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The National Energy Modeling System:
An Overview 2003

March 2003

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
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PREFACE

The National Energy Modeling System: An Overview 2003 provides a summary description of the National Energy Modeling System (NEMS), which was used to generate the forecasts of energy production, demand, imports, and prices through the year 2025 for the *Annual Energy Outlook 2003* (*AEO2003*), (DOE/EIA-0383(2003)), released in January 2003. *AEO2003* presents national forecasts of energy markets for five primary cases—a reference case and four additional cases that assume higher and lower economic growth and higher and lower world oil prices than in the reference case. 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.

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AEO2003 is available on the EIA Home Page on the Internet (http://www.eia.doe.gov/oiaf/aeo/index.html). Assumptions underlying the projections are available in *Assumptions to the Annual Energy Outlook 2003* at http://www.eia.doe.gov/oiaf/aeo/assumption/index.html. Tables of regional projections and other underlying details of the reference case are available at http://www.eia.doe.gov/oiaf/aeo/supplement/index.html. Model documentation reports and *The National Energy Modeling System: An Overview 2003* are also available on the Home Page at http://www.eia.doe.gov/bookshelf/docs.html.

For ordering information and for questions on energy statistics, please contact EIA's National Energy Information Center.

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The National Energy Modeling System (NEMS) is a computer-based, energy-economy modeling system of U.S. energy markets for the midterm period through 2025. 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 Energy Information Administration (EIA) of the U.S. Department of Energy (DOE).

The National Energy Modeling System: An Overview 2003 presents 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 economics, 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 energy, economic, environmental, and security impacts on the United States of alternative energy policies and of different assumptions about energy markets. Projections are made for each year from the present through 2025. The forecast horizon is periodically extended to approximately 20 to 25 years into the future. This time period is one in which technology, demographics, and economic conditions are sufficiently understood in order to represent energy markets with a reasonable degree of confidence. 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 provide the impacts of transitions to 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 nine Census divisions, the Electricity Market Module uses 15 supply regions based on the North American Electric Reliability Council (NERC) regions, the Oil and Gas Supply Module uses 7 onshore and 3 offshore supply regions based on geologic breakdowns, and the Petroleum Market Module uses 3 regions based on combinations of the five Petroleum Administration for Defense Districts.

Baseline forecasts are developed with NEMS and published annually in the *Annual Energy Outlook*. In accordance with the requirement that EIA remain policy-neutral, the *Annual Energy Outlook* projections are based on Federal, State, and local laws and regulations in affect at the time of the forecast. Analyses are also prepared in response to requests for special studies by the White House, U.S. Congress, the DOE Office of Policy, other offices in DOE, and other government agencies. The first version of NEMS, completed in December 1993, was used to develop the forecasts presented in the *Annual Energy Outlook 1994,* This report describes the version of NEMS used for the *Annual Energy Outlook 2003*,[1] which was extended to 2025 for the first time.

The forecasts produced by NEMS are not considered to be statements of what will happen but 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, changes in world energy supply and demand, the rate at which new energy technologies are developed and the rate and extent of technology adoption and penetration.

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 impacts of new and advanced energy production, conversion, and consumption technologies; the impacts

[1] Energy Information Administration, *Annual Energy Outlook 2003*, DOE/EIA-0383(2003) (Washington, DC, January 2003).

and costs of carbon emissions reductions, the impacts of increased use of renewable energy sources; the potential savings from increased efficiency of energy use; and the changes in emission levels that are likely to result from such policies as the Clean Air Act Amendments of 1990, regulations on the use of alternative or reformulated fuels, and climate change policy. Specific energy topics that can be, or have been, addressed by NEMS include the following:

- Impacts of existing and proposed energy tax policies on the U.S. economy and energy system
- Impacts on energy prices, energy consumption, and electricity generation in response to carbon mitigation policies such as carbon fees, limits on carbon emissions, or permit trading systems
- Responses of the energy and economic systems to changes in world oil market conditions as a result of changing levels of foreign production and demand in the developing countries
- Impacts of new technologies on consumption and production patterns and emissions
- Effects of specific policies, such as mandatory appliance efficiency and building shell standards or renewable tax credits, on energy consumption
- Impacts of fuel-use restrictions, for example, required use of oxygenated and reformulated gasoline or mandated use of alternative-fueled vehicles, on emissions and energy supply and prices
- Impacts on the production and price of crude oil and natural gas resulting from improvements in exploration and production technologies
- Impacts on the price of coal resulting from improvements in productivity.

In addition to producing the analyses in the *Annual Energy Outlook*, NEMS is used for one-time analytical reports and papers, such as *Measuring Changes in Energy Efficiency for the Annual Energy Outlook 2002*,[2] which describes the construction of an aggregate energy efficiency index based on projections of sectoral and subsector energy consumption and subsector–specific energy service indicators. The results are compared with the ratio energy to real gross domestic product, which typically is presented as a measure of energy intensity. Other analytical papers on topics of current interest in energy markets are prepared, which either underlie the assumptions and methodology of NEMS or are applications of NEMS to current issues. In the past, some of these papers have been collectively published in *Issues in Midterm Analysis and Forecasting*, and in the future they will be available at http://www.eia.doe.gov/ oiaf/analysis.html.

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

- *Analysis of Corporate Average Fuel Economy (CAFE) Standards for Light Trucks and Increased Alternative Fuel Use*,[3] requested by Senator Murkowski to analyze the effects of proposed provisions in S. 1766 and H.R. 4 calling for more stringent corporate average fuel economy standards on energy supply, demand, and prices, import dependence, and emissions.
- *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products*,[4] requested by Senator Murkowski to evaluate the effects of the provisions in H.R. 4 and S. 1766 that pertain to efficiency in the

[2] Energy Information Administration, *Measuring Changes in Energy Efficiency for the Annual Energy Outlook 2002*, (Washington, DC, 2002).

[3] Energy Information Administration, *Analysis of Corporate Average Fuel Economy (CAFE) Standards for Light Trucks and Increased Alternative Fuel Use*, SR/OIAF/2002-05 (Washington, DC, March 2002).

[4] Energy Information Administration, *Analysis of Efficiency Standards for Air Conditioners, Heat Pumps, and Other Products*, SR/OIAF/2002-01 (Washington, DC, February 2002).

residential, commercial and industrial sectors.

- *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants With Advanced Technology Scenarios,*[5] requested by Senators Jeffords and Lieberman to analyze the impacts of technology improvements and other market–based opportunities on the costs of emissions reductions.

- *Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766*,[6] requested by Senator Murkowski to evaluate the Renewable Fuels Standard and methyl teritirary butyl ether provisions of S. 1766.

- *Impact of Renewable Fuels Standard/MTBE Provisions of S. 517*,[7] was completed as an addendum to the service report *Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766*[6] for Senators Murkowski and Daschle. The addendum to the service report providws additional analysis of the impact of the Renewable Fuels Standard (RFS) and methyl tertiary butyl ether (MTBE) ban provisions of S. 517. The projected consumer cost of the S. 517 provisions is compared with a Reference Case that assumes a 2 percent oxygen requirement is maintained and that already–scheduled MTBE restrictuons or bans become effective in 14 States.

- *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*[8], requested by the U.S. House Subcommittee on National Economic Growth, Natural Resources, and Regulatory Affairs to analyze the potential costs of multi–pollutant strategies to reduce the emissions from electric power plants.

- *Impacts of a 10–Percent Renewable Portfolio Standard*,[9] requested by Senator Murkowski to examine the Renewable Portfolio Standard (RPS) called for in S. 1766. The analysis includes scenarios with a 10 percent RPS, as provided in S. 1766, and a 20 percent RPS.

- *Impacts of the Kyoto Protocol on U.S. Energy Markets & Economic Activity*,[10] requested by the U.S. House Committee on Science to analyze the impacts of the Kyoto Protocol on U.S. energy markets and the economy in the 2008 to 2012 time frame.

- *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*,[11] requested by Senators Smith, Voinovich, and Brownback that describes the impacts of scenarios with alternative power sector emission caps on nitrogen oxides, sulfur dioxides, and mercury.

[5] Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants With Advanced Technology Scenarios*, SR/OIAF/2001-05 (Washington, DC, October 2001).

[6] Energy Information Administration, *Impact of Renewable Fuels Standard/MTBE Provisions of S. 1766*, SR/OIAF/2002-06 (Washington, DC, March 2002).

[7] Energy Information Administration, *Impact of Renewable Fuels Standard/MTBE Provisions of S. 517*, SR/OIAF/2002-06 Addendum (Washington, DC, April 2002).

[8] Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide*, SR/OIAF/2000-05 (Washington, DC, December 2000).

[9] Energy Information Administration, *Impacts of a 10–Percent Renewable Portfolio Standard*, SR/OIAF/2002-03 (Washington, DC, February 2002).

[10] Energy Information Administration, *Impacts of the Kyoto Protocol on U.S. Energy Markets & Economic Activity*, SR/OIAF/98-03 (Washington, DC, October 1998).

[11] Energy Information Administration, *Reducing Emissions of Sulfur Dioxide, Nitrogen Oxides, and Mercury from Electric Power Plants*, SR/OIAF/2001-04 (Washington, DC, September 2001).

- *The Effects of the Alaska Oil and Natural Gas Provisions of H.R. 4 and S. 1766 on U.S. Energy Markets,*[12] requested by Senator Murkowski to evaluate the effects of the provisions in H.R. 4 proposing crude oil production in the Arctic National Wildlife Refuge and provisions in S. 1766 concerning the construction of a pipeline bringing Alaskan natural gas to the Lower–48 States.

- *The Transition to Ultra–Low–Sulfur Diesel Fuel: Effects on Prices and Supply*,[13] requested by U.S. House Committee on Science to assess the possible impact of the new sulfur requirements on the diesel fuel market, specifically the implications for vehicle fuel efficiency, production, distribution, and cost.

- *The Comprehensive Electricity Competition Act: A Comparison of Model Results,*[14] requested by Secretary of Energy Bill Richardson to evaluate the effects of the Clinton Administration's restructuring proposal using the parameter settings and assumptions from the Policy Office Electricity Modeling System analysis.

- *U.S. Natural Gas Markets: Mid*–Term *Prospects for Natural Gas Supply*,[15] requested by Secretary of Energy, Spencer Abraham describes the recent behavior of natural gas markets with respect to natural gas prices, their potential future behavior, the potential future supply contribution of liquefied natural gas and increased access to Federally restricted resources, and the need for improved natural gas data.

- *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*,[16] requested by Secretary of Energy, Spencer Abraham examines recent trends and prospects for the future of the U.S. natural gas markets in response to the dramatic increase in natural gas prices during 2000 and early 2001 that raised concerns about the future of natural gas prices and the potential for natural gas to fuel the growth of the U.S. economy.

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 affecting 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 designed as 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 character-

[12] Energy Information Administration, *The Effects of the Alaska Oil and Natural Gas Provisions of H.R. 4 and S. 1766 on U.S. Energy Markets,* SR/OIAF/2002-02 (Washington, DC, February 2002).

[13] Energy Information Administration, *The Transition to Ultra–Low–Sulfur Diesel Fuel: Effects on Prices and Supply*, SR/OIAF/2001-01 (Washington, DC, May 2001).

[14] Energy Information Administration, *The Comprehensive Electricity Competition Act: A Comparison of Model Results, SR/OIAF/99-04 (Washington, DC, September 1999).*

[15] Energy Information Administration, *U.S. Natural Gas Markets: Mid–Term Prospects for Natural Gas Supply*, SR/OIAF/2001-06 (Washington, DC, December 2001).

[16] Energy Information Administration, *U.S. Natural Gas Markets: Recent Trends and Prospects for the Future*, SR/OIAF/2001-02 (Washington, DC, May 2001).

istics, 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, that is 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, 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 energy module represents world oil production and demand, as well as the interactions between the domestic and world oil markets, and this module calculates the average world crude oil price and the supply of specific crude oils and petroleum products. As a result, domestic and world oil market projections are internally consistent. Imports and exports of natural gas, electricity, and coal—which are less influenced by volatile world conditions—are represented in the individual fuel supply modules.

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 a future time period 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 technology improvement over time. Five of the sectors—residential, commercial, transportation, electricity generation, 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 sector. Technological progress is 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 electricity 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 due to a lack of data on individual technologies. In the industrial sector, only the combined heat and power and motor technologies are explicity considered and characaterized. Cost reductions resulting from technological progress in combined heat and power technologies is represented as a function of time as experience with the technologies grows. Technological progress is not explicity 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

In accordance with EIA requirements, NEMS is fully documented and archived. EIA has been running NEMS on three EIA workstations under the Windows 2000 operating system. The archive file provides the source language, input files, and output files to replicate the *Annual Energy Outlook* reference case runs on an identically equipped computer; however, it does not include the proprietary portions of the model, such as the Global Insights, Inc. (formerly DRI/WEFA) macroeconomic model and the optimization modeling libraries. NEMS can be run on a high–powered individual PC as long as the required proprietary software resides 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 the Department of Energy. However, NEMS, or portions of it, is 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, and several private consulting firms.

NEMS represents domestic energy markets by explicitly representing 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.

Since energy costs and availability and energy-consuming characteristics vary widely across regions, considerable regional detail is included. Other details of production and consumption categories are represented to facilitate policy analysis and ensure the validity of the results. A summary of the detail provided in NEMS is shown below.

Summary of NEMS Detail

Energ Acti it	Categories	Regions
Residential demand	Sixteen end-use services Three housing types Thirty–four end–use technologies	Nine Census divisions
Commercial demand	Ten end–use services Eleven building types Ten distributed generation technologies Sixty–four end-use technologies	Nine Census divisions
Industrial demand	Seven energy–intensive industries Eight non–energy–intensive industries Cogeneration	Four Census regions, shared to nine Census divisions
Transportation demand	Six car sizes Six light truck sizes Sixty–three conventional fuel-saving technologies for light–duty vehicles Gasoline, diesel, and thirteen alternative–fuel vehicle technologies for light-duty vehicles Twenty vintages for light-duty vehicles Narrow and wide–body aircraft Six advanced aircraft technologies Medium and heavy freight trucks Thirty–seven advanced freight truck technologie	Nine Census divisions
Electricity	Eleven fossil generation technologies Two distributed generation technologies Seven renewable generation technologies Conventional and advanced nuclear Marginal and average cost pricing Generation capacity expansion Seven environmental control technologies	Fifteen electricity supply regions (including Alaska and Hawaii) based on the North American Electric Reliability Council regions and subregions Nine Census divisions for demand
Renewables	Wind, geothermal, solar thermal, solar photovoltaic, landfill gas, biomass, conventional hydropower	Fifteen electricity supply regions
Oil supply	Onshore Deep and shallow offshore	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions
Natural gas supply	Conventional lower–48 onshore Lower–48 deep and shallow offshore Coalbed methane Gas shales Tight sands Canadian, Mexican, and liquefied natural gas Alaskan Gas	Six lower 48 onshore regions Three lower 48 offshore regions Three Alaska regions Eight liquefied natural gas import regions
Natural gas transmission and distribution	Core vs. noncore Peak vs. offpeak Pipeline capacity expansion	Twelve lower 48 regions Ten pipeline border points
Refining	Five crude oil categories Fourteen product categories More than 40 distinct technologies Refinery capacity expansion	Three refinery regions aggregated from Petroleum Administration for Defense Districts
Coal supply	Three sulfur categories Four thermal categories Underground and surface mining types Imports and Exports	Eleven supply regions Sixteen demand regions Sixteen export regions Twenty import 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 major assumptions concern economic growth in the United States and world oil prices, as determined by world oil supply and demand.

The *Annual Energy Outloook 2003 (AEO2003)* includes five primary fully–integrated cases: a reference case, a high and low economic growth case, and a high and low world oil price case. The reference case uses mid–range assumptions for both the economic growth rate and the world oil price. The primary determinant for differenct economic growth rates are growth in the labor force and productivity, while different assumptions on oil production in the Organization of Petroleum Exporting Countries (OPEC) lead to different levels of world oil prices.

In addition to the five primary fully–integrated cases, *AEO2003* includes 21 other cases that explore the impacts of varying key assumptions in the individual components of NEMS. Many of these cases involve changes in the assumptions that impact the penetration of new or improved technologies, which is a major uncertainty in formulating projections of future energy markets. Some of these cases are run as fully integrated cases (e.g., 2003 technology case, high technology case, high renewables, slow and rapid oil and gas technology cases, and low and high coal mining cost cases). Others exploit the modular structure of NEMS by running only a portion of the entire modeling system in order to focus on the first–order impacts of changes in the assumptions (e.g., advanced nuclear cost case, high electricity demand case, low and high fossil electric generating technology cases, and low and high technology cases in the residential, commercial, industrial, and transportation sectors).

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 product 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.

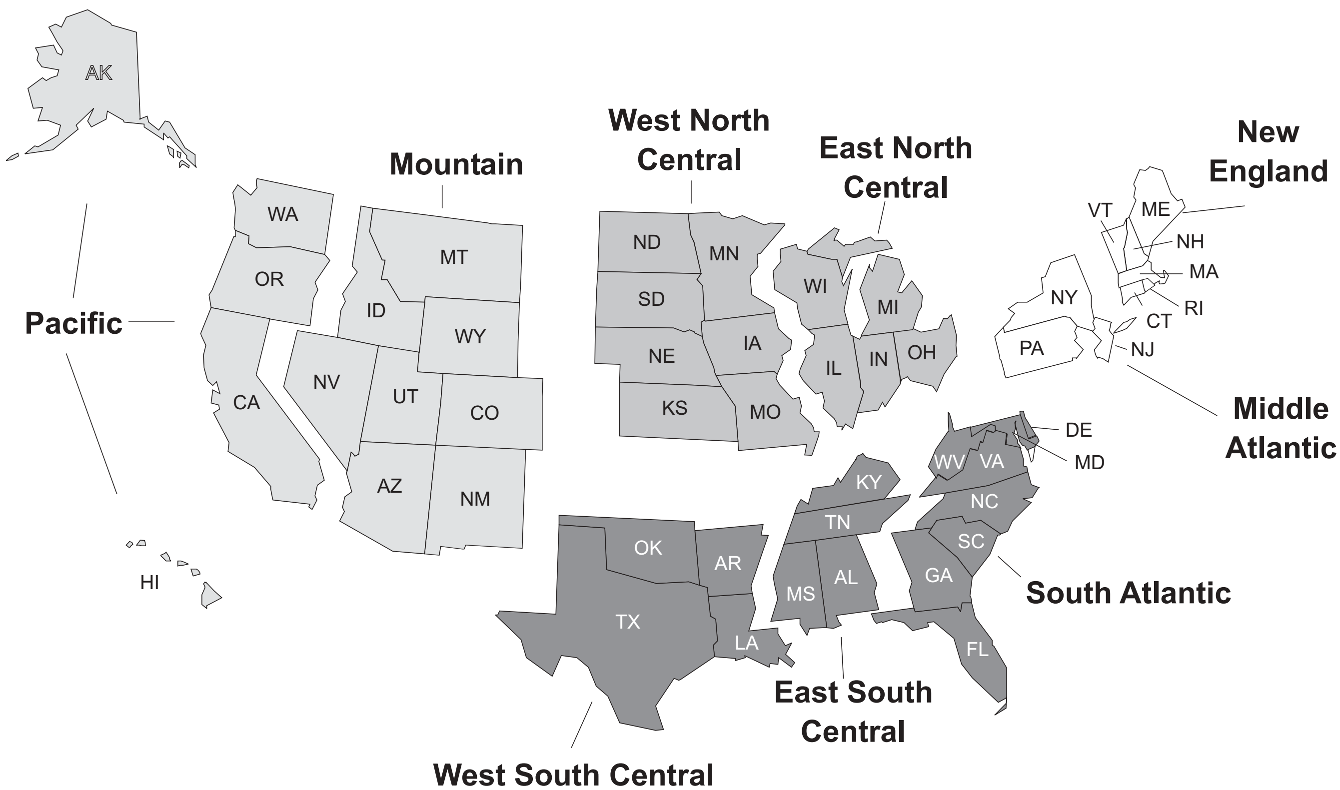
NEMS consists of four supply modules (oil and gas, natural gas transmission and distribution, coal, and renewable fuels); two conversion modules (electricity and petroleum refineries); four end-use demand modules (residential, commercial, transportation, and industrial); one module to simulate energy/economy interactions (macroeconomic activity); one module to simulate world oil markets (international energy activity); and one module that provides the mechanism to achieve a general market equilibrium among all the other modules (integrating module). Figure 2 depicts the high-level structure of NEMS.

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 which 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 for the price and quantity variables in the global data structure are the nine Census divisions. The four Census regions (shown in Figure 1 by breaks between State groups) and nine Census divisions are a common, mainstream level of regionality widely used by EIA and other organizations for data collection and analysis.

Figure 1. Census Divisions



Division 1

New England

Connecticut
Maine
Massachusetts
New Hampshire
Rhode Island
Vermont

Division 2

Middle Atlantic

New Jersey
New York
Pennsylvania

Division 3

East North Central

Illinois
Indiana
Michigan
Ohio
Wisconsin

Division 4

West North Central

Iowa
Kansas
Minnesota
Missouri
Nebraska
North Dakota
South Dakota

Division 5

South Atlantic

Delaware
District of Columbia
Florida
Georgia
Maryland
North Carolina
South Carolina
Virginia
West Virginia

Division 6

East South Central

Alabama
Kentucky
Mississippi
Tennessee

Division 7

West South Central

Arkansas
Louisiana
Oklahoma
Texas

Division 8

Mountain

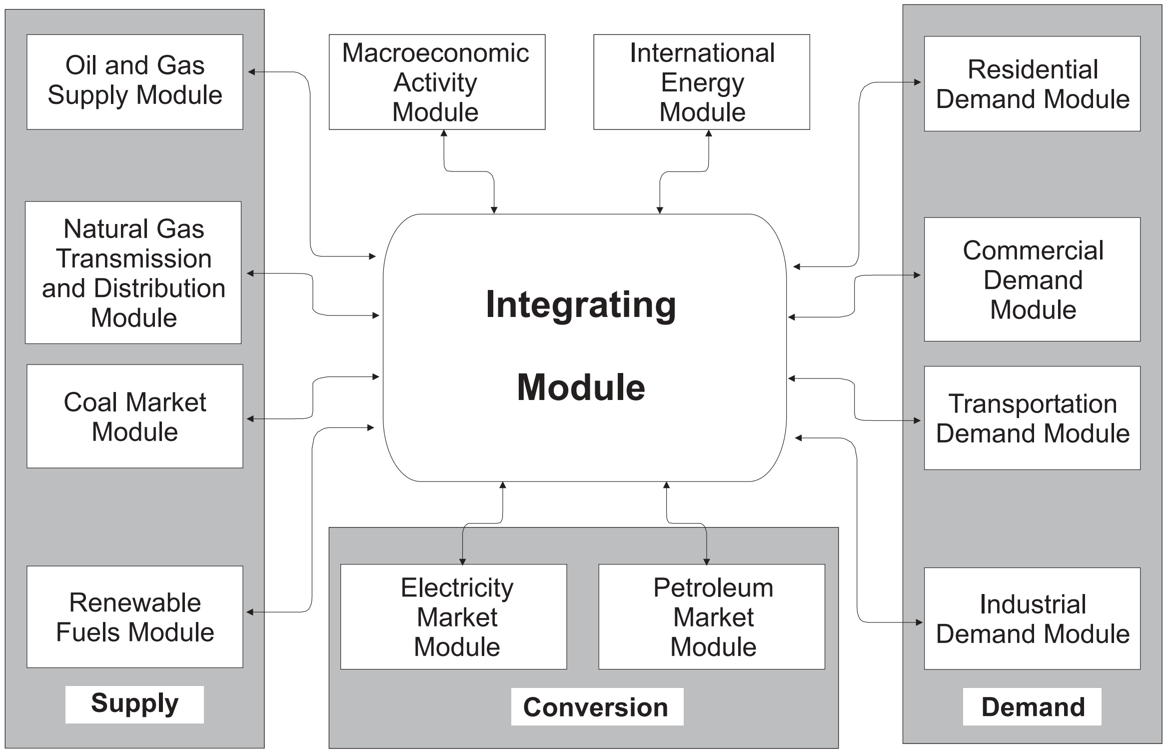
Arizona
Colorado
Idaho
Montana
Nevada
New Mexico
Utah
Wyoming

Division 9

Pacific

Alaska
California
Hawaii
Oregon
Washington

Figure 2. National Energy Modeling System



Integrating Module

The NEMS integrating module controls the entire NEMS solution process as it iterates to determine a general market equilibrium across all the NEMS modules. It has the following functions:

- Manages the NEMS global data structure
- Executes all or any of the user-selected modules in an iterative convergence algorithm
- Checks for convergence and reports variables that remain out of convergence
- Implements convergence relaxation on selected variables between iterations to accelerate convergence
- Updates expected values of the key NEMS variables.

The integrating module executes the demand, conversion, and supply modules iteratively until it achieves an economic equilibrium of supply and demand in all the consuming and producing sectors. Each module is called in sequence and solved, assuming that all other variables in the energy markets are fixed. The modules are called iteratively until the end-use prices and quantities remain constant within a specified tolerance, a condition defined as convergence. Equilibration is achieved annually throughout the midterm period, currently 2025, for each of the nine Census divisions.

In addition, the macroeconomic and international modules are executed iteratively to incorporate the feedback on the economy and international markets from changes in the domestic energy markets. Convergence tests check the stability of a set of key macroeconomic and international trade variables in response to interactions with the domestic energy system.

