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The National Energy Modeling System: An Overview 2018

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Preface

The National Energy Modeling System: An Overview 2018 (Overview) provides a summary description of the National Energy Modeling System, which was used to generate the projections of energy production, demand, imports, and prices through 2050 for the *Annual Energy Outlook 2018* (AEO2018), (DOE/EIA-0383(2018)), released in February 2018. AEO2018 presents national projections of energy markets for seven primary cases—a reference case, additional cases that assume higher and lower economic growth, higher and lower world oil prices, and higher and lower oil and natural gas technology and resources than in the Reference case. These seven cases were also run with the addition of the Clean Power Plan. The Overview presents a brief description of the methodology and scope of each of the component modules of NEMS. The model documentation reports listed in the appendix of this document provide further details. An Appendix also describes all of the cases included in AEO2018.

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AEO2018 is available on the EIA home page. Assumptions underlying the projections are also available, as are tables of regional projections and other underlying details of the Reference case. This Overview is an introduction to each of the NEMS modules. Full AEO2018 documentation for each module is also available.

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Introduction

The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system for the United States. NEMS projects the production, imports, conversion, consumption, and prices of energy, subject to assumptions on macroeconomic and financial factors, world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. NEMS was designed and implemented by the U.S. Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

The National Energy Modeling System: An Overview 2018 provides an overview of the structure and methodology of NEMS and each of its components. This chapter provides a description of the design and objectives of the system, followed by a chapter on the overall modeling structure and solution algorithm. The remainder of the report summarizes the methodology and scope of the component modules of NEMS. The model descriptions are intended for readers familiar with terminology from economic, operations research, and energy modeling. More detailed model documentation reports for all the NEMS modules are also available from EIA (Appendix Bibliography).

Purpose of NEMS

NEMS is used by EIA to project the impact that energy, economic, environmental, and security factors can have on the U.S. energy system as a result of alternative energy policies and different assumptions about energy markets. The projection period is about 30 years into the future. The projections in the *Annual Energy Outlook 2018* (AEO2018) are from the present through 2050. NEMS provides a consistent framework for representing the complex interactions of the U.S. energy system and its response to a wide variety of alternative assumptions and policies or policy initiatives. As an annual model, NEMS can also be used to examine the impact of new energy programs and policies.

Energy resources and prices, the demand for specific energy services, and other characteristics of energy markets vary widely across the United States. To address these differences, NEMS is a regional model. The regional disaggregation for each module reflects the availability of data, the regional format typically used to analyze trends in the specific area, geology, and other factors, as well as the regions determined to be the most useful for policy analysis. For example,

- The demand modules (e.g., residential, commercial, industrial, and transportation) use the 9 census divisions
- The Electricity Market Module uses 24 supply regions based on the North American Electric Reliability Council (NERC) regions
- The Oil and Gas Supply Modules use 12 supply regions (including 3 offshore and 3 Alaskan regions)
- The Liquid Fuels Market Module uses 9 regions based on the Petroleum Administration for Defense Districts

Baseline projections are developed with NEMS and published annually in the *Annual Energy Outlook* (AEO). Because EIA is policy-neutral, AEO projections are generally based on federal, state, and local laws and regulations in effect at the time of the projection. The potential impacts of pending or proposed legislation, regulations, and standards are not reflected in NEMS. Similarly, NEMS does not reflect sections of legislation that have been enacted but that require implementing regulations or appropriations of funds that have not been provided or specified in the legislation itself. The first version of NEMS, completed in December 1993, was used to develop the projections presented in the *Annual Energy Outlook* 1994. This report describes the version of NEMS used for AEO2018.[1]

The projections produced by NEMS are not statements of what will happen but rather of what might happen given the assumptions and methodologies used. Assumptions include, for example, the estimated size of the economically recoverable resource base of fossil fuels and changes in world energy supply and demand. The projections are business-as-usual trend estimates based on known technological and demographic trends.

Analytical capability

NEMS can be used to analyze the effects of existing and proposed government laws and regulations related to energy production and use; the potential impact of new and advanced energy production, conversion, and consumption technologies; the impact and cost of greenhouse gas control; the impact of increased use of renewable energy sources; the potential savings from increased efficiency of energy use; and the impact of regulations on the use of alternative or reformulated fuels.

In addition to producing the analyses in AEO, NEMS is used for one-time analytical reports and papers, including papers that either describe the assumptions and methodology of the NEMS or look at how current energy markets issues will develop in the future. Many of these papers are published in the Issues in Focus section of AEO. Past and current analyses are available on the Analysis and Projections webpage.

NEMS has also been used for a number of special analyses at the request of the Administration, U.S. Congress, other offices of DOE, and other government agencies, who specify the scenarios and assumptions for the analysis. Some recent examples include the following:

- *Analysis of the Impacts of the Clean Power Plan*,[2] requested by Representative Lamar Smith, Chairman of the U.S. House of Representatives Committee on Science, Space, and Technology, for an analysis of the Environmental Protection Agency's (EPA) proposed Clean Power Plan under which states would be required to develop plans to reduce carbon dioxide (CO2) emissions rates from existing fossil-fired electricity generating units.
- *Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets*,[3] requested by DOE's Office of Fossil Energy (DOE/FE) for an updated study of liquefied natural gas (LNG) export scenarios intended to serve as an input to be considered in the evaluation of applications to export LNG from the United States under Section 3 of the Natural Gas Act. The Natural Gas Act requires DOE to grant a permit to export domestically produced natural gas unless it finds that such action is not consistent with the public interest.
- *Analysis of the Clean Energy Standard Act of 2012*,[4] analyzing the impacts of legislation proposed by Senator Jeff Bingaman to require covered electricity retailers to supply a specified share of their electricity sales from

[1] U.S. Energy Information Administration, *Annual Energy Outlook 2018* (Washington, DC, February 2018).

[2] U.S. Energy Information Administration, *Analysis of the Impacts of the Clean Power Plan* (Washington, DC, May 2015).

[3] U.S. Energy Information Administration, *Effect of Increased Levels of Liquefied Natural Gas Exports on U.S. Energy Markets* (Washington, DC, October 2014).

[4] U.S. Energy Information Administration, *Analysis of the Clean Energy Standard Act of 2012* (Washington, DC, May 2012).

qualifying clean energy resources, including renewable energy and nuclear. Fossil fuels with low carbon intensity (carbon emissions per unit of generation) may also partially qualify as clean energy resources.

- *Analysis of Selected Provisions of the Domestic Manufacturing and Energy Jobs Act of 2010*,[5] requested by Janice Mays, Staff Director of the U.S. House of Representatives' Committee on Ways and Means, to analyze several provisions included in the July 26, 2010, discussion draft of the Domestic Manufacturing and Energy Jobs Act of 2010.
- *Energy Market and Economic Impacts of the American Power Act of 2010*,[6] requested by Senators John Kerry, Lindsey Graham, and Joe Lieberman for an analysis of the American Power Act of 2010 (APA). APA, as released by Senators Kerry and Lieberman on May 12, 2010, regulates emissions of greenhouse gases through market-based mechanisms, efficiency programs, and other economic incentives.

Representations of energy market

Interactions

NEMS is designed to represent the important interactions of supply and demand in U.S. energy markets. In the United States, energy markets are driven primarily by the fundamental economic interactions of supply and demand. Government regulations and policies can exert considerable influence, but the majority of decisions that affect fuel prices and consumption patterns, resource allocation, and energy technologies are made by private individuals who value attributes other than life-cycle costs or companies attempting to optimize their own economic interests. NEMS represents the market behavior of the producers and consumers of energy at a level of detail that is useful for analyzing the implications of technological improvements and policy initiatives.

Energy supply/conversion/demand interactions

NEMS is a modular system. Four end-use demand modules represent fuel consumption in the residential, commercial, transportation, and industrial sectors, subject to delivered fuel prices, macroeconomic influences, and technology characteristics. The primary fuel supply and conversion modules compute the levels of domestic production, imports, transportation costs, and fuel prices that are needed to meet domestic and export demands for energy, subject to resource base characteristics, industry infrastructure and technology, and world market conditions. The modules interact to solve for the economic supply and demand balance for each fuel. Because of the modular design, each sector can be represented with the methodology and the level of detail, including regional detail, appropriate for that sector. The modularity also facilitates the analysis, maintenance, and testing of the NEMS component modules in the multi-user environment.

Domestic energy system/economy interactions

The general level of economic activity, represented by gross domestic product, has traditionally been used as a key explanatory variable or driver for projections of energy consumption at the sectoral and regional levels. In turn, energy prices and other energy system activities influence economic growth and activity. NEMS captures this feedback between the domestic economy and the energy system. Thus,

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[5] U.S. Energy Information Administration, *Analysis of Selected Provisions of the Domestic Manufacturing and Energy Jobs Act of 2010* (Washington, DC, October 2010).

[6] U.S. Energy Information Administration, *Energy Market and Economic Impacts of the American Power Act of 2010* (Washington, DC, July 2010).

changes in energy prices affect the key macroeconomic variables—such as gross domestic product, disposable personal income, industrial output, housing starts, employment, and interest rates—that drive energy consumption and capacity expansion decisions.

Domestic/world energy market interactions

World oil prices play a key role in domestic energy supply, and demand decision-making and oil price assumptions are a typical starting point for energy system projections. The level of oil production and consumption in the U.S. energy system also has a significant influence on world oil markets and prices. In NEMS, an international module represents the response of world oil markets (supply and demand) to assumed world oil prices. The outputs of the module are international liquids consumption and production by region, as well as a crude oil supply curve representing international crude oil similar in quality to West Texas Intermediate that is available to U.S. markets through the Liquid Fuels Market Module (LFMM) of NEMS. 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/territories. The oil production estimates include both conventional and unconventional supply recovery technologies.

Economic decision-making over time

The production and consumption of energy products today are influenced by past investment decisions to develop energy resources and acquire energy-using capital stock. Similarly, the production and consumption of energy in the future will be influenced by decisions made today and in the past.

Current investment decisions depend on expectations about future markets. For example, expectations of rising energy prices in the future increase the likelihood of current decisions to invest in more energy-efficient technologies or alternative energy sources. A variety of assumptions about planning horizons, the formation of expectations about the future, and the role of those expectations in economic decision-making are applied within the individual NEMS modules.

Technology representation

A key feature of NEMS is the representation of technology and its improvement over time. Five of the sectors—residential, commercial, transportation, electric power, and refining—include extensive treatment of individual technologies and their characteristics, such as the initial capital cost, operating cost, date of availability, efficiency, and other characteristics specific to the particular technology. For example, technological progress in lighting technologies results in a gradual reduction in cost and is modeled as a function of time in these end-use sectors. In addition, the electric power sector accounts for technological optimism in the capital costs of first-of-a-kind generating technologies and for a decline in cost as experience with the technologies is gained both domestically and internationally. In each of these sectors, equipment choices are made for individual technologies as new equipment is needed to meet growing demand for energy services or to replace retired equipment.

In the other sectors—industrial, oil and gas supply, and coal supply—the treatment of technologies is more limited as a result of a lack of data on individual technologies. In the industrial sector, only the combined heat and power and motor technologies are explicitly considered and characterized. Cost reductions resulting from technological progress in combined heat and power technologies are represented as a function of time as experience with the technologies grows. Technological progress is not explicitly modeled for the industrial motor technologies. Other technologies in the energy-intensive industries are represented by technology bundles, with technology possibility curves representing efficiency improvement over time. In the oil and gas supply sector, technological progress is represented by econometrically estimated improvements in finding rates, success rates, and costs. Productivity improvements over time represent technological progress in coal production.

External availability

Under EIA requirements, NEMS is fully documented and archived. EIA has been running NEMS on five EIA terminal servers using the Windows Server 2012 Standard operating system. The archive file as provided on the EIA website provides the source language and input files to replicate the AEO Reference case run on an identically equipped computer; however, it does not include the proprietary portions of the model, such as the IHS Markit macroeconomic model and the optimization modeling libraries. NEMS can be run on a high-powered individual PC as long as the required proprietary software is on the PC. Because of the complexity of NEMS and the relatively high cost of the proprietary software, NEMS is not widely used outside of DOE. However, NEMS, or portions of it, has been installed at the Lawrence Berkeley National Laboratory, Oak Ridge National Laboratory, the Electric Power Research Institute, the National Energy Technology Laboratory, the National Renewable Energy Laboratory, several private consulting firms, and a few universities.

Overview of NEMS

NEMS explicitly represents domestic energy markets by the economic decision-making involved in the production, conversion, and consumption of energy products. Where possible, NEMS includes explicit representation of energy technologies and their characteristics. Because energy costs, availability, and energy-consuming characteristics vary widely across regions, considerable regional detail is included. Other details of production and consumption are represented to facilitate policy analysis and ensure the validity of the results. A summary of the detail provided in NEMS is shown in Table 1.

Table 1. Characteristics of selected modules

Energy activity	Categories	Regions
Residential demand	22 end-use services 3 housing types 45 end-use technologies	9 census divisions
Commercial demand	10 end-use services 11 building types 11 distributed generation technologies 64 end-use technologies	9 census divisions
Industrial demand	7 energy-intensive industries 8 non-energy-intensive industries 6 non-manufacturing industries Combined heat and power	4 census regions, shared to 9 census divisions
Transportation demand	6 car sizes 6 light truck sizes 86 conventional fuel-saving technologies for light-duty vehicles Gasoline, diesel, and 14 alternative-fuel vehicle technologies for light-duty vehicles 20 vintages for light-duty vehicles Regional, narrow, and wide-body aircraft 9 advanced aircraft technologies Light-medium, heavy-medium, and heavy freight truck size classes 83 advanced freight truck technologies	9 census divisions
Electricity	Coal, natural gas, and petroleum technologies Base load and peak distributed generation technologies Renewable generation technologies including wind, solar, landfill gas, biomass, and hydropower Conventional and advanced nuclear light water reactors Electricity storage technologies including pumped water and battery Marginal and average cost pricing Generation capacity expansion and nuclear plant uprates Environmental control technologies including carbon capture, scrubbers, filters, and nitrogen oxides reduction	22 electricity supply regions, plus 2 additional regions to account for Alaska and Hawaii
Renewables	Wind, geothermal, solar thermal, solar photovoltaic, landfill gas, biomass, conventional hydropower	22 electricity supply regions

Table 1. Characteristics of selected modules (cont.)

Energy activity	Categories	Regions
Oil and natural gas supply	Tight, carbon dioxide enhanced oil recovery, and other oil Coalbed methane, shale gas, and tight sands and other gas Deep and shallow Gulf of Mexico offshore oil and gas Canadian natural gas	6 Lower 48 states onshore regions 3 Lower 48 states offshore regions 3 Alaska regions 2 Canada regions
Natural gas	Flows and prices for three seasons Pipeline capacity expansion Pipeline and distributor tariffs Canada, Mexico, and LNG imports and exports Alaska gas consumption and supply	12 Lower 48 state regions 10 pipeline border points 8 liquefied natural gas import regions
Liquid fuels	11 crude oil categories 20 product categories More than 40 distinct technologies Refinery capacity expansion	8 refinery regions based on the Petroleum Administration for Defense Districts, plus one region, which represents the Caribbean and Maritime Canada
Coal supply	3 sulfur categories 4 thermal grades Underground and surface mines Imports and exports	14 supply regions 16 demand regions 17 international supply regions 20 international demand regions

Major assumptions

Each module of NEMS embodies many assumptions and data to characterize the future production, conversion, or consumption of energy in the United States. Two of the more important factors influencing energy markets are economic growth and oil prices.

The *Annual Energy Outlook 2018* (AEO2018) includes seven primary, fully integrated cases: a Reference case, high and low economic growth cases, high and low oil price cases, and high and low oil and natural gas resource cases. These seven cases were also run including the Clean Power Plan. The primary determinant for different economic growth rates are assumptions about growth in the labor force and productivity, while the long-term oil price paths are based on oil demand in developing countries.

In addition to the primary, fully integrated cases, AEO2018 includes 18 other cases to support *Issues in Focus* analysis on specific topics:

- Nuclear power costs—These sensitivity cases illustrate three different types of uncertainty surrounding the nuclear power generating capacity projections in the Reference case. The uncertainty is related to higher or lower operating and capital costs for both new and existing nuclear units, higher or lower levels of natural gas availability, and alternative levels of carbon emissions regulation, as represented by different fees on the emissions of carbon dioxide.
- Alternative policies—The alternative cases assume changes to laws and regulations that have a history of being extended beyond their legislated sunset dates or that call for periodic updates beyond current standard levels.
- Arctic National Wildlife Refuge (ANWR)—ANWR projections are uncertain because production has not yet occurred in the area. The resource bases for these cases are based on high (a 5% probability of being

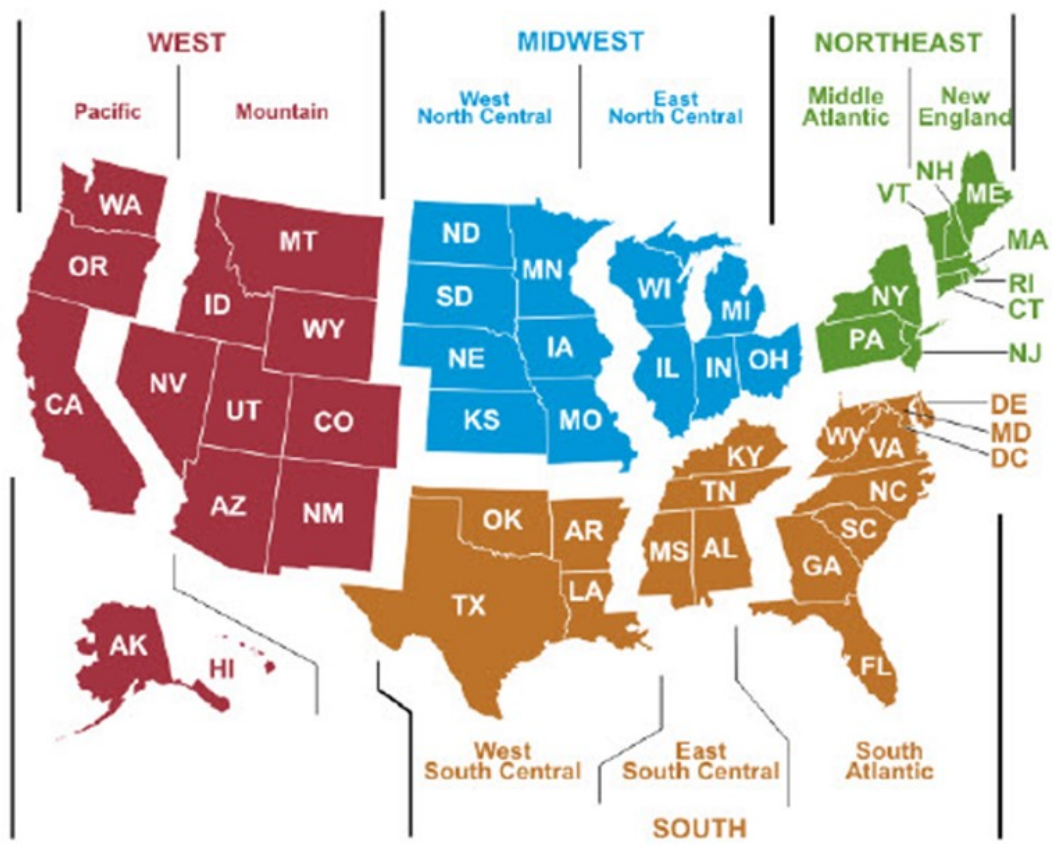
as high as 16.0 billion barrels), mean (10.4 billion barrels), and low (a 95% probability of being more than 5.7 billion barrels) assessments by the United States Geological Survey as of 1998 (the most recent year data were collected).

- Autonomous vehicles—The autonomous vehicle cases increase the number of autonomous vehicles used by commercial and government fleets and also introduce them into households, allowing increased personal mobility through vehicle miles traveled.

NEMS modular structure

Overall, NEMS represents the behavior of energy markets and their interactions with the U.S. economy. The model achieves a supply/demand balance in the end-use demand regions, defined as the nine census divisions (Figure 1), by solving for the prices of each energy type that will balance the quantities producers are willing to supply with the quantities consumers wish to consume. The system reflects market economics, industry structure, and existing energy policies and regulations that influence market behavior.

Figure 1. Census divisions



Source: U.S. Department of Commerce, Economics and Statistics Administration, U.S. Census Bureau

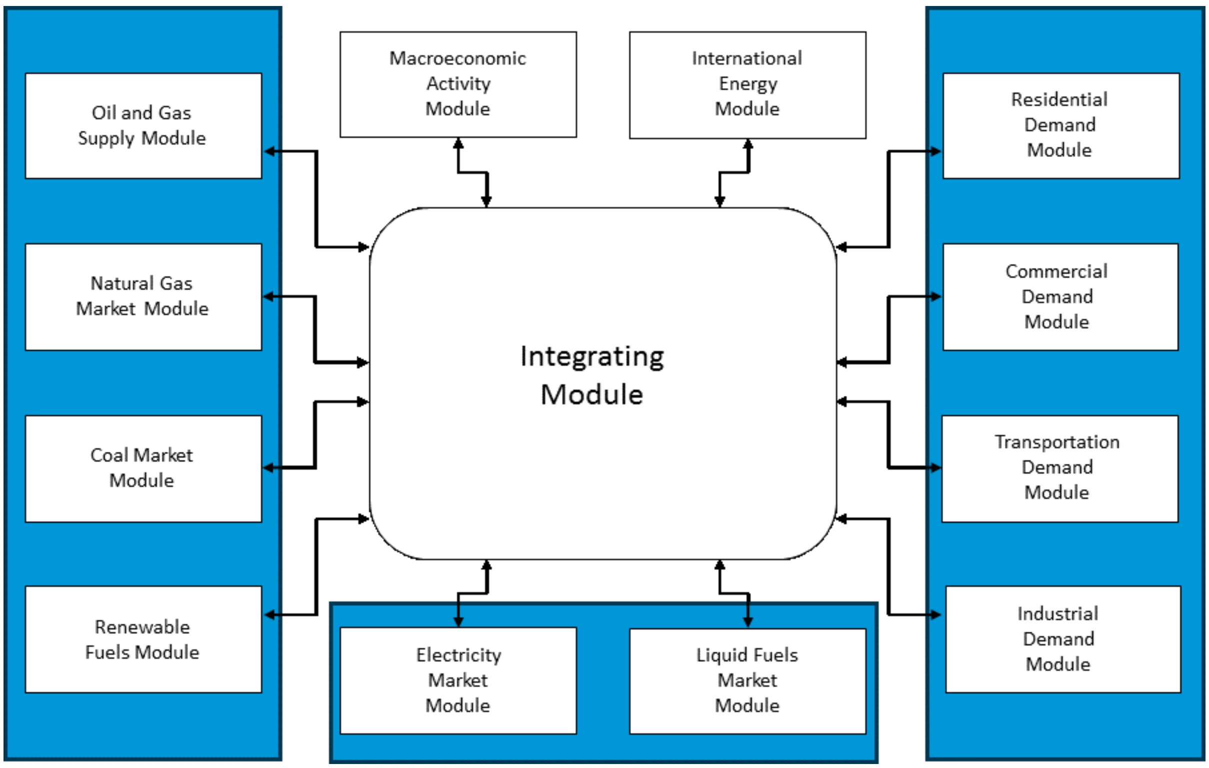
NEMS consists of 13 modules:

- Four supply modules (oil and gas supply, natural gas market, coal market, and renewable fuels)
- Two conversion modules (electricity market and liquid fuels market)
- Four end-use demand modules (residential, commercial, industrial, and transportation)

- One module to simulate energy/economy interactions (macroeconomic activity)
- One module to simulate international oil markets (international)
- One module that provides the mechanism to achieve a general market equilibrium among all the other modules (integrating).

