

Renewable Fuel Standard (RFS) Program: Standards for 2026 and 2027, Partial Waiver of 2025 Cellulosic Biofuel Volume Requirement, and Other Changes

Regulatory Impact Analysis

Renewable Fuel Standard (RFS) Program: Standards for 2026 and 2027, Partial Waiver of 2025 Cellulosic Biofuel Volume Requirement, and Other Changes Regulatory Impact Analysis

U.S. Environmental Protection Agency

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List of Acronyms and Abbreviations

Numerous acronyms and abbreviations are included in this document. While this may not be an exhaustive list, to ease the reading of this document and for reference purposes, the following acronyms and abbreviations are defined here:

AEO	Annual Energy Outlook
ASTM	American Society for Testing and Materials
BBD	Biomass-Based Diesel
bbl	Barrel
BE	Biological Evaluation
BOB	Gasoline Before Oxygenate Blending
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CBI	Confidential Business Information
CBOB	Conventional Gasoline Before Oxygenate Blending
CFPC	Clean Fuel Production Credit
CG	Conventional Gasoline
CI	Carbon Intensity
CLCA	Consequential Life Cycle Assessment
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CWC	Cellulosic Waiver Credit
DDG	Dried Distillers Grains
DDGS	Dried Distillers Grains with Solubles
DOE	U.S. Department of Energy
DRIA	Draft Regulatory Impact Analysis
DWG	Distillers Wet Grains
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EMTS	EPA-Moderated Transaction System
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 2005
EqV	Equivalence Value
EU	European Union
FFV	Flex-Fuel Vehicle
FOG	Fats, Oils, and Greases
gal	Gallon
GDP	Gross Domestic Product
GHG	Greenhouse Gas
REET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
IEA	International Energy Agency
IRA	Inflation Reduction Act
LCA	Lifecycle Analysis
LCFS	Low Carbon Fuel Standard
LNG	Liquified Natural Gas

MMBD	Million Barrels per Day
MSW	Municipal Solid Waste
MTBE	Methyl Tertiary Butyl Ether
MY	Model Year
NAICS	North American Industry Classification System
NASS	National Agricultural Statistics Service
NEMS	National Energy Modeling System
NGLs	Natural Gas Liquids
NH ₃	Ammonia
NHTSA	National Highway Transportation Administration
NLR	National Laboratory of the Rockies
NO _x	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
OBBA	One Big Beautiful Bill Act of 2025
OPEC	Organization of Petroleum Exporting Countries
OPIS	Oil Price Information Service
ORNL	Oak Ridge National Laboratory
PADD	Petroleum Administration for Defense District
PM	Particulate Matter
PTD	Product Transfer Document
RBOB	Reformulated Gasoline Before Oxygenate Blending
RFA	Regulatory Flexibility Act
RFF	Resources for the Future
RFG	Reformulated Gasoline
RFS	Renewable Fuel Standard
RIA	Regulatory Impact Analysis
RIN	Renewable Identification Number
RNG	Renewable Natural Gas
RtC3	EPA's Third Triennial Report to Congress on Biofuels and the Environment
RVO	Renewable Volume Obligation
RVP	Reid Vapor Pressure
SBA	Small Business Administration
SBREFA	Small Business Regulatory Enforcement Fairness Act of 1996
SO ₂	Sulfur Dioxide
SO _x	Sulfur Oxides
SPR	Strategic Petroleum Reserve
SRE	Small Refinery Exemption
STEO	Short Term Energy Outlook
UCO	Used Cooking Oil
USDA	U.S. Department of Agriculture
VOCs	Volatile Organic Compounds
WTI	West Texas Intermediate

Executive Summary

The Renewable Fuel Standard (RFS) program began in 2006 pursuant to the requirements in Clean Air Act (CAA) section 211(o) that were added through the Energy Policy Act of 2005 (EPAct). The statutory requirements for the RFS program were subsequently amended and extended through the Energy Independence and Security Act of 2007 (EISA). In addition to increasing the number of renewable fuel categories from one to four, increasing the volume targets, and extending those volume targets from 2012 to 2022, EISA also expanded the waiver provisions in CAA section 211(o)(7) that authorize EPA to waive the statutory volume targets under certain conditions.

The statute includes annual, nationally applicable volume targets through 2022 for cellulosic biofuel, advanced biofuel, and total renewable fuel, and through 2012 for biomass-based diesel (BBD). For years after those for which the statute specifies volume targets, the statute directs EPA to establish volume requirements based on a review of implementation of the program to date and an analysis of a set of specified factors. In order to effectuate those volume requirements, the statute required EPA to translate them through 2022 into percentage standards that obligated parties then use to determine the compliance obligations that they must meet every year. As discussed in Preamble Section V, we are continuing to use percentage standards as the implementing mechanism for 2026 and 2027, as we did for 2023–2025.

In this action we are establishing the applicable volume targets for all four categories of renewable fuel for the years 2026 and 2027. We are also establishing the annual percentage standards for all four categories that will apply to gasoline and diesel fuel produced or imported by obligated parties in 2026 and 2027. Finally, in addition to these volumes and standards, we are finalizing several other changes, including the removal of renewable electricity as a qualifying renewable fuel under the RFS program.

This Regulatory Impact Analysis (RIA) supports our rule by addressing our statutory obligations under CAA section 211(o)(2)(B)(ii) for determining the applicable volume requirements for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel. Specifically, this section of the statute directs us to establish the applicable volumes based upon a review of the implementation of the program and an analysis of various environmental, economic, and other factors. We provide this analysis here, in conjunction with the analysis in the preamble and several technical support memoranda to the docket.

Table ES-1 summarizes certain potential impacts associated with the volume requirements in this rule, including both quantified and unquantified impacts. Not all of the quantified impacts listed in Table ES-1 represent societal benefits or costs. For example, the projected \$10.1 billion annualized impacts on rural economic development generally do not represent societal benefits. The only monetized societal benefits and costs are the energy security benefits and the fuel costs. The monetized societal benefits and costs of this rule are shown in Table ES-2.

Table ES-1 is not a comprehensive listing of all the potential impacts that EPA considered in this rulemaking. The inclusion of an impact in this table also does not indicate that

EPA gave it greater weight than impacts not listed in this table. A full discussion of each impact, including the uncertainties associated with estimating the impact, is contained in the RIA Chapter identified under the “Chapter” column of Table ES-1. EPA compiled this table to provide additional information to the public regarding this rulemaking and to comply with OMB Circular A-4.

Table ES-1: Potential Annualized Quantified and Unquantified Impacts Associated with the Analyzed Volumes Relative to the No RFS Baseline^a

Potential Impacts of Analyzed Volumes	Effect	Effect Quantified	Quantified Impact	Chapter
Impacts on air quality from biofuel production, transport, and use	Increases in emissions associated with biofuel production	Quantitative	See RIA Chapter	4.1.2.1
	Increases in emissions associated with biofuel transport	Qualitative	-	4.1.2.2
	Varying emission impacts from vehicles running on ethanol blends and pre-2007 diesel vehicles running on biodiesel blends	Qualitative	-	4.1.2.3
	Changes in ambient concentrations of air pollutants varies by location across the U.S.	Qualitative	-	4.1.3
Impacts on climate change from biofuel feedstock production and displacement of petroleum fuels	Reduced greenhouse gas (GHG) emissions	Quantitative	-31 to 1 MMT average annual CO ₂ e emissions	5
Impacts on conversion of natural lands, including wetlands, from biofuel feedstock production	Increased conversion of wetlands, forests, pasture, and grasslands to cropland	Qualitative	-	4.2
Impacts on soil and water quality from biofuel feedstock production	Impacts to soil and water quality from increased erosion, nutrient, and pesticide runoff due to agricultural conversion	Qualitative	-	4.3
	Other impacts to water quality, including but not limited to leaks and spills from aboveground and underground storage as well as biogas production	Qualitative	-	4.3
Impacts on water quantity and availability from biofuel and feedstock production	Use of water resources for cropland irrigation	Qualitative	-	4.4
	Use of water in production facilities	Qualitative	-	4.4

Potential Impacts of Analyzed Volumes	Effect	Effect Quantified	Quantified Impact	Chapter
Impacts on ecosystems and wildlife habitat	Impacts due to loss of natural lands, changes to soil and water quality, air quality, and water quantity	Qualitative	-	4.5
Energy security	Increased energy security	Quantitative	\$411 million	6
Production and use of renewable fuels	Increased production and use of renewable fuels	Quantitative	See RIA Chapter	7
Infrastructure	Increased development of infrastructure of deliver and use renewable fuels	Qualitative	-	8
	No adverse impact on deliverability of materials, goods, and products other than renewable fuel	Qualitative	-	8
Jobs	Increased employment	Quantitative	96,487–108,975 jobs	9.1
Rural economic development	Increased support for rural economic development associated with biofuel and feedstock production	Quantitative	\$10.08 billion	9.1
Commodity supply and price impacts	Increased supply of certain agricultural commodities	Qualitative	-	9.2
	Higher corn, soybean, and soybean oil prices	Quantitative	See RIA Chapter	9.3
	Higher food prices	Quantitative	\$2.65–3.19 billion	9.4
Costs	Increased societal cost	Quantitative	\$18.2 billion in 2026, \$21.2 billion in 2027	10.4
	Estimated fuel price impacts	Quantitative	See RIA Chapter	10.5
	Increased costs to transport goods	Quantitative	See RIA Chapter	10.5

^a This table includes both societal costs and benefits (fuel costs, energy security) as well as distributional effects or transfers (jobs, rural economic development, higher food prices, etc.). Monetized fuel costs, energy security benefits, and rural economic development benefits in Table ES-1 represent annualized monetized impacts using a 3% discount rate. Alternative discount rates are considered in Preamble Section V.H and in the relevant chapters cited within the table.

Table ES-2: Societal Benefits and Costs of this Rule (million 2024\$)

Type	Category	2026	2027	Present Value	Annualized Value
Societal Benefits	Energy Security Benefits	\$360	\$440	\$790	\$410
Societal Costs	Fuel Costs	\$18,240	\$21,240	\$38,870	\$20,310
Net Benefits	Total	-\$17,880	-\$20,810	-\$38,080	-\$19,900

Note: Present and annualized values are estimated using a 3% discount rate. Computing annualized costs and benefits from present values spreads the costs and benefits equally over each period, taking account of the discount rate. The annualized value equals the present value divided by the sum of discount factors. For a calculation of present and annualized values from annual impact estimates, see “Set 2 Final Rule Costs and Benefits Summary,” available in the docket for this action. All costs and benefits are rounded to the nearest \$10 million.

Overview

Chapter 1: Review of the Implementation of the Program

This chapter reviews the implementation of the RFS program, focusing on renewable fuel production and use in the transportation sector since the RFS program began.

Chapter 2: Baselines

This chapter identifies the appropriate baselines for comparison.

Chapter 3: Analyzed Volumes and Volume Changes

This chapter identifies the specific biofuel types and associated feedstocks that are projected to be used to meet the volumes in the Analyzed Volumes. It also identifies the differences between the Analyzed Volumes and the baselines described in Chapter 2.

Chapter 4: Environmental Impacts

This chapter discusses the environmental factors EPA analyzed in developing the Analyzed Volumes.

Chapter 5: Climate Change Analysis

This chapter describes potential climate impacts of the Analyzed Volumes.

Chapter 6: Energy Security Impacts

This chapter reviews the literature on energy security impacts associated with petroleum consumption and imports and summarizes EPA's estimates of the benefits that will result from the Analyzed Volumes.

Chapter 7: Rate of Production and Consumption of Renewable Fuel

This chapter discusses the expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (primarily cellulosic biofuel and BBD).

Chapter 8: Infrastructure

This chapter analyzes the impact of renewable fuels on the distribution infrastructure of the U.S.

Chapter 9: Other Factors

This chapter provides greater detail on our evaluation of impacts of renewable fuels on job creation, rural economic development, supply and price of agricultural commodities, and food prices.

Chapter 10: Estimated Costs and Fuel Price Impacts

This chapter estimates the impact of the use of renewable fuels on the social cost, the cost to consumers (prices) of transportation fuel, and on the cost to transport goods. This chapter also provides a comparison of societal benefits and costs and presents analyses for alternative volume scenarios (Sensitivity Cases).

Chapter 11: Screening Analysis

This chapter discusses EPA's screening analysis evaluating the potential impacts of the RFS standards on small entities.

Note: Unless otherwise stated, all documents cited in this document are available in the docket for this action (EPA-HQ-OAR-2024-0505). We have generally not included in the docket Federal Register notices, court cases, statutes, regulations, materials with a Digital Object Identifier (DOI), or previously docketed materials. These materials are easily accessible to the public via the Internet and other means.

Chapter 1: Review of the Implementation of the Program

The statute directs EPA to establish volumes based on several factors, including “a review of the implementation of the program during calendar years specified in the tables ...” CAA section 211(o)(2)(B)(ii). The Set 1 Rule RIA contains EPA’s review of the implementation of the RFS program from the passing of the Energy Policy Act of 2005 through 2022, the last calendar year specified in the statutory tables.¹ In determining the RFS volumes in this rule, we have once again considered the implementation of the RFS program through 2022, described in detail in the Set 1 Rule RIA. We have also considered developments in the petroleum fuel and renewable fuel sectors since 2022 as part of our consideration of other relevant factors and as informed by our assessment of implementation of the RFS program for the years specified in the statutory tables. Throughout this document, we use the term “supply” of renewable fuel to refer to the quantity of qualifying renewable fuel that can be used as transportation fuel, heating oil, or jet fuel in the U.S. Unless otherwise noted, all historical data on the supply of renewable fuel is based on data from the EPA Moderated Transaction System (EMTS).

This chapter focuses on our review of the implementation of the RFS program since 2022, with references to important observations from previous years where relevant. For a more extensive review of the implementation of the RFS program from 2005–2022, see Chapter 1 of the Set 1 Rule RIA.

1.1 Gasoline, Diesel, Crude Oil, and Renewable Fuels

This section compares recent and projected crude oil and renewable fuels feedstock prices, and discusses observed and projected petroleum imports, refinery margins, and transportation fuel demand prior to and during the recent and future years of the RFS program.

1.1.1 Crude Oil Prices vs. Renewable Fuel Feedstock Price Projections

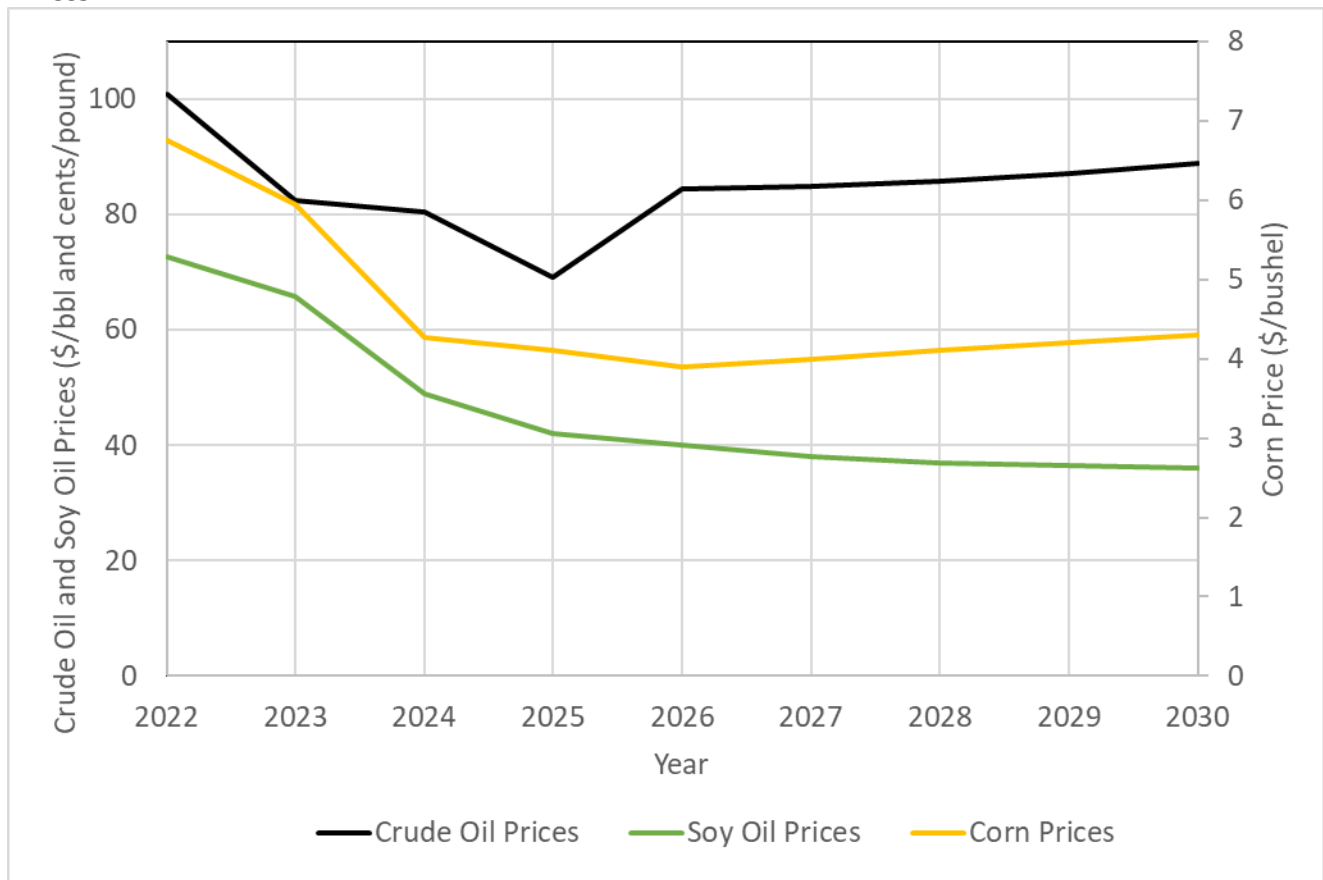
Crude oil prices have a significant impact on the economics of increased use of renewable fuels. When crude oil prices increase, both renewable fuel feedstock prices and gasoline and diesel prices tend to increase as well, although gasoline and diesel prices generally increase more relative to renewable fuel feedstock prices. Thus, higher crude oil prices generally improve the economic competitiveness and value of renewable fuels relative to gasoline and diesel. Conversely, lower crude oil prices tend to hurt the economic competitiveness and value of renewable fuels.

Figure 1.1.1-1 compares the recent historical crude oil and corn and soybean oil prices and their projected future prices in nominal dollars. The figure shows that after high crude oil and renewable fuels feedstock prices in 2022, those prices have decreased from 2023 to 2025. The U.S. Department of Agriculture (USDA) projects corn prices to decrease somewhat through 2026 and then increase slightly after that, while soybean oil prices are expected to continue decreasing. The U.S. Energy Information Administration (EIA) projects crude oil prices to jump up in 2026 and increase slightly out to 2030. It is important to note that actual crude oil prices at

¹ “EPA, Renewable Fuel Standard (RFS) Program: Standards for 2023–2025 and Other Changes – Regulatory Impact Analysis,” EPA-420-R-23-015, June 2023.

the start of 2026 are closer to the lower prices in 2025.

Figure 1.1.1-1 Historical and Projected Future Crude Oil, Corn, and Soybean Oil Nominal Prices



Note: 2024 and earlier are historical, 2025 and later are price projections in nominal dollars.

Source: EIA, "Spot Prices," *Petroleum & Other Liquids*, January 26, 2026.

https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm. USDA, "Oil Crops Yearbook," January 2026.

<https://www.ers.usda.gov/data-products/oil-crops-yearbook>. farmdoc, "US Average Farm Price Received Database,"

February 28, 2025. <https://farmdoc.illinois.edu/decision-tools/us-average-farm-price-received-database>. AEO2025,

Table 12 – Petroleum and Other Liquids Prices. USDA, "USDA Agricultural Projections to 2033," OCE-2025-1,

February 2025, <https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2034.pdf>.

1.1.2 Petroleum and Renewable Fuels Imports

As discussed further in Chapter 6, energy security is an important goal of the RFS program. Importing a significant amount of crude oil and finished petroleum products from abroad creates an energy security concern, as there could be significant costs to the U.S. economy if foreign supplies are disrupted. A good example is the oil embargo by the Organization of Petroleum Exporting Countries (OPEC) against the U.S. in 1973 and 1974, which drove up prices, reduced supply, and is credited with causing the U.S. economy to slide

into a recession.² It also led to Congress banning the export of U.S. crude oil from 1975 to 2015.³

At the time that Congress passed EPAct and EISA and EPA promulgated the RFS1 and RFS2 rules, the U.S. was importing a large portion of its crude oil and significant quantities of gasoline, particularly on the East Coast. At the time, that trend was expected to continue indefinitely. This expectation did not factor in the eventual increase in U.S. tight oil crude production, which largely occurred after the passage and promulgation of these laws and rules. Using EIA data, we reviewed how petroleum imports changed before, during, and after the passage of EPAct and EISA, and implementation of the RFS program, in the Set 1 Rule. During the time period of 2005–2020, U.S. net imports of crude oil and refined products decreased substantially.

Since 2022, net imports of gasoline and distillate increased some and then decreased, but overall the changes are modest.⁴ EIA does not specifically project future gasoline and diesel fuel net imports in its Annual Energy Outlook (AEO) reports. However, EIA does project and report a total refined product net import estimate which we show in the figure along with their historical values.⁵ Figure 1.1.2-1 summarizes the gasoline, distillate, and total refined product volumes.

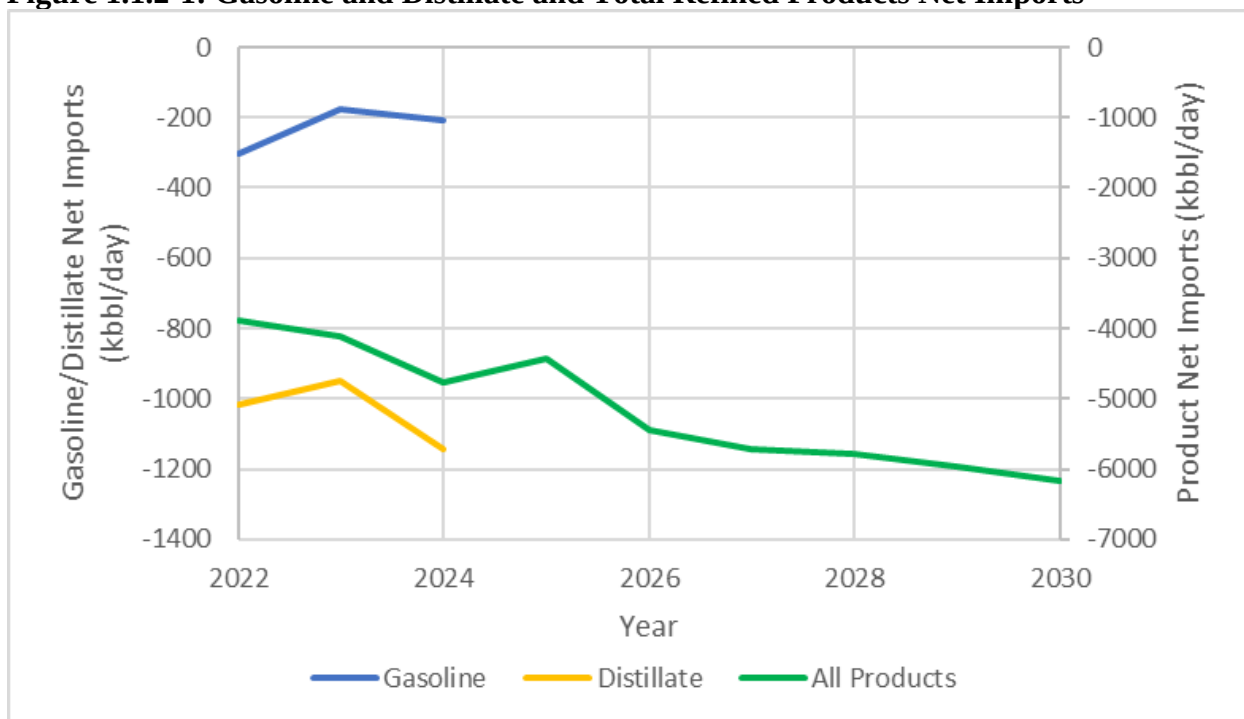
² Verrastro, Frank A. and Guy Caruso. “The Arab Oil Embargo-40 Years Later.” *Center for Strategic & International Studies*, October 16, 2013. <https://www.csis.org/analysis/arab-oil-embargo-40-years-later>.

³ 1975 Energy Policy and Conservation Act; Consolidated Appropriations Act of 2016.

⁴ EIA, “U.S. Net Imports by Country,” *Petroleum & Other Liquids*, February 6, 2026. https://www.eia.gov/dnav/pet/pet_move_netl_dc_NUS-Z00_mbbldpd_a.htm.

⁵ AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

Figure 1.1.2-1: Gasoline and Distillate and Total Refined Products Net Imports

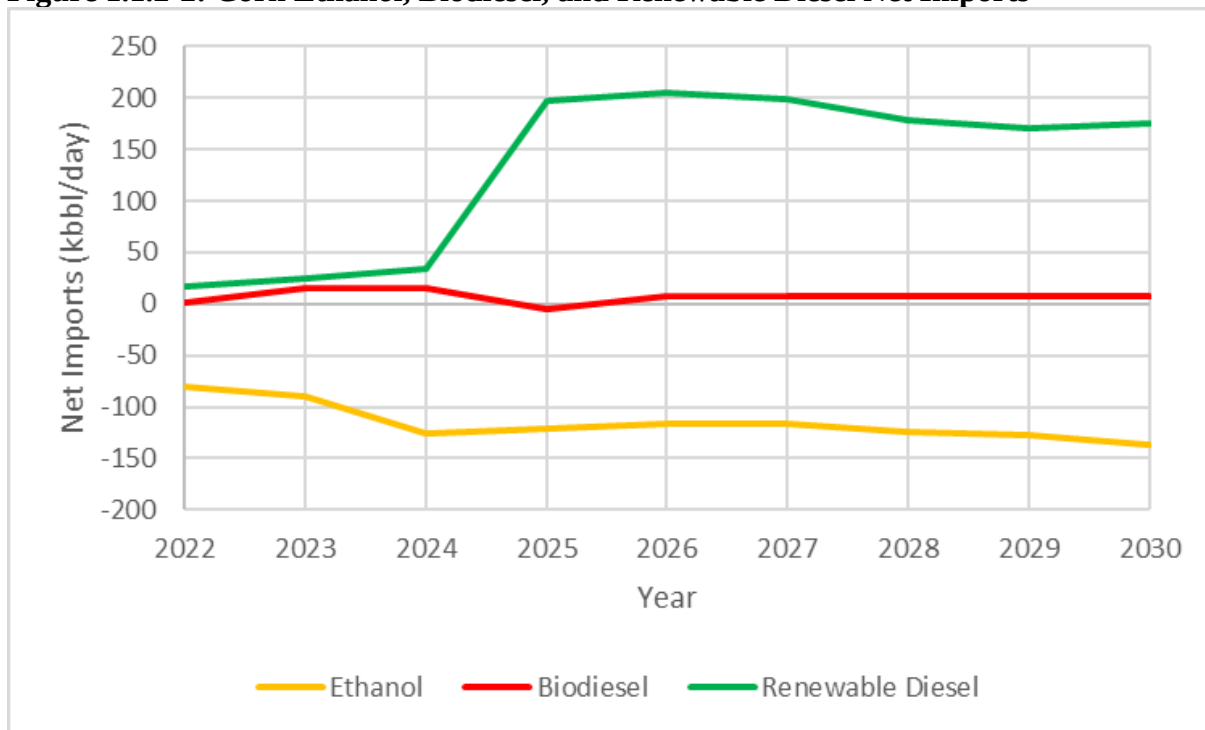


Note: 2024 and earlier are historical, 2025 and later are price projections.

The projected decrease in net imported total refined products could indicate that EIA projects further decreases in net imported gasoline and distillate; however, there are other refined products which can contribute significantly to net exports. For example, currently there are substantial exports of hydrocarbon gas liquids and residual fuel, thus, some or potentially most of the decrease in projected net refined products could be comprised of these other products instead of gasoline and distillate.

EIA also gathers information on, reports, and projects the net imports of ethanol, biodiesel, and renewable diesel. Figure 1.1.2-2 summarizes the historical and projected net imports of these renewable fuels.

Figure 1.1.2-2: Corn Ethanol, Biodiesel, and Renewable Diesel Net Imports



Note: 2024 and earlier are historical, 2025 and later are projections.

Source: EIA, "U.S. Net Imports by Country," *Petroleum & Other Liquids*, February 6, 2026.

https://www.eia.gov/dnav/pet/pet_move_net/dc_NUS-Z00_mbbldpd_a.htm. AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

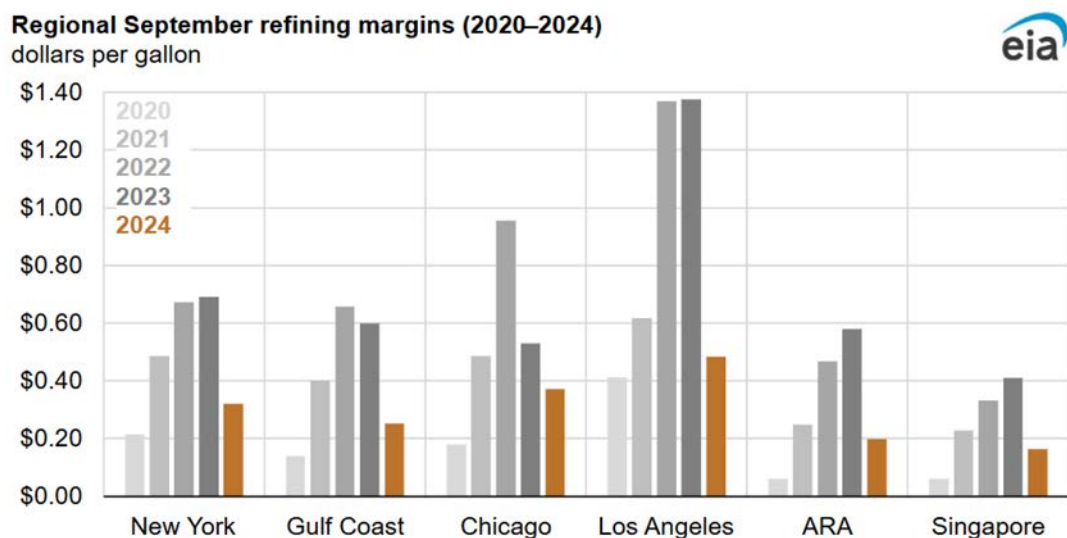
Figure 1.1.2-2 shows that biodiesel and renewable diesel net imports increased marginally until 2024. After 2024, EIA projects biodiesel to essentially be flat going forward and renewable diesel to jump up in 2025 and remain at the higher level. Corn ethanol net imports decreased from 2022 to 2024. After 2024, EIA projects corn ethanol net imports to mostly remain negative and flat through 2027 and decrease somewhat after 2027. This decrease may principally be due to EIA's projected decrease in gasoline demand, which would decrease the volume of ethanol blended into gasoline domestically at 10%. Consequently, corn ethanol producers would export the excess corn ethanol production volume which is not blended into gasoline as E15 or E85. The increased consumption of renewable fuels contributes to reductions in net petroleum imports, though by a very modest amount.

1.1.3 Refinery Margins

Refinery margins reveal the economic health of refineries. The higher the margins for a refinery, the greater its profitability and economic viability. Over time, refinery margins vary considerably but must average at least a certain level for refineries to be viable over the long term.

EIA reported refinery margin data for various U.S. refinery regions, as well as for Europe and Singapore, and is shown in Figure 1.1.3-1.⁶ The refinery margin data are 3-2-1 cracked spreads, which are gross margins (excludes refinery operating costs) and the data is for the years 2020–2024.

Figure 1.1.3-1: Refinery Margins in the U.S. and Two Other Regions



Note: ARA = Amsterdam-Rotterdam-Antwerp

The figure shows that the disruption of fuel consumption in 2020 caused by the COVID-19 pandemic resulted in severely depressed refinery margins worldwide. However, as fuel demand rebounded in 2021 and 2022, refinery margins recovered through 2023. Due to falling U.S. refined product demand, particularly distillate, and falling demand in China and Europe, refinery margins dropped back down in 2024. In addition to falling demand, several large refineries began operating in the Middle East and Africa which also contributed to lower refinery margins.⁷ Although refinery margins dropped in all regions in 2024, U.S. refinery margins are still somewhat higher than those in Western Europe and Singapore. U.S. refinery margins are typically better than overseas refinery regions due to lower prices for purchased crude oil, and natural gas which is used as a feedstock for refinery heat and hydrogen production.

1.1.4 Transportation Fuel Demand

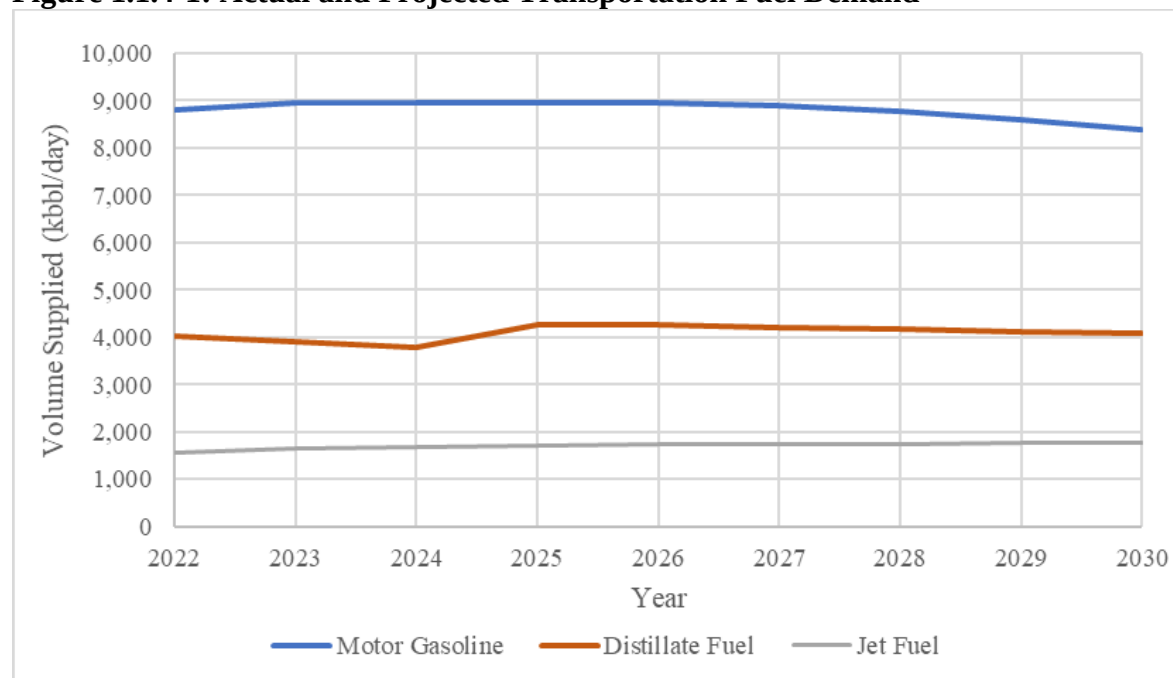
At the time the RFS2 program was being enacted through EISA in 2007, there had been a consistent increase in U.S. petroleum demand and crude oil prices were very high. The RFS program was implemented to help meet U.S. refined product demand and help to lower crude oil prices. However, transportation fuel demand slowed starting in 2008 and has remained relatively stable since that time.

⁶ EIA, “Global refinery margins fall to multiyear seasonal lows in September,” *Today in Energy*, October 15, 2024. <https://www.eia.gov/todayinenergy/detail.php?id=63447>.

⁷ Id.

Figure 1.1.4-1 shows the actual volume of gasoline, distillate, and jet fuel consumed in the U.S. from 2022–2024, as well as the projected demand of gasoline, distillate, and jet fuel from 2025–2030.

Figure 1.1.4-1: Actual and Projected Transportation Fuel Demand



Source: 2022 – 2024 data is from EIA, “U.S. Product Supplied for Crude Oil and Petroleum Products,” *Petroleum & Other Liquids*, January 26, 2026. https://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbldpd_a.htm. 2025 – 2030 data is from AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

Figure 1.1.4-1 shows that gasoline demand increased from 2022 to 2023 but is projected to remain flat through 2026 and decrease after 2026. Distillate demand decreased from 2022 to 2024, while jet fuel increased. Based on projections in AEO2025, distillate demand is expected to increase somewhat in 2025 and then decline slightly thereafter. Jet fuel has been increasing very modestly and is expected to increase slightly over the years 2025 to 2030.

Several factors are contributing to lowering transportation fuel demand:

- *Increased crude oil prices.* Periods of higher crude oil prices as far back as 2007 and as recent as 2022, which resulted in increased transportation fuel prices during these time periods, which affected consumer behavior by impacting the number of miles traveled and vehicle purchase decisions.
- *Increasing fuel economy of the motor vehicle fleet.* EPA and the National Highway Transportation Administration (NHTSA) finalized standards which reduced light-duty motor vehicle GHG emissions and increased the Corporate Average Fuel Economy (CAFE) of motor vehicles. The trend of decreasing fuel consumption intensity has been monitored and reported by EPA for decades.⁸ On balance, newer

⁸ “The 2024 EPA Automotive Trends Report,” EPA-420-R-24-022, November 2024.

vehicles consume fuel more efficiently; thus, as consumers purchase new motor vehicles, these new vehicles consume less gasoline and diesel compared to the vehicles sold in previous years, reducing overall petroleum demand.

- *Electric vehicle penetration and fuel displacement.* Electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) reduce consumption of petroleum fuel by either partially displacing petroleum fuels (in the case of PHEVs) or completely displacing petroleum demand (in the case of EVs). Based on data for electricity demand by light-duty vehicles, EIA estimates that EVs and PHEVs consumed 11.74 million MWh of electricity in 2024.⁹ If we assume that EVs travel 3 miles per kWh of electricity consumed, and the in-use light-duty fleet travels 22.7 miles per gallon of gasoline consumed, then electricity consumption by light-duty vehicles displaced 1.55 billion gallons of gasoline in 2024.

1.2 Cellulosic Biofuel

The RFS2 Rule projected strong growth for cellulosic biofuels, anticipating they would become a major contributor to total biofuel volumes.¹⁰ After that rule took effect, however, commercial-scale production of cellulosic biofuels failed to meet those high expectations, with actual volumes falling significantly below statutory targets for the first several years. A major shift occurred when renewable natural gas (RNG) derived from biogas and used as transportation fuel was recognized as a qualifying cellulosic biofuel. The RFS2 Rule did initially include a pathway¹¹ for generating advanced (D5) Renewable Identification Numbers (RINs) from biogas produced at landfills, wastewater treatment plants, and manure digesters,¹² but this did not extend to generating cellulosic (D3) RINs. However, in response to industry inquiries, EPA evaluated whether biogas from these sources could also qualify as cellulosic biofuel. Through the 2014 Pathways II Rule, EPA finalized this expansion by approving cellulosic pathways for RNG derived from biogas from landfills, wastewater treatment facility digesters, and manure digesters when used as transportation fuel. For clarity, in this document we refer to RNG used as compressed or liquefied natural gas in transportation as “renewable CNG/LNG.” EPA also approved biogas derived from the cellulosic components of biomass processed in other waste digesters to generate cellulosic RINs when used as transportation fuel.¹³ Although this pathway was not initially identified in the RFS2 Rule, this expansion under the Pathways II Rule has since been the primary driver of growth in total cellulosic biofuel volumes.

Following the implementation of the Pathways II Rule in 2014, the production of cellulosic biofuels has experienced rapid growth, increasing from approximately 33 million RINs in 2014 to over 1 billion RINs in 2025, (see Figure 1.2-1), with around 93% of all cellulosic RINs generated under the RFS program in 2025 attributed to renewable CNG/LNG. This trend is

⁹ EIA, “Electric Power Monthly,” February 2025, Table D.1 – U.S. Estimated Consumption of Electricity by Light-Duty Electric Vehicles Types. https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=table_d_1.

¹⁰ 75 FR 14674 (March 26, 2010).

¹¹ A pathway is a combination of feedstock, production process, and fuel type. EPA has evaluated a number of different pathways to determine the category of renewable fuel that fuel produced using the various pathway qualifies for. The list of generally applicable pathways can be found in 40 CFR 80.1426(f).

¹² 75 FR 14872 (March 26, 2010).

¹³ 79 FR 42128 (July 18, 2014).

expected to continue, with total volumes steadily increasing and renewable CNG/LNG remaining the primary source of cellulosic biofuels in the RFS program through 2027 (see Chapter 7). As discussed further in Chapter 7.1.4, EPA also projects growth in the relatively smaller volumes of cellulosic ethanol produced from corn kernel fiber (CKF) as part of its overall cellulosic biofuel volume projection. Taken together, EPA projects robust growth in cellulosic volumes based on these two primary components.

Alongside this robust growth in cellulosic volumes, EPA has also modernized the regulatory framework for biogas-derived fuels since the RFS2 Rule. Through the Biogas Regulatory Reform Rule (BRRR)¹⁴, finalized in the 2023 RFS Set Rule, EPA updated oversight of renewable CNG/LNG and restructured the compliance framework for RNG. This rule decoupled cellulosic RIN generation from the demonstration that RNG is used as transportation fuel. In short, RNG RINs are now generated prior to use as a transportation fuel, and such RINs are not separated—and thus made available for compliance—until the RNG RIN separator obtains documentation demonstrating that the volume of renewable CNG/LNG was used as transportation fuel.

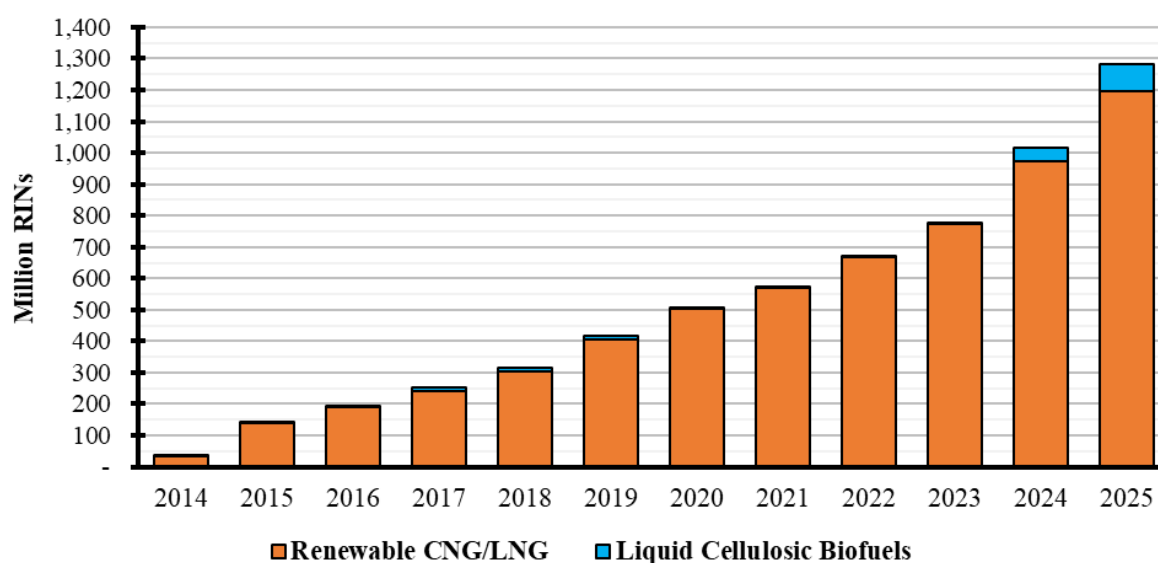
Looking ahead, EPA expects the distinction between RIN generation and RIN separation to become increasingly important for setting future volumes. Specifically, EPA anticipates a shift from a production-constrained market to one limited by consumption. Under the Pathways II framework, projections largely tied cellulosic RIN volumes to production capacity. Now, however, the market for renewable CNG/LNG appears to be nearing saturation, with the existing CNG/LNG fleet already largely supplied by biofuel. Because RINs are separated and available for compliance only when the separator obtains documentation showing that the volume of renewable CNG/LNG was used as transportation fuel, a saturated fleet means the size of the vehicle fleet capable of consuming that fuel becomes a crucial factor in setting future volumes. Accordingly, EPA has updated its methodology for projecting future cellulosic biofuel volumes to reflect these consumption constraints, as discussed in Chapter 7.1.

Evidence of this shift in market dynamics is already noticeable, as EPA adjusted the 2024 cellulosic biofuel volume obligations.¹⁵ This adjustment was necessary because 2024 cellulosic RIN availability failed to meet the volume requirement. Similarly, EPA is finalizing an adjustment to the 2025 cellulosic volume requirement in this action, as presented in Preamble Section VI and discussed in detail in Chapter 7.1.3. Therefore, while EPA is still projecting continued growth in cellulosic biofuel production, future growth is likely to be impacted by the ability to use it as a qualifying transportation fuel.

¹⁴ 88 FR 44522 - 44541 (July 12, 2023).

¹⁵ 89 FR 100442 (December 12, 2024).

Figure 1.2-1: Cellulosic RIN Generation (2014–2025)



Note: We did not yet have final renewable CNG/LNG generation data for 2025 at the time of this analysis. Based on the information available at the time of writing, we do not expect the reported figures to differ materially from the final data.

Source: EMTS.

1.3 Biodiesel and Renewable Diesel

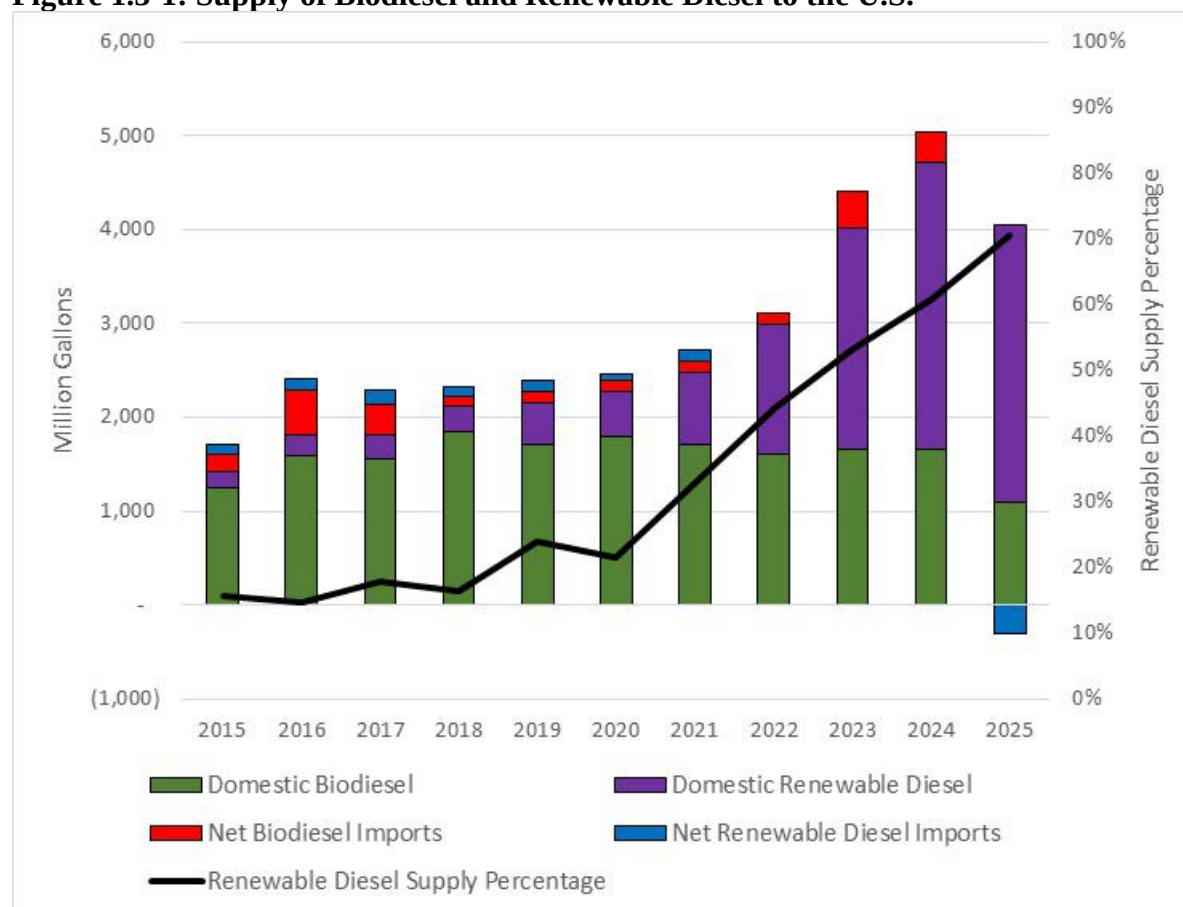
The supply of biodiesel and renewable diesel has continued to significantly exceed the BBD volume requirements since 2022, as blending of additional volumes of BBD beyond the BBD volume requirement has been the marginal strategy used by refiners and petroleum marketers to meet both the advanced biofuel and total renewable fuel volume requirements since that time. These additional volumes reflect that BBD is generally the marginal gallon of advanced biofuel supplied to the market, as well as the marginal gallon of total renewable fuel. As discussed in Chapter 1.7.2, the status of BBD as the marginal gallon of both advanced biofuel and total renewable fuel is also reflected in the convergence of the RIN prices for BBD (D4), advanced biofuels (D5), and conventional renewable fuel (D6). While we project that the supplies of other advanced biofuels and the use of ethanol in higher level ethanol blends will continue to increase in future years, we project that the advanced and total biofuel volumes we are establishing in this rule will continue to provide incentives for the production and use of BBD beyond the BBD volume requirement.

The supply of BBD to the U.S. has increased rapidly since 2022, with nearly all the increase in the supply of BBD coming from the increased domestic production of renewable diesel. The market preference for renewable diesel over biodiesel appears to be the result of a combination of different factors. First, renewable diesel production capacity has increased significantly in recent years, while the operable production capacity for biodiesel has decreased slightly (see Chapter 7.2.2 for more detail on BBD production capacity). Renewable diesel production facilities also tend to be much larger than biodiesel production facilities, allowing renewable diesel producers to benefit from economies of scale. Further, renewable diesel generates more credits per gallon than biodiesel due to the higher energy content of renewable

diesel, providing additional revenue for renewable diesel producers and blenders. Perhaps most importantly, renewable diesel can generally be blended with petroleum diesel at higher rates without violating engine manufacturer fueling recommendations or requiring additives to meet state specifications. This has allowed greater quantities of renewable diesel to be used in states with low carbon fuel programs, where there is a financial incentive for distillate biofuel blending rates to exceed warrantable biodiesel blending rates. This ability to blend at higher rates than biodiesel in these lucrative markets has in turn allowed renewable diesel producers to claim additional financial incentives under low carbon fuel programs that are not readily available to biodiesel producers. As shown in Figure 1.3-1, the supply of renewable diesel has grown rapidly in recent years and exceeded the supply of biodiesel for the first time in 2023.

In 2025 the total supply of BBD to the U.S. decreased significantly from the volumes supplied in 2023 and 2024. This drop in the supply of BBD was likely due to a combination of factors, including an oversupply of BBD in 2023 and 2024 relative to the RFS volume requirements and changes to the federal tax credit available to BBD suppliers (see Chapter 1.6).

Figure 1.3-1: Supply of Biodiesel and Renewable Diesel to the U.S.



Source: EMTS.

Another significant development in the BBD industry is the recent increase in the quantities of BBD feedstocks imported into the U.S. Historically, the U.S. has imported very small quantities of qualifying BBD feedstocks such as soybean oil, canola oil, and other

qualifying fats, oils, and greases (FOG).¹⁶ The biggest source of imported qualifying BBD feedstock through 2022 was canola oil from Canada, which is primarily used as a food ingredient rather than for biofuel production. In 2022 and 2023, imports of other qualifying BBD feedstocks, particularly FOG, increased dramatically. These imports were likely driven by several factors, including increasing used cooking oil (UCO) collection rates in other countries, declining demand for these feedstocks and biofuels produced from them in the European Union (EU), and strong demand for these feedstocks for biofuel production in the U.S. driven by the combination of federal and state incentives.

Historically, FOG could be used to produce BBD with lower carbon intensity (CI) scores than BBD produced from crop-based feedstocks such as soybean oil and canola oil. This allowed these fuels to generate significantly more credits in state low carbon fuel programs. The Clean Fuel Production Credit (CFPC) federal subsidy for domestically produced renewable fuels (hereafter referred to as “45Z” or the “45Z credit”), which replaced several pre-existing fuel tax incentives for fuel produced after December 31, 2024, also provides greater credits for fuel with lower carbon intensity. This combination of State and Federal incentives were factors in a large increase in imported feedstocks in 2023 and 2024, particularly imports of feedstocks such as FOG that can be used to produce BBD with low CI scores.

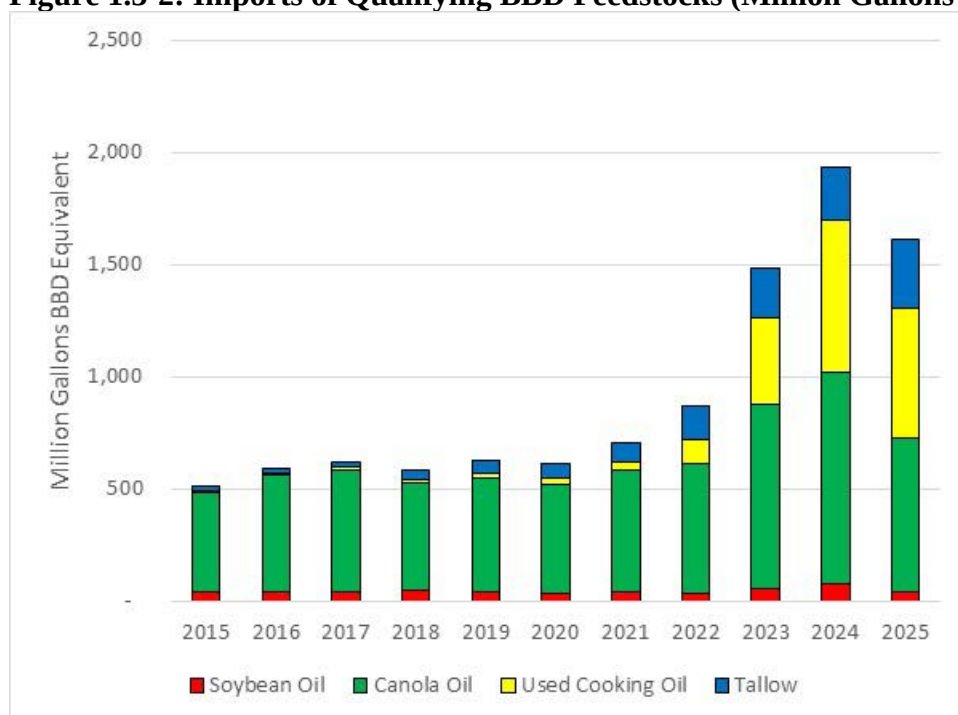
In July 2025, the One Big Beautiful Bill Act of 2025 (OBBB) included significant changes to the CFPC.¹⁷ Importantly, OBBB prohibited the consideration of land use change in the emission rates for biofuels. This decreased the tax advantages that BBD produced from FOG previously received relative to BBD produced from soybean oil and canola oil. OBBB also disqualified biofuels that were produced from feedstocks that originated outside of North America. Together these two changes are expected to significantly impact the available incentives for different types of BBD production. While BBD produced from domestic soybean oil and canola oil imported from Canada previously received a much lower tax credit than BBD produced from imported FOG, these vegetable oil-based fuels are now expected to receive a much greater tax credit than imported FOG.

The rate of future imports of feedstocks is highly uncertain, as the destination for globally traded feedstocks can change rapidly in response to changing market conditions and/or policy incentives. Tariffs on these feedstocks and other trade actions could also have a significant impact on imports of BBD feedstocks. The rapid observed increase in feedstock imports into the U.S. since 2022 illustrates how quickly feedstock suppliers can respond to changing market conditions. Imports of qualifying BBD feedstocks are shown in Figure 1.3-2. More detail on the projected supply of BBD feedstocks beyond 2025, including imported feedstocks, can be found in Chapter 7.2.3.

¹⁶ FOG as a category is comprised of a diverse collection of lipid-based feedstocks, including used cooking oil, animal fats, and various other biogenic lipid-based secondary products.

¹⁷ Public Law 119-21, H.R. 1 “One Big Beautiful Bill,” July 4, 2025.

Figure 1.3-2: Imports of Qualifying BBD Feedstocks (Million Gallons BBD Equivalent)



Source: UN ComTrade.

1.4 Ethanol

The predominant form of biofuel used to meet the standards under the RFS program—and the total renewable fuel standard in particular—has been fuel ethanol. Fuel ethanol consumed in the U.S. has predominantly been produced from corn starch, but smaller volumes are also produced from grain sorghum starch, cellulosic biomass, non-cellulosic portions of separated food waste, and sugarcane feedstocks. In 2005, just prior to implementation of the RFS1 program, ethanol accounted for 97% of all biofuels consumed in the U.S. transportation sector. In the years that followed, the total volume of ethanol used in the U.S. more than tripled from 4.1 billion gallons in 2005 to 14.6 billion gallons in 2019, even as volumes of other biofuels grew concurrently.¹⁸ Despite significant reductions in 2020 and 2021 due to the Covid-19 pandemic, domestic fuel ethanol consumption had returned to close to pre-pandemic levels in 2023 and 2024.¹⁹ In 2024, ethanol accounted for approximately 70% of the biofuel consumed in the U.S.²⁰

Total ethanol consumption is the sum of ethanol blended with fossil fuel gasoline (E0) to create motor gasoline ethanol blends (E10, E15, and E85). There is no appreciable consumption of pure fuel ethanol (E100) in the U.S. as a transportation fuel, in contrast to fueling practices in some other countries such as Brazil. A common way to evaluate the relative growth of each of these different fuel blends is to measure the average ethanol concentration in the national

¹⁸ EIA, “Monthly Energy Review,” March 2025, Tables 10.3 and 10.4.

<https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf>. Comparison is based on ethanol-equivalence.

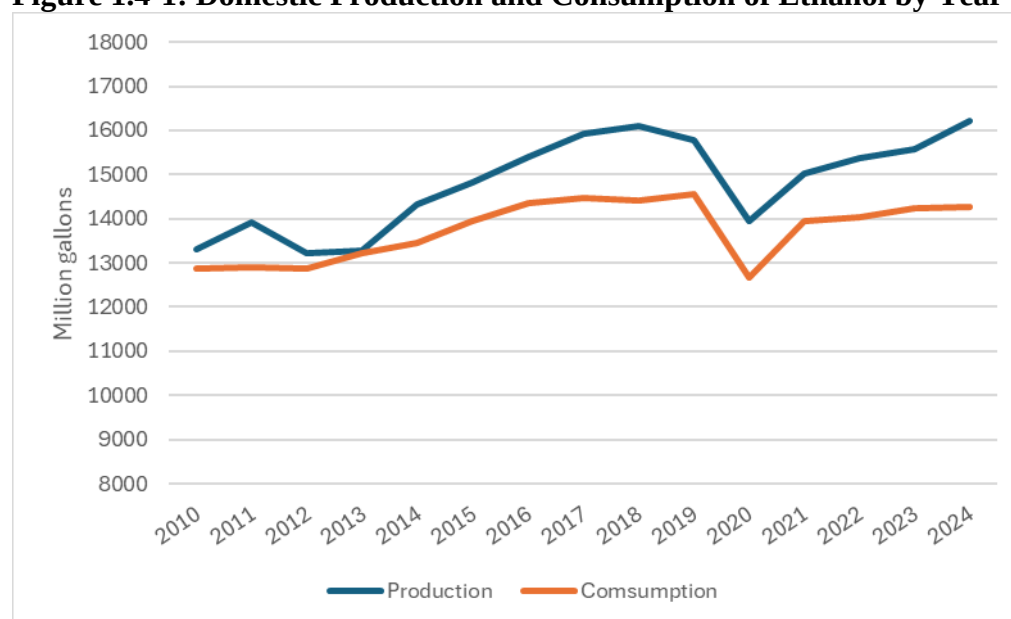
¹⁹ Id.

²⁰ Id.

gasoline pool. National average ethanol concentration surpassed 5% for the first time in 2007 and surpassed 10% (*i.e.*, the “blend wall”) for the first time in 2016. Since exceeding 10%, the share of ethanol in the gasoline pool has continued to increase, although at a slower pace as the market became saturated with E10. The total ethanol volume that can be consumed in the U.S. from all feedstocks is a function of the relative volumes of E0, E10, E15, and E85 that together comprise total motor gasoline consumption. Average ethanol concentration can exceed 10% only to the extent that E15 and E85 fuel volumes can exceed the ethanol content of E10 and more than offset the dilution caused by E0 volumes. Based on our updated methodology, EPA projects an average ethanol concentration of 10.25% in 2026, rising to 10.27% in 2027. For details regarding how EPA has projected the consumption volumes of each of these fuel blends and thereby average ethanol concentration, refer to Chapter 7.5.1.

Domestic consumption of ethanol in the U.S. was very close to domestic production through 2009. Thereafter, domestic production began exceeding domestic consumption, indicative of an increase in exports. This split is shown in Figure 1.4-1. While EPA is projecting continued growth in the consumption of higher-level ethanol blends such as E15 and E85, we are projecting that total ethanol consumption decreases slightly over the years covered by this rule due to declining gasoline (E10) consumption.

Figure 1.4-1: Domestic Production and Consumption of Ethanol by Year

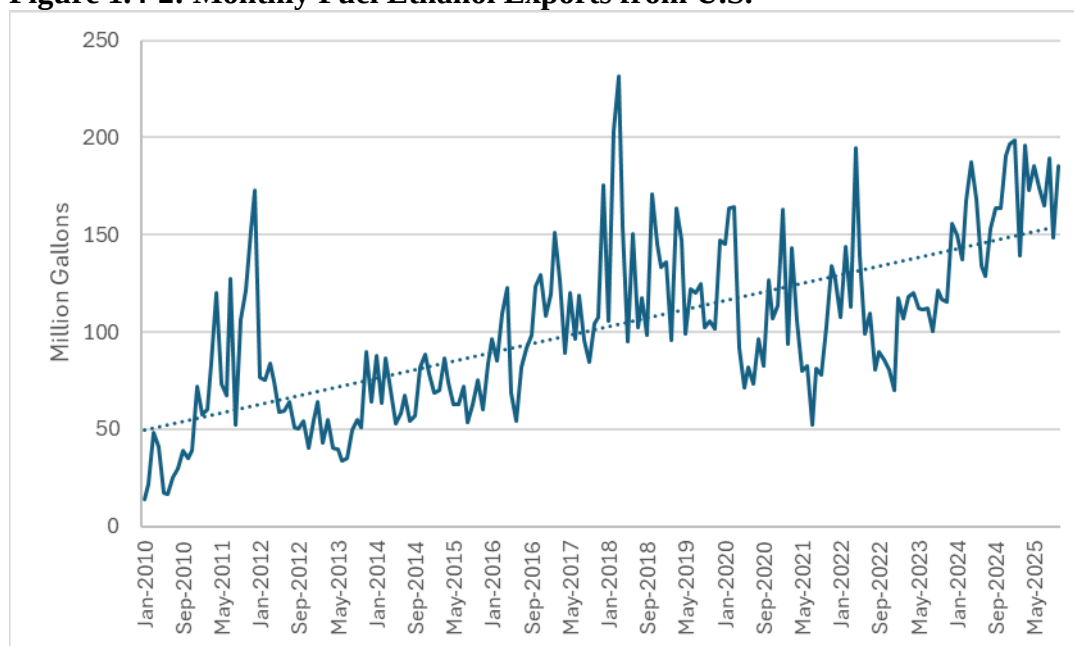


Source: EIA, “Monthly Energy Review,” March 2025, Table 10.3.
<https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf>.

EIA is the primary source of reliable data on fuel ethanol exports, and they do not report fuel ethanol export data for years prior to 2010. Since 2010, however, ethanol exports have grown steadily with only minor variations month to month, as shown by Figure 1.4-2. This growth is largely attributable to a combination of domestic and international market effects, with lower prices and plateauing demand on average for fuel ethanol in the U.S. even as prices and demand increase elsewhere. Exports of fuel ethanol reached record volumes in 2024 reflecting changes in renewable fuel mandates in other countries. For example, in early 2024, Colombia

reinstated an E10 mandate for motor gasoline sold there, which required greater volumes of ethanol imports for the standard to be met and coincided with a sudden reduction in ethanol exports from Brazilian sources due to an increase in demand for fuel ethanol in Brazil.²¹ The result is that more ethanol was exported from the U.S. to Colombia to fulfill their demand for fuel. For a more in-depth discussion of the history of fuel ethanol exports and their evolution through 2024, refer to Chapter 7.6.

Figure 1.4-2: Monthly Fuel Ethanol Exports from U.S.



Source: EIA, “U.S. Exports of Fuel Ethanol,” *Petroleum & Other Liquids*, January 1, 2026.

https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOOXE_EEX_NUS-Z00_MBBL&f=m.

The gasoline market was historically dominated by ethanol-free gasoline (E0) and, since its approval for use in all vehicles in 1979, E10. Today, consumers in large swaths of the country have a choice between E0, E10, and higher-level ethanol blends of E15 and E85. Today’s consumers of motor gasoline have to weigh a series of factors in their choice of what fuel to purchase, such as (in the case of E85, which is only approved for use in flex fuel vehicles) their vehicle’s operability and longevity, relative price, and perceptions or knowledge gaps concerning impacts of each fuel type on fuel economy, the environment, their personal financial situation, and the economy writ large. Since approaching and exceeding the E10 blendwall between 2010 and 2016, virtually all gasoline nationwide contains at least 10% ethanol by volume, meaning most consumers today have little choice but to use E10 gasoline at a minimum. With the growth of retail fueling stations offering E15 and E85, the choice has now shifted between largely E10 and these higher-level ethanol blends. For higher-level ethanol blends, consumers likely consider all the factors from when the choice was between E0 and E10, plus whether the fuel is legally permitted to be used in their vehicle and whether the manufacturer has warranted their vehicle

²¹ S&P Global, “US ethanol exports on pace for record year, fueled by low prices and increased opportunity overseas,” November 19, 2024. <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/agriculture/111924-us-ethanol-exports-on-pace-for-record-year-fueled-by-low-prices-and-increased-opportunity-overseas>.

for its use. The following sections survey recent developments in E15 and E85 gasoline in the U.S.

1.4.1 E85

The earliest form of a higher-level ethanol blend was E85. In 1996, the first flex-fuel vehicle (FFV) was produced that could operate on fuel containing up to 85% denatured ethanol (83% undenatured ethanol).²² Starting in 2007, ASTM International (ASTM) limited the maximum undenatured ethanol content of E85 to 83% in specification D5798, with a minimum ethanol content of 51%. EIA assumes for the purposes of its AEO projections that the annual, nationwide average ethanol concentration of E85 is 74% which is the value EPA has opted to use in this rule, consistent with previous rulemakings.²³

E85 is not considered gasoline under EPA's regulations, and as such is permitted to be used only in FFVs. However, FFVs can operate on either gasoline or E85. Under basic economic theory, and assuming all other factors are equal, FFV owners are more likely to purchase E85 if they believe that doing so reduces their fuel costs. E85 reduces fuel economy in comparison to E10, so E85 must sell at a discount to E10 if it is to represent equal or greater value in terms of energy content. For an average gallon of E85 containing 74% ethanol, its volumetric energy content is approximately 21% less than the energy content of E10 (or 24% lower than that of E0).^{24,25} In order for E85 to be priced equivalently to gasoline on an energy-equivalent basis, then, its price must be on average 21% lower than that of E10. As shown in Figure 1.4.1-1, the nationwide average price of E85 compared to E10 has only occasionally achieved the requisite energy equivalent pricing needed for FFV owners who are aware of and concerned about the fuel economy impacts of E85, though this has occurred more often since 2023 compared to the previous years of the RFS program. Regardless, E85 purchasers generally have no way of knowing whether their fuel contains 83% ethanol, 51% ethanol, or something in-between, confounding accurate value calculations.

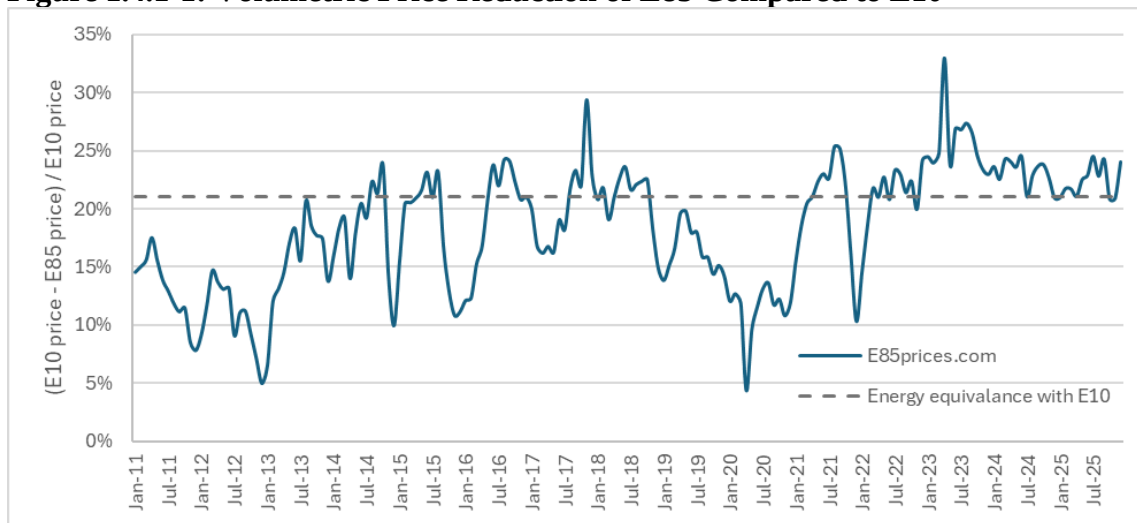
²² The Auto Channel, "Alternative Fuel Ford Taurus," January 1996

²³ AEO2025, Table 2 – Energy Consumption by Sector and Source.

²⁴ Assumes ethanol energy content is 3.554 mill Btu per barrel and gasoline energy content is 5.222 mill Btu per barrel. EIA, "Monthly Energy Review," March 2025, Tables A1 and A3.
<https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf>.

²⁵ A comparison to E0 would be more relevant prior to 2010 when there remained significant volumes of E0 for sale at retail stations.

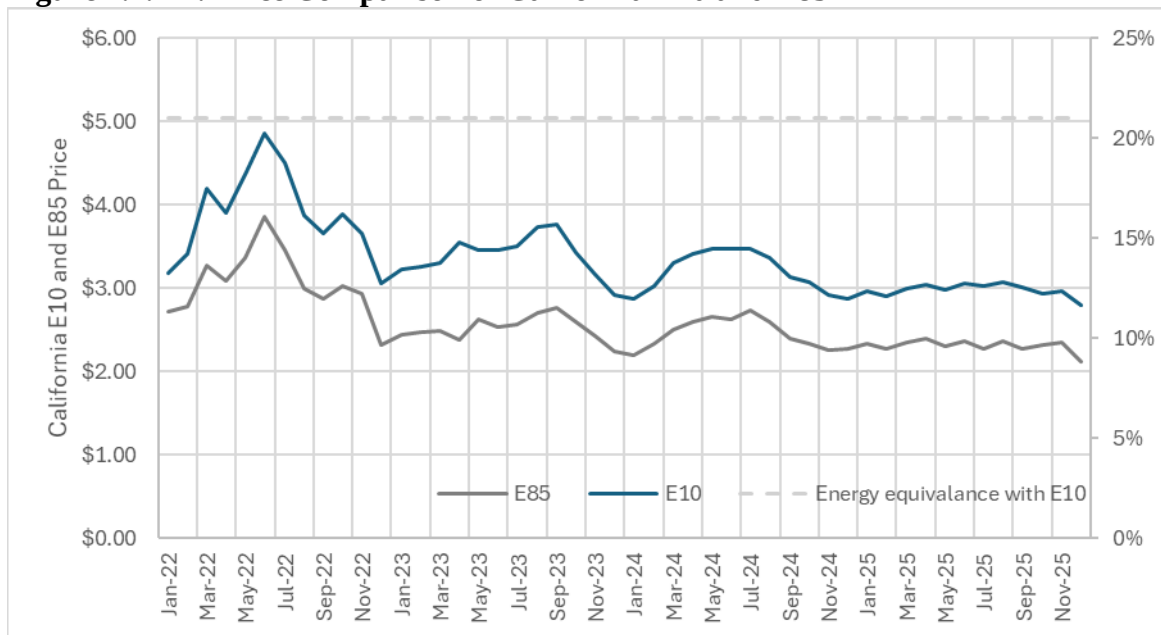
Figure 1.4.1-1: Volumetric Price Reduction of E85 Compared to E10^a



^a The 21% energy equivalence level of E85 compared to E10 assumes that E85 contains 74% ethanol.

California has been an exception recently in terms of E85 consumption, as retail station growth rates in California have surpassed the rest of the country. This is due largely to the price differential between E10 and E85. As shown in Figure 1.4.1-2, E85 in California has remained approximately \$2 below the price of E10 on average since at least 2022. This discount routinely exceeds 50%, far greater than the 21% discount needed for E85 to achieve price parity with E10 on energy content. This discount provides a significant incentive for consumers to utilize E85. Additional information on E85 nationwide and in California can be found in Chapter 7.5.

Figure 1.4.1-2: Price Comparison of California E10 and E85



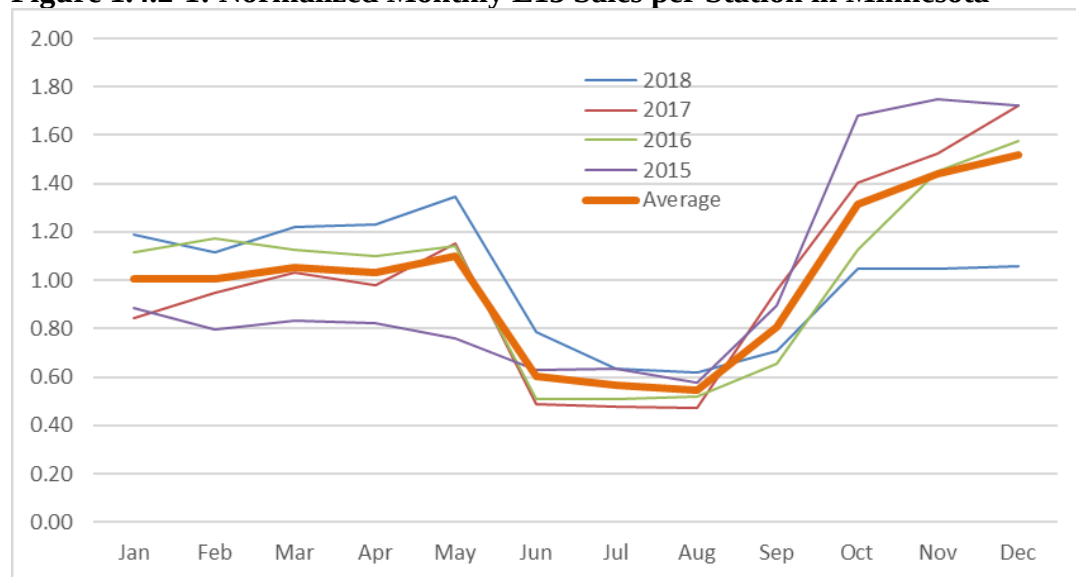
Source: e85prices.com.

1.4.2 E15

In 2011, gasoline containing up to 15% ethanol was permitted to be used in model year (MY) 2001 and newer vehicles.²⁶ E15 has since been offered at an increasing number of retail service stations.²⁷ However, there is currently no publicly available data on actual nationwide E15 sales volumes. Minnesota is the only source of month-to-month E15 sales data allowing us to see the changes in E15 sales between the summer and winter months. We present this data in Figure 1.4.2-1.

Sales of E15 prior to 2019 were mostly seasonal due to the fact that E15 did not qualify for the 1-psi Reid vapor pressure (RVP) waiver for summer gasoline in conventional gasoline (CG) areas that has been permitted for E10 since the summer volatility standards were implemented in 1989.²⁸ As shown in Figure 1.4.2-1, monthly E15 sales in Minnesota from 2015–2018 demonstrate that sales volumes of E15 in summer months were notably lower than in non-summer months in this time period.

Figure 1.4.2-1: Normalized Monthly E15 Sales per Station in Minnesota



Note: Normalized values derived by dividing the monthly E15 sales volume per station by the annual average E15 sales volume per station.

Source: Minnesota Commerce Department, “Minnesota E85 + Mid-Blends Station Report.”

<https://mn.gov/commerce/business/weights-measures/fuel/biodiesel/ethanol.jsp>.

In 2019, EPA extended the 1-psi waiver to E15 by regulation.²⁹ EPA estimated that the annual average E15 sales per station in Minnesota would have been 16% higher had the 1-psi waiver been in place from 2015–2018.³⁰ On July 2, 2021, the D.C. Circuit ruled that EPA’s extension of the 1-psi waiver to E15 was based on an impermissible reading of the statute and vacated the

²⁶ 76 FR 4662 (January 26, 2011).

²⁷ See Chapter 6.4.3.

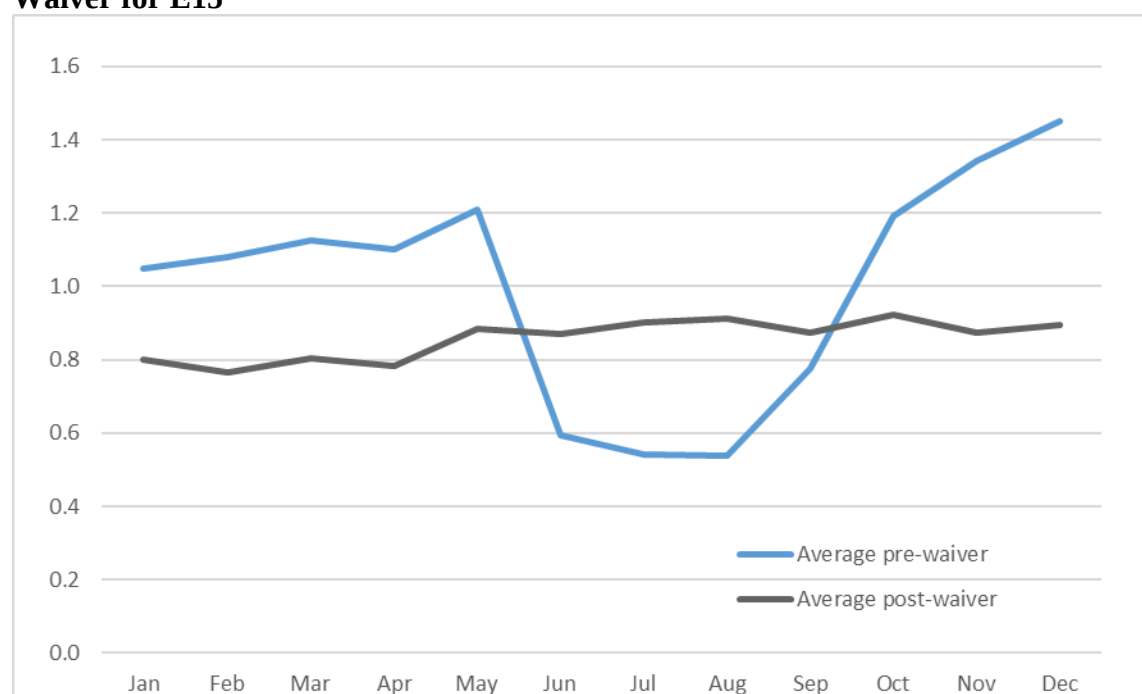
²⁸ 54 FR 11883 (March 22, 1989).

²⁹ 84 FR 26980 (June 10, 2019).

³⁰ “Estimating the impacts of the 1psi waiver for E15,” Docket Item No. EPA-HQ-OAR-2019-0136-2117. <https://www.regulations.gov/document/EPA-HQ-OAR-2019-0136-2117>.

action. EPA subsequently issued emergency fuel waivers for the summers of 2022–2025 that allowed E15 to take advantage of the 1-psi waiver to address issues related to fuel price and supply. The impact of the 1-psi waiver for E15 on summer sales of E15 can be seen for 2019–2025 in Figure 1.4.2-2. For these years, data from Minnesota on per-station sales of E15 indicates that those sales were no longer seasonal as they were prior to 2019. Average E15 sales post-waiver remain consistent year-round compared to pre-waiver, even though the overall E15 price is slightly lower. This is possibly due to impacts from the COVID-19 pandemic and decreased fuel sales during the start of the war in Ukraine.

Figure 1.4.2-2: Normalized Monthly E15 Sales per Station in Minnesota; Pre-and Post-Waiver for E15



Note: Normalized values derived by dividing the monthly E15 sales volume per station by the annual average E15 sales volume per station.

Source: Minnesota Commerce Department, “Minnesota E85 + Mid-Blends Station Report.”

<https://mn.gov/commerce/business/weights-measures/fuel/biodiesel/ethanol.jsp>.

On February 29, 2024, EPA finalized a rule to remove the 1-psi waiver for E10 in eight Midwestern states.³¹ On March 19, 2025, EPA finalized a one-year extension of the removal of the 1-psi waiver for Ohio and nine counties in South Dakota.³² However, on January 28, 2026, EPA approved Ohio’s request to reinstate the 1-psi waiver for the 2026 summer season. The result is that E10 and E15 are treated the same in these states with regard to RVP beginning with the summer of 2025 (or the summer of 2026 in the case of the nine counties in South Dakota).³³ Consequently, there may be no reduction in summer sales of E15 compared to other months in these states going forward.

³¹ Illinois, Iowa, Minnesota, Missouri, Nebraska, Ohio, South Dakota, and Wisconsin. 89 FR 14760.

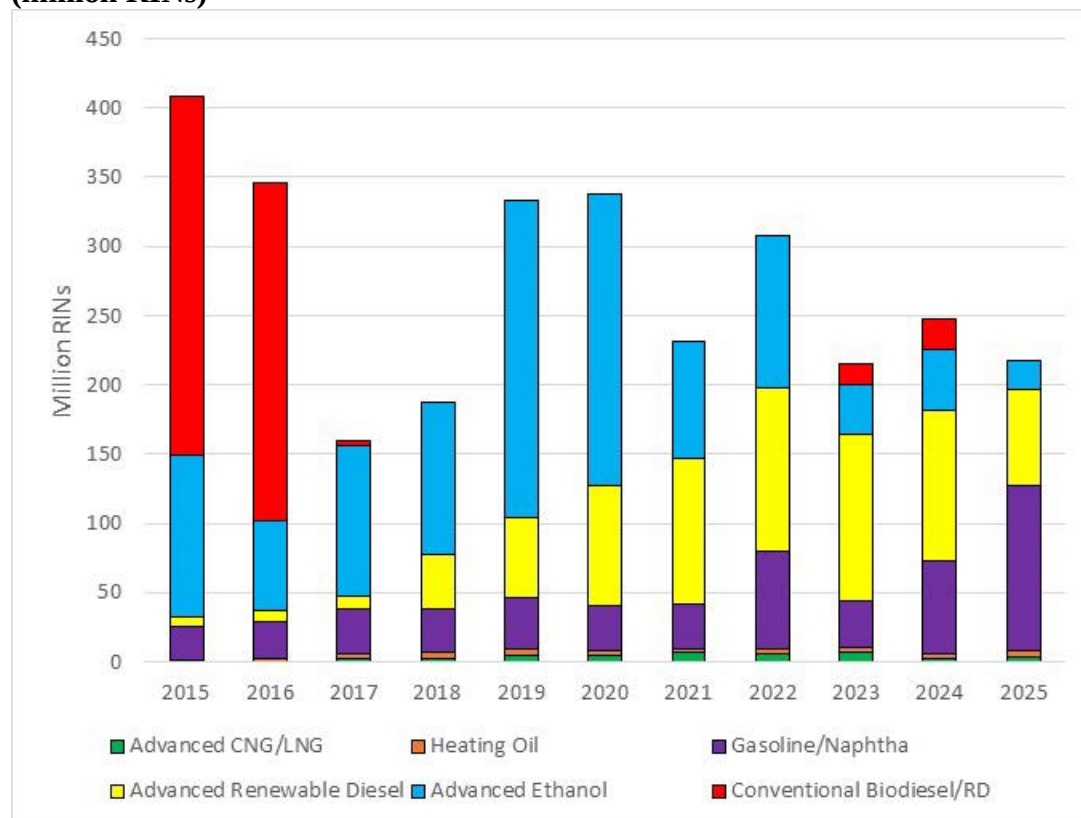
³² 90 FR 13093 (March 20, 2025).

³³ In summer 2025, EPA issued a series of emergency fuel waivers that achieved the same result nationwide. That is, E15 and E10 could be blended using the same blendstock in the summer months.

1.5 Other Biofuels

Corn ethanol and BBD have dominated the biofuels landscape since implementation of the RFS program began in 2006. In more recent years CNG/LNG derived from biogas that qualifies as cellulosic biofuel has also contributed significant volumes to the total supply of qualifying renewable fuel. Beyond these three main types of renewable fuel other biofuels have also contributed to the total renewable fuel pool, sometimes providing the marginal volumes needed to meet the other applicable standards. As shown in Figures 1.5-1, the supply of these “other biofuels” has ranged from 150 million to 450 million RINs from 2015–2025. The annual supply of biofuels other than corn ethanol, BBD, and cellulosic CNG/LNG are shown in Figure 1.5-1.

1.5-1: Supply of Biofuels Other Than Corn Ethanol, BBD, and Cellulosic CNG/LNG (million RINs)



Source: EMTS.

The largest sources of these “other biofuels” in the past decade have been advanced ethanol, renewable diesel, and conventional biodiesel and renewable diesel. The supply of advanced ethanol has varied from year to year and appears to fluctuate depending on market conditions. In some earlier years of the program, the U.S. imported significant amounts of sugarcane ethanol. Virtually all domestically produced advanced ethanol has historically been made from separated food waste. In recent years the supply of advanced ethanol has been smaller relative to volumes supplied in 2019 and 2020. Supplies of advanced renewable diesel increased

through 2023 but have been declining since then. In 2015 and 2016 significant volumes of conventional biodiesel and renewable diesel were supplied to the U.S., but since that time only very small volumes have been supplied. This likely reflects the growing impact state fuel programs have had on the supply of biofuels to the U.S., as conventional biodiesel and renewable diesel generally do not generate credits, and in some cases generate deficits, in these state programs.

1.6 Federal Tax Credits for Biofuels

For most of the history of the RFS program only biodiesel, renewable diesel, and CNG/LNG derived from biogas were eligible for Federal tax credits. Prior to 2025, a \$1 refundable credit was available to producers and blenders of biodiesel and renewable diesel for every gallon of biodiesel or renewable diesel, including blends, (\$0.10 per gallon for small agri-biodiesel producers) that was either produced, sold, or used in the U.S. This tax credit lapsed several times over the past decade but was consistently available (whether prospectively or retroactively) from the beginning of the RFS program and throughout most of the program's history. The Inflation Reduction Act (IRA) of 2022 extended the biodiesel blenders tax credit through 2024 but phased it out thereafter. The prospective availability of the biodiesel blenders tax credit for 2023 and 2024, in combination with the replacement of this tax credit with the 45Z credit were likely significant factors in the rapid increase in the supply of BBD to the U.S. in 2023 and 2024.

IRA also established two new tax credits that could apply to qualifying fuels under the RFS program, the Sustainable Aviation Fuel Credit (SAFC), often referred to as the "40B credit", and the 45Z credit. The SAFC provided a tax credit ranging from \$1.25 to \$1.75 per gallon to any renewable jet fuel that achieves at least a 50% reduction in lifecycle GHG emissions but was only available for fuel produced during 2023 and 2024. The SAFC thus provides a larger incentive for renewable jet fuel in 2023 and 2024 than that provided by the biodiesel blenders tax credit in previous years.

Starting in 2025 both the biodiesel blenders tax credit and the SAFC were replaced by 45Z. 45Z is available to all transportation fuel produced in the U.S. that has an emission rate less than 50 kilograms of CO₂ equivalent per million BTU. The magnitude of 45Z varies depending on the type of fuel produced (renewable jet fuel vs. other transportation fuel), the emissions factor of the fuel, and whether the fuel producer meets prevailing wage and apprenticeship requirements.

45Z differs from the biodiesel blenders tax credit it replaced in several important ways. First, this tax credit is available to all transportation fuels with lifecycle GHG emissions under the specified threshold. Since 2012, BBD has been the only RFS-qualifying fuel that was eligible for a federal tax credit. This broader eligibility under 45Z relative to the biodiesel blenders tax credit may open up greater opportunities for non-BBD advanced biofuels to compete for market share under the RFS program as these fuels now have similar treatment under the federal tax provisions.

45Z is also only available for biofuels produced in the U.S. Historically, significant volumes of imported biodiesel and renewable diesel have benefited from the biodiesel blenders tax credit. In 2025, OBBD made further amendments to 45Z. Notably, OBBD extended the CFPC two additional years, through the end of 2029, and after 2025, required that fuels must be produced from North American feedstocks to qualify. The restriction of 45Z to biofuels produced from North American feedstocks may have multiple impacts on the supply of biofuel to the U.S. Imports of BBD in 2025 decreased significantly and are expected to remain low in future years, as these fuels will no longer be eligible for any federal biofuel tax credit. The availability of 45Z to domestic BBD producers will advantage these producers over imported BBD, which is projected to directionally result in lower volumes of imported BBD. Lower volumes of imported BBD may increase the market demand for BBD produced in the U.S., resulting in greater domestic BBD production and/or decreased BBD exports. 45Z is also expected to shift the source of feedstocks imported for biofuel production, with increases in the quantity of feedstocks imported from Canada and Mexico and decrease in the quantity of feedstocks imported from other countries. 45Z provides domestic BBD producers with significant incentives over foreign BBD producers, but only if they can produce BBD using domestic feedstocks or feedstocks imported from North America.

45Z also provides greater incentives for biofuels with lower emission rates. In the Set 2 proposal, EPA projected that the structure of the CFPC, together with State low carbon fuel standard (LCFS) programs and the limited availability of domestic FOG, would result in significant demand for imported feedstocks, particularly feedstocks that could be used to produce BBD with low emission rates. However, the changes to 45Z in OBBD have significantly impacted the structure of the 45Z incentive. The largest supplies of imported FOG are from countries outside of North America, and BBD produced from these feedstocks no longer qualifies for 45Z. Further, OBBD prohibited the consideration of land use change in the emission rates for biofuels. This change eliminates much, if not all, of the additional incentives in 45Z to produce biofuels from FOG versus crop-based feedstocks such as soybean oil or canola oil. As a result, we now project lower volumes of imported FOG will be used to produce BBD in 2026 and 2027 and that greater volumes of soybean oil and canola oil sourced from the U.S. and Canada will be used.

1.7 RIN System and Prices

1.7.1 RIN System

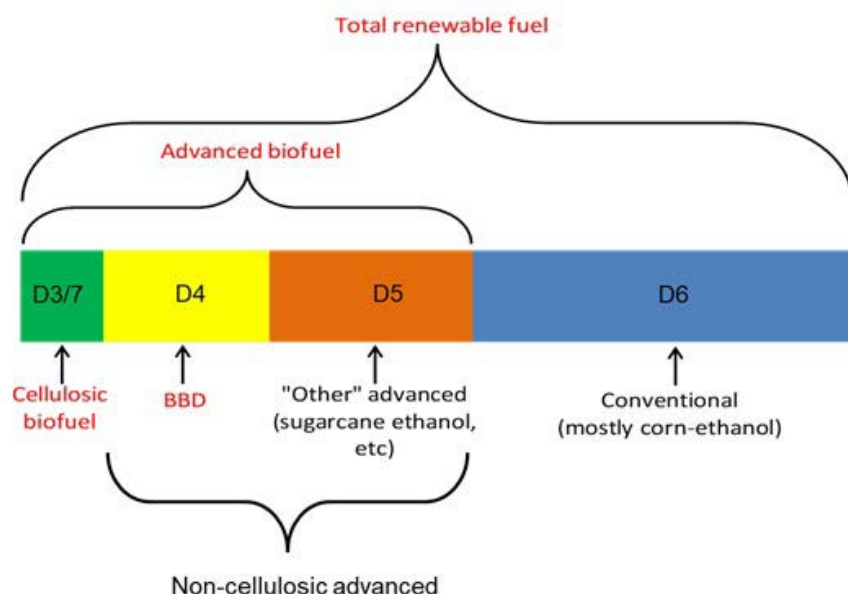
RINs were created by EPA under CAA section 211(o)(5) as a flexible credit and compliance mechanism to enable obligated parties across the country to meet their renewable fuel blending obligations under the RFS program without having to blend the renewable fuel themselves.³⁴ RINs allow: (1) Obligated parties (*i.e.*, the refining industry) to comply with the RFS program without producing, purchasing, or blending the renewable fuel themselves; (2) Non-obligated blenders of renewable fuel to maintain their preexisting blending operations; and (3) The ethanol and other biofuel industries to continue to produce biofuels, now with the support of the RIN value. Obligated parties, of course, can and do produce, purchase, and blend

³⁴ The RIN system was created in the RFS1 Rule (72 FR 23900; May 1, 2007) and modified in the RFS2 Rule (75 FR 14670; March 26, 2010).

their own renewable fuel, but the RIN system allows them the option of not doing so and instead relying on the business practices of other market participants that are already set up to do so. In this way the RIN system allows the RFS program to function smoothly with less market disruption and at a lower overall cost. RINs are generated by renewable fuel producers (or in some cases renewable fuel importers) and are assigned to the renewable fuel they produce. These RINs can be sold together with the renewable fuel to refiners or blenders, or separated from renewable fuel by obligated parties or when renewable fuel is blended into transportation fuel. Once separated, RINs can be used by obligated parties to demonstrate compliance with their RFS obligations or can be traded to other parties.

Under the RFS program, EPA created five different types of RINs: cellulosic biofuel (D3) RINs, BBD (D4) RINs, advanced biofuel (D5) RINs, conventional renewable fuel (D6) RINs, and cellulosic diesel RINs (D7).³⁵ The type of RIN that can be generated for each renewable fuel depends on a variety of factors, including the feedstock used to produce the fuel, the type of fuel produced, and the lifecycle GHG reductions relative to petroleum fuel. As shown in Figure 1.7-1, the obligations under the RFS regulations are nested, such that some RIN types can be used to satisfy obligations in multiple categories.

Figure 1.7-1: Nested Structure of the RFS Program



Since its creation the RIN system has grown and evolved along with the RFS program.

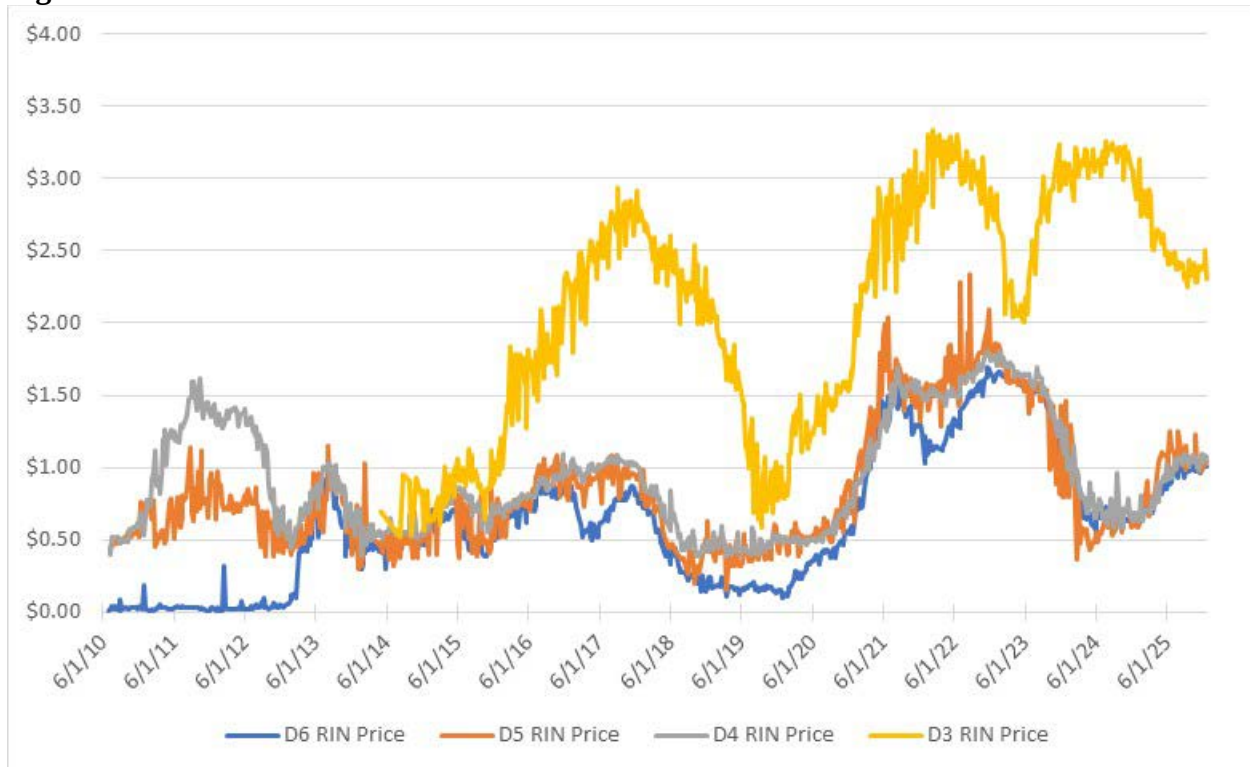
1.7.2 RIN Prices

RIN prices have varied significantly since 2010. There have also been significant and notable differences between the prices of each of the four major RIN types. A chart of RIN

³⁵ 40 CFR 80.1425(g).

prices, as reported to EPA through EMTS, is shown in Figure 1.7.2-1.³⁶ While there are a wide variety of factors that impact RIN prices, including both market-based and regulatory factors, a review of RIN prices reveals several notable aspects of the RFS program.

Figure 1.7.2-1: Historical RIN Prices in Nominal Dollars



Source: EMTS.

Prior to 2013, D6 RIN prices were low (less than \$0.05 per RIN). These low prices were likely due to the fact that from 2010–2012 it was cost-effective to blend ethanol into gasoline as E10 even without the incentives provided by the RFS program. The low RIN prices during this period also indicate that the RFS requirements were not the driving force behind increased use of E10.

Beginning in 2013, D6 RIN prices rose sharply. 2013 marked the first time the implied conventional renewable fuel requirement exceeded the volume of ethanol that could be consumed as E10.³⁷ While it has generally been cost-effective to blend ethanol as E10, higher-level ethanol blends (*e.g.*, E15 and E85) have generally not been cost effective, even with the incentives provided by the RFS program. This is largely because: (1) Fuel blends that contain

³⁶ RIN prices are reported publicly on EPA’s website (<https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information>). These prices are reported to EPA by the parties that trade RINs and are inclusive of all RIN trades (with the exception of RIN prices that appear to be outliers or data entry errors). Several other services also report daily RIN prices; however, these reports are generally not publicly available. Further, the prices reported by these services generally represent only spot trades and do not include RINs traded through long-term contracts.

³⁷ The conventional renewable fuel requirement is the difference between the total renewable fuel requirement and the advanced biofuel requirement.

greater than 10% ethanol are currently not optimized to take advantage of the high octane value of ethanol; (2) The lower energy content of ethanol is more noticeable as the amount of ethanol increases; and (3) Infrastructure limitations have restricted the availability of higher-level ethanol blends (see Chapter 6.4).

In subsequent years, D6 RIN prices have varied significantly, but they have never returned to the low prices observed prior to 2013. It is also notable that, from 2013–2016, D6 RIN prices remained close to, but slightly less than, D4 and D5 RIN prices. During this time, obligated parties were purchasing D4 and D5 RINs in excess of their BBD and advanced biofuel obligations to make up for the shortfall in conventional biofuel volume and used those RINs to meet their total renewable fuel obligations. Essentially, given the inability to successfully introduce higher-level ethanol blends into the market in sufficiently large quantities, the market relied upon biodiesel and renewable diesel (primarily as advanced biofuel and BBD, but also some volume of conventional biodiesel and renewable diesel) as the marginal RFS compliance option when other sources of conventional biofuel were not available at competitive prices. After 2018, D6 RIN prices were, for some time, significantly lower than D4 and D5 RIN prices, but still higher than the D6 RIN prices observed prior to 2013. These lower D6 RIN prices are largely the result of: (1) Small refinery exemptions (SREs) granted in 2018, which reduced the total number of D6 RINs needed for compliance with the RFS obligations to a number that was below the E10 blendwall; and (2) The large number of carryover RINs available, as discussed in Chapter 1.8.1. Beginning in the summer of 2020, D4, D5, and D6 RIN prices rose dramatically, reaching nearly \$2 per RIN in the summer of 2021. These RIN prices remained around \$1.50 per RIN through June 2023, before falling back to approximately \$0.75 per RIN in the summer of 2023. The timing of the observed changes in RIN prices in the summer of 2023 strongly suggest that the finalization of the RFS volume requirements for 2023–2025 in June 2023 contributed to the drop in RIN prices. The prices for D4, D5, and D6 RINs also reflect the cost of biodiesel and renewable diesel production (the marginal supply of RINs over this period). The prices for soybean and other vegetable oil feedstocks were unusually high from the summer of 2021 through the summer of 2023, a period with corresponds to the period of high RIN prices for D4, D5, and D6 RINs.

While D6 RIN prices have remained relatively high in recent years, these price levels have not translated into higher ethanol prices for ethanol producers. After examining market data, EPA found no correlation between D6 RIN prices and ethanol prices from 2010–2024 (see Figure 1.7.2-2). Instead, higher D6 RIN prices have resulted in lower effective prices for ethanol after the RINs have been separated and sold.³⁸ Higher D6 RIN prices have thus served to subsidize fuel blends that contain higher proportions of conventional biofuel (*e.g.*, E85) and increased the cost of fuel blends that contain little or no conventional biofuel (*e.g.*, E0 and B0).³⁹

³⁸ The effective price is the price of the ethanol after subtracting the RIN value from the price of the ethanol with the attached RIN.

³⁹ Burkholder, Dallas. “A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effects.” EPA, May 2015.

Figure 1.7.2-2: Historical Ethanol Prices and D6 RIN Prices



Sources: Ethanol Price from USDA Weekly Ag Roundup, D6 RIN Price from EMTS data

D5 RINs were priced at a level between D4 and D6 RINs from 2010–2013. However, since 2013, D5 RIN prices have been nearly identical to D4 RIN prices. This shift in the relative pricing of D5 and D4 RINs also corresponds with the market reaching the E10 blendwall. This is because there are two primary fuel types that have been used to satisfy the advanced biofuel requirements: sugarcane ethanol and BBD. From 2010–2012, obligated parties generally met their implied requirements for “other advanced biofuel” with sugarcane ethanol.⁴⁰ This is apparent in the volumes of sugarcane ethanol (which supplied the vast majority of volume requirement for “other advanced” biofuels) and BBD (which did not exceed the volume requirement for BBD by an appreciable volume) used in the U.S. in these years.⁴¹ It is also indicated by the prices for D5 RINs, which were significantly lower than the price of D4 RINs during this time, suggesting that it was more cost effective for obligated parties to meet their compliance obligations with D5 RINs (generated for sugarcane ethanol) than D4 RINs (generated for biodiesel and renewable diesel). When the E10 blendwall was reached in 2013, however, it became much more expensive to increase the volume of ethanol blended into the gasoline pool. While obligated parties could still import sugarcane ethanol to satisfy their advanced biofuel obligations, doing so would reduce the volume of corn ethanol that could be used as E10. Available non-ethanol renewable fuels were almost entirely advanced biodiesel and

⁴⁰ “Other advanced biofuel” is not a category for which a volume requirement is established under the RFS program, but is the difference between the advanced biofuel requirement and the sum of the cellulosic biofuel and BBD requirements, both of which are nested within the advanced biofuel category.

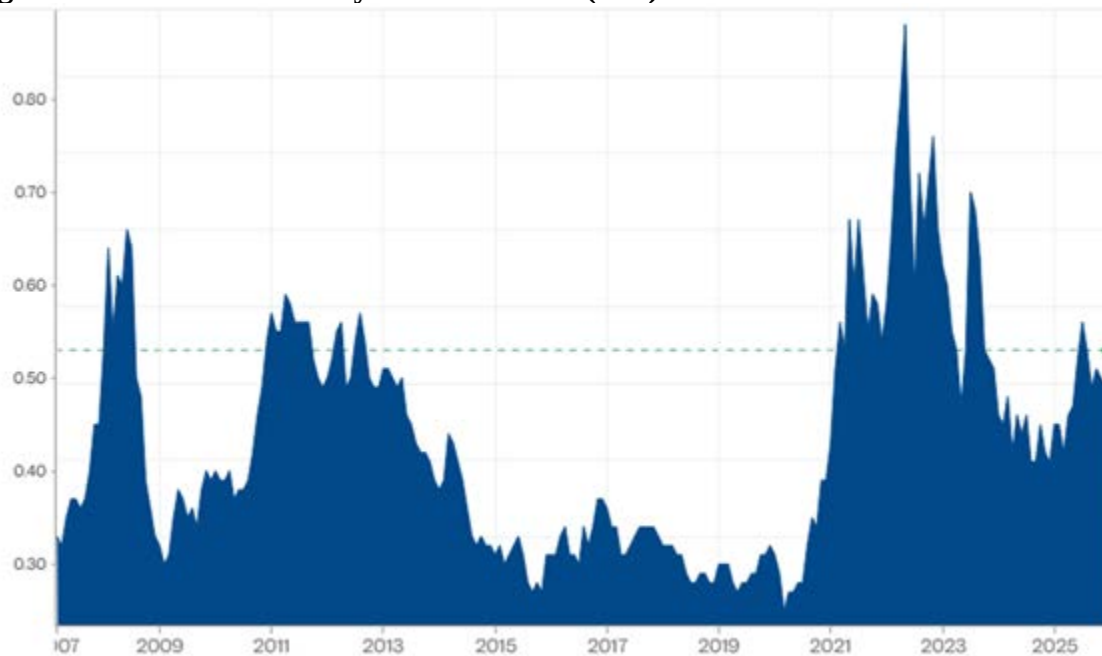
⁴¹ See Chapters 6.3 and 6.2 for volumes of sugarcane ethanol and BBD used in the U.S., respectively.

renewable diesel, so obligated parties generally used these fuels (rather than sugarcane ethanol) to meet the advanced biofuel requirements so that they could use corn ethanol to satisfy the remaining total renewable fuel requirements. RIN prices responded, and since 2013 the prices of D4 and D5 RINs have been nearly identical.

D4 RIN prices, much like all RIN prices, have varied significantly since 2010. The pricing of these RINs, however, has been relatively straightforward compared to other D-codes. D4 RINs are generally priced to account for the price difference between biodiesel and petroleum diesel, which in turn are largely a function of the pricing of their respective oil supplies. Other factors can also impact this relationship; most significantly are the presence or absence of the biodiesel tax credit and the impact of other subsidies and credits (*e.g.*, state LCFS credits).⁴² For example, as shown in Figure 1.7.2-3, D4 RIN prices increased significantly in 2021 and 2022, tracking with an increase in feedstock commodity prices (*e.g.*, soybean oil), which comprise greater than 80% of the cost of production of BBD. By the beginning of 2024, soybean oil prices dropped to lower levels. This decrease in the price of soybean oil generally corresponded to a decrease in D4 RIN prices.

⁴² A \$1 per gallon biodiesel blenders tax credit was available to biodiesel blended every year from 2010–2024. However, at various times this credit has expired and been reinstated retroactively. The biodiesel tax credit expired at the end of 2009 and was not reinstated until December 2010, applying to all biodiesel blended in 2010 and 2011. The biodiesel tax credit has since been again reauthorized semi-regularly, including in January 2013 (applying to biodiesel produced in 2012 and 2013), December 2014 (applying to biodiesel produced in 2014), December 2015 (applying to biodiesel produced in 2015 and 2016), and February 2018 (applying to biodiesel produced in 2017). In December 2019 the tax credit was retroactively reinstated for 2018 and 2019 and put in place prospectively through 2022. In August 2022, the tax credit was extended through 2024. Beginning in 2025, biodiesel and renewable diesel could qualify for the CFPC.

Figure 1.7.2-3: Historical Soybean Oil Prices (\$/lb)



Source: Business Insider, “Soybean Oil,” *Markets Insider*, January 30, 2026.
<https://markets.businessinsider.com/commodities/soybean-oil-price>.

Generally, D4 RIN prices have increased to a level that allows BBD to be cost-effective with petroleum-based fuels, increasing BBD production and use. A 2020 paper exploring the relationship between the price of D4 RINs and economic fundamentals concluded that “movements in D4 biodiesel RIN prices at frequencies of a month or longer are well explained by two economic fundamentals: (a) the spread between the biodiesel and diesel fuel prices and (b) whether the \$1 per gallon biodiesel tax credit is in effect.”⁴³ This same paper discusses in greater detail the strong correlation between weekly D4 RIN prices and predicted D4 RIN price values using a model based on economic fundamentals. As state LCFS programs have come online and increased in stringency, the value of these credits is now another increasingly important factor. The 45Z credit, which replaced the biodiesel blending credit beginning in the 2025 tax year, seems likely to fill a role for BBD somewhat similar to the blending credit for the years in which it is available.

Data on cellulosic RIN (D3 and D7) prices were not generally available until 2015. This is likely due to the fact that prior to 2015, the market for cellulosic RINs was too small to support commercial reporting services; very few cellulosic RINs were generated and traded in years prior to 2016. From 2015—when D3 RIN prices were first regularly available—through 2018, the price of these RINs was very closely related to the sum of the D5 RIN price plus the price of the cellulosic waiver credit (CWC).⁴⁴ This is as expected, since obligated parties can satisfy their

⁴³ Irwin, Scott H., Kristen McCormack, and James H. Stock. “The Price of Biodiesel RINs and Economic Fundamentals.” *American Journal of Agricultural Economics* 102, no. 3 (February 3, 2020): 734–52.
<https://doi.org/10.1002/ajae.12014>.

