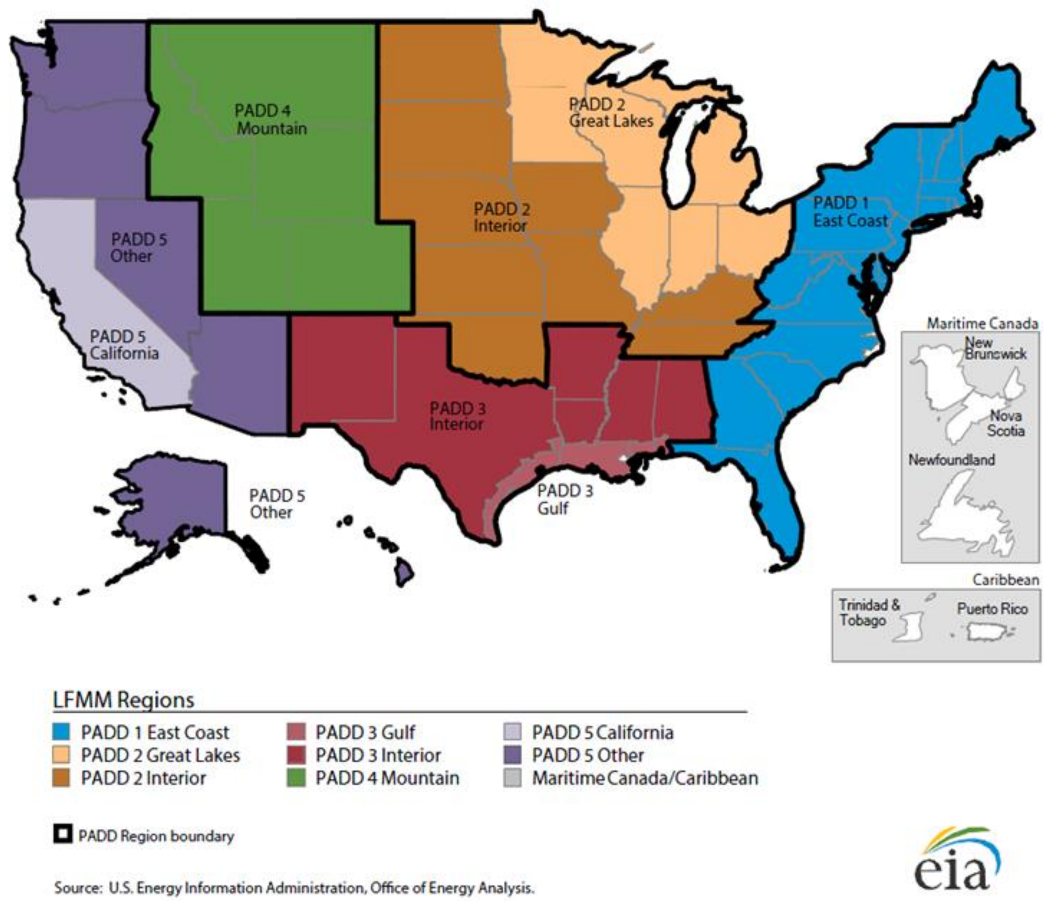
Chapter 11. Liquid Fuels Market Module

The NEMS Liquid Fuels Market Module (LFMM) projects petroleum product prices and sources of liquid fuels supply for meeting petroleum product demand. The sources of liquid fuels supply include petroleum-based fuels, such as crude oil (both domestic and imported), petroleum product imports, and unfinished oil imports. It also includes non-petroleum-based inputs, including alcohols, ethers, esters, corn, biomass, natural gas, and coal. In addition, liquid fuels supply includes natural gas plant liquids production and refinery processing gain. The LFMM also projects capacity expansion and fuel consumption at domestic refineries.

Figure 11.1. Liquid Fuels Market Module Regions



The LFMM contains a linear programming (LP) representation of U.S. petroleum refining activities, biofuels production activities, and other nonpetroleum liquid fuels production activity in eight U.S. regions. It also represents refining activity in the non-U.S. Maritime Canada/Caribbean refining region, which predominantly serves U.S. markets. In order to better represent policy, import/export patterns, and biofuels production, the eight U.S. regions are defined by subdividing three of the five Petroleum Administration for Defense Districts (PADDs) (Figure 11.1). The LP model also represents supply curves for crude imports and exports, petroleum product imports and exports, biodiesel imports, and advanced ethanol imports from Brazil. The nine LFMM regions and import/export curves are connected in the LP via crude and product transport links. In order to interact with other NEMS modules with different regional representations, certain LFMM inputs and outputs are converted from sub-PADD regions to other regional structures and vice versa. For example, the LP model converts end-use product prices from the LFMM regions (excluding the Maritime Canada/Caribbean region) into prices for the nine U.S. Census Divisions (shown in Figure 4.1) using the assumptions and methods described below.

Key assumptions

Product types and specifications

The LFMM models refinery production of the products shown in Table 11.1.

