8	137.8	135.6	135.8	137.2
Advanced Combustion Turbine	0.0	3.9	3.9	3.4	18.6	19.5	17.1	44.0	45.8	32.4
Fuel Cells	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Nuclear	101.0	105.7	105.7	105.7	110.5	110.5	110.5	110.5	110.5	117.0
Oil and Natural Gas Steam	114.4	100.3	99.9	100.5	91.6	92.8	88.4	90.2	88.7	87.3
Renewable Sources/Pumped Storage	138.8	157.8	158.0	162.4	161.8	163.4	168.8	166.2	170.2	202.9
Distributed Generation	0.0	0.3	0.5	1.1	1.0	1.3	6.7	2.1	3.1	24.3
Combined Heat and Power[1]	31.5	50.0	50.0	49.7	68.3	68.1	67.0	90.4	89.5	86.7
Total	**1033.4**	**1075.2**	**1075.0**	**1082.2**	**1112.7**	**1118.9**	**1132.7**	**1214.4**	**1221.0**	**1267.6**
Cumulative Additions										
Pulverized Coal	0.0	10.9	10.9	10.9	12.9	12.9	12.9	12.9	13.2	18.1
Coal Gasification Combined-Cycle	0.0	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Conventional Natural Gas Combined-Cycle	0.0	6.4	6.4	6.4	6.8	7.0	7.3	8.4	8.1	7.5
Advanced Natural Gas Combined-Cycle	0.0	0.4	0.3	0.2	4.5	6.0	14.4	53.1	54.6	52.3
Conventional Combustion Turbine	0.0	2.0	2.1	4.0	2.0	2.1	4.0	2.0	2.1	4.0
Advanced Combustion Turbine	0.0	3.9	3.9	3.4	18.6	19.5	17.1	44.0	45.8	32.4
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	1.1	1.1	1.1	6.3	6.3	6.3	6.3	6.3	12.9
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	19.2	19.4	23.9	23.2	24.8	30.2	27.6	31.6	64.3
Distributed Generation	0.0	0.3	0.5	1.1	1.0	1.3	6.7	2.1	3.1	24.3
Combined Heat and Power[1]	0.0	18.5	18.5	18.2	36.8	36.6	35.5	58.9	58.0	55.2
Total	**0.0**	**63.4**	**63.7**	**69.9**	**112.8**	**117.2**	**135.1**	**215.9**	**223.4**	**271.7**
Cumulative Retirements	**0.0**	**24.9**	**25.4**	**24.4**	**37.0**	**35.2**	**39.3**	**38.5**	**39.3**	**41.0**
Generation by Fuel (billion kilowatthours)										
Coal	1749	1754	1769	1794	2008	2016	2060	2089	2107	2153
Petroleum	36	38	38	38	41	40	40	42	42	42
Natural Gas	841	871	858	827	821	820	796	1043	1033	919
Nuclear Power	799	839	839	839	877	877	877	874	874	925
Renewable Sources/Pumped Storage	386	492	493	507	542	544	551	566	572	656
Distributed Generation	0	0	1	1	2	3	3	5	5	10
Combined Heat and Power[1]	167	255	255	253	382	381	374	539	533	515
Total	**3978**	**4251**	**4253**	**4259**	**4674**	**4682**	**4702**	**5159**	**5167**	**5220**
Fuel Consumption by the Electric Power Sector (quadrillion Btu)[2]										
Coal	18.30	17.83	17.99	18.28	20.53	20.61	21.11	21.44	21.64	22.07
Petroleum	0.40	0.43	0.43	0.43	0.46	0.45	0.46	0.48	0.47	0.48
Natural Gas	7.06	7.25	7.15	6.92	6.84	6.82	6.58	8.14	8.07	7.32
Nuclear Power	8.35	8.77	8.77	8.77	9.17	9.17	9.17	9.14	9.14	9.67
Renewable Sources	3.89	5.04	5.08	5.22	5.79	5.84	5.87	6.39	6.47	7.12
Total	**38.19**	**39.53**	**39.62**	**39.82**	**42.99**	**43.09**	**43.39**	**45.79**	**45.99**	**46.86**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[2]										
Coal	1742	1698	1714	1741	1945	1951	1999	2032	2049	2090
Petroleum	34	34	33	33	36	35	36	37	37	37
Natural Gas	373	385	379	367	363	362	349	432	428	388
Other[3]	12	12	12	12	12	12	12	12	12	12
Total	**2160**	**2128**	**2138**	**2153**	**2355**	**2360**	**2395**	**2514**	**2526**	**2527**

[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 solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs FRZCST11.D020911A, REF2011.D020911A, and DECCST11.D020911A.

Table D13. Key results for electric power sector renewable technology cost cases

Capacity, Generation, and Emissions	2009	2015			2025			2035		
		High Renewable Technology Cost	Reference	Low Renewable Technology Cost	High Renewable Technology Cost	Reference	Low Renewable Technology Cost	High Renewable Technology Cost	Reference	Low Renewable Technology Cost
Net Summer Capacity (gigawatts)										
Electric Power Sector[1]										
Conventional Hydropower	76.87	77.60	77.52	77.74	78.23	78.59	79.66	79.38	79.85	83.07
Geothermal[2]	2.42	2.66	2.75	2.57	4.01	4.21	4.41	4.80	6.42	6.81
Municipal Waste[3]	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37	3.37
Wood and Other Biomass[4]	2.19	2.19	2.19	2.19	2.19	2.19	2.46	2.19	2.19	4.86
Solar Thermal	0.61	1.26	1.26	1.26	1.30	1.30	1.30	1.35	1.35	1.35
Solar Photovoltaic	0.07	0.15	0.15	0.15	0.32	0.32	0.33	0.46	0.52	8.25
Wind	31.45	49.10	49.10	52.04	52.88	51.76	53.82	58.89	54.83	84.27
Total	**116.98**	**136.32**	**136.33**	**139.32**	**142.30**	**141.75**	**145.35**	**150.45**	**148.53**	**191.98**
End-Use Sector[5]										
Conventional Hydropower	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71	0.71
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Wood and Other Biomass	4.86	7.12	7.26	7.64	11.06	15.14	17.31	16.97	18.06	23.18
Solar Photovoltaic	1.50	7.15	7.73	8.10	8.35	9.51	10.72	8.73	10.68	14.40
Wind	0.18	1.37	1.45	1.61	1.53	1.70	1.90	1.57	1.83	2.14
Total	**7.55**	**16.65**	**17.46**	**18.35**	**21.95**	**27.36**	**30.94**	**28.28**	**31.58**	**40.72**
Generation (billion kilowatthours)										
Electric Power Sector[1]										
Coal	1749	1775	1769	1779	2016	2016	1999	2102	2107	2059
Petroleum	36	37	38	38	40	40	41	42	42	42
Natural Gas	841	851	858	828	815	820	795	1039	1033	912
Total Fossil	**2626**	**2663**	**2665**	**2645**	**2871**	**2876**	**2834**	**3182**	**3182**	**3013**
Conventional Hydropower	270.20	293.77	293.22	293.54	303.66	305.17	310.02	308.99	310.59	322.88
Geothermal	15.21	18.87	19.63	18.20	29.71	31.36	33.01	36.10	49.19	52.54
Municipal Waste[7]	16.39	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80	14.80
Wood and Other Biomass[4]	10.39	22.44	20.51	34.74	58.98	38.41	66.47	43.98	32.64	82.19
Dedicated Plants	8.73	7.34	7.06	9.93	12.13	8.54	11.61	10.15	8.15	28.46
Cofiring	1.66	15.10	13.45	24.81	46.85	29.87	54.87	33.83	24.49	53.72
Solar Thermal	0.76	2.49	2.49	2.49	2.56	2.56	2.56	2.66	2.66	2.66
Solar Photovoltaic	0.04	0.36	0.36	0.36	0.78	0.80	0.82	1.14	1.31	19.69
Wind	70.82	142.55	142.52	152.48	154.36	151.48	158.22	174.69	160.88	256.57
Total Renewable	**383.82**	**495.27**	**493.52**	**516.60**	**564.86**	**544.58**	**585.89**	**582.35**	**572.06**	**751.32**
End-Use Sector[5]										
Total Fossil	**118**	**176**	**176**	**177**	**238**	**237**	**239**	**368**	**365**	**365**
Conventional Hydropower[8]	3.34	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49	3.49
Geothermal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Municipal Waste[6]	1.96	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56	2.56
Wood and Other Biomass	27.88	41.74	42.60	44.81	71.86	104.98	119.01	115.84	126.57	161.27
Solar Photovoltaic	2.34	10.85	11.99	12.52	12.70	14.86	16.67	13.30	16.79	22.65
Wind	0.24	1.85	1.97	2.15	2.08	2.34	2.58	2.15	2.53	2.92
Total Renewable	**35.76**	**60.49**	**62.61**	**65.54**	**92.69**	**128.22**	**144.31**	**137.33**	**151.94**	**192.89**
Carbon Dioxide Emissions by the Electric Power Sector (million metric tons)[1]										
Coal	1742.2	1720.9	1713.6	1722.6	1954.4	1951.5	1935.5	2045.5	2049.1	2000.8
Petroleum	33.5	33.1	33.3	33.2	35.5	35.0	35.8	36.9	36.7	36.8
Natural Gas	372.6	376.6	379.4	367.3	359.6	362.0	352.6	429.1	428.3	386.2
Other [9]	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Total	**2160.3**	**2142.5**	**2138.2**	**2135.1**	**2361.4**	**2360.4**	**2335.9**	**2523.5**	**2526.1**	**2435.8**

[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]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]Includes biogenic municipal waste, landfill gas, and municipal sewage sludge. Incremental growth is assumed to be for landfill gas facilities.
[8]Represents own-use industrial hydroelectric power.
[9]Includes emissions from geothermal power and nonbiogenic emissions from municipal solid waste.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs HIRENCST11.D022811B, REF2011.D020911A, and LORENCST11.D022811A.

Table D14. Key results for electric power sector emissions cases
(gigawatts, unless otherwise noted)

Net Summer Capacity, Generation, Emissions, and Fuel Prices	2009	2035								
		Reference	Transport Rule Mercury MACT 20	Transport Rule Mercury MACT 5	Retrofit Required 20	Retrofit Required 5	GHG Price	High Shale EUR	Low Gas Price Retrofit Required 20	Low Gas Price Retrofit Required 5
Capacity										
Coal Steam	312.9	317.9	313.2	308.6	307.8	282.7	191.2	310.8	286.9	253.8
Oil and Natural Gas Steam	114.4	88.7	90.3	91.0	91.1	94.3	84.4	97.2	99.5	100.7
Combined Cycle	197.2	259.5	261.2	269.0	266.8	278.0	263.3	253.7	268.2	292.5
Combustion Turbine/Diesel	137.5	181.6	179.4	175.6	179.3	180.0	149.2	187.4	186.8	190.9
Nuclear Power	101.0	110.5	110.5	110.5	110.5	110.5	133.6	108.2	108.2	110.5
Pumped Storage	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8	21.8
Renewable Sources	117.0	148.5	148.2	148.5	150.0	151.3	203.9	138.0	141.1	145.4
Distributed Generation (Natural Gas)	0.0	3.1	2.9	3.5	4.1	4.4	1.3	14.1	13.6	10.6
Combined Heat and Power[1]	31.5	89.5	90.6	89.8	90.1	90.5	128.0	98.4	99.2	99.6
Total	**1033.4**	**1221.2**	**1218.1**	**1218.2**	**1221.6**	**1213.5**	**1176.8**	**1229.5**	**1225.4**	**1225.8**
Cumulative Additions										
Coal Steam	0.0	13.8	13.8	13.5	14.2	14.7	13.5	13.5	13.5	13.5
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	62.7	64.4	72.1	69.9	81.2	66.4	56.8	71.3	95.6
Combustion Turbine/Diesel	0.0	47.9	45.8	41.9	45.3	44.2	18.7	51.7	50.7	55.0
Nuclear Power	0.0	6.3	6.3	6.3	6.3	6.3	29.5	6.3	6.3	6.3
Renewable Sources	0.0	31.6	31.3	31.6	33.1	34.4	87.0	21.1	24.2	28.5
Distributed Generation	0.0	3.1	2.9	3.5	4.1	4.4	1.3	14.1	13.6	10.6
Combined Heat and Power[1]	0.0	58.0	59.1	58.3	58.6	59.1	96.4	66.6	67.5	67.8
Total	**0.0**	**223.4**	**223.5**	**227.2**	**231.6**	**244.2**	**312.9**	**230.1**	**247.2**	**277.5**
Cumulative Retirements	**0.0**	**39.3**	**42.5**	**46.1**	**47.2**	**67.8**	**173.4**	**38.0**	**59.2**	**89.0**
Retrofits										
Scrubber	0.0	53.6	59.7	38.1	145.0	119.3	32.4	38.2	127.3	92.8
Nitrogen Oxides Controls	0.0	51.6	44.4	43.4	40.6	35.6	34.5	50.9	34.5	26.3
SCR Post-combustion	0.0	94.7	71.9	45.5	223.5	198.4	51.7	75.2	203.0	170.3
SNCR Post-combustion	0.0	8.3	8.3	32.7	5.2	6.1	13.4	18.4	5.2	5.1
Generation by Fuel (billion kilowatthours)										
Coal	1749	2107	2051	1955	2066	1903	699	1933	1893	1689
Petroleum	36	42	41	41	46	47	37	41	45	43
Natural Gas	841	1033	1072	1150	1063	1205	1345	1214	1236	1416
Nuclear Power	799	874	874	874	874	874	1052	856	856	874
Pumped Storage	2	-0	-0	-0	-0	-0	-0	-0	-0	-0
Renewable Sources	384	572	576	583	568	567	842	551	555	553
Distributed Generation	0	5	5	4	3	3	1	45	43	30
Combined Heat and Power[1]	167	533	541	535	539	540	785	603	610	611
Total	**3978**	**5167**	**5161**	**5143**	**5159**	**5140**	**4762**	**5244**	**5238**	**5217**
Emissions by the Electric Power Sector[2]										
Carbon Dioxide (million metric tons)	2160	2526	2494	2424	2507	2390	1082	2443	2422	2265
Sulfur Dioxide (million tons)	5.72	3.93	3.38	3.37	1.99	1.84	2.26	3.83	1.79	1.65
Nitrogen Oxides (million tons)	1.99	2.03	2.19	2.20	1.44	1.37	0.93	1.99	1.39	1.30
Mercury (tons)	40.66	29.32	7.68	7.19	8.34	7.69	9.19	26.51	7.47	6.79
Prices to the Electric Power Sector[2] (2009 dollars per million Btu)										
Natural Gas	4.82	6.80	6.86	7.02	6.88	7.08	11.04	5.34	5.26	5.55
Coal	2.20	2.40	2.41	2.38	2.37	2.29	9.31	2.30	2.27	2.20

[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.
EUR = Estimated ultimate recovery.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Source: U.S. Energy Information Administration, AEO2011 National Energy Modeling System runs REF2011.D020911A, and TRMA20.D021811A, TRMA05.D021811A, BAMA20.D021811A, BAMA05.D021811A, POLMAX.D031411A, HSHLEUR.D020911A, LGBAMA20.D021811A, and LGBAMA05.D021811A.

Table D15. Liquid fuels supply and disposition, E15 availability cases
(million barrels per day, unless otherwise noted)

Supply, Disposition, and Prices	2009	2015			2025			2035		
		Low E15 Penetration	Reference	High E15 Penetration	Low E15 Penetration	Reference	High E15 Penetration	Low E15 Penetration	Reference	High E15 Penetration
Prices (2009 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	**61.66**	**94.58**	**94.58**	**94.12**	**117.38**	**117.54**	**117.33**	**124.91**	**124.94**	**124.71**
Imported Crude Oil[1]	**59.04**	**86.84**	**86.83**	**86.39**	**107.22**	**107.40**	**107.13**	**113.62**	**113.70**	**113.42**
Crude Oil Supply										
Domestic Crude Oil Production[2]	5.36	5.82	5.81	5.81	5.88	5.88	5.87	5.89	5.95	5.89
Alaska	0.65	0.49	0.49	0.49	0.41	0.41	0.41	0.39	0.39	0.39
Lower 48 Onshore	3.00	3.52	3.51	3.51	3.92	3.92	3.91	3.59	3.65	3.59
Lower 48 Offshore	1.71	1.81	1.81	1.81	1.55	1.55	1.55	1.91	1.91	1.91
Net Crude Oil Imports	8.97	8.71	8.70	8.58	8.27	8.25	8.19	8.21	8.25	8.14
Other Crude Oil Supply	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**14.33**	**14.53**	**14.52**	**14.40**	**14.15**	**14.13**	**14.06**	**14.10**	**14.20**	**14.04**
Other Petroleum Supply	**3.59**	**4.37**	**4.38**	**4.36**	**4.41**	**4.41**	**4.44**	**4.45**	**4.46**	**4.49**
Natural Gas Plant Liquids	1.91	2.22	2.23	2.22	2.67	2.68	2.68	2.94	2.94	2.95
Net Petroleum Product Imports[3]	0.75	1.14	1.14	1.11	0.81	0.81	0.83	0.66	0.64	0.67
Refinery Processing Gain[4]	0.98	1.01	1.01	1.02	0.92	0.92	0.93	0.85	0.88	0.88
Product Stock Withdrawal	-0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.81**	**1.42**	**1.42**	**1.62**	**2.35**	**2.40**	**2.41**	**3.36**	**3.28**	**3.35**
From Renewable Sources[5]	0.76	1.12	1.12	1.27	1.92	1.92	1.89	2.58	2.48	2.53
Ethanol	0.73	1.01	1.03	1.18	1.60	1.60	1.58	1.86	1.83	1.80
Domestic Production	0.72	0.95	0.97	1.11	1.44	1.44	1.43	1.59	1.58	1.54
Net Imports	0.01	0.05	0.06	0.07	0.16	0.16	0.16	0.28	0.26	0.26
Biodiesel	0.02	0.09	0.08	0.07	0.12	0.12	0.13	0.13	0.13	0.13
Domestic Production	0.03	0.09	0.07	0.07	0.12	0.12	0.12	0.13	0.13	0.13
Net Imports	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Biomass-derived Liquids	0.00	0.02	0.02	0.01	0.19	0.19	0.19	0.58	0.52	0.61
Liquids from Coal	0.00	0.05	0.05	0.04	0.17	0.19	0.18	0.51	0.55	0.54
Other[6]	0.05	0.25	0.25	0.31	0.27	0.30	0.33	0.27	0.25	0.28
Total Primary Supply[7]	**18.73**	**20.31**	**20.32**	**20.38**	**20.91**	**20.94**	**20.91**	**21.91**	**21.94**	**21.88**
Refined Petroleum Products Supplied										
Liquefied Petroleum Gases	2.13	2.33	2.32	2.32	2.33	2.33	2.33	2.19	2.19	2.19
E85[8]	0.00	0.01	0.01	0.01	0.81	0.64	0.28	1.01	0.84	0.42
Motor Gasoline[9]	9.00	9.40	9.40	9.45	8.67	8.87	9.21	9.08	9.28	9.67
Jet Fuel[10]	1.39	1.55	1.55	1.55	1.68	1.68	1.68	1.75	1.75	1.75
Distillate Fuel Oil[11]	3.63	4.14	4.13	4.14	4.49	4.49	4.49	4.87	4.87	4.86
of which: Diesel	3.18	3.68	3.68	3.68	4.09	4.09	4.09	4.50	4.51	4.50
Residual Fuel Oil	0.51	0.60	0.60	0.59	0.61	0.61	0.61	0.62	0.62	0.62
Other[12]	2.15	2.44	2.43	2.42	2.38	2.38	2.37	2.39	2.38	2.36
Total	**18.81**	**20.45**	**20.44**	**20.48**	**20.97**	**20.99**	**20.95**	**21.90**	**21.93**	**21.87**
Discrepancy[13]	**-0.08**	**-0.13**	**-0.12**	**-0.10**	**-0.06**	**-0.04**	**-0.04**	**0.01**	**0.01**	**0.01**

[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), biodiesel (including imports), pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks for the production of green diesel and gasoline.
[6]Includes alcohols, ethers, domestic sources of blending components, and other hydrocarbons.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[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 average annual 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 fuel oil and kerosene from petroleum and biomass feedstocks.
[12]Includes aviation gasoline, petrochemical feedstocks, lubricants, waxes, asphalt, road oil, still gas, special naphthas, petroleum coke, crude oil product supplied, methanol, and miscellaneous petroleum products.
[13]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs E15LOW.D030211A, REF2011.D020911A, and E15HIGH.D022811A.