The NEMS algorithm executes the system of modules until convergence is reached. The solution procedure for one iteration involves the execution of all the component modules, as well as the updating of expectation variables (related to foresight assumptions) for use in the next iteration. The system is executed sequentially for each year in the forecast period. During each iteration within a year, each of the modules is executed in turn, with intervening convergence checks that isolate specific modules that are not converging. A convergence check is made for each price and quantity variable to see whether the percentage change in the variable is within the assumed tolerance. To avoid unnecessary iterations for changes in insignificant values, the quantity convergence check is omitted for quantities less than a user-specified minimum level. The order of execution of the modules may affect the rate of convergence but will generally not prevent convergence to an equilibrium solution or significantly alter the results. An optional relaxation routine can be executed to dampen swings in solution values between iterations. With this option, the current iteration values are reset partway between solution values from the current and previous iterations.

Because of the modular structure of NEMS and the iterative solution algorithm, any single module or subset of modules can be executed independently. Modules not executed are bypassed in the calling sequence, and the values they would calculate and provide to the other modules are held fixed at the values in the global data structure, which are the solution values from a previous run of NEMS. This flexibility is an aid to independent development, debugging, and analysis.

The emissions policy submodule, part of the integrating module, estimates the energy–related emissions of carbon dioxide and methane. Carbon dioxide emissions are dependent on the fossil fuel consumed, the carbon content of the fuel, and the fraction of the fuel consumed in combustion. The product of the carbon dioxide coefficient and the combustion fraction yields a carbon dioxide emission factor. For fuel uses of fossil energy, the combustion fractions are assumed to be 0.99 for liquid fuels and 0.995 for gaseous fuels. The carbon dioxide potential of nonfuel uses of energy, such as asphalt and petrochemical feedstocks, is assumed to be sequestered in the product and not released to the atmosphere. The coefficients for carbon dioxide emissions are updated each year from the Energy Information Administration's annual, *Emissions of Greenhouse Gases in the United States*.[17]

The energy-related methane emissions are estimated as a function of energy production and consumption drivers. Methane emissions occur in various phases of the production and transportation of coal, oil, and natural gas. Additional emissions occur as a result of incomplete combustion of fossil fuels and wood. The methane equations in NEMS are derived from methodologies and data sources in Energy Information Administration's annual *Emissions of Greenhouse Gases in the United States*.[18]

The emissions policy submodule also allows for several carbon dioxide policy evaluation options to be analyzed within NEMS. Although these policy options are not assumed in the Annual Energy Outlook, the options have been used in special analyses to simulate potential market–based approaches to meet national carbon dioxide emission objectives. The policy options implemented are as follows:

- *Carbon Dioxide Tax*. A tax on carbon dioxide emissions from fossil fuels is added to raise delivered fossil fuel prices. The resulting higher prices then induce changes in fossil fuel use and carbon dioxide emissions, as well as changes in some long–term decision making, such as generating capacity decisions in the electricity market module.
- *Auction of Permits*. This option simulates an auction on carbon dioxide emissions permits to meet an overall cap on emissions. A carbon dioxide permit price is computed that clears the auction market. The permit fee is treated as a carbon dioxide tax and used as an adjustment to the fossil fuel prices. A new price is set each NEMS iteration until the emissions reach the goal. The revenue generated from the auction is calculated assuming there is no initial allocation of emission permits.
- *Market for Permits (Cap and Trade)*. A market for tradable carbon dioxide emissions permits is simulated assuming that an initial distribution of marketable permits to emission sources takes place. The permits are transferable but are not banked between years. As with the carbon dioxide tax and auction options, the full market price of the permits is added to the energy prices. The system of marketable permits is implemented in the same way as the permit auction, with the exception of the calculation of revenues from permit sales. Similar treatment is warranted because the marginal cost of a free permit is equivalent to one purchased at auction, given the opportunity cost of holding the distributed permit.[19]

The options above can be implemented for all consuming sectors of NEMS or for the electricity generating sector alone. The use of any of these emissions policy options in NEMS requires a macroeconomic analysis to assess the fiscal and monetary issues, as well as the possible international trade effects. The analysis depends on such factors as how revenues generated from the policy would be used, how monetary authorities would react to the fiscal policy

[17] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002).

[18] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2001,* DOE/EIA-0573(2001) (Washington, DC, December 2002).

[19] In an open, competitive permit market, the permit will tend to be priced at the marginal cost of reducing carbon dioxide emissions, regardless of the initial distribution of permits. If permits are purchased by suppliers and passed through to the fuel price, the marginal cost of the carbon dioxide emissions by a particular sector in a region will be reflected in the individual end–use fuel cost for tht sector.

changes, and how international agreements to reduce carbon dioxide emissions would be implemented.

A limitation of these policy options is that they address energy–related carbon dioxide emissions only. Work on NEMS is underway on a capability to estimate reductions of other greenhouse gas emissions. This capability, drawing on marginal cost of abatement curves for such gases, will enahle the economic analysis of policies targeted at capping total greenhouse gases in an internally consistent framework.

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 forecast 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 impacts associated with changing energy market conditions, such as alternative world oil price assumptions. Outside of the Annual Energy Outlook setting, MAM represents a system of linked modules which can assess the potential impacts on the economy of changes in energy events or policy proposals. These economic impacts then feed back into NEMS for an integrated solution. MAM consists of five modules:

- Global Insight Model of the U.S. Economy
- Global Insight Industry Model
- Global Insight Employment Model
- Global Insight Regional Model
- Energy Information Administration (EIA) Commercial Floorspace Model

The Global Insight Model of the U.S. Economy (Macroeconomic Model) is the same model used by Global Insight, Inc. (formerly DRI-WEFA) to generate the economic forecasts behind the company's monthly assessment of the U.S. economy. The Industry, Employment, and Regional Models are derivatives of Global Insight's industry, employment, and regional models. The models have been tailored in order to provide the industry and regional detail required by NEMS. The Commercial Floorspace Model was developed by EIA to complement the set of Global Insight models. This system of models provides a fully integrated approach to forecasting economic activity at the national, industry and regional levels. The set of models is designed to run in a recursive manner (see Figure 3).

Global Insight's Macroeconomic Model determines the national economy's growth path and final demand mix. The Macroeconomic Model provides forecasts of over 1300 concepts spanning final demands, aggregate supply, prices, incomes, international trade, industrial detail, interest rates and financial flows.

The Industry Model takes the final demand projections from the Macroeconomic Model as inputs to provide projections of output and other key indicators for 130 sectors, covering the entire economy. This is later aggregated to 45 sectors to provide information to NEMS. The Industry Model insures that supply by industry is consistent with the final demands (consumption, investment, government spending, exports and imports) generated in the Macroeconomic Model.

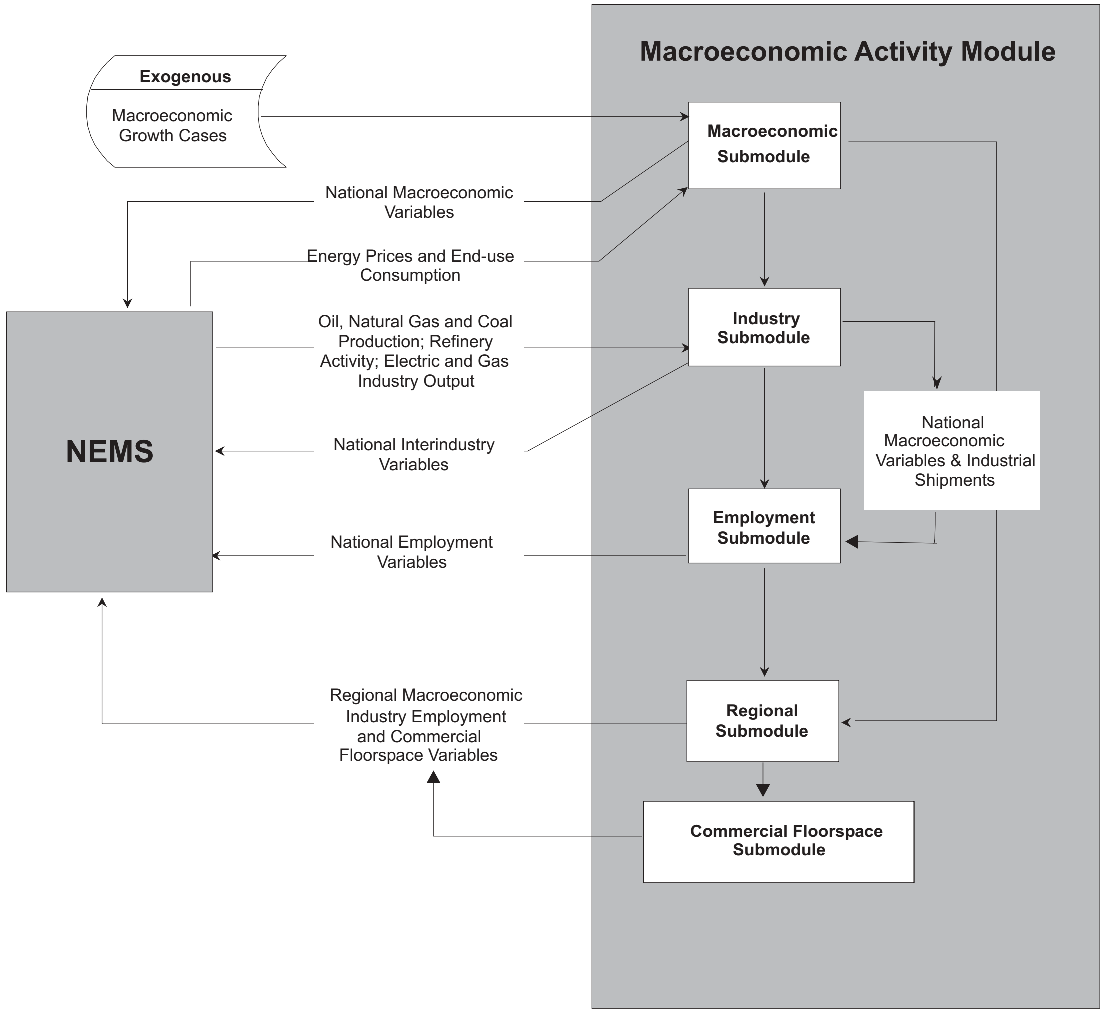
The Employment Model takes the industry output projections from the Industry Model and national wage rates, productivity trends and average workweek trends from the Macroeconomic Model to project employment for the 45 NEMS industries. The sum of non–agricultural employment is constrained to sum to the national total projected by the Macroeconomic Model.

The Regional Model determines the level of industry output and employment, population, incomes, and housing activity in each of nine Census regions. The Commercial Floorspace Model calculates regional floorspace for 13 types of building use by Census Division.

Integrated forecasts of NEMS center around estimating the state of the energy-economy system under a set of alternative energy conditions: Typically,

MAM Outputs	Inputs from NEMS	Exogenous Inputs
Gross domestic product Other economic activity measures, including housing starts, commercial floorspace growth, vehicle sales, population Price indices and deflators Production and employment for manufacturing Production and employment for nonmanufacturing Interest rates	Petroleum, natural gas, coal, and electricity prices Oil, natural gas, and coal production Electric and gas industry output Refinery output End-use energy consumption by fuel	Macroeconomic variables defining alternative economic growth cases

Figure 3. Macroeconomic Activity Module Structure



the forecasts fall into the following four types of integrated NEMS simulations:

- Baseline Projection
- Alternative World Oil Prices
- Proposed Energy Fees or Emissions Permits
- Proposed Changes in Combined Average Fuel Economy (CAFE) Standards

In these integrated NEMS simulations, forecast period baseline values for over 240 macroeconomic and demographic variables from MAM are passed to NEMS which solves for demand, supply and prices of energy for the forecast period. These energy prices and quantities are passed back to MAM and solved in the Macroeconomic Model, the Industry Model and the Employment Model in the EViews environment.[20] The Regional Model and the Commercial Floorspace Model and NEMS are run in the FORTRAN environment.

[20] Eviews is a model building and operating software package maintained by QMS (Quantitative Micro Software.)

The international energy module (IEM) consists of four submodules (Figure 4) that perform the following functions:

- world oil market submodule calculates the average annual world oil price (imported refiner acquisition cost) that is consistent with worldwide petroleum demand and supply availability
- crude oil supply submodule provides imported crude oil supply curves for five crude oil quality classes
- petroleum products supply submodule provides imported refined product supply curves for twelve types of refined products
- oxygenates supply submodule provides imported oxygenates supply curves for methyl tertiary butyl ether (MTBE) and methanol.

The world oil price that is generated by the world oil market submodule is used by all the modules of NEMS as well as the other submodules of IEM. The import supply curves for crude oils, refined products, and oxygenates are used by the petroleum market module.

World Oil Market Submodule

In NEMS, the U.S. oil market is modeled in considerable detail, while foreign markets use a less detailed approach. EIAs modeling of the near–to mid–term world oil market depends on two key assumptions: (1) oil is the marginal fuel and (2) the Organization of Petroleum Exporting Countries (OPEC) is the marginal supplier of oil. The first assumption implies that competition between oil and other fuels is not significant enough to impact the world oil price. In addition, prices remain sufficiently low such that the market penetration of new technologies that would reduce the demand for oil is inhibited. In the second assumption, OPEC producers are assumed to expand oil production capacity in order to meet the growth in worldwide oil demand.

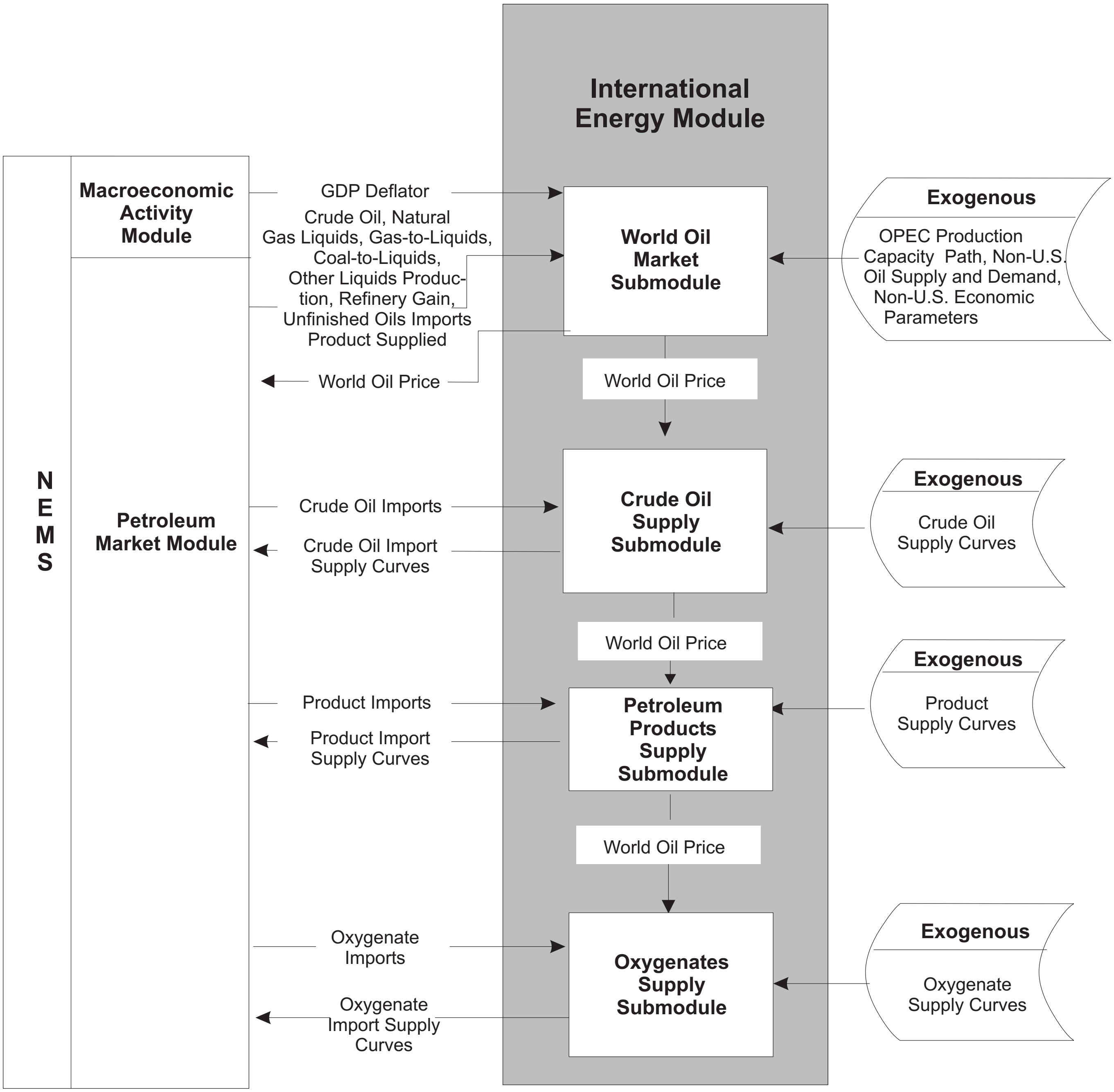
The various price cases examined by EIA differ in the magnitude to which OPEC producers expand their production capacity. Lower prices imply considerable capacity expansion activity with a probable assist from foreign investment interests. Higher prices imply an unwillingness on the part of OPEC producers to invite foreign investment participation. The world oil market submodule forecasts the world oil price and produces a regional world oil market supply/demand balance that is consistent with the forecasted price. The world oil price forecast is based upon a regression analysis of the price in the previous time period and the percent utilization of OPEC production capacity. IEM has either the capability to forecast world oil prices given OPEC production capacity estimates or the capability to forecast OPEC production given an exogenous world oil price path.

Crude Oil Supply Submodule

The crude oil supply submodule consists of a set of import supply curves to all five Petroleum Administration for Defense Districts (PADDs) for each of five quality classes of crude oils and for each simulation year. The petroleum market module uses the supply curves to determine the quantities and prices of the crude oils to be imported. Because the petroleum market module is a linear programming formulation, the imported crude oil supply curves are formulated as 3–step, piecewise–linear functions. The five classes of imported crude oils categorized by sulfur content and American Petroleum Institute (API)

IEM Outputs	Inputs from NEMS	Exogenous Inputs
World oil price Crude oil import supply curves Refined product import supply curves Oxygenate import supply curves	Domestic crude oil production Domestic natural gas liquids production Domestic gas-to-liquids production Domestic coal-to-liquids production Domestic other liquids production Domestic refinery gain Domestic product supplied GDP price deflators Domestic crude oil imports Domestic refined product imports Domestic oxygenate imports Domestic unfinished oils imports	OPEC production capacity path Reference non-U.S. oil supply and demand Non-U.S. economic parameters Base import supply curves for crude oils, refined products, and oxygenates

Figure 4. International Energy Module Structure



gravity include: low–sulfur light, medium–sulfur heavy, high–sulfur light, high–sulfur heavy, high–sulfur very heavy.

The imported crude oil supply curves are developed exogenous to NEMS using a large–scale linear programming formulation of international refining and transportation. This formulation, known as the World Oil Refining, Logistics, and Demand (WORLD) model, is run repetitively, parameterizing on the import levels of the five crude oil classes into each PADD. From these runs, base price/quantity relationships for imported crude oils are established. Within NEMS, these base relationships are shifted as a function of the world oil price and presented to the petroleum market module as a flexible set of crude oil import alternatives. By observing which import supply curves are selected by the petroleum market module, it becomes possible to map these selections back into the WORLD model in order to provide estimates of future sources of crude oil imports to the United States.

Petroleum Products Supply Submodule

The petroleum products supply submodule consists of a set of import supply curves to all five PADDs for each of twelve refined product types and for each simulation year. The petroleum market module uses the supply curves to determine the quantities and prices of refined products to be imported. Because the petroleum market module is a linear programming formulation, the imported refined product supply curves are formulated as 3–step, piecewise–linear functions. The twelve types of imported refined products include: traditional gasoline (including aviation), reformulated gasoline, reformulated gasoline blending stocks for oxygenated blending (RBOB), traditional distillate fuel, low-sulfur No. 2 heating oil, low–sulfur diesel fuel, high– and low–sulfur residual fuel, jet fuel (including naphtha jet), liquefied petroleum gases, petrochemical feedstocks, and other petroleum products.

Similar to the imported crude oil supply curves, the imported refined product supply curves are also developed exogenous to NEMS using the WORLD model. By observing which import supply curves are selected by the petroleum market module, it becomes possible to map these selections back into the WORLD model in order to provide estimates of future sources of refined product imports to the United States.

Oxygenates Supply Submodule

The oxygenates supply submodule consists of a set of import supply curves to all five PADDs for the oxygenates MTBE and methanol and for each simulation year. The petroleum market module uses the supply curves to determine the quantities and prices of oxygenates to be imported. Because the petroleum market module is a linear programming formulation, the imported oxygenate supply curves are formulated as 3–step, piecewise–linear functions. Similar to the imported crude oil supply curves, the imported oxygenate supply curves are developed exogenous to NEMS using the WORLD model. By observing which import supply curves are selected by the petroleum market module, it becomes possible to map these selections back into the WORLD model in order to provide estimates of future sources of oxygenate imports into the United States.

Because of the potential expansion of the U.S. ethanol industry and the lack of commercial markets for other oxygenates, it is assumed that ethanol, ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME), and tertiary butyl alcohol (TBA) are all supplied from domestic sources. Therefore, IEM does not provide import supply curves for these oxygenates.

By presenting NEMS with a flexible array of import choices, valuable insights can be gained on such issues as the future crude oil/refined product import composition, potential U.S. refinery expansion (both distillation capacity and downstream capacity), and future sources of petroleum imports (including Persian Gulf import dependence).

The residential demand module (RDM) forecasts energy consumption by Census division for seven marketed energy sources plus solar and geothermal energy. RDM is a structural model and its forecasts are built up from projections of the residential housing stock and of the energy-consuming equipment contained therein. The components of RDM and its interactions with the NEMS system are shown in Figure 5. NEMS provides forecasts of residential energy prices, population, disposable income, and housing starts, which are used by RDM to develop forecasts of energy consumption by end–use service, fuel type, and Census division.

RDM incorporates the effects of four broadly-defined determinants of energy consumption: economic and demographic effects, structural effects, technology turnover and advancement effects, and energy market effects. Economic and demographic effects include the number, dwelling type (single-family, multifamily or mobile homes), occupants per household, disposable income, and location of housing units. Structural effects include increasing average dwelling size and changes in the mix of desired end-use services provided by energy (new end uses and/or increasing penetration of current end uses, such as the increasing popularity of electronic equipment and computers). Technology effects include changes in the stock of installed equipment caused by normal turnover of old, worn out equipment with newer versions which tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and in the projected availability of even more energy-efficient equipment in the future. Energy market effects include the short-run effects of energy prices on energy demands, the longer-run effects of energy prices on the efficiency of purchased equipment and the efficiency of building shells, and limitations on minimum levels of efficiency imposed by legislated efficiency standards.

Housing Stock Submodule

The base housing stock by Census division and dwelling type is derived from EIA's 1997 Residential Energy Consumption Survey (RECS). Each element of the base stock is retired on the basis of a constant rate of decay for each dwelling type. RDM receives as an input from the macroeconomic activity module forecasts of housing additions by type and Census division. RDM supplements the surviving stocks from the previous year with the forecast additions by dwelling type and Census division. The average square footage of new construction is based on recent upward trends developed from the RECS and the Census Bureau's Characteristics of New Housing.

Appliance Stock Submodule

The installed stock of appliances is also taken from the 1997 RECS. The efficiency of the appliance stock is deived from historical shipments by efficiency level over a multi–year interval for the following equipment: heat pumps, gas furnaces, central air conditioners, room air conditioners, water heaters, refrigerators, freezers, stoves, dishwashers, clothes washers, and clothes dryers. A linear retirement function with both minimum and maximum equipment lives is used to retire equipment in surviving housing units. For equipment where shipment data are available, the efficiency of the retiring equipment varies over the projection. In early years, the retiring efficiency tends to be lower as the older, less efficient equipment in the stock turns over first. Also, as housing units retire, the associated appliances are removed from the base appliance stock as well. Additions to the base stock are tracked separately for housing units existing in 1997 and for cumulative new construction.