The LFMM assumes no change in the state and federal specifications for the products listed below. The costs of producing different formulations of gasoline and diesel fuel required under current regulations are determined within the LP representation of refineries.

Table 11.1. Petroleum product categories

Product Category	Specific Products
Motor Gasoline	Conventional, Reformulated (including CARB gasoline)
Jet Fuel	Kerosene-type
Distillates	Kerosene, Heating Oil, Low Sulfur, Ultra-Low Sulfur and CARB Diesel
Residual Fuels	Low Sulfur, High Sulfur
Liquefied Petroleum Gases	Ethane, Propane, Propylene, normal-Butane and iso-Butane
Petrochemical Feedstock	Petrochemical Naphtha, Petrochemical Gas Oil, Aromatics
Others	Lubricating Products and Waxes, Asphalt/Road Oil, Still Gas
	Petroleum Coke, Special Naphthas, Aviation Gasoline

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

Motor gasoline specifications and market shares

The LFMM models the production and distribution of two different types of gasoline: conventional and reformulated. The following specifications are included in the LFMM to differentiate between conventional and reformulated gasoline blends (Table 11.2): Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefins content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300). The LFMM incorporates the EPA Tier 3 program requirement that the sulfur content of delivered gasoline be no greater than 10 parts per million (PPM) by January 1, 2017. [11.1]

Table 11.2. Year-round gasoline specifications by Petroleum Administration for Defense District (PADD)

PADD/Type	Reid Vapor Pressure (Max PSI)	Aromatics Volume Percent (Max)	Benzene Volume Percent (Max)	Sulfur[1] PPM (Max)	Olefin Volume Percent (Max)	Percent Evaporated at 200° (Min)	Percent Evaporated at 300° (Min)
Conventional							
PADD I	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD II	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD III	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD IV	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD V	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
Reformulated							
PADD I	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD II	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD III	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD IV	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD V							
Nonattainment	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
CARB (attainment)	7.7	23.12	0.58	10/5.0	6.29	42.9	86.3

[1]Values reflect sulfur levels "prior to / after" January 1, 2017, to meet EPA final ruling: "EPA Sets Tier 3 Motor Vehicle Emission and Fuel Standards," https://www.epa.gov/fuels-registration-reporting-and-compliance-help/epa-webinar-slides-tier-3-gasoline-sulfur.
Max = maximum, Min = minimum, PADD = Petroleum Administration for Defense District. PPM = parts per million by weight, PSI = pounds per square inch.
Benzene volume percent changed to 0.62 for all regions and types in 2011 to meet the MSAT2 ruling.
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Reformulated gasoline must meet the Complex Model II compliance standards, which cannot exceed average 1990 levels of toxic and nitrogen oxide emissions [11.2]. Reformulated gasoline has been required in many areas in the United States since January 1995. In 1998, EPA began certifying reformulated gasoline using the "Complex Model," which allows refiners to specify reformulated gasoline based on emissions reductions from their companies' respective 1990 baselines or EPA's 1990 baseline. The LFMM reflects "Phase 2" reformulated gasoline requirements which began in 2000. The LFMM uses a set of specifications that meet the "Complex Model" requirements, but it does not attempt to determine the optimal specifications that meet the "Complex Model."

Cellulosic biomass feedstock supplies and costs are provided by the NEMS Renewable Fuels Model. Initial capital costs for biomass cellulosic ethanol were obtained from a research project reviewing cost estimates from multiple sources [11.3]. Operating costs and credits for excess electricity generated at biomass ethanol plants were obtained from a survey of literature [11.4].

Corn supply prices are estimated from the USDA baseline projections to 2019 [11.5]. Operating costs of corn ethanol plants are obtained from USDA survey of ethanol plant costs [11.6]. Energy requirements are obtained from a study of carbon dioxide emissions associated with ethanol production [11.7].

AEO2017 assumes a minimum 10% blend of ethanol in domestically-consumed motor gasoline. Federal reformulated gasoline (RFG) and conventional gasoline can be blended with up to 15% ethanol (E15) in light-duty vehicles of model year 2001 and later. Reformulated and conventional gasoline can also be blended with 16% biobutanol. Actual levels will depend on the ethanol and biobutanol blending value and relative cost-competitiveness with other gasoline blending components. In addition, current state regulation, along with marketplace constraints, limit the full penetration of E15 in the projection. The Energy Independence and Security Act of 2007 (EISA2007) defines a requirements schedule for having renewable fuels blended into transportation fuels by 2022.

RVP limitations are in effect during summer months, and typically are defined differently by consuming region. In addition, different RVP specifications apply within each PADD. The LFMM assumes that these variations in RVP are captured in the annual average specifications, which are based on summertime RVP limits, wintertime estimates, and seasonal weights.

Within the LFMM, total gasoline demand is disaggregated into demand for conventional and reformulated gasoline by applying assumptions about the annual market shares for each type. In AEO2017, the annual market shares for each region reflect actual 2010 market shares and are held constant throughout the projection (see Table 11.3 for AEO2017 market share assumptions).

