Introduction

This report presents the major assumptions of the National Energy Modeling System (NEMS) used to generate the projections in the *Annual Energy Outlook2011* [1] (*AEO2011*), including general features of the model structure, assumptions concerning energy markets, and the key input data and parameters that are the most significant in formulating the model results. Detailed documentation of the modeling system is available in a series of documentation reports [2].

The National Energy Modeling System

The projections in the *AEO2011* were produced with the (NEMS), which is developed and maintained by the Office of Energy Analysis of the Energy Information Administration (EIA) to provide projections of domestic energy-economy markets in the long term and perform policy analyses requested by decisionmakers at the White House, U.S. Congress, offices within the Department of Energy (DOE), including DOE Program Offices, and other government agencies. The *Annual Energy Outlook* (*AEO*) projections are also used by analysts and planners in other government agencies and outside organizations.

The time horizon of NEMS is approximately 25 years, the period in which the structure of the economy and the nature of energy markets are sufficiently understood that it is possible to represent considerable structural and regional detail. Because of the diverse nature of energy supply, demand, and conversion in the United States, NEMS supports regional modeling and analysis in order to represent the regional differences in energy markets, to provide policy impacts at the regional level, and to portray transportation flows. The level of regional detail for the end-use demand modules is the nine Census divisions. Other regional structures include production and consumption regions specific to oil, natural gas, and coal supply and distribution, the North American Electric Reliability Council (NERC) regions and subregions for electricity, and the Petroleum Administration for Defense Districts (PADDs) for refineries. Maps illustrating the regional formats used in each module are included in this report. Only selected regional results are presented in the *AEO2011*, which predominately focuses on the national results. Complete regional and detailed results are available on the EIA Analyses and Projections Home Page (http://www.eia.gov/forecasts/aeo/)

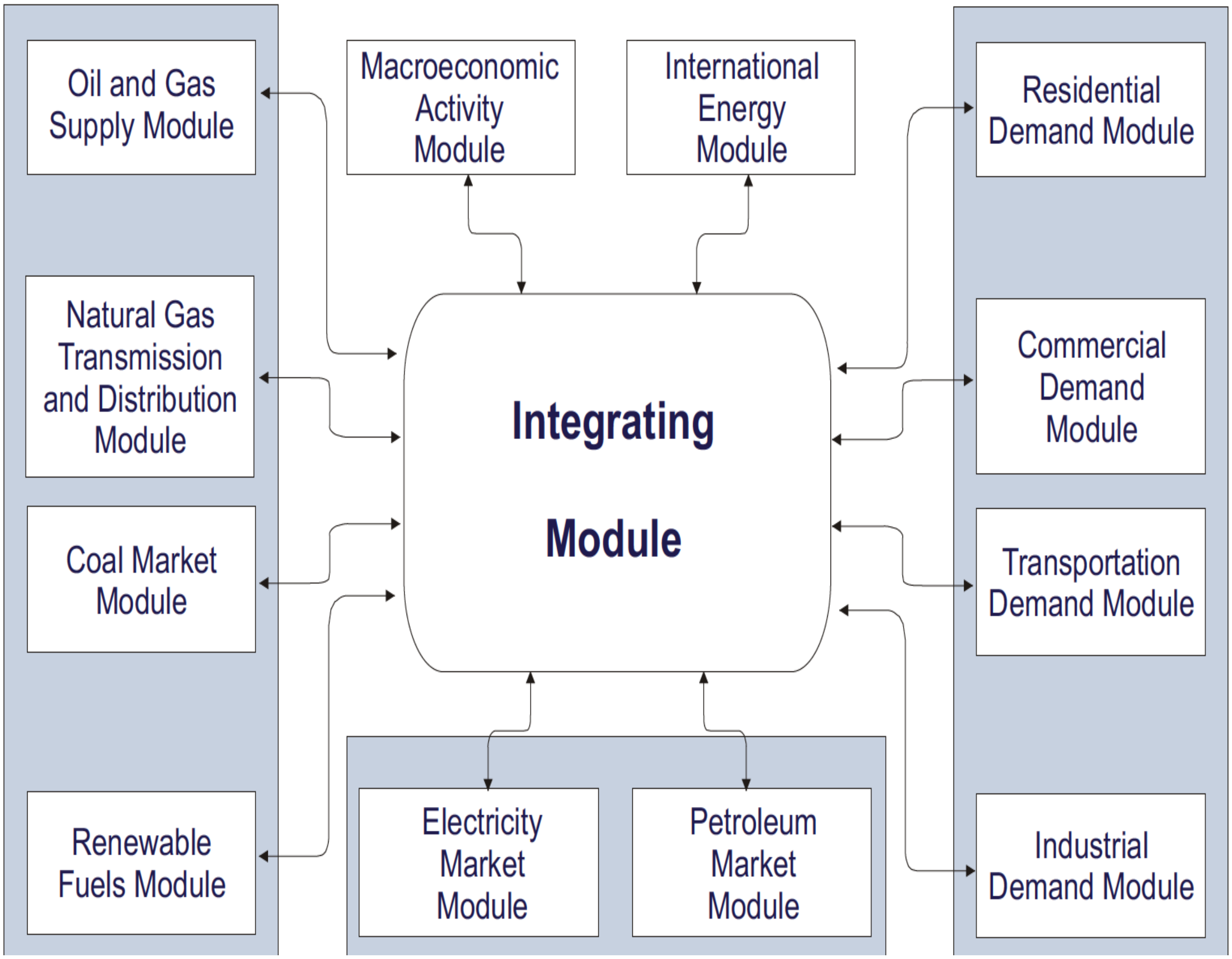
For each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. NEMS is organized and implemented as a modular system (Figure 1). The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes a macroeconomic and an international module. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered prices of fuel encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data such as economic activity, domestic production, and international petroleum supply availability.

