Assumptions to the Annual Energy Outlook 2023: Liquid Fuels Market Module

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Liquid Fuels Market Module

The National Energy Modeling System's (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:

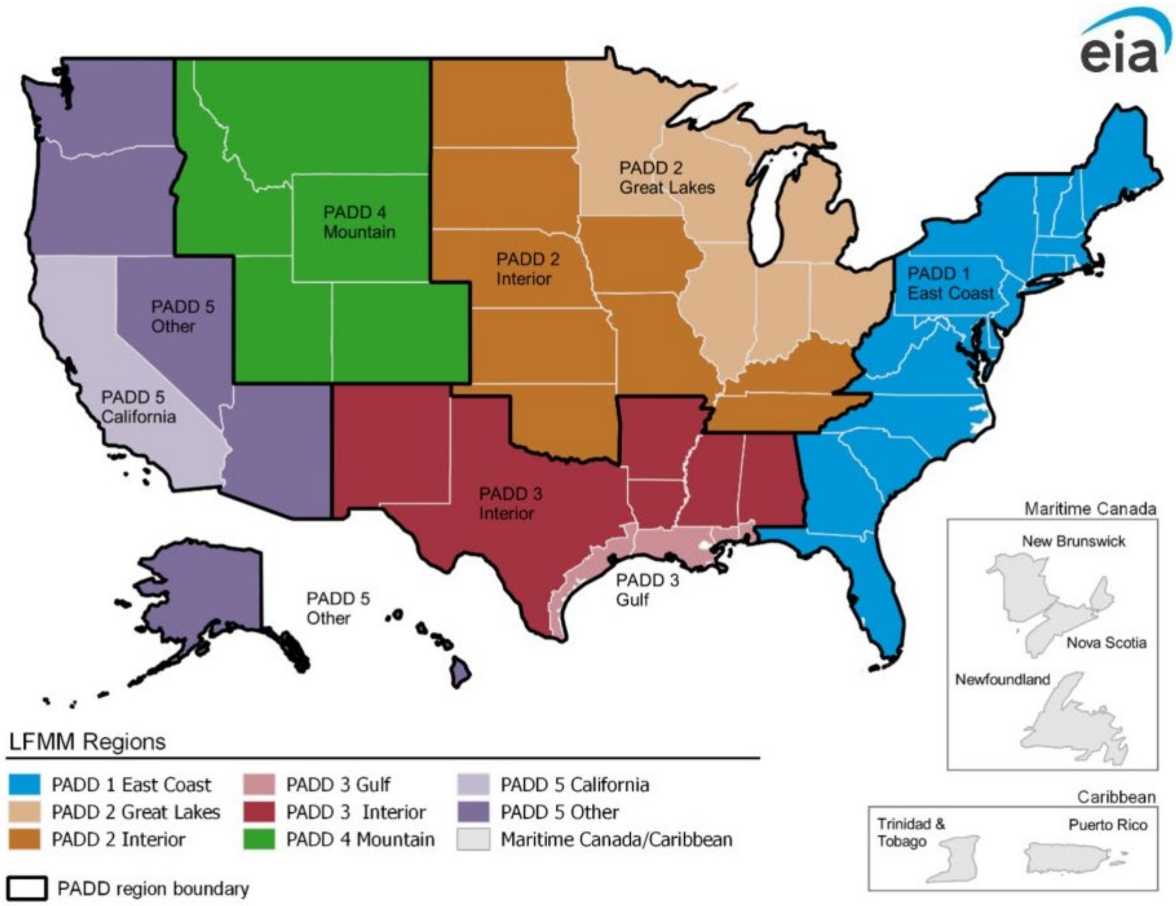
- Petroleum-based fuels, such as:
  - Domestic and imported crude oil
  - Petroleum product imports
  - Unfinished oil imports
- Non-petroleum-based inputs, such as:
  - Alcohols
  - Ethers
  - Esters
  - Corn
  - Biomass
  - Natural gas
  - Coal
- Other liquid fuels inputs, such as:
  - Natural gas plant liquids production
  - Refinery processing gain

The LFMM also projects capacity expansion and fuel consumption at domestic refineries.

To better represent policy, import and export patterns, and biofuels production, we created eight U.S. regions by subdividing three of the five Petroleum Administration for Defense Districts (PADDs) (Figure 1). It also represents refining activity in the Maritime Canada and Caribbean refining region, which predominantly serves U.S. markets. The LFMM's linear program (LP) represents:

- U.S. petroleum refining activities
- Biofuels production activities
- Other non-petroleum liquid fuels production activities

