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before the

COMMITTEE ON ENERGY AND NATURAL RESOURCES

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Mr. Chairman and Members of the Committee:

I appreciate the opportunity to appear before you today to discuss the energy and oil market outlook.

The U.S. Energy Information Administration (EIA) is the statistical and analytical agency within the U.S. Department of Energy. EIA collects, analyzes, and disseminates independent and impartial energy information to promote sound policymaking, efficient markets, and public understanding regarding energy and its interaction with the economy and the environment. EIA is the Nation's premier source of energy information and, by law, its data, analyses, and forecasts are independent of approval by any other officer or employee of the United States Government. The views expressed in our reports, therefore, should not be construed as representing those of the Department of Energy or other federal agencies.

The energy projections that I will discuss today are widely used by government agencies, the private sector, and academia as a starting point for their own energy analyses. EIA prepares both short-term energy outlooks, examining monthly trends over the next one to two years, and long-term outlooks, with annual projections over the next 20-to-25 years. While I will be focusing primarily on the long-term outlooks in my remarks today, I would like to first summarize some key findings from our January *Short Term Energy Outlook*, which includes monthly forecasts through the end of 2012.

The short-term energy outlook

EIA's *Short-Term Energy Outlook* forecasts a continued tightening of world oil markets over the next 2 years. World oil consumption grows by an annual average of 1.5 million barrels per day through 2012 while the growth in supply from countries that are not members of the Organization of the Petroleum Exporting Countries (OPEC) averages less than 0.1 million barrels per day each year. Consequently, EIA expects the market will rely on both inventories and significant increases in the production of crude oil and non-crude liquids in OPEC member countries to meet world demand growth. While on-shore commercial oil inventories in the Organization for Economic Cooperation and Development (OECD) countries remained high last year, floating oil storage fell sharply in 2010, and projected OECD oil inventories decline over the forecast period. EIA expects that OPEC members' crude oil production will continue to rise over the next 2 years to accommodate increasing world oil consumption, especially with non-OPEC supplies expected to show limited growth. Projected OPEC crude oil production increases by 0.5 and 1.1 million barrels per day in 2011 and 2012, respectively.

Because of the projected tightening in world oil markets EIA expects the price of West Texas Intermediate (WTI) crude oil to average about $93 per barrel in 2011, $14 higher than the average price last year (**Figure 1**). For 2012, EIA expects WTI prices to continue to rise, with a forecast average price of $99 per barrel in the fourth quarter 2012. Energy price forecasts are, however, uncertain. Based on futures and options prices as of January 31, 2011, the probability that the monthly average price of WTI crude oil will exceed $110 per barrel in December 2011 is about 30 percent.

EIA expects regular-grade motor gasoline retail prices to average $3.17 per gallon this year, 39 cents per gallon higher than last year and $3.29 per gallon in 2012, with prices forecast to average about 5 cents per gallon higher in each year during the April through September peak driving season. There is regional variation in the forecast, with average expected prices on the West Coast about 25 cents per gallon above the national average during the April through September period. There is also significant uncertainty surrounding the forecast, with the current market prices of futures and options contracts for gasoline suggesting a 35 percent probability that the national average retail price for regular gasoline could exceed $3.50 per gallon during summer 2011 and about a 10 percent probability that it could exceed $4.00 per gallon.

Domestic natural gas production increased by an average 3.5 percent per year over the last 4 years, primarily because of the growth in production from unconventional shale gas resources. The growth in production has contributed to higher inventories, lower natural gas prices, and an increase in natural gas use in the electric power sector. The projected Henry Hub natural gas spot price averages $4.02 per million Btu for 2011, $0.37 per million Btu lower than the 2010 average (**Figure 2**). EIA expects the natural gas market to begin to tighten in 2012, with the Henry Hub spot price increasing to an average $4.50 per million Btu.

EIA estimates fossil-fuel CO2 emissions increased by 3.8 percent in 2010, after falling by 7.0 percent in 2009. Coal- and natural gas-related CO2 emissions rose as a result of increased usage of both fuels for electricity generation and higher consumption of natural gas in the industrial sector. Projected declines in coal and natural gas consumption in the electric power sector in 2011 more than offset increased consumption of petroleum in the transportation sector (i.e., motor gasoline, diesel fuel, and jet fuel). Consequently, forecast fossil-fuel CO2 emissions fall by 0.6 percent in 2011. The forecast resumption of growth in electricity generation and improvement in economic growth in 2012 contribute to a 2.4-percent increase in fossil-fuel CO2 emissions. Projected fossil-fuel CO2 emissions in 2012 remain below the levels seen since 1999 and 4.4 percent below 2005 emissions.

Long-term energy outlooks

International Energy Outlook. Before focusing on our U.S. Annual Energy Outlook, I want to briefly discuss some highlights of our *International Energy Outlook 2010* (*IEO2010*), which was issued last May. The *IEO2011* will be issued this spring. Although the *Annual Energy Outlook* focuses on our latest thoughts about domestic energy markets, it is useful to place this within a global context given the interconnectedness of U.S. energy markets and the broader global economy.

The United States accounted for one-fifth of the world's energy consumption in 2007, but this share is likely to decline over the next two decades. Global energy consumption will grow about 50 percent over the next 25 years, with most of the growth occurring outside of developed countries, in places like China, India, and the Middle East. Energy demand in non-OECD countries is expected to grow over 80 percent from 2007 levels, and by 2035 China will account for almost 25 percent of total world energy consumption. Renewables are the fastest-growing source of world energy supply, but under current market and technology trends fossil fuels are still expected to meet more than three-fourths of total energy needs in 2035, assuming current policies are unchanged.

Total global liquid fuels consumption projected for 2035 is 110.8 million barrels per day, which is 29 percent or 24.7 million barrels per day higher than the 2007 level of 86.1 million barrels per day. Conventional oil supplies from OPEC member countries contribute 11.0 million barrels per day to the total increase in world liquid fuels production from 2007 to 2035, and conventional supplies from non-OPEC countries add another 4.8 million barrels per day. World production of unconventional resources (including biofuels, oil sands, extra-heavy oil, coal-to-liquids, and gas-to-liquids), which totaled 3.4 million barrels per day in 2007, increases fourfold to 13.5 million barrels per day in 2035.

Natural gas consumption increases 44 percent globally over the projection period. Tight gas, shale gas, and coalbed methane supplies increase substantially in the *IEO2010* Reference case—especially from the United States, but also from Canada and China.

In the absence of additional national policies and/or binding international agreements that would limit or reduce greenhouse gas emissions, world coal consumption is projected to increase from 132 quadrillion Btu in 2007 to 206 quadrillion Btu in 2035, at an average annual rate of 1.6 percent. China alone accounts for 78 percent of the total net increase in world coal use from 2007 to 2035.

Annual Energy Outlook. Turning to the *Annual Energy Outlook 2011* (*AEO2011*), the Reference case discussed today was released in December 2010 and is intended to represent an energy future through 2035 based on given market, technological and demographic trends; current laws and regulations; and consumer behavior. EIA recognizes that projections of energy markets are highly uncertain and subject to geopolitical disruptions, technological breakthroughs, and other unforeseeable events. In addition, long-term trends in technology development, demographics, economic growth, and energy resources may evolve along a different path than represented in the projections. The complete *AEO2011*, which EIA will release this spring, will include a large number of alternative cases intended to examine these uncertainties.

EIA has made numerous updates in developing its *AEO2011* Reference case. Several notable changes from the *AEO2010* include (1) a significant update of the technically recoverable U.S. shale gas resources, more than doubling the volume of shale gas resources assumed in *AEO2010*; (2) an increase of the limit for blending ethanol into gasoline for approved vehicles from 10 percent to 15 percent; (3) incorporation of California's Low Carbon Fuel Standard and other State environmental rules; and (4) updates in several key technology assumptions, including the cost of new power plants and the cost and sizes of electric and plug-in hybrid electric batteries.