The integrating module of NEMS 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 storage location. 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. This modularity allows use of the methodology and level of detail most appropriate for each energy sector. NEMS solves by calling 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. Solution is reached annually through the projection horizon. Other variables are also evaluated for convergence such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component also represents the impact and cost of Federal legislation and regulations that affect the sector and reports key emissions. 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 (CAMR), 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 nitrous oxide (NOx) and sulfur dioxide (SO2) 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. A list of the specific Federal and selected State legislation and regulations included in the *AEO*, including how they are incorporated, is provided in Appendix A.

Figure 1. National Energy Modeling System



Source: U.S. Energy Information Administration, Office of Energy Analysis

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices of energy delivered to the consuming sectors and the quantities of end-use energy consumption. This section provides brief summaries of each of the modules.

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. 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 (in Petroleum Administration for 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 2009 and 2010 consensus agreements 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 (DG). 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.

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, new coal-to-liquids (CTL), and coal and biomass-to-liquids (CBTL) plants without carbon capture and storage (CCS).

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 [3] 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, CBTL, 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.

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*.

Cases for the *Annual Energy Outlook 2011*

In preparing projections for the *AEO2011*, EIA evaluated a wide range of trends and issues that could have major implications for U.S. energy markets between now and 2035. Besides the Reference case, the *AEO2011* presents detailed results for six alternative cases that differ from each other due to fundamental assumptions concerning the domestic economy and world oil market conditions. These alternative cases include the following:

- Economic Growth - In the Reference case, real GDP grows at an average annual rate of 2.7 percent from 2009 through 2035, supported by a 2.0 percent per year growth in productivity in nonfarm business, a 1.0 percent per year growth in nonfarm employment, and population growth of 0.9 percent per year. In the High Economic Growth case, real GDP is projected to increase by 3.2 percent per year, with population growth of 1.2 percent per year and productivity and nonfarm employment growing at 2.4 percent and 1.4 percent per year, respectively. In the Low Economic Growth case, the average annual growth in GDP, population, productivity, and nonfarm employment is 2.1, 0.6, 1.6 and 0.7 percent per year, respectively.
- Price Cases - For purposes of the *AEO2011*, the world oil price is defined as the average price of light, low-sulfur crude oil delivered in Cushing, Oklahoma, and is similar to the price of light, sweet crude oil traded on the New York Mercantile Exchange. 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 four alternative oil price cases (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 Organisation for Economic Co-operation 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.

  - 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.

In addition to these cases, 49 additional alternative cases presented in Table 1.1 explore the impact of changing key assumptions on individual sectors. Many of the side cases were designed to examine the impacts of varying key assumptions for individual modules or a subset of the NEMS modules, and thus the full market consequences, such as the consumption or price impacts, are not captured. In a fully integrated run, the impacts would tend to narrow the range of the differences from the reference case. For example, the Best Available Technology case for the residential sector assumes that all future equipment purchases are made from a selection of the most efficient technologies available in a particular year. In a fully integrated NEMS run, the lower resulting fuel consumption would have the effect of lowering the market prices of those fuels with the concomitant impact increasing economic growth, thus stimulating some additional consumption. The results of single model or partially integrated cases should be considered the maximum range of the impacts that could occur with the assumptions defined for the case.