⁴⁴ CAA section 211(o)(7)(D)(ii) established a price cap mechanism for cellulosic biofuel RINs. In implementing this provision, EPA makes CWCs available for sale to obligated parties at a price determined by a statutory formula in

cellulosic biofuel obligations through the use of either cellulosic RINs or CWCs (if available) plus D4 or D5 RINs.⁴⁵ The slight discount for D3 RINs (as opposed to the combination of a CWC and a D5 RIN) is also as expected, as CWCs can be purchased directly from EPA when obligated parties demonstrate compliance and carry no risk of RIN invalidity.⁴⁶ This discount tends to be larger at the beginning of the year, before narrowing near the end of the year as the RFS compliance deadline nears for obligated parties. Starting in 2019, the D3 RIN price was significantly lower than the CWC plus D5 RIN price. This is likely due to an over-supply of D3 RINs caused by EPA granting a relatively large number of SREs for the 2017 and 2018 compliance years, lowering the effective RFS standards. The average D3 RIN price fell to near the D5 RIN price, before slowly increasing relative to the D5 RIN price starting in the second half of 2019 and remaining between the D5 RIN price and the D5 plus CWC price through the end of 2022. In 2023 EPA did not use the cellulosic waiver authority to reduce the required volume of cellulosic biofuel and therefore did not offer CWCs. The price for D3 RINs dropped shortly after the release of the proposed RFS standards for 2023–2025 at the end of 2022. The drop in the D3 RIN prices was likely due to the proposed rule, which included a proposed regulatory framework for generating D3 RINs from qualifying electricity used as transportation fuel (eRINs). Shortly after the final rule establishing RFS standards for 2023–2025 was released in June 2023 D3 RIN prices returned to about \$3 per RIN. Notably, this rule did not finalize a regulatory framework for eRINs and included higher projections for CNG/LNG derived from biogas than the proposed rule. D3 RINs remained around \$3 per RIN until December 2024, when EPA proposed reductions to the cellulosic biofuel volume requirement for 2024. This reduction not only reduced demand for D3 RINs, but also triggered the availability of cellulosic waiver credits for the 2024 compliance year. In response to this proposal, and the eventual finalization of the proposed reduction in June 2025, D3 RIN prices dropped to just under \$2.50 per RIN for most of 2025.

any year in which EPA reduces the required volume of cellulosic biofuel using the cellulosic waiver authority. A CWC satisfies an obligated party's cellulosic biofuel obligation. However, a CWC does not satisfy an obligated party's advanced biofuel and total renewable fuel obligations, unlike a cellulosic RIN, which can be used to meet all three obligations. A cellulosic RIN has similar compliance value as a CWC (which can only be used to satisfy the cellulosic biofuel obligation) and an advanced RIN (which can be used to satisfy the advanced biofuel and total renewable fuel obligations).

⁴⁵ CWCs are available to obligated parties for any year in which EPA implements the cellulosic waiver authority to reduce the cellulosic biofuel volume requirement. EPA implemented the cellulosic waiver authority to reduce the cellulosic biofuel volume requirement every year from 2010–2022 and again in 2024. EPA acknowledges that it did not waive the 2023 cellulosic biofuel requirement. EPA is also in this action reducing the 2025 cellulosic biofuel volume under the cellulosic waiver authority.

⁴⁶ During a few time periods (such as late 2016), the price for D3 RINs was higher than the price for a CWC + D5 RIN. This was likely due to the fact that up to 20% of a previous year's RINs can be used towards compliance in any given year, while CWCs can only be used towards compliance obligations in that year. Obligated parties likely purchased 2016 D3 RINs at a premium anticipating the sharp increase in the CWC price in 2017.

Figure 1.7.2-4: D3 RIN Prices and D5 RIN Price Plus CWC Price



Source: EMTS. CWC prices are available at: <https://www.epa.gov/renewable-fuel-standard-program/cellulosic-waiver-credits-under-renewable-fuel-standard-program>.

The fact that the price of D3 RINs, with some few exceptions, has generally not exceeded the CWC plus D5 RIN price has potentially significant consequences for both the cellulosic biofuel and petroleum fuel markets. For obligated parties, the CWC price effectively sets a maximum price for cellulosic RINs (CWC plus the D5 RIN price) when these credits are available and protects these parties from excessively high cellulosic RIN prices. One of the few periods during which D3 RIN prices exceeded the CWC plus D5 RIN prices was in 2024. Because EPA did not use the cellulosic waiver authority to reduce the cellulosic biofuel volume in 2023, CWCs were not available in 2023. EPA did not propose to reduce the cellulosic biofuel volumes for 2024 until December 2024. Shortly after this proposal cellulosic RIN prices dropped below the price of the CWC + D5 RIN price, consistent with the historic trends.

The CWC price is also informational to potential cellulosic biofuel producers. Potential cellulosic biofuel producers can use the CWC price, along with the projected price of the petroleum fuel displaced by the cellulosic biofuel they produce and any tax credits or other incentives available for the fuel, as an approximation of the maximum price they can reasonably expect to receive for the cellulosic biofuel they produce. Knowing this price can help potential cellulosic biofuel producers determine whether their cellulosic biofuel production processes are economically viable under both current and likely future market conditions.

At the same time, the relatively high value of the CWC plus D5 RIN price, in conjunction with EPA's statutory obligation from 2010 to 2022 to set the required volume of cellulosic

biofuel at the volume expected to be produced each year⁴⁷ and the relatively high cellulosic biofuel volumes in the Set 1 Rule have resulted in generally high D3 RIN prices. These RIN prices are realized for all cellulosic RINs, even those generated for biofuels such as CNG/LNG derived from biogas from large landfills that can in some cases be produced at a cost that is competitive with the petroleum fuels they displace even without the RIN value (see Chapter 10.1.2.6). Some of this excess RIN value may be passed on to consumers who use CNG/LNG derived from biogas as transportation fuel in the form of incentives to purchase CNG/LNG vehicles and lower cost fuel and/or longer term fixed-price fuel contracts. Even after accounting for these incentives, a significant portion of the RIN value may remain with the biofuel producer, the parties that dispense CNG/LNG derived from biogas, and any other parties involved in the production of this type of cellulosic biofuel.⁴⁸ Based on conversations with industry participants a portion of these funds have often been reinvested in expanded CNG/LNG fueling infrastructure and new biogas production facilities.

Unlike other RIN costs that are generally transferred within the liquid fuel pool (*e.g.*, from consumers of fuels with relatively low renewable fuel content such as E0 or B0 to consumers of fuels with relatively high renewable fuel content such as E85 or B20), much of the RIN value for CNG/LNG derived from biogas may be transferred from consumers who purchase gasoline and diesel to parties outside of the liquid fuel pool (*e.g.*, landfill owners, CNG/LNG fleet owners). For example, according to EMTS RIN price data, the average cellulosic RIN price was \$2.40 in 2025; thus, the total cost associated with the 1.21 billion cellulosic RINs required for compliance in 2025 was approximately \$2.9 billion and the cellulosic biofuel requirement likely increased the price of gasoline and diesel sold in the U.S. in 2025 by approximately 1.5¢ per gallon.⁴⁹ These transfers are expected to increase through 2027 as a result of the higher cellulosic biofuel volumes we are finalizing in this rule. Further discussion of the impact on RIN prices on retail fuel prices can be found in Chapter 10.5.

1.8 Carryover RIN Projections

This section details the calculations performed by EPA to project the number of available carryover RINs in the context of developing the 2026 and 2027 RFS standards. While the actual number of carryover RINs available for use by obligated parties to use towards these standards will not be known until after compliance with the preceding year's standards is complete, we are able to project these values by using 2024 compliance data and assumptions about RIN generation relative to RIN obligations in 2025.

1.8.1 Carryover RINs Available After Compliance With the 2024 Standards

In order to calculate the number of 2024 carryover RINs available for compliance with the 2025 standards, we began with the 2024 RFS compliance year data in Table 1.8.1-1. From

⁴⁷ CAA section 211(o)(7)(D).

⁴⁸ EPA currently does not have sufficient data to determine the proportion of the RIN value that is used to discount the retail price of CNG/LNG derived from biogas when used as transportation fuel.

⁴⁹ EIA's January 2026 Short-Term Energy Outlook (STEO) projects gasoline and diesel consumption in 2025 as 196.5 billion gallons (12.82 million barrels per day). Dividing the total cost of cellulosic RINs in 2025 (\$2.9 billion) by the total consumption of gasoline and diesel (196.5 billion gallons) results in an estimated cost of 1.5¢ per gallon of gasoline and diesel as a result of the 2025 cellulosic biofuel volume requirement.

this data, we calculated that approximately 23.81 billion total RINs were retired for compliance in the 2024 compliance year.⁵⁰ Of this total, approximately 21.34 billion 2024 RINs and 2.47 billion 2023 carryover RINs were used.

Table 1.8.1-1: RINs Retired by Obligated Parties and Exporters in the 2024 Compliance Year^a

RIN Type	RIN Year		Total
	2023	2024	
D3	69,969,240	939,117,670	1,009,086,910
D4	1,104,174,020	6,612,812,357	7,716,986,377
D5	18,005,685	226,676,380	244,682,065
D6	1,274,536,953	13,562,182,158	14,836,719,111
D7	0	0	0
Total	2,466,685,898	21,340,788,565	23,807,474,463

^a Data current as of February 20, 2026, and compiled from “RFS Compliance Data as of February 20, 2026,” available in the docket for this action. RINs include those retired by companies with a renewable volume obligation (RVO) as a gasoline/diesel fuel importer or refiner, as well as RINs retired by companies with an RVO as renewable fuel exporters. Renewable fuel exporters include exporters of neat renewable fuel, as well as exporters of renewable fuel blended with other fuels (including, but not limited to, gasoline, diesel fuel, heating oil, and jet fuel). See Table 1.8.4-1 for more detailed data.

Next, we calculated the net number of RINs that were generated in 2024. To do this, we took the total number of RINs generated in 2024 and then removed any RINs that were generated in error, as well as any RINs that were retired for purposes other than satisfying an obligated party or exporter RVO (*e.g.*, for spills, remedial actions, enforcement obligations, etc.). Using the data in Table 1.8.1-2, we calculated that a net of approximately 25.22 billion RINs were generated in 2024.

Table 1.8.1-2: 2024 Net RINs Generated

RIN Type	Total RINs Generated ^a	RIN Errors ^b	Other RIN Retirements ^c	Net RINs Generated ^d
D3	1,017,137,710	3,957,670	1,893,653	1,011,286,387
D4	9,182,032,867	13,479,222	56,389,438	9,112,164,207
D5	244,734,381	10,957	3,807,001	240,916,423
D6	14,906,191,638	24,716,558	23,196,569	14,858,278,511
D7	283,259	23,875	0	259,384
Total	25,350,379,855	42,188,282	85,286,661	25,222,904,912

Note: Data from January 2026 and compiled from https://www.epa.gov/system/files/other-files/2026-02/availablerins_jan2026.csv and https://www.epa.gov/system/files/other-files/2026-02/retiretransaction_jan2026.csv.

^a The total number of RINs generated includes those RINs generated for exported fuel.

^b See Table 1.8.4-2 for more detailed data.

^c See Table 1.8.4-3 for more detailed data.

^d Net RINs Generated = Total RINs Generated – (RIN Errors + Other RIN Retirements).

⁵⁰ Includes RINs retired in the 2024 compliance year to satisfy 2023 compliance deficits.

To determine the total number of 2024 carryover RINs available for compliance with the 2025 standards, we then subtracted the number of 2024 RINs retired in the 2024 compliance year from the net number of 2024 RINs generated. We calculate that there are approximately 3.88 billion 2024 carryover RINs available, as shown in Table 1.8.1-3.

Table 1.8.1-3: 2024 Carryover RINs

RIN Type	Net 2024 RINs Generated	2024 RINs Retired for Compliance	2024 Carryover RINs
D3	1,011,286,387	939,117,670	72,168,717
D4	9,112,164,207	6,612,812,357	2,499,351,850
D5	240,916,423	226,676,380	14,240,043
D6	14,858,278,511	13,562,182,158	1,296,096,353
D7	259,384	0	259,384
Total	25,222,904,912	21,340,788,565	3,882,116,347

Obligated parties are also able to carryforward a compliance deficit from one year to the next year,⁵¹ increasing their RVO for 2025 and effectively decreasing the number of 2024 carryover RINs available for compliance with the 2025 standards. In order to account for this, we calculate the effective number of 2024 carryover RINs available for compliance with the 2025 standards by subtracting out the 2024 compliance deficits, which have to be satisfied at the time of compliance with the 2025 standards.⁵² After accounting for this adjustment, we calculate that the total number of effective 2024 carryover RINs available for compliance with the 2025 standards is approximately 3.60 billion RINs, as shown in Table 1.8.1-4.⁵³

⁵¹ See 40 CFR 80.1427(b).

⁵² The compliance deadline for the 2025 standards will be the first quarterly reporting deadline after the effective date of the action establishing the 2026 standards. 40 CFR 80.1451(f)(1)(i)(A)(2).

⁵³ In other words, the number of available carryover RINs is effectively reduced in light of the volume of 2024 deficits carried forward to 2025. We note, moreover, that these numbers could change based on, for instance, enforcement actions or obligated parties truing up their RVOs pursuant to the attest engagement required by 40 CFR 80.1464.

Table 1.8.1-4: Effective 2024 Carryover RINs

RFS Standard	RIN Type	2024 Carryover RINs	2024 Compliance Deficits^a	Effective 2024 Carryover RINs^b
Cellulosic biofuel	D3+D7	72,428,101	55,110,052	17,318,049
Non-cellulosic advanced biofuel ^c	D4+D5	2,513,591,893	0	2,513,591,893
Conventional renewable fuel ^d	D6	1,296,096,353	228,735,586	1,067,360,767
Total renewable fuel	All D Codes	3,882,116,347	280,333,003	3,601,783,344

^a Data current as of February 10, 2025, and compiled from “RFS Compliance Data as of February 10, 2026,” available in the docket for this action.

^b Represents the effective number of 2024 carryover RINs that are available for compliance with the 2025 standards after accounting for deficits carried forward from 2024 into 2025.

^c Non-cellulosic advanced biofuel is not an RFS standard category but is calculated by subtracting the number of cellulosic RINs from the number of advanced RINs.

^d Conventional renewable fuel is not an RFS standard category but is calculated by subtracting the number of advanced RINs from the number of total renewable fuel RINs.

1.8.2 Carryover RINs Available for 2026 and 2027

Given the uncertainty of the impact of compliance with the 2025 standards on the number of available carryover RINs, we are unable to provide a quantitative analysis of the number of carryover RINs that may be available for compliance with the 2026 and 2027 standards.⁵⁴ However, if we assume that the uncertainties result in neither a net gain nor net loss of excess RINs for 2025, and that this is also the case for 2026, then the carryover RINs that we projected to be available in Chapter 1.8.1 would represent the number of carryover RINs available for compliance with the 2026 and 2027 standards, as shown in Table 1.8.2-1.⁵⁵

⁵⁴ Sources of uncertainty that could potentially increase the number of carryover RINs include lower actual gasoline and diesel fuel use than the projection used to derive the standards. Sources of uncertainty that could potentially decrease the number of carryover RINs include enforcement actions and higher actual gasoline and diesel fuel use than the projection used to derive the standards.

⁵⁵ The actual number of RINs that will be available for use by obligated parties to use towards the 2026 and 2027 standards will not be known until the compliance deadline for the preceding compliance year. Even after this date, however, this number could change based on, for instance, obligated parties truing up their RVOs pursuant to the attest engagement required by 40 CFR 80.1464 or enforcement actions.

Table 1.8.2-1: Projected Carryover RINs for 2026 and 2027

RFS Standard	RIN Type	Projected Effective Carryover RINs^a
Cellulosic biofuel	D3+D7	17,318,049
Non-cellulosic advanced biofuel ^b	D4+D5	2,513,591,893
Conventional renewable fuel ^c	D6	1,067,360,767
Total renewable fuel	All D Codes	3,601,783,344

^a Represents the effective number of 2024 carryover RINs that are available for compliance with the 2025 standards after accounting for deficits carried forward from 2024 into 2025.

^b Non-cellulosic advanced biofuel is not an RFS standard category but is calculated by subtracting the number of cellulosic RINs from the number of advanced RINs.

^c Conventional renewable fuel is not an RFS standard category but is calculated by subtracting the number of advanced RINs from the number of total renewable fuel RINs.

1.8.3 Carryover RIN History

In order to provide a historical perspective on the number of available carryover RINs, we calculated the absolute and effective number of carryover RINs for each year since 2013 using the same methodology described in Chapter 1.8.1. The results are provided in Table 1.8.3-1 and Figures 1.8.3-1 through 4 and represent the number of RINs of a given vintage available for compliance with the subsequent year's standard (*e.g.*, the number of available carryover RINs in 2024 are those 2024 RINs that can be used to comply with the 2025 standards).

Table 1.8.3-1: Number of Available Carryover RINs History (million RINs)

Compliance Year	Cellulosic Biofuel		Non-Cellulosic Advanced Biofuel		Conventional Renewable Fuel		Total Renewable Fuel	
	Absolute^a	Effective^b	Absolute^a	Effective^b	Absolute^a	Effective^b	Absolute^a	Effective^b
2013	0	0	565	538	1,087	1,045	1,652	1,583
2014	12	12	465	444	1,359	1,239	1,836	1,695
2015	39	39	372	367	1,248	1,242	1,659	1,649
2016	39	34	887	825	1,945	1,621	2,871	2,480
2017	28	8	801	683	2,981	2,437	3,810	3,129
2018	52	49	633	608	2,872	2,779	3,557	3,436
2019	64	59	344	237	2,693	2,518	3,102	2,814
2020	51	44	209	85	1,971	1,990	2,231	2,118
2021	45	28	249	0	1,530	1,386	1,824	1,322
2022	90	86	247	119	568	174	904	378
2023	70	13	1,124	1,012	1,278	341	2,472	1,366
2024	72	17	2,514	2,514	1,296	1,067	3,882	3,602

^a Represents the absolute number of carryover RINs that are available for compliance with the subsequent year's standards and does not account for carryforward deficits.

^b Represents the effective number of carryover RINs that are available for compliance with the subsequent year's standards after accounting for carryforward deficits. Standards for which deficits exceed the number of available carryover RINs are represented as zero.

1.8.4 EMTS RIN Data

Table 1.8.4-1: RINs Retired by Importers, Refiners, and Exporters in the 2024 Compliance Year^a

RIN Type	Year	Importers	Refiners	Exporters	Total
D3	2023	1,926,135	68,043,105	0	69,969,240
	2024	31,636,444	907,198,495	282,731	939,117,670
D4	2023	19,012,036	989,442,645	95,719,339	1,104,174,020
	2024	198,019,829	5,442,776,184	972,016,344	6,612,812,357
D5	2023	1,318,520	9,045,731	7,641,434	18,005,685
	2024	6,378,714	170,861,367	49,436,299	226,676,380
D6	2023	57,205,190	1,182,131,646	35,200,117	1,274,536,953
	2024	409,183,531	12,619,866,880	533,131,747	13,562,182,158
D7	2023	0	0	0	0
	2024	0	0	0	0
Total		724,680,399	21,389,366,053	1,693,428,011	23,807,474,463

^a Data current as of February 20, 2025, and compiled from “RFS Compliance Data as of February 20, 2026,” available in the docket for this action.

Table 1.8.4-2: 2024 RIN Errors

RIN Type	Import Volume Correction	Invalid RIN	Volume error correction	Total
<i>Retirement Code</i>	<i>30</i>	<i>50</i>	<i>60</i>	<i>--</i>
D3	0	3,957,670	0	3,957,670
D4	0	13,464,942	14,280	13,479,222
D5	0	8,854	2,103	10,957
D6	0	23,540,704	1,175,854	24,716,558
D7	0	23,875	0	23,875
Total	0	40,996,045	1,192,237	42,188,282

Note: Data from January 2026 and compiled from https://www.epa.gov/system/files/other-files/2026-02/retiretransaction_jan2026.csv.

Table 1.8.4-3: Other 2024 RIN Retirements

RIN Type	Reported spill	Contaminated or spoiled fuel	Renewable fuel used in an ocean-going vessel	Enforcement Obligation
<i>Retirement Code</i>	<i>10</i>	<i>20</i>	<i>40</i>	<i>70</i>
D3	0	0	0	911,668
D4	1	1,982,568	13,822,787	6,293,732
D5	0	417,891	0	343,466
D6	10,996	74,234	0	20,230,860
D7	0	0	0	0
Total	10,997	2,474,693	13,822,787	27,779,726

RIN Type	Renewable fuel used or designated to be used in any application that is not transportation fuel heating oil or jet fuel	Delayed RIN Retire per 80.1426(g)(3) only	Remedial action - Retirement pursuant to 80.1431(c)	Remedial Action - Retire for Compliance
<i>Retirement Code</i>	<i>90</i>	<i>100</i>	<i>110</i>	<i>120</i>
D3	420,102	0	561,883	0
D4	21,272,483	0	1,393,972	0
D5	2,925,918	0	119,726	0
D6	34,753	0	2,707,966	0
D7	0	0	0	0
Total	24,653,256	0	4,783,547	0

RIN Type	Remediation of Invalid RIN Use for Compliance	2020 Small Refinery Alternative Compliance	Voluntary RIN Retirement	Feedstock using renewable fuel with RINs	Total
<i>Retirement Code</i>	<i>130</i>	<i>150</i>	<i>160</i>	<i>170</i>	<i>--</i>
D3	0	0	0	0	1,893,653
D4	8,611,010	0	0	3,012,885	56,389,438
D5	0	0	0	0	3,807,001
D6	137,760	0	0	0	23,196,569
D7	0	0	0	0	0
Total	8,748,770	0	0	3,012,885	85,286,661

Note: Data from January 2026 and compiled from https://www.epa.gov/system/files/other-files/2026-02/retiretransaction_jan2026.csv.

Chapter 2: Baselines

This document contains a collection of analyses examining factors identified in the CAA, as well as other analyses EPA conducted to evaluate the impacts of this rule. The choice of baseline has a first-order impact on the outcome of those analyses. In Preamble Section III.D, we discuss the fact that a “No RFS” baseline is the most appropriate among available options for purposes of evaluating the impacts of the volumes in this action for 2026 and 2027.

For our assessment of costs and fuel price impacts we have considered the impacts of the Analyzed Volumes relative to both the No RFS Baseline and the 2025 Baseline. We recognize that the 2025 Baseline may be of interest to the public as it gives an indication of changes in volume requirements over time and how costs and fuel prices may change from current levels as a result of this action. Nevertheless, we believe that the No RFS Baseline better represents the overall impacts of establishing volume requirements for 2026 and 2027 relative to a scenario where there were no RFS volume requirements for 2026 or 2027. This chapter describes our derivation of the No RFS Baseline, as well as an alternate baseline—the 2025 Baseline—representing actual renewable fuel consumption in 2025.

2.1 No RFS Baseline

The No RFS Baseline represents our projection of biofuel consumption in the U.S. were the RFS program to cease to exist. Conceptually, the No RFS Baseline allows EPA to directly project the impacts of the Analyzed Volumes for 2026 and 2027 relative to a scenario without volume requirements. When estimating the No RFS baseline, we assumed that non-RFS federal and state programs that support renewable fuel production and use (*e.g.*, the federal renewable fuels production credits and state LCFS programs), would continue to exist in 2026 and 2027; in other words, the only current policy not in place in this baseline scenario is the RFS standards.

To project the No RFS Baseline, we began by projecting renewable fuel consumption in the U.S. in 2026 and 2027, and in the preceding years, in the absence of RFS volume requirements for these years. We assumed that all state mandates for renewable fuel use would continue, and that additional volumes of renewable fuel would be used if these fuels could be provided at a lower price than petroleum-based fuels, after taking into account available federal and state incentives.⁵⁶ Because we model the impact of state mandates and incentives, we project biofuel consumption on a state-by-state basis. The differences between the Analyzed Volumes and the No RFS Baseline represent the volume changes that we analyzed for this rule. These volume changes, as detailed in Chapter 3, are the starting point for the analyses presented in this document, except where noted.

In some cases, the volume difference between the No RFS Baseline and the Analyzed Volumes were sufficient to assess the impacts of the various factors enumerated in the statute. For example, the GHG impacts and the costs are directly dependent on the volume of renewable fuel used in the U.S. In other cases, however, these volume differences alone were insufficient

⁵⁶ Local renewable fuel production subsidies and renewable fuel plant construction subsidies were not considered. These subsidies could help support renewable fuel production volumes and support a slightly higher baseline volume.

and potentially misleading. For example, the final total domestic ethanol consumption volume is 660–730 million gallons per year higher than under the No RFS Baseline. This projected volume increase could imply that additional ethanol production capacity and distribution infrastructure will be needed to supply the Analyzed Volumes. However, total domestic ethanol consumption in the Analyzed Volumes for 2026 and 2027 is lower than total domestic ethanol consumption achieved in previous years, with the balance being exported. Thus, no additional ethanol production capacity or distribution infrastructure is projected to be needed to meet the ethanol volumes in the Analyzed Volumes for 2026 and 2027, although additional capital investments are required to enable retail stations to sell the increased higher ethanol blends. Where appropriate, such as in our assessment of infrastructure, we have therefore considered not only the difference in domestic renewable fuel consumption between the No RFS Baseline and the Analyzed Volumes, but also other relevant factors as they exist in 2025.

The lower demand for BBD in the No RFS Baseline would likely result in lower feedstock prices and lower production costs for the finished fuel. For feedstock prices for the No RFS Baseline, we assumed the USDA projected soybean oil prices for 2026 and 2027 would apply, which are lower than the average soybean prices in 2025, and a likely good first estimate for the lower prices and costs for No RFS Baseline. We assume that unrefined corn oil and FOG prices are priced lower based on their historical price difference.

The No RFS Baseline was derived based on the relative economics of biofuels and the petroleum fuels that those biofuels are blended into. If the blending cost of a biofuel in a particular state is less than the petroleum fuel that it is blended into, we assume that the biofuel would be used and displace the respective petroleum fuel, provided that the fuels distribution system can provide the fuels and vehicles can use those biofuels. The blending cost of a biofuel includes the value that the biofuel has when blending it into petroleum fuel. There are several components that must be considered for each fuel:

- Production cost
- Distribution cost
- Blending value to the fuel blender (*i.e.*, octane value and RVP cost of ethanol)
- Federal and state subsidies
- Relative energy value of the fuel, which may or may not be a factor
- Cost to upgrade retail stations to enable them to offer the renewable fuel

These various cost components of each renewable fuel are added together to determine the value of each fuel at the point that it is to be blended into petroleum fuel. For each renewable fuel, the combination of these various cost components is represented using an equation that will be described in each case.

There are many similarities between this No RFS Baseline analysis and that of the cost analysis described in Chapter 10, but there are differences as well. Table 2.1-1 summarizes the various cost components considered for this analysis and provides comments on how this analysis differs from the cost analysis in Chapter 10.

Table 2.1-1: Comparison of No RFS Baseline Analysis to Cost Analysis

	Included in No RFS and Cost Analysis		Notes
	No RFS	Cost	
Production Cost	Yes	Yes	For the No RFS Baseline, capital costs are amortized using higher return on investment with taxes, while cost analysis uses a lower pre-tax return on investment used for social analyses
Distribution Cost	Yes	Yes	Same
Blending Cost	Yes	Yes	Same
Fuel Economy Cost	Yes	Yes	The cost analysis always accounts for fuel economy cost, while the No RFS Baseline only does so if it impacts the value of the renewable fuel to fuel blenders
Federal and State Subsidies	Yes	No	The social cost analysis never takes subsidies into account as they are considered transfer payments
Conducted on a State-by-State, Fuel Type-by-Fuel Type Basis	Yes	No	While a national-average cost is sufficient for the cost analysis, it was necessary to estimate the economics of blending renewable fuel in individual states that offer subsidies, and by fuel type, to assess whether the renewable fuel would be blended into each fuel in that state

For the No RFS Baseline analysis, we use the latest projected feedstock prices (*e.g.*, corn, soybean oil) for estimating the production costs for their associated fuels. For some renewable fuels, the estimated volume under a No RFS scenario is projected to be smaller than under the RFS program. Economic theory would say that this could lower the market prices for the agricultural feedstocks, making the renewable fuels made from them more attractive. Nevertheless, consistent with our practice in previous RFS rules, we did not attempt to evaluate such a feedback mechanism when estimating the No RFS baseline.⁵⁷ The various economic factors shown in Table 2.1-1 are further discussed below for each renewable fuel.⁵⁸

Similarly, for the gasoline and diesel fuel prices, we use the most recent wholesale price projections in AEO2025. Since EIA models much of the RFS program in its AEO modeling, some price impacts of the RFS program are likely already represented in these wholesale gasoline and diesel fuel prices. Economic theory would again say that wholesale gasoline and diesel fuel prices would probably be lower under a No RFS scenario. However, we did not attempt to evaluate this.

As indicated in Table 2.1-1, for the No RFS Baseline analysis we assume that the 45Z credit applies even if the RFS program does not. That is because the 45Z credit was established

⁵⁷ By not estimating lower renewable fuel prices under the No RFS Baseline, it could underestimate renewable fuel demand under the No RFS Baseline and conservatively estimate higher costs for the Analyzed Volumes.

⁵⁸ The spreadsheets used to estimate the No RFS Baseline for corn ethanol (“Corn Ethanol No RFS Baseline for Set 2 Final Rule”) and biodiesel and renewable diesel (“Biodiesel and Renewable Diesel No RFS Baseline for Set 2 Final Rule”) are available in the docket for this action.

by a separate congressional action. The 45Z credit is also used for estimating the impact of the RFS final volumes on prices as described in Chapter 10.5. To estimate the Federal tax credit associated with 45Z, we estimate the producer tax credits based on carbon intensity estimates from the 45ZCF-GREET model used for implementation of the 45Z credit.⁵⁹ These estimates are for the purposes of this analysis alone—the actual production tax credit values will differ for individual taxpayers and based on rules and methods finalized by the Department of Treasury. Estimates produced for this analysis should not be used as a guide for determining actual tax credit value for any individual taxpayer. For each biofuel pathway, we use default assumptions representative of industry average practices based on data from 45ZCF-GREET and R&D GREET 2024-Rev1. We assume the midwest electricity grid region for this analysis. Consistent with 45Z as amended by OBBB, we (1) exclude tax credits for imported fuels and fuels produced from imported feedstocks,⁶⁰ (2) exclude indirect land use change emissions, (3) reduce the SAF maximum credit from \$1.75 per gallon to \$1.00 per gallon, and (4) allow negative values for manure-based pathways. For the RNG pathways, we use the estimates for biogas upgrading via pressure swing adsorption and we use manure-biogas CNG CI estimates from R&D GREET 2024-Rev1.⁶¹ We translate the carbon intensity estimates to monetary tax credits using the values in the 45Z statute and assume the wage, apprenticeship and other labor requirements are satisfied to qualify for the larger tax credit value. We estimate the tax credits in 2024 dollars.⁶² There is also a 40A Small Agri-Biodiesel Producers tax credit of \$0.20 per gallon that applies only for 2026 for producers of soybean oil, canola oil and tallow biodiesel with a production capacity of less than 60 million gallons per year. These preliminary estimates are strictly limited to the purposes of our evaluation of the No RFS Baseline and carry no significance at all for claiming tax credits under the 45Z statute. Table 2.1-2 summarizes the 45Z credits by types of feedstocks and fuels being produced.

⁵⁹ Estimates were developed by the EPA using the 45ZCF-GREET model (March 2025 version) that was developed by Argonne National Laboratory (ANL). The model is titled “45ZCF-GREET” because it was developed in support of the clean fuels (CF) tax credit authorized by § 45Z of the Internal Revenue Code.

⁶⁰ The 45Z credit requirement that feedstocks are produced in North America applies after December 31, 2025. The 45Z credit requirement that feedstocks are sourced from North America is exclusive to 2026. As a simplifying assumption for purposes of EPA’s analysis for this rule, we only include 45Z credits for fuels produced from North American feedstocks in both 2026 and 2027.

⁶¹ As amended by OBBB, the 45Z credit includes differentiated emissions rates for CNG produced from animal manure by animal type. The Department and Treasury has not finalized the methods for estimating emissions rates for each animal type. For this analysis, we use estimates from the R&D GREET 2024-Rev1 model, but the actual credit values for individual taxpayers are likely to differ from our estimates, potentially by a large amount.

⁶² The 45Z credits are estimated in 2024 dollars, but we did not adjust them to nominal dollars. This did not have any effect on the volume estimates for No RFS Baseline analysis because the very small effect would not have affected the conclusions in each case.

Table 2.1-2: 45Z Carbon Intensity and Tax Credit Estimates Used in This Analysis

Pathway	Emissions Rate (kgCO₂e/mmBtu)	Credit (\$/gal)
Corn Ethanol	43	\$0.14
Soybean Oil Biodiesel	19	\$0.62
Soybean Oil Renewable Diesel	24	\$0.52
Canola Oil Biodiesel	32	\$0.35
Canola Oil Renewable Diesel	35	\$0.29
Tallow Biodiesel	19	\$0.63
Tallow Renewable Diesel	17	\$0.65
Used Cooking Oil Biodiesel	10	\$0.80
Used Cooking Oil Renewable Diesel	17	\$0.66
Distillers Corn Oil Biodiesel	10	\$0.80
Distillers Corn Oil Renewable Diesel	12	\$0.75
Landfill Gas CNG	26	\$0.47
Dairy Manure CNG	-155	\$4.11
Beef Manure CNG	32	\$0.35
Swine Manure CNG	-150	\$4.00
Layer Manure CNG	67	-
Wastewater Treatment Plant CNG	41	\$0.18

Note: The 45Z credit estimates in this table are for the purposes of this analysis alone—the actual credit values will differ for individual taxpayers and based on rules and methods finalized by the Department of Treasury. Estimates produced for this analysis should not be used as a guide for determining actual tax credit value for any individual taxpayer.

2.1.1 Conventional Ethanol

By far the largest volume of ethanol blended into U.S. gasoline is conventional ethanol (*i.e.*, ethanol generating a D6 conventional renewable fuel RIN) produced from corn starch, though smaller quantities of conventional ethanol are produced from grain sorghum starch as well. Some even smaller quantities of ethanol produced from separated food waste, corn and grain sorghum fiber, and sugarcane are also blended into U.S. gasoline. These non-conventional volumes are discussed in Chapter 2.1.2 and Chapter 2.1.4. The baseline volumes estimated in this section are assumed to be entirely from conventional ethanol, which we assume for the purposes of this analysis to be produced entirely from corn starch.

Ethanol is mostly blended into gasoline at 10% (*i.e.*, E10). However, some volume of ethanol is also blended at higher blend percentages of 15% and 51-83% (*i.e.*, E15 and E85, respectively).⁶³ This section discusses the blending economics of ethanol and estimates the No RFS Baseline for all three of these ethanol fuel blends. The No RFS Baseline analyses presented for corn ethanol is contained in a spreadsheet entitled “Corn Ethanol No RFS Baseline for SET2 FRM” located in the Docket.

⁶³ AFDC, “E85 (Flex Fuel).” https://afdc.energy.gov/fuels/ethanol_e85.html.

2.1.1.1 E10

The cost of blending ethanol into gasoline at 10% was analyzed by EPA in a peer reviewed technical report.⁶⁴ That report and its appendix provide both a historical review and prospective analysis of the economics of blending ethanol into gasoline. The methodology used in that analysis and its conclusion are summarized here.

A number of key factors were considered when evaluating the relative economics of blending ethanol into gasoline. These factors depend on the type of gasoline the ethanol is blended into, the season or year, and tax policies. Since ethanol is blended into gasoline at the gasoline distribution terminal, it is most straightforward to consider those economic factors that impact the decision to blend ethanol at that point. From that vantage point, the relative economics of blending ethanol into gasoline—or the value of replacing ethanol in gasoline with other components—can be summarized by the following equation:

$$EBC_{E10} = (ESP + EDC - ERV - FETS - SETS) - GTP$$

Where:

- EBC_{E10} is ethanol blending cost for E10
- ESP is ethanol plant gate spot price
- EDC is ethanol distribution cost
- ERV is ethanol replacement value
- $FETS$ is federal ethanol tax subsidy
- $SETS$ is state ethanol tax subsidy
- GTP is gasoline terminal price; all are in dollars per gallon

This equation allows us to break down these factors by year, by state, and by gasoline type, enabling a detailed assessment of the relative blending economics of ethanol to gasoline over time and by location. If the resulting ethanol blending cost is negative, it is assumed to be cost-effective to blend ethanol. Since gasoline is marketed based on volume, not energy content, the lower energy density of ethanol is not part of the ethanol blending cost equation. E10 contains about 3% less energy content than E0, and the cost of the lower energy content of the gasoline is paid by consumers through lower fuel economy and more frequent refueling. Since this small change in energy content is largely imperceptible to consumers⁶⁵ and because gasoline without ethanol is not widely available, refiners are able to price ethanol based on its volume (unlike E85, for example, which must be priced lower at retail due to its more perceivably lower energy density). Thus, energy density is not a factor in this blending cost equation for E10. It is an important part of assessing the overall social costs of ethanol use but does not factor into the decision to blend ethanol as E10.

⁶⁴ EPA, “Economics of Blending 10 Percent Corn Ethanol into Gasoline,” EPA-420-R-22-034, November 2022.

⁶⁵ This is the case because the 3% reduction in average fuel economy equates to a reduction of 1 mile per gallon or less for most vehicles. This difference is difficult to perceive against the background of normal variation in vehicle performance under different conditions (*e.g.*, weather), even for consumers who regularly track their fuel economy.

Ethanol Plant Gate Spot Price (ESP)

We estimated future ethanol plant gate prices by gathering projected ethanol plant input information (*e.g.*, future corn prices projected by USDA and utility prices projected by EIA) to estimate ethanol production costs that we presume represents plant gate prices. This is essentially the same information used for estimating ethanol production costs for the cost analysis, except that the capital costs are handled differently. Instead of amortizing the capital costs using a 7% before tax rate of return on investment, capital costs are amortized using a 10% after tax return on investment. As shown in Table 2.1.1.1-1, the capital amortization factor increases to 0.16 from 0.11 used for the cost analysis.

Table 2.1.1.1-1: Capital Amortization Factor Used for Estimating Plant Gate Spot Prices Based on Production Costs

Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment	Resulting Capital Amortization Factor
10 Years	15 Years	39%	10%	0.16

The year-by-year ethanol plant gate price projections based on production costs are summarized in Table 2.1.1.1-2.⁶⁶

Table 2.1.1.1-2: Projected Ethanol Plant Gate Prices (nominal \$/gal)

Year	Price
2026	\$1.90
2027	\$1.90

Ethanol Distribution Cost (EDC)

This factor represents the added cost of moving ethanol from production plants to gasoline distribution terminals, reflecting its different modes of transport (the gasoline terminal prices in the equation already include distribution costs). Because ethanol is primarily produced in the Midwest and Great Plains and distributed longer distances to the rest of the country, the terminal price of ethanol is usually lower in the Midwest than in other parts of the U.S. Ethanol distribution costs were estimated for EPA on a regional basis, but to conduct the analysis on a state-by-state basis, these costs were interpolated or extrapolated to estimate state-specific costs based on ethanol spot prices.⁶⁷ The estimated distribution costs for ethanol ranged from 11¢/gal in the Midwest to 29¢/gal when moved to the furthest distances along the U.S. coasts, and over 50¢/gal when shipped to Alaska and Hawaii. The distribution cost to each state, adjusted to 2026 dollars, is summarized in Table 2.1.1.1-3.

⁶⁶ Projected corn ethanol production costs in nominal dollars are estimated by entering the costs of various inputs and accounting for the costs for various byproducts into a corn ethanol cost model using estimated prices for those inputs and byproducts in nominal dollars.

⁶⁷ ICF, "Modeling a 'No-RFS' Case," EPA Contract No. EP-C-16-020, July 17, 2018.

Table 2.1.1.1-3: Ethanol Distribution Cost by State

Region	States	Average Ethanol Distribution Cost in 2026 (¢/gal)
PADD 1	New York, Pennsylvania, West Virginia	25.0
	District of Columbia, Connecticut, Delaware, Maryland, Massachusetts, New Jersey, Rhode Island, Virginia	28.0
	Georgia, South Carolina Vermont, New Hampshire, North Carolina	30.0
	Florida, Maine	38.0
PADD 2	Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, Ohio, South Dakota, Wisconsin	15.0
	Kentucky, North Dakota, Oklahoma, Tennessee	28.0
PADD 3	Arkansas, Louisiana, Mississippi, Texas	21.0
	Alabama, New Mexico	28.0
PADD 4	Colorado, Idaho, Montana, Utah, Wyoming	23.0
PADD 5	Oregon, Washington	29.0
	Arizona, California, Nevada	34.0
	Alaska, Hawaii	68.0

Ethanol Replacement Value (ERV)

Ethanol has properties that provide value (primarily octane) or incur cost (vapor pressure impacts) when it is blended into gasoline. We use the term “ethanol replacement value” to refer to the sum of the values and costs due to these properties, including properties that increase and decrease ethanol’s blending value. Depending on where and when the ethanol is used, the ethanol blending value is an important consideration when gasoline production is modified to take into account the subsequent addition, or potential removal, of ethanol.

Essentially all E10 blending in the U.S. now occurs by “match-blending,” where the base gasoline (“gasoline for oxygenate blending” or BOB) is modified to account for the subsequent addition of ethanol, in which the blending value of ethanol is important. In reformulated gasoline (RFG) areas, refiners produce a reformulated gasoline before oxygenate blending (RBOB) that has both a lower octane value and lower RVP tailored to still meet the RFG standards after the addition of ethanol. This has been typical for ethanol-blended RFG since the mid-1990s. As the use of ethanol expanded into CG areas, ethanol was initially “splash blended” into finished gasoline, meaning that the gasoline was not lower in octane. As E10 gasoline filled up the conventional gasoline pool, a similar match-blending process began to be used there as well, replacing splash-blending. In these areas, a suboctane conventional gasoline for oxygenate blending (CBOB) is produced by refiners for match-blending with ethanol. CG is also adjusted to account for the octane value of ethanol, but unlike RFG, most CG is not adjusted for RVP due to a 1-psi RVP waiver provided for E10 in most locations. When RBOB and CBOB are produced, the refiner makes the decision that ethanol will be blended into their gasoline since the BOBs cannot be sold as finished gasoline without adding 10% ethanol, but the ethanol is still

blended into the gasoline at the terminal.⁶⁸ It is likely that refiners make their decision on producing BOBs based on the economics of producing finished gasoline at terminals. In the case of such match blends, the economic value of ethanol relative to gasoline includes a consideration of not only its value on a volumetric basis as a substitute for gasoline, but also the blending value of ethanol resulting from its higher octane, and in some cases, its impact on volatility.

The full value of ethanol is best reflected by the cost associated with meeting all of the gasoline standards and requirements through some means other than blending ethanol, including any capital costs to produce ethanol replacements. To assess this, ICF conducted refinery modeling for EPA for removing ethanol from the gasoline pool that the refinery model would need to replace with an energy equivalent amount of gasoline.⁶⁹ After aggregating the refinery cost modeling results—which account for the octane value and volatility of ethanol, as well as replacing its volume—the replacement costs of ethanol in regular grade CG and RFG are summarized in Table 2.1.1.1-4. The ethanol replacement costs were estimated based on a certain set of modeling conditions—projected prices for the year 2020 with crude oil priced at \$72/bbl.⁷⁰ The economics for replacing ethanol, however, would be expected to vary over time based on changing market factors, such as the market value of RVP control costs, crude oil prices, and particularly the market value for octane. The ethanol replacement costs were adjusted for the years analyzed under the No RFS Baseline based on increasing nominal crude oil prices, which likely provides a reasonable estimate of how refiners would value the octane, RVP, and other replacement costs of ethanol over time.⁷¹

Table 2.1.1.1-4 Ethanol Replacement Value (nominal \$/gal)

Gasoline Type	Gasoline Grade	2026	2027
Conventional Gasoline	Summertime Regular	1.93	1.93
	Summertime Premium	1.45	1.46
Reformulated Gasoline	Summer Regular	1.66	1.67
	Summer Premium	1.19	1.19
Conventional and Reformulated	Winter Regular	0.78	0.78
	Winter Premium	0.59	0.59

Federal and State Ethanol Tax Subsidies (FETS and SETS)

The Federal ethanol blending tax subsidy expired in 2011, so that subsidy did not figure into the No RFS Baseline analysis. We do, however, account for the 45Z credit for domestically produced renewable fuels, including domestically produced corn ethanol. For purposes of this

⁶⁸ The exception to this is a small amount of premium grade BOB that is sold as regular or midgrade E0.

⁶⁹ The results of this refinery modeling are summarized in Chapter 10.1.3.1.1. MathPro, “Analysis of the Effects of Low-Biofuel Use on Gasoline Properties – An Addendum to the ‘No-RFS’ Study,” EPA Contract EP-C-16-020, June 7, 2019.

⁷⁰ The ethanol replacement value is the equivalent value of petroleum blendstocks that would be needed to make up for ethanol’s properties and volume.

⁷¹ The adjustment is a simple ratio of the crude oil price in a particular year divided by the crude oil price in the baseline year.

analysis, as described above in Chapter 2.1, we estimate the 45Z subsidy for corn ethanol to be 14¢ per gallon on average.⁷²

Various state tax subsidies, however, have been provided for the use of ethanol. These tax subsidies incentivize the blending of ethanol into the gasoline pool and directly impact the decision of whether to use ethanol. Iowa and Illinois offer an ethanol blending subsidy of 15¢ and 26¢ per gallon, respectively.⁷³ The California LCFS program is estimated to provide corn ethanol an average blending credit of 17¢ per gallon based on a modeled projected carbon price of \$100 per metric ton.^{74,75} The clean fuels programs in Oregon and Washington state are estimated to incentivize corn ethanol by 19¢ and 5¢ per gallon, respectively.⁷⁶ Several states, including Minnesota and Missouri, also have ethanol use mandates that require the use of ethanol regardless of the economics for doing so.⁷⁷ These mandates cannot be factored into the ethanol blending cost equation, but are accounted for in EPA’s overall analysis by including the ethanol volume in gasoline in these states regardless of the blending economics. Other federal and state subsidies—such as ethanol production subsidies, loan guarantees, grants, and any other subsidies—were not considered by this analysis, although some of these subsidies, or a portion of them, may already be included in the price information we used to estimate ethanol’s production cost for the No RFS Baseline. To the extent that these subsidies are not represented in our No RFS Baseline analysis will lead to slightly underestimating the volume of corn ethanol in our No RFS Baseline.

Gasoline Terminal Price (GTP)

Refinery rack price data—which already included the distribution costs for moving gasoline to downstream terminals— from 2021 (the last year EIA reported this data) was used to represent the price of gasoline to blenders on a state-by-state basis.⁷⁸ This gasoline price data, summarized in Table 2.1.1.1-5, was collected for each state and is assumed to represent the average gasoline price for all the terminals in each state.⁷⁹

⁷² The 45Z estimates produced for this analysis should not be used as a guide for determining actual tax credit value for any individual taxpayer.

⁷³ The National Agricultural Law Center, States’ Biofuels Statutory Citations. <https://nationalaglawcenter.org/state-compilations/biofuels>.

⁷⁴ California Air Resources Board (CARB), LCFS Pathway Certified Carbon Intensities. <https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities>.

⁷⁵ CARB, “Attachment C: LCFS Fuels and Credit Market Module Modeling,” https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/15day_attc.pdf.

⁷⁶ The state of New Mexico is putting in place a clean fuels program similar to California’s, Oregon’s and Washington, but there is not any data yet available for estimating its incentive to biofuels. New Mexico Environment Department, “Clean Transportation Fuel Program,” January 29, 2026. <https://www.env.nm.gov/climate-change-bureau/clean-fuel-standard>.

⁷⁷ The National Agricultural Law Center, States’ Biofuels Statutory Citations. <https://nationalaglawcenter.org/state-compilations/biofuels>.

⁷⁸ EIA, “Spot Prices,” *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.

⁷⁹ EIA, “Refiner Gasoline Prices by Grade and Sales Type,” *Petroleum & Other Liquids*, June 1, 2022. https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_a.htm.

Table 2.1.1.1-5: Gasoline Terminal Prices in 2021 (\$/gal)

State	Gasoline Grade		State	Gasoline Grade	
	Regular	Premium		Regular	Premium
Alaska	2.73	2.74	Montana	2.23	2.68
Alabama	2.04	2.48	North Carolina	2.04	2.42
Arkansas	2.05	2.37	North Dakota	2.07	2.37
Arizona	2.26	2.56	Nebraska	2.06	2.33
California	2.72	2.98	New Hampshire	2.16	2.45
Colorado	2.23	2.58	New Jersey	2.07	2.30
Connecticut	2.11	2.40	New Mexico	2.26	2.58
D.C.	2.09	2.37	Nevada	2.44	2.72
Delaware	2.10	2.32	New York	2.15	2.47
Florida	2.07	2.41	Ohio	2.04	2.43
Georgia	2.05	2.48	Oklahoma	2.05	2.23
Hawaii	2.59	2.71	Oregon	2.29	2.60
Iowa	2.03	2.30	Pennsylvania	2.07	2.32
Idaho	2.44	2.74	Rhode Island	2.14	2.48
Illinois	2.03	2.33	South Carolina	2.04	2.44
Indiana	2.03	2.36	South Dakota	2.10	2.41
Kansas	2.01	2.22	Tennessee	2.04	2.38
Kentucky	2.10	2.47	Texas	2.06	2.26
Louisiana	2.04	2.30	Utah	2.39	2.69
Massachusetts	2.12	2.35	Virginia	2.07	2.38
Maryland	2.07	2.27	Vermont	2.13	2.40
Maine	2.15	2.45	Washington	2.28	2.63
Michigan	2.05	2.49	Wisconsin	2.03	2.44
Minnesota	2.03	2.25	West Virginia	2.03	2.45
Missouri	2.06	2.33	Wyoming	2.24	2.65
Mississippi	2.03	2.41			

Note: No data was provided by EIA for the values highlighted in grey; they were estimated by prices in a neighboring state or for that state in a previous year when crude oil prices were about the same as 2021.

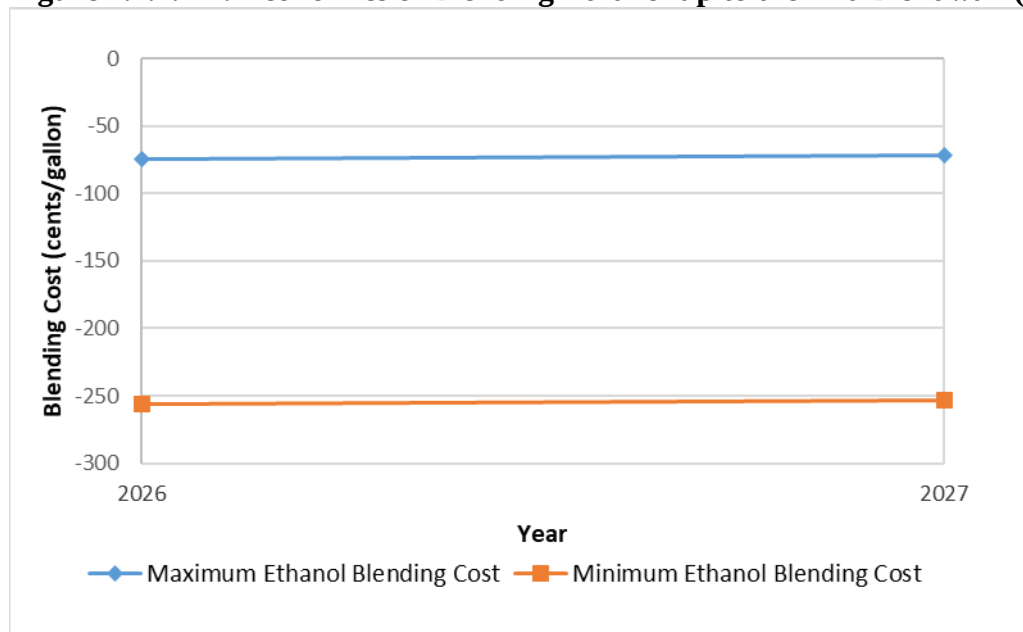
However, these prices were not projected for future years. Instead, we used projected refinery wholesale gasoline price data from AEO2025 to adjust the 2021 refinery rack price data to represent gasoline rack prices in future years. AEO2025 projected national average wholesale gasoline price information used to adjust gasoline prices in future years, and the national average wholesale gasoline price in 2021 to which the projected wholesale gasoline prices are compared, are summarized in Table 2.1.1.1-6. The state-by-state gasoline prices shown in Table 2.1.1.1-5 are ratioed upwards using the adjustment factor for adjusting the 2021 wholesale gasoline prices in each state. For example, the projected national average wholesale gasoline price adjustment factor in 2026 is 1.03; therefore, gasoline prices in 2026 are 1.03 times higher than the prices summarized in Table 2.1.1.1-5.

Table 2.1.1.1-6: National Average Wholesale Gasoline Prices

	Year	Wholesale Gasoline Price (AEO2025)	CPI	Wholesale Gasoline Price (nominal)	2021 Price Adjustment Factor
Actual National Average Gasoline Price	2021			\$2.19	-
Year dollars for AEO2025	2024		3.13		
Gasoline Price	2026	\$2.18 (2024\$)	3.24	\$2.26	1.03
	2027	\$2.13 (2024\$)	3.30	\$2.24	1.02

Source: AEO2025, Table 20 – Macroeconomic Indicators and Table 57 – Components of Selected Petroleum Product Prices.

The No RFS Baseline analysis revealed that it is economical to blend ethanol into the entire gasoline pool up to 10%. As shown in Figure 2.1.1.1-1, all blending costs are negative—ethanol is over 70¢/gal less expensive than gasoline in the most expensive market for blending ethanol, and about \$2.50/gal less expensive than gasoline in the least expensive market for blending ethanol (in which a state subsidy applies).

Figure 2.1.1.1-1: Economics of Blending Ethanol up to the E10 Blendwall (nominal dollars)

2.1.1.2 E85

Some aspects of the ethanol blending cost equation developed for E10 in Chapter 2.1.1.1—such as the Ethanol Plant Gate Spot Price (ESP) and Ethanol Distribution Cost (EDC), remain largely the same for E85 and are not discussed further here. However, the analysis for E85 has some important differences. The Gasoline Terminal Price (GTP) was replaced by Ethanol Breakeven Blending Value. The Ethanol Replacement Value (ERV), which is an important cost factor for the value of E10, is not a factor for E85, although this is discussed

below to characterize some E85 properties. Furthermore, an additional cost applies to E85 to account for the cost to modify retail stations to carry E85, which we have termed the Retail Cost (RC). We do not include a fuel economy effect for E10 because consumers bear this cost, both because they lack the ability to perceive the difference in fuel economy which creates the cost and because they generally lack reliable access to an alternative (*e.g.*, E0 gasoline) at a more attractive price. However, in E85's case, consumers command a lower price for E85 before purchasing E85 because they are able to perceive the difference in fuel economy associated with it relative to E10, which affects ethanol's value to fuel blenders at these higher rates. This E85 fuel pricing effect is captured in a breakeven price for ethanol.

The economics for using ethanol in E85 are estimated in two steps. First, we estimated the breakeven price for ethanol blended in E85 based on the price of gasoline in each state. This calculation is made for regular and premium grades of both CG and RFG in each state. In the second step, the estimated ethanol plant gate price, ethanol distribution cost, retail cost, and E85 subsidies are combined together in the following equation to estimate whether ethanol blended into E85 is economical:

$$EBC_{E85} = (ESP + EDC - FETS - SETS + RC) - EBBV$$

Where:

- EBC_{E85} is ethanol breakeven price for ethanol blended as E85
- ESP is ethanol plant gate spot price (same as section 2.1.1.1)
- EDC is ethanol distribution cost (same as section 2.1.1.1)
- $FETS$ is federal ethanol tax subsidy
- $SETS$ is state ethanol tax subsidy
- RC is retail cost (service station revamp cost to sell E85)
- $EBBV$ is ethanol breakeven blending value; all are in dollars per gallon

Ethanol Replacement Value (ERV)

Blending ethanol into gasoline for E85 is different than blending for E10 because refiners do not make a separate E85 BOB; thus, the E10 RBOBs and CBOBs are blended with ethanol to produce E85 and there is significant octane giveaway.⁸⁰ Conversely, there is no risk that the E85 blend will exceed any RVP limits because E85 has a very low RVP. In fact, the resulting E85 blend is so low in vapor pressure that it causes most E85 blends to not meet the RVP minimum standards. In those cases, E85 is blended with less ethanol—usually 70% in the winter and up to 79% in the summer—and the year-round average is 74%, which allows ethanol to comply with the ASTM RVP minimum standards.⁸¹

⁸⁰ Octane giveaway occurs when the gasoline being sold has higher octane than required in the state where the gasoline is being sold. For example, regular grade gasoline must meet an (R+M)/2 octane standard of 86 in most states. When ethanol is blended into finished gasoline, the octane of the finished E10 will be approximately 3 octane numbers higher than required.

⁸¹ ASTM D5798-21, "Standard Specification for Ethanol Fuel Blends for Flexible-Fuel Automotive Spark-Ignition Engines."

Although refiners do not create a lower octane BOB for blending into E85, ethanol producers nonetheless choose to blend natural gas liquids (NGLs) with ethanol to produce E85. NGLs are a low cost, low octane, higher RVP petroleum blending material that ethanol producers use to denature their ethanol. Since ethanol plants already have this blendstock material on hand, some ethanol producers blend E85 on-site using NGLs and then distribute the finished E85 from there. When blending up E85 with NGLs, the higher RVP of the NGLs allows blending a higher ethanol content of 83% in the summer. However, the RVP of NGLs is about the same or slightly higher than winter gasoline, so the winter blend percentage is the same. Because the more volatile NGLs are smaller hydrocarbons, they contain lower volumetric energy content, which is a factor in considering their value as well. Because NGLs are used as an E85 blendstock, we also evaluated the economics of blending E85 blended with NGLs. While this is an interesting option that ethanol producers take, we believe that most E85 is blended with gasoline.

Federal and State Ethanol Tax Subsidies (FETS and SETS)

E85 does not and has never had access to a federal ethanol blending tax subsidy. However, the ethanol used to produce most E85 is anticipated to have access to other federal incentives, such as the 45Z production credit.⁸² Various state tax subsidies have also been provided for the use of ethanol. These tax subsidies incentivize the blending of ethanol into the gasoline pool and directly impact the decision of whether to use ethanol. Table 2.1.1.2-1 provides the E85 subsidies offered by different states.

Table 2.1.1.2-1: Current State E85 Subsidies (¢/gal)

State	E85 Subsidy
Iowa	22¢
Illinois	18¢
Pennsylvania	16¢
South Dakota	14¢

The California, Oregon and Washington state clean fuels program blending credits for ethanol also apply when ethanol is blended into E85. Aside from the retail cost credit offered by USDA Higher Ethanol Blends program described below, other federal and state subsidies—such as ethanol production subsidies, loan guarantees, grants, and any other subsidies—were not considered by this analysis.

Retail Cost (RC)

The retail costs for E85 are estimated based on the investments needed to offer E85 at retail stations and the estimated throughput at E85 stations.⁸³ We obtained a report provided under the USDA Higher Blends Infrastructure Incentive Program (HBIIP) which listed the major equipment installed to enable storing and dispensing E85. For a typical retail station revamp to

⁸² As described in Chapter 2.1, we estimate an average 45Z credit of 14¢ per gallon for E100. Thus, the implied 45Z subsidy per gallon of E85 will depend on the ethanol blend level. Estimates produced for this analysis should not be used as a guide for determining actual tax credit value for any individual taxpayer.

⁸³ The methodology used and the estimated costs for these revamps are discussed in Chapter 10.1.4.1.2.

enable storing higher ethanol blends, a retail station installs 2.8 dispensers and 0.8 underground storage tanks. Each dispenser is estimated to cost \$53,000 and each underground storage tank is estimated to cost \$168,000.⁸⁴ Thus, the estimated total cost for a typical retail station revamp to enable selling E85 is \$283,000 in 2025. These stations are estimated to sell on average 82,000 gallons of E85 per year (see Chapter 7.5), although the E85 stations in California are estimated to sell about four times more gallons per station than retail stations outside of California. The initial Biofuel Infrastructure Partnership Program (BIP) and HBIIP program which superseded the BIP program, cover up to 50% and 75% of the revamp costs, respectively, so in our cost assessment we assume that these programs cover those respective portions of the retail revamp costs. When amortizing the unsubsidized portion of the capital cost over the gallons of E85 sold under the HBIIP program, the total cost of the revamp adds 15¢/gal to the cost of E85, and 22¢/gal per gallon of ethanol (accounting only for the estimated 64% of ethanol in E85 above the ethanol in E10) in E85.⁸⁵

While the typical revamp as described above involved both dispenser and tank replacement, some service stations required a greater amount of capital changes and others less. The HBIIP revamp data showed that some revamps are lower cost involving revamps of fewer pieces of equipment and analyzing this case will help us understand a lower hurdle cost point for allowing some E85 availability. The data shows that about 20% of the E85 revamps did not add an underground storage tank and added on average 1.7 dispensers per retail station. Thus, as a second cost point, we assessed the cost under the HBIIP program to the ethanol in E85 for those stations which only installed dispensers. When amortizing the unsubsidized portion of the capital cost over the gallons of E85 sold under the HBIIP program, the total cost of the revamp adds 5¢/gal to the cost of E85, and 8¢/gal to the cost of ethanol consumed as E85.⁸⁶

Although not directly impacting the relative cost of E85 to petroleum fuels, the number of E85 vehicles being produced has been declining and this can affect the throughput volume of E85 stations and increase the per-gallon cost of the retail station revamps.⁸⁷ One reason for the decline is that the federal FFV manufacturing incentives are no longer being offered. The demand for renewable fuels could cause manufacturers to ramp up production in future years.

Ethanol Breakeven Blending Value (EBBV)

There are downstream pricing effects for E85 that require the economics of E85 to be assessed differently when blending ethanol into E85 compared to blending ethanol into E10. These downstream pricing effects exist because E85 contains less energy compared to E10 on a volumetric basis—22% and 30% less when blended with gasoline and NGLs, respectively. This lower energy density of E85 is noticeable to consumers in their fuel economy. Because of this, most consumers demand a lower price at retail stations for E85 relative to E10, which therefore

⁸⁴ Average dispenser and underground storage tank costs based on discussions with USDA.

⁸⁵ The amortized the revamp cost is calculated by multiplying the capital costs by the capital cost amortization factor in Table 2.1.1.1-1 (0.16) and dividing by the E85 throughput volume.

⁸⁶ The per-gallon cost for the retail station revamps to allow dispensing E85 is calculated by multiplying the estimated revamp cost by the capital cost amortization factor in Table 2.1.1.1-1 (0.16) and dividing by the annual average amount of the ethanol contained in E85 sold from the retail stations.

⁸⁷ LookupAPlate, “14 Key Flex-fuel Vehicles (FFV) Statistics Every American Should Know,” January 9, 2026. <https://www.lookupaplate.com/blog/flex-fuel-vehicles-ffv-statistics>.

requires that the economics of E85 be assessed at retail. Price information collected for E85 shows that it is typically priced 16% lower than E10 at retail by volume.^{88,89} For the No RFS analysis, we assumed that gasoline-blended E85 is priced 16% lower than E10 and that NGL-blended E85—which has much lower volumetric energy content—is priced 21% lower than E10.⁹⁰

Figure 2.1.1.2-1 provides an example of how the breakeven price for ethanol is estimated for E85 when blended with gasoline. At the top of the figure, the pricing of gasoline is shown from terminal to retail, depicting the price impacts when distribution costs and taxes are added on. At the bottom of each figure, the pricing of E85 is shown when blended with gasoline. The E85 prices are then estimated at the terminal after the retail, tax, and distribution costs are subtracted from the retail prices. Finally, the ethanol breakeven price is estimated for the ethanol blended into E85 based on the price of gasoline at the terminal and the fraction of gasoline and ethanol in E85.

Figure 2.1.1.2-1: Example Calculations for Ethanol Breakeven Price for Gasoline-Blended E85

E85 & Ethanol Breakeven Price example (Based on \$80/bbl Crude)

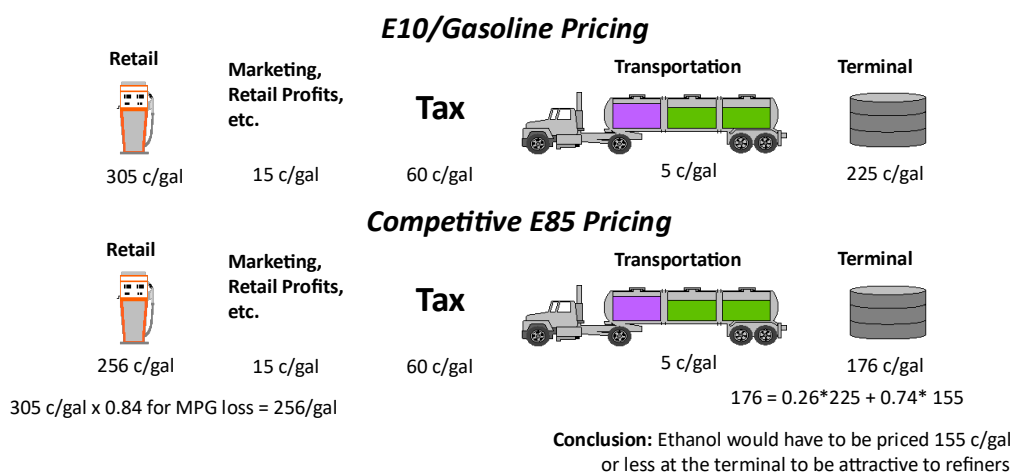


Figure 2.1.1.2-1 shows that when the E85 is blended with gasoline, the breakeven price of ethanol in E85 is 155¢/gal at an \$80/bbl crude oil price. This is 70¢/gal lower than the gasoline terminal price, although the breakeven price varies by state depending on the gasoline terminal price and tax rates. A list of gasoline tax rates by state (including all federal and state taxes) is provided in Table 2.1.1.2-2.

⁸⁸ Fuels Institute, “Retailing E85: An Analysis of Market Performance, July 2014 – August 2015,” March 23, 2017. https://www.transportationenergy.org/wp-content/uploads/2022/10/E85_2017_Report_FINAL.pdf.

⁸⁹ AAA, “National average gas prices,” December 12, 2022. <https://gasprices.aaa.com>.

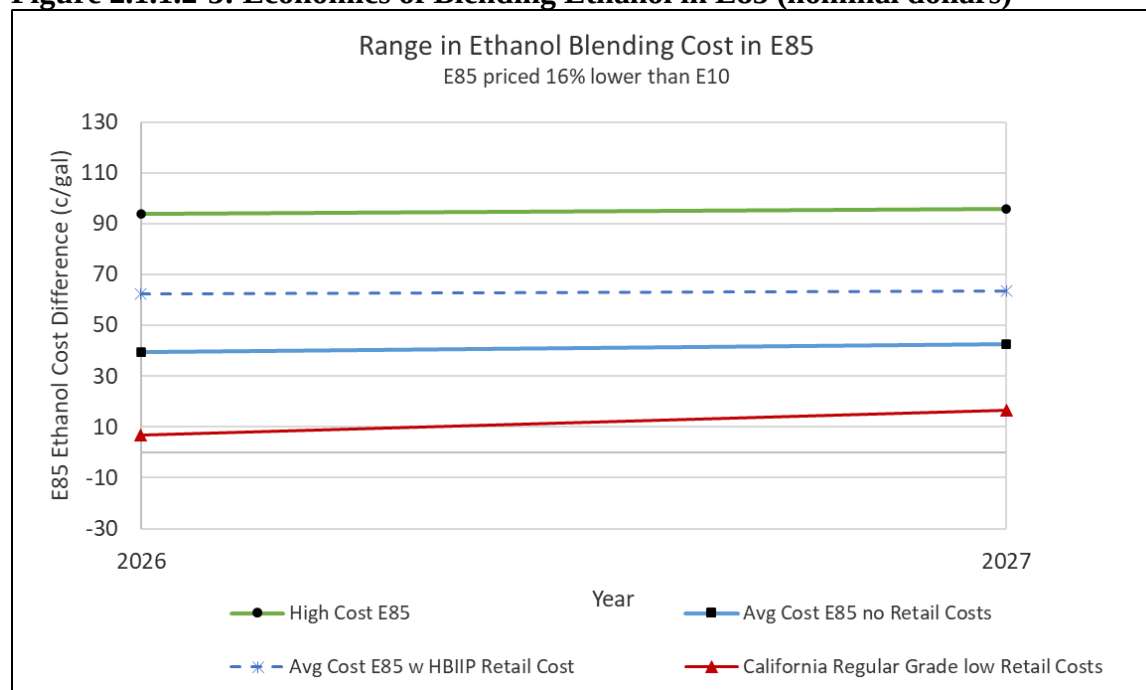
⁹⁰ It is unclear why E85’s price only reflects a portion of its lower energy content. Retailers may be choosing to balance their profit with consumer demand, or consumers may value E85’s much higher octane content, which offsets its lower energy density.

Table 2.1.1.2-2: Current Gasoline Tax Rates by State (Includes Federal and State Taxes; ¢/gal)

State	Tax Rate	State	Tax Rate
Alaska	27.4	Montana	51.4
Alabama	47.0	North Carolina	59.2
Arkansas	43.3	North Dakota	41.4
Arizona	37.4	Nebraska	48.6
California	88.8	New Hampshire	42.2
Colorado	42.1	New Jersey	59.8
Connecticut	58.6	New Mexico	37.3
DC	41.9	Nevada	65.5
Delaware	41.4	New York	66.4
Florida	60.7	Ohio	56.9
Georgia	54.1	Oklahoma	38.4
Hawaii	68.6	Oregon	58.4
Iowa	48.9	Pennsylvania	76.0
Idaho	51.4	Rhode Island	55.4
Illinois	85.0	South Carolina	47.2
Indiana	64.1	South Dakota	48.4
Kansas	43.4	Tennessee	67.8
Kentucky	44.4	Texas	38.4
Louisiana	38.4	Utah	49.5
Massachusetts	44.9	Virginia	44.2
Maryland	55.1	Vermont	49.2
Maine	48.4	Washington	67.8
Michigan	64.8	Wisconsin	51.3
Minnesota	49.9	West Virginia	54.1
Missouri	45.9	Wyoming	42.4
Mississippi	36.8		

Similar to our analysis for E10, if the ethanol blending cost is negative, ethanol is considered economical to blend as E85 in comparison to gasoline; if it is positive, it is not economical. Figure 2.1.1.2-3 provides some key results of the No RFS Baseline analysis for E85, showing a range in blending values for ethanol in E85, which vary from economic to blend to not economic to blend. For the highest cost market for E85, ethanol is priced 70-80¢/gal higher than its breakeven price. It is important to understand which gasoline in which states are economically attractive to blend E85 since this determines the potential market size.

Figure 2.1.1.2-3: Economics of Blending Ethanol in E85 (nominal dollars)



The solid blue line in Figure 2.1.1.2-3 represents the average ethanol blending value in E85 without retail costs, which is about 40¢/gal unfavorable over the years 2026 and 2027 for blending ethanol into E85 compared to E0 gasoline. Associated with this solid line is a dashed blue line just above it, which represents the marginal cost increase for the retail costs for a retail station E85 revamp.⁹¹ This retrofit cost does not have a large cost impact because E85 contains mostly ethanol, which defrays this cost.

The lowest cost market for E85 in any state is that relative to premium gasoline. This raises the question of whether retailers would pursue offering E85 if it was solely economical to blend compared to premium gasoline. Considering that premium gasoline only comprises about 10% of gasoline sales, coupled with the limited number of FFVs on the roadway, retailers would likely not offer E85 at their retail stations if this is the case. For this reason, we did not consider E85 to be economical in any state if it was solely economic relative to premium gasoline, and we did not represent E85 relative to premium gasoline in Figure 2.1.1.2-3.

The most economical market for E85 relative to regular grade gasoline is California, due to the Low Carbon Fuel Standard blending subsidy for the ethanol in E85, and higher gasoline prices. In 2026 and 2027, and in previous years, E85 is economical relative to gasoline in California for many of those years. When modeling the economics of E85 in California, we do not assume any change in the projected LCFS subsidy amount under a No RFS Baseline; however, the LCFS subsidy could increase without the RFS program in place. Also, the state of California offers low interest loans for upgrading underground storage tanks to prevent leaks into the environment, which could provide an additional incentive for retrofitting retail stations to

⁹¹ One quarter of the investment cost for retrofitting the retail station to offer E85 is assumed to be paid by the retail station owner, while three quarters is assumed to be paid by a USDA subsidy under the HBIIP program.

offer E85.⁹² Finally, the E85 throughput volumes at retail stations are much higher than the rest of the country which lowers the per-gallon costs of the amortized retail station upgrade costs. Considering these various factors, we estimated a significant amount of E85 consumption in California for the No RFS baseline analysis.

2.1.1.3 E15

The analysis for estimating the E15 baseline has similarities with how both E10 and E85 were estimated. Of the variables in the ethanol blending cost equation in Chapter 2.1.1.1, Ethanol Plant Gate Spot Price (ESP), Ethanol Distribution Cost (EDC), and Gasoline Terminal Price (GTP) are again the same. Like for E85, an additional cost applies to E15 to account for the cost to modify retail stations to carry E15 and we believe that Ethanol Replacement Value (ERV) does not apply as well, although we keep as a term and explain the possibility below for how it could apply.

The economics to determine whether ethanol blended into E15 is economical is estimated by combining the ethanol plant gate price, ethanol distribution cost, ethanol replacement cost, and retail cost in the following equation:

$$EBC_{E15} = (ESP + EDC - ERV - FETS - SETS + RC) - GTP$$

Where:

- EBC_{E15} is ethanol blending cost for E15
- ESP is ethanol plant gate spot price (same as section 2.1.1.1)
- EDC is ethanol distribution cost (same as section 2.1.1.1)
- ERV is ethanol replacement value
- $FETS$ is federal ethanol tax subsidy
- $SETS$ is state ethanol tax subsidy
- RC is retail cost (service station revamp to sell E15)
- GTP is gasoline terminal price; all are in dollars per gallon (same as section 2.1.1.1)

Ethanol Replacement Value (ERV)

Blending ethanol into gasoline for E15 is different than blending for E10 because we believe that refiners do not make a separate E15 BOB; thus, E10 BOBs are blended with ethanol to produce E15, in which case there is octane giveaway and no blending value to refiners for ethanol. It is possible, though, that some refineries with extra gasoline storage tanks could blend an E15 BOB to sell off their refinery racks; however, we have no knowledge of this currently happening. Similarly, there should be no RVP cost for blending ethanol above that of E10 because ethanol-gasoline blends reach a maximum RVP at 10%.

⁹² California State Water Resources Control Board, “Replacing, Removing, or Upgrading Underground Storage Tanks (RUST) Program.” https://www.waterboards.ca.gov/water_issues/programs/ustcf/rust.html.

Another issue for E15 is that it does not automatically receive a 1-psi waiver like E10 does in the summer. However, as discussed in Chapter 1.7.2, E15 did receive a regulatory 1-psi waiver for 2019–2021 and EPA-issued emergency fuel waivers throughout the summers of 2022–2025, which further allowed E15 to take advantage of the 1-psi waiver.⁹³ A number of Midwestern states petitioned EPA to remove the 1-psi waiver for E10⁹⁴ and EPA responded by finalizing a rulemaking to grant those states' request to remove the 1 psi waiver for E10 starting in 2025.⁹⁵ Because the E10 1-psi waiver will be removed in those states, a new lower-RVP, higher-cost BOB would be required for E10, which would also accommodate E15 and thus remove a hurdle for selling E15 in the summer months in those states. However, EPA extended the deadline for the removal of the 1-psi waiver in Ohio and nine counties in South Dakota to 2026 in response to requests by the Governors of those states due to concerns about the supply of gasoline in the summer of 2025.⁹⁶ EPA subsequently issued emergency fuel waivers in the summer of 2025 to facilitate continued E15 availability in the Midwestern states.⁹⁷ Any permanent solution that allows E15 to be blended into the same BOB as E10 during the summer is expected to encourage investment and increase sales of E15.

Federal and State Ethanol Tax Subsidies (FETS and SETS)

There is no federal nor state ethanol blending tax subsidy for E15.⁹⁸ It is important to know that at the time of drafting California did not allow the sale of E15, although it appears that California is moving towards allowing E15 in the state.⁹⁹ Other Federal and State subsidies—such as ethanol production subsidies, loan guarantees, grants, and any other subsidies—were not considered by this analysis.

Retail Cost (RC)

The retail costs for E15 are estimated based on the investments needed to offer E15 at retail stations and the estimated throughput at E15 stations.¹⁰⁰ Similar to our analysis for E85, we studied a report provided under the Higher Blends Infrastructure Incentive Program (HBIIP) which listed the major equipment installed to enable storing and dispensing E15. For a typical E15 retail station revamp, a retail station installs 2.8 dispensers and 0.9 underground storage tanks. Each dispenser is estimated to cost \$53,000, and each underground storage tank is

⁹³ EPA, “Fuel Waivers,” May 20, 2025. <https://www.epa.gov/gasoline-standards/fuel-waivers>.

⁹⁴ Providing E15 with a 1-psi waiver or removing the E10 1-psi waiver—either of which would allow E15 to use the same BOB as E10—would simply remove a logistical barrier to the use of E15 during summer months. However, E15 use under the No RFS Baseline would still be governed by the relative economics of blending additional ethanol into E10 relative to continuing to use petroleum gasoline.

⁹⁵ 89 FR 14760 (February 29, 2024).

⁹⁶ 90 FR 13093 (March 20, 2025).

⁹⁷ EPA, “EPA Addresses E-10 Standards, Allows for Nationwide Year-Round E15 Sales,” April 28, 2025. <https://www.epa.gov/newsreleases/epa-addresses-e-10-standards-allows-nationwide-year-round-e15-sales>.

⁹⁸ Based on our review of the Department of the Treasury and IRS 45Z guidance released on January 10, 2025, corn ethanol will likely earn a 6¢ per gallon subsidy. See Notice 2025-10, 2025-6 I.R.B. 682 (February 3, 2025) and Notice 2025-11, 2025-6 I.R.B. 704 (February 3, 2025).

⁹⁹ Governor Gavin Newsome, “Governor Newsom signs bill expanding fuel options to cut gas prices,” October 2, 2025. <https://www.gov.ca.gov/2025/10/02/governor-newsom-signs-bill-expanding-fuel-options-to-cut-gas-prices>.

¹⁰⁰ The methodology used and the estimated costs for these revamps are discussed in Chapter 10.1.4.1.2.

estimated to cost \$168,000.¹⁰¹ Thus, the estimated total cost for a typical retail station revamp to enable selling E15 is \$305,000 in 2025, and that these stations sell on average 218,000 gallons of E15 per year. The BIP and HBIIP programs cover up to 50% and 75% of the revamp costs, respectively, so in our cost assessment we assume that these programs cover those respective portions of the retail revamp costs. When amortizing the unsubsidized portion of the capital cost over the gallons of E15 sold under the HBIIP program, the total cost of the revamp adds 6¢/gal to the cost of E15, and 113¢/gal of ethanol (accounting only for the estimated 5% of ethanol in E15 above the ethanol in E10) in E15.¹⁰²

The HBIIP revamp data showed that about 5% of the E15 revamps did not add an underground storage tank; but these projects still added on average 2.8 dispensers per retail station. Thus, as a second cost point, we assessed the cost under the HBIIP program to the ethanol in E15 for those stations which only installed dispensers. When amortizing the unsubsidized portion of the capital cost over the gallons of E15 sold under the HBIIP program, the total cost of the revamp adds 3¢/gal to the cost of E15, and 55¢/gal per gallon of ethanol.

A new E15 marketing strategy has emerged among a small number of retailers, which is to solely sell E15 as the regular grade, thus discontinuing the sale of E10 as the regular grade. Since the retailer is not adding a new grade of gasoline—it is merely exchanging E10 for E15—this strategy will likely increase the sales of E15 at these retail stations since consumers will not have a choice to refuel with E10. This would reduce the per-gallon cost of the retail station E15 retrofit costs since the cost could then be amortized across a much larger number of gallons. Selling E15 as a feature grade also provides cost savings to retail stations since it reduces the number of new tanks needed at the station and increases ethanol sales without incurring marketing costs or having to offer price discounts. We will continue to monitor this trend. If it seems to be adopted more widely, we will incorporate it in future No RFS Baseline analyses.

E15 has different properties than E10 that allow it to be priced differently than E10. E15 has higher octane than E10, so the fuels industry could set E15 prices higher on that basis. Conversely, E15 has lower energy density than E10, which means that consumers are not able to drive the same distance on a tankful of E15. The website *e85prices.com*, which collects information on gasoline and ethanol-gasoline blend prices, reported that E15 is priced 8.5¢/gal cheaper than E10 on average. A conversation with a gasoline retail marketer explained that when beginning to offer E15 for sale, marketers will typically price it lower than E10 to promote E15 to consumers and increase its sales. If E15 is priced 8¢/gal lower than E10, it adds 160¢/gal (8/0.05) to the blending cost for blending ethanol into E15. It is likely that a significant portion of this discount is due to the value of the RIN, which normally is passed through to the refiner. We surmise that due to the higher cost of providing E15, the RIN value would instead be used by the retailer in these cases to enable these price discounts.

However, if discounting E15 prices is a marketing strategy, this practice would likely diminish over time and would change without the RFS program in place. We do not know what

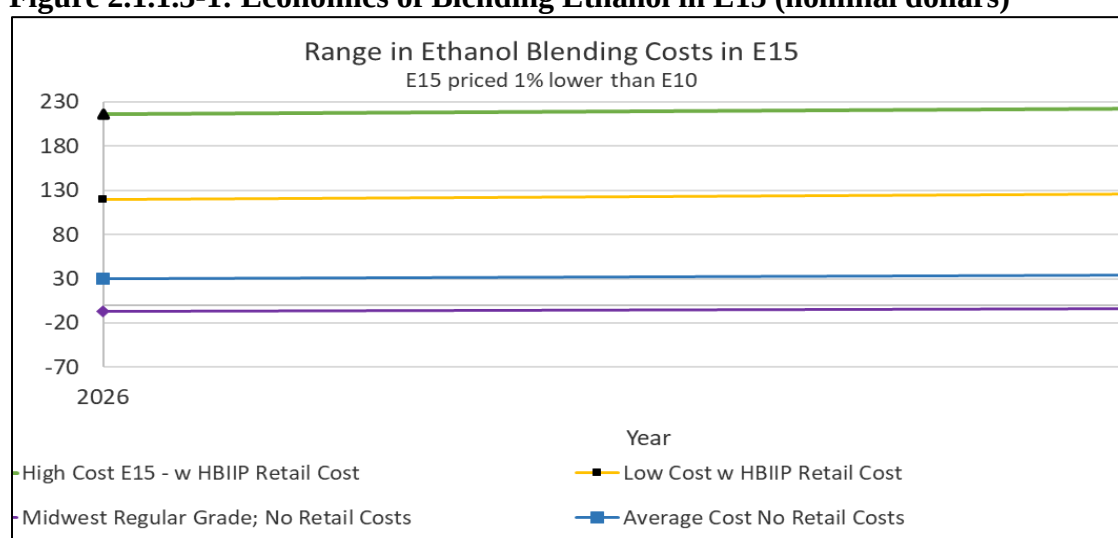
¹⁰¹ Average dispenser and underground storage tank costs based on discussions with USDA.

¹⁰² The per-gallon cost for the retail station revamps to allow dispensing E15 is calculated by multiplying the estimated revamp cost by the capital cost amortization factor in Table 2.1.1.1-1 (0.16) and dividing by the annual average amount of the ethanol contained in E15 sold from the retail stations.

the ultimate price of E15 would be relative to E10 if the RFS program was not in place since many retail station owners only began to offer E15 in recent years. To maximize their profit, retail station owners will seek the optimal E15 price that balances sales volume and pricing. For this analysis, we assumed that E15 is priced lower than E10 consistent with how E85 is priced.¹⁰³ Since E15 contains less energy than E10, we assumed that E15 is priced 1.3%, or about 3¢/gal, less than E10. This estimate reflects the price discounting method typically used with E85 based on E85's energy content.

Like E10, if the ethanol blending cost is negative, then ethanol is considered economic to blend into gasoline to produce E15, while it would not be economic if the value is positive. Figure 2.1.1.3-1 provides some key results of the No RFS Baseline analysis for E15, showing a range in blending values for ethanol in E15.

Figure 2.1.1.3-1: Economics of Blending Ethanol in E15 (nominal dollars)



The solid yellow and green lines at the top of the figure show the estimated range of lowest to highest blending cost for the incremental 5 vol% ethanol in gasoline to produce E15. That cost range includes the HBIIP-subsidized retail costs of revamping the station to enable storing and dispensing higher ethanol blends. It is important to recognize the cost impact due to revamping the retail station to enable it to sell E15. Assuming a typical retail station revamp cost of about \$300,000, and that the Higher Blends Infrastructure Incentive Program (HBIIP) program subsidized 3/4s of the cost, the retail station is estimated to need to cover a cost of about \$1.20 per gallon for that 5% increment of ethanol in E15 due solely to the station revamp cost. To illustrate the impact that the retail revamp costs have on the cost-effectiveness of blending E15, we include in the figure two estimated E15 blending costs without those retail revamp costs. The blue line at the bottom of the figure shows the estimated average blending cost for the incremental 5 vol% ethanol in gasoline without any retail revamping cost. Even if retail stations are already compatible with higher ethanol blends, the average incremental blending cost of the 5% of ethanol in E15 is still not cost-effective even with subsidies. The purple line at the bottom of the figure is similar to the blue line in that no retail revamping costs are included, but the cost

¹⁰³ E85, which contains 74% ethanol and 21% less energy than E10, is typically priced 16% lower than E10.

is for summertime, regular E15 gasoline sold in a midwestern state, and the blending costs are slightly cost-effective due to the lower distribution costs.¹⁰⁴ While the E15 blending costs are marginally cost-effective in the summer, our analysis shows that E15 is not cost-effective in Midwestern states during the winter due to lower gasoline prices.

There are two cases that would help to make E15 more economic. In one case, over 500 gasoline retailers are electing to sell only E15 as regular gasoline, which increases E15 sales at those retail stations. This lowers the per-gallon cost of retrofitting those stations to accommodate E15 because those costs can be amortized across a larger number of gallons.

In the second case, if refiners and terminal operators could overcome the steep logistical hurdles of producing and moving a hypothetical separate lower-octane BOB for E15 to terminals and eventually to retail stations, the gained ethanol replacement value for the E15 BOB would also help to offset the retail cost of making E15 available, and E15 would likely become economical in some summertime regular gasoline markets. Refiners and terminal operators are unlikely to create a separate E15 BOB until sales of E15 increase significantly. Prior to that occurring, anecdotal evidence suggests that a new low-RVP BOB could be produced to meet either E10 or E15 volatility specifications without a waiver.¹⁰⁵

Thus, the ethanol blending cost analysis finds the gasoline market uneconomical for E15 in the absence of the RFS program and we project that without the RFS program in place, the fuels market would not offer E15 for sale.

2.1.1.4 No RFS Baseline Summary for E10, E85 and E15

Corn ethanol receives a federal 14 cents per gallon 45Z federal production subsidy which benefits it whether it is blended into E10, E15 or E85. When corn ethanol is blended into E10 gasoline it benefits significantly from a hefty blending value due to its high octane content that is realized when refiners produce a conventional blendstock for oxygen blending (CBOB) for blending with E10 ethanol. E10 ethanol also avoids the need for any revamp costs to retail gasoline storage and dispensing equipment. For these reasons, E10 ethanol is cost effective for blending in all US gasoline without the RFS program.

E85 and E15 ethanol have similar issues affecting their costs. Neither receive a blending cost benefit for their high octane content. And both face revamp costs for storage and dispensing higher ethanol blends to enable their sale at retail stations. Despite the higher E15 sales volume, the lower ethanol content of E15 raises their per-gallon retail station revamp costs. For these reasons, our analysis does not support any volume of E15 without the RFS program in place. Despite the challenging economics for E85, we expect that E85 would continue to be used in California without the RFS program in place. California offers subsidies to retail stations for

¹⁰⁴ The economics of blending economics of E15 is even more favorable when referenced to premium gasoline; however, premium gasoline demand only comprises about 10% of total gasoline demand. Due to the low sales volume, retailers are unlikely to justify modifying their stations to offer E15 if they were solely targeting the premium gasoline market. For this reason, our analysis only assesses the economics of blending E15 relative to regular grade gasoline.

¹⁰⁵ Hoekstra Trading, "Midwest States Pose New Challenges for Gasoline Supply," April 21, 2025. <https://hoekstratrading.com/midwest-states-pose-new-challenges-for-gasoline-supply>.

upgrading their fuel storage and dispensing equipment, and the LCFS program subsidies would likely increase to cause E85's consumption to enable compliance with the LCFS standards.

2.1.2 Cellulosic Biofuel

The primary type of cellulosic biofuel projected to generate substantial RINs from 2026–2027 is compressed or liquefied renewable natural gas used in transportation (renewable CNG/LNG.) Additionally, we believe that some volume of liquid cellulosic ethanol from CKF will be produced during this period. Generally, cellulosic biofuels are more expensive to produce than the fossil fuels they displace. Consequently, they would likely not be utilized as transportation fuel without the support of incentives like the RFS program. However, new programs, such as the 45Z credit, are situated to become a valuable new incentive for cellulosic fuel producers in the future. The credit is technology neutral and based on carbon intensity. Because cellulosic biofuels, especially those derived from biogas, are often able to achieve very low carbon-intensity scores, they are well positioned to capture significant value under 45Z. As shown in Table 2.1-2, biogas pathways exhibit among the lowest carbon-intensity values and correspondingly higher indicative credit estimates. Despite this potential, uncertainty remains regarding the credit's precise value, specifically due to pending final Department of Treasury guidance. While the Department of Treasury's proposed rulemaking for the tax bill was released, it has not been finalized and, accordingly, we have not included it in our analysis.¹⁰⁶ Therefore, we are limiting our analysis to states that currently have State-level incentive programs. This section outlines our projections for cellulosic biofuel use under the No RFS Baseline.

2.1.2.1 Renewable CNG/LNG

As detailed in Chapter 10, renewable CNG/LNG is generally more expensive to produce than fossil-based CNG/LNG. Due to this higher production cost and the demand for RNG in sectors outside of transportation, we project that, without incentives specifically supporting the use of renewable CNG/LNG in transportation, very little or none of this fuel would be used in the transportation sector. Currently, three states¹⁰⁷—California, Oregon, and Washington—have LCFS programs that offer incentives for using CNG/LNG as transportation fuel. We assume that these state-level incentives would support some use of renewable CNG/LNG in transportation even in the absence of the RFS program.

To project renewable CNG/LNG use in these states, we used each state's program data and extrapolated it through 2027. Because Washington's program began in 2023 and has limited data, we use one method to project Washington's state-supported CNG/LNG volumes and a different method for California and Oregon. Specifically, for California and Oregon, we examined total CNG/LNG volumes (including both fossil and renewable), as well as volumes solely derived from renewable CNG/LNG. Using this information, we calculated both the year-

¹⁰⁶ 91 FR 5160 (February 4, 2026).

¹⁰⁷ New Mexico also has a state-level program to promote low-carbon fuel use (the Clean Transportation Fuel Standard (CTFS)), which was authorized in March 2024 and finalized in January 2026. Because the regulations were only recently finalized, there is insufficient information for EPA to incorporate potential volumes from this program into this analysis. New Mexico Environment Department, "Clean Transportation Fuel Program," January 22, 2026. <https://www.env.nm.gov/climate-change-bureau/clean-fuel-standard>.

over-year growth for each year and the blend rate showing the percentage of total CNG/LNG that was renewable. This data, summarized in Table 2.1.2.1-1, indicates that the CNG/LNG markets in Oregon and California have shifted to be almost entirely renewable, with renewable CNG/LNG volumes averaging 97% of the total market from 2022 to 2024. This suggests limited capacity in both states for new sources of renewable CNG/LNG to replace fossil-based CNG/LNG, meaning that the total market has been saturated with renewable CNG/LNG.

Table 2.1.2.1-1: CNG/LNG Usage in California and Oregon (million ethanol-equivalent gallons)

		2019	2020	2021	2022	2023	2024
California	Total CNG/LNG	305.0	278.0	302.6	335.4	355.8	374.4
	Year-over-year growth	7%	-9%	9%	11%	6%	5%
	Renewable CNG/LNG	236.1	256.9	295.9	323.3	344.2	370.6
	Blend Rate	77%	92%	98%	96%	97%	99%
Oregon	Total CNG/LNG	5.6	5.6	6.5	6.7	6.7	6.7
	Year-over-year growth	7%	-1%	16%	4%	0%	0%
	Renewable CNG/LNG	3.8	4.9	5.9	6.3	6.6	6.7
	Blend Rate	67%	89%	91%	94%	99%	100%

Note: Only the last five years of data are shown; however, data is available for California from 2011–2023, and for Oregon from 2016–2023.

Source: CARB, Low Carbon Fuel Standard Reporting Tool Quarterly Summaries.

<https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries>; Oregon DEQ, Oregon Clean Fuels Program – Quarterly Data Summaries.

<https://www.oregon.gov/deq/ghgp/cfp/pages/quarterly-data-summaries.aspx>.

Despite this saturation, volumes of renewable CNG/LNG can continue to rise as the overall CNG/LNG market grows. To project future volumes of renewable CNG/LNG in Oregon and California, EPA calculated the average year-over-year (YOY) growth rate of the total CNG/LNG market based on the last four years of data.¹⁰⁸ Applying this approach yields average year-over-year growth rates of 7% for California and 1% for Oregon in the total CNG/LNG market. We then applied each rate to the most recent full year of total CNG/LNG data (2024) for each state to project market growth. To estimate future renewable CNG/LNG usage, we assumed a 97% saturation factor—reflecting average market conditions as discussed above—and applied it to the projected totals. These results are shown in Table 2.1.2.1-2 and are used to project future volumes by compounding growth year over year.¹⁰⁹

¹⁰⁸ Only the last four years (2021–2024) were chosen to potentially minimize any impacts that the Covid-19 pandemic may have had on growth.

¹⁰⁹ We used the year-over-year growth in the rate of the total CNG/LNG market rather than only the renewable CNG/LNG market as the total CNG/LNG market should better reflect future growth in a vehicle consumption-limited market.

Table 2.1.2.1-2: Projected CNG/LNG Usage in California and Oregon (million ethanol-equivalent gallons)

Year	Data Type	California CNG/LNG (7% YOY Growth)	Oregon CNG/LNG (1% YOY Growth)	Total CNG/LNG Usage	Renewable CNG/LNG Usage
2024	Actual	382.1	6.9	389.0	387.0
2025	Projected ^a	402.0	6.8	408.7	407.8
2026	Projected	431.6	6.8	438.5	437.1
2027	Projected	463.5	6.9	470.4	468.6

^a At the time we developed the No RFS Baseline for this rule, full-year 2025 data was not yet available for California or Oregon.

Given that Washington’s CNG/LNG fuel market is much newer than those in California and Oregon, having only started in 2023, we used a slightly different approach to estimate future volumes. To do so, we took the total CNG/LNG usage data for Washington in 2024 and applied a year-over-year growth rate of 4%, determined by averaging the rates of both Oregon and California. We then projected the total CNG/LNG market size for Washington in 2025–2027. Given the saturation in California and Oregon’s markets, we assumed that significant volumes of renewable CNG/LNG would quickly fill the Washington market, as it may be easier for producers to find consumers in a less saturated market. Accordingly, we projected that Washington’s blend rate would reach 97% of total CNG/LNG by the end of 2025 and onward—an assumption that we believe is reasonable given that Washington reported an RNG blend rate of 87% in the program’s most recent year of data (2024).¹¹⁰ This analysis is shown in Table 2.1.2.1-4.

Table 2.1.2.1-3: CNG/LNG Usage in Washington (million ethanol-equivalent gallons)

	2023	2024
Total CNG/LNG	11.7	11.2
Year-over-year growth	N/A	(5)%
Renewable CNG/LNG	6.2	9.8
Blend Rate	53%	87%

Table 2.1.2.1-4: Projected Renewable CNG/LNG Usage in Washington (million RINs)

Year	Data Type	Renewable CNG/LNG Usage (4% year-over-year growth)
2023	Actual	6.2
2024	Actual	9.8
2025	Projected ¹¹¹	11.3
2026	Projected	11.8
2027	Projected	12.3

¹¹⁰ State of Washington Department of Ecology, “Clean Fuel Standard – Quarter 4, 2024 Data Summary,” July 2025. <https://apps.ecology.wa.gov/publications/documents/2514049.pdf>.

¹¹¹ At the time we developed the No RFS Baseline for this rule, full-year 2025 data was not yet available for Washington.

Totaling the projected volumes from each state, the projected volume of RNG-based CNG/LNG used as transportation fuel under the No RFS Baseline is summarized in Table 2.1.2.1-5.

Table 2.1.2.1-5: Renewable CNG/LNG for the No RFS Baseline (million RINs)

State	2026	2027
California	418.7	449.6
Oregon	6.6	6.7
Washington	11.8	12.3
Total	437.1	469.0

2.1.2.2 Liquid Cellulosic Biofuels

In recent years, only small quantities of liquid cellulosic biofuels have been produced, despite substantial financial incentives from programs like the RFS, federal tax credits, and state initiatives, such as California’s LCFS program. While these state and federal incentives are expected to continue in the coming years, we do not anticipate that they will be sufficient to support most types of liquid cellulosic biofuel production between 2026 and 2027.

One exception is ethanol produced from CKF at existing ethanol facilities. Many corn ethanol producers have indicated that their facilities can produce ethanol from CKF, sometimes by adding cellulose enzymes and, in other cases, by relying solely on enzymes naturally present in the corn kernel. In either case, we project that the cost of producing ethanol from CKF would be comparable to, or only slightly higher than, the cost of producing ethanol from corn starch. Because CKF-based ethanol is eligible for additional incentives through programs such as California’s LCFS, we expect that it will continue to be produced without the RFS standards at the volumes in this rule. These volumes are shown in Table 2.1.2.2-1. More information on the methodologies used to determine the liquid cellulosic biofuel volumes can be found in Chapter 7.1.5.

Table 2.1.2.2-1: Ethanol from CKF in the No RFS Baseline (million RINs)

Year	Volume
2026	128
2027	128

2.1.3 Biomass-Based Diesel

The No RFS Baseline analysis must consider several different factors before deriving the final estimate of biodiesel and renewable diesel volume for the No RFS Baseline. First, the relative economics of both biodiesel and renewable diesel compared to petroleum is evaluated by feedstock type. The volumes of lower-cost biodiesel and renewable diesel are recorded. Second, the total demand by feedstock type for both biodiesel and renewable diesel is totaled and compared to, and limited by, the volumes currently being consumed with the RFS program in place. Third, the biodiesel and renewable diesel plant capacities are each evaluated and averaged over previous years to avoid estimating sudden large swings in plant capacities, whether plant capacities are projected to increase or decrease. The dampened change in plant capacities is

meant to duplicate the more measured decisions renewable fuels companies and investors likely take when considering whether to expand or contract their renewable fuels production. The No RFS Baseline analysis for BBD is contained in a spreadsheet entitled “Biodiesel Renewable Diesel No RFS Baseline for SET2 FRM” placed in the docket.

2.1.3.1 Biodiesel

Estimating the economics of blending biodiesel requires different methods than those used to estimate the economics of ethanol because biodiesel plants are more geographically diffuse than ethanol plants. Unlike ethanol plants, which are almost exclusively located in the Midwest, biodiesel plants are scattered around the country. The more diffuse locations of biodiesel plants affect how we estimate distribution costs for using biodiesel. Also, refiners do not change the properties of the diesel they produce to accommodate the downstream blending of biodiesel, and as such there is no additional blending value associated with its use like there is for E10. However, blending biodiesel does often require the addition of additives to accommodate some of its properties. The blending cost of biodiesel is estimated using the following equation:

$$BBC = (BSP + BDC - FBTS - SBTS) - DTP$$

Where:

- *BBC* is biodiesel blending cost
- *BSP* is biodiesel plant gate spot price
- *BDC* is biodiesel distribution cost
- *FBTS* is federal biodiesel tax subsidy
- *SBTS* is state biodiesel tax subsidy
- *DTP* is diesel terminal price; all are in dollars per gallon

Biodiesel Plant Gate Spot Price (BSP)

USDA collects biodiesel plant gate pricing data, which is the price paid to biodiesel producers when they sell their biodiesel; however, USDA does not project future biodiesel prices.¹¹² Instead, we assumed that biodiesel production costs reflected plant gate prices and then estimated biodiesel production costs based on future vegetable oil and utility prices. This is essentially the same information used for estimating biodiesel production costs for the cost analysis in Chapter 10, except that the capital costs are amortized using the capital amortization factor in Table 2.1.1.1-1. For estimating the renewable fuel production costs, the feedstock and by product costs, capital costs, maintenance costs and utility costs are all estimated to derive a plant gate price estimate. The resulting projected biodiesel plant gate prices are summarized in Table 2.1.3.1-1 for three feedstocks – soybean oil, distillers corn oil (hereinafter “corn oil”), and FOG.¹¹³

¹¹² USDA, “U.S. Bioenergy Statistics,” October 2024, Table 16 – Biodiesel and Diesel Prices.
<https://www.ers.usda.gov/data-products/us-bioenergy-statistics>.

¹¹³ “FOG”, or “fats, oils and greases” is a term of art in the RFS program, encompassing a variety of lipid-based feedstocks from Animal waste material and animal byproducts (e.g., tallow) and food wastes (e.g., cooking oil, trap grease).

Table 2.1.3.1-1: Projected Biodiesel Plant Gate Prices (nominal \$/gal)

Projected Production Cost	2026	2027
Soybean Oil	3.64	3.49
Corn Oil	3.10	2.99
FOG	2.88	2.78

Biodiesel Distribution Cost (BDC)

This factor represents the added cost of moving biodiesel from production plants to terminals where it is blended into diesel. Unlike ethanol, which is almost exclusively produced in the Midwest and distributed elsewhere from there, biodiesel is produced at biodiesel plants dispersed around the country. For this reason, we took a different approach to our analysis of biodiesel than that used for ethanol. Using 2020 EIA data (the last year this data is available), we estimated the quantity of biodiesel produced within each PADD,¹¹⁴ the movement of biodiesel between PADDs, and the imports and exports of biodiesel into and out of each PADD, as summarized in Table 2.1.3.1-2.^{115,116,117,118}

Table 2.1.3.1-2: Biodiesel Production, Imports, Export, and Movement Between PADDs and Consumption in 2023 (million gallons)

PADD	Production	Imports	Exports	From PADD 2	From PADD 3	Other Movement	Consumption
PADD 1	147	242	2	59	0	1	445
PADD 2	1,139	46	114	-	3	0	727
PADD 3	221	134	99	128	0	0	368
PADD 4	0	5	5	10	0	4	15
PADD 5	202	74	40	151	14	0	396
Total	1,709	501	259	349	16	5	1,951

ICF estimated the distribution costs for distributing biodiesel both within and between PADDs, as summarized in Table 2.1.3.1-3.¹¹⁹ An additional cost is added to these estimates to account for the addition of biodiesel additives, for example, to improve biodiesel cold flow properties and reduce oxidation downstream of the production facility—the total cost of these additives is estimated to be 7¢ per gallon. The costs, estimated in 2017 dollars, are adjusted to

¹¹⁴ Petroleum Administration for Defense District (PADD): The 50 U.S. states and the District of Columbia are divided into five districts. Each PADD comprise a subset of U.S. states; PADD 1: Eastern states; PADD 2: Midwest states; PADD 3: Gulf Coast; PADD 4: Rocky Mountain States; PADD 5: Pacific Coast states.

¹¹⁵ EIA, “Monthly Biodiesel Production Report,” February 2021, Table 5 – Biodiesel (B100) production by petroleum administration for defense district.

https://www.eia.gov/biofuels/biodiesel/production/archive/2020/2020_12/biodiesel.pdf.

¹¹⁶ EIA, “Exports,” *Petroleum & Other Liquids*, April 30, 2025.

https://www.eia.gov/dnav/pet/pet_move_exp_dc_NUS-Z00_mbb1_a.htm.

¹¹⁷ EIA, “Imports by Area of Entry,” *Petroleum & Other Liquids*, April 30, 2025.

https://www.eia.gov/dnav/pet/pet_move_imp_dc_NUS-Z00_mbb1_a.htm.

¹¹⁸ EIA, “Movements by Pipeline, Tanker, Barge, and Rail between PAD Districts,” *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_ptb_dc_R20-R10_mbb1_a.htm.

¹¹⁹ ICF, “Modeling a ‘No-RFS’ Case,” EPA Contract No. EP-C-16-020, July 17, 2018.

the year dollars being analyzed. For example, in 2026, these distribution costs are increased by 34%.

Table 2.1.3.1-3: Biodiesel Distribution Costs (¢/gal)

PADD	Originally Estimated Costs 2017 dollars			Adjusted to 2026 dollars	
	Within PADD	From Outside the PADD	Additives Cost	Within PADD	From Outside the PADD
PADD 1	15	35	7	29.4	56.1
PADD 2	15	15	7	29.4	29.4
PADD 3	15	18	7	29.4	33.4
PADD 4	15	25	7	29.4	42.7
PADD 5	15	32	7	29.4	52.1

As expected, distribution costs for distributing biodiesel within a PADD are less than when the biodiesel is distributed further away from outside the PADD. Since imports come from outside the PADD, we used outside the PADD values for imports. Comparing these biodiesel distribution costs to ethanol, distributing biodiesel is expected to be more expensive, which recognizes that the larger volume of ethanol provides the opportunity to optimize the efficiency of the distribution system more than what is financially possible for biodiesel. For example, the greater volume of ethanol allows for greater use of unit trains and more streamlined logistics overall. Like for ethanol, distribution costs of biodiesel to the East and West Coasts are higher compared to distribution in the Midwest where most biofuels, including a large share of biodiesel, are produced. Although the Rocky Mountain states are located much closer to the Midwest, it is expensive to distribute biodiesel to the rural areas there and this affects overall regional distribution costs.

Federal and State Biodiesel Tax Subsidies (FBTS and SBTS)

Historically, a \$1.00 tax subsidy for blending biodiesel and renewable diesel into diesel fuel was originally enacted as part of the American Jobs Creation Act of 2004 and was subsequently extended multiple times over the course nearly 20 years thereafter. However, in the Inflation Reduction Act passed in 2022, Congress replaced the biodiesel and renewable diesel blending subsidy with a production subsidy starting in 2025.¹²⁰ Then, in 2025, Congress modified the renewable fuel production subsidies further to favor domestic feedstocks over imported ones. These most recent modifications take effect in 2026 and will also apply in 2027.¹²¹ The amount of this credit is based on certain employment wage criteria and the fuel's emissions rate. At the time we established our No RFS Baseline case for this final rule, the Department of Treasury had not yet established the credit amounts for 2026 and 2027 based on the most recent modifications to the statute. In lieu of these official updates, we have estimated the value of these subsidies in 2026 and 2027.¹²²

¹²⁰ HR5376; Public Law 117-169.

¹²¹ HR1; Public Law 119-21.

¹²² Based on our review and analysis of OBBB, which modified the 45Z biofuel production subsidies previously enacted by Congress in IRA, we estimated the amount of the biodiesel production subsidies that will be in place in 2026 and 2027. We estimate that biodiesel produced from soybean oil and canola oil will likely receive a 62¢ per

An additional small agri-biodiesel producers tax credit was approved by Congress in OBBB which increases the incentive for small biodiesel producers. The tax subsidy only applies to the first 15 million gallons produced by biodiesel producers with a total production capacity under 60 million gallons per year. Such biodiesel producers are only eligible for this additional tax credit when processing either virgin plant oils or virgin animal fats such as beef tallow. Since distillers corn oil undergoes some refining, we concluded that it would not qualify as virgin oil and thus would not receive this additional tax credit. The estimated value of the biodiesel and renewable diesel production credit by feedstock type assuming that the biodiesel producer is meeting the labor requirements is summarized in Table 2.1.3.1-4.

Table 2.1.3.1-4: Estimated Federal Biodiesel Subsidies (¢/gal)

Feedstock Type	Biodiesel Subsidy	Small Agri-Biodiesel Producer
Soybean Oil	62¢	82¢
Canola Oil	35¢	55¢
Corn Oil	80¢	0¢
Domestic FOG	80¢	100¢ (tallow only)
Imported Vegetable Oils and FOG	0¢	20¢ (tallow only)

To complete our analysis, it is necessary to estimate the quantity of biodiesel produced which would be eligible for the small agri-biodiesel producers tax credit. Table 2.1.3.1-5 summarizes the list of eligible biodiesel plants by production company and their production capacity.¹²³ There are an additional 36 biodiesel plants not included in Table 2.1.3.1-5 because they are not be not eligible for the Federal Agri-Biodiesel subsidy due to their individual plant capacities equaling or exceeding 60 million gallons per year, or in the case of companies that own and operate multiple biodiesel plants, the combined capacities of all their biodiesel plants exceeding 60 million gallons per year. There are an additional 10 biodiesel plants not included in Table 2.1.3.1-5 because their plant capacities are not reported.

Table 2.1.3.1-5: Biodiesel Plants Eligible for Agri-Biodiesel Producer Tax Subsidy (million gallons per year)

Company Name	State	Capacity	Company Name	State	Capacity
Appalachian Biofuels, LLC	VA	0	<u>Walsh BioFuels LLC</u>	WI	5
Revolution Fuels, Inc.	MN	0	<u>Pacific Biodiesel</u>	HI	5.5
Omaha Biofuels Coop	NE	0.03	<u>Integrity Biofuels, LLC</u>	IN	6.42
Kelley Green Biofuel	KY	0.1	<u>White Mountain Biodiesel</u>	NH	6.5
Loyola University Chicago	IL	0.1	<u>Green Biofuels Miami, LLC</u>	FL	7

gallon subsidy, while corn oil and domestically produced fats, oils and grease (which includes used cooking oil and beef tallow) will likely earn a 80¢/gallon subsidy. The subsidy estimates are based on publicly available industry average data and anticipated changes to the 45ZCF-GREET model related to provisions in OBBB; tax credits or subsidies for individual producers will differ from these estimates.

¹²³ Biodiesel Magazine, “Biodiesel Plant List - Active Plants,” October 2025.

<https://biodieselmagazine.com/plants/list/biodiesel>.