Economic growth

Real gross domestic product (GDP) grows by an average of 2.7 percent per year from 2009 to 2035 in the *AEO2011* Reference case, the same as in the *AEO2010* Reference case. The Nation's population, labor force, and productivity grow at annual rates of 0.9 percent, 0.7 percent, and 2.0 percent, respectively, from 2009 to 2035.

Beyond 2011, the economic assumptions underlying the *AEO2011* Reference case reflect trend projections that do not include short-term fluctuations. The near-term scenario for economic growth is consistent with that in EIA's October 2010 *Short-Term Energy Outlook*.

It is important to note that one must exercise care in evaluating percentage growth relative to 2009 levels throughout the projection results since 2009 was the low point of the economic downturn and associated energy consumption.

Energy prices

World oil prices declined sharply in the second half of 2008 from their peak in mid-July of that year. Real prices trended upward throughout 2009, and through November 2010 they remained generally in a range between $70 and $85 per barrel before climbing above $90 per barrel. Prices continue to rise gradually in the Reference case (**Figure 3**), as the world economy recovers and global demand grows more rapidly than liquids supplies from producers outside the Organization of the Petroleum Exporting Countries (OPEC). In 2035, the average real price of crude oil in the Reference case is $125 per barrel in 2009 dollars.

The *AEO2011* Reference case assumes that limitations on access to energy resources in resource-rich countries restrain the growth of non-OPEC conventional liquids production between 2009 and 2035, and that OPEC targets a relatively constant market share of total world liquids production (**Figure 4**). The degree to which non-OPEC and non-OECD countries restrict access to potentially productive resources contributes to world oil price uncertainty. Other factors causing uncertainty include OPEC investment decisions, which will affect future world oil prices and the economic viability of unconventional liquids. A wide range of price scenarios (from $50 per barrel to $200 dollars per barrel in 2035, in 2009 dollars) and discussion of the significant uncertainty surrounding future world oil prices will be included in the complete *AEO2011* publication.

Prices of motor gasoline and diesel in the *AEO2011* Reference case increase from $2.35 and $2.44 per gallon (all prices are in real 2009 dollars), respectively, in 2009 to $3.69 and $3.89 per gallon in 2035.

The price of natural gas at the wellhead is consistently lower in the *AEO2011* Reference case than it was in *AEO2010* (**Figure 5**), because of a revised representation of natural gas pricing and a significant increase in estimated technically recoverable shale gas resources. The annual average natural gas wellhead price remains under $5 per thousand cubic feet through 2022, but rises thereafter to meet growth in natural gas demand and to offset declines in natural gas production from other sources. As the shale gas resource base is developed, production gradually shifts to resources that are somewhat less productive and more expensive to produce. Natural gas wellhead prices (in 2009 dollars) reach $6.53 per thousand cubic feet in 2035, compared with $8.19 per thousand cubic feet in *AEO2010*.

The average U.S. minemouth coal price declines somewhat after 2010, as the share of higher-cost coal from mines in Appalachia declines. The Appalachian share of total coal production, on an energy content basis, declines from 40 percent in 2009 to 33 percent in 2016 and 29 percent in 2035.

The average, real delivered electricity price in the *AEO2011* Reference case falls from 9.8 cents per kilowatthour in 2009 to 8.9 cents per kilowatthour in 2016, reflecting continued low natural gas prices. Electricity prices tend to reflect trends in natural gas prices, because natural gas represents a large share of total fuel costs, and in competitive areas natural gas-fired plants often are the marginal generators. In the *AEO2011* Reference case, lower natural gas prices lead to lower electricity prices than in the *AEO2010* Reference case. Electricity prices in 2035 (in 2009 dollars) are 9.2 cents per kilowatthour in the *AEO2011* Reference case, compared with 10.3 cents per kilowatthour in the *AEO2010* Reference case.

Energy consumption

Total primary energy consumption, which was 101.7 quadrillion Btu in 2007, grows by 21 percent in the *AEO2011* Reference case, from 94.8 quadrillion Btu in 2009 to 114.3 quadrillion Btu in 2035, to about the same level as in the *AEO2010* projection in 2035 (**Figure 6**).

The energy intensity of the U.S. economy, measured as primary energy use (in Btu) per dollar of GDP (in 2005 dollars), declines by 40 percent from 2009 to 2035 in the *AEO2011* Reference case as the result of a continued shift from energy-intensive manufacturing to services, rising energy prices, and the adoption of policies that promote energy efficiency. Since 1992, the energy intensity of the U.S. economy has declined on average by 2 percent per year, in large part because the economic output of the service sectors, which use relatively less energy per dollar of output, has grown at a pace almost 6 times that of the industrial sector (in constant dollar terms). As a result, the share of total shipments accounted for by the industrial sectors fell from 31 percent in 1992 to 24 percent in 2009. In the *AEO2011* Reference case, the industrial share of total shipments continues to decline, but at a slower rate, to 21 percent in 2035.

Population is a key determinant of energy consumption, influencing demand for travel, housing, consumer goods, and services. The U.S. population increases by 27 percent from 2009 to 2035 in the *AEO2011* Reference case, and energy consumption grows by 21 percent over the same period. Energy consumption per capita declines somewhat as a result, declining by an average of 0.2 percent per year from 2009 to 2035 in the *AEO2011* Reference case.

The fossil fuel share of energy consumption falls from 84 percent of total U.S. energy demand in 2009 to 78 percent in 2035, reflecting rising fuel prices and the impacts of fuel economy standards and provisions in the American Recovery and Reinvestment Act of 2009 (ARRA), the Energy Improvement and Extension Act of 2008 (EIEA2008), the Energy Independence and Security Act of 2007 (EISA2007), and State legislation.

Total U.S. consumption of liquid fuels, including both fossil liquids and biofuels, grows from 18.8 million barrels per day in 2009 to 22.0 million barrels per day in 2035 in the *AEO2011* Reference case. The transportation sector dominates the demand for liquid fuels and its share (as measured by energy content) grows only slightly, from 72 percent of total liquids consumption in 2009 to 74 percent in 2035. *AEO2011* assumes the adoption of fuel economy standards for light-duty vehicles for model year 2011, as well as joint fuel economy and greenhouse gas emissions standards set forth by the EPA and NHTSA for model years 2012 through 2016. The fuel economy standards increase further through model year 2020 to meet the statutory requirements of EISA2007. The Reference case does not assume any further changes in fuel economy standards. Some ideas for further standards are discussed in the September 2010 EPA/NHTSA Notice of Upcoming Joint Rulemaking to Establish 2017 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions and Corporate Average Fuel Economy (CAFE) Standards. Nor does it include the proposed fuel economy standards for heavy-duty vehicles provided in *The Proposed Rule for Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles*, published by the EPA and the National Highway Traffic Safety Administration (NHTSA) in November 2010. Enactment of further binding standards would lower the projection for liquid fuels use.

Biofuels account for most of the growth in liquid fuels consumption, increasing by 1.8 million barrels per day from 2009 to 2035. The biofuel portion of 2035 liquid fuels consumption is 3.9 quadrillion Btu in *AEO2011*, about the same as in *AEO2010*. Although the situation is uncertain, EIA's present view of the projected rates of technology development and market penetration of cellulosic biofuel technologies suggests that available quantities of cellulosic biofuels will be insufficient to meet the renewable fuels standard (RFS) targets for cellulosic biofuels legislated in EISA2007 before 2022, triggering both waivers and a modification of applicable volumes, as provided in Section 211(o) of the Clean Air Act as amended in EISA2007.