Table 1.1. Summary of *AEO2011* cases

Case name	Description	Integration Mode
Reference	Baseline economic growth (2.7 percent per year from 2009 through 2035), world oil price, and technology assumptions. 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.	Fully integrated
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.	Fully integrated
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-OPEC 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.	Fully integrated
Traditional Low Oil Price	More optimistic assumptions for economic access to non-OPEC resources and OPEC production decisions than in the Reference case. Prices are the same as those used in the Low Oil Price case.	Fully integrated
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.	Fully integrated
Traditional High Oil Price	More pessimistic assumptions for economic access to non-OPEC resources and OPEC production decisions than in the Reference case. Prices are the same as those used in the High Oil Price case.	Fully integrated
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.	Fully integrated
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.	Fully integrated
Residential and commercial: Expanded Standards	Begins with Reference case assumptions for energy 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.	Residential and commercial only
Residential and Commercial: Expanded Standards and Codes	Begins with Expanded Standards case and adds multiple rounds of national building codes by 2026.	Residential and commercial only
Residential: 2010 Technology	Future equipment purchases based on equipment available in 2009. New and existing building shell efficiencies fixed at 2009 levels.	With commercial
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.	With commercial
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.	With commercial
Commercial: 2010 Technology	Future equipment purchases based on equipment available in 2010. Building shell efficiencies fixed at 2010 levels.	With residential

Table 1.1. Summary of *AEO2011* cases (cont.)

Case name	Description	Integration Mode
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.	With residential
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.	With residential
Industrial 2010 Technology	Efficiencies of plant and equipment fixed at 2010 levels.	Standalone
Industrial High Technology	Earlier availability, lower costs, and higher efficiencies for more advanced quipment.	Standalone
Transportation: Low Technology	Advanced technologies are more costly and less efficient than in the Reference case.	Standalone
Transportation: High Technology	Advanced technologies are less costly and more efficient than in the Reference case.	Standalone
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.	Fully integrated
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.	Fully integrated
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.	Fully integrated
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.	Fully integrated
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.	Fully integrated
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.	Fully integrated
Electricity High Nuclear Costs	Costs for new nuclear technology do not improve due to learning from 2011 levels in the Reference case.	Fully integrated
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.	Fully integrated
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.	Fully integrated
Electricity: Transport Rule Mercury MACT 5	Assumes that the Transport Rule limits SO2 and NOx emissions and requires use of a 90-percent mercury maximum achievable control technology (MACT). A 5-year capital recovery period is assumed for the retrofits.	Fully integrated
Electricity: Transport Rule Mercury MACT 20	Same environmental rules as above, but assuming a 20-year capital recovery period for retrofits.	Fully integrated
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.	Fully integrated

Table 1.1. Summary of *AEO2011* cases (cont.)

Case name	Description	Integration mode
Electricity; Retrofit Required 20	Same requirements on environmental controls as above, but assuming a 20-year capital recovery period for retrofits.	Fully Integrated
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 Estimated Ultimate Recovery (EUR) case described below.	Fully Integrated
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 EUR case described below.	Fully Integrated
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.	Fully Integrated
Renewable Fuels: High Renewable Technoloy Cost	Costs for new non-hydropower 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.	Fully integrated
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.	Fully integrated
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	Fully integrated
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.	Fully integrated
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.	Fully integrated
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.	Fully integrated
Oil and Gas: Low Shale EUR	EUR per shale gas well is assumed to be 50 percent lower than in the Reference case.	Fully integrated
Oil and Gas: High Shale EUR	EUR per shale gas well is assumed to be 50 percent higher than in the Reference case.	Fully integrated
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.	Fully integrated
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.	Fully integrated
Oill and Gas: Low E15 Penetration	Consumers and retailers adopt E15 at a minimal rate in States that do not prohibit E15 blends.	Fully integrated
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.	Fully integrated
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.	Fully Integrated

Table 1.1. Summary of *AEO2011* cases (cont.)

Case name	Description	Integration mode
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.	Fully Integrated
Integrated Low 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.	Fully Integrated
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	Fully Integrated
No GHG Concern	No GHG emissions reduction policy is enacted, and market investment decisions are not altered in anticipation of such a policy	Fully Integrated
GHG Price Economywide	Applies a price for CO2 emissions throughout the economy. The CO2 price assumed starts at $25 per ton beginning in 2013 and increases to $75 per ton in 2035.	Fully integrated
Low EOR	The quantity of CO2 available for CO2-enhanced oil recovery (EOR) from industrial sources with high-purity CO2 emissions is reduced from the Reference case. All other assumptions are the same as the Reference case.	Fully integrated
Low EOR/GHG Price Economywide	Same as the Low EOR case but with the same carbon price as in the GHG Price Economywide case.	Fully integrated