Table 11.3. Percent in market share for gasoline types by Census Division

Gasoline Type	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Conventional Gasoline	14	35	81	85	83	95	69	82	26
Reformulated Gasoline	86	65	19	15	17	5	31	18	74

Note: Data derived from EIA-782C, “Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption,” January-December 2015.
Note: As of January 2007, Oxygenated Gasoline is included within Conventional Gasoline.
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Diesel fuel specifications and market shares

In order to account for ultra-low sulfur diesel (ULSD, or highway diesel) regulations related to the Clean Air Act Amendments of 1990 (CAAA90), ULSD is differentiated from other distillates. In NEMS, the California portion of the Pacific Region (Census Division 9) is required to meet California Air Resources Board (CARB) standards. Both Federal and CARB standards currently limit sulfur to 15 parts per million (ppm).

AEO2017 incorporates the “nonroad, locomotive, and marine” (NRLM) diesel regulation finalized in May 2004 for large refiners and importers. The final NRLM rule established a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. For locomotive and marine diesel, the rule established an ULSD limit of 15 ppm in mid-2012.

Demand for ULSD in LFMM is assumed to be the sum of total transportation distillate demand, 85% of industrial distillate demand, and 49% of commercial distillate demand. LFMM also differentiates ultra-low sulfur fuel oil demands as mandated in some states – New York, New Jersey, Maine, and Vermont.

End-use product prices

End-use petroleum product prices are based on marginal costs of production, plus production-related fixed costs, plus distribution costs and taxes. The marginal costs of production are determined within the LP and represent variable costs of production, including additional costs for meeting reformulated fuels provisions of CAAA90. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding product-specific distribution costs to the marginal refinery production costs (product wholesale prices). The distribution costs are derived from a set of base distribution markups (Table 11.4).

State and federal taxes are also added to transportation fuels to determine final end-use prices (Tables 11.5 and 11.6). Tax trend analysis indicates that state taxes increase at the rate of inflation; therefore, state taxes are held constant in real terms throughout the projection. This assumption is extended to local taxes, which are assumed to average 1% of motor gasoline prices [11.8]. Federal taxes are assumed to remain at current levels in accordance with the overall AEO2017 assumption of current laws and regulations. Federal taxes are not held constant in real terms, but are deflated as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$$

Crude oil quality

In the LFMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into eleven categories as defined by the ranges of gravity and sulfur shown in Table 11.7.

A “composite” crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams in the category. Each category includes both domestic and foreign crude oil, which are both used to determine category characteristics. For each category’s domestic crude oil volumes, estimates of total regional production are made first. Each region’s production is then divided among each of the eleven categories based on that region’s distribution of average API gravity and sulfur content. For AEO2017, in accordance with the Consolidated Appropriations Act, 2016 [11.9], all crude types are allowed to be exported from the United States. For imported crude oil, a separate supply curve is provided (by the IEM) for each category.

In accordance with the "Bipartisan Act of 2015" and the "H.R. 22 – FAST Act," AEO2017 models the mandated SPR drawdown over 2016 to 2025. [11.10, 11.11] The SPR projected sales volumes were converted from Fiscal Year accounting to calendar year levels using a 0.25/0.75 split between last calendar year and current calendar year. Also, the crude volumes were assumed to be 40% light sweet (API 35-40, sulfur < 0.5%) and 60% medium sour (API 27-35, sulfur ≥ 1.1%).

Table 11.4. Petroleum product end-use markups by sector and Census Division

2016 dollars per gallon

			Census Division						
Sector/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Residential Sector									
Distillate Fuel Oil	0.68	0.81	0.48	0.42	0.76	0.72	0.57	0.41	0.78
Kerosene	0.19	0.87	0.79	0.80	0.65	1.29	0.74	0.89	0.00
Liquefied Petroleum Gases	1.23	1.21	0.81	0.76	1.09	1.24	1.00	0.71	0.90
Commercial Sector									
Distillate Fuel Oil	0.37	0.09	0.09	0.07	0.10	0.09	0.05	0.22	0.24
Gasoline	0.18	0.17	0.17	0.15	0.15	0.18	0.14	0.21	0.22
Kerosene	0.19	0.90	0.78	0.83	0.65	1.19	0.56	0.85	0.00
Liquefied Petroleum Gases	0.30	0.35	0.34	0.34	-0.17	0.36	0.37	0.22	0.11
Low-Sulfur Residual Fuel Oil[1]	0.00	-0.31	0.00	0.00	-0.09	-0.03	0.23	0.00	0.00
Utility Sector									
Distillate Fuel Oil	-0.09	0.41	0.08	-0.04	0.20	-0.10	-0.08	0.30	0.22
Residual Fuel Oil[1]	0.00	-0.14	0.00	0.00	-0.20	-0.25	-0.69	0.00	0.59
Transportation Sector									
Distillate Fuel Oil	0.36	0.57	0.65	0.66	0.44	0.68	0.66	0.60	0.65
E85[2]	0.16	0.15	0.13	0.11	0.12	0.13	0.10	0.17	0.16
Gasoline	0.21	0.20	0.17	0.15	0.16	0.17	0.14	0.22	0.21
High-Sulfur Residual Fuel Oil[1]	0.00	-0.03	-0.11	-0.56	-0.01	-0.44	-0.60	0.00	0.96
Jet Fuel	-0.01	-0.01	0.00	0.00	-0.01	-0.10	-0.04	0.00	-0.05
Liquefied Petroleum Gases	0.28	0.45	1.20	1.21	0.11	1.12	0.89	0.72	0.72
Industrial Sector									
Asphalt and Road Oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate Fuel Oil	0.27	0.11	0.21	0.17	0.27	0.20	0.19	0.29	0.31
Gasoline	0.21	0.19	0.17	0.15	0.16	0.18	0.13	0.21	0.22
Kerosene	0.01	0.23	0.03	-0.01	-0.02	0.52	-0.06	0.36	0.00
Liquefied Petroleum Gases	0.77	0.85	0.39	0.40	0.62	0.32	-0.30	0.53	0.21
Low-Sulfur Residual Fuel Oil[1]	0.00	-0.31	0.00	0.00	-0.03	0.08	0.17	-0.14	0.00