Figure 1. Liquid Fuels Market Module (LFMM) regions



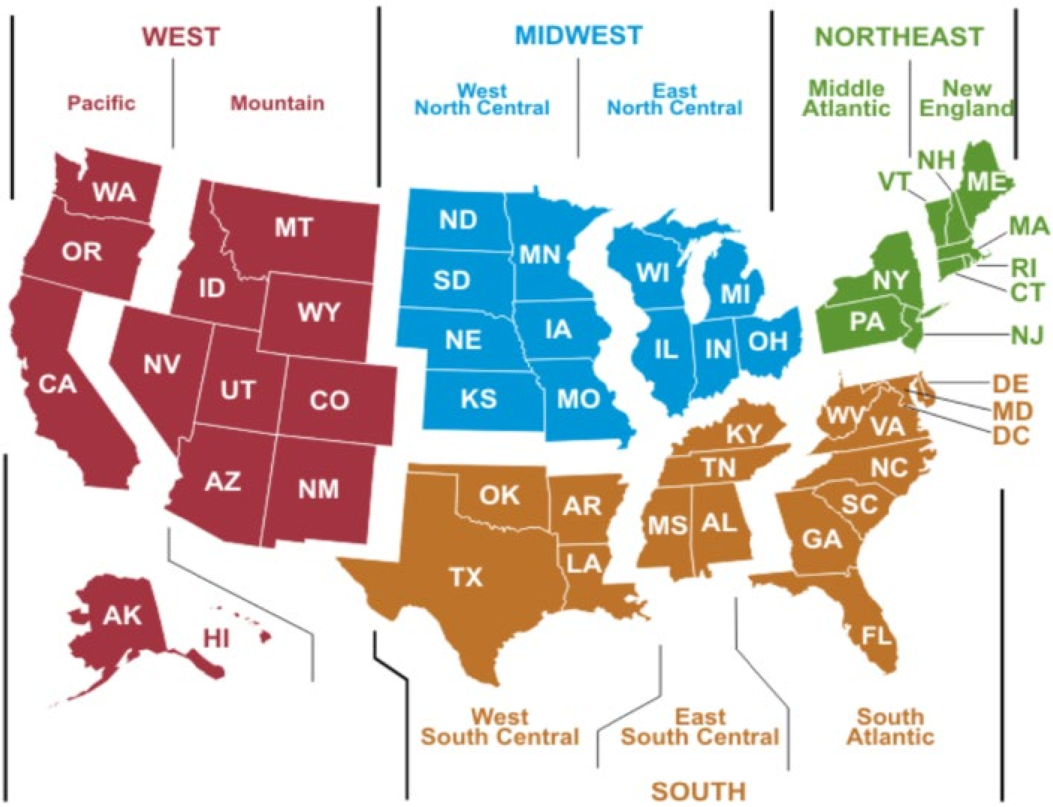
Data source: U.S. Energy Information Administration, Office of Energy Analysis
Note: PADD = Petroleum Administration for Defense District.

The LP model also represents supply curves for:

- Crude oil
- Petroleum products
- Ethanol imports and exports
- Biodiesel and renewable diesel imports

The nine LFMM regions and the import and export curves are connected in the LP model by crude oil and product transport links. To interact with other NEMS modules that have different regional representations, the module converts certain LFMM inputs and outputs 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 non-U.S. Maritime Canada and Caribbean region) into prices for the nine U.S. census divisions (Figure 2).

Figure 2. U.S. census divisions



Data source: U.S. Energy Information Administration, Office of Energy Analysis

Key assumptions

Product types and specifications

The LFMM models refinery production for a number of products (Table 1).

The LFMM assumes no change in the state and federal specifications for the products listed in Table 1. 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 in AEO2023

Product category	Specific products
Motor gasoline	Conventional and reformulated (including CARB[a]) gasoline
Jet fuel	Kerosene-type fuel
Distillates	Kerosene, heating oil, low sulfur diesel, ultra-low sulfur diesel, and CARB[a] diesel
Residual fuels	Low sulfur and high sulfur fuel
Liquefied petroleum gases	Ethane, propane, propylene, normal-butane, and isobutane
Petrochemical feedstock	Petrochemical naphtha, petrochemical gas oil, and aromatics
Others	Lubricating products and waxes, asphalt and road oil, still gas, petroleum coke, special naphthas, and aviation gasoline

Data source: U.S. Energy Information Administration, Office of Energy Analysis

[a] CARB (California Air Resources Board) establishes regulations for gasoline and diesel specifications in California.

Motor gasoline specifications and market shares

The LFMM models production and distribution of two types of gasoline: conventional and reformulated. The LFMM includes several specifications to differentiate between conventional and reformulated gasoline blends (Table 2):

- Reid vapor pressure (RVP)
- Benzene content
- Aromatic content
- Sulfur content
- Olefins content
- The percentage evaporated at 200°F and 300°F (E200 and E300)

The LFMM incorporates the U.S. Environmental Protection Agency's (EPA) Tier 3 program requirement that the sulfur content of delivered gasoline must not be greater than 10 parts per million (ppm), effective January 1, 2017.[1] The LFMM assumes refiners produce 5 ppm gasoline 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 PADD

PADD and type	Reid vapor pressure (Max PSI)	Aromatics volume percentage (Max)	Benzene volume percentage (Max)	Sulfur[a] ppm (Max)	Olefin volume percentage (Max)	Percentage evaporated at 200ºF (Min)	Percentage evaporated at 300ºF (Min)
Conventional							
PADD 1	10.11	24.23%	0.62%	22.48/5.0	10.8%	45.9%	81.7%
PADD 2	10.11	24.23%	0.62%	22.48/5.0	10.8%	45.9%	81.7%
PADD 3	10.11	24.23%	0.62%	22.48/5.0	10.8%	45.9%	81.7%
PADD 4	10.11	24.23%	0.62%	22.48/5.0	10.8%	45.9%	81.7%
PADD 5	10.11	24.23%	0.62%	22.48/5.0	10.8%	45.9%	81.7%
Reformulated							
PADD 1	8.8	21.0%	0.62%	23.88/5.0	10.36%	54.0%	81.7%
PADD 2	8.8	21.0%	0.62%	23.88/5.0	10.36%	54.0%	81.7%
PADD 3	8.8	21.0%	0.62%	23.88/5.0	10.36%	54.0%	81.7%
PADD 4	8.8	21.0%	0.62%	23.88/5.0	10.36%	54.0%	81.7%
PADD 5							
Nonattainment	8.8	21.0%	0.62%	23.88/5.0	10.36%	54.0%	81.7%
CARB[b] (attainment)	7.7	23.12%	0.58%	10/5.0	6.29%	42.9%	86.3%