Company Name	State	Capacity	Company Name	State	Capacity
Alaska Green Waste Solutions	AK	0.3	<u>Biodiesel Las Americas</u>	FL	7.5
Eberle Biodiesel	TX	0.3	<u>Delek Renewables-New Albany</u>	MS	7.5
Green Energy Biofuel, LLC	SC	0.3	<u>Newport Biodiesel, Inc.</u>	RI	8
Thumb BioEnergy LLC	MI	0.75	<u>Genuine Bio-Fuel, Inc.</u>	FL	9.2
Bently Biofuels Company	NV	1	<u>Northern Development, Biodiesel</u>	NE	10
Simple Fuels Biodiesel	CA	1	<u>W2Fuel-Crawfordsville</u>	IA	10
Smisson-Mathis Energy, LLC	GA	1	<u>Yale Energy</u>	WA	10
Cape Cod Biofuels	MA	1.2	<u>Imperial Western Products,</u>	CA	10.5
Mason Biodiesel, LLC	RI	1.2	<u>Delek Renewables-Cleburne</u>	TX	12
Maine Standard Biofuels	ME	1.5	<u>New Leaf Biofuel, LLC</u>	CA	12
Northeast Biodiesel, LLC	MA	1.75	<u>Agron Bioenergy</u>	CA	15
American Biodiesel Energy	PA	2	<u>Delek Renewables-Crossett</u>	AR	15
Down to Earth Energy	GA	2	<u>W2Fuel-Adrian</u>	MI	15
Griffin Industries, Inc.	KY	2	<u>Rio Valley Biofuels, LLC</u>	TX	17
Sullens Biodiesel LLC	TN	2	<u>SeQuential</u>	OR	17
Golden Leaf Energy, LLC	LA	2.2	<u>Michigan Biodiesel, LLC</u>	MI	17.5
Adkins Energy Biodiesel	IL	2.5	<u>Scott Petroleum Corporation-Greenville</u>	MS	20
Alternative Fuel Solutions	IN	3	<u>Viridis Fuels</u>	CA	20
Ever Cat Fuels LLC	MN	3	<u>Stepan Co.-Joliet</u>	IL	21
GeoGreen Biofuels, Inc.	CA	3	<u>Canary Renewables Corp.</u>	CA	22.5
Oilmatic Systems, LLC	NJ	3	<u>Fuel: Bio One LLC</u>	NJ	25
Wholesome Energy, LLC	VA	3	<u>Iowa Renewable Energy</u>	IA	30
Reco Biodiesel, LLC	VA	3.6	<u>Crimson Renewable Energy</u>	CA	36
Blue Ridge Biofuels LLC	NC	4	<u>Western Dubuque Biodiesel</u>	IA	36
BioVantage Fuels, LLC	IL	5	<u>American GreenFuels, LLC</u>	CT	40
Buster Biofuels LLC	CA	5	<u>Bioenergy Development Group</u>	TN	40
Foothills Bio-Energies, LLC	NC	5	<u>GEB3</u>	SC	40

Company Name	State	Capacity	Company Name	State	Capacity
Greenlight Biofuels Princess Anne, LLC	MD	5	<u>Solfuels USA, LLC</u>	AR	40
Maple River Energy	IA	5	<u>Minnesota Soybean Processors</u>	MN	41
ME Bio Energy, LLC	MO	5	<u>Incobrasa Industries, Ltd.</u>	IL	44
Natural Biodiesel Plant, LLC	MO	5	<u>Owensboro Grain Biodiesel</u>	KY	45
Northeast Nebraska Biodiesel	NE	5	<u>Western Iowa Energy LLC</u>	IA	45
Patriot Fuels Biodiesel, LLC	IL	5	<u>Deerfield Energy, LLC - Now ADM Plant</u>	MO	50
SJV Biodiesel, LLC	CA	5	<u>Duonix, LLC (Marathon)</u>	NE	50
Southeast Biodiesel LLC	NC	5	<u>Mid-America Bio Energy</u>	MO	50
Tennessee BioEnergy	TN	5	<u>United Biodiesel, Inc.</u>	NY	50
Triangle Biofuels Industries	NC	5	<u>Paseo-Cargill Energy, LLC</u>	MO	56
Virginia Biodiesel Refinery	VA	5			
Total Capacity of Eligible Plants (million gallons per year)					1,141
Total Capacity of Eligible Plants when limited to 15MM gals/yr					648

States also provide subsidies to blend biodiesel into diesel fuel. These state subsidies were enacted in previous years and are presumed to continue through 2027. Table 2.1.3.1-6 summarizes the states that offer such subsidies and the subsidy amounts.

Table 2.1.3.1-6: Current State Biodiesel Subsidies (¢/gal)

State	Biodiesel Subsidy
Hawaii	12¢
Iowa	33¢
Illinois	62¢
North Dakota	100¢
Rhode Island	37¢
Texas	20¢

The California and Oregon LCFS programs and Washington State's Clean Fuels program do not offer specific subsidies per se, but through the cap-and-trade nature of their programs, they

can be equated to subsidies.¹²⁴ For California,¹²⁵ Oregon, and Washington,¹²⁶ we estimated the equivalent per-gallon biodiesel subsidy amounts from the incentives offered by each of these LCFS programs, which vary by year. Table 2.1.3.1-7 summarizes the projected LCFS subsidies by year.

Table 2.1.3.1-7: Projected State LCFS subsidies (¢/gal)

State	Feedstock	2026	2027
California	Soybean Oil, Canola Oil	39¢	37¢
	FOG	75¢	73¢
Oregon	Soybean Oil, Canola Oil	18¢	17¢
	FOG	34¢	33¢
Washington	All Feedstocks	23¢	23¢

Although different than subsidies, several states have mandates that require the diesel fuel within their state contain a minimum quantity of biodiesel. Table 2.1.3.1-8 lists the states that have such a mandate and the percentage of biodiesel required to be blended into diesel fuel.

Table 2.1.3.1-8: State Biodiesel Mandates

State	Minimum % of Biodiesel
Minnesota	12.5
New Mexico	5
Oregon	5
Pennsylvania	2
Washington	2

Diesel Terminal Price (DTP)

Refinery rack price data—which already include the distribution costs for moving diesel to downstream terminals—were used to represent the price of diesel to blenders on a state-by-state basis. However, these prices were not projected for future years.¹²⁷ Instead, we used projected refinery wholesale price data from AEO2025 to adjust 2021 refinery rack price data

¹²⁴ New Mexico's CFTS program is scheduled to take effect by July 1, 2026. We will continue to follow the implementation of the CFTS program and include its incentives for future analyses once the program has been fully implemented.

¹²⁵ The blending incentives for California are based on recent carbon credit projections made for a state action to increase the future mandated decreases in GHG emissions. CARB, "Attachment C: LCFS Fuels and Credit Market Module Modeling," https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/15day_attc.pdf.

¹²⁶ The values for Oregon and Washington State are recent for each of the states. While it is probable that the state incentive values would increase if the RFS program was not in place, we did not attempt to estimate what the credit price would be if the RFS program was not in place. State of Oregon Department of Environmental Quality, "Monthly CFP Credit Transfer Report for March 2025," April 1, 2025, <https://www.oregon.gov/deq/ghgp/cfp/pages/monthly-data.aspx>. State of Washington Department of Ecology, "Monthly CFS Credit Report for March 2025,"

https://www.ezview.wa.gov/site/alias_1962/37916/clean_fuel_standard_data_reports.aspx.

¹²⁷ EIA, "Spot Prices," *Petroleum & Other Liquids*, May 14, 2025.

https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.

(2021 was the last year EIA reported this data) to represent diesel rack prices in future years. This diesel price data, summarized in Table 2.1.3.1-9, was collected by state and is assumed to represent the average diesel price for all the terminals in each state. The projected U.S. average wholesale diesel fuel prices are presented in the table, after adjusting the prices to nominal year dollars.

Table 2.1.3.1-9: Projected Diesel Terminal Prices (nominal \$/gal)

State	2026	2027	State	2026	2027
Alaska	2.94	2.99	Montana	2.62	2.67
Alabama	2.29	2.33	North Carolina	2.30	2.34
Arkansas	2.35	2.40	North Dakota	2.43	2.48
Arizona	2.47	2.52	Nebraska	2.40	2.44
California	2.60	2.65	New Hampshire	2.39	2.44
Colorado	2.50	2.55	New Jersey	2.25	2.30
Connecticut	2.24	2.28	New Mexico	2.44	2.49
District of Columbia	2.35	2.40	Nevada	2.58	2.63
Delaware	2.33	2.38	New York	2.32	2.36
Florida	2.35	2.40	Ohio	2.35	2.40
Georgia	2.29	2.33	Oklahoma	2.33	2.38
Hawaii	2.61	2.66	Oregon	2.49	2.53
Iowa	2.40	2.44	Pennsylvania	2.30	2.34
Idaho	2.70	2.75	Rhode Island	2.27	2.32
Illinois	2.31	2.35	South Carolina	2.35	2.39
Indiana	2.33	2.38	South Dakota	2.31	2.35
Kansas	2.36	2.41	Tennessee	2.32	2.36
Kentucky	2.40	2.44	Texas	2.27	2.32
Louisiana	2.20	2.24	Utah	2.81	2.86
Massachusetts	2.29	2.33	Virginia	2.31	2.35
Maryland	2.30	2.34	Vermont	2.40	2.45
Maine	2.34	2.39	Washington	2.41	2.45
Michigan	2.36	2.41	Wisconsin	2.35	2.40
Minnesota	2.43	2.48	West Virginia	2.35	2.40
Missouri	2.36	2.41	Wyoming	2.65	2.70
Mississippi	2.30	2.34	U.S. Average	2.36	2.41

Estimating the Biodiesel Volume Under the No RFS Baseline

Because there are state mandates and biodiesel blending subsidies offered by individual states, each state is represented separately in EPA's analysis. There are two steps for determining the No RFS Baseline biodiesel volume. First, we estimate the biodiesel volumes expected to be consumed due to existing state mandates by applying the mandate percentage to the projected diesel fuel consumption of that state. Second, we estimate the biodiesel volume which has a beneficial blending cost based on the equation in Chapter 2.1.3.1. If the biodiesel blending cost is negative, biodiesel is considered economical to blend into diesel fuel and additional nonmandated volumes are assumed to be blended. Conversely, biodiesel is initially assumed to

not be blended into diesel fuel if the biodiesel blending value is positive. Because of its relative cost, the volume of biodiesel consumption without the RFS program would be driven mostly by the state mandates, but also by state subsidies, mainly the California and Oregon LCFS programs.

If our analysis showed that biodiesel would be cost-effective to blend in any volume, it was necessary to estimate the rate at which states would then blend biodiesel, (*e.g.*, B5, B10 or B20). Assuming that a large volume of biodiesel would be blended into any given state's diesel fuel for the No RFS Baseline analysis would potentially result in large volumetric swings in some years based on the changing economics of biodiesel in those states in those years. In reality, the marketplace is unlikely to make such swings. To avoid this problem, the biodiesel blended into diesel fuel was not allowed to exceed the demand that occurred under the RFS program. During 2023, the total volume of biodiesel blended into diesel fuel averaged 1,847 million gallons per year. Since we are estimating biodiesel demand by state, we limit the total volume of biodiesel in each state to the volume of biodiesel blended into diesel fuel in that state in 2023, which was the most recent data available at the time this analysis was conducted. Because biodiesel consumption has generally plateaued since 2016, these percentages are assumed to be the maximum biodiesel percentages in each state in 2026 and 2027 for the No RFS Baseline analysis. The volume of biodiesel consumed in each state is estimated by EIA and reported in its State Energy Data System (SEDS).¹²⁸ Table 2.1.3.1-10 summarizes the percentage of biodiesel in diesel fuel for each state based on the SEDS information.

¹²⁸ EIA, "State Energy Data System," Table C2 – Energy consumption estimates for selected energy sources in physical units, 2023. https://www.eia.gov/state/seds/sep_sum/html/pdf/sum_use_tot.pdf.

Table 2.1.3.1-10: Maximum Percent of Biodiesel in Diesel Fuel by State (%)

Alaska	0.0	Montana	0.0
Alabama	2.9	North Carolina	2.7
Arkansas	2.6	North Dakota	2.0
Arizona	0.3	Nebraska	2.5
California	7.9	New Hampshire	3.1
Colorado	0.5	New Jersey	2.3
Connecticut	2.9	New Mexico	1.9
District of Columbia	9.7	Nevada	0.1
Delaware	1.8	New York	4.6
Florida	2.8	Ohio	2.6
Georgia	2.4	Oklahoma	2.5
Hawaii	3.5	Oregon	10.3
Iowa	6.5	Pennsylvania	2.2
Idaho	0.5	Rhode Island	1.4
Illinois	6.6	South Carolina	2.2
Indiana	3.0	South Dakota	1.8
Kansas	2.4	Tennessee	2.1
Kentucky	3.1	Texas	2.0
Louisiana	2.1	Utah	0.7
Massachusetts	4.0	Virginia	2.3
Maryland	2.6	Vermont	2.5
Maine	3.2	Washington	1.6
Michigan	2.7	Wisconsin	2.1
Minnesota	12.5	West Virginia	3.0
Missouri	2.2	Wyoming	0.7
Mississippi	3.2		

Table 2.1.3.1-11 lists the states where it is economical to blend biodiesel into diesel fuel under the No RFS Baseline in the years 2026 and 2027, and summarizes the volume of biodiesel by the biogenic oil feedstock types estimated to be used to produce the biodiesel. For the states that mandate the percentage of biodiesel to be blended into diesel fuel, we apportioned the biogenic oil feedstock types based on the mix of these vegetable oils being used to produce biodiesel nationwide.¹²⁹ The mix of biogenic oil feedstocks for producing mandated biodiesel is 48%, 42%, and 10% of soy oil, domestically-sourced FOG, and corn oil, respectively, in 2026 and 2027. For cases where our analysis shows biodiesel is economically viable in a state, our analysis determines if biodiesel is economically viable for only one feedstock or more than one feedstock.

¹²⁹ Although FOG is the lowest priced feedstock type and economics would normally dictate using as much of that feedstock type as the lowest cost option, many biodiesel plants cannot use FOG because of the free fatty acid content that causes operational problems in their plants. Biodiesel plants also tend to be located more in the Midwest—which is the agricultural center for the production of corn and soy oil—and they may actually have a lower cost and more reliable option to purchase these vegetable oil types that are produced close to their plants.

In a common situation where both corn and waste oil are economically viable, we estimate the proportion of each based on the portion of each used today. For the states that would use biodiesel based on economics, the volume of biodiesel in any state is estimated by multiplying the biodiesel percent in each state from Table 2.1.3.1-10 by the volume of diesel fuel consumed in that state.¹³⁰ The tables list the mandated volume by each state at the top and the volume for states where it is economical to use biodiesel. Only California and Oregon are listed separately since these states have the largest subsidies without a mandate, while the projected volumes for the other states are aggregated together. In the next rows in the tables, the total biodiesel volumes by vegetable oil type and year are totaled.

Table 2.1.3.1-11: Biodiesel in the 2026 and 2027 No RFS Baseline (million gal/yr)

	State	2026			2027		
		Soy Oil	Corn Oil	Domestic FOG	Soy Oil	Corn Oil	Domestic FOG
Volume in States with Mandates	Oregon	17	3	13	17	3	13
	New Mexico	15	1	10	14	1	10
	Minnesota	57	12	48	57	12	48
	Washington	10	1	7	9	1	7
	Pennsylvania	13	2	7	13	2	7
	Total	217			214		
Economic Volume	California	0	56	226	0	52	209
	Oregon	0	0	37	0	15	62
	Other States	83	31	535	5	42	1,030
	Total	968			1,444		
Total of Mandated and Economic Volumes		195	107	883	115	129	1,225
Total Volumes by Year		1,185			1,469		

This mix of vegetable oil types is used as a starting point for establishing the No RFS Baseline for biodiesel. However, adjustments were then made to the vegetable oil feedstock types after the initial No RFS Baseline analysis was conducted for renewable diesel. See Chapter 2.1.3.3 for details on these adjustments and the reasoning behind them.

2.1.3.2 Renewable Diesel

While renewable diesel is produced using a much different process than biodiesel, it uses the same feedstocks and so much of the blending cost analysis is similar. The blending cost of renewable diesel is estimated using the following equation:

¹³⁰ Historical diesel sales volumes and projected future diesel volumes were used to project the volume of diesel sold in each state. EIA, "Prime Supplier Sales Volume," *Petroleum & Other Liquids*, June 1, 2022. https://www.eia.gov/dnav/pet/pet_cons_prim_dcu_nus_a.htm. AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

$$RDBC = (RDSP + RDDC - FRDTS - SRDTS) - DTP$$

Where:

- *RDBC* is renewable diesel blending cost
- *RDSP* is renewable diesel plant gate spot price
- *RDDC* is renewable diesel distribution cost
- *FRDTS* is federal renewable diesel tax subsidy
- *SRDTS* is state renewable diesel tax subsidy
- *DTP* is diesel terminal price; all are in dollars per gallon (same as section 2.1.3.1)

The diesel terminal prices (DTP) are the same as those described in Chapter 2.1.3.1 for biodiesel, so the diesel fuel terminal prices will not be discussed further here. However, each of the other variables in the above equation are discussed further. The state blending mandates described in Chapter 2.1.3.1 (Table 2.1.3.1-8) are assumed to force increased volumes of biodiesel which is a less expensive biofuel compared to renewable diesel.

Renewable Diesel Plant Gate Spot Price (RDSP)

Similar to biodiesel, we estimated future renewable diesel plant gate prices by gathering projected renewable diesel plant input information (*e.g.*, future biogenic oil and utility prices) to estimate renewable diesel production costs, which we assumed represent plant gate prices. This is essentially the same information used for estimating renewable diesel production costs for the cost analysis described in Chapter 10, except that the capital costs are amortized using the capital amortization factor in Table 2.1.1.1-1 and all costs are in nominal dollars. The most likely imported feedstock is FOG, and it is estimated to be priced the same as domestic FOG. The projected renewable diesel plant gate prices are summarized in Table 2.1.3.2-1 for three feedstocks—soybean oil, corn oil, and FOG.

Table 2.1.3.2-1: Projected Renewable Diesel Plant Gate Prices (nominal \$/gal)

Feedstock	2026	2027
Soybean Oil	4.37	4.22
Corn Oil	3.80	3.68
FOG	3.56	3.46

It is important to note that the production costs must be considered along with the Federal subsidy amounts discussed below. For example, the plant gate production cost of FOG-based renewable diesel is estimated to be identical for both domestic and imported FOG, however, domestic FOG renewable diesel receives a federal subsidy while imported FOG renewable diesel does not, which affects their relative use.

Renewable Diesel Distribution Cost (RDDC)

This factor represents the added cost of moving renewable diesel from production plants to terminals where it is blended with diesel fuel. Unlike ethanol, which is almost exclusively produced in the Midwest and distributed elsewhere from there, and unlike biodiesel, for which

production is dispersed more broadly around the continental United States, renewable diesel is predominantly produced on the Gulf and West Coasts. Based on the SEDS data, virtually all renewable diesel is currently being consumed in PADD 5—mostly in California, but also some in Oregon and Washington. If the renewable diesel is produced on the Gulf Coast, the distribution cost is assumed to be the same as inter-PADD distribution costs for biodiesel. If the renewable diesel is produced on the West Coast, the primary vegetable oil feedstocks are likely to be virgin oil imported from the Midwest or imported used cooking oil, both of which would be expected to incur an inter-PADD distribution cost. Thus, in all cases we used the biodiesel inter-PADD distribution costs.

ICF estimated the costs for distributing renewable diesel both within and between PADDs, as summarized in Table 2.1.3.2-2.¹³¹ An additional cost is added on to account for the addition of renewable diesel additives, for example to improve renewable diesel flow properties downstream of the production facility—the total cost of these additives is estimated to be 3¢ per gallon. The costs, estimated in 2017 dollars, are adjusted higher to the year dollars being analyzed which is 34% higher in 2026 as shown in the table.

Table 2.1.3.2-2: Renewable Diesel Distribution Costs (¢/gal)

PADD	Originally Estimated Costs 2017\$			Distribution and Additive Costs Adjusted to 2026\$	
	Within PADD	From Outside the PADD	Additives Cost	Within PADD	From Outside the PADD
PADD 1	7	30	3	13.4	44.1
PADD 2	7	12	3	13.3	20.0
PADD 3	7	15	3	13.4	24.0
PADD 4	7	20	3	13.4	30.7
PADD 5	7	25	3	13.4	37.4

Like for biodiesel, the Inflation Reduction Act provided renewable diesel with a production subsidy starting in 2025 based on certain employment wage criteria and the fuel’s emissions rate.¹³² Then in 2025, Congress modified the renewable fuel production subsidies to favor domestic feedstocks over imported ones which takes effect in 2026 and also applies in 2027.¹³³ At the time we established our No RFS Baseline case for this final rule, the Department of Treasury had not yet established the credit amounts for 2026 and 2027 based on the most recent modifications to the statute. In lieu of these official updates, we have estimated the value of these subsidies in 2026 and 2027. The estimated value of the renewable diesel production credit by feedstock type assuming that the renewable diesel producers are meeting the labor requirements is summarized in Table 2.1.3.2-3.

¹³¹ ICF, “Modeling a ‘No-RFS’ Case,” EPA Contract No. EP-C-16-020, July 17, 2018.

¹³² HR5376; Public Law 117-169.

¹³³ HR1; Public Law 119-21.

Table 2.1.3.2-3: Estimated Federal Renewable Diesel Subsidies (¢/gal)

Feedstock Type	Renewable Diesel Subsidy
Soybean Oil	52¢
Canola Oil	29¢
Corn Oil	75¢
Domestic FOG	80¢
Imported Vegetable Oils and FOG	0¢

The California and Oregon LCFS programs and Washington State’s Clean Fuels program do not offer specific subsidies per se, but through the cap-and-trade nature of their programs, they can be equated to subsidies.¹³⁴ For California, Oregon and Washington, we estimated the equivalent per-gallon subsidy amount from the incentives offered by its LCFS program which vary by year.¹³⁵ Table 2.1.3.2-4 summarizes the projected LCFS subsidies by year.

Table 2.1.3.2-4: Projected LCFS subsidies by State and Feedstock (¢/gal)

State	Feedstock	2026	2027
California	Soybean Oil, Canola Oil	39¢	38¢
	FOG	72¢	71¢
Oregon	Soybean Oil, Canola Oil	18¢	17¢
	FOG	33¢	32¢
Washington	All Feedstocks	25¢	25¢

Estimating the Renewable Diesel Volume Under the No RFS Baseline

The methodology for analyzing renewable diesel volumes is structured similarly to that for biodiesel described in Chapter 2.1.3.1. The state with the lowest renewable diesel blending cost (*e.g.*, the state with the largest blending subsidies) would receive renewable diesel first. The percent of renewable diesel in any state’s diesel fuel while the RFS program is in place is considered the maximum volume of renewable diesel fuel which could occur under the No RFS Baseline. Because renewable diesel volumes are increasing under the combination of RFS and LCFS programs in California and Oregon, we projected the future volume of renewable diesel assuming recent volumetric growth rates and established those volumes as the maximums without the RFS program in place. An important difference from the analysis for biodiesel, however, is that states are able to displace a much higher percentage of their diesel fuel, potentially up to the quantity of biodiesel in their diesel fuel pool assuming that the combination of biodiesel and renewable diesel could displace 100% of petroleum diesel fuel.¹³⁶

¹³⁴ New Mexico’s CFTS program is scheduled to take effect by July 1, 2026. We will continue to follow the implementation of the CFTS program and include its incentives for future analyses once the program has been fully implemented.

¹³⁵ The blending incentives are based on recent carbon credit values reported by each of the states. While it is probable that the state incentive values would increase if the RFS program was not in place, we did not attempt to estimate what the credit price might be if the RFS program was not in place. California recently approved more stringent LCFS standards that will likely increase the carbon credit value. CARB, Monthly LCFS Credit Transfer Activity Report for March 2024. <https://ww2.arb.ca.gov/resources/documents/monthly-lcfs-credit-transfer-activity-reports>.

¹³⁶ Renewable diesel has properties similar to petroleum diesel and thus can displace petroleum diesel without causing vehicle compatibility or drivability issues.

Like the other biofuels analyzed for the No RFS Baseline, if the renewable diesel blending cost is negative, renewable diesel is considered economical to blend into diesel fuel. Conversely, renewable diesel is assumed to not be blended into diesel if the blending value is positive. Because of its relatively high cost, renewable diesel consumption without the RFS program would only be blended into diesel fuel if a state offers a significant subsidy, mainly the California, Oregon and Washington state LCFS programs.

Since renewable diesel is only consumed in a few states with LCFS-type programs and nearly all of that in California, we established the maximum renewable diesel demand based on their projected consumption under the RFS program accordingly. The projected maximum renewable diesel volumes are summarized in Table 2.1.3.2-5.

Table 2.1.3.2-5 Maximum Renewable Diesel Volume by State Under the RFS Program

Year	2022	2023	2024	2025	2026	2027
Total Volume	1,350	2,290	2,980	3,630	4,321	5,012
California	1,303	2,148	2,286	2,977	3,506	3,506
Oregon	47	127	659	598	741	741
Washington	0	15	35	55	74	120

Table 2.1.3.2-6 lists the volume of renewable diesel which is economically favorable for blending into diesel fuel by state for the years 2026 and 2027. Our analysis shows that renewable diesel is only economical to consume in California, and this is likely due to the higher carbon credit price, and projected lower petroleum prices by the Energy Information Administration. The volume of economical renewable diesel is shown by vegetable oil type, assuming that the mix of vegetable oils is consistent with the average percentage of vegetable oils consumed in the year 2023 under the RFS program. These vegetable oil quantities are just a starting point and are adjusted when estimating the mix of vegetable oils consumed by both biodiesel and renewable diesel plants under a No RFS Baseline to ensure that the individual vegetable oil volumes are below the established maximum volumes. The final vegetable oil volumes are shown in Table 2.1.3.3-6.

Table 2.1.3.2-6: Potential Volume of Renewable Diesel by Feedstock Type (million gallons)

Year	State	Feedstock			Total
		Soybean Oil	Corn Oil	Domestic FOG	
2026	California	0	0	3,506	3,506
	Oregon	0	0	0	0
	Other States	0	0	0	0
2027	California	0	1,451	2,055	3,506
	Oregon	0	0	0	0
	Other States	0	0	0	0

The analysis shows that only domestic FOG is economical to renewable diesel producers in California in 2026, while both corn oil and domestic FOG are economical in 2027. The total mandated and economic volume of biodiesel varies in 2026 and 2027.

This mix of vegetable oil types is used as a starting point for establishing the No RFS Baseline for renewable diesel. However, adjustments were then made to the vegetable oil feedstock types after the initial No RFS Baseline analysis was conducted for biodiesel. See Chapter 2.1.3.3 for details on these adjustments and the reasoning behind them.

2.1.3.3 Final No RFS Baseline Volumes for Biodiesel and Renewable Diesel

While the volumes of biodiesel and renewable diesel by feedstock type were initially estimated in Tables 2.1.3.1-11 and 2.1.3.2-6, using these volumes, particularly the renewable diesel volumes, would exceed the total volume of feedstocks which is available to produce fuels under the RFS program. To estimate the maximum vegetable oil volumes which could be available for producing biodiesel and renewable diesel in 2026 and 2027, we used the volume of feedstocks used in 2024, which is summarized in Table 2.1.3.3-1.

Table 2.1.3.3-1: Maximum Vegetable Oil Volumes

Year	Soy	Corn Oil	FOG	
			Domestic	Imported
2026	2,760	636	850	1,550
2027	2,760	636	850	1,550

Table 2.1.3.2-6 shows that domestic FOG renewable diesel is cost economic to blend into petroleum diesel fuel in both 2026 and 2027, and corn oil renewable diesel is economic in 2027. In both cases, imported FOG is not cost-effective to use. Table 2.1.3.3-2 summarizes the economic volumes of biodiesel and renewable diesel by feedstock type which meets the limits of feedstock availability—the biodiesel volumes are used to back-calculate the renewable diesel volumes by feedstock type.

Table 2.1.3.3-2: Calculated Volume of Economic Renewable Diesel which Does not Exceed the Current Oil Volumes

Year		Feedstock			Total
		Soy/ Canola Oil	Corn Oil	Domestic FOG	All Feedstocks
2026	Maximum Oil Volume	2,760	636	850	
	Biodiesel	1,095	19	86	650
	Economic Renewable Diesel Volume	0	0	3,506	
	Adjusted Renewable Diesel	0	0	764	502
2027	Maximum Oil Volume	2,760	636	850	
	Biodiesel	110	88	355	571
	Economic Renewable Diesel Volume	0	1,451	2,055	
	Adjusted Renewable Diesel	0	548	495	1,025

The economic analysis can project that the total mandated and economic volume of biodiesel and economic volume of renewable diesel can vary significantly in 2026 and 2027, and compared to previous years. Such swings in the production volume of biodiesel and renewable diesel are unlikely to occur based on typical decisions made by plant owners and investors on

how to invest to expand their plants, continue to operate their biodiesel and renewable diesel plants, or idle or shut down based solely on year-ever-year economic data. Thus, to smooth out unrealistic swings in the economics for using biodiesel and renewable diesel, we calculated the average of biodiesel and renewable diesel demand for the year of interest and the previous three years. Consideration of plant economics over a 4-year period is in between a short-term and medium-term time horizon. This step attempts to reflect how biofuel plant owners and potential biodiesel and renewable diesel plant owners, investors, or banks would seek to assess the economics for operating, investing in, expanding, idling or shutting down biodiesel and renewable diesel plant capacity.¹³⁷ Thus, to assess the volume of biodiesel and renewable diesel which would be produced in 2026 and 2027, it was necessary to also consider the economics of producing biodiesel and renewable diesel in 2023, 2024, and 2025. For this reason, biodiesel and renewable diesel economics were assessed historically for 2023–2025, and projected for 2026 and 2027, to determine the volume of biodiesel and renewable diesel that would be blended into diesel fuel absent the RFS program.¹³⁸ Table 2.1.3.3-3 summarizes the mandated biodiesel volume, the yearly economic biodiesel and renewable diesel volume, the 4-year average economic biodiesel and renewable diesel volume and finally the total of mandated and 4-year average biodiesel and renewable diesel volume.

Table 2.1.3.3-3: Year-by-Year Analysis of Biodiesel Volumes for the No RFS Baseline

Year	State Mandated Biodiesel Volume	Economic Biodiesel Volume	4-Year Average Volume of Economic Biodiesel Volume	Total of State Mandated Biodiesel Volume and 4-Year Volume
2023	236	336	-	-
2024	227	303	-	-
2025	222	464	-	-
2026	217	983	521	738
2027	215	339	522	737

Similarly, Table 2.1.3.3-4 summarizes the economical renewable diesel volume and 4-year average renewable diesel volume.

¹³⁷ EIA, “Investment Expectations & Decision Making In the Petroleum Refining Industry,” January 4, 2007. https://www.eia.gov/outlooks/documentation/workshops/pdf/petroleum_investment.pdf.

¹³⁸ No RFS Baseline analysis for Set 1 Rule with some minor adjustments made for the Set 2 No RFS Baseline analysis.

Table 2.1.3.3-4: Year-by-Year Analysis of Renewable Diesel Volumes for the No RFS Baseline

Year	Economic Renewable Diesel Volume	4-Year Average Volume of Economic Renewable Diesel Volume
2023	1,867	-
2024	2,074	-
2025	2,249	-
2026	764	1,739
2027	1,043	1,533

The projected biodiesel volumes in Table 2.1.3.3-3, and to a lesser extent the renewable diesel volumes in Table 2.1.3.3-4, based on the 4-year volume average, would exceed the projected volume of feedstocks consumed under the RFS program. In this case, we assume that both biodiesel and renewable diesel producers would need to purchase other feedstocks at a loss to maintain the projected plant capacity. These producers would likely be willing to do so over some period of time presuming that their plants will become profitable again in the not-too-distant future. If operating at a loss, the plant would want to at least cover their variable costs (feedstock and utility purchases). Alternatively, they may be able to cover a portion, or maybe all, of their increased costs if they are able to raise their prices if they are operating in a more constrained market. In the case of California, Washington and Oregon, the cost of a carbon credit could increase to cover the increased cost of feedstock. Alternatively, the producers may be able to secure lower feedstock prices if they are able to establish a long-term contract at a lower feedstock price. The most likely source of additional feedstock would be imported used cooking oil which became less economic due to the limitation of the 45Z credit to North American feedstocks after 2025. At the elevated cost point where used cooking oil would be used by renewable diesel plants, corn oil would also be purchased by renewable diesel plants up to the availability limit of corn oil and additional soybean oil would also be purchased by biodiesel plants.

We estimate the additional 20 cents per gallon Agri-Biodiesel subsidy for virgin vegetable oils would cause an increase in the demand for soy and canola oils in 2026, even without the RFS program. The Agri-biodiesel subsidy for animal tallow would help the economics for producing biodiesel from animal tallow; however, there are multiple challenges to biodiesel producers for using animal tallow as a feedstock.¹³⁹ The animal tallow triglycerides are comprised of a higher percentage of saturated fatty acids which causes the resulting biodiesel to have a high cloud point. The high cloud point affects the location, season and amount of this type of biodiesel which can be blended into diesel fuel. Also, depending on the rendering process, the animal tallow can have high free fatty acid and sulfur contents. The high free fatty acid content can contribute to the production of soap compounds which can lead to plugging of vehicle fuel filters and increase the metal content of the biodiesel.¹⁴⁰ If the animal tallow contains sulfur

¹³⁹ Farm Energy, “Animal Fats for Biodiesel Production,” April 3, 2019. <https://farm-energy.extension.org/animal-fats-for-biodiesel-production>.

¹⁴⁰ Bouaid, Abderrahim, Rodrigo Vázquez, Mercedes Martinez, and Jose Aracil. “Effect of Free Fatty Acids Contents on Biodiesel Quality. Pilot Plant Studies.” *Fuel* 174 (January 21, 2016): 54–62. <https://doi.org/10.1016/j.fuel.2016.01.018>.

exceeding 15 ppm, it would prevent the blending of the biodiesel into diesel fuel. Conversely, hydrotreating and associated reactions of the renewable diesel process is well suited to address these challenges, and is the reason why animal tallow is more likely a feedstock sent to renewable diesel plants. For these reasons, we did not assume that the agri-biodiesel subsidy would cause biodiesel plants to process a significantly greater amount of animal tallow. We did not assume any tariffs were in place which would cause increased demand for soy and other virgin North American sourced oils compared to imported FOG.

The final No RFS Baseline volumes for biodiesel and renewable diesel that result from the calculations described in Chapters 2.1.3.1 and 2.1.3.2, limited by the maximum vegetable oil volumes in Table 2.1.3.3-1, and which meet the projected four-year average volumes as shown in Tables 2.1.3.3-3 and 4, are summarized in Table 2.1.3.3-5. While imported FOG biodiesel and renewable diesel is not found to be economical to blend into diesel fuel, to meet the projected volume of biodiesel and renewable diesel plant capacities while staying within the volumetric limits of lipids, assuming that some imported FOG would be processed by renewable diesel plants was the most logical feedstock to bring in.

Table 2.1.3.3-5: Final No RFS Baseline Volumes for Biodiesel and Renewable Diesel (million gallons)

		Year	2026	2027
Biodiesel	Soy		633	334
	Corn Oil		19	86
	FOG	Domestic	86	317
		Imported	0	0
		Total Biodiesel	738	737
Renewable Diesel	Soy		0	0
	Corn Oil		617	550
	FOG	Domestic	764	533
		Imported	358	450
		Total Renewable Diesel	1,739	1,533
Biodiesel and Renewable Diesel		Total	2,477	2,269

2.1.4 Other Advanced Biofuel

In addition to ethanol, cellulosic biofuel, and BBD, we also estimated volumes of other advanced biofuels for the No RFS Baseline. These biofuels include imported sugarcane ethanol, domestically produced advanced ethanol, non-cellulosic RNG used in CNG/LNG vehicles, heating oil, naphtha, and advanced renewable diesel that does not qualify as BBD (coded as D5 rather than as D4). In Chapters 7.3 and 7.4, we present a derivation of the projected volumes of these other advanced biofuels for 2026 and 2027 in the context of the Analyzed Volumes that we analyzed. Here we discuss the deviations from those projections that we believe would apply under the No RFS Baseline.

According to data from EIA, all ethanol imports entered the U.S. through the West Coast in 2018–2021, and the majority did so in 2022 and 2023.¹⁴¹ We believe that these imports were likely used to help refiners meet the requirements of the California LCFS program, which provides significant additional incentives for the use of advanced ethanol beyond that of the RFS program. In the absence of the RFS program, we project that these incentives would remain. Thus, we have assumed that the volume of imported sugarcane ethanol would be the same regardless of whether the RFS program were in place in 2026 and 2027. For similar reasons, we believe that domestically produced advanced ethanol, virtually all of which we expect to be derived from separated food waste based on our analyses described in Chapter 1.5 and Chapter 7.4, would also continue to find a market in California in the absence of the RFS program.

As discussed in Chapter 7.2, a similar situation exists for advanced renewable diesel. The vast majority of the renewable diesel consumed in the U.S. has been consumed in states with incentives for low carbon fuels such as California and Oregon. Some renewable diesel would continue to be consumed in these states in the absence of the RFS program, particularly that produced from FOG due to the lower CI score assigned to it under the LCFS program. We believe that this would also be the case for advanced renewable diesel that does not qualify as BBD since the statutory threshold of 50% GHG reduction is the same for advanced biofuel and for BBD, and because such renewable diesel is generally produced from FOG. Thus, we have assumed that the volume of advanced renewable diesel that does not qualify as BBD would be the same regardless of whether the RFS program were in place in 2026 and 2027.

Remaining forms of other advanced biofuel (*i.e.*, non-cellulosic RNG used in CNG/LNG vehicles, heating oil, and naphtha) are much less likely to find their way to markets such as the California LCFS program, where the incentive would likely be insufficient to continue supporting their use in the absence of the RFS program. Therefore, we have assumed that consumption of these biofuels would be zero under the No RFS Baseline.

2.1.5 Summary of No RFS Baseline

Following our analysis of individual biofuel types as described above, we estimated the constituent mix of both renewable fuel types and feedstocks that could be used under a No RFS Baseline, as shown in Table 2.1.5-1 (in million RINs) and Table 2.1.5-2 (in million gallons).

¹⁴¹ EIA, “Fuel Ethanol Imports by Area of Entry,” *Petroleum & Other Liquids*, May 30, 2025. https://www.eia.gov/dnav/pet/pet_move_imp_a_epooxe_IM0_mbbbl_a.htm.

Table 2.1.5-1: No RFS Baseline for 2026 and 2027 (million RINs)

	2026	2027
Cellulosic Biofuel	565	597
CNG/LNG from biogas	437	469
Ethanol from CKF	128	128
Total Biomass-Based Diesel	4,068	3,563
Biodiesel	1,107	1,106
Soybean oil	843	440
FOG	129	476
Corn oil	29	129
Canola oil	0	0
Renewable Diesel	2,956	2,453
Soybean oil	0	0
FOG	1,203	763
Corn oil	1,049	880
Canola oil	0	0
Jet fuel from FOG	5	5
Other Advanced Biofuels	129	129
Renewable diesel from FOG	90	90
Imported sugarcane ethanol	15	15
Domestic ethanol from separated food waste	24	24
Other ^a	0	0
Conventional Renewable Fuel	14,040	13,958
Ethanol from corn	14,040	13,958
Biodiesel and renewable diesel from palm oil	0	0

^a Composed of non-cellulosic biogas, heating oil, and naphtha.

Table 2.1.5-2: No RFS Baseline for 2026 and 2027 (million gallons)

	2026	2027
Cellulosic Biofuel	565	597
CNG/LNG from biogas	437	469
Ethanol from CKF	128	128
Total Biomass-Based Diesel	2,477	2,270
Biodiesel	738	737
Soybean oil	556	293
FOG	86	317
Corn oil	19	86
Canola oil	77	41
Renewable Diesel	1,739	1,533
Soybean oil	0	0
FOG	1,066	927
Corn oil	617	550
Canola oil	0	0
Jet fuel from FOG	0	0
Other Advanced Biofuels	95	95
Renewable diesel from FOG	56	56
Imported sugarcane ethanol	15	15
Domestic ethanol from separated food waste	24	24
Other ^a	0	0
Conventional Renewable Fuel	14,040	13,958
Ethanol from corn	14,040	13,958
Biodiesel and renewable diesel from palm oil	0	0

^a Composed of non-cellulosic biogas, heating oil, and naphtha.

2.2 2025 Baseline

As discussed in Preamble Section III.D.3, while we believe that the No RFS Baseline is preferable as a point of reference for analyzing the impacts of the Analyzed Volumes, we have also estimated some of the impacts (*e.g.*, costs) of this rule relative to the renewable fuel volumes used in 2025 as an additional informational case. This allows for an estimate of the incremental impacts of the renewable fuel volumes compared to those previously finalized.

For this final rule, we updated the 2025 baseline using available data on renewable fuel production and use in 2025 from EMTS. For this baseline we combined the fuel volumes of renewable diesel and renewable jet fuel due to the significant overlap in facilities and technologies that produce these fuels. To estimate the feedstocks used to produce BBD in 2025 we also considered data from EIA's Monthly Biofuels Capacity and Feedstocks Update. These 2025 baseline volumes are shown in Table 2.2-1 (in million RINs) and Table 2.2-2 (in million gallons). A further discussion of how we used the EIA data to estimate the feedstocks used to produce BBD in 2025 follows these tables.

Table 2.2-1: Mix of Biofuels Used in 2025 (million RINs)

Cellulosic Biofuel	1,247
CNG/LNG from biogas	1,170
Ethanol from CKF	77
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel	5,739
Biodiesel	1,653
Soybean oil	1,190
FOG	231
Corn oil	66
Canola oil	165
Renewable Diesel	4,430
Soybean oil	886
FOG	2,525
Corn oil	709
Canola oil	354
Jet fuel from FOG	0
Other Advanced Biofuels	218
Renewable diesel from FOG	70
Imported sugarcane ethanol	0
Domestic ethanol from separated food waste	20
Other ^a	127
Conventional Renewable Fuel	14,183
Ethanol from corn	14,183
Renewable diesel from palm oil	0

^a Composed of non-cellulosic biogas, heating oil, and naphtha.

Table 2.2-2: Mix of Biofuels Used in 2025 (million gallons)

Cellulosic Biofuel	1,247
CNG/LNG from biogas	1,247
Ethanol from CKF	77
Diesel/jet fuel from wood waste/MSW	0
Total Biomass-Based Diesel	3,734
Biodiesel	1,102
Soybean oil	793
FOG	154
Corn oil	44
Canola oil	110
Renewable Diesel	2,632
Soybean oil	521
FOG	1,485
Corn oil	417
Canola oil	208
Jet fuel from FOG	0
Other Advanced Biofuels	153
Renewable diesel from FOG	44
Imported sugarcane ethanol	0
Domestic ethanol from separated food waste	20
Other ^a	89
Conventional Renewable Fuel	14,183
Ethanol from corn	14,183
Renewable diesel from palm oil	0

^a Composed of non-cellulosic biogas, heating oil, and naphtha.

To estimate the feedstocks used to supply the BBD in 2025 we first considered the data available from EMTS. This data is summarized in Table 2.2-3.

Table 2.2-3: Feedstocks used to Produce BBD in 2025 (million RINs)

Fuel	Feedstock	RINs Generated
Biodiesel	All Other Feedstocks	84.4
Biodiesel	FOG	166.0
Biodiesel	FOG, Distillers Corn Oil	37.2
Biodiesel	FOG, Distillers Corn Oil, Soybean Oil	105.2
Biodiesel	Canola Oil	149.0
Biodiesel	Soybean Oil	1,168.8
Renewable Diesel	All Other Feedstocks	2,594.4
Renewable Diesel	FOG	1,645.1
Renewable Diesel	Distillers Corn Oil	215.3
Renewable Diesel	Soybean Oil	502.4
Renewable Jet Fuel	All Other Feedstocks	460.2

The information on the feedstocks used to produce biodiesel from EMTS contains sufficient specificity for us to estimate total quantities of feedstock used to produce biodiesel in 2025. While two of the categories listed in the EMTS data contain multiple feedstocks these categories indicate which feedstocks were used and the total quantity of RINs listed for these multi-feedstock categories are relatively small.¹⁴² To estimate the proportion of each feedstock used to supply biodiesel to the U.S. in 2025 we estimated that RIN generation was evenly split between each feedstock listed when multiple feedstocks were listed. We then multiplied the proportion supplied from each feedstock by the total volume of biodiesel supplied (after accounting for exports and RINs retired for reasons other than compliance with the RFS obligations) to estimate the volume produced from each feedstock. These calculations are shown in Table 2.2-4.

Table 2.2-4: Estimating Biodiesel Production in 2025 By Feedstock

RINs Generated by Feedstock (million RINs)	
FOG	240.8 (14%)
Distillers Corn Oil	74.8 (04%)
Soybean Oil	1,225.0 (72%)
Canola Oil	170.2 (10%)
Biodiesel Volumes Supplied by Feedstock (million gallons)	
Total (All Feedstocks)	1,102
FOG	154
Distillers Corn Oil	44
Soybean Oil	793
Canola Oil	110

Estimating the quantities of renewable diesel and renewable jet fuel requires additional data, as the majority of the RINs generated for these fuels were reported under the undifferentiated “all other feedstocks” category in the EMTS data. We therefore supplemented the ETMS data with data on feedstock use for biodiesel and renewable diesel production from EIA’s Monthly Biofuels Capacity and Feedstocks Update. At the time this analysis was completed (January 2026) the most recent Monthly Biofuels Capacity and Feedstock Update was published in November 2025, with data through September 2025.¹⁴³

For each of the three crop-based feedstock categories (canola oil, distillers corn oil and soybean oil) we estimated total annual total consumption of each feedstock in 2025 by projecting the average feedstocks use from May to September for each month in 2025 for which data had not yet been reported (October to December). For soybean oil, EIA reported specific feedstock consumption by renewable diesel plants for each month, which allowed for renewable feedstock projection using the methodology described in this paragraph. For canola oil and corn oil, specific renewable diesel consumption data for many of the months was withheld to avoid

¹⁴² We did not consider the 84.4 million RINs of biodiesel produced from “all other feedstocks” in calculating the feedstock ratios to estimate the mix of feedstocks used to produce biodiesel in 2025.

¹⁴³ EIA, “Monthly Biofuels Capacity and Feedstocks Update with data for September 2025,” November 28, 2025. <https://www.eia.gov/biofuels/update>.

disclosure of individual company data. To estimate the feedstock consumption for these feedstocks we first projected the annual total for each feedstock from biodiesel plants and renewable diesel plants combined (which was available for each month through September 2025). We then used the ratio of consumption from biodiesel plants relative to consumption from renewable diesel plants in months where these data were reported to estimate the annual consumption for renewable diesel plants (separately from biodiesel plants) in 2025.

For FOG, the EIA reports do not separately list feedstocks consumed by biodiesel and renewable diesel plants.¹⁴⁴ To estimate the consumption of FOG by renewable diesel plants we first estimated the total use of FOG by both biodiesel and renewable diesel plants. To do this we again estimated to annual total consumption of each feedstock in 2025 by projecting the average feedstocks use from May to September for each month in 2025 for which data had not yet been reported (October to December).¹⁴⁵ We then subtracted from this total quantity of FOG the amount of FOG feedstock we projected was consumed by biodiesel producers using the EMTS data.¹⁴⁶ We assumed the remainder was used to produce renewable diesel.

Finally, we then calculated the proportion of the total feedstocks consumed by renewable diesel plants from each feedstock and multiplied the proportion supplied from each feedstock by the total volume of renewable diesel supplied (after accounting for exports and RINs retired for reasons other than compliance with the RFS obligations) to estimate the volume produced from each feedstock. These calculations are shown in Table 2.2-5.

Table 2.2-5: Estimating Renewable Diesel Production in 2025 By Feedstock

Consumption by Feedstock (million pounds)	
FOG	13,733 (57%)
Distillers Corn Oil	3,865 (16%)
Soybean Oil	4,822 (20%)
Canola Oil	1,844 (08%)
Renewable Diesel Volumes Supplied by Feedstock (million gallons)	
Total (All Feedstocks)	2,632
FOG	1,485
Distillers Corn Oil	417
Soybean Oil	521
Canola Oil	208

¹⁴⁴ EIA separately lists consumption of poultry grease, tallow, white grease, yellow grease, and other waste FOG. We used the sum of all these categories to project the annual consumption of FOG by biodiesel and renewable diesel plants.

¹⁴⁵ Only one month listed feedstocks consumption data for poultry grease and other FOG, with the remaining months withheld. We estimated that the consumption of these feedstocks was equal to the value listed for each month in 2025.

¹⁴⁶ We used an estimated conversion rate of 8 pounds of FOG to produce one gallon of biodiesel.

Chapter 3: Analyzed Volumes and Volume Changes

To enable more detailed analyses of the impacts of the RFS volumes for 2026 and 2027 we have identified the specific biofuel types and associated feedstocks that are projected to be used to meet the RFS volumes in these years. While we acknowledge that there is significant uncertainty about the types of renewable fuels that would be used to meet the RFS volumes, we believe that the mix of biofuel types described in this chapter are reasonable projections based on historical data and current market trends of what could be supplied for the purpose of assessing the potential impacts. As described in Chapter 2, we also acknowledge that the choice of baseline affects the estimated impacts of the Analyzed Volumes. This chapter identifies the mix of biofuels that could result from the Analyzed Volumes and the change in volumes in comparison to the No RFS and 2025 Baselines. More information on the methodologies used to determine these volumes can be found in Chapter 7.

3.1 Mix of Renewable Fuel Types for the Analyzed Volumes

In this section, we first summarize the component categories we analyzed in this rule, and how these component categories relate to each statutory and implied category of renewable fuel. Following this we summarize our estimates of the mix of more specific fuel types and feedstocks we project will be used to meet these volumes. We have based this projected mix of fuels and feedstocks on historical data, current market trends, and our projections of the potential supply in 2026 and 2027.

The Analyzed Volumes for 2026 and 2027 are presented in Preamble Section III.A and are repeated in Table 3.1-1 by the component categories and in Table 3.1-2 by the statutory and implied categories.

Table 3.1-1: Analyzed Volumes by Component Category (million RINs)

	D Code	2026	2027
Cellulosic biofuel	D3+D7	1,364	1,465
Biomass-based diesel	D4	9,961	10,118
Other advanced biofuel	D5	224	224
Conventional renewable fuel	D6	14,270	14,203

Table 3.1-2: Analyzed Volumes by Statutory and Implied Category (million RINs)

	D Code	2026	2027
Cellulosic biofuel	D3+D7	1,364	1,465
Non-cellulosic advanced biofuel ^a	D4+D5	10,185	10,342
Advanced biofuel	D3+D4+D5+D7	11,550	11,777
Conventional renewable fuel ^b	D6	14,270	14,203
Total renewable fuel	All	25,820	25,980

^a Non-cellulosic advanced biofuel is not an RFS standard category but includes all advanced biofuels that do not qualify as cellulosic biofuel.

^b Conventional renewable fuel is not an RFS standard category but includes all renewable fuels that do not qualify as cellulosic biofuel, BBD, or advanced biofuel.

We next estimated the constituent mix of renewable fuel types and feedstocks that could be used to meet the Analyzed Volumes.¹⁴⁷ The analyses supporting these projections can be found in Chapter 7. The mix of renewable fuels we project will be supplied to meet the Analyzed Volumes in 2026 and 2027 are presented in million RINs (Table 3.1-3) and million gallons (Table 3.1-4).

Table 3.1-3: Projected Biofuel Supply for 2026 and 2027 (million RINs)

	2026	2027
Cellulosic Biofuel	1,364	1,435
CNG/LNG from biogas	1,236	1,307
Ethanol from CKF	128	128
Total Biomass-Based Diesel ^a	9,961	10,118
Biodiesel	2,670	2,670
Soybean oil	1,650	1,650
FOG	225	225
Corn oil	315	315
Canola oil	480	480
Renewable Diesel	7,290	7,453
Soybean oil	2,244	2,336
FOG	2,225	2,270
Corn oil	1,152	1,085
Canola oil	1,668	1,762
Other Advanced Biofuels	224	224
Renewable diesel from FOG	90	90
Sugarcane ethanol	15	15
Domestic ethanol from separated food waste	24	24
Other ^b	95	95
Conventional Renewable Fuel	14,270	14,203
Ethanol from corn	14,270	14,203

^a Includes BBD in excess of the advanced biofuel volume requirement. The excess would be used to help meet the conventional renewable fuel volume requirement.

^b Composed of non-cellulosic biogas, heating oil, and naphtha.

¹⁴⁷ The analyses leading to the mix of renewable fuel types and feedstocks are presented in Chapter 7.

Table 3.1-4: Projected Biofuel Supply for 2026 and 2027 (million gallons)

	2026	2027
Cellulosic Biofuel	1,364	1,435
CNG/LNG from biogas	1,236	1,307
Ethanol from CKF	128	128
Total Biomass-Based Diesel ^a	6,074	6,445
Biodiesel	1,780	1,780
Soybean oil	1,100	1,100
FOG	150	150
Corn oil	210	210
Canola oil	320	320
Renewable Diesel	4,290	4,660
Soybean oil	1,320	1,460
FOG	1,309	1,419
Corn oil	678	678
Canola oil	981	1,101
Other Advanced Biofuels	162	162
Renewable diesel from FOG	56	56
Sugarcane ethanol	15	15
Domestic ethanol from separated food waste	24	24
Other ^b	67	67
Conventional Renewable Fuel	14,270	14,203
Ethanol from corn	14,270	14,203

^a Includes BBD in excess of the advanced biofuel volume requirement. The excess would be used to help meet the conventional renewable fuel volume requirement.

^b Composed of non-cellulosic biogas, heating oil, and naphtha.

The vast majority of the fuels we project to be used in the U.S. are projected to be produced domestically from domestic feedstocks. This is the case for all cellulosic biofuels, most other advanced biofuels (except for sugarcane ethanol, which we project will be imported) and all conventional renewable fuel. For BBD, however, we project that a significant portion of this fuel will be produced from imported feedstocks. Because biofuels produced from imported feedstocks are projected to have different impacts on some of the statutory factors than fuels produced from domestic feedstocks, we have projected the volumes of biodiesel and renewable diesel we expected to be produced from domestic and foreign feedstocks separately. These projections are shown in Table 3.1-5 (in million RINs) and Table 3.1-6 (in million gallons).

Table 3.1-5: BBD Volumes from Domestic and Imported Feedstocks (billion RINs)

Biofuel	2026	2027
BBD (Total)	9.96	10.12
Biodiesel (Total)^a	2.66	2.66
Domestic FOG	0.22	0.22
Domestic Soybean Oil	1.65	1.65
Domestic Canola Oil	0.00	0.00
Domestic Distillers Corn Oil	0.31	0.31
Imported FOG	0.00	0.00
Imported Soybean Oil	0.00	0.00
Imported Canola Oil	0.48	0.48
Imported Distillers Corn Oil	0.00	0.00
Renewable Diesel (Total)^b	7.30	7.43
Domestic FOG	1.36	1.36
Domestic Soybean Oil	2.24	2.34
Domestic Canola Oil	0.39	0.37
Domestic Distillers Corn Oil	1.15	1.08
Imported FOG	0.87	0.91
Imported Soybean Oil	0.00	0.00
Imported Canola Oil	1.28	1.39
Imported Distillers Corn Oil	0.01	0.01

^a Includes heating oil.

^b Includes renewable jet fuel.

Table 3.1-6: BBD Volumes from Domestic and Imported Feedstocks (million gallons)

Biofuel	2026	2027
BBD (Total)	6.07	6.44
Biodiesel (Total)^a	1.78	1.78
Domestic FOG	0.15	0.15
Domestic Soybean Oil	1.10	1.10
Domestic Canola Oil	0.00	0.00
Domestic Distillers Corn Oil	0.21	0.21
Imported FOG	0.00	0.00
Imported Soybean Oil	0.00	0.00
Imported Canola Oil	0.32	0.32
Imported Distillers Corn Oil	0.00	0.00
Renewable Diesel (Total)^b	4.29	4.66
Domestic FOG	0.80	0.85
Domestic Soybean Oil	1.32	1.46
Domestic Canola Oil	0.23	0.23
Domestic Distillers Corn Oil	0.68	0.68
Imported FOG	0.51	0.57
Imported Soybean Oil	0.00	0.00
Imported Canola Oil	0.75	0.87
Imported Distillers Corn Oil	0.00	0.00

^a Includes heating oil.

^b Includes renewable jet fuel.

3.2 Volume Changes Analyzed with Respect to the No RFS Baseline

In this RIA we have quantified the impacts of the Analyzed Volumes for 2026 and 2027 on several factors. The impacts on these factors were based on the difference in the volumes of specific renewable fuel types between the Analyzed Volumes and the No RFS Baseline. These differences are shown in Tables 3.2-1 (in million RINs) and Table 3.2-2 (in million gallons). The values in these tables reflect the difference between values of the tables containing the Analyzed Volumes (Tables 3.1-3 and 3.1-4) and the tables containing the No RFS Baseline volumes (Tables 2.1.5-1 and 2).

Table 3.2-1: Volume Changes Relative to the No RFS Baseline (million RINs)

	2026	2027
Cellulosic Biofuel	799	838
CNG/LNG from biogas	799	838
Ethanol from CKF	0	0
Total Biomass-Based Diesel	5,893	6,555
Biodiesel	1,563	1,565
Soybean oil	816	1,210
FOG	96	-251
Corn oil	287	186
Canola oil	480	480
Renewable Diesel	4,334	5,000
Soybean oil	2,244	2,336
FOG	1,022	1,508
Corn oil	104	205
Canola oil	1,668	1,762
Jet fuel from FOG	-5	-5
Other Advanced Biofuels	95	95
Renewable diesel from FOG	0	0
Sugarcane ethanol	0	0
Domestic ethanol from separated food waste	0	0
Other ^a	95	95
Conventional Renewable Fuel	231	245
Ethanol from corn	231	245

^a Composed of non-cellulosic biogas, heating oil, and naphtha.

Table 3.2-2: Volume Changes Relative to the No RFS Baseline (million gallons)

	2026	2027
Cellulosic Biofuel	799	838
CNG/LNG from biogas	799	838
Ethanol from CKF	0	0
Total Biomass-Based Diesel	3,597	4,175
Biodiesel	1,042	1,043
Soybean oil	544	807
FOG	64	-167
Corn oil	191	124
Canola oil	243	279
Renewable Diesel	2,551	3,127
Soybean oil	1,320	1,460
FOG	601	942
Corn oil	61	128
Canola oil	981	1,101
Jet fuel from FOG	0	0
Other Advanced Biofuels	67	67
Renewable diesel from FOG	0	0
Sugarcane ethanol	0	0
Domestic ethanol from separated food waste	0	0
Other ^a	67	67
Conventional Renewable Fuel	231	245
Ethanol from corn	231	245

^a Composed of non-cellulosic biogas, heating oil, and naphtha.

Note that the changes in ethanol from corn shown in Tables 3.2-1 through 3.2-2 can be entirely attributed to ethanol used as E15 and E85, since under the No RFS Baseline we project that E10 would be used regardless of the RFS program but E15 and/or E85 would only be used in a very few states with state incentives and mandates.¹⁴⁸ There is some uncertainty related to how changes in ethanol consumption will impact ethanol production. For example, ethanol producers could respond to increased domestic demand for ethanol by increasing production or by decreasing ethanol exports. In this latter case, decreases in domestic ethanol demand would have little to no impact on domestic ethanol production. For the analyses conducted in support of this rule we generally projected that any increase in ethanol consumption would result in a gallon-for-gallon increase in ethanol production. This would be the maximum expected impact we would expect from any changes in ethanol consumption attributable to the RFS program.

We determined that a more robust analysis could be performed for some statutory factors if BBD produced from FOG could be disaggregated into specific types. EMTS, which is the source of the feedstock data used in this rule, does not differentiate between different types of FOG. Therefore, EPA used data from EIA's Monthly Biofuels Capacity and Feedstocks Update, to estimate that FOG consisted of about 35% UCO and 65% tallow in 2025 through

¹⁴⁸ See Chapter 2.1.1 for more discussion on E15 and E85.

September.¹⁴⁹ These fractions were applied to the volumes projected to be supplied in 2026 and 2027. The projected volumes of biodiesel and renewable diesel produced from UCO and tallow are shown in Table 3.2-3. The projected increase in biodiesel and renewable diesel produced from UCO and tallow relative to the No RFS Baseline is shown in Table 3.2-4.

Table 3.2-3: Disaggregated Biofuels Produced from FOG (million gallons)

	2026	2027
Biodiesel from FOG	150	150
UCO	53	53
Tallow	98	98
Renewable diesel from FOG	1,309	1,419
UCO	458	497
Tallow	851	922

Table 3.2-4: Volume Changes in Biodiesel and Renewable Diesel Produced from FOG and Tallow Relative to the No RFS Baseline (million gallons)

	2026	2027
Biodiesel from FOG	64	-167
UCO	22	-58
Tallow	42	-109
Renewable diesel from FOG	601	942
UCO	210	330
Tallow	391	612

3.3 Volume Changes Analyzed with Respect to the 2025 Baseline

As described in Chapter 2.2, for some of the factors (*e.g.*, cost) we also analyzed the impacts of volume changes with respect to the 2025 Baseline. These differences are shown in Table 3.3-1 (in million RINs) and Tables 3.3-2 (in million gallons). The values in these tables reflect the difference between values of the tables containing Analyzed Volumes (Tables 3.1-3 and 3.1-4) and the tables containing the 2025 Baseline volumes (Tables 2.2-1 and 2).

¹⁴⁹ EIA, “Monthly Biofuels Capacity and Feedstocks Update with data for September 2025,” November 28, 2025, Table 2b – U.S. Feedstocks consumed for production of biofuels. <https://www.eia.gov/biofuels/update>. For months where information was withheld we assumed consumption of FOG was equal to the average consumption in months where information was listed.

Table 3.3-1: Volume Changes Relative to 2025 Baseline (million RINs)

	2026	2027
Cellulosic Biofuel	117	188
CNG/LNG from biogas	66	137
Ethanol from CKF	51	51
Total Biomass-Based Diesel	4,222	4,379
Biodiesel	1,017	1,017
Soybean oil	460	460
FOG	-6	-6
Corn oil	249	249
Canola oil	315	315
Renewable Diesel	2,860	3,023
Soybean oil	1,358	1,450
FOG	-300	-255
Corn oil	444	376
Canola oil	1,314	1,408
Jet fuel from FOG	0	0
Other Advanced Biofuels	6	6
Renewable diesel from FOG	20	20
Sugarcane ethanol	15	15
Domestic ethanol from separated food waste	4	4
Other	-32	-32
Conventional Renewable Fuel	87	20
Ethanol from corn	87	20

Table 3.3-2: Volume Changes Relative to 2025 Baseline (million gallons)

	2026	2027
Cellulosic Biofuel	117	188
CNG/LNG from biogas	66	137
Ethanol from CKF	51	51
Total Biomass-Based Diesel	2,340	2,711
Biodiesel	678	678
Soybean oil	307	307
FOG	-4	-4
Corn oil	166	166
Canola oil	210	210
Renewable Diesel	1,658	2,028
Soybean oil	799	939
FOG	-176	-66
Corn oil	261	261
Canola oil	773	893
Jet fuel from FOG	0	0
Other Advanced Biofuels	9	9
Renewable diesel from FOG	13	13
Sugarcane ethanol	15	15
Domestic ethanol from separated food waste	4	4
Other	-23	-23
Conventional Renewable Fuel	87	20
Ethanol from corn	87	20

Unlike the comparison to the No RFS Baseline, the changes in ethanol from corn shown in Table 3.3-1 and 3.3-2 are a function of both changes in total gasoline demand as well as changes in the consumption of E15 and E85. Table 3.3-3 shows the amount of ethanol that can be attributed to each of these factors.

Table 3.3-3: Source of Ethanol Changes in the Analyzed Volumes Relative to the 2025 Baseline (million gallons)

	2026	2027
Changes in ethanol consumption attributable to changes in gasoline demand	118	6
Changes in ethanol consumption attributable to changes in E15 and E85 consumption	39	83
Total	158	90

Note: Totals do not add due to rounding.

Chapter 4: Environmental Impacts

CAA section 211(o)(2)(B)(ii) requires EPA to analyze a number of environmental factors in its determination of the appropriate volumes to establish under the set authority, including factors on air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality, and water supply. This chapter discusses these environmental factors except for climate change, which is evaluated separately in Chapter 5. Where applicable, this chapter discusses additional factors, such as soil quality and ecosystem services, per EPA’s authority to consider “other” factors as explained in more detail in Preamble Section II.B. For example, soil quality is evaluated due to its close association and impacts on water quality. In addition, the discussions in this chapter reference and leverage the findings from the Third Triennial Report to Congress on Biofuels and the Environment (RtC3), finalized in January 2025, which provides additional information on environmental impacts from biofuels and the RFS program.¹⁵⁰

4.1 Air Quality

Air quality, as measured by the concentration of air pollutants in the ambient atmosphere, can be affected by increased production and use of biofuels. Some air pollutants are emitted directly (*e.g.*, nitrogen oxides (NO_x)), while other air pollutants are formed secondarily in the atmosphere (*e.g.*, ozone), and some air pollutants are both emitted directly and formed secondarily (*e.g.*, particulate matter (PM) and aldehydes). Air quality can be affected by emissions from: (1) Production and transport of feedstocks, (2) Emissions from conversion of feedstocks to biofuels, (3) Emissions from transport of the finished biofuels, and (4) Emissions from combustion of biofuels in vehicles. Emissions from increased production and use of biofuels contribute to ambient concentrations of air pollutants, and the health and environmental effects associated with exposure to these air pollutants, including effects on children, are discussed further in a memorandum to this docket.¹⁵¹

The emissions from production and transport of biofuel feedstocks and finished biofuels, and from combustion of biofuels in vehicles, differ depending on the type of biofuel. In addition to the type of biofuel, other factors may affect emissions, including the blend composition of biofuel with fossil or petroleum fuel, vehicle technology, emissions control technology, and operating conditions.

4.1.1 Background on Air Quality Impacts of Biofuels

This section summarizes current knowledge about the air quality impacts of biofuels, specifically biofuels whose volumes are impacted by this rule. The biofuels we focus on in this section are conventional corn ethanol, BBD (including biodiesel and renewable diesel), and

¹⁵⁰ EPA, “Biofuels and the Environment: Third Triennial Report to Congress,” EPA/600/R-24/343F, January 2025.

¹⁵¹ The health and environmental effects of the pollutants discussed in this chapter are described “Health and environmental effects of pollutants discussed in Chapter 4 of Draft Regulatory Impact Analysis (DRIA) supporting the proposed Renewable Fuel Standard (RFS) standards for 2026–2027,” available in the docket for this action.

renewable CNG/LNG.¹⁵² Chapter 4.1.2 includes an evaluation of the emission impacts associated with the Analyzed Volumes when compared to the No RFS Baseline, and Chapter 4.1.3 describes the likely air quality impacts associated with the Analyzed Volumes when compared to the No RFS Baseline.

When considering background information from previous work on emissions and air quality impacts of biofuels, it is important to understand whether the rule would be increasing or decreasing volumes of biofuels; this requires defining the baseline volume of biofuels for comparison. Preamble Section III.B and Chapter 2 detail the determination of the Analyzed Volumes as compared with the No RFS and 2025 Baselines. Generally, the No RFS Baseline is used for analytical purposes and the 2025 Baseline is an additional informational case.

EPA has previously assessed the air quality impacts of biofuels in prior RFS rules, including the RFS2 Rule and in the “anti-backsliding study” (ABS).^{153,154} Air quality modeling was done for the RFS2 Rule in order to assess the impacts of the required RFS2 volumes compared to two different baselines or reference cases, both of which included some usage of ethanol fuels.¹⁵⁵ The RFS2 modeling indicated that the increased use of renewable fuels increased emissions of hydrocarbons, NO_x, acetaldehyde, and ethanol and decreased emissions of other pollutants such as carbon monoxide (CO) and benzene when evaluating production, transport, and end use. However, the impacts of these emissions on criteria air pollutants were highly variable from region to region. Overall, the emission changes were projected to lead to increases in national population-weighted annual average ambient PM_{2.5} and ozone concentrations. Air quality impacts associated with changes in ethanol production and transport are expected to be primarily in the local area where the emissions occur.¹⁵⁶

Air quality modeling was also performed for the ABS, which examined the impacts on air quality in 2016 that might result from changes in vehicle and engine emissions associated with renewable fuel volumes under the RFS relative to approximately 2005 levels.¹⁵⁷ The ABS modeling found potential increases and decreases in ambient concentrations of pollutants. For example, compared to the “pre-RFS” scenario, the 2016 “with-RFS” scenario had increased ozone concentrations across the eastern U.S. and in some areas in the western U.S., with some decreases in localized areas. In the 2016 “with-RFS” scenario, concentrations of fine particulate

¹⁵² This includes all fuel categories appearing in Tables 3.2-1 and 2 with increased volumes from the No RFS Baseline with the exception of “Other Advanced Biofuels (D5) – Other.” This fuel category represents an unknown mix of various fuel types with smaller volumes.

¹⁵³ EPA, “Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis,” EPA-420-R-10-006, February 2010.

¹⁵⁴ EPA, “Clean Air Act Section 211(v)(1) Anti-backsliding Study,” EPA-420-R-20-008, May 2020.

¹⁵⁵ See RFS2 Rule RIA Tables 3.2.7 and 3.2.8 for the emissions impacts associated with biodiesel and ethanol volume changes.

¹⁵⁶ Cook, Rich, Sharon Phillips, Marc Houyoux, Pat Dolwick, Rich Mason, Catherine Yanca, Margaret Zawacki, et al. “Air Quality Impacts of Increased Use of Ethanol Under the United States’ Energy Independence and Security Act.” *Atmospheric Environment* 45, no. 40 (September 16, 2010): 7714–24. <https://doi.org/10.1016/j.atmosenv.2010.08.043>.

¹⁵⁷ The ABS focused on the impacts of statutorily required renewable fuel volumes on concentrations of criteria and toxic pollutants due to changes in vehicle and engine emissions; this study was not an examination of the lifecycle impacts of renewable fuels on air quality.

matter (PM_{2.5}) were relatively unchanged in most areas, with increases in some areas and decreases in some localized areas.

In this rule, we rely primarily on the conclusions from the RtC3, which summarized available information on air quality impacts associated with biofuels.¹⁵⁸ The RtC3 notes that there is no new evidence that contradicts the fundamental conclusions of previous reports to Congress.¹⁵⁹ The RtC3 concluded that emissions of NO_x, sulfur oxides (SO_x), CO, volatile organic compounds (VOCs), ammonia (NH₃), PM_{2.5}, and PM₁₀, can be impacted at each stage of biofuel production, distribution, and usage, and emphasized that the impacts associated with feedstock and fuel production and distribution are important to consider, along with those associated with fuel usage.

4.1.1.1 Corn Ethanol

Corn can be used to produce fuel ethanol for blending with gasoline and usage in vehicles. The RtC3 states that increased corn production results in higher agricultural dust and NH₃ emissions from fertilizer use, although improved nitrogen management practices can reduce these increases in NH₃ emissions. Increased corn ethanol production and refining also leads to increased NO_x, SO_x, VOCs, PM_{2.5}, and PM₁₀, and dispersion modeling has shown elevated pollutant concentrations near corn biorefineries.¹⁶⁰ Pollutant emissions associated with corn ethanol also result from evaporative losses of VOCs during storage and transport, as well as combustion emissions from commercial marine vessels, rail, tanker trucks, and other equipment used to transport the ethanol to end use. Finally, the combustion of ethanol in end use applications causes emissions of NO_x, VOCs, PM_{2.5}, and CO as well. As increased ethanol volumes are displacing petroleum and petroleum-related emissions in each of these areas, the overall impact on the environment is a complex issue.

The RtC3 also included a comparison of air quality impacts from corn ethanol versus gasoline.¹⁶¹ Overall the total potential air quality impacts were much lower from corn ethanol than from gasoline because much less corn ethanol is consumed than gasoline. However, results also show a trend of increased life cycle emissions for the corn ethanol pathways compared with petroleum-based gasoline. The trend is stronger for some pollutants (*e.g.*, SO_x and PM_{2.5}) and nearly negligible for others (*e.g.*, CO and VOCs). In addition, per megajoule potential life cycle air quality impacts were larger for corn ethanol compared with gasoline but were decreasing through time as the industry matured and efficiencies improved.

¹⁵⁸ EPA, “Biofuels and the Environment: Third Triennial Report to Congress,” EPA/600/R-24/343F, January 2025. Chapter 8 “Air Quality.”

¹⁵⁹ The cutoff date for publication of literature included in the RtC3 was early- to mid-2022.

¹⁶⁰ Lee, Eun Kyung, Xiaobo Xue Romeiko, Wangjian Zhang, Beth J. Feingold, Haider A. Khwaja, Xuesong Zhang, and Shao Lin. “Residential Proximity to Biorefinery Sources of Air Pollution and Respiratory Diseases in New York State.” *Environmental Science & Technology* 55, no. 14 (July 7, 2021): 10035–45. <https://doi.org/10.1021/acs.est.1c00698>.

¹⁶¹ See RtC3 Chapter 8.5 “Comparison with Petroleum” for more details on results. The models run were the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model and the Bio-based circular carbon economy Environmentally-extended Input-Output Model (BEIOM).

A study that focused on papers relevant to California and was published since the RtC3 reviewed available literature and concluded that while the use of bioethanol (ethanol produced from plants, such as sugarcane or corn) was beneficial with respect to GHG emissions, it was associated with an increase in criteria air pollutant emissions relative to petroleum gasoline on a per-unit basis.¹⁶²

4.1.1.2 Biomass-based diesel

For the purposes of this analysis, BBD includes biodiesel and renewable diesel. Although BBD is sourced from a variety of feedstocks, domestic soybean oil and domestic biogenic waste fats, oils, and greases make up greater than 80% of the BBD fuel and feedstock volumes. The RtC3 states that emissions from production of biodiesel from soybean oil vary depending on the oil extraction method and that mechanical extraction is associated with the highest emissions. RtC3 also states that compared to corn ethanol, data are lacking on emission and air quality impacts of the feedstock production (soybean), storage, and transport stages of BBD production.¹⁶³ The RtC3 concluded that for heavy-duty engines model years 2007 and forward, the impacts of biodiesel on end use emissions of criteria pollutants and precursors are insignificant compared to petroleum diesel.

The RtC3 also included a comparison of air quality impacts from soy biodiesel and petroleum diesel.¹⁶⁴ The results generally show a trend of increased life cycle emissions for the soy oil biodiesel pathways compared with petroleum diesel. The trend is stronger for some pollutants (*e.g.*, SO_x and VOC) and less conclusive for others (*e.g.*, CO and PM_{2.5}). In addition, the per megajoule potential life cycle air quality effects were larger for biodiesel compared with petroleum diesel. However, the report also observed that per megajoule effects were decreasing through time as the industry matured and efficiencies improved.

The 2026 California-based study by Freer-Smith, et al. reviewed available literature and concluded that the use of biodiesel is mostly seen as having a beneficial impact on criteria pollutant emissions relative to petroleum diesel use.¹⁶⁵ In addition, a recent dispersion modeling study has shown elevated pollutant concentrations near soybean biorefineries.¹⁶⁶

¹⁶² Freer-Smith, Peter, Jack H. Bailey-Bale, Caspar L. Donnison, and Gail Taylor. “The Good, the Bad, and the Future: Systematic Review Identifies Best Use of Biomass to Meet Air Quality and Climate Policies in California.” *GCB Bioenergy* 15, no. 11 (September 23, 2023): 1312–28. <https://doi.org/10.1111/gcbb.13101>.

¹⁶³ We do not include information on production impacts on air quality for BBD made from FOG in this section because FOG are considered byproducts or waste products of other processes that occur regardless of producing BBD from FOG.

¹⁶⁴ See RtC3 Chapter 8.5 “Comparison with Petroleum” for more details on results. The models run were the GREET model and BEIOM.

¹⁶⁵ Freer-Smith, Peter, Jack H. Bailey-Bale, Caspar L. Donnison, and Gail Taylor. “The Good, the Bad, and the Future: Systematic Review Identifies Best Use of Biomass to Meet Air Quality and Climate Policies in California.” *GCB Bioenergy* 15, no. 11 (September 23, 2023): 1312–28. <https://doi.org/10.1111/gcbb.13101>.

¹⁶⁶ Lee, Eun Kyung, Xiaobo Xue Romeiko, Wangjian Zhang, Beth J. Feingold, Haider A. Khwaja, Xuesong Zhang, and Shao Lin. “Residential Proximity to Biorefinery Sources of Air Pollution and Respiratory Diseases in New York State.” *Environmental Science & Technology* 55, no. 14 (July 7, 2021): 10035–45. <https://doi.org/10.1021/acs.est.1c00698>.

4.1.1.3 Renewable CNG/LNG

Renewable CNG and LNG, categorized as cellulosic biofuel in RFS, can be derived from biogas that is produced by the anaerobic digestion of biomass by natural organisms and collected and upgraded for use in CNG/LNG vehicles. We assume for the purposes of the RFS program that biogas produced at landfills, municipal wastewater treatment facilities, agricultural waste digesters, and separated municipal solid waste digesters would otherwise have been flared were it not productively used to produce transportation fuel.

The RtC3 notes that research on biofuel impacts on air quality has focused on corn ethanol and soy biodiesel more than on biofuels from other feedstocks. A 2023 review of studies on biomass use pathways determined that utilizing biogas recovered from the anaerobic digestions of municipal solid waste, water waste, animal waste, and food waste results in an overall reduction of criteria air pollutant emissions compared to allowing the waste to decompose in a landfill or by natural composting or decomposition.¹⁶⁷

4.1.2 Emission Impacts of Analyzed Volumes

We have evaluated air pollutant emissions impacts from biofuels determined to have an increase in production due to this rule. These fuels include corn ethanol, biodiesel, renewable diesel, and renewable CNG/LNG from biogas. Chapter 4.1.2.1 estimates emissions impacts associated with increased biofuel production, Chapter 4.1.2.2 discusses expected emissions impacts from the transport of additional biofuels, and Chapter 4.1.2.3 focuses on impacts on end-use or onroad emissions due to increases in the Analyzed Volumes.

As discussed in Preamble Section III.B, there are several baselines to which we can compare the Analyzed Volumes and determine the air quality impacts of this rule. The difference between the Analyzed Volumes and the No RFS Baseline was used to determine the emissions impacts presented here. Chapter 3 details the volume changes associated with this rule relative to the No RFS Baseline (Table 3.2-1 through Table 3.2-4). While using the No RFS Baseline is most appropriate in evaluating the total impact of this rule, the 2025 Baseline, representing the current RFS biofuels requirements, could be used to determine the emission impacts of this rule compared to current conditions. As shown in Tables 3.3-1 through 6, the Analyzed Volumes are lower than the 2025 Baseline volumes for several of the fuel categories.

4.1.2.1 Emissions from the Production of Biofuels

In this section, we estimate emissions associated with producing biofuels with an increase in production volumes, relative to a No RFS Baseline, due to this rule.¹⁶⁸ These biofuels include conventional corn ethanol (D6), BBD (D4), including biodiesel and renewable diesel, and renewable CNG and LNG derived from biogas (D3). We have not addressed production emissions from other categories of biofuels, including renewable diesel co-processed with

¹⁶⁷ Freer-Smith, Peter, Jack H. Bailey-Bale, Caspar L. Donnison, and Gail Taylor. "The Good, the Bad, and the Future: Systematic Review Identifies Best Use of Biomass to Meet Air Quality and Climate Policies in California." *GCB Bioenergy* 15, no. 11 (September 23, 2023): 1312–28. <https://doi.org/10.1111/gcbb.13101>.

¹⁶⁸ Biofuel volume production impacts relative to the No RFS Baseline are presented in Tables 3.2-1 through 4.

petroleum diesel (RFS Fuel Code D5, Other Advanced Biofuel). In this analysis, we are defining production emissions as those produced at the biorefinery and not including emissions upstream of the refining facility (for example, emissions associated with crop production or transport of the feedstock to the refinery). While much of the focus on emissions from the production of biofuels has been on criteria air pollutants, there are also emissions of hazardous air pollutants (HAPs) at biorefineries that can impact air quality.¹⁶⁹ We have estimated emissions of selected HAPs, or air toxics, from the production of biofuels where possible. The air toxics selected were those determined to be risk drivers in the 2020 AirToxScreen and that could reasonably be emitted during the refining of biofuel feedstocks.¹⁷⁰ This list includes 1,3-butadiene, acetaldehyde, acrolein, benzene, formaldehyde, and naphthalene.

There are several approaches, each with varying strengths and weaknesses, that could be used to estimate pollutant emissions from the production of biofuel. A global equilibrium model, such as the Global Change Analysis Model (GCAM), can account for interactions between various biofuels and petroleum fuels over a full lifecycle; however, the comprehensive, global nature of the model does not allow for the individual determination of emissions associated with incremental processes in the full life cycle of a biofuel.¹⁷¹ Another option for a quantitative evaluation of the emissions impact from the production of biofuels is to use Argonne National Laboratory's R&D GREET (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) model.¹⁷² The GREET model allows for the evaluation of production emissions from all biofuels impacted by this rule. However, only a limited number of criteria pollutant emission rates, and no HAP emission rates, are available from fuel production in GREET, and GREET cannot project market-mediated criteria air pollutant or HAP emissions impacts of changes to fuel pathways. Another approach is to evaluate annual biorefining facility emissions using EPA's Air Emissions Modeling Platform (EMP) as a function of the volume of fuel produced at each facility. The most recent version, the 2022 EMP, is based on the emissions in the 2020 National Emissions Inventory and contains both criteria air pollutant and HAP annual emissions reported by individual biorefining facilities to state and regional air agencies, EPA, and Federal Land Management agencies.¹⁷³ In this analysis, we chose to use the EMP as the preferred data source to determine biofuel production emissions.¹⁷⁴ However, as described

¹⁶⁹ Environmental Integrity Project, "Farm to Fumes: Hazardous Air Pollution from Biofuel Production," June 12, 2024. https://environmentalintegrity.org/wp-content/uploads/2024/06/EIP_Report_FarmtoFumes_06.12.2024.pdf.

¹⁷⁰ 2020 AirToxScreen Risk Drivers. <https://www.epa.gov/system/files/documents/2024-08/2020-airtoxscreen-risk-drivers.pdf>.

¹⁷¹ GCIMS, "GCAM: Global Change Analysis Model." <https://gcims.pnnl.gov/modeling/gcam-global-change-analysis-model>.

¹⁷² Wang, Michael, Cai, Hao, Ou, Longwen, Elgowainy, Amgad, Alam, Md Rakibul, Benavides, Pahola T., Benvenutti, Livia, Burnham, Andrew, Do, Thai N., Farhad, Masum, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Kwon, Hoyoung, Lee, Uisung, Lim, Juin Y., Liu, Xinyu, Lu, Zifeng, Morales, Michele, Ng, Clarence, Pandey, Ishan, Shukla, Siddharth, Siddique, Nazib, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhou, Jo. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2024 Excel)." Computer software. December 20, 2024. <https://doi.org/10.11578/GREET-Excel-2024/dc.20241203.1>.

¹⁷³ An emissions modeling platform is the full set of emissions inventories, other data files, software tools, and scripts that process the emissions into the form needed for air quality modeling. As discussed in Chapter 4.1.3, we did not perform air quality modeling for this rule.

¹⁷⁴ EPA, "2022v2 Emissions Modeling Platform." <https://www.epa.gov/air-emissions-modeling/2022v2-emissions-modeling-platform>.

below, facility process-level data is not available for all biofuels, namely renewable CNG/LNG from biogas, and we used GREET to determine production emissions of these fuels.¹⁷⁵

4.1.2.1.1 Corn Ethanol and Biomass-based Diesel

To estimate the emissions impacts of fuel production from the Analyzed Volumes for corn ethanol and BBD, RINs generated for corn ethanol, biodiesel, and renewable diesel were compared to reported air emissions at the facility level. The facility-level emissions rates were then used to determine a national emission factor for each pollutant and fuel type that could then be applied to the fuel volume differences between this rule and the No RFS Baseline. Emission factors were determined for the year 2022 as this was the most recent year that facility-level emissions were available at the time of this analysis.

Facilities that generated corn ethanol, biodiesel, and renewable diesel RINs in 2022 were identified through EMTS RIN generation records specifying the fuel type, number of RINs generated, and total volume of fuel produced.¹⁷⁶ These facilities were then matched to their reported 2022 emissions inventory in the 2022 Emission Modeling Platform (EMP) version 2.1 through the Emissions Information Systems (EIS).^{177,178,179}

As shown in Table 4.1.2.1.1-1, most ethanol biorefineries, but only some biodiesel and renewable diesel refineries, reported air emissions in 2022. For example, 175 of the 187 domestic ethanol biorefineries generating RINs in 2022 have reported air pollutant emissions available in the EMP, and these 175 ethanol facilities with reported emissions generated 97% of the total ethanol RINs in 2022. Facilities with reported emissions information were generally larger, with an average 85 million RINs generated in 2022 compared to an average of 33 million RINs for facilities that did not report emissions.

¹⁷⁵ The methodology for determining pollutant emission rates from biofuel production is discussed in “Determination of Air Pollutant Emissions Factors from the Production of Biofuels,” available in the docket for this action.

¹⁷⁶ EPA, “EMTS: RFS RIN Generation Report.” <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/emts-rfs-rin-generation-report>.

¹⁷⁷ EPA, “2022v2 Emissions Modeling Platform.” <https://www.epa.gov/air-emissions-modeling/2022v2-emissions-modeling-platform>.

¹⁷⁸ EPA, “Emissions Inventory System (EIS) Gateway.” <https://www.epa.gov/air-emissions-inventories/emissions-inventory-system-eis-gateway>.

¹⁷⁹ EPA, “Technical Support Document (TSD): Preparation of Emissions Inventories for the 2022v2 North American Emissions Modeling Platform,” EPA-454/B-25-002, December 2025. https://www.epa.gov/system/files/documents/2025-12/2022v2_emismod_tsd_base_december2025.pdf.

Table 4.1.2.1.1-1: Number of Domestic Biorefineries Producing Ethanol, Biodiesel, and Renewable Diesel in 2022 and the Percentage of RINs Generated at Facilities Reporting Pollutant Emissions to Federal, State, or Local Agencies

	Ethanol	Biodiesel	Renewable Diesel
Number of facilities generating RINs	187	57	9
Number of facilities with reported emissions	175	21	4
Percentage of RINs at facilities with reported emissions	97%	61%	78%

Using the 2022v2.1 EMP annual emissions mass and total RINs generated at each biorefinery, an emissions rate was determined for each pollutant at each facility. National weighted emissions factors were then calculated using each facility's emission rate and fraction of the total volume of fuel produced by category. The resulting national emissions factors are presented in Table 4.1.2.1.1-2. The weighting was determined separately for each pollutant based on available data. No biodiesel refining facilities reported emissions of 1,3-butadiene; therefore, a production emissions factor of 1,3-butadiene was unable to be determined from biodiesel production. As the equivalence value (EqV) of renewable diesel is adjusted to 1.6 RINs per gallon in 2027 from the previous equivalence value of 1.7 RINs per gallon, emission factors for renewable diesel with both a 1.7 EqV and a 1.6 EqV were determined and applied to the 2026 and 2027 renewable diesel volumes.

Table 4.1.2.1.1-2: Pollutant Emission Factors From Ethanol, Biodiesel, and Renewable Diesel Production (tons/million RINs)

Pollutant	Ethanol	Biodiesel	Renewable Diesel (1.7 EqV)	Renewable Diesel (1.6 EqV)
CO	0.84	0.40	0.39	0.42
NH ₃	0.08	0.01	0.01	0.01
NO _x	1.090	0.61	0.20	0.22
PM ₁₀	0.62	0.25	0.07	0.08
PM _{2.5}	0.50	0.16	0.07	0.08
SO ₂	0.92	1.94	0.06	0.06
VOC	1.37	2.69	0.61	0.64
1,3-Butadiene	0.00001	-	0.00001	0.00001
Acetaldehyde	0.06141	0.00187	0.00040	0.00043
Acrolein	0.01513	0.00002	0.00003	0.00003
Benzene	0.00112	0.00081	0.00676	0.00718
Formaldehyde	0.01033	0.00056	0.00363	0.00385
Naphthalene	0.00008	0.00001	0.00433	0.00460

The emission factors were then applied to the additional fuel volumes for ethanol, biodiesel, and renewable diesel estimated from the Analyzed Volumes as compared to the No RFS Baseline for 2026 and 2027. The emissions impacts resulting from the production of these additional biofuel volumes are presented in Tables 4.1.2.1.1-3 and Table 4.1.2.1.1-4.

Table 4.1.2.1.1-3: Emission Impact Estimates of CO, NH₃, NO_x, PM₁₀, PM_{2.5}, SO₂, and VOCs From the Production of Ethanol, Biodiesel, and Renewable Diesel for the Analyzed Volumes Relative to the No RFS Baseline

Year	Volume Difference to No RFS (million RINs)	Production Emissions (tons)						
		CO	NH ₃	NO _x	PM ₁₀	PM _{2.5}	SO ₂	VOC
Conventional (D6) Ethanol								
2026	231	193	19	252	143	115	212	315
2027	245	205	20	267	151	122	225	335
Biomass-Based Diesel (D4): Biodiesel								
2026	1,563	622	13	948	386	253	3037	4,209
2027	1,565	622	13	949	386	253	3041	4,214
Biomass-Based Diesel (D4): Renewable Diesel								
2026	4,507	1779	52	914	330	323	250	2,728
2027	5,000	2097	61	1077	389	380	294	3,215

Table 4.1.2.1.1-4: HAP Emissions Impact Estimates From the Production of Ethanol, Biodiesel, and Renewable Diesel for the Analyzed Volumes Relative to the No RFS Baseline

Year	Volume Difference to No RFS (million RINs)	Production Emissions (tons)					
		1,3-Butadiene	Acetaldehyde	Acrolein	Benzene	Formaldehyde	Naphthalene
Conventional (D6) Ethanol							
2026	212	0	14	3	0	2	0
2027	228	0	15	4	0	3	0
Biomass-Based Diesel (D4): Biodiesel							
2026	1,716	-	3	0	1	1	0
2027	1,752	-	3	0	1	1	0
Biomass-Based Diesel (D4): Renewable Diesel							
2026	3,823	0	2	0	29	16	19
2027	4,132	0	2	0	36	19	23

Note: An emissions estimate of zero indicates the production emissions to be less than 0.45 tons/year.

These emissions estimates assume the full additional fuel volume relative to the No RFS Baseline will be fulfilled by increasing biofuel production at domestic biorefineries. However, we note that some of this additional biofuel volume may be fulfilled both by reducing exports, whereby no changes in domestic biofuel production will occur, or by increasing imports, whereby emission impacts would occur abroad. As such, this analysis may overestimate

domestic emissions. For example, in 2022, approximately 0.1% of corn ethanol, 13% of biodiesel, and 21% of renewable diesel RINs were issued to importers or foreign producers.¹⁸⁰

4.1.2.1.2 Renewable CNG/LNG from Biogas

Renewable CNG/LNG is produced from biogas generated during the decomposition of organic waste products from several feedstock pathways under the RFS program. These feedstocks include gas produced at landfills and wastewater treatment facilities as well as animal waste and food waste decomposed through anaerobic digestion by natural organisms. Biogas collected from these feedstock sources can be purified and compressed or liquefied for use as transportation fuel.

As biogas is often produced at facilities like landfills or dairy farms that have a main purpose other than the production of renewable fuel, using facility-wide emission inventories as an estimate for fuel production emissions, as used with liquid renewable fuels, would be inappropriate. Consequently, to estimate emission impacts from the production of fuels from biogas, we have used emission factors determined in Argonne National Laboratory's R&D GREET (Greenhouse gases, Regulated Emissions, and Energy use in Technologies) 2024rev1 model for CO, NO_x, PM₁₀, PM_{2.5}, SO₂, and VOCs.¹⁸¹ Table 4.1.2.1.2-1 summarizes emissions resulting from the process steps of upgrading, purifying, and compressing or liquifying biogas to create transportation fuel as published in GREET. We have excluded emissions from process steps that would occur regardless of if the waste product would be used to produce renewable CNG/LNG or handled through typical disposal method (*e.g.*, onsite transport and anaerobic breakdown). Analogous to our analysis of emissions from the production of ethanol, biodiesel, and renewable diesel, we have also excluded emissions occurring upstream of the CNG or LNG production facility and those from transport and storage of the finished fuel.

¹⁸⁰ EPA, "RINs Generated Transactions." <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions>.

¹⁸¹ Wang, Michael, Cai, Hao, Ou, Longwen, Elgowainy, Amgad, Alam, Md Rakibul, Benavides, Pahola T., Benvenuti, Livia, Burnham, Andrew, Do, Thai N., Farhad, Masum, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Kwon, Hoyoung, Lee, Uisung, Lim, Juin Y., Liu, Xinyu, Lu, Zifeng, Morales, Michele, Ng, Clarence, Pandey, Ishan, Shukla, Siddharth, Siddique, Nazib, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhou, Jo. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2024 Excel)." Computer software. December 20, 2024. <https://doi.org/10.11578/GREET-Excel-2024/dc.20241203.1>.

Table 4.1.2.1.2-1: GREET Pollutant Emission Factors From the Production of Renewable CNG and LNG from Biogas by Various Feedstocks (g/mmBtu)

Pollutant	CNG				LNG		
	Landfill Gas	Wastewater Treatment	Animal Waste Digestion	Food Waste Digestion	Landfill Gas	Wastewater Treatment	Animal Waste Digestion
VOC	1.28	1.06	1.34	1.56	1.74	1.57	1.84
CO	4.51	3.75	4.73	10.11	6.13	5.54	6.52
NO _x	7.18	5.97	7.53	10.43	9.75	8.81	10.37
PM ₁₀	0.88	0.73	0.92	0.99	1.20	1.08	1.27
PM _{2.5}	0.50	0.42	0.52	0.50	0.68	0.61	0.72
SO ₂	4.54	3.77	4.76	4.01	6.16	5.57	6.55

While biogas CNG and LNG are considered a single fuel category in this rule, pollutant emission rates differ depending on the biogas feedstock and product. To determine emissions factors that can be applied nationally to future years, the ratio of RINs generated from biogas feedstock sources for the year 2024 was used to determine a weighted emissions factor to apply to 2026 and 2027. While we do not anticipate this rule would significantly alter the ratio of biogas feedstock sources or renewable CNG:LNG, external factors may influence the industry and affect these ratios.

The breakdown of biogas feedstock sources was determined using the 2024 RIN generation feedstock summary report and is presented in Tables 4.1.2.1.2-2 and 3.¹⁸² The feedstock summary report does not distinguish RINs generated at facilities producing biogas domestically from RINs generated for imported biogas CNG and LNG. Therefore, both imported and domestic RINs are used in determining the production emission factors for biogas. In 2024, less than 1% of renewable CNG generating RINs were imported. Approximately 46% of renewable LNG RINs were generated by importers, representing about 4% of the total CNG/LNG biogas RINs. Additionally, the feedstock summary report only specifies LNG RINs generated from biogas from landfills, agricultural digesters, and “All Other Feedstocks.” In this analysis, we have assumed biogas from wastewater treatment facilities as the feedstock for the entirety of the “All Other Feedstock” RINs.

Table 4.1.2.1.2-2: RINs Generated in 2024 From the Production of Renewable CNG From Biogas

Facility Type	million RINs	% of CNG RINs
Landfill	581	66%
Animal Waste Digester	274	31%
Wastewater Treatment or Food Waste Digester	25	3%
Total	881	

¹⁸² EPA, “RINs Generated Transactions.” <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions>.

Table 4.1.2.1.2-3: RINs Generated in 2024 From the Production of Renewable LNG From Biogas

Facility Type	million RINs	% of LNG RINs
Landfill	80	96%
Animal Waste Digester	3	4%
All Other Feedstock	0.04	0%
Total	83	

Applying the 2024 fractions of biogas RINs from feedstock and fuel types and, weighting by number of RINs produced from each pathway, total emissions rates for criteria air pollutants were determined for biogas production as shown in Table 4.1.2.1.2-4. Emission rates are presented as mass of pollutant per million RINs using the 77,000 Btu per RIN equivalence value for renewable CNG/LNG. Emissions impacts from the production of renewable CNG/LNG from biogas resulting from the difference between the Analyzed Volumes and the No RFS Baseline are presented in Table 4.1.2.1.2-5.

Table 4.1.2.1.2-4: Pollutant Emission Factors From Production of Biogas Renewable CNG and LNG

Pollutant	Weighted Emission Factors (g/mmBtu)			Biogas Production Emissions Factor (tons/million RIN)
	CNG	LNG	Total Biogas	
CO	4.57	6.15	4.70	0.399
NO _x	7.26	9.78	7.47	0.634
PM ₁₀	0.89	1.20	0.92	0.078
PM _{2.5}	0.50	0.68	0.52	0.044
SO ₂	4.58	6.18	4.72	0.401
VOC	1.29	1.74	1.33	0.113

Table 4.1.2.1.2-5: Pollutant Emission Impact Estimates From Production of Biogas Renewable CNG and LNG Relative to the No RFS Baseline

Year	Volume Difference to No RFS (million RINs)	Biogas CNG/LNG Production Emissions (tons)					
		CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	VOC
2026	799	319	507	62	35	320	90
2027	838	334	532	65	37	336	95

We also acknowledge that biogas is generated from landfill and wastewater treatment facility waste products, and the typical treatment of these waste products also results in pollutant emissions. Biogas generated at landfills and wastewater treatment plants is typically flared for safety and odor purposes, and these flares also generate emissions that are avoided when using the landfill gas or wastewater treatment gas to produce biofuel. The avoided flared emissions are not accounted for in this quantitative analysis and are a limitation of our estimates.

4.1.2.1.3 Comparison of Emissions from the Production of Renewable Fuels to Petroleum and Fossil Fuels

We compared the criteria air pollutant emission rates from the production of renewable fuels, as determined in Chapter 4.1.2.1.1 and 4.1.2.1.2, to fossil fuel production emission rates. While the production and use of renewable fuels may not actually reduce one-for-one the production and use of fossil fuels, for the purposes of this comparison, we have assumed such a one-for-one displacement. Emission rates from the production of petroleum and fossil fuels were determined with the GREET model using process steps analogous to the steps included in our estimates for renewable fuels.¹⁸³ As with renewable fuels, we did not estimate emissions from the transportation and storage of finished fuels. For direct comparison, production emission rates are presented as mass of pollutant per unit energy, as renewable fuels do not necessarily have the same energy density as their petroleum and fossil counterparts. Pollutant emission factors from fuel production are presented in Tables 4.1.2.1.3-1 and 2.¹⁸⁴

Emission rates from the production of petroleum gasoline were compared to those from production of ethanol, and emission rates from production of diesel were compared to those from production of biomass-based biodiesel and renewable diesel. Specifically, emission rates for gasoline blendstock (E0) production were used as a comparison to emission rates for ethanol production as GREET models gasoline containing 10% ethanol. Gasoline blendstock and petroleum diesel production emission rates included emissions that occur at the refinery, including intermediate product combustion, and facility non-combustion emissions. Feedstock emissions upstream of the petroleum refinery were not included.

To compare emission rates from the production of fossil natural gas to renewable CNG and LNG, we used emission rates which included the compression or liquefaction of natural gas along with pipeline transport of natural gas and upstream feedstock emissions. Emissions from feedstocks and transport for fossil natural gas were included while upstream emissions of biogas were not. This is consistent with our flaring baseline for biogas. For the purpose of determining pollutant emissions associated with renewable CNG/LNG production, we assume onsite fueling of renewable CNG/LNG at the location of production. Emissions associated with the transport and end use of renewable CNG/LNG are discussed in Section 4.1.2.2 and Section 4.1.2.3.3, respectively.

¹⁸³ Wang, Michael, Cai, Hao, Ou, Longwen, Elgowainy, Amgad, Alam, Md Rakibul, Benavides, Pahola T., Benvenuti, Livia, Burnham, Andrew, Do, Thai N., Farhad, Masum, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Kwon, Hoyoung, Lee, Uisung, Lim, Juin Y., Liu, Xinyu, Lu, Zifeng, Morales, Michele, Ng, Clarence, Pandey, Ishan, Shukla, Siddharth, Siddique, Nazib, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhou, Jo. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2024 Excel)." Computer software. December 20, 2024. <https://doi.org/10.11578/GREET-Excel-2024/dc.20241203.1>.

¹⁸⁴ The GREET model determines emission rates for only certain pollutants, limiting our analysis to those presented in this section.

Table 4.1.2.1.3-1: Comparison of Emission Rates From the Production of Corn Ethanol, Gasoline Blendstock, Biodiesel, Renewable Diesel, and Petroleum Diesel (g/mmBtu)

Pollutant	Corn Ethanol	Gasoline Blendstock (E0)	Biodiesel	Renewable Diesel	Petroleum Diesel
CO	9.93	2.38	4.52	4.95	1.52
NO _x	12.96	3.64	6.90	2.54	2.25
PM ₁₀	7.35	0.96	2.81	0.92	0.54
PM _{2.5}	5.92	0.84	1.84	0.90	0.47
SO ₂	10.93	1.23	22.10	0.70	0.78
VOC	16.23	2.21	30.63	7.59	1.65

Table 4.1.2.1.3-2: Comparison of Emission Rates From the Production of Renewable CNG/LNG and Fossil CNG/LNG (g/mmBtu)

Pollutant	Renewable CNG	Fossil CNG	Renewable LNG	Fossil LNG
CO	4.57	54.08	6.15	40.68
NO _x	7.26	63.18	9.78	45.29
PM ₁₀	0.89	0.69	1.20	0.76
PM _{2.5}	0.50	0.56	0.68	0.74
SO ₂	4.58	1.50	6.18	1.17
VOC	1.29	17.39	1.74	14.46

As seen in Table 4.1.2.1.3-1, emission rates from the production of ethanol are higher than gasoline, and, with the exception of SO₂ emissions from the production of renewable diesel, biodiesel and renewable diesel emissions are higher than petroleum diesel. Particulate emission rates, both PM₁₀ and PM_{2.5}, are comparable from the production of renewable CNG/LNG and fossil CNG/LNG, as shown in Table 4.1.2.1.3-2. There is a lower emission rate of SO₂ from the production of fossil LNG as compared to renewable LNG. However, emission rates of other criteria air pollutants are higher for fossil CNG/LNG than renewable CNG/LNG, primarily as a result of emissions from sourcing fossil natural gas.

Emission impacts presented in Table 4.1.2.1.1-3 and Table 4.1.2.1.2-5 represent emissions from the production of biofuels resulting from the difference in the fuel volumes of this rule and the No RFS baseline. However, a No RFS scenario could result in the increased production of petroleum or fossil fuels to meet transportation needs. To account for the potential reduction in fossil fuel production because of this rule, we determined a net emissions impact of the 2026 and 2027 biofuel volumes by subtracting the emissions generated from the production of equivalent energy volumes of fossil fuels from the emissions generated from producing the volume difference to the No RFS baseline of biofuels. The net emissions impact from the production of the Analyzed Volumes of biofuels are presented in Table 4.1.2.1.3-4.

Table 4.1.2.1.3-4: Net Emissions Impacts From the Production of Biofuels Relative to the No RFS Baseline for Analyzed Volumes Accounting for the Potential Reduction in Petroleum and Fossil Fuel Production

Year	Fuel	Volume Difference to No RFS (million RINs)	Volume Difference to No RFS (mmBtu)	Net Pollutant Emissions (tons)					
				CO	NO _x	PM ₁₀	PM _{2.5}	SO ₂	VOC
2026	Ethanol	231	17,632,230	147	181	124	99	189	273
	Biodiesel	1,563	124,648,208	412	639	311	189	2,930	3,982
	Renewable Diesel	4,334	313,289,564	1,184	103	130	148	-29	2,054
	Biogas CNG/LNG	799	61,523,000	-3,271	-3,674	15	-4	221	-1,072
2027	Ethanol	245	18,700,850	155	192	132	105	200	289
	Biodiesel	1,565	124,807,707	413	640	311	189	2,933	3,987
	Renewable Diesel	5,000	384,021,875	1,452	127	159	182	-36	2,518
	Biogas CNG/LNG	838	64,526,000	-3,430	-3,853	16	-4	231	-1,124

As seen in Tables 4.1.2.1.3-4, our analysis estimates the production of ethanol, biodiesel, and renewable diesel due to the Analyzed Volumes would result in additional emissions of CO, NO_x, PM₁₀, PM_{2.5}, and VOCs even with accounting for the potential reduction in petroleum fuel production emissions. The production of ethanol and biodiesel contributes to additional SO₂ emissions compared to a No RFS Baseline; however, the production of renewable diesel volumes decreases emissions of SO₂ if petroleum-based diesel production is reduced by an equivalent amount. We also estimate the Analyzed Volumes of renewable CNG/LNG would reduce emissions of CO, NO_x, PM_{2.5}, and VOCs if the production of fossil CNG/LNG were to be reduced by the same volume, but additional SO₂ and PM₁₀ emissions would occur.

4.1.2.2 Emissions from the Transport of Biofuels

Emissions are also associated with the transport of biofuels from the production facility to the user. This includes emissions occurring from the storage of finished fuel, leakage during fueling or transport, and combustion emissions from the distribution mode of transport (*e.g.*, road, rail). With biodiesel, renewable diesel, and renewable CNG/LNG from biogas, transport-related emissions are expected to be comparable to those from the transport of petroleum or fossil fuels.

Because ethanol is blended with gasoline before it can be used as a transportation fuel, there are emissions due to the additional transport and storage for blending that would not exist for a single product fuel. At the blending terminal, ethanol and gasoline are combined for various fuel combinations (*e.g.*, E10, E15, E85) prior to distribution to retail gasoline outlets where it is sold to the customer. Primary modes of distributing ethanol to the blending terminal and the blended fuel to the retail outlets are rail, road, or barges. Previous modeled emissions from the transportation and storage of ethanol found the largest emission impact was to VOCs due to evaporation.¹⁸⁵ However, as the volume difference to the No RFS baseline for conventional corn

¹⁸⁵ EPA, "RFS Program: Standards for 2023–2025 and Other Changes – Regulatory Impact Analysis," EPA-420-R-23-015. Chapter 4.1.1.

ethanol is a small fraction (less than 2%) of the 2026–2027 volumes, emissions due to the transport of ethanol as a result of these volumes are considered to be minimal.

4.1.2.3 Emissions from the End Use of Biofuels

End-use emissions are generated when biofuels are used in vehicles. This includes tailpipe exhaust emissions from the combustion of the fuels, non-tailpipe exhaust emissions (such as crankcase exhaust), and evaporative emissions from fuel dispensing, leakage, permeation, and venting. As biofuels may differ in chemical composition from fossil fuels, end-use emissions from these fuels may also differ.

4.1.2.3.1 Ethanol

Impacts of ethanol blends on vehicle exhaust emissions are the result of complex interactions between fuel properties, vehicle technologies, and emission control systems. Depending on the pollutant and blend concentration, the impacts vary both in direction and magnitude. Several test programs in recent years have evaluated the impacts of fuel properties, including those of ethanol blends on emissions from vehicles meeting Tier 2 and Tier 3 standards.^{186,187,188,189,190,191} However, as E10 gasoline is economical to blend in the absence of the RFS program after 2020, the only volumes of ethanol expected to result from this rule are relatively small increases in ethanol used as E15 and E85. These small increases in E15 and E85 use are not expected to have a significant impact on overall vehicle evaporative and exhaust emissions.

4.1.2.3.2 Biodiesel

Biodiesel consists of straight-chain molecules that boil in the diesel range and typically contain at least one double bond as well as oxygen incorporated into a methyl ester group. These chemical features can cause differences in emissions relative to petroleum diesel, primarily when used in older engines. EPA's MOVES model estimates criteria pollutant emission impacts for

¹⁸⁶ EPA, "Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards: Analysis of Data from EPA Act Phase 3 (EPA Act/V2/E-89)," EPA-420-R-13-002. <https://nepis.epa.gov/Exe/ZyPDF.cgi/P100GA0V.PDF?Dockey=P100GA0V.PDF>.

¹⁸⁷ EPA, "EPA Act/V2/E-89: Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards – Final Report on Program Design and Data Collection," EPA-420-R-13-004, April 2013. <https://nepis.epa.gov/Exe/ZyPDF.cgi/P100GA80.PDF?Dockey=P100GA80.PDF>.

¹⁸⁸ Morgan, Peter, Peter Lobato, Vinay Premnath, Svitlana Kroll, Kevin Brunner, and Robert Crawford. "Impacts of Splash-Blending on Particulate Emissions for SIDI Engines." *Coordinating Research Council Report*, June 26, 2018. https://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC-E-94-3_Final-Report_2018-06-26.pdf.

¹⁸⁹ Morgan, Peter, Ian Smith, Vinay Premnath, Svitlana Kroll, and Robert Crawford. "Evaluation and Investigation of Fuel Effects on Gaseous and Particulate Emissions on SIDI in-Use Vehicles." *Coordinating Research Council Report*, March 2017. https://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC_2017-3-21_03-20955_E94-2FinalReport-Rev1b.pdf.

¹⁹⁰ Karavalakis, Georgios, Thomas Durbin, Tianbo Tang. "Comparison of Exhaust Emissions Between E10 CaRFG and Splash Blended E15." June 2022. https://ww2.arb.ca.gov/sites/default/files/2022-07/E15_Final_Report_7-14-22_0.pdf.

¹⁹¹ EPA, "Exhaust Emission Impacts of Replacing Heavy Aromatic Hydrocarbons in Gasoline with Alternate Octane Sources," EPA-420-R-23-008, April 2023. <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017FPA.pdf>.

pre-2007 engines based on data generated for B20 (20 vol%) blends of soybean-based biodiesel in petroleum diesel and the percent change in emissions of total hydrocarbons, CO, NO_x, and PM_{2.5} are shown in Table 4.1.2.3.2-1.¹⁹² The biodiesel effects implemented in MOVES were obtained from an analysis conducted as part of the 2010 RFS2 Rule.¹⁹³ Studies of engines equipped with particulate filter and selective catalytic reduction aftertreatment systems that became widespread in 2007 and later models had shown no effect of B20 blends on emissions.

Table 4.1.2.3.2-1: Emission Impacts on Pre-2007 Heavy-Duty Diesel Engines for All Cycles Tested on 20 Vol% Soybean-Based Biodiesel Fuel Relative to an Average Base Petroleum Diesel Fuel

Pollutant	Percent Change in Emissions
THC (Total Hydrocarbons)	-14.1
CO	-13.8
NO _x	+2.2
PM _{2.5}	-15.6

4.1.2.3.3 Renewable Diesel

Renewable diesel is made by hydrotreating vegetable oils or other fats or greases to remove oxygen and unsaturated bonds leaving a primarily paraffinic fuel. As a result, renewable diesel has a higher cetane index and lower aromatics and sulfur content in comparison to petroleum diesel fuel. Studies indicate no impact, or in some cases reductions, of regulated pollutant and toxic emissions from vehicles operating on renewable diesel as compared to petroleum diesel.^{194,195,196,197,198} Therefore, we do not expect an increase in air pollutant emissions from the end use of renewable diesel from this rule.