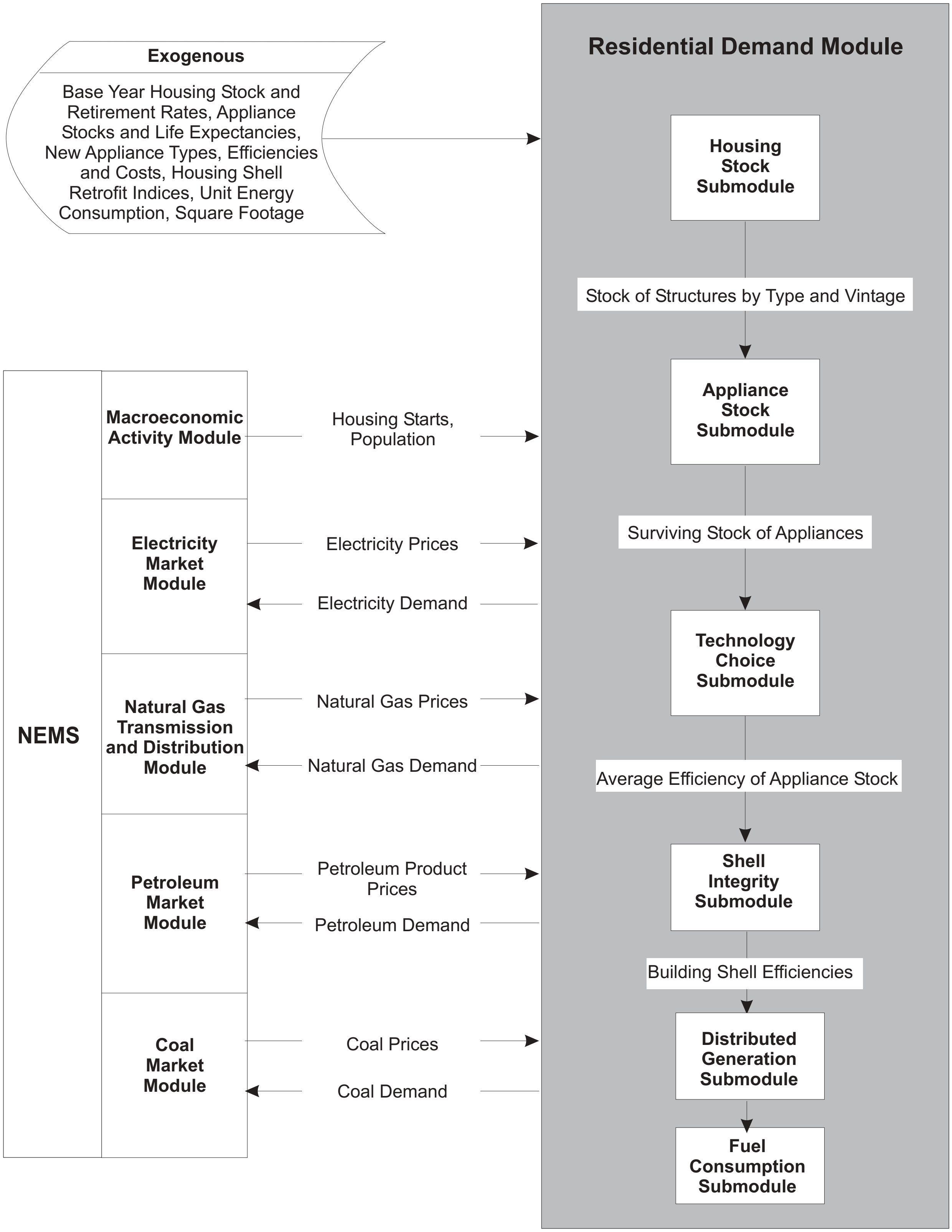
As appliances are removed from the stock, they are replaced by new appliances with generally higher efficiencies due to technology improvements, equipment standards, and market forces. Appliances added due to new construction are accumulated and retired parallel to appliances in the existing stock. Appliance stocks are maintained by fuel, end use, and technology as shown in the above table.

Technology Choice Submodule

Fuel-specific equipment choices are made for both new construction and replacement purchases. For new construction, initial heating system shares

RDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in housing and appliance stocks Appliance stock efficiency	Energy product prices Housing starts Population	Current housing stocks and retirement rates Current appliance stocks and life expectancy New appliance types, efficiencies, and costs Housing shell retrofit indices Unit energy consumption Square footage

Figure 5. Residential Demand Module Structure



NEMS Residential Module Equipment Summary

Space Heating Equipment: electric furnace, electric air-source heat pump, natural gas furnace, natural gas hydronic, kerosene furnace, liquefied petroleum gas, distillate furnace, distillate hydronic, wood stove, ground-source heat pump, natural gas heat pump.
Space Cooling Equipment: room air conditioner, central air conditioner, electric air-source heat pump, ground-source heat pump, natural gas heat pump.
Water Heaters: solar, natural gas, electric, distillate, liquefied petroleum gas.
Refrigerators: 18 cubic foot top-mounted freezer, 25 cubic foot side-by-side with through-the-door features.
Freezers: chest - manual defrost, upright - manual defrost
Lighting: incandescent, compact fluorescent, mercury vapor
Clothes Dryers: natural gas, electric
Cooking: natural gas, electric, liquefied petroleum gas.
Dishwashers
Clothes Washers
Fuel Cells
Solar Photovoltaic

(taken from the most recently available Census Bureau survey data covering new construction, currently 2001) are adjusted based on relative life cycle costs for all competing technology and fuel combinations. Once new home heating system shares are established, the fuel choices for other services, such as water heating and cooking, are determined based on the fuel chosen for space heating. For replacement purchases, fuel switching is allowed for an assumed percentage of all replacements but is dependent on the estimated costs of fuel–switching (for example, switching from electric to gas heating is assumed to involve the costs of running a new gas line).

For both replacement equipment and new construction, a "second-stage" of the equipment choice decision requires selecting from several projected available efficiency levels. The projected efficiency range of available equipment represents a "menu" of efficiency levels and installed cost combinations projected to be available at the time the choice is being made. Costs and efficiencies for selected appliances are shown in the table on page 25, derived from the report *Assumptions to the Annual Energy Outlook 2003*.[21] At the low end of the efficiency range are the minimum levels required by legislated standards. In any given year, higher efficiency levels are associated with higher installed costs. Thus, purchasing higher than the minimum efficiency involves a trade-off between higher installation costs and future savings in energy expenditures. In RDM, these trade-offs are calibrated to recent shipment, cost, and efficiency data. Changes in projected purchases by efficiency level are based on changes in either the installed capital costs or changes in the first-year operating costs across the available efficiency levels. As energy prices increase, the incentive of greater energy expenditures savings will promote increased purchases of higher-efficiency equipment. In some cases, due to government programs or general projections of technology improvements, projected increases in efficiency or decreases in the installed costs of higher-efficiency equipment will also promote purchases of higher-efficiency equipment.

Shell Integrity Submodule

Shell integrity is also tracked separately for the existing housing stock and new construction. Shell integrity for existing construction is assumed to respond to increases in real energy prices by becoming more efficient. There is no change in existing shell integrity when real energy prices decline. New shell efficiencies are based on the cost and performance of the heating and cooling equipment as well as the shell dharacteristics. Several efficiency levels of shell characteristics are available throughout the projection period and can change over time based on changes to building codes. All shell efficiencies are subject to a maximum shell efficiency based on studies of currently available residential construction methods.

Distributed Generation Submodule

Distributed generation equipment with explicit technology characterizations is also modeled for residential customers. Currently, two technologies are characterized, photovoltaics and fuel cells. The submodule incorporates historical estimates of photovoltaics (residential-sized fuel cells are not expected to be commercialized until after 2001) from its technology characterization and exogenous penetration input file. Program-based photovoltaic estimates for the Department of Energy's Million Solar

[21] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf (Washington, DC, January 2003).

Roofs program are also input to the submodule from the exogenous penetration portion of the input file. Endogenous, economic purchases are based on a penetration function driven by a cash flow model which simulates the costs and benefits of distributed generation purchases. The cash flow calculations are developed from NEMS projected energy prices coupled with the technology characterizations provided from the input file.

Potential economic purchases are modeled by Census division and technology for all years subsequent to the base year. The cash flow model develops a 30-year cost-benefit horizon for each potential investment. It includes considerations of annual costs (down payments, loan payments, maintenance costs and, for fuel cells, gas costs) and annual benefits (interest tax deductions, any applicable tax credits, electricity cost savings, and water heating savings for fuel cells) over the entire 30-year period. Penetration for a potential investment in either photovoltaics or fuel cells is a function of whether it achieves a cumulative positive cash flow, and if so, how many years it takes to achieve it.

Once the cumulative stock of distributed equipment is projected, reduced residential purchases of electricity are provided to NEMS. For fuel cells, increased residential natural gas consumption is also provided to NEMS based on the calculated energy input requirements of the fuel cells, partially offset by natural gas water heating savings from the use of waste heat from the fuel cell.

Fuel Consumption Submodule

The fuel consumption submodule modifies base year energy consumption intensities in each forecast year. Base year energy consumption for each end use is derived from energy intensity estimates from the 1997 RECS. The base year energy intensities are modified for the following effects: (1) increases in efficiency, based on a comparison of the projected appliance stock serving this end use relative to the base year stock, (2) changes in shell integrity for space heating and cooling end uses, (3) changes in real fuel prices—(short-run price elasticity effects), (4) changes in square footage, (5) changes in the number of occupants per household, (6) changes in disposable income, (7) changes in weather relative to the base year, (8) adjustments in utilization rates caused by efficiency increases (efficiency “rebound” effects), and (9) reductions in purchased electricity and increases in natural gas consumption from distributed generation. Once these modifications are made, total energy use is computed across end uses and housing types and then summed by fuel for each Census division.

Characteristics of Selected Equipment

Equipment Type	Relative Performance[1]	2001 Installed Cost (2001 dollars)[2]	Efficiency[3]	2015 Installed Cost (2001 dollars)[2]	Efficiency[3]	Approximate Hurdle[4] Rate
Electric Heat Pump	Minimum	$2,930	10.0	$3,500	12.0	15%
	Best	$5,600	18.0	$5,600	18.0	
Natural Gas Furnace	Minimum	$1,300	0.80	$1,300	0.80	15%
	Best	$2,700	0.97	$1,950	0.97	
Room Air Conditioner	Minimum	$540	8.7	$540	9.7	140%
	Best	$760	11.7	$760	12.0	
Central Air Conditioner	Minimum	$2,080	10.0	$2,300	12.0	25%
	Best	$3,500	18.0	$3,500	18.0	
Refrigerator (18 cubic ft)	Minimum	$600	690	$600	478	19%
	Best	$950	515	$950	400	
Electric Water Heater	Minimum	$337	0.86	$500	0.90	83%
	Best	$1,200	2.60	$1,100	2.6	
Solar Water Heater	N/A	$3,200	2.0	$2,533	2.0	83%

[1]Minimum performance refers to the lowest efficiency equipment available. Best refers to the highest efficiency equipment available.
[2]Installed costs represents the capital cost of the equipment plus the cost to install it, excluding any finance costs.
[3]Efficiency measurements vary by equipment type. Electric heat pumps and central air conditioners are rated for cooling performance using the Seasonal Energy Efficiency Ratio (SEER); natural gas furnaces are based on Annual Fuel Utilization Efficiency; room air conditioners are based on Energy Efficiency Ratio (EER); refrigerators are based on kilowatt-hours per year; and water heaters are based on Energy Factor (delivered Btu divided by input Btu).
[4]The hurdle rate represents the consumer's "willingness" to invest in energy efficiency is by weighing the first cost and operating cost of competing technologies. The higher the hurdle rate, the less likely a consumer will invest in energy efficiency. These rates include all financial and non–financial factors (such as size, color) that influence a consumer's purchase decision.

Source: Arthur D. Little, *EIA Technology Forecast Updates*, Reference Number 8675309, October 2001.

The commercial demand module (CDM) forecasts energy consumption by Census division for eight marketed energy sources plus solar and geothermal energy. For the three major commercial sector fuels, electricity, natural gas and distillate oil, CDM is a structural model and its forecasts are built up from projections of the stock of commercial floorspace and energy–consuming equipment. For the remaining five marketed minor fuels, simple econometric projections are made.

The commercial sector encompasses business establishments that are not engaged in industrial or transportation activities. Commercial sector energy is consumed mainly in buildings, except for a relatively small amount for services such as street lights and water supply. CDM incorporates the effects of four broadly–defined determinants of energy consumption: economic and demographics, structural, technology turnover and change, and energy markets. Demographic effects include total floorspace, building type and location. Structural effects include changes in the mix of desired end–use services provided by energy (such as the penetration of telecommunications equipment, personal computers and other office equipment). Technology effects include changes in the stock of installed equipment caused by the normal turnover of old, worn out equipment to newer versions which tend to be more energy efficient, the integrated effects of equipment and building shell (insulation level) in new construction, and the projected availability of equipment with even greater energy–efficiency. Energy market effects include the short–run effects of energy prices on energy demands, the longer–run effects of energy prices on the efficiency of purchased equipment, and limitations on minimum levels of efficiency imposed by legislated efficiency standards. The model structure carries out a sequence of five basic steps, as shown in Figure 6. The first step is to forecast commercial sector floorspace. The second step is to forecast the energy services (space heating, lighting, etc.) required by the projected floorspace. The third step is to project the electricity generation and water and space heating supplied by distributed generation and combined heat and power (CHP) technologies. The fourth step is to select specific technologies (natural gas furnaces, fluorescent lights, etc.) to meet the demand for energy services. The last step is to determine how much energy will be consumed by the equipment chosen to meet the demand for energy services.

Floorspace Submodule

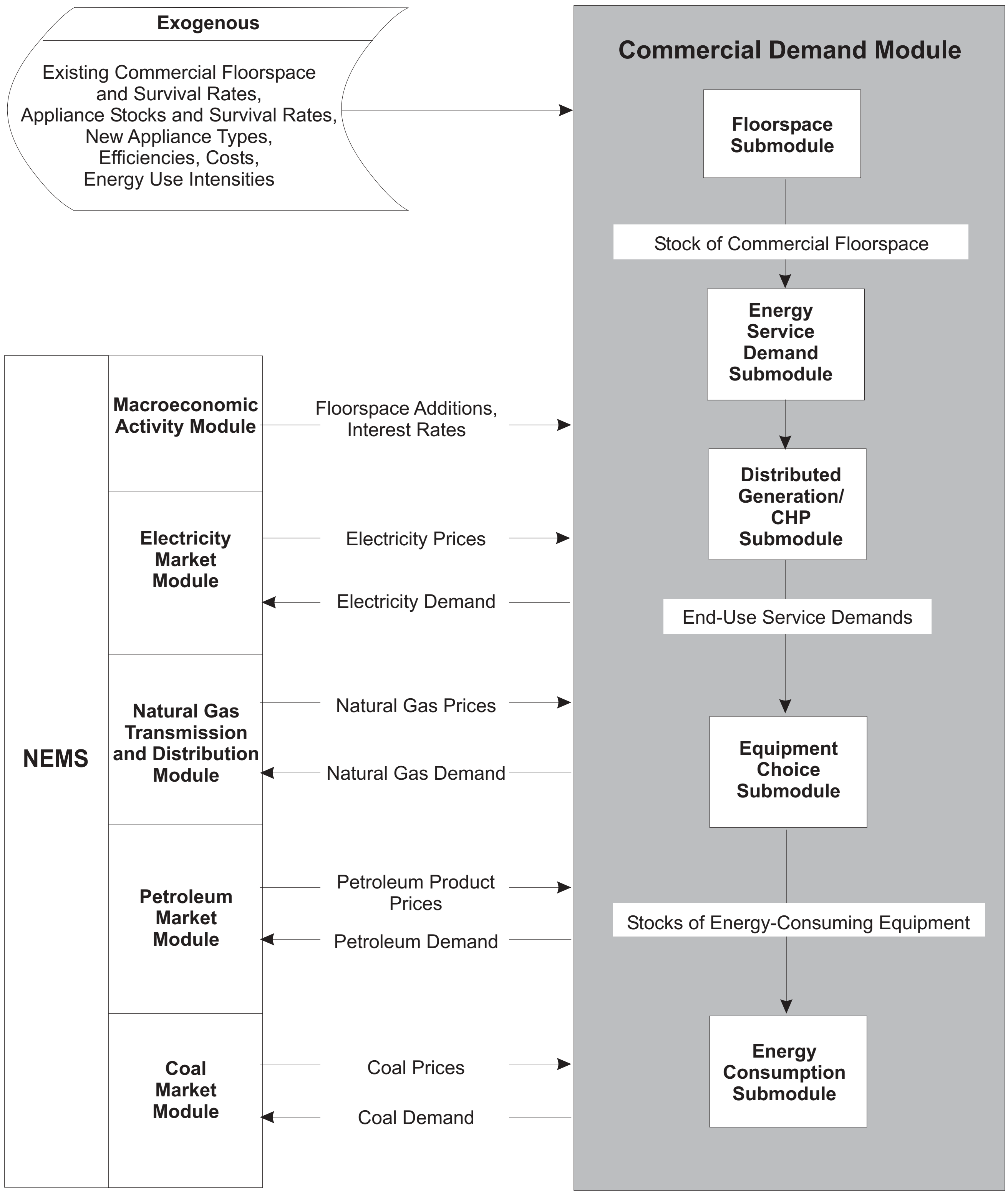
The base stock of commercial floorspace by Census division and building type is derived from EIA's 1999 Commercial Buildings Energy Consumption Survey (CBECS). CDM receives forecasts of total floorspace by building type and Census division from the macroeconomic activity module (MAM) based on Global Insight, Inc. (formerly DRI–WEFA) definitions of the commercial sector. These forecasts embody both economic and demographic effects on commercial floorspace. Since the definition of commercial floorspace from Global Insight, Inc. is not calibrated to CBECS, CDM estimates the surviving floorspace from the previous year and then calibrates its new construction so that growth in total floorspace matches that from MAM by building type and Census division.

CDM models commercial floorspace for the following 11 building types:

- Assembly
- Education
- Food sales
- Food service
- Health care
- Lodging
- Office–large
- Office–small
- Mercantile and service
- Warehouse
- Other

CDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Changes in floorspace and appliance stocks	Energy product prices Interest rates Floorspace growth	Existing commercial floorspace Floorspace survival rates Appliance stocks and survival rates New appliance types, efficiencies, costs Energy use intensities

Figure 6. Commercial Demand Module Structure



Energy Service Demand Submodule

Energy consumption is derived from the demand for energy services. So the next step is to forecast energy service demands for the projected floorspace. CDM models service demands for the following ten end–use services:

- Heating
- Cooling
- Ventilation
- Water heating
- Lighting
- Cooking
- Refrigeration
- Office equipment personal computer (PC)
- Office equipment other
- Other end uses.

Different building types require unique combinations of energy services. A hospital must have more light than a warehouse. An office building in the Northeast requires more heating than one in the South. Total service demand for any service depends on the floorspace, type, and location of buildings. Base service demand by end use by building type and Census division is derived from estimates developed from CBECS energy consumption. Projected service demands are adjusted for trends in new construction based on CBECS data concerning recent construction.

Distributed Generation and CHP Submodule

Commercial consumers may decide to purchase equipment to generate electricity (and perhaps provide heat as well) rather than depend on purchased electricity to fulfill all of their electric power requirements. The third basic step of the commercial module structure projects electricity generation, fuel consumption, water heating, and space heating supplied by ten distributed generation and CHP technologies. The characterized technologies include: photovoltaic solar systems; natural gas fuel cells, reciprocating engines, turbines and microturbines; diesel engines; coal–fired CHP; and municipal solid waste, wood, and hydroelectric generators.

Existing electricity generation by CHP technologies is derived from historical data contained in the most recent year's version of Form EIA–860B, Annual Electric Generator Report–Nonutility. The estimated units form the installed base of CHP equipment that is carried forward into future years and supplemented with any projected additions. Program driven installations of solar photovoltaic systems and fuel cells are also included based on information from the Departments of Energy and Defense. For years following the base year, an endogenous forecast of distributed generation and CHP is developed based on the economic returns projected for distributed generation technologies. A detailed cash–flow approach is used to estimate the number of years required to achieve a positive cumulative cash flow. The calculations include the annual costs (down payments, loan payments, maintenance costs, and fuel costs) and returns (tax deductions, tax credits, and energy cost savings) from the investment covering a 30–year period from the time of the investment decision. Penetration of these technologies is a function of how quickly an investment in a technology is estimated to recoup its flow of costs. In terms of NEMS projections, investments in distributed generation reduce purchases of electricity. Fuel consuming technologies also generate waste heat which is assumed to be partially captured and used to offset commercial water heating and space heating energy use.

Equipment Choice Submodule

Once service demands are projected, the next step is to project the type and efficiency of equipment that will be used to satisfy the demands. The bulk of equipment required to meet service demand will carry over from the equipment stock of the previous model year. However, equipment must always be purchased to satisfy service demand for new construction. It must also be purchased for equipment which has either worn out (replacement equipment) or reached the end of its economically useful life (retrofit equipment). For required equipment replacements, CDM uses a constant decay rate based on equipment life. A technology will be retrofitted only if the combined annual operating and maintenance costs plus annualized capital costs of a potential technology are lower than the annual operating and maintenance costs of an existing technology.

Equipment choices are made based on a comparison of annualized capital and operating and maintenance costs across all allowable equipment for a particular end–use service. In order to add inertia to the equipment choices, only subsets of the total menu of potentially available equipment may be allowed for defined market segments. For example,only 8 percent of floorspace in large office buildings may consider all available equipment using any fuel or technology when making space heating equipment replacement decisions. A second segment equal to 35 percent of floorspace, must select from technologies using the same fuel as already installed. A third segment, the remaining 57 percent of floorspace, is constrained to consider only different efficiency levels of the same fuel and technology already installed. For lighting, all replacement choices are limited to the same technology, where technologies are broadly defined to encompass principal competing technologies (outdoor lighting types do not compete for indoor lighting service demand).

When computing annualized costs for determining equipment choices, commercial floorspace is segmented by what are referred to as hurdle rates or implicit discount rates (to distinguish them from the generally lower and more common notion of financial discount rates). Seven segments are used to simulate consumer behavior when purchasing commercial equipment. The segments range from rates as low as the 10–year Treasury bond rate, to rates high enough to guarantee that only equipment with the lowest capital cost (and least efficiency) is chosen. As real energy prices increase (decrease) there is an incentive for all but the highest implicit discount rate segments to purchase increased (decreased) levels of efficiency.

The equipment choice submodule is designed to choose among a discrete set of technologies that are characterized by a menu which defines availability, capital costs, maintenance costs, efficiencies, and equipment life. Technology characteristics for selected space heating equipment are shown in the table on page 31, derived from the report *Assumptions to the Annual Energy Outlook 2003*.[22] This menu of projected equipment models projects technological innovation, market developments, and policy interventions. For the *Annual Energy Outlook 2003*, the technology types that are included for seven of the ten service demand categories are listed in the table on page 32.

The remaining three end–use services (PC–related office equipment, other office equipment, and other end uses) are considered minor services and are forecast using exogenous equipment efficiency and market penetration trends.

Energy Consumption Submodule

Once the required equipment choices have been made, the total stock and efficiency of equipment for a particular end use are determined. Energy consumption by fuel can be calculated from the amount of service demand satisfied by each technology and the corresponding efficiency of the technology. At this stage, adjustments to energy consumption are also made.

These include adjustments for changes in real energy prices (short–run price elasticity effects), adjustments in utilization rates caused by efficiency increases (efficiency rebound effects), and changes for weather relative to the CBECS survey year. Once these modifications are made, total energy use is computed across end uses and building types for the three major fuels, for each Census division. Combining these projections with the econometric/trend projections for the five minor fuels yields total projected commercial energy consumption.

[22] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003,* http://www.eia.doe.gov/loiaf/aeo/assumption/pdf/0554(2003).pdf (Washington, DC, January 2003).

Characteristics of Selected Space Heating Equipment in the Commercial Sector

Equipment Type[1]	Vintage	Efficiency[2]	Capital Cost (2001 dollars per thousand Btu per hour)[3]	Maintenance Cost (2001 dollars per thousand Btu per hour)[3]	Service Life (years)
Electric Heat Pump	Current Standard	6.8	$81.39	$3.33	14
	2000- typical	7.5	$97.92	$3.33	14
	2000- high efficiency	9.8	$155.56	$3.33	14
	2005- typical	7.5	$97.22	$3.33	14
	2005- high efficiency	9.8	$155.56	$3.33	14
	2010 - typical	7.5	$97.22	$3.33	14
	2010 - high efficiency	9.8	$155.56	$3.33	14
	2020 - typical	7.8	$97.22	$3.33	14
	2020 - high efficiency	10.0	$150.00	$3.33	14
Ground-Source Heat Pump	2000- typical	3.4	$167.50	$1.46	20
	2000- high efficiency	4.0	$229.17	$1.46	20
	2005- typical	3.4	$166.67	$1.46	20
	2005- high efficiency	4.3	$229.17	$1.46	20
	2010 - typical	3.4	$166.67	$1.46	20
	2010 - high efficiency	4.3	$208.33	$1.46	20
	2020- typical	3.8	$166.67	$1.46	20
	2020 -high efficiency	4.5	$197.92	$1.46	20
Electric Boiler	Current Standard	0.98	$21.83	$0.14	21
Packaged Electric	1995	0.93	$19.77	$3.49	18
Natural Gas Furnace	Current Standard	0.80	$9.11	$1.00	15
	2000- high efficiency	0.92	$14.82	$0.88	15
	2010 - typical	0.81	$8.70	$0.96	15
Natural Gas Boiler	Current Standard	0.80	$16.11	$0.55	25
	2000 - high efficiency	0.87	$33.82	$0.69	25
	2005- typical	0.81	$17.87	$0.55	25
	2005- high efficiency	0.90	$31.68	$0.67	25
Natural Gas Heat Pump	2005- absortion	1.4	$173.61	$4.17	15
Distillate Oil Furnace	Current Standard	0.81	$14.25	$1.00	15
	2000	0.86	$23.46	$1.00	15
	2010	0.89	$22.69	$1.00	15
Distillate Oil Boiler	Current Standard	0.83	$15.76	$0.13	20
	2000- high efficiency	0.88	$18.83	$0.12	20
	2005- typical	0.83	$15.76	$0.13	20
	2005- high efficiency	0.88	$18.83	$0.12	20

[1]Equipment listed is for the New England Census division but is also representative of the technology data for the rest of the United States.
[2]Efficiency measurements vary by equipment type. Electric air-source and natural gas heat pumps are rated for heating performance using the Heating Seasonal Performance Factor (HSPF); natural gas and distillate furnaces are based on Annual Fuel Utilization Efficiency; ground-source heat pumps are rated on coefficient of performance; and boilers are based on combustion efficiency.
[3]Capital and maintenance costs are given in 2001 dollars.
Source: Energy Information Administration, "Technology Forecast Updates - Residential and Commercial Building Technologies - Reference Case", Arthur D. Little, Inc., Reference Number 8675309, October 2001.