Figure 2 depicts the high-level structure of NEMS.

Figure 2. National Energy Modeling System



Because energy markets are heterogeneous, a single methodology does not adequately represent all supply, conversion, and end-use demand sectors. The modularity of the NEMS design provides the flexibility for each component of the U.S. energy system to use the methodology and coverage that is most appropriate. Furthermore, modularity provides the capability to execute the modules individually or in collections of modules, which facilitates the development and analysis of the separate component modules. The interactions among these modules are controlled by the integrating module.

The NEMS global data structure is used to coordinate and communicate the flow of information among the modules. These data are passed through common interfaces via the integrating module. The global data structure includes energy market prices and consumption; macroeconomic variables; energy production, transportation, and conversion information; and centralized model control variables, parameters, and assumptions. The global data structure excludes variables that are defined locally within the modules and are not communicated to other modules.

A key subset of the variables in the global data structure is the end-use prices and quantities of fuels that are used to equilibrate the NEMS energy balance in the convergence algorithm. These delivered prices of energy and the quantities demanded are defined 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 regions used for the price and quantity variables in the global data structure are the nine census divisions. The four census regions (shown in Figure 1) and nine census divisions represent a common, mainstream level of regionality widely used by EIA and other organizations for data collection and analysis.

Carbon Dioxide Emissions

The emissions policy submodule, part of the integrating module, estimates energy-related carbon dioxide (CO2) emissions and is capable of representing two related greenhouse gas (GHG) emissions policies: a cap-and-trade program and a carbon dioxide emission tax.

CO2 emissions are calculated from fossil fuel consumption and fuel-specific emissions factors. The estimates are adjusted for carbon capture technologies where applicable. CO2 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. The adjusted carbon emissions factors, one for each fuel and sector, are provided as input to the emissions policy module.

Data on past CO2 emissions and emissions factors are estimated monthly, based on energy consumption plus the relatively small amount of emissions from the non-combustion use of fossil fuels, in the *Monthly Energy Review*.[7] To provide a more complete accounting of GHG emissions, a baseline emissions projection for the non-energy CO2 and other GHGs may be specified as an exogenous input.

To represent carbon tax or cap-and-trade policies, an incremental cost of using each fossil fuel (on a dollar-per-British thermal unit basis) is calculated based the CO2 emissions factors and the per-ton CO2 tax or cap-and-trade allowance cost. This incremental cost, or carbon price adjustment, is added to the corresponding energy prices as seen by the energy demand modules. These price adjustments influence energy demand and energy-related CO2 emissions, as well as macroeconomic trends.

Under a cap-and-trade policy, the allowance or permit price is determined in an iterative solution process so that the annual covered emissions match the cap each year. If allowance banking is permitted, a constant-growth allowance price path is found such that cumulative emissions over the banking interval match the cumulative covered emissions. To the extent the policies cover GHGs other than CO2, the coverage assumptions and abatement potential for the gases must be provided as input. In past studies, EIA has drawn on work by the U.S. Environmental Protection Agency (EPA) to represent exogenous estimates of emissions abatement and the use of offsets as a function of allowance prices.

Representing specific cap-and-trade policies in NEMS almost always requires customization of the model. Among the issues that must be addressed are what gases and sectors are covered, what offsets are eligible as compliance measures, how the revenues raised by the taxes or allowance sales are used, how allowances or the value of allowances are distributed, and how the distribution affects energy pricing or the cost of using energy.

[7] U.S. Energy Information Administration, *Monthly Energy Review*.

Macroeconomic Activity Module

The Macroeconomic Activity Module (MAM) links NEMS to the rest of the economy by providing projections of economic driver variables for use by the supply, demand, and conversion modules of NEMS. The derivation of the baseline macroeconomic projection lays a foundation for the determination of the energy demand and supply forecast. MAM is used to present alternative macroeconomic growth cases to provide a range of uncertainty about the growth potential for the economy and its likely consequences for the energy system. MAM is also able to address the macroeconomic effects associated with changing energy market conditions, such as alternative world oil price assumptions. Outside of the AEO setting, MAM represents a system of linked modules that can assess the potential impacts on the economy of changes in energy events or policy proposals. These economic outcomes then feed back into NEMS for an integrated solution. MAM consists of:

- A model of the U.S. economy;
- Industrial output and employment by industry models; and
- Regional models.

NEMS employs the IHS Markit Ltd. model of the U.S. economy in the EViews environment,[8] the same model used by IHS Markit Ltd. to generate the economic projections behind the company's quarterly assessment of the U.S. economy. The Industrial Output and Employment by Industry submodules are derivatives of IHS Markit Ltd.'s industrial output and employment by industry models. The models have been tailored to provide the industrial output and employment by industry detail required by NEMS. The regional models were developed by EIA to provide economic activity, industrial output, employment by industry, and commercial floor space at the census division level.

All of the MAM models are linked (Figure 3) to provide a fully integrated approach to estimating economic activity at the national, industrial and regional levels. IHS Markit Ltd.'s model of the U.S. economy determines the national economy's growth path and the final demand mix. EIA's Industrial Output Model ensures that supply by industry is consistent with the final demands (consumption, investment, government spending, exports and imports) calculated in the U.S. Model. Industrial output is the key driver of the employment estimation in EIA's Employment by Industry Model. The employment by industry projection also uses aggregate hours per week and productivity trends found in the U.S. Model. The employment by industry projection is aligned with the aggregate employment estimation of the U.S. Model. Key inputs to EIA's regional models include projections of national output, employment by industry, population, national income, and housing activity. EIA's regional models then calculate levels of industrial output, employment by industry, population, incomes, and housing activity for each of the nine census divisions. The sum of each of these concepts across the nine census divisions is aligned with the national totals estimated by the U.S. Model.

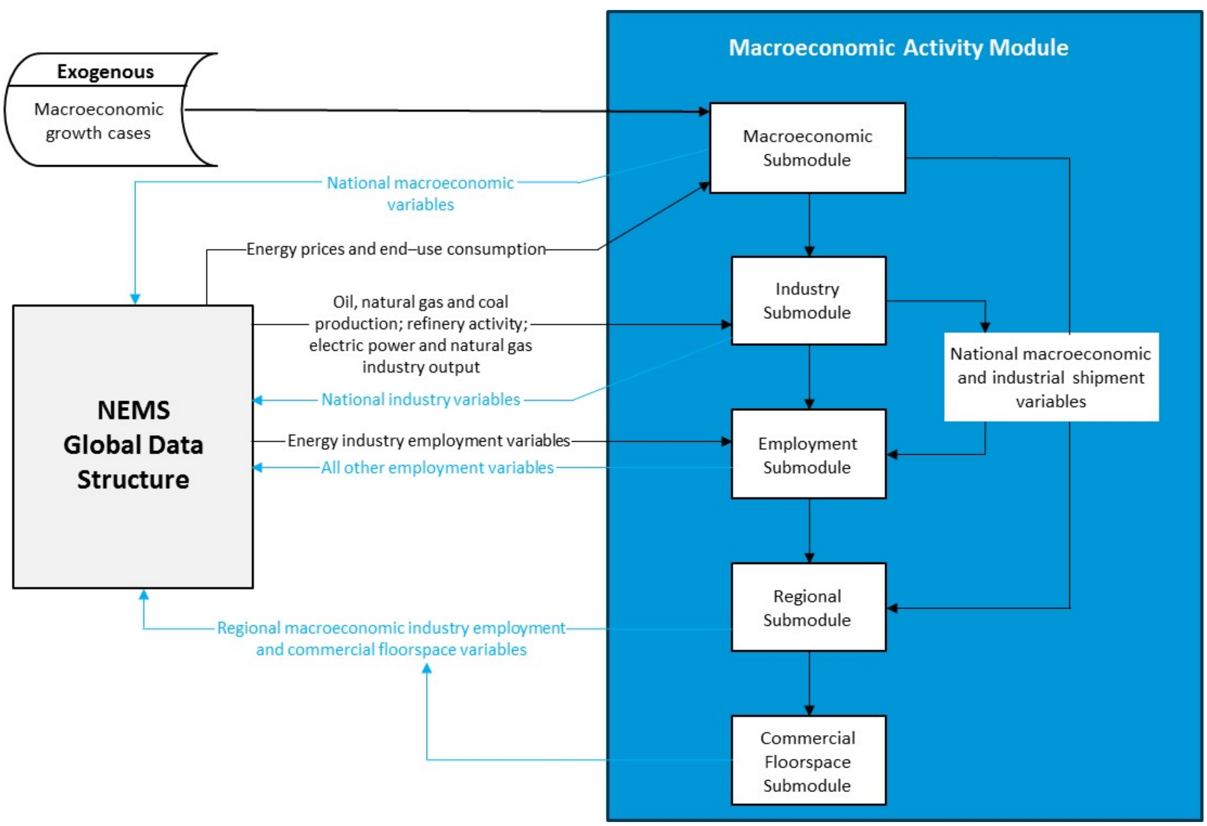
MAM obtains energy prices, consumption, and domestic production from the other NEMS modules. More than 70 energy prices and quantities are extracted from the output of the demand and supply modules of the NEMS. Transformations of the exogenous assumptions are necessary to map these

[8] EViews is a Windows-based econometric and forecasting software package maintained by IHS Markit Ltd.

inputs from the NEMS into more aggregated concepts in the MAM. After the appropriate transformations are done, the U.S., Industrial Output, Employment by Industry, and Regional Models execute in sequence to produce an estimate of economic activity at the national, industrial, and regional levels. Drawn from the projections are economic driver variables that are then passed to the supply, demand, and conversion modules of the NEMS, which then react to the new economic activity assumptions.

A few industrial output and employment by industry concepts have projections in the MAM that are determined by the NEMS. The MAM's results for industrial output of the five energy-related industries are based upon growth rates extracted from the appropriate modules in the NEMS. The growth rates in output of petroleum refining, coal mining, oil and gas extraction, electric utilities, and gas utilities are applied to the last historical value of the appropriate series in the MAM's Industrial Output Model. A similar computation is done for employment by industry but for only two of the five energy industries. Growth in employment is computed for coal mining and for oil and gas extraction using projections from the appropriate NEMS modules. These growth rates are then applied to the last historical value of the appropriate series in the MAM's employment by industry model.

Figure 3. Macroeconomic Activity Module Structure



International Energy Module

The International Energy Module (IEM) performs the following functions (also shown in Figure 4):

- Calculates the oil price. Changes in the oil price are computed in response to:
  - The difference between projected U.S. total crude-like liquids production and the expected U.S. total crude-like liquids production at the current oil price (estimated using the current oil price and the exogenous U.S. total crude-like liquids supply curve for each year)
  - The difference between projected U.S. total crude-like liquids consumption and the expected U.S. total crude-like liquids consumption at the current oil price (estimated using the current oil price and the exogenous U.S. total crude-like liquids demand curve)
- Projects international crude oil market conditions, including consumption, price, and supply availability, as well as the effects of the U.S. petroleum market on the world market.
- Provides supply curves for foreign crude types imported to the United States.
- Provides exogenous assumptions for crude oil exported from the United States.
- Provides supply curves for petroleum products imported to the United States.
- Provides demand curves for petroleum products exported from the United States.
- Provides demand curves for petroleum products in refinery region 9.

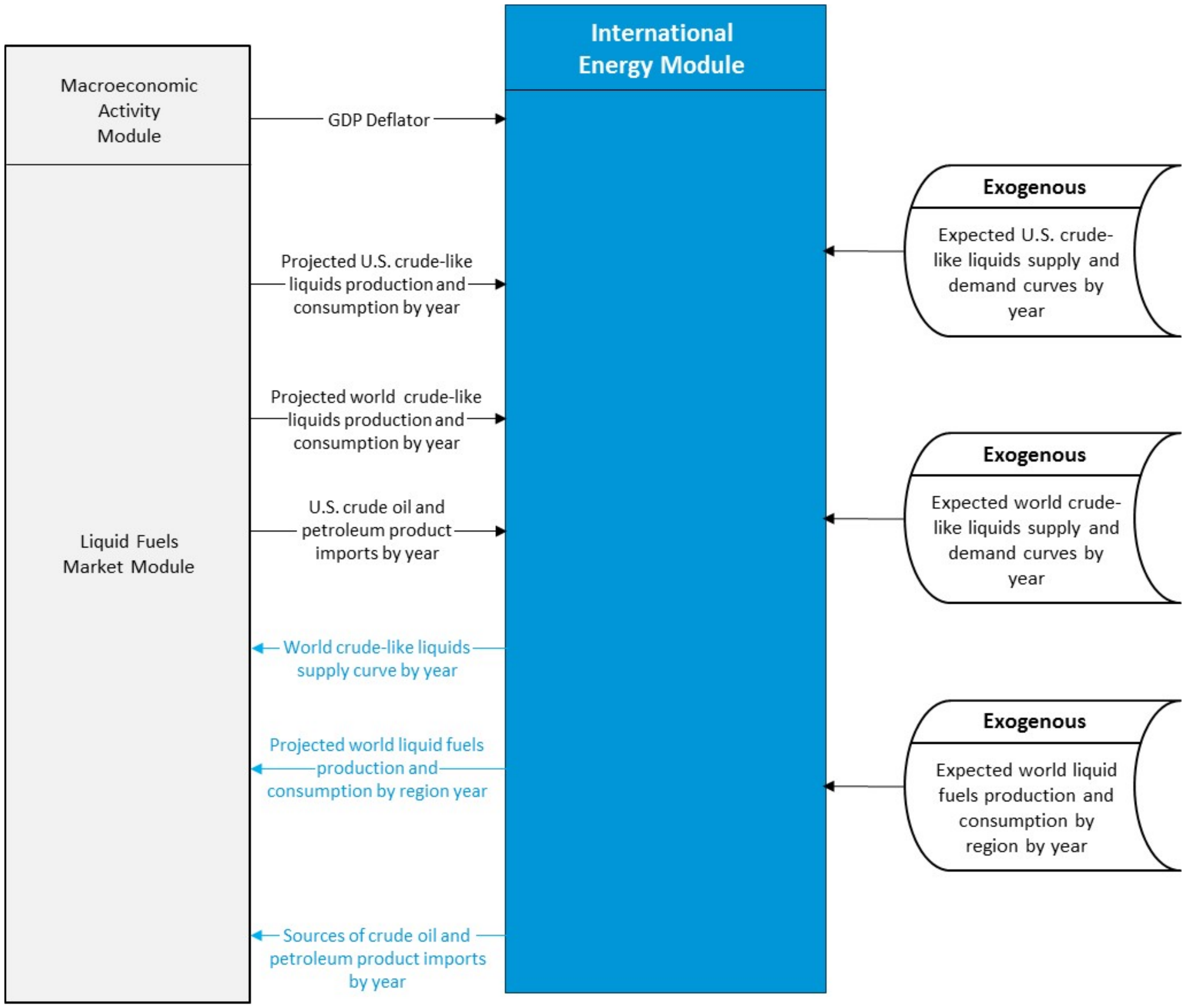
Scope of IEM

One main purpose of the IEM is to re-estimate oil prices. The IEM also provides a supply curve of world crude-like liquids, supply curves for each of the 10 foreign imported crude types, supply curves for imported petroleum products, demand curves for exported petroleum products, petroleum products demand curves for refinery region 9 (Maritime Canada and Caribbean region) and generates a worldwide liquids supply-demand balance with regional detail. The IEM provides this data for each year of the projection period. The IEM calculates the oil prices based on differences between U.S. total crude-like consumption and production and the expected U.S. total crude-like liquids consumption and production at the current oil price. All of the above must be achieved by keeping world oil markets in balance. Supply import curves are isoelastic curves, and points on the curve are adjusted as other NEMS modules (the Liquid Fuels Market Module, the Oil and Gas Supply Module, various end-use demand modules, and the Integrating Module) provide U.S. liquids projections.

A substantial amount of support information for the IEM is calculated exogenously. Various techniques, including simple and logarithmic linear regressions, are used to estimate the coefficients and elasticities that are applied within the IEM. Other exogenous data include world crude-like liquids supply and demand curves, supply curves for each of the 10 foreign-imported crude types, as well as data on U.S. petroleum product imports and exports.

The first step after data input is to re-estimate the oil price. Next, the model builds all supply and demand curves mentioned above. Then, the IEM computes non-U.S. crude oil demands in order to balance worldwide crude oil supplies with demand.

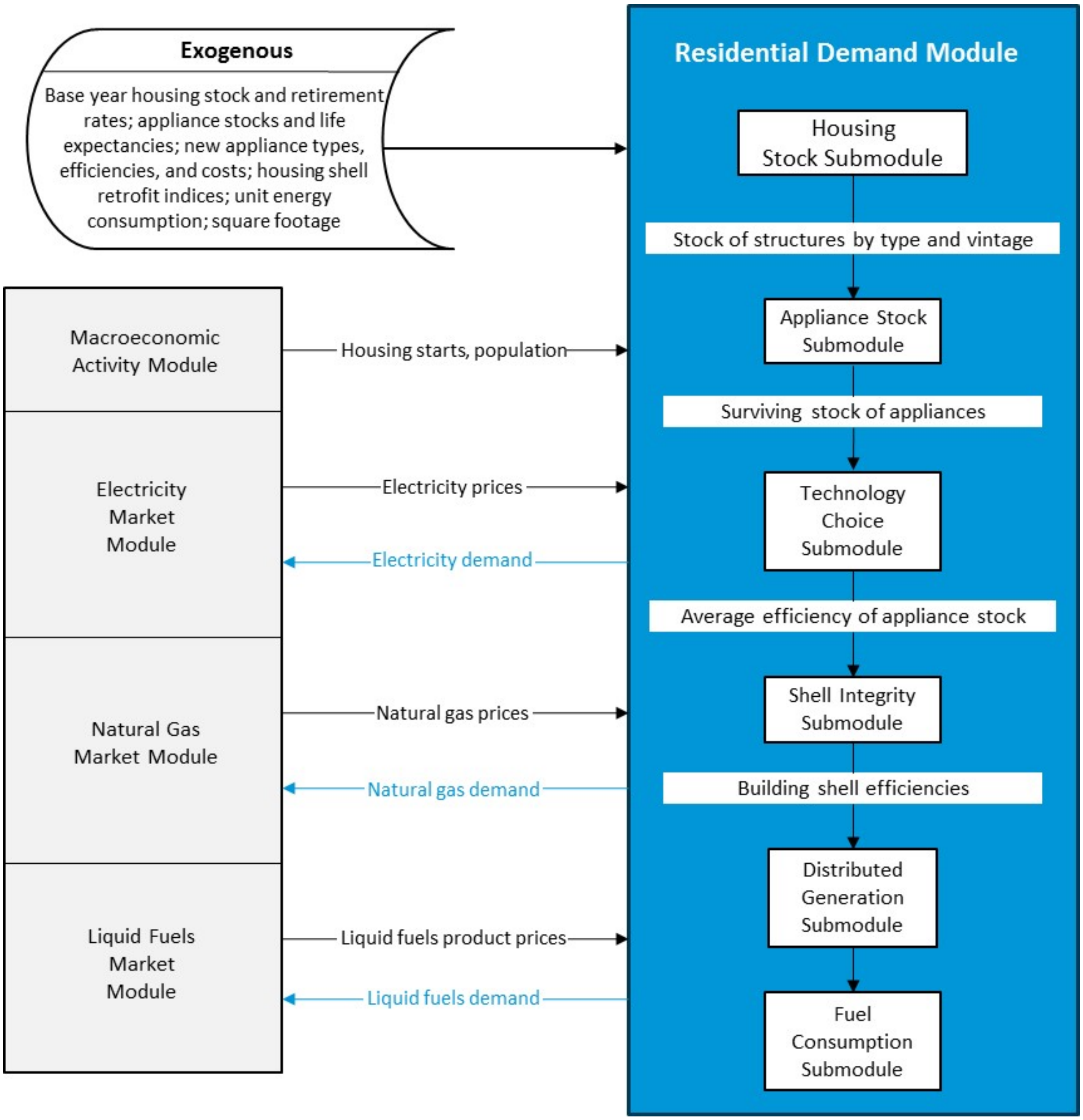
Figure 4. International Energy Module structure



Residential Demand Module

The Residential Demand Module (RDM) projects residential sector energy demand in six sequential steps. These steps produce information on housing stocks, appliance stocks, technology choices, building shell integrity, distributed generation, and energy consumption (Figure 5). The module uses a stock-vintaging approach that monitors equipment stock and equipment efficiency over time.

Figure 5. Residential Demand Module structure



The RDM characterizes energy consumption using a series of algorithms that account for the stocks of housing and appliances, equipment market shares, and energy intensity. The base year of the RDM is developed using U.S. census division-level housing characteristics and end-use consumption data from

EIA's *Residential Energy Consumption Survey*. The module then assesses the shifts of market shares between competing technologies based on fuel prices, equipment costs, and assumptions about the behavior of residential consumers using a sequential structured system of algorithms. Succeeding computations use the results from previously executed components as inputs.