¹⁹² EPA, “Fuel Effects on Exhaust Emissions from Onroad Vehicles in MOVES3,” EPA-420-R-20-016, November 2020.

¹⁹³ EPA, “Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis,” EPA-420-R-10-006, February 2010, Appendix A.

¹⁹⁴ Karavalakis, Georgios, Kent Johnson, and Thomas D. Durbin. “Combustion and Engine-Out Emissions Characteristics of a Light Duty Vehicle Operating on a Hydrogenated Vegetable Oil Renewable Diesel.” *Coordinating Research Council Report*. July 2022. <https://crcao.org/wp-content/uploads/2022/07/CRC-E-117-2022-Revised-CRC-Final-Report.pdf>.

¹⁹⁵ Coordinating Research Council, “Biodiesel and Renewable Diesel Characterization and Testing in Modern LD Diesel Passenger Cars and Trucks,” Project CRC AVFL-17b, November 2014.

¹⁹⁶ Na, Kwangsam, Subhasis Biswas, William Robertson, Keshav Sahay, Robert Okamoto, Alexander Mitchell, and Sharon Lemieux. “Impact of Biodiesel and Renewable Diesel on Emissions of Regulated Pollutants and Greenhouse Gases on a 2000 Heavy Duty Diesel Truck.” *Atmospheric Environment* 107 (February 24, 2015): 307–14. <https://doi.org/10.1016/j.atmosenv.2015.02.054>.

¹⁹⁷ Singh, Devendra, K.A. Subramanian, and Mo Garg. “Comprehensive Review of Combustion, Performance and Emissions Characteristics of a Compression Ignition Engine Fueled With Hydroprocessed Renewable Diesel.” *Renewable and Sustainable Energy Reviews* 81 (July 3, 2017): 2947–54. <https://doi.org/10.1016/j.rser.2017.06.104>.

¹⁹⁸ California EPA, “Staff Report – Multimedia Evaluation of Renewable Diesel,” May 2015. https://ww2.arb.ca.gov/sites/default/files/2018-08/Renewable_Diesel_Multimedia_Evaluation_5-21-15.pdf.

4.1.2.3.4 Renewable CNG/LNG

Renewable CNG and LNG are predominantly methane and are not distinct chemically from fossil CNG and LNG. Therefore, end use emissions of renewable CNG/LNG fuels are expected to be no different from vehicles using fossil CNG/LNG.

4.1.3 Air Quality Impacts of Analyzed Volumes

The geographic distribution of emissions impacts due to the Analyzed Volumes varies depending on the feedstock and the process step, and the overall impact on air quality is a complex issue. At each step in the production, distribution, and end use stages, there are changes to the location, amount, and composition of emissions. Full-scale photochemical air quality modeling would be necessary to accurately project impacts on concentrations of various criteria and air toxic pollutants across the country. However, photochemical air quality modeling is time and resource intensive and as such requires knowledge of the volume requirements early in the analytical process. Additionally, the spatial resolution of the air quality modeling data (12km by 12km grid cells) is not sufficient to capture very local impacts from production or the pollution concentration gradients near roads and other transport routes. For these reasons we use the emission impacts discussed above, rather than conducting photochemical modeling, to draw broad conclusions regarding the likely air quality impacts associated with the Analyzed Volumes as compared to the No RFS Baseline.

Comparing the Analyzed Volumes to the No RFS Baseline, we would expect some localized increases in some air pollutant concentrations, particularly at locations near production and transport routes. Production emissions from processing biofuel feedstocks would vary by pollutant, location, and magnitude. However, we would expect increases in emissions at biofuel production facilities due to the Analyzed Volumes, and these increases in emissions could impact local air quality. The location of emissions from biofuel production tends to be in more rural areas. Simultaneously, the production of petroleum fuels could decrease due to increased volumes of biofuels, but it could also stay the same with exports increasing or imports decreasing.¹⁹⁹ The location, composition, and magnitude of emissions from storage and transport of fuel would also be impacted as additional biofuels are stored and transported; the storage and transport of petroleum fuels could also change (*e.g.*, transport to shipping terminals rather than gas stations). We would also expect varying impacts on end use emissions from vehicles running on fuels containing biofuel. We would expect emission increases for some pollutants and emission decreases for other pollutants from vehicles running on fuel with biodiesel or corn ethanol and negligible impacts from vehicles running on fuel with renewable diesel or renewable CNG/LNG. Overall, we expect the emission impacts from the Analyzed Volumes to be variable in how they affect ambient concentrations of ozone and PM_{2.5} in specific locations across the U.S.

In addition to drawing conclusions based on the projected emission changes from the Analyzed Volumes, we can look at life-cycle and air quality modeling analyses included in other renewable fuels assessments like the RtC3, the RFS2 rule, and the ABS. The per gallon results of

¹⁹⁹ Further discussion on the potential impacts of the Analyzed Volumes on the production of petroleum fuels can be found in Chapter 6.4.1.

the lifecycle analysis (LCA) modeling included in the RtC3 indicate that we would expect that increased volumes of biofuels would lead to increased criteria air pollutant emissions and air quality impacts.²⁰⁰ However, as the biofuels industry continues to mature, and if efficiencies improve with industry maturity, those increases are likely to become smaller. We can also compare the changes in volumes and emissions for increased volumes of corn ethanol to the RFS2 air quality modeling analysis, and we would expect the impacts of the corn ethanol volumes on air quality to be relatively minor compared to RFS2, with any significant impacts likely to be localized in rural areas. RFS2 included a smaller impact on BBD than what is being finalized in this rule. In addition to RFS2 comparisons, we can also compare the changes in volume and emissions for increased end use emissions of vehicles running on fuel with corn ethanol and biodiesel to the ABS. The ABS only considered impacts of the RFS program on end use emissions and overall, found relatively little change in PM_{2.5} concentrations and increases and decreases in ozone concentrations depending on the location.

4.2 Conversion of Natural Lands

Regarding the conversion of wetlands and other natural lands to agriculture to meet demand for biofuel, EPA has explored this topic extensively in the Biofuels and the Environment: Reports to Congress, including the First Triennial Report to Congress (RtC1),²⁰¹ the Second Triennial Report to Congress (RtC2),²⁰² and the more recent RtC3. The RtC1 and RtC2 assessed how biofuels broadly may be increasing cropland and driving conversion of natural lands (*e.g.*, wetlands, forests, grasslands) for feedstock production. In January 2025, EPA finalized and published the RtC3. The RtC3 builds on the previous two reports and includes new analyses to estimate the separable effects of the RFS program from the impacts of biofuels generally.

In the Set 1 Rule RIA and Biological Evaluation (BE),²⁰³ EPA further assessed how the Set 1 Rule for years 2023–2025 may increase cropland. The Set 1 Rule BE was completed in accordance with the Endangered Species Act (ESA) Section 7 consultation process to ensure that the rule is not likely to jeopardize the continued existence of any endangered or threatened species or result in the destruction or adverse modification of designated critical habitat for such species. EPA has developed another BE to assess the same from potential effects of this Set 2 Rule.²⁰⁴

In this chapter, we first summarize the historical data and information contributing to our current understanding of natural land conversion effects from agriculture and biofuels, as well as our understanding of potential effects from past RFS volumes specifically (Chapter 4.2.1). Because the Set 1 Rule RIA, finalized in 2023, included a literature review of articles examining conversion of wetlands and other lands, we also reviewed and discuss new literature that has

²⁰⁰ EPA, “Biofuels and the Environment: Third Triennial Report to Congress,” EPA/600/R-24/343F, January 2025. Chapter 8.5

²⁰¹ EPA, “Biofuels and the Environment: First Triennial Report to Congress,” EPA/600/R-10/183F, December 2011.

²⁰² EPA, “Biofuels and the Environment: Second Triennial Report to Congress,” EPA/600/R-18/195F, June 2018.

²⁰³ EPA, “Biological Evaluation of the Renewable Fuel Standard Set Rule and Addendum,” EPA-420-R-23-029, May 2023 (“Set 1 Rule BE”).

²⁰⁴ See “Biological Evaluation of the Renewable Fuel Standard (RFS) Set 2 Rule and EPA’s Effects Determination” (“Set 2 Rule BE”), available in the docket for this action.

come out in recent years related to this topic (Chapter 4.2.2). The last subsection explores the potential natural land conversion impacts from this rule (Chapter 4.2.3). Related findings from the Set 2 Rule BE, since it applies to the Set 2 Rule, are discussed in Chapter 4.2.3.

4.2.1 Natural Land Conversion Effects

The aforementioned reports and documents (*e.g.*, Biofuels and the Environment: Reports to Congress) have greatly contributed to EPA’s understanding of how agriculture, biofuel production and consumption, and past RFS renewable volume obligations influenced the conversion of natural lands. The findings and conclusions from these documents relied heavily on studies from the peer reviewed literature as well as additional analyses completed by EPA. A summary of findings and EPA’s understanding in these areas are explained in this subsection.

The conversion of natural lands (*e.g.*, wetlands, grasslands, forests) is associated with biofuel production and consumption through the growth of crop-based feedstocks, rather than through the production of waste fats, oils and greases, or biogas. Corn and soybeans are the dominant crops used for biofuel feedstock used for biofuel production, followed by canola. As such, the production of these three feedstock crops is the main concern when it comes to conversion of natural lands.²⁰⁵

The RtC3 discusses historical trends from several federal land cover datasets. Data from the USDA National Resource Inventory (NRI), Cropland Data Layer (CDL), and Census of Agriculture support a finding that from 2007 to 2017 there has been a 10 million-acre increase in cultivated cropland.²⁰⁶ The report found that more than half of the corn and soybean increase in this time period came from other cultivated cropland (56%). Additionally, the 10 million-acre increase in cultivated cropland from 2007 to 2017 coincided with a 15 million-acre decline in perennially managed land, including Conservation Reserve Program (CRP) lands, pasture, and noncultivated cropland.

Findings from a study by Lark et al. (2015)²⁰⁷ showed that, from 2008 to 2012, grasslands were the source for 77% of all new croplands. The category of “grasslands” in this study included both native and planted grasslands, as well as those that may have been cultivated for pasture or hay. The study authors found that just over a quarter of these grasslands, or 22% of all lands converted, qualified as long-term grasslands. Further, they found that shrubland and long-term idle lands each accounted for 8% of all new croplands. In contrast, 3% of lands converted to agriculture came from forested areas and 2% came from wetlands.

²⁰⁵ Though it should be highlighted that to the extent the use of FOG for biofuel production comes from shifting the uses of those feedstocks from other uses, they may then be backfilled with crop-based feedstocks, resulting in the very same concerns with respect to conversion of natural lands.

²⁰⁶ Despite the observed increase in cropland from 2007–2017, cultivated cropland for this period was still below historic levels. Further, the latest Census of Agriculture data suggests that harvested cropland has declined since 2017, from about 320 million acres in 2017 to 301 million acres in 2022. Though, it is important to note that this was likely affected by a drought in the Midwestern U.S. in 2022, and, since that drought, planted and harvested acres have recovered.

²⁰⁷ Lark, Tyler J, J Meghan Salmon, and Holly K Gibbs. “Cropland Expansion Outpaces Agricultural and Biofuel Policies in the United States.” *Environmental Research Letters* 10, no. 4 (April 1, 2015): 044003. <https://doi.org/10.1088/1748-9326/10/4/044003>.

Similarly, Lark et al. (2020)²⁰⁸ found that 88% of new croplands were sourced from grasslands when looking at a longer timeframe, from 2008–2016. A total of 2.8 million acres, or 28%, of new cropland cultivated over this period originated from longstanding habitat sites, of which a majority (2.3 million acres) were long-term grasslands. They found that, relative to all land converted to new cropland over this period, 26% of converted grasslands, 29% of converted wetlands, 44% of converted forest, and 52% of converted shrublands were previously categorized as long-term sites.

The studies referenced above examined historical land use changes and natural land conversion patterns that can be attributed to various causes. Demand for renewable fuel and production of crop-based feedstocks are only two of the many potential causes for these observed land use changes. Regarding the potential natural land conversion effects from the RFS program alone, it is also important to note that there are many factors, including economic and policy drivers at local, state, nation, and global scales, that influence renewable fuel production and consumption in the U.S. For example, biodiesel tax policy in the U.S. has had a significant impact on the volume of biodiesel and renewable diesel used in the U.S. historically, as discussed in more detail in Chapter 7. The RFS program is only one factor that influences renewable fuel use and consumption, and it is challenging to separate out the effects of the RFS program from other factors. Despite the challenges, EPA has worked in recent years to evaluate the potential effects of the RFS program alone. We summarize what EPA has previously evaluated for past RFS volumes in the text immediately below. A discussion on the potential effects of this rule is included in Chapter 4.2.3.

EPA’s analyses conducted in past years, separate from this rule, demonstrate that the RFS program has played a larger role in production and consumption of biodiesel and renewable diesel compared to corn ethanol. For example, the RtC3 completed an attribution analysis for corn ethanol and estimated that 0–9% of corn ethanol production and consumption is likely attributable to the RFS program historically from 2006–2019. In contrast, 36% of biodiesel production was found to be attributable to the RFS program from 2002–2020 based on a study that used the Bioenergy Scenario Model.²⁰⁹ Another study which used a multi-period, partial equilibrium economic model (BEPAM) found that land use change intensity of biodiesel ranged from 0.78–1.5 million acres per billion gallons in 2018; in comparison, the values for corn ethanol ranged from 0.57–0.75 million acres per billion gallons over the same period.²¹⁰ Given these findings, potential land use changes from the RFS program in past years would likely have been greater for soybean production for biodiesel and renewable diesel, relative to corn production for corn ethanol.

²⁰⁸ Lark, Tyler J., Seth A. Spawn, Matthew Bougie, and Holly K. Gibbs. “Cropland Expansion in the United States Produces Marginal Yields at High Costs to Wildlife.” *Nature Communications* 11, no. 1 (September 9, 2020). <https://doi.org/10.1038/s41467-020-18045-z>.

²⁰⁹ Miller, Jesse, Christopher Clark, Steve Peterson, and Emily Newes. “Estimated Attribution of the RFS Program on Soybean Biodiesel in the U.S. Using the Bioenergy Scenario Model.” *Energy Policy* 192 (July 3, 2024): 114250. <https://doi.org/10.1016/j.enpol.2024.114250>.

²¹⁰ Wang, Weiwei, and Madhu Khanna. “Land Use Effects of Biofuel Production in the US.” *Environmental Research Communications* 5, no. 5 (May 1, 2023): 055007. <https://doi.org/10.1088/2515-7620/acd1d7>.

Because grasslands, pasturelands, CRP lands, idle lands, and noncultivated cropland have been most impacted by agricultural expansion historically, any land conversion due to the RFS program likely affected these land types to a greater extent (*i.e.*, more acres of conversion) relative to wetlands and forests. Still, some effects of past RFS volumes on wetland and forest conversion may have occurred. An analysis in the RtC3, for example, estimated that nearly 275,000 acres of wetlands concentrated in the Prairie Pothole Region were lost from 2008–2016. However, the report recognized that only a percentage of this (0–20%) may be attributable to the RFS program.

In addition, the Set 1 Rule RIA and BE discussed the potential for an associated increase in crop production from the 2023–2025 Set 1 Rule alone. In the Set 1 Rule BE, EPA’s analyses estimated that the Set 1 Rule could potentially lead to an increase of as much as 2.65 million acres of cropland by 2025, approximately 1% of the projected U.S. acreage for major field crops in 2025. Related to this finding, it is important to note the following:

- The estimated 2.65 million acres of cropland increase from the Set 1 Rule represents the maximum potential impact based on a number of assumptions, many of which were very conservative in nature, that EPA made in the BE.
- Additional analyses supporting the BE suggested that the demand for biodiesel and renewable diesel from the Set 1 Rule could be met fully by changes to imports/exports or by projected increases in feedstock yields on existing soybean lands, highlighting the uncertainty in knowing the exact impacts from the Set 1 Rule.

Out of the estimated 2.65 million acres, a maximum potential acreage impact of 1.93 million acres by 2025 (or 1.57 and 1.78 million acres by 2023 and 2024, respectively) was estimated to come from soybean biodiesel volume increases in the Set 1 Rule. In addition, a maximum potential acreage impact of 0.26 million acres by 2025 was estimated to come from canola biodiesel. Since 2023–2025 have come to pass, we can look at BBD supply data from those years to infer what may have actually happened. For example, as explained in Chapter 7, through 2021 biodiesel imports from the EU had never exceeded 100 million gallons in any single year. Biodiesel imports from the EU increased to approximately 114 million gallons in 2022 and then quite dramatically to approximately 320 million gallons in 2023. In these same years, imports of feedstocks used by domestic biodiesel and renewable diesel producers, such as tallow from Brazil and used cooking oil from China, increased significantly. This dynamic shifted again in 2025 due to trade policy in the US and other countries, leading to a significant decrease in the availability of imported Chinese used cooking oil, though this was partially offset by an increase in tallow imports from Latin America. Given these changes in BBD imports, it is possible that minimal to no land use impacts occurred, especially for those years that saw greater imports of FOG and biodiesel.

Moreover, EPA acknowledges that, for any effects that may have occurred from the RFS program, it is currently not possible to project the precise locations of agricultural expansion with confidence due to the vast quantity of potential cropland in the U.S. and the multitude of factors that contribute to an individual farmer’s decision whether to bring additional land into crop production. For natural lands that were converted to agriculture in past years, it is also not possible to say which parcels of land were converted due to the RFS program alone. To date,

EPA has advanced our knowledge of the land use impacts from the RFS program at a national scale but understanding the impacts at the local level remains a challenge. In fact, with the currently available science, the finest level possible for understanding the effect of biofuel production on cropland is at the county scale, though such analyses for the Set 1 Rule rendered limited information.²¹¹ We are unaware of any published literature or efforts that have estimated impacts at smaller scales, such as the field or 30-meter scale.

4.2.2 New Literature on the Conversion of Natural Lands

The above subsection summarizes information known by EPA from previous work completed, including the Biofuels and the Environment: Reports to Congress and Set 1 Rule BE. To keep abreast of the latest science, EPA also completed a literature review of research of articles and other federal agency assessments published in recent years.

In conducting this literature review, EPA did not find any articles or publications examining the potential impacts of the RFS program alone on conversion of natural lands. Nonetheless, other publications, such as the 2024 Status and Trends of Wetlands in the Conterminous United States Report to Congress by the U.S. Fish and Wildlife Service (FWS),²¹² provide insights into how agriculture impacted wetland ecosystems from 2009–2019. The report shows that agricultural activities have been a significant cause of wetland loss. From 2009–2019, the U.S. experienced a net loss of 221,000 acres of wetlands. Of this total, the report states that “[c]onversion to upland categories (agriculture, urban, forested plantation, rural development, other upland) was the dominant driver of net wetland loss,” contributing to a total loss of 194,000 wetland acres.

The report also explains that vegetated wetlands, and freshwater vegetated wetlands in particular, were especially impacted. These wetlands are important for controlling floods, improving water quality, and storing carbon. According to the report, the largest driver of all freshwater wetland net loss was an increase in upland forested plantations, followed by increases in upland agriculture.

In addition, the Status and Trends of Wetlands in the Conterminous United States report from FWS highlights that net wetland loss has accelerated by more than 50% compared to the previous study period (2004–2009), continuing a long-term pattern of wetland degradation. This ongoing loss has reduced wetlands' ability to provide critical ecosystem services such as flood control. The report also emphasizes that agriculture not only replaces wetlands, but also “reduces wetland pollutant removal services, and increases pollutant inputs in the form of fertilizer, waste, sediment, and toxins.”

²¹¹ In the Set 1 Rule, county-level estimates would have been possible by leveraging an econometric analysis for corn ethanol effects due to proximity to ethanol facilities, specifically, as opposed to corn ethanol crop price effects. However, the proximity to ethanol facility effects were estimated to be zero for total cropland in the Set 1 Rule BE, so EPA was not able to accomplish county-level estimates for this. See Li et al. (2019) and updated analyses by Madhu Khanna as described in the Set 1 Rule BE for more information.

²¹² U.S. Fish & Wildlife Services, “Status and Trends of Wetlands in the Conterminous United States 2009 to 2019,” 2024. https://www.fws.gov/sites/default/files/documents/2024-04/wetlands-status-and-trends-report-2009-to-2019_0.pdf.

Another study by Guptaa (2024)²¹³ highlights the concerning rate of green cover loss worldwide, with a specific focus on wetlands, forests, and grasslands impacted by agricultural expansion and biofuel production. The study details that agricultural expansion remains a primary driver of green cover depletion, particularly for crops like soybeans and oil palm, which replace diverse ecosystems with monocultures, “severely affecting biodiversity and carbon storage.” The report adds that wetland areas in the Mississippi River Delta have been significantly impacted, as human activities such as “levee construction and oil extraction” compound climate-driven stressors like sea-level rise, leading to further degradation of these ecosystems.

Findings from other studies uphold our understanding that cropland expansion in the U.S. has historically come from conversion of forest, shrubland, and grassland and that agriculture continues to be an ongoing threat to grasslands.^{214,215} Bedrosian et al. (2024)²¹⁶ further highlight the risk of conversion of the sagebrush biome (e.g., in the Northern Great Plains), and the importance of land conservation efforts to protect these vulnerable ecosystems. As stated above, EPA found no studies or publications linking the effects of the RFS specifically to conversion of natural lands such as grasslands and wetlands.

4.2.3 Potential Natural Land Conversion Impacts

A first step to understanding the potential natural land conversion impacts from this rule is looking at the volume changes expected from this rule relative to the No RFS and 2025 Baselines. The projected BBD and conventional renewable fuel volume changes for the Analyzed Volumes are shown in Tables 4.2-1 and 2. More detailed information can be found in Chapter 3.

Table 4.2-1: Total BBD Renewable Fuel Volume Changes Relative to the No RFS Baseline and 2025 Baseline (million gallons)

	2026	2027
Relative to the No RFS Baseline	3,597	4,175
Relative to the 2025 Baseline	2,340	2,711

²¹³ Guptaa, Rakshan. “Green Cover Depletion and Its Projection Over the Upcoming Years.” *Darpan International Research Analysis* 12, no. 2 (May 23, 2024): 76–87. <https://doi.org/10.36676/dira.v12.i2.06>.

²¹⁴ Li, Xiaoyong, Hanqin Tian, Chaoqun Lu, and Shufen Pan. “Four-century History of Land Transformation by Humans in the United States (1630–2020): Annual and 1 Km Grid Data for the HIStory of LAND Changes (HISLAND-US).” *Earth System Science Data* 15, no. 2 (March 3, 2023): 1005–35. <https://doi.org/10.5194/essd-15-1005-2023>.

²¹⁵ Douglas, David J. T., Jessica Waldinger, Zoya Buckmire, Kathryn Gibb, Juan P. Medina, Lee Sutcliffe, Christa Beckmann, et al. “A Global Review Identifies Agriculture as the Main Threat to Declining Grassland Birds.” *Ibis* 165, no. 4 (May 9, 2023): 1107–28. <https://doi.org/10.1111/ibi.13223>.

²¹⁶ Bedrosian, Geoffrey, Kevin E. Doherty, Brian H. Martin, David M. Theobald, Scott L. Morford, Joseph T. Smith, Alexander V. Kumar, et al. “Modeling Cropland Conversion Risk to Scale-Up Averted Loss of Core Sagebrush Rangelands.” *Rangeland Ecology & Management* 97 (October 15, 2024): 73–83. <https://doi.org/10.1016/j.rama.2024.08.011>.

Table 4.2-2: Conventional Renewable Fuel Volume Changes Relative to the No RFS Baseline and 2025 Baseline (million gallons)

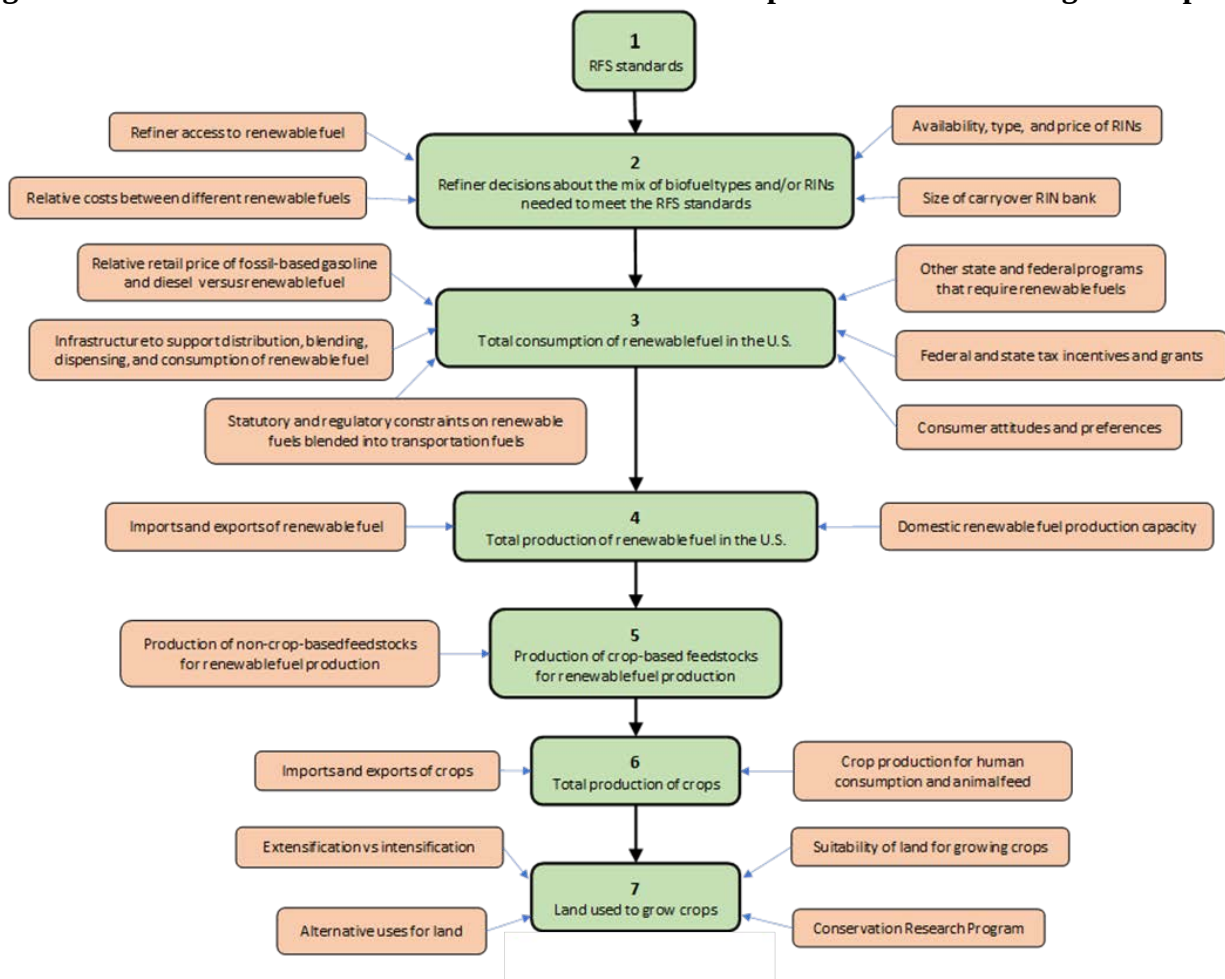
	2026	2027
Relative to the No RFS Baseline	231	245
Relative to the 2025 Baseline	87	20

Based on the values in Table 4.2-1, we would expect increases in BBD volumes attributable to this rule. BBD volumes could be met through a variety of ways, for example by increased imports of FOG or diversions from other feedstock uses. But it could also potentially be met, at least in part, through an increase in land conversion for agricultural lands to produce more feedstock (specifically soybeans and, to a lesser extent, canola) to meet extra BBD volume demand generated by this rule. Such an increase in land conversion for agricultural lands, were it to occur, could contribute to further loss of natural lands such as grasslands, wetlands, and forests.

The conventional renewable fuel projected volumes relative to the No RFS and 2025 Baselines tell a slightly different story (Table 4.2-2). The numbers suggest we would also see an increase in conventional volumes from this rule, albeit to a much smaller degree compared to BBD volumes.

For any conclusions drawn regarding the potential natural land conversion effects from this rule (*e.g.*, from increased BBD volumes), it is important to note the significant assumptions and high uncertainty inherent in estimating acreage impact numbers at every step in the underlying causal relationship between the RFS standards and the land use effects that could result from increased production of crop-based feedstocks (Figure 4.2-1). For example, projecting the impact of increased biofuel demand on crop-based feedstock production is complicated by the fact that the majority of feedstocks are used in non-biofuel markets as well.

Figure 4.2-1. Causal chain between RFS standards and impacts on land used to grow crops



Of note is the “imports and exports of crops” factor in Figure 4.2-1, especially due to trends in recent years. As explained further in Chapter 7, increasing U.S. soybean oil production in future years will require investment to increase the domestic soybean crushing capacity. Domestic soybean crushers that have made these investments in the past are able to do so in the future but are unlikely to do so unless they have a reasonable expectation of increasing demand for soybean oil to provide a return on their investments. In recent years, a significant increase in imported FOG to domestic BBD producers is the result of increased global collection of these feedstocks and changes to biofuel policies in both the U.S. and other countries, such that the U.S. became a preferred destination for these feedstocks. The marked shift back to lower imports of Asian UCO and imported feedstocks and fuels in 2025 was again marked by significant shifts to biofuel and trade policy in the U.S. and other countries. Any number of factors, such as other countries adopting more stringent biofuel mandates, providing higher incentives for biofuels produced from FOG, or restricting FOG exports, could quickly change these market dynamics. Potential changes in these and other export and import dynamics complicate our understanding of the actual land use change and natural land conversion effects from this rule.

Assuming some natural land loss effects could occur, and that land use change patterns mirror past trends, any future expansion of agriculture attributable to this rule would most likely

impact grasslands, pasturelands, CRP lands, idle lands, and noncultivated cropland, as demonstrated by findings from studies discussed in Section 4.2.1. Increased cropland may contribute to additional declines in wetlands and forests, but likely to a much lesser extent. As such, EPA expects that any potential extensification of agriculture from this rule would likely occur on these lands that have historically been impacted the most by agricultural expansion. Any impacts to wetlands and forests would likely occur at a much smaller scale since historically they have been impacted by agricultural conversion to a lesser degree than other land types. Still, additional losses of wetlands and forests could occur in ecologically sensitive areas or in places that are already experiencing cumulative environmental effects.

Regarding potential conversion of grasslands, pasture, idle lands, shrubland, and CRP lands, it is also important to note that only a portion of these lands would qualify as loss of long-term grasslands that likely support greater wildlife biodiversity, soil carbon storage, and ecosystem services. As stated previously, Lark et al. (2015) found that, from 2008–2012, grasslands were the source of 77% of new cropland and just over a quarter of these grasslands that were converted qualified as long-term grasslands. Pasture, idle croplands, and CRP lands that could fall under the category of grasslands or natural lands may also be converted due to land use changes from this rule, but ecosystem impacts such as soil carbon and species impacts, would likely occur to a lesser extent on these lands compared to scenarios in which conversion of long-term grasslands occurs.

EPA further explored the potential land use change effects from this rule in a BE document in support of ESA Section 7 consultation with the FWS and National Marine Fisheries Service (NMFS). EPA largely used the same analytical approaches that were used in the Set 1 Rule BE. We leveraged econometric analyses available in published literature (Li et al. 2019)²¹⁷ combined with updated data from Dr. Madhu Khanna²¹⁸ to estimate the change in corn acres and total cropland per billion gallons of ethanol production. New in the Set 2 Rule BE, EPA applied the same approach to assess potential change in soybean acres and total cropland in response to soybean oil production from this rule. Including an additional and separate analysis looking at impacts from canola biodiesel and renewable diesel, the BE estimated that the Analyzed Volumes could contribute up to approximately 3.4 million new acres of cropland. As discussed previously, other factors outside of the RFS standards (e.g., import/export trends, other state and federal policies) can also influence land use change for biofuel production. The 3.4 million acres would also include potential conversion of pasture, idle croplands, and CRP lands that are not considered long-term, pristine natural landscapes.

4.3 Soil and Water Quality

As was done in the Set 1 Rule RIA, soil and water quality are addressed together in one section because, in many ways, they are intertwined. Soil health, organic matter content, erosion, and nutrient leaching from agricultural soils affects the water quality of nearby and downstream

²¹⁷ Li, Y., Miao, R., & Khanna, M. “Effects of Ethanol Plant Proximity and Crop Prices on Land-Use Change in the United States.” *American Journal of Agricultural Economics* 101, no. 2 (March 2019) 467–491. <https://doi.org/10.1093/ajae/aay080>.

²¹⁸ Khanna, M. “Effects of Ethanol Plant Proximity and Crop Prices on Land-Use Change in the United States: Updated Analysis for 2003–2023.” September 15, 2025.

water bodies. Potential impacts of biofuel production and use on soil and water quality, like the potential impacts on conversion of natural lands, have been discussed in detail in the Biofuels and the Environment: Reports to Congress. The past effects of the RFS program alone have also been assessed in more recent years and are discussed in detail specifically in the RtC3 and Set 1 Rule BE.

In this section, we first explore the historical data and information contributing to our understanding of soil and water quality effects from agriculture and biofuels broadly, as well as our understanding of potential effects from past RFS volumes (Chapter 4.3.1). Because the Set 1 Rule RIA, finalized in 2023, included a literature review of articles examining soil and water quality effects, we also reviewed and discuss new literature that has come out in recent years related to this topic (Chapter 4.3.2). The last subsection explores the potential soil and water quality impacts from this rule (Chapter 4.3.3).

4.3.1 Soil and Water Quality Impacts

In this subsection, we summarize findings and EPA’s understanding of how agriculture, biofuel production, and the RFS program have historically impacted soil and water quality. For more detailed information including references to scientific articles that support such findings, please see Chapter 9 (Soil Quality) and Chapter 10 (Water Quality) in the RtC3. Furthermore, for the purposes of this rulemaking, we are most interested in the potential effects from domestic production of crop-based feedstocks. We acknowledge that impacts outside the U.S. may also occur. But for statutory and program evaluation purposes, we limit our scope to impacts within the U.S.

It is well understood as a general scientific matter that soil quality effects from biofuels are largely associated with production of crop-based feedstocks (corn, soybean, canola) rather than FOG or biogas feedstocks, as the latter categories do not require land for production. The conversion of grasslands or other lands to production of agriculture affects soil quality, with increases in erosion and the loss of soil nutrients, organic matter, and soil carbon.

With regard to water quality, extensification of cropland typically corresponds with an increase in nutrient (nitrogen and phosphorus) and sediment pollution from agricultural runoff, which impairs local water quality and contributes to algal blooms and hypoxia in the Gulf of America and other water bodies. An increase in cropland also typically corresponds to an increase in pesticide use which detrimentally affects nearby and downstream water quality. It is also well understood that the soil and water quality effects of converting to corn or soybeans from other crops, such as wheat, are generally less than those of the conversion of natural lands such as grasslands.

The unique physical, biological, and geological characteristics of the land affected are important to understanding the magnitude of soil and water quality effects. For example, as referenced in the Set 1 Rule RIA, LeDuc et al. (2017)²¹⁹ simulated greater erosion and loss of

²¹⁹ LeDuc, Stephen D., Xuesong Zhang, Christopher M. Clark, and R. César Izaurralde. “Cellulosic Feedstock Production on Conservation Reserve Program Land: Potential Yields and Environmental Effects.” *GCB Bioenergy* 9, no. 2 (February 26, 2016): 460–68. <https://doi.org/10.1111/gcbb.12352>.

soil carbon and nitrogen from converting low productivity, highly sloped Conservation Reserve Program grasslands compared to those with higher productivity soils and lower slopes.

The type of feedstock crop cultivated also matters. Soybean, a nitrogen fixer, generally requires less fertilizer application compared to corn and other crops. As such, nitrogen runoff from soybean cropland may be lower relative to other crops. Soil and water quality impacts further depend on whether best management practices, if any, are being applied on the agricultural land. The adoption of conservation tillage, cover crops, and soil amendments among other practices can help counterbalance the detrimental effects to soil and water quality from agriculture. That said, there is nuance in the scientific literature that suggests there is still much to be learned about these practices, as for example a recent meta-analysis suggests that some conservation tillage (*e.g.*, no till) actually increases nitrate leaching.²²⁰

The weather conditions on a given day or year matter as well. The amount of precipitation will affect runoff of nutrients and sediment from agricultural lands, affecting both edge of stream environments and the size of dead zones such as in the Gulf of America.^{221,222}

It is also important to recognize other potential effects from biofuel production and consumption that may affect soil and water quality. For example, although perennial grasses and other types of feedstocks are not grown at the commercial scale, the scientific literature shows that perennial grasses or woody biomass grown on marginal lands can help restore soil quality,²²³ depending on the plant species being grown and the type of land being converted.²²⁴

Chemical releases, biofuel leaks, and spills from above-ground and underground storage tanks as well as transportation tanks can contaminate soil and groundwater. As such, increased consumption of biofuels could increase leaks that affect soil and water quality. This is discussed in more detail in the Set 1 Rule RIA.

In addition, consumed biogas that is upgraded to RNG may have localized soil or water impacts, depending on the source of the biogas. Biogas sourced from anaerobic digesters processing agricultural manure, and the manure collection associated with them, may decrease

²²⁰ Li, Jinbo, Wei Hu, Henry Wai Chau, Mike Beare, Rogerio Cichota, Edmar Teixeira, Tom Moore, et al. “Response of Nitrate Leaching to No-tillage Is Dependent on Soil, Climate, and Management Factors: A Global Meta-analysis.” *Global Change Biology* 29, no. 8 (January 26, 2023): 2172–87. <https://doi.org/10.1111/gcb.16618>.

²²¹ Chang, Di, Shuo Li, and Zhengqing Lai. “Effects of Extreme Precipitation Intensity and Duration on the Runoff and Nutrient Yields.” *Journal of Hydrology* 626 (October 6, 2023): 130281. <https://doi.org/10.1016/j.jhydrol.2023.130281>.

²²² Lu, Chaoqun, Jien Zhang, Hanqin Tian, William G. Crumpton, Mathew J. Helmers, Wei-Jun Cai, Charles S. Hopkinson, and Steven E. Lohrenz. “Increased Extreme Precipitation Challenges Nitrogen Load Management to the Gulf of Mexico.” *Communications Earth & Environment* 1, no. 1 (September 18, 2020). <https://doi.org/10.1038/s43247-020-00020-7>.

²²³ Blanco-Canqui, Humberto. “Growing Dedicated Energy Crops on Marginal Lands and Ecosystem Services.” *Soil Science Society of America Journal* 80, no. 4 (July 1, 2016): 845–58. <https://doi.org/10.2136/sssaj2016.03.0080>.

²²⁴ Robertson, G. Philip, Stephen K. Hamilton, Bradford L. Barham, Bruce E. Dale, R. Cesar Izaurralde, Randall D. Jackson, Douglas A. Landis, Scott M. Swinton, Kurt D. Thelen, and James M. Tiedje. “Cellulosic Biofuel Contributions to a Sustainable Energy Future: Choices and Outcomes.” *Science* 356, no. 6345 (June 30, 2017). <https://doi.org/10.1126/science.aal2324>.

pathogen risk in water. But without proper treatment, excess nutrient pollution can also be a concern from these facilities.

An increase in cropland acreage for renewable fuel production and consumption in the U.S. would generally be expected to lead to negative soil and water quality impacts on balance. The RFS is only one of many factors that influence cropland acreage in the U.S. However, EPA has worked in recent years to evaluate the potential effects of the RFS program specifically on domestic soil and water quality, and in particular from past RFS volumes.

As described in the RtC3, EPA conducted an analysis using the Environmental Policy Integrated Climate (EPIC) model and found that the RFS program increased erosion, nitrogen loss, and soil organic carbon loss from 0–1.6%, 0–0.7%, and 0–1.1%, respectively, across a 12-state region between 2008–2016. As the report notes, these modeled estimates represent RFS effects for corn ethanol only. At the time of the analysis EPA was not able to evaluate additional quantitative effect from the RFS Program on soybean oil-based biodiesel or renewable diesel, nor the effect on soybean acreage, nor any effect from crop switching on existing cropland. The report also notes that this finding for corn ethanol only comparatively represents up to 3.7% of the nitrogen retention benefits of the Conservation Reserve Program for the entire U.S.

The RtC3 also evaluated the potential water quality impacts from agriculture and the RFS program historically. Using the Soil and Water Assessment Tool (SWAT) model, EPA completed an analysis of estimated historical cropland expansion on water quality in the Missouri River Basin from 2008–2016. Grassland conversion to continuous corn resulted in the greatest increase in total nitrogen and total phosphorus loads (6.4% and 8.7% increase, respectively); followed by conversion to corn/soybean rotation (6.0% and 6.5%); and then conversion to corn/wheat rotation (2.5% and 3.9%). These results represent estimated water quality effects from general agricultural expansion in the Missouri River Basin from 2008–2016 and not the effects from the RFS program alone. Based on other analyses, the report suggests that approximately 0–20% of the observed changes may have been due to the RFS program.

Additionally, the Set 1 Rule BE leveraged the Missouri River Basin SWAT analysis from the RtC3 to assess the potential water quality effects from the Set 1 Rule. Results indicated that, even if the maximum projected acreage impacts from the Set 1 Rule (2.65 million acres total) were to occur, the water quality impacts would be small relative to total nutrient, sediment, and pesticide effects already happening at the mouth of the Mississippi and other larger water bodies within the action area. Moreover, based on additional qualitative analyses, EPA found in the Set 1 Rule BE that localized water quality impacts from the Set 1 Rule were likely to be discountable as defined under the ESA.

As discussed in Chapter 4.2.1, based on what we know happened from 2023 to 2025, those estimates from the Set 1 Rule BE likely overestimated the actual effects from the Set 1 Rule. For example, in 2023 alone there was very little increase in domestic feedstock production and additional BBD supply came from a significant increase in imports. These observed trends from recent years are discussed in more detail in Chapter 7.

Beyond EPA’s work in these areas, a study by Lark et al (2022)²²⁵ examined the specific impacts from the RFS in past years. The authors found that, from 2008–2016, the RFS expanded corn cultivation in the U.S. by 2.8 million acres and total cropland by 2.1 million acres. These changes corresponded with an estimated increase in annual nationwide fertilizer use by 3–8% and an increase in water quality degradants by 3–5%. EPA explained in the Set 1 Rule BE how the coefficient (*i.e.*, value for cropland expansion per billion gallons of ethanol) that Lark et al. used for estimating these effects compares to the coefficient that EPA used in the RtC3 and BE. We found that the coefficients used in both efforts were similar in magnitude. The difference in results, however, was due to how many billion gallons of corn ethanol was assumed to come from the RFS. In the RtC3, EPA estimated a smaller effect from the RFS based on an additional attribution analysis that separated the effects of the RFS program from the impacts of biofuels generally.

4.3.2 New Literature on Soil and Water Quality Effects

To assess the current state of the science, EPA also completed a review of more recent literature related to agriculture and biofuel production soil and water quality effects. EPA looked for articles published in recent years. EPA found no studies that directly linked potential soil and water quality effects to the RFS program.

One study by Byers et al. (2024)²²⁶ shows how intensified agriculture disrupts soil health, particularly through soil carbon loss and microbiome degradation. As they note, “human-driven land use change, such as agricultural intensification, is a major driver of soil [carbon] loss globally,” making sustainable land use challenging. The study emphasizes the importance of soil microbes in “regulating soil biogeochemical cycling processes, including soil [carbon] cycling.” By analyzing microbial DNA, the researchers discovered that intense farming areas had more microbial genes that break down soil carbon, potentially leading to “greater loss of soil C as respired CO₂ into the atmosphere”. This increase in carbon loss suggests that intensive farming may boost GHG emissions.

Byers et al. also shows that areas with more intense land use, such as pastures, have lower soil carbon and less microbial diversity, following what the authors call a “disturbance gradient.” This pattern of soil degradation due to intensive farming hopes to discover a balance between high productivity and healthy ecosystems.

Byers et al. recommends strategies like “protection of remnant native forest fragments and greater incorporation of regenerating native vegetation” to preserve soil carbon levels. These types of practices focus on sustainable land use that can help maintain long-term soil health and climate adaptability by diminishing some of the negative impacts of intensive agriculture.

²²⁵ Lark, Tyler J., Nathan P. Hendricks, Aaron Smith, Nicholas Pates, Seth A. Spawn-Lee, Matthew Bougie, Eric G. Booth, Christopher J. Kucharik, and Holly K. Gibbs. “Environmental outcomes of the US Renewable Fuel Standard.” *Proceedings of the National Academy of Sciences* 119, no. 9 (February 14, 2022). <https://doi.org/10.1073/pnas.2101084119>.

²²⁶ Byers, Alexa K., Leo Condrón, Steve A. Wakelin, and Amanda Black. “Land Use Intensity Is a Major Driver of Soil Microbial and Carbon Cycling Across an Agricultural Landscape.” *Soil Biology and Biochemistry* 196 (June 26, 2024): 109508. <https://doi.org/10.1016/j.soilbio.2024.109508>.

Other studies focused on the impacts of pesticide use on soil and water quality. Traditionally, pesticides have been employed in the agricultural sector to minimize the yield losses due to insects, disease, and weeds, however, the chemicals in pesticides have significant consequences, especially when overused. When pesticides are over-applied, the excess cannot be absorbed by the plants, and is susceptible to being washed off by precipitation into the soil; as Zhou et al. (2025)²²⁷ explain, once these chemicals enter the soil, they can react to form new compounds, and depending on how deep into the soil they penetrate, can either leach into groundwater or get carried to a body of water downstream. These chemicals then contaminate water bodies and impact both the health of aquatic ecosystems and human health. In the case of aquatic ecosystems, these chemicals can enter the food chain and bioaccumulate at higher trophic levels. Human health implications of pesticides include linkages to increased risk of cancer, diabetes, respiratory disease, neurological disorders, organ damage, and reproductive syndromes.

Using a partial equilibrium model of corn-soy production and trade, Johnson et al. (2023)²²⁸ estimated that a reduction of 24% of U.S. demand for corn as a renewable fuel feedstock would keep agricultural land use and nitrogen leaching rates below 2020 levels through the year 2025. Further, they found that a 41% reduction in demand for corn as a renewable fuel feedstock would do the same through 2030. The authors discuss how such demand reductions have potential to mitigate short-term impacts of population and income growth over the next decade.

In a review of consequential life cycle assessments (CLCAs), Bamber et al. (2023)²²⁹ compared a series of 23 papers from several countries comparing the environmental impact of grain and oilseed crops used in biofuel production to traditional fossil fuels. Among other metrics, the team compared the CLCA results on differences in eutrophication, acidification, and toxicity, which had conflicting results. Compared to conventional fuels, the studies ranged from a 100-fold decrease in eutrophication to a 45-fold increase in eutrophication; for acidification, this ranged from a 248% decrease to a 500% increase; for toxicity, this ranged up to a 20,000-fold increase, with some decreases being reported but no calculable percentage changes.

Of the five studies focusing on water quality impacts of corn, soybean, and canola, which came out of the United States, Sweden, Switzerland, Spain, and Argentina, there was still disagreement among results: three of the five studies determined that biofuel production had greater acidification and eutrophication impacts than conventional fuel; only four of the studies evaluated ecotoxicity, three of which determined that biofuel production was associated with worsened ecotoxicity and/or downstream carcinogenic effects compared to conventional fuels. The study was largely inconclusive, with the researchers suggesting a more unified approach and

²²⁷ Zhou, Wei, Mengmeng Li, and Varenayam Achal. "A Comprehensive Review on Environmental and Human Health Impacts of Chemical Pesticide Usage." *Emerging Contaminants* 11, no. 1 (August 26, 2024): 100410. <https://doi.org/10.1016/j.emcon.2024.100410>.

²²⁸ Johnson, David R., Nathan B. Geldner, Jing Liu, Uris Lantz Baldos, and Thomas Hertel. "Reducing US Biofuels Requirements Mitigates Short-term Impacts of Global Population and Income Growth on Agricultural Environmental Outcomes." *Energy Policy* 175 (February 24, 2023): 113497. <https://doi.org/10.1016/j.enpol.2023.113497>.

²²⁹ Bamber, Nicole, Ian Turner, Baishali Dutta, Mohammed Davoud Heidari, and Nathan Pelletier. "Consequential Life Cycle Assessment of Grain and Oilseed Crops: Review and Recommendations." *Sustainability* 15, no. 7 (April 4, 2023): 6201. <https://doi.org/10.3390/su15076201>.

more specific focus on a select group of crops to ensure similar production methods are implemented to make comparison across studies more useful (Bamber et al. 2023).

4.3.3 Potential Soil and Water Quality Impacts

As was done in Section 4.2.3 for potential natural land conversion effects, we examine the volume changes expected from this rule relative to the No RFS and 2025 Baselines, for both BBD and conventional renewable fuels, to understand potential soil and water quality effects. The projected BBD volume changes (Table 4.2-1) relative to both baselines suggest that this rule would increase demand for BBD. If BBD supply were to come from crop-based feedstocks such as soybean and canola, then this rule could contribute to further declines in soil and water quality.

Similarly, we would see higher conventional renewable fuel volumes attributable to this rule relative to the No RFS Baseline, but to a smaller degree compared to BBD volumes as indicated by smaller values in Table 4.2-2 compared to Table 4.2-1. This could contribute to further domestic land use changes that impact soil and water quality.

Based on results from the EPIC modeling work done in the RtC3 and summarized previously, if future impacts follow the same pattern as historical trends, the volume increases from this rule could contribute to small percentage increases in erosion, nutrient loss, and soil organic carbon loss. Of course, the true impacts on soil and water quality would depend on many factors, including imports and exports of BBD supplies in the coming years. Decreasing exportation of whole soybeans and crushing more soybeans domestically could provide more BBD supply and thus decrease any demand for additional soybean production from agriculture.

Additionally, in the event of any land conversion to agriculture due to this rule, other factors that are highly variable at the local scale would affect the true impacts on soil and water quality. For example, one factor to consider is the baseline nutrient, sediment, and pesticide loadings from pre-converted land uses. Even forests, which provide the highest water quality among all land cover types,²³⁰ contribute to nutrient loadings in watersheds. As another example, livestock grazing on pastureland can affect sediment runoff. Pastureland that is converted to cropland would still contribute to soil and water quality degradation, but likely to a lesser extent compared to natural grassland that is converted to cropland. As such, it is important to consider the loadings from any pre-extensification or pre-intensification scenarios to understand the potential net effect in pesticide, nutrient, and sediment loadings. In some cases, the net effect may actually be a decrease in pollutants, as may be the case in crop conversion from corn to soy, a nitrogen fixer, leading to a decrease in nitrogen runoff assuming nitrogen fertilizer applications to the field decrease as well.

²³⁰ Caldwell, Peter V., Katherine L. Martin, James M. Vose, Justin S. Baker, Travis W. Warziniack, Jennifer K. Costanza, Gregory E. Frey, Arpita Nehra, and Christopher M. Mihlar. "Forested Watersheds Provide the Highest Water Quality Among All Land Cover Types, but the Benefit of This Ecosystem Service Depends on Landscape Context." *The Science of the Total Environment* 882 (April 19, 2023): 163550. <https://doi.org/10.1016/j.scitotenv.2023.163550>.

The magnitude of effects also depends on feedstocks planted, the biogeophysical traits of the land being farmed on, the management practices in place, and many other factors that are not determined by the RFS standards. While past analyses can provide insight, the likely future effects of this rulemaking are not fully understood because it is not possible to understand the true effects at the local level due to such complexities. Further, for any potential effects, additional conservation measures—such as further adoption of conservation tillage and cover crops—would help reduce the impacts of biofuels and the RFS program. In the Set 2 Rule BE, EPA further explores how the Set 2 Rule may impact water quality due to land use conversion to agriculture.

Soil and water quality effects from other issues beyond agriculture could occur in connection to this rulemaking. These include chemical leaks and spills from storage and transportation tanks. It is not possible at this time to attribute such leaks and spills to the RFS program. However, if any potential effects occur, EPA expects them to be minimal, and EPA is involved in a separate process outside of the Clean Air Act for taking corrective actions and completing remediation for any chemical releases.

There are also concerns regarding potential soil and water quality impacts from biogas production through manure collection and animal feeding operations on farms. However, the majority of biogas for cellulosic biofuel is sourced from landfills and not agricultural digesters. As such, we expect any potential impacts from agricultural digesters to be very minimal.

4.4 Water Quantity and Availability

We have previously explored this topic in the Biofuels and the Environment Reports to Congress and Set 1 Rule RIA. We summarize major findings below.

4.4.1 Water and Biofuel Crop Growth

Growth of biofuel feedstock crops such as corn and soybeans are the primary uses of water in the process of creating renewable fuels. Although there are several other “fuel crops” used in the RFS program, corn and soybeans are the focus of our evaluation on water quantity as they collectively represent a significant majority of the crop-based feedstocks consumed to produce fuel under the RFS program.

4.4.1.1 Corn

Historically, corn has been grown in mostly rain-fed locations such as in Iowa and Minnesota where irrigation is often not needed. Because of this, corn has historically been considered to have a low to modest water footprint. However, with changes in cropland needs such as meat production and the RFS program, cropland usage has shifted. With increased production of corn for ethanol production, corn growth has expanded further into locations where irrigation is needed more frequently.

As discussed in the Set 1 Rule BE, several studies have evaluated land use change attributable to the volumes from the Set 1 Rule. Data from this evaluation concluded that corn

acreage growth did not necessarily result in total crop land acreage growth. This work suggested it was more likely that other crops were being displaced in order to plant additional corn. This could indicate the planting of corn in locations previously not thought to be ideal for the crop's growth (*e.g.*, the Northern Great Plains region) and requiring the need for additional irrigation.

4.4.1.2 Soybeans

Soybeans in general require less irrigation than corn. Corn and soybeans are typically grown in rotation and therefore in the same growing regions, which historically in the U.S. have been primarily those regions which receive higher rainfall and require less additional irrigation.

Projections for biodiesel and renewable diesel volumes from the Analyzed Volumes suggest an increase in soybean production in the years analyzed. Between 2022 and 2024 a large influx of UCO was being imported and utilized in biodiesel market. Due to changes in tax incentives further described in Chapter 1.3 UCO has become less incentivized in the biofuel world. These tax incentive changes also increased the incentive for domestically produced feedstocks such as canola and soybean oil. Although soybean oil demand will continue to increase with the anticipated fuel volumes, the impact to land use change could be minimal with implementation of other crop sustainability practices as well as optimization of the soybean oil market.

As stated above, the irrigation of corn, soybeans, and other biofuel crops is the predominant driver of water quantity impacts attributable to the RFS program. Some studies show land use change over time coincided with areas experiencing groundwater depletion²³¹. But this correlation does not mean there is a direct, causal relationship between biofuel production and groundwater depletion. USDA data suggests that total irrigated acres have increased in the U.S. over time (2013–2018), however irrigation rates have declined on a per acre level over the same time period for both corn and soybeans.²³²

4.4.2 Use of Water in Production Facilities

Production of biofuels also requires water for the actual production of fuels at biofuel facilities. With increases in potential volumes in biofuel production, we can assume an increased need for water in the fuel production process.

Similar to petroleum-based fuels, biofuel production requires the use of water to produce fuel. At many biofuel facilities, consumption of water has declined over time through more efficient water use, water recycling and recovery processes and reuse of wastewater, for example. The biofuel production process itself requires less water consumption than the growth of the biofuel feedstock crops. That said, biofuel facility water use, even with the implementation

²³¹ Yao, Yi, Wim Thiery, Agnès Ducharne, Benjamin I. Cook, Anxin Ding, Steven J. De Hertog, Petra Sieber, et al. "Irrigation-induced Land Water Depletion Aggravated by Climate Change." *Nature Water* 3, no. 12 (November 5, 2025): 1424–35. <https://doi.org/10.1038/s44221-025-00529-1>.

²³² USDA, "Irrigation and Water Use," January 8, 2025. <https://www.ers.usda.gov/topics/farm-practices-management/irrigation-water-use>.

of water saving techniques, may still be locally consequential in areas that are already experiencing stress on water availability.

Overall, while values will vary across states and counties, ethanol, biodiesel and renewable diesel made from vegetable oils are substantially more water intensive than the petroleum fuels they would displace.²³³

In summary, based on the approaches above, there will likely be some increased irrigation pressure on water resources due to the Analyzed Volumes. Specifically, the fuel volume increases for 2026–2027 compared to the No RFS Baseline which we estimate in Chapter 3 will be produced from agricultural feedstocks (especially corn and soybeans) would suggest the potential for some associated increase in crop production. This in turn would likely increase irrigation pressure on water resources. The increased volume requirements, especially that of biodiesel and renewable diesel, could incent greater production of soybeans. There is uncertainty in projecting changes in acreage and irrigation rates associated with corn, soybeans, and other crops. Additional information and modeling are needed to fully assess changes in water demands and effects on water stressed regions, both for crop irrigation as well as impacts of biofuel facility water use.

4.5 Ecosystem and Wildlife Habitat

The previous sections in this chapter discussed this rulemaking’s potential impacts on air quality, wetland and other natural land loss, soil quality, water quality, and water quantity. Changes to any of these environmental end points could subsequently impact ecosystems. This may include impacts on habitat and threatened and endangered species that are in danger of becoming extinct in the future.

EPA has previously assessed the impacts of biofuel consumption and production on ecosystems and wildlife in the Biofuels and the Environment: Reports to Congress. The RtC3, the Set 1 Rule RIA, and Set 1 Rule BE further evaluate impacts from the RFS program, of which the latter two examine potential impacts from the Set 1 Rule specifically. The BE examined impacts of the Set 1 Rule’s 2023–2025 volumes on endangered and threatened (referred to as “listed” species), and found that the rule may affect, but is not likely to adversely affect (NLAA), any of the 810 populations or critical habitats found in a large action area comprising most of the U.S. where corn, soy, and canola can be grown. EPA has completed another BE for this Set 2 Rule, in accordance with ESA Section 7 consultation with the Services.

In this section, we first explore the historical data and information contributing to our understanding of ecosystem and wildlife habitat effects from agriculture and biofuels broadly, as well as our understanding of potential effects from past RFS volumes specifically (Chapter 4.5.1). Because the Set 1 Rule RIA and BE, finalized in 2023, included a literature review and information examining wildlife impacts, we also reviewed and discuss new literature from more

²³³ Institute of Medicine of the National Academies. “The Nexus of Biofuels, Climate Change, and Human Health: Workshop Summary.” Roundtable on Environmental Health Sciences, Research, and Medicine; Board on Population Health and Public Health Practice. April 2, 2014. Chapter 5, Water Use, Water Pollution, and Biofuels. <https://www.ncbi.nlm.nih.gov/sites/books/NBK196445>.

recent years related to this topic (Chapter 4.5.2). The last subsection explores the potential ecosystem and wildlife habitat impacts from this rule (Chapter 4.5.3).

4.5.1 Ecosystems and Wildlife Habitat Impacts

In this section, we summarize previous findings and EPA's current understanding of how agriculture, biofuel production, and the RFS program historically impacted ecosystems and wildlife habitat. For more detailed information including references to scientific articles that support such findings, please see Chapter 12 (Terrestrial Ecosystem Health and Biodiversity) in the RtC3 as well as the Set 1 Rule BE.

Land conversion to cropland is generally associated with negative impacts to ecosystem health and biodiversity. Demand for crop-based feedstocks used for biofuel production (corn, soy, canola) can lead to further agricultural conversion which may affect species by contributing to overall habitat loss associated with cropland extensification more generally. Because native grasslands have seen higher conversion rates to agriculture compared to wetlands and forests, it is likely that terrestrial wildlife species with the largest potential risk are grassland species, including bird species and various insect species that rely on those ecosystems. However, some impacts to species in wetland and forest ecosystems may still occur due to direct land conversion to agriculture.

Pesticide drift, or the movement of pesticide dust or droplets through the air, can affect nearby ecosystems and species after application to farm fields. In addition, nutrients, sediment, and pesticides carried by agriculture runoff affect the health of aquatic ecosystems and species that live or rely on such ecosystems. This pollution can impact water quality at nearby edge-of-field streams and rivers as well as at a significant distance from the location of the land use change as contaminants associated with crop production travel downstream and into major waterways. This is particularly true for contaminants with greater mobility and contaminants that persist for longer time periods in soil and aquatic environments.

Many species of fish, for example, rely on creeks and streams with low turbidity, well oxygenated and moderately clean water, and riffles, pools, and runs with differing substrates of gravel, pebble, and sand. They may also need riparian cover and cooler temperature of waters, an abundant source of food, geo-morphically stable river channels and banks, and sufficient water depth. Some or all of these features in creeks and streams could be affected by agricultural land conversion and runoff. For instance, increased sediment can alter the geomorphology of streams, and increased turbidity and nutrients could affect macroinvertebrate communities that provide sources of food for fish.

Furthermore, excess nutrients (eutrophication) and sediment in places like the Gulf of America and Chesapeake Bay contribute to hypoxia and dead zone conditions in the summertime. Species that live in or rely on these estuarine and coastal ecosystems may therefore be impacted as well.

Potential air quality and water quantity effects could also occur due to production and consumption of biofuels, as discussed in greater detail in Sections 4.1 and 4.4, respectively. Such

effects could subsequently impact the health of ecosystems and species that rely on clean air or adequate water supply.

To better understand potential impacts of land use change and biofuels on listed species, an analysis in the RtC3 found that shifts from perennial cover to corn and soybeans from 2008–2016 occurred in areas adjacent to or within critical habitat of 27 terrestrial threatened and endangered species across the contiguous U.S. The RtC3 found that past RFS volume obligations during those years were just one factor out of many that could have played a role in these land use changes. The Report states that the range of possible impacts from the RFS program likely spanned from no impact to a negative impact on terrestrial biodiversity historically.

As stated previously, EPA also assessed the potential impacts to listed species from the Set 1 Rule volumes in the Set 1 Rule BE. EPA identified 810 populations or critical habitats found within a large action area that may be affected by the rulemaking. Ultimately, however, EPA found the Set 1 Rule is NLAA listed species and their designated critical habitats. The Set 1 Rule BE document details the specific analyses and findings that led to this conclusion. In accordance with the ESA, EPA submitted this BE and received letters of concurrence with this NLAA determination from NMFS on July 27, 2023, and from FWS on August 3, 2023, thereby concluding informal consultation on the Set 1 Rule.

To date, EPA’s work to understand the impacts of past RFS volume obligations on habitats and listed species has fully relied on EPA’s understanding of how the RFS, separate from other influencing factors, impacts land use change and intensification and extensification to agriculture. EPA has advanced this understanding in recent years by including an RFS attribution analysis in the RtC3, for example. Still, it has not been possible historically, and is still not possible at this time to the best of our knowledge, to say which parcels of lands were converted in the past due to the RFS program alone, nor to project with confidence where land use change will occur in the future due to the RFS. With the currently available science, the finest grain possible for understanding the effect of biofuel production on cropland that we are aware of is at the county scale. However, such analyses for the Set 1 Rule rendered limited information²³⁴ and, further, are conservative estimates as they do not directly account for trends in imports and exports of crop-based feedstocks. These limitations make it even more challenging to fully understand how the RFS may affect unique habitats and wildlife that live and rely on location-specific ecosystems across the contiguous U.S.

Beyond our understanding of impacts from biofuels, the RFS, and land use change broadly, it is well known both in the scientific literature and environmental management field at large that conservation practices may help to mitigate any potential effects. These practices include protecting environmentally sensitive lands and increasing habitat heterogeneity to mitigate impacts from land conversion of habitat. Furthermore, the adoption and expansion of sustainable conservation practices on farmland can reduce impacts on aquatic ecosystems by

²³⁴ In the Set 1 Rule, county-level estimates would have been possible by leveraging an econometric analysis for corn ethanol effects due to proximity to ethanol facilities, specifically, as opposed to corn ethanol crop price effects. However, the proximity to ethanol facility effects were estimated to be zero for total cropland in the Set 1 Rule BE, so EPA was not able to accomplish county-level estimates for this. See Li et al. (2019) and updated analyses by Madhu Khanna as described in the Set 1 Rule BE for more information.

restoring flow and decreasing loads of nutrients, sediment, and pesticides to levels that are less harmful to aquatic organisms.

4.5.2 New Literature on Ecosystem and Wildlife Habitat Impacts

Like in previous sections, EPA completed a literature review of research articles from recent years to assess the current state of the science related to agriculture and biofuel production effects on habitat and species. EPA found only one study that directly linked potential effects to the RFS program.

The one article that related species and habitat impacts to the RFS program is from Lark (2023).²³⁵ In this article, Lark explores how the RFS program may have affected land use changes and critical habitat, illustrates example pathways of interaction between biofuels and endangered species, provides examples of potentially impacted species, and proposes solutions to mitigate harm. Lark further acknowledged in the article that the “extent, duration, and magnitude of influence from the RFS specifically is unknown and remains a topic ripe for further research.” Lark also encouraged EPA to complete consultation with the FWS and NMFS in accordance with the ESA, which EPA accomplished for the Set 1 Rule a few months after the article’s publication.

Other studies did not look at the potential impacts from RFS program specifically but instead examined impacts from agriculture and biofuel crop-based feedstocks more broadly. The findings from these studies support much of our current understanding, for example that species that live and rely on grasslands are especially affected by agricultural conversion, and that there is a link between agricultural activity and declining fish populations.

In one study, van der Burg et al. (2023)²³⁶ examined how biofuel crop production and oil and gas development impact grassland bird species in North Dakota. The researchers looked at four types of birds—Bobolink, Grasshopper Sparrow, Savannah Sparrow, and Western Meadowlark—between 1998 and 2021. They found that biofuel feedstocks, like corn and soybeans, had a more negative effect on grassland bird populations than oil and gas development. The authors observed that “all four species responded positively to the proportion of grasslands surrounding a point on the landscape. Likewise, [they] found that all four species responded negatively to the proportion of corn and soybeans on the landscape,” meaning that birds were less likely to live in or use areas where biofuel crops dominated. They also found that small grain crops, like wheat and barley, had less of a negative effect, and in some cases, even a slight positive effect on the birds likely due to features on small grain fields that mimic the vegetation structure and phenology of grasslands.

²³⁵ Lark, Tyler J. “Interactions Between U.S. Biofuels Policy and the Endangered Species Act.” *Biological Conservation* 279 (January 16, 2023): 109869. <https://doi.org/10.1016/j.biocon.2022.109869>.

²³⁶ Van Der Burg, Max Post, Clint Otto, and Garrett MacDonald. “Trending Against the Grain: Bird Population Responses to Expanding Energy Portfolios in the US Northern Great Plains.” *Ecological Applications* 33, no. 7 (July 7, 2023). <https://doi.org/10.1002/eap.2904>.

Another study, Crawford and Alexander (2024)²³⁷ investigated the relationship between historic fish kills and insecticide use, comparing data across 10 watersheds in Prince Edward Island, Canada, with varying degrees of agricultural activity (including corn and soybeans). Severely impacted watersheds—identified as those with greater than 50% of land being used for agriculture—generally exhibited nitrate levels in excess of the guidance levels, as well as elevated levels of other nutrients (*e.g.*, total phosphorus) and insecticide concentrations. Though the researchers suggested a more targeted study be performed in the future, the results achieved point toward a link between industrial-scale pesticide use and detrimental impacts to downstream water quality.

4.5.3 Potential Ecosystem and Wildlife Habitat Impacts

As was done in previous sections, as a first step we can look at the volume changes expected from this rule relative to the No RFS and 2025 Baselines, for both BBD and conventional renewable fuels, to assess potential impacts to ecosystems and wildlife. The projected BBD volume changes from the Analyzed Volumes (Table 4.2-1) suggest that this rule would increase demand for BBD. If BBD supply were to come from crop-based feedstocks such as soybean oil and canola oil, then this rule could contribute to additional land use change, declines in soil and water quality, and, subsequently, impacts to wildlife and habitat.

Similarly, EPA estimates higher conventional renewable fuel volumes attributable to this rule relative to the No RFS Baseline, but to a smaller degree compared to BBD volumes, as indicated by smaller values in Table 4.2-2 compared to Table 4.2-1. As such, this rule could lead to additional demands for conventional fuel and contribute to further domestic land use changes that impact wildlife and habitat, though to a lesser extent compared to BBD volume impacts.

Imports and exports of BBD supplies in the coming years will also play an important role. For example, decreasing soybean exportation and crushing more soybeans domestically would allow for greater U.S. soybean oil production without the need for increasing cropland for crop-based feedstocks. As described in more detail in Chapter 7, BBD has been imported at significantly greater quantities in recent years, especially starting in 2021 and through 2024. Should similar trends continue, this could provide greater BBD supplies in the domestic market. If BBD is largely supplied by changing import and export dynamics, then it could mean fewer land use impacts may be expected, and minimal wildlife and ecosystem effects from this rule.

EPA completed a BE for this rule that assessed the rule’s potential impacts on listed species. As was done for the Set 1 Rule BE, EPA applied probabilistic analyses to select available lands for conversion and estimate the overlap between potential cropland changes and critical habitats or listed species’ ranges. Supported by the analysis in the Set 2 Rule BE, we determined that formal consultation is not required for the Set 2 Rule.

In addition, in the event that some land conversion does occur due to this rule, there are many other factors at the local level that would affect soil and water quality, and thus ecosystems

²³⁷ Crawford, Miranda, and Alexa C. Alexander. “Fish Kills and Insecticides: Historical Water Quality Patterns in 10 Agricultural Watersheds in Prince Edward Island, Canada (2002–2022).” *Frontiers in Sustainable Food Systems* 8 (July 26, 2024). <https://doi.org/10.3389/fsufs.2024.1356579>.

at large. These include, but are not limited to, the type of land that was converted (*e.g.*, pastureland versus long-term, pristine grasslands), the feedstocks that are planted, and management practices put in place. Further, the weather conditions on a given day or year matter as well; the amount of precipitation will affect runoff of nutrients and sediment from agricultural lands, affecting both edge of stream environments and the size of dead zones such as in the Gulf of America. The true effects on ecosystems from this rulemaking are challenging to understand due to the unique factors, conditions, as well as decisions at the local level that are not determined by the RFS.

Impacts on air quality or water quantity from this rulemaking could also affect wildlife and ecosystems. However, any effects on water quantity and air quality impacts would likely be highly variable and dependent on the local context. For example, as explained in Section 4.1 of this chapter, we would expect some localized increases in some air pollutant concentrations, particularly at locations near production and transport routes and in more rural areas. Overall, we expect the emission impacts from the Analyzed Volumes to be variable in how they affect ambient concentrations of ozone and PM_{2.5} in specific locations across the U.S. With regard to water quantity, there remains great uncertainty in projecting changes at the local level as well; for example, with irrigation rates as decided by farmers for growth of corn, soybeans, and other crops.

4.6 Ecosystem Services

Ecosystem services broadly consist of the many life-sustaining benefits humans receive from nature, such as clean air and water, fertile soil for crop production, pollination, and flood control.²³⁸ The United Nations Millennium Ecosystem Assessment²³⁹ categorized four different types of ecosystem services, including:

- Provisioning Services; the provision of food, fresh water, fuel, fiber, and other goods
- Regulating Services; climate, water, and disease regulation as well as pollination
- Supporting Services; soil fermentation and nutrient cycling
- Cultural services; education, aesthetic, and cultural heritage values as well as recreation and tourism

Several of the drivers of ecosystem loss identified in the Millennium Ecosystem Assessment, such as climate change, poor air quality, poor water quality, water quantity, and land use change, are expected to be impacted by the production of renewable fuels generally and may be impacted by the Analyzed Volumes in this rule specifically.

The previous sections in this chapter discussed the projected impacts associated with this rule on a variety of different environmental end points such as air quality, climate change, land-use change, soil and water quality, and water quantity as required by the statute. Each of the impacts discussed in these sections would be expected to have an impact on one or more ecosystems services. These impacts could be positive (*e.g.*, result in ecosystem services benefits)

²³⁸ EPA, “Ecosystem Services.” <https://www.epa.gov/eco-research/ecosystem-services>.

²³⁹ Millennium Ecosystem Assessment, “Ecosystems and Human Well-being: Synthesis,” 2005. <https://www.millenniumassessment.org/documents/document.356.aspx.pdf>.

or negative. We have focused our analyses on the specific factors identified in the statute and we have not quantified all of the human well-being changes or monetized these effects. We have, however, provided a potential framework for how the impacts on ecosystem services might be considered (see Figure 4.6-1). Note that there are multiple frameworks for categorizing ecosystem services in the literature. Future analyses, such as those presented in the Triennial Biofuels and the Environment reports to Congress, may refine this approach to better capture incremental ecosystem service benefits and costs.

In recent years, humans have become more reliant upon these ecosystem services to the point where ecosystems have begun to rapidly change. These changes have been made to meet growing needs for food, water, and in the case of the RFS program, fuel. These changes, although beneficial to human well-being, have often been at the cost of environmental well-being. Water scarcity and land conversion are two of the most prominent potential consequences of a robust RFS biofuels program. As stated in previous sections, there are several ways to attempt to mitigate the effects of these volumes. Cropland is often able to have an increased harvest which allows for significantly less potential land expansion to meet the volume needs. Additionally, the processing of biofuels has become increasingly more water efficient than previous methods.

Figure 4.6-1: Framework for Considering the Impact of the RFS Volumes on Ecosystem Services



Chapter 5: Climate Change Analysis

CAA section 211(o)(2)(B)(ii) states that the basis for setting applicable renewable fuel volumes after 2022 must include, among other things, “an analysis of...the impact of the production and use of renewable fuels on the environment, including on...climate change.” This chapter describes our analysis of the potential climate change impacts of this rule. While the statute requires EPA to base its determinations on, among other things, an analysis of the climate change impact of renewable fuels, it does not require a specific type of analysis. Additionally, while we consider the impacts on climate change as required by the statute, the range of potential GHG emission reductions, when coupled with additional uncertainties involved in commonly used climate change end points, makes it difficult to quantify potential climate change impacts such as changes in global temperature.

This chapter is organized as follows: Chapter 5.1 details the methodologies, models, scenarios, and assumptions used to assess the potential climate change impacts of the volumes assessed for purposes of this final rule. This section describes the methods for evaluating the GHG emissions associated with two different categories of biofuels: fuels produced from residues, byproducts, and other non-crop feedstocks; and fuels produced from crops.²⁴⁰ Chapter 5.2 presents the results of an analysis of the Analyzed Volumes relative to the No RFS Baseline Scenario. Results are presented in tons of GHG emissions changes. Chapter 5.3 presents several sensitivity scenarios under a range of assumptions about market mediated effects in the energy sector.

5.1 Methodology

Our assessment of the climate impacts of the Analyzed Volumes includes: (1) economic modeling of the estimated impact of combined changes in volumes of fuels produced from crop-based feedstocks; and (2) supply chain GHG emissions modeling for estimates for all fuels.

This section is organized as follows: Chapter 5.1.1 provides an overview of the methodology, including comparisons with past analyses of climate change impacts under the RFS program and the two categories of fuels and methods noted above. Chapter 5.1.2 describes the scenarios modeled in our analysis. Chapter 5.1.3 focuses on the methodology of assessing emissions impacts of volumes of biofuels produced from secondary products. Chapter 5.1.4 focuses on the methodology of assessing emissions impacts of volumes of fuels produced from crops.

5.1.1 Overview

The CAA prescribes multiple assessments of the GHGs associated with biofuels, including biofuel lifecycle assessments for the purpose of determining the qualification of a fuel

²⁴⁰ Additional details of this methodology and model results are available in “Economic Modeling of Climate Change Impacts for Crop-based Fuels,” available in the docket for this action.

under the RFS program,²⁴¹ and, separately, as required by CAA section 211(o)(2)(B)(ii), assessments of climate change impacts of setting volume standards. These two prescribed sets of analyses serve different purposes under the statute. While there are many methodological similarities between the two, there are also important differences that are informed by their statutory bases and programmatic purposes.²⁴² This section describes our methods of assessing the potential climate change impacts of setting volume standards under various scenarios, as required by CAA section 211(o)(2)(B)(ii).²⁴³

EISA required substantial changes to the RFS program as it existed at the time. Among these changes was the establishment of statutorily defined volumes of different categories of renewable fuels. For three categories—renewable fuel, advanced biofuel, and cellulosic biofuel—statutorily defined volumes extended through 2022. For the BBD category, statutory volumes extended through 2012.²⁴⁴ When setting volume requirements beyond the statutorily defined volumes, and in limited other circumstances, CAA section 211(o)(2)(B)(ii) states that the basis for setting RVOs must include, among other things, “an analysis of...the impact of the production and use of renewable fuels on the environment, including on...climate change.”

The substantial changes to the RFS program prescribed by EISA were implemented in the 2010 RFS2 Rule. At that time the volumes were still defined by the statute and EPA was not required to analyze climate change impacts under CAA section 211(o)(2)(B)(ii) in order to promulgate RVOs. Regardless, EPA developed and applied a methodology for assessing the climate impacts of volumes established under EISA in the 2010 RFS2 Rule²⁴⁵ for the purpose of inclusion in a cost benefit analysis, following guidelines established Executive Order 12866, which provides guidance on conducting cost benefit analysis for significant regulatory actions.²⁴⁶

In the RFS rules setting BBD volume standards in years between and including 2013 and 2020, the climate change analysis required by CAA section 211(o)(2)(B)(ii) was limited to BBD standards because volumes for the other three categories of renewable fuels were defined by statute. In those actions, EPA concluded that volumes of BBD supplied to the U.S. market were driven by the advanced standard, not the BBD standard, so the impact of the BBD standard on climate change and other statutorily defined factors was negligible.²⁴⁷ Thus for these rules, EPA

²⁴¹ “Lifecycle greenhouse gas emissions” is defined under the RFS program in CAA section 211(o)(1)(H) and is applicable to the determinations of GHG reduction thresholds for different categories of fuels defined in CAA section 211(o)(1)(B)(i), (D), (E), and (o)(2)(A)(i).

²⁴² For this reason, it may be misleading or analytically inappropriate to interpret results from a climate change analysis conducted under CAA section 211(o)(2)(B)(ii) as determinative evidence in a threshold determination under CAA section 211(o)(1), or vice versa. See additional discussion in RTC Section 9.2.1.

²⁴³ This action does not address EPA’s methodology for assessing “lifecycle greenhouse gas emissions” as defined under CAA section 211(o)(1)(H) for the purpose of determining qualification of fuels under the RFS program.

²⁴⁴ CAA section 211(o)(2)(B)(i)

²⁴⁵ RFS2 Rule RIA, Chapter 2.7.

²⁴⁶ Executive Order 12866: Regulatory Planning and Review. <https://www.federalregister.gov/executive-order/12866>.

²⁴⁷ See, e.g., discussion in the 2019 Rule: “...EPA’s primary assessment of the statutory factors for the 2020 BBD applicable volume is that because the BBD requirement is nested within the advanced biofuel volume requirement, we expect that the 2020 advanced volume requirement, when set next year, will determine the level of BBD use, production and imports that occur in 2020. Therefore, EPA continues to believe that approximately the same overall

determined it was not required to and did not conduct quantitative analyses of the impacts of the RVO standards on climate change.

In the 2020–2022 Rule,²⁴⁸ EPA utilized the volume waiver defined in CAA section 211(o)(7)(F) to set standards deviating from statutorily defined volumes. This waiver authority invokes the analytical criteria set forth in 211(o)(2)(B)(ii). Thus, the 2020–2022 Rule was the first time EPA conducted a quantitative assessment of climate change impacts to satisfy 211(o)(2)(B)(ii).²⁴⁹

The analytical criteria set forth in 211(o)(2)(B)(ii) apply for all volume standards set under the RFS program after 2022. Thus, for the Set 1 Rule, which established volume standards for 2023, 2024 and 2025, EPA assessed the potential climate change impacts of those standards. We again assess the potential climate change impacts of the 2026 and 2027 standards under this rule, as required by the CAA.

The climate change assessment presented in the 2010 RFS2 rule relied on a combination of models and additional data sources to estimate potential global GHG emissions impacts of the RFS program from 2010–2022. This methodology was based on the best models and science available at the time. While our 2010 analysis represented a best-in-class approach at the time of publication, evidence gathered over the course of the 2010s and early 2020s from expert discussions, input from public stakeholders, and EPA’s review of the available literature subsequently led us to conclude that an updated approach would be appropriate for any new evaluations going forward.

First and most critically, some of the tools which comprised our 2010 methodology were no longer maintained and ceased to be operational by the end of 2022. In addition, our 2010 methodology required the use of one model to represent impacts in the U.S. and another to represent the rest of the world. This was necessary in 2010 when no suitable modeling tool was available which integrated the global agricultural economy into a single framework. However, by 2022, several potentially suitable global models which integrated key economic sectors and global trade were available. In 2010, we estimated land use change emissions by stitching together individual sets of economic modeling results with satellite imagery and soil carbon datasets using elaborate and largely manual post-processing routines, which had numerous opportunities for user errors. By 2022, several models could integrate all these factors more accurately and consistently. Finally, in 2010 we were reliant on historical data and forward-looking projections from 2008 or earlier to estimate future impacts in 2022 and onward. These factors led to the conclusion that relative to our 2010 methodology for assessing climate change

volume of BBD would likely be supplied in 2020 even if we were to mandate a somewhat lower or higher BBD volume for 2020 in this final rule. Thus, we do not expect our 2020 BBD volume requirement to result in a significant difference in the factors we consider pursuant to CAA section 211(o)(2)(B)(ii)(I)–(VI) in 2020.” (83 FR 63738–39; December 11, 2018)

²⁴⁸ 87 FR 39600 (July 1, 2022).

²⁴⁹ For the 2020–2022 Rule, EPA developed illustrative scenarios of the potential GHG impacts of the volume standards by adapting results from the analysis conducted for the 2010 RFS2 Rule.

impacts of volume standards, better tools were available to meet our statutory obligations under the RFS program.²⁵⁰

Recognizing that public input on models and methods available would be integral to incorporating the latest scientific advancements, EPA undertook multiple steps to engage with the scientific community and develop updated approaches suitable for assessing climate change impacts of volume standards under the RFS program. These steps included co-hosting a public workshop on biofuel GHG modeling,²⁵¹ publishing a model comparison exercise (MCE) technical report,²⁵² and considering the findings of a report published by the National Academy of Sciences, Engineering and Medicine (NASEM) on lifecycle analysis methods for low-carbon transportation fuel policies (hereafter the “the NASEM LCA Report”).²⁵³

However, when technical work commenced on the Set 1 Rule, the models used to conduct analysis of the costs and benefits of the RFS2 Rule were no longer operational and work on the MCE and NASEM LCA Report was still ongoing. For this reason, EPA was unable to conduct new modeling to assess climate change impacts of the volume scenarios, one of the statutory factors listed in the CAA that EPA was obligated to assess in the Set 1 Rule. EPA instead relied on a literature review approach for the Set 1 Rule. In that analysis, we identified ranges of potential lifecycle GHG emissions associated with each individual fuel pathway (*i.e.*, each unique combination of a feedstock, production process and fuel) from the available scientific literature. Lifecycle emissions estimates for each individual fuel pathway were then scaled to the projected change in the volume of that fuel to estimate a range of potential GHG impacts of the 2023–2025 standards.

While the literature review-based approach was necessary to assess GHG impacts under the Set 1 Rule for the reasons outlined above, it does have several deficiencies. First, combining assessments of individual pathways of fuels, as EPA did in the Set 1 Rule literature review-based approach, fails to represent key interactions that are present when a policy is expected to simultaneously affect volumes of multiple fuels. The lack of representation of interactions between fuels is particularly notable when assessing volumes of multiple fuels produced from feedstocks with significant land use requirements. For example, in simulations representing only an increase in corn ethanol, corn production may expand at the expense of soybean production via crop switching, while simulations representing increases in soybean biodiesel production may show the opposite: crop switching from corn to soybeans. Combining per-fuel effects to assess the overall impacts of simultaneous changes in fuel volumes can introduce such

²⁵⁰ Note that the 2020–2022 Rule was published in June 2022, at which point EPA had not developed an alternative modeling framework for conducting the climate impacts analysis of an RFS standards rule. Thus, the illustrative climate impacts analysis in the 2020–2022 Rule relied on straightforward adjustments to existing modeling conducted in the 2010 RFS2 Rule.

²⁵¹ EPA opened a public docket for the workshop (86 FR 73757; December 28, 2021) and received numerous public comments on appropriate data, models, and interpretive methods suitable for biofuel GHG emissions assessments.

²⁵² EPA, “Model Comparison Exercise Technical Document,” EPA-420-R-23-017, June 2023.
<https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf>.

²⁵³ National Academies of Sciences, Engineering, and Medicine (“NAS”). *Current Methods for Life Cycle Analyses of Low-Carbon Transportation Fuels in the United States*. National Academies Press eBooks, 2022.
<https://doi.org/10.17226/26402>.

inconsistencies between simulations, and can substantially affect the overall emissions estimates, as was recognized in the 2010 RFS2 Rule.²⁵⁴

Second, for fuels produced from feedstocks with land use requirements (*i.e.*, crop-based fuels), only a handful of the studies identified in the literature review produced emissions estimates that represented the temporal dynamics of land use change emissions; among these, only the pathway specific modeling from EPA's own 2010 RFS2 Rule analysis reported annual emissions impacts.²⁵⁵ This limitation restricted the illustrative monetized scenario, for volumes of crop-based biofuels, to represent only the results of EPA's 2010 modeling, not the full breadth of impacts reported across more recent studies identified in the literature.

Finally, the literature review-based analysis did not attempt to weigh or rank the validity or robustness of the many different methods employed in studies it considered. Instead, the literature review-based approach presented a summary of the state of recent literature on biofuel lifecycle analysis and the wide breadth of potential impacts estimated therein.²⁵⁶ For the above reasons, the climate impacts assessment in the Set 1 Rule was presented as "illustrative" of the range of potential GHG impacts of the 2023–2025 volume standards.

While a literature review remains a reasonable methodological approach for meeting EPA's obligation to analyze climate change impacts, the Agency has now had sufficient time to develop an updated modeling-based approach. For the GHG impacts assessment in the Set 2 rule, we have developed a methodology based on information gathered through the biofuel modeling workshop, the MCE Technical Report, the NASEM LCA Report, and the literature review conducted for the Set 1 Rule. This methodology utilizes new modeling with separate approaches for two categories of fuels which differ in their scope of expected significant market-mediated impacts: fuels produced from secondary products, and fuels produced from crops.

Secondary product feedstocks are, by definition, not the primary driver of an economic activity; they are produced as secondary or tertiary outputs of a primary activity which is responsive to market pressures. Our review of the best available science has led us to conclude that it is appropriate to evaluate fuels produced from these feedstocks with supply chain models

²⁵⁴ In the RFS2 Rule EPA said: "...simply adding up the individual lifecycle results... multiplied by their respective volumes would yield a different assessment of the overall impacts. The two analyses [individual fuel scenarios and combined fuel scenarios] are separate in that the overall impacts capture interactions between the different fuels that cannot be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions... [W]hen looking at individual fuels there is some interaction between different crops (*e.g.*, corn replacing soybeans), but with combined volume scenario when all mandates need to be met there is less opportunity for crop replacement (*e.g.*, both corn and soybean acres needed) and therefore more land is required." 75 FR 14797-14798 (March 26, 2010).

²⁵⁵ Most studies of GHG emissions impacts of individual biofuels present per-megajoule CI metrics that represent average emissions over an assumed period of analysis (30 years in EPA's methodology).

²⁵⁶ Chapter 4.2.2 of the Set 1 Rule RIA states: "Given that all LCA studies and models have particular strengths and weaknesses, as well as uncertainties and limitations, our goal for this compilation of literatures estimates is to consider the ranges of published estimates, not to adjudicate which particular studies, estimates or assumptions are most appropriate. Reflecting the many approaches to LCA and associated assumptions and uncertainties, our review is intentionally broad and inclusive of a wide range of estimates based on a variety of study types and assumptions."

rather than economic models.²⁵⁷ Although there may be market-mediated effects associated with increased demand for these fuels and feedstocks, we have concluded that the use of currently available economic modeling tools representing global commodity markets is not necessary or useful in this context. Global economic models as a class currently lack detail on the supply chains for key non-crop-based fuels, such as FOG and biogas. This makes use of dedicated supply chain models the most appropriate choice, given that they can represent supply chains for these fuels in significant detail. NASEM recommendations, available studies examined through the Set 1 Rule literature review, and stakeholder input received through the 2023 LCA workshop all support the conclusion that assessment of the GHG impacts of these fuels can be adequately addressed using supply chain modeling. In the climate change analysis undertaken for the purpose of assessing the costs and benefits of the RFS2 Rule, we used aspects of the GREET supply chain model to assess this category of fuels. In our climate change analysis for this rule, we rely more fully on a recent release of the R&D GREET model, specifically the R&D GREET 2024 Revision 1 version.²⁵⁸ For the purposes of this rule, we hereafter use the terms “the R&D GREET model” to specifically mean R&D GREET 2024 Revision 1, unless otherwise noted. Implementation and additional assumptions for our assessment of pathways for fuels produced from secondary products are detailed in Chapter 5.1.3.

By contrast, feedstock crops used in the production of biofuels are primarily global commodities with values influenced by multiple end-uses, including human consumption, animal feed, biofuel production, and other industrial uses. The amount of additional production of these crops that is needed to meet increasing U.S. demand for biofuels is directly influenced by market reactions specific to each of these end-use sectors, including the elasticities of demand to changes in price, and availability and affordability of substitutes. On the supply side, the source of additional feedstock crops is also governed by market factors. Production of feedstock crops can be expanded through changing planting patterns on existing cropland (*i.e.*, “crop switching”), increasing yields through more intensive use of inputs, or expanding overall cropland into other land use types. Choices between these options are governed by availability and costs of technologies and land which are specific to each region. Accounting for these market dynamics requires use of a model that represents economic relationships between these key sectors for each region. Additionally, these market dynamics have been repeatedly demonstrated to have significant impacts on overall GHG emissions estimates. In the literature review of biofuel lifecycle analyses conducted in the Set 1 Rule, a majority of studies of crop-based fuels that were considered showed emission from land use change to be a significant portion of overall estimated emissions impacts. Furthermore, EPA’s MCE Technical Report found that assessment of

²⁵⁷ Supply chain models are detailed accounting tools which assess direct inputs, processes, and associated emissions throughout the supply chain of a product, from feedstock production to final distribution and use. Supply chain models typically do not represent price effects induced by changes in demand for process inputs or changes in supply of outputs, nor the market impacts of those changes across other economic sectors. Economic models, by contrast, are designed to represent relevant economic relationships and assess market-mediated impacts associated with changes in supply or demand.

²⁵⁸ Wang, Michael, Cai, Hao, Ou, Longwen, Elgowainy, Amgad, Alam, Md Rakibul, Benavides, Pahola T., Benvenuti, Livia, Burnham, Andrew, Do, Thai N., Farhad, Masum, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Kwon, Hoyoung, Lee, Uisung, Lim, Juin Y., Liu, Xinyu, Lu, Zifeng, Morales, Michele, Ng, Clarence, Pandey, Ishan, Shukla, Siddharth, Siddique, Nazib, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhou, Jo. “Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2024 Excel).” Computer software. December 20, 2024. <https://doi.org/10.11578/GREET-Excel-2024/dc.20241203.1>.

emissions from land use change is critical for assessment of biofuel GHG impacts. For these reasons, and based on our review of the available science referenced above, we continue to conclude that production and use of crop-based fuels have the potential for substantial market-mediated effects with significant implications for GHG emissions.²⁵⁹

As such, the GHG impacts of changes in volumes of these fuels are most appropriately assessed through simulation within global economic models with detailed representations of the key markets and biophysical processes associated with a change in biofuel production and use.²⁶⁰ For this analysis, we rely on modeling of changes in crop-based fuels using three of the models considered in the 2023 MCE Technical Report: the Global Trade Analysis Project-Biofuels model (GTAP-BIO), the Global Change Analysis Model (GCAM), and the Global Biosphere Management Model (GLOBIOM). This modeling incorporates several important advancements over past climate change impact assessments under the RFS program. First, whereas the modeling for crop-based fuels conducted under the RFS2 Rule analysis imperfectly combined results from different U.S. and international economic models and post-hoc land use change estimation methods, the models used in the analysis for this rule have globally integrated representations of relevant agricultural commodities, including trade, and endogenously represent land use change. Second, these models all have benefited from significant ongoing development over the last decade, incorporating the latest science and agricultural and energy system data into their simulations. Finally, for two of the three models used we were able to conduct scenarios that represent important interactions under simultaneous changes in volumes of fuels produced from different agricultural feedstocks—a key deficiency, noted above, of the Set 1 Rule approach. The GTAP-BIO, GCAM, and GLOBIOM models, their relative strengths and reasons for selection, and implementation for the Analyzed Volumes are discussed in 5.1.4 and in a memo to the docket.²⁶¹

Finally, while the methodology used in this rule represents significant progress in GHG emission impacts assessment modeling since 2010, the conclusions of the NASEM report, the MCE Technical Report, and stakeholder input all make clear that estimating the climate change impacts of biofuels is inherently complex and that significant uncertainties will continue to be a feature of this type of analysis. Over the last decade, numerous studies have been published examining how uncertainty associated with structural choices within, and parameterization of,

²⁵⁹ EPA first established a multi-model approach to assessing market-mediated impacts of crop-based fuels in the RFS2 Rule. See discussion in the 2009 NPRM at 74 FR 25025 (May 26, 2009).

²⁶⁰ The use of economic modeling for this assessment is also well aligned with the recommendations of the 2022 NASEM LCA Report, which concluded that regulatory impact analyses should use consequential methods to evaluate market-mediated impacts to assess the extent to which a given policy design will result in changes in GHG emissions (Conclusion 3-1, Recommendations 2-2, 3-2).

²⁶¹ See “Economic Modeling of Climate Change Impacts for Crop-based Fuels,” available in the docket for this action.

economic models influence assessments of biofuel GHG emissions impacts.^{262,263,264} While this work has yielded important insights into the most critical assumptions in these models, other aspects of forward-looking impacts analysis are inherently uncertain. For example, changes in future policies, both in the U.S. and in other countries, can affect international trade and land use decisions globally, with subsequent effects on emissions outcomes. Such uncertainty cannot be eliminated in this, or any, forward-looking impacts analysis, but further characterizing that uncertainty and outcomes under different potential scenarios, across and within individual models, remains an important area for continued research.

5.1.2 Scenarios Assessed

Scenarios described in Preamble Section III include estimates of volumes of different qualifying biofuels that would be expected to be consumed in the United States under Analyzed Volumes. The differences between the estimated future effects of these projected fuel volumes and the estimated future effects of the parallel volumes developed for the No RFS Baseline form the basis of our analysis of the GHG impacts of Analyzed Volumes.

5.1.2.1 Analyzed Volumes

Chapter 3 presents the renewable fuel volumes represented by each of the scenarios assessed for this rule. Analyzed Volumes by RIN category are presented in Table 3.1-1. These RIN volumes are translated into projected volumes by fuel and feedstock and compared against projections of volumes by fuel and feedstock under the No RFS Baseline. The resulting differences between the projected volumes and No RFS Baseline are presented in Table 3.2-2 and form the basis of our analysis of the potential climate change impacts of this rule.

For the climate change analysis, we assess only volumes of the qualifying fuels which are estimated to have significant volume differences compared to the No RFS Baseline. This includes all fuel categories appearing in Table 3.2-1 with the following exceptions: “Jet Fuel from FOG” is assumed to be renewable diesel for the purposes of this assessment, and “Other” shows a relatively small volume (67 million gallons delta compared to the No RFS Baseline) and represents an unknown mix of various fuel types with smaller volumes. We have excluded this volume from our analysis because this mix is unknown and unpredictable. However, we would expect it to have only minor additional emissions impacts as this is a relatively small amount of fuel compared to the overall changes in volumes; we do not believe this exclusion meaningfully changes the results of our analysis, or the conclusions stakeholders may draw from them, in any way.

²⁶² Escobar, Neus, Hugo Valin, Stefan Frank, Diana Galperin, Christopher M. Wade, Leopold Ringwald, Daniel Tanner, et al. “Understanding Uncertainty in Market-Mediated Responses to US Oilseed Biodiesel Demand: Sensitivity of ILUC Emission Estimates to GLOBIOM Parametric Uncertainty.” *Environmental Science & Technology* 59, no. 1 (December 18, 2024): 302–14. <https://doi.org/10.1021/acs.est.3c09944>.

²⁶³ Golub, Alla A., and Thomas W. Hertel. “Modeling Land-Use Change Impacts of Biofuels in the Gtap-Bio Framework” *Climate Change Economics* 03, no. 03 (August 1, 2012): 1250015. <https://doi.org/10.1142/s2010007812500157>.

²⁶⁴ Plevin, Richard J., Jason Jones, Page Kyle, Aaron W. Levy, Michael J. Shell, and Daniel J. Tanner. “Choices in Land Representation Materially Affect Modeled Biofuel Carbon Intensity Estimates.” *Journal of Cleaner Production* 349 (March 22, 2022): 131477. <https://doi.org/10.1016/j.jclepro.2022.131477>.

For the purposes of our climate change analysis, we disaggregate estimated volumes of biofuels produced from FOG into fuels produced from animal tallow and fuels produced from used cooking oil. To do this, we assume 35% of fuels produced from FOG are produced from used cooking oil, and 65% are produced from tallow. This assumption is based on EIA data and is described in additional detail in Chapter 3.2. Additionally, FOG-based fuels are disaggregated into fuels produced from domestic vs. imported feedstocks, which is discussed in Chapter 3.1. Finally, we note that biofuels produced from distillers corn oil are treated as byproduct-based fuels, following the convention established in the RFS2 Rule. In that rule, EPA determined that distillers corn oil should be treated as a byproduct of the dry mill process of producing ethanol from corn starch for the purpose of estimating the lifecycle GHG emissions of distillers corn oil-based fuels and corn starch based fuels. Consequently, these analyses attributed the indirect land use change emissions associated with using corn for ethanol production entirely to the corn starch ethanol; we continue to follow that established convention for the purposes of this analysis.

The volumes used in our climate change assessment of the Analyzed Volumes are presented in Table 5.1.2.1-1. Our assessment of the climate impacts under these scenarios is presented in Chapter 5.2.

Table 5.1.2.1-1: Difference in Consumption of Renewable Fuels (Trillion BTUs) in the Analyzed Volumes Relative to the No RFS Baseline

Fuel	Assessed market-mediated GHG emissions?	2026	2027
CNG/LNG from biogas	No	62	65
Biodiesel from Corn oil		23	15
Biodiesel from Used Cooking Oil (Domestic)		3	-7
Biodiesel from Used Cooking Oil (Imported)		0	0
Biodiesel from Tallow (Domestic)		5	-13
Biodiesel from Tallow (Imported)		0	0
Renewable Diesel from Corn Oil		7	16
Renewable Diesel from Used Cooking Oil (Domestic)		4	16
Renewable Diesel from Used Cooking Oil (Imported)		7	5
Renewable Diesel from Tallow (Domestic)		7	30
Renewable Diesel from Tallow (Imported)		12	10
Biodiesel from Soybean oil	Yes	65	97
Biodiesel from Canola oil		29	33
Renewable Diesel from Soybean oil		162	179
Renewable Diesel from Canola oil		121	135
Ethanol from Corn starch		18	19

5.1.2.2 Period of Analysis

Any analysis of the GHG emissions impacts of biofuel policies must specify the time period considered in the analysis (*i.e.*, the time period over which those emissions impacts will

be assessed). This decision can have a substantial impact on the result of the analysis, particularly for renewable fuels produced from feedstocks with land use requirements (*i.e.*, crops). To the extent that increased demand for crop-based biofuels results in cropland expansion onto previously natural lands (*e.g.*, new soybean hectares planted in the Brazilian Cerrado), then an initial pulse of emissions from carbon sequestered in biomass and soils would likely take place when the land is converted. Over time, if production and use of biofuels continue, the GHG benefits of displacing fossil fuels may eventually “pay back” the initial increase in GHG emissions from the initial expansion of cropland. Alternatively, to the extent that cropland is expected to revert to grassland or forest under a baseline (no policy) scenario, then continued use of that cropland under a policy scenario can result in foregone sequestration, with gradual but non-linear carbon uptake, relative to the baseline. It is therefore important that an analysis of the GHG emissions impacts of biofuels formulate assumptions about the period of analysis intentionally and then describe these choices transparently, as we do in this subsection.

In the specific context of this rule and EPA’s recurring responsibility to set RVOs under the RFS program, EPA must determine the appropriate timeframe over which to assess the GHG emissions impacts of setting only one or several years of RVO standards. Were EPA to use a scenario covering only the years for which volumes are set (*e.g.*, only 2026 and 2027 in this rule,) our analyses of the climate impacts of setting RFS volumes would account for all of the near term emissions increases associated with expanding use of renewable fuels produced from crops, but would never account for the longer term emissions decreases associated with continued displacement of fossil fuel over time through continued production and use of those fuels. We believe it is not reasonable to limit our climate assessment to the impacts in the years in which we are establishing volume standards. Nor would such a choice be the norm for assessing the impacts of a policy with effects that continue over time. When impacts of a regulatory action are anticipated to occur over a longer period than the time horizon of the regulatory action itself, it is both appropriate and a well-established best practice to consider that longer period in the regulatory impact analysis. For example, the cost analysis for this rule assumes a 15-year amortization period for capital expenses associated with increasing U.S. production capacity of affected fuels—also well beyond the time horizon covered by the standards in this rule.

The example of EPA’s LCA methodology under CAA section 211(o)(1)(H) provides an instructive illustration of the necessity of and the established scientific basis for considering this longer time horizon when estimating GHG impacts of renewable fuels. While this methodology serves a separate purpose in implementation of the RFS program, with statutory and analytical requirements that are distinct from our assessment of the climate impacts of setting RVO standards discussed in this section, the lifecycle analysis methodology similarly considered the question of the appropriate temporal scope of analysis. After considering public comments and the input of an expert peer review panel, in the RFS2 Rule, EPA determined that our lifecycle analysis for renewable fuels would quantify the GHG impacts over a 30-year period.²⁶⁵ In 2010, EPA listed the following reasons supporting the 30-year temporal scope: 1) it aligns with the average life of a typical biofuel production facility; 2) extending the analysis further than 30 years would add uncertainty; 3) this relatively short temporal scope (*e.g.*, relative to 100 years, which was supported by a number of stakeholders as an alternative to 30 years) is consistent with

²⁶⁵ See discussion of the selection of the 30-year period of analysis in the RFS2 Rule DRIA Chapter 2.4.5.

science indicating the benefits of reducing emissions in the near term.²⁶⁶ Since our lifecycle analysis methodology is the approach through which we determine whether individual biofuels meet the statutory GHG reduction thresholds necessary to be included in the program,²⁶⁷ and setting volumes standards is a key mechanism through which the RFS program promotes the use of those fuels, we believe it is appropriate for our accounting for the climate benefits of increasing volumes of those fuels to be consistent in temporal scope with the 30-year period of analysis.

Thus, the climate change analysis for this rule considers a time horizon of 30 years of impacts of renewable fuel consumption. For secondary product-based fuels, this represents 30 years of continuous production and displacement of fossil fuels at the volumes set in the 2027 standards. For crop-based fuels, the 30-year time horizon is represented in different ways, depending on the model structure. For GCAM and GLOBIOM, scenarios represent 2026 volumes developed for the No RFS Baseline scenario and the Analyzed Volumes and hold constant the 2027 volumes from 2027 through 2055, thus covering a 30-year analytical time frame from 2026 through 2055. For GTAP-BIO, which is a static-comparative modeling framework, scenarios represent different biofuel consumption volumes in a single timestep (2017) and thus do not explicitly model impacts over an extended time horizon. Instead, land area differences and associated carbon emissions are computed for the single timestep, and those emissions are then amortized over the analytical time horizon (*i.e.*, emissions are divided by 30). Additional discussion of the scenarios assessed in GCAM, GLOBIOM, and GTAP-BIO can be found in a memo to the docket.²⁶⁸

For the reasons outlined above, we believe a 30-year period of analysis is both reasonable and has the benefit of being consistent with other analysis used in RFS program implementation. However, we recognize that scenarios representing alternative renewable fuel consumption trajectories over the portion of the 30-year timeframe extending past the modeled standards years could be developed. Although analyses of other time frames could provide potentially useful sensitivities for the analysis of the potential climate impacts of volume standards, EPA did not have sufficient time to conduct such analyses at this time.

5.1.3 Secondary Product-based Fuels

For the purposes of defining categories of renewable fuel feedstocks in this climate change analysis, secondary products, including wastes, residues, and other byproduct materials, are considered to not be the primary driver of an economic activity; they are produced as secondary or tertiary outputs of a primary activity which is responsive to market pressures.²⁶⁹ For the purposes of this analysis, we assume that the market-mediated emissions impacts for these materials and the fuels produced from them are negligible. That is, we assume that there are no significant emissions associated with diverting materials in this category for use as feedstock

²⁶⁶ Id.

²⁶⁷ GHG reduction thresholds for different categories of fuels under the RFS program are defined in CAA section 211(o)(1)(B)(i), (D), (E), and (o)(2)(A)(i).

²⁶⁸ See “Economic Modeling of Climate Change Impacts for Crop-based Fuels,” available in the docket for this action.

²⁶⁹ See discussion of wastes and byproducts in the RFS2 Rule at 75 FR 14794 (March 26, 2010).

to produce renewable fuels. We recognize that some feedstocks considered to be secondary products in this analysis are globally traded commodities with prices tracked on major price reporting platforms. However, limitations on global production data make it challenging to model and assess potential market-mediated effects of changes in use of these fuels. So, while we do not estimate the market-mediated effects of fuels produced from secondary products here, this remains an ongoing topic of interest.²⁷⁰

Provided that using these feedstocks for biofuel production does not cause significant market-mediated impacts, it is then appropriate to estimate the emissions associated with these fuels with a supply chain analysis. A supply chain analysis focuses on the direct emissions that result from procuring and processing the feedstock into fuel, as well as the emissions associated with transporting and using that fuel. For fuels produced from secondary products, this represents all the relevant categories of emissions that should be considered as this type of analysis estimates the emissions associated with all the stages of the supply chain from the collection and transport of the feedstocks through to the production, transport and use of the finished fuel. Listed below are the fuels that are produced from feedstocks considered to be secondary products and which are assessed in our climate change analysis (*i.e.*, fuels with significant volume differences between the Analyzed Volumes and the No RFS Baseline).

- CNG/LNG produced from biogas from landfills
- Biodiesel and renewable diesel produced from distillers corn oil
- Biodiesel and renewable diesel produced from animal tallow
- Biodiesel and renewable diesel produced from used cooking oil

For each of these fuel pathways, we estimate the emissions impacts associated with the use of these fuels based on an analysis of the supply chain lifecycle GHG emissions for each pathway, including all relevant stages of fuel and feedstock production and distribution. Our estimates are based on modeling with the R&D GREET model developed and maintained by ANL. The DRIA used the 2023-Rev1 version of the R&D GREET model. The DRIA said, “Time permitting, we intend to update our estimates for the final rule based on the most recent version of the R&D GREET model available at that time.” We have undertaken the work to update these estimates using the 2024-Rev1 version of the R&D GREET model.²⁷¹ While our estimates rely on the R&D GREET model for data and emissions factors, we have made several adjustments and used a particular set of co-product accounting methods as appropriate based on

²⁷⁰ For example, see the following analysis of the relationship between increasing demand for fuels produced from used cooking oil and prices of virgin vegetable oils: Swanson, Andrew, Shawn Arita, Joseph Cooper, and Seth Meyer. “Secondary Impacts From Rising Used Cooking Oil Demand on Crop-Oil Prices.” *farmdoc daily* 14, no. 230 (December 19, 2024). <https://farmdocdaily.illinois.edu/2024/12/secondary-impacts-from-rising-used-cooking-oil-demand-on-crop-oil-prices.html>.

²⁷¹ Wang, Michael, Cai, Hao, Ou, Longwen, Elgowainy, Amgad, Alam, Md Rakibul, Benavides, Pahola T., Benvenuti, Livia, Burnham, Andrew, Do, Thai N., Farhad, Masum, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Kwon, Hoyoung, Lee, Uisung, Lim, Juin Y., Liu, Xinyu, Lu, Zifeng, Morales, Michele, Ng, Clarence, Pandey, Ishan, Shukla, Siddharth, Siddique, Nazib, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhou, Jo. “Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2024 Excel).” Computer software. December 20, 2024. <https://doi.org/10.11578/GREET-Excel-2024/dc.20241203.1>.

the purpose of our analysis. This section describes our analysis with the R&D GREET model and the resulting estimates.

For each fuel in this category, we multiply the volume changes, converted to megajoules, with the lifecycle GHG emissions factor we estimate for that fuel pathway. We then compare these emissions with the lifecycle GHG emissions associated with the fossil-based fuels they displace; emissions from fossil-based fuels are also estimated using the R&D GREET model and then multiplied by the assumed number of megajoules being displaced by renewable fuels.²⁷² Emissions factors estimated using the R&D GREET model for each of the renewable and fossil-based fuel pathways included in this part of the analysis are presented in Table 5.1.3-1. Additional information about the assumptions used for each of these estimates is presented in the subsections below.

Table 5.1.3-1: Emissions Factors Used for Climate Impacts Analysis of Secondary Product-based Fuels

	Fuel Pathway	gCO ₂ e/MJ
Secondary Product-based Fuels	CNG: Landfill Biogas	29.1
	Biodiesel: Distillers Corn Oil	27.7
	Biodiesel: UCO (Domestic)	14.7
	Biodiesel: UCO (Imported)	20.8
	Biodiesel: Tallow (Domestic)	15.1
	Biodiesel: Tallow (Imported)	21.1
	Renewable Diesel: Distillers Corn Oil	31.3
	Renewable Diesel: UCO (Domestic)	16.9
	Renewable Diesel: UCO (Imported)	23.1
	Renewable Diesel: Tallow (Domestic)	17.2
	Renewable Diesel: Tallow (Imported)	23.4
Fossil Fuels	Gasoline (E0)	92.1
	Diesel (B0)	90.6
	Natural Gas (CNG Vehicle)	70.1

Note that in our analysis of biodiesel for the final rule, volumes of fuel assessed in the scenarios in this section are calculated using energy densities of end-use biofuels, which includes the non-biogenic methanol portion of biodiesel. For this reason, and in contrast with the analysis conducted for the proposed rule, we include the CO₂ emissions from combustion of the non-biogenic methanol portion of biodiesel.²⁷³

We assume that the methanol used for biodiesel production is produced from conventional natural gas (21,652 gCO₂e/mmBtu), and that hydrogen for renewable diesel

²⁷² We assume use of renewable fuels displaces use of an equal amount of the relevant fossil fuel on an energy equivalent basis. We assume CNG derived from biogas displaces use of fossil natural gas and biodiesel and renewable diesel of all sources displaces use of diesel produced from petroleum. A sensitivity analysis for different levels of oil rebound (*i.e.*, with less than one-for-one energy equivalent displacement of fossil fuels) is presented in Chapter 5.3.