[1]Negative values indicate that average end-use sales prices were less than wholesale prices. This often occurs with residual fuel which is produced as a byproduct when crude oil is refined to make higher-value products like gasoline and heating oil.

[2]E85 refers to a blend of 85% ethanol (renewable) and 15 % motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% is used.

Note: Data from markups based on Form EIA-782A, Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report; EIA, Form EIA-782B, Resellers'/Retailers' Monthly Petroleum Report Product Sales Report; Form FERC-423, Monthly Report of Cost and Quality of Fuels for Electric Plants prior to 2008; Form EIA-923, Power Plant Operations Report starting in 2008; EIA Form EIA-759 Monthly Power Plant Report; EIA, State Energy Data Report 2014, Consumption (June 2016); EIA, State Energy Data 2014: Prices and Expenditures (June 2016).

Sources: U.S. Energy Information Administration (EIA), Office of Energy Analysis.

Table 11.5. State and local taxes on petroleum transportation fuels by Census Division

2016 dollars per gallon

	Census Division								
Year/Product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East south Central	West South Central	Mountain	Pacific
Gasoline[1]	0.33	0.28	0.27	0.26	0.23	0.24	0.24	0.25	0.26
Diesel	0.30	0.35	0.24	0.24	0.24	0.20	0.20	0.24	0.34
Liquefied Petroleum Gases	0.14	0.14	0.20	0.22	0.21	0.20	0.16	0.16	0.07
E85[2]	0.23	0.25	0.19	0.18	0.15	0.16	0.16	0.17	0.28
Jet Fuel	0.08	0.06	0.01	0.04	0.08	0.08	0.03	0.05	0.04

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.
[2]E85 refers to a blend of 85% ethanol (renewable) and 15% motor gasoline (non-renewable). To address cold starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% is used.
Source: American Petroleum Institute, "September 2015 State Motor Fuel Taxes by State," September 2015, http://www.api.org/oil-and-natural-gas/consumer-information/motor-fuel-taxes

Table 11.6. Federal taxes

nominal dollars per gallon

Product	Tax
Gasoline	0.180
Diesel	0.242
Jet Fuel	0.043
E85[1]	0.200

[1]74% ethanol and 26% gasoline.
Note: IRS Internal Revenue Bulletin 2006-43 available on the web at www.irs.gov/pub/irs-irbs/irb06-43.pdf.
Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34), Clean Fuels Report (Washington, DC, April 1998) and Energy Policy Act of 2005 (PL 109-58).

Table 11.7. Crude oil specifications

Crude oil categories	a.k.a.	Sulfur (%)	Gravity (degrees API)
API 50+	Light Sweet	<0.5	API≥50
API 40-50	Light Sweet	<0.5	40≤API<50
API 35-40 sweet	Light Sweet	<0.5	35≤API<40
API 35+ sour	Light Sour	≥0.5	API≥35
API 27-35 Med-sour	Medium Med-sour	<1.1	27≤API<35
API 27-35 sour	Medium Sour	≥1.1	27≤API<35
API<27 sweet	Heavy Sweet	<1.1	API<27
API<27 sour	Heavy Sour	≥1.1	API<27
California		1.1-2.6	API<27
Syncrude		<0.5	API≥35
DilBit/SynBit		>1.1	API<27

Note: Sources include U.S. Energy Information Administration, "U.S. Crude Oil Production Forecast- Analysis of Crude Types,"
Dilbit/Synbit definition = Bitumen diluted with lighter petroleum products or synthetic crude
May 29, 2014, (http://www.eia.gov/analysis/petroleum/crudetypes/
Sources: U.S. Energy Information Administration.

Capacity expansion

The LFMM allows for capacity expansion of all processing unit types. This includes distillation units like the atmospheric distillation unit (ADU), vacuum distillation unit (VDU), and condensate splitters, as well as secondary processing units like the hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation units. Capacity expansion occurs by processing unit, starting from regional capacities established using historical data.