Projected residential fuel demand generated by the RDM is used by NEMS in the calculation of the demand and supply equilibrium. In addition, the NEMS supply modules use the residential sector outputs to determine the patterns of consumption and the resulting prices for energy delivered to the residential sector.

Housing stock projection

The location and type of housing stock are the primary model drivers. This component uses data from the NEMS Macroeconomic Activity Module to project new housing for three dwelling types—single-family, multifamily, and mobile homes—at the census division level.

Equipment technology choice

The Technology Choice Component simulates the behavior of consumers by projecting market shares for each available equipment type. New and replacement equipment decisions are modeled for each technology type. For new construction, the home heating fuel is determined by the relative life-cycle costs of all competing heating systems.

Relative weights are determined for each equipment type based on the existing market share, the installed capital cost minus any equipment rebates or subsidies, and the operating cost. These relative weights are then used to compute the market shares and composite average efficiencies for each end-use service. The technologies are distinguished by the service demand that they satisfy, by the fuel that they consume, and by their energy efficiency.

Energy efficiency can be defined as the ratio of service demand to energy input. For relatively simple devices such as space heaters or light bulbs, service demand is a unit of heat or light, respectively. For such devices, efficiency is described in terms of heat output per unit of energy (such as coefficient of performance or annual fuel utilization efficiency) or efficacy as light output per unit of energy (lumens per watt).

For other equipment, service demand can be more difficult to quantify, or other factors beyond the primary service demand may contribute to a unit's energy consumption. In the case of refrigerators, the primary service demand is the volume of interior space refrigerated, but features such as an icemaker or through-the-door water dispenser can increase consumption. Another example is televisions, where service demand may be described as the area of the visual display, but other factors such as power draw in standby and off modes affect their consumption. For this reason, some equipment is described by a unit energy consumption—typically in units of kilowatthours per year—rather than an energy efficiency metric.

Appliance stock projection

The appliance stock component of the module projects the number of end-use appliances within all occupied housing units. This component tracks equipment additions and replacements. Appliance stocks are maintained by fuel, end use, and technology.

Building shell integrity

Building shell or envelope integrity is modeled for existing and new housing. The existing housing stock responds to rising prices of space conditioning fuels by improving shell integrity. Shell integrity improvements might range from relatively inexpensive measures, such as caulking and weather-stripping, to projects with substantial costs, such as window replacement and comprehensive air sealing. These improvements exhibit a one-way price response; more measures are installed as prices increase, but those measures are not undone when prices fall.

New housing stock also incorporates shell integrity improvements. The shell integrity of new housing is a function of capital and operating costs for several levels of total system efficiency. New housing stock includes homes that meet the 2009 International Energy Conservation Code (as well as some non-code-compliant homes), those that meet ENERGY STAR criteria, those that qualify for federal tax credits for efficient shells, and those that include the most efficient commercially available building shell components.

Distributed generation component

The distributed generation component allows adoption of solar photovoltaic, fuel cells, and small wind turbine systems for on-site generation to compete with purchased electricity for satisfying electricity needs. Penetration rates of these systems are projected using a ZIP Code-level econometric hurdle model for solar photovoltaics and a cash-flow formulation for fuel cells and wind. Electricity generated by these systems is deducted from space cooling and other electricity consumption, or it is sold back to the grid, if feasible.

Energy consumption

The energy consumption component calculates end-use consumption for each service and fuel type. The consumption projections are constructed as products of the number of units in the equipment stock and the average technology unit energy consumption (UEC). The average UEC changes as the composition of the equipment stock changes over time. For each year of the projection period, the following steps are performed to develop the projection of energy consumption:

- Generate a projection of housing stock based on the retirement of existing housing stock and the addition of new construction as determined in the Macroeconomic Activity Module.
- Estimate a current-year equipment stock, accounting for housing demolitions and additions.
- Determine market shares for equipment types and efficiencies by end-use service.
- Determine the previous year's equipment additions and replacements for both existing homes and new construction vintages based on the current-year market share.
- Calculate efficiencies weighted by market share.
- Calculate fuel consumption using UEC and the weighted efficiencies.
- Consumption can also vary based on projected heating and cooling shell integrities, fuel prices,

personal disposable income, housing unit sizes, and weather as applicable to specific equipment and end-use services.

Projected energy consumption is then benchmarked to EIA's State Energy Data consumption estimates for the residential sector, applying a correction term to ensure that simulated model results correspond to published State Energy Data historical values. This benchmarking adjustment accounts for unknown energy consumption (e.g., outdoor uses, multifamily common spaces, or homes outside of the scope of the *Residential Energy Consumption Survey*) and provides a consistent starting point for the projections. Benchmark factors may be additive, meaning the difference between the modeled fuel total and benchmarked fuel total is maintained throughout, or multiplicative, meaning the ratio is maintained throughout. Fuels with more consumption—such as electricity, natural gas, distillate fuel oil, and propane—use additive benchmarking, but kerosene uses multiplicative benchmarking.

Commercial Demand Module

The Commercial Demand Module (CDM) uses a simulation approach to project commercial sector energy demands, using the latest *Commercial Buildings Energy Consumption Survey* (CBECS) to inform assumptions for the CDM base year. The module conducts an explicit economic and engineering-based analysis of the building energy end uses of space heating, space cooling, water heating, ventilation, cooking, lighting, and refrigeration. Computing and other end-uses are modeled in less detail. These end uses are modeled for 11 categories of commercial buildings at the census division level.

The model is a sequentially structured system of algorithms, with succeeding computations using the outputs of previously executed routines as inputs (Figure 6). For example, the building square footage projections developed in the floorspace routine are used to calculate demands of specific end uses in the Service Demand routine. Calculated service demands provide input to the Technology Choice subroutine, and they subsequently contribute to the development of end-use consumption projections.

Commercial building floorspace projection

Model runs begin in 2013, a year after the CBECS base year. Initially, the existing stock, geographic distribution, building usage distribution, and vintaging of floorspace are assumed to be the same as published in the 2012 CBECS.

Building shell characteristics for new additions to the floorspace stock through the projection period are assumed to at least conform to the American Society of Heating, Refrigerating and Air-Conditioning Engineers Standard (ASHRAE) 90.1-2004. Additional improvement is assumed for new construction to account for adoption of the ASHRAE 90.1-2007 and ASHRAE 90.1-2013 standards for building shell measures.

Commercial sector energy consumption patterns depend on numerous factors, including the composition of commercial building and equipment stocks, regional climate, and building construction variations. The CDM first develops projections of commercial floorspace construction and retirement by type of building and census division. Floorspace is projected for the following 11 building types:

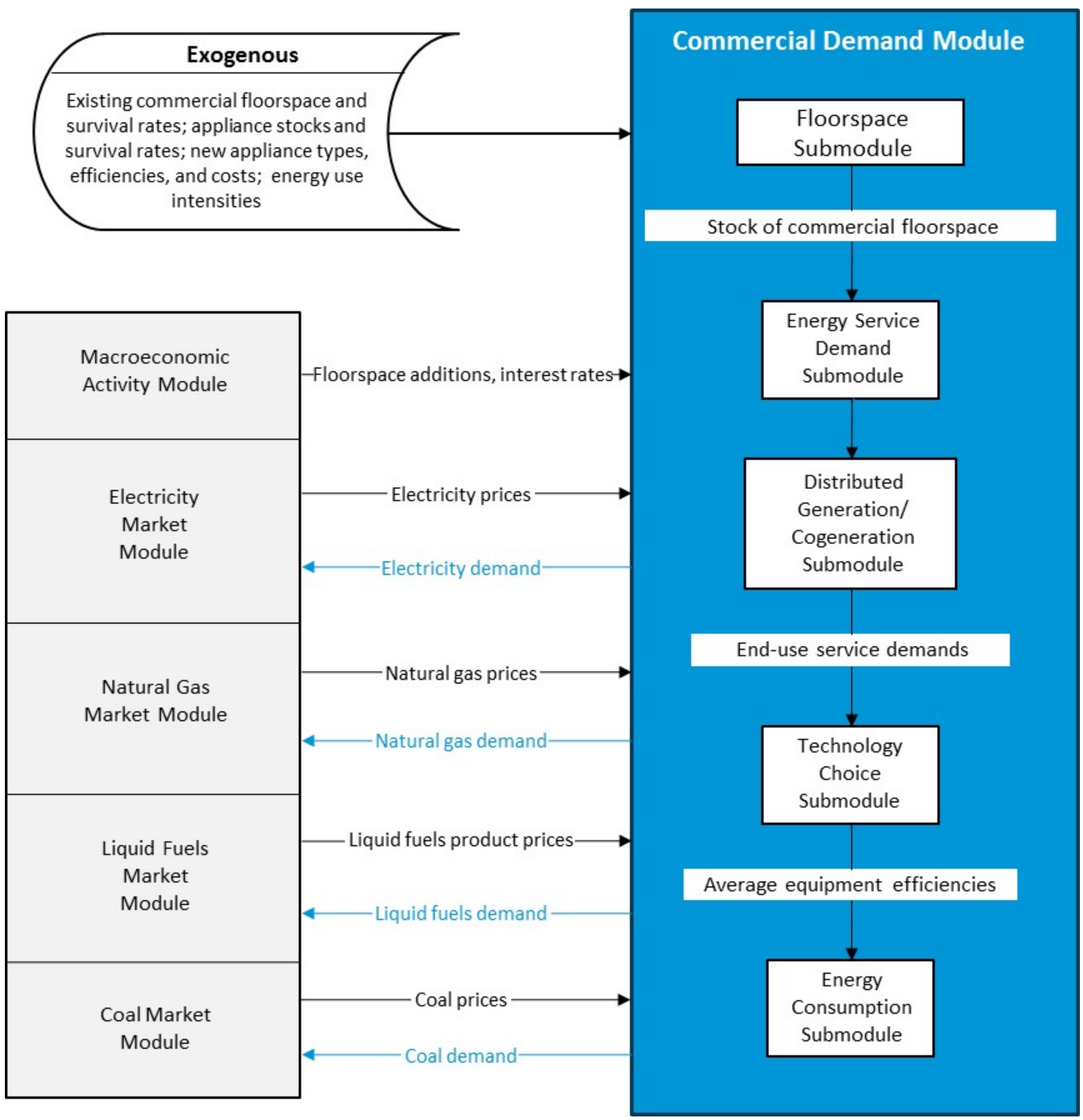
- Assembly
- Education
- Food sales
- Food services
- Health care
- Lodging
- Offices larger than 50,000 square feet
- Offices up to 50,000 square feet
- Mercantile and service
- Warehouse
- Other

Service demand projection

Once the building inventory is defined, the model projects demand for energy-consuming services within buildings. Consumers do not demand energy per se, but rather the services that energy provides. This demand for delivered forms of energy is measured in units of British thermal units out by the CDM, to distinguish it from the consumption of fuel, measured in British thermal units in, necessary to produce the useful services. The CDM models service demands for the following 10 end-use services:

- Space heating
- Space cooling
- Ventilation
- Water heating
- Lighting
- Cooking
- Refrigeration
- Computing
- Office equipment
- Other

Figure 6. Commercial Demand Module structure



The energy intensity of usage, measured in British thermal units per square foot, differs across service and building type. For example, health care facilities typically require more space heating per square foot than warehouses. Intensity of usage also varies across census divisions. Educational buildings in the New England Census Division typically require more heating services than educational buildings in the South Atlantic Census Division. As a result, total service demand for any service depends on the number, size, type, and location of buildings.

In each projection year, a proportion of energy-consuming equipment wears out in existing floorspace, leaving a gap between the energy services demanded and the equipment available to meet this demand. The efficiency of the replacement equipment, along with the efficiency of equipment chosen for new floorspace, is reflected in the calculated average efficiency of the equipment stock.

Consumers may increase or decrease their usage of a service in response to a change in energy prices. The model accounts for this behavioral impact by adjusting projected service demand using price elasticity of demand estimates for the major fuels: electricity, natural gas, and distillate fuel oil. For electricity, the model uses a weighted-average price for each end-use service and census division. For the other two major fuels, the model uses a single average annual price for each census division. In performing this adjustment, the model also takes into account the effects of changing technology efficiencies and building shell efficiencies on the marginal cost of the service to the consumer, resulting in a secondary take-back or rebound effect modification of the pure price elasticity.

Distributed Generation and Combined Heat and Power (CHP) Submodule

The Distributed Generation and CHP Submodule projects electricity generation and water and space heating supplied by distributed generation technologies and corresponding fuel consumption. CHP accounts for historical levels of electricity generation. In addition, program-driven installation of solar photovoltaic systems, small wind turbines, and fuel cells are input based on information from EIA Form 860, the U.S. Department of Energy, the U.S. Department of Defense, the Solar Energy Industries Association, the American Wind Energy Association, the Interstate Renewable Energy Council, and state programs.

Distributed and CHP electricity generation projections are developed based on a detailed cash-flow approach. Penetration of distributed and CHP generation technologies is a function of payback years, which are calculated based on the internal rate of return.

Technology Choice Submodule

Given the level of energy services demanded, the algorithm then projects the class and model of equipment selected to satisfy the demand. Commercial consumers purchase energy-using equipment using one of three decision types to meet service demand:

- New—service demand in newly-constructed buildings (constructed in the current projection year)
- Replacement—service demand formerly met by retiring equipment (equipment that is at the end of its useful life and must be replaced)
- Retrofit—service demand formerly met by equipment at the end of its economic life (equipment with a remaining useful life that is nevertheless subject to retirement on economic

grounds)

One possible approach to describe consumer choice behavior in the commercial sector would require the consumer to choose the equipment that minimizes the total expected cost over the life of the equipment. However, empirical evidence suggests that traditional cost-minimizing models do not adequately account for the full range of economic factors that influence consumer behavior. The CDM is coded to allow the use of several possible assumptions about consumer behavior:

- Buy equipment with the minimum life-cycle cost.
- Buy equipment that uses the same fuel as existing or retiring equipment, but minimizes life-cycle costs under that constraint.
- Buy (or keep) the same technology as the existing or retiring equipment, but choose between models with different efficiency levels based upon minimum life-cycle costs.

These behavior rules are designed to represent the range of economic factors that are empirically observed to influence consumer decisions. The consumers who minimize life-cycle cost are the most sensitive to energy price changes; thus, the price sensitivity of the model depends in part on the share of consumers using each behavior rule. The proportion of consumers in each behavior rule segment varies by building type, the end-use service under consideration, and decision type for each of the three decision types (new construction, replacement, or retrofit).

The model is designed to choose among a discrete set of technologies exogenously characterized by commercial availability, capital cost, operating and maintenance cost, removal/disposal cost, efficiency, and equipment life. Certain technology vintages meeting ENERGY STAR or better energy efficiency criteria may also receive subsidies under federal and utility energy efficiency programs. These subsidies are determined exogenously based on legislation, ENERGY STAR, and utility surveys, and they are subtracted from the installed capital cost of the equipment.

The menu of equipment cost and performance depends on technological innovation, market development, and policy intervention. The design is capable of accommodating a changing menu of technologies, recognizing that changes in energy prices and consumer demand may significantly change the set of relevant technologies the model user wishes to consider. The model includes an option to allow endogenous price-induced technology change in the determination of equipment costs and availability for the menu of equipment. This concept allows future technologies faster diffusion into the marketplace if fuel prices increase markedly for a sustained period.

Energy consumption

Following the choice of equipment to satisfy service demand, the model computes the total amount of energy consumed. To calculate energy use, the fuel shares of service resulting from the selected mix of equipment, together with the average efficiency of that mix, are applied to service demand. Projected building energy consumption is then benchmarked to EIA's State Energy Data consumption estimates for the commercial sector, applying an additive correction term to ensure that simulated model results correspond to published State Energy Data historical values. This benchmarking adjustment accounts for non-building commercial sector energy consumption (e.g., radio transmission towers) and provides a consistent starting point for the projection.

Industrial Demand Module

The Industrial Demand Module (IDM) estimates energy consumption by energy source (fuels and feedstocks) for 15 manufacturing and 6 non-manufacturing industries. The IDM incorporates three major industry categories, consisting of energy-intensive manufacturing industries, non-energy-intensive manufacturing industries, and non-manufacturing industries (Table 2). The level and type of modeling and the attention to detail is different for each.

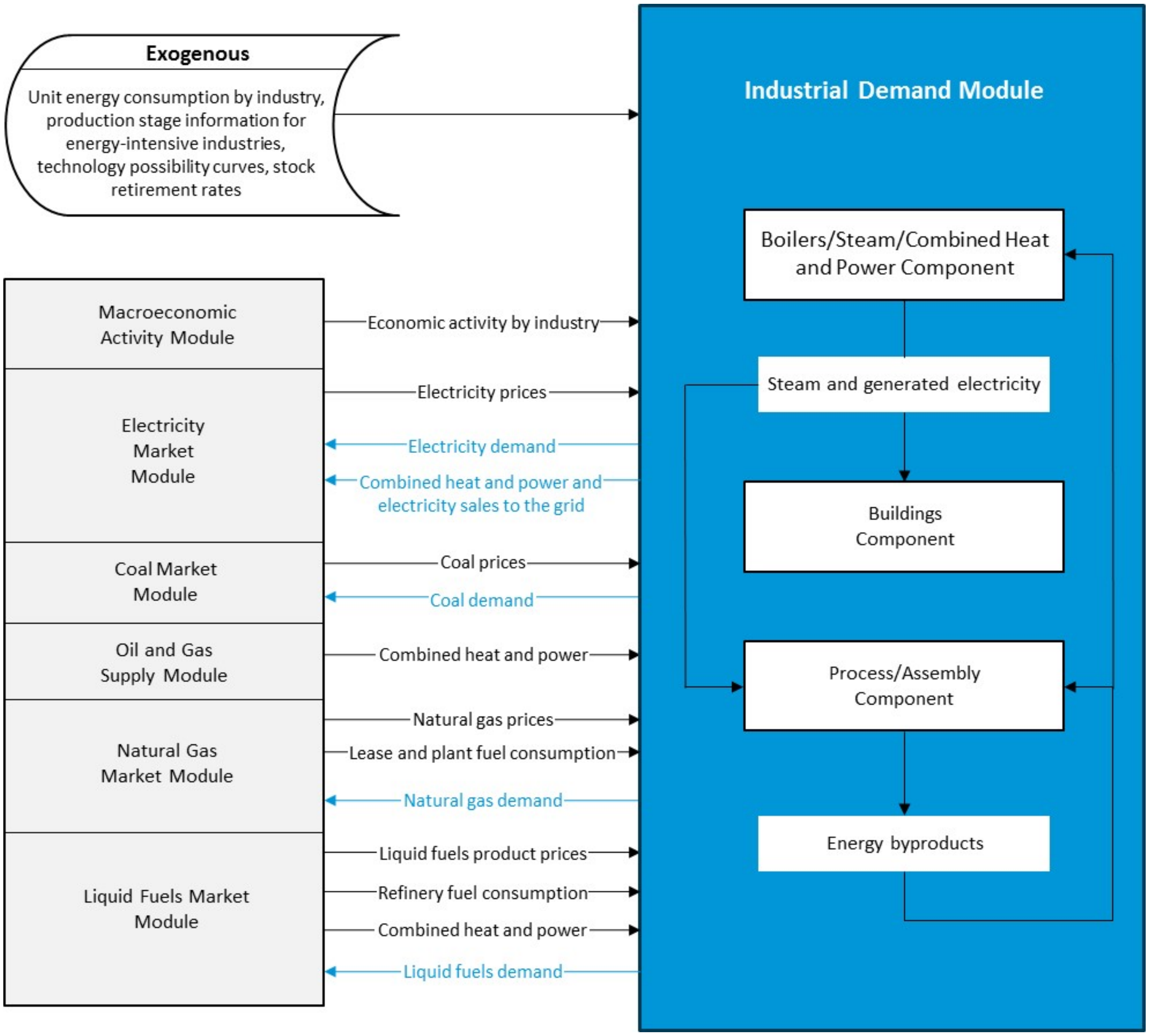
The manufacturing industries are modeled using detailed process flows or end-use accounting procedures. In addition, some of the end-use models are modeled in somewhat more detail. The energy-intensive bulk chemicals industry is subdivided into four industry components, and the food industry is also subdivided into four components. NEMS has detailed process flow submodules for the energy-intensive industries of cement and lime, aluminum, glass, iron and steel, and pulp and paper. The non-manufacturing industries are represented in less detail. The IDM projects energy consumption at the census region level. Energy consumption at the census division level is allocated by using data from the State Energy Data System. The IDM structure is shown in Figure 7.

Most industries use three separate but interrelated components, consisting of boiler/steam/cogeneration (BSC), buildings (BLD), and process/assembly (PA) activities. The paper, iron and steel, and aluminum industries include a BLD component and a PA component, but boiler/steam/cogeneration is modeled within the PA component.

Five manufacturing industries (paper, glass, cement and lime, iron and steel, and aluminum) are modeled with a structure that explicitly describes the major process flows or major consuming uses in the industry. Manufacturing industries are modeled using a process-flow model that allows for technology selection over time. Each year the IDM calculates the physical capacity needed to fulfill those shipments based on the value of shipments from the Macroeconomic Activity Module. The type of capacity added is chosen from a predefined slate of technologies. The source of the technology data is the Consolidated Impacts Modeling System. Model results include physical output and the share of technology chosen each year new capacity is added.

Currently, all other industries use the end-use model approach. The amount of energy consumption reported by the IDM is also a function of the vintage of the capital stock that produces the shipments. The end-use models use a capital stock vintage accounting framework that models energy use in new additions to the stock and in the existing stock. The existing stock is retired based on retirement rates specified for each industry. The end-use models assume that new capital stock will consist of state-of-the-art technologies that are, on average, more energy efficient than the existing capital stock. Consequently, the amount of energy required to produce a unit of output using new capital stock is less than that required using the existing capital stock. The energy intensity of the new capital stock relative to 2014 capital stock is represented by a parameter called a Technology Possibility Curve (TPC), which is estimated for each process step or end use. These TPCs are based on engineering judgments about the likely future path of energy intensity changes.

Figure 7. Industrial Demand Module structure



The energy intensity of the existing capital stock for the end-use models is assumed to decrease over time but not as rapidly as the assumed decline in new capital stock. The decline is because of retrofitting and the replacement of equipment from normal wear and tear. Retrofitting existing capacity is assumed to incorporate 50% of the improvement that is achieved by installing new capacity.