²⁷³ In the proposed rule, volumes of fuel assessed in the analytical scenarios were calculated using RIN equivalence values, which account only for the renewable content of the fuel.

production is produced by steam methane reforming of conventional natural gas (8,921 kgCO₂e/kg). The emissions associated with fuel produced at specific facilities that use other types of inputs (*e.g.*, renewable electricity, renewable natural gas, electrolytic hydrogen) would be associated with lower supply chain emissions.

5.1.3.1 CNG from Biogas

To determine the lifecycle GHG intensity of CNG from biogas, we used the R&D GREET model for background and process data. We modeled the offsite CNG fueling scenario where landfill gas is captured, upgraded to RNG, transported via pipeline and used to fuel a CNG vehicle at another location. We primarily used the default R&D GREET parameters for this analysis; the only notable exception is that we adjusted the pipeline transportation distance from 50 miles to 600 miles to match the default assumption for natural gas pipeline distribution. Given the prevalence of book-and-claim accounting for RNG we do not see a strong reason to assume RNG is transported a shorter distance than natural gas in the pipeline distribution network. This adjustment increased the estimated lifecycle emissions by approximately 3 grams of CO₂-equivalent per megajoule (gCO₂e/MJ).

For this analysis we assume that biogas is a byproduct of landfilling and collected by the landfills to prevent the emission of methane gas, as required by regulation,²⁷⁴ and flared. This assumption is consistent with the approach that EPA adopted for Pathways II Rule.²⁷⁵ See in particular the technical memo to the docket for the 2014 rule explaining EPA’s rationale for using a flaring baseline to evaluate biogas lifecycle emissions.²⁷⁶

Finally, the tailpipe emissions associated with CNG use as a transportation fuel were modeled using a passenger vehicle from the 2019 model year that utilizes a spark ignition system in its internal combustion engine. Using the above methodology, we calculate that CNG from the assessed sources of biogas have supply chain GHG emissions and total lifecycle emissions intensities as summarized in Table 5.1.3.1-1.

Table 5.1.3.1-1: Supply Chain Emissions Associated with CNG Fuel from Biogas (gCO₂e/MJ)

Supply Chain Stage	Landfill Biogas CNG
Fuel Production	22.4
Fuel Transport and Distribution	5.6
Fuel Use	1.1
Total	29.1

²⁷⁴ 61 FR 9905 (March 12, 1996).

²⁷⁵ 79 FR 42128 (July 18, 2014).

²⁷⁶ “Support for Classification of Biofuel Produced from Waste Derived Biogas as Cellulosic Biofuel and Summary of Lifecycle Analysis Assumptions and Calculations for Biofuels Produced from Waste Derived Biogas,” Docket Item No. EPA-HQ-OAR-2012-0401-0243. <https://www.regulations.gov/document/EPA-HQ-OAR-2012-0401-0243>.

5.1.3.2 Distillers Corn Oil-based Fuels

As part of the climate change analysis, we estimate the emissions associated with biodiesel and renewable diesel produced from distillers corn oil. For this analysis, we assume the feedstocks and fuels are produced and used in the U.S. using industry average production practices. Our analysis assumes the biodiesel is produced through a standard transesterification process and that the renewable diesel is produced through a standard hydrotreating process.

Distillers corn oil is a byproduct of dry mill corn ethanol production. At dry mill ethanol plants, corn grain is ground and fermented to produce ethanol with co-product distillers grains and solubles (hereafter “distillers grains”), a protein-rich livestock feed. The large majority of dry mill ethanol plants extract distillers corn oil from the distillers grains. The distillers corn oil is used as feedstock to produce BBD or added back to livestock feed as a source of fat and calories. Based on the data from the R&D GREET model, on an energy content basis (lower heating value), the outputs from an average U.S. dry mill ethanol plant with corn oil extraction are approximately 63% ethanol, 33% distillers grains, and 4% distillers corn oil.

Given that distillers corn oil is one of three outputs from a dry mill ethanol plant, co-product accounting methods are required to estimate what quantity of the gross emissions associated with the ethanol supply chain are attributable to the ethanol production and what quantity of emissions are attributable to the distillers corn oil production. To make these estimates, we use a unit-process level energy allocation approach.²⁷⁷ That is, we evaluate the emissions and outputs associated with each individual process in the supply chain and allocate the emissions among the outputs from each of these processes based on the energy content of each output and an assessment of the primary purpose of each process.

We allocate the supply chain emissions associated with corn farming and transport to all three co-products on an energy basis. Thus, we allocate approximately 4% of the supply chain corn farming and transport emissions to the distillers corn oil.²⁷⁸

For all but one of the unit processes within the dry mill ethanol process, we allocate all the emissions associated with the process energy and chemical inputs to the ethanol output, as these processes are carried out for the specific purpose of ethanol production. The one exception is that we allocate emissions associated with distillers corn oil extraction to the corn oil. We make this choice because extracting corn oil does not contribute to the production of ethanol or distillers grains. The reason corn oil extraction is undertaken is not because of the decision to produce ethanol; instead, corn oil extraction is an additional step for the purpose of producing corn oil as a product distinct from distillers grains. Even if the corn had not been used to produce ethanol, a separate oil extraction process would still be needed to produce corn oil. That is, any extraction process to produce corn oil from corn would occur regardless of whether that corn was

²⁷⁷ ISO 14044 defines unit process as the “smallest element considered in the life cycle inventory analysis for which input and output data are quantified.”

²⁷⁸ This ensures that the supply chain emissions associated with distillers corn oil production are not double counted when we sum the market-mediated emissions estimates associated with corn ethanol with the supply chain emissions estimates associated with distillers corn oil-based biodiesel and renewable diesel.

involved in ethanol production. For example, wet mill corn processing facilities which make high fructose corn syrup may engage in similar unit processes to also produce corn oil.

We recognize that there are multiple methods for co-product accounting. The NASEM LCA Report discusses the various co-product accounting methods used in policy and scientific literature. This report observes that “it is important to pair allocation methods with the policy objective,” but it does not make any conclusions or recommendations about which methods are most appropriate. Overall, we observe that existing low-carbon fuel policies and models have taken various approaches to co-product accounting, reflecting a lack of consensus on the most appropriate approach.

While there are many viable options for co-product accounting, we believe that the unit process energy allocation approach is the most appropriate method for the supply chain emissions component of our analysis of biodiesel and renewable diesel produced from distillers corn oil. Energy allocation is an appropriate approach because the primary purpose of the biodiesel and renewable diesel production we are evaluating is to produce transportation fuel as a source of energy. The energy allocation method is based on the physical properties of the co-products, which are stable characteristics in the sense that they do not depend on context or market value fluctuations. In contrast, both the system expansion approach and the market-based allocation approaches are subject to fluctuations due to changing markets, policies, technologies, and other factors. Using these other allocation methods therefore requires a substantial number of additional assumptions to account for these considerations, many of which are uncertain and difficult to parameterize, and which can also significantly influence the results of the analysis. This makes LCA using these approaches more complex, more difficult to adequately document, explain, and understand, and more uncertain. Thus, relative to other options, energy allocation is a more transparent and stable methodology based on physical properties rather than fluctuating market dynamics.

To estimate the supply chain emissions associated with growing and harvesting corn, we use data from the R&D GREET model on the average inputs and yields associated with U.S. corn production. The R&D GREET model sources these data from USDA’s major survey programs, the National Agricultural Statistics Service (NASS), the Economic Research Service (ERS), and the Office of the Chief Economist (OCE) reports.²⁷⁹ For our analysis of the supply chain lifecycle emissions, we assume average corn yield of 177 bushels per harvested acre. Our analysis considers average inputs to corn farming, such as fertilizer, pesticide, diesel fuel to run tractors, and electricity to run irrigation pumps. Based on the R&D GREET model background data, we assume that the harvested corn is transported 10 miles by medium-duty truck to a collection point and then 40 miles by heavy-duty truck to an ethanol plant.

We estimate the emissions associated with extracting corn oil from the distillers grains based on data from the R&D GREET model representing an average U.S. dry mill ethanol plant with corn oil extraction. Based on the R&D GREET model data, we assume that the oil

²⁷⁹ For further information, see Lee, Uisung, Hoyoung Kwon, May Wu, and Michael Wang. “Retrospective Analysis of the U.S. Corn Ethanol Industry for 2005–2019: Implications for Greenhouse Gas Emission Reductions.” *Biofuels Bioproducts and Biorefining* 15, no. 5 (May 4, 2021): 1318–31. <https://doi.org/10.1002/bbb.2225>.

extraction equipment consumes 183 Btu of electricity per pound of distillers corn oil output (we assume the extraction equipment does not consume natural gas or other thermal process energy).

Our analysis includes the emissions associated with transporting the distillers corn oil feedstock to biodiesel or renewable diesel production facilities. Based on data from the R&D GREET model, we assume that 20% of distillers corn oil used as biofuel feedstock is transported by rail 400 miles, and 80% of this oil is transported by heavy-duty truck 100 miles. We assume that these feedstock transport modes and distances are the same for biodiesel and renewable diesel production.

Our estimates include the emissions associated with biodiesel and renewable diesel production. We use operational data from the R&D GREET model and the energy allocation approach discussed above to account for co-products. For biodiesel production, we assume the process inputs per pound of biodiesel output are 1.003 pounds of distillers corn oil, 1,137 Btu of natural gas, 146 Btu of electricity and 896 Btu of methanol. The other biodiesel inputs considered in our analysis are nitrogen gas, sodium methoxide, hydrochloric acid, and phosphoric acid. We assume that 0.097 dry pounds of byproduct glycerin is produced per pound of biodiesel output. For renewable diesel production, we assume the process inputs per pound of renewable diesel output are 1.26 pounds of distillers corn oil, 352 Btu of natural gas, 185 Btu of electricity and 2,071 Btu of hydrogen. We assume that 0.099 pounds of propane fuel mix is co-produced per pound of renewable output.

We estimate the emissions associated with biodiesel and renewable diesel transportation and distribution based on data and emissions factors from the R&D GREET model. We assume that biodiesel is transported from the production facility to a bulk terminal with the following modes and distances: 49% by barge for 200 miles, 46% by pipeline for 110 miles, and 5% by rail for 490 miles. We assume that renewable diesel is transported from the production facility to a bulk terminal with the following modes and distances: 8% by barge for 520 miles, 29% by rail for 800 miles, and 63% by truck for 50 miles. We assume that both biodiesel and renewable diesel are distributed from bulk terminals to refueling stations 30 miles via heavy-duty tanker truck. Consistent with the R&D GREET model, we assume 0.004% of biodiesel and renewable diesel is lost during transportation, distribution and refueling.

Finally, based on emissions factors from the R&D GREET model, we include the emissions associated with using the biodiesel and renewable diesel in a diesel engine car. We include the non-CO₂ emissions associated with biodiesel combustion. Consistent with the methodology developed for the RFS2 Rule, we do not include the biodiesel combustion CO₂ emissions because we treat the carbon in the finished fuel derived from renewable biomass as biologically derived carbon recently originating from the atmosphere. In the context of a full lifecycle analysis, the uptake of this carbon from the atmosphere by the renewable biomass and the carbon dioxide emissions from combusting it cancel each other out. Therefore, instead of evaluating both the carbon uptake and tailpipe carbon dioxide emissions, we leave both values out of our estimates. Note that, when applicable, our analysis also accounts for all significant supply chain and market-mediated emissions, such as from land use changes, meaning that we do not simply assume that the ethanol or other biofuels are “carbon neutral.”

Our estimates of the supply chain GHG emissions associated with U.S. average biodiesel and renewable diesel produced from distillers corn oil are summarized in Table 5.1.3.2-1.

Table 5.1.3.2-1: Supply Chain Emissions Associated with Distillers Corn Oil-based Fuels (gCO_{2e}/MJ)

Supply Chain Stage	Biodiesel	Renewable Diesel
Corn Production and Transport	17.6	19.1
Corn Oil Extraction	1.2	1.2
Corn Oil Transport	0.3	0.3
Fuel Production	3.6	9.5
Fuel Transport	0.3	0.4
Fuel Use	4.7	0.7
Total	27.7	31.3

5.1.3.3 Tallow and Used Cooking Oil-based Fuels

As part of the climate change analysis, we estimate the emissions associated with biodiesel and renewable diesel produced from animal tallow and UCO. For the analysis in this final rule, we differentiate fuels produced from domestically produced versus imported fats, oils, and greases, where imported feedstocks have higher lifecycle emissions estimates due to higher emissions associated with transportation. Our analysis assumes that the biodiesel is produced through a standard transesterification process and that the renewable diesel is produced through a standard hydrotreating process.

Tallow is produced through rendering animal by-products from cattle slaughtering.²⁸⁰ While edible tallow is used as shortening for baked goods, we assume that only inedible tallow is used as a feedstock for biofuel production. Inedible tallow is a byproduct that, when not used as biofuel feedstock, can be used in animal feed, soap production, and lubricants.

UCO is collected from commercial kitchens and restaurants. The collected UCO is brought to rendering facilities where excess water is removed. The result of UCO rendering is sometimes referred to as yellow grease, but for simplicity here we use the term UCO to refer to the UCO before and after rendering. When not used as a biofuel feedstock, UCO can be used an additive in pet food and animal feed.

To estimate the supply chain emissions associated with collecting rendering and transport tallow and UCO, we use data and emissions factors from the R&D GREET model representing average U.S. practices. The R&D GREET model data are based on industry surveys and data from the literature.

For domestic UCO collection, we assume UCO is collected at restaurants and commercial kitchens and trucked 150 miles by heavy-duty truck to rendering facilities. We assume that 23% of the collected UCO is transported to a transfer station and then trucked an

²⁸⁰ Seber, Gonca, Robert Malina, Matthew N. Pearlson, Hakan Olcay, James I. Hileman, and Steven R.H. Barrett. "Environmental and economic assessment of producing hydroprocessed jet and diesel fuel from waste oils and tallow." *Biomass and Bioenergy* 67 (May 20, 2014): 108–18. <https://doi.org/10.1016/j.biombioe.2014.04.024>.

additional 200 miles by heavy-duty truck to the rendering facilities. We assume that on average 908 Btu of natural gas and 107 Btu of electricity are used to render each pound of resulting dewatered UCO. The rendered UCO is then transported to biofuel plants using the following modes and distances: 95% by truck for 130 miles, and 5% by rail for 500 miles. Based on the R&D GREET default assumptions, we assume that on average imported UCO is transported 8,975 miles by ocean tanker.

For tallow rendering, we assume 1,052 Btu of natural gas and 307 Btu of electricity are used per pound of rendered tallow. R&D GREET assumes the following average transportation modes and distances for transporting domestically produced tallow from rendering facilities to biofuel plants: 20% by rail for 400 miles, and 80% by truck for 100 miles. Because imported tallow is not explicitly represented in R&D GREET, we use the additional emissions associated with importing UCO as a proxy for the additional transportation emissions associated with importing tallow.

Our estimates include the emissions associated with biodiesel and renewable diesel production. We use operational data from the R&D GREET model and the energy allocation approach discussed above to account for co-products. For UCO and tallow biodiesel production, we assume the process inputs per pound of biodiesel output are 1.05 pounds of UCO, 1,142 Btu of natural gas, 147 Btu of electricity and 900 Btu of methanol. We assume that 0.071 dry pounds of glycerin are coproduced with each pound of biodiesel output.

For renewable diesel production, we assume the process inputs and outputs are the same when either tallow or UCO are used as feedstock. Per pound of renewable diesel output, the process inputs are 1.26 pounds of feedstock, 352 Btu of natural gas, 185 Btu of electricity, and 2,071 Btu of hydrogen. We assume that 0.099 pounds of propene fuel mix is coproduced per pound of renewable output.

To evaluate the emissions associated with biodiesel and renewable diesel transportation, distribution, and use, we use the same methods and data for corn oil-based fuels as described in Chapter 5.1.3.2. For this analysis we use emissions factors from the R&D GREET model representing current average U.S. industry operations (see Chapter 5.1.3.2 for further description of these emissions factors).

Our estimates of the supply chain GHG emissions associated with U.S. average biodiesel and renewable diesel produced from UCO and tallow are summarized in Tables 5.1.3.3-1 and 5.1.3.3-2 respectively. The calculations upon which these estimates are based are contained in spreadsheets that are available in the public docket for this rule.

Table 5.1.3.3-1: Supply Chain Emissions Associated with UCO-based Fuels (gCO₂e/MJ)

Fuel Type:	Biodiesel		Renewable Diesel	
UCO Source:	Domestic	Imported	Domestic	Imported
Collection, Rendering and Transport	6.2	12.2	6.3	12.4
Fuel Production	3.6	3.6	9.5	9.5
Fuel Transport	0.3	0.3	0.4	0.4
Fuel Use	4.7	4.7	0.7	0.7
Total	14.7	20.8	16.9	23.1

Table 5.1.3.3-2: Supply Chain Emissions Associated with Tallow-based Fuels (gCO₂e/MJ)

Fuel Type:	Biodiesel		Renewable Diesel	
Tallow Source:	Domestic	Imported	Domestic	Imported
Collection, Rendering and Transport	6.5	12.5	6.6	12.8
Fuel Production	3.6	3.6	9.5	9.5
Fuel Transport	0.3	0.3	0.4	0.4
Fuel Use	4.7	4.7	0.7	0.7
Total	15.1	21.1	17.2	23.4

5.1.3.4 Fossil Fuel Baselines

For this climate change analysis, we assume that secondary product-based fuels displace conventional fuels one-for-one on an energy-equivalent basis. We recognize this is likely an oversimplification as market prices can affect the overall level of transportation fuel consumption. However, given the lack of a robust model or methodology for estimating the global market-mediated energy sector effects of these particular biofuels, we believe the energy-equivalent displacement assumption is appropriate for the purposes of this analysis. See Chapter 5.3 for additional discussion and sensitivity analyses on potential alternative displacement assumptions.

For this analysis, we assume that biodiesel and renewable diesel replace conventional diesel fuel and that renewable CNG displaces conventional CNG. For the GTAP- and GLOBIOM-based analysis described in Chapters 5.1.4.1 and 5.1.4.2 respectively, we assume that ethanol displaces conventional gasoline. In this section we describe our estimates of the GHG emissions associated with these conventional fuels.

We use the R&D GREET model to evaluate the emissions associated with these conventional fossil fuels. The GREET model has been used for many years to estimate the emissions associated with conventional transportation fuels. This model includes all the stages in conventional fuel production and use, from raw material extraction through refining, fuel transport and use in vehicles. It is widely used for this purpose, including for peer reviewed publications and regulatory programs. The R&D GREET model analysis of petroleum leverages site specific data for crude oil extraction from the Oil Production Greenhouse Gas Emissions

Estimator (OPGEE) model,^{281,282,283} and a detailed assessment of the energy intensities of 27 oil sands projects.²⁸⁴ Furthermore, the R&D GREET model uses unit-process level analysis with linear programming models with data from 43 refineries that process approximately 70% of total crude input to U.S. refineries.^{285,286} For these reasons, we believe the R&D GREET model is an appropriate method for evaluating the emissions associated with fossil fuels for the purpose of this analysis.

Given that we are estimating the emissions associated with the conventional fuels that would be displaced by additional renewable fuel blending, we estimate the emissions associated with conventional fuels containing 0% biofuel blends. Thus, we evaluate gasoline with 0% ethanol (E0), diesel with 0% biodiesel (B0) and 100% conventional CNG. For gasoline, we use the lifecycle emissions estimates for fuel used in a spark ignition passenger car. For conventional diesel, we use the lifecycle emissions estimates for B0 used in a compression ignition direct injection passenger car. For CNG we evaluate fuel used in a medium-duty spark ignition CNG vehicle. Given that we do not include the vehicle cycle emissions in our estimates (*e.g.*, emissions associated with vehicle manufacturing), our estimates on a per MJ of fuel basis would not be significantly different if we evaluated fuel used in a different type of typical vehicle, such as spark ignition direct injection passenger car or a sport utility vehicle.

Other than selecting these fuel parameters and vehicle types, we make no other adjustments to the R&D GREET model to produce the emissions estimates summarized in Table 5.1.2.4-1.

²⁸¹ Brandt, Adam R., Tim Yeskoo, Michael S. McNally, Kourosh Vafi, Sonia Yeh, Hao Cai, and Michael Q. Wang. "Energy Intensity and Greenhouse Gas Emissions From Tight Oil Production in the Bakken Formation." *Energy & Fuels* 30, no. 11 (October 20, 2016): 9613–21. <https://doi.org/10.1021/acs.energyfuels.6b01907>.

²⁸² Yeh, Sonia, Abbas Ghandi, Bridget R. Scanlon, Adam R. Brandt, Hao Cai, Michael Q. Wang, Kourosh Vafi, and Robert C. Reedy. "Energy Intensity and Greenhouse Gas Emissions From Oil Production in the Eagle Ford Shale." *Energy & Fuels* 31, no. 2 (January 8, 2017): 1440–49. <https://doi.org/10.1021/acs.energyfuels.6b02916>.

²⁸³ Eker, Ilkay, Basak Kurtoglu, and Hossein Kazemi. "Multiphase Rate Transient Analysis in Unconventional Reservoirs: Theory and Applications." *SPE/CSUR Unconventional Resources Conference*, September 25, 2014. <https://doi.org/10.2118/171657-ms>.

²⁸⁴ Cai, Hao, Adam R. Brandt, Sonia Yeh, Jacob G. Englander, Jeongwoo Han, Amgad Elgowainy, and Michael Q. Wang. "Well-to-Wheels Greenhouse Gas Emissions of Canadian Oil Sands Products: Implications for U.S. Petroleum Fuels." *Environmental Science & Technology* 49, no. 13 (June 9, 2015): 8219–27. <https://doi.org/10.1021/acs.est.5b01255>.

²⁸⁵ Elgowainy, Amgad, Jeongwoo Han, Hao Cai, Michael Wang, Grant S. Forman, and Vincent B. DiVita. "Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries." *Environmental Science & Technology* 48, no. 13 (May 28, 2014): 7612–24. <https://doi.org/10.1021/es5010347>.

²⁸⁶ Forman, Grant S., Vincent B. Divita, Jeongwoo Han, Hao Cai, Amgad Elgowainy, and Michael Wang. "U.S. Refinery Efficiency: Impacts Analysis And Implications For Fuel Carbon Policy Implementation." *Environmental Science & Technology* 48, no. 13 (May 28, 2014): 7625–33. <https://doi.org/10.1021/es501035a>.

Table 5.1.3.4-1: Supply Chain Emissions Associated with Conventional Fuels (gCO₂e/MJ)

Supply Chain Stage	Gasoline	Diesel	CNG
Feedstock	6.3	7.3	11.3
Fuel	12.6	7.6	2.7
Vehicle Operation	73.1	75.7	56.1
Total	92.1	90.6	70.1

5.1.4 Crop-based Fuels

For the reasons discussed in Chapter 5.1.1, our analysis of the climate change impacts of crop-based fuels is based on economic modeling that represents the fuel volumes under consideration in this rule. EPA's review of available models capable of biofuel GHG emissions modeling in the 2023 MCE Technical Document included five models: ADAGE, GCAM, GLOBIOM, GREET, and GTAP-BIO. Of these models, GREET is a supply chain model that does not endogenously represent market-mediated impacts of biofuel consumption. Thus, relying solely on estimates from GREET's core biofuel supply chain representation would fail to account for the market-mediated GHG emissions effects of changing volumes of biofuels that are produced from feedstocks with land use requirements. In the proposed rule, EPA used two economic models to estimate potential climate change impacts: GCAM and GLOBIOM. Both models were found in the 2023 MCE Technical Document to be capable tools for modeling market-mediated impacts of biofuels over time. Results from both models were presented in the draft preamble and regulatory impact analysis.

EPA received numerous detailed comments on the GCAM and GLOBIOM modeling presented in the RIA to the proposed rule. Many comments highlighted the uncertainty in the modeling results arising from the two models' differing parameter assumptions, model structures, and system boundaries. Detailed responses are provided in the Response to Comments document in the docket for this final rule. In general, we agree with comments that parametric and model uncertainty and differences between models and resulting differences in modeled impacts of renewable fuels should be investigated and clearly communicated; this principle is well aligned with EPA's findings in the MCE and with NASEM recommendations.²⁸⁷ To this end, in addition to the parametric sensitivity analysis conducted on our GCAM modeling in the proposal, we have included additional sensitivity results in Chapter 5.3 that illustrate the role and importance of potential market-mediated responses in the energy sector with regard to overall emissions estimates. While several comments on GCAM and GLOBIOM modeling raise issues that could benefit from additional research and/or model development, we continue to find that each of the available analytical tools for conducting consequential analyses has relative strengths and weaknesses, and that both models are appropriate and provide useful analysis for illustrating a potential range of outcomes under the assessed scenarios.

In the proposed rule, we noted that while our assessment of the potential climate change impacts of the proposed volumes considered emissions over a 30-year analytical timeframe, GTAP-BIO is a static comparative model which cannot estimate emissions impacts over time. For this reason, GTAP-BIO was not used in the analysis in the proposed rule. Comments on the

²⁸⁷ See NASEM LCA Report, Recommendation 4-2, p. 57.

proposal argued that GTAP-BIO modeling represents reasonable alternative potential land use outcomes that differ from the GCAM and GLOBIOM modeling, and that expanding the multi-model approach employed in the proposal to include a computable general equilibrium model would improve robustness and align more closely with NASEM recommendations. We agree with commenters on the benefits of including additional economic modeling approaches in the climate change analysis for this final rule. While EPA was unable to conduct new modeling using GTAP-BIO for this final rule, pathway-specific results from GTAP-BIO are readily available through the latest distribution of the R&D GREET model and provide estimated emissions factors for three different categories of market-mediated emissions impacts.

The climate impacts estimates based on the emissions factors in GTAP-BIO do not account for some of the interactions and effects represented in scenarios available in the other economic models presented in this chapter. For example, relying on GREET supply chain modeling combined with the available per-MJ emissions factors by feedstock does not represent market-mediated energy sector impacts, nor does it represent agricultural sector interactions from simultaneous shocks on different feedstock crops.²⁸⁸ However, we nevertheless believe including estimates based on the GTAP-BIO modeling available with this final rule provides a useful extension of our climate analysis by representing a broader range of methodologies and modeling frameworks for assessing emissions impacts associated with crop-based biofuel use. For this reason, our analysis in the final rule includes additional cumulative emissions impacts estimates based on a combination of GREET supply chain modeling and other emissions factors developed using GTAP-BIO to represent a set of market-mediated emissions impacts. More information on the use of GREET and GTAP-BIO is presented in Chapter 5.1.4.1.

We considered the inclusion of estimates from other models but ultimately determined not to include them in our quantitative assessment of the climate impacts for this rule. For example, the analytical work undertaken during the MCE identified several model updates that we believe would be necessary before results from the ADAGE model could be included in this analysis. These included numerous updates to historical data which parameterize the model, including a major overhaul to represent a more recent model base year, significant updates to the model's representation of non-commercial forests and grasslands, and significant updates to the model's representation of soil carbon pools. We were not able to complete those model updates for the analyses undertaken for this rule.

Finally, undertaking analyses with each model discussed in this section requires significant effort and resources. We believe that utilizing three models appropriately balances the objective of considering framework uncertainty by comparing results using multiple models of different types, with practical considerations of using a flexible and responsive approach that allows updating analyses as appropriate for each volume rule within given timing and resource constraints. For these reasons, we use the estimates derived from GTAP-BIO, GLOBIOM, and GCAM modeling in our assessment of the climate change impacts of volumes of crop-based biofuels under this rule. Considerations for scenario implementation specific to each of the

²⁸⁸ Sensitivities and additional discussion on potential energy sector impacts are presented in Chapter 5.3.

models follow in Chapters 5.1.4.1 through 5.1.4.3. Additional details on these models, scenarios, and necessary adjustments are provided in a memo to the docket.²⁸⁹

5.1.4.1 GTAP-BIO Scenario Implementation

As discussed above, we are including estimates from the GTAP-BIO model as part of the quantitative assessment for the final rule. However, due to timing considerations, we were unable to conduct new GTAP-BIO modeling specific to the Analyzed Volumes. Instead, we utilize emissions factors for three categories of market-mediated effects specific to individual feedstock-fuel pathways estimated by GTAP-BIO and developed for and distributed with the latest release of the R&D GREET model. These emissions factors then are combined with estimated supply chain emissions factors using the R&D GREET model for the other stages of the fuel lifecycle, such as feedstock and biofuel production and use. Emissions factors are expressed on a per-megajoule of finished fuel basis. These factors are then applied to the analyzed difference in volumes of crop-based fuels between the Analyzed Volumes and No RFS Baseline.

While the emissions factors distributed with GREET for market-mediated impacts of crop-based fuels represent the only readily available GTAP-BIO modeling that could be used to expand the climate change analysis in the final rule, we recognize that the scalar emissions factors relied on were developed for integration with an attributional LCA tool for the purpose of policy implementation, and have some limitations when used in a consequential analysis.

Our use of the GTAP-BIO modeling results distributed with GREET is limited to the sectoral impacts in the three categories of emissions factors provided. However, GTAP-BIO is a general equilibrium model with endogenous representation of impacts in other sectors of key importance for consequential analysis of renewable fuel policy analysis. Notably GTAP-BIO represents energy sector impacts, but these impacts are not included in the GREET distribution. For example, although the GTAP-BIO model estimates the amount of petroleum fuel displacement per unit of renewable fuel production, and marginal changes in electricity supplies, these effects and associated emissions impacts are not included with the GREET model. Without the scenario-specific energy sector outputs from GTAP-BIO, we are unable to account for these dynamics. In the absence of this portion of the GTAP-BIO output, we assume a one-to-one displacement effect with fossil fuels (*i.e.*, we assume each MJ of biofuel production displaces an equivalent amount of fossil transportation fuel). Given that this assumption may play a significant role in the overall net emissions estimates for the Analyzed Volumes, alternative displacement assumptions are considered in the sensitivity results in Chapter 5.3.

Additionally, combining per-fuel emissions factors to assess the overall impacts of simultaneous changes in fuel volumes introduces inconsistencies between simulations and can substantially affect the overall emissions estimates, particularly when assessing changes in

²⁸⁹ See “Economic Modeling of Climate Change Impacts for Crop-based Fuels,” available in the docket for this action.

multiple fuels produced from crops which compete for farmland.²⁹⁰ For this reason, GCAM and GLOBIOM modeling developed for the NPRM assessed scenarios with combined volume shocks across all of the major crop-based fuels likely to be affected by setting RFS volumes standards. While we were unable to conduct new modeling with GTAP-BIO for this final rule, in future assessments, new modeling using GTAP-BIO could be conducted that better represents the impacts on demands of multiple fuels of setting RFS volume standards.

Finally, we note that GTAP-BIO is a comparative static modeling framework and does not dynamically represent the chosen 30-year period of analysis. Instead, for market-mediated emissions impacts from livestock and non-feedstock crops, differences in production (and the resulting differences in emissions) in the base year are assumed to persist for all future years within the period of analysis. For land use change, emissions from land conversion are treated as though they occurred instantaneously, much as GTAP-BIO does when computing a new economic equilibrium. The emissions factors distributed with GREET amortize those land use change emissions over a 30-year period of analysis by dividing changes in carbon stocks by 30. This amortization calculation extends static results to represent a longer period of analysis and implicitly assumes that future (*i.e.*, after the GTAP reference year) land use decisions are unaffected by the expanded need for cropland in the reference year of analysis.

While such emissions impact estimates based on static modeling approaches may demonstrate less variance under investigations of parametric uncertainty, it is important to recognize that this is a direct result of a lack of representation of the inherent uncertainty of potential future impacts of current policy decisions.²⁹¹ That is, the lesser variance in these estimates due to parametric uncertainty is a consequence of the reduced scope of modeling, which only assesses impacts within the context of data representing the base year—2017 in the case of the GTAP-BIO results used in this analysis. For the reasons discussed in Chapter 5.1.2.2, we believe that 30 years is an appropriate temporal scope for assessing the potential GHG impacts of biofuel policies. Thus, analytical tools for this climate change analysis would ideally represent the uncertainty in potential impacts of setting volumes over that timeframe. While GTAP-BIO is unable to perform such an assessment in its current form, we continue to believe that the benefits of including additional modeling methods and tools—in this case a computable general equilibrium model—in our GHG impacts assessment for this volume rule provides valuable breadth of representation of structural uncertainty across modeling frameworks.

²⁹⁰ EPA explained these issues in the 2010 RFS2 Rule, stating: “...simply adding up the individual lifecycle results... multiplied by their respective volumes would yield a different assessment of the overall impacts. The two analyses [individual fuel scenarios and combined fuel scenarios] are separate in that the overall impacts capture interactions between the different fuels that cannot be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions... [W]hen looking at individual fuels there is some interaction between different crops (*e.g.*, corn replacing soybeans), but with combined volume scenario when all mandates need to be met there is less opportunity for crop replacement (*e.g.*, both corn and soybean acres needed) and therefore more land is required.” 75 FR 14797–98 (March 26, 2010).

²⁹¹ Escobar, Neus, Hugo Valin, Stefan Frank, Diana Galperin, Christopher M. Wade, Leopold Ringwald, Daniel Tanner, et al. “Understanding Uncertainty in Market-Mediated Responses to US Oilseed Biodiesel Demand: Sensitivity of ILUC Emission Estimates to GLOBIOM Parametric Uncertainty.” *Environmental Science & Technology* 59, no. 1 (December 18, 2024): 302–14. <https://doi.org/10.1021/acs.est.3c09944>.

5.1.4.2 GLOBIOM Scenario Implementation

For the proposed rule, the analytical scenario implemented in GLOBIOM represented volume requirements that differed somewhat from the proposed volumes. This discrepancy was necessary because of the lead time necessary to implement scenarios in economic models and assess model outputs. Thus, for the proposal, some scaling of the modeled GLOBIOM results was necessary to better represent the proposed volumes.²⁹² For this final rule, we were also unable to conduct new GLOBIOM modeling of the specific RVOs being finalized given the time required to review public feedback on the proposal, determine the volume standards to be finalized, and implement those within economic models. Any new modeled scenarios developed prior to determining the Analyzed Volumes would need to be scaled, similar to the scaling performed on the modeling conducted for the proposed rule. For this reason, we continue to rely on GLOBIOM modeling conducted for the proposed rule, with scaling and adjustments consistent with the method of assessing the proposed. In summary, the scaling for our analysis of the Analyzed Volumes involves multiplying all modeled GLOBIOM impacts by 1.09 to account for the total difference in crop-based fuel volumes between the Analyzed Volumes and the scenarios actually simulated in GLOBIOM. Additional details on methods and data used for this scaling are presented in a memo to the docket.²⁹³

We use GLOBIOM model outputs to estimate five different categories of emissions, either directly or using post hoc adjustments or assumptions to supplement components which are not represented endogenously in GLOBIOM. These categories of emissions are

1. Land Use Change
2. Livestock Production
3. Crop Production
4. Fuel Production, Transport, Distribution, and Use
5. Fossil Fuel Use

For categories of emissions that are estimated within GLOBIOM, model outputs are translated and interpolated to provide emissions estimates for each year in the period of analysis (2026–2055). Emissions categories represented in GLOBIOM include Land Use Change, Livestock Production, and a subset of the components categorized as Crop Production. For other components of Crop Production emissions not represented in GLOBIOM (*e.g.*, emissions from on-farm energy use) we relied on emissions factors specific to region, crop, and activity which were developed externally to the GLOBIOM modeling. These adjustments are all described in detail in the above referenced docket memo. For emissions associated with fuel production, transport, distribution, and use we rely on emissions factors calculated using the R&D GREET model.

Finally, GLOBIOM does not represent energy sector impacts or emissions associated with biofuels displacing use of fossil fuels. We assume a straightforward one-for-one energy equivalent displacement of fossil gasoline (for ethanol volumes) and fossil diesel (for BBD

²⁹² See DRIA Chapter 5.

²⁹³ See “Economic Modeling of Climate Change Impacts for Crop-based Fuels,” available in the docket for this action.

volumes) in the United States and apply emissions factors representing process energy inputs for renewable fuel production as estimated in R&D GREET. These emissions factors are similarly used in our assessment of fuels produced from secondary products. Alternative displacement effects are considered in the sensitivity analyses presented in Chapter 5.3.

5.1.4.3 GCAM Scenario Implementation

As discussed above in Chapter 5.1.4.2, we were unable to conduct new economic modeling of the Analyzed Volumes given the time required to review public feedback on the proposal, determine the volume standards to be finalized, and implement those within economic models. Thus, similar to the GLOBIOM analysis of the Analyzed Volumes, we rely on GCAM modeling conducted for the proposed rule in our assessment of Analyzed Volumes, and using a similar calculation to scale GCAM outputs to the Analyzed Volumes.

We use GCAM outputs to estimate five different categories of emissions. These categories, however, differ from the categories discussed above for the GLOBIOM modeling. They are:

1. Land Use Change
2. Crop Production
3. Livestock Production
4. Other Industrial
5. Fossil Fuel Use

For Land Use Change, Crop Production, Livestock Production, and Other Industrial²⁹⁴ emissions, GCAM endogenously represents all major emissions components. Outputs in these categories are directly translated and interpolated to provide emissions estimates for each year in the period of analysis (2026–2055).

Note that, because detailed energy demands are endogenously represented in GCAM, the emissions estimates under the category of Fossil Fuel Use in GCAM represent displacement of use of fossil-based fuels with use of biofuels, market-mediated impacts on global energy use (*e.g.*, “oil rebound”), and the additional energy and other inputs necessary for biofuel production. Thus, while in the GLOBIOM modeling we include additional biofuel production and downstream emissions estimates, these categories are represented within the fossil fuel use category in GCAM results, with one exception. GCAM does not explicitly represent renewable diesel—only biodiesel—which necessitated the representation of all volumes of biodiesel and renewable diesel in the modeled scenarios as biodiesel on an energy equivalent basis. In order to account for the different input and energy requirements between biodiesel and renewable diesel production, we apply factors to the volume of renewable diesel in the assessed scenarios

²⁹⁴ Other Industrial emissions represent market mediated changes in emissions from other industrial categories represented in GCAM. While these sectors are not represented in GLOBIOM, which therefore has no comparable emissions category estimate, the effects are extremely minor relative to the other components estimated, and exclusion of this category of emissions would not affect our overall assessment of the climate impacts of the Analyzed Volumes.

representing the marginal additional emissions associated with producing renewable diesel rather than biodiesel. These emissions factors were developed using the R&D GREET model.

5.2 Assessment of Analyzed Volumes

Table 5.1.2.1-1 presents the volume differences between the Analyzed Volumes for 2026 and 2027 and the volumes in the No RFS Baseline. For fuels produced from secondary products, we apply emissions factors developed using the R&D GREET model to the difference in volumes of renewable fuels in each year and compare those emissions with similar estimates of displaced fossil fuels. Descriptions of these factors can be found in Chapter 5.1.3. Estimated impacts for crop-based fuels are based on economic modeling, as described in Chapter 5.1.4.

Table 5.2-1 presents cumulative emissions estimates using the model frameworks discussed in Chapter 5.1.3 (fuels produced from secondary products) and Chapter 5.1.4 (fuels produced from crops). Table 5.2-2 presents the resulting estimates for potential emissions impacts of the Analyzed Volumes across all categories of fuels. All calculations are provided in an Excel workbook in the docket for this rule.²⁹⁵

Table 5.2-1: Cumulative (30-year) GHG Emissions Estimates (Million Metric Tons CO₂e) by Feedstock Type

Feedstock Type	Model Framework	Cumulative Emissions ^a
Crop	GTAP-BIO + GREET	-704
Crop	GLOBIOM + GREET	-264
Crop	GCAM	264
Secondary Product	GREET	-231

^a Annual emissions estimates from each model are available in “Set 2 FRM Climate Change Analyses.xlsx,” available in the docket for this action. These annual emissions illustrate the impact of the assumed 30-year time horizon.

Table 5.2-2: Combined Cumulative (30-year) and Average Annual GHG Emissions Estimates (Million Metric Tons CO₂e) for the Analyzed Volumes (2026–2027 Standards)

	Estimate 1	Estimate 2	Estimate 3
Modeling for secondary product-based fuels	GREET	GREET	GREET
Modeling for crop-based fuels	GTAP-BIO + GREET	GLOBIOM + GREET	GCAM
Cumulative Emissions Impacts	-936	-496	33
Average Annual Emissions Impacts	-31	-17	1

Our analysis of the effects of the Analyzed Volumes on climate change shows a range of potential GHG emissions impacts, from 1 million metric tons of average annual CO₂e emissions increase through 2055 to 31 million metric tons of average annual CO₂e emissions reductions through 2055. As noted elsewhere in this chapter, modeling of market reactions and subsequent market-mediated emissions impacts of these volume standards is inherently uncertain, especially when projecting impacts over multiple decades into the future. Given the differences in model

²⁹⁵ See “Set 2 FRM Climate Change Analyses.xlsx” available in the docket for this action.

scopes, assumptions, and mathematical forms, and the uncertainty inherent in this type of forward-looking modeling, differences among the estimates presented in this section should not be interpreted as any models or modeled results being more or less “accurate” than others. Rather, each of these models and modeled estimates presents a plausible alternative possible long-term outcome from this action. Two of these estimates show substantial reductions in GHG emissions relative to the assessed No RFS Baseline, while one estimate shows a comparatively much smaller increase in GHG emissions. As a whole, these estimates demonstrate the potential for this action to result in substantial GHG emissions reductions.

Here, we briefly summarize each set of model simulation results at a high level. GCAM simulation results include relatively large energy sector responses to changes in U.S. biofuel consumption, including relatively substantial incremental rebound in global oil consumption, and notable diversion of biofuels and associated feedstocks to the United States from other regions. Additional demand for feedstock crops is met in significant part through greater areas of cropland relative to the No RFS Baseline, both within and outside of the United States. GLOBIOM simulations do not internally represent energy market responses; the one-for-one energy equivalent displacement assumption represents a simple displacement effect within the United States only. Additional demand for feedstock crops is met in GLOBIOM simulation results primarily through diversion from other uses, crop switching in the U.S., and cropland expansion outside the U.S. While full simulation outputs for the GTAP-BIO modeling used in this assessment were not available, we believe, based on similar past assessments using GTAP-BIO, that additional demand for feedstock crops was met substantially through diversion of crops from other uses, reduced overall demand for livestock feed, and increasing crop yields within the U.S.²⁹⁶ Given the lack of simulation data from GTAP-BIO on energy market responses, our estimates based on GTAP-BIO use a one-for-one energy equivalent displacement assumption which represents a simple displacement effect within the United States only. Additional detail for all of these sets of modeled results is available in the docket for this action.²⁹⁷

EPA is not monetizing the estimated GHG emissions for this rule. The Agency acknowledges that this is a change from past RFS rules in which it has applied the social cost of carbon to GHG emissions estimates to monetize the impacts of such emissions.²⁹⁸ However, EPA recognizes that there are significant uncertainties related to monetization of GHGs that include, but are not limited to:

- The magnitude of the change in climate;
- The relationship between changes in climate and the impacts and resulting economic impacts;
- Climate-economic interactions;
- Future economic growth across all countries of the world;

²⁹⁶ EPA, “Model Comparison Exercise Technical Document,” EPA-420-R-23-017, June 2023. <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockkey=P1017P9B.pdf>.

²⁹⁷ See “Economic Modeling of Climate Change Impacts for Crop-based Fuels” and “Set 2 FRM Climate Change Analyses.xlsx,” available in the docket for this action.

²⁹⁸ See, e.g., Set 1 Rule RIA Chapter 4.2.4. Note that, in providing the monetized climate change impacts in the Set 1 Rule, EPA also explained that there are a number of limitations and uncertainties associated with the social cost of carbon estimates, including uncertainties in key model parameters such as the equilibrium climate sensitivity and questions about an appropriate discount rate. *Id.* at 188-89.

- Future population growth;
- Future technological advancements;
- Impact from emissions on the regulated entities in the United States; and
- Appropriate discount rates.

Due to the orders of magnitude of uncertainties related to monetization of emissions from GHGs, it would result in the following if EPA continued to monetize GHG impacts:

- Misleading the public that the federal government has a better understanding of monetized climate impacts from these actions.
- Reduce confidence in the federal government and confuse the public on why the federal government is taking actions.
- Potentially result in flawed decision making due to overreliance on highly uncertain values.

EPA notes that, even in its past rules in which it has monetized the GHG impacts associated with volumes, these estimates have been provided for “illustrative” purposes.²⁹⁹ Given that EPA continues, consistent with past practice,³⁰⁰ to consider climate change impacts in terms of GHG emissions, not monetizing those emissions does not impact EPA’s evaluation of the statutory factors to determine volumes and does not implicate any reliance interests.

5.3 Rebound Sensitivities

Among the analytical methods used in this chapter to assess GHG emissions associated with the Analyzed Volumes, only estimates derived from GCAM modeling represent endogenous market mediated energy market impacts of increased use of biofuels.³⁰¹ That is, only the estimates derived from GCAM modeling incorporate the potential reaction of domestic and global energy markets to the domestic displacement of use of fossil fuels that would result from the Analyzed Volumes. In order to use the GLOBIOM and GTAP-BIO modeling of crop-based fuels and the GREET modeling of secondary product-based fuels to assess GHG emissions associated with the Analyzed Volumes, post-hoc assumptions about the displacement of use of fossil fuels are required. In the central assessment of the Analyzed Volumes in Chapter 5.2, we assumed a one-for-one displacement of fossil fuels on an energy equivalent basis.

Comments submitted on the proposal argued that the one-for-one displacement assumption (also used in the analysis of the proposed volumes) overestimates the displacement effect, and therefore, the emissions reductions, of increasing biofuel volumes. Central to this argument is the concept of oil rebound, a theoretical market response defined by the following logic: an increase in biofuel use for transportation displaces the use of some amount of fossil-based fuels. Decreased demand for oil results in downward pressure on the price of oil. While

²⁹⁹ See, e.g., “RFS Program: RFS Annual Rules – Regulatory Impact Analysis,” EPA-420-R-22-008, June 2022 (“2020–2022 Rule RIA”), Chapter 3.2.2.3.2; Set 1 Rule RIA Table ES-1.

³⁰⁰ See, e.g., 88 FR 44468, 44500 (July 12, 2023).

³⁰¹ While the GTAP-BIO model does endogenously represent energy sector responses to increased biofuel production, the GTAP-BIO-based estimates used in this chapter rely on emissions factors distributed with the R&D GREET model, which do not include GTAP-BIO modeled energy sector responses.

costs of end-use blended fuels may go up in the U.S., downward pressure on the price of oil globally can result in increased global demand for oil when markets equilibrate. That is, global oil use “rebounds” from the first order displacement effect.

While rebound effects associated with biofuel use have been examined in the literature,³⁰² they depend on numerous interrelated market interactions that are difficult to project with certainty and can be substantially affected by actors with significant market power (*e.g.*, OPEC). While we agree with commenters that there would likely be some rebound effect, we are unable to assess the magnitude of the effect with enough confidence to apply a single rebound adjustment to our one-for-one displacement assumption. Thus, the estimates in Chapter 5.2 are presented without any post-hoc adjustments to represent oil rebound that is not already represented in the estimates (*i.e.*, in GCAM).

However, we agree with commenters that illustrating the sensitivity of emissions estimates to different assumptions about rebound provides valuable information about the uncertainty in emissions estimates associated with the Analyzed Volumes. For this reason, we present in this section several sensitivities with alternative oil rebound assumptions. As mentioned above, GCAM modeling used our analysis endogenously represents energy market dynamics. GCAM results from the scenario used in this assessment show roughly a 19% rebound effect. In other words, in this scenario, the reduction in global oil consumption relative to the baseline is roughly 81% of the increase in global biofuel consumption resulting from the modeled U.S. volumes.³⁰³

In the table below, we provide results for the non-GCAM modeling under assumed 10%, 20%, and 30% oil rebound. These cases correspond with 90%, 80%, and 70% displacement of petroleum-based fuels respectively. These illustrative sensitivities are not intended to reflect the range of possible or most likely rebound effects that EPA expects as a result of this rule; rather, they are intended to bracket the level of oil rebound exhibited in GCAM scenarios by roughly ± 10 percentage points and illustrate what emissions could look like under comparable energy market responses. These illustrative sensitivities demonstrate how uncertainty in energy market responses to volume standards is associated with additional uncertainty in emissions estimates. Furthermore, these sensitivities help to explain how differences in the scopes of the modeling tools used in EPA’s climate change analysis contribute to differences in the emissions estimates presented in Chapter 5.2. Future research into rebound effects under different market conditions would help refine this sensitivity analysis and EPA’s ability to characterize the results as more or less likely.

³⁰² Rajagopal, D., G. Hochman, and D. Zilberman. “Indirect Fuel Use Change (IFUC) and the Lifecycle Environmental Impact of Biofuel Policies.” *Energy Policy* 39, no. 1 (October 15, 2010): 228–33. <https://doi.org/10.1016/j.enpol.2010.09.035>.

³⁰³ Additional illustration of the energy market responses to biofuel shocks in GCAM and how the 19% rebound effect was estimated is available in “Economic Modeling of Climate Change Impacts for Crop-based Fuels,” available in the docket for this action.

Table 5.3-1: 30-year Cumulative Emissions Differences Under Alternative Oil Displacement Assumptions (Million Metric Tonnes CO₂e)

Modeling for Secondary Product-based Fuels	Modeling for Crop-based Fuels	90% Displacement	80% Displacement	70% Displacement
GREET	GTAP-BIO + GREET	-783	-631	-478
GREET	GLOBIOM + GREET	-343	-191	-38

Note: Sensitivities presented in Table 5.3-1 are comparable to estimated cumulative emissions values presented in Estimate 1 and Estimate 2 in Table 5.2-2, which assume one-for-one energy equivalent displacement (*i.e.*, 100% displacement) of fossil fuels.

Chapter 6: Energy Security Impacts

The CAA at section 211(o)(2)(B)(ii) directs EPA to analyze “the impact of renewable fuels on the energy security of the United States” in using the set authority to establish volumes. This chapter describes our analysis of the energy security impacts of the Analyzed Volumes relative to the No RFS Baseline.

Energy security is broadly defined as the uninterrupted availability of energy sources at an acceptable price.³⁰⁴ Most discussions of U.S. energy security have historically revolved around the topic of the economic costs of U.S. dependence on oil imports.³⁰⁵ However, all exposures to global energy supply disruptions and price spikes—including those related to renewable fuels and renewable fuel feedstocks—create risks to energy security. A related but separate consideration is U.S. energy independence, which is achieved by reducing the exposure of the U.S. economy to energy imports and foreign energy markets to the point where the costs of depending on foreign energy (fossil fuels, biofuels, electricity, etc.) are so small that they have minimal effects on the U.S.’s economic, military, or foreign policies.³⁰⁶ In this definition of U.S. energy independence, it is necessary to reduce, but not eliminate, all energy imports to the U.S. to achieve independence.

Reducing oil imports and, thus, becoming more independent from foreign suppliers of oil has been a central goal of U.S. energy security policy for decades. In addition to evaluating impacts on energy security, we have also considered the impacts of the Analyzed Volumes on U.S. energy independence in this analysis. While energy independence is not a statutory factor in the CAA, one goal of the RFS program is to improve the U.S.’s energy independence.³⁰⁷ As stated above, energy independence and energy security are distinct but related concepts. Analysis of energy independence also helps to inform our analysis of energy security.

Given the historical focus in the U.S. on reducing oil imports, the discussion and analysis in this chapter first addresses the role of oil imports in energy security and energy independence and the impact of the Analyzed Volumes on oil imports. Note that this analysis is generally focused on imports of crude oil (as opposed to, for example, imports of refined petroleum products), as crude import volume tends to be the more critical vector of U.S. exposure to global energy market shocks. However, to the extent it is meaningful to do so, we also address other exposures to global energy markets potentially impacted by the Analyzed Volumes.

³⁰⁴ IEA, “Energy Security.” <https://www.iea.org/topics/energy-security>.

³⁰⁵ The issue of cyberattacks is another energy security issue that could grow in significance over time. For example, one of the U.S.’s largest pipeline operators, Colonial Pipeline, was forced to shut down after being hit by a ransomware attack. The pipeline carries refined gasoline and jet fuel from Texas to New York. Sanger, David E., Clifford Krauss, and Nicole Perlroth. “Cyberattack Forces a Shutdown of a Top U.S. Pipeline,” *New York Times*, May 8, 2021. <https://www.nytimes.com/2021/05/08/us/politics/cyberattack-colonial-pipeline.html>.

³⁰⁶ Greene, David L. “Measuring Energy Security: Can the United States Achieve Oil Independence?” *Energy Policy* 38, no. 4 (March 7, 2009): 1614–21. <https://doi.org/10.1016/j.enpol.2009.01.041>.

³⁰⁷ See *Americans for Clean Energy v. Env’t Prot. Agency*, 864 F.3d 691, 696 (D.C. Cir. 2017) (“By mandating the replacement—at least to a certain degree—of fossil fuel with renewable fuel, Congress intended the Renewable Fuel Program to move the United States toward greater energy independence and to reduce greenhouse gas emissions.”); *id.* 697 (citing 121 Stat. at 1492).

One other such potential vector of energy security risk exposure is the role of imported renewable fuels and renewable fuel feedstocks. The interplay between reductions in imports of oil with market trends in imports of renewable fuels and renewable fuel feedstocks on U.S. energy security and independence is also a significant factor to consider. We currently lack the tools to assess these impacts with the same robustness as we address impacts from changes in crude oil market exposure. However, we do address these factors to a limited extent in this chapter.

The U.S. has witnessed a significant change in its exposure to the world oil market since initial implementation of the RFS2 Rule in 2010. This shift in exposure has implications for U.S. energy security. Between 2010 and 2025 U.S. production of crude oil and petroleum products grew at an average annual rate of approximately 7%, as shown in Figure 6-1. The growth rate in U.S. oil production was largely due to significant increases in U.S. tight (*i.e.*, shale) oil production.³⁰⁸ As of 2025, as a result of growing oil production, the U.S. was the largest producer of oil in the world, producing 13.7 million barrels per day (MMBD), followed by Saudi Arabia producing 9.2 MMBD and Russia producing 9.1 MMBD.³⁰⁹

During this same timeframe, U.S. consumption of crude oil and petroleum products has grown much more slowly, with an average annual growth rate of 0.7%, as shown in Figure 6.1. The significant increase in U.S. oil production and relatively slow growth in U.S. oil consumption has resulted in a significant reversal in the U.S.'s petroleum trade balance position. Two milestones from this period are notable. First, in 2011, U.S. oil production exceeded net imports for the first time since 1996.³¹⁰ Second, in 2020, the U.S. became a net exporter of crude oil and petroleum products (*i.e.*, the U.S. was no longer a net petroleum importer) for the first time since the early 1950s.³¹¹ Thus, we can observe the U.S. has achieved a greater degree of energy independence with respect to petroleum by reducing dependence on imports since 2010.

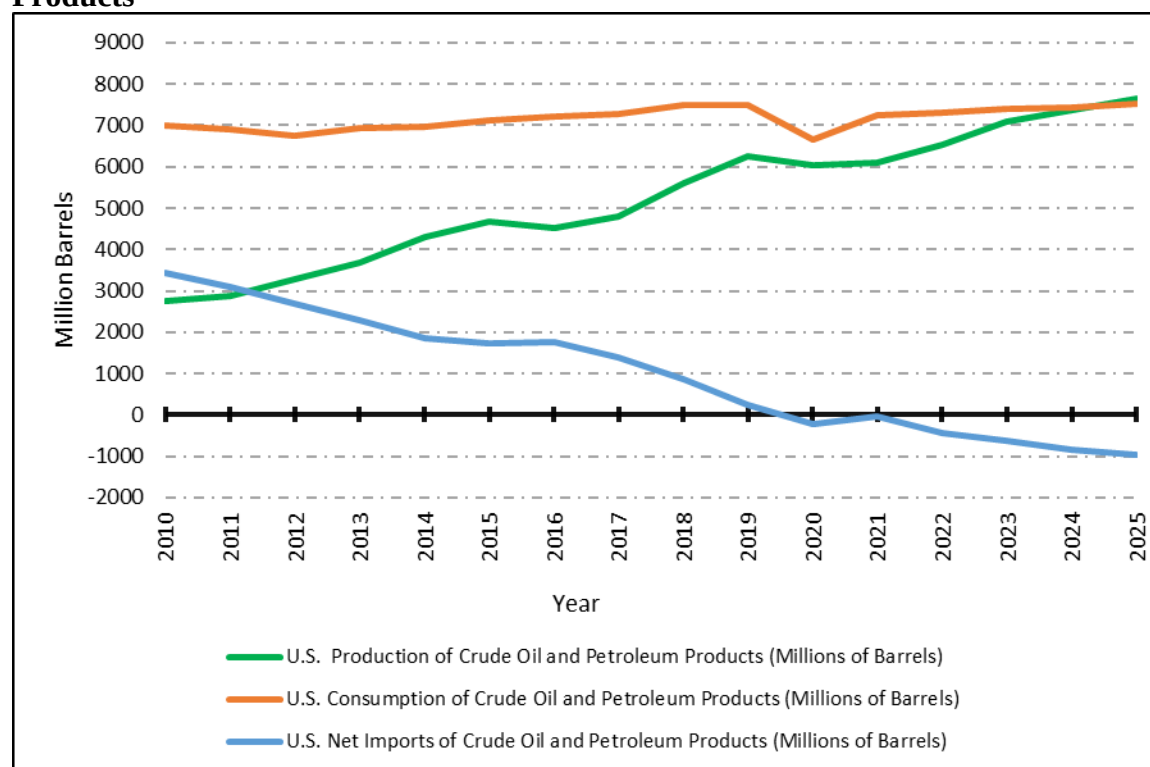
³⁰⁸ EIA, "Tight oil production estimates by play," *Petroleum & Other Liquids*, May 2025.
<https://www.eia.gov/petroleum/data.php>.

³⁰⁹ EIA, "Petroleum and other liquids (production)," International, October 2025.
<https://www.eia.gov/international/data/world/petroleum-and-other-liquids/monthly-petroleum-and-other-liquids-production>. Oil production estimates include crude oil and lease condensate.

³¹⁰ EIA, "Oil imports and exports", *Oil and petroleum products explained*, January 19, 2024.
<https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php>.

³¹¹ *Id.*

Figure 6-1: U.S. Consumption, Production, and Net Imports of Crude Oil and Petroleum Products



Note: For 2025, monthly estimates based on monthly averages were used to forecast values for the last two months in 2025.

Source: EIA, “Supply and Disposition,” Petroleum & Other Liquids, Annual 2024.

https://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbbbl_a_cur.htm.

From 2026 to 2027, EIA estimates that U.S. oil consumption will be steady at 19.2 MMB/D, roughly similar to the amount of oil that the U.S. consumed in 2010. However, in 2010, the U.S. imported roughly 9.4 MMB/D of petroleum.³¹² In contrast, the U.S. is now anticipated to be a net petroleum exporter of roughly 3.3 MMB/D in 2026 and 3.7 MMB/D in 2027.³¹³

The Analyzed Volumes in this rule represent net increases in U.S. renewable fuel consumption in comparison to the 2025 Baseline and, also, net increases in comparison to the No RFS Baseline. Increasing the use of renewable fuels in the U.S. displaces domestic consumption of petroleum-based fuels. Given the U.S.’s projected pattern of petroleum trade with other countries, reductions in U.S. oil consumption will likely result in increased U.S. gross petroleum exports as well as reduced U.S. gross petroleum imports. The result of these two impacts would be a reduction in U.S. net petroleum imports. This would reduce U.S. exposure to global energy markets. As demonstrated by the literature and analysis described in Chapter 6.1 6.2, 6.3 and 6.4, such a reduction in exposure would mitigate financial and strategic risks caused by potential sudden disruptions in the supply of petroleum to the U.S., increasing U.S. energy security.

³¹² Id.

³¹³ Calculated from AEO2025, Table 11 as Total Net Exports minus Biofuels.

Though less well studied than the impacts from exposure to global petroleum markets, exposure to global renewable fuel and renewable fuel feedstock markets also has potential implications for U.S. energy security. In recent years, a substantial quantity of imports of renewable fuels and renewable fuel feedstocks have been used to meet the RFS volume obligations. Trade balances for some renewable fuels and renewable fuel feedstocks have been moving in different directions than the historical oil import trends discussed above. In particular, there has been a recent expansion of imports of BBD feedstocks since 2021, which can be seen in Preamble Figure III.B.2.d-2. This shift, which has been driven by a confluence of factors discussed elsewhere (*e.g.*, Chapter 7), has implications for energy security and energy independence. One of these factors is the Clean Fuel Production Credit federal subsidy for domestically-produced renewable fuels (hereafter referred to as “45Z” or the “45Z credit”), which was established under the 45Z provisions of the Inflation Reduction Act and then was revised under OBBB. The 45Z credit is likely to impact the competitiveness of biofuels produced from different feedstocks in the U.S and hence imports of feedstocks into the U.S., with implications for energy security. Prior to 2025, all qualifying biodiesel and renewable diesel was eligible for the \$1 per gallon 40A tax credit and this was available for biodiesel and renewable diesel produced in the U.S. as well as biodiesel or renewable diesel produced in foreign countries and used in the U.S. The 45Z credit, which replaces this \$1 per gallon credit under 40A, is limited to transportation fuels produced in the U.S., and, starting in 2026, transportation fuels produced exclusively from North American feedstock. EPA anticipates that the change in the tax credit will continue to negatively impact imports of biodiesel and renewable diesel in future years. Section 7.2. has a more detailed discussion on the implications of 45Z for imports of feedstocks.

Despite recent changes in the U.S. trade balances of oil and expansion of renewable fuel consumption in the U.S., important energy security risks to the U.S. transportation fuel sector still remain. These remaining risks stem from three primary sources.

First, oil, renewable fuels, and renewable fuel feedstocks are globally traded commodities and, as a result, a price shock to any of these commodities is transmitted globally even if a country is a net exporter of a commodity. For example, were U.S. oil producers to attempt to keep their prices low in the face of a global oil price shock, foreign consumers would attempt to buy up that cheaper oil, bidding up the price. In this way, U.S. consumers of oil would also be exposed to oil price shocks, even when purchasing oil produced in the U.S. As a result, an oil price shock would raise the price of oil and oil products that U.S. households and businesses pay for petroleum products, which could adversely affect the U.S. economy as a whole. Additional use of renewable fuels and renewable fuel feedstocks can dampen price impacts from oil price shocks, if these prices are largely uncorrelated, but will result in new exposure in the renewable fuel markets.

Second, certain U.S. refineries rely on significant imports of heavy crude oil which could be subject to direct supply disruptions. These refiners are unable to consume the lighter crude oil produced by U.S. tight oil operations without expensive and time-consuming changes to their refinery configurations and supply chain logistics. They therefore lack the agility to make such changes in the face of acute short- or medium-term oil supply disruptions. While U.S. petroleum exports now exceed imports, the volume of gross imports remains quite significant. In 2024,

gross petroleum imports totaled roughly 8.4 MMBD.³¹⁴ Likewise, there has been an expansion in imported BBD feedstocks in recent years.

Third, oil exporters with a large share of global production have the ability to raise or lower the price of oil by exerting their market power through OPEC to alter oil supply relative to demand. It is somewhat uncertain how much market power OPEC will have in 2026–2027. But in the face of such uncertainty, OPEC’s market power must be considered a significant risk to U.S. energy security. All three of the factors listed above contribute to the vulnerability of the U.S. economy to episodic energy supply shocks and price spikes, even though the U.S. is projected to be a net petroleum exporter for the foreseeable future.

To summarize, the increase in U.S. tight oil production and in production and consumption of renewable fuels have contributed to a shift in the U.S. net energy trade position in recent years. We expect these trends to continue and for the U.S. to remain a net petroleum exporter in 2026–2027.³¹⁵ However, because the U.S. is a participant in the world market for oil, renewable fuels, and renewable fuel feedstocks, its economy cannot be shielded from worldwide price shocks from these commodities.³¹⁶ Even if the recent trend of increasing imports of renewable fuel feedstocks changes course, renewable fuel feedstocks will still exist within the context of global commodity markets and may be exposed to global price and supply pressures. The potential for petroleum supply disruptions has also not been eliminated, due to the continued need to import petroleum to satisfy the demands of the U.S. petroleum.³¹⁷ In the next section, we consider how the Analyzed Volumes may alter these exposures and reduce the economic impact of shocks to the global energy system on U.S. energy security.

While exposure to economic shocks to global petroleum, renewable fuel, and renewable fuel feedstock markets (*e.g.*, global price spikes, global supply shortages) each carries some attendant risk, diversifying the portfolio of U.S. energy supplies is a means of reducing the potential impact of any one of these risks on U.S. energy security. As described in Chapter 1, despite growth in renewable fuel consumption under the RFS program since 2010, petroleum products still account for most of the U.S. transportation fuel supply. To the extent that the Analyzed Volumes further diversify the fuel supply, there may be benefits to energy security. In Section 6.5 below we describe an example analysis to demonstrate this point by illustrating the potential impact of transportation fuel feedstock diversification on U.S. transportation fuel prices.

For example, the supply of renewable fuels and renewable fuel feedstocks could be subject to market supply disruptions such as weather-related events (*e.g.*, droughts) in the U.S. or abroad. To the extent that renewable fuel and renewable fuel feedstock prices are subject to only modest price shocks, and the price shocks are not strongly correlated with oil price shocks, blending renewable fuels with petroleum fuels will likely provide energy security benefits. The

³¹⁴ EIA, “U.S. Imports from All Countries,” *Petroleum & Other Liquids*, May 2025.
https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mbbldpd_a.htm.

³¹⁵ AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

³¹⁶ Bordoff, Jason. “The Myth of U.S. Energy Independence Has Gone up in Smoke.” *Foreign Policy*, September 18, 2019. <https://foreignpolicy.com/2019/09/18/the-myth-of-u-s-energy-independence-has-gone-up-in-smoke>.

³¹⁷ Foreman, Dean. “Why the US must Import and Export Oil,” *American Petroleum Institute*, June 14, 2018.

use of renewable fuels, therefore, may dampen the impacts of oil price shocks but expose fuel markets to new shocks. From the standpoint of U.S. energy independence, reducing imported renewable fuels and renewable fuel feedstocks moves the U.S. towards the goal of energy independence. This chapter focuses primarily on the literature on energy security impacts associated with U.S. petroleum consumption and U.S. net oil imports and summarizes EPA's estimates of the benefits of reduced U.S. net imports of petroleum that would result from this rule. The energy security risks of using renewable fuels/feedstocks are not well understood, nor well studied. Chapter 6.5 discusses available research and potential future research on that topic.

6.1 Review of Historical Energy Security Literature (1981–2014)

Energy security discussions are typically based around the concept of the “oil import premium”, sometimes also labeled the “oil security premium.” The oil import premium is the extra cost or impacts of importing oil beyond the price of the oil itself as a result of: (1) potential macroeconomic disruption and increased oil import costs to the economy from oil price spikes or “shocks”; and (2) monopsony impacts. Monopsony impacts stem from changes in the demand for imported oil, which changes the price of all imported oil.

The so-called oil import premium gained attention as a guiding concept for energy policy in the aftermath of the oil shocks of the 1970s (Bohi and Montgomery (1982),³¹⁸ EMF (1982),³¹⁹ and Plummer (1982)³²⁰). Bohi and Montgomery detailed the theoretical foundations of the oil import premium and established many of the critical analytic relationships that can be used to estimate the magnitude of the oil import premium. Hogan (1981)³²¹ and Broadman and Hogan (1986,³²² 1988³²³) revised and extended the established analytical framework to estimate optimal oil import premia with a more detailed accounting of macroeconomic effects. Since the original work on energy security was undertaken in the 1980s, there have been several reviews on this topic by Leiby, Jones, Curlee and Lee (1997), and Parry and Darmstadter (2004).^{324,325}

The economics literature on whether oil shocks have continued to present the same level of threat to economic stability as they were when this literature emerged in the 1980s has been mixed over time. Hamilton (2012) reviewed the empirical literature on oil shocks and suggested that the results were mixed, noting that some work (*e.g.*, Rasmussen and Roitman (2011)) found less evidence for economic effects of oil shocks or declining effects of shocks (Blanchard and

³¹⁸ Bohi, D.R. and W.D. Montgomery. “Social Cost of Imported Oil and US Import Policy.” *Annual Review of Energy* 7, no. 1 (November 1, 1982): 37–60. <https://doi.org/10.1146/annurev.eg.07.110182.000345>.

³¹⁹ “World Oil: Summary Report.” *Energy Policy* 10, no. 4 (December 1, 1982): 367. [https://doi.org/10.1016/0301-4215\(82\)90059-3](https://doi.org/10.1016/0301-4215(82)90059-3).

³²⁰ Plummer, James L. *Energy Vulnerability*. Ballinger Publishing Company, 1982.

³²¹ Hogan, W. “Import Management and Oil Emergencies,” Chapter 9 in D. Deese and J. Nye, eds. *Energy and Security*, Cambridge: Ballinger Press, 1981.

³²² Broadman, Harry G. “The Social Cost of Imported Oil.” *Energy Policy* 14, no. 3 (June 1, 1986): 242–52. [https://doi.org/10.1016/0301-4215\(86\)90146-1](https://doi.org/10.1016/0301-4215(86)90146-1).

³²³ Broadman, Harry G., and William W. Hogan. “The numbers say yes.” *The Energy Journal* 9, no. 3 (July 1, 1988): 7–30. <https://doi.org/10.1177/01956574198809031>.

³²⁴ Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee. “Oil Imports: An Assessment of Benefits and Costs.” *Oak Ridge National Laboratory*, ORNL-6851. November 1, 1997.

³²⁵ Parry, Ian W.H., Joel Darmstadter. “The Costs of U.S. Oil Dependency.” *Resources for the Future*, December 2003. <https://media.rff.org/documents/RFF-DP-03-59.pdf>.

Gali (2010)), while other work found more evidence regarding the economic importance of oil shocks.³²⁶ For example, Baumeister and Peersman (2012) found that an “oil price increase of a given size seems to have a decreasing effect over time, but noted that the declining price-elasticity of demand meant that a given physical disruption had a bigger effect on price and turned out to have a similar effect on output as in the earlier data.”³²⁷ Ramey and Vine (2010) found “remarkable stability in the response of aggregate real variables to oil shocks once we account for the extra costs imposed on the economy in the 1970s by price controls and a complex system of entitlements that led to some rationing and shortages.”³²⁸

Some of the literature on oil price shocks has emphasized that economic impacts depend on the nature of the oil shock, with differences between price increases caused by a sudden supply loss and those caused by rapidly growing demand. Analyses of oil price shocks have confirmed that “demand-driven” oil price shocks have greater effects on oil prices and tend to have positive effects on the economy while “supply-driven” oil shocks still have negative economic impacts (Baumeister, Peersman, and Robays (2010)).³²⁹ A paper by Kilian and Vigfusson (2014), for example, assigned a more prominent role to the effects of price increases that are unusual, in the sense of being beyond the range of recent experience.³³⁰ Kilian and Vigfusson also concluded that the difference in response to oil shocks may well stem from the different effects of demand- and supply-based price increases: “One explanation is that oil price shocks are associated with a range of oil demand and oil supply shocks, some of which stimulate the U.S. economy in the short-run and some of which slow down U.S. growth (see Kilian 2009).”³³¹

The general conclusion that oil supply-driven shocks reduce economic output is also reached in a paper by Cashin et al. (2014), which focused on 38 countries from 1979–2011.³³² They state: “The results indicate that the economic consequences of a supply-driven oil-price shock are very different from those of an oil-demand shock driven by global economic activity, and vary for oil-importing countries compared to energy exporters.” Cashin et al. continues “...oil importers (including the U.S.) typically face a long-lived fall in economic activity in

³²⁶ Rasmussen, Tobias N., and Agustin Roitman. “Oil Shocks in a Global Perspective: Are They Really That Bad?” *IMF Working Paper* 11, no. 194 (January 1, 2011): 1. <https://doi.org/10.5089/9781462305254.001>.

³²⁷ Baumeister, Christiane, and Gert Peersman. “The Role of Time-Varying Price Elasticities in Accounting for Volatility Changes in the Crude Oil Market.” *Journal of Applied Econometrics* 28, no. 7 (June 26, 2012): 1087–1109. <https://doi.org/10.1002/jae.2283>.

³²⁸ Ramey, Valerie A., and Daniel J. Vine. “Oil, Automobiles, and the U.S. Economy: How Much Have Things Really Changed?” *NBER Macroeconomics Annual* 25, no. 1 (January 1, 2011): 333–68. <https://doi.org/10.1086/657541>.

³²⁹ Baumeister Christiane, Gert Peersman and Ine Van Robays. “The Economic Consequences of Oil Shocks: Differences across Countries and Time,” Reserve Bank of Australia Annual Conference – 2009. <https://www.rba.gov.au/publications/confs/2009/baumeister-peersman-vanrobays.html>.

³³⁰ Kilian, Lutz, and Robert J. Vigfusson. “The Role of Oil Price Shocks in Causing U.S. Recessions.” *Journal of Money Credit and Banking* 49, no. 8 (November 16, 2017): 1747–76. <https://doi.org/10.1111/jmcb.12430>.

³³¹ Kilian, Lutz. “Not All Oil Price Shocks Are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market.” *American Economic Review* 99, no. 3 (May 1, 2009): 1053–69. <https://doi.org/10.1257/aer.99.3.1053>.

³³² Cashin, Paul, Kamiar Mohaddes, Maziar Raissi, and Mehdi Raissi. “The Differential Effects of Oil Demand and Supply Shocks on the Global Economy.” *Energy Economics* 44 (April 6, 2014): 113–34. <https://doi.org/10.1016/j.eneco.2014.03.014>.

response to a supply-driven surge in oil prices.” But almost all countries see an increase in real output caused by an oil-demand disturbance.

Considering all of the energy security literature from the 1981–2014 timeframe, EPA’s assessment concludes that there are benefits to the U.S. from reductions of its net oil imports. There is some debate as to the magnitude of energy security benefits from U.S. oil import reductions. However, differences in economic impacts from oil demand and oil supply shocks have been distinguished, with oil supply shocks resulting in economic losses in oil importing countries. The oil import premium calculations in this analysis (described in Chapter 6.4) are based on price shocks from potential future supply events. Oil supply shocks have been the predominant focus of oil security issues since the oil price shocks/oil embargoes of the 1970s. While we project an increase in imported feedstocks to make renewable fuels due to this rule, the rule would result in an overall reduction in the combined total of imported fossil and renewable fuel feedstocks used to make transportation fuels, moving the U.S. modestly towards the goal of energy independence while enhancing the U.S.’s energy security.

6.2 Review of Energy Security Literature from the Last Decade

There have also been a handful of studies from the last decade (*i.e.*, since 2015) that are relevant for the issue of energy security. We provide a brief review and high-level summary of each of these studies below.

6.2.1 Oil Energy Security Studies from the Last Decade

The first studies on the energy security impacts of oil we reviewed are by Resources for the Future (RFF), a study by Brown, and two studies by Oak Ridge National Laboratory (ORNL). The RFF study (2017) attempted to develop updated estimates of the relationship among gross domestic product (GDP), oil supply and oil price shocks, and world oil demand and supply elasticities.³³³ In a follow-on study, Brown summarized the RFF study results as well.³³⁴ The RFF argued that there have been major changes that have occurred over the last two decades which have reduced the impacts of oil shocks on the U.S. economy. First, the U.S. became less dependent on imported oil in the 2010s due in part to the “fracking revolution” (*i.e.*, tight/shale oil), and to a lesser extent, increased production of renewable fuels. In addition, RFF argued that the U.S. economy became more resilient to oil shocks in the 2010s compared to an early 2000s. Some of the factors that made the U.S. more resilient to oil shocks include increased global financial integration and greater flexibility of the U.S. economy (especially labor and financial markets).

In the RFF effort, a number of comparative modeling scenario exercises were conducted by several economic modeling teams using three different types of energy-economic models to examine the impacts of oil shocks on U.S. GDP. The first framework involved was a dynamic

³³³ Krupnick, Alan, Richard Morgenstern, Nathan Balke, Stephen P.A. Brown, Ana María Herrera, and Shashank Mohan. “Oil Supply Shocks, US Gross Domestic Product, and the Oil Security Premium.” *Resources for the Future*. November 2017. <https://media.rff.org/documents/RFF-Rpt-OilSecurity.pdf>.

³³⁴ Brown, Stephen P.A. “New Estimates of the Security Costs of U.S. Oil Consumption.” *Energy Policy* 113 (November 22, 2017): 171–92. <https://doi.org/10.1016/j.enpol.2017.11.003>.

stochastic general equilibrium model developed by Balke and Brown.³³⁵ The second set of modeling frameworks used alternative structural vector autoregressive models of the global crude oil market.³³⁶ The last of the models utilized was the National Energy Modeling System (NEMS).³³⁷

Two key parameters were focused upon to estimate the impacts of oil shock simulations on U.S. GDP: oil price responsiveness (*i.e.*, the short-run price elasticity of demand for oil) and GDP sensitivity (*i.e.*, the elasticity of GDP to an oil price shock). The more inelastic (*i.e.*, the less responsive) short-run oil demand is to changes in the price of oil, the higher the price impacts of a future oil shock. Higher price impacts from an oil shock result in higher GDP losses. The more inelastic (*i.e.*, less sensitive) GDP is to an oil price change, the less the loss of U.S. GDP with future oil price shocks.

For oil price responsiveness, RFF reported three different values: a short-run price elasticity of oil demand from their assessment of the “new literature,” -0.17 ; a “blended” elasticity estimate; -0.05 , and short-run oil price elasticities from the “new models” RFF uses, ranging from -0.20 to -0.35 . The “blended” elasticity is characterized by RFF in the following way: “Recognizing that these two sets of literature [old and new] represent an *evolution* in thinking and modeling, but that the older literature has not been wholly overtaken by the new, Benchmark-E [the blended elasticity] allows for a range of estimates to better capture the uncertainty involved in calculating the oil security premiums.”

The second parameter that RFF examined is the GDP sensitivity. For this parameter, RFF’s assessment of the “new literature” finds a value of -0.018 , a “blended elasticity” estimate of -0.028 , and a range of GDP elasticities from the “new models” that RFF uses that range from -0.007 to -0.027 . One of the limitations of the RFF study was that the large variations in oil price over the last 15 years are believed to be predominantly “demand shocks” (*e.g.*, for example, a rapid growth in global oil demand followed by the Great Recession and then the post-recession recovery).

There have only been three situations where events have led to a potentially significant supply-side oil shock in the last decade. The first event was the attack on the Saudi Aramco Abqaiq oil processing facility and the Khurais oil field. On September 14, 2019, a drone and cruise missile attack damaged the Saudi Aramco Abqaiq oil processing facility and the Khurais oil field in eastern Saudi Arabia. The Abqaiq oil processing facility was the largest crude oil

³³⁵ Balke, Nathan S., and Stephen P.A. Brown. “Oil Supply Shocks and the U.S. Economy: An Estimated DSGE Model.” *Energy Policy* 116 (February 28, 2018): 357–72. <https://doi.org/10.1016/j.enpol.2018.02.027>.

³³⁶ These models include:

Kilian, Lutz. “Not All Oil Price Shocks Are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market.” *American Economic Review* 99, no. 3 (May 1, 2009): 1053–69. <https://doi.org/10.1257/aer.99.3.1053>.

Kilian, Lutz, and Daniel P. Murphy. “The Role of Inventories and Speculative Trading in the Global Market for Crude Oil.” *Journal of Applied Econometrics* 29, no. 3 (April 10, 2013): 454–78. <https://doi.org/10.1002/jae.2322>.

Baumeister, Christiane, and James D. Hamilton. “Structural Interpretation of Vector Autoregressions With Incomplete Identification: Revisiting the Role of Oil Supply and Demand Shocks.” *American Economic Review* 109, no. 5 (May 1, 2019): 1873–1910. <https://doi.org/10.1257/aer.20151569>.

³³⁷ Mohan, Shashank. “Oil Price Shocks and the US Economy: An Application of the National Energy Modeling System.” *Resources for the Future*. November 2017. <https://media.rff.org/documents/RFF-Rpt-OilSecurity-Appendix.pdf>.

processing and stabilization plant in the world, with a capacity of roughly 7 million barrels of oil a day (MMBD) or about 7% of global crude oil production capacity.³³⁸ On September 16, the first full day of commodity trading after the attack, both Brent and West Texas Intermediate (WTI) crude oil prices surged by \$7.17/barrel and \$8.34/barrel, respectively, in response to the attack, the largest price increase in roughly a decade.

However, by September 17, Saudi Aramco reported that the Abqaiq plant was producing 2 MMBD, and they expected its entire output capacity to be fully restored by the end of September.³³⁹ Tanker loading estimates from third-party data sources indicated that loadings at two Saudi Arabian export facilities were restored to the pre-attack levels.³⁴⁰ As a result, both Brent and WTI crude oil prices fell on September 17, but not back to their original levels. The oil price spike from the attack on the Abqaiq plant and Khurais oil field was prominent and unusual, as Kilian and Vigfusson (2014) describe. While pointing to possible risks to world oil supply, the oil shock was short-lived, and generally viewed by market participants as being transitory, so it did not influence oil markets over a sustained time period.

The second situation was the set of events leading to the recent world oil price spike experienced in 2022. World oil prices rose fairly rapidly in the first half of 2022. For example, on January 3, 2022, the WTI crude oil price was roughly \$76/barrel.³⁴¹ The WTI oil price increased to roughly \$124/barrel on March 8, 2022, a 63% increase.³⁴² Crude oil prices increased in the first half of 2022 because of oil supply concerns. Russia's invasion of Ukraine came during eight consecutive quarters (from the third quarter of 2020 to the second quarter of 2022) of global crude oil inventory decreases.³⁴³ The lower inventory of crude oil was the result of withdrawals from storage to meet the demand that resulted from rising economic activity after pandemic-related restrictions eased.³⁴⁴ More recently, as of July 28, 2025, the WTI crude oil price was \$68/barrel, a somewhat lower price than before the Russian invasion of Ukraine.³⁴⁵ Oil prices at present are relatively low mainly because of a projected slowdown in world oil demand growth, particularly in China.³⁴⁶ According to AEO2025, crude oil prices (*i.e.*, the WTI crude oil price) are expected to be flat in 2026–2027, in the range of \$78–79 per barrel (2024\$).³⁴⁷

Geopolitical disruptions that occurred in 2022 are likely to continue to affect global trade of crude oil and refined petroleum products. In response to Russia's invasion of Ukraine in late February 2022, the U.S. and many of its allies, particularly in Europe, announced various

³³⁸ EIA, "Saudi Arabia crude oil production outage affects global crude oil and gasoline prices," *Today in Energy*, September 23, 2019. <https://www.eia.gov/todayinenergy/detail.php?id=41413>.

³³⁹ *Id.*

³⁴⁰ *Id.*

³⁴¹ EIA, "Spot Prices," *Petroleum & Other Liquids*, May 14, 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

³⁴² *Id.*

³⁴³ EIA, "Crude oil prices increased in the first half of 2022 and declined in the second half of 2022," *Today in Energy*, January 4, 2023. <https://www.eia.gov/todayinenergy/detail.php?id=55079>.

³⁴⁴ *Id.*

³⁴⁵ EIA, "Spot Prices," *Petroleum & Other Liquids*, July 28 2025. https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

³⁴⁶ EIA, "Short-Term Energy Outlook," September 2024. <https://www.eia.gov/outlooks/steo/archives/sep24.pdf>.

³⁴⁷ AEO2025, Table 12 – Petroleum and Other Liquids Prices.

sanctions against Russia's petroleum industry.³⁴⁸ For the EU, petroleum from Russia had accounted for a large share of all energy imports, but the EU banned imports of crude oil from Russia starting in December 2022 and imports of refined petroleum products starting in February 2023.³⁴⁹ In light of this geopolitical environment and other market factors, the U.S. has seen its refined petroleum product exports grow steadily since 2021. It is anticipated that the U.S. will continue to witness an increase in refined petroleum product exports in 2026–2027.³⁵⁰

Since both significant demand and supply factors are influencing world oil prices in 2022 and the early part of 2023, it is not clear how to evaluate unfolding oil market price trends from an energy security standpoint. Thus, the attack of the Abqaiq oil processing facility in Saudi Arabia and the events in the world oil market in 2022 and 2023 in response to the Russian invasion of Ukraine do not currently provide enough empirical evidence to provide an updated estimate of the response of the U.S. economy to an oil supply shock of a significant magnitude.³⁵¹

The third event that could have led to a significant oil supply shock was the 12 day “Iran-Israel War” in June 2025. As a result of the War, there was the potential for the closure of the Strait of Hormuz which could have restricted oil supply from the Persian Gulf. This threat led to a more significant geopolitical risk premium for the price of oil stemming from the conflict. In EIA's July 2025 STEO, EIA increased its estimate of the crude oil price (*i.e.*, the Brent crude oil price) for the year 2025 from \$66/barrel to \$69/barrel (in nominal dollars).³⁵²

The August 2025 STEO significantly revised the July 2025 STEO oil market outlook. EIA now sees world oil prices falling significantly in their August 2025 STEO.³⁵³ The price forecast is driven largely by more oil inventory builds following OPEC+ members' decision to accelerate the pace of oil production increases. EIA now expects global oil inventory builds will average more than 2 million barrels per day (MMBD) in the fourth quarter of 2025 and the first quarter of 2026, which is 0.8 million MMBD more than in the July 2025 STEO. EIA forecasts that the Brent crude oil price will average \$51/barrel (in nominal dollars) in 2026, down significantly from its forecast of \$58/barrel (in nominal dollars) in July STEO, and significantly lower than the AEO2025 oil price forecast for 2026.

A second set of studies related to energy security were from ORNL. In the first study, ORNL (2018) undertook a quantitative meta-analysis of world oil demand elasticities based upon

³⁴⁸ EIA, “U.S. petroleum product exports set a record high in 2022,” *Today in Energy*, March 20, 2023. <https://www.eia.gov/todayinenergy/detail.php?id=55880>.

³⁴⁹ *Id.*

³⁵⁰ AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

³⁵¹ Hurricanes Katrina and Rita in 2005 primarily caused a disruption in U.S. oil refinery production, with a more limited disruption of some crude supply in the U.S. Gulf Coast area. Thus, the loss of refined petroleum products exceeded the loss of crude oil, and the regional impact varied even within the U.S. Hurricanes Katrina and Rita were a different type of oil disruption event than is quantified in the Stanford Energy Modeling Forum (EMF) risk analysis framework, which provides the oil disruption probabilities than ORNL is using.

³⁵² EIA, “Short-Term Energy Outlook,” July 2025. <https://www.eia.gov/outlooks/steo/archives/jul25.pdf>.

³⁵³ EIA, “Short-Term Energy Outlook,” August 2025. <https://www.eia.gov/outlooks/steo/archives/aug25.pdf>.

the recent economics literature.³⁵⁴ The ORNL study estimates oil demand elasticities for two sectors (transportation and non-transportation) and by world regions (OECD and Non-OECD) by meta-regression. To establish the data set for the meta-analysis, ORNL undertook a literature search of peer reviewed journal articles and working papers between 2000–2015 that contain estimates of oil demand elasticities. The data set consisted of 1,983 observations from 75 published studies. The study found a short-run price elasticity of world oil demand of -0.07 and a long-run price elasticity of world oil demand of -0.26 .

The second relevant ORNL (2018) study from the standpoint of energy security was a meta-analysis that examines the impacts of oil price shocks on the U.S. economy as well as many other net oil-importing economies.³⁵⁵ Nineteen studies after 2000 were identified that contain quantitative/accessible estimates of the economic impacts of oil price shocks. Almost all studies included in the review were published since 2008. The key result that the study found is a short-run oil price elasticity of U.S. GDP, roughly one year after an oil shock, of -0.021 , with a 68% confidence interval of -0.006 to -0.036 .

6.2.2 Studies on Tight/Shale Oil

The discovery and development of U.S. tight oil (*i.e.*, shale oil) reserves that started in the mid-2000s affected U.S. energy security; two of the ways this might occur are discussed here.³⁵⁶ First, the increased availability of domestic supplies has resulted in a reduction of U.S. oil imports and an increasing role of the U.S. as exporter of crude oil and petroleum-based products. In December 2015, the 40-year ban on the export of domestically produced crude oil was lifted as part of the Consolidated Appropriations Act, 2016.³⁵⁷ According to the GAO, the ban was lifted in part due to increases in tight (*i.e.*, shale) oil.³⁵⁸ Second, due to differences in development cycle characteristics and average well productivity, tight oil producers could be more price responsive than most other oil producers. However, the oil price level that triggers a substantial increase in tight oil production appears to be higher in 2021–2023 relative to the

³⁵⁴ Uria-Martinez, Rocio, Paul Leiby, Gbadebo Oladosu, David Bowman, and Megan Johnson. “Using Meta-Analysis to Estimate World Oil Demand Elasticity,” *Oak Ridge National Laboratory ORNL/TM-2018/1070*, December 10, 2018. <https://doi.org/10.2172/1491306>.

³⁵⁵ Oladosu, Gbadebo A., Paul N. Leiby, David C. Bowman, Rocio Uria-Martinez, and Megan M. Johnson. “Impacts of Oil Price Shocks on the United States Economy: A Meta-analysis of the Oil Price Elasticity of GDP for Net Oil-importing Economies.” *Energy Policy* 115 (February 3, 2018): 523–44. <https://doi.org/10.1016/j.enpol.2018.01.032>.

³⁵⁶ “Tight oil is a type of oil found in impermeable shale and limestone rock deposits. Also known as ‘shale oil,’ tight oil is processed into gasoline, diesel, and jet fuels—just like conventional oil—but is extracted using hydraulic fracturing, or ‘fracking.’” Union of Concerned Scientists, “What Is Tight Oil?” March 3, 2015. <https://www.ucs.org/resources/what-tight-oil>.

³⁵⁷ Pub. L. 114-113 (December 18, 2015).

³⁵⁸ GAO, “Crude Oil Markets: Effects of the Repeal of the Crude Oil Export Ban,” GAO-21-118, October 2020. <https://www.gao.gov/assets/gao-21-118.pdf>. According to the GAO, “Between 1975 and the end of 2015, the Energy Policy and Conservation Act directed a ban on nearly all exports of U.S. crude oil. This ban was not considered a significant policy issue when U.S. oil production was declining and import volumes were increasing. However, U.S. crude oil production roughly doubled from 2009 to 2015, due in part to a boom in shale oil production made possible by advancements in drilling technologies. In December 2015, Congress effectively repealed the ban, allowing the free export of U.S. crude oil worldwide.”

2010s as tight oil producers seek higher profit margins per barrel in order to reduce the debt burden accumulated in previous cycles of production growth.³⁵⁹

U.S. crude oil production increased from 5.0 MMBD in 2008 to 13.2 MMBD in 2024 and tight oil wells have been responsible for most of the increase.³⁶⁰ Figure 6.2.2-1 shows tight oil production changes from various tight oil producing regions (*e.g.*, Eagle Ford, Bakken, etc.) in the U.S. and the WTI crude oil spot price. Viewing Figure 6.2.2-1, one can see that the annual average U.S. tight oil production grew from 0.5 MMBD in 2008 to 8.9 MMBD in 2024.³⁶¹ Growth in U.S. tight oil production during this period was only interrupted in 2015–2016 following the world oil price downturn that began in mid-2014. The second growth phase started in late 2016 and continued until 2020. The sharp decrease in demand that followed the onset of the COVID-19 pandemic resulted in a 26% decrease in tight oil production in the period from December 2019 to May 2020. U.S. tight oil production averaged 7.2 MMBD in 2020–2021 and resumed growth in 2022–2024. The 2024 average production (8.9 MMBD) is the new all-time peak for U.S. tight oil production. It represents a relatively modest share (10.9% in 2024) of global crude oil supply.³⁶²

Importantly, U.S. tight oil is considered the most price-elastic component of non-OPEC supply due to differences between its development and production cycle and that of conventional oil wells. Unlike conventional wells where oil starts flowing naturally after drilling, shale oil wells require the additional step of fracking to complete the well and release the oil.³⁶³ Shale oil producers keep a stock of drilled but uncompleted wells and can optimize the timing of the completion operation depending on price expectations. Combining this decoupling between drilling and production with the front-loaded production profile of tight oil—the fraction of total output from a well that is extracted in the first year of production is higher for tight oil wells than conventional oil wells—tight oil producers have a clear incentive to be responsive to prices in order to maximize their revenues.³⁶⁴

³⁵⁹ Kemp, John. “U.S. shale restraint pushes oil prices to multi-year high,” *Reuters*, June 4, 2021.

<https://www.reuters.com/business/energy/us-shale-restraint-pushes-oil-prices-multi-year-high-kemp-2021-06-04>.

³⁶⁰ EIA, “Crude Oil Production,” *Petroleum & Other Liquids*, April 30, 2025.

https://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbldp_a.htm.

³⁶¹ EIA, “Short Term Energy Outlook,” May 2025, Table 10b – Crude Oil and Natural Gas Production from Shale and Tight Formations. <https://www.eia.gov/outlooks/steo/tables/pdf/10btap.pdf>.

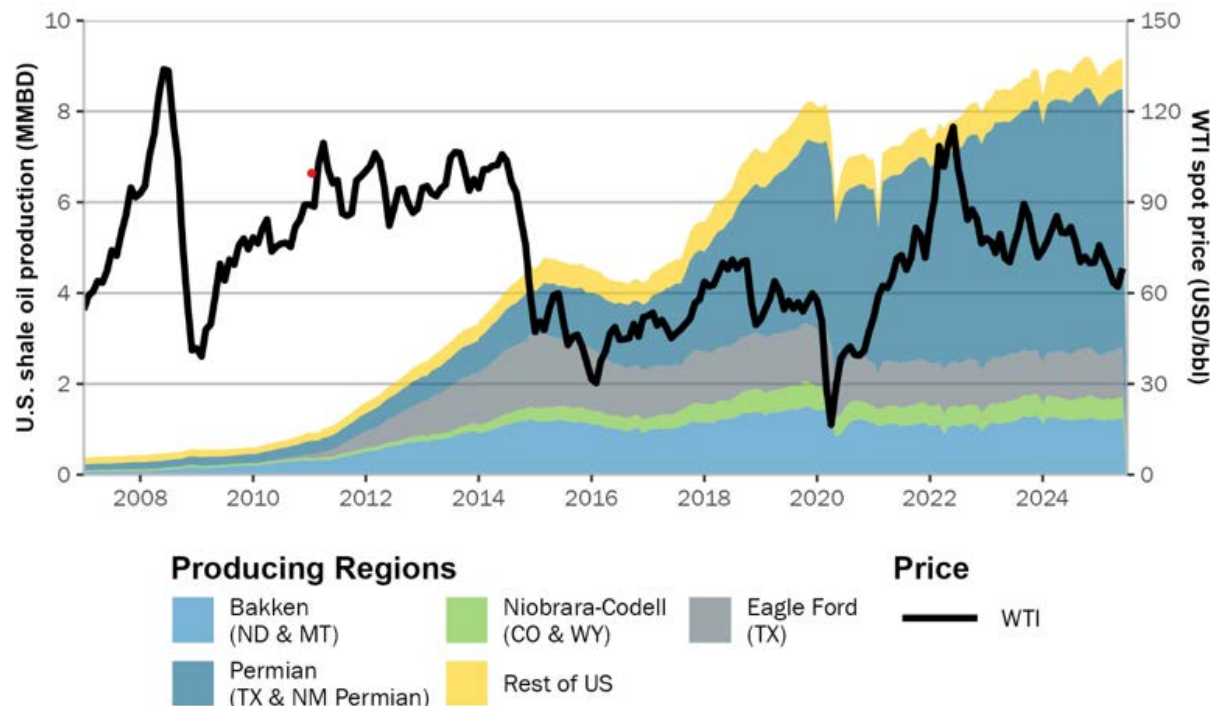
³⁶² The 2024 global crude oil production value used to compute the U.S. tight oil share (81.7 MMBD). EIA, “Petroleum and other liquids (production),” International, May 15, 2025.

<https://www.eia.gov/international/data/world/petroleum-and-other-liquids/annual-petroleum-and-other-liquids-production>.

³⁶³ Hydraulic fracturing (“fracking”) involves injecting water, chemicals, and sand at high pressure to open fractures in low-permeability rock formations and release the oil that is trapped in them.

³⁶⁴ Bjørnland, Hilde C., Frode Martin Nordvik, and Maximilian Rohrer. “Supply Flexibility in the Shale Patch: Evidence From North Dakota.” *Journal of Applied Econometrics* 36, no. 3 (February 5, 2021): 273–92. <https://doi.org/10.1002/jae.2808>.

Figure 6.2.2-1: U.S. Tight Oil Production (by Producing Regions) and WTI Crude Oil Spot Price



Source: EIA, “Tight oil production estimates by play,” *Petroleum & Other Liquid*, July 2025.
<https://www.eia.gov/petroleum/data.php>. EIA, “Spot Prices,” *Petroleum & Other Liquids*, July 23, 2025.
https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

Only in recent years have the implications of the “tight/shale oil revolution” been felt in the international market where U.S. production of oil has risen to be larger than the production of oil from either Russia or Saudi Arabia. Economic literature of the tight oil expansion in the U.S. has a bearing on the issue of energy security as well. It could be that the large expansion in tight oil has eroded the ability of OPEC to set world oil prices, since OPEC cannot directly influence tight oil production decisions. Also, by effecting the percentage of global oil supply controlled by OPEC, the growth in U.S. oil production may be influencing OPEC’s degree of market power. But given that the tight oil expansion is a relatively recent trend, it is difficult to know how much of an impact the increase in tight oil is having, or will have, on OPEC behavior.

Three recent studies have examined the characteristics of tight oil supply that have relevance for the topic of energy security. In the context of energy security, recent literature has considered the question of whether tight oil might be able to respond to an oil price shock more quickly and substantially than conventional oil.³⁶⁵ If so, then tight oil could potentially lessen the impacts of future oil shocks on the U.S. economy by moderating the price increases from a future oil supply shock.

³⁶⁵ “Tight oil is a type of oil found in impermeable shale and limestone rock deposits. Also known as ‘shale oil,’ tight oil is processed into gasoline, diesel, and jet fuels—just like conventional oil—but is extracted using hydraulic fracturing, or ‘fracking.’” Union of Concerned Scientists, “What Is Tight Oil?” March 3, 2015.
<https://www.ucs.org/resources/what-tight-oil>.

Newell and Prest (2019) looked at differences in the price responsiveness of conventional versus shale oil wells, using a detailed data set of 150,000 oil wells, during 2005–2017 in five major oil-producing states: Texas, North Dakota, California, Oklahoma, and Colorado.³⁶⁶ For both conventional oil wells and shale oil wells (*i.e.*, unconventional oil wells), Newell and Prest estimated the elasticities of drilling operations and well completion operations with respect to expected revenues and the elasticity of supply from wells already in operation with respect to spot prices. Combining the three elasticities and accounting for the increased share of tight oil in total U.S. oil production during the period of analysis, they concluded that U.S. oil supply responsiveness to prices increased more than tenfold from 2006 to 2017. They found that tight/shale oil wells were more price responsive than conventional oil wells, mostly due to their much higher productivity, but the estimated oil supply elasticity was still small. Newell and Prest noted that the tight oil supply response still takes more time to arise than is typically considered for a “swing producer,” referring to a supplier able to increase production quickly, within 30–90 days. In the past, only Saudi Arabia and possibly one or two other oil producers in the Middle East have been able to ramp up oil production in such a short period of time.

Another study, by Bjørnland et al. (2021), used a well-level monthly production data set covering more than 16,000 crude oil wells in North Dakota to examine differences in supply responses between conventional and tight/shale oil.³⁶⁷ They found a short-run (*i.e.*, one-month) supply elasticity with respect to oil price for tight oil wells of 0.71, whereas the one-month response of conventional oil supply was not statistically different from zero. It should be noted that the elasticity value estimated by Bjørnland et al. combined the supply response to changes in the spot price of oil as well as changes in the spread between the spot price and the 3-month futures price.

Walls and Zheng (2022) explored the change in U.S. oil supply elasticity that resulted from the tight oil revolution using monthly, state-level data on oil production and crude oil prices from January 1986 to February 2019 for North Dakota, Texas, New Mexico, and Colorado.³⁶⁸ They conducted statistical tests that reveal an increase in the supply price elasticities starting between 2008–2011, coinciding with the times in which tight oil production increased sharply in each of these states. Walls and Zheng also found that supply responsiveness in the tight oil era is greater with respect to price increases than price decreases. The short-run (one-month) supply elasticity with respect to price increases during the tight oil era ranged from zero in Colorado to 0.076 in New Mexico; pre-tight oil, it ranged from zero to 0.021.

The results from Newell and Prest, Bjørnland et al., and Walls and Zheng all suggest that tight oil may have a larger supply response to oil prices in the short-run than conventional oil, although the estimated short-run elasticity is still small. The three studies used data sets that end in 2019 or earlier. The responsiveness of U.S. tight oil production to recent price increases in the 2020s does not appear to be consistent with that observed during the episodes of crude oil price

³⁶⁶ Newell, Richard, and Brian Prest. “The Unconventional Oil Supply Boom: Aggregate Price Response From Microdata,” October 1, 2017. <https://doi.org/10.3386/w23973>.

³⁶⁷ Bjørnland, Hilde C., Frode Martin Nordvik, and Maximilian Rohrer. “Supply Flexibility in the Shale Patch: Evidence From North Dakota.” *Journal of Applied Econometrics* 36, no. 3 (February 5, 2021): 273–92. <https://doi.org/10.1002/jae.2808>.

³⁶⁸ Walls, W.D., and Xiaoli Zheng. “Fracking and Structural Shifts in Oil Supply.” *The Energy Journal* 43, no. 3 (April 21, 2021): 1–32. <https://doi.org/10.5547/01956574.43.3.wwal>.

increases in the 2010s captured in these three studies. Despite an 80% increase in the WTI crude oil spot price from October 2020 to the end of 2021, Figure 6.2.2-1 shows that U.S. tight oil production has increased by only 8% in the same period. It is a somewhat challenging period in which to examine the supply response of tight oil to its price to some degree, given that the 2020–2021 time period coincided with the COVID-19 pandemic. However, previous shale oil production growth cycles were financed predominantly with debt, at very low interest rates.³⁶⁹ Most U.S. tight oil producers did not generate positive cashflow.³⁷⁰ As of 2021, U.S. shale oil producers have pledged to repay their debt and reward shareholders through dividends and stock buybacks.³⁷¹ These pledges translate into higher prices that need to be reached (or sustained for a longer period) than in the past decade to trigger large increases in drilling activity.

More recently, the Dallas Fed (*i.e.*, the Federal Reserve Bank of Dallas) found that activity in the U.S. oil and gas sector contracted slightly in the second quarter of 2025, according to oil and gas executives responding to the Dallas Fed’s survey. Also, oil and gas production decreased slightly in the second quarter of 2025, according to executives at oil exploration and production firms. On average, respondents expected a WTI crude oil price of \$68/bbl at year-end 2025. When asked about longer-term expectations, oil and gas executives expect a WTI oil price of \$72/bbl in 2027.³⁷²

Finally, despite continuing uncertainty about oil market behavior and outcomes and the sensitivity of the U.S. economy to oil shocks, it is generally agreed that it is beneficial to reduce petroleum fuel consumption from an energy security standpoint. The relative significance of petroleum consumption and import levels for the macroeconomic disturbances that follow from oil price shocks is not fully understood. Recognizing that changing petroleum consumption will change U.S. imports, our quantitative assessment of oil costs of this rule in Chapter 6.4 focuses on those incremental social costs that follow from the resulting changes in net imports, employing the usual oil import premium measure.

6.3 Cost of Existing U.S. Energy Security Policies

An additional often-identified component of the full economic costs of U.S. oil imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining the Strategic Petroleum Reserve (SPR) and maintaining a military presence to help secure a stable oil supply from potentially vulnerable regions of the world.

The SPR is the largest stockpile of government-owned emergency crude oil in the world. Established in the aftermath of the 1973/1974 oil embargo, the SPR provides the U.S. with a response option should a disruption in commercial oil supplies threaten the U.S. economy.³⁷³

³⁶⁹ McLean, Bethany. “The Next Financial Crisis Lurks Underground,” *New York Times*, September 1, 2018. <https://www.nytimes.com/2018/09/01/opinion/the-next-financial-crisis-lurks-underground.html>.

³⁷⁰ *Id.*

³⁷¹ Crowley, Kevin and David Wethe. “Shale Bets on Dividends to Match Supermajors, Revive Sector,” *Bloomberg*, August 2, 2021. <https://www.bloomberg.com/news/articles/2021-08-02/shale-heavyweights-shower-investors-with-dividends-on-oil-rally>.

³⁷² Federal Reserve Bank of Dallas, “Oil and gas activity contracts slightly as uncertainty remains elevated,” July 2, 2025. <https://www.dallasfed.org/research/surveys/des/2025/2502>.

³⁷³ Energy Policy and Conservation Act, 42 U.S.C. § 6241(d) (1975).

Emergency SPR drawdowns have taken place in 1991 (Operation Desert Storm), 2005 (Hurricane Katrina), 2011 (Libyan Civil War), and 2022 (War in Ukraine). All of these releases have been in coordination with releases of strategic stocks from other International Energy Agency (IEA) member countries. In the first four months of 2022, using the statutory authority under Section 161 of the Energy Policy and Conservation Act, DOE conducted two emergency SPR drawdowns in response to ongoing oil supply disruptions.³⁷⁴ The first drawdown resulted in a sale of 30 million barrels in March 2022. The second drawdown, announced in April, authorized a total release of approximately one MMBD from May to October 2022.³⁷⁵ In 2023, the DOE sold 26 million barrels of oil between April and June.³⁷⁶ A total of 246.6 million barrels were released from the SPR from January 2022 to July 2023. By the end of July 2023, the SPR stock level was 346.8 million barrels (the lowest level since August 1983). To start replenishing the stock, the SPR office purchased 60.5 million barrels through competitive solicitations conducted between May 2023 and November 2024, for deliveries from August 2023 to May 2025. While the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while the effect of the SPR in moderating price shocks is factored into the analysis that EPA is using to estimate the macroeconomic oil security premiums, the cost of maintaining the SPR is excluded.

We have also considered the possibility of quantifying the military benefits components of energy security but have not done so here for several reasons. The literature on the military components of energy security has described four broad categories of oil-related military and national security costs, all of which are difficult to quantify. These include possible costs of U.S. military programs to secure oil supplies from unstable regions of the world, the energy security costs associated with the U.S. military's reliance on petroleum to fuel its operations, possible national security costs associated with expanded oil revenues to "rogue states", and relatedly the foreign policy costs of oil insecurity.

Of these categories listed above, the one that is most clearly connected to petroleum use and is, in principle, quantifiable is the first: the cost of military programs to secure oil supplies and stabilize oil supplying regions. There is ongoing literature on the measurement of this component of energy security, but methodological and measurement issues—attribution and incremental analysis—pose two significant challenges to providing a robust estimate of this component of energy security. The attribution challenge is to determine which military programs and expenditures can properly be attributed to oil supply protection, rather than some other objective. The incremental analysis challenge is to estimate how much the petroleum supply protection costs might vary if U.S. oil use were to be reduced or eliminated. Methods to address

³⁷⁴ DOE, "DOE Announces Emergency Notice of Sale of Crude Oil from the Strategic Petroleum Reserve to Address Oil Supply Disruptions," March 2, 2022. <https://www.energy.gov/ceser/articles/doe-announces-emergency-notice-sale-crude-oil-strategic-petroleum-reserve-address>.

³⁷⁵ DOE, "DOE Announces Second Emergency Notice of Sale of Crude Oil From The Strategic Petroleum Reserve to Address Putin's Energy Price Hike," April 4, 2022. <https://www.energy.gov/articles/doe-announces-second-emergency-notice-sale-crude-oil-strategic-petroleum-reserve-address>.

³⁷⁶ DOE, "DOE Issues Notice of Congressionally Mandated Sale to Purchase Crude Oil from the Strategic Petroleum Reserve," February 13, 2023. <https://www.energy.gov/ceser/articles/doe-issues-notice-congressionally-mandated-sale-purchase-crude-oil-strategic>.

both of these challenges are necessary for estimating the effect on military costs arising from a modest reduction (not elimination) in oil use attributable to this action.

Since “military forces are, to a great extent, multipurpose and fungible” across theaters and missions (Crane et al. 2009), and because the military budget is presented along regional accounts rather than by mission, the allocation to particular missions is not always clear.³⁷⁷ Approaches taken usually either allocate “partial” military costs directly associated with operations in a particular region, or allocate a share of total military costs (including some that are indirect in the sense of supporting military activities overall) (Koplow and Martin 1998).³⁷⁸

The challenges of attribution and incremental analysis have led some to conclude that the mission of oil supply protection cannot be clearly separated from others, and the military cost component of oil security should be taken as near zero (Moore et al. 1997).³⁷⁹ Stern (2010), on the other hand, argued that many of the other policy concerns in the Persian Gulf follow from oil, and the reaction to U.S. policies taken to protect oil.³⁸⁰ Stern presented an estimate of military cost for Persian Gulf force projection, addressing the challenge of cost allocation with an activity-based cost method. He used information on actual naval force deployments rather than budgets, focusing on the costs of carrier deployment. As a result of this different data set and assumptions regarding allocation, the estimated costs are much higher, roughly 4–10 times, than other estimates. Stern also provides some insight on the analysis of incremental effects, by estimating that Persian Gulf force projection costs are relatively strongly correlated to Persian Gulf petroleum export values and volumes. Still, the issue remains of the marginality of these costs with respect to Persian Gulf oil supply levels, the level of U.S. oil imports, or U.S. oil consumption levels.

Delucchi and Murphy (2008) sought to deduct from the cost of Persian Gulf military programs the costs associated with defending U.S. interests other than the objective of providing more stable oil supply and price to the U.S. economy.³⁸¹ Excluding an estimate of cost for missions unrelated to oil, and for the protection of oil in the interest of other countries, Delucchi and Murphy estimated military costs for all U.S. domestic oil interests of between \$24–74 billion per year. Delucchi and Murphy assumed that military costs from oil import reductions can be scaled proportionally, attempting to address the incremental issue.