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

The LFMM models capacity expansion using a three-period planning approach similar to that used in the NEMS Electricity Market Module (EMM). The first two periods contain a single planning year (current year and next year, respectively), and the third period represents a net present value of the next 19 years in the projection. The second and third planning periods are used to establish an economic plan for capacity expansion for the next NEMS model year. In period 2, product demands and legislative requirements must be met. Period 3 acts like a leverage in the capacity expansion decision for period 2, and is controlled by the discount rate assumptions. Larger discount rates increase the net present value (NPV) of revenue and expenditures in earlier periods and decrease the NPV of revenue and expenditure in later periods. The LFMM uses multiple discount rates for the NPV calculation to represent various categories of risk. For AEO2017, the LFMM uses an 18% discount rate.

Capacity expansion is also modeled for production of corn and cellulosic ethanol, biobutanol, biomass pyrolysis oil, biodiesel, renewable diesel, coal-to-liquids, gas-to-liquids, and biomass-to-liquids. All process unit capacity that is expected to begin operating in the future is added to existing capacities in their respective start year. The retirement and replacement of existing refining capacity is not explicitly represented in the LFMM.

Capacity utilization of a process unit is the ratio of the actual throughput for a unit to the total capacity for that unit. The throughput for an atmospheric distillation unit (ADU) typically is a blend of crude oils, but historically has included unfinished oil imports at some refineries. Therefore, historical ADU capacity utilization at these refineries includes both crude oil and unfinished oil imports. Since the LFMM only processes unfinished oil imports in secondary units, downstream from the ADU, an assumption was made to include a historical percentage of the unfinished oils imported to the refinery as part of the throughput when calculating the ADU capacity utilization reported in AEO2017.

Non-petroleum fuel technology characteristics

The LFMM explicitly models a number of liquid fuels technologies that do not require petroleum feedstock. These technologies produce both fuel-grade products for blending with traditional petroleum products, and alternative feedstock for the traditional petroleum refinery (Table 11.8).

Table 11.8. Alternative fuel technology product type

Technology	Product Type	Feedstock	Product Yield (percent by volume)
Biochemical			
Corn Ethanol	Fuel Grade	corn	100% ethanol
Advanced Grain Ethanol	Fuel Grade	grain	100% ethanol
Cellulosic Ethanol	Fuel Grade	stover	100% ethanol
Biobutanol	Fuel Grade	corn	biobutanol
Thermochemical Catalytic			
Methyl Ester Biodiesel	Fuel Grade	yellow or white grease	100% biodiesel
Non-Ester Renewable Diesel	Fuel Grade	yellow or white grease	98% renewable diesel, 2% renewable naphtha
Pyrolysis	Fuel Grade	agriculture residue, forest residue, or urban wood waste	60% distillate, 40% naphtha
Thermochemical Fischer-Tropsch			
Gas-to-Liquids (GTL)	Fuel Grade/Refinery Feed	natural gas	52% diesel, 23% kerosene, 24.5% naphtha, 0.5% LPG
Coal-to-Liquids (CTL)	Fuel Grade/Refinery Feed	coal	51% diesel, 21% kerosene, 28% naphtha
Biomass-to-Liquids (BTL)	Fuel Grade/Refinery Feed	biomass	22% diesel, 46% kerosene, 32% naphtha

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

Estimates of capital and operating costs corresponding to specified nameplate capacities for these technologies are shown in Table 11.9. The cost data are defined assuming a 2020 base year, and are deflated to 2016 dollars using the GDP deflator in NEMS.

Overnight capital cost is defined as the anticipated cost of completing a project from start to finish, including working capital, but excluding time-related costs such as accrued interest and depreciation of assets (i.e., the lump sum cost of a project as if it were completed overnight). Since some components of technologies have not yet been proven at a commercial scale, a technology optimism factor is applied to the assumed first-of-a-kind overnight capital cost, a multiplier that increases the first-of-a-kind plant cost (e.g., 1.2 for BTL). The multiplier is an estimate of the underestimated construction errors (redos) and underestimated costs in building the first full-scale commercial plant. As experience is gained (after building the first 4 units), the technological optimism factor is gradually reduced to 1.0, after which the overnight capital cost may be reduced due to learning.

The learning function has the nonlinear form:

$$OC(C) = a*C-b,$$

where C is the cumulative capacity (or number of standard-sized units) for each technology component and OC represents the overnight capital cost expected with cumulative capacity C of the technology.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary, or mature. Different learning rates are assumed for each component, based on the level of construction experience with the component. In the case of the LFMM, the second and third phases of a technology will have only evolutionary/revolutionary (fast) and mature (slower) learning components, depending on the mix (percent) of new and mature processes that compose a particular technology.