Commercial End-Use Technology Types

End-Use Service by Fuel	Technology Types
Electric Space Heating:	air-source heat pump, ground-source heat pump, boiler, packaged space heating
Natural Gas Space Heating:	boiler, furnace, engine-driven heat pump, absorption heat pump
Fuel Oil Space Heating:	boiler, furnace
Electric Space Cooling:	air-source heat pump, ground-source heat pump, reciprocating chiller, centrifugal chiller, rooftop air conditioner, residential style central air conditioner, window unit
Natural Gas Space Cooling:	absorption chiller, engine-driven chiller, rooftop air conditioner, engine-driven heat pump, absorption heat pump
Electric Water Heating:	electric resistance, heat pump water heater, tankless water heater
Natural Gas Water Heating:	natural gas water heater, tankless water heater
Fuel Oil Water Heating:	fuel oil water heater
Ventilation:	small Constant Air Volume (CAV) system, large CAV system, small Variable Air Volume (VAV) system, large VAV system, fan coil unit, multi-zone CAV system
Electric Cooking:	range, convection oven, deck oven, fryer, griddle, other electric
Natural Gas Cooking:	range, range w/power burner, deck oven, fryer, infrared fryer, griddle, infrared griddle, other
Incandescent Style Lighting:	incandescent, compact fluorescent, halogen, halogen-infrared, coated filament, hafnium carbide
Four-foot Fluorescent Lighting:	magnetic ballast, electronic ballast, electronic w/controls, electronic w/reflectors, scotopic, electrodeless
Eight-foot Fluorescent Lighting:	magnetic ballast, electronic ballast, magnetic-high output, electronic-high output, scotopic, electrodeless
High Intensity Discharge Lighting:	metal halide, mercury vapor, high pressure sodium, sulfur
Refrigeration:	centralized refrigeration system, walk-in cooler, walk-in freezer, reach-in refrigerator, reach-in freezer, ice machine, refrigerated vending machine

The industrial demand module (IDM) forecasts energy consumption for fuels and feedstocks for nine manufacturing industries and six nonmanufacturing industries, subject to delivered prices of energy and macroeconomic variables representing the value of shipments for each industry. The module includes electricity generated through combined heat and power (CHP) systems that is either used in the industrial sector or sold to the electricity grid. The IDM structure is shown in Figure 7.

Industrial energy demand is projected as a combination of "bottom up" characterizations of the energy-using technology and "top down" econometric estimates of behavior. The influence of energy prices on industrial energy consumption is modeled in terms of the efficiency of use of existing capital, the efficiency of new capital acquisitions, and the mix of fuels utilized, given existing capital stocks. Energy conservation from technological change is represented over time by trend-based "technology possibility curves." These curves represent the aggregate efficiency of all new technologies that are likely to penetrate the future markets as well as the aggregate improvement in efficiency of 1998 technology.

IDM incorporates three major industry categories: energy–intensive manufacturing industries, nonenergy–intensive manufacturing industries, and nonmanufacturing industries. The level and type of modeling and the attention to detail is different for each. Manufacturing disaggregation is at the 3-digit North American Indusrial Classification System (NAICS) level, with some further disaggregation of more energy–intensive or large energy–consuming industries. Industries treated in more detail include food, paper, chemicals, glass, cement, steel, and aluminum. Energy product demands are calculated independently for each industry.

Each industry is modeled (where appropriate) as three interrelated components: buildings (BLD), boilers/steam/CHP (BSC), and process/assembly (PA) activities. Buildings are estimated to account for 6 percent of energy consumption in manufacturing industries (in nonmanufacturing industries, building energy consumption is assumed to be negligible).

Consequently, IDM uses a simple modeling approach for the BLD component. Energy consumption

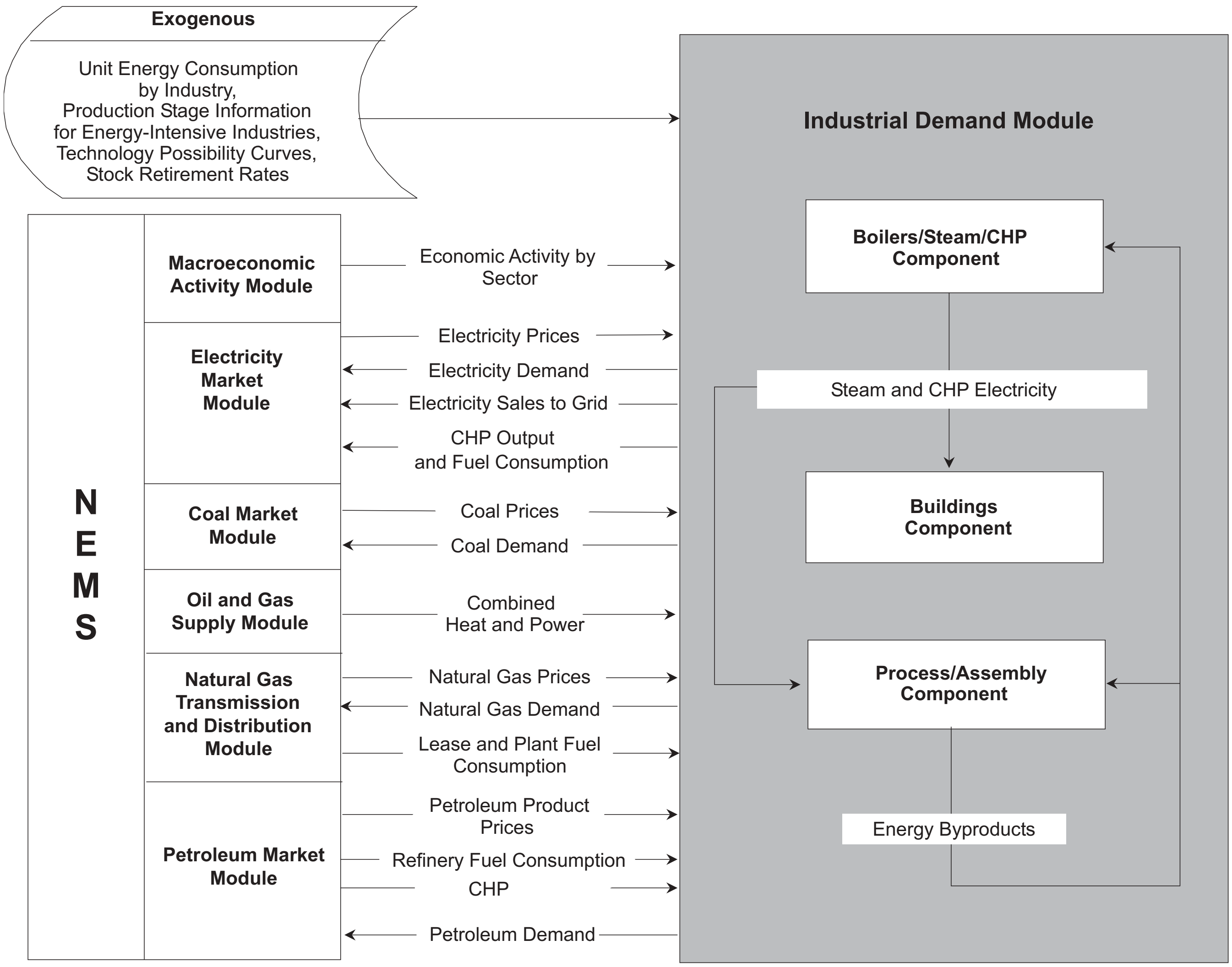
Economic Subsectors Within the IDM

Energy-Intensive Manufacturing	Nonmanufacturing Industries
Food and Kindred Products (NAICS 311)	Agricultural Production - Crops (NAICS 111)
Paper and Allied Products (NAICS 322)	Other Agriculture including Livestock (NAICS 112-115)
Bulk Chemicals (NAICS 325)	Coal Mining (NAICS 2121)
Glass and Glass Products (NAICS 3272)	Oil and Gas Extraction (NAICS 211)
Hydraulic Cement (NAICS 32731)	Metal and Other Nonmetallic Mining (NAICS 2122-2123)
Blast Furnaces and Basic Steel (NAICS 331111)	Construction (NAICS 233-235)
Aluminum (NAICS 3313)	
Nonenergy-Intensive Manufacturing	
Metals-Based Durables (NAICS 332-336)	
Other Manufacturing (all remaining manufacturing NAICS)	

NAICS = North American Industry Classification System.

IDM Outputs	Inputs from NEMS	Exogenous Inputs
Energy demand by service and fuel type Electricity sales to grid Cogeneration output and fuel consumption	Energy product prices Economic output by industry Refinery fuel consumption Lease and plant fuel consumption Cogeneration from refineries and oil and gas production	Production stages in energy-intensive industries Technology possibility curves Unit energy consumption Stock retirement rates

Figure 7. Industrial Demand Module Structure



in industrial buildings is assumed to grow at the same rate as the average growth rate of employment and output in that industry. The BSC component consumes energy to meet the steam demands from the other two components and to provide internally generated electricity to the BLD and PA components. The boiler component consumes fossil fuels to produce steam, which is passed to the PA component.

IDM models "traditional" combined heat and power (CHP) based on steam demand from the BLD and the PA components. The "nontraditional" CHP units are represented in the electricity market module since these units are mainly grid-serving, electricity-price-driven entities.

CHP capacity, generation, and fuel use are calculated from exogenous data on existing and planned capacity additions and new additions determined from an engineering and economic evaluation. Existing CHP capacity and planned additions are derived from Form EIA-860B, "Annual Electric Generator Report-Nonutility," formerly Form EIA-867, "Annual Nonutility Power Producer Report." Existing CHP capacity is assumed to remain in service throughout the forecast or, equivalently, to be refurbished or replaced with similar units of equal capacity.

EIA has comprehensively reviewed and revised how it collects, estimates, and reports fuel use for facilities producing electricity. The review addressed both

Fuel Consuming Activities for the Energy-Intensive Manufacturing Subsectors

End Use Characterization

Food: direct fuel, hot water/steam, refrigeration, and other electric.

Bulk Chemicals: direct fuel, hot water/steam, electrolytic, and other electric.

Process Step Characterization

Pulp and Paper: wood preparation, waste pulping, mechanical pulping, semi-chemical pulping, Kraft pulping, bleaching, and papermaking.

Glass: batch preparation, melting/refining, and forming.

Cement: dry process clinker, wet process clinker, and finish grinding.

Steel: coke oven, open hearth steel making, basic oxygen furnace steel making, electric arc furnace steel making, ingot casting, continuous casting, hot rolling, and cold rolling.

Aluminum: only primary aluminum smelting is explicitly included.

inconsistent reporting of the fuels used for electric power across historical years and changes in the electric power marketplace that have been inconsistently represented in various EIA survey forms and publications. In comparison with EIA's past energy data publications, the impact of the definition changes for the industrial sector is to reduce measured natural gas consumption. For example, the previously reported value for 2000 has been revised from 9.39 trillion cubic feet to 8.25 trillion cubic feet. In comparison with past energy data publications, the impact of the definition changes and new data sources for total energy use increases measured natural gas consumption. Total natural gas consumption in 2000 is 0.6 trillion cubic feet higher than was previously reported. A more detailed discussion of this update is available in EIA's *Annual Energy Review 2001*, Appendix H, "Estimating and Presenting Power Sector Fuel Use in EIA Publications and Analyses," web site www.eia.doe.gov/emeu/aer/pdf/pages/sec_h.pdf.

Calculation of unplanned CHP capacity additions begins in 2001. Modeling of unplanned capacity additions is done in two parts: biomass-fueled and fossil-fueled. Biomass CHP capacity is assumed to be added to the extent possible as additional biomass waste products are produced, primarily in the pulp and paper industry. The amount of biomass CHP capacity added is equal to the quantity of new biomass available (in Btu), divided by the total heat rate from biomass steam turbine CHP.

Additions to fossil-fueled CHP capacity are limited to gas turbine plants. It is assumed that the technical potential for CHP is based primarily on supplying thermal requirements. First, the model assesses the amount of capacity that could be added to generate the industrial steam requirements not met by existing CHP. The second step is an economic evaluation of gas turbine prototypes for each steam load segment. Finally, CHP additions are projected based on a range of acceptable payback periods.

The PA component accounts for the largest share of direct energy consumption for heat and power, 55 percent. For the seven most energy-intensive industries, process steps or end uses are modeled using engineering concepts. The production process is decomposed into the major steps, and the energy relationships among the steps are specified.

The energy intensities of the process steps or end uses vary over time, both for existing technology and for technologies expected to be adopted in the future. In IDM, this variation is based on engineering judgment and is reflected in the parameters of technology possibility curves, which show the declining energy intensity of existing and new capital relative to the 1998 stock.

IDM uses "technology bundles" to characterize technological change in the energy-intensive industries. These bundles are defined for each production process step for five of the industries and for end use in two of the industries. The process step industries are pulp and paper, glass, cement, steel, and aluminum. The end-use industries are food and bulk chemicals.

Machine drive electricity consumption in the food, bulk chemicals, metal-based durables, and balance of manufacturing sectors is calculated by a motor stock model. The beginning stock of motors is modified over the forecast horizon as motors are added to accommodate growth in shipments for each sector, as motors are retired and replaced, and as failed motors are rewound. When a new motor is added, either to accommodate growth or as a replacement, an economic choice is made between purchasing a motor which meets the EPACT minimum for efficiency or a premium efficiency motor. There are seven motor size groups in each of the four industries. The EPACT efficiency standards only apply to the five smallest groups (up to 200 horsepower). As the motor stock changes over the forecast horizon, the overall efficiency of the motor population changes as well.

The unit energy consumption is defined as the energy use per ton of throughput at a process step or as energy use per dollar of shipments for the end use industries. The "Existing UEC" is the current average installed intensity as of 1998. The "New 1998 UEC" is the intensity expected to prevail for a new installation in 1999. Similarly, the "New 2025 UEC" is the intensity expected to prevail for a new installation in 2025. For intervening years, the intensity is interpolated.

The rate at which the average intensity declines is determined by the rate and timing of new additions to capacity. In IDM, the rate and timing of new additions are functions of retirement rates and industry growth rates.

IDM uses a vintaged capital stock accounting framework that models energy use in new additions to the stock and in the existing stock. This capital stock is represented as the aggregate vintage of all plants built within an industry and does not imply the inclusion of specific technologies or capital equipment.

The capital stock is grouped into three vintages: old, middle, and new. The old vintage consists of capital in production prior to 1998, which is assumed to retire at a fixed rate each year. Middle-vintage capital is that added after 1998, excluding the year of the forecast. New production capacity is built in the forecast years when the capacity of the existing stock of capital in IDM cannot produce the output forecasted by the NEMS regional submodule of the macroeconomic activity module. Capital additions during the forecast horizon are retired in subsequent years at the same rate as the pre-1998 capital stock.

The energy-intensive and/or large energy-consuming industries are modeled with a structure that explicitly describes the major process flows or "stages of production" in the industry (some industries have major consuming uses).

Technology penetration at the level of major processes in each industry is based on a technology penetration curve relationship. A second relationship can provide additional energy conservation resulting from increases in relative energy prices. Major process choices (where applicable) are determined by industry production, specific process flows, and exogenous assumptions.

IDM achieves fuel switching by application of a logit function methodology for estimating fuel shares in the boilers/steam/CHP component. A small amount of additional fuel switching capability takes place within the PA component.

Recycling, waste products, and byproduct consumption are modeled using parameters based on off-line analysis and assumptions about the manufacturing processes or technologies applied within industry. These analyses and assumptions are mainly based upon environmental regulations such as government requirements about the share of recycled paper used in offices. IDM also accounts for trends within industry toward the production of more specialized products such as specialized steel which can be produced using scrap material versus raw iron ore.

The transportation demand module (TRAN) forecasts the consumption of transportation sector fuels by transportation mode, including the use of renewables and alternative fuels, subject to delivered prices of energy fuels and macroeconomic variables, including disposable personal income, gross domestic product, level of imports and exports, industrial output, new car and light truck sales, and population. The structure of the module is shown in Figure 8.

NEMS projections of future fuel prices influence fuel efficiency, vehicle-miles traveled, and alternative-fuel vehicle (AFV) market penetration for the current fleet of vehicles. Alternative-fuel shares are projected on the basis of a multinomial logit vehicle attribute model, subject to State and Federal government mandates.

Fuel Economy Submodule

This submodule projects new light-duty vehicle fuel efficiency by 12 U.S. Environmental Protection Agency (EPA) vehicle size classes and 15 engine technologies (gasoline, diesel, and 13 AFV technologies) as a function of energy prices and income-related variables. There are 59 fuel-saving technologies which vary in cost and marginal fuel savings by size class. Characteristics of a sample of these technologies are shown on page 40, a complete list is published in *Assumptions to the Annual Energy Outlook 2003.*[23] Technologies penetrate the market based on a cost-effectiveness algorithm which compares the technology cost to the discounted stream of fuel savings and the value of performance to the consumer. In general, higher fuel prices lead to higher fuel efficiency estimates within each size class, a shift to a more fuel-efficient size class mix, and an increase in the rate at which alternative-fuel vehicles enter the marketplace.

Regional Sales Submodule

Vehicle sales from the macroeconomic activity module are divided into car and light truck sales based on demographic analysis. The remainder of the submodule is a simple accounting mechanism that uses endogenous estimates of new car and light truck sales and the historical regional vehicle sales adjusted for regional population trends to produce estimates of regional sales, which are subsequently passed to the alternative-fuel vehicle and the light-duty vehicle stock submodules.

Alternative-Fuel Vehicle Submodule

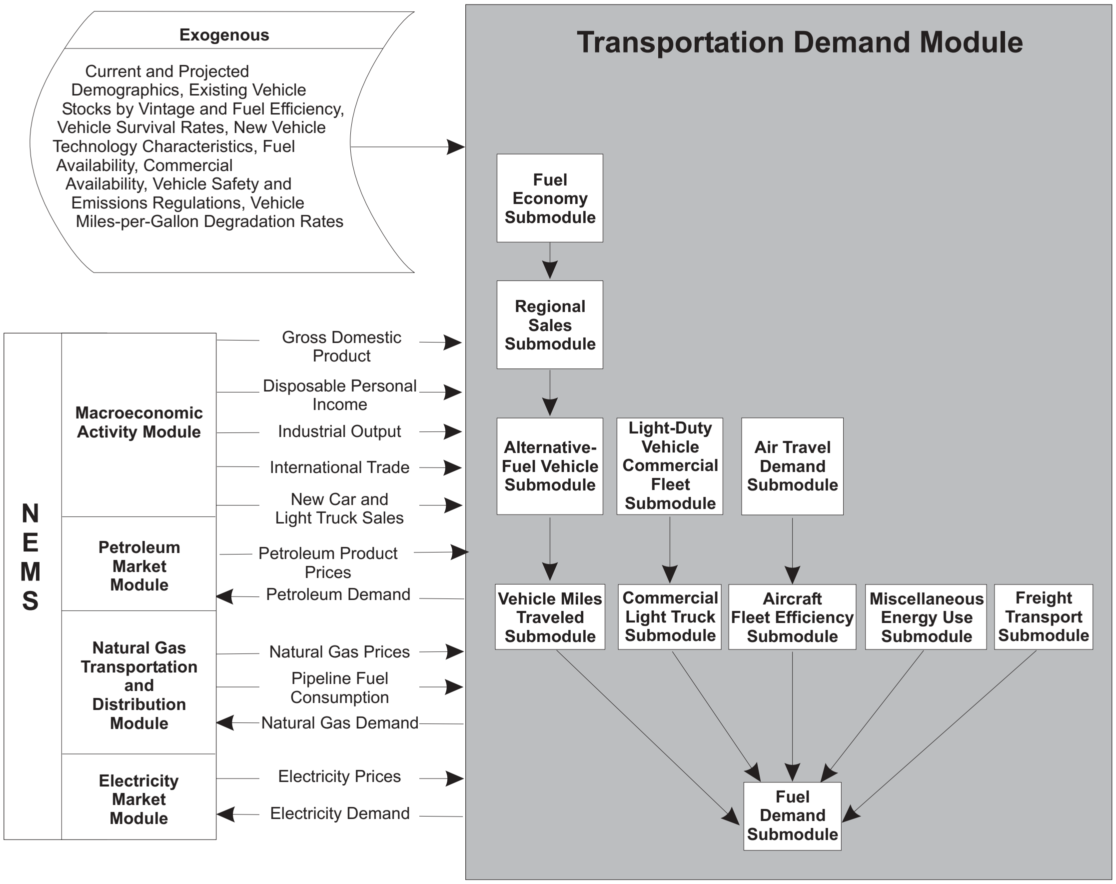
This submodule projects the sales shares of alternative-fuel technologies as a function of time, technology attributes, costs, and fuel prices. The alternative-fuel technologies are listed on the next page. Vehicle attributes are shown on page 40, derived from *Assumptions to the Annual Energy Outlook 2003.* Both conventional and new technology vehicles are considered. The alternative–fuel vehicle submodule receives regional new car and light truck sales by size class from the regional sales submodule.

The forecast of vehicle sales by technology utilizes a nested multinomial logit (NMNL) model that predicts sales shares based on relevant vehicle and fuel attributes. The nesting structure first predicts the probability of fuel choice for multi-fuel vechicles within a technology set. The second level nesting predicts penetration among similar technologies within a technology set (i.e. Gasoline versus diesel

TRAN Outputs	Inputs from NEMS	Exogenous Inputs
Fuel demand by mode Sales, stocks and characteristics of vehicle types by size class Vehicle-miles traveled Fuel efficiencies by technology type Alternative-fuel vehicle sales by technology type Light-duty commercial fleet vehicle characteristics	Energy product prices Gross domestic product Disposable personal income Industrial output Vehicle sales International trade Natural gas pipeline consumption	Current and projected demographics Existing vehicle stocks by vintage and fuel efficiency Vehicle survival rates New vehicle technology characteristics Fuel availability Commercial availability Vehicle safety and emissions regulations Vehicle miles-per-gallon degradation rates

[23] Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003*, http:/www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf (Washngton, DC, January 2003).

Figure 8. Transportation Demand Module Structure



Alternative Fuel Vehicles

Methanol flex-fueled
Methanol neat (85 percent methanol)
Ethanol flex-fueled
Ethanol neat (85 percent ethanol)
Compressed natural gas (CNG)
CNG bi-fuel
Liquefied petroleum gas (LPG)
LPG bi-fuel
Electric
Diesel-electric hybrid
Fuel cell gasoline
Fuel cell hydrogen
Fuel cell methanol

hybrids). The third level choice determines market share among the different technology sets.[24] The technology sets include:

- Conventional fuel capable (gasoline, diesel, bi-fuel and flex-fuel),
- Hybrid (gasoline and diesel),
- Dedicated alternative fuel (CNG, LPG, methanol, and ethanol),
- Fuel cell (gasoline, methanol, and hydrogen), and

[24] Greene, David L. and S.M. Chin, “Alternative Fuels and Vehicles (AFV) Model Changes,” Center for Transportation Analysis, Oak Ridge National Laboratory, page 1, (Oak Ridge, TN, November 14, 2000).

- Electric battery powered (lead acid, nickel-metal hydride, lithium polymer)[25]

The vehicles attributes considered in the choice algorithm include: price, maintenance cost, battery replacement cost, range, multi-fuel capability, home refueling capability, fuel economy, acceleration and luggage space. With the exception of maintenance cost, battery replacement cost, and luggage space, vehicle attributes are determined endogenously.[26] The fuel attributes used in market share estimation include availability and price. Vehicle attributes vary by six EPA size classes for cars and light trucks and fuel availability varies by Census division. The NMNL model coefficients were developed to reflect purchase decisions for cars and light trucks separately.

Light Vehicle Size Classes

Cars:
- Mini-compact - less than 85 cubic feet
- Subcompact - between 85 and 99 cubic feet
- Compact - between 100 and 109 cubic feet
- Mid-size - between 110 and 119 cubic feet
- Large - 120 or more cubic feet, including all station wagons (small, mid-size, and large)
- Two-seater - designed to seat two adults

Trucks:
- Passenger vans
- Cargo vans
- Small pickups - trucks with gross vehicle weight rating (GVWR) less than 4,500 pounds
- Large pickups - trucks with GVWR 4,500 to 8,500 pounds
- Small utility
- Large utility

Light-Duty Vehicle Stock Submodule

This submodule specifies the inventory of light-duty vehicles from year to year. Survival rates are applied to each vintage, and new vehicle sales are introduced into the vehicle stock through an accounting framework. The fleet of vehicles and their fuel efficiency characteristics are important to the translation of transportation services demand into fuel demand.

TRAN maintains a level of detail that includes twenty vintage classifications and six passenger car and six light truck size classes corresponding to EPA interior volume classifications for all vehicles less than 8,500 pounds, as follows:

Vehicle-Miles Traveled (VMT) Submodule

This submodule projects travel demand for automobiles and light trucks. VMT per capita estimates are based on the fuel cost of driving per mile, per capita disposable personal income, and an adjustment for female-to-male driving ratios. Total VMT is calculated by multiplying VMT per capita by the driving age population.

Light-Duty Vehicle Commercial Fleet Submodule

This submodule generates estimates of the stock of cars and trucks used in business, government, and utility fleets. It also estimates travel demand, fuel efficiency, and energy consumption for the fleet vehicles prior to their transition to the private sector at predetermined vintages.

Commercial Light Truck Submodule

The commercial light truck submodule estimates sales, stocks, fuel efficiencies, travel, and fuel demand for all trucks greater than 8,500 pounds and less than 10,000 pounds.

Air Travel Demand Submodule

This submodule estimates the demand for both passenger and freight air travel. Passenger travel is forecasted by domestic travel, which is dissaggregated between business and personal travel, and international travel. Dedicated air freight travel is disaggregated between the total air freight demand and air freight carried in the lower hull of commercial passenger aircraft. In each of the market segments, the demand for air travel is estimated as a function of the cost of air travel (including fuel costs)

[25] U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, prepared by Interlaboratory Working Group, Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy Technologies by 2010 and Beyond, (Washington, DC, 1998).