The model structure accommodates several industrial sector activities, including fuel switching, cogeneration, renewables consumption, recycling, and byproduct consumption. For the end-use models, the principal model calculations are performed at the census region level and aggregated to a national total. For the process-flow models, the model calculations are done at the national level and parsed out to the census regions based on regional macroeconomic data.

Energy consumption in the IDM is primarily a function of the level of industrial economic activity. Industrial economic activity in NEMS is measured by the dollar value of shipments (in constant 2009 dollars) produced by each industry group. The value of shipments by the North American Industrial Classification System (NAICS) code is provided to the IDM by the Macroeconomic Activity Module. As the level of industrial economic activity increases, energy consumption typically increases, but at a slower rate than the growth in economic activity.

Energy consumption in the buildings component is assumed to grow at the same rate as the average growth rate of employment and output in that industry. This formulation has been used to account for the countervailing movements in manufacturing employment and value of shipments. Manufacturing employment falls during the projection period, which alone would imply falling building energy use. However, the quickly growing number of shipments implies that air-conditioned floorspace is increasing. Energy consumption in the BSC component is assumed to be a function of the steam demand of the buildings and process/assembly components.

Electricity consumption by the machine drive end use for the food, bulk chemicals, metal-based durables, and balance of manufacturing industries is modeled differently than for the other end uses in these industries. Instead of using the TPC approach, a motor stock model calculates machine drive electricity consumption. Seven motor size groups are modeled for each industry.

Table 2. Industries within the IDM as identified by their NAICS codes

Energy-intensive manufacturing		Non-energy-intensive manufacturing		Nonmanufacturing	
Industry	**NAICS Codes**	**Industry**	**NAICS Codes**	**Industry**	**NAICS Codes**
Food products	311	*Metal-based durables industries*		Agricultural crop production	111
Paper and allied products	322	Fabricated metal products	332	Other agricultural production	112, 113, 115
Bulk chemicals[1]		Machinery	333	Coal mining	2121
Inorganic chemicals	325120–325180	Computer and electronic products	334	Oil and natural gas extraction	211
Organic chemicals	325110, 32519	Electrical equipment and appliances	335	Metal and other nonmetallic mining	2122–2123
Resins	3252	Transportation equipment	336	Construction	23
Agricultural chemicals	3253	Wood products	321		
Glass and glass products	3272, 327993	Plastic and rubber products	326		
Cement and lime	327310, 327410	Balance of manufacturing	312–316, 323, 3254–3256, 3259, 3271, 327320, 327330, 327390, 327420, 3279, 3314, 3315, 337, 339		
Iron and steel	331110, 3312, 324199[2]				
Aluminum	3313				

[1]Bulk chemicals energy consumption is reported as an aggregate in the *Annual Energy Outlook*.

[2]NAICS 324199 contains merchant coke ovens, which are considered part of the iron and steel industry in the *Annual Energy Outlook*.

NAICS = North American Industry Classification System.

Source: U.S. Department of Commerce, Census Bureau, North American Industry Classification System 2012 - United States.

Transportation Sector Demand Module

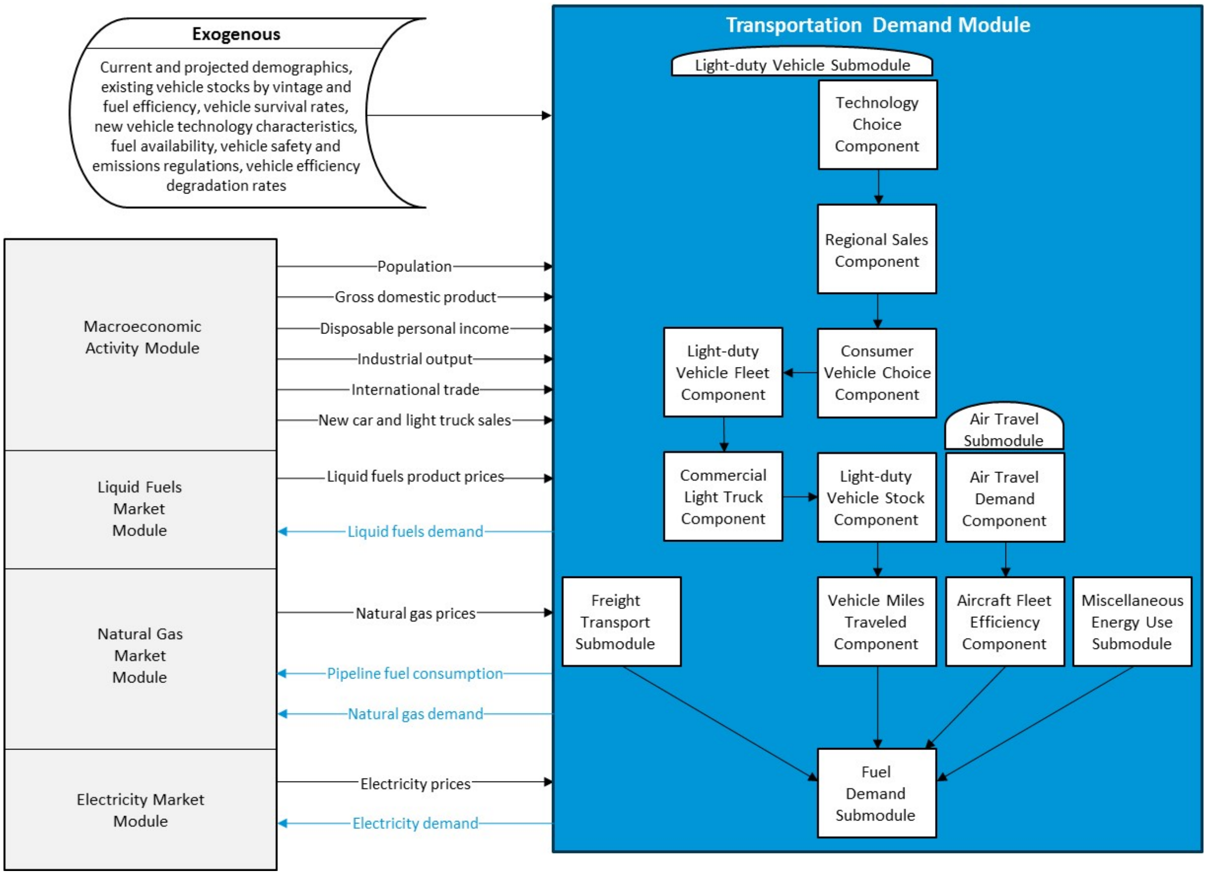
The Transportation Sector Demand Module (TDM) encompasses a series of semi-independent submodules and components that address different aspects of the transportation sector. The primary purpose of the comprehensive module is to provide projections of transportation energy demand by fuel type. Projections are generated through separate consideration of energy consumption within the various modes of transport: private and fleet light-duty vehicles; aircraft; and marine, rail, and truck freight. Other transportation demands such as mass transit, military, and recreational boating are also considered. This modular approach is useful in assessing the impacts of policy initiatives, legislative mandates affecting individual modes of travel, and technological developments.

The module also projects selected intermediate values necessary to determine energy consumption. These elements include estimates of passenger travel demand by light-duty vehicles, air, and mass transit; estimates of the energy requirements to meet this demand; projections of vehicle stock and the penetration of new technologies; and estimates of the demand for truck, rail, marine, and air freight transport that are linked to projections of industrial output, international trade, and energy supply.

The structure of the module is shown in Figure 8, which consists of four submodules representing a variety of travel modes that differ in design and use but share the same ultimate purpose: to convey passengers and freight. The four submodules include: Light-Duty Vehicle, Air Travel, Freight Transport, and Miscellaneous Energy Demand. Each submodule is composed of one or more components, consistent with the methodological requirements of the sector and commensurate with the relative impact that sector has on overall transportation demand and energy use.

The Light-Duty Vehicle Submodule uses econometric models to forecast passenger travel demand and new vehicle market share and uses engineering and expert judgment for estimating fuel economy. The Air Travel Submodule also uses econometrics to forecast passenger travel demand and aircraft efficiency, as well as using other inputs such as jet fuel prices, world regional population, world regional gross domestic product, U.S. disposable personal income, and merchandise export. The Freight Transportation Submodule uses output from selected industries to estimate travel demand and energy consumption in each of three primary freight modes: truck, rail, and marine. The Miscellaneous Energy Demand Submodule forecasts passenger travel and energy and oil demand from military, mass transit (including bus and rail), recreational boating, and lubricants.

Figure 8. Transportation Demand Module structure



Light-Duty Vehicle Submodule

The Light-Duty Vehicle (LDV) Submodule tracks the purchase and retirement of cars and light trucks, projects fuel efficiency, and estimates the consumption of transportation fuels based on projections of travel demand, primarily consisting of seven components:

- Manufacturer Technology Choice Component
- Regional Sales Component
- Consumer Vehicle Choice Component
- LDV Fleet Component
- Class 2b Vehicle Component
- LDV Stock Accounting Component
- Vehicle Miles Traveled Component

Each component performs calculations at a level of disaggregation commensurate with the nature of the mode of transport, the quality of the input data, and the level of detail required in the output. The projections are calculated for nine vehicle manufacturers, including four car groups and five light truck groups. Cars and light trucks are each separated into six market classes. Each market class represents an aggregation of vehicle models that are similar in size and price and are perceived by consumers to offer similar attributes. The car classes are similar to the U.S. Environmental Protection Agency (EPA) size classes and are based on passenger car interior volume. Truck classification is based on statutorily determined vehicle inertia weight class by truck type (pickup, sport utility vehicle, and van). This classification leads to a total of 12 size classes, which are individually projected for 9 manufacturer groups.

The fuel economy of new vehicles is affected by changes in four factors:

- Technology penetration
- Level of acceleration performance achieved
- Mix of vehicle size classes and vehicle technology types (e.g., hybrid and diesel) sold
- Vehicle fuel economy, safety, and emission standards

Technological improvements to each of these market classes are then projected based on the availability of new technologies to improve fuel economy as well as their cost-effectiveness under two user-specified alternative scenarios. The central assumptions involved in this technological projection are as follows:

- All manufacturers can obtain the same benefits from a given technology, provided they have adequate lead time (i.e., no manufacturer exclusively owns a technology in the long term).
- Manufacturers will generally adopt technological improvements that are perceived as cost-effective to the consumer, even without regulatory pressure. However, the term cost-effective needs to be interpreted in the manufacturer's context.

These projections also account for manufacturer lead time and tooling constraints that limit the rate of increase in the market penetration of new technologies. Based on the technological improvements adopted, a fuel economy projection is developed for each of the manufacturers and market classes.

The fuel economy projection must be adjusted to account for changes in technology and changes in consumer preference for performance. The demand for increased acceleration performance for each market class is estimated based on an econometric equation relating fuel prices and personal disposable income to demand for performance or horsepower, by market class. These relationships are used to project the change in horsepower, which is then used to project the change in fuel economy through an engineering relationship that links performance and fuel economy.

The change in the mix of market classes sold is projected as a function of fuel price, vehicle price, and personal disposable income. The sales mix by six car and six light truck market classes is used to calculate new fuel economy. The sales mix by market class is used to calculate new fuel economy. The submodule projects sales mix for the six car and six light truck classes, but import market shares are held at fixed values by market class based on historical estimates.

The Light-Duty Vehicle Submodule also allows specification of fuel economy standards by year and of different standards for each of nine manufacturer groups, as well as the penalty (in dollars) per car per mile per gallon below the standard. The standards are accounted for in the projection by incorporating the penalty into the technology cost-effectiveness calculation in the submodules. Finally, the submodule also accounts for select state-level regulations, such as the California Zero Emission Vehicle mandate, which is also enforced in Connecticut, Maine, Maryland, Massachusetts, New Jersey, New York, Oregon, Rhode Island, and Vermont.

Manufacturer's technology choice component

The manufacturer's technology choice component in the Light-Duty Vehicle Submodule produces estimates of new light-duty vehicle fuel economy. Fuel economy is a significant aspect of the transportation sector demand module because automotive fuel demand is directly affected by fuel efficiency. Because of the disparate characteristics of the various classes of light-duty vehicles, this component addresses the commercial viability of up to 86 separate technologies within each of 12 vehicle market classes, 9 manufacturer groups, and 16 vehicle/fuel types.

Each available technology is subjected to a cost-effectiveness test that balances the cost of the technology against the potential fuel savings and the value of any increase in performance provided by the technology. The cost-effectiveness test is used to generate an economic market share for the technology. In certain cases, adjustments must be made to the calculated market shares to reflect the effects of engineering limitations or external forces that require certain types of technologies, including both safety and emissions technologies.

Regional sales component

The regional sales component is a simple accounting mechanism using new car and light truck sales from the Macroeconomic Activity Module and the results of the manufacturer's technology choice component to produce estimates of regional sales and the characteristics of light-duty vehicles that are subsequently passed to the light-duty vehicle stock component.

Consumer vehicle choice component

The consumer vehicle choice component estimates the market penetration of conventional and alternative-fuel vehicles using estimates of new car fuel economy (from the manufacturer's technology choice component), vehicle price, vehicle range, fuel availability, battery replacement cost, performance (measured by the horsepower-to-weight ratio), home refueling capability, maintenance costs, luggage space, make and model diversity or availability, and fuel price estimates.

The consumer vehicle choice component uses attribute-based discrete choice techniques and logit-type choice functions, which represent a demand function for vehicle sales in the United States. The demand function uses projections of the changes in vehicle and fuel attributes for the considered technologies to estimate the market share penetration for the various technologies.

Light-duty vehicle fleet component

This component generates estimates of the stock of cars and trucks used in business, government, utility, and autonomous ride-hail vehicle fleets and subsequently estimates travel demand, fuel efficiency, and energy consumption by these fleet vehicles before their transition to the private sector at predetermined vintages.

Light-duty vehicle stock component

This submodule takes sales and efficiency estimates for new cars and light trucks and returns the number and characteristics of the total surviving fleet of light-duty vehicles, along with regional estimates of light-duty vehicle fuel consumption. It uses vintage-dependent constants such as vehicle survival, relative driving rates, and fuel economy degradation factors to obtain estimates of stock efficiency. The component encompasses 25 vintages, with the 25th being an aggregate of all vehicles 25 years or older.

The TDM maintains a level of detail that includes 20 vintage classifications and 6 passenger car and 6 light truck size classes corresponding to EPA interior volume classifications for all vehicles less than 8,500 pounds.

Vehicle miles traveled component

The vehicle miles traveled component is a subcomponent of the light-duty vehicle stock component that uses estimates of fuel price and personal income, along with population projections, to generate a projection of the demand for personal travel, expressed in vehicle miles traveled per licensed driver. This estimate is subsequently combined with projections of car fleet efficiency to estimate fuel consumption.

The primary concern in projecting vehicle miles traveled per licensed driver in the mid- to long-term is to address those effects that alter historical growth trends. The factors affecting future vehicle miles traveled trends in the model are the fuel cost of driving, disposable personal income, employment, vehicles per licensed driver, and past vehicle miles traveled trends. Historical licensed driver rates are provided by the Federal Highway Administration by age cohort, gender, and region.

Air Travel Submodule

The Air Travel Submodule comprises two separate components: the air travel demand component and the aircraft fleet efficiency component. These components use projections of fuel price, macroeconomic activity, and population growth, as well as assumptions about aircraft retirement rates and technological improvements, to generate projections of passenger and freight travel demand and the fuel required to meet that demand. The Air Travel Submodule receives exogenous estimates of aircraft load factors, new technology characteristics, and aircraft specifications that determine the average number of available seat-miles each plane will supply in a year.

Air travel demand component

The air travel demand component produces projections of domestic and international per-capita passenger travel demand by 13 world regions on a per-capita basis, expressed in revenue passenger-miles per-capita, and world regional air freight demand, measured in revenue ton-miles. Domestic travel means both takeoff and landing occur in the same region, while international travel means that either takeoff or landing is in the region but not both. Domestic and international travel are combined into a single regional demand for seat-miles and passed to the aircraft fleet efficiency component, which adjusts aircraft stocks to meet that demand. Aircraft stock is composed of three types of aircraft: wide body, narrow body, and regional jets.

Aircraft fleet efficiency component

The aircraft fleet efficiency component provides estimates of the number of narrow-body, wide-body, and regional jet aircraft available to meet passenger and freight travel demand subject to user-specified parameters. This mechanism also estimates fleet efficiency using a harmonically weighted average of the characteristics of active aircraft and those acquired to meet demand. Fuel efficiency of new aircraft is calculated based on estimates of technology penetration and efficiency improvements of a slate of nine aircraft technologies. A structured accounting method is used to provide estimates of the movement of aircraft, active and parked, both within and between regions. The structured accounting defines a priority scheme to determine which regions receive the aircraft. The fleet average efficiency for each body type is then calculated as a weighted harmonic mean of efficiencies for the active aircraft stock. The resulting fleet average efficiencies along with the demand for travel provide the projection of commercial passenger and freight carriers' jet fuel consumption.

Freight Transportation Submodule

The Freight Transportation Submodule addresses the three primary modes of freight transport: truck, rail, and marine. This submodule uses projections of real fuel prices, trade indices, coal production, and selected industries' output from the Macroeconomic Activity Module to estimate travel demand for each freight mode and the fuel required to meet that demand. The carriers in each of these modes are characterized by long operational lifetimes and the ability to extend these lifetimes through retrofitting. This process results in a low turnover of capital stock and the consequent dampening of improvement in average energy efficiency. Given the long projection horizon, however, this submodule provides estimates of modal efficiency growth, driven by assumptions about systemic improvements and the adoption of new technology.

Freight truck stock adjustment component

The freight truck stock adjustment component projects the consumption of diesel fuel, motor gasoline, propane, compressed/liquefied natural gas, flex fuel, electricity, and hydrogen used by freight trucks in each of 12 industrial sectors. The submodule tracks 34 truck vintages, 19 truck market classes, 14 fuel-efficiency standard market subclasses, and 2 fleet types, each having its own average fuel economy and number of miles driven per year. The results are reported in four truck market classes defined as follows: class 2b includes trucks with a gross vehicle weight rating of 8,501 to 10,000 pounds; class 3 includes trucks 10,001 to 14,000 pounds; classes 4 through 6 include trucks 14,001 to 26,000 pounds; and classes 7 and 8 include trucks over 26,000 pounds. The 14 fuel-efficiency market subclasses include 1 breakout for pickups and vans in classes 2b and 3, 3 breakouts for vocational vehicles (classes 2b-5, classes 6-7, and class 8), 9 breakouts for tractors, and 1 heavy-haul breakout. The 10 subclasses for heavy trucks include parceling the class by class 7 or class 8, by day cab or sleeper cab, and by low-, mid- or high-roof.

Rail component

Rail projections represent a simplification of the freight truck approach, in that only one class of freight rail and vehicle technology is considered. Projections of energy use by rail are driven by projections of coal production and of ton-miles traveled for each of the industrial categories used in the trucking sector.

Waterborne freight component

Two classes of waterborne freight transportation are considered in this component: domestic marine traffic and freighters conducting foreign trade. The two classes are useful because vessels that comprise freighter traffic on rivers and in coastal regions have different characteristics than those that travel in international waters.

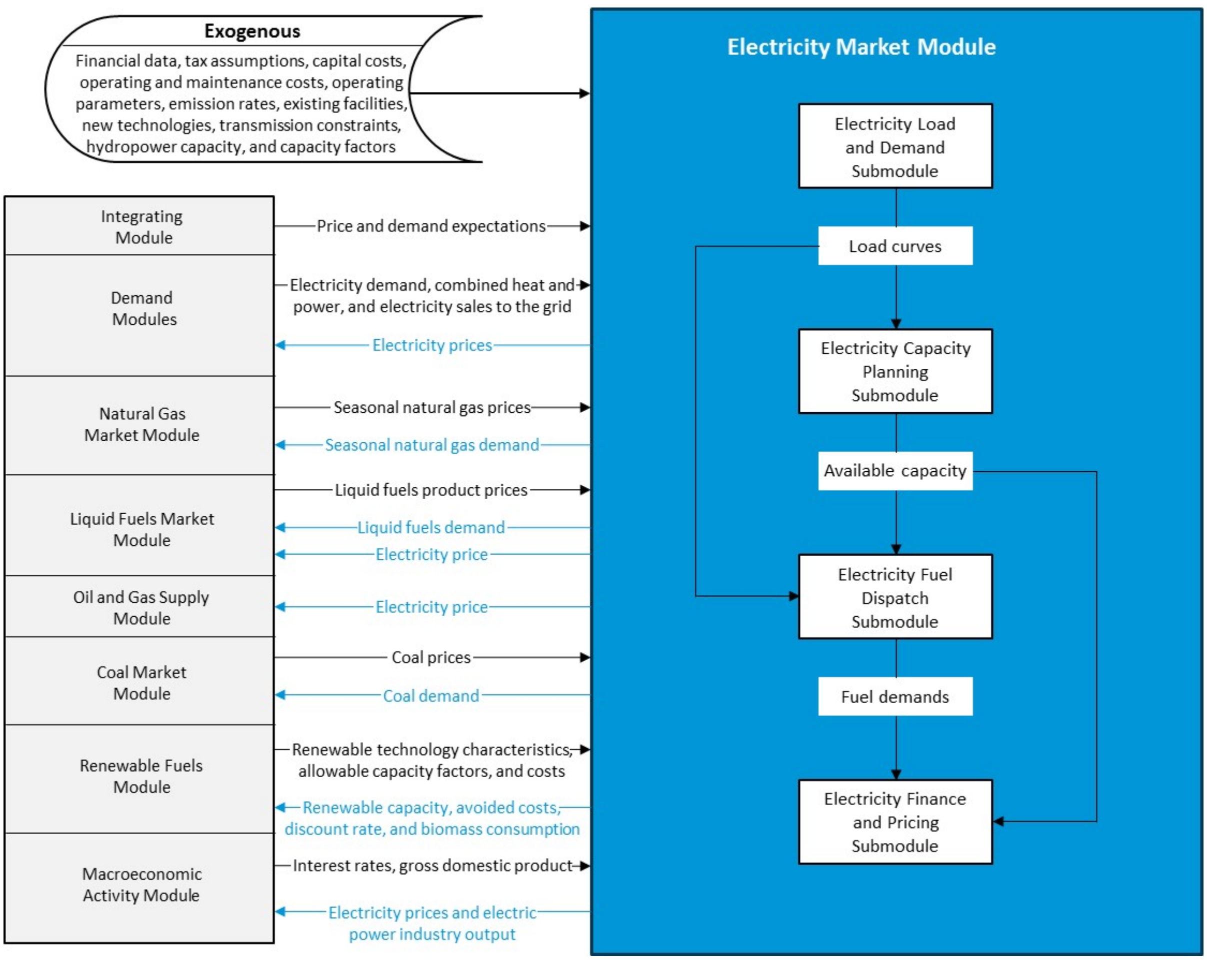
Miscellaneous Energy Demand Submodule

This submodule projects the use of energy in military operations, mass transit (passenger rail and buses), recreational boating, and lubricants used in all modes of transportation. Fuel demand for military operations is considered proportional to the projected military budget. The growth of passenger-miles in each mode of mass transit is assumed to be proportional to the growth of passenger-miles in light-duty vehicles. The growth in fuel use by recreational boats is related to the growth in disposable personal income. Lastly, the growth in demand for lubricants is considered proportional to the growth in highway travel by all types of vehicles.

