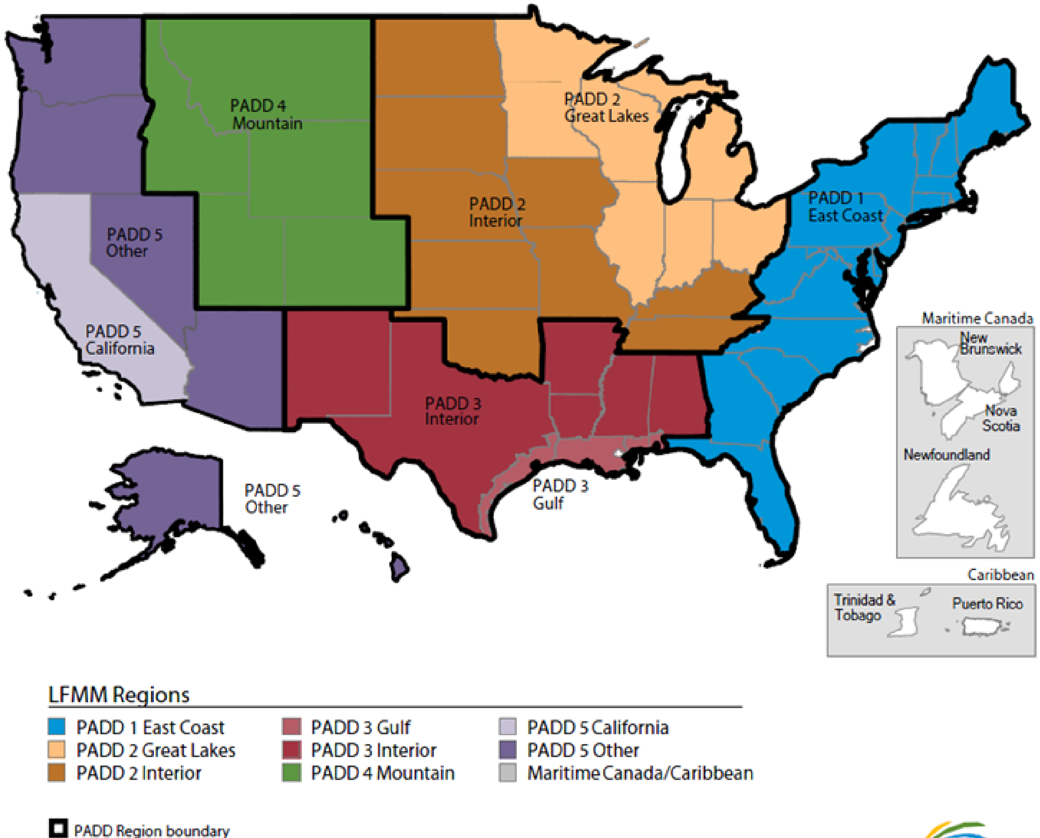
Liquid Fuels Market Module

The National Energy Modeling System (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. They also include non-petroleum-based inputs, such as 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.

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. To better represent policy, import/export patterns, and biofuels production, the eight U.S. regions are created by subdividing three of the five Petroleum Administration for Defense Districts (PADDs) (Figure 1).