[26] Energy and Environmental Analysis, Inc., Updates to the Fuel Economy Model (FEM) and Advanced Technology Vehicle (ATV) Module of the National Energy Modeling System (NEMS) Transportation Model, Prepared for the Energy Information Administration (EIA), (Arlington, VA, October 23, 2000).

and economic growth (GDP, disposable income, and merchandise exports).

Aircraft Fleet Efficiency Submodule

This submodule forecasts the total stock and the average fleet efficiency of narrow body and wide body aircraft required to meet the projected travel demand. The stock estimation is based on the growth of travel demand and a logistic function that calculates the survival of the older planes. The overall fleet efficiency is determined by the weighted average of the surviving aircraft efficiency (including retrofits) and the efficiencies of the newly acquired aircraft. The efficiency improvements of the new aircraft are determined by technology choice which depends on the trigger fuel price, the time in which the technology is commercially viable, and by the expected efficiency gains of aircraft incorporating those technologies. Technology characteristics are shown on page 41.

Freight Transport Submodule

This submodule translates NEMS estimates of industrial production into ton-miles traveled requirements for rail and ship travel, and into vehicle-miles traveled for trucks, then into fuel demand by mode of freight travel. The freight truck stock is subdivided into medium and heavy-duty trucks. VMT freight estimates by truck size class and technology are based on matching freight needs, as measured by the growth in industrial output by Standard Industrial Classification (SIC) code, to VMT levels associated with truck stocks and new vehicles. Rail and shipping ton-miles traveled are also estimated as a function of growth in industrial output.

Selected Technology Characteristics for Automobiles

	Fractional Fuel Efficiency Change	First Year Introduced	Fractional Horsepower Change
Material Substitution IV	0.099	2006	0
Drag Reduction IV	0.063	2002	0
5–Speed Automatic	0.065	1995	0
CVT	0.105	1998	0
Automated Manual Trans	0.080	2006	0
VVL–6 Cylinder	0.050	2000	0.10
Camless Valve Actuation 6 Cylinder	0.110	2008	0.13
Electric Power Steering	0.020	2004	0
42V–Launch Assist and Regen	0.030	2005	-0.05

Examples of Midsize Automobile Attributes

	Year	Gasoline	Diesel Flex	Ethanol Flex	LPG	Electric-Diesel Hybrid	Fuel Cell Hydrogen
Vehicle Price (thousand 2001 dollars)	2001	25.0	27.2	27.3	30.7	36.1	81.0*
	2025	26.5	28.4	26.8	32.2	28.9	53.8
Vehicle Miles per Gallon	2001	26.7	35.9	26.9	27.7	42.6	52.9*
	2025	27.6	34.5	27.9	28.5	40.0	49.8
Vehicle Range (miles)	2001	450	610	330	390	590	450*
	2025	470	630	340	400	610	470
Fuel Availability Relative to Gasoline	2001	1.00	1.00	1.00**	0.30	1.00	0.00*
	2025	1.00	1.00	1.00	0.40	1.00	0.90

*Data for fuel cell hydrogen automobiles is for 2005, first year of availability.
**Due to availability using gasoline.

Freight truck fuel efficiency growth rates are tied to historical growth rates by size class and are also dependent on the maximum penetration, introduction year, fuel trigger price (based on cost-effectiveness), and fuel economy improvement of advanced technologies, which include alternative-fuel technologies. A subset of the technology characteristics are shown on page 42. In the rail and shipping modes, energy efficiency estimates are structured to evaluate the potential of both technology trends and efficiency improvements related to energy prices.

Miscellaneous Energy Use Submodule

This submodule projects the use of energy in military operations, mass transit vehicles, recreational boats, and lubricants, based on endogenous variables within NEMS (e.g., vehicle fuel efficiencies) and exogenous variables (e.g., the military budget).

Aircraft Technology Characteristics

Technology	Introduction Year	Jet Fuel Prices Necessary for Cost-Effectiveness (1997 dollars per gallon)	Seat-Miles per Gallon Gain Over 1990 (Percent)	
			Narrow Body	Wide Body
Engines				
Ultra-high Bypass	1995	0.69	10	10
Propfan	2000	1.36	23	0
Thermodynamics	2010	1.22	20	20
Aerodynamics				
Hybrid Laminar Flow	2020	1.53	15	15
Advanced Aerodynamics	2000	1.70	18	18
Other				
Weight Reducing Materials	2000	-	15	15

Freight Truck Technology Characteristics

	Fuel Economy Improvement (percent)		Maximum Penetration (percent)		Introduction Year		Capital Cost (2001 dollars)	
	Medium	Heavy	Medium	Heavy	Medium	Heavy	Medium	Heavy
Aero Dynamics: bumper, underside air baffles, wheel well covers	2.3	2.7	50	66	2005	2005	$280	$550
Low rolling resistence tires	3.6	2.3	50	40	2004	2005	$800	$1,500
Transmission: lock-up, electronic controls, reduced friction	1.8	1.8	100	100	2005	2005	$900	$1,000
Diesel Engine: hybrid electric powertrain	36.0	N/A	15	N/A	2010	N/A	$8,000	N/A
Reduce waste heat, thermal mgmt	N/A	9.0	N/A	35	N/A	2010	N/A	$2,000
Gasoline Engine:								
Direct injection	10.8	N/A	25	N/A	2008	N/A	$700	N/A
Weight Reduction	4.5	9.0	20	30	2007	2005	$2,000	$2,000
Diesel Emission NO_x non-thermal plasma catalyst	-1.5	-1.5	25	25	2006	2007	$1,200	$1,250
PM catalytic filter	-2.5	-1.5	95	95	2006	2006	$1,250	$1,500
HC/CO: oxidation catalyst	-0.5	-0.5	95	95	2002	2002	$200	$250
NO_X adsorbers	-3.0	-3.0	90	90	2006	2007	$2,000	$2,500

The electricity market module (EMM) represents the generation, transmission, and pricing of electricity, subject to: delivered prices for coal, petroleum products, and natural gas; the cost of centralized generation from renewable fuels; 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 load and demand–side management (Figure 9). In addition, nonutility supply and electricity trade are represented in the fuel dispatching and capacity planning submodules. Nonutility generation from combined heat and power (CHP) and other facilities whose primary business is not electricity generation is represented in the demand and fuel supply modules. All other nonutility generation is represented in the EMM. The generation of electricity is accounted for in 15 supply regions (Figure 10), and fuel consumption is allocated to the 9 Census divisions.

The EMM determines airborne emissions produced by the generation of electricity. It represents limits for sulfur dioxide and nitrogen oxides specified in the Clean Air Act Amendments of 1990. The EMM can also examine potential legislation that requires more stringent restrictions on sulfur dioxide and nitrogen oxides as well as limits on mercury and carbon dioxide.

Operating (dispatch) decisions are provided by the cost–minimizing mix of fuel and variable operating and maintenance (O&M) costs, subject to environmental costs. Capacity expansion is determined by the least–cost mix of all costs, including capital, O&M, and fuel. Electricity demand is represented by load curves, which vary by region, season, and time of day. 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 load and demand–side management submodule processes electricity demand to construct load curves
- The electricity capacity planning submodule projects the construction of new utility and nonutility plants, the level of firm power trades, and the addition of scrubbers for environmental compliance
- The electricity fuel dispatch submodule dispatches the available generating units, both utility and nonutility, allowing surplus capacity in select regions to be dispatched for another regions needs (economy trade)
- The electricity finance and pricing submodule calculates total revenue requirements for each operation and computes average and marginal–cost based electricity prices.

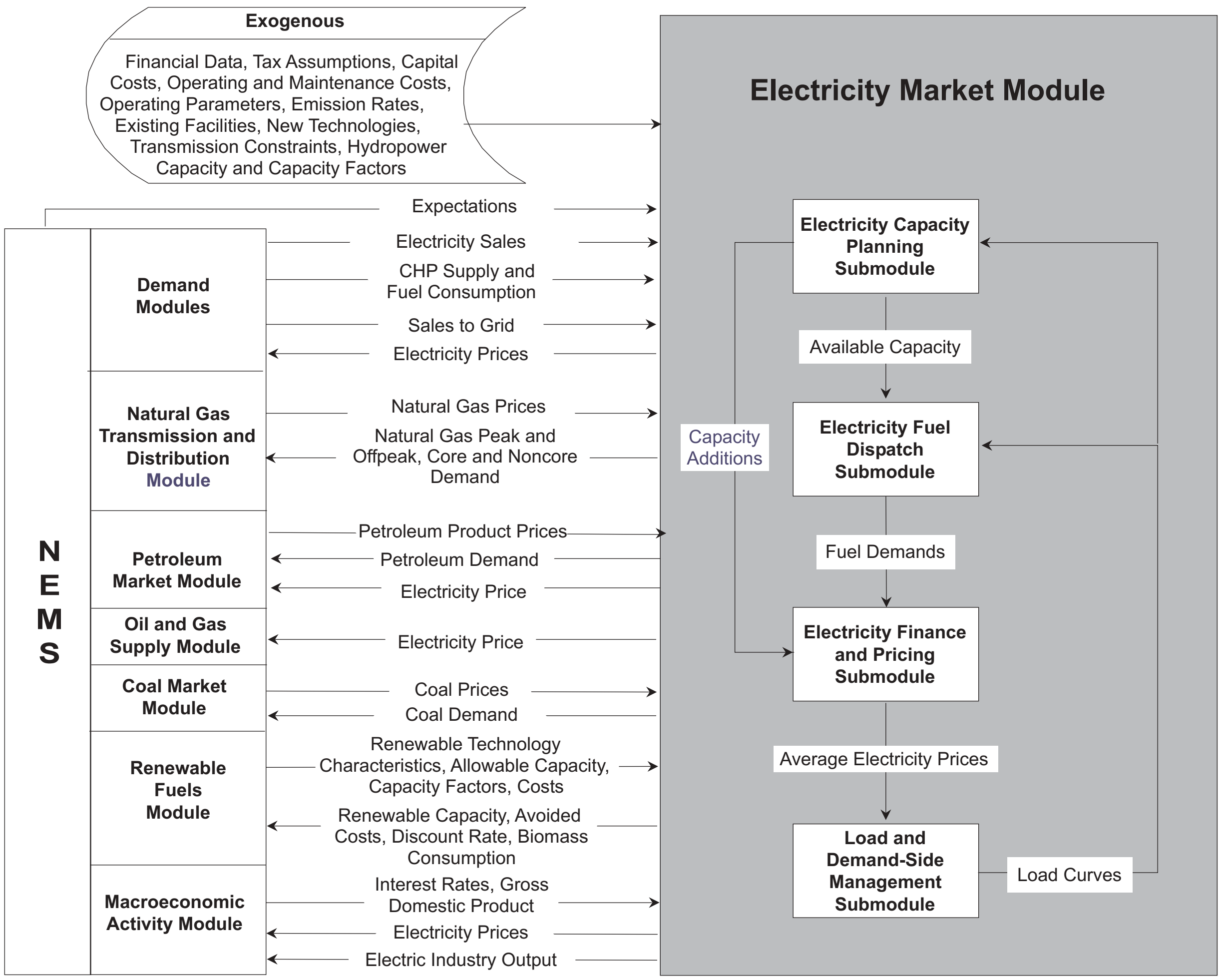
Electricity Capacity Planning Submodule

The electricity capacity planning (ECP) submodule determines how best to meet expected growth in electricity demand, given available resources, expected load shapes, expected demands and fuel prices, environmental constraints, and costs for utility and nonutility technologies. When new capacity is required to meet growth in electricity demand, the technology choosen 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 expected utilization of the capacity is important in the decision–making process. A technology with

EMM Outputs	Inputs from NEMS	Exogenous Inputs
Electricity prices and price components	Electricity sales	Financial data
Fuel demands	Fuel prices	Tax assumptions
Capacity additions	Cogeneration supply and fuel consumption	Capital costs
Capital requirements	Electricity sales to the grid	Operation and maintenance costs
Emissions	Renewable technology characteristics, allowable capacity, and costs	Operating parameters
Renewable capacity	Renewable capacity factors	Emissions rates
Avoided costs	Gross domestic product	New technologies
	Interest rates	Existing facilities
		Transmission constraints
		Hydropower capacity and capacity factors

Figure 9. Electricity Market Module Structure



relatively high capital costs but comparatively low operating costs (primarily fuel costs) 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 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 baseload plants and cheaper to operate than peak load plants.

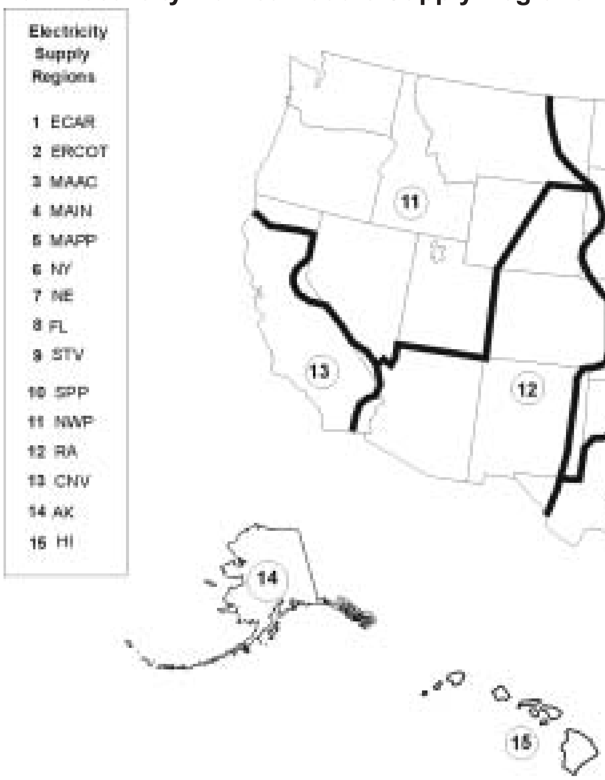
Technologies are compared on the basis of total capital and operating costs incurred over a 20–year period. As new technologies become available, they are competed against conventional plant types. Fossil–fuel, nuclear, and renewable central–station generating technologies are represented, as listed on page 46. The EMM also considers two distributed generation technologies–baseload and peak.

Uncertainty about investment costs for new technologies is captured in 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 due to learning–by–doing. For new technologies, cost reductions due to learning also account for international experience in building generating capacity.

he decrease in overnight capital costs due to learning depends on the stage of technological development. The cost for a revolutionary technology is assumed to decrease by 10 percent for the first three doublings of capacity constructed, 5 percent for the next five

Figure 10. Electricity Market Module Supply Regions



doublings, and 1 percent for every doubling thereafter. The cost for an evolutionary technology is assumed to decrease by 5 percent for the first five doublings and 1 percent for every doubling thereafter. The cost for a conventional technology is assumed to decrease by 1 percent for every doubling of capacity constructed.

Capital costs for all new electricity generating technologies (fossil, nuclear, and renewable) decrease in response to foreign and domestic experience. Foreign units of new technologies are assumed to contribute to reductions in capital costs for units that are installed in the United States to the extent that (1) the technology characteristics are similar to those used in U.S. markets, (2) the design and construction firms and key personnel compete in the U.S. market, (3) the owning and operating firm competes actively in the United States, and (4) there exists relatively complete information about the status of the associated facility. If the new foreign units do not satisfy one or more of these requirements, they are given a reduced weight or not included in the learning effects calculation. Capital costs, heat rates, and first year of availability from the Annual Energy Outlook 2003 reference case are shown on page 46; capital costs represent the costs of building new plants beginning in 2002. For renewable technologies, the capital costs are for California, which is representative of the United States. Additional information about costs and performance characteristics can be found on page 73 of the *Assumptions to the Annual Energy Outlook 2003*.[27]

Initially, investment decisions are determined in 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, ECP uses a market–sharing algorithm to adjust the initial solu-

[27] Energy Informtion Administration, *Assumptions to the Annual Energy Outlook 2003*, http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2003).pdf (January 2003).

tion and reallocate some of the capacity expansion decisions to technologies that are competitive but do not have the lowest average cost.

Fossil–fired steam and nuclear plant retirements are calculated endogenously within the model. Plants are retired if the market price of electricity is not sufficient to support continued operation. The expected revenues from these plants are compared to the annual going–forward costs, which are mainly fuel and operations and maintenance costs. A plant is retired if these costs exceed the revenues and the overall cost of electricity can be reduced by building replacement capacity.

The ECP submodule also determines whether to contract for unplanned firm power imports from Canada and from neighboring electricity supply regions. Imports from Canada are competed using supply curves developed from cost estimates for potential hydroelectric projects in Canada. Imports from neighboring electricity supply regions are competed in 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 building 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.

Central–Station Generating Technologies

Fossil
Existing coal steam plants (with or without environmental controls)
New pulvberized coal with environmental controls
Advanced clean coal technology
Advanced clean coal technology with sequestration
Oil/Gas steam
Conventional combined cycle
Advanced combined cycle
Advanced combined cycle with sequestration
Conventional combustion turbine
Advanced combustion turbine
Fuel Cells
Nuclear
Conventional nuclear
Advanced nuclear
Renewables
Conventional hydropower
Pumped storage
Geothermal
Solar-thermal
Solar-photovoltaic
Wind
Wood
Municipal solid waste
Environmental controls include flue gas desulfurization (FGD), selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), fabric filters, spray cooling, activated carbon injection (ACI), and particulate removal equipment.

2002 Overnight Capital Costs (including Contingencies), 2002 Heat Rates, and Online Year by Technology for the AEO2003 Reference Case

Technology	Capital Costs[1/] (2001$/Kwhr)	2002 Heat Rates (Btu/Kwhr)	Online Year[2/]
Advanced Combustion Turbine	460	8,550	2004
Conventional Combustion Turbine	409	10,450	2004
Advanced Gas/Oil Combined Cycle	608	7,000	2005
Conventional Gas/Oil Combined Cycle	536	7,500	2005
Scrubbed Coal New	1,154	9,000	2006
Integrated Gas Combined Cycle	1,367	8,000	2006
Fuel Cells	2,137	7,500	2005
Advanced Nuclear	2,117	10,400	2007
Biomass	1,763	8,911	2006
Solar Thermal	2,594	10,280	2005
Solar Photovoltaic	3,915	10,280	2004
Wind	1,003	10,280	2005

[1/]Overnight capital cost include contingency factors, and exclude regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2002.
[2/]Online year represents the first year that a new unit could be completed, given an order date of 2002.

Electricity Fuel Dispatch Submodule

Given available capacity, firm purchased–power agreements, fuel prices, and load curves, the electricity fuel dispatch (EFD) submodule minimizes variable costs as it solves for generation facility utilization and economy power exchanges to satisfy demand in each time period and region. The submodule uses merit order dispatching; that is, utility, independent power producer, and small power producer plants are dispatched until demand is met in a sequence based on their operating costs, with least–cost plants being operated first. Limits on emissions of sulfur dioxide from generating units and the engineering characteristics of units serve as constraints. Coal–fired capacity can cofire with biomass in order to lower operating costs and/or emissions.

During off–peak periods, the submodule institutes load following, which is the practice of running plants near their minimum operating levels rather than shutting them down and incurring shutoff and startup costs. In addition, to account for scheduled and unscheduled maintenance, the capacity of each plant is derated (lowered) to the expected availability level. Finally, the operation of utility and nonutility plants for each region is simulated over six seasons to reflect the seasonal variation in electricity demand.

Interregional economy trade is also represented in the EFD submodule by allowing surplus generation in one region to satisfy electricity demand in an importing 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 energy in an importing region if it results in a cost savings. After dispatching, fuel use is reported back to the fuel supply modules 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 (EFP) submodule, which simulates both competitive electricity pricing and the cost–of–service method often used by State regulators to determine the price of electricity. While there is considerable near–term uncertainty, twenty–two States and the District of Columbia either had or were still planning to initiate competitive retail pricing of electricity at the time the AEO2003 was prepared. In these States, it is assumed that such programs are in effect as of the date established by each State's legislation and/or regulations. The remaining States are assumed to continue traditional cost-of-service regulation through 2025.

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, plant phase–in costs, and purchased power costs, the EFP submodule calculates total revenue requirements for each area of operation—generation, transmission, and distribution—for pricing of electricity in the fully regulated States. Revenue requirements shared over sales by customer class yield the price of electricity for each class. Electricity prices are returned to the demand modules. In addition, the submodule generates detailed financial statements.

For those States for which it is applicable, EFP also 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. The competitive price also includes a reliability price adjustment, which represents the value consumers place on reliability of service when demands are high and available capacity is limited. 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.

Load and Demand-Side Management Submodule

The load and demand–side management (LDSM) submodule generates load curves representing the demand for electricity. The demand for electricity varies over 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. For operational and planning analysis, an annual load duration curve, which represents the aggregated hourly demands, is constructed. Because demand varies by geographic area and time of year, the LDSM submodule generates load curves for each region and season.

Emissions

EMM tracks emission levels for sulfur dioxide (SO_2) and nitrogen oxides (NO_x). Facility development, retrofitting, and dispatch are constrained to comply with the pollution constraints of the Clean Air Act Amendments of 1990 (CAAA90) and other pollution constraints. An innovative feature of this legislation is a system of trading emissions allowances. 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 level set by CAAA90, but it does tend to minimize the overall cost of compliance.

In addition to SO_2 and NO_X, the EMM also determines mercury and carbon dioxide emissions. It represents control options to reduce emissions of these four gases, either individually or in any combination. Fuel switching from coal to natural gas, renewables, or nuclear can reduce all of these emissions. Flue gas desulfurization equipment can decrease SO_2 and mercury emissions. Selective catalytic reduction can reduce NO_X and mercury emissions. Selective non-catalytic reduction and low–NO_X burners can lower NO_X emissions. Fabric filters, spray cooling, and activated carbon injection can reduce mercury emissions. Lower emissions resulting from demand reductions are determined in the end-use demand modules.

The renewable fuels module (RFM) represents renewable energy resoures and large–scale technologies used for grid-connected U.S. electricity supply (Figure 11). Since most renewables (biomass, conventional hydroelectricity, geothermal, landfill gas, solar photovoltaics, solar thermal, and wind) are used to generate electricity, the RFM primarily interacts with the electricity market module (EMM).

New renewable energy generating capacity is either model–determined or based on surveys or other published information. A new unit is only included in surveys or acccepted from published information if it is reported to or identified by the Energy Information Administration and the unit meets EIA criteria for inclusion (the unit exists, is under construction, under contract, is publicly declared by the vendor, or is mandated by state law, such as under a state renewable portfolio standard). EIA may also assume minimal builds for reasons based on historical experience (floors). The penetration of grid-connected renewable energy generating technologies, with the exception of landfill gas, is determined by the EMM.

Each renewable energy submodule of the RFM is treated independently of the others, except for their least-cost competition in the EMM. Because variable operation and maintenance costs for renewable technologies are lower than for any other major generating technology, and because they generally produce little or no air pollution, all available renewable capacity, except biomass, is assumed to be dispatched first by the EMM. Because of its potentially significant fuel cost, biomass is dispatched according to its variable cost by the EMM.

The near–term costs of renewable energy technologies can increase due to infrastructure constraints if new capacity is projected to increase by greater than 50 percent a year nationally. With significant growth over time, costs in the longer term are also assumed to be higher because of growing constraints on the availability of sites, natural resource degradation, and the need to upgrade existing transmission or distribution networks.

Geothermal-Electric Submodule

The geothermal-electric submodule provides the EMM the amounts of new geothermal capacity that can be built at 51 individual sites, along with related cost and performance data. The information is expressed in the form of a three–step supply function that represents the aggregate amount of new capacity and associated costs that can be offered in each year in each region.

Geothermal resource data are based on Sandia National Laboratory's 1991 geothermal resource assessment. Only hydrothermal (hot water and steam) resources are considered. Hot dry rock resources are not included, because they are not expected to be economically accessible during the NEMS forecast horizon.

Capital and operating costs are estimated separately, and life-cycle costs are calculated by the RFM. The costing methodology incorporates the effects of Federal and State energy tax construction and production incentives (if any).