Electricity Market Module

The Electricity Market Module (EMM) represents the capacity planning, generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biomass; the cost of centralized generation facilities; macroeconomic variables for costs of capital and domestic investment; and electricity load shapes and demand. The submodules consist of capacity planning, fuel dispatching, finance and pricing, and electricity load and demand (Figure 9). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from cogenerators and other facilities whose primary business is not electricity generation is represented in the NEMS demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 22 supply regions (Figure 10). Alaska and Hawaii are not modeled explicitly in the EMM, but generation and consumption projections for those states are estimated for reporting national totals.

Figure 9. Electricity Market Module structure



Operating (dispatch) decisions are made by choosing the mix of plants that minimizes fuel, variable operating and maintenance (O&M), and environmental costs, subject to meeting electricity demand and environmental constraints. The least-cost mix of all costs (including capital, O&M, and fuel) determines capacity expansion. Electricity demand is represented by load curves, which vary by region, season, and time of day.

The EMM also represents distributed generation that is owned by electricity suppliers. Consumer-owned distributed generation is determined in the end-use demand modules of NEMS. The EMM considers construction, operating, and avoided transmission and distribution costs associated with distributed generation to evaluate these options as an alternative to central-station capacity. The solution to the submodules of EMM is simultaneous in that, directly or indirectly, the solution for each submodule depends on the solution to every other submodule. A solution sequence through the submodules can be viewed as follows:

- The Electricity Load and Demand Submodule processes electricity demand to construct load curves.
- The Electricity Capacity Planning Submodule projects the construction of new generating plants, the retirement (if appropriate) of existing plants, the level of firm power trades, and the addition of scrubbers and other equipment for environmental compliance. The Electricity Fuel Dispatch Submodule dispatches the available generating units, allowing surplus capacity in selected regions to be dispatched to meet another region's needs (economy trade).
- The Electricity Finance and Pricing Submodule calculates retail electricity prices based on both average and marginal costs.

Electricity Load and Demand Submodule

The Electricity Load and Demand Submodule (ELD) has been designed to perform two major functions:

- Translate census division demand data into North American Electric Reliability Corporation (NERC) region data, and vice versa.
- Translate total electricity consumption forecasts into system load shapes.

The demand for electricity varies during the course of a day. Many different technologies and end uses, each requiring a different level of capacity for different lengths of time, are powered by electricity. The ELD generates load curves representing the variations in the demand for electricity. For operational and planning analysis, a load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the ELD generates load curves for each region and season for operational and planning purposes.

Electricity Capacity Planning Submodule

The Electricity Capacity Planning Submodule (ECP) determines how best to meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and technology costs and performance characteristics. When new capacity is required to meet electricity demand, the technology that is chosen is determined by the timing of the demand increase, the expected utilization of the new capacity, the operating efficiencies, and the construction and operating costs of available technologies.

The ECP evaluates retirement decisions for fossil fuel and nuclear plants and captures responses to environmental regulations. It includes traditional and nontraditional sources of supply. The ECP also represents changes in the competitive structure (i.e., deregulation). Because of competition, no distinction is made between utilities and nonutilities as owners of new capacity.

The utilization of the capacity is important in the decision-making process. A technology with relatively high capital costs but comparatively low operating costs (such as coal-fired technologies) may be the appropriate choice if the capacity is expected to operate continuously (base load). However, a plant type with high operating costs but low capital costs (such as a natural gas-fired turbine technology) may be the most economical selection to serve the peak load (i.e., the highest demands on the system), which occurs infrequently. Intermediate or cycling load occupies a middle ground between base and peak load and is best served by plants that are cheaper to build than base load plants and cheaper to operate than peak load plants (such as a natural gas-fired combined cycle plant). Intermittent renewable plants, such as solar photovoltaic and wind technologies, have variable output throughout the year, which may or may not line up with regional demand patterns. A battery storage technology can be built to store generation during low demand periods that may be more valuable to meet demand during other periods.

Technologies are compared on the basis of total capital and operating costs incurred during a 30-year period. As new technologies become available, they compete against conventional plant types. Fossil fuel, nuclear, and renewable generating technologies are represented as listed in Table 3. Base overnight capital costs are assumed to be the current cost per kilowatt for a unit constructed today. The EMM also considers two distributed generation technologies—baseload and peak. The EMM also has the ability to model a demand storage technology to represent load shifting, although this feature is not used in the AEO2018 cases. An annual cost factor is calculated based on the change from a base year for the macroeconomic variable tracking the metals and metal products producer price index, thereby creating a link between construction costs and commodity prices.

Table 33. Generating technologies

Existing coal steam plants[1]
Ultra-supercritical coal[2]
Advanced coal—integrated coal gasification combined cycle[2]
Ultra-supercritical coal with carbon capture and sequestration—30% and 90% removal options
Gas/oil steam
Conventional combined cycle
Advanced combined cycle
Advanced combined cycle with carbon capture and sequestration
Conventional combustion turbine
Advanced combustion turbine
Fuel cells
Distributed generation—base and peak load options
Conventional nuclear
Advanced nuclear
Conventional hydropower
Pumped storage
Battery storage
Geothermal
Solar thermal
Solar photovoltaic—single-axis tracking and fixed-tilt options
Wind
Wood
Municipal waste

[1]The EMM represents different types of existing coal steam plants, based on current or potentially installed environmental controls, including flue gas desulfurization, selective catalytic reduction, selective non-catalytic reduction, fabric filters, activated carbon injection, particulate removal equipment, and carbon capture.
[2]AEO2018 assumes new coal plants without carbon capture and sequestration cannot be built because of emission standards for new plants. These technologies exist in the modeling framework, but they are not assumed to be available to be built in the projections.

Uncertainty about investment costs for new technologies is captured in the ECP using technological optimism and learning factors. The technological optimism factor reflects the inherent tendency to underestimate costs for new technologies. The degree of technological optimism depends on the complexity of the engineering design and the stage of development. As development proceeds and more data become available, cost estimates become more accurate and the technological optimism factor declines.

Learning factors represent reductions in capital costs as a result of learning-by-doing. Learning factors are calculated separately for each of the major design components of the technology. Generally, overnight costs for new, untested components are assumed to decrease by a technology specific percentage for each doubling of capacity for the first three doublings, by 10% for each of the next five doublings of capacity, and by 1% for each further doubling of capacity. For mature components or conventional designs, costs decrease by 1% for each doubling of capacity.

Figure 10. Electricity Market Module supply regions

Table 44. Overnight capital costs (including contingencies), heat rates, and online year by technology for the AEO2018 Reference case

Technology	Capital costs [1] (2017 dollars per kilowatt)	Heatrate[2] in 2017 (Btu/kilowatthour)	First available Year[3]
Coal with 30% carbon sequestration (CCS)	5,089	9,750	2021
Coal with 90% CCS	5,628	11,650	2021
Conventional gas/oil combined cycle	982	6,600	2020
Advanced gas/oil combined cycle	1,108	6,300	2020
Advanced combined cycle with CCS	2,175	7,525	2020
Conventional combustion turbine	1,107	9,880	2019
Advanced combustion turbine	680	9,800	2019
Fuel cells	7,132	9,500	2020
Advanced nuclear	5,946	10,460	2022
Distributed generation—base	1,553	8,969	2020
Distributed generation—peak	1,866	9,961	2019
Battery storage	2,170	- -	2018
Biomass	3,837	13,500	2021
Geothermal[4]	2,746	9,271	2021
MSW—landfill gas	8,742	18,000	2020
Conventional hydropower[4]	2,898	9,271	2021
Wind[5]	1,657	9,271	2020
Wind offshore	6,454	9,271	2021
Solar thermal	4,228	9,271	2020
Solar photovoltaic—with axis tracking[5]	2,105	9,271	2019
Solar photovoltaic—fixed tilt[5]	1,851	9,271	2019

[1]Overnight capital cost including contingency factors, excluding regional multipliers (except as noted for wind and solar PV) and learning effects. Interest charges are also excluded. These represent current costs for plants that would come online in 2018. Capital costs are shown before investment tax credits are applied, where applicable.
[2]For hydropower, wind, solar and geothermal technologies, the heat rate shown represents the average heat rate for conventional thermal generation as of 2016. This heat rate is used for purposes of calculating primary energy consumption displaced for these resources, and it does not imply an estimate of their actual energy conversion efficiency. The nuclear average heat rate is the weighted average tested heat rate for nuclear units as reported on the Form EIA-860, Annual Electric Generator Report. No heat rate is reported for battery storage because it is not a primary conversion technology; conversion losses are accounted for when the electricity is first generated; electricity-to-storage losses are accounted for through the additional demand for electricity required to meet load.
[3]Represents the first year that a new unit could become operational.
[4]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.
[5]Wind and both solar PV technologies' total overnight cost shown in the table represents the average input value across all 22 electricity market regions, as weighted by the respective capacity of that type installed during 2016 in each region to account for the substantial regional variation in wind and solar costs (as shown in Table 8.3). The input value used for wind in AEO2018 was $1,887 per kilowatt (kW), for solar PV with tracking was $2,207/kW, and for solar PV fixed tilt was $2,068, representing the cost of building a plant excluding regional factors. Region-specific factors contributing to the substantial regional variation in cost include differences in typical project size across regions, accessibility of resources, and variation in labor and other construction costs through the country.
- - = Not applicable.
Btu=British thermal unit

Capital costs, heat rates, and first year of availability from the AEO2018 reference case are shown in Table 4; capital costs represent the costs of building new plants ordered in 2017. Additional information about costs and performance characteristics can be found in Table 2 on page 4 of the *Assumptions to the Annual Energy Outlook 2018: Electricity Market Module*.[9]

Initially, investment decisions are determined in the ECP using cost and performance characteristics that are represented as single point estimates corresponding to the average (expected) cost. However, these parameters are also subject to uncertainty and are better represented by distributions. If the distributions of two or more options overlap, the option with the lowest average cost is not likely to capture the entire market. Therefore, the ECP uses a market-sharing algorithm to adjust the initial solution and reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

The ECP also determines whether it is economic for a region to obtain new firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are represented using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are modeled in the ECP based on the cost of the unit in the exporting region plus the additional cost of transmitting the power. Transmission costs are computed as a fraction of revenue.

After projecting the construction of new capacity, the submodule passes total available capacity to the Electricity Fuel Dispatch Submodule and new capacity expenses to the Electricity Finance and Pricing Submodule.

Electricity Fuel Dispatch Submodule

The objective of the Electricity Fuel Dispatch Submodule (EFD) is to represent the economic, operational, and environmental considerations in electricity dispatching and trade. Given available capacity, firm trade agreements, fuel prices, and load curves, the EFD minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. The EFD dispatches utility, independent power producer, and small power producer plants throughout a transmission network until demand is met. A linear programming approach allows a least cost optimization of plants based on their operating costs and any transmission costs. Limits on emissions of sulfur dioxide and nitrogen oxides from generating units and the engineering characteristics and maintenance requirements of units serve as constraints. The dispatch explicitly accounts for spinning reserve requirements, and it provides several operating options for any given plant to allow for co-optimization of the production of energy with the deployment of spinning reserves. Dispatch is done for three time slices within three seasons to account for seasonal variation in electricity demand and available generation, as well as peak versus off-peak demand levels.

Interregional economy trade (i.e., transactions that are not firm contracts) is also represented in the EFD. The simultaneous dispatch decision across all regions linked by transmission network allows generation in one region to satisfy electricity demand in an adjacent region, resulting in a cost savings. Economy trade with Canada is determined in a similar manner as interregional economy trade. Surplus Canadian energy is allowed to displace U.S. energy in an adjacent U.S. region if it results in cost savings. After dispatching, fuel

[9] U.S. Energy Information Administration, Electricity Market Module Assumptions to the Annual Energy Outlook 2018, April 2018.

use is reported back to the fuel supply modules and fuel and operating expenses and revenues from trade are reported to the Electricity Finance and Pricing Submodule.

Electricity Finance and Pricing Submodule

The costs of building capacity, buying power, and generating electricity are tallied in the Electricity Finance and Pricing Submodule (EFP), which then uses these costs to compute both competitive and regulated end-use electricity prices. For those states that still regulate electricity generation, the EFP applies the cost-of-service method to determine the price of electricity. The EFP submodule calculates total revenue requirements for each area of utility operation—generation, transmission, and distribution—by using

- Historical costs for existing plants derived from various sources, such as Federal Energy Regulatory Commission (FERC) Form 1, Annual Report of Major Electric Utilities, Licensees and Others, and Form EIA-412, Annual Report of Public Electric Utilities
- Cost estimates for new plants
- Fuel prices from the NEMS fuel supply modules
- Unit operating levels
- Plant decommissioning costs
- Purchased power costs

Revenue requirements shared over sales by customer class yield the price of electricity for each class. In addition, the submodule generates detailed financial statements.

For those states that have deregulated their electricity generation markets, the EFP determines competitive prices for electricity generation. Unlike cost-of-service prices, which are based on average costs, competitive prices are based on marginal costs. Marginal costs are primarily the operating costs of the most expensive plant required to meet demand in a given region during a given time period. The competitive price also includes a capacity payment, which is designed to represent a proxy for additional capital recovery that must be procured from consumers, rather than representing a specific market. The capacity payment also recovers costs associated with meeting spinning reserve requirements in the EFD. Prices for transmission and distribution are assumed to remain regulated, so the delivered electricity price under competition is the sum of the marginal price of generation and the average price of transmission and distribution.

The delivered price of electricity calculated in the EFP for each EMM region is passed to the end-use demand models in NEMS. The price transmitted is either the cost-of-service price, the competitive price, or a combination of both, depending on whether a given EMM region has committed to competitive electricity markets and what percentage of the region's sales are in competitive markets.

Emissions

The EMM tracks emission levels for sulfur dioxide, nitrogen oxides, and mercury. Facility development, retrofitting, and dispatch are constrained to comply with the requirements of the Clean Air Act Amendments of 1990 (CAAA90). The EMM also represents California Assembly Bill 32: California Global Warming Solutions Act of 2006, which limits on carbon dioxide emissions; the Regional Greenhouse Gas Initiative, which limits carbon emissions from electricity generating facilities in nine northeastern states;

and the U.S. Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards, which regulates hazardous air pollutants. It also incorporates the EPA Cross State Air Pollution Rule, which was upheld by the Supreme Court as a replacement for the Clean Air Interstate Rule. The Cross State Air Pollution Rule regulates sulfur dioxide and/or nitrogen oxides emissions for 27 states.

The EMM includes Section 111(b) of the Clean Air Act, which specifies performance standards for carbon dioxide emissions from new generating sources. This provision is represented by assuming that new coal-fired plants have carbon capture and sequestration (CCS) equipment removing at least 30% of the emissions. The EMM can represent the Clean Power Plan (CPP), which established standards for carbon dioxide emissions from existing sources in the power sector under Section 111(d) of the Clean Air Act. The AEO2018 Reference case does not assume the CPP is in place, but alternate cases are provided that include the rule. The CPP provides state-level emissions standards; however, the EMM operates at a regional level so the specified targets are converted to equivalent values for the 22 EMM regions.

The CPP provides the flexibility to use either mass-based or rate-based standards. The AEO2018 cases that include this regulation use the mass-based standard. The cases also include the option to cover both existing and new generating sources as a mechanism to meet the EPA requirement that implementation does not result in shifting emissions to uncovered generators (leakage). With a mass-based program, the method for allocating allowances also needs to be specified. The AEO cases assume that allowances are given to load-serving entities to minimize the price impacts on consumers, but the EMM includes the capability to examine alternative allowance allocation methods.

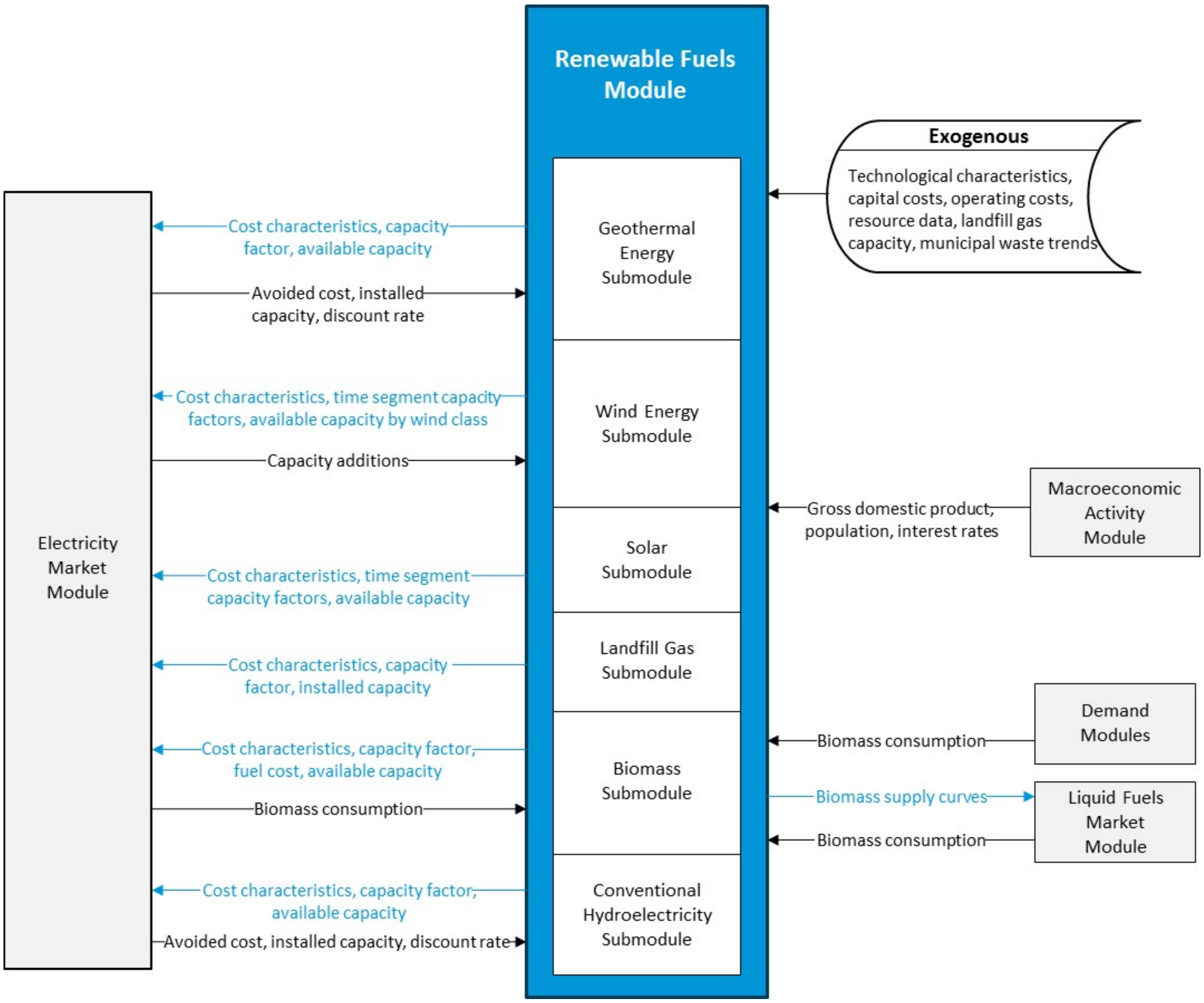
Some current and proposed regulations use an allowance trading market. The trading system allows a utility with a relatively low cost of compliance to sell its excess compliance (i.e., the degree to which its emissions per unit of power generated are below maximum allowable levels) to utilities with a relatively high cost of compliance. The trading of emissions allowances does not change the national aggregate emissions levels, but it does tend to minimize the overall cost of compliance. In the EMM, trading is assumed to occur at the regional level, with those regions having a low cost of compliance allowed to sell excess allowances to the higher-cost regions, where allowed by the specific program.

Because the Clean Power Plan represents the emissions standards at the EMM region level, it implicitly assumes allowance trading between states within a given region. The EMM also includes the capability to represent interregional trading with the mass-based standards of the Clean Power Plan.

Renewable Fuels Module

The Renewable Fuels Module (RFM) represents renewable energy resources and large-scale technologies used for grid-connected U.S. electricity supply (Figure 11) and consists of six submodules that represent major renewable electricity resources: biomass, landfill gas (LFG), solar (thermal and photovoltaic), wind, geothermal, and conventional hydroelectricity energy.

Figure 11. Renewable Fuels Module structure



The purpose of the RFM is to define the technology, cost, performance, and renewable resource supply for renewable electricity technologies in NEMS. The RFM estimations are provided to the Electricity Market Module (EMM) for use in projecting grid-connected central station electricity capacity planning and dispatch decisions. Projected characteristics include available generating capacity, location, unit size, capital cost, fixed operating cost, variable operating cost, capacity factor, heat rate, construction lead time, and fuel price. Because of the extensive interaction between the RFM and the EMM, these two modules must be run together.

Renewable electricity technology cost and performance characteristics that are common to all electricity generating technologies are input directly to the EMM. Unique characteristics such as renewable resource values for regional, seasonal, and hourly time segments of intermittent renewables are supplied in specific files and subroutines to specific renewable electricity technologies.