Table D16. Natural gas supply and disposition, oil and gas technology progress cases
(trillion cubic feet per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	2015			2025			2035		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Natural Gas Prices										
(2009 dollars per million Btu)										
Henry Hub Spot Price	3.95	5.16	4.66	4.33	6.83	5.97	5.33	7.69	7.07	6.45
Average Lower 48 Wellhead Price[1]	3.62	4.57	4.13	3.83	6.04	5.29	4.72	6.81	6.26	5.71
(2009 dollars per thousand cubic feet)										
Average Lower 48 Wellhead Price[1]	3.71	4.69	4.24	3.93	6.20	5.43	4.84	6.98	6.42	5.86
Dry Gas Production[2]	**20.96**	**21.47**	**22.43**	**23.02**	**22.65**	**23.98**	**24.78**	**25.92**	**26.32**	**26.89**
Lower 48 Onshore	17.88	19.09	20.00	20.57	20.09	21.31	22.03	21.36	23.05	23.46
Associated-Dissolved	1.40	1.45	1.48	1.49	1.32	1.36	1.34	1.00	1.02	1.02
Non-Associated	16.48	17.64	18.51	19.08	18.78	19.95	20.69	20.36	22.04	22.44
Tight Gas	6.59	5.83	5.90	5.76	5.55	5.74	5.55	5.35	5.84	5.59
Shale Gas	3.28	6.32	7.20	8.00	8.66	9.69	10.69	11.14	12.25	12.92
Coalbed Methane	1.80	1.72	1.67	1.62	1.75	1.72	1.64	1.63	1.72	1.70
Other	4.80	3.77	3.74	3.69	2.82	2.81	2.80	2.24	2.23	2.23
Lower 48 Offshore	2.70	2.10	2.15	2.17	2.32	2.42	2.51	2.79	3.05	3.21
Associated-Dissolved	0.64	0.63	0.64	0.65	0.66	0.68	0.70	0.73	0.80	0.82
Non-Associated	2.05	1.47	1.51	1.52	1.66	1.74	1.81	2.07	2.26	2.39
Alaska	0.37	0.28	0.28	0.28	0.24	0.24	0.24	1.77	0.21	0.22
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	**2.64**	**2.84**	**2.69**	**2.66**	**1.22**	**1.08**	**1.12**	**-0.03**	**0.18**	**0.50**
Pipeline[4]	2.23	2.46	2.33	2.32	0.84	0.74	0.82	-0.17	0.04	0.36
Liquefied Natural Gas	0.41	0.38	0.36	0.35	0.38	0.34	0.30	0.14	0.14	0.14
Total Supply	**23.66**	**24.38**	**25.18**	**25.75**	**23.94**	**25.12**	**25.97**	**25.96**	**26.57**	**27.45**
Consumption by Sector										
Residential	4.75	4.77	4.81	4.84	4.77	4.83	4.88	4.73	4.78	4.82
Commercial	3.11	3.32	3.38	3.41	3.46	3.56	3.64	3.74	3.82	3.90
Industrial[5]	6.14	7.95	8.05	8.14	7.89	8.10	8.29	7.79	8.02	8.28
Electric Power[6]	6.89	6.41	6.98	7.36	5.92	6.66	7.15	7.54	7.88	8.30
Transportation[7]	0.03	0.04	0.04	0.04	0.10	0.10	0.11	0.16	0.16	0.19
Pipeline Fuel	0.64	0.64	0.65	0.66	0.61	0.62	0.64	0.71	0.65	0.67
Lease and Plant Fuel[8]	1.16	1.17	1.20	1.23	1.14	1.19	1.22	1.26	1.25	1.28
Total	**22.71**	**24.31**	**25.11**	**25.67**	**23.88**	**25.07**	**25.92**	**25.93**	**26.55**	**27.43**
Discrepancy[9]	**0.95**	**0.07**	**0.07**	**0.07**	**0.06**	**0.05**	**0.05**	**0.03**	**0.02**	**0.02**
Lower 48 End of Year Reserves	**261.37**	**273.29**	**279.40**	**285.23**	**290.09**	**299.51**	**309.12**	**306.69**	**314.16**	**322.51**

[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.
[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, 2009 values include net storage injections.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 consumption based on: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs OGLTEC11.D020911A, REF2011.D020911A, and OGHTEC11.D020911A.

Table D17. Liquid fuels supply and disposition, oil and gas technology progress cases
(million barrels per day, unless otherwise noted)

Supply, Disposition, and Prices	2009	2015			2025			2035		
		Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology	Slow Technology	Reference	Rapid Technology
Prices (2009 dollars per barrel)										
Imported Low Sulfur Light Crude Oil[1]	**61.66**	**94.85**	**94.58**	**94.35**	**118.13**	**117.54**	**117.16**	**125.83**	**124.94**	**124.24**
Imported Crude Oil[1]	**59.04**	**87.11**	**86.83**	**86.61**	**108.18**	**107.40**	**106.93**	**114.89**	**113.70**	**112.86**
Crude Oil Supply										
Domestic Crude Oil Production[2]	5.36	5.76	5.81	5.86	5.64	5.88	5.94	5.58	5.95	6.05
Alaska	0.65	0.49	0.49	0.49	0.41	0.41	0.41	0.19	0.39	0.36
Lower 48 Onshore	3.00	3.49	3.51	3.53	3.75	3.92	3.93	3.63	3.65	3.77
Lower 48 Offshore	1.71	1.78	1.81	1.84	1.49	1.55	1.60	1.76	1.91	1.92
Net Crude Oil Imports	8.97	8.79	8.70	8.63	8.52	8.25	8.15	8.57	8.25	8.01
Other Crude Oil Supply	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**14.33**	**14.55**	**14.52**	**14.50**	**14.16**	**14.13**	**14.08**	**14.15**	**14.20**	**14.06**
Other Petroleum Supply	**3.59**	**4.38**	**4.38**	**4.40**	**4.29**	**4.41**	**4.48**	**4.33**	**4.46**	**4.48**
Natural Gas Plant Liquids	1.91	2.17	2.23	2.28	2.52	2.68	2.79	2.72	2.94	3.02
Net Petroleum Product Imports[3]	0.75	1.20	1.14	1.11	0.84	0.81	0.77	0.76	0.64	0.60
Refinery Processing Gain[4]	0.98	1.02	1.01	1.00	0.94	0.92	0.91	0.85	0.88	0.86
Product Stock Withdrawal	-0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.81**	**1.40**	**1.42**	**1.43**	**2.40**	**2.40**	**2.41**	**3.42**	**3.28**	**3.39**
From Renewable Sources[5]	0.76	1.12	1.12	1.12	1.90	1.92	1.91	2.59	2.48	2.57
From Non-renewable Sources[6]	0.05	0.28	0.30	0.31	0.49	0.49	0.50	0.82	0.80	0.82
Total Primary Supply[7]	**18.73**	**20.33**	**20.32**	**20.33**	**20.85**	**20.94**	**20.98**	**21.89**	**21.94**	**21.93**
Refined Petroleum Products Supplied										
Residential and Commercial	1.04	0.95	0.95	0.95	0.88	0.88	0.88	0.85	0.85	0.85
Industrial[8]	4.25	5.00	4.99	4.98	4.93	4.94	4.95	4.78	4.77	4.77
Transportation	13.61	14.31	14.31	14.32	14.92	14.96	14.97	16.07	16.10	16.09
Electric Power[9]	0.18	0.20	0.19	0.19	0.21	0.20	0.20	0.22	0.21	0.21
Total	**18.81**	**20.46**	**20.44**	**20.45**	**20.94**	**20.99**	**21.01**	**21.91**	**21.93**	**21.93**
Discrepancy[10]	**-0.08**	**-0.13**	**-0.12**	**-0.12**	**-0.09**	**-0.04**	**-0.03**	**-0.02**	**0.01**	**0.01**
Lower 48 End of Year Reserves (billion barrels)[2]	**17.88**	**19.47**	**19.69**	**19.85**	**21.46**	**21.89**	**22.07**	**22.18**	**22.76**	**23.01**

[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), biodiesel (including imports), pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks for the production of green diesel and gasoline.
[6]Includes alcohols, ethers, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[9]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.
[10]Balancing item. Includes unaccounted for supply, losses and gains.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs OGLTEC11.D020911A, REF2011.D020911A, and OGHTEC11.D020911A.

Table D18. Liquid fuels supply and disposition, enhanced oil recovery cases
(million barrels per day, unless otherwise noted)

Supply, Disposition, and Prices	2009	2025				2035			
		Low EOR	Reference	Low EOR – GHG Price	GHG Price	Low EOR	Reference	Low EOR – GHG Price	GHG Price
Prices (2009 dollars per barrel)									
Imported Low Sulfur Light Crude Oil[1]	**61.66**	**117.83**	**117.54**	**115.34**	**115.29**	**125.24**	**124.94**	**120.78**	**120.80**
Imported Crude Oil[1]	**59.04**	**107.81**	**107.40**	**104.50**	**104.41**	**114.08**	**113.70**	**108.79**	**108.77**
Crude Oil Supply									
Domestic Crude Oil Production[2]	5.36	5.76	5.88	5.88	5.90	5.81	5.95	5.95	5.98
Alaska	0.65	0.41	0.41	0.41	0.41	0.39	0.39	0.19	0.19
Lower 48 Onshore	3.00	3.80	3.92	3.92	3.94	3.52	3.65	3.86	3.89
Lower 48 Offshore	1.71	1.55	1.55	1.55	1.55	1.90	1.91	1.90	1.90
Net Crude Oil Imports	8.97	8.36	8.25	7.68	7.66	8.38	8.25	7.00	7.10
Other Crude Oil Supply	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**14.33**	**14.13**	**14.13**	**13.56**	**13.57**	**14.19**	**14.20**	**12.95**	**13.08**
Other Petroleum Supply	**3.59**	**4.41**	**4.41**	**4.47**	**4.47**	**4.44**	**4.46**	**4.13**	**4.05**
Natural Gas Plant Liquids	1.91	2.67	2.68	2.93	2.93	2.94	2.94	2.98	2.98
Net Petroleum Product Imports[3]	0.75	0.82	0.81	0.66	0.67	0.63	0.64	0.38	0.31
Refinery Processing Gain[4]	0.98	0.92	0.92	0.87	0.87	0.87	0.88	0.77	0.76
Product Stock Withdrawal	-0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.81**	**2.40**	**2.40**	**2.62**	**2.62**	**3.32**	**3.28**	**4.35**	**4.30**
From Renewable Sources[5]	0.76	1.92	1.92	2.14	2.13	2.51	2.48	3.52	3.48
From Non-renewable Sources[6]	0.05	0.48	0.49	0.49	0.49	0.81	0.80	0.82	0.83
Total Primary Supply[7]	**18.73**	**20.94**	**20.94**	**20.65**	**20.65**	**21.94**	**21.94**	**21.43**	**21.44**
Refined Petroleum Products Supplied									
Residential and Commercial	1.04	0.88	0.88	0.87	0.87	0.85	0.85	0.83	0.83
Industrial[8]	4.25	4.93	4.94	4.82	4.82	4.77	4.77	4.58	4.58
Transportation	13.61	14.96	14.96	14.73	14.73	16.09	16.10	15.79	15.80
Electric Power[9]	0.18	0.21	0.20	0.19	0.19	0.22	0.21	0.19	0.19
Total	**18.81**	**20.98**	**20.99**	**20.61**	**20.61**	**21.93**	**21.93**	**21.39**	**21.40**
Discrepancy[10]	**-0.08**	**-0.04**	**-0.04**	**0.04**	**0.04**	**0.01**	**0.01**	**0.04**	**0.03**
Lower 48 End of Year Reserves (billion barrels)[2]	**17.88**	**21.60**	**21.89**	**21.88**	**22.06**	**22.32**	**22.76**	**22.96**	**23.19**

[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), biodiesel (including imports), pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks for the production of green diesel and gasoline.
[6]Includes alcohols, ethers, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[9]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.
[10]Balancing item. Includes unaccounted for supply, losses and gains.
EOR = Enhanced oil recovery.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs LOWCO2.D030711A, REF2011.D020911A, POLMAXLCO2.D032111A, and POLMAX.D031411A.

Table D19. Liquid fuels supply and disposition, Outer Continental Shelf resource cases
(million barrels per day, unless otherwise noted)

Supply, Disposition, and Prices	2009	2025				2035			
		High OCS Costs	Reduced OCS Access	Reference	High OCS Resource	High OCS Costs	Reduced OCS Access	Reference	High OCS Resource
Prices (2009 dollars per barrel)									
Imported Low Sulfur Light Crude Oil[1]	**61.66**	**117.71**	**117.51**	**117.54**	**117.12**	**125.47**	**125.93**	**124.94**	**122.04**
Imported Crude Oil[1]	**59.04**	**107.67**	**107.41**	**107.40**	**106.91**	**114.44**	**115.13**	**113.70**	**110.47**
Crude Oil Supply									
Domestic Crude Oil Production[2]	5.36	5.80	5.87	5.88	5.93	5.72	5.57	5.95	7.01
Alaska	0.65	0.41	0.41	0.41	0.47	0.19	0.19	0.39	1.11
Lower 48 Onshore	3.00	3.89	3.92	3.92	3.91	3.64	3.63	3.65	3.60
Lower 48 Offshore	1.71	1.50	1.55	1.55	1.55	1.89	1.74	1.91	2.30
Net Crude Oil Imports	8.97	8.33	8.26	8.25	8.20	8.44	8.61	8.25	7.19
Other Crude Oil Supply	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Crude Oil Supply	**14.33**	**14.13**	**14.13**	**14.13**	**14.13**	**14.16**	**14.18**	**14.20**	**14.20**
Other Petroleum Supply	**3.59**	**4.43**	**4.44**	**4.41**	**4.40**	**4.44**	**4.43**	**4.46**	**4.53**
Natural Gas Plant Liquids	1.91	2.67	2.68	2.68	2.68	2.92	2.93	2.94	2.95
Net Petroleum Product Imports[3]	0.75	0.83	0.83	0.81	0.80	0.66	0.63	0.64	0.67
Refinery Processing Gain[4]	0.98	0.93	0.93	0.92	0.92	0.87	0.86	0.88	0.91
Product Stock Withdrawal	-0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other Non-petroleum Supply	**0.81**	**2.40**	**2.38**	**2.40**	**2.38**	**3.30**	**3.29**	**3.28**	**3.30**
From Renewable Sources[5]	0.76	1.91	1.91	1.92	1.91	2.50	2.50	2.48	2.50
From Non-renewable Sources[6]	0.05	0.48	0.47	0.49	0.47	0.80	0.79	0.80	0.79
Total Primary Supply[7]	**18.73**	**20.95**	**20.95**	**20.94**	**20.91**	**21.90**	**21.90**	**21.94**	**22.02**
Refined Petroleum Products Supplied									
Residential and Commercial	1.04	0.88	0.88	0.88	0.88	0.85	0.85	0.85	0.85
Industrial[8]	4.25	4.94	4.94	4.94	4.94	4.77	4.76	4.77	4.78
Transportation	13.61	14.97	14.96	14.96	14.95	16.07	16.07	16.10	16.13
Electric Power[9]	0.18	0.20	0.20	0.20	0.20	0.21	0.21	0.21	0.21
Total	**18.81**	**20.99**	**20.98**	**20.99**	**20.97**	**21.91**	**21.89**	**21.93**	**21.97**
Discrepancy[10]	**-0.08**	**-0.04**	**-0.03**	**-0.04**	**-0.06**	**-0.00**	**0.00**	**0.01**	**0.05**
Lower 48 End of Year Reserves (billion barrels)[2]	**17.88**	**21.79**	**21.87**	**21.89**	**21.88**	**22.67**	**22.00**	**22.76**	**23.91**

[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), biodiesel (including imports), pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks for the production of green diesel and gasoline.
[6]Includes alcohols, ethers, domestic sources of blending components, other hydrocarbons, natural gas converted to liquid fuel, and coal converted to liquid fuel.
[7]Total crude supply plus natural gas plant liquids, other inputs, refinery processing gain, and net product imports.
[8]Includes consumption for combined heat and power, which produces electricity and other useful thermal energy.
[9]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.
[10]Balancing item. Includes unaccounted for supply, losses and gains.
OCS = Outer continental shelf.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 product supplied data and imported crude oil price based on: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). 2009 imported low sulfur light crude oil price: EIA, Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." Other 2009 data: EIA, *Petroleum Supply Annual 2009,* DOE/EIA-0340(2009)/1 (Washington, DC, July 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs OCSHCST.D031811A, OCSACCESS.D032911A, REF2011.D020911A, and OCSHRES3S.D032911A.