In the *AEO2011* Reference case, natural gas consumption rises from 22.7 trillion cubic feet in 2009 to 26.5 trillion cubic feet in 2035. The total in 2035 is about 1.6 trillion cubic feet higher than in the *AEO2010* Reference case due to lower natural gas prices.

Total coal consumption, which was 22.7 quadrillion Btu in 2007, increases from 19.7 quadrillion Btu (1,000 million short tons) in 2009 to 25.2 quadrillion Btu (1,302 million short tons) in 2035 in the *AEO2011* Reference case. Coal consumption, mostly for electric power generation, grows gradually throughout the projection period, as existing plants are used more intensively, and a few new plants already under construction are completed and enter service. Coal consumption in the electric power sector in 2035 in the *AEO2011* Reference case is about 1.3 quadrillion Btu (53 million short tons) lower than in the *AEO2010* Reference case, however, as a result of higher levels of natural gas use for electric power generation due to relatively lower natural gas prices in the *AEO2011* Reference case.

Total consumption of marketed renewable fuels grows by 2.9 percent per year in the *AEO2011* Reference case. Growth in the consumption of renewable fuels results mainly from the implementation of the Federal RFS for transportation fuels and State renewable portfolio standard (RPS) programs for electricity generation. Marketed renewable fuels include wood, municipal waste, biomass, and hydroelectricity in the end-use sectors; hydroelectricity, geothermal, municipal waste, biomass, solar, and wind for generation in the electric power sector; and ethanol for gasoline blending and biomass-based diesel in the transportation sector. Excluding hydroelectricity, renewable energy consumption in the electric power sector grows from 113.6 billion kilowatthours in 2009 to 261.6billion kilowatthours in 2035.

Energy production and imports

Net imports of energy meet a major, but declining, share of total U.S. energy demand in the *AEO2011* Reference case. Energy imports decline due to increased domestic natural gas production, increased use of biofuels (much of which are produced domestically), and demand reductions resulting from the adoption of new efficiency standards and rising energy prices. The net import share of total U.S. energy consumption in 2035 is 18 percent, compared with 24 percent in 2009. The share was 29 percent in 2007, but it dropped considerably during the recession.

Oil and other liquids

U.S. dependence on imported liquid fuels, measured as a share of total U.S. liquid fuel use, reached 60 percent in 2005 and 2006 before falling to 52 percent in 2009. The liquids import share continues to decline over the projection period, to 42 percent in 2035 (**Figure 7**).

In the *AEO2011* Reference case, U.S. domestic crude oil production increases from 5.4 million barrels per day in 2009 to 5.7 million barrels per day in 2035. Production increases are expected from onshore enhanced oil recovery (EOR) projects, shale oil plays, and deepwater drilling in the Gulf of Mexico. Cumulatively, oil production in the lower 48 States in the *AEO2011* Reference case is approximately the same as in the *AEO2010* Reference case, but the pattern differs in that more onshore and less offshore oil is produced in *AEO2011*.

Onshore oil production is higher in *AEO2011* as a result of an increase in EOR, as well as increased shale oil production, for which the resource estimate has been increased relative to *AEO2010*. In *AEO2011*, EOR accounts for 33 percent of cumulative onshore oil production. The bulk of the EOR production uses CO2. For CO2 EOR oil production, naturally produced CO2 or man-made CO2 captured from sources such as natural gas plants and power plants is injected into a reservoir to allow the oil to flow more easily to the well bore.

Offshore oil production in *AEO2011* is lower than in *AEO2010* throughout most of the projection period because of expected delays in near-term projects, in part as a result of drilling moratoria and associated regulatory changes, and in part due to the change in lease sales expected in the Pacific and Atlantic outer continental shelf (OCS), as well as increased uncertainty about future investment in offshore production.

As with natural gas, the application of horizontal drilling together with hydrofracturing techniques have allowed significant increases in the development of shale oil resources (oil resident in shale rock). With *AEO2011* incorporating five key shale oil plays (as opposed to two in *AEO2010*), oil production rises significantly in areas of the country where shale oil is being produced, including the Rocky Mountains (primarily from the Bakken shale), the Gulf Coast (primarily from the Eagle Ford and Austin Chalk plays), the Southwest (primarily from the Avalon play), and California (primarily from the Lower Monterey and Santos plays).

Natural gas

The emerging role of shale gas resources highlights the outlook for natural gas supply. Cumulative U.S. natural gas production increases by 25 percent over the 2009-2035 projection period in the *AEO2011* Reference case as a result of greater supply availability from shale gas plays (**Figure 8**). The higher shale gas production and a higher rate of development results from the addition of shale gas resources in existing plays that can be produced at prices under $7 per thousand cubic feet.

In the *AEO2010* Reference case, technically recoverable unproved shale gas resources were estimated at 347 trillion cubic feet; in the *AEO2011* Reference case they are estimated at 827 trillion cubic feet. The revised estimate results from the availability of additional information as more drilling activity takes place in both existing and new shale plays. U.S. shale gas production has increased 14-fold over the last decade, and reserves have tripled over the last few years (**Figure 9**).

As a result of updated shale gas resources in existing plays (key additions were in the Marcellus, Haynesville, and Eagle Ford plays) and an assumption of increased well productivity for the newer plays, shale gas production in 2035 in the *AEO2011* Reference case is almost double that in the *AEO2010* Reference case.

There is considerable uncertainty about the amounts of recoverable shale gas in both developed and undeveloped areas. Well characteristics and productivity vary widely not only across different plays but within individual plays. Initial production rates can vary by as much as a factor of 10 across a formation, and the productivity of adjacent gas wells can vary by as much as a factor of 2 or 3. Many shale formations, such as the Marcellus Shale, are so large that only a small portion of the entire formation has been intensively production-tested. Environmental considerations, particularly with respect to water, lend additional uncertainty. Although significant updates have been made to the estimates of undiscovered shale gas resources in newer areas, most of the resulting additions are not economically recoverable at *AEO2011* prices and have little, if any, impact on the projection.

The Alaska natural gas pipeline, expected to be completed in 2023 in the *AEO2010* Reference case, is not constructed in the *AEO2011* Reference case. This change is a result of increased capital cost assumptions and lower natural gas wellhead prices, which hurt the economics of the project over the projection period. Total U.S. net imports of natural gas in the *AEO2011* Reference case are lower than in the *AEO2010* Reference case (**Figure 10**), due in part to stronger North American production, less world liquefaction capacity than previously assumed, and increased use of LNG in markets outside North America.

Coal

Although coal remains the leading fuel for U.S. electricity generation, its share of total electricity generation is consistently lower in the *AEO2011* Reference case than in the *AEO2010* Reference case through about 2023 (but similar thereafter). As a consequence, total coal production is slightly lower in the *AEO2011* Reference case than in the *AEO2010* Reference case.

As U.S. coal use grows, domestic coal production increases at an average rate of 0.7 percent per year, from 21.6 quadrillion Btu (1,075 million short tons) in 2009 to 25.8 quadrillion Btu (1,305 million short tons) in 2035. Production from mines west of the Mississippi River trends upward over the entire projection period. Following a substantial decline in output between 2009 and

2015, coal production east of the Mississippi River remains relatively constant from 2015 through 2035. On a Btu basis, 60 percent of domestic coal production originates from States west of the Mississippi River in 2035, up from 50 percent in 2009.