Data source: U.S. Energy Information Administration, Office of Energy Analysis
Note: PADD=Petroleum for Administration of Defense District
[a] The two values reflect sulfur levels before and after January 1, 2017, to meet the U.S. Environmental Protection Agency final ruling, "EPA Sets Tier 3 Motor Vehicle Emission and Fuel Standards." The Liquid Fuels Market Module uses 5 ppm at the refinery to ensure sulfur contamination does not cause the specification to exceed 10 ppm at the market point.
[b] CARB (California Air Resources Board) establishes regulations for gasoline and diesel specifications in California.
Note: Max=maximum, Min=minimum, PADD=Petroleum Administration for Defense District, ppm=parts per million by weight, PSI=pounds per square inch.

Many areas in the United States have required reformulated gasoline (RFG) since January 1995.[2] In 1998, EPA began certifying reformulated gasoline using the Complex Model, which required refiners to achieve emissions reductions compared with a baseline for four categories.[3] Other clean gasoline programs[4] have currently subsumed requirements for air toxics, benzene, and nitrogen oxide emissions, leaving only a standard for volatile organic compounds. As an estimate of compliance with this remaining standard, LFMM restricts RVP to levels sufficient to achieve these reductions.

The *Annual Energy Outlook 2023* (AEO2023) assumes a minimum 10% blend of ethanol in domestically consumed motor gasoline. Federal reformulated and conventional gasoline can be blended with up to 15% ethanol (E15) in light-duty vehicles for model years 2001 and later and with up to 85% ethanol (E85) in flex-fuel vehicles (LFMM assumes an average annual ethanol content of 74% for E85 fuel.) Current state regulations, along with marketplace constraints, limit the market share of E15 in the projection period. In addition, reformulated and conventional gasoline can be blended with 16% biobutanol; however, because no biobutanol has entered the gasoline market in recent years,[5] AEO2023 assumes no biobutanol blends into motor gasoline. The Energy Independence and Security Act of 2007 (EISA2007) defines a requirements schedule for blending renewable fuels into transportation fuels by 2022.

Although RVP limitations are in effect during the summer and typically differ by consuming region, the LFMM does not represent RVP at this level of detail. Instead, the LFMM assumes that the annual average specifications—based on summertime RVP limits, wintertime estimates, and seasonal weights—capture these variations in RVP.

Within the LFMM, total gasoline demand is separated into demand for conventional gasoline and demand for reformulated gasoline by applying assumptions about the annual market shares for each type. In AEO2023, the annual market shares for each region reflect actual 2015 market shares and remain constant throughout the projection period (Table 3).

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%

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: The data are derived from Form EIA-782C, *Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption*, January–December 2015. As of January 2007, oxygenated gasoline is included within conventional gasoline.

Distillate, residual, and jet fuel specifications and market shares

Distillate fuel in the LFMM consists of low-sulfur diesel, ultra-low sulfur diesel (ULSD), and heating oil. Residual fuel is represented as high and low-sulfur residual fuel. Jet fuel is kerosene-based jet fuel. The quality specifications required for each of these fuels include (Table 4):

- Sulfur content
- Aromatics and cetane levels
- American Petroleum Institute (API) gravity
- Freeze point index

Table 4. Year-round distillate and residual fuel specifications

Type	Freeze point index (max)	Sulfur ppm (max)	API[a] gravity (max)	Aromatics volume percentage (max)	Cetane index (min)
CARB diesel	24.35	10[b]	37.0°	10%	53
Ultra-low sulfur diesel	24.35	15	37.0°	35%	40
Low sulfur diesel	24.35	500	37.0°	40%	40
Heating oil	24.35	3,000	37.0°	100%	--
Ultra-low sulfur heating oil	24.35	15	37.0°	35%	40
Jet fuel	28.77	3,000	51.1°	29%	--
Low sulfur residual fuel oil	--	5,000	12.39°	--	--
High sulfur residual fuel oil	--	29,000	13.62°	--	--

Data source: U.S. Environmental Protection Agency, MARPOL Annex VI and the Act To Prevent Pollution From Ships (APPS); International Maritime Organization, In Focus: Sulfur 2020–cutting Sulphur dioxide emissions; Electronic Code of Federal Regulations, Part 80—Regulations of Fuels and Fuel Additives, item 80.520 Motor Vehicle Diesel Fuel Standards and Requirements; S&P Global, Platts, Specifications Guide, Americas Refined Oil Products, 2020; U.S. Energy Information Administration, Office of Energy Analysis, analyst judgment

[a] American Petroleum Institute

[b] The Liquid Fuels Market Module uses 10 parts per million (ppm) for CARB (California Air Resources Board) diesel at the refinery to ensure sulfur contamination does not cause the specification to exceed 15 ppm at the market point.

[c] -- = not applicable

In the LFMM, ULSD is differentiated from other distillates to account for highway diesel regulations related to the Clean Air Act Amendments of 1990 (CAAA90). This ruling currently limits sulfur in ULSD to 15 ppm. AEO2023 also 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. In addition, for locomotive and marine diesel, the rule established a ULSD limit of 15 ppm in mid-2012.

In NEMS, California's share of diesel demand in the Pacific Census Division is required to meet CARB standards for diesel. The CARB standards currently limit sulfur to 15 ppm. However, the LFMM sets the CARB diesel sulfur requirement to 10 ppm at the refinery to ensure sulfur contamination does not cause the specification to exceed 15 ppm when purchased.