Carbon dioxide emissions

Carbon dioxide emissions from energy use are dependent on the carbon content of the fossil fuel, the fraction of the fuel consumed in combustion, and the consumption of that fuel. The product of the carbon content at full combustion and the combustion fraction yields an adjusted carbon emission factor for each fossil fuel. The emissions factors are expressed in millions of metric tons of carbon dioxide emitted per quadrillion Btu of energy use, or equivalently, in kilograms of carbon dioxide per million Btu. The adjusted emissions factors are multiplied by the energy consumption of the fossil fuel to arrive at the carbon dioxide emissions projections.

For fuel uses of energy, all of the carbon is assumed to be oxidized, so the combustion fraction is equal to 1.0 (in keeping with a recent change in international conventions). Previously, a small fraction of the carbon content of the fuel was assumed to remain unoxidized. The carbon in nonfuel use of energy, such as for asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere. For energy categories that are mixes of fuel and nonfuel uses, the combustion fractions are based on the proportion of fuel use. In calculating carbon dioxide emissions for motor gasoline, the direct emissions from renewable blending stock (ethanol) is omitted. Similarly, direct emissions from biodiesel are omitted from reported carbon dioxide emissions.

Any carbon dioxide emitted by biogenic renewable sources, such as biomass and alcohols, is considered balanced by the carbon dioxide sequestration that occurred in its creation. Therefore, following convention, net emissions of carbon dioxide from biogenic renewable sources are assumed to be zero in reporting energy-related carbon dioxide emissions; however, to illustrate the potential for these emissions in the absence of any offsetting sequestration, as might occur under related land use change, the carbon dioxide emissions from biogenic fuel use are calculated and reported separately.

Table 1.2 presents the assumed carbon dioxide coefficients at full combustion, the combustion fractions, and the adjusted carbon dioxide emission factors used for *AEO2011*.

Table 1.2. Carbon dioxide emission factors
million metric tons carbon dioxide equivalent per quadrillion Btu

Fuel Type	Carbon Dioxide Coefficient at Full Combustion	Combustion Fraction	Adjusted Emission Factor
Petroleum			
Motor Gasoline (net of ethanol)	70.88	1.0000	70.88
Liquefied Petroleum Gas			
Used as Fuel	62.97	1.0000	62.97
Used as Feedstock	61.27	0.2000	12.25
Jet Fuel	70.88	1.0000	70.88
Distillate Fuel (net of biodiesel)	73.15	1.0000	73.15
Residual Fuel	78.80	1.0000	78.80
Asphalt and Road Oil	75.61	0.0000	0.00
Lubricants	74.21	0.5000	37.11
Petrochemical Feedstocks	71.02	0.3533	25.09
Kerosene	72.31	1.0000	72.31
Petroleum Coke	102.12	0.9014	92.05
Petroleum Still Gas	64.20	1.0000	64.20
Other Industrial	74.54	1.0000	74.54
Coal			
Residential and Commercial	95.35	1.0000	95.35
Metallurgical	93.71	1.0000	93.71
Coke	114.14	1.0000	114.14
Industrial Other	93.88	1.0000	93.98
Electric Utility[1]	95.52	1.0000	95.52
Natural Gas			
Used as Fuel	53.06	1.0000	53.06
Used as Feedstocks	53.06	0.5270	27.96
Biogenic Energy Sources			
Biomass	88.45	1.0000	88.45
Biogenic Waste	90.65	1.0000	90.65
Biofuels Heats and Coproducts	88.45	1.0000	88.45
Ethanol	65.88	1.0000	65.88
Biodiesel	73.88	1.0000	73.88
Liquids from Biomass	73.15	1.0000	73.15
Green Liquids	73.15	1.0000	73.15

[1]Emission factors for coal used for electricity generation are specified by coal supply region and types of coal, so the average carbon dioxide content for coal varies throughout the projection. The 2009 average is 95.52.
Source: U.S. Energy Information Administration, Emissions of Greenhouse Gases in the United States 2009, DOE/EIA-0573(2009), (Washington, DC, February 2010).

Notes and sources

[1] Energy Information Administration, *Annual Energy Outlook 2011* (*AEO2011*), DOE/EIA-0383(2011), (Washington, DC, April 2011).

[2] NEMS documentation reports are available on the EIA Homepage (http://www.eia.gov/analysis/model-documentation.cfm).

[3] Alternative liquids technologies include all biofuel technologies plus CTL and GTL.

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