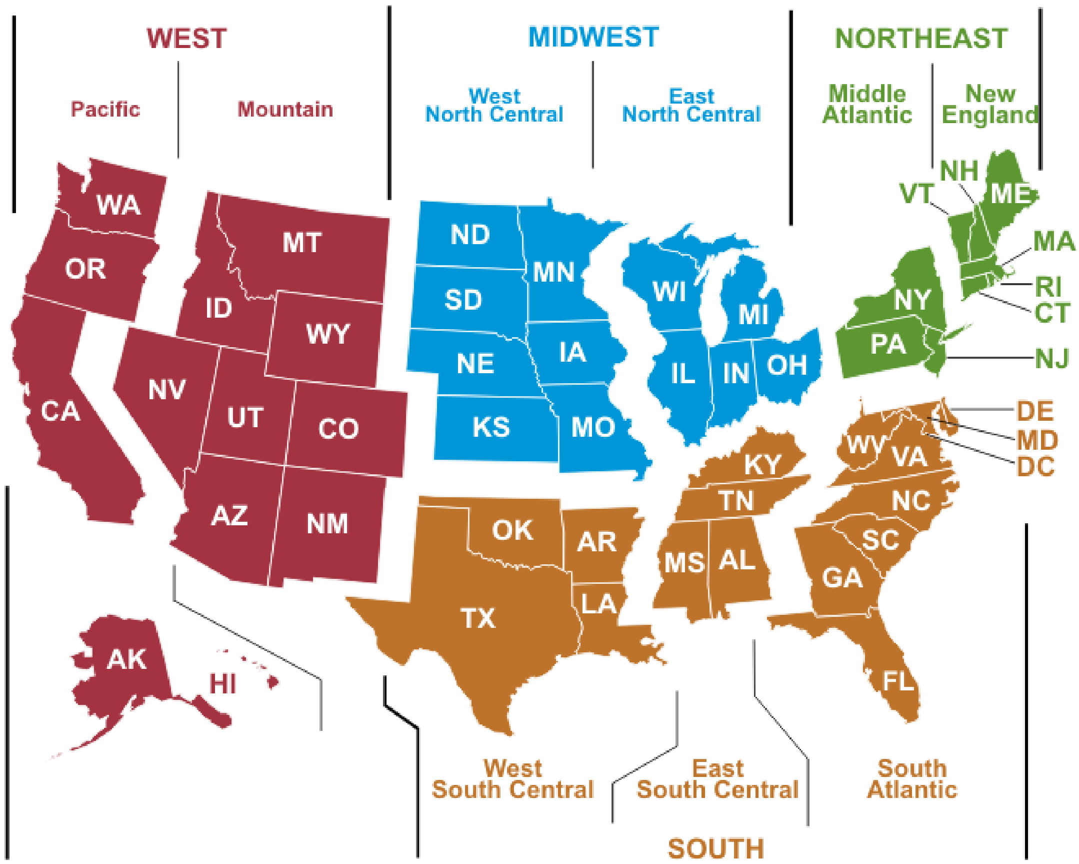
The LP model also represents supply curves for crude oil imports and exports, petroleum product imports and exports, biodiesel imports, and advanced ethanol imports from Brazil. The nine LFMM regions and import/export curves are connected in the LP via crude oil and product transport links. To interact 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 (Figure 2) using the assumptions and methods described below.

Figure 1. Liquid fuels market module regions



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

Figure 2. U.S. Census Divisions



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

Key assumptions

Product types and specifications

The LFMM models refinery production of the products shown in Table 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 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 types of gasoline: conventional and reformulated. The following specifications are included in the LFMM to differentiate between conventional and reformulated gasoline blends: Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefins content, and the percent evaporated at 200 degrees and 300 degrees Fahrenheit (E200 and E300) (Table 2). 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 [1]. Within the LFMM, refiners are assumed to produce 5 ppm gasoline (Table 2) because some sulfur content will increase during transportation to the end user. By producing 5 ppm gasoline, the refiner ensures that the gasoline will meet the 10 ppm requirement by the time it gets to the end user.

Table 2. Year-round gasoline specifications by Petroleum Administration for Defense District

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 200º (Min)	Percent evaporated at 300º (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 *before/after* January 1, 2017, to meet EPA final ruling: "EPA Sets Tier 3 Motor Vehicle Emission and Fuel Standards."

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 has been required in many areas in the United States since January 1995 [2]. In 1998, the U.S. Environmental Protection Agency (EPA) began certifying reformulated gasoline using the Complex Model, which required refiners to achieve emissions reductions compared with a baseline for four categories [3]. At present, requirements for air toxics, benzene, and nitrogen oxide emissions have been subsumed by other clean gasoline programs [4], leaving only a volatile organic compounds standard. As an estimate of compliance with this remaining standard, LFMM restricts Reid vapor pressure (RVP) to specific levels sufficient to achieve these reductions.