In NEMS, diesel and heating oil demands are provided as an aggregate distillate demand for each end-use sector. The LFMM developed a methodology to parse the distillate demand into ULSD and heating oil. The LFMM assumes demand for ULSD is the sum of total transportation distillate demand, 78% of industrial distillate demand, and 67% of commercial distillate demand. The LFMM also differentiates ultra-low sulfur heating oil demands as required in some states:

- Connecticut
- Delaware

- Maine
- Massachusetts
- New Hampshire
- New Jersey
- New York
- Rhode Island
- Vermont

Beginning in 2020, the International Maritime Organization's MARPOL Annex 6 rule requires marine vessels traveling in specified international waters to reduce sulfur emissions, either by adding scrubbers to their high-sulfur residual fuel-fired engines or by switching to a compliant lower-sulfur fuel mix (low-sulfur residual, ULSD, or a combination). Although the LFMM does not directly represent fuel exports that international marine vessels use to meet MARPOL requirements, it does model low-sulfur residual and ULSD production and allows exports of each to the global international market. In addition, the Transportation Demand Module (TDM) provides the LFMM with demand for any fuel purchased at U.S. ports by marine vessels.

End-use product prices

We base end-use petroleum product prices on marginal costs of production plus production-related fixed costs, distribution costs, and taxes. The LP determines the marginal costs of production, which represent variable costs of production, including additional costs for meeting the reformulated fuels provisions of CAAA90. The LFMM implicitly assumes environmental costs associated with controlling pollution at refineries 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 obtained from a set of base distribution markups and are defined for each census division (Table 5).

Table 5. Petroleum product end-use markups by sector and census division

2022 dollars per gallon

			Census division						
Sector and 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	$1.14	$1.30	$0.00	$0.00	$1.24	$1.19	$1.00	$0.82	$1.28
Kerosene	$0.00	$1.05	$1.14	$1.14	$0.97	$1.70	$1.05	$1.22	$0.00
Liquefied petroleum gases	$1.58	$1.55	$1.08	$1.02	$1.41	$1.56	$1.29	$0.97	$1.20
Commercial sector									
Distillate fuel oil	$0.78	$0.44	$0.00	$0.00	$0.45	$0.44	$0.39	$0.59	$0.63
Gasoline	$0.65	$0.52	$0.45	$0.47	$0.47	$0.45	$0.41	$0.46	$0.67
Kerosene	$0.00	$1.08	$1.13	$1.15	$0.96	$1.59	$0.84	$1.17	$0.00
Liquefied petroleum gases	$0.53	$0.58	$0.55	$0.55	$0.00	$0.57	$0.58	$0.42	$0.32
Low sulfur residual fuel oil	$0.00	-$0.09	$0.00	$0.00	$0.18	$0.00	$0.52	$0.00	$0.00
Utility sector									
Distillate fuel oil	$0.23	$0.82	$0.00	$0.00	$0.57	$0.20	$0.22	$0.69	$0.60
Low sulfur residual fuel oil[a]	$0.00	$0.11	$0.00	$0.00	$0.04	-$0.05	-$0.58	$0.00	$0.70
Transportation sector									
Distillate fuel oil	$0.51	$0.62	$0.50	$0.39	$0.46	$0.45	$0.42	$0.49	$0.90
E85[b]	$0.27	$0.29	$0.29	$0.23	$0.24	$0.18	$0.18	$0.29	$0.45
Gasoline	$0.31	$0.34	$0.33	$0.27	$0.27	$0.21	$0.21	$0.33	$0.51
High and low sulfur residual fuel oil[a]	$0.00	-$0.05	$0.08	-$0.46	-$0.19	-$0.28	-$0.48	$0.00	$1.41
Jet fuel	$0.02	$0.03	$0.04	$0.08	$0.03	$0.01	$0.04	$0.01	$0.00
Liquefied petroleum gases	$0.36	$0.53	$1.36	$1.37	$0.16	$1.27	$1.01	$0.83	$0.85
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	$0.65	$0.46	$0.00	$0.00	$0.65	$0.57	$0.55	$0.68	$0.71
Gasoline	$0.64	$0.52	$0.51	$0.48	$0.48	$0.45	$0.41	$0.49	$0.58
Kerosene	$0.00	$0.28	$0.23	$0.17	$0.17	$0.79	$0.10	$0.59	$0.00
Liquefied petroleum gases[a]	$1.06	$1.14	$0.60	$0.61	$0.88	$0.52	-$0.17	$0.77	$0.43
Low sulfur residual fuel oil[a]	$0.00	-$0.10	$0.00	$0.00	$0.24	$0.35	$0.45	$0.05	$0.00

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: Data from markups are based on Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report;* Form EIA-923*, Power Plant Operations Report*, starting in 2008*;* Form EIA-759, *Monthly Power Plant Report;* EIA, *State Energy Data Report 2021, Consumption (January 2023)*; and EIA, *State Energy Data 2021: Prices and Expenditures* (January 2023)

[a] 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.

[b] E85 refers to a high-level ethanol-gasoline blend containing 51% to 83% ethanol, depending on geography and season. An annual average ethanol content of 74% is used.