Other renewables modeled elsewhere in NEMS include biomass in the Industrial Demand Module, biofuels in the Liquid Fuels Market Module, wood and solar hot water heating in the Residential Demand Module, and geothermal heat pumps and distributed (grid-connected) solar photovoltaics in the Residential and Commercial Demand Modules. In addition, several areas are not represented in NEMS, primarily nonelectric and off-grid electric applications. They include direct applications of geothermal heat, several types of solar thermal use, and off-grid photovoltaics. For the most part, the expected contributions from these sources are confined to niche markets; however, as these markets develop in importance, they will be considered for representation in NEMS.

Landfill Gas Submodule

The Landfill Gas Submodule provides annual projections of energy produced from estimates of U.S. landfill gas capacity. The submodule calculates the quantity of landfill gas produced, derived from an econometric equation that uses gross domestic product and U.S. population as the principal forecast drivers. The landfill gas capacity is estimated based on reported waste and gas production data and judgment about future trends in recycling. The submodule uses supply curves for landfill gas to reflect competition between new landfill gas-to-electricity capacity and other technologies in each projection period. The supply curves account for the amounts of high, low, and very low methane-producing landfills located in each EMM Region.

Wind Energy Submodule

The Wind Energy Submodule projects the availability of wind resources. Projected undeveloped wind resource availability, expressed as megawatts of capacity in each region, is passed to the EMM, which models the building and dispatching of wind turbines in competition with other electricity generating technologies. The wind turbine data are expressed in the form of energy supply curves. The supply curves provide the estimated maximum amount of turbine generating capacity that could be installed, given the available land area, average wind speed, and capacity factor. These variables are passed to the EMM in the form of nine time segments, derived from three distinct eight-hour segments of the day for three seasons (winter, summer, and off-peak) that are matched to electricity load curves within the EMM.

Solar Submodule

Two solar technologies are represented in NEMS, a 150-megawatt single-axis tracking grid-connected central station photovoltaic unit without energy storage and a 100-megawatt central receiver (power tower) solar thermal unit (also called concentrating solar power) also without energy storage. Both technologies are grid-connected and are provided by electric utilities, small power producers, or independent power producers.

Photovoltaic and solar thermal electric cost and performance characteristics are defined consistently with characteristics of fossil and other fuels and are input exogenously to the EMM. Performance characteristics unique to solar technologies (such as season and region-dependent capacity factors), however, are passed to the EMM via the Solar Submodule.

Biomass Submodule

The Biomass Submodule provides biomass resource and technology cost and performance characteristics for a biomass-burning electricity-generating technology to the EMM. The technology currently modeled is a direct combustion system. The submodule uses a regional biomass supply schedule from which the biomass fuel price is determined; fuel prices are added to variable operating costs because fuel costs are not included in the structure of NEMS for renewable fuels. The biomass supply schedule is based on the accessibility of wood resources by the consuming sectors from existing wood and wood residues, crop residues, and energy crops. The Liquid Fuels Market Module also accesses the biomass supply curve to determine availability of feedstocks for production of cellulosic ethanol, biomass pyrolysis oils, and biomass-to-liquids. Projected feedstocks for production of sugar/starch based ethanol (primarily from corn/maize in the United States) are determined within the Liquid Fuels Market Module.

Geothermal Energy Submodule

The Geothermal Energy Submodule models current and future regional supply, capital cost, and operation and maintenance costs of electric generating facilities using hydrothermal resources (hot water and steam) and near-field enhanced geothermal systems sites, which are areas around the hydrothermal sites with high temperatures but less fluid. The data are assembled from 125 known hydrothermal sites and the 125 corresponding near-field enhanced geothermal system areas, each represented by information that reflects the specific resource conditions of that location. The Geothermal Energy Submodule generates a three-part geothermal resource supply curve for geothermal capacity for each region in each forecast year for competition with fossil-fueled and other generating technologies.

Conventional Hydroelectricity Submodule

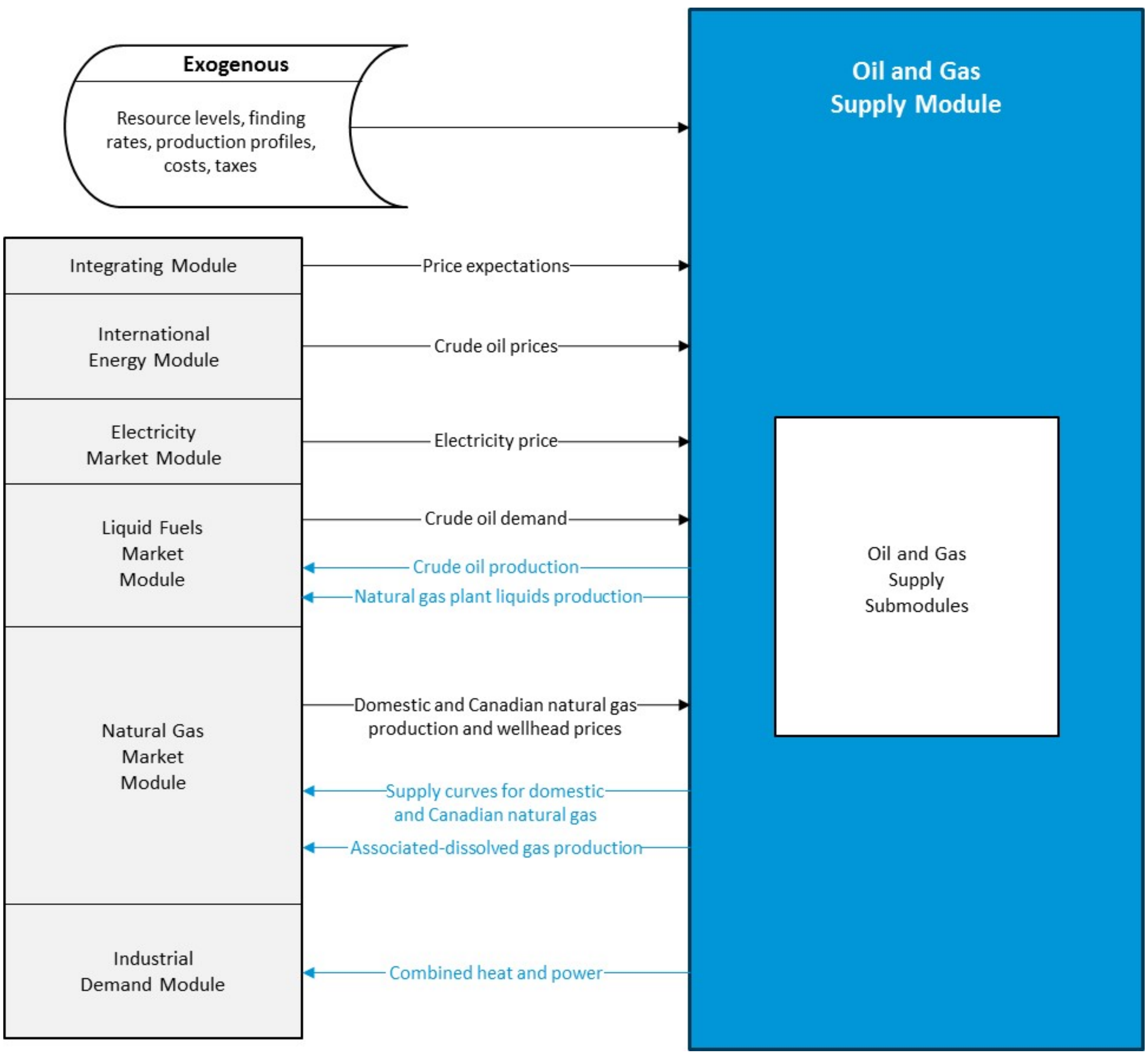
The Conventional Hydroelectricity Submodule (CHS) models the supply (megawatts), capital cost, and operation and maintenance costs of conventional hydroelectric power available from adding new hydro generating capacity in increments of 1 megawatt or greater to new sites without dams, sites with existing dams but without hydroelectricity, and existing hydroelectricity sites able to accommodate additional capacity. The CHS uses the Idaho Hydropower Resource Economics Database. The CHS does not account for pumped storage capacity, increments of capacity less than 1 megawatt, potential available from refurbishing and upgrading existing hydro capacity, or capacity available from new in-stream, offshore, or ocean technologies. Within each NEMS region, for each NEMS cycle, the CHS first identifies additional hydroelectric capacity available at or lower than an avoided cost specified by the EMM, then segments the available capacity into three cost categories: lowest cost, midrange cost, and highest cost. The CHS then submits the megawatts of available capacity (expressed as average capital cost and operation and maintenance costs) and capacity factors to the EMM for each of the three cost categories. After projecting capacity change decisions, the EMM informs the CHS of required decrements to potential available for selection in the next NEMS cycle.

Oil and Gas Supply Module

The Oil and Gas Supply Module (OGSM) is a comprehensive framework used to analyze oil and natural gas supply potential and related issues. Its primary function is to produce domestic projections of crude oil and natural gas production in response to price data received from the Natural Gas Market Module (NGMM) and the Liquid Fuels Market Module (LFMM). Projected natural gas and crude oil wellhead prices are determined within the NGMM and the LFMM, respectively. As the supply component only, the OGSM cannot project prices, which are the outcome of the equilibration of both demand and supply.

The basic interaction between the OGSM and the other oil and gas modules is represented in Figure 12. The OGSM provides expected natural gas production to the NGMM for use in its short-term domestic non-associated gas production functions and associated-dissolved natural gas production. The interaction of supply and demand in the NGMM determines nonassociated gas production.

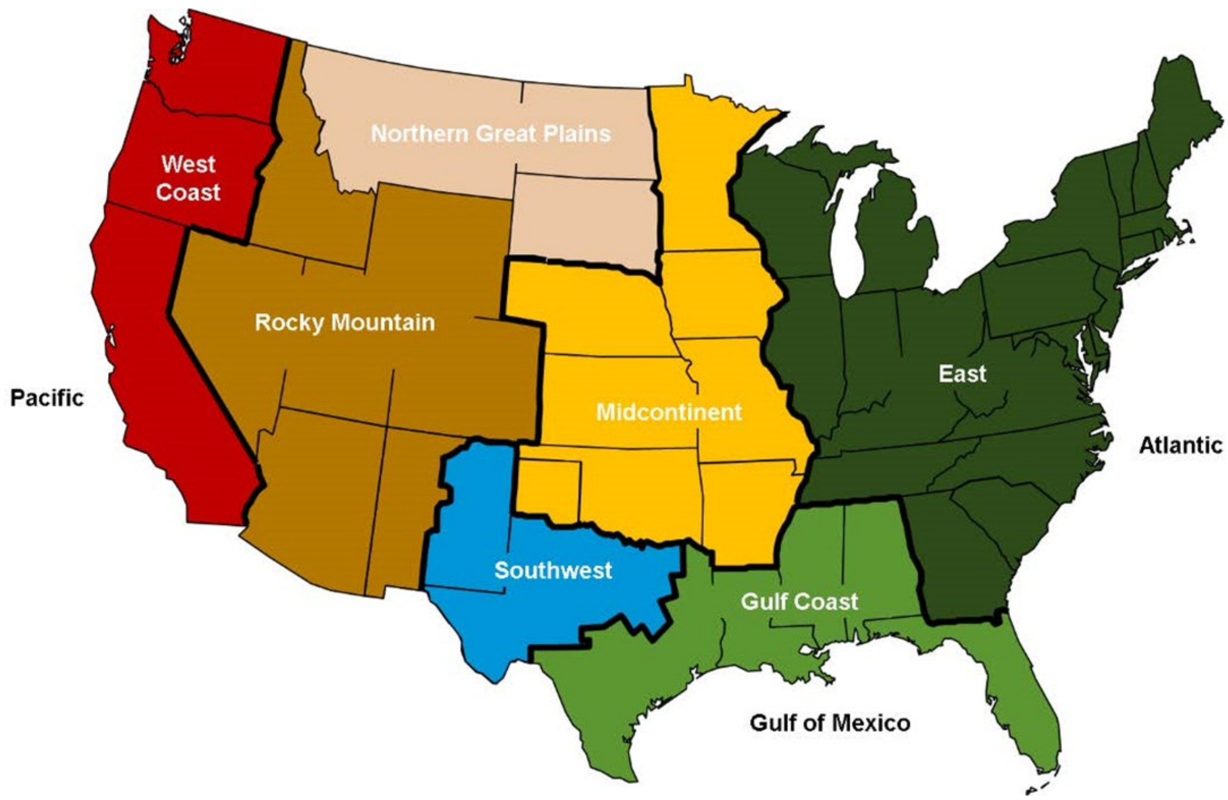
Figure 12. Oil and Gas Supply Module structure



The OGSM provides domestic crude oil production to the LFMM. The interaction of supply and demand in the LFMM determines the level of imports. System control information (e.g., projection year) and expectations (e.g., expected price paths) come from the Integrating Module. Major exogenous inputs include resource levels, finding-rate parameters, costs, production profiles, and tax rates—all of which are critical determinants of the oil and gas supply outlook of the OGSM.

The OGSM operates on a regionally disaggregated level, further differentiated by fuel type. The basic geographic regions are Lower 48 onshore, Lower 48 offshore, and Alaska, each of which, in turn, is divided into a number of subregions (Figure 13). The primary fuel types are crude oil and natural gas, which are further disaggregated based on type of deposition, method of extraction, or geologic formation. Crude oil supply includes lease condensate. Natural gas is differentiated by nonassociated and associated-dissolved gas. Nonassociated natural gas is categorized by fuel type: high-permeability carbonate and sandstone (conventional), low-permeability carbonate and sandstone (tight gas), shale gas, and coalbed methane.

Figure 13. Oil and Gas Supply Module regions



Analytical issues that the OGSM can address involve policies that affect the profitability of drilling based on certain variables, including the following:

- Drilling and production costs
- Regulatory or legislatively mandated environmental costs
- Taxation provisions (severance taxes, state or federal income taxes, depreciation schedules, and tax credits)

- The rate of penetration for different technologies into the industry by fuel type

The cash flow approach to the determination of drilling levels enables the OGSM to address some financial issues. In particular, the treatment of financial resources within the OGSM allows for explicit consideration of the financial aspects of upstream capital investment in the petroleum industry.

The OGSM is also useful for policy analysis of resource base issues. OGSM analysis is based on explicit estimates for technically recoverable oil and gas resources for each of the sources of domestic production (i.e., geographic region/fuel type combinations).

The methodology of the OGSM is shaped by the basic principle that the level of investment in a specific activity is determined largely by its expected profitability. Output prices influence oil and natural gas supplies in distinctly different ways in the OGSM. Quantities supplied as the result of the annual market equilibration in the LFMM and the NGMM are determined as a direct result of the observed market price in that period. Longer-term supply responses are related to investments required for subsequent production of oil and natural gas. Output prices affect the expected profitability of these investment opportunities as determined by use of a discounted cash flow evaluation of representative prospects.

The breadth of supply processes that are encompassed within OGSM result in different methodological approaches for determining crude oil and natural gas production. The present OGSM consequently comprises five submodules. The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) models crude oil and natural gas supply from resources in the Lower 48 states. The Offshore Oil and Gas Supply Submodule (OOGSS) models crude oil and natural gas exploration and development in the Federal Offshore Gulf of Mexico, Pacific, and Atlantic regions. The Alaska Oil and Gas Supply Submodule (AOGSS) models industry supply activity in Alaska. Oil shale (synthetic) is modeled in the Oil Shale Supply Submodule (OSSS). The Canadian Natural Gas Supply Submodule (CNGSS) models Canadian natural gas production excluding natural gas production needed to support Canadian liquefied natural gas exports.

Onshore Lower 48 Oil and Gas Supply Submodule

The OLOGSS projects the annual crude oil and natural gas production from existing fields, reserves growth, and exploration. It performs economic evaluation of the projects and ranks the reserves growth and exploration projects for development in a way designed to mimic the way decisions are made by the oil and gas industry. Development decisions and project selection depend upon economic viability and capital, drilling, and other available development constraints. Finally, the model aggregates production and drilling statistics using geographical and resource categories.

The OLOGSS determines the potential domestic production in three phases. The first phase is the evaluation of the known crude oil and natural gas fields using a decline curve analysis. As part of the analysis, each project is subject to a detailed economic analysis used to determine the economic viability and expected life span of the project. In addition, the model applies regional factors used for history matching and resource base coverage. The remaining resources are categorized as either exploration or enhanced oil recovery (EOR)/advanced secondary recovery (ASR). Each year, the exploration projects are subject to economic analysis that determines their economic viability and profitability.

For the EOR/ASR projects, development eligibility is determined before the economic analysis is conducted. The eligibility is based upon the economic life span of the corresponding decline curve project and the process-specific eligibility window. If a project is not currently eligible, it will be re-evaluated in future years. The eligible projects are subject to the same type of economic analysis applied to existing and exploration projects in order to determine the viability and relative profitability of the project.

After the economics have been determined for each eligible project, the projects are sorted. The exploration projects maintain their discovery order. The EOR/ASR projects are sorted by their relative profitability. The finalized lists are then considered by the project selection routines.

A project will be selected for development only if it is economically viable and if sufficient development resources are available to meet the project's requirements. Development resource constraints are used to simulate limits on the availability of infrastructure related to the oil and gas industries. If sufficient resources are not available for an economic project, the project will be reconsidered in future years if it remains economically viable. Other development options are considered in this step, including the waterflooding of undiscovered conventional resources and the extension of carbon dioxide floods through an increase in total pore volume injected.

The production and other key parameters for the timed and developed projects are aggregated at the regional and national levels.

Offshore Oil and Gas Supply Submodule

The OOGSS uses a field-based engineering approach to represent the exploration and development of U.S. offshore oil and natural gas resources. The OOGSS simulates the economic decision-making at each stage of development from frontier areas to post-mature areas. Offshore petroleum resources are divided into three categories:

- **Undiscovered Fields.** The number, location, and size of the undiscovered fields are based on a hydrocarbon resource assessment by the Bureau of Ocean Energy Management (BOEM) and the Bureau of Safety and Environmental Enforcement (BSEE).
- **Discovered, Undeveloped Fields.** Any discovery that has been announced but is not currently producing is evaluated in this component of the model. The first production year is an input and is based on announced plans and expectations.
- **Producing Fields.** The fields in this category have wells that have produced oil and/or gas according to the BOEM production database.

Resource and economic calculations are performed at an evaluation unit basis. An evaluation unit is defined as the area within a planning area that falls into a specific water depth category. Planning areas are the Western Gulf of Mexico, Central Gulf of Mexico, Eastern Gulf of Mexico, Pacific Ocean, and Atlantic Ocean. There are six water depth categories: 0–200 meters, 200–400 meters, 400–800 meters, 800–1600 meters, 1600–2400 meters, and greater than 2400 meters.

Supply curves for crude oil and natural gas are generated for three offshore regions: Pacific, Atlantic, and Gulf of Mexico. Crude oil production includes lease condensate. Natural gas production accounts for both nonassociated gas and associated-dissolved gas. The model is responsive to changes in oil and natural gas prices, royalty relief assumptions, oil and natural gas resource base, and technological improvements affecting exploration and development.

Alaska Oil and Gas Supply Submodule

The AOGSS solely focuses on projecting the exploration and development of undiscovered oil resources, primarily with respect to the oil resources expected to be found onshore and offshore in North Alaska. The AOGSS is divided into three components: new field discoveries, development projects, and producing fields. Transportation costs are used in conjunction with the crude oil price to Southern California refineries to calculate an estimated wellhead (netback) oil price. A discounted cash flow calculation is used to determine the economic viability of Alaskan drilling and production activities. Oil field investment decisions are modeled based on discrete projects. The exploration, discovery, and development of new oil fields depend on the expected exploration success rate and new field profitability. Production is determined based on assumed drilling schedules and production profiles for new fields and developmental projects, along with historical production patterns and announced plans for currently producing fields.

Oil Shale Supply Submodule

The OSSS only represents economic decision-making. In the absence of any existing commercial oil shale projects, it was impossible to determine the potential environmental constraints and costs of producing oil on a large scale. Given the considerable technical and economic uncertainty of an oil shale industry based on an in-situ technology and the infeasibility of the large-scale implementation of an underground mining/surface retorting technology, the oil shale syncrude production projected by the OSSS should be considered highly uncertain.

Given this uncertainty, the construction of commercial oil shale projects is constrained by a linear market penetration algorithm that restricts the oil production rate, which, at best, can reach a maximum of 2 million barrels per day by the end of a 40-year period after commercial oil shale facilities are deemed to be technologically feasible. Whether domestic oil shale production actually reaches 2 million barrels per day at the end of the 40-year period depends on the relative profitability of oil shale facilities. If oil prices are too low to recover the weighted average cost of capital, no new facilities are built. However, if oil prices are sufficiently high to recover the cost of capital, then the rate of market penetration rises in direct proportion to facility profitability. Thus, as oil prices rise and oil shale facility profitability increases, the model assumes that oil shale facilities are built in greater numbers, as dictated by the market penetration algorithm.

The OSSS is based on underground mining and surface retorting technology and costs. During the late 1970s and early 1980s, when petroleum companies were building oil shale demonstration plants, almost all demonstration facilities employed this technology. The facility parameter values and cost estimates in the OSSS are based on information reported for the Paraho Oil Shale Project, which are inflated to constant 2004 dollars. Oil shale rock mining costs are based on western United States underground coal mining costs, which would be representative of the cost of mining oil shale rock because coal mining techniques and technology would be employed to mine oil shale rock. The Paraho cost structure might seem unrealistic because the in-situ process is more likely to be used than the underground mining/surface retorting process. However, the Paraho cost structure is well documented, while no detailed public information regarding the expected cost of the in-situ process exists.