The progress ratio (pr) is related by the speed of learning or learning rate (LR) (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (i.e., LR) is an exogenous input parameter for each component. The progress ratio and LR are related by:

$$pr = 2^{-b} = (1 - LR).$$

The parameter "b" is calculated from the second half of the equality above:

$$b = -(\ln(1-LR)/\ln(2)).$$

The parameter "a" is computed from initial overnight cost and capacity conditions of the nonlinear learning curve:

$$a = OC\,(C0)/Co^{-b}$$

Note that Co is the cumulative capacity or number of units built as of the beginning of the current time period/year.

As a new technology matures, the capital cost is expected to decline, reflecting the principle of "learn by doing" and manufacturing experience. This principle is implemented in the LFMM similar to the methodology used in the EMM. The learning occurs in three phases. The first phase is represented by the linear phase out of optimism (and some revolutionary learning) over the first four plants (such that the optimism factor for the fifth and later plant is 1.0). The non-linear learning function shown above is used for the second (up to 32 plants built) and third (beyond 32 plants) phases.

Each technology was assessed to determine the mix of technological maturity of each component (revolutionary/evolutionary or mature). This was used to define what percent (m) of the cost would decline slowly (slow for mature) versus quickly (fast for evolutionary/revolutionary) due to learning. Next, for each learning category (fast and slow), a rate of learning (f) is assumed (i.e., a percent reduction in overnight capital cost for every doubling of cumulative capacity).

The overall learning factor is the weighted combination of the fast and slow learning factors (OC), weighted by the percentage that each component represents of the technology. Model parameters for both optimism (1st of a kind) and learning (after the 4th unit is built) are shown in Table 11.10 for applicable technologies.

Table 11.9. Non-petroleum fuel technology characteristics[1]

AEO2017 2020 Basis (2016$)	Nameplate Capacity[2] b/sd	Overnight Capital Cost[3] $/b/sd	Thermal Efficiency[4] %	Utilization Rate[5] %	Cost of Capital[6] (WACC) %	Fixed O&M Cost[7] $/d/b/sd	Non-Feedstock Variable O&M Cost[7] $/b
Biochemical							
Corn Ethanol	6,800	$25,900	49%	100%	12%	$7	$7
Advanced Grain Ethanol	3,400	$61,900	49%	100%	12%	$19	$3
Cellulosic Ethanol	4,400	$195,300	28%	85%	12%	$39	$1
Biobutanol (retrofit of corn ethanol plant)	6,500	$13,500	62%	90%	12%	$2	$7
Thermochemical Catalytic							
Methyl Ester Biodiesel (FAME)	1,200	$28,200	21%	100%	12%	$22	$7
Non-Ester Renewable Diesel (NERD)	2,100	$40,000	21%	95%	12%	$23	$7
Pyrolysis	5,200	$394,600	60%	90%	12%	$69	$6
Thermochemical Fischer-Tropsch							
Gas-to-Liquids (GTL)[8]	48,000	$197,800	55%	85%	12%	$32	$9
Coal-to-Liquids (CTL)	48,000	$246,200	49%	85%	15%	$39	$12
Biomass-to-Liquids (BTL)	6,000	$448,800	38%	85%	12%	$73	$8

[1]This table is based on the AEO2017 Reference case projections for year 2020.
[2]Nameplate capacity is the expected size of a unit based on historical builds and engineering estimations. Capacity amounts provided on an output basis.
[3]Overnight capital cost is given in unit costs, relative to nameplate capacity and is defined as the cost of a project with no interest incurred, or the lump sum cost of a project as if it were completed overnight. It excludes additional costs from optimism on the 1st unit, and cost reductions on the nth unit due to learning effects (see Table 11.10).
[4]Thermal efficiency represents the ratio of the combustive energy of the products to the combustive energy of the feedstock used to produce the products.
[5]Utilization rate represents the expected annual production divided by the plant capacity divided by 365 days.
[6]Cost of Capital is the weighted average cost of capital (WACC) during construction and lifetime operations. This term is used with the plant lifetime and overnight capital cost to compute an amortized unit capital cost ($/b/sd for a year).
[7]Fixed and Non-Feedstock variable operations and maintenance (O&M) costs impact the annual costs ($/year) and units costs ($/b).
[8]While these costs are for a Gulf Coast facility, the costs in other regions, particularly Alaska, are expected to be much higher.
b/sd = barrels per stream day.
$/b/sd = dollars per barrel per stream day
Note 1: For all technologies listed, length of construction is assumed to be 4 years and plant lifetime is assumed to be 20 years; where, length of construction impacts the interest that accrues during construction, and plant lifetime impacts the amortized cost of capital.
Note 2: Values from this table come from analysis of reports and discussions with various sources from industry, government, and the U.S. Department of Energy Fuel Offices and National Laboratories. They are meant to represent the cost and performance of typical plants under normal operating conditions for each technology.
Key sources reviewed are listed in "Notes and Sources" at the end of the chapter.
Source: U.S. Energy Information Administration.