Table D20. Natural gas supply and disposition, shale gas recovery cases
(trillion cubic feet per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	2025					2035				
		Low Shale EUR	Low Shale Recovery	Reference	High Shale Recovery	High Shale EUR	Low Shale EUR	Low Shale Recovery	Reference	High Shale Recovery	High Shale EUR
Natural Gas Prices											
(2009 dollars per million Btu)											
Henry Hub Spot Price	3.95	8.53	7.38	5.97	5.16	4.45	9.26	8.17	7.07	6.03	5.35
Average Lower 48 Wellhead Price[1]	3.62	7.55	6.54	5.29	4.57	3.94	8.20	7.23	6.26	5.34	4.74
(2009 dollars per thousand cubic feet)											
Average Lower 48 Wellhead Price[1]	3.71	7.74	6.71	5.43	4.69	4.05	8.41	7.42	6.42	5.48	4.86
Dry Gas Production[2]	**20.96**	**20.03**	**21.46**	**23.98**	**25.81**	**27.50**	**22.43**	**24.61**	**26.32**	**28.49**	**30.11**
Lower 48 Onshore	17.88	17.07	18.71	21.31	23.23	24.98	17.17	19.62	23.05	25.51	27.24
Associated-Dissolved	1.40	1.34	1.36	1.36	1.34	1.33	1.02	1.02	1.02	1.02	1.02
Non-Associated	16.48	15.73	17.35	19.95	21.89	23.64	16.14	18.60	22.04	24.49	26.22
Tight Gas	6.59	6.54	6.27	5.74	5.56	5.43	6.35	6.20	5.84	5.48	5.26
Shale Gas	3.28	4.37	6.44	9.69	11.88	13.82	5.50	8.24	12.25	15.12	17.13
Coalbed Methane	1.80	1.99	1.85	1.72	1.63	1.62	2.06	1.91	1.72	1.65	1.62
Other	4.80	2.82	2.80	2.81	2.82	2.78	2.23	2.24	2.23	2.23	2.22
Lower 48 Offshore	2.70	2.72	2.52	2.42	2.34	2.28	3.48	3.21	3.05	2.76	2.66
Associated-Dissolved	0.64	0.73	0.69	0.68	0.67	0.66	0.84	0.80	0.80	0.72	0.70
Non-Associated	2.05	2.00	1.83	1.74	1.67	1.62	2.64	2.41	2.26	2.05	1.96
Alaska	0.37	0.24	0.24	0.24	0.24	0.24	1.78	1.78	0.21	0.21	0.21
Supplemental Natural Gas[4]	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06
Net Imports	**2.64**	**2.44**	**1.89**	**1.08**	**0.59**	**0.26**	**1.66**	**0.72**	**0.18**	**-0.27**	**-0.54**
Pipeline[5]	2.23	1.97	1.48	0.74	0.30	0.01	1.52	0.58	0.04	-0.41	-0.68
Liquefied Natural Gas	0.41	0.48	0.42	0.34	0.30	0.26	0.14	0.14	0.14	0.14	0.14
Total Supply	**23.66**	**22.54**	**23.42**	**25.12**	**26.47**	**27.82**	**24.15**	**25.39**	**26.57**	**28.28**	**29.63**
Consumption by Sector											
Residential	4.75	4.66	4.73	4.83	4.90	4.96	4.63	4.70	4.78	4.85	4.91
Commercial	3.11	3.29	3.41	3.56	3.66	3.76	3.58	3.69	3.82	3.95	4.06
Industrial[6]	6.14	7.61	7.81	8.10	8.36	8.62	7.51	7.77	8.02	8.37	8.68
Electric Power[7]	6.89	5.17	5.61	6.66	7.50	8.30	6.43	7.14	7.88	8.89	9.62
Transportation[8]	0.03	0.08	0.09	0.10	0.11	0.14	0.15	0.15	0.16	0.20	0.25
Pipeline Fuel	0.64	0.61	0.61	0.62	0.64	0.67	0.69	0.69	0.65	0.68	0.70
Lease and Plant Fuel[9]	1.16	1.05	1.10	1.19	1.26	1.33	1.14	1.22	1.25	1.33	1.39
Total	**22.71**	**22.48**	**23.37**	**25.07**	**26.42**	**27.78**	**24.12**	**25.37**	**26.55**	**28.26**	**29.62**
Discrepancy[10]	**0.95**	**0.06**	**0.05**	**0.05**	**0.05**	**0.04**	**0.03**	**0.03**	**0.02**	**0.02**	**0.02**
Lower 48 End of Year Reserves	**261.37**	**278.92**	**283.19**	**299.51**	**315.25**	**322.81**	**295.54**	**299.40**	**314.16**	**331.79**	**336.03**

[1]Represents lower 48 onshore and offshore supplies.
[2]Marketed production (wet) minus extraction losses.
[3]Includes tight gas.
[4]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.
[5]Includes any natural gas regasified in the Bahamas and transported via pipeline to Florida.
[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 a vehicle fuel.
[9]Represents natural gas used in field gathering and 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. In addition, 2009 values include net storage injections.
EUR = Estimated ultimate recovery.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 supply values: U.S. Energy Information Administration (EIA), *Natural Gas Monthly*, DOE/EIA-0130(2010/07) (Washington, DC, July 2010). 2009 consumption based on: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **Projections:** EIA, AEO2011 National Energy Modeling System runs LSHLEUR.D020911A, LSHLDRL.D020911A, REF2011.D020911A, HSHLDRL.D020911A, and HSHLEUR.D020911A.

Table D21. International liquids supply and disposition, world oil price cases
(million barrels per day, unless otherwise noted)

Supply and Disposition	2009	2025 Low Oil Price	2025 Traditional Low Oil Price	2025 Reference	2025 Traditional High Oil Price	2025 High Oil Price	2035 Low Oil Price	2035 Traditional Low Oil Price	2035 Reference	2035 Traditional High Oil Price	2035 High Oil Price
Crude Oil Prices[1]											
(2009 dollars per barrel)											
Imported Low Sulfur Light Crude Oil	61.66	51.28	51.28	117.54	185.87	185.87	50.07	50.07	124.94	199.95	199.95
Imported Crude Oil	59.04	41.36	41.36	107.40	175.09	175.09	39.66	39.66	113.70	187.79	187.79
(nominal dollars per barrel)											
Imported Low Sulfur Light Crude Oil	61.66	68.94	68.94	155.46	246.11	246.11	81.59	81.59	199.37	321.76	321.76
Imported Crude Oil	59.04	55.61	55.61	142.05	231.84	231.84	64.62	64.62	181.43	302.20	302.20
Conventional Production (Conventional)[2]											
OPEC[3]											
Middle East	22.61	31.81	37.59	28.64	23.01	27.48	34.74	45.10	33.87	22.96	30.24
North Africa	3.92	4.15	5.35	3.84	3.12	3.72	3.94	5.68	3.98	2.76	3.70
West Africa	4.06	6.54	6.52	5.10	3.93	4.90	6.81	7.21	5.31	3.37	4.86
South America	2.31	1.86	2.38	1.73	1.42	1.68	1.62	2.29	1.64	1.18	1.54
Total OPEC	**32.91**	**44.35**	**51.85**	**39.32**	**31.47**	**37.78**	**47.10**	**60.29**	**44.80**	**30.28**	**40.33**
Non-OPEC											
OECD											
United States (50 states)	8.26	9.07	9.07	9.78	10.89	10.89	8.45	8.45	9.89	10.70	10.70
Canada	1.96	1.78	1.79	1.78	1.84	1.84	1.71	1.75	1.78	1.87	1.94
Mexico	2.90	1.35	1.35	1.22	1.20	1.19	1.50	1.57	1.48	1.41	1.52
OECD Europe[4]	4.62	2.73	2.77	2.67	2.61	2.61	2.48	2.64	2.66	2.51	2.73
Japan	0.13	0.15	0.17	0.14	0.13	0.14	0.16	0.18	0.15	0.13	0.14
Australia and New Zealand	0.65	0.53	0.53	0.52	0.51	0.51	0.49	0.52	0.54	0.51	0.55
Total OECD	**18.52**	**15.62**	**15.68**	**16.13**	**17.18**	**17.18**	**14.79**	**15.11**	**16.49**	**17.13**	**17.59**
Non-OECD											
Russia	9.66	12.43	12.41	10.86	10.59	10.41	12.90	13.63	12.64	12.03	13.15
Other Europe and Eurasia[5]	3.08	4.47	4.47	3.97	3.88	3.81	4.48	4.73	4.47	4.26	4.64
China	3.93	4.10	4.12	4.02	3.93	3.89	3.83	4.08	4.22	3.99	4.40
Other Asia[6]	3.70	3.03	3.04	2.99	2.93	2.91	2.63	2.77	2.85	2.71	2.94
Middle East	1.54	1.26	1.26	1.24	1.22	1.20	0.98	1.04	1.10	1.05	1.15
Africa	2.34	2.89	2.89	2.85	2.80	2.75	2.82	2.99	3.16	3.03	3.32
Brazil	2.05	4.41	4.40	3.87	3.78	3.72	5.02	5.29	4.93	4.71	5.11
Other Central and South America	1.87	2.27	2.27	2.24	2.20	2.17	2.35	2.47	2.59	2.48	2.70
Total Non-OECD	**28.17**	**34.86**	**34.86**	**32.03**	**31.32**	**30.85**	**35.00**	**36.99**	**35.95**	**34.27**	**37.41**
Total Conventional Production	**79.60**	**94.83**	**102.39**	**87.47**	**79.97**	**85.81**	**96.89**	**112.38**	**97.24**	**81.67**	**95.33**
Unconventional Production[7]											
United States (50 states)	0.75	1.55	1.55	1.94	3.01	3.01	1.95	1.95	2.90	5.42	5.42
Other North America	1.68	2.70	2.70	3.57	5.38	5.38	3.32	3.32	5.27	7.11	7.11
OECD Europe[3]	0.22	0.11	0.11	0.26	0.29	0.29	0.18	0.18	0.28	0.33	0.33
Middle East	0.01	0.19	0.19	0.24	0.21	0.21	0.19	0.19	0.24	0.21	0.21
Africa.	0.21	0.16	0.16	0.39	0.40	0.40	0.16	0.16	0.44	0.46	0.46
Central and South America	1.14	3.28	3.28	2.61	2.98	2.98	4.70	4.70	3.17	3.60	3.60
Other	0.12	0.25	0.25	0.64	0.88	0.88	0.50	0.50	1.22	2.61	2.61
Total Unconventional Production	**4.14**	**8.23**	**8.23**	**9.66**	**13.15**	**13.15**	**11.00**	**11.00**	**13.54**	**19.72**	**19.72**
Total Production	**83.74**	**103.06**	**110.62**	**97.13**	**93.11**	**98.96**	**107.90**	**123.39**	**110.78**	**101.40**	**115.06**

Table D21. International liquids supply and disposition, world oil price cases (continued)
(million barrels per day, unless otherwise noted)

Supply and Disposition	2009	2025					2035				
		Low Oil Price	Traditional Low Oil Price	Reference	Traditional High Oil Price	High Oil Price	Low Oil Price	Traditional Low Oil Price	Reference	Traditional High Oil Price	High Oil Price
Consumption[8]											
OECD											
United States (50 states)	18.81	22.34	22.34	20.99	20.18	20.18	23.76	23.76	21.93	20.91	20.91
United States Territories	0.27	0.30	0.34	0.30	0.29	0.32	0.28	0.36	0.32	0.30	0.36
Canada	2.15	2.48	2.47	2.14	2.01	2.01	2.64	2.60	2.24	2.08	2.08
Mexico	2.13	2.57	2.60	2.30	2.18	2.20	3.02	3.03	2.63	2.47	2.51
OECD Europe[3]	14.49	14.61	14.76	12.82	12.05	12.14	14.91	15.01	12.95	12.00	12.11
Japan	4.37	4.49	4.57	3.98	3.72	3.75	4.37	4.41	3.88	3.52	3.55
South Korea	2.32	3.01	3.04	2.63	2.52	2.54	3.45	3.47	3.13	2.87	2.89
Australia and New Zealand	1.19	1.26	1.27	1.13	1.09	1.08	1.30	1.30	1.17	1.10	1.10
Total OECD	**45.73**	**51.06**	**51.38**	**46.29**	**44.03**	**44.23**	**53.72**	**53.93**	**48.25**	**45.25**	**45.51**
Non-OECD											
Russia	2.83	2.73	3.02	2.66	2.54	2.71	2.59	3.17	2.78	2.60	3.01
Other Europe and Eurasia[5]	2.16	2.41	2.78	2.25	2.12	2.36	2.33	3.03	2.48	2.22	2.70
China	8.32	15.60	17.77	14.36	14.06	15.97	16.50	21.16	19.13	16.31	20.68
India	3.06	4.80	5.41	4.54	4.28	4.82	4.96	6.31	5.64	4.93	6.12
Other Asia	6.13	8.01	9.25	7.98	7.59	8.46	8.69	11.21	9.75	8.89	10.94
Middle East	6.64	8.27	9.31	8.76	8.69	9.50	9.01	11.42	11.02	10.32	12.81
Africa	3.31	3.82	4.39	3.76	3.55	3.97	3.96	5.12	4.45	4.04	4.94
Brazil	2.46	3.10	3.60	3.20	3.06	3.42	3.16	4.20	3.79	3.57	4.40
Other Central and South America	3.09	3.27	3.72	3.33	3.19	3.52	3.00	3.86	3.51	3.28	3.94
Total Non-OECD	**38.01**	**52.00**	**59.24**	**50.84**	**49.08**	**54.73**	**54.20**	**69.48**	**62.54**	**56.15**	**69.54**
Total Consumption	**83.74**	**103.06**	**110.62**	**97.13**	**93.11**	**98.95**	**107.92**	**123.41**	**110.79**	**101.40**	**115.06**
OPEC Production[9]	33.45	47.25	54.75	40.77	33.03	39.34	50.88	64.06	46.50	32.08	42.14
Non-OPEC Production[9]	50.29	55.81	55.88	56.37	60.09	59.62	57.02	59.33	64.28	69.32	72.92
Net Eurasia Exports	9.80	16.17	15.49	13.80	13.59	12.87	17.48	17.44	16.78	16.19	17.18
OPEC Market Share (percent)	39.9	45.8	49.5	42.0	35.5	39.8	47.2	51.9	42.0	31.6	36.6

[1]Weighted average price delivered to U.S. refiners.
[2]Includes production of crude oil (including lease condensate), 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, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela.
[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]Other Europe and Eurasia = Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Macedonia, Malta, Moldova, Montenegro, Romania, Serbia, Slovenia, 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]Includes liquids produced from energy crops, natural gas, coal, extra-heavy oil, oil sands, and shale. Includes both OPEC and non-OPEC producers in the regional breakdown.
[8]Includes both OPEC and non-OPEC consumers in the regional breakdown.
[9]Includes both conventional and unconventional liquids production.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 low sulfur light crude oil price: U.S. Energy Information Administration (EIA), Form EIA-856, "Monthly Foreign Crude Oil Acquisition Report." 2009 imported crude oil price: EIA, *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010). **2009 quantities and projections:** EIA, AEO2011 National Energy Modeling System runs LP2011LNO.D022511A, LP2011MNO.D020911A, REF2011.D020911A, HP2011MNO.D022811A, and HP2011HNO.D022511A and EIA, Generate World Oil Balance Model.

Table D22. Key results for the No Greenhouse Gas Concern case
(million short tons per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	2015		2025		2035	
		Reference	No GHG Concern	Reference	No GHG Concern	Reference	No GHG Concern
Production[1]	**1075**	**1040**	**1032**	**1188**	**1303**	**1319**	**1512**
Appalachia	343	274	277	282	293	282	297
Interior	147	156	158	166	176	177	195
West	585	610	597	739	834	860	1020
Waste Coal Supplied[2]	**12**	**14**	**14**	**14**	**15**	**14**	**17**
Net Imports[3]	**-38**	**-40**	**-40**	**-19**	**-18**	**-18**	**-16**
Total Supply[4]	**1049**	**1014**	**1006**	**1183**	**1300**	**1315**	**1513**
Consumption by Sector							
Residential and Commercial	3	3	3	3	3	3	3
Coke Plants	15	22	22	21	21	18	18
Other Industrial[5]	45	49	49	48	48	47	47
Coal-to-Liquids Heat and Power	0	6	6	23	86	66	166
Coal-to-Liquids Liquids Production	0	5	6	21	80	62	156
Electric Power[6]	937	928	919	1066	1061	1119	1124
Total Coal Use	**1000**	**1013**	**1005**	**1182**	**1300**	**1315**	**1513**
Average Minemouth Price[7]							
(2009 dollars per short ton)	33.26	32.36	32.72	33.22	33.56	33.92	34.12
(2009 dollars per million Btu)	1.67	1.62	1.63	1.68	1.71	1.73	1.76
Delivered Prices[8]							
(2009 dollars per short ton)							
Coke Plants	143.01	157.51	158.07	169.26	169.13	172.38	172.06
Other Industrial[5]	64.87	61.78	61.87	63.58	65.56	66.89	68.54
Coal to Liquids	- -	30.96	30.98	31.66	35.64	36.68	36.56
Electric Power[6]							
(2009 dollars per short ton)	43.48	40.94	41.24	43.33	44.69	46.36	47.87
(2009 dollars per million Btu)	2.20	2.11	2.12	2.24	2.30	2.40	2.46
Average	**46.03**	**44.40**	**44.72**	**45.97**	**46.34**	**47.87**	**47.58**
Exports[9]	101.44	123.13	123.47	136.16	137.60	133.36	131.94
Cumulative Electricity Generating Capacity Additions (gigawatts)[10]							
Coal	0.0	12.4	12.5	17.4	28.0	25.5	47.9
Conventional	0.0	10.9	10.9	10.9	10.9	11.2	17.2
Advanced without Sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6
Advanced with Sequestration	0.0	0.0	0.0	2.0	2.0	2.0	2.0
End-Use Generators[11]	0.0	0.9	1.0	3.9	14.5	11.7	28.1
Petroleum	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Natural Gas	0.0	20.0	20.1	48.0	46.6	135.1	125.2
Nuclear	0.0	1.1	1.1	6.3	6.3	6.3	6.3
Renewables [12]	0.0	29.3	29.0	44.7	43.7	55.7	52.8
Other	0.0	0.8	0.8	0.8	0.8	0.8	0.8
Total	**0.0**	**63.7**	**63.6**	**117.2**	**125.5**	**223.4**	**233.0**
Liquids from Coal (million barrels per day)	0.00	0.05	0.05	0.19	0.70	0.55	1.33

[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]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2009. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[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.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
GHG = Greenhouse gas.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2009*, DOE/EIA-0584(2009) (Washington, DC, October 2010); EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010); and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. **Projections:** EIA, AEO2011 National Energy Modeling System runs REF2011.D020911A and NORSK2011.D020911A.