Canadian Natural Gas Supply Submodule

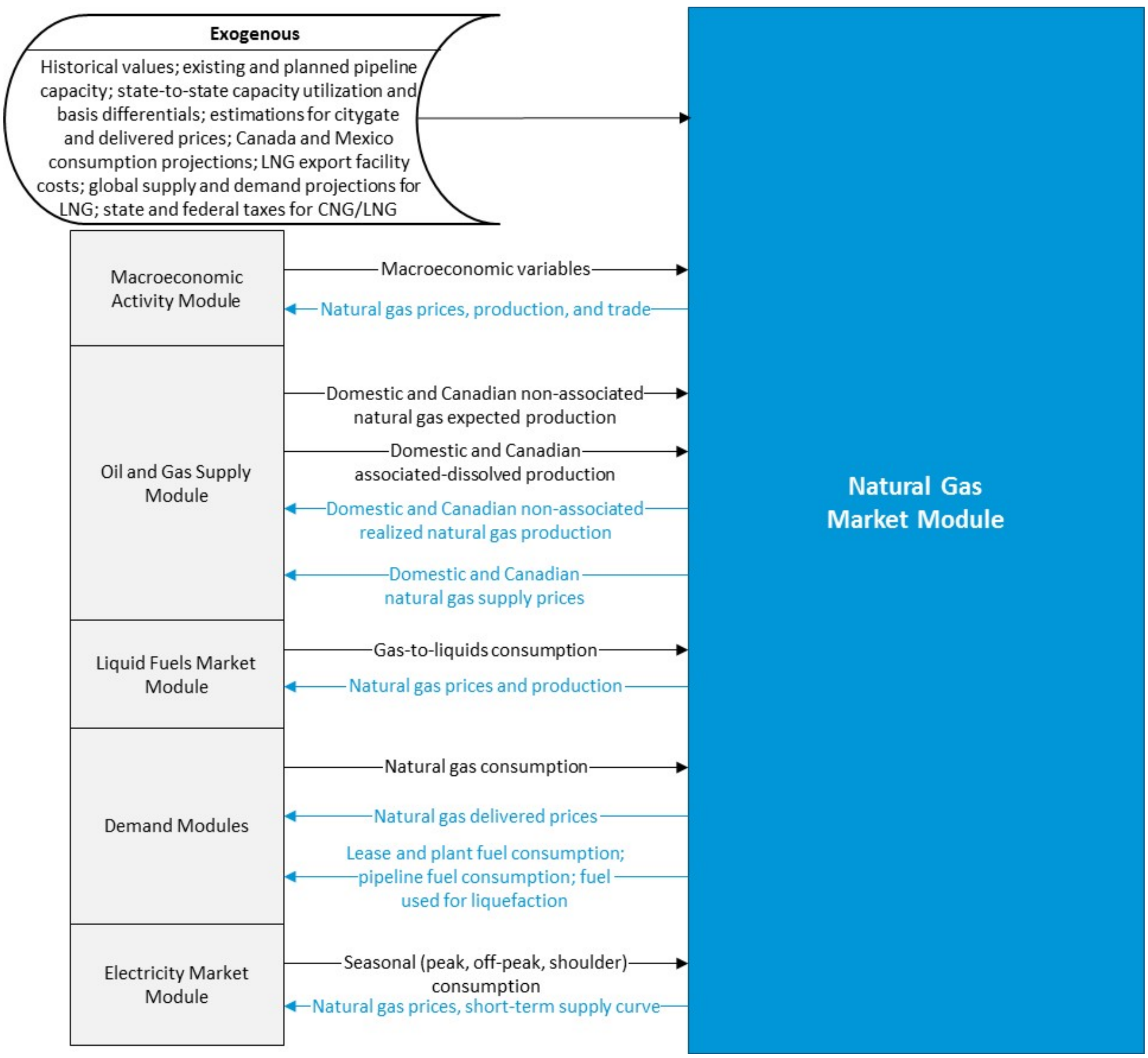
The CNGSS is designed to project Canadian natural gas production. These volumes are passed to the NGMM and used in determining Canadian imports to the United States as a result of the North American market equilibration that occurs in the NGMM. Liquefied natural gas imports into Canada also are determined in the NGMM.

Canadian natural gas production is represented for two regions—Western Canada (Alberta, British Columbia, and Saskatchewan) and Eastern Canada (Nova Scotia, New Brunswick, Ontario, Yukon, and Northwest Territories). Production from Western Canada is further disaggregated into natural gas associated-dissolved with crude oil and nonassociated conventional, tight, shale, and coalbed methane. Western Canadian associated-dissolved gas production and all natural gas production from the Eastern Canada region are set exogenously and are a user-specified input to the CNGSS. Natural gas production from the Mackenzie Delta is dependent on the construction of a pipeline to Alberta and is determined in the NGMM.

Natural Gas Market Module

The Natural Gas Market Module (NGMM) represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGMM also includes representations of the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market (see Figure 14). The NGMM links natural gas suppliers (including importers) and consumers (including liquefied natural gas export terminals) in the Lower 48 states and across the Mexican and Canadian borders through transmission between market hubs. For all months in a year, the NGMM determines the production, flows, and market clearing prices of natural gas within a state-level representation of the U.S. pipeline network and a regional representation of the Canadian and Mexican pipeline network.

Figure 14. Natural Gas Market Module structure



Natural gas pricing and flow patterns are derived by obtaining a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. This equilibrium is obtained by optimizing for producer plus consumer surplus minus transportation costs and takes the form of a quadratic program. The methodology employed allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary expansion requirements for pipeline capacity. Distributor tariffs are also projected in order to arrive at the delivered price of natural gas to domestic consumers.

The Lower 48 states' demand regions are represented at the state level. Canada is represented with an eastern and western region, and Mexico is represented with five regions. For all regions, consumption is represented for five end-use sectors: residential, commercial, industrial, electric power, and transportation (or natural gas vehicles). The U.S. transportation sector is separated into compressed and liquefied natural gas for use in vehicles (retail and fleet), ships, and trains. In addition, the NGMM is responsible for projecting natural gas consumed in lease and plant operations, consumed or lost during interstate transport of natural gas via pipeline, and used for liquefaction at liquefied natural gas export facilities. Canadian and Mexican demand projections are based on EIA's *International Energy Outlook*; however, Canadian consumption of natural gas in oil sands production is modeled by the NGMM.

The NGMM quadratic program balances natural gas supply and demand by maximizing consumer plus producer surplus minus variable transport costs, ensuring mass balance at each node. Although the model is specified by a quadratic objective function, it is subject to linear constraints. Supply and demand elements are represented by either price-responsive curves or as fixed volumes, with the model code accommodating user selection of one or the other. The representative network contains a market hub in each state, as well as international and border hubs, and it solves each month in a given year independently of all other months.

The objective function in the NGMM is an application of economic surplus, or the maximum economic benefit that an economy can obtain. The consumer surplus represents the amount of money saved by consumers who would buy natural gas at a given price but are able to obtain it at a lower one. The producer surplus represents the added revenue of suppliers who could sell natural gas at a lower price but are able to charge a higher one. Therefore, by maximizing this combined surplus and subtracting transportation costs, the model arrives at an equilibrium price for the market.

First year initialization

Done during the first NGMM model year, the first year initialization is where all input files are read in, the time horizon is set and synchronized with the calendar, and all historical data are processed to calculate market shares or averages that are used throughout the projections. Historical pipeline capacities, as well as planned capacity additions, are fixed, which define the allowable transportation links along which natural gas can flow. As a quality check on the input data, the NGMM verifies that all historical pipeline flows are along arcs that have pipeline capacity, and the NGMM ensures that total annual flow volumes do not exceed that capacity. For flows that violate these conditions, the NGMM adds sufficient capacity to the historical data.

Supply

There are six types of supply represented in the NGMM: nonassociated gas, associated-dissolved gas, liquefied natural gas imports, synthetic natural gas from coal, synthetic natural gas from liquids, and other synthetic natural gas. All supply regions, including those in Canada and Mexico, can have any number of these supply types. Only nonassociated gas is considered a variable supply (i.e., it is solved for in the mathematical program and allowed to change dynamically in response to the supply price in a given region). The supply levels for the remaining categories are fixed at the beginning of each projection year (i.e., before market clearing prices are determined). Alaskan natural gas supply is not represented in the quadratic program. Instead, it is set to equal the projected consumption as determined in the Alaska pre-processing routine.

Storage

Storage is represented in the NGMM for all Lower 48 states and Canada. Although storage is an integral part of balancing natural gas markets in the short term to mitigate price increases during periods of peak demand, over the long term it is not expected to play a role in setting prices. The NGMM assumes that net storage withdrawals over a projection year equal zero, i.e., storage injections equal storage withdrawals at each hub.

Capacity expansion

For the first years of the projection period, before new builds are allowed, pipeline expansion will be set to historical levels plus planned pipeline capacity expansions. These expansions are defined as pipelines either under construction, approved by the Federal Energy Regulatory Commission, or those deemed likely to move forward. For subsequent years, the capacity expansion quadratic program is solved in order to determine if additional pipeline capacity is needed along any arcs in the model where capacity currently exists. Capacities are then assigned according to last year's capacity, including any planned capacity expansions and the additions built in the NGMM capacity expansion quadratic program. This quadratic program has the same structure as the main quadratic program described below.

Canada

The NGMM represents two hubs in Canada: eastern Canada (Ontario, Quebec, Manitoba, and the four Atlantic provinces) and western Canada (Saskatchewan, Alberta, British Columbia, and all three territories). These regions have the same representation as those for the Lower 48 states within the model code; however, lease, plant, and pipeline fuel are not explicitly calculated because of lack of available historical data. Each region has average monthly storage injections and withdrawals and liquefied natural gas imports based on historical data. Liquefied natural gas exports from western Canada are also included as an exogenous assumption. The additional supply required to produce these exports is assumed to be exclusively reserved for export and not able to flow directly into the larger North American pipeline network. Hubs that represent the U.S. border crossing for each state and the associated pipeline capacity are also represented. The flows through these hubs reflect the projected import and export levels.

Canadian production is modeled in the OGSM. Canadian demand is largely an exogenous assumption; however, natural gas consumption during oil sands production is calculated endogenously using assumed values for oil sands production, which vary by world oil price case, and the ratio of syncrude to dilbit/synbit that is produced in Canada in response to global demand (including that of U.S. refineries).

Mexico

The NGMM represents five hubs in Mexico. There are also three hubs representing U.S. border crossings. Three supply types are represented for Mexico: nonassociated gas production, associated-dissolved gas production, and liquefied natural gas imports. Although the production of associated-dissolved gas, which is co-produced with crude oil, is expected to depend on world oil price, nonassociated gas production is expected to respond to natural gas prices. Liquefied natural gas imports are needed to meet demand in regions that do not have sufficient access to pipeline gas. Mexican demand is based on an exogenous consumption projection.

Liquefied natural gas exports

The long-term economic viability of adding (or expanding) a generic liquefaction export facility consisting of up to three large trains of a specified capacity is evaluated in each projection year. This is done for each of the allowed coastal regions of the United States before selecting the most economically profitable region for construction, if any, and accounting for any assumed restrictions, such as earliest start year or maximum allowable volume. An underlying assumption is that facilities will be built if consumers are interested in signing long-term contracts at a price that allows cost recovery, so the economic viability is evaluated from the perspective of potential consumers. Once built, the liquefaction facility is assumed to be able to operate at full capacity (accounting for some operational down-time) throughout the rest of the projection period.

To effectively assess the economic viability to consumers in representative world destinations of signing a contract with a new U.S. liquefaction facility versus an assumed alternative, the NGMM calculates a net present value over the assumed lifetime of a contract with the liquefaction facility. This net present value corresponds to the cost of purchasing from the United States versus another global supplier. The price of the alternative supplier, or the world price of liquefied natural gas at a given destination, during that period is compared with the price of U.S. liquefied natural gas at these destinations. The price of U.S. liquefied natural gas includes a sunk cost to recover the initial investment required to build the facility, the operational costs (including regasification), and the shipping costs to a cargo’s destination.

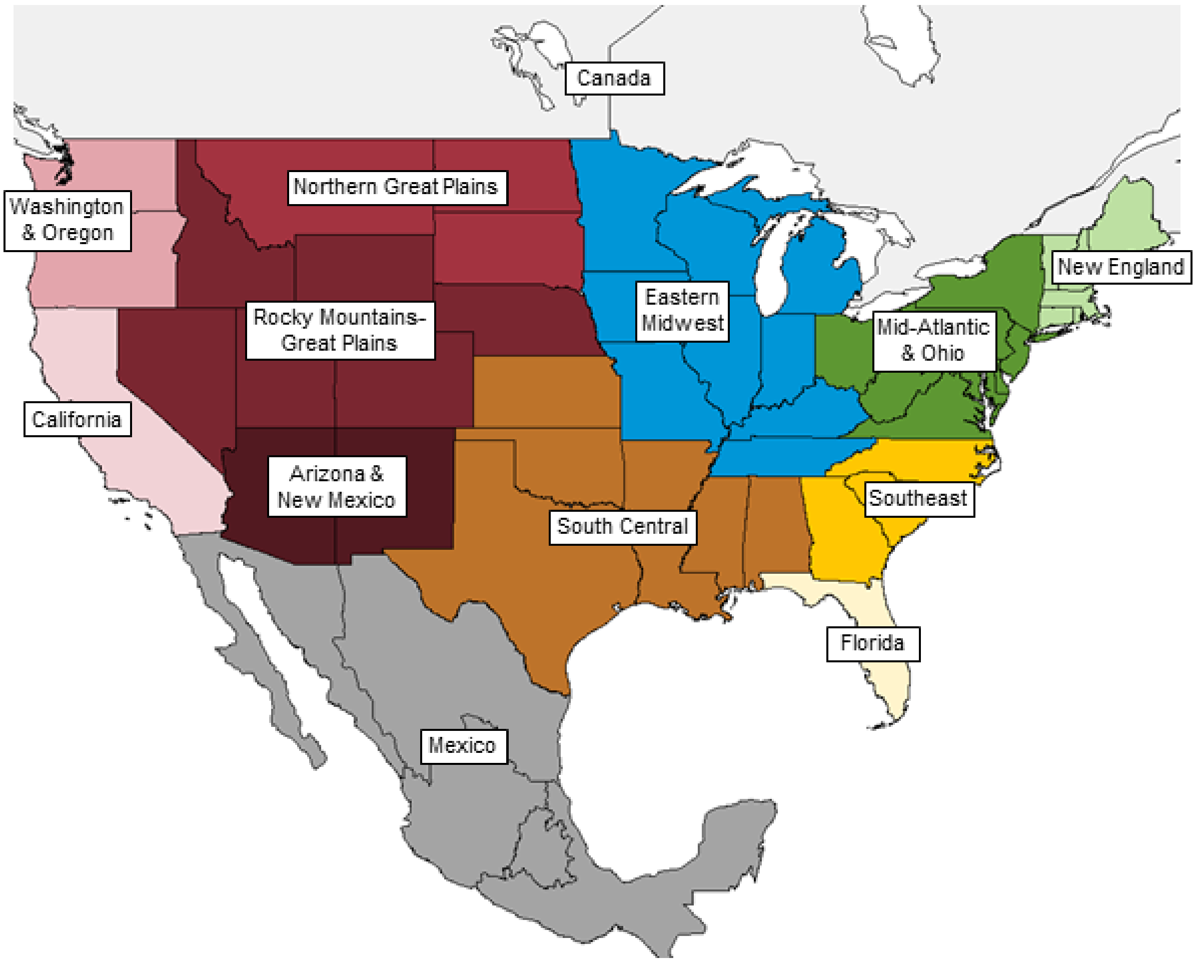
Alaska

The NGMM projects Alaskan consumption by sector using historical data and then calculates Alaskan natural gas production by assuming it fulfills the projected demand. The NEMS demand modules provide a projection of natural gas consumption for the total Pacific Census Division, which includes Alaska. Therefore, the NGMM derives annual estimates of contiguous Pacific Division consumption levels by first estimating Alaska natural gas consumption for all sectors and then subtracting these from the core market consumption levels in the Pacific Division provided.

Post-processing routines

After the quadratic program solves the function, the solution values can be extracted to pass to other modules or to the report writer in the NEMS. Volumes include nonassociated and total dry gas production, natural gas import and export volumes, region-to-region flows (see Figure 15), lease and plant fuel, pipeline fuel, and fuel used for liquefaction. Supplemental supplies, liquefied natural gas imports, and associated-dissolved production are also made available, but the quadratic program does not set them. Prices include spot prices, wellhead prices, citygate prices, import and export prices, and delivered prices to residential, commercial, industrial, electric power, and natural gas vehicle (including rail and marine) customers.

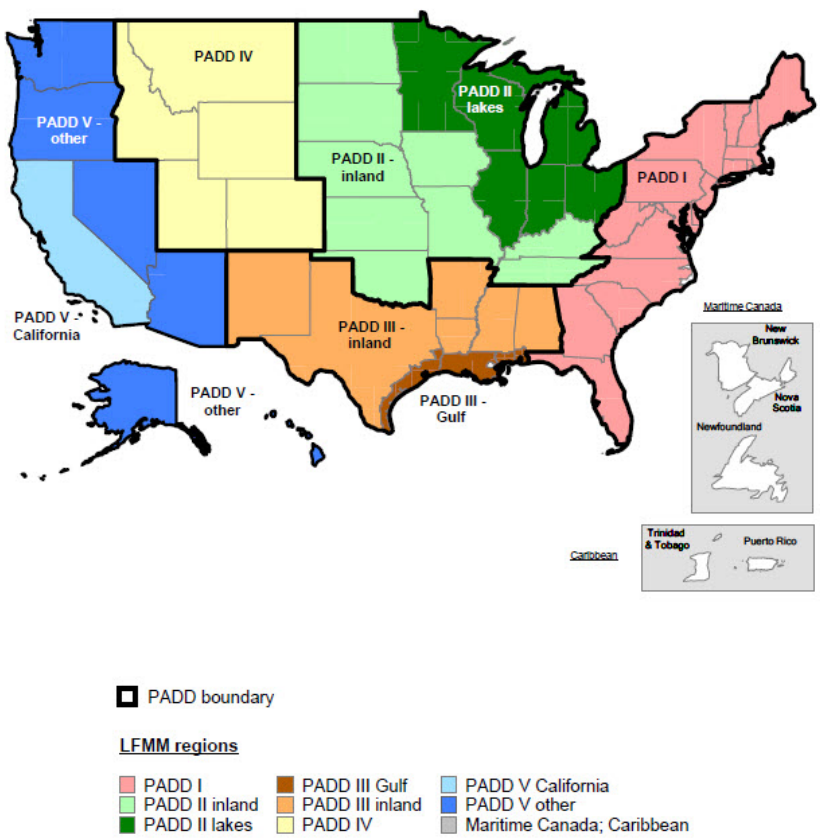
Figure 15. Natural gas regions for reporting regional flows and capacity



Liquid Fuels Market Module

The Liquid Fuels Market Module (LFMM) is a regional, linear programming formulation that models petroleum refining activities, the marketing of petroleum products to consumption regions, and the production of renewable fuels (including ethanol, biodiesel, and cellulosic biofuels) and non-petroleum fossil fuels (including coal- and gas-to-liquids). The LFMM projects domestic petroleum product prices and sources of liquid fuels supply for meeting petroleum product demands by supply source, fuel, and region. These sources of supply include domestic and imported crude oil; ethanol, biodiesel, and other biofuels; domestic natural gas plant liquids production; petroleum product imports; and unfinished oil imports. In addition, the LFMM projects capacity expansion and fuel consumption at domestic refineries. Product prices are estimated at the census division level; however, much of the liquid fuels production activity information is at the level of U.S. Petroleum Administration for Defense Districts (PADDs) and sub-PADDs with one region representing Maritime Canada and the Caribbean (Figure 16).

Figure 16. Petroleum Administration for Defense Districts



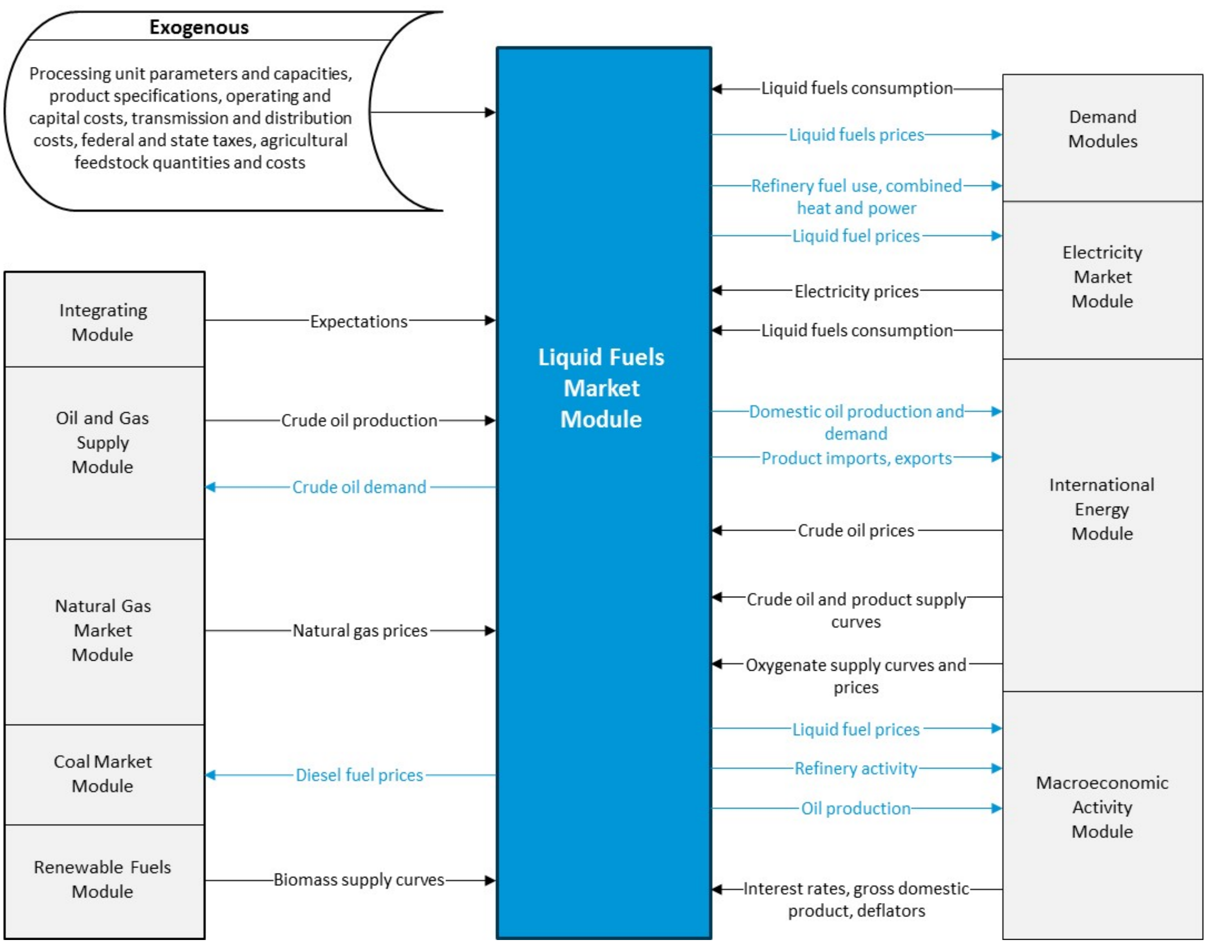
Source: U.S. Energy Information Administration, Office of Energy Analysis.