Annual Energy Outlook 2019 (AEO2019) 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 years 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 regulations, along with marketplace constraints, limit the full penetration of E15 in the projection period. The Energy Independence and Security Act of 2007 (EISA2007) defines a requirements schedule for blending renewable fuels into transportation fuels by 2022.

RVP limitations are in effect during summer months, and typically, they are defined differently by consuming region. In addition, different RVP specifications exist 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 separated into demand for conventional and for reformulated gasoline by applying assumptions about the annual market shares for each type. In AEO2019, the annual market shares for each region reflect actual 2015 market shares and are held constant throughout the projection period (see Table 3 for AEO2019 market share assumptions).

Table 3. Percentage in market shares 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 Form 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

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 share of the Pacific Region (Census Division 9) is required to meet California Air Resources Board (CARB) standards for diesel. Both federal and CARB standards currently limit sulfur to 15 parts per million (ppm).

AEO2019 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, 78% of industrial distillate demand, and 67% of commercial distillate demand. LFMM also differentiates ultra-low sulfur fuel oil demands as mandated in some states—Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

End-use product prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs, 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 (Table 4) are obtained from a set of base distribution markups.

Table 4. Petroleum product end-use markups by sector and Census division

2018 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	0.99	1.13	0.00	0.00	1.07	1.03	0.87	0.71	1.11
Kerosene	0.00	0.91	0.98	0.99	0.84	1.48	0.91	1.06	0.00
Liquefied petroleum gases	1.45	1.41	0.98	0.92	1.28	1.41	1.17	0.88	1.09
Commercial sector									
Distillate fuel oil	0.67	0.38	0.00	0.00	0.39	0.38	0.33	0.51	0.55
Gasoline	0.56	0.45	0.39	0.41	0.41	0.39	0.35	0.40	0.58
Kerosene	0.00	0.94	0.98	1.00	0.83	1.38	0.72	1.02	0.00
Liquefied petroleum gases	0.49	0.53	0.50	0.50	0.00	0.52	0.53	0.39	0.29
Low-sulfur residual fuel oil[1]	0.00	-0.08	0.00	0.00	0.15	0.00	0.45	0.00	0.00
Utility sector									
Distillate fuel oil	0.20	0.71	0.00	0.00	0.49	0.17	0.19	0.60	0.52
Low-sulfur residual fuel oil[1]	0.00	0.10	0.00	0.00	0.03	-0.04	-0.50	0.00	0.61
Transportation sector									
Distillate fuel oil	0.55	0.46	0.49	0.49	0.49	0.61	0.62	0.49	0.49
E85[2]	0.44	0.36	0.35	0.32	0.33	0.30	0.28	0.33	0.39
Gasoline	0.55	0.46	0.44	0.40	0.42	0.39	0.36	0.42	0.50
High/low-sulfur residual fuel oil[1]	0.00	-0.04	0.07	-0.40	-0.16	-0.25	-0.42	0.00	1.22
Jet fuel	0.13	-0.01	0.14	0.14	0.11	0.02	0.07	0.07	0.07
Liquefied petroleum gases	0.32	0.49	1.24	1.25	0.14	1.15	0.91	0.76	0.77
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	0.57	0.40	0.00	0.00	0.57	0.49	0.48	0.59	0.61
Gasoline	0.56	0.45	0.45	0.42	0.42	0.39	0.36	0.42	0.50
Kerosene	0.00	0.24	0.20	0.15	0.15	0.69	0.09	0.51	0.00
Liquefied petroleum gases	0.96	1.03	0.54	0.56	0.80	0.47	-0.16	0.70	0.39
Low-sulfur residual fuel oil[1]	0.00	-0.09	0.00	0.00	0.21	0.30	0.39	0.04	0.00

[1]Negative values indicate that average end-use sales prices were less than wholesale prices. This difference often occurs with residual fuel, which is produced as a byproduct when crude oil is refined to make higher-value products such as 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 are based on EIA 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;* EIA 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).
Source: U.S. Energy Information Administration, Office of Energy Analysis