Table D23. Key results for coal cost cases
(million short tons per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	2020			2035			Growth Rate, 2009-2035		
		Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost	Low Coal Cost	Reference	High Coal Cost
Production[1]	**1075**	**1154**	**1100**	**1030**	**1435**	**1319**	**1007**	**1.1%**	**0.8%**	**-0.3%**
Appalachia	343	287	279	273	274	282	270	-0.9%	-0.8%	-0.9%
Interior	147	157	160	164	122	177	203	-0.7%	0.7%	1.3%
West	585	710	661	594	1038	860	534	2.2%	1.5%	-0.4%
Waste Coal Supplied[2]	**12**	**13**	**14**	**15**	**12**	**14**	**32**	**-0.2%**	**0.6%**	**3.7%**
Net Imports[3]	**-38**	**-40**	**-38**	**-24**	**-56**	**-18**	**15**	**1.5%**	**-2.8%**	**- -**
Total Supply[4]	**1049**	**1126**	**1076**	**1021**	**1391**	**1315**	**1054**	**1.1%**	**0.9%**	**0.0%**
Consumption by Sector										
Residential and Commercial	3	3	3	3	3	3	3	-0.2%	-0.2%	-0.2%
Coke Plants	15	22	22	22	18	18	18	0.7%	0.6%	0.5%
Other Industrial[5]	45	49	49	48	47	47	46	0.2%	0.1%	0.0%
Coal-to-Liquids Heat and Power	0	7	7	6	70	66	34	- -	- -	- -
Coal-to-Liquids Liquids Production	0	7	6	6	66	62	32	- -	- -	- -
Electric Power[6]	937	1037	989	936	1186	1119	922	0.9%	0.7%	-0.1%
Total Coal Use	**1000**	**1125**	**1076**	**1021**	**1391**	**1315**	**1054**	**1.3%**	**1.1%**	**0.2%**
Average Minemouth Price[7]										
(2009 dollars per short ton)	33.26	25.55	32.85	42.40	16.37	33.92	67.62	-2.7%	0.1%	2.8%
(2009 dollars per million Btu)	1.67	1.29	1.65	2.12	0.85	1.73	3.34	-2.6%	0.2%	2.7%
Delivered Prices[8] (2009 dollars per short ton)										
Coke Plants	143.01	140.19	165.95	189.18	119.48	172.38	253.08	-0.7%	0.7%	2.2%
Other Industrial[5]	64.87	54.01	62.45	72.80	44.43	66.89	100.64	-1.4%	0.1%	1.7%
Coal to Liquids	- -	26.63	35.63	46.32	20.25	36.68	57.03	- -	- -	- -
Electric Power[6]										
(2009 dollars per short ton)	43.48	35.14	41.57	50.96	28.09	46.36	79.12	-1.7%	0.2%	2.3%
(2009 dollars per million Btu)	2.20	1.82	2.15	2.62	1.48	2.40	3.95	-1.5%	0.3%	2.3%
Average	**46.03**	**37.94**	**45.00**	**54.91**	**29.08**	**47.87**	**81.58**	**-1.8%**	**0.2%**	**2.2%**
Exports[9]	101.44	111.44	132.67	150.29	94.32	133.36	181.30	-0.3%	1.1%	2.3%
Cumulative Electricity Generating Capacity Additions (gigawatts)[10]										
Coal	0.0	14.7	14.7	14.6	30.4	25.5	19.2	- -	- -	- -
Conventional	0.0	10.9	10.9	10.9	16.0	11.2	10.9	- -	- -	- -
Advanced without Sequestration	0.0	0.6	0.6	0.6	0.6	0.6	0.6	- -	- -	- -
Advanced with Sequestration	0.0	2.0	2.0	2.0	2.0	2.0	2.0	- -	- -	- -
End-Use Generators[11]	0.0	1.2	1.2	1.1	11.8	11.7	5.7	- -	- -	- -
Petroleum	0.0	0.0	0.0	0.0	0.0	0.0	0.0	- -	- -	- -
Natural Gas	0.0	28.8	26.7	26.9	135.6	135.1	126.1	- -	- -	- -
Nuclear	0.0	6.3	6.3	6.3	6.3	6.3	6.3	- -	- -	- -
Renewables[12]	0.0	34.4	34.1	34.1	56.6	55.7	52.2	- -	- -	- -
Other	0.0	0.8	0.8	0.8	0.8	0.8	0.8	- -	- -	- -
Total	**0.0**	**85.1**	**82.7**	**82.8**	**229.8**	**223.4**	**204.7**	**- -**	**- -**	**- -**
Liquids from Coal (million barrels per day)	0.00	0.06	0.06	0.06	0.55	0.55	0.27	- -	- -	- -

Table D23. Key results for coal cost cases (continued)
(million short tons per year, unless otherwise noted)

Supply, Disposition, and Prices	2009	2020			2035			Growth Rate, 2009-2035		
		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, 2009=1.000)										
Transportation Rate Multipliers										
Eastern Railroads	1.000	0.920	1.019	1.120	0.760	1.004	1.260	-1.0%	0.0%	0.9%
Western Railroads	1.000	0.890	0.983	1.090	0.790	1.058	1.320	-0.9%	0.2%	1.1%
Mine Equipment Costs										
Underground	1.000	0.909	1.005	1.111	0.782	1.005	1.289	-0.9%	0.0%	1.0%
Surface	1.000	0.895	0.989	1.093	0.769	0.989	1.269	-1.0%	-0.0%	0.9%
Other Mine Supply Costs										
East of the Mississippi: All Mines	1.000	0.904	1.000	1.105	0.778	1.000	1.282	-1.0%	0.0%	1.0%
West of the Mississippi: Underground	1.000	0.904	1.000	1.105	0.778	1.000	1.282	-1.0%	0.0%	1.0%
West of the Mississippi: Surface	1.000	0.904	1.000	1.105	0.778	1.000	1.282	-1.0%	0.0%	1.0%
Coal Mining Labor Productivity										
(short tons per miner per hour)	5.61	7.97	5.97	4.40	13.18	6.12	2.58	3.3%	0.3%	-2.9%
Average Coal Miner Wage										
(2009 dollars per hour)	26.13	23.62	26.13	28.87	20.33	26.13	33.50	-1.0%	0.0%	1.0%

[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]Includes reported prices for both open market and captive mines.
[8]Prices weighted by consumption tonnage; weighted average excludes residential and commercial prices, and export free-alongside-ship (f.a.s.) prices.
[9]F.a.s. price at U.S. port of exit.
[10]Cumulative additions after December 31, 2009. Includes all additions of electricity only and combined heat and power plants projected for the electric power, industrial, and commercial sectors.
[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.
[12]Includes conventional hydroelectric, geothermal, wood, wood waste, municipal waste, landfill gas, other biomass, solar, and wind power. Facilities co-firing biomass and coal are classified as coal.
- - = Not applicable.
Btu = British thermal unit.
Note: Totals may not equal sum of components due to independent rounding. Data for 2009 are model results and may differ slightly from official EIA data reports.
Sources: 2009 data based on: U.S. Energy Information Administration (EIA), *Annual Coal Report 2009*, DOE/EIA-0584(2009) (Washington, DC, October 2010); EIA, *Quarterly Coal Report, October-December 2009*, DOE/EIA-0121(2009/4Q) (Washington, DC, April 2010); U.S. Department of Labor, Bureau of Labor Statistics, Average Hourly Earnings of Production Workers: Coal Mining, Series ID : ceu1021210008; and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A. **Projections:** EIA, AEO2011 National Energy Modeling System runs LCCST11.D020911A, REF2011.D020911A, and HCCST11.D020911A.

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Appendix E
NEMS overview and brief description of cases

The National Energy Modeling System

The projections in the Annual Energy Outlook 2011 (*AEO2011*) are generated from the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Energy Analysis (OEA), formerly known as the Office Integrated Analysis and Forecasting (OIAF), of the U.S. Energy Information Administration (EIA) [*2*]. In addition to its use in developing the *Annual Energy Outlook* (*AEO*) projections, NEMS is also used to complete analytical studies for the U.S. Congress, the Executive Office of the President, other offices within the U.S. Department of Energy (DOE), and other Federal agencies. NEMS is also used by other nongovernment groups, such as the Electric Power Research Institute, Duke University, Georgia Institute of Technology, and OnLocation, Inc. In addition, the *AEO* projections are 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 period through 2035, 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; 22 subregions of the North American Electric Reliability Council regions and subregions for electricity [*3*]; and the 5 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 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 projection 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 (SO_2), nitrogen oxides (NO_x), and mercury from the electricity generation sector.

The version of NEMS used for *AEO2011* represents current legislation and environmental regulations as of January 31, 2011, such as: the October 13, 2010, U.S. Environmental Protection Agency (EPA) waiver that allows the use of E15 in light-duty vehicles (LDVs) built in 2007 or later; EPA guidelines regarding compliance of surface coal mining operations in Appalachia, issued on April 1, 2010; the American Recovery and Reinvestment Act (ARRA), which was enacted in mid-February 2009; the Energy Improvement and Extension Act of 2008 (EIEA2008), signed into law on October 3, 2008; the Food, Conservation, and Energy Act of 2008; and the Energy Independence and Security Act of 2007 (EISA2007), signed into law on December 19, 2007. The *AEO2011* models do not represent the Clean Air Mercury Rule, which was vacated and remanded by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, but it does represent State requirements for reduction of mercury emissions.

The *AEO2011* Reference case reflects the temporary reinstatement of the NO_x and SO_2 cap-and-trade programs included in the Clean Air Interstate Rule (CAIR) as a result of the ruling issued by the United States Court of Appeals for the District of Columbia on December 23, 2008. The potential impacts of proposed Federal and State legislation, regulations, or standards—or of sections of legislation that have been enacted but require funds or implementing regulations that have not been provided or specified—are not reflected in NEMS. However, many pending provisions are examined in alternatives cases included in *AEO2011* or in other analyses completed by EIA.

In general, the historical data used for the *AEO2011* projections are based on EIA's *Annual Energy Review 2009*, published in August 2010 [*4*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2009. CO_2 emissions were calculated by using CO_2 coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2009*, published in April 2011 [*5*]. Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Footnotes to the *AEO2011* appendix tables indicate the definitions and sources of historical data.

The *AEO2011* projections for 2010 and 2011 incorporate short-term projections from EIA's October 2010 *Short-Term Energy Outlook (STEO)*. For short-term energy projections, readers are referred to monthly updates of the *STEO* [6].

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 prices or expenditures for energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) provides a set of macroeconomic drivers to the energy modules and receives energy-related indicators from the NEMS energy components as part of the 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, sales of new LDVs, interest rates, and employment. Key energy indicators fed back to the MAM include aggregate energy prices and costs. The MAM uses the following models from IHS Global Insight: 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 Energy Module

The International Energy Module (IEM) uses assumptions of economic growth and expectations of future U.S. and world petroleum liquids production and consumption, by year, to project the interaction of U.S. and international liquids markets. The IEM computes world oil prices, provides a world crude-like liquids supply curve, generates a worldwide oil supply/demand balance for each year of the projection period, and computes initial estimates of crude oil and light and heavy petroleum product imports to the United States by PADD regions. 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, current investment trends in exploration and development, and long-term resource economics for 221 countries and territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

In interacting with the rest of NEMS, the IEM changes the world oil price—which is defined as the price of foreign light, low-sulfur crude oil delivered to Cushing, Oklahoma (Petroleum Allocation Defense District 2)—in response to changes in expected production and consumption of crude oil and product liquids in the United States.

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 and cost of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and non-building 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 recent consensus agreement reached between manufacturers and environmental interest groups. 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 new construction and remodeling.

Industrial Demand Module

The Industrial Demand Module (IDM) projects the consumption of energy for heat and power, feedstocks, and raw materials in each of 21 industries, subject to the delivered prices of energy and the values of macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the MAM, 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 IDM, with energy-consuming components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. The use of energy for petroleum refining is modeled in the Petroleum Market Module (PMM), as described below, and the projected consumption is included in the industrial totals.

A generalized representation of cogeneration and a recycling component also are included. A new economic calculation for CHP systems was implemented for *AEO2011*. The evaluation of CHP systems now uses a discount rate, which depends on the 10-year Treasury bill rate plus a risk premium, replacing the previous calculation that used simple payback. Also, the base year of the IDM was updated to 2006 in keeping with an update to EIA's 2006 Manufacturing Energy Consumption Survey [7].

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 other legislation and legislative proposals specific to those market segments. The Transportation Demand Module also includes a component to assess the penetration of alternative-fuel vehicles. The Energy Policy Act of 2005 (EPACT2005) and EIEA2008 are reflected in the assessment of impacts of tax credits on the purchase of hybrid gas-electric, alternative-fuel, and fuel-cell vehicles. Representations of corporate average fuel economy (CAFE) standards and of biofuel consumption in the module reflect standards enacted by the National Highway Traffic Safety Administration (NHTSA) and EPA, and provisions in EISA2007.

The air transportation component of the Transportation Demand Module 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. For passenger travel and air freight shipments, the module represents regional fuel use in regional, narrow-body, and wide-body aircraft. An infrastructure constraint, which is also modeled, can potentially limit overall growth in passenger and freight air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

There are three primary submodules of the Electricity Market Module—capacity planning, fuel dispatching, and finance and pricing. The capacity expansion submodule uses the stock of existing generation capacity; the menu, cost, and performance of future generation capacity; expected fuel prices; expected financial parameters; expected electricity demand; and expected environmental regulations to project the optimal mix of new generation capacity that should be added in future years. The fuel dispatching submodule uses the existing stock of generation equipment types, their operation and maintenance costs and performance, fuel prices to the electricity sector, electricity demand, and all applicable environmental regulations to determine the least-cost way to meet that demand. The submodule also determines transmission and pricing of electricity. The finance and pricing submodule uses capital costs, fuel costs, macroeconomic parameters, environmental regulations, and load shapes to estimate generation costs for each technology.

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 for CO_2 that affect the electricity generation sector, and those regulations are represented in *AEO2011*. The *AEO2011* Reference case reflects the temporary reinstatement of the NO_x and SO_2 cap-and-trade programs included in CAIR due to the ruling issued by the United States Court of Appeals for the District of Columbia on December 23, 2008. State regulations on mercury also are reflected in *AEO2011*.

Although currently there is no Federal legislation in place that restricts greenhouse gas (GHG) emissions, regulators and the investment community have continued to push energy companies to invest in technologies that are less GHG-intensive. The trend is captured in the *AEO2011* Reference case through a 3-percentage-point increase in the cost of capital when evaluating investments in new coal-fired power plants and new coal-to-liquids (CTL) plants without carbon capture and storage (CCS).

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 (dedicated biomass plants and co-firing in existing coal plants), 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 (ITCs) for renewable fuels are incorporated, as currently enacted, including a permanent 10-percent ITC for business investment in solar energy (thermal nonpower uses as well as power uses) and geothermal power (available only to those projects not accepting the production tax credit [PTC] for geothermal power). In addition, the module reflects the increase in the ITC to 30 percent for solar energy systems installed before January 1, 2017, and the extension of the credit to individual homeowners under EIEA2008.

PTCs for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants also are represented. They provide a credit of up to 2.1 cents per kilowatthour for electricity produced in the first 10 years of plant operation. For *AEO2011*, new wind plants coming on line before January 1, 2013, are eligible to receive the PTC; other eligible plants must be in service before January 1, 2014. As part of the ARRA, plants eligible for the PTC may instead elect to receive a 30-percent ITC or an equivalent direct grant. *AEO2011* also accounts for new renewable energy capacity resulting from State renewable portfolio standard (RPS) programs, mandates, and goals, as described in *Assumptions to the Annual Energy Outlook 2011* [*8*].

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 all production 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 activities are modeled for 12 supply regions, including 6 onshore, 3 offshore, and 3 Alaskan regions.

The Onshore Lower 48 Oil and Gas Supply Submodule evaluates the economics of future exploration and development projects for crude oil and natural gas at the play level. Crude oil resources are divided into known plays and undiscovered plays, including highly fractured continuous zones, such as the Austin chalk and Bakken shale formations. Production potential from advanced secondary recovery techniques (such as infill drilling, horizontal continuity, and horizontal profile) and enhanced oil recovery (such as CO_2 flooding, steam flooding, polymer flooding, and profile modification) are explicitly represented. Natural gas resources are divided into known producing plays, known developing plays, and undiscovered plays in high-permeability carbonate and sandstone, tight gas, shale gas, and coalbed methane.

Domestic 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 (NGTDM) for determining natural gas wellhead prices and domestic production.

Natural Gas Transmission and Distribution Module

The NGTDM 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. lower 48 demand regions. The 12 regions align with the 9 Census divisions, with three subdivided and Alaska handled separately. The flow of natural gas is determined for both a peak and off-peak period in the year, assuming a historically based seasonal distribution of natural gas demand. Key components of pipeline and distributor tariffs are included in separate pricing algorithms. An algorithm is included to project the addition of compressed natural gas retail fueling capability. The module also accounts for foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, as well as liquefied natural gas (LNG) imports and exports.

Petroleum Market Module

The PMM projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations, subject to demand for petroleum products, availability and price of imported petroleum, and domestic production of crude oil, natural gas liquids, and biofuels—ethanol, biodiesel, biomass-to-liquids (BTL), CTL, and gas-to-liquids (GTL). Costs, performance, and first dates of commercial availability for the advanced alternative liquids technologies [*9*] are reviewed and updated annually.

The module represents refining activities in the five PADDs, as well as a less detailed representation of refining activities in the rest of the world. It models the costs of automotive fuels, such as conventional and reformulated gasoline, and includes production of biofuels for blending in gasoline and diesel. 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 or less by volume (E10), 15 percent by volume (E15) in States that lack explicit language capping ethanol volume or oxygen content, and up to 85 percent by volume (E85) for use in flex-fuel vehicles.