We also add state, local, and federal taxes to transportation fuels to determine final end-use prices (Table 6 and Table 7). 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 extends to local taxes, which we assume to average 1% of motor gasoline prices.[6] We assume federal taxes remain at current levels, in line with the overall AEO2023 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 6. State and local taxes on petroleum transportation fuels by census division

2022 dollars per gallon

	Census division								
	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Gasoline[a]	$0.27	$0.43	$0.34	$0.25	$0.32	$0.26	$0.21	$0.24	$0.49
Diesel	$0.31	$0.51	$0.41	$0.25	$0.32	$0.25	$0.21	$0.27	$0.39
Liquefied petroleum gases	$0.16	$0.16	$0.23	$0.25	$0.23	$0.22	$0.17	$0.18	$0.08
E85[b]	$0.28	$0.29	$0.22	$0.22	$0.18	$0.19	$0.19	$0.21	$0.34
Jet fuel	$0.01	$0.08	$0.06	$0.07	$0.04	$0.02	$0.16	$0.04	$0.03

Data source: American Petroleum Institute, *State Motor Fuel Taxes by State*, January 2022; Federation of Tax Administrators, *State Excise Taxes*, January 2022

[a] Tax also applies to gasoline consumed in the commercial and industrial sectors.

[b] E85 refers to a high-level ethanol-gasoline blend containing 51% to 83% ethanol, depending on geography and season. An annual average ethanol content of 74% is used.

Table 7. Federal taxes on select transportation fuels

nominal dollars per gallon

Product	Tax
Gasoline	$0.184
Diesel	$0.242
Jet fuel	$0.043
E85[a]	$0.196

Data source: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264), Taxpayer Relief Act of 1997 (PL 105-34), *Clean Fuels Report* (Washington, DC, April 1998), and Energy Policy Act of 2005 (PL 109-58)

[a] E85 refers to a high-level ethanol-gasoline blend containing 51% to 83% ethanol, depending on geography and season. An annual average ethanol content of 74% is used.

Note: The IRS Internal Revenue Bulletin 2006-43.pdf is available online.

Crude oil quality

In the LFMM, the quality of crude oil is characterized by average API gravity and sulfur levels. Domestic and imported crude oil are divided into 11 categories, as defined by the ranges of API gravity and sulfur (Table 8).

Table 8. Crude oil specifications by API gravity and sulfur levels

Crude oil categories	Crude oil designation	Sulfur (percentage)	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°

Data source: U.S. Energy Information Administration, *U.S. Crude Oil Production to 2025: Updated Projection 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; API=American Petroleum Institute

We develop a composite crude oil with the appropriate yields and qualities 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 we use to determine category characteristics. For each category's domestic crude oil volumes, we estimate total regional production first. We divide each region's production among each of the 11 categories based on that region's distribution of average API gravity and sulfur content. For AEO2023, as allowed under the Consolidated Appropriations Act, 2016,[7] the United States can export all crude oil types. For imported crude oil, the International Energy Module (IEM) provides a separate supply curve for each category.

Under a number of different Acts of Congress, AEO2023 models the required Strategic Petroleum Reserve (SPR) drawdown from 2016 to 2031. We converted the SPR projected sales volumes from fiscal year accounting to calendar year levels by splitting them 25% and 75%, respectively, between the previous calendar year and the current calendar year. In addition, we assume crude oil volumes were 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 for all processing unit types, which include:

- Distillation units, such as:
  - Atmospheric distillation unit (ADU)
  - Vacuum distillation unit (VDU)
  - Condensate splitters
- Secondary processing units, such as:
  - Hydrotreating
  - Coking
  - Fluid catalytic cracking
  - Hydrocracking
  - Alkylation

Capacity expansion occurs by processing unit, starting from regional capacities established through 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. Those costs also include 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 coal-to-liquids (CTL) plant construction.

The LFMM models capacity expansion using a three-period (Periods 1, 2, and 3) planning approach similar to that used in the NEMS Electricity Market Module (EMM). The first two periods contain a single model year (current year and next year), and the third period represents a net present value of the next 19 years in the projection period. The LFMM uses the second and third planning periods 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 as leverage in the capacity expansion decision for Period 2, and this decision 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 AEO2023, the LFMM uses an 18% discount rate.

The LFMM also models capacity expansion for producing:

- Corn and cellulosic ethanol
- Biobutanol
- Biomass pyrolysis oil
- Biodiesel
- Renewable diesel
- Sustainable aviation fuel
- Coal-to-liquids (CTL)
- Gas-to-liquids (GTL)

- Biomass-to-liquids

All process-unit capacity that is scheduled 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 this throughput 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 unfinished oil imports only 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 AEO2023.

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 9). In AEO2023, sustainable aviation fuel production is modeled with a process unit that can produce both hydroprocessed non-ester renewable diesel (NERD) and hydroprocessed esters and fatty acids (HEFA) sustainable aviation fuel.

Table 9. Alternative fuel technology product type

Technology	Product type	Feedstock	Product yield (percentage 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	100% biobutanol
Thermochemical catalytic			
Methyl ester biodiesel	Fuel grade	Yellow or white grease, or seed oil	98.5% biodiesel 1.5% glycerol
Hydroprocessed non-ester renewable diesel (NERD)	Fuel grade	Yellow or white grease, or seed oil	98% renewable diesel 2% renewable naphtha
HEFA sustainable aviation fuel/NERD	Fuel grade	Yellow or white grease, or seed oil	50% sustainable aviation fuel 50% renewable diesel
Pyrolysis	Fuel grade	Agriculture residue, forest residue, or urban wood waste	60% distillate 40% naphtha
Thermochemical Fischer-Tropsch			
Gas-to-liquids (GTL)	Fuel grade and refinery feed	Natural gas	52% diesel 23% kerosene 24.5% naphtha 0.5% liquid petroleum gas (LPG)
Coal-to-liquids (CTL)	Fuel grade and refinery feed	Coal	51% diesel 21% kerosene 28% naphtha
Biomass-to-liquids (BTL)	Fuel grade and refinery feed	Biomass	22% diesel 46% kerosene 32% naphtha

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: HEFA = hydroprocessed esters and fatty acids

Estimates of capital and operating costs corresponding to specified nameplate capacities for these technologies are in Table 10. The cost data are defined assuming a 2022 base year, and we represent the data in 2022 dollars using the gross domestic product (GDP) deflator in NEMS, as needed.