The LFMM assumes that the petroleum refining and marketing industry is competitive. The market will move toward lower-cost refiners who have access to crude oil and markets. The selection of crude oils, refinery process utilization, and logistics (transportation) will adjust to minimize the overall cost of supplying the market with liquid fuels. Each regional refinery is represented by a single detailed refinery consisting of atmospheric and vacuum distillation units and a comprehensive set of downstream processing units, all with a wide range of operating modes. Capacity for all refinery process units is allowed to expand in each region, but the model does not distinguish between additions to existing refineries or the building of new facilities. Similarly, capacity expansion is allowed for non-petroleum based liquids production units. Investment criteria are developed exogenously, although the decision to invest is endogenous.

Existing regulations concerning product types and specifications, the cost of environmental compliance, and federal and state taxes are also modeled. The LFMM incorporates provisions from the Energy Independence and Security Act of 2007 (EISA2007) and the Energy Policy Act of 2005 (EPACT05). The costs of producing new formulations of gasoline and diesel fuel as a result of the Clean Air Act Amendments of 1990 (CAAA90) are determined within the linear programming representation by incorporating specifications and demands for these fuels.

The LFMM also includes the interaction between the domestic and international markets. The LFMM and the International Energy Module (IEM) work together to estimate supply and demand curves for imported and exported crude oils and products based on, among other factors, U.S. participation in global trade of crude oil and liquid fuels. The relationship of the LFMM to other NEMS modules is illustrated in Figure 17.

Figure 17. Petroleum Market Module structure



Product categories

Product categories, specifications, and recipe blends modeled in the LFMM include

- E10 (conventional motor gasoline, reformulated motor gasoline, and California Air Resource Board gasoline, all blended at up to 10% ethanol by volume)
- E15 (conventional gasoline blended at up to 15% ethanol by volume)
- E85 (conventional gasoline blended at 76% ethanol by volume)
- Heating oil (distillate)
- Ultra-low-sulfur distillate (up to 15 parts per million (ppm) sulfur)
- Low-sulfur distillate (greater than 15 ppm sulfur to 500 ppm sulfur)
- Distillate greater than 500 ppm sulfur
- Kerosene-based jet fuel
- Low-sulfur residual fuel oil (containing an average of 0.75% sulfur)
- High-sulfur residual fuel oil (containing an average of 2.9% sulfur)
- Hydrocarbon gas liquids (ethane, ethylene, propane, propylene, isobutane, normal butane, and natural gasoline)
- Petrochemical feedstocks
- Asphalt and road oil
- Still gas
- Petroleum coke (catalytic and fuel-grade)
- Lubricants
- Aviation gasoline
- Ethanol
- Biobutanol (reformulated and conventional gasoline can also be blended with 16% biobutanol)
- Biodiesel (fatty acid methyl ester)
- Liquids from the Fischer-Tropsch process using coal, natural gas, and/or biomass as feedstock

End-use product prices

End-use petroleum product prices are based on marginal costs of production, plus production-related fixed costs, plus distribution costs and taxes. The marginal costs of production are determined within the linear program and represent variable costs of production, including additional costs for meeting legislated fuel provisions. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding product-specific distribution costs to the marginal refinery production costs (product wholesale prices). The distribution costs are derived from a set of base distribution markups.

State and federal taxes are also added to transportation fuels to determine final end-use prices. Tax trend analysis indicates that state taxes increase at the rate of inflation; therefore, state taxes are held constant in real terms throughout the projection period. This assumption is extended to local taxes, which are assumed to average 1% of motor gasoline prices. Federal taxes are assumed to remain at current nominal levels.

Fuel use

The LFMM determines refinery fuel use by refining region for purchased electricity, natural gas, distillate fuel, residual fuel, hydrocarbon gas liquids, and other petroleum products. The fuels (natural gas, petroleum, other gaseous fuels, and other) consumed within the refinery to generate electricity from combined heat and power facilities are also determined.

Crude oil categories

In the LFMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into 11 categories as defined by the ranges of gravity and sulfur shown in Table 5.

A composite crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams in the category. Each category includes both domestic and foreign crude oil, which are both used to determine category characteristics. For each category's domestic crude oil volumes, estimates of total regional production are made first. Each region's production is then divided among each of the 11 categories based on that region's distribution of average API gravity and sulfur content. All crude types are allowed to be exported from the United States; however, the LFMM requires all crude oil produced in California (crude oil category = California) to be processed only in California. For imported crude oil, a separate supply curve is provided (by the IEM) for each category except California.

Capacity expansion

The LFMM allows for capacity expansion of all processing unit types, including distillation units such as atmospheric distillation units, vacuum distillation units, and condensate splitters, as well as secondary downstream processing units such as hydrotreaters, delayed cokers, fluid catalytic crackers, hydrocrackers, and alkylation units. Capacity expansion occurs by processing unit, starting from regional capacities established using historical data.

Table 55. Crude oil specifications

Crude oil categories	Alias	Percent sulfur	API gravity
API 50+		less than 0.5%	at least 50
API 40-50	Ultra-light sweet	less than 0.5%	at least 40; less than 50
API 35-40 sweet	Light sweet	less than 0.5%	at least 35; less than 40
API 35+ sour	Light sour	at least 0.5%	at least 35
API 27-35 medium sour	Medium medium sour	less than 1.1%	at least 27; less than 35
API 27-35 sour	Medium sour	at least 1.1%	at least 27; less than 35
API<27 sweet	Heavy sweet	less than 1.1%	less than 27
API<27 sour	Heavy sour	at least 1.1%	less than 27
California		1.1% to 2.6%	less than 27
Syncrude		less than 0.5%	at least 35
Dilbit/synbit		more than 1.1%	less than 27

Expansion occurs in the LFMM when the value received from the sale of products that could be produced with new processing capacity exceeds the investment and operating costs of adding this new capacity, plus the cost of purchasing additional feedstock. The investment costs assume a financing ratio of 60% equity and 40% debt, with a hurdle rate and an after-tax return on investment ranging from 6% for building new refinery processing units to more than 13% for higher-risk projects such as the construction of a coal-to-liquids plant.

The LFMM models capacity expansion using a three-period planning approach. The first two periods contain a single planning year (current year and next year, respectively), and the third period represents a net present value of the next 19 years in the projection period. The second and third planning periods are used to establish an economic plan for capacity expansion for the next NEMS model year. All process unit capacity that is expected to begin operating in the future is added to existing capacities in their respective start year. The retirement and replacement of existing refining capacity is not explicitly represented in the LFMM.

Biofuels

The LFMM incorporates existing biofuels legislation and models biofuels production. Biofuels are mainly blended with motor gasoline and diesel and are used in the transportation sector. Ethanol can be made from corn, grain, or stover and is assumed to be blended with motor gasoline blendstock at either at 10% or 15% by volume or at 74% by volume as E85. Biomass-based distillate from vegetable oils or fats, and distillate streams from the Fischer-Tropsch biomass-to-liquids process can be blended with diesel. Food feedstock supply curves (corn, soybean oil, etc.) are updated to U.S. Department of Agriculture baseline projections. Biomass feedstocks are drawn from the same supply curves that also supply biomass fuel to renewable power generation within the Renewable Fuels Module. The merchant processing units which generate the biofuels supplies sum these feedstock costs with other cost inputs (e.g., capital, operating).

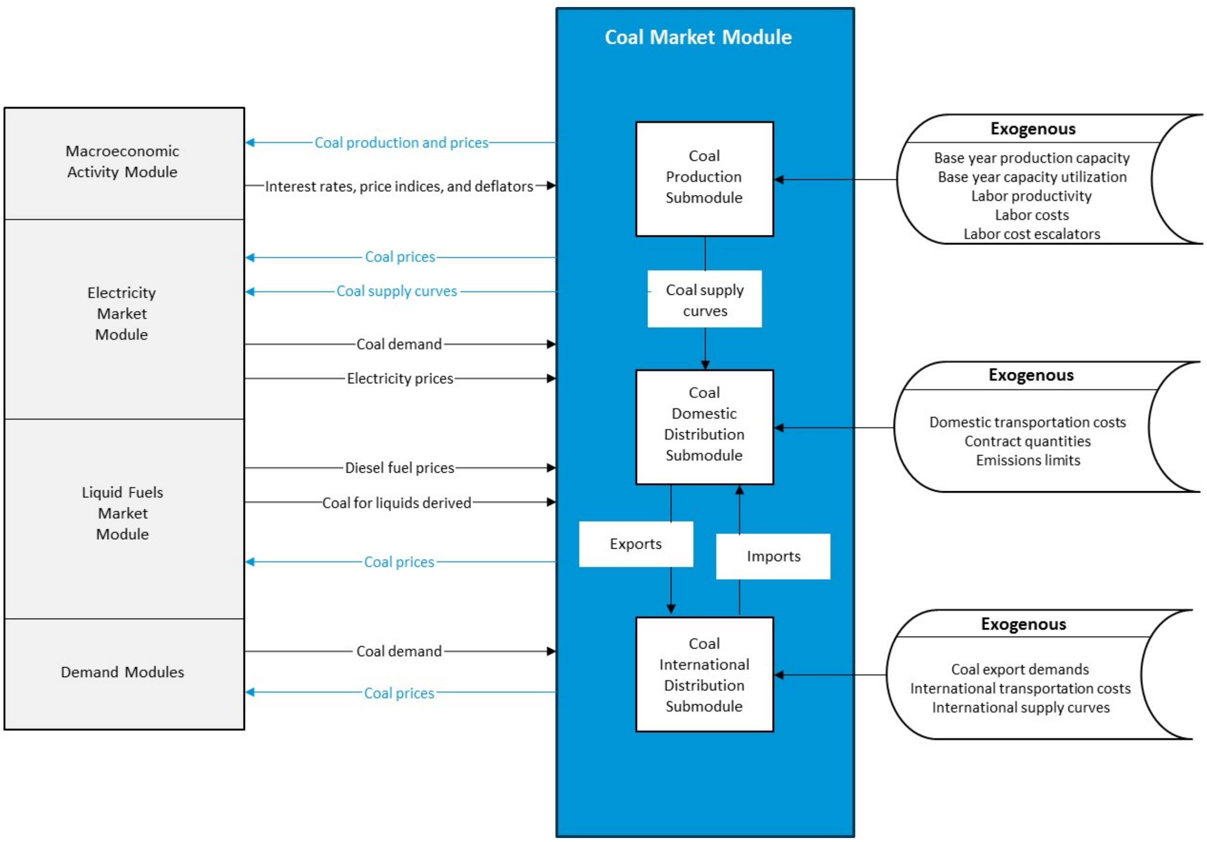
Combined heat and power

Electricity consumption at the refinery and other liquid fuels production facilities is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, and electricity generated by other liquid fuels producers (including cellulosic/advanced ethanol, coal- and biomass-to-liquids). Power generators and combined heat and power plants are modeled in the LFMM linear program as separate units, and they are allowed to compete along with purchased electricity. Operating characteristics for these electricity producers are based on historical parameters and available data. Sales to the grid or own-use decisions are made on an economic basis within the linear program. The price for electricity sales to the grid is set to the marginal energy price for baseload generation as provided by the Electricity Market Module.

Coal Market Module

The Coal Market Module (CMM) provides annual forecasts of prices, production, and consumption of coal through 2050 for NEMS. The Coal Production Submodule generates a set of minemouth coal supply curves by coal supply region, coal type, and mine type. The supply curves are passed to the Domestic Coal Distribution Submodule (DCDS), along with regional coal demand requirements from other NEMS components. The CMM provides delivered coal prices and quantities to the NEMS economic sectors and regions. The DCDS solves for the interregional flows of coal from supply region to demand region, by minimizing the production and transportation costs. The International Coal Distribution Submodule forecasts annual world coal trade flows from major international supply to major demand regions and provides annual forecasts of U.S. coal exports. The structure of the CMM is shown in Figure 18.

Figure 1818. Coal Market Module structure



Coal Production Submodule (CPS)

The CPS generates a different set of supply curves for the CMM for each year in the forecast period. The construction of these curves involves three steps for any given year. First, the CPS calibrates a previously estimated regression model of minemouth prices to base-year production and price levels by region, mine type, and coal type. Second, the CPS converts the regression equation into continuous coal supply curves. Finally, the supply curves are converted to step-function form, as required by the CMM's coal distribution routines, and prices for each step are calibrated to base-year data (2015 for AEO2018).

Domestic Coal Distribution Submodule (DCDS)

The Domestic Coal Distribution Submodule (DCDS) determines the least-cost (minemouth price plus transportation cost plus sulfur and mercury allowance costs) supplies of coal by supply region (Figure 19) for a given set of coal demands in each demand sector in each demand region using a linear programming (LP) algorithm. Delivered prices to each demand region (Figure 20) and sector are a function of the transportation costs, which are assumed to change over time based on a demand index described in a later section. The DCDS uses the available data on existing coal contracts (tonnage, duration, coal type, origin, and destination of shipments) as reported by electricity generators to represent coal under contract up to the contract's expiration date.

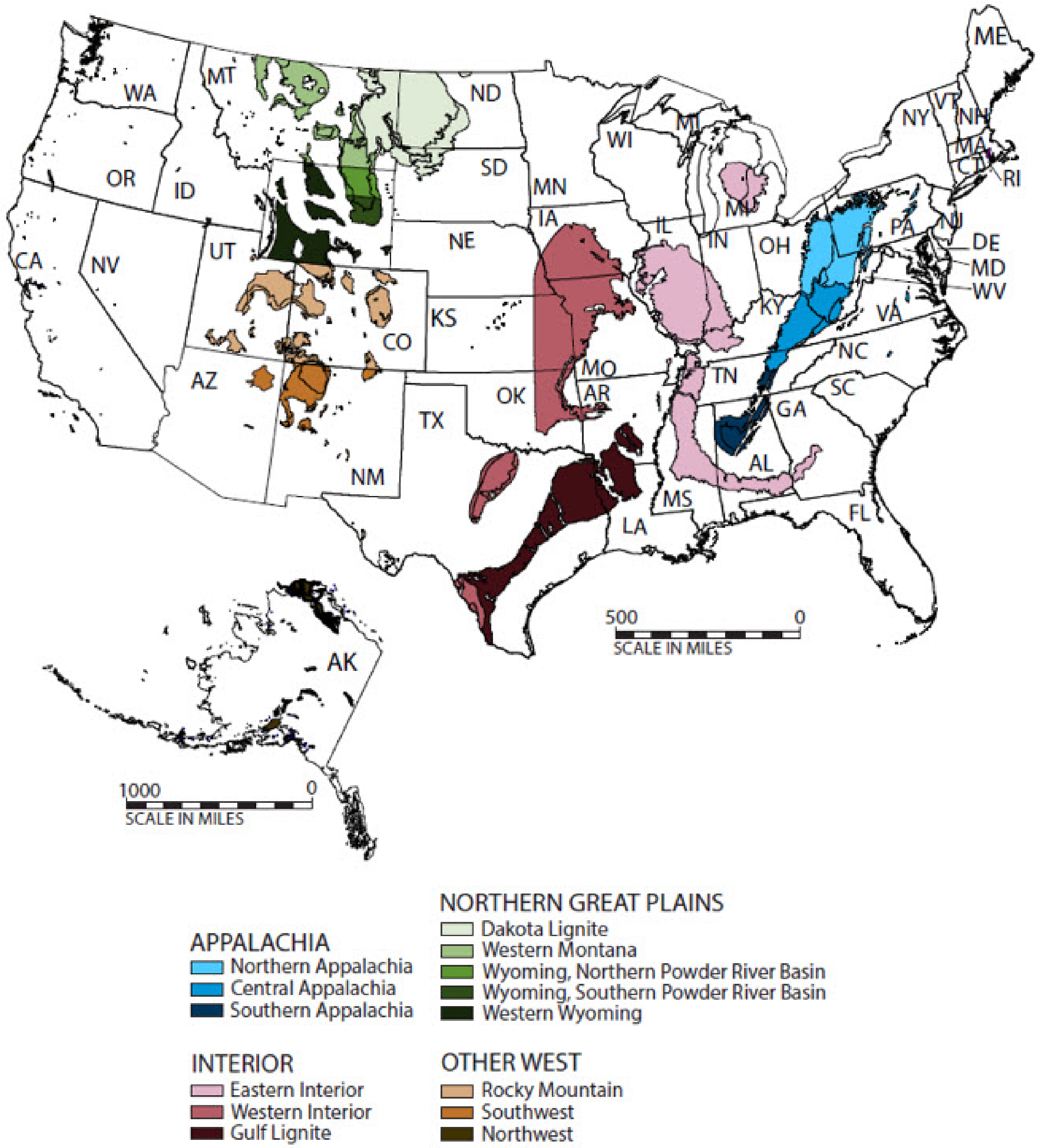
International Coal Distribution Submodule (ICDS)

The International Coal Distribution Submodule (ICDS) provides annual forecasts of U.S. coal exports and imports in the context of world coal trade demand, which is estimated outside of NEMS. The model uses 17 coal export regions (including 5 U.S. export regions) and 20 coal import regions (including 4 U.S. import regions) to forecast the international flow of steam and metallurgical coal (Table 6). The model solves for exports and imports of coal by minimizing total delivered cost given constraints on the LP model for regional export capabilities, sulfur dioxide limits, and exogenously specified international coal supply curves.

Table 66. Coal export components

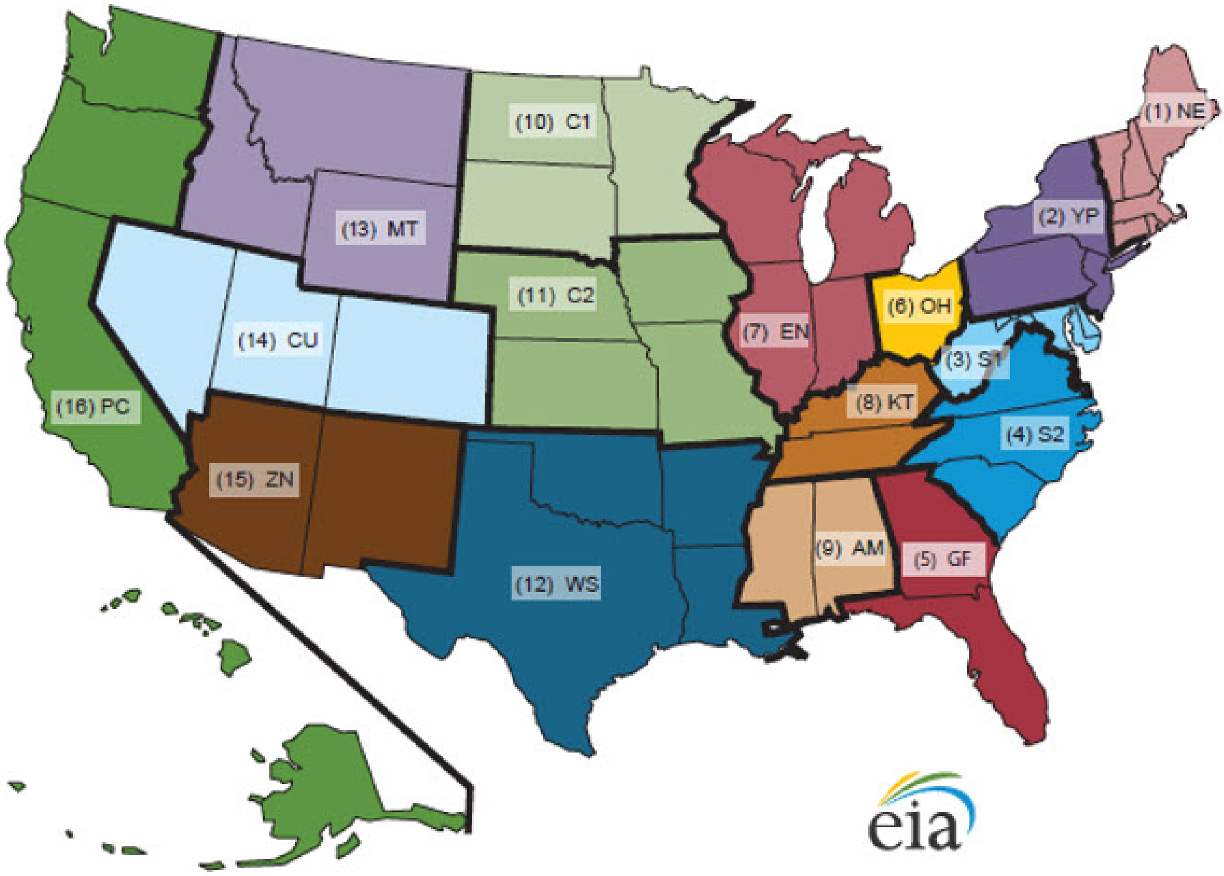
Coal export regions	Coal import regions
U.S. East Coast	U.S. East Coast
U.S. Gulf Coast	U.S. Gulf Coast
U.S. Southwest and West	U.S. Northern Interior
U.S. Northern Interior	U.S. Noncontiguous
U.S. Noncontiguous	Eastern Canada
Australia	Interior Canada
Western Canada	Scandinavia
Interior Canada	United Kingdom and Ireland
Southern Africa	Germany and Austria
Poland	Other Northwestern Europe
Eurasia, exports to Europe	Iberia
Eurasia, exports to Asia	Italy
China	Mediterranean and Eastern Europe
Colombia	Mexico
Indonesia	South America
Venezuela	Japan
Vietnam	East Asia
	China and Hong Kong
	ASEAN (Association of Southeast Asian Nations)
	India and South Asia

Figure 19. Coal Market Module supply regions



Source: U.S. Energy Information Administration

Figure 20. Coal Market Module demand regions



Region	Code	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	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

Appendix Bibliography

The National Energy Modeling System is documented in a series of model documentation reports, available on the EIA website at https://www.eia.gov/outlooks/aeo.

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