The PMM includes representation of the Renewable Fuels Standard (RFS) included in EISA2007, which mandates the use of 36 billion gallons of renewable fuel by 2022. Both domestic and imported ethanol count toward the RFS. Domestic ethanol production is modeled for three feedstock categories: corn, cellulosic plant materials, and advanced feedstock materials. Corn-based ethanol plants are numerous (more than 180 are now in operation, with a total operating production capacity of more than 13 billion gallons annually), and they are based on a well-known technology that converts starch and sugar into ethanol. Ethanol from cellulosic sources is a new technology with only a few small pilot plants in operation.

Fuels produced by gasification and Fischer-Tropsch synthesis and through a pyrolysis process are also modeled in the PMM, based on their economics relative to competing feedstocks and products. The five processes modeled are CTL, GTL, BTL, coal- and biomass-to-liquids, and pyrolysis.

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 41 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves respond 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 region and sector, environmental restrictions, and accounting for minemouth prices, transportation costs, and coal supply contracts. Over the projection horizon, coal transportation costs in the CMM vary in response to changes in the cost of rail investments.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports in the context of world coal trade, determining the pattern of world coal trade flows that minimizes production and transportation costs while 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 regions and 20 import regions. U.S. coal production and distribution are computed for 14 supply regions and 16 demand regions.

Annual Energy Outlook 2011 cases

Table E1 provides a summary of the cases produced as part of *AEO2011*. For each case, the table gives the name used in *AEO2011*, a brief description of the major assumptions underlying the projections, 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 text sections following Table E1 describe the various cases. The Reference case assumptions for each sector are described in *Assumptions to the Annual Energy Outlook 2011* [*10*]. Regional results and other details of the projections are available at website www.eia.gov/oiaf/aeo/supplement.

Macroeconomic growth cases

In addition to the *AEO2011* Reference case, *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:

- In the *Reference case*, population grows by 0.9 percent per year, nonfarm employment by 1.0 percent per year, and labor productivity by 2.0 percent per year from 2009 to 2035. Economic output as measured by real GDP increases by 2.7 percent per year from 2009 through 2035, and growth in real disposable income per capita averages 1.6 percent per year.
- The *Low Economic Growth case* assumes lower growth rates for population (0.6 percent per year) and labor productivity (1.6 percent per year), resulting in lower nonfarm employment (0.7 percent per year), 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 2.1 percent per year from 2009 through 2035, and growth in real disposable income per capita averages 1.5 percent per year.
- The *High Economic Growth case* assumes higher growth rates for population (1.2 percent per year) and labor productivity (2.4 percent per year), resulting in higher nonfarm employment (1.4 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the Reference case, and consequently economic output grows at a higher rate (3.2 percent per year) than in the Reference case (2.7 percent). Disposable income per capita grows by 1.63 percent per year, compared with 1.57 percent in the Reference case.

Oil price cases

The world oil price in *AEO2011* 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. *AEO2011* 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 domestic 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. *AEO2011* considers five oil price cases (Reference, Low Oil Price, Traditional Low Oil Price, High Oil Price, and Traditional High Oil Price) to allow an assessment of alternative views on the course of future oil prices. The Low Oil Price case and Traditional Low Oil Price case use the same price path, as do the High Oil Price case and Traditional High Oil Price.

The Low and High Oil Price cases reflect a wide range of potential price paths, resulting from variation in demand for countries outside the Organization for Economic Cooperation and Development (OECD) for liquid fuels due to different levels of economic growth. The Traditional Low and Traditional High Oil Price cases define the same wide range of potential price paths, but they also reflect different assumptions about decisions by members of the Organization of the Petroleum Exporting Countries (OPEC) regarding the preferred rate of oil production and about the future finding and development costs and accessibility of conventional oil resources outside the United States. Because the Low, Traditional Low, High, and Traditional High Oil 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.

- In the *Reference case*, real world oil prices rise from a low of $78 per barrel (2009 dollars) in 2010 to $95 per barrel in 2015, then increase more slowly to $125 per barrel in 2035. The Reference case represents EIA's current judgment regarding exploration and development costs and accessibility of oil resources outside the United States. 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 42 percent of the world's total liquids production.
- In the *Low Oil Price case*, world crude oil prices are only $50 per barrel (2009 dollars) in 2035, compared with $125 per barrel in the Reference case. In the Low Oil Price case, the low price results from lower demand for liquid fuels in the non-OECD nations. Lower demand is derived from lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD is reduced by 1.5 percentage points in each projection year beginning in 2015 relative to Reference case. The OECD projections are only affected by the price impact.

Table E1. Summary of the *AEO2011* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (2.7 percent per year from 2009 through 2035), world oil price, and technology assumptions. Complete projection tables in Appendix A. World light, sweet crude oil prices rise to about $125 per barrel (2009 dollars) in 2035. Assumes RFS target to be met as soon as possible.	Fully integrated	--	--
Low Economic Growth	Real GDP grows at an average annual rate of 2.1 percent from 2009 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	Fully integrated	p. 58	p. 213
High Economic Growth	Real GDP grows at an average annual rate of 3.2 percent from 2009 to 2035. Other energy market assumptions are the same as in the Reference case. Partial projection tables in Appendix B.	Fully integrated	p. 58	p. 213
Low Oil Price (primary low price case)	Low prices result from low demand for liquid fuels in the non-OECD nations. Lower demand is measured by lower economic growth relative to the Reference case. In this case, GDP growth in the non-OECD region is reduced by 1.5 percentage points in each projection year relative to Reference case assumptions from 2015 to 2035. World light, sweet crude oil prices fall to about $50 per barrel in 2035, compared with $125 per barrel in the Reference case (2009 dollars). Other assumptions are the same as in the Reference case. Partial projection tables in Appendix C.	Fully integrated	p. 23	p. 213
Traditional Low Oil Price	More optimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the Reference case. Prices are the same as those used in the Low Oil Price case. Partial projection tables in Appendix C.	Fully integrated	p. 24	p. 218
High Oil Price (primary high price case)	High prices result from high demand for liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD region is raised by 1.0 percentage points in each projection year relative to Reference case assumptions from 2015 to 2035. World light, sweet crude oil prices rise to about $200 per barrel (2009 dollars) in 2035. Other assumptions are the same as in the Reference case. Partial projection tables in Appendix C.	Fully integrated	p. 23	p. 218
Traditional High Oil Price	More pessimistic assumptions for economic access to non-OPEC resources and OPEC behavior than in the Reference case. Prices are the same as those used in the High Oil Price case. Partial projection tables in Appendix C.	Fully integrated	p. 24	p. 218
No Sunset	Begins with the Reference case and assumes extension of all existing energy policies and legislation that contain sunset provisions, except those requiring additional funding (e.g., loan guarantee programs) and those that involve extensive regulatory analysis, such as CAFE improvements and periodic efficiency standard updates. Partial projection tables in Appendix D	Fully integrated	p. 18	p. 223
Extended Policies	Begins with the No Sunset case but excludes extension of blender and other biofuel tax credits that were included in No Sunset case. Assumes expansion of the maximum industrial ITC and CHP credits and extension of the program. Includes assumptions of the "Expanded Standards and Codes case" described below. Assumes new LDV CAFE standards (to 46 miles per gallon by 2025) and tailpipe emissions proposal consistent with the CAFE 3% Growth case described below. Partial projection tables in Appendix D.	Fully Integrated	p. 18	p. 223
Expanded Standards	Begins with Reference case assumptions for standards. Adds additional rounds of efficiency standards for currently covered products as well as new standards for products not yet covered. Efficiency levels assume improvement similar to those in ENERGY STAR or Federal Energy Management Plan (FEMP) guidelines. Partial projection tables in Appendix D.	Residential and commercial only	p. 32	p. 219

Table E1. Summary of the *AEO2011* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Expanded Standards and Codes	Begins with Expanded Standards case and adds multiple rounds of national building codes by 2026. Partial projection tables in Appendix D.	Residential and commercial only	p. 32	p. 219
Residential: 2010 Technology	Future equipment purchases based on equipment available in 2010. New and existing building shell efficiencies fixed at 2010 levels. Partial projection tables in Appendix D.	With commercial	p. 64	p. 218
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 2015. Consumers evaluate efficiency investments at a 7-percent real discount rate. Partial projection tables in Appendix D.	With commercial	p. 64	p. 218
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 2010. Partial projection tables in Appendix D.	With commercial	p. 64	p. 218
Commercial: 2010 Technology	Future equipment purchases based on equipment available in 2010. Building shell efficiencies fixed at 2010 levels. Partial projection tables in Appendix D.	With residential	p. 66	p. 218
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Energy efficiency investments evaluated at a 7-percent real discount rate. Building shell efficiencies for new and existing buildings increase by 17.4 and 7.5 percent, respectively, from 2003 values by 2035. Partial projection tables in Appendix D.	With residential	p. 66	p. 218
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 20.8 and 9.0 percent, respectively, from 2003 values by 2035. Partial projection tables in Appendix D.	With residential	p. 66	p. 218
Industrial: 2010 Technology	Efficiencies of plant and equipment fixed at 2010 levels. Partial projection tables in Appendix D.	Standalone	p. 184	p. 219
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 184	p. 219
Transportation: Low Technology	Advanced technologies are more costly and less efficient than in the Reference case. Partial projection tables in Appendix D.	Standalone	p. 71	p. 219
Transportation: High Technology	Advanced technologies are less costly and more efficient than in the Reference case. Partial projection tables in Appendix D.	Standalone	p. 71	p. 219
Transportation: CAFE 3% Growth	Implements a 3-percent annual increase in fuel economy standards for LDVs from 2017 to 2025, with CAFE standard reaching 46 miles per gallon in 2025. Standards are held constant after 2025. Partial projection tables in Appendix D.	Fully integrated	p. 25	p. 220
Transportation: CAFE 6% Growth	Implements a 6-percent annual increase in fuel economy standards for LDVs from 2017 to 2025, with CAFE standard reaching 59 miles per gallon in 2025. Standards are held constant after 2025. Partial projection tables in Appendix D.	Fully integrated	p. 25	p. 220
Transportation: Heavy-Duty Vehicle Fuel Economy Standards	Implements increased fuel economy standards for heavy-duty vehicles for model years 2014 through 2018. Standards are held constant after 2018. Partial projection tables in Appendix D.	Fully integrated	p. 29	p. 220
Electricity: Low Fossil Technology Cost	Capital and operating costs for all new fossil-fired generating technologies start 20 percent below the Reference case level and decline to 40 percent below the Reference case in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 41	p. 220
Electricity: High Fossil Technology Cost	Costs for all new fossil-fired generating technologies do not improve due to learning from 2011 levels in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 193	p. 220

Table E1. Summary of the *AEO2011* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Electricity: Low Nuclear Cost	Capital and operating costs for new nuclear capacity start 20 percent lower than in the Reference case and fall to 40 percent lower in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 41	p. 220
Electricity: High Nuclear Cost	Costs for new nuclear technology do not improve due to learning from 2011 levels in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 192	p. 220
Electricity: Frozen Plant Capital Costs	Base overnight costs for all new electricity generating technologies are frozen at 2015 levels. Costs decline due to learning, but do not decline due to commodity price changes. Partial projection tables in Appendix D.	Fully integrated	p. 41	p. 221
Electricity: Decreasing Plant Capital Costs	Base overnight costs for all new electric generating technologies fall more rapidly than in the Reference case, starting 20 percent below the Reference case costs in 2011 and falling to 40 percent below in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 41	p. 221
Electricity: Transport Rule Mercury MACT 5	Assumes that the Transport Rule limits on SO2 and NOx and 90-percent mercury MACT are enacted. A 5-year capital recovery period is assumed for the retrofits. Partial projection tables in Appendix D.	Fully integrated	p. 48	p. 221
Electricity: Transport Rule Mercury MACT 20	Same environmental rules as above, but assuming a 20-year capital recovery period for retrofits. Partial projection tables in Appendix D.	Fully integrated	p. 48	p. 221
Electricity: Retrofit Required 5	Assumes that all coal-fired plants are required to install flue gas desulfurization (FGD) scrubbers by 2020 to comply with acid gas reduction requirements and that all plants install selective catalytic reduction (SCR) in order to meet future NOx and ozone requirements. Assumes a 5-year capital recovery period for retrofits. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 221
Electricity: Retrofit Required 20	Same requirements on environmental controls as above, but assuming a 20-year capital recovery period for retrofits. Partial projection tables in Appendix D.	Fully integrated	p. 48	p. 221
Electricity: Low Gas Price Retrofit Required 5	Same assumptions as the Retrofit Required 5 case, plus assumption of increased domestic shale gas availability and utilization rate as in the High Shale EUR case described below. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 221
Electricity: Low Gas Price Retrofit Required 20	Same assumptions as the Retrofit Required 20 case, plus assumption of increased domestic shale gas availability and utilization rate as in the High Shale Estimated Ultimate Recovery (EUR) case described below. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 221
Renewable Fuels: Low Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies start 20 percent lower in 2011 and decline to 40 percent lower than Reference case levels in 2035. Capital costs of renewable liquid fuel technologies start 20 percent lower in 2011 and decline to approximately 40 percent lower than Reference case levels in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 195	p. 219
Renewable Fuels: High Renewable Technology Cost	Costs for new nonhydropower renewable generating technologies do not improve from 2011 levels over the projection. Capital costs of renewable liquid fuel technologies do not improve from 2011 levels over the projection. Partial projection tables in Appendix D.	Fully integrated	p. 195	p. 219
Oil and Gas: Slow Technology	Improvements in exploration and development costs, production rates, and success rates due to technological advancement are 50 percent lower than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 78	p. 221
Oil and Gas: Rapid Technology	Improvements in exploration and development costs, production rates, and success rates due to technological advancement are 50 percent higher than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 78	p. 222

Table E1. Summary of the *AEO2011* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Oil and Gas: Reduced OCS Access	No lease sales occur in the Eastern Gulf of Mexico, Pacific, Atlantic, and Alaska Outer Continental Shelf (OCS) through 2035. Partial projection tables in Appendix D.	Fully integrated	p. 35	p. 222
Oil and Gas: High OCS Resource	Oil and natural gas resources in the Pacific, Eastern Gulf of Mexico, Atlantic, and Alaska OCS are assumed to be three times higher than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 35	p. 222
Oil and Gas: High OCS Costs	Costs for exploration and development of oil and natural gas resources in the OCS are assumed to be 30 percent higher than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 35	p. 222
Oil and Gas: Low Shale EUR	EUR per shale gas well is assumed to be 50 percent lower than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 38	p. 222
Oil and Gas: High Shale EUR	EUR per shale gas well is assumed to be 50 percent higher than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 38	p. 222
Oil and Gas: Low Shale Recovery	Estimated undeveloped technically recoverable shale gas resource base is 50 percent lower than in the Reference case, with recovery rate per well unchanged from the Reference case, resulting in fewer wells needed to fully recover the resource. Partial projection tables in Appendix D.	Fully integrated	p. 38	p. 222
Oil and Gas: High Shale Recovery	Estimated undeveloped technically recoverable shale gas resource base is 50 percent higher than in the Reference case, with recovery rate per well unchanged from the Reference case, resulting in more wells needed to fully recover the resource. Partial projection tables in Appendix D.	Fully integrated	p. 38	p. 222
Oil and Gas: Low E15 Penetration	Consumers and retailers adopt E15 at a minimal rate in States that do not prohibit E15 blends. Partial projection tables in Appendix D.	Fully Integrated	p. 197	p. 224
Oil and Gas: High E15 Penetration	All States that currently limit or prohibit E15 remove the restrictions by 2015. Consumers and retailers adopt widespread E15 blending. Partial projection tables in Appendix D.	Fully Integrated	p. 197	p. 224
Coal: Low Coal Cost	Regional productivity growth rates for coal mining are approximately 2.7 percent per year higher than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are between 22 and 25 percent lower by 2035 than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 85	p. 222
Coal: High Coal Cost	Regional productivity growth rates for coal mining are approximately 2.7 percent per year lower than in the Reference case, and coal mining wages, mine equipment, and coal transportation rates are between 25 and 28 percent by higher by 2035 than in the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 85	p. 222
Integrated 2010 Technology	Combination of the Residential, Commercial, and Industrial 2010 Technology cases and the Electricity High Fossil Technology Cost, High Renewable Technology Cost, and High Nuclear Cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 78	p. 223
Integrated High Technology	Combination of the Residential, Commercial, Industrial, and Transportation High Technology cases and the Electricity Low Fossil Technology Cost, Low Renewable Technology Cost, and Low Nuclear Cost cases. Partial projection tables in Appendix D.	Fully integrated	p. 78	p. 223
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy. Partial projection tables in Appendix D.	Fully integrated	p. 87	p. 223
GHG Price Economywide	Applies a price for CO_2 emissions throughout the economy. The CO_2 price assumed starts at $25 per ton beginning in 2013 and increases to $75 per ton in 2035. Partial projection tables in Appendix D.	Fully integrated	p. 49	p. 223

Table E1. Summary of the *AEO2011* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Low EOR	The quantity of CO_2 available for CO_2-enhanced oil recovery (EOR) from industrial sources with high-purity CO_2 emissions is reduced from the Reference case. All other assumptions are the same as the Reference case. Partial projection tables in Appendix D.	Fully integrated	p. 45	p. 223
Low EOR/GHG Price Economywide	Same as the Low EOR case but with the same carbon price as in the GHG Price Economywide case. Partial projection tables in Appendix D.	Fully integrated	p. 45	p. 223

- In the *Traditional Low Oil Price case*, the OPEC countries increase their conventional oil production to obtain a 52-percent share of total world liquids production, and oil resources outside the U.S. are 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, conventional oil production outside the United States is higher in the Traditional Low Oil Price case than in the Reference case. Prices are the same as in the Low Oil Price case.
- In the *High Oil Price case*, world oil prices reach about $200 per barrel (2009 dollars) in 2035. In the High Oil Price case, the high prices result from higher demand for liquid fuels in the non-OECD nations. Higher demand is measured by higher economic growth relative to the Reference case. In this case, GDP growth in the non-OECD region is raised by 1.0 percentage points relative to Reference case in each projection year, starting in 2015. The OECD projections are only affected by the price impact.
- In the *Traditional High Oil Price case*, OPEC countries are assumed to reduce their production from the current rate, sacrificing market share, and oil resources outside the United States are assumed to be less accessible and/or more costly to produce than in the Reference case. Prices are the same as in the High Oil Price case.