Table 10. Non-petroleum fuel technology characteristics

AEO2023 2025 basis (2022$)	Nameplate capacity[a] b/sd	Overnight capital cost[b] $/b/sd	Thermal efficiency[c] percentage	Utilization rate[d] percentage	Cost of capital[e] (WACC) percentage	Fixed O&M cost[f] $/d/b/sd	Non-feedstock variable O&M cost[g] $/b
Biochemical							
Corn ethanol	6,800	$27,500	49%	100%	12%	$7	$7
Advanced grain ethanol	3,400	$65,500	49%	100%	12%	$20	$3
Cellulosic ethanol	4,400	$206,600	28%	85%	12%	$42	$1
Biobutanol (retrofit of corn ethanol plant)	6,500	$14,300	62%	90%	12%	$2	$7
Thermochemical catalytic							
Methyl ester biodiesel (FAME)	1,200	$29,800	21%	100%	12%	$23	$8
Hydroprocessed non-ester renewable diesel (NERD)	2,100	$42,300	21%	95%	12%	$24	$8
HEFA sustainable aviation fuel/NERD	2,100	$52,300	21%	95%	12%	$24	$8
Pyrolysis	5,200	$420,400	60%	90%	12%	$73	$7
Thermochemical Fischer-Tropsch							
Gas-to-liquids (GTL)[i]	24,000	$209,300	55%	85%	12%	$36	$10
Coal-to-liquids (CTL)	24,000	$260,500	49%	85%	15%	$44	$12
Biomass-to-liquids (BTL)	6,000	$474,700	38%	85%	12%	$78	$8

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: For all technologies listed, we assume length of construction to be 4 years and plant lifetime to be 20 years. Length of construction affects the interest that accrues during construction, and plant lifetime affects the amortized cost of capital. Values from this table come from analysis of reports and discussions with various sources from industry, government, and the U.S. Department of Energy's Fuel Offices and National Laboratories. These values represent the cost and performance of typical plants under normal operating conditions for each technology.

Note: This table is based on the *Annual Energy Outlook 2023* (AEO2023) Reference case projections for year 2025.

[a] *Nameplate capacity* is the expected size of a unit based on historical builds and engineering estimations. Capacity amounts are provided on an output basis.

[b] *Overnight capital cost* is given in unit costs, relative to nameplate capacity, and we define this category 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 *n*th unit as a result of learning effects (for example, new technology) (Table 11).

[c] *Thermal efficiency* represents the ratio of the combustive energy of the products to the combustive energy of the feedstock used to produce the products.

[d] *Utilization rate* represents the expected annual production divided by the plant capacity divided by 365 days.

[e] *Cost of capital* is the weighted average cost of capital (WACC) during construction and lifetime operations. We use this term with the plant lifetime and overnight capital cost to compute an amortized unit capital cost ($/b/sd for a year).

[f] *Fixed operations and maintenance (O&M) cost* and *non-feedstock variable O&M cost* affect the annual costs ($/year) and units costs ($/b).

[g] These costs are for a Gulf Coast facility. We expect higher costs in other regions, particularly Alaska.

b/sd=barrels per stream day

$/b/sd=dollars per barrel per stream day

$/d/b/sd=(dollars per day) per (barrel per stream day)

HEFA=hydroprocessed esters and fatty acids

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 (that is, 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, we apply a technology optimism factor to the assumed first-of-a-kind overnight capital cost. This factor is a multiplier that increases the first-of-a-kind plant cost (for example, 1.2 for biomass-to-liquids). 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 technology 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 we identify each component as revolutionary, evolutionary, or mature. We assume different learning rates 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 evolutionary or revolutionary (fast) and mature (slower) learning components, depending on the mix (percentage) of new and mature processes that make up a particular technology.

The progress ratio (pr) is related to the speed of learning or learning rate (LR) (for example, how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (that is, 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 11) is the assumed cumulative capacity, which is the number of units built as of the beginning of the current period or year plus one. In addition, *OC* (*Co*) is factored into two components: unadjusted overnight capital costs and the learning type fraction (*m* in Table 11).

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

We expect the capital cost to decline as new technology matures, 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 phaseout of optimism (and some revolutionary learning) for the first four plants (so that the optimism factors for the fifth and later plants are 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.

We assessed each technology to determine the mix of technological maturity of each component (revolutionary, evolutionary, or mature). We used this assessment to define what percentage (*m*) of the cost would decline slowly (slow meaning mature) versus quickly (fast meaning evolutionary or revolutionary) as a result of learning. Next, for each learning category (fast and slow), we assume a rate of learning (*f*) (in other words, 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) for applicable technologies appear in Table 11.