State, local, and federal taxes (Tables 5 and 6) are also added to transportation fuels to determine final end-use prices. Tax trend analysis indicates that state taxes increase at the rate of inflation; therefore, state taxes are held constant in real terms throughout the projection period. This assumption is extended to local taxes, which are assumed to average 1% of motor gasoline prices [5]. Federal taxes are assumed to remain at current levels in line with the overall AEO2019 assumption of current laws and regulations. Federal taxes are not held constant in real terms, but are deflated as follows:

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

Table 5. State and local taxes on petroleum transportation fuels by Census division

2018 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]	0.31	0.45	0.35	0.23	0.32	0.23	0.20	0.24	0.51
Diesel	0.32	0.56	0.36	0.24	0.31	0.23	0.20	0.27	0.69
Liquefied petroleum gases	0.15	0.14	0.21	0.22	0.21	0.20	0.16	0.17	0.07
E85[2]	0.24	0.25	0.19	0.19	0.16	0.17	0.17	0.18	0.29
Jet fuel	0.00	0.08	0.04	0.07	0.05	0.06	0.17	0.03	0.03

[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.
Sources: American Petroleum Institute, *State Motor Fuel Taxes by State*, January 2018; The 2018 Sales Tax Handbook (a free public resource site) is used to define taxes for jet fuel

Table 6. Federal taxes

nominal dollars per gallon

Product	**Tax**
Gasoline	0.184
Diesel	0.242
Jet fuel	0.043
E85[1]	0.195

[1]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: IRS Internal Revenue Bulletin 2006-43.pdf is available on the web.
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)

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 7.

Table 7. Crude oil specifications

Crude oil categories	Crude designation	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	California	1.1-2.6	API<27
Syncrude	Syncrude	<0.5	API≥35
DilBit/SynBit	DilBit/SynBit	>1.1	API<27

Note: Sources include U.S. Energy Information Administration, *U.S. Crude Oil Production Forecast- Analysis of Crude Types*, May 28, 2015.
Note: Syncrude = synthetic crude oil from oil sands; Dilbit/Synbit = Bitumen diluted with lighter petroleum products or synthetic crude oil.
Source: U.S. Energy Information Administration

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 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 AEO2019, as required under the Consolidated Appropriations Act, 2016 [6], all crude oil types are permitted to be exported from the United States. For imported crude oil, a separate supply curve is provided (by the International Energy Module (IEM)) for each category.

Under the Bipartisan Act of 2015 and the H.R. 22 – FAST Act, AEO2019 models the required Strategic Petroleum Reserve (SPR) drawdown from 2016 to 2025 [7, 8]. The SPR projected sales volumes were converted from fiscal year accounting to calendar year levels using a 0.25/0.75 split between previous calendar year and current calendar year. In addition, the crude oil volumes were assumed to be 40% light sweet (API 35-40, sulfur < 0.5%) and 60% medium sour (API 27-35, sulfur ≥ 1.1%).

Capacity expansion

The LFMM allows for capacity expansion of all processing unit types. These processing unit types include distillation units such as the atmospheric distillation unit (ADU), vacuum distillation unit (VDU), and condensate splitters, as well as secondary processing units such as 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 the LFMM when the value received from the sale of products that could be produced with new processing capacity exceeds the investment and operating costs of adding this new capacity, plus the cost of purchasing additional feedstock. The investment costs assume a financing ratio of 60% equity and 40% debt, with an after-tax return on investment ranging from 6% for building new refinery processing units to more than 13% for higher-risk projects such as the construction of a coal-to-liquids plant.

The LFMM models capacity expansion using a three-period planning approach 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 it 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 AEO2019, 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 years. 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. Throughput for an atmospheric distillation unit (ADU) is typically a blend of crude oils, but historically it has included unfinished oil imports at some refineries. Therefore, historical ADU capacity utilization at these refineries includes both crude oil and unfinished oil imports. Because the LFMM processes only unfinished oil imports in secondary units, downstream from the ADU, an assumed historical percentage of the unfinished oils imported to the refinery was included as part of the throughput when calculating the ADU capacity utilization reported in AEO2019.

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 8).

Table 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 9. The cost data are defined assuming a 2020 base year and are deflated to 2018 dollars using the GDP deflator in NEMS.