Crane et al. considered force reductions and cost savings that could be achieved if oil security were no longer a consideration. Taking two approaches and guided by post-Cold War force draw downs and by a top-down look at the current U.S. allocation of defense resources,

³⁷⁷ Crane, Keith, Andreas Goldthau, Michael Toman, Thomas Light, Stuart Johnson, Alireza Nader, Angel Rabasa, and Harun Dogo. “Imported Oil and U.S. National Security.” *RAND Corporation*, 2009. <https://doi.org/10.7249/mg838>.

³⁷⁸ Koplow, Douglas, and Aaron Martin. “Fueling Global Warming: Federal Subsidies to Oil in the United States.” *Greenpeace*, 1998. <https://www.earthtrack.net/sites/default/files/fdsuoboil.pdf>.

³⁷⁹ Moore, John L., Carl E. Behrens, and John E. Blodgett. “Oil Imports: An Overview and Update of Economic and Security Effects,” *CRS Environment and Natural Resources Policy Division* 98, no. 1 (December 12, 1997): 1-14.

³⁸⁰ Stern, Roger J. “United States Cost of Military Force Projection in the Persian Gulf, 1976–2007.” *Energy Policy* 38, no. 6 (February 25, 2010): 2816–25. <https://doi.org/10.1016/j.enpol.2010.01.013>.

³⁸¹ Delucchi, Mark A., and James J. Murphy. “US Military Expenditures to Protect the Use of Persian Gulf Oil for Motor Vehicles.” *Energy Policy* 36, no. 6 (April 23, 2008): 2253–64. <https://doi.org/10.1016/j.enpol.2008.03.006>.

they concluded that \$75–91 billion, or 12–15% of the current U.S. defense budget, could be reduced.

Finally, an Issue Brief by Securing America’s Future Energy (SAFE) (2018) found a conservative estimate of approximately \$81 billion per year spent by the U.S. military protecting global oil supplies.³⁸² This is approximately 16% of the recent U.S. Department of Defense’s budget. Spread out over the 19.8 million barrels of oil consumed daily in the U.S. in 2017, SAFE concluded that the implicit subsidy for all petroleum consumers is approximately \$11.25/barrel of crude oil, or \$0.28/gallon. According to SAFE, a more comprehensive estimate suggests the costs could be greater than \$30/barrel, or over \$0.70/gallon.³⁸³

As in the examples above, an incremental analysis can estimate how military costs would vary if the oil security mission were no longer needed, and many studies stop at this point. It is substantially more difficult to estimate how military costs would vary if U.S. oil use or imports were partially reduced, as is projected to be a consequence of this rule. Partial reduction of U.S. oil use likely diminishes the magnitude of the energy security problem, but there is uncertainty that supply protection forces and their costs could be scaled down in proportion, and there remains the associated goal of protecting supply and transit for U.S. allies and other importing countries, if they do not decrease their petroleum use as well.³⁸⁴ We are unaware of a robust methodology for assessing the effect on military costs of a partial reduction in U.S. oil use. Therefore, we are unable to quantify this effect resulting from the projected reduction in U.S. oil use attributable to this rule.

6.4 Energy Security Impacts

6.4.1 U.S. Oil Import Reductions

From 2026 to 2027, the AEO2025 Reference Case projects that the U.S. will be both an exporter and an importer of crude oil and petroleum products and, on balance, a net exporter of petroleum.³⁸⁵ The U.S. produces more light crude oil than its refineries can refine.³⁸⁶ Thus, the U.S. exports lighter crude oil and imports heavier crude oil to satisfy the needs of U.S. refineries which are configured to efficiently refine heavy crude oil. Projections from AEO2025 of U.S. consumption and trade of petroleum are presented in Table 6.4.1-1 below. These projections confirm that the U.S. will continue to face significant exposure to global petroleum markets in 2026 and 2027. As discussed earlier in this chapter, both imports and consumption of petroleum expose the U.S. to energy security risks from shocks in the world oil price and supplies. Because the U.S. is projected to continue to consume significant quantities of oil and to rely on significant

³⁸² Securing America’s Future Energy, “Issue Brief – The Military Cost of Defending the Global Oil Supply,” September 21, 2018. <https://secureenergy.org/wp-content/uploads/2020/03/Military-Cost-of-Defending-the-Global-Oil-Supply.-Sep.-18.-2018.pdf>.

³⁸³ Id.

³⁸⁴ Crane, Keith, Andreas Goldthau, Michael Toman, Thomas Light, Stuart Johnson, Alireza Nader, Angel Rabasa, and Harun Dogo. “Imported Oil and U.S. National Security.” *RAND Corporation*, 2009. <https://doi.org/10.7249/mg838>.

³⁸⁵ AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

³⁸⁶ Washington Post, “Why importing and exporting oil makes sense.” <https://www.washingtonpost.com/sf/brand-connect/wp/enterprise/why-importing-and-exporting-oil-makes-sense>.

quantities of crude oil imports in 2026 and 2027, U.S. oil markets are expected to remain tightly linked to trends in the world crude oil market.

Table 6.4.1-1: Projected Petroleum Consumption and Net Imports from AEO2025 (MMBD)

	2026	2027
U.S. Crude Oil Exports	4.2	4.2
U.S. Crude Oil Imports	6.4	6.2
U.S. Net Petroleum Refined Product Exports ^a	5.4	5.6
U.S. Net Crude Oil Exports + Net Refined Petroleum Product Exports ^b	3.3	3.7
U.S. Oil Consumption ^c	19.2	19.2

^a Calculated from AEO2025, Table 11 as Net Product Exports minus Ethanol, Biodiesel, Renewable Diesel, and Other Biomass-derived Liquid Net Exports.

^b Calculated from AEO2025, Table 11 as Total Net Exports minus Ethanol, Biodiesel, Renewable Diesel, and Other Biomass-derived Liquid Net Exports.

^c Calculated from AEO2025, Table 11 as Total Primary Supply minus Biofuels.

To estimate how the Analyzed Volumes may impact this exposure, we must first estimate their effect on consumption and net imports of oil. Estimated differences in refined oil consumption relative to the No RFS Baseline are presented in Table 10.4.2.1.1-1b. As described in Chapter 10.4.2.1.1, changes in net imports of crude oil and refined petroleum are then estimated based on the changes in refined oil consumption using an “oil import reduction factor” of 97.5%. That is, we estimate that 97.5% of the reduction in U.S. petroleum consumption will come from reduced net imports, with the remaining 2.5% coming from reduced domestic production. See Chapter 10.4.2.1.1 for more details on the calculations summarized here. The calculated changes in net imports of crude oil are presented in Table 10.4.2.1.1-2, which amount to reductions of roughly 0.27 MMBD in 2026 and 0.33 MMBD in 2027.

6.4.2 Oil Import Premiums

In order to understand the energy security implications of reducing U.S. net oil imports, EPA has worked with ORNL, which has developed approaches for evaluating the social costs and energy security implications of U.S. oil imports. The energy security estimates provided below are based upon a methodology first developed in a peer-reviewed 2008 ORNL study.³⁸⁷ This 2008 ORNL study was an updated version of the approach used for estimating the energy security benefits of U.S. oil import reductions developed in an earlier 1997 ORNL Report.³⁸⁸ Since 2008, ORNL has updated this methodology periodically for EPA to account for updated projections of future energy market and economic trends reported in the EIA’s AEO. For this final rule, EPA has updated the ORNL methodology using AEO2025.

³⁸⁷ Leiby, Paul. “Estimating the Energy Security Benefits of Reduced U.S. Oil Imports.” *Oak Ridge National Laboratory*, ORNL/TM-2007/028. March 2008.

https://cfpub.epa.gov/si/si_public_file_download.cfm?p_download_id=504469.

³⁸⁸ Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee. “Oil Imports: An Assessment of Benefits and Costs.” *Oak Ridge National Laboratory*, ORNL-6851. November 1, 1997.

https://www.esd.ornl.gov/eess/energy_analysis/files/ORNL6851.pdf.

The ORNL methodology is used to compute the oil import security premium per barrel of imported oil.³⁸⁹ The values of U.S. oil import security premium components (macroeconomic disruption/adjustment costs and monopsony components) are numerically estimated with a compact model of the oil market by performing simulations of market outcomes using probabilistic distributions for the occurrence of oil supply shocks. Each of these simulations inform the estimates of the marginal changes in economic welfare with respect to changes in U.S. oil import levels. ORNL then summarizes the results from the individual simulations into a mean and 90% confidence interval for the import premium.

EPA only considers the avoided macroeconomic disruption/adjustment oil import premiums (*i.e.*, labeled macroeconomic oil security premiums below) as costs, since the monopsony impacts stemming from changes in oil imports are considered transfer payments. In previous EPA rules when the U.S. was projected by EIA to be a net petroleum importer, monopsony impacts represented reduced payments by U.S. consumers to oil producers outside of the U.S. There was some debate among economists as to whether the U.S. exercise of its monopsony power in oil markets (*e.g.*, from the implementation of EPA's rules) was a "transfer payment" or a "benefit." Given the redistributive nature of this monopsony impact from a global perspective, and since there are no changes in resource costs when the U.S. exercises its monopsony power, some economists argued that it is a transfer payment. Other economists argued that monopsony impacts were a benefit since they partially address, and partially offset, the market power of OPEC. In previous EPA rules, after weighing both countervailing arguments, EPA concluded that the U.S.'s exercise of its monopsony power was a transfer payment, and not a benefit.³⁹⁰

In the context of this rule, the U.S.'s oil trade balance position has shifted notably from the position it held when we assessed energy security impacts for most previous RFS rules. As discussed above (see Figure 6-1), the U.S. became a net petroleum exporter for the first time in several decades in 2020, and these net exports have continued to grow since that time. As also observed above, the EIA projects the U.S. will continue to be a net petroleum exporter in 2026–2027. As a result, reductions in U.S. oil consumption and, in turn, U.S. net oil imports, lower the world oil price, albeit modestly. But the net effect of the lower world oil price is now a decrease in revenue for U.S. exporters of crude oil and petroleum-based products, instead of a decrease in payments to foreign oil producers. The argument that monopsony impacts address the market power of OPEC is therefore no longer appropriate. Thus, we continue to consider the U.S. exercise of monopsony power to be transfer payments. We also do not consider the effect of this rule on the costs associated with existing energy security policies (*e.g.*, maintaining the Strategic Petroleum Reserve or strategic military deployments), which are discussed in Chapter 6.3.

The macroeconomic oil security premiums arise from the effect of U.S. oil imports on the expected cost of supply disruptions and accompanying price increases. A sudden increase in oil prices triggered by a disruption in world oil supplies has two main effects: (1) it increases the costs of oil imports in the short-run, and (2) it leads to macroeconomic contraction, dislocation,

³⁸⁹ The oil import premium concept is defined in Chapter 6.1.

³⁹⁰ We also discuss monopsony oil import premiums in previous EPA GHG vehicle rules. See, *e.g.*, EPA, "Revised 2023 and Later Model Year Light Duty Vehicle GHG Emissions Standards: Regulatory Impact Analysis," EPA-420-R-21-028, December 2021, Section 3.2.5. <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1013ORN.pdf>.

and GDP losses. Since future disruptions in foreign oil supplies are an uncertain prospect, each of the disruption cost components must be weighted by the probability that the supply of petroleum to the U.S. will actually be disrupted. Thus, the “expected value” of these costs—the product of the probability that a supply disruption will occur and the sum of costs from reduced economic output and the economy’s abrupt adjustment to sharply higher petroleum prices—is the relevant measure of their magnitude.

In addition, EPA and ORNL have worked together to revise the oil import premiums based upon the on-going, updated energy security literature. Based on EPA and ORNL’s review of the energy security literature, EPA is using updated macroeconomic oil security premiums for this rule. The recent economics literature (discussed in Chapter 6.2) focuses on three factors that can influence the macroeconomic oil security premiums: (1) price elasticity of oil demand, (2) GDP elasticity in response to oil price shocks, and (3) the impacts of the tight (*i.e.*, shale) oil boom. We discuss each factor below and provide a rationale for how we are developing new estimates of the macroeconomic oil security premiums.

First, we assess the price elasticity of demand for oil. In RFS rules prior to the 2020–2022 RFS Rule, EPA used a short-run elasticity of demand for oil of -0.045 .³⁹¹ From the RFF study (2017) discussed previously in Chapter 6.2.1, the “blended” price elasticity of demand for oil is -0.05 . The ORNL meta-analysis estimate of this parameter is -0.07 . We find the elasticity estimates from what RFF characterizes as the “new literature,” -0.175 , and from the “new models” that RFF uses, -0.20 to -0.33 , somewhat high. Most of the world’s oil demand is concentrated in the transportation sector and there are limited alternatives to oil use in this sector in 2026–2030. According to IEA, the share of global oil consumption attributed to the transportation sector grew from 60% in 2000 to 66% in 2019.³⁹² The next largest sector by oil consumption, and an area of recent growth, is petrochemicals. There are limited alternatives to oil use in this sector also, particularly in 2026–2030. Thus, we believe it would be surprising if short-run oil demand responsiveness has changed in the dramatic fashion implied by the RFF “new literature” estimates.

The ORNL meta-analysis estimate encompasses the full range of the economics literature on this topic and develops a meta-analysis estimate from the results of many different studies in a structured way, while the RFF study’s “new models” results represent only a small subset of the economics literature’s estimates. Thus, for the analysis of this rule, and consistent with the 2020–2022 RFS Rule and the Set 1 Rule, we have increased the short-run price elasticity of demand for oil from -0.045 to -0.07 , a 56% increase.³⁹³ This increase has the effect of lowering the macroeconomic oil security premium estimates undertaken by ORNL for EPA.

Second, we consider the elasticity of GDP to an oil price shock. In RFS rules prior to the 2020–2022 RFS Rule, a GDP elasticity to an oil price shock of -0.032 was used.³⁹⁴ The RFF

³⁹¹ See, *e.g.*, 75 FR 26049, May 10, 2010.

³⁹² IEA, “World Energy Statistics and Balances.” <https://www.iea.org/data-and-statistics/data-product/world-energy-statistics-and-balances>.

³⁹³ EPA and ORNL worked together to develop an updated estimate of the short-run elasticity of demand for oil for use in the ORNL model.

³⁹⁴ See, *e.g.*, 75 FR 26049 (May 10, 2010).

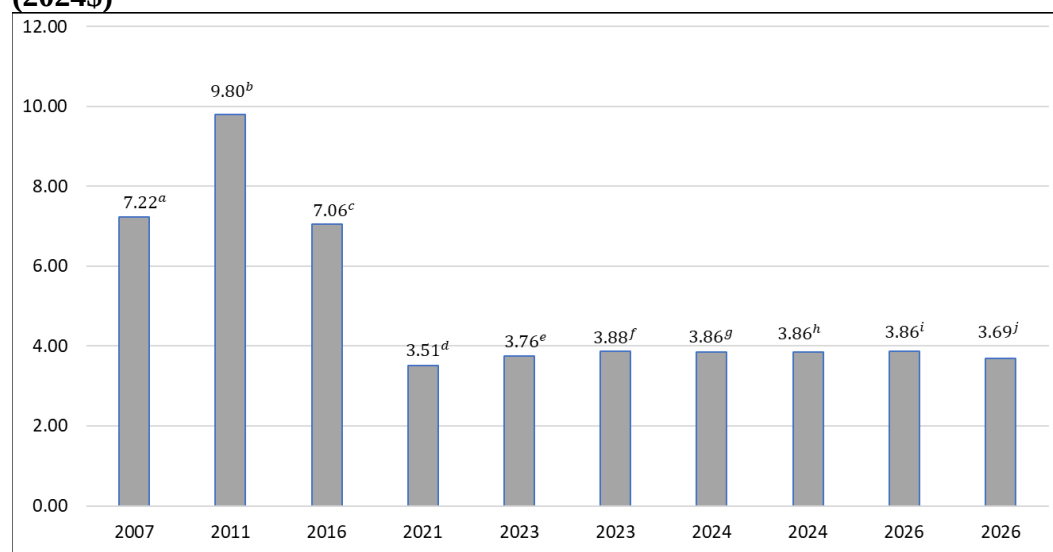
“blended” GDP elasticity is -0.028 , the RFF’s “new literature” GDP elasticity is -0.018 , while the RFF “new models” GDP elasticities range from -0.007 to -0.027 . The ORNL meta-analysis GDP elasticity is -0.021 . We believe that the ORNL meta-analysis value is representative of the economics literature on this topic since it considers a wide range of recent studies and does so in a structured way. Also, the ORNL meta-analysis estimate is within the range of GDP elasticities of RFF’s “blended” and “new literature” elasticities. For this rule and consistent with the 2020–2022 RFS Rule and Set 1 Rule, EPA is using a GDP elasticity of -0.021 , a 34% reduction from the GDP elasticity used previously (*i.e.*, the -0.032 value).³⁹⁵ This GDP elasticity is within the range of RFF’s “new literature” elasticity, -0.018 , and the elasticity EPA has used in previous rules, -0.032 , but lower than RFF’s “blended” GDP elasticity, -0.028 . This decrease in the GDP elasticity has the effect of lowering the macroeconomic oil security premium estimates. For U.S. tight oil, EPA has not made any adjustments to the ORNL model, given the limited tight oil production response to rising world oil prices since 2020.³⁹⁶ Increased tight oil production still results in energy security benefits through its impact of reducing U.S. oil imports in the ORNL model.

Figure 6.4.2-1 shows the evolution of oil security premiums for this rule in comparison with oil security premiums for previous EPA final rules from 2007–2024. For each rulemaking, the estimated oil security premium value is computed using the ORNL oil security premium model, which is based upon oil market and economic conditions projected by each relevant AEO. The premiums are all computed following the same methodology, but under changing oil market balances and conditions, with some parameters evolving to reflect changing understanding of oil market flexibility and declining macroeconomic sensitivity to oil price shocks. Each bar corresponds to the first year for which the premium was estimated in each specific rule. Oil security premiums are estimated to be approximately \$7/barrel in 2007 and increased to \$9.47 in 2011. Then, the oil security premiums decreased markedly through the 2010s, landing at \$3.39/barrel in 2021. Values estimated for 2022 through 2026 have all been approximately \$3.70/barrel.

³⁹⁵ EPA and ORNL worked together to develop an updated estimate of the GDP elasticity to an oil shock for use in the ORNL model. This slightly different value also was produced by an earlier draft of the ORNL meta-analysis.

³⁹⁶ The short-run oil supply elasticity assumed in the ORNL model is 0.06 and is applied to production from both conventional and shale oil wells.

Figure 6.4.2-1: Comparison of Oil Security Premiums of this Final Rule and Previous Rules (2024\$)



- a. RFS1: Final Rule. (2007). Based on AEO2006.
- b. Final Rule for Phase 1 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (2011). Based on AEO2011.
- c. Final Rule for Phase 2 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles (2016). Based on AEO2015.
- d. 2020–2022 RFS Rule (2022). Based on AEO2021.
- e. Final Rule to Revise Existing National GHG Emissions Standards for Passenger Cars and Light Trucks Through Model Year 2026 (2023). Based on AEO2021.
- f. Set 1 Rule (2023). Based on AEO2023.
- g. Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles - Phase 3 (2024). Based on AEO2023.
- h. Final Rule: Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles (2024). Based on AEO2023.
- i. RFS Set 2 Rule 2026–2027: NPRM. Based on AEO2023.
- j. RFS Set 2 Rule 2026–2027: Final Rule. Based on AEO2025.

Multiple factors drive the change in magnitude of the U.S. oil security premiums over time. First, the U.S. oil trade balance is a key component in the calculation of premiums. The marginal change in expected net oil import costs during disruption events depends directly on the magnitude of net oil imports. The U.S. went from being a net importer of crude oil and petroleum products of roughly 12 million barrels per day in 2007 to becoming a net exporter in 2020. This trend reversal is mirrored in the evolution of the oil import premium from 2011 to 2021 in Figure 6.4.2-1. Second, in the calculation of premiums, OPEC’s share of global oil production is modelled to influence the size of potential supply disruptions. OPEC is the main production region that is assumed to have an insecure supply and is subject to the disruption events considered in the premium calculation. A larger share of OPEC production implies more oil supply is at risk and potentially higher price shocks from oil market disruptions. Third, all else equal, the oil import premium varies with oil price levels, with higher price levels presenting a risk of even larger price shocks during a disruption, with a greater effect on GDP and the net trade balance in oil.

Fourth, two important parameters going into the oil security premium calculation (the elasticity of demand for oil with respect to oil prices and the U.S. elasticity of U.S. GDP with

respect to oil prices) have been updated over time to reflect the U.S. economy's evolving market structure. See the discussion above for more details about how the short-run price elasticity of demand for oil increased, indicating greater short-run flexibility. In addition, the central value used for elasticity of GDP in response to oil price shocks has been updated based upon the most recent estimations in the economics literature.

The combined effect of all these factors aligns directionally with the evolution of oil security premium values shown in Figure 6.4.2-1. From 2007 to 2011, despite U.S. net oil imports trending downward, the oil security premium value increased due to higher oil prices and higher OPEC market share. The decreasing trend from 2011 to 2021 resulted from a combination of decreases in U.S. net oil imports and oil prices. Additionally, the premiums for year 2021 and later are based on calculations with more price elastic oil demand and less elastic U.S. GDP to price shocks. Small increases in the premium estimates for 2023 and 2024 relative to 2021 can be mostly explained by modest changes in expected market conditions, including higher oil prices projections.

The premia estimates in the NPRM were computed based on AEO2023. For the final rule, the estimates were updated based on AEO2025. Relative to the AEO2023 values, in AEO2025, the disruption premia start with lower values, and then the rise to somewhat higher values after approximately 2035. Premia estimates computed for 2026–2030, computed with AEO2025 inputs are 5%–7% lower than the ones computed with AEO2023 inputs. This modest decline results from offsetting effects between improving oil market conditions and macroeconomic growth. The combined effect of differences in the projections of several macroeconomic and oil market variables between the two AEOs explain the lower estimated premia, which can be further understood by decomposing the optimal disruption premium into its two components: the disruption import-cost component and the larger disruption macroeconomic component. First, in AEO2025 projections, the U.S. is a larger net exporter of all petroleum liquids than in AEO2023. In AEO2023, the average projected net exports in 2026–2030 are 2.41 million barrels per day vs 3.8 million barrels per day in AEO2025. Somewhat larger net exports result in improved terms of trade during disruption events. Because the U.S. is a net exporter over this time period, the “disruption import-cost component” of the premium is negative (*i.e.*, a benefit that partially offsets macroeconomic disruption costs). Second, AEO2025 projects the Brent spot price, used in the oil security premium calculations as representative of the world oil price, to be 10% lower in 2026–2030 than AEO2023. All else equal, a lower baseline price will also lead to lower oil prices during the simulated supply disruptions and, therefore, lower expected GDP disruption costs. Third, the projected OPEC share of global oil supply is 7 percentage points lower in AEO2025 than AEO2023 (30% vs. 37%). This contributes to a lower share of global oil supply at risk for oil supply shocks and lower expected price impacts from the set of disruptions simulated. Finally, real U.S. GDP projected for 2026–2030 is 9% higher in AEO2025 than AEO2023. For a given set of disruption risks, price shocks, and GDP sensitivity to price changes, the expected GDP disruption component is proportional to economic size. However, the other three factors mentioned above more than offset the role of the larger GDP in the oil security premium calculations resulting in about 6% lower premia values using AEO2025 inputs than using AEO2023 inputs.

Table 6.4.2-1 provides EPA’s estimates of the macroeconomic oil security premiums for 2026–2027, showing that they are gradually increasing over this time period. The macroeconomic oil security premiums range from \$3.69/barrel to \$3.67 /barrel in 2026 and 2027, respectively. In terms of cents per gallon, the macroeconomic oil security premiums range from 0.088 cents per gallon in 2026 and 0.087 cents per gallon in 2027. These estimates of the macroeconomic oil security premiums are actual values as opposed to discounted values, implying that they do not reflect the time value of money.

Table 6.4.2-1: Macroeconomic Oil Security Premiums (2024\$/barrel)

Year	Macroeconomic Oil Security Premiums (2024\$/Barrel of Reduced Oil Imports)
2026	\$3.69 (\$0.25–\$7.25)
2027	\$3.67 (\$0.16–\$7.31)

Note: Top values in each cell are mean values. Values in parentheses are 90% confidence intervals.

6.4.3 Energy Security Benefits

Estimates of the total annual energy security benefits of the Analyzed Volumes are based on the ORNL oil import premium methodology with updated oil import premium estimates reflecting the energy security literature and using AEO2025. Section 6.4.2 above discusses how and why the premia estimates have changed based on the AEO (2023 vs. 2025). To calculate total energy security benefits, annual macroeconomic oil security premiums (Table 6.4.2-1) are multiplied by the annual reduction in U.S. net oil imports (Table 6.4.1-1). The total annual energy security benefits are presented in Tables 6.4.3-1. We do not consider military cost impacts or the monopsony effect of U.S. crude oil and refined petroleum product import changes. These benefit estimates are actual values as opposed to discounted values, implying that they do not reflect the time value of money. The present value and annualized value of estimated energy security impacts of the Analyzed Volumes using 3% and 7% discount rates are presented in Preamble Section III.H.2 and in RIA Chapter 10.6.

Table 6.4.3-1: Total Annual Energy Security Benefits for the Analyzed Volumes (millions 2024\$, undiscounted)

Year	Total Energy Security Benefits Final Renewable Fuel Volumes
2026	\$361 (\$24–\$710)
2027	\$438 (\$19–\$873)

Note: Top values in each cell are the mean values, while the values in parentheses define 90% confidence intervals. U.S. net oil import reductions used for the energy security analysis in this section are a combination of reduced U.S. imports of gasoline, diesel fuel, and crude oil from Chapter 10.4.2.1.1 converted to crude oil-equivalent barrels.

The impact on crude oil and refined petroleum product exports alone does not fully capture the broader implications of this rule. This rule will likely result in substantial imports of feedstocks that are used to produce renewable fuels to meet the RFS renewable fuel volume

requirements. As discussed in Chapter 10.4.2.1, if, for example, we conservatively assume that all the volume of canola oil and used cooking oil demanded to meet the increased volumes are imported, as much as 26.3% (in 2026) and 27.5% (in 2027) of the increased vegetable oil demanded under the Analyzed Volumes could be imported. Additionally, this would mean that 26.4 % in 2026 and 27.6 % in 2027 of the renewable fuels used to meet the renewable fuel volumes will be derived from imported feedstocks.

6.5 Feedstock Diversification

This section is a preliminary attempt to analyse the impact of biofuel and biofuel feedstock imports on U.S. energy security. Biofuels and biofuel feedstocks are traded on global markets and as such are susceptible to the same risk factors that affect the supply and price of energy and agricultural commodities globally. As discussed across Chapter 3, Chapter 7, and Chapter 9, the Analyzed Volumes are estimated to intensify the competition for limited feedstocks, most notably vegetable oils and FOG, relative to the previous RFS volume standards. The same is not necessarily true for imported biofuels specifically, as our analyses generally project that these imports will decline substantially in 2026 and 2027 compared to 2024 and previous years, due to changes in federal tax incentives (see Chapter 3 and Chapter 7). Nevertheless, exposure of the U.S. renewable fuel and biofuel feedstock supply to global supply and price volatility risks, and the associated potential risks to energy security benefits from this exposure, are understandably a concern.

EPA has not previously analyzed the supply and price volatility risk factors associated with renewable fuels and renewable fuel feedstocks as part of our energy security analysis. This is a relatively unexplored space in economic literature, and we could not identify methods of sufficient robustness to merit inclusion of estimated social benefits associated with the reduction of these risks. However, some relevant literature does exist, allowing us to begin consideration of these factors, and perhaps build on this understanding in future volume-setting efforts.

In this subsection, we consider approaches that may begin to shed light on this issue and suggest areas of future work. We examine the concept of portfolio diversification in the context of renewable fuel feedstocks. We then consider how diversifying this portfolio of energy products might affect energy security and suggest areas for future work.

6.5.1 Portfolio Diversification in the Context of Renewable Fuel Feedstocks

Volatility in renewable fuel feedstock prices has the potential to be transmitted to finished transportation fuel prices that consumers face. Price volatility can arise from numerous vectors, including from global supply shocks and other commodity market disruptions and from fluctuations in competition among fuels and feedstocks to meet the RFS standards. Price volatility and supply volatility are intertwined but separate concepts and an in-depth analysis might explore those nuances. However, for the purposes of this discussion, we will largely treat them as an interconnected nexus of risks to energy security.

Across economic sectors, portfolio diversification is a common strategy to reduce exposure to price and supply volatility risks. The concept of portfolio diversification itself is the

main tenet of Markowitz’s Modern Portfolio Theory (1952)³⁹⁷ (hereafter “portfolio theory”), which explains how and why this strategy is effective. Specifically, portfolio theory explains that diversification can mitigate unsystematic risk (*i.e.*, the risk specific to an individual financial holding or economic sector) and lead to more predictable returns overall. In Markowitz’s original formulation, portfolio theory observes that low stock price correlations among a group of stocks indicate that prices for that group of stocks are relatively less likely to move in the same direction in response to an economic shock compared to a group of stocks whose prices are highly correlated. This observation illustrates the potential for diversification to reduce risk within the portfolio; by combining uncorrelated assets, the poor performance of one asset during a market downturn or some other type of economic shock (*e.g.*, in the context of biofuel feedstocks, an unexpectedly low feedstock crop yield in a particular growing region) can be offset by the better performance of another, leading to more stable, risk-adjusted returns for the overall portfolio over time. This phenomenon applies not only to stocks and stock portfolios, but also to commodities such as transportation fuels and feedstocks.

What this means in the context of transportation fuels is that diversifying feedstock types and geographic sources could result in reduced overall volatility of transportation fuel prices, since adverse shocks affecting agricultural feedstock prices (*e.g.*, a drought causing low crop yields) and shocks affecting petroleum prices (*e.g.*, geopolitical instability) are likely unrelated. Demonstrating this effect would, however, require an assessment of the extent to which changes in prices of feedstocks are passed through to prices of finished fuels. Empirically, there is evidence in the literature on the volatility passthrough of crude oil prices to transportation fuel prices.³⁹⁸ While literature on the volatility passthrough of biofuel feedstock prices to transportation fuel prices is a bit dated, it exists nonetheless, and points to the potential merits of feedstock diversification to reduce volatility in feedstock prices and hence finished fuel prices. As explained earlier in this chapter, we define energy security the “uninterrupted availability of energy sources at an acceptable price.”³⁹⁹ Recognizing this, high volatility in energy markets has the potential to make the “acceptable price” component unpredictable and at times unaffordable, with the potential to lower the energy security benefits accruing from this rule.

With these motivations in mind, we analyzed some simple statistical relationships to understand at a first principles level how feedstock diversification may potentially impact volatility of transportation fuel prices and hence improve energy security. As an illustrative example, we chose to focus on the case of diesel and biodiesel (with soybean oil and canola oil as the assumed feedstocks used in biodiesel production). Data on canola oil and soybean oil were sourced from USDA’s Oil Crops Yearbook.⁴⁰⁰ Data on Brent and WTI prices were sourced from the FRED database maintained by the St Louis Federal Reserve Bank.^{401,402}

³⁹⁷ Markowitz, Harry M. “Portfolio Selection: Efficient Diversification of Investments.” Yale University Press, 1959. <http://www.jstor.org/stable/j.ctt1bh4c8h>.

³⁹⁸ See “Volatility Passthrough,” available in the docket for this action.

³⁹⁹ IEA, “Energy Security.” <https://www.iea.org/topics/energy-security>.

⁴⁰⁰ USDA, “Oil Crops Yearbook,” March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

⁴⁰¹ Federal Reserve Economic Data, “Global price of Brent Crude,” January 22, 2026. <https://fred.stlouisfed.org/series/POILBREUSDA>.

⁴⁰² Federal Reserve Economic Data, “Global price of WTI Crude,” January 22, 2026. <https://fred.stlouisfed.org/series/POILWTIUSDA>.

Correlations in monthly returns of canola oil and soybean oil with Brent and WTI were computed. Volatility metrics for each of these series were also computed over the same time period. All prices were expressed in nominal 2024\$ per metric ton.⁴⁰³ Table 6.5.1-1 below shows the pairwise correlation in returns (*i.e.*, the strength of the correlation between each feedstock price and each other feedstock price) across the various feedstocks for the time period of our analysis (1991–2024). Table 6.5.1-2 below shows the volatility⁴⁰⁴ in feedstock prices between 1991 and 2024.

Table 6.5.1-1: Pairwise Correlation in Feedstock Prices (1991–2024)

	Canola	Soybean	WTI	Brent
Canola	1.00	0.44	0.20	0.21
Soybean	0.44	1.00	0.20	0.21
WTI	0.20	0.20	1.00	0.95
Brent	0.21	0.21	0.95	1.00

Table 6.5.1-2: Volatility in Feedstock Prices (1991–2024)

Feedstock	Volatility
Canola Oil	6.27%
Soybean Oil	5.75%
Brent Crude	9.39%
WTI Crude	9.24%

From Table 6.5.1-1 we see that the correlations in monthly returns of crude oil with both canola and soybean oil are low. Conversely, soybean oil and canola oil prices are fairly correlated with one another, and Brent and WTI crude oil prices are strongly correlated with each other, which aligns with our general understanding of the global markets for vegetable oil and crude oil. As noted above, low stock price correlations among a group of stocks (feedstocks in this case) are indicative of the potential for diversification to reduce risk/volatility. Furthermore, from Table 2 we note that both canola and soybean oil have been less volatile than crude oil during that same period. The fact that both canola oil and soybean oil are less volatile than crude oil and that the correlation of returns of crude oil prices with canola oil and soybean oil prices are low or negative are indicative of the potential for soybean oil- and canola oil-based biodiesel to reduce fuel price volatility.

Table 6.5.1-3 below shows the volatility in monthly returns (computed from average monthly retail fuel prices) in B99/B100 and B20 biodiesel blends and onroad diesel pre-RFS2 (*i.e.*, before 2010) and after initial implementation of RFS2 (*i.e.*, 2010 and onward). B99/B100, B20, and on-road diesel data were obtained from DOE’s Alternative Fuels Data Center.⁴⁰⁵

⁴⁰³ Monthly prices were adjusted by the Index of personal consumption expenditure. Federal Reserve Economic Data, “Personal Consumption Expenditures: Chain-type Price Index,” February 20, 2026. <https://fred.stlouisfed.org/series/PCEPI>.

⁴⁰⁴ We calculate volatility as the standard deviation of monthly price returns relative to the long-run average price return across the entire time series. As an example, if returns on the price of a commodity increase by 5% every year, then over a 5-year period the mean increase would be about 0.05/5. The standard deviation over this 5-year period would then be computed as the square root of the deviation from this mean and when expressed as a percentage would be the volatility.

⁴⁰⁵ AFDC, “Fuel Prices,” <https://afdc.energy.gov/fuels/prices.html>.

Table 6.5.1-3: Volatility in Diesel, B20, and B99/B100

Fuel	2003–2025	2003–2009	2010–2025
Diesel	11.1%	14.7%	9.4%
B20	10.2%	13.3%	8.8%
B99/B100	7.5%	11.0%	6.3%

Note: Data on B99/B100 was available starting 2005.

A comparison of the price volatility estimates across this time series shows that the volatility in returns for diesel, B20 and B99/B100 all appear to have decreased after the implementation of the RFS2 program in 2010. These estimates further show that B99/B100 has the lowest price volatility of the three fuel types across each time segment.

6.5.2 Concluding Observations on Feedstock Diversification and Transportation Fuel Volatility

Feedstock diversification (feedstock mix as well as the source of the mix itself) may have contributed to the lower volatility in transportation fuel prices. Based on this limited analysis, however, we can at best infer correlation and not causation. To understand both directional causation and the strength of this causal relationship, we would need to carry out more detailed analysis, starting with the potential for risk mitigation (lower volatility) through diversifying origin or source of the feedstocks. Diversification in terms of the feedstock point of origin may also affect price correlations and hence their impact on feedstock portfolio volatility and the volatility of finished transportation fuels. Additionally, we would need to use more robust techniques to quantify the extent to which there is a volatility passthrough from feedstock prices to finished transportation fuel prices. A more comprehensive understanding and analysis of these impacts would allow us to better assess the implications of feedstock diversification for energy security.

Chapter 7: Rate of Production and Consumption of Renewable Fuel

This chapter outlines the anticipated annual rate of future commercial production for renewable fuels, including advanced biofuels in categories such as cellulosic biofuel and BBD in 2026 and 2027. Our projections for this period are based on historical data and other relevant factors, considering both domestically produced biofuels and imported biofuels available for use in the United States.⁴⁰⁶

We also project the use (*i.e.*, consumption) of qualifying renewable fuels in the U.S. While not an explicit factor that we must consider under the statute, domestic consumption of qualifying renewable fuels as transportation fuel is the primary basis for compliance with our RFS standards. It is also inherent in the requisite consideration of infrastructure which is addressed in Chapter 8, and in the cost to consumers of transportation fuel which is addressed in Chapter 10. For 2026 and 2027 the projection of consumption is based on our assessment of production, exports and imports, infrastructure constraints on distributing and using biofuels, costs, and other factors explained below and throughout this document. Sometimes, we term this overall resulting use of biofuels as the “supply” of biofuels. In general, we expect that all cellulosic biofuels produced in the U.S. will be used here as they have been historically. By contrast, some quantities of domestically produced advanced and conventional renewable fuels have historically been exported, and we expect exports of such fuels to continue through 2027.

We discuss the production and use of each major type of biofuel in turn: cellulosic biofuel (Chapter 7.1), BBD (biodiesel and renewable diesel) (Chapter 7.2), imported sugarcane ethanol (Chapter 7.3), other advanced biofuels (besides ethanol, biodiesel, and renewable diesel) (Chapter 7.4), total ethanol (Chapter 7.5), corn ethanol (Chapter 7.6), and conventional biodiesel and renewable diesel (Chapter 7.7).

7.1 Cellulosic Biofuel

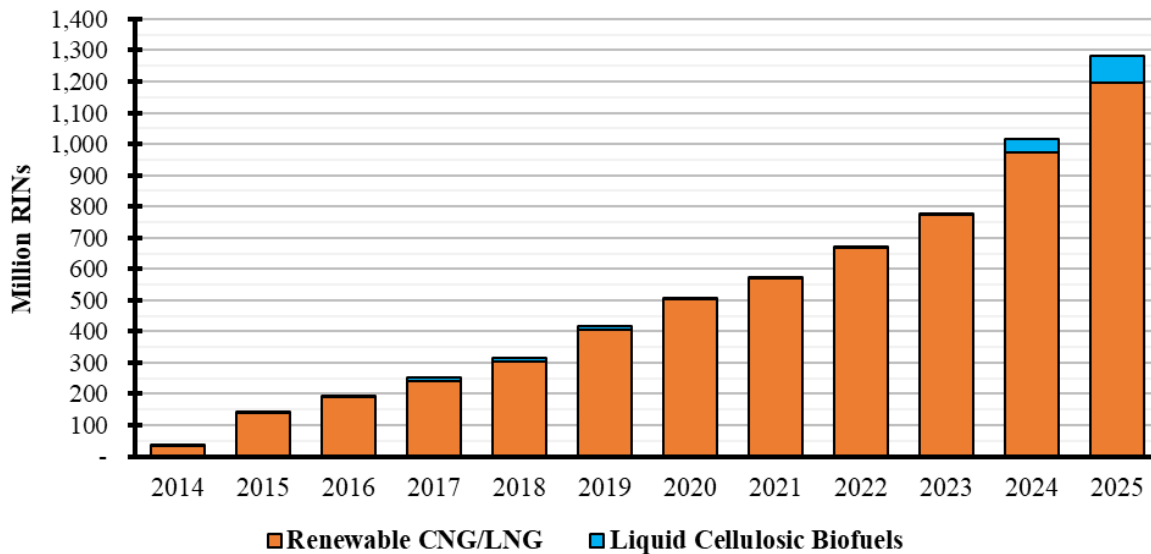
The RFS2 Rule projected strong growth for cellulosic biofuels, anticipating they would become a major contributor to total biofuel volumes.⁴⁰⁷ After that rule took effect, however, commercial-scale production of cellulosic biofuels failed to meet those high expectations, with actual volumes falling significantly below statutory targets through 2022. More recently, however, production has increased steadily, reaching record levels in 2025, driven mainly by RNG, which is consumed as CNG/LNG.⁴⁰⁸ However, small volumes of liquid cellulosic biofuels, particularly ethanol produced from CKF, have also played a contributing role (see Figure 7.1-1). This section describes our assessment of the expected production rate and consumption of qualifying cellulosic biofuel for 2025–2027, along with some of the uncertainties associated with the projected volume for these years.

⁴⁰⁶ This is what we generally mean when we use the term biofuel “production” in this chapter and do not specify whether we are discussing domestic production or imports.

⁴⁰⁷ 75 FR 14674 (March 26, 2010).

⁴⁰⁸ The majority of the cellulosic RINs generated for renewable CNG/LNG are sourced from biogas from landfills; however, the biogas may come from a variety of sources including municipal wastewater treatment facility digesters, agricultural digesters, separated municipal solid waste (MSW) digesters, and the cellulosic components of biomass processed in other waste digesters.

Figure 7.1-1: Cellulosic RIN Generation (2014–2025)



Note: We did not yet have final renewable CNG/LNG generation data for 2025 at the time of this analysis. Based on the information available at the time of writing, we do not expect the reported figures to differ materially from the final data.

Source: EMTS.

To project the volume of cellulosic biofuel production in 2025–2027, we evaluated several key factors. These include assessing the accuracy of previous methodologies used to estimate cellulosic biofuel production, data reported to EPA through EMTS, the projected use of renewable CNG/LNG as transportation fuel, and insights gathered from meetings with representatives of facilities that have recently produced or have the potential to produce qualifying volumes of cellulosic biofuel by 2027.

This section of Chapter 7 is organized as follows: Chapter 7.1.1 provides an industry-wide assessment of the cellulosic biofuel sector to understand its current state. Chapter 7.1.2 reviews and analyzes EPA’s previous cellulosic biofuel projections. Chapter 7.1.3 addresses the projected volume of cellulosic biofuel for 2025. Chapter 7.1.4 addresses the projected volume of renewable CNG/LNG from 2026–2027. Chapter 7.1.5 focuses on the projected production of liquid cellulosic biofuels from 2026–2027. Finally, Chapter 7.1.6 summarizes the overall projected rate of cellulosic biofuel production for 2026–2027.

7.1.1 Cellulosic Biofuel Industry Assessment

This section evaluates the cellulosic biofuel producers expected to generate qualifying cellulosic biofuel through 2027. This includes producers of both D3 RIN-generating cellulosic biofuels and D7 RIN-generating cellulosic diesel. Analysis of existing RIN data shows two primary contributors: renewable CNG/LNG as well as ethanol produced from CKF. Beyond these main sources, we have also looked at other potential contributors that could impact the future of cellulosic biofuel production.

7.1.1.1 Renewable Compressed Natural Gas and Liquefied Natural Gas

In July 2014, EPA approved cellulosic biofuel pathways under the “Pathways II” Rule, allowing RNG to generate cellulosic (D3) RINs when used as transportation fuel. Eligible biogas sources include landfills, separated municipal solid waste digesters, municipal wastewater treatment facilities, agricultural digesters, and the cellulosic components of biomass processed in other waste digesters. Since the implementation of the Pathways II Rule, cellulosic biofuel production has grown significantly, increasing from approximately 33 million RINs in 2014 to over 1 billion RINs in 2025. In 2025, approximately 93% of cellulosic RINs came from renewable CNG/LNG (see Figure 7.1-1). We expect renewable CNG/LNG to remain the primary source through 2027.

7.1.1.2 Ethanol from Corn Kernel Fiber

Outside of renewable CNG/LNG, few other sources of commercial-scale cellulosic biofuel exist. A notable exception is ethanol made from CKF. During corn ethanol production, part of the cellulosic fraction of the kernel fiber can be co-processed with corn starch to produce cellulosic ethanol. With limited additional processing or equipment changes, facilities can co-produce meaningful volumes of cellulosic ethanol alongside starch ethanol.

To qualify for D3 RINs, facilities must quantify the ethanol derived from the cellulosic portion, using reliable methods that distinguish it from starch-derived ethanol. In September 2022, EPA issued updated guidance on analytical methods for quantifying ethanol when co-processing CKF and corn starch and has engaged with registered cellulosic producers.⁴⁰⁹ As a result, EPA anticipates that most facilities currently producing corn starch ethanol will generate D3 RINs for cellulosic ethanol during the years analyzed in this rule. Given the large scale of corn starch ethanol production, ethanol from CKF is expected to make a meaningful contribution to future cellulosic biofuel volumes.

7.1.1.3 Other Cellulosic Biofuels

Between 2026 and 2027, EPA expects that commercial-scale production of cellulosic biofuel, beyond renewable CNG/LNG and ethanol produced from CKF, to remain very limited. While cellulosic ethanol from grain sorghum fiber could be produced, we do not expect it to have any impact during the years analyzed under this rulemaking. Because of this, we assume that any volumes attributable to grain sorghum cellulosic ethanol are captured within our analysis of CKF ethanol. In the past, small volumes of D7 RINs have been generated from foreign facilities producing cellulosic heating oil/diesel. While this production is worth noting, the total volume has remained consistently low,⁴¹⁰ making it almost indistinguishable from the background uncertainty of any future projections. Outside of these sources, there are several cellulosic biofuel production facilities in various stages of development, construction, and commissioning that may be capable of producing small volumes of cellulosic biofuel by 2027. These facilities primarily focus on producing cellulosic hydrocarbons from feedstocks such as

⁴⁰⁹ EPA, “Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch,” EPA-420-B-22-041, September 2022.

⁴¹⁰ EMTS data reports that from 2020 to 2025, annual D7 RIN generation varied from 55,892 to 236,790 RINs.

separated MSW, precommercial thinnings, and tree residues, which can be blended into gasoline, diesel, and jet fuel. Several of these facilities are currently registered with EPA and have the potential to generate RINs for qualifying cellulosic biofuel by 2027. However, according to data from EMTS, none of these facilities have generated cellulosic RINs for liquid cellulosic biofuel since March 2019. As a result, while these facilities have been considered potential sources of cellulosic biofuel, we do not project any volume of other cellulosic biofuel through 2027.

7.1.2 Review of EPA’s Projection of Cellulosic Biofuel in Previous Years

Before estimating future cellulosic biofuel volumes, we first review and evaluate the accuracy of EPA’s past projections to identify potential improvements to past methodologies. Table 7.1.2-1 provides a comparison of actual cellulosic biofuel volumes—including cellulosic biofuel (which generate D3 RINs) and cellulosic diesel (which generate D7 RINs)—against EPA’s projections from 2015 to 2025. This data shows that EPA projections underestimated total cellulosic RIN availability in 2015, 2018, and 2022, while overestimating it in 2016, 2017, 2019, 2020,⁴¹¹ 2023, 2024, and 2025.⁴¹² This variability highlights the inherent challenges in forecasting cellulosic biofuel production and emphasizes the need to continue refining our projection methods to improve accuracy in the future.

⁴¹¹ Cellulosic biofuel production in 2020 was affected by the COVID-19 pandemic. Since the projections were made before the pandemic, the resulting overestimates are attributed to the pandemic’s impact, rather than to any issues in EPA’s projection methodology.

⁴¹² See Chapter 7.1.3 for more information on the 2025 cellulosic biofuel projection.

Table 7.1.2-1: Projected and Actual Cellulosic Biofuel RIN Availability (million RINs)

Year	Projected Volume			Actual Volume ^a			
	Source	Liquid Cellulosic Biofuel	Renewable CNG/LNG	Total Cellulosic Biofuel ^b	Liquid Cellulosic Biofuel	Renewable CNG/LNG	Total Cellulosic Biofuel ^b
2015	c,d	2	33	35	<1	53	53
2016	d	23	207	230	4	186	190
2017	e	13	298	311	12	239	251
2018	f	14	274	288	11	304	315
2019	g	20	399	418	11	403	414
2020	h,i	16	577	593	2	503	505
2021	j	N/A	N/A	N/A	1	562	563
2022	k	0	632	632	1	662	663
2023	l	7	831	840	1	772	773
2024	l,m	51	1,039	1,090	43	971	1,014
2025	l,n	77	1,299	1,380	85	1,126	1,210

^a Actual production volumes are the total number of RINs generated minus the number of RINs retired for reasons other than compliance with the annual standards, based on EMTS data.

^b Total cellulosic biofuel may not be precisely equal to the sum of liquid cellulosic biofuel and renewable CNG/LNG due to rounding.

^c Projected and actual volumes for 2015 represent only the final 3 months of 2015 (October–December) as EPA used actual RIN generation data for the first 9 months of the year.

^d 2014–2016 RFS Rule (80 FR 77506; December 14, 2015).

^e 2017 RFS Rule (81 FR 89760; December 12, 2016).

^f 2018 RFS Rule (82 FR 58486; December 12, 2017).

^g 2019 RFS Rule (83 FR 63704; December 11, 2018).

^h 2020 RFS Rule (85 FR 7016; February 6, 2020).

ⁱ Cellulosic biofuel production in 2020 was affected by the COVID-19 pandemic, likely causing the actual volumes to fall short of the projections.

^j The 2021 cellulosic volume requirement was retroactively established at the actual volume of cellulosic biofuel produced in 2021. 2020–2022 RFS Rule (87 FR 39600; July 1, 2022).

^k 2020–2022 RFS Rule (87 FR 39600; July 1, 2022).

^l Set 1 Rule (88 FR 44468; July 12, 2023).

^m EPA waived the 2024 cellulosic volumes down from the projections made in the Set 1 Rule given that a RIN deficit was carried from 2023 into 2024, compounded by another shortfall in 2024 shortfall and the limited availability of 2023 carryover RINs. (90 FR 29751; July 7, 2025).

ⁿ EPA is revising the 2025 cellulosic biofuel volume requirement in this rule, as discussed in Preamble Section VI and Chapter 7.1.3. We do not yet have final RNG RIN generation data at the time of this action. This data can lag because producers must submit pipeline statements verifying production and delivery, which takes additional time. Based on the information available at the time of writing, we do not expect the reported figures to differ materially from the final data.

Reviewing the data in this table, EPA’s projections for liquid cellulosic biofuel were consistently higher than actual production from 2015 through 2017. In response, the 2018 final rule revised our approach to incorporate more recent data and improve accuracy. The updated method first grouped potential producers into (1) “consistent producers” with a demonstrated record of commercial-scale output and (2) “new producers” still ramping up. For each group, we defined a likely production range and then applied a percentile value, calibrated to historical performance, to generate a single projected volume per group.

Despite this refinement, EPA continued to over-project from 2018 to 2020, with 2020 particularly affected by COVID-19 disruptions that could not be anticipated. In 2022, by contrast, the method under-projected liquid cellulosic volumes. For the 2023–2025 rule, we again updated our analysis, with a particular focus on the growth of ethanol from CKF, including more granular assumptions about facility ramp-up and feedstock availability. Based on observed outcomes, we slightly under-projected liquid cellulosic volumes in 2023 and 2024 and slightly over-projected in 2025.

Next, we turn to the projection of renewable CNG/LNG. From 2015 to 2017, EPA applied a facility-by-facility approach to project renewable CNG/LNG production, estimating volumes for individual companies or facilities. However, this methodology also significantly overestimated renewable CNG/LNG production in 2016 and 2017, prompting EPA to develop a broader industry-wide projection method, first implemented in 2018.

This broader approach estimates future production by applying an industry-wide, year-over-year growth rate to current renewable CNG/LNG production rate. Specifically, EPA analyzes RIN generation data from the most recent 24 months available at the time of each rulemaking and calculates a growth rate from that period. This growth rate is then applied to the latest full calendar year of data and compounded for each subsequent year to project future production. This updated approach reflects the maturity of the renewable CNG/LNG industry, which has a greater number of potential producers than the liquid cellulosic biofuel industry. In such mature markets, industry-wide projections tend to be more accurate than a facility-by-facility method, as broader economic trends generally outweigh the performance of individual facilities.

The industry-wide approach slightly under-projected renewable CNG/LNG in 2018, 2019, and 2022. This approach overestimated production in 2020, likely due to the impacts of COVID-19. For the rulemaking that established volumes for 2023–2025, EPA again applied this methodology. However, unlike in the 2018–2022 rules, the growth rate for projections was calculated based on data from 2015–2022, rather than the previous 24 months. This adjustment was made to counteract the anticipated negative impacts of the COVID-19 pandemic on the 2020 and 2021 data, with pre-pandemic growth rates believed to reflect future renewable CNG/LNG production potential more accurately. The available information shows that EPA overestimated renewable CNG/LNG production for all years projected in the Set 1 Rule, including 2023, 2024, and 2025. For more details, refer to Chapter 7.1.3.

Reflecting on these past projections highlights two key points. First, estimating these volumes is inherently challenging, underscoring the need to continually refine our methods for greater accuracy. Second, the production of renewable CNG/LNG has consistently exceeded that of liquid cellulosic biofuel. This difference likely results from several factors, including the maturity of renewable CNG/LNG production technology relative to liquid cellulosic biofuel technologies, the lower production costs for RNG (see Chapter 10), and the relatively high value of the cellulosic RIN. While we project liquid cellulosic biofuel and renewable CNG/LNG volumes separately, the overall accuracy of the combined cellulosic biofuel volume projection is ultimately what matters for obligated parties.

7.1.2.1 Cellulosic RIN Generation Versus Separation

Historically, EPA’s efforts to project cellulosic biofuel volumes have been complicated by the industry’s novelty and the volatility of emerging technologies. More recently, changes to the RFS regulatory framework have also added a new temporal rhythm for RIN generation and separation and affected our methods for projecting industry-wide growth rates. Specifically, EPA updated the regulatory framework for biogas-derived fuels to enhance oversight. Through the Biogas Regulatory Reform Rule (BRRR),⁴¹³ finalized in the 2023 RFS Set 1 Rule, EPA restructured the oversight and compliance framework for biogas-derived RNG. A key change in the BRRR, effective in early 2025, requires RINs to remain attached to the RNG after generation and move with the fuel through the supply chain rather than be separated immediately by the producer. Separation of the RIN can now only occur once a registered “RIN separator” demonstrates that the RNG has been physically withdrawn from the grid and used as transportation fuel, thereby closing the loop between production and usage. In short, RNG RINs are now generated prior to use as a transportation fuel, and such RINs are not separated—and thus made available for compliance—until the RNG RIN separator obtains documentation demonstrating that the volume of renewable CNG/LNG was used as transportation fuel.

Consequently, relying solely on cellulosic RIN generation data would overstate the actual number of cellulosic RINs available for compliance, as it assumes every unit of RNG for which a RIN is generated is successfully dispensed to a vehicle, ignoring distinct downstream constraints on consumption. Essentially, conflating the two would ignore the possibility of produced fuel never finding a compliant end-use as transportation fuel. Thus, looking forward, EPA expects this distinction between RINs generated and RINs separated and made available for compliance to become increasingly critical when setting cellulosic volumes. By focusing on RIN separation and availability data when considering future volumes, we can more accurately account for real-world usage and ensure that mandated volumes reflect the fuel that can actually reach the transportation market

7.1.3 Projection of the 2025 Cellulosic Biofuel Volumes

As discussed in Chapter 7.1.2, EPA overestimated cellulosic biofuel volumes for 2023 and 2024, largely due to over-projecting D3 RIN availability from renewable CNG/LNG, which constitutes most of the cellulosic volume. In both years, the supply of available D3 RINs from renewable CNG/LNG was insufficient to meet the Set 1 cellulosic biofuel requirement. In response, EPA adjusted the 2024 cellulosic biofuel volume requirement.⁴¹⁴

While the exact causes of these past shortfalls are unclear and may involve multiple factors, EPA has long recognized that the renewable CNG/LNG market could reach a saturation point, where nearly all eligible CNG/LNG vehicles are already fueled by renewable CNG/LNG. Under the RFS regulations for biogas-derived renewable fuel (see Chapter 7.1.2.1), RINs are generated when the RNG is produced;⁴¹⁵ however, RINs are not separated—and thus made available for compliance—until the RNG RIN separator obtains documentation demonstrating

⁴¹³ 88 FR 44522 - 44541 (July 12, 2023)

⁴¹⁴ 90 FR 29751 (July 7, 2025).

⁴¹⁵ 40 CFR 80.125(b).

that the volume of renewable CNG/LNG was used as transportation fuel.⁴¹⁶ Because of this, the growth of the CNG/LNG vehicle market could act as a ceiling when determining appropriate volumes.

While EPA had anticipated this eventual limitation, we did not believe the market had reached this point when establishing the 2023–2025 volume requirements. At the time of that rulemaking, EPA projected future volumes based on the assumption that RNG production capacity, not renewable CNG/LNG market consumption, would be the primary constraint on cellulosic RIN availability. Accordingly, as discussed in Chapter 7.1.2, EPA used the historical growth rate of cellulosic RIN generation to set appropriate future volumes for 2023–2025. However, in that rulemaking EPA acknowledged that this methodology might become less appropriate as the CNG/LNG vehicle market becomes increasingly saturated with renewable CNG/LNG.⁴¹⁷ Given the shortfalls in projecting the 2023 and 2024 volumes, EPA has reason to believe that the CNG/LNG vehicle market is approaching this saturation point. Because of this, the methods originally used to set the 2025 volumes may no longer be dependable.

Further evidence of consumption constraints appears in cellulosic RIN retirement data, which show a substantial increase in retirements due to RNG being used in non-transportation applications. Specifically, comparing 2020–2024 and 2025 retirement data (see Table 7.1.3-1), we observe a pronounced rise, providing additional evidence of market consumption limits.⁴¹⁸

Table 7.1.3-1: Cellulosic RINs Retired Due to Use in Non-Transportation Applications (million RINs)

Year	Cellulosic RINs Retired
2020	0.0
2021	0.0
2022	0.0
2023	0.0
2024	0.4
2025	74.5

With these considerations in mind, we reevaluated the expected availability of cellulosic RINs for 2025. To estimate the total number available for compliance, we assessed both how much cellulosic fuel is likely to be produced in 2025 and how much of that fuel can realistically be used in transportation. We then compared these estimates against the cellulosic RINs generated and available for compliance as of this analysis. Given the timing, we already have most of the actual 2025 cellulosic production data in the form of RIN generation data.⁴¹⁹ Based

⁴¹⁶ 40 CFR 80.125(d).

⁴¹⁷ Set 1 Rule RIA Chapter 6.1.3.

⁴¹⁸ See “RIN retirement data from January 2026” RIN data file available at: <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-rin-retirement-data-renewable-fuel>.

⁴¹⁹ We do not yet have final RNG RIN generation data at the time of this analysis. This data can lag because producers must submit pipeline statements verifying production and delivery, which takes additional time. Based on the information available at the time of writing, we do not expect the reported figures to differ materially from the final data.

on this data, and as shown in Table 7.1.3-2, we estimate 2025 cellulosic RIN generation, and by extension cellulosic biofuel production, to be 1.29 billion RINs.⁴²⁰

Table 7.1.3-2: 2025 Cellulosic RIN Generations (millions of RINs)

Month	RINs Generated
January	84
February	83
March	99
April	106
May	116
June	109
July	116
August	119
September	114
October	114
November	113
December	115
Total	1,289

As noted earlier, RIN generation and production capacity estimates are only half of the challenge of projecting future renewable CNG/LNG volumes. Relying solely on production estimates would overstate compliance-eligible RINs because this method assumes every RNG unit tied to a RIN is used in a vehicle and ignores downstream consumption constraints. To address this issue, we estimated how much RNG can reasonably be used as transportation fuel by evaluating the size of the CNG/LNG vehicle fleet and its fuel consumption rates. The resulting estimate is shown in Table 7.1.3-3, and the calculation methodology is provided in Chapter 7.1.4.1.

Ethanol from CKF differs from renewable CNG/LNG in this context because production is a reasonable proxy for consumption. For fuels other than renewable CNG/LNG—including CKF ethanol—producers must report to EPA within five business days of the production or sale of the fuel,⁴²¹ so CKF ethanol does not exhibit the same reporting lag seen with renewable CNG/LNG. Accordingly, we assume the 2025 CKF ethanol data available as of this analysis reflects the final 2025 generation volumes. Additionally, because CKF ethanol is chemically indistinguishable from starch ethanol, it can be used in the same applications. Moreover, given the higher value of cellulosic fuels relative to conventional fuels, obligated parties have an incentive to prioritize cellulosic ethanol and separate those RINs before conventional ethanol. Combined with the large size of the ethanol market and the prevalence of ethanol-capable vehicles, it is reasonable to assume CKF ethanol will be fully consumed. Because of this, we can use actual 2025 RIN generation data for our estimate of both CKF production and consumption.

⁴²⁰ See “Available RINs to date from January 2026” RIN data file available at: <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-available-rins-date-renewable-fuel>.

⁴²¹ 40 CFR 80.1452

Combining this renewable CNG/LNG consumption estimate with the actual cellulosic ethanol volume produced and consumed in 2025, we project 2025 total cellulosic biofuel consumption volumes as shown below in Table 7.1.3-3.

Table 7.1.3-3: Projected 2025 Cellulosic Fuel Consumption (million RINs)

	Estimated Renewable CNG/LNG	Actual Ethanol from CKF	Projected Total Cellulosic
Cellulosic Fuel Consumption	1,170	84	1,254

A comparison of the 1.29 billion RIN upper limit based on in-year production data with our bottom-up estimate of 1.25 billion RINs (renewable CNG/LNG consumption plus CKF production; see Table 7.1.3-3) indicates that production capacity is not expected to be the main constraint on 2025 cellulosic RINs; the limiting factor is expected to be the use of renewable CNG/LNG as transportation fuel. This is even clearer when accounting for RINs already retired for reasons other than annual compliance. Taking the total number of cellulosic RINs generated in 2025 through the date of this analysis (1.29 billion cellulosic RINs),⁴²² and subtracting the number of RINs retired for reasons other than annual compliance by refiners (0.08 billion RINs)⁴²³ we estimate that approximately 1.21 billion cellulosic RINs will be both generated and available for compliance in 2025. Because the estimate of cellulosic RINs generated and available for compliance is lower than both the production- and consumption-based estimates, we use it to reevaluate expected 2025 availability. As a result, we project 1.21 billion RINs as the final 2025 availability and adjust the 2025 cellulosic fuel volume accordingly.⁴²⁴

7.1.4 Projecting the Renewable CNG/LNG Market

As discussed in the previous chapters, RINs from renewable CNG/LNG can only be used by obligated parties to demonstrate compliance with the RFS obligations when the renewable CNG/LNG is used as transportation fuel. To do so, raw biogas from eligible sources must first be collected and upgraded. This upgrading process involves removing contaminants and other undesirable components from the biogas. Biogas that has been upgraded and distributed through a closed, private distribution system is defined as “treated biogas,” whereas biogas that has been upgraded to be suitable for injection into the commercial natural gas pipeline system is defined as RNG.⁴²⁵ While treated biogas is typically used at the site of production, RNG is injected into the commercial natural gas pipeline system. Because RNG is upgraded to meet pipeline specifications, it is functionally identical to fossil-based natural gas. Once injected into pipelines, RNG can be used just like fossil-based natural gas—for fueling CNG/LNG vehicles, generating electricity, residential heating, and various industrial and commercial applications. Currently, large volumes of biogas are produced at landfills and wastewater treatment plants across the

⁴²² See “Available RINs to date from January 2026” RIN data file available at: <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-available-rins-date-renewable-fuel>.

⁴²³ See “RIN retirement data from January 2026” RIN data file available at: <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-rin-retirement-data-renewable-fuel>.

⁴²⁴ See Preamble Section VII.

⁴²⁵ 40 CFR 80.2.

U.S., with further potential for biogas generation from manure and other agricultural residues.⁴²⁶ Although the quantity of biogas from qualifying sources potentially far exceeds current CNG/LNG usage as transportation fuel,⁴²⁷ much of this biogas is not being upgraded to RNG⁴²⁸—a necessary step for its use in CNG/LNG vehicles. Instead, due to the significant capital investment required for collection and treatment, much of this biogas is currently either flared or used for onsite electricity generation.⁴²⁹

Despite these challenges, the incentive created by the cellulosic biofuel RIN has led to rapid growth in renewable CNG/LNG⁴³⁰ use since 2014 (see Table 7.1.4-1). Considering this incentive, we believe that the volume of renewable CNG/LNG can continue to grow under the influence of the RFS through 2027. At the same time, however, there are several market factors that we expect could limit the rate of growth of this biofuel in future years. As initially discussed in Chapter 7.1.3, we believe the market for renewable CNG/LNG used as transportation fuel is becoming increasingly demand-limited, a factor that must be considered when projecting future volumes. The following subsections further explore the supply and demand dynamics of RFS-qualifying renewable CNG/LNG.

Table 7.1.4-1: RIN Generation (million RINs) and Annual Growth Rate for Renewable CNG/LNG

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025 ^a
Renewable CNG/LNG RIN Generation	140	189	241	304	404	504	568	667	773	973	1,206
Annual Growth Rate	-	35%	28%	26%	33%	25%	13%	18%	16%	26%	24%

^a Final 2025 generation data are not yet available at the time of this analysis. The figures presented are estimates based on the best available information, and given the timing of this action, we do not expect them to differ materially from the final data.

7.1.4.1 Projected Demand of Renewable CNG/LNG

To estimate the future demand for renewable CNG/LNG, we first looked to identify an appropriate estimate for all CNG/LNG usage in transportation, including both fossil and renewable sources. Because RINs can only be used to demonstrate compliance with the RFS obligations when the fuel is used in transportation, the maximum potential transportation use of CNG/LNG defines the theoretical and practical upper limit for compliance-eligible renewable

⁴²⁶ American Biogas Council, “Biogas Market Snapshot,” April 2025. <https://americanbiogascouncil.org/biogas-market-snapshot>.

⁴²⁷ A discussion of EPA’s estimates for current and future CNG/LNG usage as transportation fuel is in Chapter 7.1.4.1.

⁴²⁸ EPA, “LFG Energy Project Development Handbook,” January 2024. https://www.epa.gov/system/files/documents/2024-01/pdh_full.pdf.

⁴²⁹ EPA, “LMOP Landfill and Project Database.” <https://www.epa.gov/lmop/lmop-landfill-and-project-database>.

⁴³⁰ RNG is biogas upgraded to commercial pipeline quality and injected into the commercial natural gas pipeline system; “treated biogas” is biogas conditioned for transportation use but not injected and delivered via closed or private distribution systems. In this document, we use “RNG” to refer to both RNG and treated biogas. We likewise use “renewable CNG/LNG” to refer to both when used as transportation fuel in CNG/LNG vehicles, and we use this term where such use is eligible for, and results in, RIN generation and separation under the RFS program.

CNG/LNG volumes. Several projections exist for total CNG/LNG usage in the 2026–2027 period. One key source is AEO2025, which projects nationwide CNG/LNG use as transportation fuel will be equivalent to 1,343 and 1,403 million ethanol-equivalent gallons for the years 2026 and 2027 respectively (see Table 7.1.4.1-1). However, these AEO projections include all transportation-related energy usage, including sectors like international shipping, which are outside the RFS scope.⁴³¹ After adjusting the AEO estimates to exclude non-relevant CNG/LNG volumes,⁴³² the revised projections indicate lower estimates equivalent to 1,256; and 1,316 million ethanol-equivalent gallons for the years 2026 and 2027 respectively, as shown in Table 7.1.4.1-1.

Table 7.1.4.1-1: Projected CNG/LNG Transportation Usage from EIA’s 2025 AEO⁴³³ (million ethanol-equivalent gallons)

	2026	2027
CNG/LNG Transportation Usage	1,342	1,403
Adjusted ^a CNG/LNG Transportation Usage	1,256	1,316

^a Usage adjusted to exclude volumes attributed to international shipping.

Additionally, given the high likelihood of nationwide consumption limitations emerging by the mid-to-late 2020s, we believe it is valuable to develop an additional estimate of future CNG/LNG demand to compare with the AEO estimate and more comprehensively assess potential saturation points. To that end, EPA created a separate estimate of future CNG/LNG demand, independent of the AEO estimate. Referred to in this section as the “EPA Estimate,” it was developed using a combination of data sources and modeling techniques tailored to different vehicle categories, consistent with the methods used in the Set 2 proposal but updated with the most recent data. Commenters generally agreed with our methodologies for estimating consumption, though some urged more aggressive assumptions for fuel use and anticipated market growth. We address these points in detail in RTC Section 3; however, based on the available data, we believe the EPA Estimate strikes an appropriate balance that reflects potential growth in total CNG/LNG consumption while remaining grounded in the available data and observed market trends. We provide the specifics of the EPA Estimate, including data sources, key assumptions, and category-specific modeling, in the paragraphs that follow.

The vehicle categories in the EPA Estimate are based primarily on the U.S. Department of Transportation (DOT) Highway Performance Monitoring System (HPMS) vehicle classifications, as outlined in Table VM-1 of the Federal Highway Administration’s (FHWA) annual Highway Statistics report.⁴³⁴ The HPMS classifications include light-duty vehicles with a

⁴³¹ Under the definition of transportation fuel in 40 CFR 80.2, fuel for use in ocean-going vessels is excluded as a transportation fuel.

⁴³² Volumes attributed to: Light-Duty Vehicle, Commercial Light Trucks, Domestic Shipping, Freight Trucks, Freight Rail, Transit Buses, and School Buses were included. Volumes attributed to: International Shipping were excluded due to these being ocean-going vessels.

⁴³³ AEO2025, Table 36 – Transportation Sector Energy Use by Fuel Type Within a Mode.

⁴³⁴ FHWA, Highway Statistics Series, Table VM-1: Annual Vehicle Distance Traveled in Miles and Related Data - 2022. <https://www.fhwa.dot.gov/policyinformation/statistics/2022/vm1.cfm>.

short wheelbase, light-duty vehicles with a long wheelbase, motorcycles, buses, single unit trucks,⁴³⁵ and combination trucks.

For this analysis, EPA consolidated short- and long- wheelbase light-duty vehicles into a single “light-duty vehicle” category. Motorcycles were excluded from EPA’s estimates of CNG/LNG consumption, as historically, no motorcycles have been powered by these fuels. EPA further refined the bus category by distinguishing between “school buses” and “transit buses” based on the availability of data that allowed for a more detailed analysis of their fuel consumption. Additionally, refuse haulers were separated from other single-unit trucks because of the historically high usage rate of CNG/LNG for these vehicles, resulting in the refuse hauler category being a key sector in EPA’s fuel consumption estimates. As a result of this additional refinement, EPA chose to estimate fuel consumption for the following vehicle categories: light-duty vehicles, public transit, school buses, refuse trucks, single unit trucks (excluding refuse haulers), and combination trucks.

To estimate fuel consumption from the light-duty vehicle category, EPA relied on data from the U.S. Department of Energy (DOE) as the primary source for vehicle count information.⁴³⁶ This vehicle count data for natural gas vehicles was integrated with assumptions for average vehicle miles traveled (VMT)⁴³⁷ and average fuel efficiency⁴³⁸ in the light-duty vehicle sector. Using this methodology, EPA calculated a total estimate for CNG/LNG consumption among light-duty vehicles, which is shown in Table 7.1.4.1-2. Based on current trends, EPA does not anticipate significant growth in CNG/LNG volumes within the light-duty sector, given the limited introduction of new light-duty natural gas vehicles models. Notably, no new CNG light-duty vehicle models have been introduced since MY2022.⁴³⁹ Despite the lack of growth and the likely decrease in vehicle numbers due to future scrappage, EPA has opted to keep the vehicle count steady in this analysis for simplicity, given that consumption for the light-duty category is already minimal.

Table 7.1.4.1-2: CNG/LNG Usage from the Light-duty Vehicle Sector (million ethanol-equivalent gallons)

Year	Data Type	Vehicle Count	CNG/LNG Usage
2024	Actual	23,700	22
2025–2027	Projected	23,700	22

Note: Calculated using an average efficiency of 17.8 miles per gasoline-equivalent gallon and an average VMT of 11,318 miles per vehicle.

⁴³⁵ Single-Unit: single frame trucks that have 2-axles and at least 6 tires or a gross vehicle weight rating exceeding 10,000 lbs.

⁴³⁶ AFDC, “Vehicle Registration Counts by State,” 2024. <https://afdc.energy.gov/vehicle-registration?year=2024>.

⁴³⁷ AFDC, “Average Annual Vehicle Miles Traveled by Major Vehicle Category,” September 2024. <https://afdc.energy.gov/data/10309>.

⁴³⁸ AFDC, “Average Fuel Economy by Major Vehicle Category,” January 2024. <https://afdc.energy.gov/data/10310>.

⁴³⁹ AFDC, “Fuel and Advanced Technology Vehicles,” Model Year 2022 (<https://afdc.energy.gov/vehicles/search/download.pdf?year=2022>), Model Year 2023 (<https://afdc.energy.gov/vehicles/search/download.pdf?year=2023>), Model Year 2024 (<https://afdc.energy.gov/vehicles/search/download.pdf?year=2024>) and Model Year 2025, (<https://afdc.energy.gov/vehicles/search/download.pdf?year=2025>).

To estimate consumption from public transit, EPA utilized data from the American Public Transportation Association’s *2025 Public Transportation Fact Book*, which provides energy consumption data separated by fuel type.⁴⁴⁰ Data from this source indicate significant variability in annual fuel use, with no clear trend beyond a marked decline during the COVID-19 pandemic. The most recent years of actual data, 2022 and 2023, show higher transit CNG/LNG usage, potentially signaling a return toward pre-pandemic ridership levels, although it may still reflect residual pandemic effects. Given this volatility and the lack of a stable trend, EPA calculated an average annual growth rate using data from 2014 onward, which aligns with the period when renewable CNG/LNG was classified as a cellulosic biofuel under the RFS program. We applied the resulting average growth rate of 2.2% per year to project CNG/LNG consumption in public transportation beyond 2023. The projected usage is presented in Table 7.1.4.1-3.

Table 7.1.4.1-3: CNG/LNG Usage from the Public Transportation Sector (million ethanol-equivalent gallons)

Year	Data Type	CNG/LNG Usage	Year-over Year Growth
2014	Actual	288	N/A
2015	Actual	302	4.8%
2016	Actual	321	6.4%
2017	Actual	317	-1.3%
2018	Actual	328	3.4%
2019	Actual	347	5.8%
2020	Actual	314	-9.4%
2021	Actual	303	-3.5%
2022	Actual	320	5.5%
2023	Actual	345	7.9%
2024	Projected	353	2.2%
2025	Projected	360	2.2%
2026	Projected	368	2.2%
2027	Projected	376	2.2%

For school buses, EPA is using data from the World Resources Institute’s *Dataset of U.S. School Bus Fleets*,⁴⁴¹ which provides information on the composition of school bus fleets across the U.S. This dataset includes data from 46 states and the District of Columbia; however, it does have some limitations. Specifically, data are unavailable for four states: Colorado, Hawaii, Louisiana, and New Hampshire. In addition, several states (Illinois, Indiana, Michigan, Mississippi, Nevada, Oklahoma, Oregon, South Carolina, Texas, Wisconsin, and Wyoming) have high rates of records with unknown fuel type. To address these gaps, EPA estimated CNG school bus counts for the affected states by combining state population figures with state-level

⁴⁴⁰ American Public Transportation Association, “2025 Public Transportation Fact Book,” Appendix A: Historical Tables, Table 58 – Non-Diesel Fossil Fuel Consumption by Fuel Type. <https://www.apta.com/research-technical-resources/transit-statistics/public-transportation-fact-book>.

⁴⁴¹ Lazer, Leah, Lydia Freehafer, and Jessica Wang. “Dataset of U.S. School Bus Fleets (State Summary) Version 3,” *World Resources Institute*, May 10, 2024. <https://datasets.wri.org/datasets/usa-school-bus-fleets>.

CNG bus counts from states with well-characterized fleets.⁴⁴² The estimated vehicle count data for CNG buses was then combined with average VMT⁴⁴³ and average fuel efficiency specific to school buses.⁴⁴⁴ This approach resulted in an estimate of total CNG/LNG consumption for the school bus sector. Because the dataset covers only March–November 2022 and does not track trends over time, EPA adopted a conservative projection approach: no growth or decline factors are applied, and the number of CNG school buses is held constant over the analysis period. This decision reflects recent funding trends,⁴⁴⁵ which largely favor electric buses over CNG.⁴⁴⁶ Given the limited evidence for future growth in the CNG school bus fleet, applying a growth rate could overstate CNG use in this sector. Accordingly, EPA assumes no change in CNG school bus counts over time for this analysis. Based on this assumption, the estimated consumption data for the school bus sector are presented in Table 7.1.4.1-4. We are aware of recent developments that may influence future CNG school bus adoption, including EPA’s announcement to revamp the Clean School Bus Program.⁴⁴⁷ EPA will continue to analyze this vehicle market in future rulemakings. However, given the recent nature of these changes and the limited number of years that we are establishing volumes, we do not expect them to affect our current assumption of no growth or decline.

Table 7.1.4.1-4: CNG/LNG Usage from the School Bus Sector (million ethanol-equivalent gallons)

Year	Data Type	Vehicle Count	Year-over-Year Growth	CNG/LNG Usage
2022	Actual	7,085	N/A	23
2023	Projected	7,085	0%	23
2024	Projected	7,085	0%	23
2025	Projected	7,085	0%	23
2026	Projected	7,085	0%	23
2027	Projected	7,085	0%	23

Note: Calculated using an average efficiency of 6.46 miles per gasoline-equivalent gallon and an average VMT of 14,084 miles per vehicle.

For refuse trucks, EPA derived a vehicle count estimate from fleet information reported in the sustainability reports of the largest waste management companies in the U.S. In addition, our review found no reliable centralized data regarding the specific number or growth rates of municipality-owned refuse trucks. Because of this lack of data, municipal fleets were not explicitly isolated in this analysis. Instead, our estimates rely on the robust data available from the major private providers that dominate the market. For many companies, especially smaller

⁴⁴² The spreadsheet used to estimate the CNG bus counts can be found in “Data and Methods for Estimating School Bus and Refuse Hauler CNG Populations (Set 2 Final Rulemaking),” available in the docket for this action.

⁴⁴³ AFDC, “Average Annual Vehicle Miles Traveled by Major Vehicle Category,” September 2024.

<https://afdc.energy.gov/data/10309>.

⁴⁴⁴ AFDC, “Average Fuel Economy by Major Vehicle Category,” January 2024. <https://afdc.energy.gov/data/10310>.

⁴⁴⁵ EPA, “Clean School Bus Program Awards.” <https://www.epa.gov/cleanschoolbus/clean-school-bus-program-awards>.

⁴⁴⁶ EPA, “Clean School Bus Program Rebates.” <https://www.epa.gov/cleanschoolbus/clean-school-bus-program-rebates>.

⁴⁴⁷ EPA, “EPA Announces Path Forward to Revamp the Clean School Bus Program to Provide Safe, Affordable, Efficient Transportation for America’s Youth,” February 19, 2026. <https://www.epa.gov/newsreleases/epa-announces-path-forward-revamp-clean-school-bus-program-provide-safe-affordable>.

ones, data were more limited, and historical data were unavailable for several of the years reviewed. In cases with missing information, EPA applied average growth rates from companies with available data to estimate vehicle counts for those periods. Following this approach, total vehicle counts from the analyzed companies were aggregated⁴⁴⁸ and are shown in Table 7.1.4.1-5. Using this aggregated dataset, EPA calculated an average annual growth rate, which was then applied to the most recent vehicle totals to project future vehicle counts. These projected vehicle counts, in conjunction with average VMT⁴⁴⁹ and average fuel efficiency for refuse haulers,⁴⁵⁰ were used to estimate total CNG/LNG consumption within the refuse hauler sector. Comparing this vehicle count to data from The Transportation Project, we note that The Transportation Project reports “Over 17,000 natural gas refuse trucks operate across the country and about 60% of new trucks on order are NGVs [Natural Gas Vehicles].”⁴⁵¹ This figure is lower than EPA’s estimate of approximately 23,000 vehicles in 2024. However, given the rapid growth and adoption of CNG/LNG usage in this sector, EPA believes that its higher estimate may better represent future vehicle counts. The resulting data for refuse haulers are presented in Table 7.1.4.1-6.

Table 7.1.4.1-5: Estimated Refuse Hauler Vehicle Counts

Company	2018	2019	2020	2021	2022	2023	2024
Waste Management	7,944	8,924	10,388	10,832	11,307	12,119	13,170
Republic Services	3,200	3,200	3,423	3,444	3,380	3,440	3,646
Waste Connections	1,070	1,119	1,166	1,090	1,070	1,069	1,069
Clean Harbors	-	-	-	-	13	100	211
GFL Environmental	-	776	983	1,179	1,238	1,515	1,637
Recology	-	1,950	2,080	2,158	2,210	2,184	2,236
Waste Pro USA	800	800	800	800	800	847	900
Casella Waste Systems	-	-	-	30	44	40	43
Total	13,014	16,769	18,840	19,533	20,062	21,315	22,913

Note: Vehicle counts are estimated based on limited data, including information available only from earlier years.

Source: WM Sustainability Reports (<https://sustainability.wm.com/esg-data-center>); Republic Services SASB Reports (<https://investor.republicservices.com/financials/reports>); Waste Connections Sustainability Reports (<https://sustainability.wasteconnections.com/sustainability-data-hub.html>); Clean Harbors Sustainability Reports (<https://www.cleanharbors.com/sites/g/files/bdczcs356/files/2023-11/CLH%20Sustainability%20Supplement%20110323.pdf>); GFL Environmental SASB Reports (<https://investors.gflenv.com/English/esg/sustainability/default.aspx>); Recology Sustainability Reports (<https://www.recology.com/sustainability-at-recology>); Waste Pro USA (<https://www.wasteprousa.com/blog/waste-pro-recognized-for-eco-friendly-operations>); Casella Waste Systems SASB Reports.

⁴⁴⁸ The spreadsheet used to estimate the CNG refuse hauler counts can be found in “Data and Methods for Estimating School Bus and Refuse Hauler CNG Populations (Set 2 Final Rulemaking),” available in the docket for this action.

⁴⁴⁹ AFDC, “Average Annual Vehicle Miles Traveled by Major Vehicle Category,” September 2024. <https://afdc.energy.gov/data/10309>.

⁴⁵⁰ AFDC, “Average Fuel Economy by Major Vehicle Category,” January 2024. <https://afdc.energy.gov/data/10310>.

⁴⁵¹ The Transport Project, “Vehicles for every route”. <https://transportproject.org/vehicles>.

Table 7.1.4.1-6: CNG/LNG Usage from the Refuse Hauler Sector (million ethanol-equivalent gallons)

Year	Data Type ^a	Vehicle Count	Year-over Year Growth	CNG/LNG Usage
2019	Actual	16,769	N/A	253
2020	Actual	18,840	12.3%	284
2021	Actual	19,533	3.7%	294
2022	Actual	20,062	2.7%	302
2023	Actual	21,315	6.2%	321
2024	Actual ^b	22,913	7.5%	345
2025	Projected	24,402	6.5%	367
2026	Projected	25,987	6.5%	391
2027	Projected	27,675	6.5%	417

Note: Calculated using an average efficiency of 2.48 miles per gasoline-equivalent gallon and an average VMT of 25,000 miles per vehicle.

^a In this context, what we call actual data remains an estimate.

^b Calculated using both projections and actual data.

For single-unit trucks (excluding refuse haulers) and combination trucks, EPA used national CNG/LNG vehicle counts processed by the Motor Vehicle Emission Simulator (MOVES5) for each calendar year, derived from vehicle registration data for 2014, 2020, and 2023.⁴⁵² The MOVES5 team interpolated between those registration years to produce annual counts for the intervening years (2015–2019 and 2021–2022), and we relied on that fully interpolated time series in our analysis. Although MOVES5 includes forward-looking vehicle population trajectories that reflect anticipated market responses to the regulatory landscape at the time the model was developed, we did not use those projections. Instead, our future-year counts (shown in Table 7.1.4.1-9 and 7.1.4.1-10) are based on a simple extrapolation of historical growth observed in the processed registration-based data.

In addition to registration data, EPA incorporated average VMT and fuel efficiency data from the Bureau of Transportation Statistics' *National Transportation Statistics* publication.⁴⁵³ Using historic vehicle counts, along with average VMT and fuel efficiency for both single-unit and combination trucks, EPA estimated total CNG/LNG consumption in these sectors for each year from 2014 to 2022, shown in Tables 7.1.4.1-7 and 8. Based on this aggregated dataset, EPA calculated the average annual growth rate of total CNG/LNG usage and applied it to the most recent totals to project future fuel volumes, shown in Tables 7.1.4.1-9 and 10.

⁴⁵² Vehicle count data shown in Tables 7.1.4.1-7 and 8 are from the Motor Vehicle Emission Simulator (MOVES5), (<https://www.epa.gov/moves/latest-version-motor-vehicle-emission-simulator-moves>). The years for which EPA has national vehicle registration data from correspond to the update schedule of the MOVES model. For information on how this data was derived, see EPA, "Population and Activity of Onroad Vehicles in MOVES5," EPA-420-R-24-019, November 2024, Chapters 4 and 5. <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockkey=P101CUN7.pdf>.

⁴⁵³ Bureau of Transportation Statistics, National Transportation Statistics, Table 4-13 – Single-Unit 2-Axle 6-Tire or More Truck Fuel Consumption and Travel (<https://www.bts.gov/content/single-unit-2-axle-6-tire-or-more-truck-fuel-consumption-and-travel>) and Table 4-14 – Combination Truck Fuel Consumption and Travel. (<https://www.bts.gov/content/combination-truck-fuel-consumption-and-travel>).

Table 7.1.4.1-7: CNG/LNG Usage from the Single Unit Truck Sector (miles; miles per diesel-equivalent gallon; million ethanol-equivalent gallons)

Year	Single Unit Truck Vehicle Count	Single Unit Truck VMT	Single Unit Truck Fuel Economy	Single Unit Truck Fuel Consumption
2014	11,710	13,123	7.34	35.5
2015	14,286	12,960	7.38	42.5
2016	17,160	12,958	7.39	51.0
2017	19,025	12,435	7.44	53.9
2018	22,832	11,687	7.51	60.3
2019	25,335	12,278	7.49	70.4
2020	27,250	11,892	7.56	72.6
2021	29,899	12,287	7.67	81.2
2022	32,020	12,290	7.93	84.1

Note: Diesel-equivalent gallons (DGE) converted to ethanol-equivalent gallons (EGE) using 1 EGE = 0.59 DGE.

Table 7.1.4.1-8: CNG/LNG Usage from the Combination Truck Sector (miles; miles per diesel-equivalent gallon; million ethanol-equivalent gallons)

Year	Combination Truck Vehicle Count	Combination Truck VMT	Combination Truck Fuel Economy	Combination Truck Fuel Consumption
2014	4,539	65,897	5.83	86.9
2015	6,908	61,978	5.89	123.1
2016	8,527	63,428	5.91	155.2
2017	9,667	62,751	5.98	172.0
2018	10,832	63,374	6.07	191.6
2019	11,420	59,929	6.05	191.8
2020	11,967	60,120	6.16	197.9
2021	14,048	62,169	6.42	230.6
2022	17,256	60,018	6.91	254.0

Note: Diesel-equivalent gallons (DGE) converted to ethanol-equivalent gallons (EGE) using 1 EGE = 0.59 DGE.

Table 7.1.4.1-9: CNG/LNG Usage from the Single Unit Truck Sector (million ethanol-equivalent gallons)

Year	Data Type	CNG/LNG Usage	Year-over Year Growth
2017	Actual	53.9	N/A
2018	Actual	60.3	11.8%
2019	Actual	70.4	16.8%
2020	Actual	72.6	3.1%
2021	Actual	81.2	11.8%
2022	Actual	84.1	3.6%
2023	Projected	92.0	9.4%
2024	Projected	100.7	9.4%
2025	Projected	110.1	9.4%
2026	Projected	120.5	9.4%
2027	Projected	131.8	9.4%

Table 7.1.4.1-10: CNG/LNG Usage from the Combination Truck Sector (million ethanol-equivalent gallons)

Year	Data Type	CNG/LNG Usage	Year-over Year Growth
2017	Actual	172.0	N/A
2018	Actual	191.6	11.4%
2019	Actual	191.8	0.1%
2020	Actual	197.9	3.2%
2021	Actual	230.6	16.5%
2022	Actual	254.0	10.1%
2023	Projected	274.8	8.2%
2024	Projected	297.3	8.2%
2025	Projected	321.7	8.2%
2026	Projected	348.1	8.2%
2027	Projected	376.6	8.2%

In the proposal, EPA included an alternative scenario that projected accelerated deployment of CNG/LNG vehicles, driven largely by the market entry of the Cummins X15N engine.⁴⁵⁴ Under this scenario, we modeled rapid expansion in which natural gas engines captured up to 10% of the new freight truck market by 2030.⁴⁵⁵ Although many commenters supported higher market share projections, EPA does not yet see sufficient evidence of a structural shift in purchasing behavior to support a 10% market share. Accordingly, we are retaining a more conservative growth rate in this final rulemaking. We expect to continue discussions with stakeholders on this issue, as it will be critical for future rulemakings. Further details on this decision are provided in the RTC Section 3.

After estimating volumes for each vehicle category, we aggregated these individual totals to produce an overall “EPA Estimate” of future CNG/LNG consumption, shown in Table 7.1.4.1-11.

Table 7.1.4.1-11: Total CNG/LNG Usage for the “EPA Estimate” (million ethanol-equivalent gallons)

	2025	2026	2027
Light-duty Vehicles	22	22	22
Public Transportation	360	368	376
School Buses	23	23	23
Refuse Trucks	367	391	417
Single Unit Trucks	110	121	132
Combination Trucks	322	348	377
Total	1,205	1,273	1,347

Note: Totals may not be precisely equal to the sum of each vehicle sector due to rounding.

⁴⁵⁴ Cummins, “Engines – X15N (2024).” <https://www.cummins.com/engines/x15n-2024>.

⁴⁵⁵ Cummins stated that their goal is for this engine to reach 10% of market sales by 2030. See: Patrick Campbell, Cummins Alternative Power Technologies - Regional Sales Manager, Fleets and Fuel Conference Presentation from BIOGAS AMERICAS 2024 (May 13-16, 2024). <https://youtu.be/fOH6j1ccIkI> (19:15 in video).

This aggregated CNG/LNG consumption is broadly consistent with the AEO estimate shown in Table 7.1.4.1-1, though it is slightly higher. Given this alignment and our stronger understanding of the inputs to EPA’s demand-side estimate, we rely on EPA’s consumption estimate for subsequent analyses. With respect to that estimate, commenters generally agreed with the overall methodology but urged more aggressive assumptions for per-vehicle fuel use and anticipated market growth. EPA assumed per-vehicle consumption comparable to diesel-equivalent vehicles, while many commenters recommended higher per-vehicle usage. Because market-wide data on per-vehicle CNG/LNG consumption remain limited and duty cycles vary widely, we are maintaining our current assumptions. We will continue discussions with stakeholders on these issues, which will be important for future rulemakings. Additional detail on these decisions is provided in RTC Section 3.

With the consumption estimate selected, we next looked to determine how much of the total CNG/LNG market could be met with renewable CNG/LNG. In a model scenario where all fossil-based CNG/LNG could be fully replaced by renewable CNG/LNG, this total CNG/LNG estimates would serve as the maximum potential renewable CNG/LNG volumes, with no further adjustment needed. In practice, however, facility-level constraints, including infrastructure limitations, costs, and other operational considerations, make 100% replacement unlikely, so some fossil-based CNG/LNG would remain in use. To better reflect realistic renewable CNG/LNG consumption in a saturated market, we calibrated our projections to observed market conditions, drawing on data from California’s LCFS program to benchmark RNG uptake under saturation. Since its inception in 2011, California’s LCFS program has awarded credits for both renewable and fossil-based natural gas used as transportation fuel within the state. In 2014, when RNG used as CNG/LNG was classified as a cellulosic biofuel under the RFS program, the utilization of renewable CNG/LNG surged significantly due to the ability to generate lucrative credits under both programs for displacing existing fossil CNG/LNG demand. This aggressive growth under both the LCFS and RFS has resulted in renewable CNG/LNG dominating the market in California. As seen in Table 7.1.4.1-14, the California CNG/LNG market has shifted to be almost entirely renewable, with volumes accounting for an average of 97% of the total market from 2022 through 2024. Thus, we assumed that California represents a mature, fully saturated market.

Table 7.1.4.1-12: California Low Carbon Fuel Standard Program Data (million ethanol-equivalent gallons)⁴⁵⁶

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Renewable CNG/LNG	49	113	151	181	203	236	257	296	323	344	370
Fossil-based CNG/LNG	164	122	95	87	82	69	21	7	12	12	4
Total CNG/LNG	213	234	247	268	285	305	278	303	335	356	374
Year-over-year Growth of Total	-	10%	5%	8%	6%	7%	-9%	9%	11%	6%	5%
Renewable CNG/LNG Blend Rate	23%	48%	61%	68%	71%	77%	92%	98%	96%	97%	99%

Subsequently, we assume that any fully saturated CNG/LNG market would consist of approximately 97% renewable CNG/LNG. Using this approach, we applied a 97% utilization factor to the EPA projections for future CNG/LNG volumes to estimate the potential renewable CNG/LNG consumption under saturated market conditions. These consumption estimates for renewable CNG/LNG are detailed in Table 7.1.4.1-13.

Table 7.1.4.1-13: Projected Maximum Amount of Renewable CNG/LNG That Could Be Used (million RINs)

	2025	2026	2027
EPA CNG/LNG Consumption Estimate	1,205	1,273	1,347
Renewable CNG/LNG Usage Assuming 97% Replacement	1,169	1,235	1,306

7.1.4.2 Projected Supply of RNG

In addition to projecting future demand for renewable CNG/LNG, EPA also analyzed the potential production capacity of RNG under unrestricted market conditions, assuming no consumption limitations. This analysis was conducted to assess whether the market is genuinely constrained by consumption rather than production capacity. To do so, we utilized the same industry-wide production projection methodology that has been employed in RFS standard-setting rules since 2018. This methodology is based on applying an industry-wide year-over-year growth rate to the current production rate of RNG (see Chapter 7.1.2 for more information on this methodology).

To determine the growth rate, EPA analyzed D3 RNG RIN generation data over the two most recent full calendar years.⁴⁵⁷ While EPA has historically relied on the most recent rolling 24-month period, we determined that aligning the data to full calendar years (January through December) was necessary to minimize the distortions of seasonality. Historically, RIN

⁴⁵⁶ CARB, “Low Carbon Fuel Standard Reporting Tool Quarterly Summaries.” <https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries>.

⁴⁵⁷ See “Available RINs to date from January 2026” RIN data file available at: <https://www.epa.gov/fuels-registration-reporting-and-compliance-help/spreadsheet-available-rins-date-renewable-fuel>.

generation follows a cyclical trend: a slowdown at the start of the calendar year followed by a surge in generation at year-end (see 2024 data in Table 7.1.4.2-1). However, early 2025 deviated from this historical pattern, likely due to new biogas oversight regulations taking effect (see Chapter 7.1.2.1). By utilizing full calendar years, we capture the complete seasonal cycle and the impacts of the regulatory changes. Accordingly, based on this analysis, we determined a year-over-year growth rate of 24% for 2025 over 2024, as shown in Table 7.1.4.2-2.

Table 7.1.4.2-1: D3 RNG RIN Generation Data for Last Two Calendar Years (million RINs)

Month	2024	2025
January	7	76
February	69	77
March	66	92
April	74	97
May	75	109
June	81	104
July	79	109
August	85	112
September	89	106
October	87	108
November	91	107
December	170	107
Total	973	1,206

Table 7.1.4.2-2: Actual D3 RNG RIN Generation Data (million RINs)

Volume Generated Between Jan. 2024 – Dec. 2024	Volume Generated Between Jan. 2025 – Dec. 2025 ^a	Year-Over-Year Increase
973	1,206	24%

^a This was the most recent 12 months for which data was available at the time of this analysis.

EPA applied this 24% year-over-year growth rate to the estimated 2025 total of cellulosic RNG RINs. Specifically, we multiplied the calculated growth rate by the volume of RNG supplied in 2025, based on actual RIN generation. The RNG volume potential projected using this methodology are shown in Table 7.1.4.2-3.

Table 7.1.4.2-3: Projected Production Potential of RNG (million RINs)

Year	Date Type	Growth Rate	Volume
2025	Actual	24%	1,206
2026	Projected	24%	1,495
2027	Projected	24%	1,853

The projected production shown in Table 7.1.4.2-3 serves as the estimated volume of RNG that could be produced without any constraint on demand for use as transportation fuel.

7.1.4.3 Projected Volume of Renewable CNG/LNG

In Table 7.1.4.3-1 we combine the consumption estimate selected from Chapter 7.1.4.1 with the production estimates from Chapter 7.1.4.2.

Table 7.1.4.3-1: Estimated Production of RNG and Estimated Consumption of Renewable CNG/LNG (million RINs)

	2026	2027
RNG Production	1,495	1,853
Renewable CNG/LNG Consumption	1,235	1,306

Based on our analysis of renewable CNG/LNG consumption and RNG production, we reach the same conclusion as in the proposal: in 2026 and 2027, cellulosic volumes from renewable CNG/LNG are constrained by total CNG/LNG use in transportation, not by production. Commenters were divided on this point; some agreed that consumption, rather than production, will limit volumes in the near term, while others argued that we should base our analyzed volumes solely on projected production. We address these comments in detail in RTC Section 3. However, we have chosen not to adopt a production-only approach; we continue to consider both production and consumption. Accordingly, EPA projects future volumes based on projected consumption of renewable CNG/LNG. These estimated volumes are shown in Table 7.1.4.3-2.

Table 7.1.4.3-2: Projected Volume Renewable CNG/LNG (million RINs)

	2026	2027
Volume of Renewable CNG/LNG	1,235	1,306

7.1.5 Projected Supply of Liquid Cellulosic Biofuels

Several technologies are currently being developed to produce liquid fuels from cellulosic biomass. However, most of these technologies are unlikely to yield significant volumes by 2027. One notable exception is the production of ethanol from CKF, which is currently in use at numerous commercial-scale production facilities using one of several processes.

Many of these processes involve simultaneously co-processing of both the starch and cellulosic components of the corn kernel. However, to be eligible for generating cellulosic RINs, facilities must accurately determine the amount of ethanol produced specifically from the cellulosic portion. This requires the ability to reliably and precisely calculate the ethanol derived from the cellulosic component, distinct from the starch portion of the corn kernel. In September 2022, EPA issued updated guidance on analytical methods that could be used to quantify the amount of ethanol produced when co-processing CKF and corn starch.⁴⁵⁸ One potential limitation on CKF ethanol production would be if production through compliant methods were not feasible for some facilities.

⁴⁵⁸ EPA, “Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch,” EPA-420-B-22-041, September 2022.

To evaluate the practical extent of this potential limitation, EPA has had substantive discussions with technology providers intending to use analytical methods consistent with this guidance, as well as with owners of facilities registered as cellulosic biofuel producers using these methods. Based on information from these technology providers, EPA believes that cellulosic ethanol production from CKF is technically feasible at all existing corn ethanol facilities with minimal additional processing units or modification. However, for the purposes of this analysis, we have applied a 90% adoption ceiling. This 10% adjustment accounts for site-specific idiosyncratic factors that may preclude 100% implementation. By assuming 90% adoption, EPA’s analysis reflects a robust yet pragmatic expectation of the industry’s capacity from 2026–2027.

Based on data submitted to EPA by renewable fuel producers generating cellulosic RINs for CKF ethanol, the current industry-wide average conversion among registered facilities is approximately 1%. Accordingly, for this analysis we use a 1% conversion rate. We recognize that some parties have claimed they can demonstrate up to 1.5% conversion using analytical methods consistent with EPA guidance, but we do not yet have sufficient data to support adopting that higher rate.

Commenters generally supported our inclusion of robust volumes of CKF ethanol. Some, however, urged more aggressive assumptions for facility participation and conversion efficiency. We address these comments in detail in RTC Section 3; however, based on the available data, we do not find sufficient support to increase these rates at this time.

The projected production of cellulosic ethanol from CKF, as shown in Table 7.1.4-1, is based on projections of total corn ethanol production (see Chapter 7.6 for more information on our total corn ethanol projections), with a 90% facility participation rate and a 1% conversion efficiency applied.

Table 7.1.4-1: Projected Production of Ethanol from CKF (million RINs)

Year	Volume
2026	128
2027	128

7.1.6 Projected Rate of Cellulosic Biofuel Production for 2026–2027

After projecting production of ethanol from CKF and renewable CNG/LNG, EPA combined these estimates to project total cellulosic biofuel production for 2026–2027. These projections are shown in Table 7.1.6-1.

Table 7.1.6-1: Projected Production of Cellulosic Biofuel in 2026–2027 (million RINs)

	2026	2027
Renewable CNG/LNG	1,235	1,306
Ethanol from CKF	128	128
Total Cellulosic Biofuel	1,364	1,434

7.2 Biomass-Based Diesel

Since 2010 when the BBD volume requirement was added to the RFS program, production of BBD has generally increased. The volume of BBD supplied in any given year is influenced by a number of factors including production capacity, feedstock availability and cost, available incentives, the availability of imported BBD, the demand for BBD in foreign markets, and other economic factors. From 2010 through 2015 the vast majority of BBD supplied to the U.S. was biodiesel. Since 2015, increasing volumes of renewable diesel have also been supplied. In 2023, the quantity of renewable diesel supplied to the U.S. surpassed the supply of biodiesel for the first time. Production of renewable diesel is expected to continue to increase in future years. Along with biodiesel and renewable diesel, there are also small volumes of renewable jet fuel and heating oil that qualify as BBD. However, as the vast majority of BBD is biodiesel and renewable diesel, we have focused on these fuels in this section.

This section presents information on the factors we consider in projecting the domestic production and net imports of BBD in 2026 and 2027. First, we present the available data on biodiesel and renewable diesel production, import, and use in previous years (Chapter 7.2.1). Next, we assess the current and projected future production capacity for biodiesel and renewable diesel (Chapter 7.2.2). The availability of qualifying feedstocks for biodiesel and renewable diesel production (Chapter 7.2.3) and potential imports and exports of BBD (Chapter 7.2.4) are in the following sections. Finally, we describe our assessment of the rate of production and use of qualifying BBD in 2026 and 2027 based on this information (Chapter 7.2.5) and discuss some of the uncertainties associated with those volumes. This section addresses the projected rate of production and consumption of all BBD projected to be produced and used in the U.S. in 2026 and 2027, regardless of whether the production and use of the BBD is driven by the BBD, advanced, or total renewable fuel volume requirements. An analysis of the projected rate of production and consumption of advanced (D5) biodiesel and renewable diesel and conventional (D6) biodiesel and renewable diesel can be found in Chapters 7.4 and 7.7, respectively.

7.2.1 Production and Use of Biomass-Based Diesel in Previous Years

As a first step in considering the rates of production and use of BBD in future years we review the volumes of BBD produced domestically, imported, and exported in previous years. Reviewing the historical volumes is useful since there are many complex and inter-related factors beyond simple total production capacity that could affect the supply of BBD. These factors include, but are not limited to, the RFS volume requirements (including the BBD, advanced biofuel, and total renewable fuel requirements), the availability of BBD feedstocks,⁴⁵⁹ demand for those feedstocks in other markets and internationally, the federal tax credits available

⁴⁵⁹ Throughout this chapter we refer to BBD as well as BBD feedstocks. In this context, BBD refers to any biodiesel or renewable diesel for which RINs can be generated that satisfy an obligated party's BBD biofuel obligation (*i.e.*, D4 RINs). While cellulosic diesel (D7) can also contribute towards an obligated party's advanced biofuel obligation, these fuels are included instead in the projection of cellulosic biofuel presented in Chapter 6.1. An advanced biodiesel or renewable feedstock refers to any of the biodiesel, renewable diesel, jet fuel, and heating oil feedstocks listed in Table 1 to 40 CFR 80.1426 or in petition approvals issued pursuant to 40 CFR 80.1416 that can be used to produce fuel that qualifies for D4 or D5 RINs. These feedstocks include but are not limited to: soybean oil; oil from annual cover crops; oil from algae grown photosynthetically; biogenic waste oils/fats/greases; non-food grade corn oil; camelina sativa oil; and canola/rapeseed oil (see Rows F, G, and H of Table 1 to 40 CFR 80.1426).

to biodiesel and renewable diesel producers, tariffs on imported biodiesel and renewable diesel (and the feedstocks used to produce these fuels), biofuel policies in other countries, import and distribution infrastructure, and other market-based factors. Thus, while historical data and trends alone are insufficient to project the volumes of biodiesel and renewable diesel that could be provided in future years, historical data can serve as a useful reference point in considering future volumes. Production, import, export, and total volumes of BBD are shown in Table 7.2.1-1.

Table 7.2.1-1: BBD (D4) Production, Imports, and Exports from 2016 to 2025 (million gallons)

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025 ^a
Domestic Biodiesel (Annual Change)	1,581 (+336)	1,552 (-29)	1,841 (+289)	1,706 (-135)	1,802 (+96)	1,701 (-101)	1,614 (-87)	1,665 (+51)	1,656 (-9)	1,100 (-556)
Imported Biodiesel (Annual Change)	562 (+301)	462 (-100)	175 (-287)	185 (+10)	209 (+24)	208 (-1)	240 (+32)	501 (+261)	398 (-103)	34 (-364)
Exported Biodiesel (Annual Change)	89 (+16)	129 (+40)	74 (-55)	76 (+2)	88 (+12)	91 (+3)	117 (+26)	98 (-19)	82 (-16)	32 (-50)
Total Biodiesel (Annual Change) ^b	2,054 (+621)	1,885 (-169)	1,942 (+57)	1,815 (-127)	1,924 (+109)	1,817 (-107)	1,738 (-79)	2,067 (+329)	1,972 (-95)	1,102 (-870)
Domestic Renewable Diesel (Annual Change)	231 (+62)	252 (+21)	282 (+30)	454 (+172)	472 (+18)	777 (+305)	1,369 (+592)	2,344 (+975)	3,064 (+720)	2,720 (-344)
Imported Renewable Diesel (Annual Change)	165 (+45)	191 (+26)	176 (-15)	267 (+91)	280 (+13)	362 (+82)	311 (-51)	361 (+50)	428 (+67)	105 (-323)
Exported Renewable Diesel (Annual Change)	40 (+19)	37 (-3)	80 (+43)	145 (+65)	223 (+78)	241 (+18)	326 (+85)	414 (+88)	581 (+167)	458 (-123)
Total Renewable Diesel (Annual Change) ^b	356 (+88)	406 (+50)	378 (-28)	576 (+198)	529 (-47)	897 (+368)	1,354 (+457)	2,291 (+937)	2,912 (+621)	2,367 (-545)
Total BBD (Annual Change) ^c	2,412 (+711)	2,293 (-119)	2,322 (+29)	2,393 (+71)	2,457 (+64)	2,717 (+260)	3,106 (+389)	4,376 (+1,270)	4,884 (+508)	3,734 (-1,150)

Note: All data from EMTS. EPA reviewed all BBD RINs retired for reasons other than demonstrating compliance with the RFS standards and subtracted these RINs from the RIN generation totals for each category to calculate the volume in each year. Similar tables of biodiesel and renewable diesel production, imports, and exports presented in previous annual rules included advanced (D5) biodiesel and renewable diesel. This table does not include D5 or D6 biodiesel and renewable diesel. These fuels are discussed in Chapters 7.4 and 7.7, respectively.

^a Data for 2025 are preliminary.

^b Total is equal to domestic production plus imports minus exports.

^c Total BBD includes D4 jet fuel. These volumes were small (≤ 20 million gallons per year) through 2023, but increased to 112 million gallons in 2024 and 264 million gallons in 2025.

Since 2016, the year-over-year changes in the volume of BBD used in the U.S. have varied greatly, from a low of 1.15 billion fewer gallons from 2024 to 2025 to a high of 1.27 billion additional gallons from 2022 to 2023. As discussed previously, these changes were likely influenced by multiple factors. This historical information does not by itself demonstrate that the maximum previously observed annual increase of 1.27 billion gallons of BBD would be reasonable to expect in a future year, nor does it indicate that greater increases are not possible. Significant changes have occurred in both the fuel and feedstock markets (discussed further below) that will impact the rates of growth of biodiesel and renewable diesel production and use

in future years. Rather, this data illustrates both the magnitude of the changes in BBD in previous years and the significant variability in these changes.

This data also shows the increasing importance of renewable diesel in the BBD pool. In 2016 approximately 15% of all BBD was renewable diesel, and the remaining 85% was biodiesel. However, since 2016 nearly all the net growth in the BBD category has been in renewable diesel volume. By 2024 production and net imports of renewable diesel had increased not only in absolute terms (from 365 million gallons in 2016 to 2.95 billion gallons in 2024), but also as a percentage of the BBD pool. In 2025 approximately 63% of all BBD was renewable diesel, while the remaining 37% was biodiesel. As discussed further in the following sections, we expect that renewable diesel will represent an even greater percentage of total BBD in future years.

The historic data indicate that the biodiesel tax policy in the U.S. can have a significant impact on the volume of biodiesel and renewable diesel used in the U.S. in any given year. The availability of federal tax credits has also historically provided biodiesel and renewable diesel with a competitive advantage relative to other biofuels that have not historically qualified for most of the federal biofuel tax credits (*e.g.*, the 40A biodiesel and renewable diesel blending credit). This is likely one of the factors that has contributed to the high growth of BBD relative to other advanced biofuels over the years.

While the biodiesel blenders tax credit (known to many as the “40A” credit) applied in each tax year from 2010 through 2024, it was historically only prospectively in effect during the calendar year in 2011, 2013, 2016, and 2020–2024, while other years it has been applied retroactively. Years in which the biodiesel blenders tax credit was in effect during the calendar year (2011, 2013, 2016, 2020–2024) generally resulted in significant increases in the volume of BBD used in the U.S. over the previous year (629 million gallons, 711 million gallons, 64 million gallons,⁴⁶⁰ 260 million gallons, 389 million gallons, 1,272 million gallons, and 508 gallons, respectively). However, following the large increases in 2013 and 2016, there was little to no growth in the use of BBD in the following years. Data from 2018 and 2019 suggests that while the availability of the tax credit certainly incentivizes an increasing supply of biodiesel and renewable diesel, supply increases can also occur in the absence of the tax credit, likely as the result of the incentives provided by the RFS program, state LCFS programs, trade dynamics, and other economic factors.