Wind-Electric Submodule

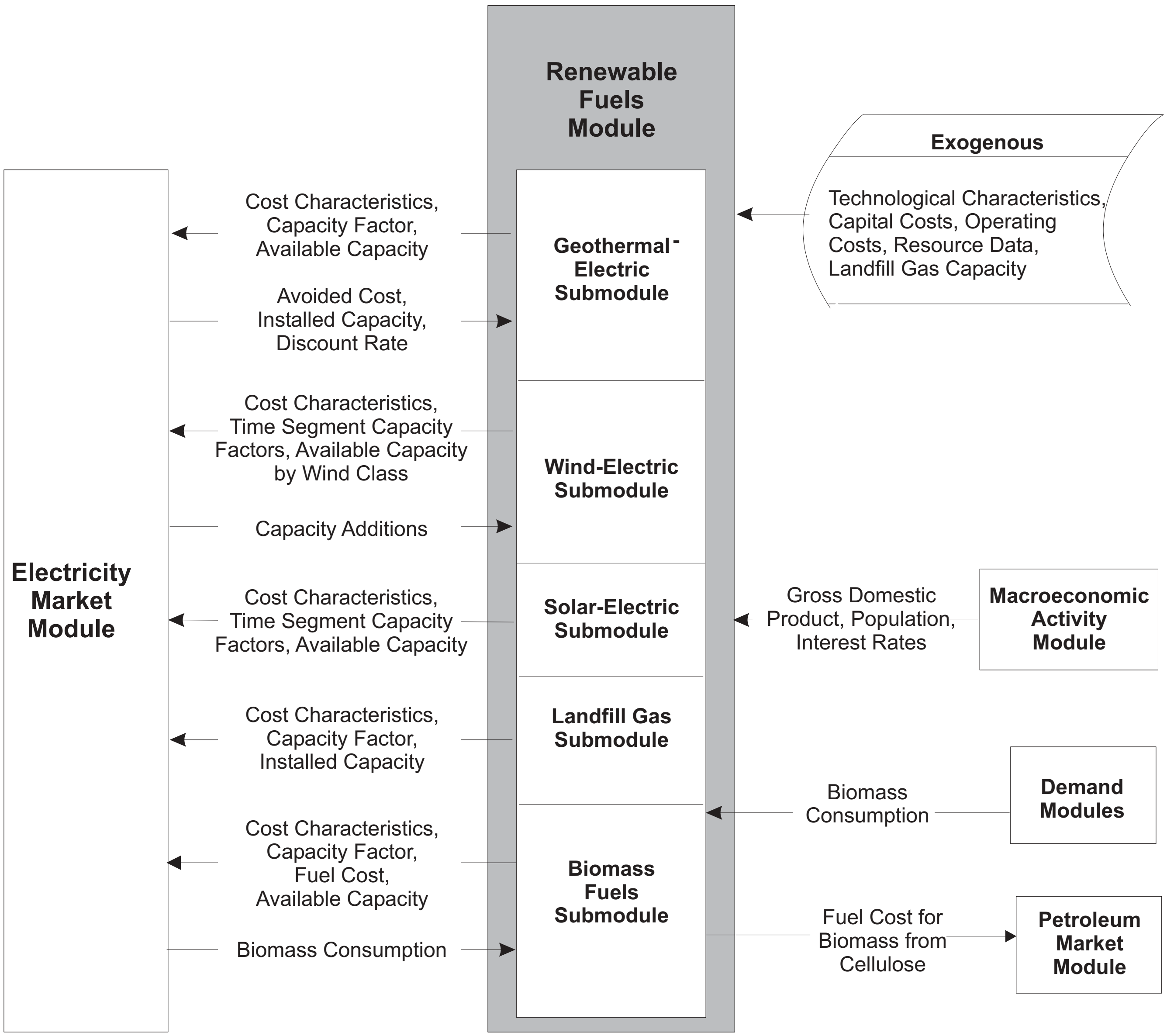
The wind-electric submodule projects the availability of wind resources as well as the cost and performance of wind turbine generators. This information is passed to EMM so that wind turbines can be built and dispatched in competition with other electricity generating technologies. The wind turbine data are expressed in the form of energy supply curves that provide the maximum amount, capital cost, and capacity factor of turbine generating capacity that could be installed in a region in a year, given the available land area and wind speed.

Solar-Electric Submodule

The solar-electric submodule represents both photovoltaic and high-temperature thermal electric (con-

RFM Outputs	Inputs from NEMS	Exogenous Inputs
Energy production capacities Capital costs Operating costs (including wood supply prices for the wood submodule) Capacity factors Available capacity Biomass fuel costs Biomass supply curves	Installed energy production capacity Gross domestic product Population Interest rates Avoided cost of electricity Discount rate Capacity additions Biomass consumption	Site-specific geothermal resource quality data Site-specific wind resource quality data Plant utilization (capacity factor) Technology cost and performance parameters Landfill gas capacity

Figure 11. Renewable Fuels Module Structure



centrating solar power) installations. Only central-station, grid-connected applications constructed by a utility or independent power producer are considered in this portion of the model.

The solar-electric submodule provides the EMM with time-of-day and seasonal solar availability data for each region, as well as current costs. The EMM uses this data to evaluate the cost and performance of solar-electric technologies in regional grid applications. The commercial and residential demand modules of NEMS also model photovoltaic systems installed by consumers, as discussed in the demand module descriptions under “Distributed Generation.”

Landfill Gas Submodule

The landfill gas submodule provides annual projections of electricity generation from methane from landfills (landfill gas). The submodule uses the quantity of municipal solid waste (MSW) that is produced, the proportion of MSW that will be recycled, and the methane emission characteristics of three types of landfills to produce forecasts of the future electric power generating capacity from landfill gas. The amount of methane available is calculated by first determining the amount of total waste generated in the United States. The amount of total waste generated is derived from an econometric equation that uses gross domestic product and population as the forecast drivers. It is assumed that no new mass burn waste–to–energy (municipal solid waste) facilities will be built and operated during the forecast period in the United States. It is also assumed that operational mass-burn facilities will continue to operate and retire as planned throughout the forecast period. The landfill gas submodule passes cost and performance characteristics of the landfill gas–to–electricity technology to the EMM for capacity planning decisions. The amount of new landfill-gas-to-electricity capacity competes with other technologies using supply curves that are based on the amount of high, medium, and low methane producing landfills located in each EMM region.

Biomass Fuels Submodule

The biomass fuels submodule provides biomass-fired plant technology characterizations (capital costs, operating costs, capacity factors, etc.) and fuel information for EMM, thereby allowing biomass-fueled power plants to compete with other electricity generating technologies.

Biomass fuel prices are represented by a supply curve constructed according to the accessibility of resources to the electricity generation sector. The supply curve employs resource inventory and cost data for four categories of biomass fuel - urban wood waste and mill residues, forest residues, energy crops, and agricultural residues.[28] Fuel distribution and preparation cost data are built into these curves. The supply schedule of biomass fuel prices is combined with other variable operating costs associated with burning biomass. The aggregate variable cost is then passed to EMM.

[28] Urban Wood Waste and Mill Residues: Antares Group, Inc; Forest and Crop Residues: Oak Ridge National Laboratory; Energy Crops: Oak Ridge Energy Crop County Level Database (December 20, 1996); and Agricultural Residues: Oak Ridge National Laoboratory.

The oil and gas supply module (OGSM) consists of a series of process submodules that project the availability of:

- Domestic crude oil production and dry natural gas production from onshore, offshore, and Alaskan reservoirs
- Imported pipeline–quality gas from Mexico and Canada
- Imported liquefied natural gas.

The OGSM regions are shown in Figure 12.

The driving assumption of OGSM is that domestic oil and gas exploration and development are undertaken if the discounted present value of the recovered resources at least covers the present value of taxes and the cost of capital, exploration, development, and production. Crude oil is transported to refineries, which are simulated in the petroleum market module, for conversion and blending into refined petroleum products. The individual submodules of the oil and gas supply module are solved independently, with feedbacks achieved through NEMS solution iterations (Figure 13).

Technological progress is represented in OGSM through annual increases in the finding rates and success rates, as well as annual decreases in costs. For conventional onshore, a time trend was used in econometrically estimated equations as a proxy for technology. Reserve additions per well (or finding rates) are projected through a set of equations that distinquish between new field discoveries and discoveries (extensions) and revisions in known fields. The finding rate equations capture the impacts of technology, prices, and declining resources. Another representation of technology is in the success rate equations. Success rates capture the impact of technology and saturation of the area through cumulative drilling. Technology is further represented in the determination of drilling, lease equipment and operating costs. Technological progress puts downward pressure on the drilling, lease equipment, and operating cost projections. For unconventional gas, a series of eleven different technology groups are represented by time–dependent adjustments to factors which influence finding rates, success rates, and costs.

Lower 48 Onshore and Shallow Offshore Supply Submodule

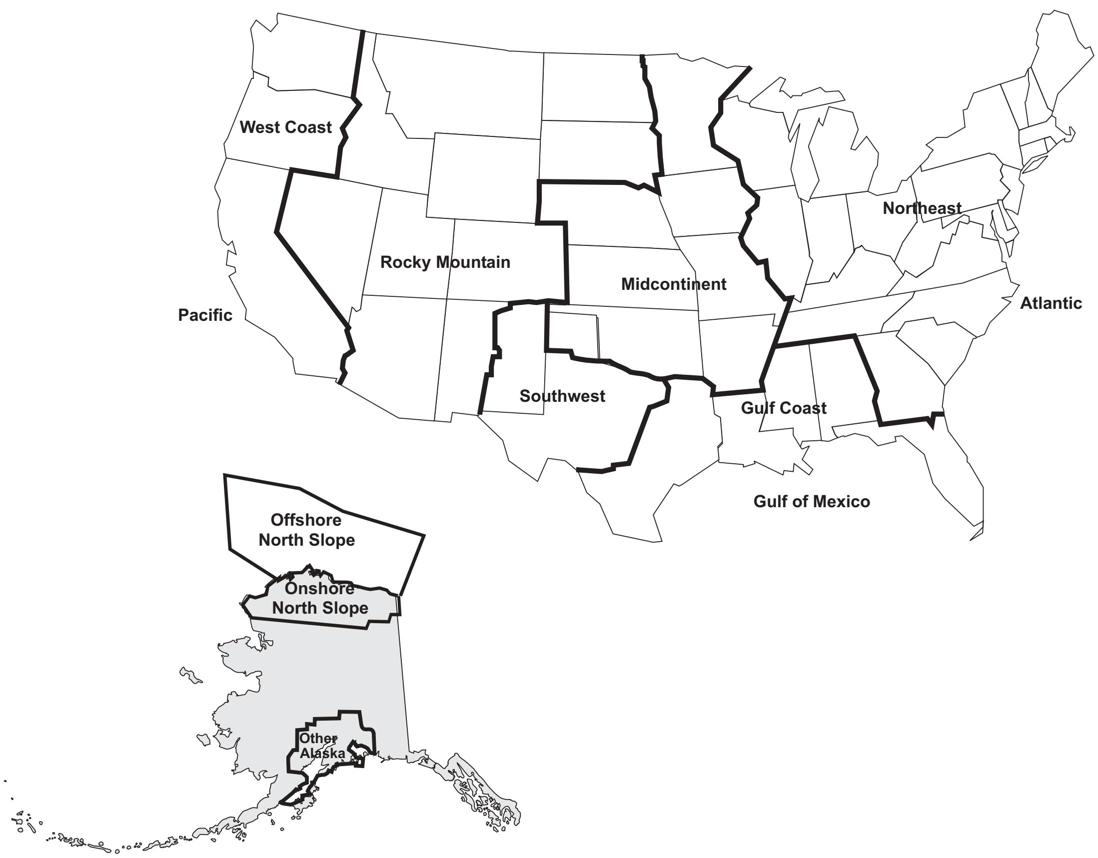
The lower 48 onshore supply submodule projects crude oil and natural gas production from conventional recovery techniques. This submodule accounts for drilling, reserve additions, total reserves, production-to-reserves ratios for each lower 48 onshore supply region.

The basic procedure is as follows:

- First, the prospective costs of a representative drilling project for a given fuel category and well class within a given region are computed. Costs are a function of the levels of drilling activity, average well depth, rig availability and the effects of technological progress.
- Second, the present value of the discounted cash flows (DCF) associated with the representative project is computed. These cash flows include both the capital and operating costs of the project, including royalties and taxes, and the revenues derived from a declining well production profile, computed after taking into account the progressive effects of resource depletion and valued at constant real prices as of the year of initial valuation.
- Third, drilling levels are calculated as a function of projected profitability as measured by the projected DCF levels for each project and national level cashflow.

OGSM Outputs	Inputs from NEMS	Exogenous Inputs
Crude oil production Domestic and Canadian nonassociated natural gas supply curves Mexican and liquefied natural gas imports and exports Cogeneration from oil and gas production Reserves and reserve additions Drilling levels Associated-dissolved gas production	Domestic and Canadian natural gas production and wellhead prices Crude oil demand World oil price Electricity price Gross Domestic Product Inflation Rate	Resource levels Initial finding rate parameters and costs Production profiles Tax parameters Mexican natural gas consumption and capacities Liquefied natural gas costs and capacities

Figure 12. Oil and Gas Supply Module Regions



- Fourth, regional finding rate equations are used to forecast new field discoveries from new field wildcats, new pools and extensions from other exploratory drilling, and reserve revisions from development drilling.

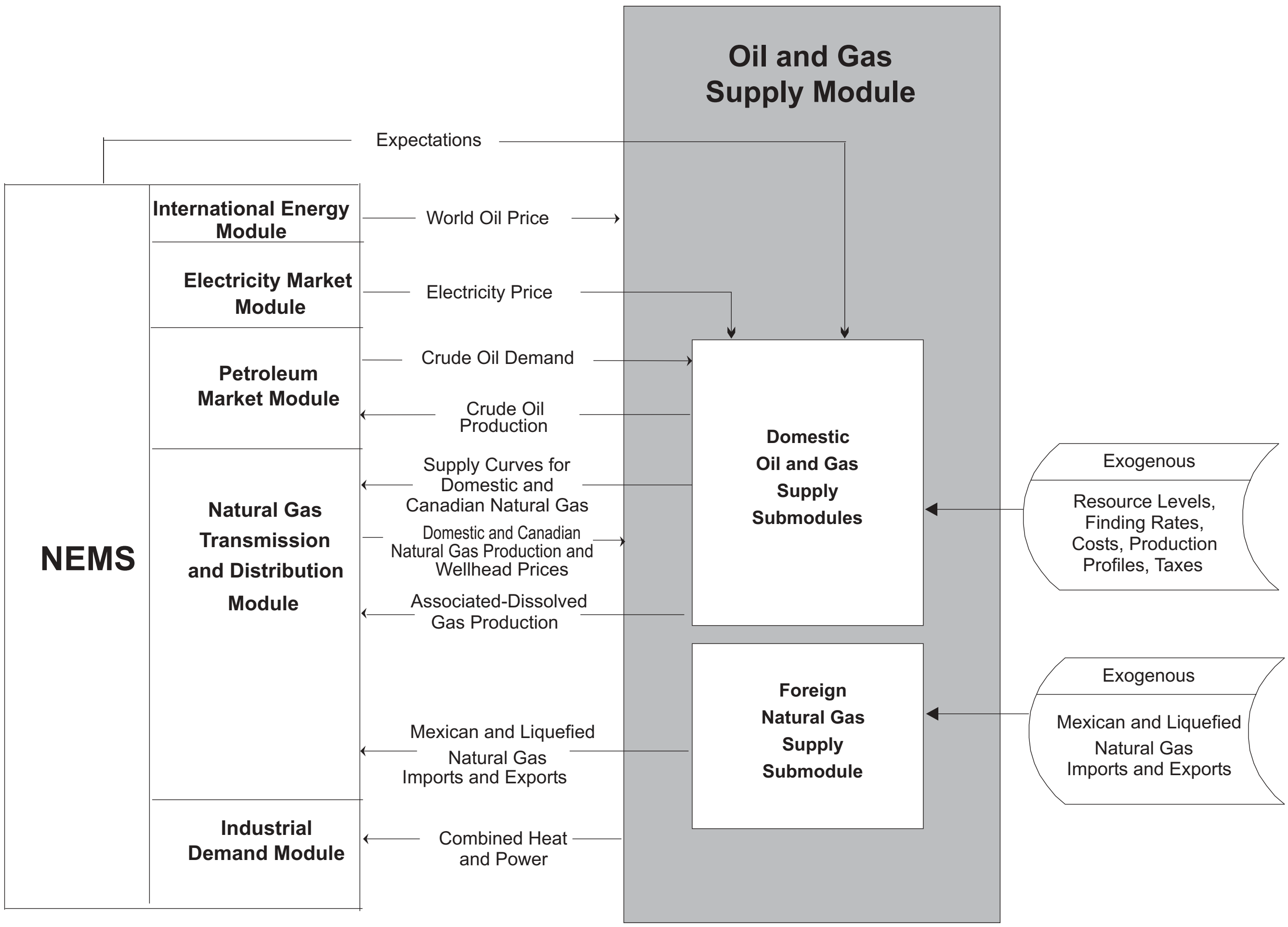
- Fifth, production is determined on the basis of reserves, including new reserve additions, previous productive capacity, flow from new wells, and, in the case of natural gas, fuel demands. This occurs within the market equilibration of the natural gas transmission and distribution module (NGTDM) for natural gas and within OGSM for oil.

Unconventional Gas Recovery Supply Submodule

Unconventional gas is defined as gas produced from nonconventional geologic formations, as opposed to conventional (sandstones) and carbonate rock formations. The three nonconventional geologic formations considered are low–permeability or tight sandstones, gas shales, and coalbed methane.

For unconventional gas, a play–level model calculates the economic feasibility of individual plays based on locally specific wellhead prices and costs, resource quantity and quality, and the various effects of technology on both resources and costs. In each year, an initial resource characterization determines the expected ultimate recovery (EUR) for the wells drilled in a particular play. Resource profiles are adjusted to reflect assumed technological impacts on the size, availability, and industry knowledge of the resources in the play. Subsequently, prices received from NGTDM and endogenously determined costs adjusted to reflect technological progress are utilized to calculate the economic profitability (or lack thereof) for the play. If the play is profitable, drilling occurs according to an assumed schedule, which is adjusted annually to account for technological improvements, as well as varying economic conditions. This drilling results in reserve additions, the quantities of which are directly related to the EURs for the wells in that play. Given these reserve additions, reserve levels and expected production–to–reserves (P/R) ratios are calculated at both the OGSM and the NGTDM region level. The resultant values are aggregated with similar values from

Figure 13. Oil and Gas Supply Module Structure



the conventional onshore and offshore submodules. The aggregate P/R ratios and reserve levels are then passed to NGTDM, which determines the prices and production for the following year through market equilibration.

Offshore Supply Submodule

This submodule uses a field–based engineering and economic analysis approach to project reserve additions and production from resources in the shallow and deep water offshore Gulf of Mexico Outer Continental Shelf and Pacific regions. Two structural components make up the offshore supply submodule, an exogenous price/supply data generation routine and an endogenous reserves and production timing algorithm.

The price/supply data generation methodology employs a rigorous field–based DCF approach. This offline model utilizes key field properties data, algorithms to determine key technology components, algorithms to determine the exploration, development and production costs, and computes a minimum acceptable supply price (MASP) at which the discounted net present value of an individual prospect equals zero. The MASP and the recoverable resources for the different fields are aggregated by planning region and by resource type to generate resource–specific price–supply curves. In addition to the overall supply price and reserves, costs components for exploration, development drilling, production platform, and operating expenses, as well as exploration and development well requirements, are also carried over to the endogenous component.

After the exogenous price/supply curves have been developed, they are transmitted to an endogenous algorithm. This algorithm makes choices for field exploration and development based on relative economics of the project profitability compared with the equilibrium crude oil and natural gas prices determined by the petroleum market module and natural gas transmission and distribution module. Development of economically recoverable resources into proved reserves is constrained by drilling activity. Proved reserves are translated into production based on a P/R ratio. The drilling activity and the P/R ratio are both determined by extrapolating the historical information.

Alaska Oil and Gas Submodule

This submodule projects the crude oil and natural gas produced in Alaska. The Alaskan oil submodule is divided into three sections: new field discoveries, development projects, and producing fields. Oil transportation costs to lower 48 facilities are used in conjunction with the relevant market price of oil to calculate the estimated net price received at the wellhead, sometimes called the netback price. A discounted cash flow method is used to determine the economic viability of each project at the netback price.

Alaskan oil supplies are modeled on the basis of discrete projects, in contrast to the onshore lower 48 conventional oil and gas supplies, which are modeled on an aggregate level. The continuation of the exploration and development of multiyear projects, as well as the discovery of new fields, is dependent on profitability. Production is determined on the basis of assumed drilling schedules and production profiles for new fields and developmental projects, historical production patterns, and announced plans for currently producing fields.

Alaskan gas production is set separately for any gas targeted to flow through a pipeline to the lower 48 States and gas produced for consumption in the State and for export to Japan. The latter is set based on a forecast of Alaskan consumption in the NGTDM and an exogenous specification of exports. North Slope production for the pipeline is dependent on construction of the pipeline, set to commence if the lower 48 average wellhead price is maintained at a level exceeding the established comparable cost of delivery to the lower 48 States.

Foreign Natural Gas Supply Submodule

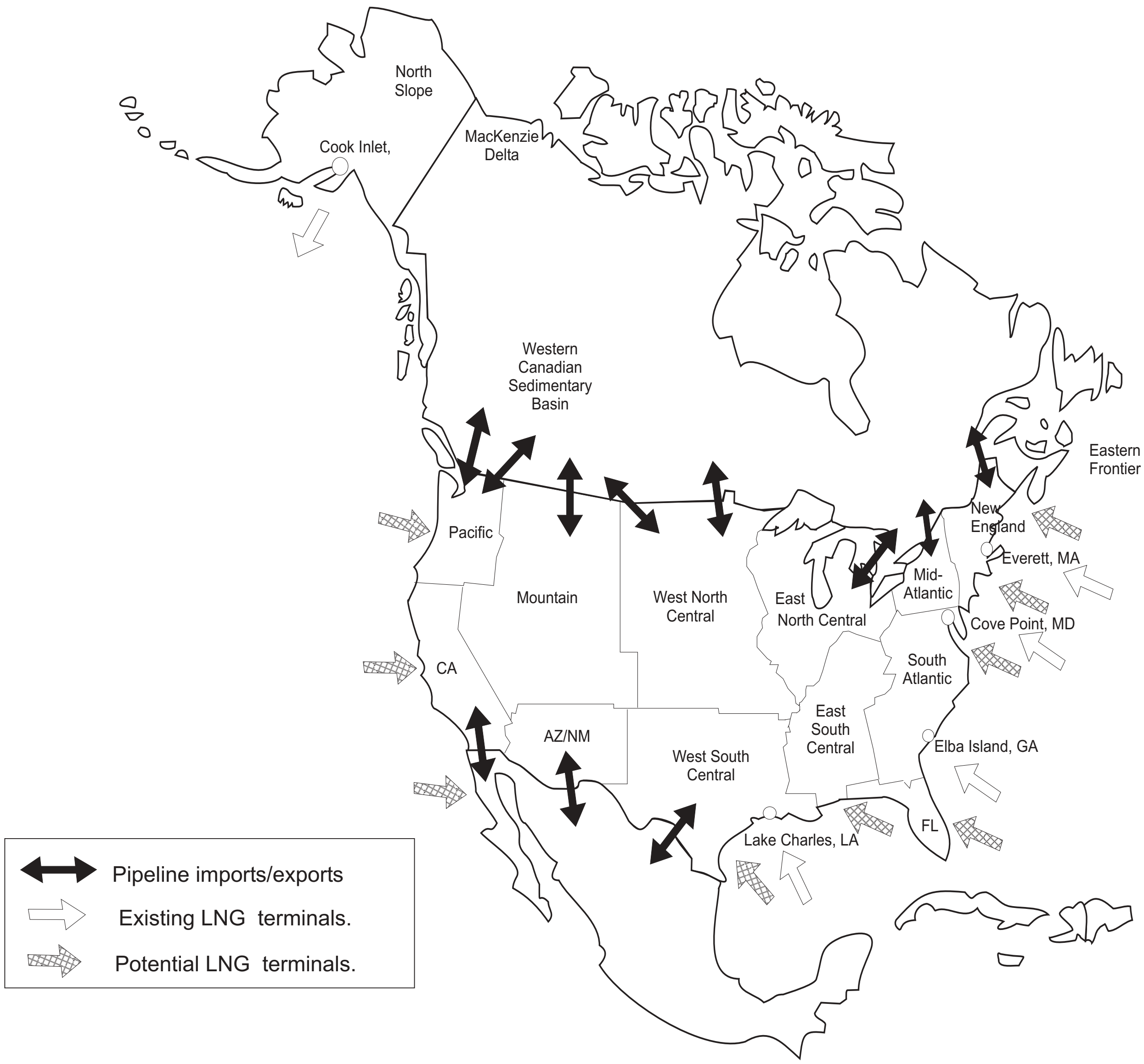
The foreign natural gas supply submodule (FNGSS) establishes production in the Western Canadian Sedimentary Basin (WCSB) and Eastern Canada, natural gas trade via pipeline with Mexico, as well as liquefied natural gas (LNG) trade. The receiving regions for foreign gas supplies correspond to those of the natural gas integrating framework established for NGTDM. Within NGTDM, pipeline natural gas imports flow from two sources: Canada and Mexico. U.S. natural gas trade with Canada is represented by seven entry/exit points, and trade with Mexico is represented by three entry/exit points (Figure 14).

OGSM provides NGTDM with the beginning–of–year natural gas proved reserves from the WCSB and an associated expected production–to–reserve ratio. NGTDM uses this information to establish a short–term supply curve for the region. Along with exogenously specified forecasts for exports of gas to Canada, other Canadian supplies, and Canadian consumption, this supply curve is used to determine the wellhead gas production and price in the WCSB and the level and price of imports from Canada at the seven border crossings. Based on the WCSB gas wellhead price, OGSM forecasts drilling activity in the WCSB using an econometrically derived equation, along with the associated reserve additions. The finding rate is set using an assumed exponential decline function which responds to the drilling activity. The reserve additions are added to the beginning-of-year proved reserves from the current forecast year, after the forecasted production levels are subtracted, to establish the beginning–of–year proved reserves for the next forecast year. Construction is set to commence on a pipeline to bring natural gas from the MacKenzie Delta to market after the lower 48 average wellhead price is maintained at a level exceeding the established comparable cost.

Mexican gas trade is a highly complex issue. A range of noneconomic factors influences, if not determines, flows of gas between the United States and Mexico. The uncertainty is so great that not only is the magnitude of flow for any future year in doubt, but also the direction of flow. Reasonable scenarios have been developed and defended in which Mexico may be either a net importer or exporter of hundreds of billions of cubic feet of gas by 2025 or sooner.