Typically, trends in U.S. coal production are linked to its use for electricity generation, which currently accounts for 93 percent of total coal consumption. Coal consumption in the electric power sector in the *AEO2011* Reference case (21.8 quadrillion Btu in 2035) is about 1.3 quadrillion Btu less than in the *AEO2010* Reference case (23.1 quadrillion Btu in 2035). For the most part, the reduced outlook for coal consumption in the electricity sector is the result of lower natural gas prices that support increased generation from natural gas in the *AEO2011* Reference case.

Electricity generation

Total electricity consumption, including both purchases from electric power producers and on-site generation, grows 30 percent, from 3,745 billion kilowatthours in 2009 to 4,880 billion kilowatthours in 2035 in the *AEO2011* Reference case, increasing at an average annual rate of 1.0 percent (**Figure 11**). The growth in electricity consumption continues to slow due to structural change in the economy away from manufacturing and more stringent appliance efficiency standards. The growth rate in the *AEO2011* Reference case is about the same as in the *AEO2010* Reference case.

Although the mix of investments in new power plants includes fewer coal-fired plants than other fuel technologies, a total of 21 gigawatts of coal-fired generating capacity is added from 2009 to 2035 in the *AEO2011* Reference case. Coal remains the single largest energy source for electricity generation (**Figure 12**) because of continued reliance on existing coal-fired plants and the addition of some new plants in the absence of an explicit Federal policy to reduce greenhouse gas emissions. Concerns about greenhouse gas emissions continue to slow the expansion of coal-fired capacity in the *AEO2011* Reference case, even under current laws and policies. Lower projected fuel prices for new natural gas-fired plants also affect the relative economics of coal-fired capacity, as does the continued rise in construction costs for new coal-fired power plants. Total coal-fired generating capacity grows to 330 gigawatts in 2035 in the *AEO2011* Reference case.

Compared with the *AEO2010* Reference case, electricity generation from natural gas is higher in the *AEO2011* Reference case, particularly over the next 10 years, during which natural gas prices remain low. New natural gas-fired plants are also much cheaper to build than new renewable or nuclear plants.

Nuclear generating capacity in the *AEO2011* Reference case increases from 101 gigawatts in 2009 to 111 gigawatts in 2035, with 6.3 gigawatts of new capacity (5 new plants) and the balance coming from rerated capacity. Electricity generation from nuclear power plants grows 10 percent, from 799 billion kilowatthours in 2009 to 879 billion kilowatthours in 2035, accounting for about 17 percent of total generation in 2035 (compared with 20 percent in 2009). Higher construction costs for new nuclear plants in *AEO2011*, along with lower projected natural gas prices, make new nuclear capacity slightly less attractive than was projected in the *AEO2010* Reference case.

Increased renewable energy consumption in the electric power sector, excluding hydropower, accounts for 23 percent of the growth in electricity generation from 2009 to 2035. Generation from renewable resources grows in response to key Federal tax credits, but it is lower in the *AEO2011* Reference case than in the *AEO2010* Reference case because of lower natural gas prices and somewhat higher costs for new wind power plants. The drop in renewable generation relative to *AEO2010* is seen primarily in lower projections for wind and biomass generation. Growth in renewables is also supported by the many State requirements for renewable generation. The share of generation coming from renewable fuels (including conventional hydro) grows from 11 percent in 2009 to 14 percent in 2035. In the *AEO2011* Reference case, federal tax credits for renewable generation are assumed to expire as enacted. Extension of these tax credits could have a large impact on renewable generation.

Energy-related carbon dioxide emissions

After falling by 3 percent in 2008 and nearly 7 percent in 2009, largely driven by the economic downturn, projected U.S. energy-related CO2 emissions in the AEO2011 Reference case do not return to 2005 levels (5,980 million metric tons) until 2027, and then rise by an additional 5 percent from 2027 to 2035, reaching 6,315 million metric tons in 2035 (**Figure 13**). Energy-related CO2 emissions grow by 0.2 percent per year from 2005 to 2035. Emissions per capita fall by an average of 0.8 percent per year from 2005 to 2035, as growth in demand for electricity and transportation fuels is moderated by higher energy prices, efficiency standards, State RPS requirements, and Federal CAFE standards.

Energy-related CO2 emissions reflect the share of fossil fuels in energy as well as the mix of fossil fuels consumed, because of their different carbon contents. Given the relatively high carbon content of coal and its current use to generate more than one-half of the U.S. electricity supply, prospects for CO2 emissions depend in part on growth in electricity demand. After a decline from 2007 to 2009, electricity sales resume growth in 2012 in the *AEO2011* Reference case, but the growth is tempered by a variety of regulatory and socioeconomic factors, including appliance and building efficiency standards, higher energy prices, shifts in housing growth, and the continued transition to a more service-oriented economy. With modest electricity demand growth and increased use of renewables for electricity generation influenced by RPS laws in many States, electricity-related CO2 emissions grow by 18 percent from 2009 to 2035. Growth in CO2 emissions from transportation activity also slows in comparison with the recent pre-recession experience, as Federal CAFE standards increase the efficiency of the vehicle fleet, employment recovers slowly, and higher fuel prices moderate growth in travel.

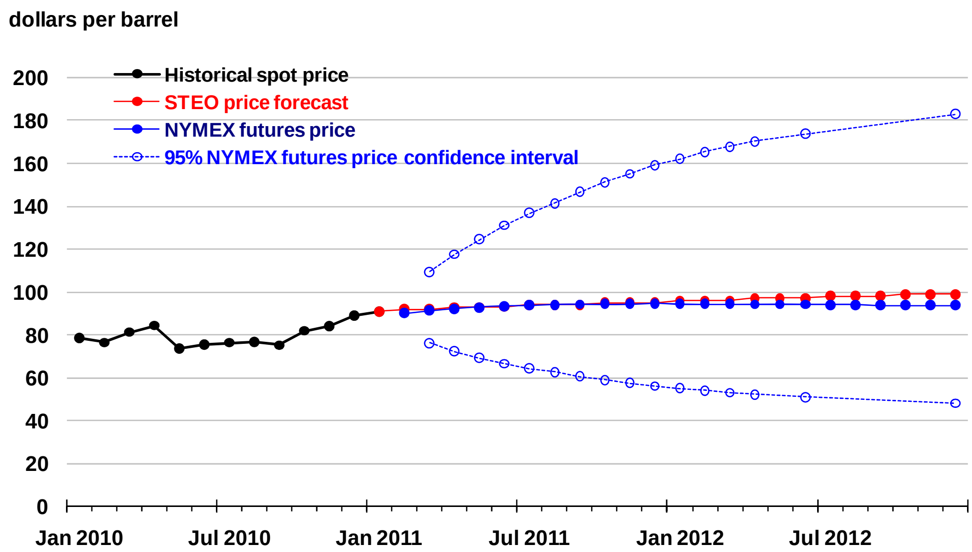
Taken together, these factors tend to slow the growth in primary energy consumption and CO2 emissions. As a result, energy-related CO2 emissions grow by 16 percent from 2009 to 2035—lower than the 21-percent increase in total energy use. Over the same period, the economy becomes less carbon-intensive, as energy-related CO2 emissions per dollar of GDP decline by 42 percent.

Conclusion

As I noted at the outset, while EIA does not take policy positions, its data, analyses, and projections are meant to assist policymakers in their energy deliberations. In addition to the work on baseline projections that I have reviewed this morning, EIA has often responded to requests from this Committee and others for analyses of the energy and economic impacts of energy policy proposals. We look forward to providing whatever further analytical support that you may require on energy-related topics.

This concludes my testimony, Mr. Chairman and members of the Committee. I would be happy to answer any questions you may have.