Beginning in 2025, the structure of the federal tax credit available to biodiesel and renewable diesel changed significantly. Prior to 2025 all qualifying biodiesel and renewable diesel (including biodiesel and renewable diesel co-processed with petroleum) was eligible for the \$1 per gallon 40A tax credit. This tax credit was available for biodiesel and renewable diesel produced in the U.S. as well as biodiesel or renewable diesel produced in foreign countries and used in the U.S. In 2025, the 45Z credit for domestically produced renewable fuels came into effect. This credit consolidates and replaces the previous \$1 per gallon credit for blending biodiesel and renewable diesel into diesel fuel under 40A and also provides a production credit for other alternative fuels and sustainable aviation fuel. This credit differs from the biodiesel blenders tax credit in several significant ways. First, it is available to other forms of

⁴⁶⁰ This is the volume increase in 2020, which was impacted by the COVID-19 pandemic.

transportation fuel, potentially including ethanol. Second, beginning January 1, 2026, the tax credit is available only for transportation fuel produced in the United States with feedstocks from the US, Canada, or Mexico. Finally, and perhaps more importantly, the magnitude of the tax credit is a function of the CI of the transportation fuel. This means that fuels must have lifecycle GHG emissions lower than 50 kilograms CO₂ equivalent per mmBTU to qualify for the tax credit, and fuels with lower GHG emissions are eligible for a higher tax credit than fuels with higher GHG emissions. The tax credit amount rises based on the CI of the transportation fuel—up to \$1.00 per gallon (as of January 1, 2026) for all liquid fuels—provided certain wage and labor requirements are met. Fuels derived from animal manure may exceed a \$1.00 per gallon credit, as they can potentially have a negative emissions rate. The structure of the 45Z credit therefore has a significant impact on the relative competitiveness of biofuels produced from different feedstocks in the U.S. market.

Another important factor highlighted by the historic data is the impact of changing renewable fuel and trade policies in other countries on the supply of biodiesel and renewable diesel to the U.S. In December 2017, the U.S. International Trade Commission adopted tariffs on biodiesel imported from Argentina and Indonesia.⁴⁶¹ According to data from EIA, no biodiesel has been imported from Argentina or Indonesia since September 2017, after a preliminary decision to impose tariffs on biodiesel imported from these countries was announced in August 2017.⁴⁶² As a result of these tariffs, total imports of biodiesel into the U.S. were significantly lower in 2018 than they had been in 2016 and 2017. The decrease in imported biodiesel did not, however, result in a decrease in the volume of BBD supplied to the U.S. in 2018. Instead, higher domestic production of BBD, in combination with lower exported volumes of domestically produced biodiesel, resulted in an overall increase in the volume of BBD supplied in 2018 and subsequent years.

More recently changes in demand for biodiesel in the EU resulted in significant increased imports to the U.S. from the EU. Through 2021 biodiesel imports from the EU had never exceeded 100 million gallons in any single year.⁴⁶³ Biodiesel imports from the EU increased to approximately 114 million gallons in 2022 and then quite dramatically to approximately 320 million gallons in 2023.⁴⁶⁴ In these same years, imports of feedstocks used by domestic biodiesel and renewable diesel producers, such as tallow from Brazil and used cooking oil from China, increased significantly. These countries had historically exported biofuel feedstocks to the EU, and increased exports to the U.S. were likely impacted by declining demand for these feedstocks by biofuel producers in the EU. This dynamic shifted again in 2025, when the removal of a Chinese government-issued export rebate was shortly followed by a high-tariff environment, leading to a significant decrease in the availability of imported Chinese used cooking oil. This was partially offset by an increase in tallow imports from Latin America. These impacts are discussed in greater detail in Chapters 7.2.3 and 7.2.4.

⁴⁶¹ USITC, “Biodiesel from Argentina and Indonesia Injures U.S. Industry, says USITC,” December 5, 2017. https://www.usitc.gov/press_room/news_release/2017/er12051l876.htm.

⁴⁶² EIA, “U.S. Imports by Country of Origin – Biodiesel,” *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_epoordb_im0_mbbbl_a.htm.

⁴⁶³ Id. Total reported biodiesel imports from the EU include imports from Belgium, Finland, France, Germany, Italy, the Netherlands, Norway, Portugal, and Spain.

⁴⁶⁴ Id.

7.2.2 Biomass-Based Diesel Production Capacity and Utilization

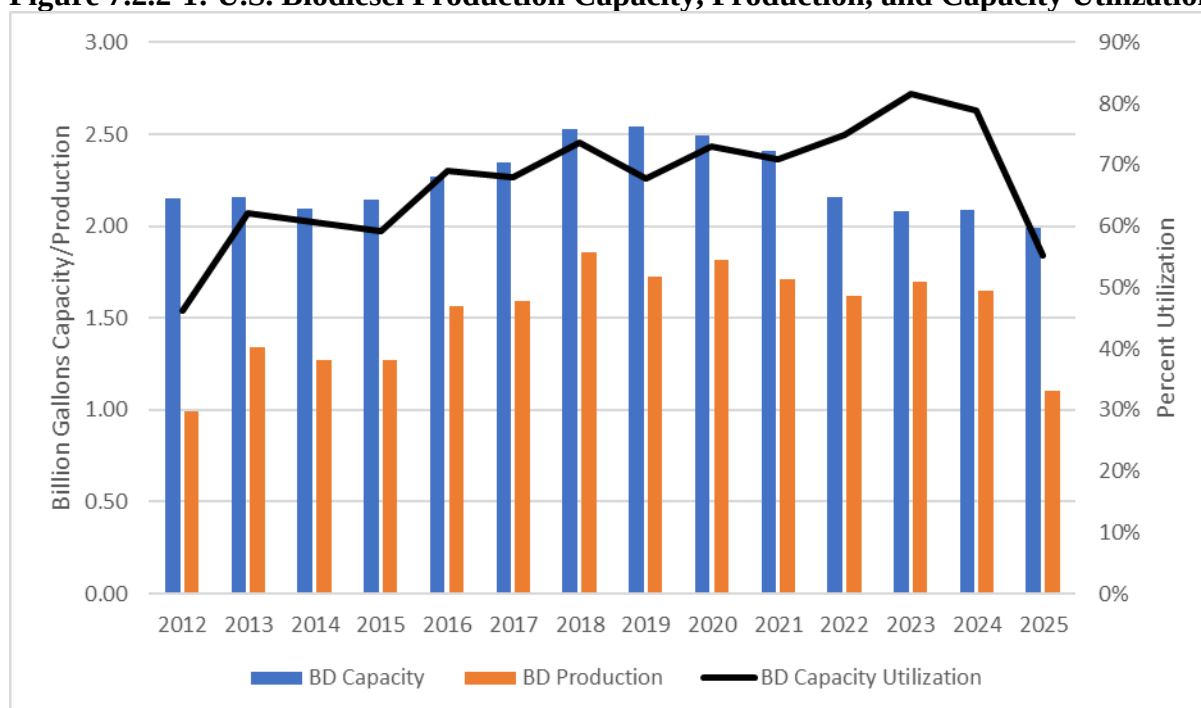
One of the factors considered when projecting the rate of production of BBD in future years is the production capacity. This section focuses on current and projected future BBD production capacity. While many of the biodiesel and renewable diesel production facilities considered in this section are also capable of producing conventional biodiesel and renewable diesel, very low volumes of conventional biodiesel and renewable diesel have been supplied to the U.S. in recent years.⁴⁶⁵ Domestic biodiesel production capacity, domestic biodiesel production, and the utilization rate of the existing biodiesel production capacity each year is shown in Figure 7.2.2-1. Active biodiesel production capacity in the U.S. has experienced modest growth in recent years, from approximately 2.1 billion gallons in 2012 to just over 2.5 billion gallons in 2019.⁴⁶⁶ As of November 2025, active biodiesel production capacity has decreased to approximately 2 billion gallons.⁴⁶⁷ While production of biodiesel has generally increased during this time period (with the notable exception of 2025), excess production capacity remains. Facility utilization was below 75% for each year through 2022, but increased to 82% in 2023 due in part to decreases in the operating biodiesel capacity since 2019. EPA data on total registered biodiesel production capacity in the U.S., which includes both facilities that are producing biodiesel and idled facilities, is much higher, approximately 3.9 billion gallons. Active biodiesel capacity as reported by EIA is the aggregate production capacity of biodiesel facilities that produced biodiesel in any given month, while the total registered capacity based on EPA data includes all registered facilities, regardless of whether they are currently producing biodiesel or not. This data suggest that domestic biodiesel production capacity is unlikely to limit biodiesel production in future years. In 2025, utilization of biodiesel capacity was only 56%, according to EIA data.

⁴⁶⁵ EMTS data indicates that from 2018–2022, no conventional biodiesel or renewable diesel was supplied to the U.S. In 2023, 10 million gallons of conventional biodiesel and renewable diesel were supplied. As there are currently no approved pathway for generating RINs for conventional biodiesel and renewable diesel, conventional biodiesel and renewable diesel can only generate RINs if produced at grandfathered facilities that are exempt from the 20% GHG emission reduction requirements per 40 CFR 80.1403.

⁴⁶⁶ EIA, “Monthly Biodiesel Production Report With data for December 2020,” February 2021, https://www.eia.gov/biofuels/biodiesel/production/archive/2020/2020_12/biodiesel.pdf.

⁴⁶⁷ EIA, “U.S. Total Biofuels Operable Production Capacity,” *Petroleum & Other Liquids*, February 6, 2026. https://www.eia.gov/dnav/pet/pet_pnp_cpbio_dcu_nus_m.htm.

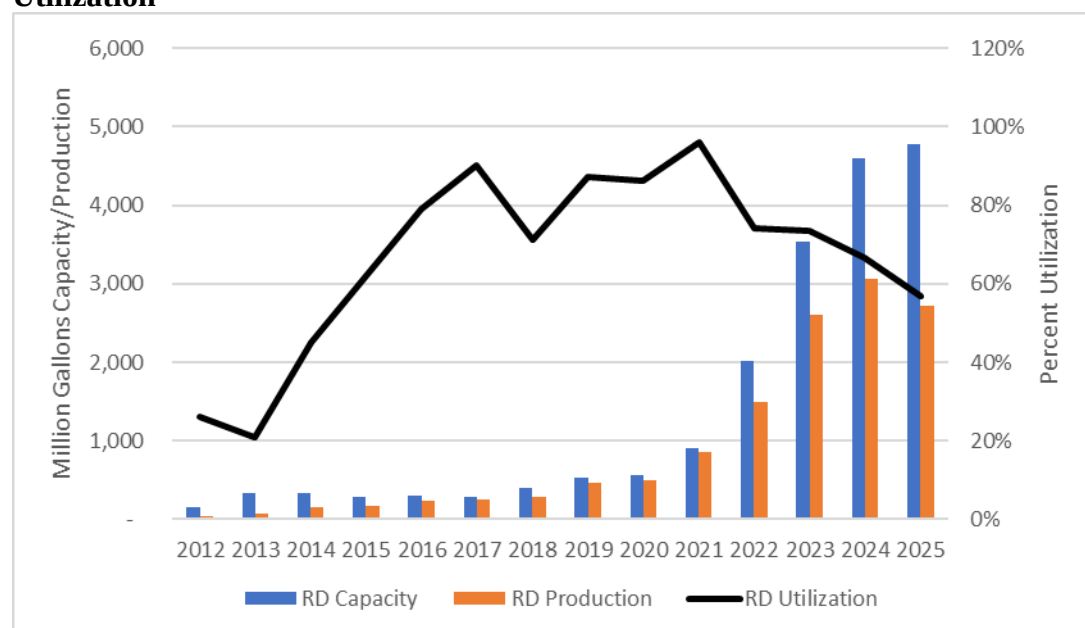
Figure 7.2.2-1: U.S. Biodiesel Production Capacity, Production, and Capacity Utilization



Unlike domestic biodiesel production capacity, domestic renewable diesel production capacity has increased significantly in recent years, from approximately 280 million gallons in 2017 to approximately 5 billion gallons in November 2025 (Figure 7.2.2-2).⁴⁶⁸ Domestic renewable diesel production has increased along with production capacity in recent years, and capacity utilization at domestic renewable diesel production facilities has typically been high, with a precipitous decline in 2025. Further, much of the unused capacity was likely the result of facilities ramping up new capacity to full production rates. Unlike the biodiesel industry, in which unused production capacity has persisted for many years, renewable diesel production neared or exceeded the production capacity from the previous year in every year from 2017 through 2024. As renewable diesel production capacity continues to expand aggressively, it is unclear if this trend will continue in future years (production did not exceed prior year capacity in 2025), particularly as affordable feedstocks may become more scarce with increasing renewable diesel production (see Chapter 7.2.3 for further discussion of available feedstocks).

⁴⁶⁸ RFS facility registration data and EIA, “U.S. Total Biofuels Operable Production Capacity,” *Petroleum & Other Liquids*, February 6, 2026. https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm.

Figure 7.2.2-2: U.S. Renewable Diesel Production Capacity, Production, and Capacity Utilization



Source: Renewable diesel production volumes are from EIA, “Monthly Energy Review,” March 2025, Table 10.4b. <https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf>, as well as EMTS. Renewable diesel production capacity for 2012–2020 is from EMTS. Renewable diesel production capacity for 2021–2025 is from EIA, “U.S. Total Biofuels Operable Production Capacity,” *Petroleum & Other Liquids*, February 6, 2026. https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm. EIA first reported renewable diesel production capacity in 2021. Production capacity shown for 2021–2023 is the average of the monthly reported production capacities. Capacity utilization is calculated by dividing actual production by the total production capacity.

A number of parties have announced their intentions to build new renewable diesel production capacity with the potential to begin production of renewable diesel and/or jet fuel through 2030. These new facilities include new renewable diesel production facilities, expansions of existing renewable diesel production facilities, and the conversion of units at petroleum refineries to produce renewable diesel. In 2023, EIA projected that renewable diesel production capacity would continue to expand and could reach nearly 6 billion gallons by 2025.⁴⁶⁹ However, as of November 2025, that number had reached just over 5 billion gallons.⁴⁷⁰ A recent report published by the National Renewable Energy Laboratory (NREL) estimated that by 2028 the domestic production capacity for renewable diesel and jet fuel could increase to 9.6 billion gallons per year.⁴⁷¹ A map of the facilities expected to begin producing renewable diesel and/or jet fuel by 2028 from the NREL study is shown in Figure 7.2.2-3.

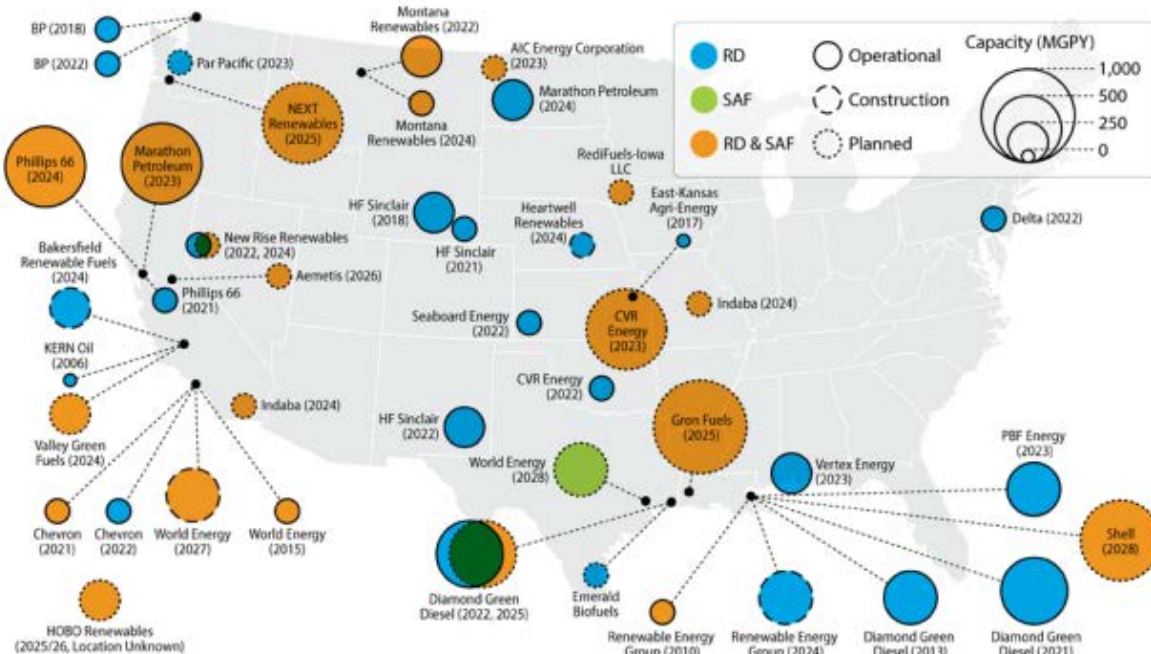
⁴⁶⁹ EIA, “Domestic renewable diesel capacity could more than double through 2025,” *Today in Energy*, February 2, 2023. <https://www.eia.gov/todayinenergy/detail.php?id=55399>.

⁴⁷⁰ EIA, “U.S. Total Biofuels Operable Production Capacity,” *Petroleum & Other Liquids*, February 6, 2026. https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm

⁴⁷¹ Calderon, Oscar Rosales, Ling Tao, Zia Abdullah, Michael Talmadge, Anelia Milbrandt, Sharon Smolinski, Kristi Moriarty, et al. “Sustainable Aviation Fuel State-of-Industry Report: Hydroprocessed Esters and Fatty Acids Pathway,” *National Renewable Energy Laboratory*, NREL/TP-5100-87803, July 30, 2024. <https://doi.org/10.2172/2426563>.

We note, however, that despite the potential for rapidly increasing production capacity over the next several years, feedstock limitations (discussed in Chapter 7.2.3) are not expected to support utilization of all of this planned capacity. It is also possible that some of these projects may be delayed or cancelled. Thus, it is likely that the domestic renewable diesel production will fall short of the 9.6 billion gallons implied by the sum of current production capacity and announced new and expanded facilities. Nevertheless, it appears that domestic production capacity of renewable diesel and SAF is poised to experience continued growth during the timeframe of this rule.

Figure 7.2.3-3: New or Expanded Renewable Diesel and Jet Fuel Production Capacity in the U.S. Through 2028



Source: Calderon, Oscar Rosales, Ling Tao, Zia Abdullah, Michael Talmadge, Anelia Milbrandt, Sharon Smolinski, Kristi Moriarty, et al. "Sustainable Aviation Fuel State-of-Industry Report: Hydroprocessed Esters and Fatty Acids Pathway," *National Renewable Energy Laboratory*, NREL/TP-5100-87803, July 30, 2024. <https://doi.org/10.2172/2426563>.

While renewable diesel and biodiesel capacity utilization has averaged 78% and 70%, respectively, over the past decade, the renewable diesel industry has demonstrated the ability to exceed a 90% capacity utilization rate⁴⁷², in line with typical utilization rates seen in the petroleum industry. As the renewable fuels industry matures and demand for biofuels grows, it is reasonable to project greater capacity utilization of domestic renewable fuel production, as this is more cost effective than a new build. However, sustained demand for SAF may supplement the growth rate of RD/SAF facilities, which are often co-processed. If the industry, which thus far has undershot the expected 6 billion gallons detailed in this study by 2025, is capable of sustained growth in addition to greater capacity utilization, one could expect an annual capacity

⁴⁷² The renewable diesel industry exceeded 90% capacity utilization in 2017 and 2021. See Figure 7.2.3-2.

increase of up to 1.2 billion gallons. This considers the projected capacity of this study less the deficit the industry has undershot by thus far.

7.2.3 2025 Baseline Data and Estimates of BBD Feedstock Availability

Given oscillating trends and frequent upheavals in virgin oilseed and FOG markets, it is difficult to predict the exact nature of some feedstock growth in the future. While some growth rates are assured, historical trends from the past 25 years were disrupted by events such as COVID-19, the Russian invasion of Ukraine, abrupt changes in tariff policy, and complicated supply chains have made feedstock acquisition writ large difficult to predict. While it is clear there is an abundance of feedstocks available to U.S. BBD producers, it is less with which exact feedstock they will fulfill the volume mandates of this rule.

In the hierarchy of feedstocks, it is apparent that domestic and North American feedstocks are heavily advantaged, in large part due to the 45Z credit and the ability of shorter and local supply chains to withstand rapidly shifting trade dynamics. In this environment, soybean oil, Canadian canola oil, North American UCO, and DCO will likely be economically advantageous, with gaps between their supply and the analyzed volumes made up by varying amounts of other eligible feedstocks, most likely dependent on individual contracts and relationships. EPA considers these feedstocks most likely to maintain or surpass their historical growth rates, as there are similar or greater incentives for them to do so between a lack of tariffs, high demand, and tax advantages. EPA first assessed feedstock availability in 2025 before beginning to project growth rates.

2025 saw a decline in BBD production, as evidenced in Chapter 7.2.1. However, feedstock availability remained high. In the United States, distiller's corn oil has been a stable and increasing source of domestic BBD production. Distiller's corn oil output in the U.S. in 2025 was 627 million gallons, of which 560 million gallons is estimated to have been used for BBD.⁴⁷³ Soybean oil also remained a steadfast source of feedstocks in 2025, and total availability was estimated to remain beyond 3.85 billion gallons in the 2025/2026 marketing year after reaching 3.79 billion gallons in the 2024/2025 marketing year.^{474,475,476} Used cooking oil and other fats, oils, and greases continued to mirror population growth, with availability reaching between 2.8 billion and 6 billion gallons in 2025.⁴⁷⁷ Canola oil, a burgeoning feedstock especially in renewable diesel production, reached an estimated domestic production of 1.3 billion gallons in the 2024/2025 marketing year after reaching 1.2 billion gallons in the

⁴⁷³ USDA, "Grain Crushings and Co-Products Production Monthly," February 2, 2026. <https://esmis.nal.usda.gov/sites/default/release-files/795755/cagc0226.pdf>.

⁴⁷⁴ Latest data available at the time of writing due to the publication timelines of agricultural marketing year data by USDA.

⁴⁷⁵ USDA, "Oilseed Crop Yearbook," Soybean Oil," March 20, 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

⁴⁷⁶ USDA, "Grains and Oilseeds Outlook for 2026," February 19, 2026. <https://www.usda.gov/sites/default/files/documents/2026AOF-grains-oilseeds-outlook.pdf>.

⁴⁷⁷ 2.8 billion gallons represents million gallons of BBD equivalent using total global exports. 6 billion gallons represents the global potential collection. Global Data, "UCO Supply Outlook," August 2023. https://cleanfuels.org/wp-content/uploads/GlobalData_UCO-Supply-Outlook_Sep2023.pdf.

2023/2024 marketing year, with an additional 1.3 billion gallons of Canadian canola oil available in the 2023/2024 marketing year.⁴⁷⁸

Beyond these now-favored sources, there are large quantities of importable feedstocks available globally. While imported soybean oil has rarely made inroads into the U.S., there are large quantities of (mostly Latin American) soybean oil available to domestic biodiesel producers. EPA does not project any importation of Latin American soybean oil, but it is an available and eligible feedstock, though heavily disadvantaged.

FOG, on the other hand, is a plentiful and economical feedstock, especially for coastal refineries. While total production data encompassing all sources of FOG publicly, import/export databases do offer an insight into total FOG availability to U.S. domestic BBD producers. Using partial year data, EPA estimates that total global UCO exports numbered 17.9 billion gallons (2.23 billion gallons BBD equivalent) and global tallow exports reached 5.1 billion gallons (636 million gallons BBD equivalent) in 2025.⁴⁷⁹ Of this amount, in 2025, an estimated 7.1 billion gallons (886 million gallons BBD equivalent) was imported into the United States.⁴⁸⁰

Total production data and import/export data show the theoretical limit of BBD feedstock acquisition. Some of this supply is committed to local foreign industries or other domestic industries, such as food or other industrial uses, but given the incentives from tax, trade, and biofuel policy, it is likely that some of that supply is fungible.

7.2.4 Projections of Biomass-Based Diesel Feedstock Availability to Domestic Biofuel Producers

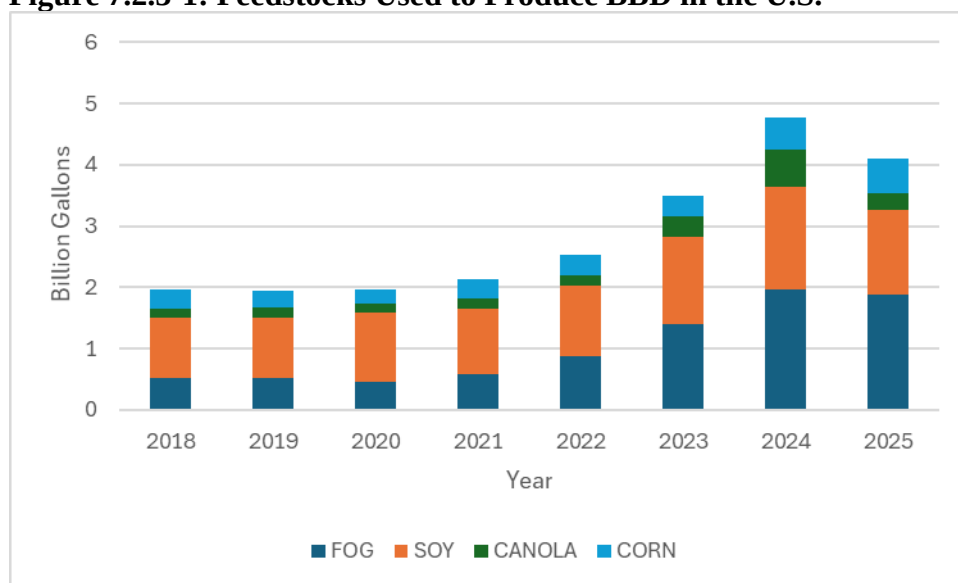
As EPA considered the historical rate of production of BBD through 2027, an important factor influencing the Analyzed Volumes was our assessment of the availability of qualifying feedstocks. To assess the availability of feedstocks for producing BBD through 2027 we first reviewed the feedstocks used by domestic BBD producers (including both domestically produced and imported feedstocks) in previous years. This review of feedstocks used by domestic BBD producers in previous years can provide information about the feedstocks most likely to be used by domestic BBD producers in future years, as well as the likely increase in the availability of such feedstocks in future years. A summary of the feedstocks used to produce BBD from 2012 through 2025 is shown in Figure 7.2.3-1.

⁴⁷⁸ USDA, “Oilseed Crop Yearbook,” Canola Oil, March 20, 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

⁴⁷⁹ United Nations, “UN Comtrade Database,” <https://comtradeplus.un.org>.

⁴⁸⁰ Id.

Figure 7.2.3-1: Feedstocks Used to Produce BBD in the U.S.



Source: EMTS.

Historically, the largest sources of feedstock used by domestic BBD producers have been FOG (which includes both used cooking oil and animal fats) and soybean oil, with smaller volumes of distillers corn oil and canola oil. Through 2021, FOG was primarily sourced domestically and the total supply to BBD producers was relatively stable. Beginning in 2021, the quantity of FOG used for domestic BBD production increased significantly, primarily as the result of increasing imports of these feedstocks. The soybean oil and distillers corn oil used by domestic BBD producers have also historically been primarily sourced domestically. Use of soybean oil and distillers corn oil by BBD producers has generally increased with the increased domestic production of these feedstocks. Finally, relatively small quantities of canola oil have been used by domestic BBD producers historically; however, the use of canola oil increased notably from 2023–2024. This increase was likely the result of EPA’s approval of a RIN generating pathway for renewable diesel produced from canola oil. Most canola oil used in the U.S. is imported from Canada, but smaller volumes of canola oil are also produced domestically.

Projecting the availability of feedstocks to domestic BBD producers requires a consideration of a wide range of factors including the total production and/or collection of these feedstocks (both in the U.S. and foreign countries) and competition for these feedstocks from both non-biofuel markets and biofuel producers in other countries. Each of these factors are in turn impacted by a variety of technical and political issues that are very difficult to project with certainty in future years. To illustrate these complex dynamics, consider the potential growth in soybean oil and FOG to U.S. biofuel producers. Increasing U.S. soybean oil production in future years will require investment to increase the domestic soybean crushing capacity. Domestic soybean crushers that have made these investments in the past are able to do so in the future but are unlikely to do so unless they have a reasonable expectation of increasing demand for soybean oil to provide a return on their investments. The recent observed increase of imported FOG to domestic BBD producers is the result of increased global collection of these feedstocks and changes to biofuel policies in both the U.S. and other countries, such that the U.S. became a preferred destination for these feedstocks. The marked shift back to lower imports of Asian UCO

and imported feedstocks and fuels in 2025 was again marked by significant shifts to biofuel and trade policy in the U.S. and other countries. Any number of factors, such as other countries adopting more stringent biofuel mandates, providing higher incentives for biofuels produced from FOG, or restricting FOG exports, could quickly change these market dynamics.

The remainder of Chapter 7.2.3 provides more detail on the historic and projected future supply of these feedstocks to domestic BBD producers. In general, these sections focus on projecting the total quantity of feedstocks that could be provided to domestic producers if there are sufficient economic incentives to increase the production and/or collection of these feedstocks and if the U.S. remains a preferred destination for these feedstocks. A further discussion of the uncertainties related to these projections, and how these uncertainties impact the Analyzed Volumes, can be found in Chapter 7.2.5 and Preamble Section III.A.2, respectively. In our discussion of available feedstocks we have differentiated between domestically sourced feedstocks and imported feedstocks, as both the historic trends and factors that are expected to impact future supplies to BBD producers often differ depending on the source of the feedstock. While this section considers the availability of imported feedstocks to domestic BBD producers, it does not consider BBD imported from foreign producers, which is covered in Chapter 7.2.4.

7.2.4.1 Domestic BBD Feedstocks

Domestic feedstocks used for BBD production have historically come from three primary sources: FOG (including UCO and animal fats), distillers corn oil, and soybean oil. Domestic BBD producers generally do not report whether the feedstock they use to produce biofuel is sourced domestically or imported. In many cases EPA had to infer the quantity of BBD feedstock from domestic sources based on total reported feedstock use records of the quantity of BBD feedstocks imported to the U.S. from UN Comtrade.⁴⁸¹ While this data has its own limitations (for example, it only reports total import quantities of various products and does not identify the importers or the industries using the imported feedstock), we have been able to reasonably estimate the quantities of domestic and imported feedstocks used by BBD producers using a combination of EMTS data on domestic biofuel production by feedstock, domestic feedstock production from USDA and other sources, and import data from UN Comtrade.

Domestic BBD production from FOG in the U.S. was mostly from domestically sourced feedstocks and was relatively stable from 2014 through 2020. However, from 2022 through 2024 FOG imports and total domestic usage increased. These feedstocks are generally byproducts of other industries. Their historical growth prior to 2014 domestically was driven by the greater economic incentive provided by the RFS and LCFS programs, increasing collection rates, reducing disposal, and shifting them from other uses. Once the majority of FOG that could economically be collected in the U.S. had been used productively, the subsequent growth in the collection of these feedstocks has tended to follow population growth. We expect this trend to continue in future years and that any significant increases in the availability of FOG to domestic biofuel producers will primarily be the result of increased imports of these feedstocks (see Chapter 7.2.3.2 for a discussion of the availability of imported FOG to domestic BBD producers).

⁴⁸¹ United Nations, “UN Comtrade Database,” <https://comtradeplus.un.org>.

To project increases in the supply of FOG from the U.S. to domestic BBD producers we relied primarily on historical data. Table 7.2.3.1-1 shows the total quantity of FOG used by domestic BBD producers each year from 2014 through 2025. Prior to the significant increase in imported FOG in 2021, the general trend in the production of BBD from FOG was relatively small but predictable growth. From 2014 through 2021 the average annual increase in the domestic production of BBD from FOG was approximately 25 million gallons per year. A study conducted by Global Data similarly projected that the domestic supply of UCO would increase by approximately 30 million gallons per year from 2022 through 2030.⁴⁸² Based on this data we project that the domestic supply of FOG to BBD producers will increase at a rate of approximately 25 million gallons per year through 2027.

Table 7.2.3.1-1: Domestic BBD production from FOG (million gallons)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025*
391	406	477	469	518	516	455	587	869	1,395	1970	1890

*Estimated from partial year 2025 EMTS data

Production of BBD from distillers corn oil has also generally increased through 2025. The most significant increases in the volume of BBD produced from distillers corn occurred through 2018, as more corn ethanol plants installed equipment to produce distillers corn oil and corn ethanol production expanded (see Table 7.2.3.1-2). However, production of BBD from this feedstock has been fairly consistent at about 250–350 million gallons per year since 2017. Total production of distillers corn oil in the U.S. in 2025 was approximately enough to produce 630 million gallons of BBD. This suggests that distillers corn oil could be used to produce over 60 million gallons of additional BBD, but that would require shifting distillers corn oil from other existing uses, such as animal feed, which would then have to be backfilled with other new sources.⁴⁸³ It is also possible that domestic production of distillers corn oil could increase or decrease in future years for a variety of reasons, including new varieties of corn with higher oil content, greater extraction rates, or changes in U.S. ethanol production for domestic or international markets. While it is possible that the use of distillers corn oil by domestic BBD producers will increase in future years through the diversion of this feedstock from other markets or increased production, we project that there will not be any increase (or decrease) in the supply of distillers corn oil to domestic BBD producers through 2027.

Table 7.2.3.1-2: Domestic BBD production from Distillers Corn Oil (million gallons)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025*
187	183	224	245	308	278	226	299	325	332	520	560

*Estimated from partial year 2025 EMTS data available at the time of writing.

The remaining volume of domestic BBD has been produced from soybean oil and canola oil. The largest source of BBD production in the U.S. historically has been soybean oil. While there have been small quantities of soybean oil imported into the U.S. in previous years, the vast

⁴⁸² Global Data, “UCO Supply Outlook,” August 2023. https://cleanfuels.org/wp-content/uploads/GlobalData_UCO-Supply-Outlook_Sep2023.pdf. Annual growth in UCO collection based on estimated growth in per capita UCO collection rates from 2022–2030.

⁴⁸³ For a discussion of backfilling when oil is removed from dried distillers grains, see 83 FR 37735 (August 2, 2018).

majority of soybean oil available in the U.S. is from domestic sources due to the large domestic soybean oil industry and significant tariffs on imported soybean oil.⁴⁸⁴ Conversely, the domestic canola oil industry is relatively small, and most of the canola oil used in the U.S. is imported from Canada. Domestic production of canola oil has been relatively stable since 2013/2014,⁴⁸⁵ and we are therefore only projecting small increases in the availability of domestic canola oil to U.S. biofuel producers through 2027. Our projections of potential increases in imported canola oil from Canada are covered in Chapter 7.2.3.2. However, there does hypothetically exist the potential for greater quantities of canola oil to be shifted away from other end uses to biofuel production. For the 2023/24 harvest year, domestic disappearance of canola oil was about 8.9 billion pounds across all industries and including exports.⁴⁸⁶ Less than half of that volume was used as biofuel feedstock. In a hypothetical scenario where all domestic canola oil was shifted to biofuel production, there would be sufficient supply to produce about 662 million gallons of BBD from this domestically produced canola oil.

Use of soybean oil to produce biodiesel increased from approximately 5.1 billion pounds in the 2013/2014 agricultural marketing year to approximately 13 billion pounds in the 2023/2024 agricultural marketing year, the latest data available at the time the analyses for this rule were completed.⁴⁸⁷ This time period saw significant increases in total soybean oil production (through increased domestic soybean crushing) and the use of soybean oil for biofuel production, both in absolute terms and relative to other markets. Domestic soybean crushing increased by 39% from 2013/2014 (1,734 million bushels) to 2024/2025 (2,410 million bushels). At the same time that domestic soybean oil production was increasing, the percentage of all soybean oil produced in the U.S. for biodiesel also increased, from approximately 25% in 2013/2014 to approximately 48% in 2023/2024.

As a point of reference, if all soybeans grown in the U.S. in 2023/2024 were crushed domestically (rather than exported) we project that domestic soybean oil production would be approximately 53.1 billion pounds, enough feedstock to produce approximately 6.6 billion gallons of BBD. In the near term it is not possible to crush all the soybeans produced in the U.S. domestically due to crushing capacity limitations, nor is it likely possible to divert all soybean oil to biofuel production due to strong demand in other non-biofuel industries such as food. These numbers illustrate, however, the theoretical maximum level of BBD production from the current U.S. soybean crop if recent trends toward increasing domestic soybean crushing and greater use of soybean oil for biofuel production relative to other markets were to continue indefinitely. We note, however, that shifting greater quantities of soybean oil from current markets for increased biofuel production could result in these markets turning to other sources of vegetable oil such as palm oil.

Additional soybean oil availability to biofuel producers in future years is primarily expected to come from increased domestic crushing of soybeans. Some quantities of soybean oil used in non-biofuel markets are also likely to be shifted into the biofuels market. While the total

⁴⁸⁴ USDA, “Oil Crops Yearbook,” March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>. The agricultural marketing year for soybeans runs from September to August.

⁴⁸⁵ Id.

⁴⁸⁶ Id.

⁴⁸⁷ Id.

use of soybean oil for non-biofuel markets has remained relatively stable in the past five years, strong incentives for biofuel use from 45Z, the RFS, and state clean fuels programs are stronger than they have historically been.⁴⁸⁸ U.S. soybean oil production could continue to increase in future with investments in expanding domestic soybean crush capacity, with increases in soybean crush likely resulting in reduced soybean exports. Since 2000/2001 the percentage of U.S. soybean production that has been crushed domestically has varied from a low of 44% in the 2016/2017 agricultural year to a high of 67% in the 2007/2008 marketing year.⁴⁸⁹ Most of the rest of the whole soybeans are exported to foreign countries, where the beans are then crushed to produce soybean meal and soy oil for their own markets.

Strong demand for vegetable oil has already resulted in increasing domestic crushing of soybeans. Recent data from USDA indicates that soybean crushing reached record levels of approximately 3.8 billion gallons in the 2024/2025 agricultural marketing year and is expected to increase to 4 billion gallons in 2026/2027.⁴⁹⁰ There have also been numerous investment announcements to increase domestic soybean crush capacity through the construction of new facilities as well as the expansion of existing facilities. Crush capacity expansion that is planned and/or currently under construction is expected to continue to add to domestic soybean crush capacity through 2027. Accounting for only facilities that have broken ground and are currently under construction the domestic soy crush industry is projected to add the equivalent capacity of 360 million gallons in 2026. Including proposed and announced facilities (that will be completed 2027 or beyond), the domestic soy crush industry was expected to add up to the equivalent of 757 million gallons of crush capacity as soon as 2027.^{491,492,493} Future crush expansion in 2028 and beyond is dependent on the expected demand for soybean oil in these years from the biofuel sector and other markets. If the increased domestic crushing capacity results in reduced exports of whole soybeans (rather than increased soybean production), this increased soybean oil production could be achieved with little impact on overall U.S. soybean production. However, shifting soybean crushing to the U.S. and using the oil domestically would decrease soy oil supplies abroad. Foreign countries could respond to this reduction of soybean oil supply by increasing their consumption of other vegetable oils.

The USDA Agricultural Projections to 2033 project increasing domestic soybean oil production through 2030 as a result of an increased soybean crushing. USDA projects that domestic soybean oil production will increase by approximately 2 billion pounds from 2025 (28 billion pounds) to 2030 (30 billion pounds).⁴⁹⁴ If this entire increase in soybean oil production

⁴⁸⁸ Id.

⁴⁸⁹ Id.

⁴⁹⁰ USDA, “Grains and Oilseeds Outlook,” <https://www.usda.gov/sites/default/files/documents/2026AOF-grains-oilseeds-outlook.pdf>, February 2026

⁴⁹¹ American Soybean Association, “Soybean Crush Expansion, 2025 Update,” April 10, 2025. <https://soygrowers.com/news-releases/soybean-crush-expansion-2025-update>.

⁴⁹² USDA, “Oil Crops Outlook: February 2026,” February 12, 2026. <https://ers.usda.gov/sites/default/files/laserfiche/outlooks/113803/OCS-26b.pdf?v=57362>.

⁴⁹³ Projection using early 2025 data, the latest available at the time of writing.

⁴⁹⁴ USDA, “USDA Agricultural Projections to 2033,” OCE-2024-1, February 2024. <https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2033.pdf>. For each year, we converted soybean oil production projections to calendar year prices by weighting production in the first agricultural marketing year (e.g., 2024/2025 for the 2025 price) by 0.75 and production in the second agricultural marketing year (e.g., 2025/2026 for the 2025 price) by 0.25.

were used to produce biodiesel or renewable diesel, it would result in an increase of approximately 250 million gallons of biofuel from 2025 to 2030, or an increase of approximately 50 million gallons per year.⁴⁹⁵ These projections are based on macroeconomic forecasts and do not appear to account for the number of facilities that have recently begun construction or announced plans to build or expand soybean crushing facilities, which could significantly increase domestic soybean oil production through 2027. As such, they are better projections of domestic soybean oil production with static RFS volume requirements at 2025 levels rather than projections of potential domestic soybean oil production supported by strong and growing RFS volume requirements.

EMTS data on domestic BBD production from soybean oil (see Table 7.2.3.1-3) show that the use of soybean oil for BBD production has increased significantly since 2014. The average annual increase in domestic BBD produced from soybean oil from 2014–2023 was approximately 90 million gallons per year. More recent data showed an accelerated growth rate before a sudden decline. From 2021 to 2023 the average annual growth rate increased to approximately 170 million gallons per year, and the increase from 2022 to 2023 was approximately 260 million gallons. 2023 to 2024 saw an increase of about 260 million gallons, and 2024 to 2025 saw overall BBD production decrease, resulting in a decrease in overall use of soy oil in BBD of 310 million gallons. However, the percentage of total BBD produced from soy oil in 2025 remained similar to 2023 and 2024 (32%, 26%, and 26%, respectively).

Table 7.2.3.1-3: Domestic BBD production from Soybean Oil (million gallons)

2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
641	616	774	745	984	987	1,123	1,072	1,159	1,418	1680	1370

Recent announcements of plans to invest in increasing the domestic soybean crush capacity suggest that the higher observed rates of growth in the supply of soybean oil to BBD producers may continue in future years. The American Soybean Association projected that the increase in domestic soybean oil production from 2023–2025 would be sufficient to produce approximately 700 million gallons of biodiesel and renewable diesel.⁴⁹⁶ The Clean Fuels Alliance America submitted a study conducted by LMC international that found that the projected growth in soybean oil production in the U.S. from 2021–2025 would be sufficient to produce approximately 750–800 million gallons of biodiesel and renewable diesel.⁴⁹⁷ More recently a study conducted by S&P Global projected that U.S. soybean crushing expansion from 2024 through 2027 would increase crush capacity by 700 million bushels, producing enough soybean oil to produce approximately 1 billion gallons of renewable diesel.⁴⁹⁸ These estimates are summarized in Table 7.2.3.1-4.

⁴⁹⁵ These projections are based on the existing RFS volume requirements through 2025 and not any assumed increase in RFS volumes for 2026 and beyond. Future growth projections are therefore based on increases in future demand from non-biofuel sectors.

⁴⁹⁶ Comment submitted by American Soybean Association (ASA), Docket Item No. EPA-HQ-OAR-2021-0427-0579. <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0579>.

⁴⁹⁷ Comment submitted by Clean Fuels Alliance America, Docket Item No. EPA-HQ-OAR-2021-0427-0805. <https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0805>.

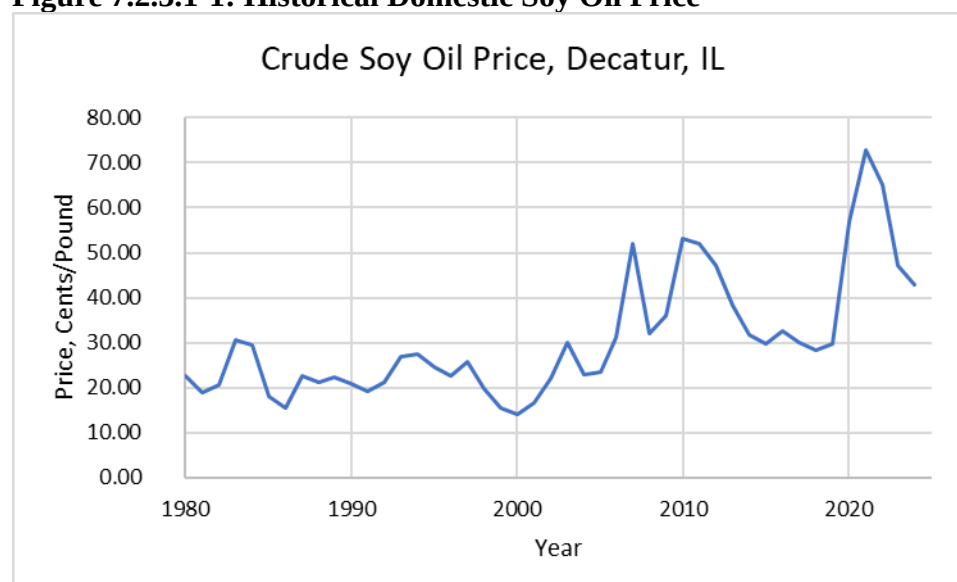
⁴⁹⁸ S&P Global, “Availability of Feedstocks for Biofuel Use – Key Highlights,” July 2024. <https://www.nopa.org/wp-content/uploads/2024/07/NOPA-SPGCI-Availability-of-Feedstocks-Key-Highlights.pdf>.

Table 7.2.3.1-4: Summary of Projections of Soybean Oil Supply to BBD Producers (million gallons BBD)

Data Source	Estimated Increase	Timeframe	Annual Average Increase
USDA Agricultural Projections to 2033	250	2025–2030	50
EMTS Data	780	2014–2023	90
EMTS Data	350	2021–2023	170
American Soybean Association	700	2023–2025	350
LMC	750-800	2021–2025	200
S&P Global	1,000	2024–2027	250

The higher observed and projected increases in domestic soybean oil production occurred following a period when soybean oil prices were historically high. From 2013/2014 through 2018/2019 the average price of soybean oil was approximately \$0.31 per pound.⁴⁹⁹ Starting in 2019/2020 soybean oil prices increased dramatically and remained high for several years, averaging \$0.61 per pound from 2019/2020 through 2023/2024.⁵⁰⁰ Industry data suggest that the construction timeline for a soybean crushing facility is approximately 2 years, aligning the observed and projected periods of significant growth in domestic soybean oil production with a two year lag of the observed price increase. Thus, the available data suggest that future increases in domestic soybean crushing are possible, but that future increases are dependent on increased demand for soybean oil, whether from BBD producers or other markets.

Figure 7.2.3.1-1: Historical Domestic Soy Oil Price



While there are some slight variations in these estimates, the data submitted by commenters demonstrates that domestic soybean oil production is likely to increase beyond 2025 levels. With the exception of the USDA estimate from the agricultural projections to 2033 and the EMTS data from 2014–2023, all of these estimates cover a time period during which high

⁴⁹⁹ USDA, “Oil Crops Yearbook,” March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

⁵⁰⁰ Id.

soybean oil prices lead to increased investment in soybean oil production. These estimates are therefore likely indicative of the level of increases in domestic soybean oil production that could be achieved with continued high demand for domestic soybean oil.

In addition to increasing U.S. soybean crushing, additional quantities of soybean oil could be made available for biofuel production from decreased exports of soybean oil itself. Prior to the ramp-up in biodiesel and renewable diesel use the U.S. exported significant quantities of soybean oil, with soybean oil exports peaking in 2009/2010 at approximately 3.4 billion pounds.⁵⁰¹ Since that time soybean oil exports have generally decreased as the quantity of soybean oil used for domestic biofuel production has increased. USDA estimates that in the 2022/2023 agricultural marketing year soybean oil exports decreased by approximately 90% to 0.38 billion pounds before slightly increasing to 0.62 billion pounds in 2023/2024, still well below recent historical export levels.⁵⁰² While it is possible that these soybean oil exports could be diverted to domestic biofuel production in future years, diverting all of the soybean oil exports from 2022/2023 to biofuel production would only increase BBD production by approximately 50 million gallons per year.

Based on our review of historical data on the use of soybean oil for domestic BBD production and the available projections of increases in soybean crushing capacity in future years, we project that the production of BBD from domestic soybean oil could increase at a rate of approximately 250 million gallons per year through 2027 if supported by increases in demand. This does not account for any potential diversion from non-biofuel markets. Non-biofuel markets for soybean oil have shrunk as the RFS has grown in scope, and there are many alternatives for domestic soybean oil in the food industry, such as imported soybean oil from Argentina or Brazil or imported canola oil.

7.2.4.2 Imported BBD Feedstocks

In recent years domestic BBD producers have used increasing quantities of imported feedstocks to produce BBD. The primary imported feedstocks used for BBD production are FOG (UCO and animal fats) and canola oil. While we do not have reliable information on the quantity of imported soybean oil used for BBD production, USDA estimates total soybean oil imports of approximately 621 million pounds in the agricultural marketing year 2023/2024.⁵⁰³ Even if this entire volume were used for BBD production it would result in approximately 80 million gallons of renewable diesel per year. Similarly, we are not aware of any available data on imported distillers corn oil used for BBD production. While we do not project significant imports of distillers corn ethanol through 2027 it is possible that imported distillers corn ethanol may become a source of feedstock to domestic BBD producers as corn ethanol production in foreign countries such as Brazil increases.⁵⁰⁴ This chapter focuses on projected imports of FOG and

⁵⁰¹ Id.

⁵⁰² Id.

⁵⁰³ Id.

⁵⁰⁴ Colussi, Joana, Nick Paulson, Gary Schnitkey, and Jim Baltz. "Brazil Emerges as Corn-Ethanol Producer with Expansion of Second Crop Corn." *farmdoc daily* (13):120, June 30, 2023. <https://farmdocdaily.illinois.edu/2023/06/brazil-emerges-as-corn-ethanol-producer-with-expansion-of-second-crop-corn.html>.

canola oil, which are projected to be the dominant sources of imported BBD feedstocks through 2027.

Imports of FOG to the U.S. were relatively small through 2021. From 2014–2021 imports of FOG increased gradually, reaching a total of about 0.5 million metric tons in 2021.⁵⁰⁵ Imports of these feedstocks increased significantly in 2022 and 2023 (see Table 7.2.4.2-1). This rapid rise in the imports of FOG is likely due to a number of factors, including the rapid increase in renewable diesel production capacity,⁵⁰⁶ greater incentives from California’s LCFS program and other state clean fuels programs (and further disincentives for seed oil use in LCFS) for BBD produced from FOG, and biofuel policies internationally, especially in the EU and now China.

Table 7.2.4.2-1: U.S. Imports of FOG (million metric tons)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
UCO	0.02	0.02	0.02	0.04	0.06	0.09	0.08	0.13	0.40	1.41	2.45	2.11
Animal Fats	0.06	0.06	0.08	0.08	0.14	0.19	0.24	0.33	0.55	0.79	0.88	1.11
Total	0.08	0.09	0.10	0.12	0.20	0.28	0.33	0.46	0.95	2.20	3.33	3.22

Projecting the future supply of imported FOG to U.S. BBD producers is an inherently difficult task, as it requires projecting not only the global supply of these feedstocks but also making assumptions about future worldwide market conditions for these feedstocks. For example, the recent increase in UCO imports to the U.S. is largely a function of the U.S. surpassing the EU as the preferred destination for UCO exports from foreign countries. The subsequent decline was largely a function of U.S. imposed tariffs, declining U.S. biofuel production, and removal of Chinese export rebates on UCO. These types of market changes can dramatically impact the supply of imported feedstocks to the U.S., and it is not possible to project these changes with any degree of certainty. In this Chapter we have projected the potential available supply of imported FOG to the U.S. assuming that the U.S. maintains some levels of UCO imports, especially pertaining to Asia, while also beginning to see imports of UCO from Mexico as a result of the altered 45Z credit that requires feedstock use from North America. In Chapter 7.2.6 we provide further discussion on some of the key uncertainties related to market conditions for imported feedstocks, and potential future scenarios if other countries increase their market share of imported FOG in future years.

To project potential future supplies of imported FOG, we first examined several data sets, including historical data on FOG imports and projections of future FOG imports from several sources. EPA considered both historical data on total FOG imports sourced from UN Comtrade and data on domestic BBD production from FOG from EMTS. The data considered are shown in Table 7.2.4.2-2. In 2022, UCO imports began to increase dramatically until levelling off in 2025, while animal fat imports have continued to grow by approximately 64 million gallons per year. The fact that the increase in the quantity of BBD produced from FOG from 2021 to 2025 is

⁵⁰⁵ Data on imports of FOG from UN Comtrade. Data for imports of UCO and animal fats are based on HS Codes 1518 and 1502.10, respectively.

⁵⁰⁶ In general, renewable diesel production facilities are able to process FOG feedstocks, while only a subset of biodiesel production facilities can process these feedstocks. Additionally, many renewable diesel production facilities are located near ports and have easier access to imported feedstocks.

larger than the total quantity of FOG imported suggests that very little, if any, FOG was used in markets other than biofuel production.

Table 7.2.4.2-2: FOG Imports and Domestic BBD Production from FOG (million gallons)

	2019	2020	2021	2022	2023	2024	2025
UCO Imports ^a	24	23	36	109	387	673	581
Animal Fat Imports ^a	53	67	91	152	218	242	305
Total FOG Imports ^a	77	90	127	261	605	924	886
BBD Produced from FOG ^b	516	455	587	869	1,395	1920	1,870

^a Import data from UN Comtrade (Data on FOG represents HS code 1518 and data on animal fats represents HS code 1502.10). Data from Comtrade was converted from kilograms to million gallons BBD assuming 8 lbs FOG per gallon of BBD.

^b Data from EMTS.

EPA also considered available estimates of potential FOG imports. A study conducted by Global Data on behalf of the Clean Fuels Alliance America in August 2023 projected the potential increase in the supply of UCO to domestic BBD producers of approximately 0.9 billion gallons from 2025 to 2030 in their base case, an increase of approximately 180 million gallons per year.⁵⁰⁷ This same study also estimated additional global potential beyond the base case. Global Data estimated that the additional global potential could increase the global supply of UCO available to biofuel producers to support an additional 4.7 billion gallons of BBD production from 2025 to 2030. Another study conducted by S&P Global projected that UCO imports to the U.S. could increase by about 5 billion pounds per year from 2023 – 2030 (enough to produce over 600 million gallons of BBD) and tallow imports could increase by about 3.25 billion pounds from 2023–2030 (enough to produce over 400 million gallons of BBD).⁵⁰⁸ The estimates of the potential growth rate in the production of BBD from FOG from both the historic data and these studies are summarized in Table 7.2.4.2-3.

⁵⁰⁷ Global Data, “UCO Supply Outlook,” August 2023. https://cleanfuels.org/wp-content/uploads/GlobalData_UCO-Supply-Outlook_Sep2023.pdf.

⁵⁰⁸ S&P Global, “Availability of Feedstocks for Biofuel Use,” July 2024. <https://www.nopa.org/wp-content/uploads/2024/07/NOPA-SPGCI-Availability-of-Feedstocks-Key-Highlights.pdf>.

Table 7.2.4.2-3: Summary of Projections of FOG Supply to BBD Producers (million gallons BBD)

Data Source	Estimated Increase	Timeframe	Annual Average Increase
All FOG (undifferentiated)			
EMTS Data	808	2021–2023	404
UCO			
UN Comtrade Imports	351	2021–2023	176
Global Data (Base Case)	900	2025–2030	180
Global Data (Base + Potential)	5,600	2025–2030	1,120
S&P Global	600	2023–2030	86
Tallow			
UN Comtrade Imports	127	2021–2023	64
S&P Global	400	2023–2030	58

Based on our review of the historical data on the use of imported UCO and tallow for domestic BBD production and the available projections of increases in the imports of these feedstocks in future years, we project that the production of BBD from imported UCO could increase at a rate of 200 million gallons per year through 2030 and imported tallow could increase at a rate of 50 million gallons per year through 2030. These projections are slightly lower than the observed rate of increase in domestic BBD production from FOG from 2021–2023 when the U.S. became a more significant importer of these feedstocks. We note, however, that these numbers also include increases from domestic sources of FOG. It should be noted that, while general supply dynamics will generally remain unchanged, these feedstocks going forward are more likely to be second choices as the effects of 45Z and trade policy take hold over the broader FOG market.

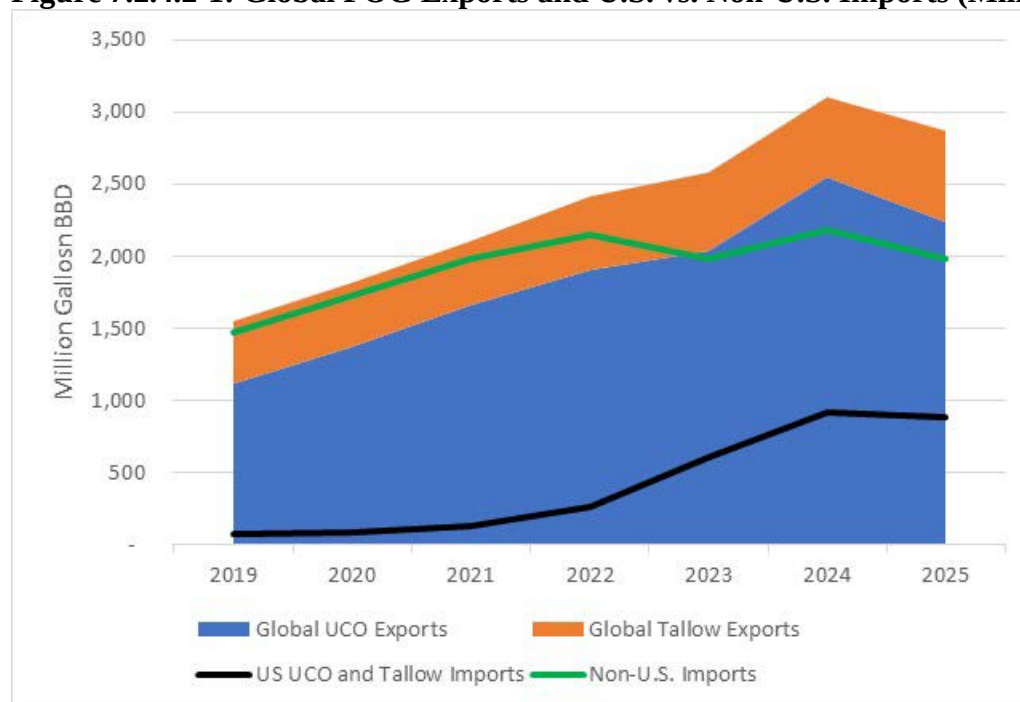
To assess the feasibility of increasing imports of FOG for biodiesel production we considered the global volumes of these feedstocks exported over the past five years for which data were available and the total quantity of these feedstocks imported by the U.S. This information is shown in Figure 7.2.4.2-1. During this time period, global exports of tallow have increased gradually, while UCO exports have increased more quickly. However, policy actions by the U.S. to discourage imports and China to discourage exports, including high tariffs on Asian used cooking oil and removal of export rebates, respectively, have dampened growth in imports, with 2025 seeing a large decline in overall UCO imports to the U.S. from China. While previous growth rates of 250 million gallons per year are likely to continue in an environment similar to those of 2019–2023, it is far more likely that UCO imports will continue to see a decline given the policy uncertainties and robust growth in domestic and North American crush of virgin seed oils.

One exception to this trend is Canada and Mexico. The Canadian FOG market is relatively developed, with rates of UCO collection rivaling the US. US imports of Canadian FOG reached an estimated 70 million gallons in 2023.⁵⁰⁹ Mexican used cooking oil is now highly advantaged, thanks to a lower tariff environment compared to Asian competitors,

⁵⁰⁹ Global Data, “UCO Supply Outlook,” August 2023.

eligibility for the 45Z credit, low operating costs, and proximity to US refineries and logistics networks. Given the untapped potential of this market, high expected domestic biodiesel and renewable diesel capacity utilization, and faltering Asian UCO imports to the US, we believe that used cooking oil collection in Mexico will begin to reach its full potential. In 2010, Sheinbaum et al. estimated that UCO potential in Mexico was concentrated in high density areas and could reach collection rates of 45%, or 245 million gallons.⁵¹⁰ More recently, Global Data estimated that Mexico consumes about 5.4 gallons per capita of cooking oil. At similar collection rates, this would be a potential of 322 million gallons of Mexican UCO in 2023.⁵¹¹ Given increasing population, high incentives for collection, and an 80% urban population, we project growth in U.S. imports of Mexican UCO of 50 million gallons per year, mirroring domestic U.S. UCO growth. Collection is projected to ramp up by 2027 in response to the RFS, tax incentives, and trade dynamics.⁵¹²

Figure 7.2.4.2-1: Global FOG Exports and U.S. vs. Non-U.S. Imports (Million Gallons)



In addition to imported FOG, we also project significant quantities of imported canola oil could be made available to domestic BBD producers in future years. As with other potential sources of feedstock for domestic BBD producers, we used the historic BBD production and canola oil import data as a starting point for our future projections. Annual domestic BBD production and canola oil imports are shown in Table 7.2.4.2-4. From 2014 through 2022 production of BBD from canola oil fluctuated between 100 and 200 million gallons per year.

⁵¹⁰ Sheinbaum-Pardo, Claudia, Andrea Calderón-Irazoque, and Mariana Ramírez-Suárez. "Potential of Biodiesel From Waste Cooking Oil in Mexico." *Biomass and Bioenergy* 56 (June 7, 2013): 230–38. <https://doi.org/10.1016/j.biombioe.2013.05.008>.

⁵¹¹ Global Data, "UCO Supply Outlook," August 2023. https://cleanfuels.org/wp-content/uploads/GlobalData_UCO-Supply-Outlook_Sep2023.pdf.

⁵¹² UN Habitat "Country Overview – Mexico." <https://unhabitat.org/mexico>.

Production of BBD from canola oil increased significantly in 2025, to approximately 600 million gallons likely as the result of increased canola crushing in Canada and the approval of the pathway for renewable diesel to generate BBD RINs for fuel produced from canola oil in 2023.⁵¹³ Since the 2010/2011 agricultural marketing year approximately 70% of all canola oil supplied to the U.S. has been imported,⁵¹⁴ and greater than 95% of the imported canola oil is imported from Canada.⁵¹⁵ We anticipate that through 2027 Canada will be the predominant source of any increase in imports of canola oil to domestic BBD producers and have therefore primarily focused on potential imports from Canada in projecting the availability of canola oil for biofuel production.

Table 7.2.4.2-4: Domestic BBD Production from Canola Oil and Total Canola Oil Imports (Million Gallons BBD Equivalent)

	2014	2015	2106	2017	2018	2019	2020	2021	2022	2023	2024	2025
Domestic BBD Production from Canola Oil	141	115	207	177	159	157	159	166	174	344	542	600
Canola Oil Imports for All Uses	433	470	509	541	505	493	506	524	610	809	906	974

We also considered projections of increased canola oil production in Canada in future years and how much of that increased production would be made available to U.S. biofuel producers. In the Set 1 rule EPA used publicly available data to project increasing canola oil production in Canada from 2022–2025. We projected that total canola oil production in Canada would increase by approximately 1.1 million metric tons from 2022–2025, and that half of this increase in production would be available to U.S. BBD producers (enough canola oil to produce approximately 280 million gallons of BBD). Given more recent data, we have adjusted our estimates of Canadian canola crush capacity. The Canadian Canola Council reports average annual growth in domestic oilseed production of 33.2 million gallons. The industry in Canada crushed 11.4 MMT, or approximately 1330 million gallons of canola in marketing year 2024/2025, and capacity is expected to reach 15 MMT by the end of 2026, in part thanks to the soon opening Cargill Regina Canola Crush Facility, which will bring online 1 MMT of capacity.^{516,517,518} The USDA Foreign Agricultural Service reports a 28% year over year growth in Canadian canola crush capacity since 2021. As seen in Table 7.2.4.2-5, capacity continues to grow, and capacity utilization has reached 90%+ after the industry recovered from a Sino-Canadian trade war in 2023.

⁵¹³ 87 FR 73956 (December 2, 2022).

⁵¹⁴ USDA, “Oil Crops Yearbook,” March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

⁵¹⁵ Data from UN Comtrade.

⁵¹⁶ Canadian Canola Council, “Domestic Processing,” <https://www.canolacouncil.org/markets-stats/processing>.

⁵¹⁷ USDA, “Oilseeds and Products Annual – Canada,” March 31, 2025. <https://apps.fas.usda.gov/newgainapi/api/Report/DownloadReportByFileName?fileName=Oilseeds%20and%20Products%20Annual%20Ottawa%20Canada%20CA2025-0017.pdf>.

⁵¹⁸ Cargill, “Regina Canola Crush Facility.” <https://www.cargillag.ca/regina>.

Table 7.2.4.2-5: Canadian Crush Capacity, Oilseed Production, and Capacity Utilization

Marketing Year	20/21	21/22	22/23	23/24	24/25	25/26^b
Capacity ^a (MMT)	11.10	11.10	11.20	13.46	14.46	16.86
Production, Canola Oil (MMT)	4.62	3.69	4.25	4.81	4.95	5.17
Capacity Utilization	94%	77%	89%	82%	79%	71%

^a As reported by the Foreign Agricultural Service

^b All 2025/2026 data projected based on available 2025/2026 Marketing Year data from Canadian Canola Council and Ag Canada.

The data laid out in Table 7.2.4.2-5 suggests that, while capacity has continued to grow at a high rate, actual crush has lagged capacity growth. However, the industry has demonstrated historically that it is able to run at 90%+ capacity utilization, including from 2015–2021. Given historic run rates, new capacity expansions, and full recovery from the COVID-19 pandemic, it is reasonable to expect a maximum of 1,933 million gallons in 2026. Canola oil usage in biofuel in the U.S. reached 50% of all available canola oil in 2024, meaning 966 million gallons available for use as BBD in 2025. This assumption is conservative, especially considering the proportion of canola oil used for biofuels in the U.S. has increased every year since 2015.^{519,520} S&P Global estimated that canola oil production in Canada would increase by about 5.4 billion pounds from 2024–2027. This quantity of canola could be used to produce approximately 700 million gallons of BBD if it were all used for this purpose.

To estimate how much of this biofuel could be available to U.S. BBD producers we considered projected BBD demand in Canada. Canada passed the Clean Fuels Regulations in 2022. These regulations require decreasing carbon intensities from transportation fuel used in Canada each year from 2023–2030. USDA FAS estimated BBD use in Canada in 2023 at approximately 370 million gallons.⁵²¹ A document published by Environment Canada in February 2024 projected that under a current measures scenario BBD consumption in Canada could increase to approximately 1.1 billion gallons in 2035.⁵²² Reaching 1.1 billion gallons of BBD consumption in 2035 would require an average annual increase of approximately 60 million gallons per year. If Canadian canola oil production continues to increase at the rate projected by S&P Global from 2024–2027 (175 million gallons per year) the availability of canola oil to U.S. BBD producers could increase by over 100 million gallons per year after accounting for the projected increase in BBD demand in Canada. The estimates of the potential growth rate in the production of BBD from canola oil from both the historic data and these future projections are summarized in Table 7.2.4.2-5.

⁵¹⁹ USDA, “Oilseed Crop Yearbook,” Canola Oil, March 20, 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

⁵²⁰ Canola Council of Canada, “Market and Statistics,” <https://www.canolacouncil.org/markets-stats>.

⁵²¹ USDA, “Biofuels Annual – Canada,” December 8, 2024. https://apps.fas.usda.gov/newgainapi/api/Report/DownloadReportByFileName?fileName=Biofuels%20Annual%20Canada_CA2024-0057.pdf.

⁵²² Canada Energy Regulator, “Market Snapshot: Bioenergy Use Could Double in Canada’s Net-Zero Future,” February 21, 2024. <https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2024/market-snapshot-bio-energy-use-could-double-canadas-net-zero-future.html>.

Table 7.2.4.2-5: Summary of Projections of Canola Oil Supply to BBD Producers (million gallons BBD)

Data Source	Estimated Increase	Timeframe	Annual Average Increase
EMTS BBD Production from Canola Oil	178	2021–2023	89
USDA Canola Oil Imports	285	2021–2023	143
EPA Projection in Set1	283	2022–2025	94
S&P Global (Total) ^a	700	2024–2027	175
S&P Global (50%) ^a	350	2024–2027	88
EPA Projection ^b	366	2025–2026	366

^a Estimate includes expansion in 2024.

^b One year estimate based on certain capacity expansion. Planned expansion through 2028 exceeds 18.7 MMT, but the industry is prone to longer timelines as a result of trade policy induced demand uncertainty

At the time of these estimates, the 45Z credit did not advantage Canadian canola oil the way it does in 2026, after passage of the OBBB. Canadian canola oil is now advantaged thanks to the removal of land use change impact considerations and the newly limited geographic scope (North America only). Based on our review of the historical data on the use of imported canola oil used for domestic BBD production and the available projections of increases in the imports of canola oil in future years we project that the production of BBD from imported canola oil could increase at a rate of between 100 and 150 million gallons per year through 2030. This projection is similar to the observed rate of increase in BBD produced from canola oil since 2021, as well as the average annual increase of canola oil we projected would be available to domestic BBD producers in the Set 1 Rule, taking into account a greater demand for canola thanks to changes to the RFS, US trade policy, and the 45Z credit.

7.2.4.3 Emerging Oilseed Feedstocks

In addition to the feedstocks that have historically been used for BBD production, a number of BBD producers have expressed interest in using emerging feedstocks, such as oil from camelina, carinata, or pennycress, for BBD production in future years. These emerging oilseed crops are most often intended to be grown as second crops on existing cropland and/or as an alternative to fallow years when no commercial crops would otherwise be grown. As such, they have the potential to increase vegetable oil production with little or no increase in total cropland or displacement of other crops. While there are currently approved RFS pathways for several of these emerging oilseed feedstocks, very little BBD has been produced from them to date. We anticipate that there will be increasing interest in developing and adopting these crops in future years. The process of introducing new crops at commercial scale, however, generally takes many years. At this time we are not projecting significant volumes of vegetable oil will be made available to domestic BBD producers from emerging oilseeds through 2027.

7.2.4.4 Summary of the Availability of BBD Feedstocks

As described in the preceding Chapters, EPA has projected the average annual increase in the feedstocks available to domestic BBD producers. We have considered the primary feedstocks used to produce BBD since the beginning of the RFS program (FOG, distillers corn oil, soybean

oil, and canola oil) from both domestic and imported feedstocks. Our projections assume that soybean oil will remain a preferred choice for biodiesel and become more popular in renewable diesel production as a result of trade policy and the 45Z credit. They also project a modest increase in imported FOG, representing acknowledgement of potential growth due to high volumes and greater supply dampened by tariffs and changes to the 45Z credit excluding non-North American feedstocks. They also assume a high growth rate of Canadian canola crush that led to increased imports to replace imported FOG feedstocks, especially in West Coast renewable diesel facilities. Outside of these three main categories (domestic soy, imported FOG, and imported canola), we project few changes to feedstock availability or historical growth rates in other feedstocks.

These projections represent the projected annual volume increases that could be achieved under favorable market conditions. Because these feedstocks are reasonable substitutes for each other in many markets we have greater confidence in the total projected annual increase than in any of the individual feedstock estimates. The actual supply of any single feedstock will likely depend on a number of factors, including the incentive available for biofuel produced from each feedstock in the U.S. and other countries. For example, some mixed feedstock facilities could just as easily accept FOG over canola, or vice versa. Their choices are likely to ultimately come down to price at time of contract. Our projected annual increases of the potential BBD feedstocks are summarized in Table 7.2.4.4-1. These increases represent an acknowledgement of continued preference for continuation of pre-2025 feedstock usage while also evaluating how facilities with diminished production might respond to increased volumes well above 2025 production. The gap between production in 2025 and the volumes in the out years of this rule may be filled by a variety of feedstocks, but most likely will be fulfilled by continued FOG imports, canola oil imports from Canada, or domestic soy oil. Further discussion of the likely supply of these feedstocks and domestic BBD production in alternative circumstances can be found in Chapter 7.2.6.

Table 7.2.4.4-1: Projected Annual Increase in BBD Feedstocks Through 2027 (million gallons BBD equivalent)

Feedstock	Projected Annual Average Increase
Domestic FOG	50
Domestic Distillers Corn Oil	0
Domestic Soybean Oil	140
Imported UCO	40
Imported Tallow/Animal Fats	20
Imported Canola Oil	120
Emerging Vegetable Oils	0
Total	625

7.2.5 Imports and Exports of Biomass-Based Diesel

In evaluating the potential consumption of BBD through 2027 we also examined BBD imports and exports in previous years. Since 2014 gross biodiesel imports have generally averaged about 200 million gallons per year, with the exception of 2015–2017 and 2023–2024.

During this time (2015–2017) biodiesel imports from Argentina surged, with biodiesel imported from Argentina responsible for 64% of all biodiesel imports in these three years. In August 2017, the U.S. announced preliminary tariffs on biodiesel imported from Argentina and Indonesia.⁵²³ These tariffs were subsequently confirmed in April 2018.⁵²⁴ Since the time the preliminary tariffs were announced, EIA has not reported any biodiesel imported from these countries.⁵²⁵ After the imposition of these tariffs, imports of biodiesel from other countries increased marginally; however, the biggest effect of these tariffs has been a decrease in the total volume of imported biodiesel back to approximately 200 million gallons during 2018–2022. However, in 2023 biodiesel imports increased significantly once again and again in 2024. Most of the increase in biodiesel imports were supplied by countries in the EU, including Germany, Italy, and Spain.⁵²⁶ The increase in imports from the EU observed in 2023 reflect both strong biodiesel demand in the U.S. (supported by incentives such as the RFS program, the federal tax credit, and state incentives) and weakening demand for these fuels in the EU.

Similarly, renewable diesel imports generally increased from 2014–2021. Since 2021, renewable diesel imports were relatively stable, ranging between 300 and 400 million gallons per year, before a steep decrease in 2025 to less than 200 million gallons. A significant factor in the increasing imports of renewable diesel appears to be the California LCFS program, as most of the renewable diesel consumed in the U.S. (including both domestically produced and imported renewable diesel) has been consumed in California where it could benefit from both RFS and LCFS incentives.⁵²⁷

In 2025, these dynamics abruptly changed after tax credit changes and lower domestic consumption of these fuels. The \$1 40A credit was no longer in effect and its replacement, the 45Z clean fuel production credit, only applies to domestic production. Imports of both fuels reached their lowest levels since 2012, with biodiesel imports slumping to 2,000 barrels per day (approximately 30 million gallons per year) and renewable diesel down to 5,000 barrels per day (approximately 75 million gallons per year).⁵²⁸

Exports of RIN generating biodiesel, based on EMTS data, have been fairly consistent since 2014, generally ranging between 70 and 130 million gallons per year. According to EMTS data, renewable diesel exports increased with domestic renewable diesel production, reaching over 400 million gallons in 2023. Increasing exports of renewable diesel reflect the existence of biofuel mandates and significant financial incentives creating high demand in other countries that the U.S. must compete with. As one example, Canada recently finalized new Clean Fuel

⁵²³ 82 FR 40748 (August 28, 2017).

⁵²⁴ 83 FR 18278 (April 26, 2018).

⁵²⁵ EIA, “U.S. Imports by Country of Origin – Biodiesel,” *Petroleum & Other Liquids*, April 30, 2025. https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDB_im0_mbbl_a.htm.

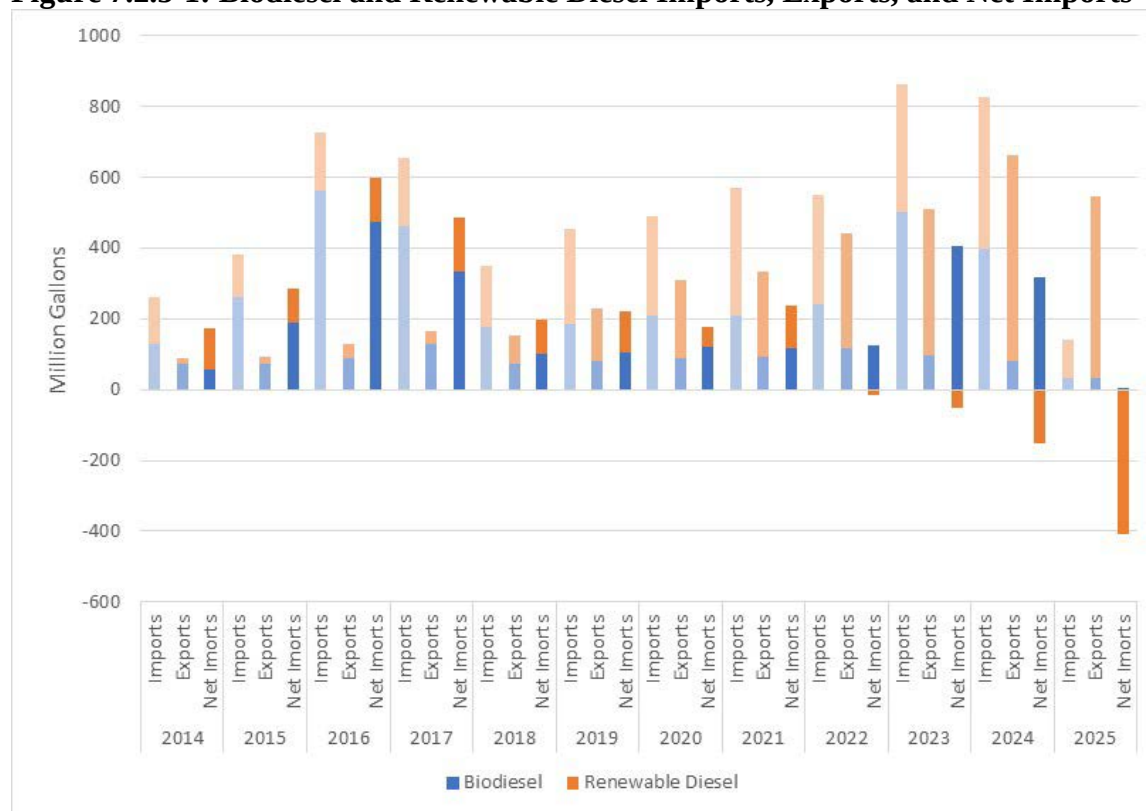
⁵²⁶ Id.

⁵²⁷ Data from California’s LCFS program indicates that approximately 1.97 billion gallons of renewable diesel were consumed in California in 2023, the most recent year for which data are available (CARB, LCFS Data Dashboard. <https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm>). Data from EMTS indicates that 2.36 billion gallons of renewable diesel were consumed in the U.S. in 2023, including both renewable diesel that generated BBD RINs and advanced RINs.

⁵²⁸ EIA, “U.S. biodiesel and renewable diesel imports fall sharply in 2025 after tax credit change,” September 4, 2025. <https://www.eia.gov/todayinenergy/detail.php?id=66045>.

Regulations that require increasing volumes of low-carbon fuels in future years.⁵²⁹ Biodiesel and renewable diesel imports, exports, and net imports are shown in Figure 7.2.5-1.

Figure 7.2.5-1: Biodiesel and Renewable Diesel Imports, Exports, and Net Imports



The fact that there are both imports and exports of BBD simultaneously suggests that there are efficiencies associated with importing into and exporting from certain parts of the country as well as economic advantages associated with the use of BBD from different feedstocks in different foreign and domestic markets. Historically, this is because the biodiesel blenders tax credit was able to be claimed on fuel both used and produced in the US. Thus, it was possible to claim it on imported fuels and exported fuels produced domestically as well. This dynamic has changed with the passage of IRA and subsequent amendments to the 45Z credit in OBBB. The 45Z credit is limited to transportation fuels produced in the U.S. from North American feedstocks. We expect the change in the tax credit will continue to negatively impact imports of biodiesel and renewable diesel in future years. While feedstock imports from North American countries will continue, finished fuel imports are likely to decline. This, in turn, may lead to a decrease in exports as U.S. markets seek alternatives to imported biodiesel and renewable diesel that are no longer eligible for the tax credit.

In projecting net imports of BBD through 2027 we considered both the historical trends and the impact of the 45Z credit. Net BBD imports have been relatively stable at around 200 million gallons per year since 2018. As imported BBD is not eligible for the 45Z credit, we

⁵²⁹ Tuttle, Robert. "Canada Releases California-Style Fuel Rules to Cut Emissions," *Bloomberg*, June 29, 2022. <https://www.bloomberg.com/news/articles/2022-06-29/canada-releases-california-style-fuel-rules-to-cut-emissions>.

expect imports of BBD will likely decline in future years. We do not expect imports of BBD to cease altogether, as some BBD producers with established markets in the U.S. may not find it economically viable to find alternative markets for their fuels. We acknowledge that there is significant uncertainty in projecting the available supply of imported BBD in future years. In addition to the normal market uncertainty, the potential market reactions to the new tax policy make it even more difficult to project BBD net imports going forward. Ultimately, we project that any decrease in BBD imports will likely be offset, in whole or in large part, by decreases in BBD exports, such that we do not project significant changes to net BBD imports through 2027.

7.2.6 Projected Rate of Production and Use of Biomass-Based Diesel

The preceding sections describe the factors EPA considered when projecting the rate of production and use of BBD through 2027. These factors include the supply of these fuels to the U.S. in previous years, the current and projected BBD production capacity, the availability for the market to consume these fuels, the available supply of feedstocks to domestic BBD producers, and the projected imports and exports of BBD. After reviewing this data we have determined that the factor most likely to limit the production and use of BBD through 2027 is the production capacity of domestic BBD facilities.

The availability of qualifying feedstocks is not a hard limit. The global oil market, writ large, generally moves in tandem and there are options for swapping out different feedstocks at many facilities. Our projections have generally assumed somewhat consistent demand for potential BBD feedstocks from food markets and other industries in the past. However, given strong support for domestic feedstocks due to 45Z credit changes, high biofuel volume mandates from state programs alongside the RFS, and co-location of many rail terminals, biofuel facilities, and food manufacturers, some oils previously destined for food use may instead be bid away to the biofuel market. We have focused our assessment of BBD feedstock availability on projections of increasing feedstock production rather than immediate diversion from existing uses, but believe that up to 20% of existing soy oil may be diverted from food markets as a result of the 45Z credit, geographic constraints, and high volume mandates that induce 90% capacity utilization of existing biofuel capacity. For example, producers in the Midwestern and Southern U.S. have access to large quantities of domestic soybean oil feedstocks, with ample rail and barge capacity. These facilities are more likely than West Coast facilities to bid away soy oil from food markets, as West Coast facilities are rail capacity limited and are more likely to continue to source FOG or switch to canola oil. The large increases in canola oil we project in 2026 and 2027, as well as a relatively untapped Latin American soy oil market, make it likely that the market can absorb increases to biofuel oil supply and backfilling food oil markets.⁵³⁰ We recognize, however, that it is possible that feedstocks supplied to domestic BBD producers can be sourced from both new production/collection of feedstocks as well as diversions of these feedstocks from existing uses.

To project the available quantity of BBD in the U.S. through 2027 we started with production capacity utilization. As discussed in Chapter 7.2.2, renewable diesel capacity utilization has in past individual years surpassed 90% capacity utilization, mirroring capacity

⁵³⁰ Latin American soybean oil is not incented to be used as a biofuel feedstock in the United States, but it can serve as a replacement for domestic soybean oil crushed in the U.S. destined for food use.

utilization of more mature corollaries, such as the oil refining sector.⁵³¹ Biodiesel production has also neared 90%, in 2023. Given the incentivized environment for biofuels at the time of analysis, historical precedent, and capabilities of the BBD production industry and its analogs, EPA projects volumes corresponding to 90% production capacity. Table 7.2.6-1 details this.

Table 7.2.6-1: Production Capacity and Utilization for Analyzed Volumes (million gallons)

	2026	2027
Production Capacity ^a	6,705	7,205
BBD Volume	6,074	6,445
Production Capacity Utilization ^b	90.6%	89.5%

^a 2026 production capacity reflects November 2025 production capacity data. 2027 production capacity is a conservative estimate of the total potential capacity increase. Estimates of potential renewable diesel and biodiesel capacity growth are discussed further in Chapter 7.2.2. Given the potentially unused or otherwise mothballed biodiesel capacity alongside the aggressive growth potential of renewable diesel, this is a capacity increase likely to be achieved.

^b We recognize these do not precisely correspond to 90% capacity numbers. To enable a thorough analysis of the impacts of the required volumes the volumes must be set some time in advance of the final rule. Our estimate of the capacity utilization was updated using more recent data after the volumes for analysis had been set, resulting in a temporal disconnect between various data products, including capacities.

From this point, we then applied existing feedstock baselines and projected growth rates, discussed in greater detail in Chapter 7.2.3 and 7.2.4. Feedstocks with greater incentives and certainty were prioritized in terms of fulfilling the volume obligations, and then the remaining gap between the volumes and the “certain” feedstocks was then apportioned between three major feedstocks—Canadian canola, which stands poised to benefit from greater trading dynamics and the 45Z credit, domestic soybean oil, which will likely be diverted from the non-biofuel market, and imported FOG, which, despite exclusion from 45Z (if imported from outside North America) and higher tariffs, benefits from a lower base cost and greater incentives in many U.S. state programs. Table 7.2.6-2 contains volumes prior to apportionment of this gap, which is again projected to be filled with a greater supply of canola oil, diverted soybean oil from non-biofuel uses, and imported FOG. In reality, individual circumstances and supplier and trade relationships may alter the exact mix.

⁵³¹ EIA, “Refinery Utilization and Capacity,” February 6, 2026.
https://www.eia.gov/dnav/pet/pet_pnp_unc_dcu_nus_m.htm.

Table 7.2.6-2: Feedstock Availability from North America Less Imports and Diversion

Feedstock	2026		2027	
	Biodiesel	Renewable Diesel	Biodiesel	Renewable Diesel
Domestic FOG	0.15	0.8	0.15	0.85
Domestic Soy	1	1.06	1	1.13
Domestic Canola	0	0.23	0	0.23
Domestic Corn Oil	0.21	0.68	0.21	0.68
Imported FOG	0	0.148	0	0.148
Imported Soy	0	0	0	0
Imported Canola	0.32	0.39	0.32	0.44
Imported Corn Oil	0	0	0	0
Total	4.99		5.16	

Note: Table does not include feedstocks that could be imported from countries outside of North America or feedstocks that could be diverted from non-biofuel markets

This left an artificial shortfall of 1.07 billion gallons in 2026 and 1.28 billion gallons in 2027. Given that feedstock acquisition will largely be based on geography, supply chain dynamics, and individual decision-making, it is difficult to predict with certainty what feedstocks might fill the remaining volume requirements. However, as discussed in section 7.2.4, there is broad availability of BBD feedstocks globally, well beyond the required volumes. EPA thus chose to project equal apportionment of the remaining volumes to three major feedstock categories, as previously mentioned. Soybean oil diverted from non-biofuel markets, representing a 20% diversion of soybean oil in the food market, is easily backfilled with other virgin seed oils, including Latin American soybean oil. Canola oil crush is growing rapidly in Canada, and diversions from exports and food markets are possible. While not as incentivized at a national level, imported FOG remains a useful stopgap due to price and lingering incentives from state clean fuels programs. Based on supply trends, recently announced crush capacity expansions, and stronger incentives for North American feedstocks, we project that much of the growth in the BBD category will come from renewable diesel and jet fuel, and that domestic biodiesel production will remain relatively constant in the years to come. The annual supply of BBD through 2027 by fuel type and feedstock that result from these projections are shown in Tables 7.2.6-4 in million gallons.

Table 7.2.6-4: Projected Supply of BBD Through 2027 (million gallons)

Category	2026	2027
Biomass-Based Diesel	6,074	6,445
<i>Biodiesel</i>	<i>1,780</i>	<i>1,780</i>
Soybean Oil	1,100	1,100
FOG	150	150
Corn Oil	210	210
Canola Oil	320	320
<i>Renewable Diesel</i>	<i>4,290</i>	<i>4,660</i>
Soybean Oil	1,320	1,460
FOG	1,309	1,419
Corn Oil	678	678
Canola Oil	981	1,101

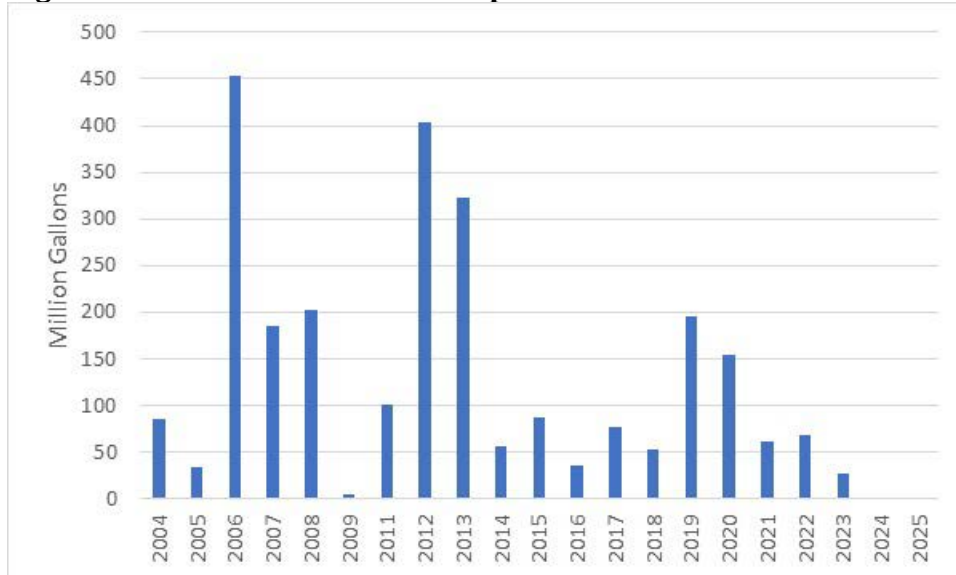
These projected volumes reflect two significant assumptions, both of which are subject to significant uncertainty. The first assumption is that policies in the U.S. (including the RFS, 45Z credit, and other State-level incentives and volume mandates) continue to provide a strong incentive for BBD produced from virgin vegetable oils such as soybean oil and canola oil. The projected increases in the supply of BBD produced from soybean oil and canola oil are primarily driven by projected investment in and expansion of soybean and canola crushing facilities in the U.S. and Canada in addition to those already underway. They also acknowledge high potential for FOG usage in tandem with adverse trade policies that will likely sunset some portion of the U.S. FOG import market. The second assumption is that strong volumes (and strong state programs), in tandem with various tax credits, continue to send a strong signal to the virgin oilseed market and biofuel producers. These volumes reflect our assessment that the BBD industry is capable of achieving 90%+ capacity utilization, as canola and soy crush continue to grow in North America and state programs continue to incentivize FOG despite changes to 45Z and trade policy.

The changing import patterns for these feedstocks also demonstrate that the primary destination for these feedstocks can change quickly. Even if incentives for BBD produced from these feedstocks remain strong through 2027, the rate of increase in the imported volumes of FOG could decline if, for example, other countries adopt mandates or even greater incentives for biofuels produced from these feedstocks in future years. It is also possible that countries currently exporting these feedstocks, primarily in Asia and South America, may seek to establish their own biofuel programs through a combination of incentives, biofuel use mandates, or taxes or prohibitions on the export of these feedstocks.

7.3 Imported Sugarcane Ethanol

The predominant available source of advanced biofuel other than cellulosic biofuel and BBD has historically been imported ethanol. Most of the ethanol imported to the U.S. has been produced in Brazil from sugarcane and imported either directly from Brazil or through the Caribbean Basin Initiative and Central America Free Trade Agreement (CAFTA). However, data through 2025 demonstrates considerable variability in imports of ethanol, with no ethanol imported since 2023.

Figure 7.3-1: Historical Ethanol Imports



Source: EIA, “U.S. Fuel Ethanol Imports,” *Petroleum & Other Liquids*, February 4, 2026. <https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MFEIMUS1&f=A>.

Moreover, data from EIA indicates that all 2018–2021 ethanol imports entered the U.S. through the West Coast, as did the majority of ethanol imports in 2022 and 2023. We believe that these imports were likely used to help refiners meet the requirements of the California LCFS program, which provide significant additional incentives for the use of advanced ethanol beyond the RFS program.

As noted in previous RFS rulemakings, the high variability in historical ethanol import volumes makes any projection of future imports uncertain.⁵³² However, import volumes for more recent years are likely to provide a better basis for making future projections than import volumes for earlier years. To address these issues, we developed a methodology used in the final rulemaking which established the volume requirements for 2022 as well as the Set 1 Rule that established volumes for 2023–2025. Specifically, we used a weighted average of import volumes for all years where the weighting was higher for more recent years and lower for earlier years. The weighting factor for any given year’s volume was twice as large as the weighting factor for the previous year’s volume. This approach provided a better predictor of future imports of sugarcane ethanol than either simple averages of historical volumes or a trendline based on historical volumes.

We have again used this methodology in this action to estimate the volumes of imported ethanol that could be expected in the future. The volumes and weighting factors we are using are shown in Table 7.3-1. The resulting weighted average is 15 million gallons. As we are projecting volumes for 2026 and 2027 in this action, and this is the latest data available, the same projection applies for each year.

⁵³² See, e.g., 85 FR 7032-33 (February 6, 2020) and 87 FR 39600 (July 1, 2022).

Table 7.3-1: Annual Advanced Ethanol Imports and Weighting Factors

Year	Imported Advanced Ethanol^a (million gallons)	Weighting Factor
2015	89	0.00098
2016	34	0.00195
2017	74	0.00391
2018	78	0.00781
2019	196	0.0156
2020	185	0.03125
2021	60	0.0625
2022	81	0.125
2023	21	0.25
2024	0	0.5
2025	0	1

^a Based on RINs generated for imported ethanol and assigned a D code of 5 according to EMTS.

As noted above, the future projection of imports of ethanol is inherently imprecise, and actual imports in years 2026 and 2027 could be lower or higher than 15 million gallons. Factors that could affect import volumes include uncertainty in world ethanol demand and prices, constraints associated with the E10 blendwall in the U.S., world demand for and prices of sugar, the cost of sugarcane ethanol relative to that of corn ethanol, and transportation fuel prices and demand, potential tariffs or other trade barriers.

7.4 Other Advanced Biofuel

In addition to cellulosic biofuel, imported ethanol, and BBD, there are other advanced biofuels that can be supplied in 2026 and 2027. These other advanced biofuels include non-cellulosic CNG, naphtha, heating oil, renewable diesel co-processed with petroleum, and domestically produced advanced ethanol. However, the supply of these fuels has been relatively low in the last several years.

Table 7.4-1: Historical Supply of Other Advanced Biofuels (million ethanol-equivalent gallons)

Year	CNG/LNG	Domestic Ethanol	Heating Oil	Naphtha	Renewable Diesel (D5)	Total
2015	0	25	1	24	8	58
2016	0	27	2	27	8	64
2017	2	25	2	32	9	70
2018	2	25	3	31	40	101
2019	5	24	3	37	58	127
2020	5	23	3	33	86	150
2021	7	26	2	33	105	173
2022	6	29	3	71	118	227
2023	7	30	4	33	120	194
2024	2	28	4	67	109	210
2025	4	20	4	119	70	217

We have used the same weighted averaging approach (see Table 7.3-1) for other advanced biofuels as we have used for sugarcane ethanol to project the supply of these other advanced biofuels. Based on this approach, the weighted average of other advanced biofuels is 209 million RINs. This volume of other advanced biofuel is composed of 24 million RINs of domestic advanced ethanol (primarily derived from separated food waste), 90 million RINs of co-processed renewable diesel, 87 million RINs of naphtha, and 8 million RINs of other advanced biofuels (non-cellulosic RNG and heating oil). We used the results of this weighted average approach to project the supply of these other advanced biofuels in 2026 and 2027.

We do not believe the available data and the methodology we employed can reasonably be used to project new developments in the production of other advanced biofuels. We recognize that the potential exists for additional volumes of advanced biofuel from sources such as D5 renewable jet fuel, liquefied petroleum gas (LPG), butanol, and non-cellulosic CNG and LNG from biogas produced in digesters. However, since these types of fuels have been produced in very small amounts in the past, if at all, we do not believe the market will make available substantial volumes from these sources in 2026 and 2027.

7.5 Total Ethanol Consumption

Total ethanol consumption is the sum of ethanol blended with petroleum-based gasoline (E0) to create E10, E15, and E85 transportation fuel blends. In the Set 1 Rule, EPA projected ethanol concentration in the national gasoline pool for future years using a least-squares regression model using E15 and E85 fueling station population data.⁵³³ With the addition of new data, EPA was able to produce a projection of total ethanol consumption that we believe better represents current and future ethanol consumption. Thus, EPA opted to take a different approach. For this rule, volume data from the BIP/HBIIP program and volume data acquired directly from six states with high volumes of higher-level ethanol blends (CA, KS, IA, MN, NY, and ND) has

⁵³³ For more details on our prior methods, see Set 1 Rule RIA Chapter 6.5.1.

enabled EPA to employ this more robust data-driven, bottom-up approach to projecting total ethanol consumption for the years 2026–2027.

7.5.1 Projection of Motor Gasoline Consumption

The national average ethanol concentration in the nationwide gasoline pool surpassed 5% in 2007 and experienced a period of rapid growth, finally surpassing 10% (*i.e.*, the “blend wall”) for the first time in 2016. The share of ethanol in the gasoline pool has continued to increase since then, albeit at a slower pace after the market became saturated with E10. The total volume of ethanol that can be consumed, including that produced from corn and sorghum, cellulosic biomass, sugarcane, and the non-cellulosic portions of separated food waste, is a function of the relative volumes of E0, E10, E15, and E85 that comprise pool-wide motor gasoline consumption. Average ethanol concentration can exceed 10% only to the extent ethanol in E15 and E85 fuels can exceed the ethanol content of E10 and more than offset the dilution effect of E0 volumes.

As mentioned, EPA has adopted a new, simplified, bottom-up methodology for projecting ethanol consumption into the future for the years covered by this rule. Volume projections were generated using data on fueling station populations and the average volume sold per station (*i.e.*, station throughput) using the following relation:

$$\textit{Total volume} = \textit{Number of stations} * \textit{Avg gallons sold per station}$$

Volumes were projected for E0, E10, E15, and E85 independently for economic analysis because distribution practices and costs vary between different proofs of ethanol-gasoline blends.⁵³⁴ A tabular presentation of the main variables and their data sources (or derivations of their values, where data was not available) is shown in Table 7.5.1-1.

In producing projections of station counts across the years covered by this rule, EPA projected E85 in California separate from the remainder of the country. This is due to the unique policy environment in California, where E85 sales are disproportionately high due to California’s high gasoline prices and the added incentive provided by the California Low Carbon Fuel Standard allowing E85 pricing to be much more favorable than in other states. Approximately 10% of E85 stations are in California and these stations move much greater volumes of fuel on a per-station basis. To reflect the most recent trends in E85 sales, we used only data from years 2021–2024 to extrapolate projections of E85 stations nationally and E85 volumes for California. We are unaware that a similar E85 sales trend has occurred to date in Oregon or Washington, despite the presence of similar state-level policy incentives. For this reason, we did not model these states separately from the remainder of the country.

⁵³⁴ See Chapter 10 for more detailed analyses of renewable fuel costs.

Table 7.5.1-1: Main Variables and Data Sources Used for the Projection of Poolwide Ethanol Consumption (2026–2027)

Variable	Data Source or Derivation
E0 Stations	Pure-Gas.org ⁵³⁵
E15 Stations	AFDC ⁵³⁶ /Prime the Pump ⁵³⁷
E85 Stations (Non-CA)	
E85 Stations (CA)	
E0 Throughput	Iowa Department of Revenue ⁵³⁸
E15 Throughput	Derived from BIP ⁵³⁹ /HBIIP ⁵⁴⁰
E85 Throughput (Non-CA)	State Reports (IA, MN, NY, KS, and ND)
E85 Throughput (CA)	Calculated quotient of: E85 Total Volume (CA) / E85 Station Counts (CA)
E0 Total Volume	Calculated product of: E0 Stations * E0 Throughput
E10 Total Volume	Remainder of projected motor gasoline consumption published by EIA in AEO2025 ⁵⁴¹ that is not E0, E15, or E85
E15 Total Volume	Calculated product of: E15 Stations * E15 Throughput
E85 Total Volume (Non-CA)	Calculated product of: E85 Stations (Non-CA) * E85 Throughput (Non-CA)
E85 Total Volume (CA)	CARB ⁵⁴²

The annual number of stations offering E0, E15 and E85 in the U.S. are shown in Table 7.5.1-2. Historical annual averages of E15 station populations based on data provided by Prime the Pump and corroborated by DOE’s Alternative Fuel Data Center (AFDC). The AFDC does not publish E15 station population data but does report just over 3,000 stations offering E15 blends for sale in 2023. Based on stakeholder data and recently updated numbers from Prime the Pump, EPA expects about 4,500 E15 fueling stations in operation at the end of 2025.⁵⁴³ As stated above, EPA separated E85 projections from California from the remainder of the nation. The total and broken out stations are shown in the table below.

⁵³⁵ Pure-Gas.org, “Stations.” <https://www.pure-gas.org>.

⁵³⁶ AFDC, “Historical Alternative Fueling Station Counts.” <https://afdc.energy.gov/stations/states>.

⁵³⁷ Prime the Pump is an biofuels industry-led program seeking to encourage and expand retail adoption of E15 by building out infrastructure.

⁵³⁸ Iowa Department of Revenue, “2023 Retailers Fuel Gallons Annual Report,” March 2024.

<https://revenue.iowa.gov/media/3846/download?inline>.

⁵³⁹ USDA, “Biofuel Infrastructure Partnership.” <https://sandbox.fsa.usda.gov/programs-and-services/energy-programs/bip/index>.

⁵⁴⁰ USDA, “Higher Blends Infrastructure Incentive Program.” <https://www.rd.usda.gov/hbiip>.

⁵⁴¹ AEO2025, Table 2 – Energy Consumption by Sector and Source.

⁵⁴² CARB, “Annual E85 Volumes,” April 11, 2025. <https://ww2.arb.ca.gov/resources/documents/alternative-fuels-annual-e85-volumes>.

⁵⁴³ Projection based on historical growth of E15 Stations. Growth Energy, “Historical Growth of E15 Stations,” <https://growthenergy.org/data-set-category/higher-blends-retail-footprint>. This projected number was reached by early 2026. Growth Energy, “Retailer & Supplier Hub,” <https://growthenergy.org/retailer-supplier-hub>.

Table 7.5.1-2: Average Annual Number of Stations by Gasoline Blend

Year	E0 Stations	E15 Stations	E85 Stations		
			Total Stations	California	Non-California
2014	8,160	105	2,713	94	2,619
2015	9,591	184	2,932	107	2,825
2016	11,044	431	3,091	119	2,972
2017	12,356	1,214	3,251	146	3,105
2018	13,509	1,700	3,567	161	3,406
2019	14,362	2,081	3,717	195	3,522
2020	15,479	2,302	3,841	198	3,643
2021	15,855	2,605	4,063	271	3,792
2022	16,993	2,758	4,420	331	4,089
2023	17,012	3,414	4,495	369	4,126
2024	17,206	3,724	4,586	513	4,073
2025	17,541	4,503*	4,859	555*	4,304

* Value projected for this rule.

Source: AFDC, “Historical Alternative Fueling Station Counts,” <https://afdc.energy.gov/stations/states>; Growth Energy, “Historical Growth of E15 Stations,” <https://growthenergy.org/data-set-category/higher-blends-retail-footprint>; Pure-gas.org, E0 station counts.

Table 7.5.1-3 shows the projection of retail fueling station growth broken down by gasoline blend. EPA is projecting slight or moderate growth in station counts for stations offering all blend types, with the fastest growing blends between 2026–2027 being E85 in California and E15. E0 stations were extrapolated based on historical data from Pure-Gas.org.

Table 7.5.1-3: Projections of Retail Fueling Station Population by Gasoline Blend

Blend	2026	2027
E0	17,786	18,052
E15	4,682	5,052
E85 (non-CA)	4,427	4,520
E85 (CA)	664	745

Table 7.5.1-4 lists projected average throughput for stations selling each gasoline blend. To calculate station throughput for California E85 stations, we simply took the quotient of total E85 volume sold in California as reported by CARB and the total number of E85 stations in California from AFDC. E85 throughput for non-California stations was projected using data reported by five other states that produce or consume elevated volumes of E85 (IA, MN, NY, KS, and ND).⁵⁴⁴ Throughput data for E85 stations reported by these five states are the best available E85 data that EPA is aware of outside of California and we therefore believe it is reasonable to accept this data as a proxy for all non-California states because they comprise a significant share of national E85 stations (representing nearly 25% of all E85 stations located outside of California). For these states combined, historical station counts, and total gallons sold for years 2015–2024 were used to calculate an average E85 sales per station figure for each year. We then extrapolated those average throughputs using regression analysis to calculate the average E85 gallons sold per station in all states besides California for years 2026–2027. The

⁵⁴⁴ See “E85 Consumption Based on State Data for RFS Set 2 FRM,” available in the docket for this action.

result shows very little growth in E85 throughput outside of California across the years covered in this rule. E15 throughput was projected based on BIP/HBIIP data provided to EPA. Retail sales data for E0 stations is sparse, but Iowa’s Retailer Fuel Gallons annual report provides the basis for calculating E0 throughput in Iowa, which we treated as representative of national average E0 throughput mirroring the methods used in the Set 1 Rule. Annual E0 throughput declines from 115,862 gallons per station in 2026 to 114,944 gallons per station in 2027, as more volumes of ethanol-free gasoline are replaced by increased sales of higher-level ethanol blends as availability of these fuels continues to grow.

Table 7.5.1-4: Projected Average Annual Throughput Volume by Gasoline Blend (gallons per station)

Blend	2026	2027
E0	115,862	114,944
E15	213,285	222,638
E85 (non-CA)	61,971	63,563
E85 (CA)	255,733	255,359

The total volumes of each gasoline blend that EPA projects to be consumed during the time covered by this rule are shown in Table 7.5.1-5. Projected volumes of E10 are the calculated difference between projected overall national motor gasoline consumption as published by EIA and the sum of EPA’s projected volumes of E0, E15, and E85.⁵⁴⁵ Increasing station counts and increasing throughputs of E15 and E85 gasoline, coupled with decreasing throughputs of E0 gasoline and increased penetration of electric vehicles, causes overall gasoline consumption to decrease across these years while E15 and E85 grow as a share of the total.

Table 7.5.1-5: Projection of Total Motor Gasoline Consumption by Blend Level (million gallons)

Blend	2026	2027
E0	2,061	2,075
E10	137,404	136,301
E15	998	1,124
E85 (non-CA)	274	287
E85 (CA)	169	190

There is inherent uncertainty in any projection of future conditions. Market dynamics can shift rapidly with new policy signals and political pressure. For example, E15 has historically not been approved for sale in the state of California and as such no E15 gallons are sold in the state in these projections. However, on October 25, 2024, the Governor of California directed CARB to expedite the approval of E15 gasoline to be sold in California.⁵⁴⁶ If this were to come to pass, it would open a large, currently untapped market for E15 which would see much higher volumes than projected in this rule. Similarly, a recent Iowa state law has set new retail E15 access requirements and will require every retail gasoline fueling station in the state to advertise and sell

⁵⁴⁵ AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition.

⁵⁴⁶ Letter to CARB from California Governor Gavin Newsom, October 25, 2024, available at <https://d35t1syewk4d42.cloudfront.net/file/2894/10.25.24-letter-to-CARB.pdf>.

E15 from at least one dispenser beginning in 2026.⁵⁴⁷ This would likewise increase the volume of E15 we would expect to see consumed for these years.

7.5.2 Projection of Total Ethanol Consumption

Total gasoline volumes from Table 7.5.1-5 were used to calculate total ethanol consumption. To do this, EPA assumes E10 contains 10.16% ethanol by volume (based on data retrieved by RFG Survey Association and assuming 2% denaturant), E15 contains 15% ethanol by volume, and E85 contains 74% ethanol by volume (consistent with EIA assumptions). Our projection results in over 14.4 billion gallons of ethanol consumed in 2026 and a slight decline in 2027. Table 7.5.2-1 depicts EPA’s projections of total ethanol consumption aggregated by blend level, rounded to the nearest million gallons.

Table 7.5.2-1: Projection of Total Ethanol Consumption by Blend Level (million gallons)

Blend	2026	2027
E10	13,960	13,848
E15	149	168
E85	328	353
Total	14,438	14,370

Table 7.5.2-2 shows EPA’s projection of total ethanol consumption (equating to the ethanol volumes) and the difference between these volumes and the No RFS and 2025 Baselines. Based on our projections, we expect to see a pool-wide ethanol concentration that rises in the projected years.

Table 7.5.2-2: Total Ethanol Consumption Projection (million gallons)

Year	Ethanol Consumption	Difference from No RFS Baseline	Difference from 2025 Baseline	Ethanol Concentration
2026	14,438	231	158	10.25%
2027	14,370	245	90	10.27%

7.6 Corn Ethanol

As described in more detail in Chapter 1.4, total domestic ethanol production capacity increased dramatically between 2005 and 2010 and increased at a slower rate thereafter. By the beginning of 2025, production capacity exceeded 18 billion gallons.⁵⁴⁸ Actual production of ethanol in the U.S. reached about 16.3 billion gallons in 2025.⁵⁴⁹ Thus, while production of corn ethanol may be limited by production capacity in the abstract, it does not appear that production capacity will be a limiting factor in 2026–2027 for determining potential volumes.

⁵⁴⁷ AFDC, “Iowa Retail E15 Access Requirements.” <https://afdc.energy.gov/laws/12998>.

⁵⁴⁸ EIA, “U.S. Fuel Ethanol Plant Production Capacity,” *Petroleum & Other Liquids*, September 26, 2025. <https://www.eia.gov/petroleum/ethanolcapacity>.

⁵⁴⁹ EIA, “Monthly Energy Review,” January 2026, Table 10.3. <https://www.eia.gov/totalenergy/data/monthly/pdf/mer.pdf>.

