PETROLEUM MARKET MODULE

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

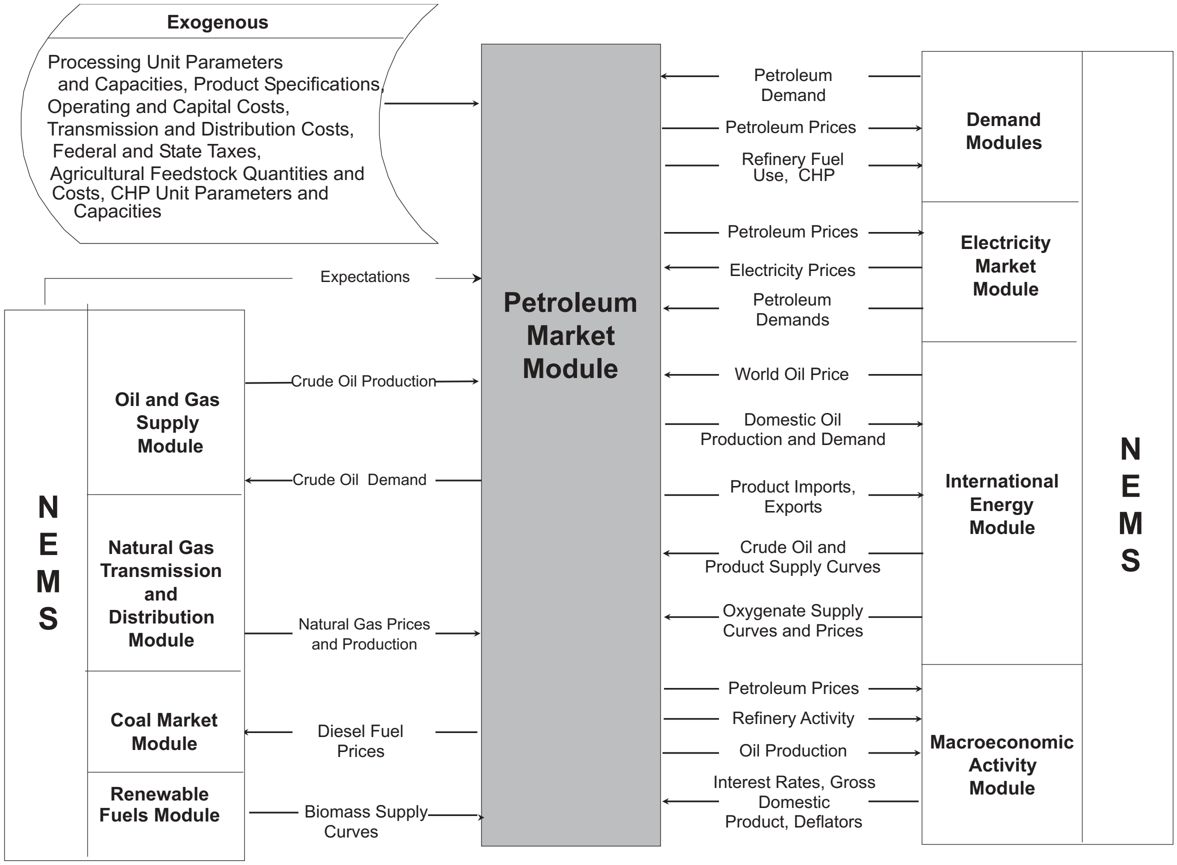
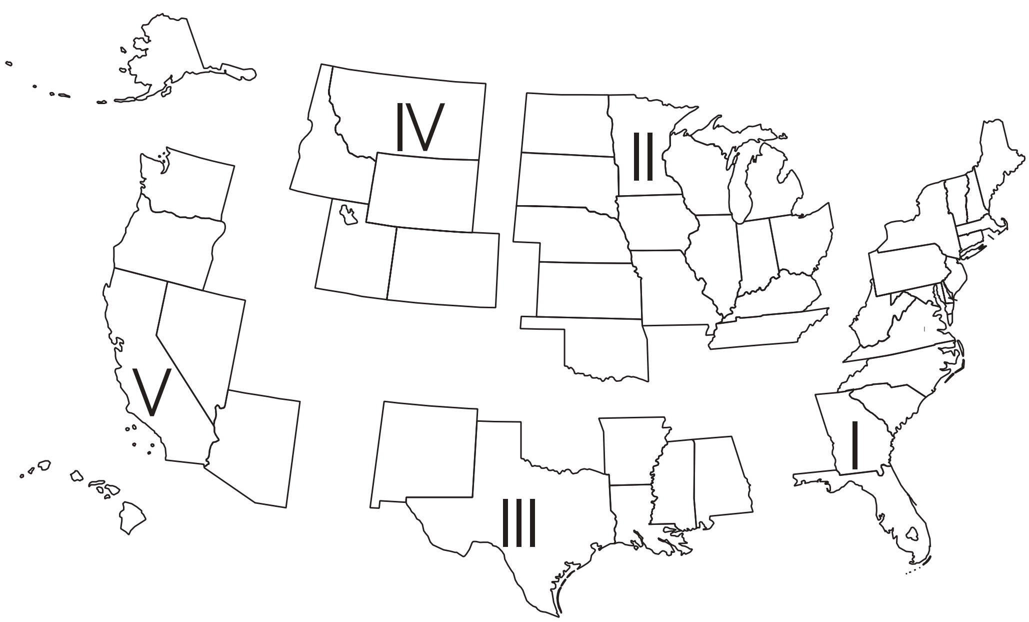


Figure 18. Petroleum Administration for Defense Districts



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.