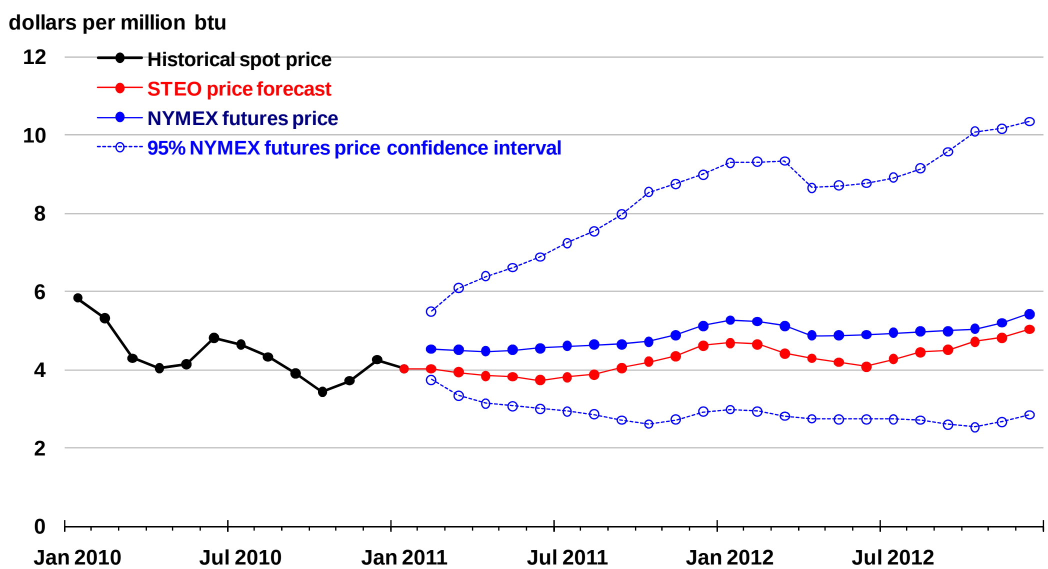
Figure 1. West Texas intermediate crude oil price



Note: Confidence interval derived from options market information for the 5 trading days ending January 6, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: EIA, *STEO January 2011*

Figure 2. Henry Hub natural gas price



Note: Confidence interval derived from options market information for 5 trading days ending January 6, 2011
Intervals not calculated for months with sparse trading in "near-the-money" options contracts

Source: EIA, *STEO January 2011*

Figure 3. Oil prices in the Reference case rise steadily; the full *AEO2011* explores a range of cases

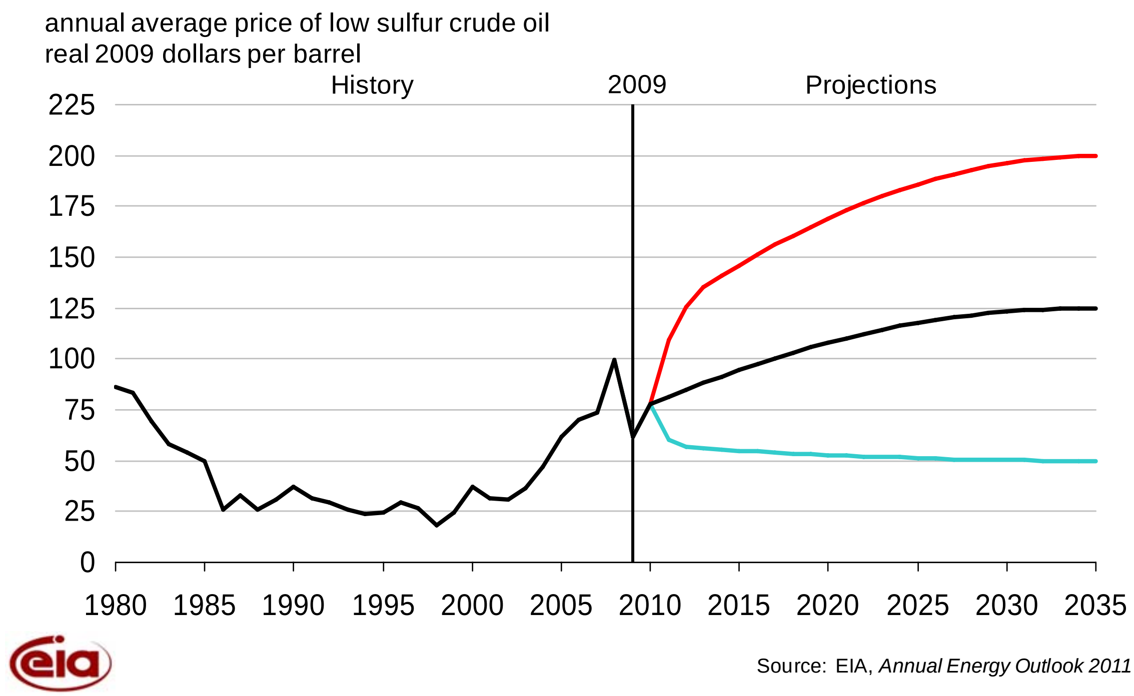


Figure 4. Unconventional liquids sources triple globally; conventional petroleum remains the predominant source of global liquids supply

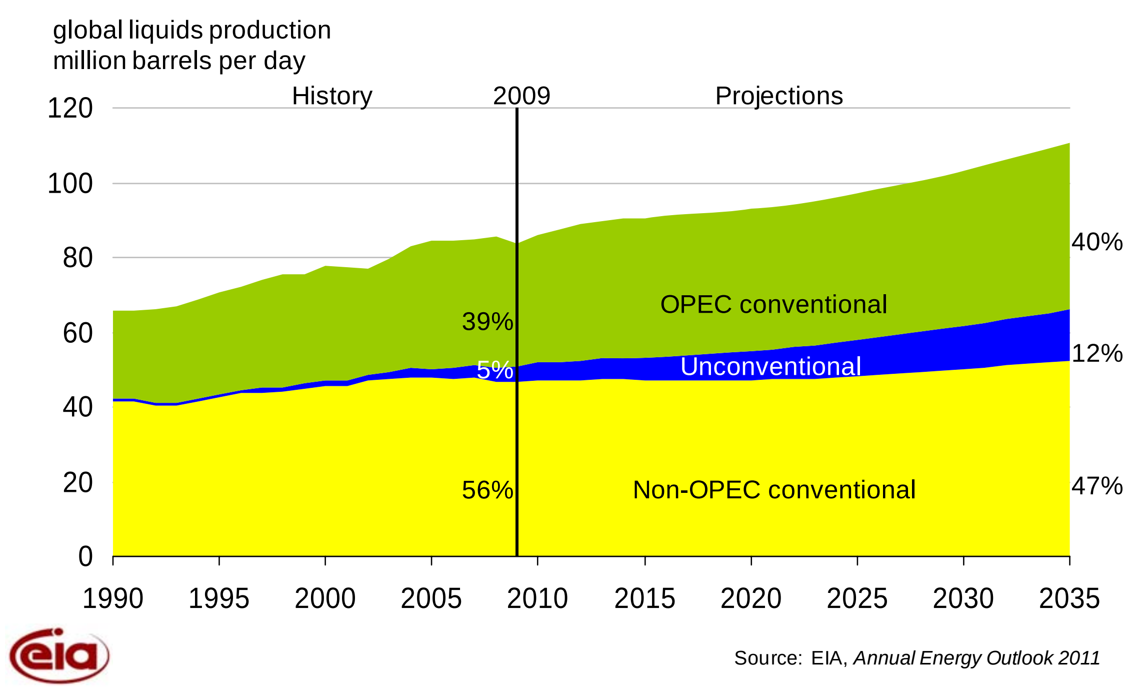


Figure 5. Natural gas price projections are lower due to an expanded shale gas resource base