Table 11.10. Non-petroleum fuel technology learning parameters

Technology Type	Cumulative Plants (k)	Phase 1 1st of a Kind Optimism	Phase 2 5th of a Kind Fast[1]	Phase 2 5th of a Kind Slow[1]	Phase 3 32nd of a Kind Fast[1]	Phase 3 32nd of a Kind Slow[1]
Cellulosic Ethanol	Optimism Factor and Revolutionary Learning	1.20	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	33%	67%	33%	67%
	Learning Rate (f)	--	0.25	0.10	0.10	0.05
Pyrolysis	Optimism Factor and Revolutionary Learning	1.20	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	33%	67%	33%	67%
	Learning Rate (f)	--	0.25	0.10	0.10	0.05
Biomass-to-Liquids (BTL)	Optimism Factor and Revolutionary Learning	1.20	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	15%	85%	15%	85%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01
Coal-to-Liquids (CTL)	Optimism Factor and Revolutionary Learning	1.15	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	15%	85%	15%	85%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01
Gas-to-Liquids (GTL)	Optimism Factor and Revolutionary Learning	1.10	1.0	1.0	1.0	1.0
	Learning Type Fraction (m)	--	10%	90%	10%	90%
	Learning Rate (f)	--	0.10	0.01	0.10	0.01

[1]Fast = evolutionary/revolutionary learning; slow = mature learning.

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

Biofuels supply

Supply functions for corn, non-corn grain, and cellulosic biomass feedstocks are provided on an annual basis through 2050 for the production of ethanol (blended into transportation fuel). Supply functions for soy oil, other seed-based oils, and grease are provided on an annual basis through 2050 for the production of biodiesel and renewable diesel.

- Corn feedstock supplies and costs are provided exogenously to NEMS. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Feedstock supplies and costs reflect the competition between corn and its co-products and alternative crops, such as soybeans and their co-products.

- Biodiesel and renewable diesel feedstock supplies and costs are provided exogenously to NEMS.
- Cellulosic (biomass) feedstock supply and costs are provided by the Renewable Fuels Module in NEMS.
- To model the Renewable Fuel Standard in EISA2007, several assumptions were required.
    - The penetration of cellulosic ethanol into the market is limited before 2023 to several planned projects with aggregate nameplate capacity of approximately 60 million gallons per year. Planned capacity through 2019 for pyrolysis and biomass-to-liquids (BTL) processes is approximately 75 million gallons per year.
    - Methyl ester biodiesel production contributes 1.5 credits towards the advanced mandate.
    - Renewable diesel fuel and cellulosic diesel fuel, including that from pyrolysis oil, and Fischer-Tropsch diesel contribute 1.7 credits toward the cellulosic mandate.
    - Cellulosic drop-in gasoline contributes 1.54 credits toward the cellulosic mandate.
    - Imported Brazilian sugarcane ethanol counts towards the advanced renewable mandate.
    - Separate biofuel waivers can be activated for each of the four RFS fuel categories.
    - Biodiesel and BTL diesel are assumed to be compatible with diesel engines without significant infrastructure modification (either vehicles or delivery infrastructure).
    - Ethanol is assumed to be consumed as E10, E15 or E85, with no intermediate blends. The cost of placing E85 pumps at the most economic stations is spread over diesel and gasoline.
    - To accommodate the ethanol requirements in particular, transportation modes are expanded or upgraded for E10, E15 and E85, and it is assumed that most ethanol originates from the Midwest, with nominal transportation costs of a few cents per gallon.
    - For E85 dispensing stations, it is assumed the average cost of a retrofit and new station is about $160,000 per station (2016 dollars). Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in the LFMM.
    - Potential RFS target reductions by EPA are provided exogenously to NEMS.

Non-petroleum fossil fuel supply

Gas-to-liquids (GTL) facilities convert natural gas into distillates, and are assumed to be built if the prices for lower-sulfur distillates reach a high enough level to make them economic. The earliest start date for a GTL facility is set at 2024.

It is also assumed that coal-to-liquids (CTL) facilities will be built when low-sulfur distillate prices are high enough to make them economic. A 48,000-barrel-per-day CTL facility is assumed to cost nearly $7.4 billion in initial capital investment (2016 dollars). These facilities could be built near existing refineries. For the East Coast, potential CTL facilities could 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. It is further assumed that the earliest build date for CTL facilities is 2028.

Combined heat and power (CHP)

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

Short-term methodology

Petroleum balance and price information for 2016 and 2017 is projected at the U.S. level in the Short-Term Energy Outlook, (STEO). The LFMM adopts the STEO results for 2016 and 2017, using regional estimates derived from the national STEO projections.

Legislation and regulation

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the federal gasoline tax on a Btu basis.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and on-highway diesel fuel. These are explicitly modeled in the LFMM. Reformulated gasoline represented in the LFMM meets the requirements of Phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications.

AEO2017 reflects “Tier 3 Vehicle Emissions and Fuel Standards” which states that the average annual sulfur content of federal gasoline will not contain more than 10 ppm by January 1, 2017. For projection years prior to 2017, AEO2017 reflects the “Tier 2” Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements which requires that the average annual sulfur content of all gasoline used in the United States be 30 ppm.