Table 9. Non-petroleum fuel technology characteristics[1]

AEO2018 2020 basis (2018$)	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	26,900	49%	100%	12%	7	7
Advanced grain ethanol	3,400	64,100	49%	100%	12%	20	3
Cellulosic ethanol	4,400	202,400	28%	85%	12%	41	1
Biobutanol (retrofit of corn ethanol plant)	6,500	14,000	62%	90%	12%	2	7
Thermochemical catalytic							
Methyl ester biodiesel (FAME)	1,200	29,200	21%	100%	12%	23	8
Non-ester renewable diesel (NERD)	2,100	41,400	21%	95%	12%	24	8
Pyrolysis	5,200	412,000	60%	90%	12%	72	7
Thermochemical Fischer-Tropsch							
Gas-to-liquids (GTL)[8]	24,000	205,100	55%	85%	12%	35	10
Coal-to-liquids (CTL)	24,000	255,300	49%	85%	15%	44	12
Biomass-to-liquids (BTL)	6,000	465,200	38%	85%	12%	76	8

[1]This table is based on the AEO2019 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 are provided on an output basis.
[3]Overnight capital cost is given in unit costs, relative to nameplate capacity, and it is defined as the cost of a project with no interest incurred or as the lump sum cost of a project as if it were completed overnight. It excludes additional costs from optimism on the first unit and cost reductions on the nth unit due to learning effects (e.g., new technology) (see Table 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 ($/b/sd for a year).
[7]Fixed and non-feedstock variable operations and maintenance (O&M) costs affect the annual costs ($/year) and units costs ($/b).
[8]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: length of construction affects the interest that accrues during construction and plant lifetime affects 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. These values 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 this section.
Source: U.S. Energy Information Administration

Overnight capital cost is 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). Because some components of technologies have not yet been proven on 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 and underestimated costs in building the first full-scale commercial plant. As experience is gained (after building the first four units), the technological optimism factor is gradually reduced to 1.0, after which the overnight capital cost may be reduced as a result of learning (reflected through new technology).

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 comprise 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:

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

Note that Co (or (k+1) in Table 10) is the assumed cumulative capacity, which is the number of units built as of the beginning of the current time period/year plus 1. In addition, OC(Co) is factored into two components: unadjusted overnight capital costs and the learning type fraction (m in Table 10).

In the LFMM, both parameters *a* and *b* are calculated offline for each advanced process unit, maturity phase, and learning speed (fast/slow), and they are read into the model as input values.

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 much like 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 plants 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 assessment was used to define what percentage (m) of the cost would decline slowly (slow meaning mature) versus quickly (fast meaning evolutionary/revolutionary) as a result of learning. Next, for each learning category (fast and slow), a rate of learning (f) is assumed (i.e., a percentage 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 (first-of-a-kind) and learning (after the fourth unit is built) are shown in Table 10 for applicable technologies.

Table 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]	slow[1]	Phase 3 32nd-of-a-kind fast[1]	slow[1]
All technology types	Cumulative plants (k)	< 4	4	4	32	32
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

Note: Parameters *a* and *b* (see text) are calculated offline where *b* = func(f) and *a* = func(k, m, f, *b*).

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

- Corn feedstock supplies and costs are represented in the LFMM as corn supply curves, defined using U.S. corn supply/cost data and corn-to-ethanol data provided by Polysys in the NEMS Renewable Fuels Module. Feedstock costs reflect credits for co-products (livestock feed, corn oil, etc.). Operating costs of corn ethanol plants are from the U.S. Department of Agriculture

(USDA) survey of ethanol plant costs [9]. Energy requirements are from a study about energy consumption by corn and ethanol producers [10].