Table 11. 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[a]	Phase 2 5th-of-a-kind slow[a]	Phase 3 32nd-of-a-kind fast	Phase 3 32nd-of-a-kind slow
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

Data source: U.S. Energy Information Administration, Office of Energy Analysis, analyst judgment
Note: Parameters *a* and *b* (see text) are calculated offline
where *b* = func(f) and *a* = func(k, m, f, *b*).
-- = not applicable
[a] Fast = evolutionary or revolutionary learning; slow = mature learning

Biofuels supply

Supply functions for corn, non-corn grain, and cellulosic biomass feedstocks are available 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 available on an annual basis through 2050 for biodiesel and renewable diesel production. Available ethanol imports and potential ethanol exports are represented by supply and demand curves, respectively.

Corn feedstock

Corn feedstock supplies and costs are represented in the LFMM as corn supply curves, defined using U.S. corn supply and cost data and corn-to-ethanol data provided by Polysys in the NEMS Renewable Fuels Module (RFM). Operating costs of corn ethanol plants are from the U.S. Department of

Agriculture (USDA) survey of ethanol plant costs.[8] Energy requirements come from a study about energy consumption by corn and ethanol producers.[9]

Biodiesel and renewable diesel feedstock

Biodiesel and renewable diesel feedstock supplies include seed oils, yellow grease, and white grease. Seed oils include soybean, cottonseed, sunflower, and canola oils. All seed oil supplies, except soybean oils, are provided externally to NEMS. The price and supply data for soybean oil come from Polysys in the RFM. Based on a 2019 to 2020 estimate by USDA[10] in July 2020, the LFMM assumes that 34.3% of the soybean oil supply is used for biodiesel. We use the soybean oil price as a proxy for defining the price in the seed oil supply curves. The supply data for yellow and white grease that are available for biodiesel production are a function of regional population, fat production, and an estimate of how much fat is available for biodiesel production. Corresponding costs are about 67.5% of soybean oil supply costs.

Biomass feedstock

The RFM in NEMS provides cellulosic (biomass) feedstock supply and costs. Initial capital costs for biomass cellulosic ethanol come from a research project that reviewed cost estimates from multiple sources. Operating costs and credits for excess electricity generated at biomass ethanol plants are from a survey of literature.[11]

Ethanol exports

Demand curves for ethanol exports allow corn ethanol to be exported. The curve is an isoelastic demand curve built from an initial price, quantity, and elasticity (Po, Qo, eps=-0.4). For historical years, we estimate Po to be 50% higher than the historical domestic wholesale ethanol price, and Po grows 1% each projection year. We assume Qo to grow 2.5% from the previous year, beginning with historical 2019 levels. Po is in dollars per barrel ($/b), and Qo is in thousand barrels per calendar day (Mb/cd).

Ethanol imports

Ethanol import supply curves represent sugarcane ethanol available for import from Brazil. The curve is an isoelastic supply curve built from an initial price, quantity, and elasticity (Po, Qo, eps=0.4). For historical years, we estimate Po to be 2% higher than the historical domestic wholesale ethanol price, and Po grows 2% each projection year. We assume Qo to grow 1% from the previous year, beginning with historical 2019 levels (Po in $/b, Qo in Mb/cd).

Renewable Fuel Standard (RFS)

Modeling the RFS in EISA2007 required a number of assumptions:

- The penetration of cellulosic ethanol into the market is limited to one operational plant before 2023. Planned capacity through 2021 for pyrolysis and biomass-to-liquids (BTL) processes is about 46 million gallons per year.
- Methyl ester biodiesel (FAME) production contributes 1.50 credits toward the advanced requirement
- Renewable diesel fuel contributes 1.70 credits toward the biomass-based diesel requirement.

- Diesel from biomass pyrolysis and Fischer-Tropsch contribute 1.70 credits toward the cellulosic requirement.
- Cellulosic drop-in gasoline contributes 1.54 credits toward the cellulosic requirement.
- Imported sugarcane ethanol from Brazil contributes 1 credit and counts toward the advanced renewable requirement.
- Separate biofuel waivers can be activated for each of the four RFS fuel categories.
- Renewable diesel and BTL diesel are compatible with diesel engines without significant infrastructure modification (either in vehicles or delivery infrastructure).
- Ethanol is consumed as E10, E15, or E85 with no intermediate blends. The cost of placing E85 pumps at the most economical stations is spread over diesel and gasoline pump costs.
- To accommodate the ethanol requirements, transportation modes are expanded or upgraded for E10, E15, and E85, and we assume most ethanol originates in the Midwest and has 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 about $160,000 per station (2016 dollars). Interregional transportation is by rail, ship, barge, and truck, and the associated costs are included in the LFMM.
- LFMM does not model all fuels and accounting items that EPA includes in the RFS requirements (for example, biogas, renewable heating fuel imports, renewable identification number [RIN] banking), which is why the LFMM models reduced RFS targets.
- No small refinery exemptions are modeled for 2021 and onward.

Non-petroleum fossil fuel supply

GTL facilities convert natural gas into distillates, and the model assumes they are built if the prices for lower sulfur distillates are sufficiently high enough to make production of GTL distillates economical. The earliest start date for a GTL facility in the model is set to 2024.

The model assumes CTL facilities are built when low-sulfur distillate prices are high enough to make them economical. The model assumes a 48,000-barrel-per-day CTL facility costs nearly $7.4 billion in initial capital investment (2016 dollars). The model assumes the earliest build date for CTL facilities is 2027.

Combined heat and power (CHP)

Electricity consumption at refineries 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
- CHP from other liquid fuels producers (including cellulosic ethanol, advanced ethanol, and coal- and biomass-to-liquids)

The LFMM linear program models power generators and CHP plants 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 for each NEMS model year).