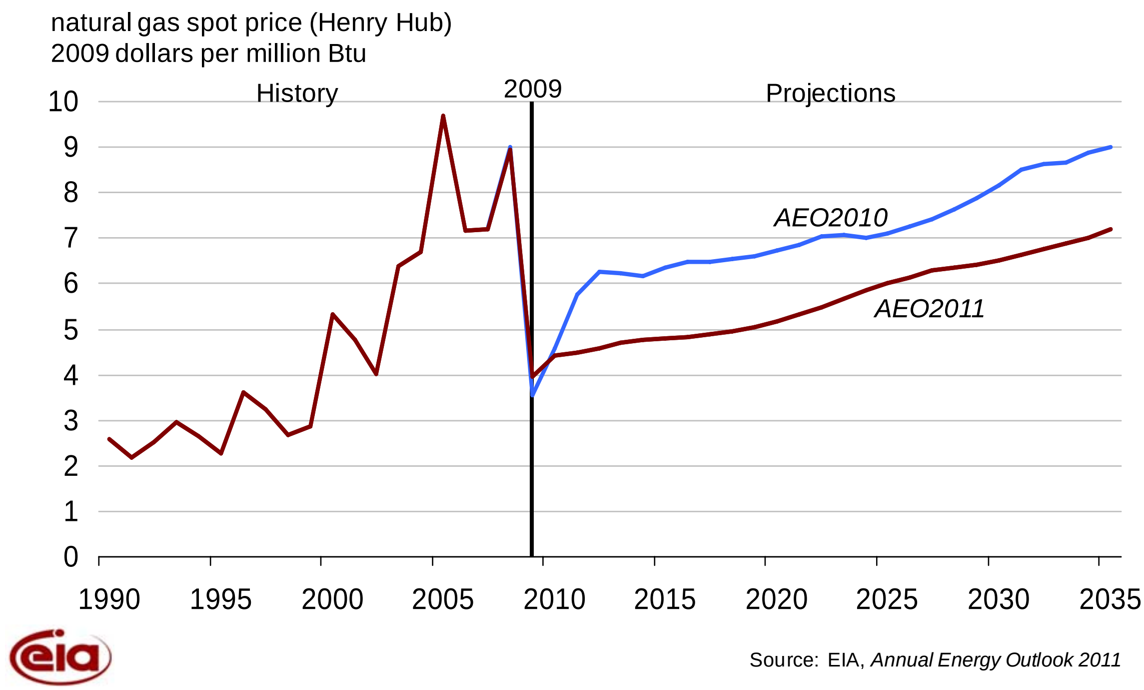


Figure 6. Renewables grow rapidly, but fossil fuels still provide 78 percent of U.S. energy use in 2035

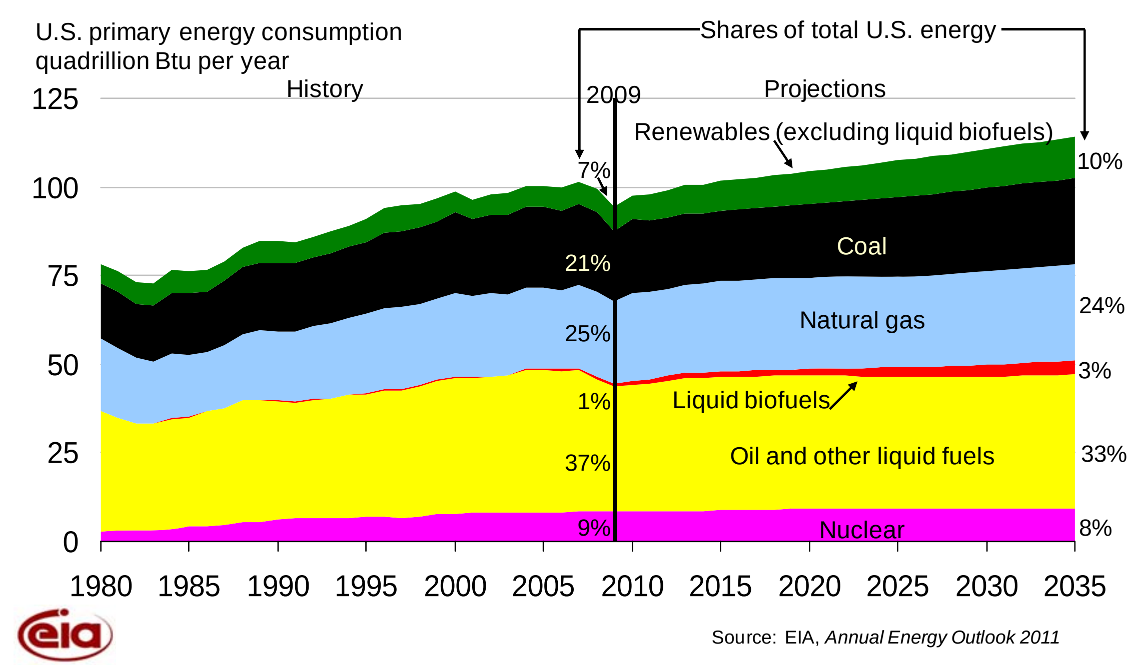


Figure 7. U.S. imports of liquid fuels fall due to increased domestic production—including biofuels—and greater fuel efficiency

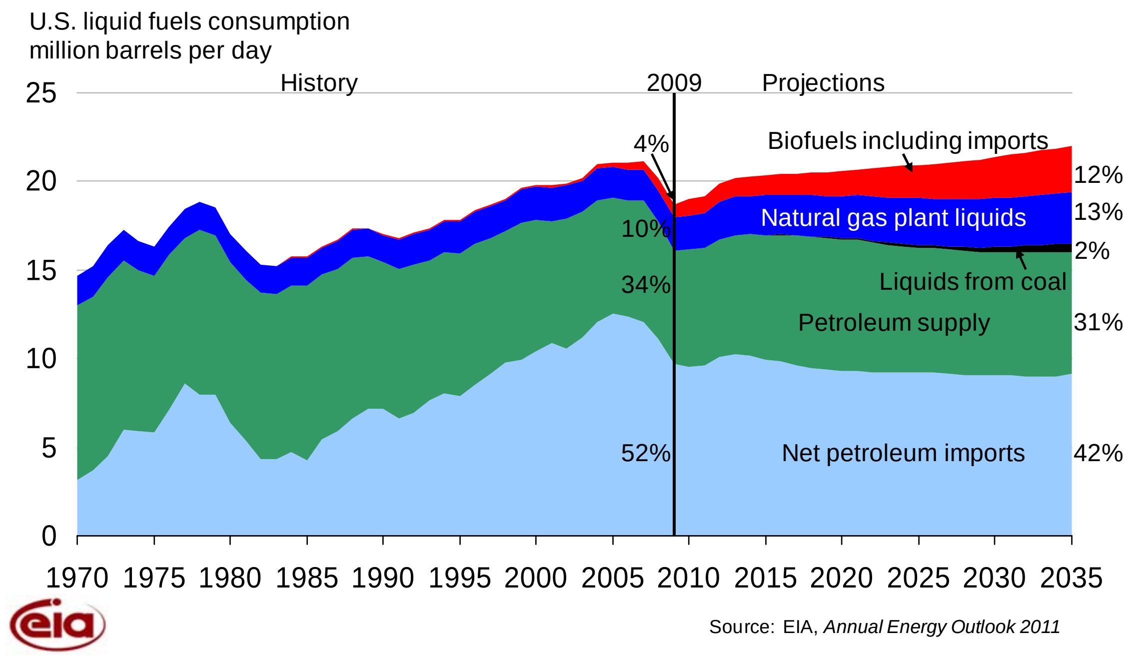


Figure 8. Shale gas more than offsets the declines in other U.S. natural gas supply sources