Buildings sector cases

In addition to the *AEO2011* Reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes in equipment and building shell efficiencies. Residential and commercial sector assumptions for the 2010 Technology case and the High Technology case are also used in the appropriate Integrated Technology cases.

Residential sector assumptions for the three technology-focused cases are as follows:

- The *2010 Technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2010. Existing building shell efficiencies are assumed to be fixed at 2010 levels (no further improvements). For new construction, building shell technology options are constrained to those available in 2010.
- The *High Technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*11*]. For new construction, building shell efficiencies are assumed to meet ENERGY STAR requirements after 2015. Consumers evaluate investments in energy efficiency at a 7-percent real discount rate.
- 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 2010.

Commercial sector assumptions for the three technology-focused cases are as follows:

- The *2010 Technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2010. Building shell efficiencies are assumed to be fixed at 2010 levels.
- The *High Technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the Reference case [*12*]. Energy efficiency investments are evaluated at a 7-percent real discount rate. Building shell efficiencies for new and existing buildings in 2035 are assumed to be 17.4 percent and 7.5 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 2035 are assumed to be 20.8 percent and 9.0 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 and Low Renewable Technology Cost cases, which are discussed in more detail below, in the renewable fuels cases section. In combination with assumptions for electricity generation from renewable fuels in the electric power sector and industrial sector, these sensitivity cases analyze the impacts 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 Technology Cost case* assumes greater improvements in residential and commercial PV and wind systems than in the Reference case. The assumptions result in capital cost estimates that are 20 percent below Reference case assumptions in 2011 and decline to at least 40 percent lower than Reference case costs in 2035.
- The *High Renewable Technology Cost case* assumes that costs and performance levels for residential and commercial PV and wind systems remain constant at 2010 levels through 2035.

The No Sunset and Extended Policies cases described below in the cross-cutting integrated cases discussion also include assumptions in the Residential and Commercial Demand Modules of NEMS. The Extended Policies case builds on the No Sunset case and adds multiple rounds of appliance standards and building codes. In the two cases described below, those standards and codes are examined on their own. Essentially, these cases are similar to the Extended Policies case, but without the tax-credit extension assumptions of the No Sunset case.

- The *Expanded Standards case* includes updates to appliance standards, as prescribed by the timeline in DOE's multiyear plan, and introduces new standards for products currently not covered by DOE. Efficiency levels for the updated residential appliance standards are based on current ENERGY STAR guidelines. Efficiency levels for updated commercial equipment standards are based on the technology menu from the *AEO2011* Reference case and FEMP-designated purchasing specifications for Federal agencies.
- The *Expanded Standards and Codes case* begins with the Expanded Standards case and adds national building codes to reach 30-percent improvement relative to the IECC 2006 for residential households and ASHRAE 90.1-2004 for commercial buildings by 2020, with additional rounds of improved codes in 2023 and 2026.

Industrial sector cases

In addition to the *AEO2011* Reference case, two standalone cases using the IDM of NEMS were developed to examine the effects of less rapid and more rapid technology change and adoption. Because they 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. Different assumptions for the IDM were also used as part of the Integrated Low and High Renewable Technology Cost cases, Integrated Technology cases, No Sunset case, and Extended Policies case. For the industrial sector:

- The *2010 Technology case* holds the energy efficiency of new plant and equipment constant at the 2010 level over the projection period. Changes in aggregate energy intensity may result both from changing equipment and production efficiency and from changing composition of output within an individual industry. Because the level and composition of overall industrial output are assumed to be the same as in the Reference, 2010 Technology, and High Technology cases, the change in energy intensity in the two technology side cases is attributable to process and efficiency changes and increased use of CHP.
- The *High Technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*13*] 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 Technology Cost case, which focuses on electricity generation. Although the choice of the 0.7-percent annual rate of improvement in byproduct recovery is an assumption in the High Technology case, it is based on the expectation of higher recovery rates and substantially increased use of CHP in that case.

The 2010 Technology and High Technology cases were run with only the IDM, rather than in fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions are captured, and energy consumption and production in the refining industry, which are modeled in the PMM, are excluded.

- The *No Sunset and Extended Policies cases* include an assumption for CHP that extends the existing industrial CHP ITC through the end of the forecast. Additionally, the Extended Policies case includes expansion of the ITC for all industrial CHP capacities and raises the maximum credit that can be claimed. These assumptions are based on the current proposals in S. 1639 and H.R. 4751.

Transportation sector cases

In addition to the *AEO2011* Reference case, two standalone cases using the NEMS Transportation Demand Module were developed to examine the effects of advanced technology costs and efficiency improvement on technology adoption and vehicle fuel economy [*14*]. For the transportation sector:

- In the *Low Technology case*, the characteristics of conventional technologies, advanced technologies, and alternative-fuel LDVs, heavy-duty vehicles, and aircraft reflect more pessimistic assumptions about cost and efficiency improvements achieved over the projection. More pessimistic assumptions for fuel efficiency improvement are also reflected in the rail and shipping sectors.
- In the *High Technology case*, the characteristics of conventional and alternative-fuel LDVs reflect more optimistic assumptions about incremental improvements in fuel economy and costs. In the freight truck sector, the High Technology case assumes more

rapid incremental improvement in fuel efficiency for engine and emissions control technologies. More optimistic assumptions for fuel efficiency improvements are also made for the air, rail, and shipping sectors.

The Low and High Technology cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback related to vehicles costs or travel demand was captured, nor were changes in fuel prices incorporated.

Three additional integrated cases were developed to examine the potential energy impacts associated with the implementation of stricter fuel economy standards for LDVs and heavy-duty trucks, including:

- A *CAFE 3% Growth case* that examines the impact of increasing fuel economy standards by 3 percent annually for model years 2017 through 2025, reaching a combined standard of 46 miles per gallon for new LDVs by 2025. The standards are held constant beyond model year 2025.
- A *CAFE 6% Growth case* that examines the impact of increasing fuel economy standards by 6 percent annually for model years 2017 through 2025, reaching a combined standard of 59 miles per gallon for new LDVs by 2025. The standards are held constant beyond model year 2025.
- A *Heavy-Duty Vehicle Fuel Economy Standards case* that simulates the expected fuel economy impact of the fuel economy standards for heavy-duty vehicles (Class 2b through Class 8) for model years 2014 through 2018 proposed by the EPA and NHTSA.

Electricity sector cases

In addition to the Reference case, several 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 the major component costs. The electricity cases analyze what could happen if costs of new plants were either lower or higher 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 cost cases

- The cost assumptions for the *Low Nuclear Cost case* reflect a 20-percent reduction in the capital and operating costs for advanced nuclear technology in 2011, relative to the Reference case, and fall to 40 percent below the Reference case in 2035. The Reference case projects a 35-percent reduction in the capital costs of nuclear power plants from 2011 to 2035; the Low Nuclear Cost case assumes a 51-percent reduction from 2011 to 2035.
- The *High Nuclear Cost case* assumes that capital costs for advanced nuclear technology remain fixed at the 2011 levels assumed in the *Reference case*. The capital costs are still tied to key commodity price indices, but no cost improvement from "learning-by-doing" effects is assumed.

Fossil technology cost cases

- In the *Low Fossil Technology Cost case*, capital costs and operating costs for all coal- and natural-gas-fired generating technologies are assumed to start 20 percent lower than *Reference case* levels and fall to 40 percent lower than Reference case levels in 2035. Because learning in the Reference case reduces costs with manufacturing experience, costs in the Low Fossil Technology Cost case are reduced by 43 to 58 percent between 2011 and 2035, depending on the technology.
- In the *High Fossil Technology Cost case*, capital costs for all coal- and natural-gas-fired generating technologies remain fixed at the 2011 values assumed in the Reference *case*. Costs are still adjusted year to year by the Commodity Price Index, but no learning-related cost reductions are assumed.

Additional details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the Low and High Fossil Technology Cost cases are provided in *Assumptions to the Annual Energy Outlook 2011* [15].

Electricity plant capital cost cases

Costs to build new power plants have risen dramatically in the past few years, driven primarily by significant increases in the costs of construction-related materials, such as cement, iron, steel and copper. For the *AEO2011* Reference case, initial overnight costs for all technologies were updated to be consistent with cost estimates for 2010. A cost adjustment factor based on the projected producer price index for metals and metal products is also applied throughout the projection, allowing overnight costs to fall in the future if the index drops or to rise if the index increases. Although there is significant correlation between commodity prices and power plant costs, there may be other factors influencing future costs that increase the uncertainties surrounding the future costs of building new power plants. For *AEO2011*, two additional cost cases were run that focus on the uncertainties of future plant construction costs. These cases use exogenous assumptions for the annual adjustment factors, rather than linking to the metals price index. The cases are discussed in the Issues in focus article, "Electricity Plant Cost Uncertainties."

- In the *Frozen Plant Capital Costs case*, base overnight costs for all new electric generating technologies are assumed to be frozen at 2015 levels. Cost decreases due to learning can still occur. In this case, costs do decline slightly over the projection, but by 2035 are roughly 25 percent above Reference case costs for the same year.
- In the *Decreasing Plant Capital Costs case*, base overnight costs for all new electricity generating technologies are assumed to fall more rapidly than in the Reference case. The base overnight costs are assumed to be 20 percent below the Reference case, through a reduction in the annual cost index. Costs are also assumed to decline more rapidly, so that by 2035 the cost factor is 40 percentage points below the Reference case value.

Electricity environmental regulation cases

Over the next few years, electricity generators will have to begin steps to comply with a large number of new environmental regulations currently in various stages of promulgation. The *AEO2011* Reference case does not include regulations that are still under development. However, the Issues in focus article "Power sector environmental regulations on the horizon" discusses the status of the different rules and examines potential impacts through a number of cases.

- The *Transport Rule Mercury MACT 5 case* assumes that the Air Transport Rule limits on SO_2 and NO_x and a 90-percent mercury MACT (maximum achievable control technology) are enacted. A 5-year recovery period for investments in environmental control projects is assumed.
- The *Transport Rule Mercury MACT 20 case* assumes the same rules as above, but a 20-year recovery period for investments in environmental control projects is assumed.
- The *Retrofit Required 5 case* represents stringent requirements for reductions in airborne emissions from coal-fired power plants. It assumes that utility boilers fall under the MACT rule, which requires all plants to install FGD scrubbers by 2020 in order to comply with acid gas reduction requirements. It also requires that all plants install SCR in order to meet future NO_x and ozone emission reduction requirements. If the investment in an FGD and SCR is not economical, the plant is retired. Investments in retrofits are assumed to be recovered over a 5-year period.
- The *Retrofit Required 20 case* assumes the same requirements as above, but investments in retrofits are assumed to be recovered over a 20-year period.
- The *Low Gas Price Retrofit Required 5 case* is identical to the Retrofit Required 5 case but adds an assumption of increased availability domestic shale availability and utilization rate, as in the High Shale EUR case. Increased access to natural gas lowers the natural gas prices paid by the electric power sector.
- The *Low Gas Price Retrofit Required 20 case* is identical to the Low Gas Price Retrofit Required 5 case, but investments in retrofits are assumed to be recovered over a 20-year period.

Renewable fuels cases

In addition to the *AEO2011* 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 the cost of renewable technologies. The cases are as follows:

- In the *Low Renewable Technology Cost case*, the levelized costs of energy resources for generating technologies using renewable resources are assumed to start at 20 percent below Reference case assumptions in 2011 and decline to 40 percent below the Reference case costs for the same resources in 2035. In general, lower costs are represented by reducing the capital costs of new plant construction. Biomass fuel supplies also are assumed to be 40 percent less expensive than in the Reference case for the same resource quantities used in the Reference case. Assumptions for other generating technologies are unchanged from those in the Reference case. In the Low Renewable Technology Cost case, the rate of improvement in recovery of biomass byproducts from industrial processes is also increased.
- In the *High Renewable Technology Cost case*, capital costs, operating and maintenance costs, and performance levels for wind, solar, biomass, geothermal, and renewable liquid fuel technologies are assumed to remain constant at 2011 levels through 2035. Costs are still tied to key commodity price indexes, but no cost improvement from "learning-by-doing" effects is assumed. Although biomass prices are not changed from the Reference case, this case assumes that dedicated energy crops (also known as "closed-loop" biomass fuel supply) do not become available.

Oil and gas supply cases

The sensitivity of the *AEO2011* projections to changes in the assumed rates of technological progress in oil and natural gas supply are examined in two cases:

- In the *Slow Technology case*, parameters representing the effects of technological progress on production rates, exploration and development costs, and success rates for conventional and unconventional oil and natural gas drilling are 50 percent less optimistic than those in the Reference case. Key Canadian supply parameters also are 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.

- In the *Rapid Technology case*, parameters representing the effects of technological progress on production rates, exploration and development costs, and success rates for conventional and unconventional oil and natural gas drilling in the Reference case are improved by 50 percent. Key supply parameters for Canadian oil and natural gas also are 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 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 is provided in *Assumptions to the Annual Energy Outlook 2011* [*16*].

Seven additional cases examine key uncertainties affecting exploration and development of offshore and shale gas resources and their impacts on future domestic natural gas supply.

- In the *Reduced OCS Access case*, no new lease sales occur in the Eastern Gulf of Mexico, Pacific, Atlantic, and Alaska OCS through 2035.
- In the *High OCS Resource case*, oil and natural gas resources in undeveloped areas of the OCS (namely the Pacific, Eastern Gulf of Mexico, Atlantic, and Alaska) are assumed to be 3 times higher than in the Reference case.
- In the *High OCS Costs case*, the costs of exploration and development of oil and natural gas resources in the OCS are assumed to be 30 percent higher than in the Reference case.
- In the *Low Shale EUR case*, the estimated ultimately recovery (EUR) per shale gas well is assumed to be 50 percent lower than in the Reference case, increasing the per-unit cost of developing the resource. The total unproved technically recoverable shale gas resource is decreased to 423 trillion cubic feet.
- In the *High Shale EUR case*, the EUR per shale gas well is assumed to be 50 percent higher than in the Reference case, decreasing the per-unit cost of developing the resource. The total unproved technically recoverable shale gas resource is increased from 827 trillion cubic feet in the Reference case to 1,230 trillion cubic feet.
- In the *Low Shale Recoverability case*, the total unproved technically recoverable shale gas resource base is the same as in the Low Shale EUR case (423 trillion cubic feet), but instead of decreasing the EUR per well, the estimate of the number of wells that need to be drilled to fully recover the shale gas in each play is assumed to be 50 percent lower than in the Reference case. This means that the per-unit cost of developing the resource is the same as in the Reference case.
- In the *High Shale Recoverability case*, the total unproved technically recoverable shale gas resource base is the same as in the High Shale EUR case (1,230 trillion cubic feet), but instead of increasing the EUR per well, the estimate of the number of wells that need to be drilled to fully recover the shale gas in each play is assumed to be 50 percent higher than in the Reference case. This means that the per-unit cost of developing the resource is the same as in the Reference case.

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, mine equipment costs, and coal transportation rates. The alternative productivity and cost assumptions are applied in every year from 2011 through 2035. For the coal cost cases, adjustments to the Reference case assumptions for coal mining productivity are based on variation in the average annual productivity growth of 2.7 percent observed since 2000. Transportation rates are lowered (in the Low Coal Cost case) or raised (in the High Coal Cost case) from Reference case levels to achieve a 25-percent change in rates relative to the Reference case in 2035. 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 productivity are higher than those in the Reference case and are applied at the supply curve level. As an example, the average annual growth rate for Wyoming's Southern Powder River Basin supply curve is increased from -0.5 percent in the Reference case for the years 2011 through 2035 to 2.2 percent in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs all are assumed to be about 22 percent lower in 2035 in real terms in the Low Coal Cost case than in the Reference case. Coal transportation rates, excluding the impact of fuel surcharges, are assumed to be 25 percent lower in 2035.
- In the *High Coal Cost case*, the average annual productivity growth rates for coal mining are lower than those in the Reference case and are applied as described in the Low Coal Cost case. Coal mining wages, mine equipment costs, and other mine supply costs in 2035 are assumed to be about 28 percent higher than in the Reference case, and coal transportation rates in 2035 are assumed to be 25 percent higher.

Additional details of the productivity, wage, mine equipment cost, and coal transportation rate 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 are used in *AEO2011* to analyze specific cases with broader sectoral impacts. For example, two integrated technology progress cases combine the assumptions from the other technology progress cases to analyze the broader impacts of more rapid and slower technology improvement rates. In addition, two cases also were run with alternative assumptions about expectations of future regulation of GHG emissions.

Integrated technology cases

The *Integrated 2010 Technology case* combines the assumptions from the Residential, Commercial, and Industrial 2010 Technology cases and the Electricity High Fossil Technology Cost, High Renewable Technology Cost, and High Nuclear Cost cases. The *Integrated High Technology case* combines the assumptions from the Residential, Commercial, and Industrial High Technology cases and the Electricity Low Fossil Technology Cost, Low Renewable Technology Cost, and Low Nuclear Cost cases.

Greenhouse gas cases

Although currently no Federal cap-and-trade legislation or carbon allowance pricing for CO_2 emissions is in place in the United States, the EPA announced a proposal in September 2009 to regulate emissions under the CAAA90. Under the proposal, industrial facilities with emission over 25,000 metric tons per year would be required to obtain permits that would demonstrate they are using the best practices and technologies to minimize GHG emissions. The rule also proposes new CAAA90 thresholds for permits to new or existing industrial facilities for GHG emissions under the New Source Review (NSR) and Title V operating permits programs. As a result, regulators and the investment community are beginning to push energy companies to invest in less GHG-intensive technologies. To reflect the market reaction to potential future GHG regulation, a 3-percentage-point increase is assumed in the cost of capital for investments in new coal-fired power plants without CCS and new CTL plants without CCS in the Reference case and all other *AEO2011* cases except the No GHG Concern and GHG Price Economywide cases. Those assumptions affect cost evaluations for the construction of new capacity but not the actual operating costs when a new plant begins operation

Two alternative GHG cases are used to provide a range of other potential outcomes, from no concern about future GHG legislation to the imposition of a specific economy-wide carbon allowance price. In the *GHG Price Economywide case*, an economy-wide carbon allowance price is examined. The price begins at $25 per metric ton CO_2 in 2013 and rises to $75 per metric ton CO_2 in 2035 (2009 dollars). This trajectory is consistent with the cost containment provisions in both the Kerry-Lieberman and Waxman-Markey GHG legislation. No assumptions are made for offsets, bonus allowances for CCS, or specific allocation of allowances in these cases.