Despite the uncertainty and the significant influence of noneconomic factors that influence Mexican gas trade with the United States, a methodology to anticipate the path of future Mexican imports and exports has been incorporated into FNGSS. This outlook is generated using assumptions regarding regional supply and regional/sectoral demand growth for natural gas in Mexico that have been developed from an assessment of current and expected industry and market circumstances as indicated in industry announcements, or articles or reports in relevant publications. Excess supply is assumed to be available for export to the United States, and any short-

Figure 14. Foreign Natural Gas Trade via Pipeline and Liquefied Natural Gas Terminals



fall is assumed to be met by imports from the United States. The importation of liquefied natural gas into Baja, Mexico is expected to commence when the market price, established as a netback from the price in California, exceeds the assumed cost.

Liquefaction is a process whereby natural gas is cooled to minus 260 degrees Fahrenheit, causing it to be converted from a gas to a liquid. This also reduces its volume significantly, making it possible to transport to distant markets. This allows stranded gas, or gas that would otherwise be inaccessible due either to lack of nearby markets or lack of pipeline infrastructure to deliver it to local markets, to be monetized.

Costs of producing, liquefying, transporting, and re-gasifying the gas for delivery via pipeline to end-users are input to the FNGSS. The summations of these values for each location serve as economic thresholds that must be achieved before investment in expansion at an existing, or construction of a new, LNG project occurs. Imported LNG costs compete with the purchase price of gas prevailing in the vicinity of the import terminal. This is a significant element in evaluating the competitiveness of LNG supplies, since LNG terminals vary greatly in their proximity to domestic producing areas. Terminals close to major consuming markets and far from competing producing areas may provide a sufficient economic advantage to make LNG a competitive gas supply source in some markets.

In addition to costs, extensive operational assumptions are required to determine LNG imports. Dominant general factors affecting the outlook include expected developments with respect to the use of existing capacity, expansion at existing sites, and construction at additional locations. The LNG forecast also requires the specification of a combination of factors: available gasification capacity, schedules for and lags between constructing and opening a facility, tanker availability, expected utilization rates, and worldwide liquefaction capacity. For inactive terminals, it is necessary to determine the length of time required to restart operations, normally between 12 and 18 months. These considerations are taken into account when the economic viability of LNG supplies is determined.

The algorithm for representing LNG regasification capacity expansion in the United States compares estimated costs for bringing LNG into various regions in the United States with the average market price in the region over the previous three years of the forecast. If the market price has been sustained above the estimated cost, construction of additional regasification capacity is expected to occur. The regions represented are: New England Census Division, Middle Atlantic Census Division, South Atlantic Census Division (excluding Florida), Florida, East South Central Census Division, West South Central Census Division, California, and Washington/Oregon. The incremental expansion volumes are specified exogenously, along with the expected utilization of the capacity across time. Under special circumstances (e.g., rapid consumption growth) these utilization rates are adjusted endogenously. The assumed costs for bringing LNG into the United States reflect the least cost aggregation of cost estimates for production, liquefaction, transportation, and regasification from potential supply sources to each of the coastal regions of the United States. Build decisions occur under various restrictions, such as the limitation that new capacity can not be added in a region until existing capacity has been expanded to a specified limit and all of this capacity is fully utilized within the region. In deciding upon capacity expansion, the model does not attempt to anticipate future market situations, factor in regional demand for LNG (except through its indirect impact on prices), nor select between potential regasification sites. The model accounts for LNG exports to Japan from Alaska using an exogenously–specified forecast.

NATURAL GAS TRANSMISSION AND DISTRIBUTION MODULE

The natural gas transmission and distribution module (NGTDM) of NEMS represents the natural gas market and determines regional market–clearing prices for natural gas supplies and for end–use consumption, given the information passed from other NEMS modules (Figure 15). A transmission and distribution network (Figure 16), composed of nodes and arcs, is used to simulate the interregional flow and pricing of gas in the contiguous United States and Canada in both the peak (December through March) and offpeak (April through November) period. This network is a simplified representation of the physical natural gas pipeline system and establishes the possible interregional flows and associated prices as gas moves from supply sources to end users.

Flows are further represented by establishing arcs from transshipment nodes to each demand sector represented in an NGTDM region (residential, commercial, industrial, electric generators, and transportation). Mexican exports and net storage injections in the offpeak period are also represented as flow exiting a transshipment node. Similarly, arcs are also established from supply points into a transshipment node. Each transshipment node can have one or more entering arcs from each supply source represented: U.S. or Canadian onshore or U.S. offshore production, liquefied natural gas imports, supplemental gas production, gas produced in Alaska and transported via pipeline, Mexican imports, or net storage withdrawals in the region in the peak period. Most of the types of supply listed above are set independently of current year prices and before NGTDM determines a market equilibrium solution. Only the onshore and offshore lower 48 U.S. and Western Canadian Sedimentary Basin production, along with net storage withdrawals, are represented by short–term supply curves and set dynamically during the NGTDM solution process. The construction of natural gas pipelines from Alaska and Canada's MacKenzie Delta are triggered when market prices exceed estimated project costs. The flow of gas during the peak period is used to establish interregional pipeline and storage capacity requirements and the associated expansion. These capacity levels provide an upper limit for the flow during the offpeak period.

Arcs between transshipment nodes, from the transshipment nodes to end–use sectors, and from supply sources to transshipment nodes are assigned tariffs. The tariffs along interregional arcs reflect reservation (represented with volume dependent curves) and usage fees and are established in the pipeline tariff submodule. The tariffs on arcs to end–use sectors represent the interstate pipeline tariffs in the region, intrastate pipeline tariffs, and distributor markups set in the distributor tariff submodule. Tariffs on arcs from supply sources represent gathering charges or other differentials between the price at the supply source and the regional market hub. The tariff associated with injecting, storing, and withdrawing from storage is assigned to the arc representing net storage withdrawals in the peak period. During the primary solution process in the interstate transmission submodule, the tariffs along an interregional arc are added to the price at the source node to arrive at a price for the gas along the arc right before it reaches its destination node.

NGTDM Outputs	Inputs from NEMS	Exogenous Inputs
Natural gas end–use and electric generator prices Domestic and Canadian natural gas wellhead prices Domestic natural gas production Canadian natural gas imports and production Lease and plant fuel consumption Pipeline fuel use Pipeline and distribution tariffs Interregional natural gas flows Storage and pipeline capacity expansion Supplemental gas production	Natural gas demands Domestic and Canadian natural gas supply curves Mexican and liquefied natural gas imports and exports Macroeconomic variables Associated-dissolved natural gas production	Historical consumption patterns Historical flow patterns Rate design specifications Company-level financial data Pipeline and storage capacity and utilization data Historical end-use prices State and Federal tax parameters Pipeline and storage expansion cost data Supplemental gas production

Figure 15. Natural Gas Transmission and Distribution Module Structure

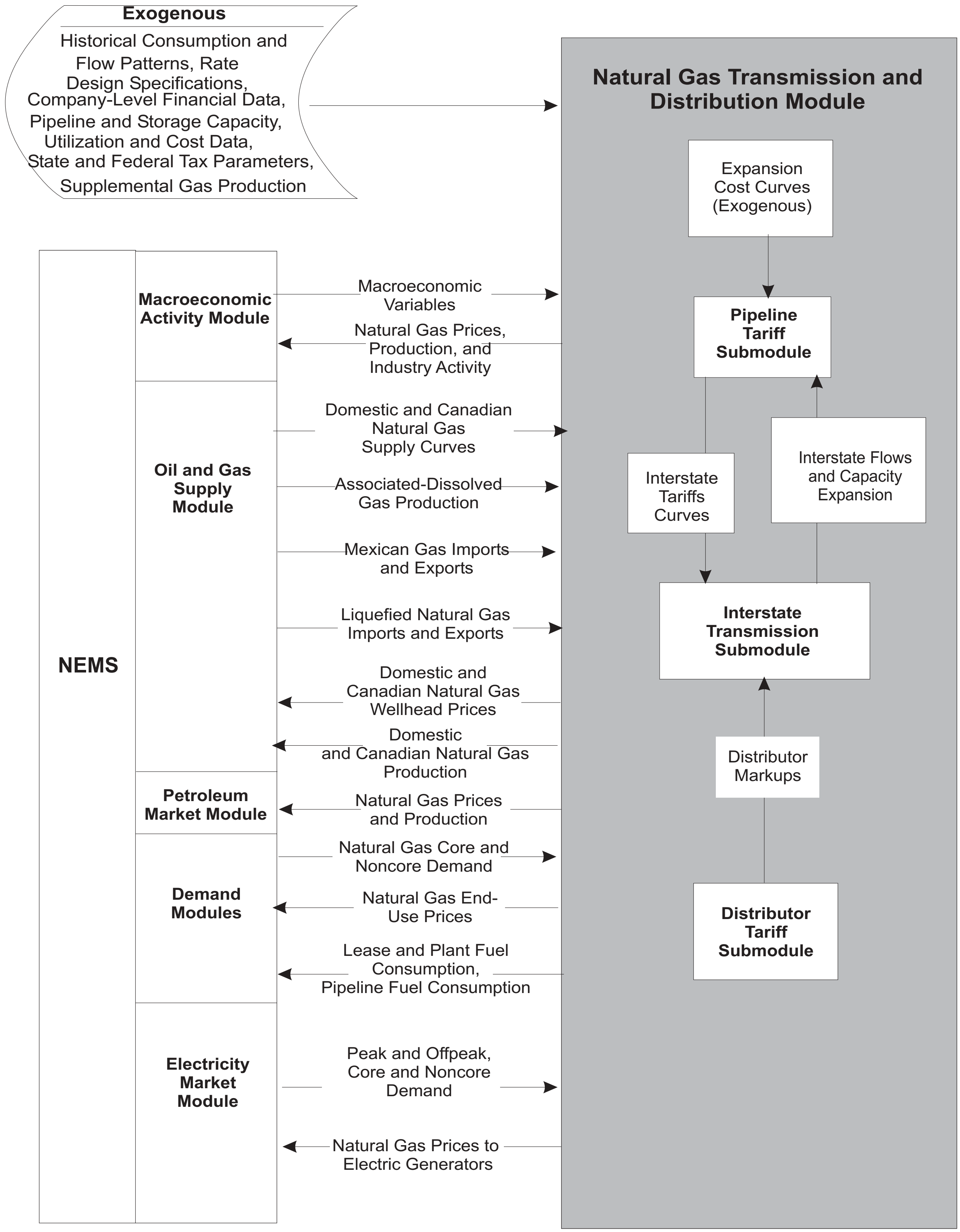
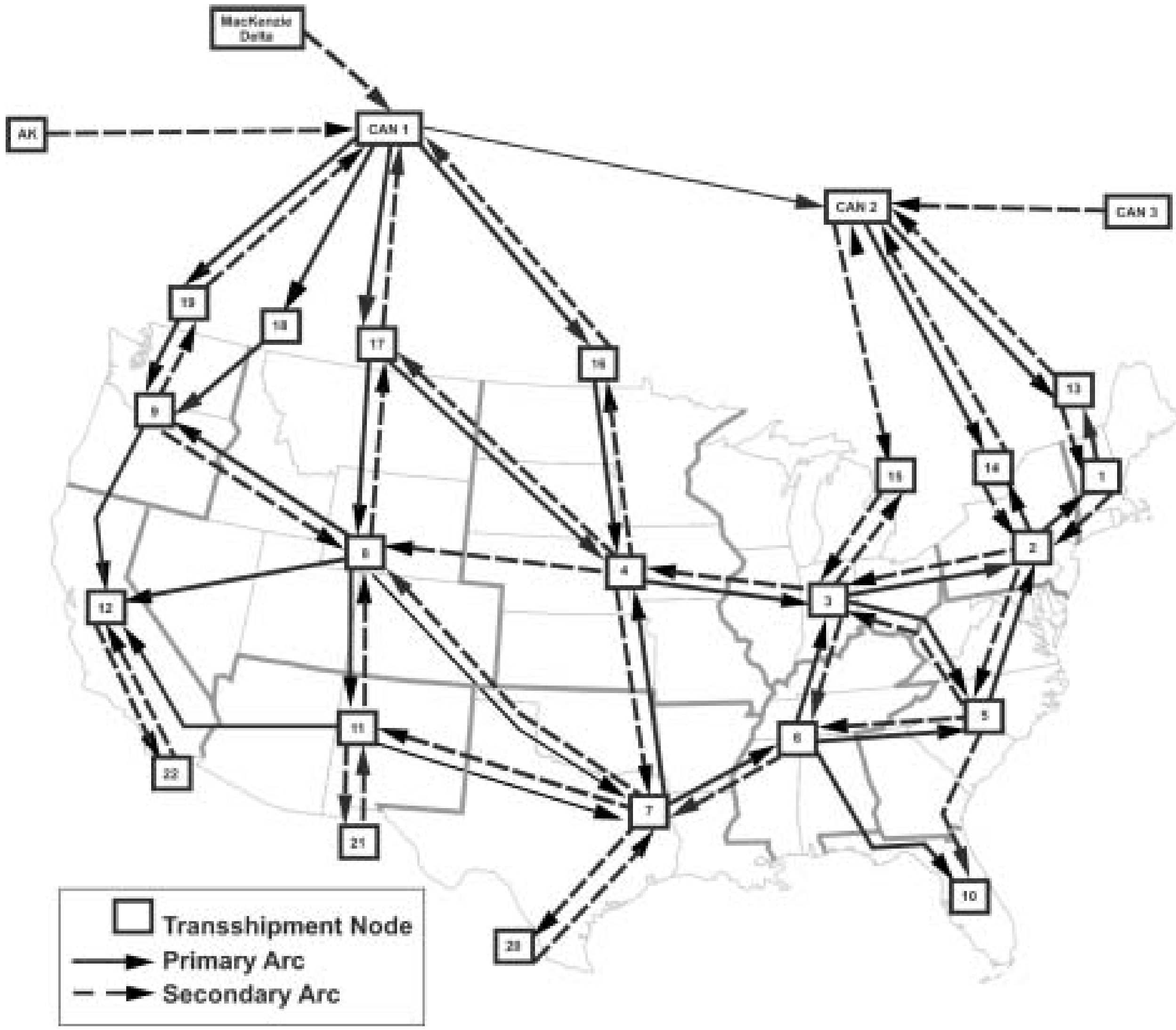


Figure 16. Natural Gas Transmission and Distribution Module Network



Interstate Transmission Submodule

The interstate transmission submodule (ITS) is the main integrating module of NGTDM. One of its major functions is to simulate the natural gas price determination process. ITS brings together the major economic factors that influence regional natural gas trade on a seasonal basis in the United States, the balancing of the demand for and the domestic supply of natural gas, including competition from imported natural gas. These are examined in combination with the relative prices associated with moving the gas from the producer to the end user where and when (peak versus offpeak) it is needed. In the process, ITS simulates the decision–making process for expanding pipeline and/or seasonal storage capacity in the U.S. gas market, determining the amount of pipeline and storage capacity to be added between or within regions in NGTDM. Storage serves as the primary link between the two seasonal periods represented.

ITS employs an iterative heuristic algorithm, along with an acyclic hierarchical representation of the primary arcs in the network, to establish a market equilibrium solution. Given the consumption levels from other NEMS modules, the basic process followed by ITS involves first establishing the backward flow of natural gas in each period from the consumers, through the network, to the producers, based primarily on the relative prices offered for the gas from the previous ITS iteration. This process is performed for the peak period first since the net withdrawals from storage during the peak period will establish the net injections during the offpeak period. Second, using the model's supply curves, wellhead prices are set corresponding to the desired production volumes. Also, using the pipeline and storage tariffs from the pipeline tariff submodule, pipeline and storage tariffs are set corresponding to the associated flow of gas, as determined in the first step. These prices are then translated from the producers, back through the network, to the city gate and the end users, by adding the appropriate tariffs along the way. A regional storage tariff is added to the price of gas injected into storage in the offpeak to arrive at the price of the gas when withdrawn in the peak period. This process is then repeated until the solution has converged. Finally, end–use prices are derived for residential, commercial, and transportation customers, as well as for both core and noncore industrial and electric generation sectors using the distributor tariffs provided by the distributor tariff submodule.

Pipeline Tariff Submodule

The pipeline tariff submodule (PTS) provides usage fees and volume dependent curves for computing unitized reservation fees (or tariffs) for interstate transportation and storage services within ITS. These curves extend beyond current capacity levels and relate incremental pipeline or storage capacity expansion to corresponding estimated rates. The underlying basis for each tariff curve in the model is a forecast of the associated regulated revenue requirement. Econometrically estimated forecasting equations within a general accounting framework are used to track costs and compute revenue requirements associated with both reservation and usage fees under current rate design and regulatory scenarios. Other than an assortment of macroeconomic indicators, the primary input to PTS from other modules in NEMS is the level of pipeline and storage capacity expansions in the previous forecast year. Once an expansion is forecast to occur, PTS calculates the resulting impact on the revenue requirement. PTS assumes rolled–in (or average), not incremental, rates for new capacity. The pipeline tariff curves generated by PTS are used within the ITS when determining the relative cost of purchasing and moving gas from one source versus another in the peak and offpeak seasons.

Distributor Tariff Submodule

The distributor tariff submodule (DTS) sets distributor markups charged by local distribution companies for the distribution of natural gas from the city gate to the end user. End–use distribution service is distinguished within DTS by sector (residential, commercial, industrial, electric generators, and transportation), season (peak and offpeak), and service type (core and noncore). DTS sets distribution tariffs by estimating or assuming the annual change in these tariffs, starting from base–year values that are established using historical data.

The annual change in distributor tariffs for residential, commercial, and industrial core customers depends on an assumed increase in operational efficiencies combined with a depreciation rate, as well as the annual change in natural gas consumption and in national average capital and employment costs. Distributor markups to the noncore industrial customers are assumed not to change over time. Distributor markups to electric generators are allowed to change in response to annual changes in consumption levels within the sector. The natural gas vehicle sector markups are calculated separately for fleet and personal vehicles. Markups for fleet vehicles are set and held constant at historical levels, with taxes added. Markups for personal vehicles are set at the industrial sector core price, plus taxes, plus an assumed distribution cost. This price is capped at the gasoline equivalent price, as long as minimum costs are covered.

The petroleum market module (PMM) represents domestic refinery operations and the marketing of petroleum products to consumption regions. PMM solves for petroleum product prices, crude oil and product import activity (in conjunction with the international energy module and the oil and gas supply module), and domestic refinery capacity expansion and fuel consumption. The solution is derived, satisfying the demand for petroleum products and incorporating the prices for raw material inputs and imported petroleum products, the costs of investment, and the domestic production of crude oil and natural gas liquids. The relationship of PMM to other NEMS modules is illustrated in Figure 17.

PMM is a regional, linear–programming representation of the U.S. petroleum market. Refining operations are represented by a three–region linear programming formulation of the five Petroleum Administration for Defense Districts (PADDs) (Figure 18). PADDs I and V are each treated as single regions, while PADDs II, III, and IV are aggregated into one region. Each region is considered as a single firm where more than 40 distinct refinery processes are modeled. Refining capacity is allowed to expand in each region, but the model does not distinguish between additions to existing refineries or the building of new facilities. Investment criteria are developed exogenously, although the decision to invest is endogenous.

PMM 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 petroleum products.

Although the petroleum market responds to pressure, it rarely strays from the underlying refining costs and economics for long periods of time. If demand is unusually high in one region, the price will increase, driving down demand and providing economic incentives for bringing supplies in from other regions, thus restoring the supply/demand balance.

Existing regulations concerning product types and specifications, the cost of environmental compliance, and Federal and State taxes are also modeled. PMM incorporates taxes imposed by the 1993 Budget Reconciliation Act as well as costs resulting from the Clean Air Act Amendments of 1990 (CAAA90) and other environmental legislation. The costs of producing new formulations of gasoline and diesel fuel as a result of the CAAA90 are determined within the linear–programming representation by incorporating specifications and demands for these fuels.

An important innovation in NEMS involves the relationship between the domestic and international markets. Whereas earlier models postulated entirely exogenous prices for oil on the international market (the world oil price), NEMS includes an international energy module that estimates supply curves for imported crude oils and products based on, among other factors, U.S. participation in international trade.

Regions

PMM models U.S. crude oil refining capabilities based on the five PADDs which were established during World War II and are still used by EIA for data collection and analysis. The use of PADD data permits PMM to take full advantage of EIA's historical database and allows analysis and forecasting within the same framework used by the petroleum industry.

PMM Outputs	Inputs from NEMS	Exogenous Inputs
Petroleum product prices	Petroleum product demand by sector	Processing unit operating parameters
Crude oil imports and exports	Domestic crude oil production	Processing unit capacities
Crude oil demand	World oil price	Product specifications
Petroleum product imports and exports	International crude oil supply curves	Operating costs
Refinery activity and fuel use	International product supply curves	Capital costs
Ethanol demand and price	International oxygenates supply curves	Transmission and distribution costs
Combined heat and power (CHP)	Natural gas prices	Federal and State taxes
Natural gas plant liquids production	Electricity prices	Agricultural feedstock quantities and costs
Processing gain	Natural gas production	CHP unit operating parameters
Capacity additions	Macroeconomic variables	CHP unit capacities
Capital expenditures	Biomass supply curves	
Revenues	Coal prices	

Figure 17. Petroleum Market Module Structure

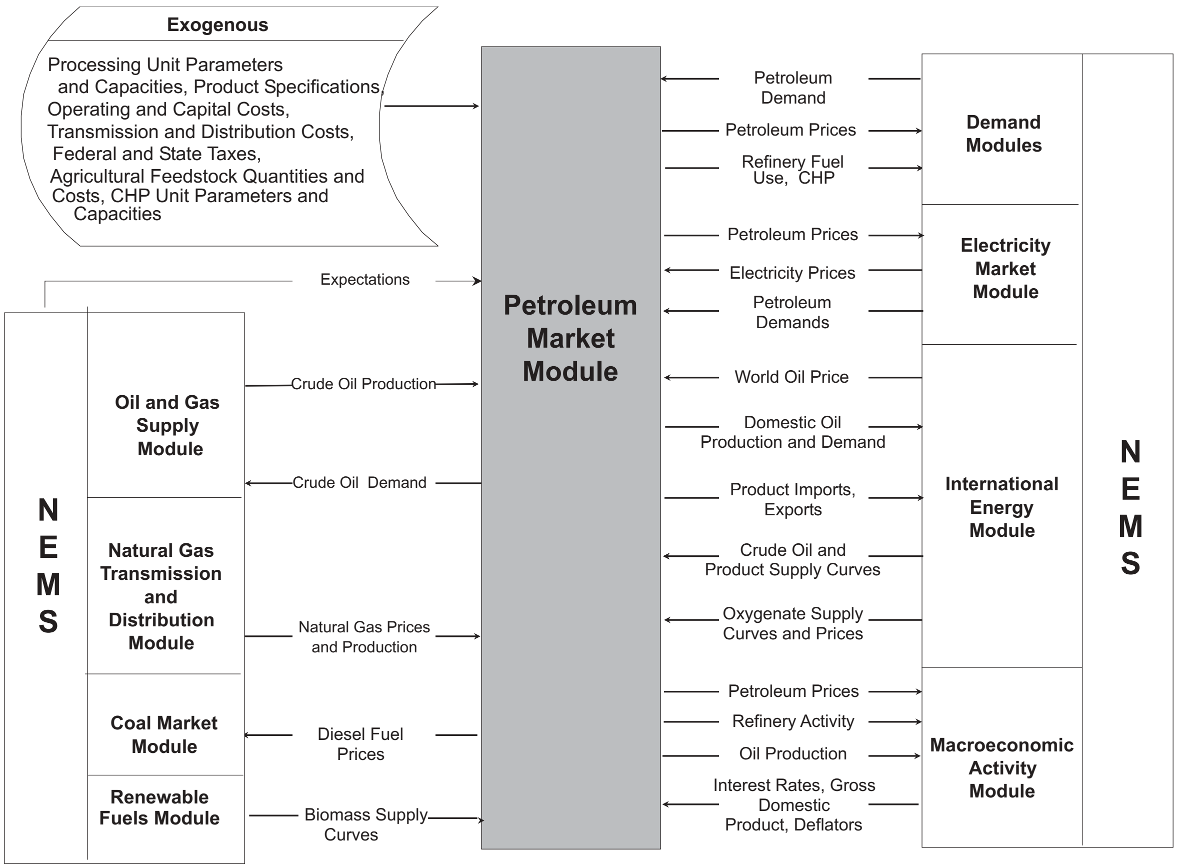
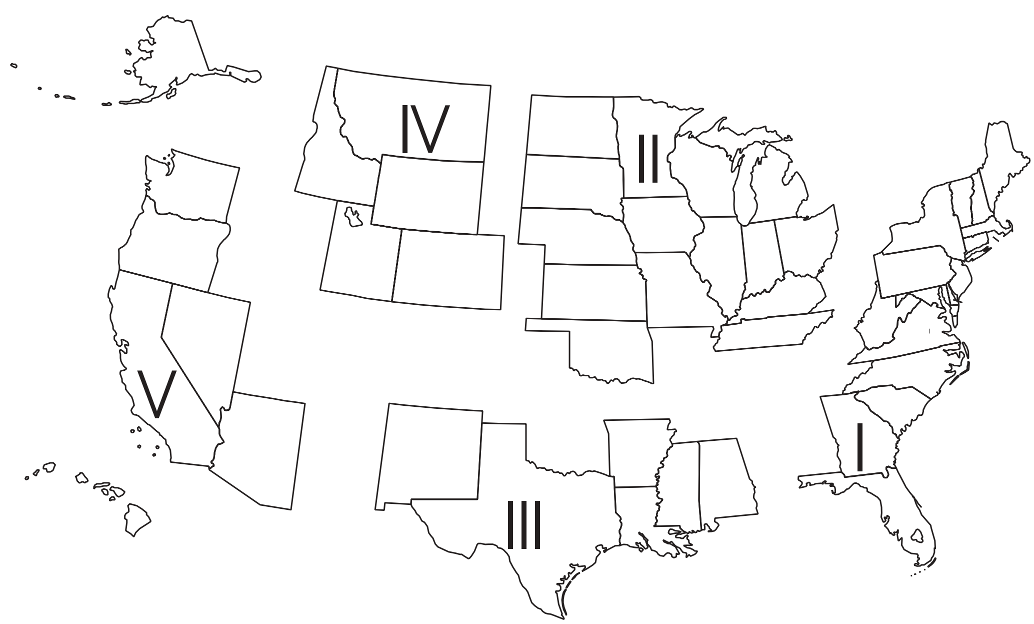


Figure 18. Petroleum Administration for Defense Districts



Product Categories

Product categories, specifications, and recipe blends modeled in PMM include the following:

Petroleum Products Modeled in PMM

Motor gasoline: conventional, oxygenated (2.7% oxygen), Federal reformulated (2.0% oxygen), California reformulated (no oxygen).
Jet fuels: kerosene-based.
Distillates: kerosene, heating oil, low-sulfur (500 ppm) and ultra–low–sulfur(15 ppm) highway diesel.
Residual fuels: low-sulfur, high-sulfur.
Liquefied petroleum gas (LPG): propane, LPG mixes.
Petrochemical feedstocks: petrochemical naphtha, petrochemical gas oil, propylene, aromatics.
Other: asphalt and road oil, still gas, petroleum coke, lubricating products and waxes, special naphthas.