- Biodiesel and renewable diesel feedstock supplies and costs are provided externally to NEMS.
- Cellulosic (biomass) feedstock supply and costs are provided by the Renewable Fuels Module in NEMS. Initial capital costs for biomass cellulosic ethanol are from a research project reviewing cost estimates from multiple sources. Operating costs and credits for excess electricity generated at biomass ethanol plants are from a survey of literature [11].
- 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 46 million gallons per year.
    - Methyl ester biodiesel production contributes 1.5 credits toward the advanced mandate.
    - Renewable diesel fuel, 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 toward 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 in 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 pump costs.
    - To accommodate the ethanol requirements, in particular, transportation modes are expanded or upgraded for E10, E15, and E85, and most ethanol is assumed to originate in the Midwest, with nominal transportation costs of a few cents per gallon.
    - For E85 dispensing stations, the average cost to retrofit an existing station or to build a new station is assumed to be 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 the EPA are provided externally to NEMS.

Non-petroleum fossil fuel supply

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

Coal-to-liquids (CTL) facilities are assumed to 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. The earliest build date for CTL facilities is assumed to be 2027.

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 they are allowed to compete 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 2018 and 2019 are projected at the U.S. level in EIA's *Short-Term Energy Outlook* (STEO), October 2018. The LFMM adopts STEO results for 2018 and 2019, using regional estimates taken 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, based on British thermal units.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and on-highway diesel fuel. These regulations 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.

AEO2019 reflects EPA's *Tier 3 Vehicle Emissions and Fuel Standards*, which requires the average annual sulfur content of federal gasoline to contain no more than 10 ppm after January 1, 2017. For years before 2017, AEO2019 reflects the *Tier 2* Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, which require the average annual sulfur content of all gasoline used in the United States to be 30 ppm.

AEO2019 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. All highway diesel must not contain more than 15 ppm sulfur at the pump.

AEO2019 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.

AEO2019 represents major provisions in the Energy Policy Act of 2005 (EPACT05) for the petroleum industry, including removal of the oxygenate requirement in RFG.

AEO2019 includes provisions outlined in the Energy Independence and Security Act of 2007 (EISA2007) for the petroleum industry, including a Renewable Fuel Standard (RFS) that increases total U.S.

consumption of renewable fuels. To account for the possibility that RFS targets might be unattainable at reasonable cost, LFMM includes a provision for purchasing waivers. The price of a cellulosic waiver is specified in EISA2007. The non-cellulosic LFMM RFS waivers function as maximum allowed Renewable Identification Number (RIN) prices. LFMM also assumes that EPA will reduce RFS targets as allowed by the EISA2007 statute.

AEO2019 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 must contain no more than 0.62% benzene by volume. This requirement does not include gasoline produced or sold in California, which is already covered by the current California Phase 3 Reformulated Gasoline Program.

AEO2019 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% from 2012 through 2020.

AEO2019 incorporates the cap-and-trade program within the California Assembly Bill (AB32), 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 No. 1 and No. 2 were 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 of CO2 equivalent (MTCO2e) in any year from 2011 to 2014.

AEO2019 includes mandates passed by Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, 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 a transition to a 2% biodiesel content in Maine and Connecticut.

The International Maritime Organization's *MARPOL Annex 6* rule that covers cleaner marine fuels and ocean ship engine emissions is not explicitly represented in LFMM, but it is reflected in the effects on transportation and petroleum product export demands, which are provided to the LFMM from the Transportation Demand Module (TDM) and IEM, respectively, in NEMS.

The AEO2019 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 during the projection period.

Notes and sources

[1] U.S. Environmental Protection Agency (EPA), "Final Rule for Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards."

[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).

[3] U.S. Environmental Protection Agency (EPA), "Complex Model used to Analyze RFG and Anti-dumping Emissions Performance Standards."

[4] Electronic Code of Federal Regulations, "Title 40: Protection of Environment, PART 80—REGULATIONS OF FUELS AND FUEL ADDITIVES, Subpart D—Reformulated Gasoline," Standards and Requirements for compliance: §80.41(f)(2) and §80.41(f)(3).

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

[6] *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 December 18, 2015.

[7] U.S. Congress, "H.R. 1314 – Bipartisan Budget Act of 2015," Title IV--Strategic Petroleum Reserve, Sec. 401-403, 114th Congress (2015-2016).

[8] U.S. Congress, "H.R. 22 – FAST Act," Sec 32204. Strategic Petroleum Reserve drawdown and sale, 114th Congress (2015-2016).

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

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

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