The *No GHG Concern case*, which was run without any adjustment for concern about potential GHG regulations, is similar to what was run in previous *AEO*s (without the 3-percentage-point increase). In the No GHG Concern case, the same cost of capital is used to evaluate all new capacity builds, regardless of type.

CO_2 availability cases

Two alternative CO_2 availability cases are used to provide sensitivity analysis of oil production from CO_2-EOR, depending on the availability of relatively inexpensive CO_2 both with a carbon price and without one. The *Low EOR case* assumes that industrial CO_2 available from CTL and BTL plants is reduced by 50 percent from the Reference case. The *Low EOR/GHG Price Economywide case* assumes that the CO_2 availability is reduced and a carbon price exists that provides incentives for emitters to install carbon capture capabilities.

No Sunset case

In addition to the *AEO2011* Reference case, a case was run assuming that selected policies with sunset provisions like the PTC, ITC, and tax credits for energy-efficient equipment in the buildings and industrial sectors will be extended indefinitely rather than allowed to sunset as the law currently prescribes.

For the residential sector, these extensions include: (a) personal tax credits for selected end-use equipment, including furnaces, heat pumps, and central air conditioning; (b) personal tax credits for PV installations, solar water heaters, small wind turbines, and geothermal heat pumps; (c) manufacturer tax credits for refrigerators, dishwashers, and clothes washers, passed on to consumers at 100 percent of the tax credit value.

For the commercial sector, business ITCs for PV installations, solar water heaters, small wind turbines, geothermal heat pumps, and CHP are extended to the end of the projection. The business tax credit for solar technologies remains at the current 30-percent level without reverting to 10 percent as scheduled.

In the industrial sector, the existing ITC for industrial CHP, which currently ends in 2016, is extended to 2035.

For the refinery sector, blending credits are extended; the $1.00 per gallon biodiesel tax credit is extended; the $0.54 per gallon imported ethanol tariff is extended; and the $1.01 per gallon cellulosic biofuels PTC is extended.

For renewables, the PTC of 2.1 cents per kilowatthour (or 30 percent for wind, geothermal, biomass, hydroelectric, and landfill gas resources), which currently are set to expire at the end of 2012 for wind and 2013 for other eligible resources, are extended to 2035; and the 30-percent solar power ITC, which currently is scheduled to revert to 10 percent, is extended indefinitely.

Extended Policies case

Assumptions for tax credit extensions are the same as in the No Sunset case described above. Further, updates to Federal appliance efficiency standards are assumed to occur at regular intervals, and new standards for products not currently covered by DOE are introduced. Finally, proposed rules by NHTSA and the EPA for national tailpipe CO_2-equivalent emissions and fuel economy standards for LDVs, including both passenger cars and light-duty trucks, are harmonized and incorporated in this case.

Updates to appliance standards are assumed to occur as prescribed by the timeline in DOE's multiyear plan, and new standards for products currently not covered by DOE are introduced by 2019. The efficiency levels chosen for the updated residential appliance standards are based on current ENERGY STAR guidelines. The efficiency levels chosen for updated commercial equipment standards are based on the technology menu from the *AEO2011* Reference case and either FEMP-designated purchasing specifications for Federal agencies or ENERGY STAR guidelines. National building codes are added to reach 30-percent improvement relative to IECC 2006 for residential households and ASHRAE 90.1-2004 for commercial buildings by 2020, with additional rounds of improvements in 2023 and 2026.

In the industrial sector, tax credits are further extended to cover all systems sizes rather than applying only to systems under 50 megawatts, and the maximum credit (cap) is increased from $15,000 to $25,000 per system. These extensions are consistent with previously proposed legislation (S. 1639) or pending legislation (H.R. 4751).

For transportation, the Extended Policies case assumes that the standards are further increased, so that the minimum fuel economy standard achieved by LDVs increases to 45.6 miles per gallon in 2035.

E15 cases

Two alternative E15 cases were established to reflect the potential variability in consumer demand for E15, which depends on multiple factors and ultimately affects the conversion rate of gasoline stations from E10 to E15.

- In the *Low E15 Penetration case*, the infrastructure and regulatory barriers to E15 adoption are more pronounced, and penetration of E15 in all demand regions grows at a slower rate, reaching a lower maximum level than in the Reference case. E15 penetration never rises to one-third of the maximum potential penetration level in any of the U.S. Census Divisions.
- In the *High E15 Penetration case*, E15 adoption occurs at a faster rate and reaches a higher overall level than in the Reference case. Any State that currently has laws or regulations that prohibit the use of ethanol blends above 10 percent or gasoline with an oxygenate content in excess of 3.5 percent is assumed to remove those restrictions by 2015. In addition, E15 penetration rises to 99 percent of the potential maximum level in all regions by 2020, indicating that infrastructure or regulatory barriers do not inhibit the use of E15 in gasoline markets.

Endnotes for Appendix E

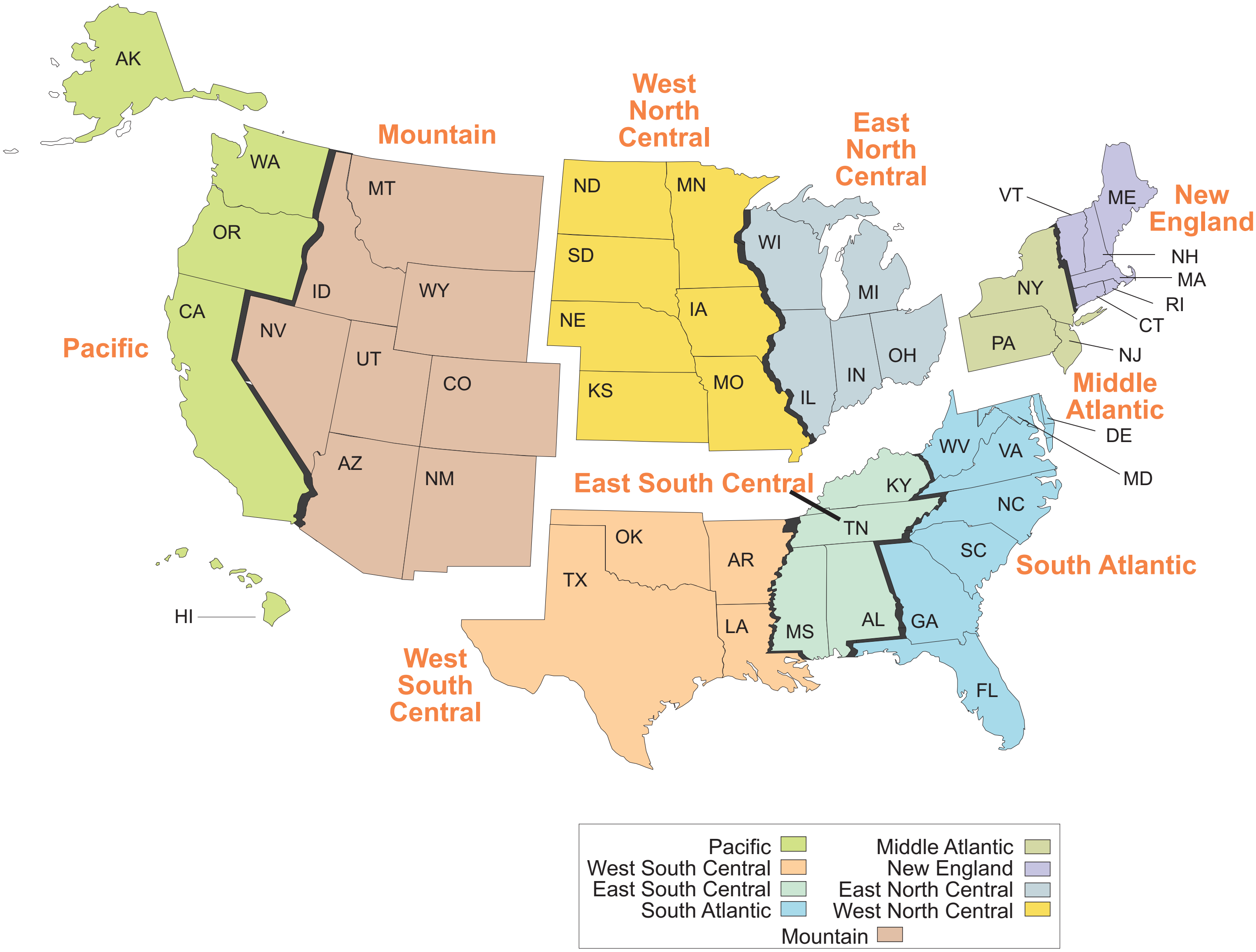
Links current as of April 2011

1. U.S. Energy Information Administration, The National Energy Modeling System: An Overview 2009, DOE/EIA-0581(2009) (Washington, DC: March 2009), website www.eia.gov/oiaf/aeo/overview.
2. On October 1, 2010, the U.S. Energy Information Administration was reorganized along functional lines. The new Office of Energy Analysis has been assigned all analysis responsibilities for EIA, including short- and mid-term functions as well as fuel-specific analysis. The referenced documents on the EIA website will be changed gradually over the next year to reflect the new organizational structure.
3. The disaggregation to 22 subregions for electricity planning and dispatch is new for *AEO2011*. Disaggregation of the Electricity Market Module (EMM) is intended to reduce errors that result from aggregation and averaging, to better represent environmental and regional issues, and thus to improve the projections of capacity additions and fuels consumed for generation.
4. U.S. Energy Information Administration, Annual Energy Review 2009, DOE/EIA-0384(2009) (Washington, DC: August 2010), website www.eia.gov/emeu/aer.
5. U.S. Energy Information Administration, Emissions of Greenhouse Gases in the United States 2009, DOE/EIA-0573(2009) (Washington, DC, April, 2011), website www.eia.gov/environment/emissions/ghg_report.
6. U.S. Energy Information Administration, "Short-Term Energy and Summer Fuels Outlook," website www.eia.gov/emeu/steo/pub. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.
7. U.S. Energy Information Administration, "Manufacturing Energy Consumption Survey," website www.eia.doe.gov/emeu/mecs.
8. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2011*, DOE/EIA-0554(2011) (Washington, DC: April 2011), website www.eia.gov/forecasts/aeo/assumptions/.
9. Alternative liquids technologies include all biofuel technologies plus CTL and GTL.
10. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2011*, DOE/EIA-0554(2011) (Washington, DC: April 2011), website www.eia.gov/forecasts/aeo/assumptions/.
11. High technology assumptions for the residential sector are based on U.S. 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 Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
12. High technology assumptions for the commercial sector 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 Updates—Residential and Commercial Building Technologies—Advanced Case: Residential and Commercial Lighting, Commercial Refrigeration, and Commercial Ventilation Technologies* (Navigant Consulting, Inc., September 2008).
13. These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).
14. U.S. 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. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2011*, DOE/EIA-0554(2011) (Washington, DC: April 2011), website www.eia.gov/forecasts/aeo/assumptions/.
16. U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2011*, DOE/EIA-0554(2011) (Washington, DC: April 2011), website www.eia.gov/forecasts/aeo/assumptions/.

Appendix F

Regional Maps

Figure F1. United States Census Divisions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F1. United States Census Divisions (continued)

Division 1
New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2
Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3
East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4
West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5
South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6
East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7
West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8
Mountain

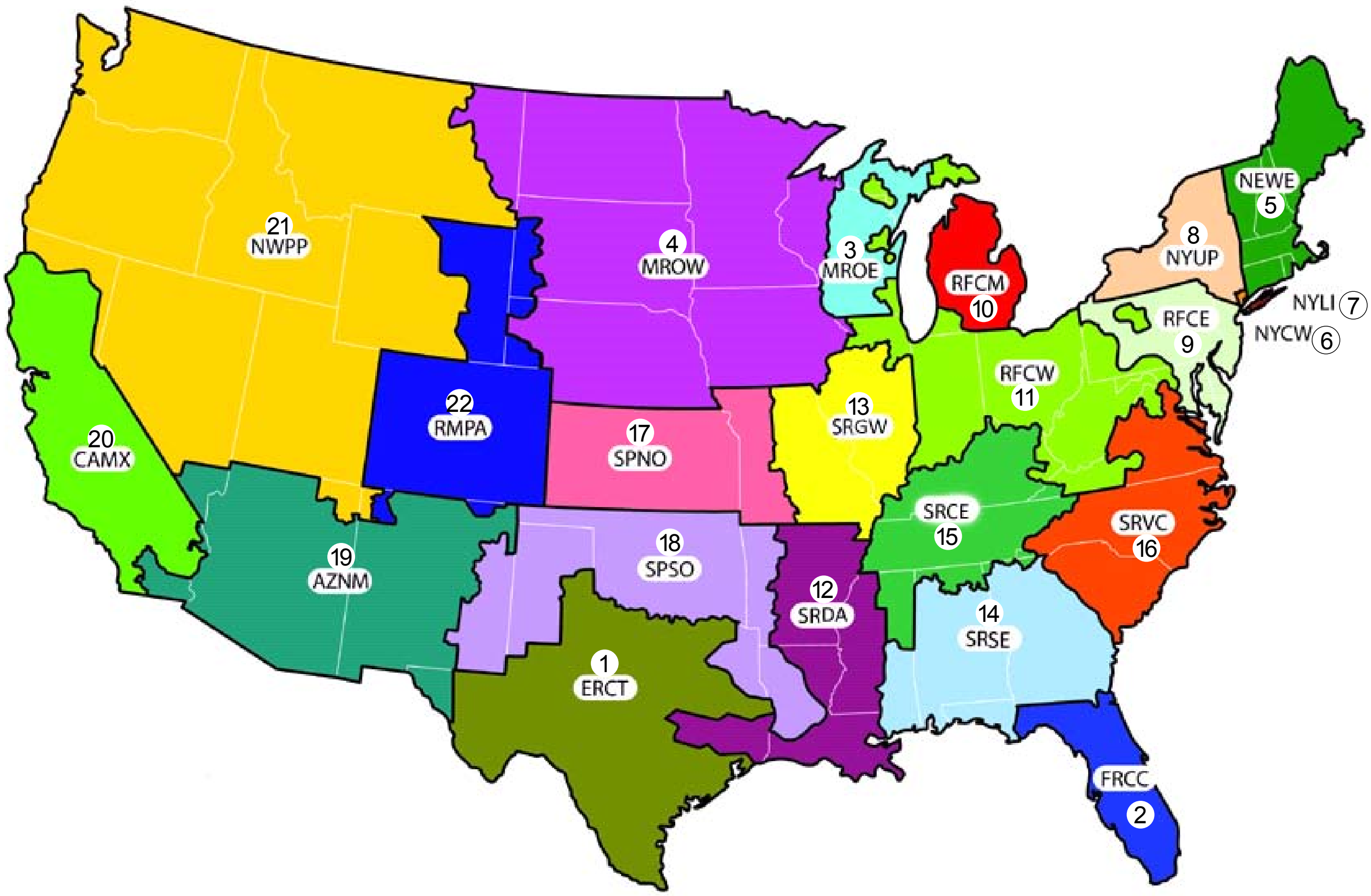
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9
Pacific

Alaska
California
Hawaii
Oregon
Washington

Source: U.S. Energy Information Administration, Office of Energy Analysis.

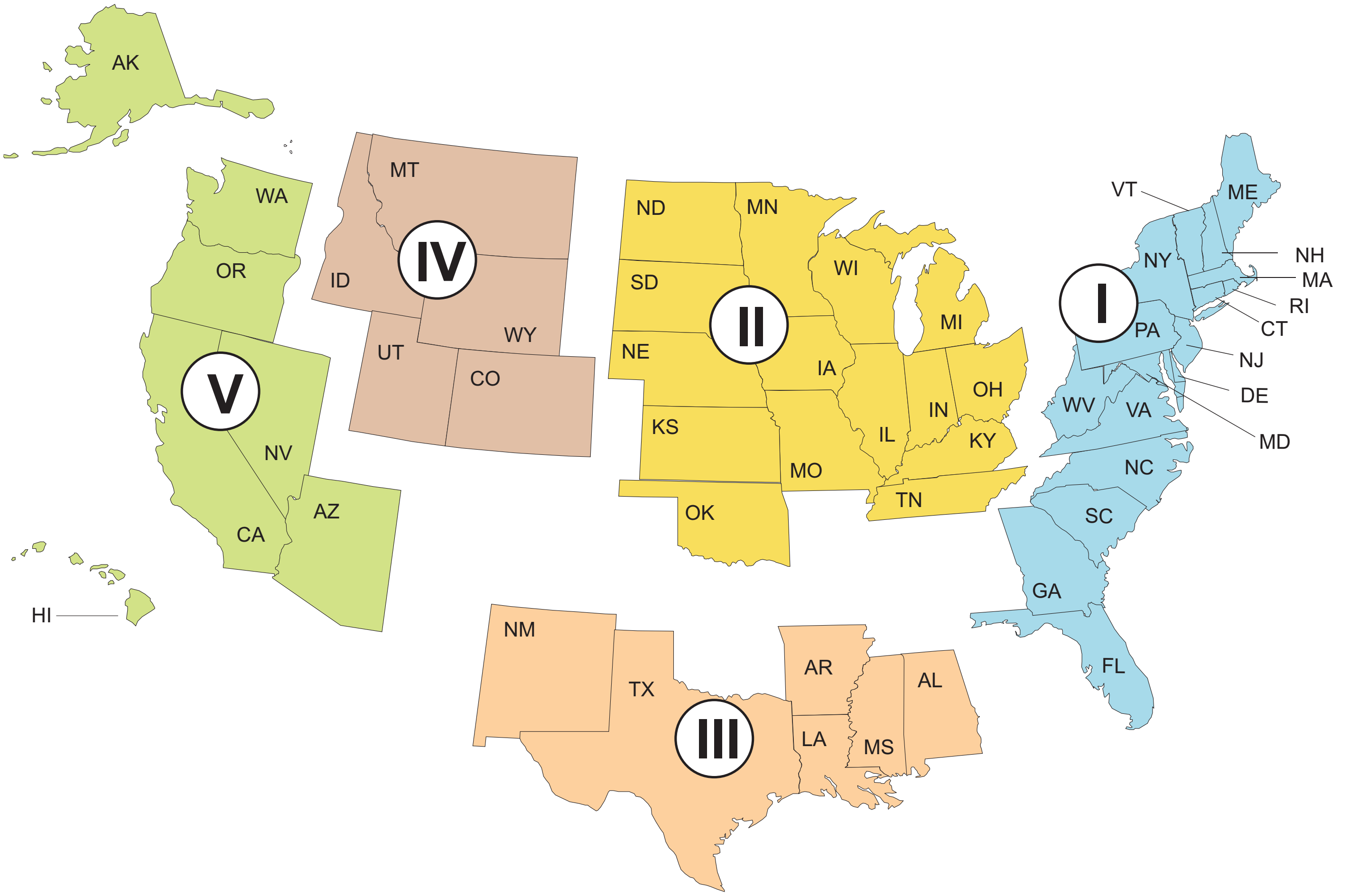
Figure F2. Electricity market module regions



1.	ERCT	ERCOT All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Source: U.S. Energy Information Administration, Office of Energy Analysis.