AEO2017 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. All highway diesel is required to contain no more than 15 ppm sulfur at the pump.

AEO2017 reflects nonroad locomotive and marine (NRLM) diesel requirements that nonroad diesel supplies contain no more than 15 ppm sulfur. For locomotive and marine diesel, the action establishes a NRLM limit of 15 ppm in mid-2012.

AEO2017 represents major provisions in the Energy Policy Act of 2005 (EPACT05) concerning the petroleum industry, including removal of the oxygenate requirement in RFG.

AEO2017 includes provisions outlined in the Energy Independence and Security Act of 2007 (EISA2007) concerning the petroleum industry, including a Renewable Fuel Standard (RFS) increasing total U.S. consumption of renewable fuels. In order to account for the possibility that RFS targets might be unattainable at reasonable cost, LFMM includes a provision for purchase of waivers. The price of a cellulosic waiver is specified in EISA2007. The non-cellulosic LFMM RFS waivers function as maximum allowed RIN prices. LFMM also assumes that EPA will reduce RFS targets as allowed by the EISA2007 statute.

AEO2017 includes the EPA Mobil Source Air Toxics (MSAT 2) rule which includes the requirement that all gasoline products (including reformulated and conventional gasoline) produced at a refinery during a calendar year will need to contain no more than 0.62 percent benzene by volume. This does not include gasoline produced or sold in California, which is already covered by the current California Phase 3 Reformulated Gasoline Program.

AEO2017 includes California's Low Carbon Fuel Standard which aims to reduce the Carbon Intensity (CI) of gasoline and diesel fuels in that state by about 10% respectively from 2012 through 2020.

AEO2017 incorporates the cap-and-trade program within the California Assembly Bill (AB 32), the Global Warming Solutions Act of 2006. The program started January 1, 2012, with enforceable compliance obligations beginning in 2013. Petroleum refineries are given allowances (calculated in the LFMM) in the cap-and-trade system based on the volumetric output of aviation gasoline, motor gasoline, kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. Suppliers of reformulated blend stock for oxygenate blending (RBOB) and Distillate Fuel Oil #1 and #2 are required to comply starting in 2015 if the emissions from full combustion of these products are greater than or equal to 25,000 metric tons CO_2 equivalent ($MTCO_2e$) in any year 2011-2014.

AEO2017 includes mandates passed by New York, New Jersey, Maine, and Vermont that aim to lower the sulfur content of all heating oil to ultra-low sulfur diesel over different time schedules. It also includes transition to a 2% biodiesel content in the case of Maine and Connecticut.

The International Maritime Organization's "MARPOL Annex 6" rule covering cleaner marine fuels and ocean ship engine emissions is not explicitly represented in LFMM, but is reflected in the impact on transportation demands, which are provided to the LFMM from the Transportation Demand Module (TDM) in NEMS.

The AEO2017 Reference Case does not extend the $1.00-per-gallon biodiesel excise tax credit or the $1.01-per-gallon cellulosic biofuels production tax credit over the projection.

Notes and sources

[11.1] U.S. Environmental Protection Agency (EPA), "EPA Sets Tier 3 Vehicle Emission and Fuel Standards," http://www.epa.gov/otaq/documents/tier3/420f14009.pdf.

[11.2] Federal Register, U.S. Environmental Protection Agency, 40 CFR Part 80, Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline, Rules and Regulations, p. 7800, (Washington, DC, February 1994).

[11.3] Marano, John, "Alternative Fuels Technology Profile: Cellulosic Ethanol", March 2008.

[11.4] Ibid.

[11.5] U.S. Department of Agriculture, "USDA Agricultural Baseline Projections to 2019," February 2009, www.ers.usda.gov/publications/oce-usda-agricultural-projections/oce-2010-1.aspx.

[11.6] Shapouri, Hosein and Gallagher, Paul. USDA's 2002 Ethanol Cost-of-Production Survey, July 2005.

[11.7] U.S. Department of Agriculture. 2008 Energy Balance for the Corn-Ethanol Industry, June 2010.

[11.8] American Petroleum Institute, How Much We Pay for Gasoline: 1996 Annual Review, May 1997.

[11.9] *Consolidated Appropriations Act, 2016*, H.R.2029, 114th Congress (2015-2016), *Division O – Other Matters, Title I – Oil Exports, Safety Valve, and Maritime Security*, became Public Law No: 114-113 on 12/18/2015; https://www.congress.gov/bill/114th-congress/house-bill/2029.

[11.10] U.S. Congress, "H.R. 1314 – Bipartisan Budget Act of 2015," Title IV--Strategic Petroleum Reserve, Sec. 401-403, 114th Congress (2015-2016), https://www.congress.gov/bill/114th-congress/house-bill/1314/text#toc-H2D8D609ED2A3417887CC3EAF49A81E15 .

[11.11] U.S. Congress, "H.R. 22 – FAST Act," Sec 32204. Strategic petroleum Reserve drawdown and sale, 114th Congress (2015-2016), https://www.congress.gov/bill/114th-congress/house-bill/22/text.