Short-term methodology

Our November 2022 *Short-Term Energy Outlook* (STEO) forecasts U.S. petroleum balance and price information for 2022 and 2023 at the national level. The LFMM adopts STEO results for 2022 and 2023, using regional estimates based on the national STEO forecasts.

Legislation and regulation

The Tax Payer Relief Act of 1997

This law reduces 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.

Clean Air Act Amendments of 1990 (CAAA90)

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

EPA's Tier 3 Vehicle Emissions and Fuel Standards

EPA's Tier 3 Vehicle Emissions and Fuel Standards require the average annual sulfur content of federal gasoline to contain no more than 10 ppm after January 1, 2017. For years before 2017, AEO2023 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 no more than 30 ppm.

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.

Nonroad, locomotive, and marine diesel regulation (NRLM)

The Environmental Protection Agency (EPA) requires that nonroad diesel supplies must not contain more than 15 ppm sulfur. For locomotive and marine diesel, these requirements established a NRLM limit of 15 ppm beginning in mid-2012.

Energy Policy Act of 2005 (EPACT2005)

EPACT2005 sets a number of requirements for the petroleum industry, which include removing the oxygenate requirement in RFG.

Energy Independence and Security Act of 2007 (EISA2007)

EISA2007 includes a number of provisions 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. EISA2007 specifies the price of a cellulosic waiver. 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.

EPA Mobile Air Toxics (MSAT2)

The MSAT2 requires all gasoline products (including reformulated and conventional gasoline) produced at a refinery during a calendar year to 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.

California's Low Carbon Fuel Standard

This state law aims to reduce the carbon intensity of gasoline and diesel fuels in that state by 20% from 2010 through 2030.

Oregon's Clean Fuels Program

This program aims to reduce the carbon intensity of gasoline and diesel fuels sold in Oregon by 10% by 2025 from a 2015 baseline.

Global Warming Solutions Act of 2006

The cap-and-trade program within the California Assembly Bill (AB32), the Global Warming Solutions Act of 2006 started on January 1, 2012, and enforceable compliance obligations began in 2013. Petroleum refineries receive 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
- 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 were greater than or equal to 25,000 metric tons of carbon dioxide (CO_2) equivalent ($mtCO_2e$) in any year from 2011 to 2014.

Other state laws

Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont all have laws that lower the sulfur content of all heating oil to ULSD levels over different time schedules. Main and Connecticut law require a transition to 2% biodiesel content.

International Maritime Organization's MARPOL Annex 6

The LFMM does not explicitly represent the MARPOL Annex 6 rule that covers cleaner marine fuels and ocean ship engine emissions. However, the rule is reflected in the effects on transportation and petroleum product export demands, which are provided to the LFMM from the TDM and IEM, respectively, in NEMS. LFMM produces several fuels that meet marine fuel demands, including ULSD, low-sulfur residual fuel oil, and high-sulfur residual fuel oil (if the marine vessel has a scrubber on board).

Federal tax credits

The AEO2023 Reference case extends the $1.00 per gallon biodiesel excise tax credit (Public Law 116-94) through 2024. The $1.01 per gallon cellulosic biofuels production tax credit is extended through 2024.

The Inflation Reduction Act (IRA), which creates a sustainable aviation fuel credit through 2024, ranges from $1.25 per gallon (gal) to $1.75/gal, based on greenhouse gas reductions. In AEO2023, this credit is included as a $1.25/gal credit, assuming that the fuel has met the requisite 50% reduction in lifecycle greenhouse gas emissions compared with traditional aviation fuel.

The IRA also created a new clean fuel production credit for the sale and production of *qualifying fuels* from 2025 to 2027. Qualifying fuels are subject to specific emissions reductions and other requirements, such as the prevailing wage for employees. Total potential credits amount to $1.00/gal of transportation fuel or $1.75/gal of sustainable aviation fuel. In AEO2023, the clean fuel production credit is included as a $1.00/gal credit for biodiesel, renewable diesel, and renewable naphtha and a $1.25/gal credit for sustainable aviation fuel.

AEO2023 also includes scheduled sales of crude oil from the Strategic Petroleum Reserve. These sales, which occur between 2016 and 2031, are required by a number of congressional acts.[12]

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] U.S. Environmental Protection Agency (EPA), 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] U.S. Environmental Protection Agency (EPA), "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] U.S. Department of Energy (DOE), Energy Efficiency and Renewable Energy, *Alternative Fuels Data Center* posting titled "Biobutanol," estimated update to content is 2020.
[6] American Petroleum Institute, How Much We Pay for Gasoline: 1996 Annual Review, May 1997.
[7] Consolidated Appropriations Act, 2016, Pub. L. No: 114-113, H.R.2029, *Division O – Other Matters, Title I – Oil Exports, Safety Valve, and Maritime Security*.
[8] Shapouri, Hosein and Gallagher, Paul, "USDA's 2002 Ethanol Cost-of-Production Survey," July 2005.
[9] U.S. Department of Agriculture (USDA), "2008 Energy Balance for the Corn-Ethanol Industry," June 2010.
[10] U.S. Department of Agriculture (USDA), "U.S. Bioenergy Statistics," data set: Feedstocks, Table 6—Soybean oil supply, disappearance and share used for biodiesel (All Tables in One.xls, sheet: Table006).
[11] Marano, John, "Alternative Fuels Technology Profile: Cellulosic Ethanol," March 2008.
[12] Refer to the AEO2023's *Summary of Legislation and Regulations Included in the Annual Energy Outlook 2023* for a complete list of relevant acts of Congress.