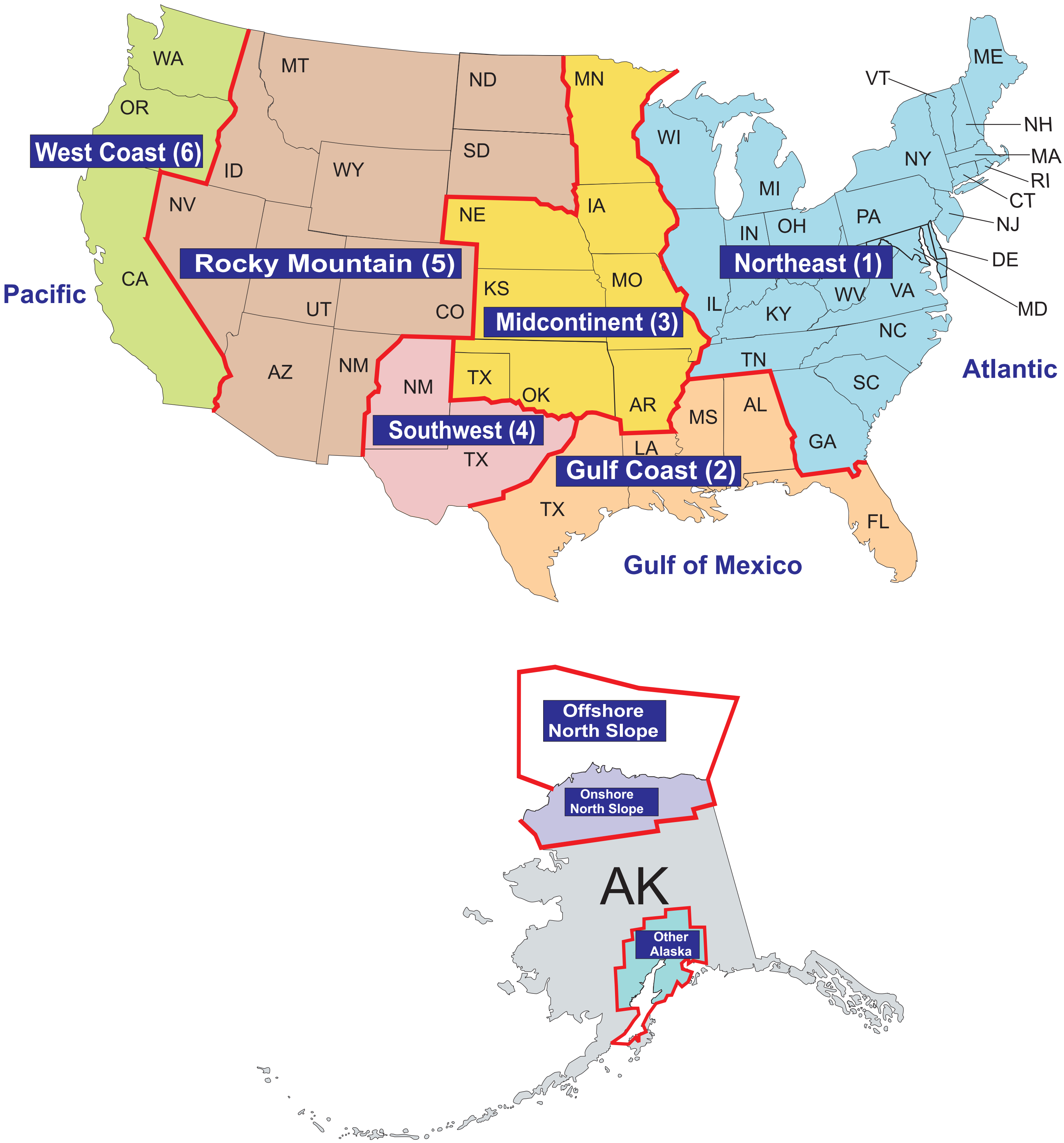
Figure F3. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

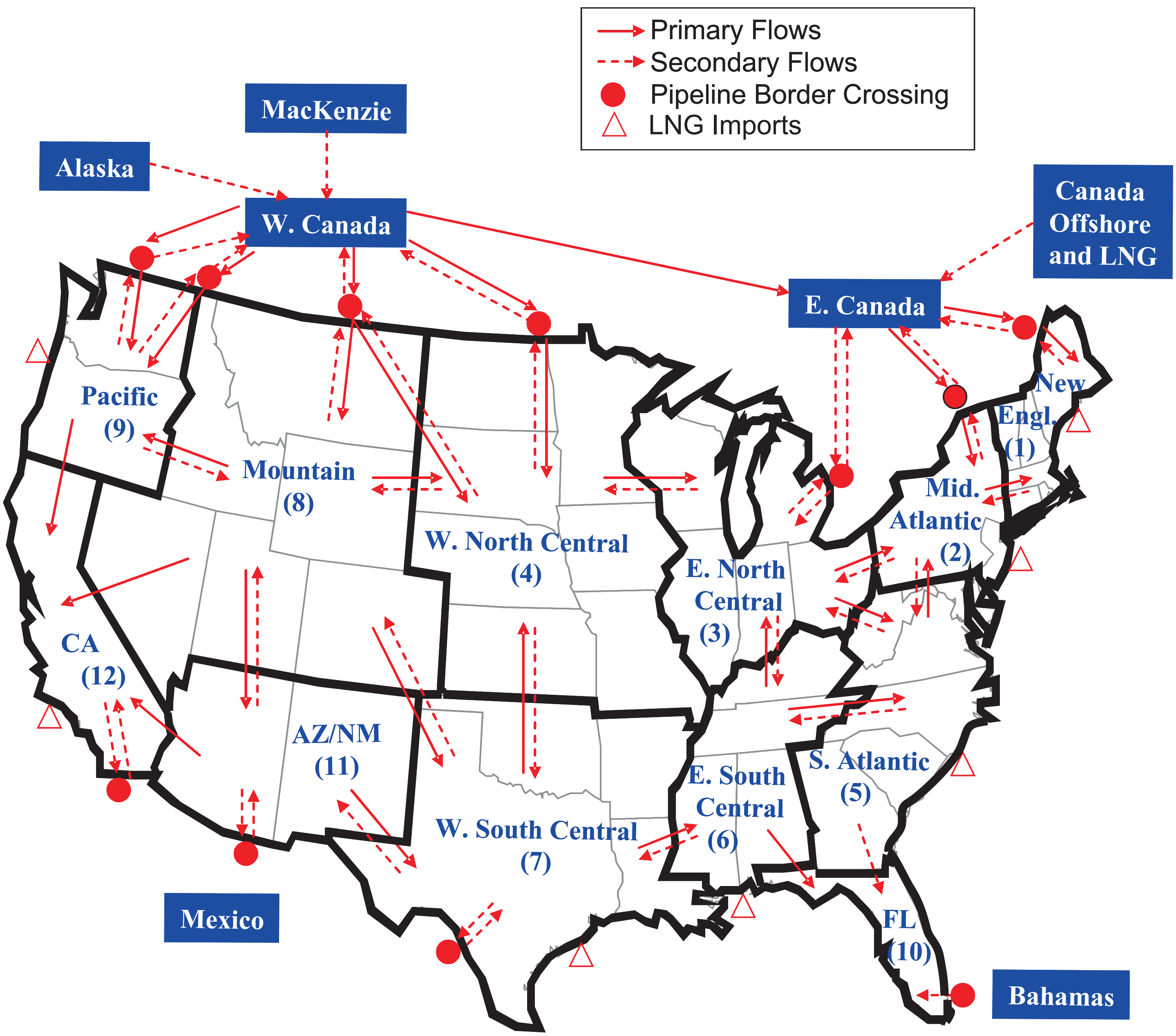
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F4. Oil and gas supply model regions



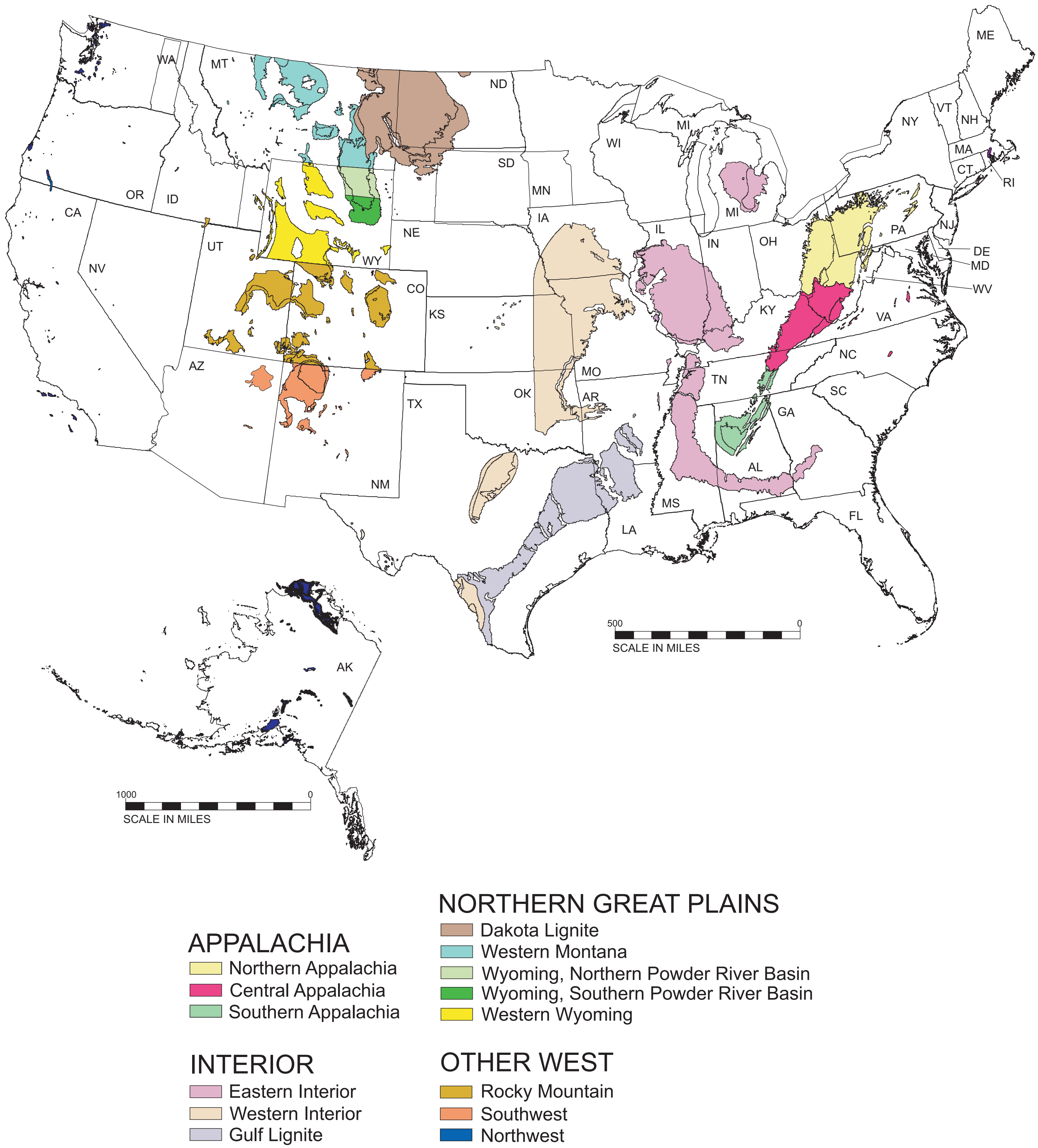
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F5. Natural gas transmission and distribution model regions



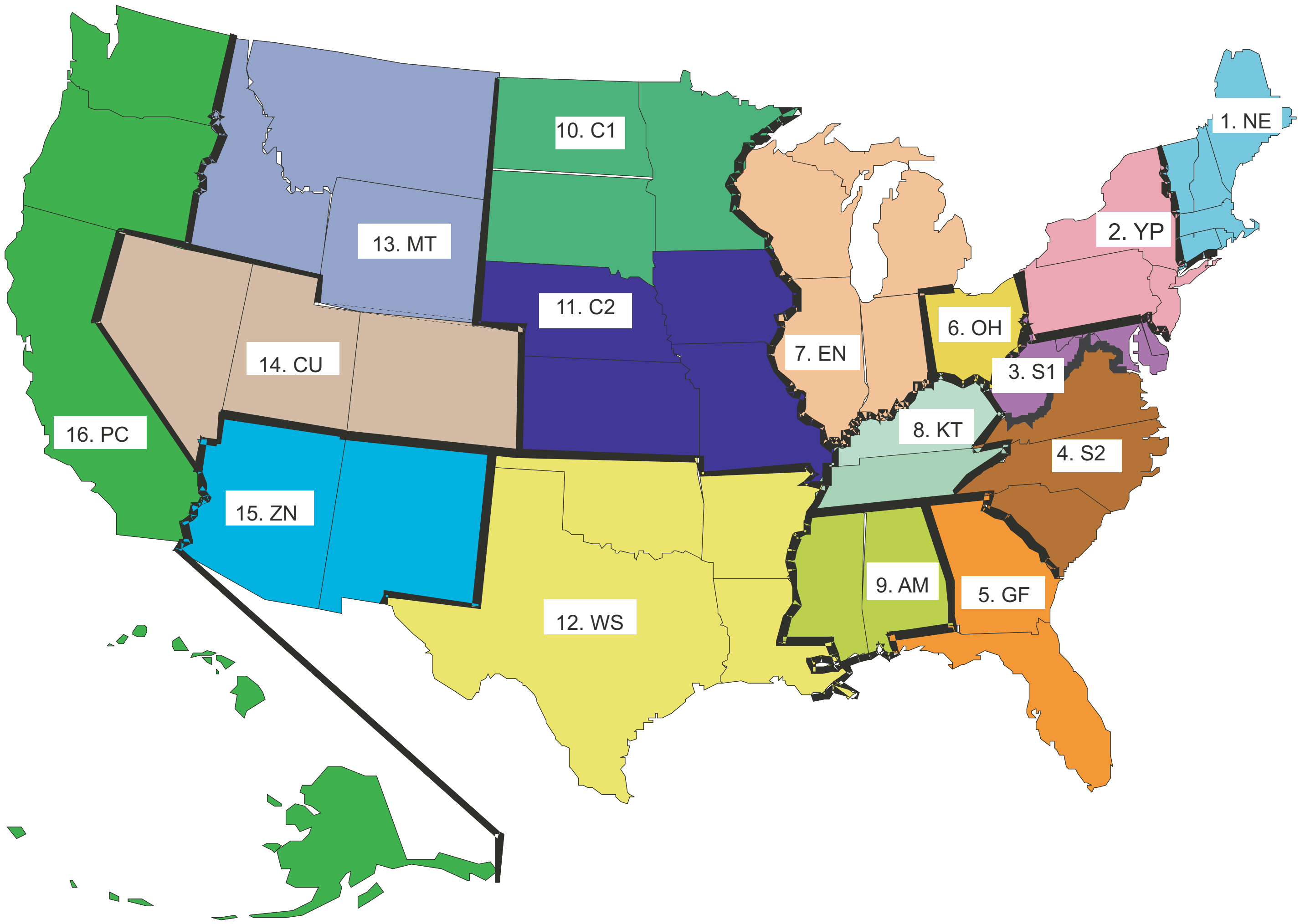
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F6. Coal supply regions



Source: U.S. Energy Information Administration, Office of Energy Analysis.

Figure F7. Coal demand regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. S1	WV,MD,DC,DE
4. S2	VA,NC,SC
5. GF	GA,FL
6. OH	OH
7. EN	IN,IL,MI,WI
8. KT	KY,TN

Region Code	Region Content
9. AM	AL,MS
10. C1	MN,ND,SD
11. C2	IA,NE,MO,KS
12. WS	TX,LA,OK,AR
13. MT	MT,WY,ID
14. CU	CO,UT,NV
15. ZN	AZ,NM
16. PC	AK,HI,WA,OR,CA

Source: U.S. Energy Information Administration, Office of Energy Analysis.

Appendix G

Conversion factors

Table G1. Heat rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	19.933
Consumption	million Btu per short ton	19.800
Coke Plants	million Btu per short ton	26.327
Industrial	million Btu per short ton	21.911
Residential and Commercial	million Btu per short ton	21.284
Electric Power Sector	million Btu per short ton	19.536
Imports	million Btu per short ton	24.786
Exports	million Btu per short ton	25.550
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.989
Petroleum Products and Other Liquids		
Consumption[1]	million Btu per barrel	5.261
Motor Gasoline[1]	million Btu per barrel	5.119
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil[1]	million Btu per barrel	5.775
Diesel Fuel[1]	million Btu per barrel	5.766
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gases[1]	million Btu per barrel	3.558
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[1]	million Btu per barrel	5.506
Unfinished Oils	million Btu per barrel	6.118
Imports[1]	million Btu per barrel	5.520
Exports[1]	million Btu per barrel	5.782
Ethanol	million Btu per barrel	3.539
Biodiesel	million Btu per barrel	5.376
Natural Gas Plant Liquids		
Production[1]	million Btu per barrel	3.692
Natural Gas[1]		
Production, Dry	Btu per cubic foot	1,026
Consumption	Btu per cubic foot	1,026
End-Use Sectors	Btu per cubic foot	1,027
Electric Power Sector	Btu per cubic foot	1,025
Imports	Btu per cubic foot	1,025
Exports	Btu per cubic foot	1,009
Electricity Consumption	Btu per kilowatthour	3,412

[1]Conversion factor varies from year to year. The value shown is for 2009.
Btu = British thermal unit.
Sources: U.S. Energy Information Administration (EIA), *Annual Energy Review 2009*, DOE/EIA-0384(2009) (Washington, DC, August 2010), and EIA, AEO2011 National Energy Modeling System run REF2011.D020911A.

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