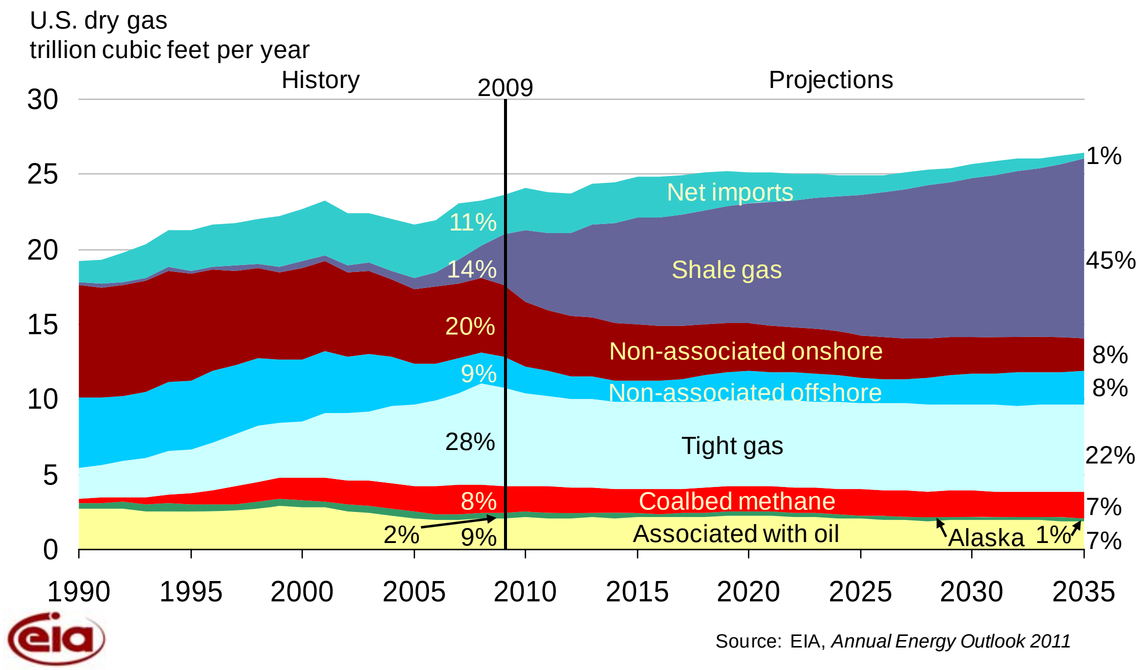


Figure 9. U.S. shale gas production increases 14-fold over the last decade; reserves tripled over the last few years

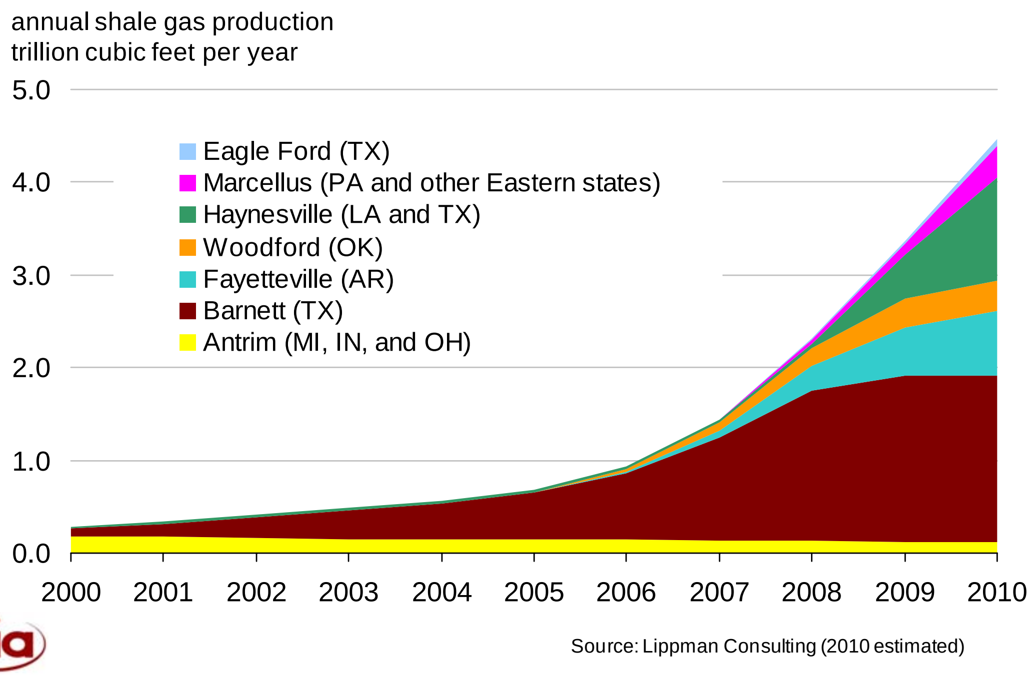


Figure 10. Domestic natural gas production growth outpaces consumption; net imports decline

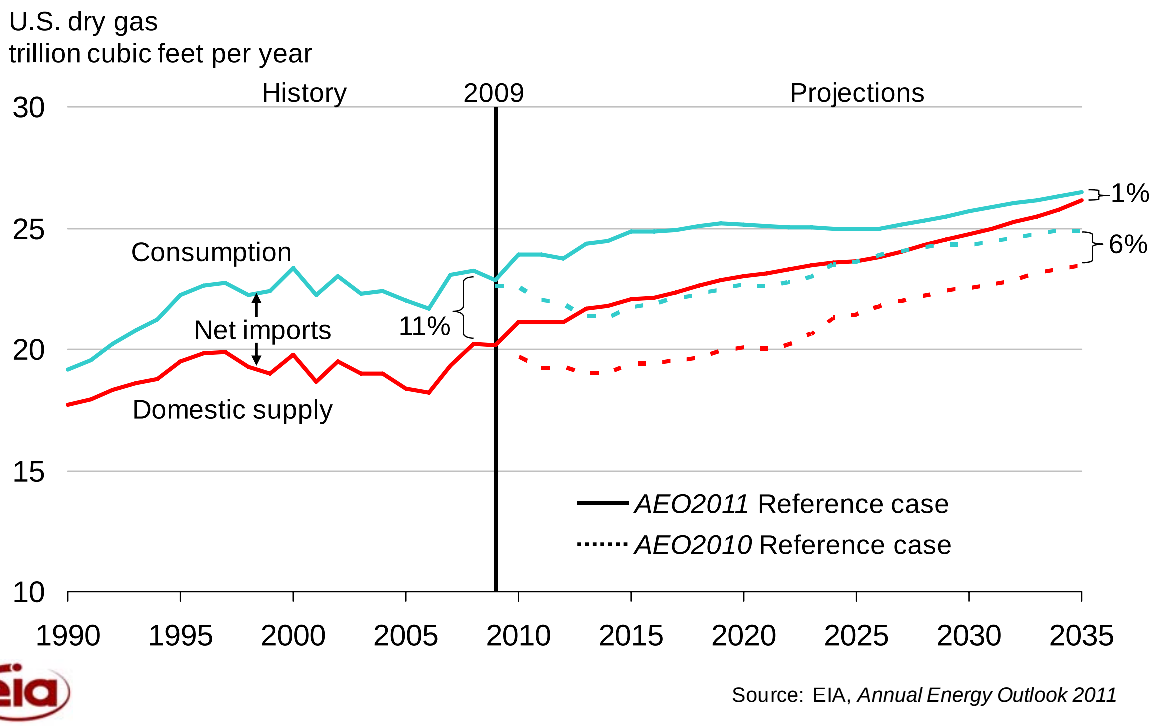


Figure 11. Electricity consumption growth slows to 1 percent a year, a cumulative increase of 30-percent by 2035