Fuel Use

PMM determines refinery fuel use by refining region for purchased electricity, natural gas, distillate fuel, residual fuel, liquefied petroleum gas, and other petroleum. The fuels (natural gas, petroleum, other gaseous fuels, and other) consumed within the refinery to generate electricity from CHP facilities are also measured.

Crude Oil Categories

Both domestic and imported crude oil are aggregated into five categories, as defined by the following ranges of gravity and sulfur:

Crude Oil Categories in PMM

Category	Sulfur	Gravity
Low-sulfur light	0.5%	>24
Medium-sulfur heavy	0.35-1.1%	>24
High-sulfur light	>1.1%	>32
High-sulfur heavy	>1.1%	24-33
High-sulfur very heavy	>0.7%	<23

This aggregation of crude oil types allows PMM to account for changes in crude oil composition over time. A composite crude with the appropriate yields and qualities is developed for each category by averaging characteristics of specific crude oil streams that fall into each category. While the domestic and foreign categories are the same, the composites for each type may differ, because different crude oil streams make up the composites.

Refinery Processes

Not every refinery processing unit is represented in PMM. The refinery processes represented were chosen because they have the most significant impact on production. The following distinct processes are represented:

Refinery Processing Units Modeled in PMM

Atmospheric distillation, vacuum distillation
Delayed coker
Fluid coker-includes flexicoking mode
Fluid catalytic cracker (FCC)-includes distillate, vacuum gas oil, coker gas oil, atmospheric residual, unallowable feeds; conversion ranges 65 to 85 percent; ZSM catalyst mode, low severity mode
Gas oil hydrocracker (including advanced technologies)
Residuum hydrocracker
Naphtha hydrotreater
Distillate desulfurization
FCC feed hydrofiner
Residuum desulfurizer (including atmospheric)
Lube and wax units
Module distillate deep hydrotreater
Solvent deasphalting
Catalytic reforming-separate units for semi-regenerative high-pressure, low-pressure cyclic; severity range as appropriate to the reactor; allow light straight run through heavy naphtha virgin streams, heavy naphthas from FCC, coker, and hydrocracker operations; allow new highly active catalyst operation
Naphtha splitter
FCC gasoline fractionation
FCC naphtha desulfurization
C2-C5 dehydrogenation
Butane splitter
Butane isomerization
Isomerization for pentanes, hexanes
Isomarization - butane, butylene, butene
Alkylation
Aromatics recovery
Diesel hydro desulfurization (S-Zorb and others)
Coal–to–liquids facility, including cogeneration
Gas–to–liquids process, including Syntroleum, Shell middle distillate
Iso-Octane
Olifin hydrogenation
FCC olefins to gasoline and distillate
Thermal Cracker, including C2-C4 feed, Naphtha feed, Gas Oil feed, Visbreaker
Hydrocracker— naphtha, partial, low conversion
High density jet fuel pre/processing— prefractionation, hydrotreating
Polymerization of prolylene, butylene
MTBE, ETBE, and TAME production (captive and merchant)
Gas processing
Hydrogen generation, purification
Steam generation
Power generation
Cogeneration
Sulfur plant
Fuel mixer
Methanol production

ETBE=Ethyl tertiary butyl ether.
MTBE=Methyl tertiary butyl ether.
TAME= Tertiary amyl methyl ether.

Natural Gas Plants

The outputs of natural gas processing plants, including ethane, propane, butane, isobutane, and natural gasoline are modeled in PMM. These products move directly into the market to meet demand or are inputs to the refinery.

Ethanol

PMM contains an ethanol submodule which provides the PMM linear program with regional ethanol supplies and prices. Ethanol quantity/price curves are calculated in each Census Division for both corn–derived and cellulose–derived ethanol, allowing PMM to forecast transportation ethanol demand. The supply curves take into account feedstock costs, feedstock conversion costs, and energy prices. Corn and corn co–product quantities and costs are provided exogenously from the USDA Agricultural Baseline Projections to 2011.[29] Cellulose feedstock supply/price curves are provided by the renewable fuels module of NEMS.

End-Use Markups

The linear–programming portion of the model provides unit prices of products sold in the refinery regions (refinery gate) and in the demand regions (wholesale). End–use markups are added to produce a retail price for each of the Census Divisions. The markups are based on an average of historical markups, defined as the difference between the end–use prices by sector and the corresponding wholesale price for that product. The average is calculated using data from 1989 to the present. Because of the lack of any consistent trend in the historical end–use markups, the markups remain at the historical average level over the forecast period.

State and Federal taxes are also added to transportation fuel prices to determine final end–use prices. Recent tax trend analysis indicates that State taxes increase at the rate of inflation, while Federal taxes do not. In PMM, therefore, State taxes are held constant in real terms throughout the forecast while Federal taxes are deflated at the rate of inflation.

Gasoline Types

Federal and State legislations have resulted in the production of several blends of gasoline. PMM categorizes these blends into four gasoline types: conventional gasoline, oxygenated gasoline, Federal reformulated gasoline, and California reformulated gasoline. The conventional category includes gasoline blended with 10–percent ethanol, also known as gasohol. Oxygenated gasoline is conventional gasoline containing a minimum of 2.7–percent oxygen by weight for use in specific regions of the United States during the winter months to reduce carbon monoxide.

Federal reformulated gasoline is blended according to U.S. Environmental Protection Agency (EPA) Complex Model II specifications with a minimum oxygen content of 2.0 percent by weight for use in ozone non–attainment areas. PMM uses either ethanol or ethers (MTBE, ETBE, and other ethers) to obtain the 2.0 percent oxygen requirement. However, after 2004, the model uses only ethanol in Census Division 9 to make Federal reformulated gasoline, because of California legislation which bans the use of MTBE in gasoline by the end of 2003. California reformulated gasoline is blended to the California Air Resources Board (CARB) specifications, which are more severe than the Federal reformulated standards, but have no minimum oxygen requirement. Because about two–thirds of California's gasoline consumption occurs within Federal ozone nonattainment areas, gasoline in these areas is also assumed to meet the Federal oxygen requirement of 2.0 percent. Although the reference case assumes current laws and regulations, additional product specifications can be modeled for policy analysis.

[29] U.S. Department of Agriculture, *USDA Agricultural Baseline Projections to 2011*, Staff Report WAOB-2002-01 (Washington, DC, February 2002).

Ultra–Low–Sulfur Diesel

In December 2000, EPA promulgated the "ultra-low-sulfur diesel" (ULSD) regulation for highway diesel. By definition, ULSD is highway diesel that contains no more than 15–ppm sulfur at the pump. The new regulation contains the "80/20" rule, which requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100–percent requirement for ULSD thereafter. Because NEMS is an annual average model, the full impact of the 80/20 rule cannot be seen until 2007, and the impact of the 100– percent requirement cannot be seen until 2011. Major assumptions related to the implementation of the ULSD rule are as follows:

- Highway diesel at the refinery gate will contain a maximum of 7–ppm sulfur. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel below 10 ppm sulfur in order to allow for contamination during the distribution process.
- The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 10 percent at the onset of the program, declining to 4.4 percent at full implementation. The decline reflects an expectation that the distribution system will become more efficient at handling ULSD with experience.
- Demand for highway-grade diesel, both 500 and 15 ppm combined, is assumed to be equivalent to the total transportation distillate demand. Historically, highway-grade diesel supplied has nearly matched total transportation distillate sales, although some highway-grade diesel has gone to nontransportation uses such as construction and agriculture.
- ULSD production is modeled through improved distillate hydrotreating units as well as the ConocoPhillips S–Zorb process. Revamping (retrofitting) existing units to produce ULSD will be undertaken by refineries representing two–thirds of highway diesel production; the remaining refineries will build new units. The capital cost of a revamp is assumed to be 50 percent of the cost of adding a new unit.
- No change in the sulfur level of non-road diesel is assumed, because the EPA has not yet promulgated non-road diesel standards.

Gas–To–Liquids and Coal–To–Liquids

If prices for lower sulfur distillates reach a high level, it is assumed that gas-to-liquids (GTL) facilities will be built on the North Slope of Alaska to convert stranded natural gas into distillates, to be transported on the Trans-Alaskan Pipeline System (TAPS) to Valdez and shipped to markets in the lower 48 States. The facilities are assumed to be built incrementally, no earlier than 2005, with output volumes of 50,000 barrels per day, at a cost of $21,500 per barrel of daily capapcity (2001 dollars). Operating costs are assumed to be $3.99 per barrel. Transportation costs to ship the GTL product from the North Slope to Valdez along the TAPS range from $2.75 to $4.45 per barrel, depending on total oil flow on the pipeline and the potential need for GTL to maintain the viability of the TAPS line if Alaskan oil production declines. Initially, the natural gas feed is assumed to cost $0.82 per million cubic feet (2001 dollars).

It is also assumed that coal-to-liquids (CTL) facilities will be built when low sulfur distillate prices are high. One CTL facility is capable of processing 16,400 tons per day bituminous coal and will have a production capacity of 33,200 barrels per day of synthetic fuels and 696 MW of CHP electric generating capacity. CTL facilities are assumed to be built near existing refineries. For the East Coast, potential CTL facilities are assumed to be built near the Delaware River basin; for the Central region, near the Illinois River basin or near Billings, Montana; and for the West Coast, in the vicinity of Puget Sound in Washington State. The CTL yields are assumed to be similar to those from a GTL facility because both involve the Fischer-Tropsch process to convert syngas ($CO + H_2$) to liquid hydrocarbons. The primary yields would be distillate and kerosene, with additional yields of naphthas and LPG. Petroleum product production from CTL's is assumed to be competitive when distillate prices rise above the cost of CTL production – adjusted for credits from the sale of electricity co-products.

The coal market module (CMM) represents the mining, transportation, and pricing of coal, subject to end–use demand. Coal supplies are differentiated by heat and sulfur content. CMM also determines the minimum cost pattern of coal supply to meet exogenously defined U.S. coal export demands as a part of the world coal market. Coal supply is projected on a cost–minimizing basis, constrained by existing contracts. Twelve different coal types are differentiated with respect to thermal grade, sulfur content, and underground or surface mining. The domestic production and distribution of coal is forecast for 13 demand regions and 11 supply regions (Figures 19 and 20).

The CMM components are solved simultaneously. The sequence of solution among components can be summarized as follows. Coal supply curves are produced by the coal production submodule and input to the coal distribution submodule. Given the coal supply curves, distribution costs, and coal demands, the coal distribution submodule projects delivered coal prices. The module is iterated to convergence with respect to equilibrium prices to all demand sectors. The structure of the CMM is shown in Figure 21.

Coal Production Submodule

This submodule produces annual coal supply curves, relating annual production to minemouth prices. The supply curves are constructed from an econometric analysis of prices as a function of productive capacity, capacity utilization, and costs. A separate supply curve is provided for surface and underground mining for all significant production by coal rank (bituminous, subbituminous and lignite), coal grade (steam or metallurgical), and sulfur level in each supply region. Constructing curves for the coal types available in each region yields a total of 36 curves that are used as inputs to the coal distribution submodule. Supply curves are updated for each year in the forecast period.

The factors accounted for in constructing the supply curves are labor productivity and the costs of factor inputs (mining equipment, mine labor, and fuel). Labor productivity projections are developed and applied to each supply curve, based on historical data. The projections incorporate an assumption that the rate of improvement will decline as the rate of technology penetration slows. Labor costs are tied to labor productivity and wage rates. It is assumed, in the reference case, that wage rates keep pace with inflation.

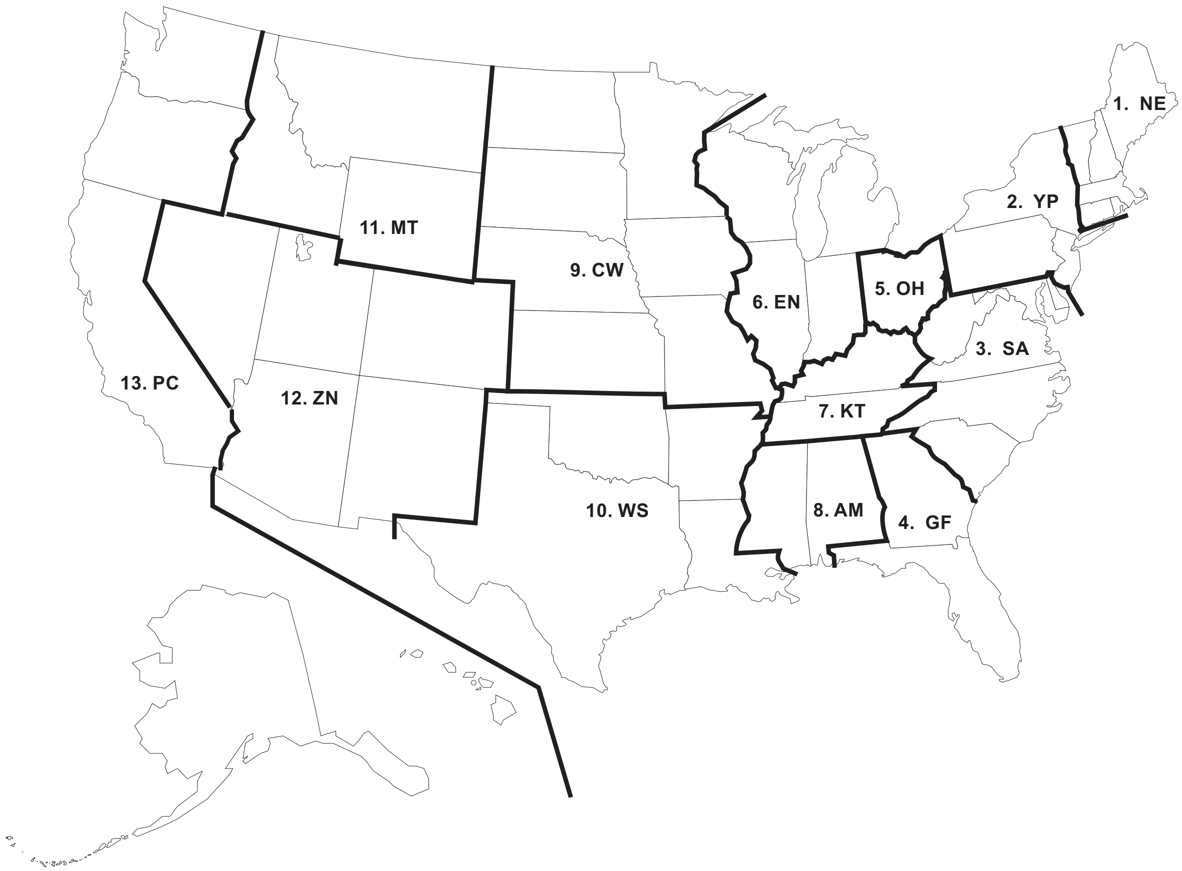
Coal Distribution Submodule

The coal distribution submodule is a linear program that determines the least–cost supplies of coal for a given set of coal demands by demand region and sector, accounting for transportation costs from the different supply curves, heat and sulfur content, existing coal supply contracts, technical limitations of older boiler types, and sulfur allowance costs under the Clean Air Act Amendments of 1990. Existing supply contracts between coal producers and utilities are incorporated in the model as minimum flows between specific supply curves and region–sulfur level combinations. The minimum flows are generally assumed to remain in effect for the duration of the contract and then be replaced by market–determined flows.

Coal transportation costs are simulated using interregional coal transportation costs derived by subtracting reported minemouth costs for each supply curve from reported delivered costs for each demand type in each demand region. Transportation rates are assumed to change in response to railroad labor productivity, labor costs, diesel fuel costs, and equipment costs. In recent years, railroad rates have de-

CMM Outputs	Inputs from NEMS	Exogenous Inputs
Coal production and distribution Minemouth coal prices End-use coal prices Coal exports Transportation rates Coal quality by source, destination, and end-use sector World coal flows	Coal demand Interest rates Price indices and deflators Diesel fuel prices Electricity prices	Base year productive capacity, capacity utilization, prices, and coal quality parameters Contract quantities Labor productivity Labor costs Labor cost escalators Domestic transportation costs International transportation costs International supply curves International coal import demands Demand for U.S. coal imports

Figure 19. Coal Market Module Demand Regions



Region Code	Region Content
1	New England
2	Middle Atlantic
3	South Atlantic
4	Georgia and Florida
5	Ohio
6	East North Central
7	Kentucky and Tennessee

Region Code	Region Content
8	Alabama and Mississippi
9	West North Central
10	West South Central
11	Montana, Wyoming, and Idaho
12	Mountain
13	Pacific

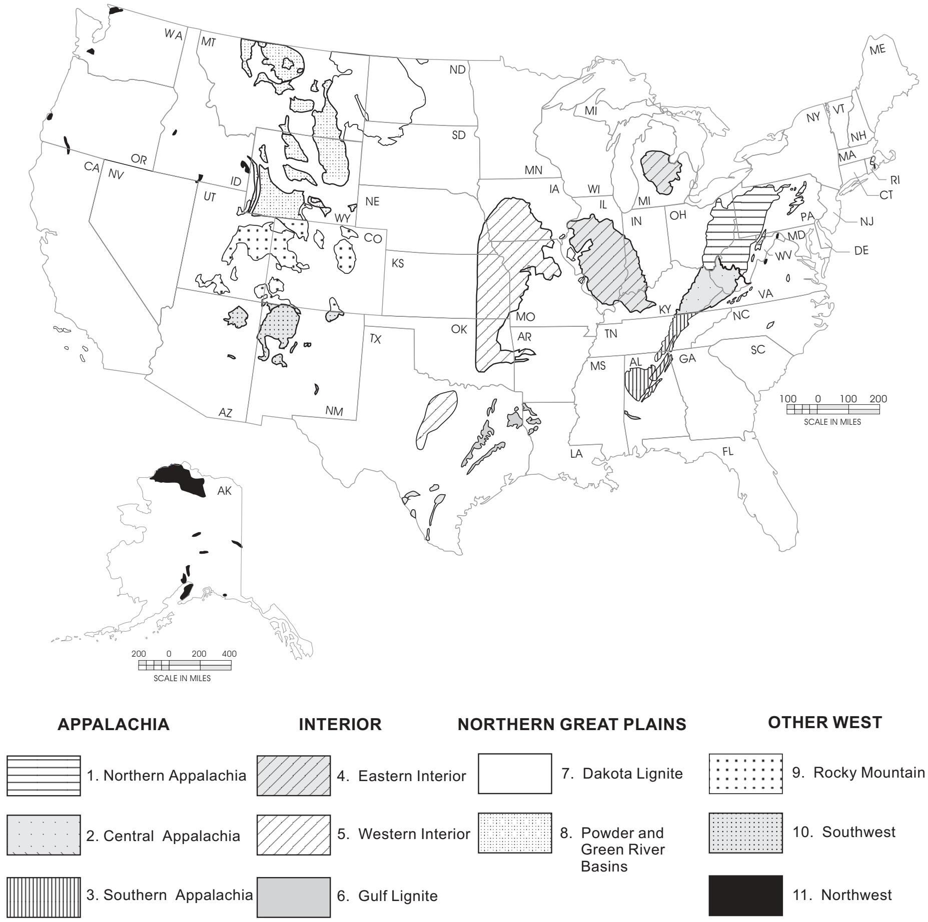
clined because of operating efficiencies from such measures as improved scheduling and lower fuel cost per ton–mile that have resulted from low crude oil prices, more efficient diesel engines, and larger and lighter aluminum cars.

Coal Export Component

The coal export component of the coal distribution submodule projects quantities of coal imported and exported from the United States. The quantities are determined within a world trade context, based on assumed characteristics of foreign coal supply and demand. The component disaggregates coal into 16 export regions and 20 import regions, as shown on the following page.

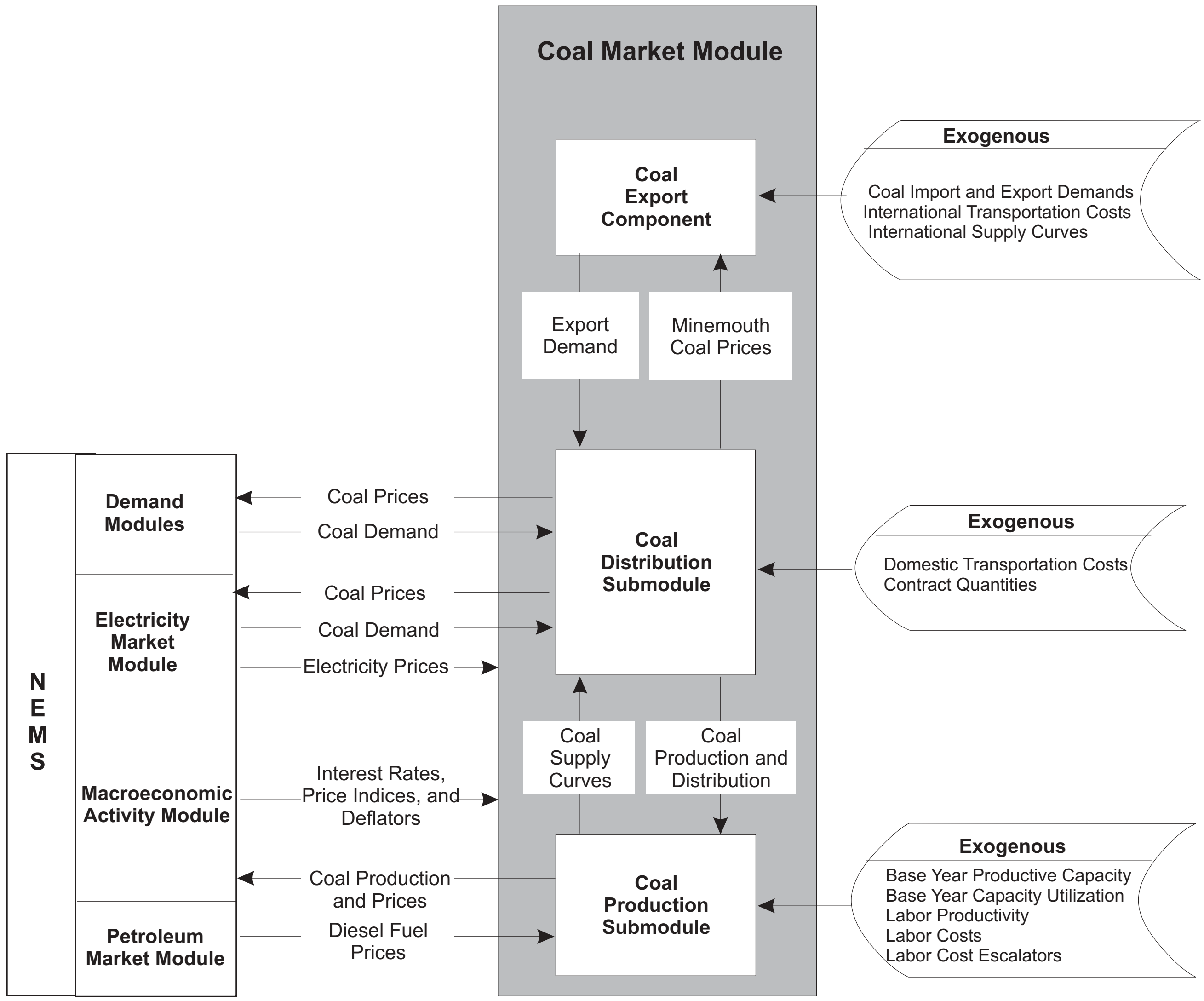
The export component is a part of the linear program that optimizes domestic coal supply. It determines world coal trade distribution by minimizing overall costs for coal, subject to U.S. coal supply prices and a number of constraints. Supply costs (mining and preparation plus transportation) for each coal export region, coal type, and end use compete in two demand sectors (coking and steam). The component also incorporates within the model structure supply diversity constraints that reflect the observed tendency of coal–importing countries to avoid excessive dependence upon one source of supply, even at a somewhat higher cost.

Figure 20. Coal Market Module Supply Regions



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
South Africa	Germany and Austria
Poland	Other Northwestern Europe
CIS (Europe)	Iberia
CIS (Asia)	Italy
China	Mediterranean and Eastern Europe
Colombia	Mexico
Indonesia	South America
Venezuela	Japan
	East Asia
	China and Hong Kong
	ASEAN (Association of Southeast Asian Nations)
	India and South Asia

Figure 21. Coal Market Module Structure



APPENDIX
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