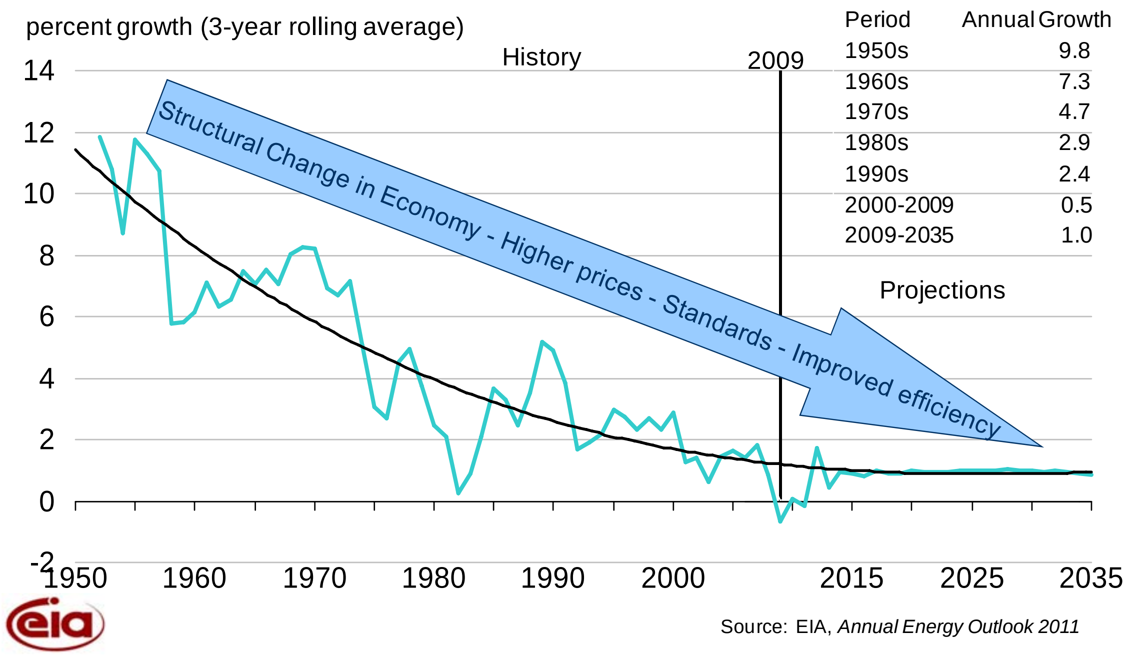


Figure 12. The electricity mix shifts to lower-carbon options by 2035, with natural gas generation rising 37 percent and renewables rising 73 percent

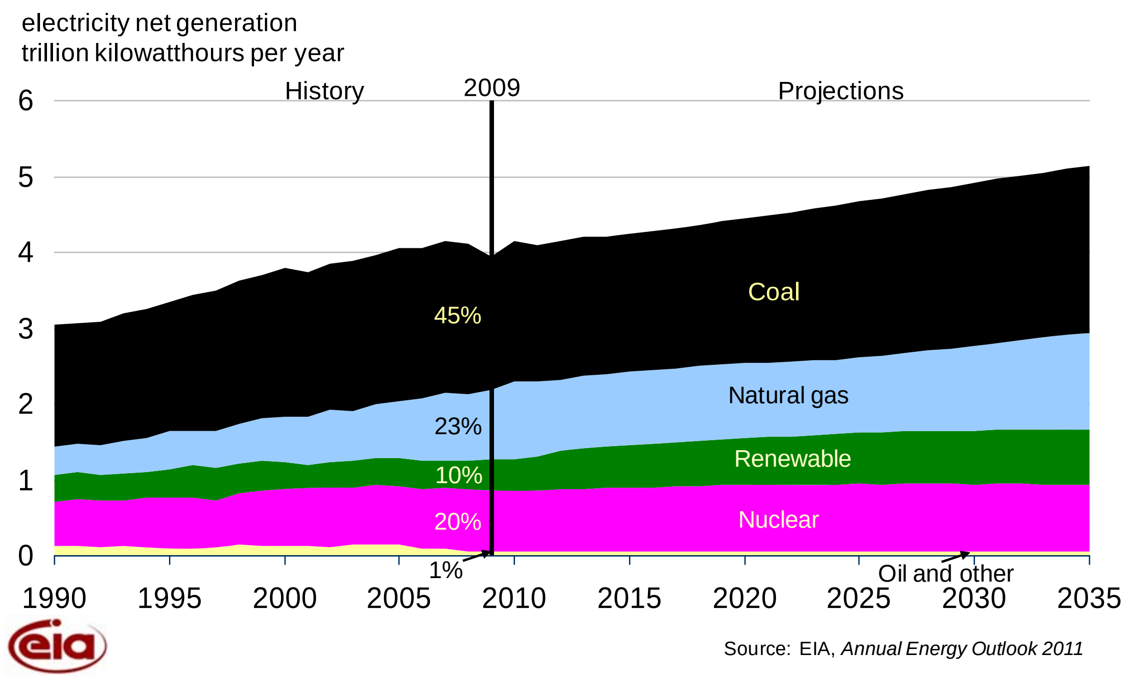
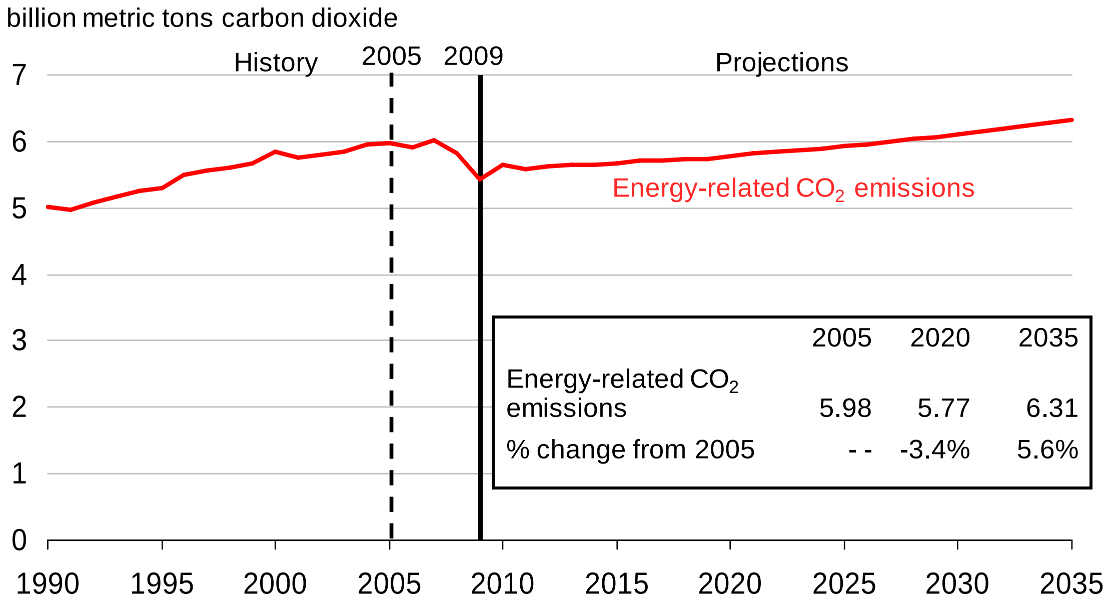


Figure 13. Energy-related carbon dioxide emissions grow almost 6 percent over 2005 levels by 2035



Source: EIA, *Annual Energy Outlook 2011*