The expected annual rate of future commercial production of corn ethanol will be driven primarily by gasoline demand in the U.S. as most gasoline is expected to continue to contain at least 10% ethanol. However, commercial production of corn ethanol is also a function of exports of ethanol and to a much smaller degree the demand for E15, and E85 fuels. As shown in Chapters 7.5.1 and 7.5.2, the contribution of E15 and E85 to domestic ethanol consumption is projected to remain below 1 billion gallons into 2027. In 2024, ethanol exported from the U.S. to foreign markets were 1.9 billion gallons.⁵⁵⁰ In the first 10 months of 2025, U.S. fuel ethanol exports were approximately 10% higher than the first 10 months of 2024.⁵⁵¹

Much of the growth in export volume is attributable to a combination of domestic and international market effects, with lower prices and plateauing demand on average for fuel ethanol in U.S. markets even as prices and demand are increasing elsewhere. For example, Brazil (traditionally the second-largest exporter of fuel ethanol to global markets after the U.S.) has seen their own domestic demand for fuel ethanol increase significantly in recent years due to growth in hydrous E100 demand at retail fuel pumps. This shift has meant that as more Brazilian ethanol is being sold domestically, there has been a corresponding reduction in Brazilian outflows of fuel ethanol, which have been largely replaced by rising exports of American fuel ethanol. Similarly, other countries have updated their own renewable fuel mandates which has led to increasing demand for imported ethanol that has been met by increasing supplies from the American ethanol industry.⁵⁵²

As described in Chapter 7.5.1, we estimated total ethanol consumption for 2026–2027 by extrapolating from historical retail fueling station population and station-level throughput data coupled with reported volumes where available. This total volume is a combination of conventional ethanol, cellulosic ethanol, and advanced ethanol. We assume that the advanced and cellulosic ethanol will be used preferentially under the RFS program due to their added RIN value, federal tax credit value, and LCFS credit value (where available) and that conventional ethanol will comprise the remainder. Our estimate of corn ethanol consumption for 2026–2027 for the purposes of estimating the mix of biofuels that could be made available is shown in Table 7.6.1-1.

Table 7.6.1-1: Calculation of Projected Corn Ethanol Consumption (million gallons)

	2026	2027
Total ethanol	14,438	14,370
Imported sugarcane ethanol	15	15
Domestic advanced ethanol	24	24
Ethanol from CKF	128	128
Conventional ethanol	14,270	14,203

⁵⁵⁰ EIA, “Exports by Destination,” *Petroleum & Other Liquids*, April 30, 2025.

https://www.eia.gov/dnav/pet/pet_move_expc_dc_NUS-Z00_mbbbl_a.htm.

⁵⁵¹ EIA, “U.S. Exports of Fuel Ethanol,” *Petroleum & Other Liquids*, April 30, 2025.

https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOOXE_EEX_NUS-Z00_MBBL&f=a.

⁵⁵² S&P Global, “US ethanol exports on pace for record year, fueled by low prices and increased opportunity overseas,” November 19, 2024. <https://www.spglobal.com/commodity-insights/en/news-research/latest-news/agriculture/111924-us-ethanol-exports-on-pace-for-record-year-fueled-by-low-prices-and-increased-opportunity-overseas>.

7.7 Conventional Biodiesel and Renewable Diesel

While the vast majority of conventional renewable fuel supplied in the RFS program has been corn ethanol, there have been smaller volumes of conventional biodiesel and renewable diesel used in the U.S. in some years. Conventional biodiesel and renewable diesel can only be produced at facilities grandfathered under the provisions of 40 CFR 80.1403 as there are currently no valid RIN-generating pathways for the production of conventional (D6) biodiesel or renewable diesel. These biofuels are not required to meet the 50% GHG reduction threshold to qualify as BBD under the statutory definition, but the feedstocks used to produce grandfathered biodiesel or renewable diesel must still meet the regulatory definition of renewable biomass, and the biofuel produced must meet all other statutory and regulatory requirements. The quantity of conventional biodiesel and renewable diesel consumed each year from 2015–2025 is shown in Table 7.7-1.

Table 7.7-1: Conventional Biodiesel and Renewable Diesel Used in the U.S. (million gallons)

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Domestic D6 Biodiesel	0	0	0	0	0	0	0	0	3	9	0
Domestic D6 Renewable Diesel	0	0	0	0	0	0	0	0	1	0	0
Imported D6 Biodiesel	74	113	0	0	0	0	0	0	6	6	0
Imported D6 Renewable Diesel	86	45	2	0	0	0	0	0	0	0	0
All D6 Biodiesel and Renewable Diesel	160	158	2	0	0	0	0	0	10	15	0

In 2015–2016 the volume of conventional biodiesel and renewable diesel used in the U.S. was relatively small, but still significant. Use of these fuels in the U.S. dropped to very low levels in 2017 and was less than 1 million gallons per years from 2018–2022. The supply of conventional biodiesel and renewable diesel increased slightly in 2023 and 2024, though the overall supply remained small (less than 0.1% of the total biofuel supply to the U.S.). In 2025 the supply of conventional biodiesel and renewable diesel was again near zero. Most of the conventional biodiesel and renewable diesel used in the U.S. has been imported, with the only exceptions being small volumes in 2023 and 2024. However, conventional (D6) RINs have continued to be generated for biodiesel and renewable diesel in recent years. From 2018 through 2024 the volumes of renewable diesel for which conventional biofuel RINs were generated each year (in million gallons) were 107, 116, 76, 135, 75, 69, and 15 respectively. Most of these RINs were retired for reasons other than compliance with the annual volume obligations, suggesting that they were used outside of the U.S. or for purposes other than transportation fuel.

The potential for conventional biodiesel and renewable diesel production and use in the U.S. from feedstocks such as palm oil is far greater than the quantity of these fuels actually supplied in previous years. The total production capacity of registered grandfathered biodiesel and renewable diesel producers is over 1.6 billion gallons in the U.S., with an additional 0.9 billion gallons internationally. While domestic feedstock availability may be limited, worldwide feedstock availability does also not appear to be a limiting factor, as USDA estimates that approximately 223 million metric tons of vegetable oil was produced globally in the 2023/2024

agricultural marketing year.⁵⁵³ If all of it were to be used to produce biodiesel and renewable diesel, this quantity of vegetable oil could be used to produce over 60 billion gallons.⁵⁵⁴ While the majority of this vegetable oil is used for food and other non-biofuel purposes, any of this vegetable oil that meets the regulatory definition of renewable biomass could be used to produce conventional biodiesel or renewable diesel at a grandfathered facility so long as it meets all other RFS program requirements. The quantity of conventional biodiesel and renewable diesel that could be supplied to the U.S. through 2027 is not without limit, but this data suggests that large quantities of this fuel are being or could be produced,⁵⁵⁵ and that the use of these fuels in the U.S. is largely a function of demand for this fuel in the U.S. versus other markets.

⁵⁵³ USDA, “World Agricultural Supply and Demand Estimates,” November 8, 2024.

<https://downloads.usda.library.cornell.edu/usda-esmis/files/3t945q76s/s4657804b/z029qx92b/latest.pdf>.

⁵⁵⁴ This calculation assumes one gallon of renewable diesel can be produced from 8 pounds of vegetable oil.

⁵⁵⁵ The OECD-FAO Agricultural Outlook 2024–2033 projects global biodiesel consumption to grow from an average volume of about 60 billion liters (15.8 billion gallons) in 2021–2023 to approximately 79 billion liters (20.9 billion gallons) in 2033.

Chapter 8: Infrastructure

This chapter describes the analysis of the impact of renewable fuels on the distribution infrastructure of the U.S. The CAA indicates that this assessment must address two aspects of infrastructure:

- Deliverability of materials, goods, and products other than renewable fuel.
- Sufficiency of infrastructure to deliver and use renewable fuel.

This chapter begins by addressing the sufficiency of infrastructure to deliver and use different types of renewable fuels. We then address how the use of renewable fuels affects the deliverability of materials, goods, and products other than renewable fuel.

Note that while we are projecting higher volumes of renewable fuel consumption relative to the No RFS Baseline, in analyzing the impacts of the projected volumes on infrastructure we have considered whether the projected volumes would require additional infrastructure relative to that which currently exists. We believe that the existing infrastructure is the relevant point of reference for the No RFS Baseline since it is unlikely that the infrastructure enabling and supporting consumption of renewable fuel in 2026 would change even if we did not establish volume requirements for future years, at least not in 2026–2027. The number of vehicles that can consume particular renewable fuels, pipelines, storage tanks, fuel delivery vehicles, and retail service stations generally change only on longer timescales, and only insofar as the outlook for renewable fuel demand changes. Therefore, this chapter discusses infrastructure impacts primarily in terms of the changes that might be needed or expected to occur in 2026–2027 in comparison to their recent or current status.

8.1 Renewable Compressed Natural Gas

Renewable compressed natural gas and liquefied natural gas (renewable CNG/LNG) infrastructure considerations differ from those for most other biofuels not only because it is typically a gas rather than a liquid,⁵⁵⁶ but also because renewable CNG/LNG can be processed to be chemically identical to fossil-based CNG/LNG, which is used for many purposes including transportation.⁵⁵⁷ Fossil-based natural gas was used in CNG/LNG vehicles for many years prior to the introduction of renewable CNG/LNG. The RFS program allows RINs to be generated and separated for renewable CNG/LNG that is fungible with the wider natural gas pool, provided that a contract is in place to demonstrate that the same volume of natural gas is used for transportation purposes and all other regulatory requirements are met.⁵⁵⁸ As the cost of running spur pipelines for anything beyond short distances becomes prohibitively expensive, only those renewable CNG/LNG sources that are in relatively close proximity to the existing natural gas pipeline infrastructure are likely to be developed. Once connected to the natural gas pipeline

⁵⁵⁶ Although renewable LNG is in use, its volumes are minimal compared with renewable CNG. For more information, see Chapter 7.1.1. Accordingly, this analysis focuses on renewable CNG.

⁵⁵⁷ Growth in biogas may require investment in additional gas cleanup operations prior to pipeline injections, particularly in California where pipeline standards currently preclude the injection of most biogas. The potential for such biogas cleanup costs is discussed in Chapter 10.1.2.5.1.

⁵⁵⁸ See 40 CFR 80.1426(f).

network, renewable CNG/LNG uses the existing natural gas distribution system and CNG/LNG vehicle refueling infrastructure, and it is used in the same CNG/LNG vehicle fleet as fossil natural gas. According to data from the AFDC, there are currently approximately 1,359 public and private CNG fueling stations and approximately 67 public and private LNG refueling stations in the U.S.⁵⁵⁹

Once injected into the pipeline, processed renewable CNG/LNG is virtually indistinguishable from fossil natural gas, so increasing transportation use depends on dedicated vehicle fueling infrastructure. However, expanding CNG/LNG vehicle infrastructure to support renewable CNG/LNG growth beyond the transportation sector's projected use for 2026 and 2027—estimated at 1.27–1.35 million ethanol-equivalent gallons of CNG/LNG per year—would represent a substantial challenge.⁵⁶⁰ The incentives for increasing the use of CNG/LNG in the transportation sector, including incentives from the RFS program and state programs such as the California LCFS program, may be insufficient to cause a substantial increase in the CNG/LNG vehicle fleet and refueling infrastructure. CNG/LNG vehicles are predominately used in fleet applications where there is a unique situational advantage (*e.g.*, a natural gas supplier's utility fleet or landfill's waste hauler fleet). In addition, it would be more challenging to establish the necessary contracts to demonstrate that natural gas was used in CNG/LNG vehicles outside of fleet operations. The cost of removing impurities from raw biogas and upgrading it to renewable CNG/LNG may be a barrier to broader use. These processing steps are needed to meet vehicle fuel specifications and to enable injection into and transport through the natural gas distribution system. Nevertheless, we do not expect infrastructure to constrain the use of renewable CNG/LNG to levels below those projected to be available in Chapter 7.1.3.

8.2 Biodiesel

The RFS2 Rule projected that 1.5 billion gallons of biodiesel would be used in 2017 and 1.82 billion gallons would be used in 2022 to meet the statutory biofuel volume requirements.⁵⁶¹ We noted that biodiesel plants tended to be more dispersed than ethanol plants, thereby facilitating delivery to local markets by tank truck and lessening the need to distribute biodiesel over long distances. Biodiesel imports also helped to serve coastal markets. We projected that as biodiesel volumes grew, there would be more need for long-distance transport of domestically-produced biodiesel. We estimated that such long-distance transport would be accomplished by manifest rail and, to a lesser extent, by barge, since the economy of scale would not justify the use of unit trains. We estimated that biodiesel and biodiesel blends would not be shipped by pipeline to a significant extent due to concerns over potential contamination of jet fuel that is also shipped by pipeline.

In 2010, much of the biodiesel blending was taking place at facilities downstream of terminals, such as storage facilities operated by individual fuel marketers. We projected that this

⁵⁵⁹ AFDC, "Alternative Fueling Station Locator," February 25, 2026.

<https://afdc.energy.gov/stations#/analyze?fuel=LNG&fuel=CNG&access=public&access=private&country=US&tab=fuel>

⁵⁶⁰ See Chapter 7.1.4 for further discussion of the estimated total use of CNG/LNG as transportation fuel in 2026–2027 and Chapter 10.1.4 for discussion of the costs associated with refueling stations.

⁵⁶¹ See RFS2 RIA Chapter 1.2.2.

would take place to a lesser extent as volumes grew with most biodiesel being blended at terminals to the 5% (B5) blend level that is approved for use in diesel engines by all manufacturers for distribution to retail and fleet fueling facilities. We acknowledged that the expansion of biodiesel volumes could pose issues for petroleum terminals, but that these issues could be resolved.⁵⁶² Since vehicle refueling infrastructure is compatible with biodiesel blends up to 20% (B20), we estimated that there would be no changes needed at retail and fleet facilities to accommodate the projected increase in biodiesel use.

There are significant instances where actual biodiesel production and use have developed differently than we projected in the RFS2 Rule. Most importantly, biodiesel consumption reached over 2 billion gallons in 2016 and has remained between 1.7–2 billion gallons per year from 2017–2022, often exceeding the 1.82 billion gallons that we projected would be used in 2022.⁵⁶³ Another significant difference is that much of the biodiesel blending is taking place downstream of terminals at fuel marketer storage facilities and even at fuel retail facilities.

One factor that could somewhat ease biodiesel transportation to terminals is the fact that in some limited cases, shipment of low-level biodiesel blends up to 5% is currently taking place on some petroleum product pipelines that do not also carry jet fuel.⁵⁶⁴ If the transportation of biodiesel blends via pipeline were expanded more broadly, this change could significantly reduce the cost of biodiesel distribution. However, jet fuel is a significant product on much of the petroleum pipeline system and concern over biodiesel contamination of jet fuel remains a significant limitation on the ability to expand the shipment of biodiesel blends by pipeline.⁵⁶⁵

Finally, there appear to be substantial volumes of B10–B20 being used despite the fact that a significant number of vehicle manufacturers only warranty their engines for up to B5.⁵⁶⁶ This has resulted in an uneven distribution of biodiesel use across the nation, with some parts using more than 5% while other locales use little or no biodiesel.⁵⁶⁷

We are projecting that the Analyzed Volumes for 2026 and 2027 would require a substantial increase in biodiesel volumes relative to the No RFS Baseline and a small increase in volumes relative to the volume of biodiesel projected to be used in 2025 in the Set 1 Rule. The primary expansion of BBD from the Analyzed Volumes is projected to occur through renewable diesel, not biodiesel, as discussed in Chapter 7.4. As such, we do not anticipate any challenges associated with the infrastructure to distribute and use biodiesel through 2027.

With these volume projections, domestic biodiesel production and/or biodiesel imports may increase in 2026 and 2027. As discussed in Chapter 7.2, domestic biodiesel production

⁵⁶² There is additional difficulty in storing and blending biodiesel because of the need for insulated and/or heated equipment to prevent cold flow problems in the winter. This issue is typically not present for B5.

⁵⁶³ Biodiesel consumption numbers based on EMTS data.

⁵⁶⁴ Association of Oil Pipelines and American Petroleum Institute, “Ethanol, Biofuels, and Pipeline Transportation.” https://www.api.org/~media/files/oil-and-natural-gas/pipeline/aopl_api_ethanol_transportation.pdf.

⁵⁶⁵ ASTM specifications currently limit biodiesel contamination in jet fuel to 50 mg/kg (ASTM D1655-24b).

⁵⁶⁶ “Pilot Flying J Fuel Offerings,” Docket Item No. EPA-HQ-OAR-2021-0427-0065.

<https://www.regulations.gov/document/EPA-HQ-OAR-2021-0427-0065>.

⁵⁶⁷ “Average Biodiesel Blend Level By State Based on EIA Data,” Docket Item No. EPA-HQ-OAR-2021-0427-0119. <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0427-0119>.

capacity is significantly higher than current production levels. A review of monthly biodiesel imports suggests that import infrastructure can support significantly higher volumes of imports.⁵⁶⁸ For example, over 700 million gallons of biodiesel was imported in 2016.⁵⁶⁹ Monthly import data suggests that 1.3 billion gallons per year of imports could be supported using the existing infrastructure if we were to assume that the 112 million gallons of biodiesel imports that took place in December 2016 could be maintained year-round. With increases in biodiesel production, some additional expansion in import infrastructure may have occurred in 2025. Therefore, we do not believe that domestic production capacity or import infrastructure constraints would be a substantial impediment to an expansion in biodiesel volumes at current levels.⁵⁷⁰

We anticipate that if biodiesel production and imports increase significantly, investment in the infrastructure to transport biodiesel from the points of production to locations where it can be consumed would be needed. These investments would primarily be associated with securing sufficient downstream biodiesel storage and the requisite number of rail cars and tank trucks suitable for biodiesel transport.⁵⁷¹

Expanding biodiesel blending infrastructure to accommodate significantly higher biodiesel volumes may also pose challenges. Many terminals that have yet to distribute biodiesel would likely need to install the infrastructure. All vehicle refueling infrastructure is compatible with B20 blends, thereby easing the expansion to retail of biodiesel blends made at terminals. However, significant infrastructure changes would be needed to biodiesel storage and blending facilities downstream of terminals and at retail facilities if substantial additional volumes of biodiesel blends were to be made downstream of terminals.

Further, the cold flow of petroleum-based diesel dispensed to vehicles must often be improved in the winter through the addition of #1 diesel fuel and/or cold-flow improver additives. Biodiesel blends tend to have poorer cold flow performance than straight petroleum-based diesel fuel. This requires the use of additional cold-flow improvers and sometimes limits the biodiesel blend ratio that can be used under the coldest conditions.⁵⁷² Biodiesel cold flow properties are dependent on the source of the feedstock, with biodiesel produced from palm oil being subject to wax formation at higher temperatures than soy-based biodiesel.⁵⁷³ Thus, additional actions are necessary to ensure adequate cold-flow performance of palm-based biodiesel blends compared to soy-based biodiesel. Such additional actions may be uneconomical

⁵⁶⁸ EIA, “U.S. Imports of Biodiesel,” *Petroleum & Other Liquids*, April 30, 2025.

https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=p&s=m_eoedb_im0_nus-z00_mbbf&f=a.

⁵⁶⁹ *Id.*

⁵⁷⁰ The expansion of biodiesel imports to the extent discussed above is for purposes of the infrastructure analyses only. There would be significant challenges in obtaining foreign-produced biodiesel volumes to approach such a substantial increase in imported biodiesel. See Chapter 1.3.

⁵⁷¹ Biodiesel rail cars and to a lesser extent tank trucks must often be insulated and or heated during the winter to prevent cold flow problems. The use of such insulated/heated vessels is sometimes avoided by shipping pre-heated biodiesel.

⁵⁷² B5 blend levels can typically be maintained.

⁵⁷³ Hazrat, M. A., M. G. Rasul, M. Mofijur, M. M. K. Khan, F. Djavanroodi, A. K. Azad, M. M. K. Bhuiya, and A.S. Silitonga. “A Mini Review on the Cold Flow Properties of Biodiesel and Its Blends.” *Frontiers in Energy Research* 8 (December 18, 2020). <https://doi.org/10.3389/fenrg.2020.598651>.

in some cases.⁵⁷⁴ Therefore, a substantial increase in the use of biodiesel, especially biodiesel produced from palm oil, during the winter may be a challenge.

8.3 Renewable Diesel

The RFS2 Rule projected that the volume of “drop-in” cellulosic and renewable diesel fuel would range from 0.15–3.4 billion gallons in 2017 and 0.15–9.5 billion gallons in 2022.⁵⁷⁵ Such fuels are referred to as drop-in fuels because their physical properties are sufficiently similar to petroleum-based diesel to be fungible in the common diesel fuel distribution system.⁵⁷⁶ Thus, little change is needed to the fuels infrastructure system to support the use of drop-in biofuels. The RFS2 Rule projected that the distribution infrastructure could expand in a timely fashion to accommodate that projected range of growth in drop-in cellulosic and renewable diesel fuel.⁵⁷⁷

In practice, much of the renewable diesel produced in the U.S. has been transported by truck, rail, and ship, rather than by pipelines. This is in part due to the location of the renewable diesel production and demand and the lack of available pipelines to transport renewable diesel from production sites to demand centers. Renewable diesel can generate credits under state LCFS programs, and the magnitude of this incentive, especially in California, has caused most renewable diesel production in the U.S. to be shipped in segregated batches to California rather than being blended into diesel where it is produced. Regulatory challenges have also limited the transportation of renewable diesel via pipeline. Product transfer document (PTD) requirements for fuel shipped by pipeline and fuel pump labeling requirements often require that the blend level be indicated, but the concentration would often be uncertain in a fungible distribution system. Transportation of renewable diesel via common carrier pipelines can make documenting the use and blend levels of renewable diesel difficult, if not impossible.

The projected increase in domestic renewable diesel production through 2027 is significant relative to both the No RFS Baseline and the 2025 Baseline, as discussed in Chapter 7.2. We expect that much of this new renewable diesel will also be used in California and other states with state incentive programs (*e.g.*, Oregon). Renewable diesel produced in California will likely be distributed locally, and much of the renewable diesel produced on or near the Gulf Coast is likely to be transported via ship. The remaining renewable diesel production facilities are not located near the coast, and we therefore project that the fuel they produce will likely be transported via truck and/or rail to markets where the fuel is used. This may require some expansion to the existing infrastructure, such as additional rail cars to transport renewable diesel. The fact that the new or expanding renewable diesel production facilities are generally located in the western U.S., relatively close to California and Oregon, likely reduces the impact of distributing these fuels on the transportation infrastructure, though this may be somewhat offset by the need to transport feedstocks to the renewable diesel production facilities. While some adjustments will likely be needed to accommodate the expected increase in renewable diesel

⁵⁷⁴ Verma, Puneet, M.P. Sharma, and Gaurav Dwivedi. “Evaluation and Enhancement of Cold Flow Properties of Palm Oil and Its Biodiesel.” *Energy Reports* 2 (January 9, 2016): 8–13. <https://doi.org/10.1016/j.egyr.2015.12.001>.

⁵⁷⁵ See RFS2 RIA Chapter 1.2.2.

⁵⁷⁶ Such drop-in fuels are typically blended with petroleum-based diesel prior to use.

⁵⁷⁷ See RFS2 RIA Chapter 1.6.

production, we do not expect that these adjustments will inhibit the growth of renewable diesel production or appreciably impact transportation networks in the U.S. more broadly.

8.4 Ethanol

We are anticipating that the projected volumes for 2026 and 2027 would result in increased use of higher-level ethanol blends such as E15 and E85; E10 is economical to be blended in the absence of the RFS program.

The infrastructure needed to deliver ethanol includes that required for distribution of denatured ethanol from production facilities to terminals, storage and blending equipment, and distribution of gasoline-ethanol blends to retail service stations. With regard to infrastructure needed to use ethanol, essentially all retail service stations are certified to offer E10 and all vehicles and equipment are designed to use E10. As a result, any infrastructure-related impacts on the use of ethanol in 2026 and 2027 are associated with service station storage and dispensing equipment for higher-level ethanol blends such as E15 and E85, and the vehicles capable of using those blends. The majority of the E15 and E85 volume projected to be used in 2026 and 2027 was already being used in 2025; consequently, the infrastructure is already in place. However, the expanded volume in 2026 and 2027 would require additional infrastructure, primarily the expansion of retail stations as discussed below.

Based on our analysis below of the sufficiency of infrastructure to deliver and use ethanol, we have determined that there are constraints associated with E15 and E85 that limit the rate of future growth in their consumption. These constraints are appropriately reflected in our projections of total ethanol consumption in Chapter 7.5 since those projections represent only moderate changes in the nationwide average ethanol concentration in comparison to earlier years.⁵⁷⁸

8.4.1 Ethanol Distribution

To support the RFS2 Rule, ORNL conducted an analysis of potential distribution constraints that might be associated with attaining the statutory volume targets through 2022.⁵⁷⁹ The ORNL analysis examined ethanol transport pathways from production to blending facilities at terminals by rail, waterways, and roads, and projected that most ethanol would require long-distance shipment to demand centers. The primary mode of long-distance transport in 2010 was via manifest rail and, to a lesser extent, by barge, although transport by unit train was beginning to spread. ORNL projected that rail would continue to be the predominate means of long-distance ethanol transport through 2022, with a substantial increase in the use of unit trains and continued supplemental transport by barge. ORNL concluded that there would be minimal additional stress on most U.S. transportation networks overall to distribute the increased biofuel volumes.

⁵⁷⁸ A nationwide average ethanol concentration above 10.00% can only occur insofar as there is consumption of E15 and/or E85.

⁵⁷⁹ Das, Sujit, Bruce Peterson, and Shih-Miao Chin. "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints." *Transportation Research Record Journal of the Transportation Research Board* 2168, no. 1 (January 1, 2010): 136–45. <https://doi.org/10.3141/2168-16>.

However, ORNL stated that there would be considerable increased traffic along certain rail corridors due to the shipment of biofuels that would require significant investment to overcome the resulting congestion. We concluded that these investments could be made to increase the capacity of the affected rail corridors without undue difficulty, and that therefore the infrastructure system to the blending terminal could accommodate the projected increased volume of ethanol in a timely fashion.⁵⁸⁰

To update and expand upon the analysis of distribution infrastructure upstream of retail that was conducted for the 2010 RFS2 Rule, EPA contracted with ICF International Inc. (“ICF”) to conduct a literature review, background research, and stakeholder interviews to characterize the impacts of distributing ethanol and other biofuels.⁵⁸¹ The 2018 ICF report determined that the conclusions from the 2009 ORNL analysis have largely turned out to be accurate based on an absence of indicators of distribution constraints up to and including the blending terminal. ICF noted that there were instances when the ethanol industry went through rapid expansion, such that the rail industry was not able to fully accommodate the expansion of inter-regional trade in ethanol for a time. However, ICF found no evidence to suggest that rail congestion from shipment of biofuel was a persistent or common problem at the time that the study was completed. Likewise, ICF found no evidence that marine networks, including those used for import and export, were experiencing significant issues in accommodating increased volumes of biofuels. Consistent with the 2010 analysis, ICF stated that the expansion of ethanol and biodiesel volumes could pose issues for petroleum terminals, but that these issues could be resolved. While ICF indicated that there likely had been negative impacts on rural and highway transportation networks surrounding ethanol production facilities, ICF also determined that these impacts could be mitigated with network infrastructure planning and increased funding for road maintenance. ICF noted these increased costs would be small in comparison to broader maintenance costs for roads and that the road network could accommodate substantial growth in the movement of biofuels.

Based on the ICF study and our own assessment of the implementation of the RFS program, we conclude that the response of the ethanol distribution infrastructure system upstream of retail has largely unfolded as we projected in the 2010 RFS2 Rule. Ethanol imports to coastal demand centers have helped to satisfy local demand. Ethanol transport over long distances is primarily being accomplished by unit train and, to a lesser extent, by manifest rail and barge. Materials compatibility issues continue to prevent ethanol and ethanol blends from being shipped in petroleum product pipelines. Tank trucks are used to distribute ethanol to markets close to the ethanol production facility and from rail receipt facilities to more distant markets. Petroleum terminals have installed the necessary ethanol receipt, storage, and blending infrastructure. Intermodal facilities, such as those that transfer ethanol directly from rail cars to tank trucks, are also being used to ease the burden on terminals.

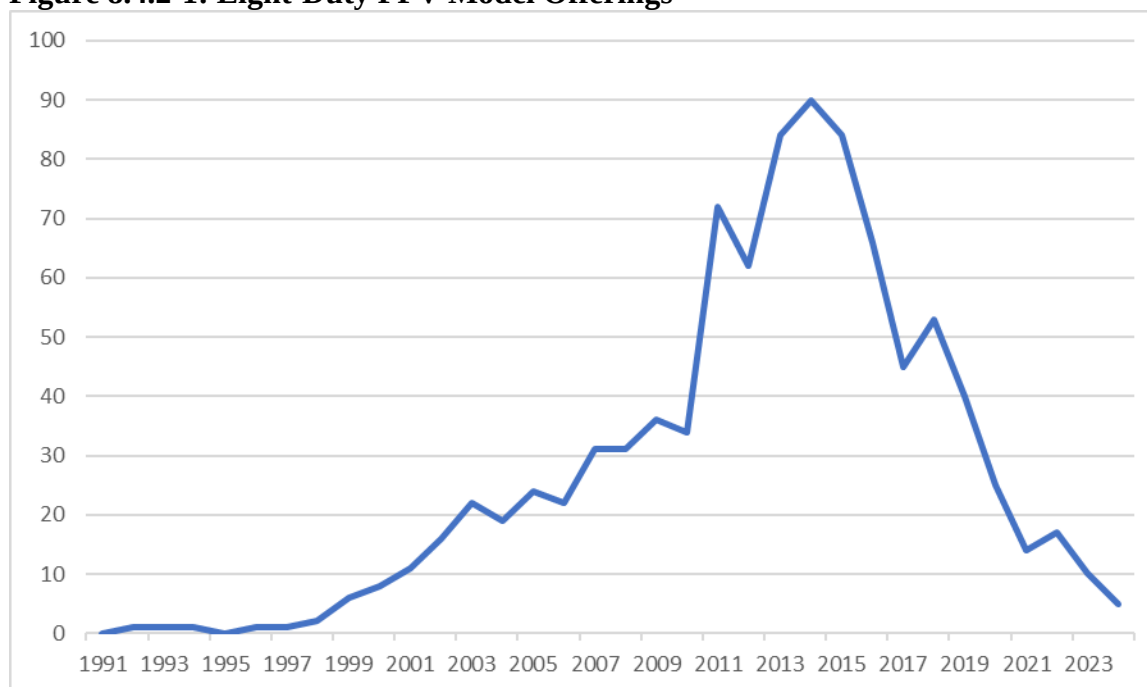
⁵⁸⁰ See RFS2 RIA Chapter 1.6.

⁵⁸¹ ICF, “Task 5: Impact of Biofuels on Infrastructure,” January 2018.

8.4.2 Infrastructure for E85

E85 is permitted to be used only in designated FFVs. As of 2023, there were about 20 million registered light-duty FFVs in the U.S., representing about 7% of all spark-ignition vehicles.^{582,583} The number of registered FFVs has been declining over the past several years. As of 2025, only six FFV models were in production for consumer use.⁵⁸⁴ However, California is seeing a resurgence in use of E85 which may push a small increase in FFVs in that region.⁵⁸⁵

Figure 8.4.2-1: Light-Duty FFV Model Offerings



Source: AFDC, “Light-Duty AFV HEV and Diesel Model Offerings by Technology-Fuel,” May 2024. <https://afdc.energy.gov/data/10303>.

E85 is sold at retail stations where the pumps, underground storage tanks, and associated equipment have all been certified to operate safely with the high ethanol concentrations.⁵⁸⁶ As shown in Figure 8.4.2-2, the number of stations offering E85 has increased steadily since about 2005. By September 2025, the total number of stations offering E85 had reached 4,975.

⁵⁸² AFDC, “Light-Duty AFV Registrations,” June 2024. <https://afdc.energy.gov/data/10861>.

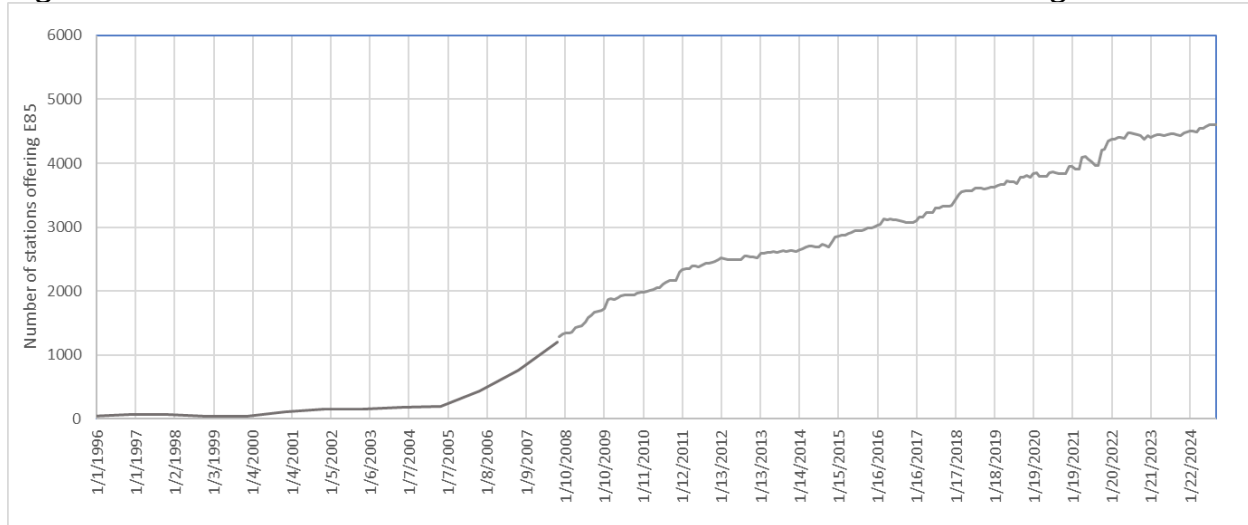
⁵⁸³ Bureau of Transportation Statistics, “Table 1-11: Number of U.S. Aircraft, Vehicles, Vessels, and Other Conveyances,” April 24, 2025. <https://www.bts.gov/content/number-us-aircraft-vehicles-vessels-and-other-conveyances>.

⁵⁸⁴ AFDC, “Alternative Fuel and Advanced Vehicle Search Ethanol (E85),” 2025. https://afdc.energy.gov/vehicles/search/results?view_mode=grid&search_field=vehicle&search_dir=desc&per_page=12&current=true&display_length=25&model_year=2025&fuel_id=11,-1&all_categories=y&manufacturer_id=365,377,211,235,215,223,225,379,219,213,209,351,385,275,361,387,243,227,239,425,263,217,391,349,383,237,221,347,395,-1.

⁵⁸⁵ Renewable Fuels Association, “RFA Calls on California to Expand Flex Fuel Vehicles for Lower Costs, Cleaner Air,” January 16, 2024. <https://ethanolrfa.org/media-and-news/category/news-releases/article/2024/01/rfa-calls-on-california-to-expand-flex-fuel-vehicles-for-lower-costs-cleaner-air>.

⁵⁸⁶ EPA, “UST System Compatibility with Biofuels,” EPA-510-K-20-001, July 2020.

Figure 8.4.2-2: Number of Public and Private Retail Service Stations Offering E85



Note: Data through 2007 is annual, whereas data for 2008 and later is monthly.

Source: AFDC, “Historical Alternative Fueling Station Counts.” <https://afdc.energy.gov/stations/states>.

Grant programs such as the USDA Biofuels Infrastructure Partnership (BIP), USDA Higher Blends Infrastructure Incentive (HBIIP) and the ethanol industry’s Prime the Pump program, in addition to individual company efforts, have helped to fund the expansion of E85 offerings at retail stations. The combined effects of these efforts have ensured ongoing growth in the number of stations offering E85.

Although the total number of retail stations in the U.S. has varied, the fraction of those stations offering E85 has steadily increased. A large number of these E85 stations have materialized in California, which has seen a large private incentivization for retail stations to supply this blend.⁵⁸⁷ Using available data, EPA estimates retail stations offering E85 using a linear projection. With this growth rate, we estimated the total for the projected years of 2026 and 2027 as shown in Table 8.4.2-2.

Table 8.4.2-2: Projected Annual Average Number of Stations Offering E85

Year	Stations (Non-CA)	Stations (CA)
2026	4,427	664
2027	4,520	745

8.4.3 Infrastructure for E15

E15 is permitted to be used only in MY2001 and newer light-duty motor vehicles.⁵⁸⁸ The infrastructure needed to support the use of E15 includes blending and storage equipment at terminals, certified storage and dispensing equipment at retail service stations, and the vehicles that are permitted to use E15. While the majority of service stations currently offering E15 do so

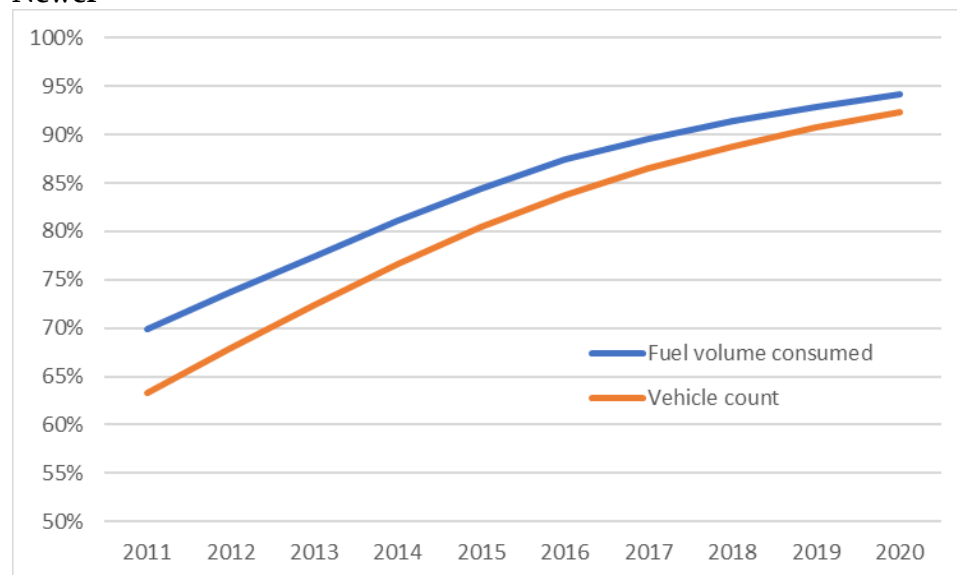
⁵⁸⁷ AFDC, “Historical Alternative Fueling Station Counts.” <https://afdc.energy.gov/stations/states>.

⁵⁸⁸ 76 FR 4662 (January 26, 2011).

through blender pumps—which can produce E15 on demand for consumers through the combination of E10 (or E0) and E85—the number of terminals offering preblended E15 directly to service stations has been increasing.⁵⁸⁹

As shown in Figure 8.4.3-1, the fraction of the in-use fleet that is MY2001 and newer has increased steadily since E15 was approved in 2011, and with it the fraction of all gasoline consumed by highway vehicles that is consumed by MY2001 and newer vehicles.

Figure 8.4.3-1: Fraction of In-Use Fleet and In-Use Gasoline Consumption for MY2001 and Newer



Source: Davis, Stacy, and Robert Boundy. “Transportation Energy Data Book (Edition 40),” *Oak Ridge National Laboratory*, ORNL/TM-2022/2376, May 1, 2022. Tables 3.15, 4.6, 4.7, 4.12, and 9.11. <https://doi.org/10.2172/1878695>.

Based on the two modes of E15 production (terminals and blender pumps at retail stations), and the fact that the majority of in-use vehicles are legally permitted to use E15, it appears that the primary constraint on the consumption of E15 in the near term is likely the number of retail stations that offer it. Since E15 was not approved for use until 2011, there were no retail stations offering it before 2011. Most of the existing retail infrastructure (including the entire system of tanks, pipes, pumps, dispensers, vent lines, and pipe dope) is not confirmed to be entirely compatible with E15, so growth in the number of retail stations offering E15 is dependent on investments in retail outlets to convert them to E15 compatibility or make them compatible when newly constructed. In cases wherein a retail station already offers E85 through a blender pump, there may be few or no investments needed for new equipment, and the decision to offer E15 may depend largely on the perceived economic benefit of doing so. For other station owners, the costs can be substantial. Growth in the number of stations offering E15 was slow until the BIP, HBIIP, and Prime the Pump programs began providing funding for station conversions in 2016.

⁵⁸⁹ Renewable Fuels Association, “Terminal Availability of E15 Grows as EPA Prepares to Remove RVP Barrier,” March 12, 2019. <https://ethanolrfa.org/media-and-news/category/blog/article/2019/03/terminal-availability-of-e15-grows-as-epa-prepares-to-remove-rvp-barrier>.

Table 8.4.3-1: Number of Retail Stations Offering E15

Year	E15 Stations
2014	105
2015	184
2016	431
2017	1,214
2018	1,700
2019	2,081
2020	2,302
2021	2,605
2022	2,758
2023	3,414
2024	3,751
2025	4,503*

* Value projected for this rule.

Source: Growth Energy, “Higher Blends Retail Footprint,” October 1, 2024. <https://growthenergy.org/data-set-category/higher-blends-retail-footprint>.

USDA followed up its BIP program with the HBIIP program, which also provides funds to help retail service station owners to upgrade or replace their equipment to offer biofuels. HBIIP is composed of several rounds of funding often referred to as HBIIP 1.0 and HBIIP 2.0. This program effectively began in 2021 and had been accepting applications as recently as 2024.

With regard to equipment compatibility, even if much of the existing equipment at retail is compatible with E15 as argued in studies from NREL⁵⁹⁰ and Stillwater Associates,⁵⁹¹ compatibility with E15 is not the same as being approved for E15 use. Under EPA regulations, parties storing ethanol in underground tanks in concentrations greater than 10% are required to demonstrate compatibility of their tanks with the fuel through one of the following methods:⁵⁹²

- A certification or listing of underground storage tank system equipment or components by a nationally recognized, independent testing laboratory such as Underwriter’s Laboratory.
- Written approval by the equipment or component manufacturer.
- Some other method that is determined by the agency implementing the new requirements to be no less protective of human health and the environment.

The use of any equipment to offer E15 that does not satisfy these requirements, even if that equipment is technically compatible with E15, would pose potential liability for the retailer. This issue is of particular concern for underground storage tanks and associated hardware, as the

⁵⁹⁰ Moriarty, K., and J. Yanowitz. “E15 And Infrastructure,” *National Renewable Energy Laboratory*, NREL/TP-5400-64156, May 27, 2015. <https://doi.org/10.2172/1215238>.

⁵⁹¹ Stillwater Associates, “Infrastructure Changes and Cost to Increase RFS Ethanol Volumes through Increased E15 and E85 Sales in 2016,” July 27, 2015. <https://ethanolrfa.org.cybertest.link/file/2006/Infrastructure-Changes-Cost-to-Increase-RFS-Stillwater-2016.pdf>.

⁵⁹² EPA, “UST System Compatibility with Biofuels,” EPA-510-K-20-001, July 2020.

documentation for their design and the types of materials used, and even their installation dates, is often unavailable. As existing underground storage tank systems reach the end of their warranties or are otherwise in need of repair or upgrade, there is an opportunity for retail station owners to install new systems that are compatible with E15. For instance, tanks installed earlier than 1990 have reached the end of their warranties and should be replaced to safely store fuel.

With regard to retailer concerns about litigation liability for E15 misfueling related to vehicles not designed and/or approved for use with E15, we note that EPA regulations are designed to address potential misfueling. These regulations require pump labeling, a misfueling mitigation plan, surveys, PTDs, and approval of equipment configurations, providing consumers with the information needed to avoid misfueling.⁵⁹³ In addition, the portion of vehicles not designed and/or approved for E15 use continues to decline. MY2000 and earlier light-duty vehicles represent less than 10% of the in-use fleet, and just slightly over 5% of miles traveled. Vehicles designed and warranted by manufacturers to be fueled on E15 are likewise representing an ever-increasing portion of the in-use fleet.

In sum, the relatively small, albeit growing, number of stations offering E15 represents a significant constraint on the expansion of E15 through 2027. While the applicable standards under the RFS program could theoretically provide some incentive for retail station owners to upgrade their equipment to offer E15, there is little direct evidence that the RFS program has operated in this capacity in the past.

Using the E15 station information in Table 8.4.3-1, we projected the total number of E15 stations for 2026 and 2027, as shown in Table 8.4.3-2.

Table 8.4.3-2: Projected Number of Retail Stations Offering E15

Year	E15 Stations
2026	4,507
2027	4,872

8.5 Deliverability of Materials, Goods, and Products Other Than Renewable Fuel

The distribution of renewable fuels relies on the same rail, marine, and road infrastructure networks that are used to deliver materials, goods, and products other than renewable fuels. Therefore, we evaluated whether the use of renewable fuels would impact the deliverability of other items that rely on these infrastructure networks.

The 2009 ORNL study of biofuel distribution for the 2010 RFS2 Rule concluded that there would be minimal additional stress on most U.S. transportation networks overall due to increased biofuel volumes.⁵⁹⁴ This indicates that the shipment of the statutory biofuel volumes could be accommodated without impacting the deliverability of other items. However, as

⁵⁹³ See, e.g., 40 CFR 1090.1420 and 1090.1510.

⁵⁹⁴ Das, Sujit, Bruce Peterson, and Shih-Miao Chin. "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints." *Transportation Research Record Journal of the Transportation Research Board* 2168, no. 1 (January 1, 2010): 136–45. <https://doi.org/10.3141/2168-16>

discussed in Chapter 8.5.1, ORNL noted that significant investment would be needed to overcome congestion on certain rail corridors. The 2018 ICF study of impacts of distributing ethanol and other biofuels determined that the conclusions from the 2009 ORNL analysis have largely turned out to be accurate based on an absence of indicators of distribution constraints.⁵⁹⁵ However, ICF noted that there were instances when the ethanol industry went through rapid expansion where the rail industry was not able to fully accommodate the expansion in inter-regional trade in ethanol. During these periods, the volume of ethanol permitted to be shipped along the sensitive rail corridors was limited to mitigate the congestion. However, ICF found no evidence to suggest that rail congestion from shipment of biofuel was a persistent or common problem at the time of the study's completion in 2018.

Likewise, ICF found no evidence that the shipment of biofuels has had a negative impact on marine networks. While ICF indicated that there likely have been negative impacts on rural and highway transportation networks surrounding ethanol production facilities, it also determined that these impacts can be mitigated with network infrastructure planning and increased funding for road maintenance. ICF noted these increased costs are small in relation to broader maintenance costs for roads and that the road network can accommodate substantial growth in the movement of biofuels.

Based on both the ORNL study and the more recent ICF study, there appears to be minimal overall impact on transportation infrastructure from the distribution of biofuels, and the system appears to have been able to resolve localized instances of increased stress on the system in a timely fashion. As a result, we believe that the candidate volumes would not impact the deliverability of materials and products other than renewable fuel.

As part of considering impacts of biofuels on the deliverability of other items, we also considered constraints on the deliverability of feedstocks used to produce renewable fuel. We do not anticipate constraints that would make the candidate volumes difficult to achieve. For instance, biogas for CNG/LNG vehicles will be delivered through the same pipeline network used to distribute natural gas (see Chapter 7.1). Since that biogas will be displacing natural gas used in CNG/LNG vehicles, we do not expect a net increase in total volume of biogas and natural gas delivered.

As shown in Table 3.1-7, corn ethanol consumption volumes are expected to decrease slightly in 2026–2027, with projected volumes around 14.2 billion gallons. However, ethanol production levels are not expected to decrease as export volumes have remained high. Corn collection and distribution networks have been functioning without difficulty since 2018. It is therefore anticipated that there should be no issues with the infrastructure for 2026–2027 and beyond.

In the proposal, we estimated that the use of FOG for the production of biofuel would increase. This projected increase in the use of FOG for biofuel production was consistent with the observed trend in the domestic supply of FOG for biofuel production from 2014–2021, before the rapid increase in FOG imports. In 2025, these dynamics abruptly changed after tax credit changes, trade dynamics, and lower domestic consumption of these fuels, thus lowering

⁵⁹⁵ ICF, “Impact of Biofuels on Infrastructure,” January 2018.

our projections for FOG in the Set 2 Final Rule (see Chapter 7.2). FOG is collected and distributed through a diverse network of trucking companies, and this increase would represent a very small portion of their activities. As a result, we do not anticipate any hindrances to the deliverability of FOG for the production of renewable diesel in 2026–2027.

Total soybean oil use for the production of BBD is projected to increase from approximately 1.37 billion gallons in 2025 to approximately 3.98 billion gallons in 2027. This projected increase is based on the expected expansion of soybean crushing over this time period in the U.S (see Chapter 7.2). We expect that the existing infrastructure is sufficient to distribute biodiesel and renewable diesel to the markets where these fuels are used.

Chapter 9: Other Factors

CAA section 211(o)(2)(B)(ii) directs EPA to consider the impact of the use of renewable fuels on “other factors” that have a more indirect relationship to volume standards, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices.^{596,597} Broadly speaking, these factors can be thought of as various key economic impacts of the RFS program, each of which Congress believed was important to consider when determining the levels of renewable volume obligations. This chapter describes the ways in which we have assessed the impact of the Analyzed Volumes on these factors through qualitative and/or quantitative economic impact analysis. Chapter 9.1 discusses the projected employment and rural economic development impacts of increased renewable fuel production. Chapter 9.2 discusses the projected impact on the supply of agricultural commodities. Chapters 9.3 and 9.4 discuss the impact of the Analyzed Volumes on the prices of agricultural commodities and food, respectively.

9.1 Employment and Rural Economic Development Impacts

In this section, we discuss the potential impacts of the Analyzed Volumes on employment and rural economic development. As noted in the Executive Summary and consistent with DRIA Chapter 9.1, the impacts presented in this section likely constitute transfers, rather than societal costs or benefits. For the proposed rule⁵⁹⁸, we reviewed the relevant historical data and recent trends and the economic literature and methods available for the quantification of employment and rural economic development impacts related to renewable fuel production and consumption. We then presented multiple quantitative analyses of employment impacts, one using a “Rule-of-Thumb” approach and another using the National Laboratory of the Rockies (NLR)⁵⁹⁹ Jobs and Economic Development Impacts (JEDI) model. Based on these two analyses, we presented estimates of agricultural employment impacts and rural economic development impacts associated with the volume scenarios discussed in the proposal.

For the final rule, we have made use of the same methodologies presented in the proposal. We have updated our analysis to reflect the Analyzed Volumes. However, the modeling inputs and intermediate outputs are the same as those discussed in the proposal. In the proposal, we estimated the employment and rural economic development impacts attributable to representative biofuel production facilities producing RNG, BBD (*i.e.*, biodiesel and renewable diesel) produced from soybean oil, FOG, corn oil, and canola oil, and ethanol (which for the purposes of this analysis we assumed would be produced from corn starch). These fuel types were selected because they represented the vast majority of additional fuel projected to be produced under the proposed volumes. We then applied these per-facility estimates to the expected volumes of each fuel projected to be produced under the proposed volumes. In the final rule, we make use of these same per-facility estimates and apply them to the projected amounts

⁵⁹⁶ As explained in Preamble Section II, we also consider several other factors besides those enumerated in the statute.

⁵⁹⁷ The impacts evaluated in this chapter are for volume increases for 2026–2027 compared to the No RFS Baseline.

⁵⁹⁸ See DRIA Chapter 9.

⁵⁹⁹ This laboratory was formerly known as the National Renewable Energy Laboratory (NREL).

of RNG, BBD, and ethanol associated with the Analyzed Volumes (see Chapter 3 for more details on these volumes).

Economic models show that renewable fuel use can result in higher crop prices, though the range of estimates in the literature is wide. A 2013 study carried out to estimate the impacts of biofuels on corn prices projected (for 2015) price increases in the range of 5–53%.⁶⁰⁰ A report by the National Research Council (NRC)⁶⁰¹ on the RFS program included several studies finding a 20–40% increase in corn prices from biofuels during 2007–2009. A working paper from the National Center for Environmental Economics (NCEE) found that, on average, corn prices rise by 2–3% in the long term for every billion-gallon increase in corn ethanol production, based on an analysis of 19 studies.⁶⁰² The NRC report also found that higher crop prices lead to higher food prices, though impacts on retail food in the U.S. were estimated to be small. Studies have found that, from a global perspective, higher crop prices might lead to higher rates of malnutrition in developing countries.^{603,604,605}

Some research has also suggested the growth of biofuels may also contribute to the ongoing trend of U.S. farmland consolidation.⁶⁰⁶ These studies suggest that increasing production of corn and soy have increasingly pushed small farms out of business because crops like corn and soy are often cultivated in large monocropping operations.⁶⁰⁷ Historically, midsize farms have been vital to the economies of many local communities, and their decline has intensified economic and social difficulties in areas such as the rural Midwest.^{608,609} According to an analysis by the Union of Concerned Scientists covering data from 1978–2017, it was observed that large crop farms are expanding, small crop farms are shrinking, and midsize crop farms are vanishing.⁶¹⁰ During the nearly four decades examined, the overall number of farms has decreased while farm sizes have tripled.⁶¹¹ This consolidation of farmland also impacts

⁶⁰⁰ Wei Zhang et al., “The impact of biofuel growth on agriculture: Why is the range of estimates so wide?,” *Food Policy* 38 (January 11, 2013): 227–39. <https://doi.org/10.1016/j.foodpol.2012.12.002>.

⁶⁰¹ National Research Council. *Renewable fuel Standard*. National Academies Press eBooks, 2011. <https://doi.org/10.17226/13105>.

⁶⁰² Condon, Nicole, Heather Klemick, and Ann Wolverton. “Impacts of Ethanol Policy on Corn Prices: A Review and Meta-analysis of Recent Evidence.” *Food Policy* 51 (January 13, 2015): 63–73. <https://doi.org/10.1016/j.foodpol.2014.12.007>.

⁶⁰³ IIASA, “Biofuels and Food Security – Implications of an accelerated biofuels production,” March 2009. <https://pure.iiasa.ac.at/id/eprint/8984/1/XO-09-062.pdf>.

⁶⁰⁴ EPA, “Economics of Biofuels.” https://19january2021snapshot.epa.gov/environmental-economics/economics-biofuels_.html.

⁶⁰⁵ Rosegrant, Mark W., Tingju Zhu, Siwa Msangi, and Timothy Sulser. “Global Scenarios for Biofuels: Impacts and Implications*.” *Review of Agricultural Economics* 30, no. 3 (September 1, 2008): 495–505. <https://doi.org/10.1111/j.1467-9353.2008.00424.x>.

⁶⁰⁶ Scafidi, Angela. “Increased Biofuel Production in the US Midwest May Harm Farmers and the Climate.” *World Resources Institute*, February 27, 2024. <https://www.wri.org/insights/increased-biofuel-production-impacts-climate-change-farmers>.

⁶⁰⁷ Union of Concerned Scientists. “Losing Ground,” April 14, 2021. <https://www.ucs.org/resources/losing-ground>.

⁶⁰⁸ Id.

⁶⁰⁹ Scafidi, Angela. “Increased Biofuel Production in the US Midwest May Harm Farmers and the Climate.” *World Resources Institute*, February 27, 2024. <https://www.wri.org/insights/increased-biofuel-production-impacts-climate-change-farmers>.

⁶¹⁰ Union of Concerned Scientists. “Losing Ground,” April 14, 2021. <https://www.ucs.org/resources/losing-ground>.

⁶¹¹ Id.

agricultural communities by driving up real estate prices and making it difficult for small-scale farmers to buy or lease land.⁶¹² Our analysis in this section does not attempt to quantify or model these phenomena or any potential impacts of demand for biofuel feedstock on farm size. However, we acknowledge that, to the extent these ongoing trends in farm size are linked to demand for biofuel feedstocks and do continue into the future, this may affect the magnitude of employment and rural economic development impacts associated with our RFS program standards.

Economic advantages of renewable fuels compared to fossil fuels stem from value added to the renewable fuel feedstock, increased numbers of rural manufacturing jobs, and support for the agricultural sector by providing more employment opportunities and market opportunities for domestic crops. The impacts to the local economy from investment in new renewable fuel production facilities, including increases in employment, output and income, and the subsequent increases in demand for local goods and services all create additional beneficial ripple effects.⁶¹³

Increased biofuel production is expected to offset employment in certain sectors. While our analysis presented below suggests expanding biofuel production will generate new positions in biofuel processing plants and associated industries, this expansion could also result in job reductions or transitions in sectors such as fossil fuels. While such shifts may benefit certain individuals and communities, in societal economic impact terms these jobs would be considered transfers rather than net benefits to the U.S. economy.

Increased U.S. biofuel production will also necessitate the development and expansion of production systems and networks to effectively cultivate, harvest, and transport substantial amounts of feedstock. Additionally, industry requires technologies that can convert biomass more efficiently and cost-effectively for various applications.⁶¹⁴ These trends will result in shifting employment across sectors with subsequent impacts on local and regional spending in these impacted areas.

This section focuses on the gross employment impacts, not net impacts, and the income impacts that follow from increased investment in renewable fuels. We evaluate how renewable fuels affect employment and rural economic development. Subsequent sections (Chapters 9.2, 9.3, and 9.4) address the impacts on agricultural commodity supply and prices, as well as food prices.

While these two categories of economic impacts (employment and rural economic development) are distinct, there is significant overlap between them in the context of renewable fuels, given the reliance of these supply chains on rural economic output. Most feedstocks used to produce biofuels in the U.S. are produced and processed (*e.g.*, oilseeds are crushed) in rural areas. Biofuel production facilities themselves are also often located in rural areas. There is also

⁶¹² Scafidi, Angela. “Increased Biofuel Production in the US Midwest May Harm Farmers and the Climate.” *World Resources Institute*, February 27, 2024. <https://www.wri.org/insights/increased-biofuel-production-impacts-climate-change-farmers>.

⁶¹³ Demirbas, Ayhan. “Political, economic and environmental impacts of biofuels: A review.” *Applied Energy* 86 (May 23, 2009): S108–17. <https://doi.org/10.1016/j.apenergy.2009.04.036>.

⁶¹⁴ DOE, “Jobs & Economic Impact of a Billion-Ton Bioeconomy,” June 2017. <https://www.energy.gov/eere/bioenergy/articles/jobs-economic-impact-billion-ton-bioeconomy>.

overlap in the methods available to assess the impacts of renewable fuels on employment and on rural economic development. The following subsection details these methodological options.

Due to these substantial overlaps in both impacts and methodologies, we have chosen to analyze employment and rural economic development impacts together using a cohesive set of methods. We first introduce the concepts of employment and rural economic development impact analysis, followed by a discussion of available methods and existing literature.

Employment impact assessment can be conceived of as a subset of economic impact analysis that focuses specifically on the employment-related effects of a project, policy, or event, while the superset (economic impact analysis) examines broader economic changes. This method is often used to assess the employment potential and impact of sectoral policies and investments. Typically, an employment impact assessment assesses both the quantitative (number of jobs created and associated monetary impacts) as well qualitative (type of jobs created) impacts following a change in policy.⁶¹⁵ Such analyses are often used to support the development of evidence-based pro-employment policies and strategies that are appropriate to the context of the local or national economy.

An employment impact assessment is often carried out within the framework of an input-output model and generally characterizes three types of job impacts: direct (on-site or immediate effects created by an increase in expenditure, *i.e.*, a policy shock), indirect (economic activity that occurs when a contractor/vendor or manufacturer receives payment for goods and services and is in turn able to pay others who support the business, *i.e.*, business to business purchases in the supply chain taking place in the region), and induced (economic values stemming from household spending of labor income after removal of taxes, savings and commuter income).⁶¹⁶ In the context of developing a biofuel plant, these impacts are further divided into two temporal phases: Construction Phase (temporary jobs and other impacts) and Operations and Maintenance Phase (permanent jobs and impacts).

Figures 9.1-1 and 9.1-2 illustrate the various categories of these employment impacts, other economic impacts, and financial flows in the construction and operations phase respectively of a biofuel facility. For both figures, the light purple boxes measure the economic impacts in dollar terms while the dark purple ones measure the economic impacts in terms of job numbers. The solid arrows capture the flow of financial services.⁶¹⁷ In this section, we compute the direct, indirect, and induced impacts from the production of biofuels to the U.S. economy. The total indirect impacts are broken out into impacts to the agricultural sector and impacts to the industry. Additionally, the job estimates have been computed based on changes from the No RFS Baseline and as such should be interpreted as additive gross jobs relative to that baseline. However, were the analysis to be carried out relative to the 2025 Baseline, some of these

⁶¹⁵ International Labour Organization, “Employment Impact Assessments (EmpIA): Analysing the Employment Impacts of Investments in Infrastructure,” 2021.
https://www.ilo.org/sites/default/files/wcmsp5/groups/public/@ed_emp/documents/publication/wcms_774061.pdf.

⁶¹⁶ Demski, Joe. “Understanding IMPLAN: Direct, Indirect, and Induced Effects,” *IMPLAN*, April 18, 2025.
<https://blog.implan.com/understanding-implan-effects>.

⁶¹⁷ International Labour Organization, “Guide for Monitoring Employment and Conducting Employment Impact Assessments (EmpIA) of Infrastructure Investments,” 2020.
https://www.ilo.org/sites/default/files/wcmsp5/groups/public/%40ed_emp/documents/publication/wcms_741553.pdf

computed estimates would then be interpreted as jobs at risk were the RFS program discontinued.

Figure 9.1-1: Direct, Indirect, and Induced Economic Impacts in the Construction Phase of a Biofuel Facility

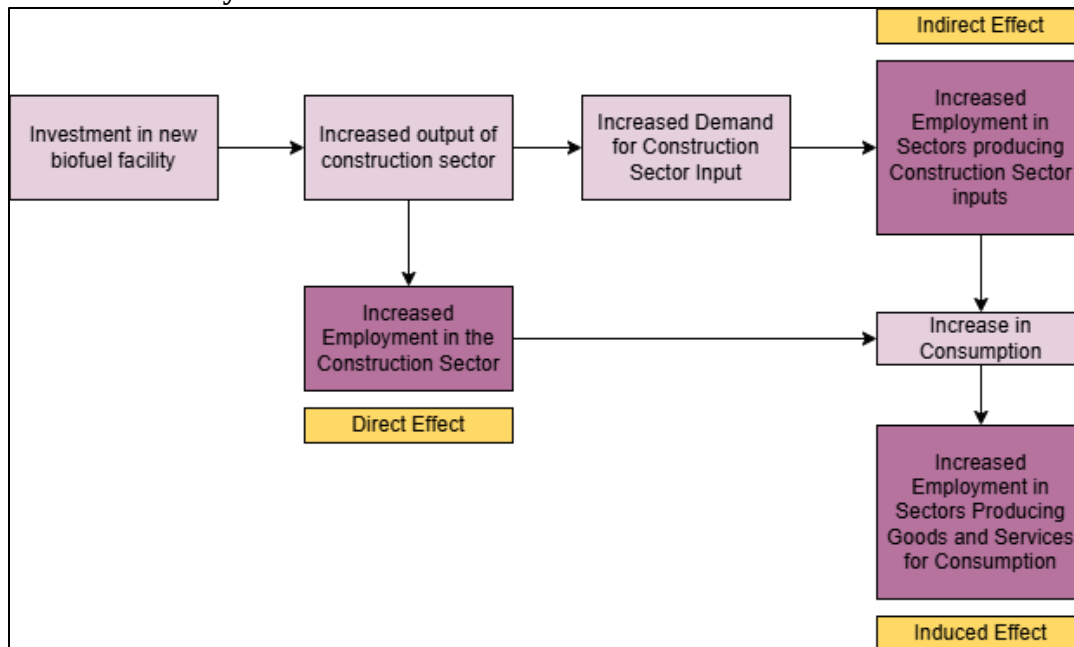
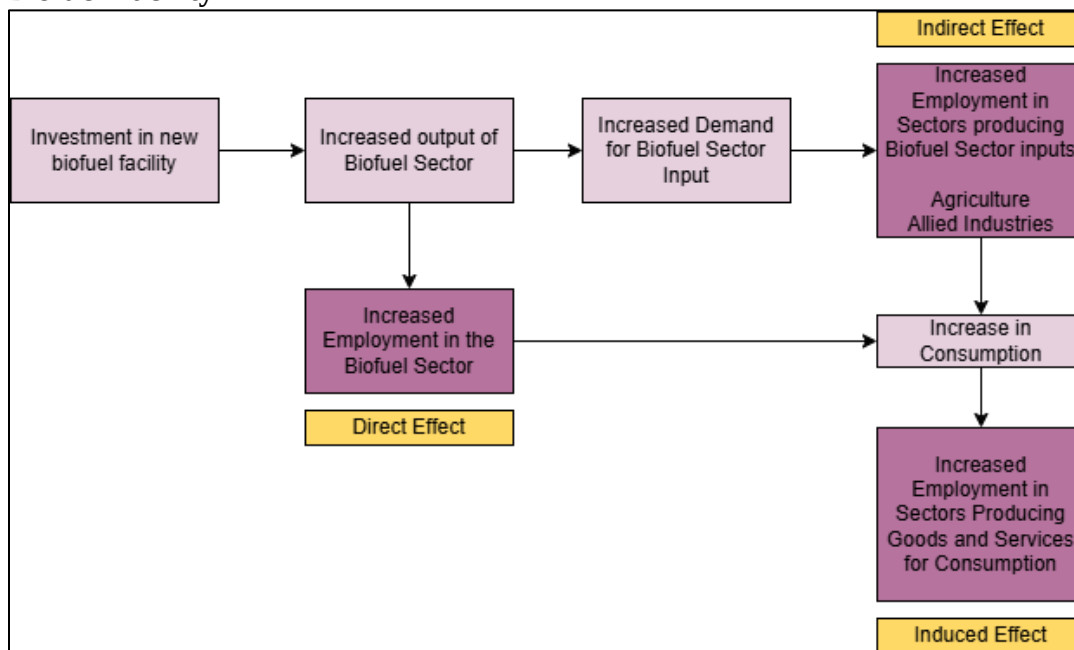


Figure 9.1-2: Direct, Indirect, and Induced Economic Impacts in the Operations Phase of a Biofuel Facility



Rural economic development encompasses a wide range of strategies and activities, all of which have the common goal of enhancing living standards and financial security of the rural

community.⁶¹⁸ Through these strategies and activities, actors seek to enhance infrastructure, stimulate economic growth, and otherwise economically empower rural residents and communities. This involves building rural wealth and incomes through job creation and other channels; for example, by improving agricultural production to increase revenue from the sale of agricultural commodities. One can assess rural economic development through an array of metrics; the choice of metric largely depends on the dimension of development under analysis. Metrics like income, employment, and agricultural productivity—variables that are crucial to the financial growth and stability of the agricultural sector—are often used to assess aspects of rural economic development. Since income and employment are also necessary metrics of our analysis of the employment impacts of renewable fuels, and since the renewable fuel supply chain relies substantively on rural economic output, the same methodologies that we applied in the context of employment impact analysis can also be used to generate useful estimates of rural economic development impacts.

9.1.1 Methodology and Existing Literature

Economic impact analysis allows policymakers to evaluate the potential consequences of different policy options on communities and economic sectors of interest to the program. Historically, the range of models and methods available to assess economic, environmental, and social impacts of policies varied based on a wide variety of considerations, including methodological discipline (*e.g.*, machine learning based models,⁶¹⁹ cross disciplinary models,⁶²⁰ statistical/econometric models), methodological scope (*e.g.*, sector specific/local/global and or static/dynamic), the nature of the policy question being analyzed (*e.g.*, prescriptive vs. proscriptive⁶²¹), and data availability. In the DRIA, we applied two such methods to estimate the impacts of the proposal. We apply these same two methods in the same manner in this analysis of the Analyzed Volumes. Table 9.1.1-1 describes a non-exhaustive list of these approaches based on ease of use.

⁶¹⁸ Social For Action, “How to Measure Rural Development: Key Indicators and Metrics,” November 17, 2024. <https://www.socialforaction.com/blog/how-to-measure-rural-development>.

⁶¹⁹ Peet, Evan D., Brian G. Vegetabile, Matthew Cefalu, Joseph D. Pane, and Cheryl L. Damberg. “Machine Learning in Public Policy: The Perils and the Promise of Interpretability.” *RAND Corporation*, 2022. <https://doi.org/10.7249/pea828-1>.

⁶²⁰ Game, Edward T., Heather Tallis, Lydia Olander, Steven M. Alexander, Jonah Busch, Nancy Cartwright, Elizabeth L. Kalies, et al. “Cross-discipline Evidence Principles for Sustainability Policy.” *Nature Sustainability* 1, no. 9 (September 6, 2018): 452–54. <https://doi.org/10.1038/s41893-018-0141-x>.

⁶²¹ Horne, Christine. “Norms.” Data set. *Oxford Bibliographies Online Datasets*, November 27, 2013. <https://doi.org/10.1093/obo/9780199756384-0091>.

Table 9.1.1-1: Select Methods for Jobs and Economic Impact Analysis

	Basic Methods	Moderate Methods	Complex Methods
Approach	- Rule of Thumb - Meta-analysis	- Input-Output or based on input-output	- Computable General Equilibrium (CGE) - Partial Equilibrium (PE) Econometric - System Dynamics – Linear & Non-Linear Programming
Examples	- Rule-of-Thumb estimates (<i>i.e.</i>, "5 jobs/MW") - Screening models	- Impact Analysis for Planning (IMPLAN)^a - Regional Input-Output Modeling System (RIMS II)^b - Jobs and Economic Development Impacts (JEDI)	- National Energy Modeling System (NEMS)^c - Berkeley Energy & Resource (BEAR) Model^d - U.S. Regional Energy Policy (USREP) Model^e - Regional Economic Models Inc Policy Insight (REMI PI)^f - RAND Econometric Model^g
Benefits	- Easy to use - Minimal time requirement - Transparent - Inexpensive	- Easy to moderately easy to use - Time requirement can be minimal but varies - Can be inexpensive - Widely used, accepted	- More comprehensive than input-output - Can model more scenarios - Retrieve more information
Limitations	- Results can be limited - Often overly simplistic assumptions - Inflexible	- Not very transparent - Many restrictive assumptions (<i>i.e.</i>, constant prices) - Scenarios limited to changes in demand - Difficult or moderately difficult to develop - Can be expensive	- Not very transparent - Assumptions vary - Often difficult to operate or modify - Most require expensive software licenses - Difficult, expensive to build - Data intensive

	Basic Methods	Moderate Methods	Complex Methods
When to use	- When time and resources are short - For high level preliminary analysis - To get quick estimates of employment, output and price changes - As a screening tool	- When policy options are well defined - When a high degree of precision and analytic rigor is desired - When sufficient data, time, and financial resources are available	- When policy options are well defined - When a high degree of precision and analytic rigor is desired - When sufficient data, time, and financial resources are available

^a IMPLAN is a commercially available model that uses an input output analysis technique along with social accounting matrices and publicly available data to carry out economic impact assessment.

^b RIMS II is an input-output-based model that uses regional multipliers to help users estimate gross jobs, developed by the Department of Commerce/Bureau of Economic Analysis.

^c The National Energy Modeling System (NEMS) is a computer-based model developed and maintained by EIA. It is used to forecast energy supply, demand, and prices, and to analyze the impacts of various energy policies.

^d BEAR is a state-level computable general equilibrium model developed by the Lawrence Berkeley National Laboratory, which can account for many different factors affecting jobs, producing net jobs estimates.

^e USREP is a computable general equilibrium model developed and maintained by the Massachusetts Institute of Technology (MIT). The model is national but splits the United States into multiple regions.

^f REMI PI is a commercial model that uses hybrid techniques, combining aspects of input-output, econometric, and computable general equilibrium techniques, and produces net jobs estimates.

^g The RAND econometric model is a commercial tool that uses sets of related equations, and mathematical and statistical techniques to analyze economic conditions over time, generally producing net jobs estimates.

Source: NLR, “Assessment of the Value, Impact, and Validity of the Jobs and Economic Development Impacts (JEDI) Suite of Models,” August 2013. <https://docs.nlr.gov/docs/fy13osti/56390.pdf>. EPA, “Assessing the Multiple Benefits of Clean Energy—A Resource for States,” February 2010.

<https://nepis.epa.gov/Exe/ZyPDF.cgi/P100FLQ9.PDF?Dockey=P100FLQ9.PDF>.

When selecting an analytical method and interpreting the output from any of these frameworks, however, there is a need to be mindful about the strengths and limitations of each. There are times when a combination of these approaches may be necessary to capture the multifaceted impacts of policies, ensuring robust and comprehensive analysis to inform effective policymaking. In this chapter, we have relied upon multiple analytical approaches to quantify the impacts of renewable fuels on “other factors”.

9.1.1.1 Overview of Methodologies Applied

We have focused our analysis on the biofuels that are projected to have the largest changes in volumes relative to the No RFS Baseline: corn ethanol, BBD, and RNG.⁶²² For each of these fuels, we have made use of methods that we were able to identify as available off-the-shelf. We acknowledge that complex methods such as Computable General Equilibrium (CGE) models may be helpful when a high degree of precision and analytic rigor is desired given sufficient data, time, and financial resources.

For all biofuels, to estimate the impact of volume changes compared with the No RFS Baseline, we have relied on a basic method (as laid out in Table 9.1.1-1)—a Rule-of-Thumb

⁶²² The impacts evaluated in this chapter are for volume increases for 2026–2027 compared to the No RFS Baseline.

approach—to draw conclusions about economic impacts. We utilize the results of existing studies for estimates of multipliers or the impact per unit of biofuel and then apply these estimates to the projected Analyzed Volumes to derive employment and other economic impacts.

For the corn ethanol case alone, we have additionally applied NLR’s JEDI model. The results using NLR’s JEDI model that are presented here are linearly scaled estimates of the Proposed Volumes. We also performed a sensitivity analysis on the results of the latter method to capture the range of impacts to the agricultural sector and the rural economy. This approach illustrates both how results from a simple Rule-of-Thumb type approach compared with a more robust approach like an input-output model, and how changes in some key modeling parameters will alter the extent of economic impacts on the agricultural sector and the rural economy. Since these industries bear similarities in their backward and forward linkages with other sectors of the economy (supply chain⁶²³ and logistic networks⁶²⁴), one can expect similar type of sectoral level impacts; the size of the impacts, however, will be a function of the initial policy shock. It is important to note that the impact estimates in our analysis (for all the biofuels) correspond to the volume projections relative to the No RFS Baseline.

9.1.1.2 Rule-of-Thumb Analytical Method

Of the available methods discussed above, only input-output models appear to have been applied recently to estimate the impact of renewable fuels on jobs and economic output. We have identified four relevant studies with outputs which can inform our Rule-of-Thumb approach to estimating the impacts of renewable fuels on job creation and rural economic development. Three of these studies focused on a specific subset of the fuels we have targeted for analysis: a 2024 study on the contribution of the ethanol industry to the U.S. economy by Agriculture and Biofuels Consulting (ABF), LLP (hereafter the ABF study),⁶²⁵ a 2022 study on the economic impact analysis of biodiesel and renewable diesel on the U.S. economy by LMC International (hereafter the LMC study),⁶²⁶ and a 2024 study on renewable natural gas economic impact analysis by Guidehouse (hereafter the Guidehouse study).⁶²⁷ A fourth study by PwC compares the impacts of renewable fuels to those of oil and gas, employing a similar IO approach to the three fuel-specific studies (hereafter the PwC study).⁶²⁸ The analysis in this chapter uses the results of these studies to parameterize our Rule-of-Thumb analysis.

⁶²³ Babazadeh, Reza, Jafar Razmi, and Mir Saman Pishvae. “Sustainable Cultivation Location Optimization of the *Jatropha Curcas* L. Under Uncertainty: A Unified Fuzzy Data Envelopment Analysis Approach.” *Measurement* 89 (April 10, 2016): 252–60. <https://doi.org/10.1016/j.measurement.2016.03.063>.

⁶²⁴ Hong, Jae-Dong, and Judith L. Mwakalonge. “Biofuel Logistics Network Scheme Design with Combined Data Envelopment Analysis Approach.” *Energy* 209 (July 26, 2020): 118342. <https://doi.org/10.1016/j.energy.2020.118342>.

⁶²⁵ ABF Economics, “Contribution of the Ethanol Industry to the Economy of the United States in 2023,” February 1, 2024. <https://d35t1syewk4d42.cloudfront.net/file/2659/RFA%202023%20Economic%20Impact%20Final.pdf>.

⁶²⁶ LMC International. “Economic Impact of Biodiesel on the United States Economy 2022: Main Report.” *Clean Fuels Alliance America*, 2022. https://cleanfuels.org/wp-content/uploads/LMC_Economic-Impact-of-Biodiesel-on-the-US-Economy-2022_Main-Report_November-2022.pdf.

⁶²⁷ Guidehouse, “Renewable Natural Gas Economic Impact Analysis,” December 2024. https://static1.squarespace.com/static/53a09c47e4b050b5ad5bf4f5/t/67577e1c8695832cc7125f86/1733787172143/2024+RNG+Economic+Impact+Report_FINAL.pdf.

⁶²⁸ PwC, “Impacts of the Oil and Natural Gas Industry on the US Economy in 2021,” April 2023. <https://www.api.org/-/media/files/policy/american-energy/pwc/2023/api-pwc-economic-impact-report-2023.pdf>.

While other methods have been applied to estimate impacts on job creation and rural economic development, we choose to focus on the results of input-output models in our analysis, for several reasons. First, these have been the most widely used in recent literature. Second, studies using these methods can provide usable impact estimates for ethanol, biodiesel, renewable diesel, and RNG production. Third and finally, focusing on input-output model results allows for direct comparisons across studies to characterize the range of potential impacts.

Before describing our analysis, we review the studies listed above and summarize their main results, which are the foundation of our Rule-of-Thumb analytical approach.

9.1.1.2.1 The ABF Study of Ethanol Impacts

The ABF study uses the IMPLAN (Impact Analysis for Planning) multiplier database to develop a model of the national economy, including sectors that support ethanol industry, the links between them, and the level of national economic activity. The data inputs are based on the recent benchmark input-output data and 2021 regional data published by the U.S. Bureau of Economic Analysis. The report assesses direct effects, indirect effects, and induced effects as well as the additional value of output of ethanol co-products (DDGS, distillers corn oil, corn gluten meal, and corn gluten feed). The report also incorporates the explicit impact of ethanol and DDGS exports in the economic impact analysis by applying USDA Agricultural Trade multipliers for output and employment to the estimated value of exports for 2023 reported by EIA and U.S. Census Bureau trade databases. The ABF study assesses the impact of ethanol production on job creation and GDP across several sectors of the economy, including:

- Ongoing ethanol production operations, including total production effect and the impact on farm incomes
- Research and development
- Ethanol co-product value streams
- Exports
- Construction

The ABF study estimates that the ethanol industry supported 394,464 jobs across all sectors of the economy in 2023. Excluding the impact associated with construction, the impact was 392,371 full-time equivalent [FTE] jobs in 2023. See Table 9.1.1.2.1-1.

Table 9.1.1.2.1-1: The ABF Study—Jobs Supported by Ethanol Production in 2023 (FTE)

	All	Construction	All, Excluding Construction
Direct	72,463	1,015	71,448
Indirect	203,597	359	203,238
Induced	118,405	718	117,687
Total	394,464	2,093	392,371

The ABF study does not assess rural economic development explicitly. However, we can infer the impact on rural economies based on reported impacts for certain stages in the ethanol

value chain compared to the total estimated impact of ethanol economy wide. For instance, we could assume that corn production and ethanol production both take place predominantly within the bounds of the rural economy. Production of ethanol feedstock (mostly corn) contributed \$27,916 million to the U.S. economy, while the manufacturing activity of ethanol production accounted for another \$14,602 million. The ABF study also estimates an economy-wide impact of \$54,226 million from the ethanol industry in 2023. With the assumptions stated above, we can roughly estimate that the impact on rural economies is about 78% ($= (27,916+14,602)/54,226$) of the total GDP impact of ethanol. The job impact is even larger in relative terms, about 91% ($= (264,464+95,166)/394,464$) of the total economy-wide employment impact. See Table 9.1.1.2.1-2.

Table 9.1.1.2.1-2: The ABF Study—Job Creation and GDP Impacts of Ethanol Production by Sector

	Job Creation (FTE)		GDP (million 2023\$)	
	Agriculture	Ethanol Production	Agriculture	Ethanol Production
Direct	58,324	11,781	3,137	2,602
Indirect	127,638	46,014	14,299	7,394
Induced	78,533	37,372	10,480	4,606
Total	264,464	95,166	27,916	14,602

Our estimates here could be viewed as an upper limit since we assume that both corn and ethanol production are within the bounds of the rural economy. To get the lower limit, we assume that only corn production (excluding ethanol production) is within the bounds of the rural economy. The estimate of the impact on rural economy is about 51% ($=27,916/54,226$) of the total GDP impact of ethanol. The job impact is about 67% ($=264,464/394,464$) of the total economy-wide employment impact. We rely on the lower limit to conduct our impact analyses in Chapters 9.1.4.1 and 9.1.5.1.

9.1.1.2.2 The LMC Study of Biodiesel and Renewable Diesel Impacts

The LMC study assesses the economic impact of BBD, including both renewable diesel and biodiesel. The study divides its findings into several categories of effects. These include several annual (*i.e.*, ongoing) effects, including direct effects directly attributed to the BBD value chain, such as fuel production facilities and oilseed crops grown and crushed at least in part for fuel use, indirect effects associated with industries that supply the BBD value chain, and induced effects stemming from expenditure of households from those affected industries. In addition, the study also considers “one-off effects” that are not estimated to be sustained over time, such as those associated with construction of new BBD production facilities.

LMC (2022) uses multipliers developed from the input-output tables from the U.S. Department of Commerce’s Bureau of Economic Analysis across 406 industries and by state. These multipliers are applied to the direct effects that LMC estimated under the following scenarios.

- Baseline: 3.1 billion gallons of biodiesel supply (*i.e.*, production plus net imports) in 2021 (the authors' estimate of actual 2021 U.S. supply)
- 3.5 billion gallons of supply in 2021
- 4.0 billion gallons
- 6.0 billion gallons

The effects are calculated for the actual 2021 U.S. production/import split of 80% domestic production and 20% import and for an assumed production/import split of 100% domestic production and 0% import, respectively. The analysis also assumes the 2021 market conditions (*e.g.*, prices), an 80% utilization rate of fuel production capital (*e.g.*, the study assumes 7.5 billion gallons of capacity is required to produce 6 billion gallons), and the renewable diesel representing half of U.S. domestic production in all except the baseline scenario (which assumes 67% biodiesel and 33% renewable diesel).

Table 9.1.1.2.2-1 summarizes the annual impacts in terms of job creation by scenario. Based on 2021 conditions, the LMC study estimates the BBD sector's job impact was about 75,000 in that year. The study also estimates that doubling the production to 6.0 billion gallons would have also doubled the job creation impact of the BBD sector in 2021.

Table 9.1.1.2.2-1: The LMC Study—The Annual Job Creation Impacts by Scenario (FTE)

	Scenario (billion gallons of BBD)			
	3.1 (Baseline)	3.5	4.0	6.0
80%/20% U.S./import split	75,196	86,204	99,078	150,572
100%/0% U.S./import split	93,755	107,373	123,299	187,003

Table 9.1.1.2.2-2 summarizes the one-off effects associated with construction. The LMC study estimates that doubling the production of BBD in 2021 would have created 144,500 temporary job-years (*e.g.*, with two years to build an average plant, this implies 72,250 FTE jobs lasting two years).

Table 9.1.1.2.2-2: The LMC Study—The One-Off Job Creation Effects from Construction (FTE)

	Scenario (billion gallons of BBD)	
	4.0	6.0
Total temporary construction job-years created	61,400	144,500

The LMC study does not explicitly assess the impact on rural economic development. We can infer the impact on rural economies based on reported impacts for certain stages in the BBD value chain compared to the total estimated impact of BBD economywide. For the purposes of our analysis, we assume that oilseed production, crushing, and processing occur predominantly in rural areas. Table 9.1.1.2.2-3 summarizes the estimated effects on rural development in the LMC study based on these assumptions. The estimated impact on rural economic development represents at least 30% of the total economy-wide impact across job, GDP, and wage estimates.

Table 9.1.1.2.2-3: The LMC Study—Estimates of the Impacts of BBD Production in Rural Areas

	Jobs (FTE)	GDP (\$2021)	Wages (\$2021)
Oilseed production	28,236 jobs 38% of the total	\$7.41 billion 30% of the total	\$1.36 billion 38% of the total
Oilseed processing	6,000 jobs 8% of the total	\$4.97 billion 21% of the total	\$380 million 11% of the total

9.1.1.2.3 The Guidehouse Study of Renewable Natural Gas Impacts

The Guidehouse study estimates the economic impact of 2024 RNG industry spending in the U.S. in terms of job creation and GDP. The RNG industry generates direct economic effects through annual capital expenditures and operational spending incurred by RNG facilities (*e.g.*, spending on new construction and RNG production and distribution). The Guidehouse study estimates these direct effects of RNG on the economy (*e.g.*, the annual capital expenditures and operational spending incurred by RNG facilities) based on a dataset on RNG facility capacity and costs compiled and maintained by RNG Coalition. The dataset used in the report was up to date as of October 2024. In turn, these expenditures spur business-to-business transactions within the RNG supply chain (indirect effects) and increase household spending among RNG industry and supply chain employees (induced effects). The Guidehouse study employs an IMPLAN model to estimate these indirect and induced effects.

As of October 2024, the RNG Coalition database estimates there were 411 operational RNG facilities and 130 projects under construction. The Guidehouse study estimates that the RNG industry supported over 55,000 jobs and generated \$7.2 billion in GDP in that year. Table 9.1.1.2.3-1 summarizes the three components of the job creation impacts.

Table 9.1.1.2.3-1: The Guidehouse Study—Job Creation Impacts of RNG Production

	Direct	Indirect	Induced	Total
Job Creation (FTE)	23,359	13,395	18,910	55,664
GDP (billion 2024\$)	3.0	1.9	2.2	7.2

The Guidehouse study estimates that there are currently about 230 RNG projects in planning phases in the U.S. Table 9.1.1.2.3-2 summarizes the planned and existing RNG projects' job creation impacts by facility status. While the impact associated with construction is one-off, that associated with operations is annual. The planned projects have larger one-off impacts as well as annual impacts in terms of total job creation.

Table 9.1.1.2.3-2: The Guidehouse Study—The Planned and Existing RNG Projects' Job Creation Impacts by Facility Status (FTE)

	Operations	Construction	Total
Existing	23,917	31,747	55,664
Planned	19,586	74,237	93,823

The Guidehouse study does not assess rural economic development explicitly. However, we can infer this impact by disaggregating these impacts by feedstock. The Guidehouse study

identifies four categories of biogas feedstocks for RNG: municipal solid waste, food waste, agricultural digesters (termed “agricultural waste” in the study), and wastewater.⁶²⁹ Assuming RNG projects using agricultural digesters are those pertinent to rural areas and thus rural economic development, we can use the impact associated with agricultural digesters as an estimate for rural economic development. In 2024, agricultural digester projects generated the second largest economic impacts, accounting for 19,751 jobs (35% of the total job impact) and \$2.6 billion in GDP (36% of the total GDP impact). Table 9.1.1.2.3-3 summarizes these impacts.

Table 9.1.1.2.3-3: The Guidehouse Study—Agricultural Job Creation and Rural Economic Development Impacts

	Direct	Indirect	Induced	Total
Job creation (FTE)	8,297	4,612	6,843	19,752
GDP (billion 2024\$)	1.2	0.7	0.8	2.6

9.1.1.2.4 The PWC Study of Fossil Fuel Impacts and Comparison with Three Renewable Fuels Studies

We compare the impacts of renewable fuels in the ABF, LMC, and Guidehouse studies to those of oil and natural gas based on PWC (2023), which also employed a similar IO approach. The PWC study quantifies the economic impacts of the U.S. oil and natural gas industry in terms of employment, labor income, and value added at the national, state, and congressional district level for 2021. They consider all three separate channels—the direct impact, the indirect impact, and the induced impact, and in aggregate provide a measure of the total economic impact of the oil and natural gas industry.

Industries vary in size; therefore, to assess job creation, we divide the total FTE by GDP (in billions), measuring the number of jobs generated per \$1 billion GDP. Applying this metric to all four reports discussed in this section indicates that almost all renewable fuels (with the exception of BBD) create more jobs per \$1 billion GDP than fossil fuels. Construction impacts, which are one-time effects, are excluded from this comparison. Table 9.1.1.2.4-1 shows employment per billion dollars GDP for the oil and gas, ethanol, BBD, and RNG industries.

Table 9.1.1.2.4-1: The PWC Study—Employment per GDP for Fossil Fuel and Renewable Fuel Production

	Oil & Gas	Ethanol	BBD	RNG
Employment (FTE)	9,400,000	392,371	75,196	23,917
GDP (billion 2021\$)	1,618	54	23	4
Employment/GDP	5,809	7,265	3,241	6,294

Since these renewable fuels rely significantly on agricultural feedstocks and are often produced in rural areas, they contribute to rural economic development. Fossil fuels, by contrast, do not use agricultural feedstocks, and there is no direct farm income boost from crops. In addition, their indirect and induced effects on rural economic development may be mixed or

⁶²⁹ These categories differ somewhat from the categories established by EPA in Table 1 to 40 CFR 80.1426 in both wording and substance but are a reasonable general guide for this purpose.

negative, particularly in the long run. For instance, unlike agriculture that provides relatively stable demand for rural labor and services, fossil fuel markets are prone to price fluctuations. The resulting economic instability makes long-term rural development difficult. Fossil fuel operations may displace farmland, contaminate water sources, and pollute the air, negatively affecting crops and livestock. Table 9.1.1.2.4-2 summarizes the results based on only estimated agricultural production.

Table 9.1.1.2.4-2: The PWC Study—Employment and GDP Impacts of Agricultural Production Supported by Renewable Fuel Production

	RNG	BBD	Ethanol
Employment (FTE)	19,752	28,236	264,464
GDP (billion 2021\$)	2.6	7.4	27.9

In summary, the PWC study finds renewable fuels generally create more jobs per unit of GDP than fossil fuels. This finding is supported by other studies comparing the job impacts of fossil fuel and renewable fuel production. IEA’s World Energy Employment Report⁶³⁰ finds that clean energy has “surpassed the 50% mark for its share of total energy employment” and has the biggest potential for job creation.⁶³¹ Peltier finds “on average, 2.65 FTE jobs are created from \$1 million spending in fossil fuels, while that same amount of spending would create 7.49 or 7.72 FTE jobs in renewables or energy efficiency.”⁶³² Thus each \$1 million shifted from brown to green energy will create a net increase of 5 jobs.” Though biofuels accounted for only a small fraction of the overall addition to clean jobs (Clean Jobs America reports that biofuels added over 1200 jobs in 2023⁶³³), the International Renewable Energy Agency (IRENA) estimated that liquid biofuels supported 2.42 million jobs globally in 2021 and most of these were in planting and harvesting feedstock,⁶³⁴ implying that expansion of the biofuel industry will likely have the biggest job impacts to the agricultural and rural community.

Note that the jobs created by increased biofuel production are unlikely to be completely offset by job declines in the fossil fuel sector. Our impact analyses on employment and rural economic development in Chapters 9.1.2 through 9.1.5 focus on the gross impacts, not net impacts.

In Chapters 9.1.2, 9.1.4, and 9.1.5, we combine the estimates derived above from each of these three studies with the projected production increases associated with the Analyzed Volumes relative to the No RFS Baseline to estimate the potential impacts of this rule on jobs and rural economic development.

⁶³⁰ IEA, “World Energy Employment,” August 2022. <https://doi.org/10.1787/5d44ff7f-en>.

⁶³¹ E2. “Clean Jobs America 2024,” September 2024. https://cleanjobsamerica.e2.org/wp-content/uploads/2024/09/E2-2024-Clean-Jobs-America-Report_September-17-2024.pdf.

⁶³² Garrett-Peltier, Heidi. “Green Versus Brown: Comparing the Employment Impacts of Energy Efficiency, Renewable Energy, and Fossil Fuels Using an Input-output Model.” *Economic Modelling* 61 (November 28, 2016): 439–47. <https://doi.org/10.1016/j.econmod.2016.11.012>.

⁶³³ E2. “Clean Jobs America 2024,” September 2024. https://cleanjobsamerica.e2.org/wp-content/uploads/2024/09/E2-2024-Clean-Jobs-America-Report_September-17-2024.pdf.

⁶³⁴ IRENA. “Renewable Energy and Jobs Annual Review 2022,” 2022. https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Sep/IRENA_Renewable_energy_and_jobs_2022.pdf.

9.1.1.3 Input-Output Modeling Analytical Method for Corn Ethanol

In addition to our Rule-of-Thumb analysis, which largely relies on estimates derived from pre-existing input-output modeling studies, we also present original input-output modeling estimates for just the corn ethanol case using a Jobs and Economic Development Impacts (JEDI) model. The JEDI modeling suite was developed by NLR for the DOE Office of Energy Efficiency and Renewable Energy (EERE). At a very high level, the JEDI suite relies on the use of an input-output based methodology to estimate gross jobs and economic impacts of building and operating selected types of renewable electricity generation and fuel plants.

Between 2004 and 2012, JEDI has been used and cited in more than 70 public studies including 12 studies in five different peer-reviewed journals. The validity of JEDI estimates was assessed through comparison to both published modeled estimates and data on empirical observations of jobs associated with renewable energy projects. For the former, compared to modeled job results for O&M of several corn ethanol plants, JEDI results ranged from 20% lower to 28% higher. For the latter, comparison of several empirical estimates for O&M jobs at corn ethanol plants showed that JEDI results ranged from 9% higher to 21% lower than the empirical estimates.

According to expert evaluations, references, and various user metrics, the JEDI suite of models is recognized as a reliable and widely utilized tool for estimating or screening gross job numbers associated with the construction and operation of renewable energy power and fuel facilities in the U.S. Considering the aforementioned comparisons involving both modeled and empirical estimates, the outcomes produced by the JEDI model are fairly similar with other modeled results and empirical observations.

The default assumptions in the JEDI model are based on interviews with industry experts and project developers. While these input assumptions are reasonable, the user does have the option to override some of these project specific data for some categories of inputs. Economic multipliers contained within the model are derived from Minnesota IMPLAN Group's IMPLAN accounting software and state data files. Construction jobs are defined as full-time equivalents (FTE), or 2,080-hour units of labor (one construction period job equates to one full-time job for one year). A part-time or temporary job may be considered one job by other models but would constitute only a fraction of a job according to the JEDI models. For example, if an engineer worked only 3 months on a wind farm project (assuming no overtime), that would be considered one-quarter of a job by the JEDI models. Operations-period results are long term, for the life of the project, and are reported as annual full-time-equivalent jobs and annual economic activity, which continue to occur throughout the operating life of the facility. Like all models, the JEDI model too has its own set of limitations, and precisely because of these the model results are meant to be estimates and not precise forecasts.

Input-output modeling is a data-intensive effort and requires access to sector specific multipliers⁶³⁵ that permit us to compute rates of change for several different variables—output,

⁶³⁵ Multipliers are rates of change that describe how a given change in a particular industry generates impacts in the overall economy.

employment, labor income, and value added. In the case of corn ethanol, IMPLAN⁶³⁶ maintains a database of multipliers that is available for purchase and NLR has developed an input-output model for Dry Mill Corn Ethanol⁶³⁷ using these multipliers,⁶³⁸ results of which have been validated with both modeled job results as well as empirical employment data.⁶³⁹ However, to the extent that such tools can be developed for BBD and RNG going forward, we may choose to make use of them. Other tools to assess economic and environmental impacts, such as WIRED, BEIOM,⁶⁴⁰ EMPLOY, and others⁶⁴¹ for some of the other biofuel categories and technologies are either in the R&D phase or employ slightly different modeling capabilities compared with JEDI, and could be used as well in future analyses if appropriate.⁶⁴²

9.1.2 Employment Impacts using the Rule-of-Thumb Approach

Our estimates of the employment impacts relying on the use of a basic Rule-of-Thumb approach and existing studies are summarized by fuel type (ethanol, BBD, and RNG) in this section. In the next section, to provide a complementary estimate of the local economic impacts associated with constructing and operating a corn ethanol facility, we relied on NLR's JEDI module for dry mill corn ethanol.

Changes in ethanol volumes evaluated in this rule result from increased consumption of higher-level ethanol motor gasoline blends (*e.g.*, E15 and E85) and a corresponding decrease in E10 gasoline consumption that they replace. The connection between these estimated changes in domestic consumption and domestic production of ethanol is unlikely to be a perfect correlation as ethanol is produced not only for domestic consumption but also for export. Significant quantities of ethanol have been exported to foreign markets in recent years (see Chapter 7.5 and Chapter 7.6 for more details). The volume of ethanol that EPA projects to be consumed in 2026–2030 under the No RFS Baseline is significantly less than the domestic ethanol production capacity, and less than projected domestic ethanol production in 2025. For this reason, the exact strength of the correlation between ethanol production and the ethanol consumption estimates

⁶³⁶ <https://implan.com>.

⁶³⁷ NLR, “JEDI Corn Ethanol Model rel. CE12.23.16.” <https://www.nlr.gov/docs/libraries/analysis/01d-jedi-corn-ethanol-model-rel-ce12-23-16.xlsm>.

⁶³⁸ NLR, “Jobs and Economic Development Impact Models,” April 21, 2025. <https://www.nlr.gov/analysis/jedi>.

⁶³⁹ Billman, L., and D. Keyser. “Assessment of the Value, Impact, and Validity of the Jobs and Economic Development Impacts (JEDI) Suite of Models,” *National Renewable Energy Laboratory*, August 1, 2013. <https://doi.org/10.2172/1090964>.

⁶⁴⁰ Avelino, Andre F.T., Patrick Lamers, Yimin Zhang, and Helena Chum. “Creating a Harmonized Time Series of Environmentally-extended Input-output Tables to Assess the Evolution of the US Bioeconomy - a Retrospective Analysis of Corn Ethanol and Soybean Biodiesel.” *Journal of Cleaner Production* 321 (September 2, 2021): 128890. <https://doi.org/10.1016/j.jclepro.2021.128890>.

⁶⁴¹ Oke, Doris, Lauren Sittler, Hao Cai, Andre Avelino, Emily Newes, George G. Zaimes, Yimin Zhang, et al. “Energy, Economic, and Environmental Impacts Assessment of Co-optimized On-road Heavy-duty Engines and Bio-blendstocks.” *Sustainable Energy & Fuels* 7, no. 18 (January 1, 2023): 4580–4601. <https://doi.org/10.1039/d3se00381g>.

⁶⁴² WIRED is an updated regional IO tool much like the JEDI suite of models that is under development and will likely have a public release by the end of the year (2025). BEIOM is both a retrospective and prospective dynamic environmentally extended input-output model that is not publicly available but can be used internally by NLR and DOE. EMPLOY has the capability to model several fuel pathways (conventional petroleum products, corn starch ethanol, cellulosic ethanol, biodiesel, renewable diesel, sustainable aviation fuel, etc.) and is used to estimate the *net* impacts (economic, jobs, workforce and environmental) of large-scale industry deployment up to 2050.

presented in our Analyzed Volumes is not completely clear. Thus, it is possible that a decrease in ethanol consumption in the absence of the RFS program, such as that estimated in our forward-looking No RFS Baseline, could result in a decrease in domestic ethanol production or alternatively could result in increased ethanol exports.

The following is the employment impact analysis for all types of renewable fuels using the basic method based on the three specific IO studies of renewable fuels discussed in DRIA Chapter 9.1.1.2. These IO studies we rely upon are the ABF study, the LMC study, and the Guidehouse study.

The impact estimates from these three studies are based on total production of these renewable fuels. Table 9.1.2-1 summarizes the volume increases of RNG, BBD, and ethanol attributable to the RFS volume requirements relative to the No RFS Baseline under the Analyzed Volumes.

Table 9.1.2-1: Projected Production Increases under the Analyzed Volumes (million ethanol-equivalent gallons)

	2026	2027
RNG	799	838
BBD	3,597	4,175
Ethanol	231	245

To generate impact estimations based on projected production increases in million ethanol equivalent gallons (in Table 9.1.2-1), we calculate the impact per million ethanol equivalent gallons for each renewable fuel. To do so, we make two important assumptions. First, although the impact of renewable fuels may be nonlinear (*e.g.*, a 5% increase in production may not require any increases in labor), we assume these impacts will scale in a linear manner. Prior research in this space does not provide a sufficient basis to accurately estimate potential nonlinear impacts. Absent this basis, we assume the simpler, more straightforward functional form. Second, we estimate impacts from facility operations only. Since the projections under the Analyzed Volumes are generally below production capacity (see Table 9.1.2-2), there may not be a need to construct new facilities. This is also conservative and may help mitigate potential overestimation (*e.g.*, due to the linear assumption we make). These assumptions mirror the analytical choices made in the DRIA as well.

Table 9.1.2-2: Production Capacity and Annual Production from the ABF Study, the LMC Study, and the Guidehouse Study and Production Projections by Fuel

	Production Year	Production Capacity	Annual Production		2026 Production Projections under the Analyzed Volumes
		Original Unit	Original Unit	Million Gallons (ethanol equivalent)	Million Gallons (ethanol equivalent)
RNG	2024	133 tril Btu	878 mil gal	878	1,364
BBD	2021	4.6 bil gal	2.5 bil gal	3,925	6,074
Ethanol	2023	17.8 bil gal	15.6 bil gal	15,600	14,438

We estimate the impacts on employment on a full-time equivalent (FTE) basis. The FTE estimated impacts associated with the Analyzed Volumes are summarized in Table 9.1.2-3. For BBD, the LMC study did not provide separate estimates for direct, indirect, and induced impacts associated with operations. We use the average effective multiplier reported in the LMC study to decompose the total impact into direct and non-direct (*i.e.*, combined indirect and induced) effects.

Table 9.1.2-3: Job Creation Impacts of Production Based on the ABF Study, the LMC Study, and the Guidehouse Study (FTE)

	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	7,948	7,505	8,464		23,917
BBD	18,799			56,397	75,196
Ethanol	71,448	203,238	117,687		392,373

Because the job creation impacts summarized in Table 9.1.2-3 represent the impacts of differing quantities of biofuel production, we next normalized these estimates to calculate the job impacts per million ethanol-equivalent gallons of biofuel production. To do this we divide the total impact estimates in Table 9.1.2-3 by the total production in million ethanol equivalent gallons to estimate the impact per million ethanol equivalent gallons for each renewable fuel, which are reported in Table 9.1.2-4. Compared with BBD and ethanol, RNG has the highest direct and total impacts per million ethanol equivalent gallons (9.1 and 27.2, respectively). BBD and ethanol have higher indirect and induced impacts relative to their direct impacts because their multipliers are higher than RNG's.

Table 9.1.2-4: Job Creation Impacts per Million Ethanol Equivalent Gallons Based on the ABF Study, the LMC Study, and the Guidehouse Study (FTE)

	Direct	Indirect	Induced	Indirect + Induced	Total	Multiplier
RNG	9.1	8.5	9.6		27.2	3.0
BBD	4.8			14.4	19.2	4.0
Ethanol	4.6	13.0	7.5		25.2	5.5

Using the same methodology as applied in the DRIA, we then estimate the impacts of the projected fuel production increases by multiplying the projected production increases with the impact per million ethanol equivalent gallons estimates. We report two sets of the projections, one based on the direct effects only and the other based on all effects (*i.e.*, direct, indirect, and induced effects). Table 9.1.2-5 shows the projected job impacts relative to the No RFS Baseline accounting for only the direct effects while Table 9.1.2-6 shows the projected job impacts considering the direct, indirect, and induced effects. Relative to the baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest job creation impact, primarily due to substantially higher production increases relative to the baseline.

Table 9.1.2-5: Job Creation Impacts of the Projected Production Increases Based on Direct Effects Only under the Analyzed Volumes (FTE)

	Direct	
	2026	2027
RNG	7,233	7,586
BBD	17,228	19,996
Ethanol	1,058	1,122
All Fuels	25,519	28,704

Table 9.1.2-6: Job Creation Impacts of the Projected Production Increases Based on All Effects under the Analyzed Volumes (FTE)

	Direct + Indirect + Induced	
	2026	2027
RNG	21,765	22,827
BBD	68,912	79,986
Ethanol	5,810	6,162
All Fuels	96,487	108,975

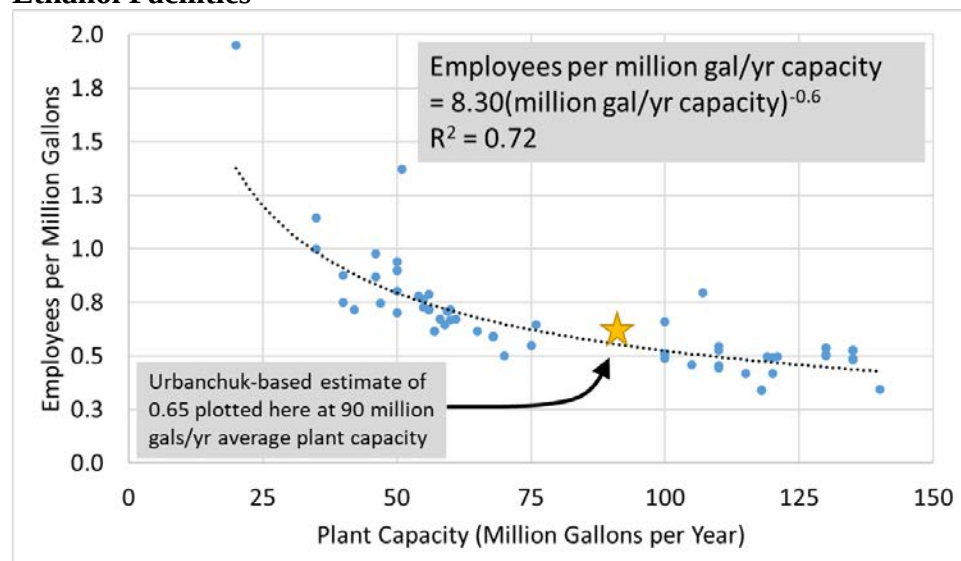
9.1.3 Employment Impacts using NLR’s JEDI model for Dry Mill Corn Ethanol

In the case of ethanol, we were able to assess employment impacts (in both the construction and the operations phase) using NLR’s JEDI model to produce a second estimate. We proceed under the assumption that the Analyzed Volumes for this rule relative to the No RFS Baseline comes entirely from higher domestic production, either from continuing operations in existing facilities which now produce a higher volume or from addition of new capacity. Using the JEDI model, we were able to compute the direct, indirect, and induced jobs resulting from the Analyzed Volumes under these assumptions. In this subsection, we report the cumulative impact to direct gross jobs that result from the Analyzed Volumes. We present results for the number of indirect (agriculture and industry) and induced operations jobs, along with the commensurate increase in incomes and the sensitivity analysis, in subsequent sections on Agricultural Employment (Chapter 9.1.3) and Rural Economic Development (Chapter 9.1.4).

We demonstrate results for two cases. In the first case, we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the Analyzed Volumes relative to the No RFS Baseline is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline). Since the No RFS Baseline is forward-looking and represents a potential future where the RFS program ceases to exist after 2025, this may be the more realistic representation of the job impacts of the ethanol volumes in our scenarios. However, for completeness we also present a second case, in which we assume the increased ethanol volumes come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances.

For both temporary and permanent direct job impacts, the assumed size of the model ethanol production facility in our analysis is an important assumption. In 2018, Ethanol Producer Magazine made available data on the capacity and number of employees at 65 corn ethanol facilities.⁶⁴³ These plant capacities generally compare well with those reported by EIA and estimated in the ABF study, deviating by less than 3% from the EIA report when averaged on a state-by-state basis. For these 65 facilities, we examined employee concentration as a function of production capacity. The results show a nonlinear decreasing trend in employee concentration with production capacity, suggesting economies of scale are associated with labor in ethanol plants and larger facilities are associated with fewer jobs per unit of output (Figure 9.1.3-1).

Figure 9.1.3-1: Correlation Between Employee Concentration and Facility Size for Corn Ethanol Facilities



For the purposes of this analysis, it means that depending on the size of the ethanol plant where increases (or avoided decreases) in ethanol production occur, the impacts are likely to be very different. For context, of the 187 ethanol production facilities that were currently operational in the U.S. as of January 1, 2024, approximately 57% produce less than or equal to 90 MG annually, (62.5% produce less than 100 MG or less annually), while 3.7% produce over 200 MG annually.⁶⁴⁴ Uncertainty regarding the size of the facility or facilities which will provide the incremental volume of ethanol projected in the Analyzed Volumes. Recognizing this, for the DRIA we developed two analytical perspectives, to bound uncertainty associated with facility construction. In these two perspectives, we show the cumulative job impacts assuming the construction and/or operation of both a single large facility and also assuming multiple 90 MGY facilities that add up to the total volume projected in our scenarios for that year.

While we have analyzed a full range of scenarios based on the permutations described above, here we present only the two scenarios which bound the lower and upper ends of the

⁶⁴³ Ethanol plant employment data obtained via Ethanol Producer Magazine. See “Employment information sources for corn-ethanol facilities,” available in the docket for this action.

⁶⁴⁴ EIA, “U.S. Fuel Ethanol Plant Production Capacity,” *Petroleum & Other Liquids*, August 15, 2024. <https://www.eia.gov/petroleum/ethanolcapacity>.

range of estimated employment impacts. Table 9.1.3-1 shows the cumulative number of direct jobs (permanent annual operations jobs), construction jobs (temporary annual jobs) and total jobs that would result under both scenarios (a single large “existing” facility that continues operations and multiple smaller facilities that are newly constructed). The last column in table 9.1.3-1 shows the range (maximum and minimum) of expected new total (direct) jobs that would be added to the economy during 2026 and 2027.

Table 9.1.3-1: Cumulative Direct Permanent Annual Operations Jobs, Temporary Construction Jobs & Total Direct Jobs for Analyzed Volumes (FTE)

Year	Aggregate Volume in mil gal (Multi-plant Volumes in mil gal)	Single Facility	Multi-plant Facility			Range (min– max)
		Cumulative Operations Jobs (Aggregate)	Cumulative Operations Jobs (Aggregate)	Construction Jobs	Total (Direct) Jobs	
2026	231 (90,90,51)	4	154	549	703	4–703
2027	245 (90,90,65)	5	316	578	894	5–894

9.1.4 Agricultural Employment

Job creation in the agricultural sector, beyond jobs associated with the fuel production activities discussed above, is expected primarily in the areas of production and transportation of crops serving as renewable fuel feedstocks.

Because RNG used as CNG/LNG is produced from waste or byproduct materials (*e.g.*, separated MSW, wastewater, and agricultural residue), we expect the projected increases in the production of RNG used as CNG/LNG to have very little impact on employment related to feedstock production. As noted above, EPA is projecting higher volumes of ethanol and BBD production for 2026–2027 relative to the No RFS Baseline. Substantial volumes of these fuels are expected to be produced from domestic corn, soybean oil and canola oil.

9.1.4.1 Agricultural Employment Impacts Using the Rule-of-Thumb Approach

From these studies, we have estimated the impacts of the projected crop-based renewable fuel volumes on agricultural employment. These estimates are summarized in Table 9.1.4.1-1.

Table 9.1.4.1-1: Agricultural Employment Impacts of Production (FTE)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	2,823	2,584	3,063		8,470
BBD	Oilseed production	7,059			21,177	28,236
Ethanol	Feedstock (mostly corn)	58,324	127,638	78,533		264,464

Because these estimated agricultural employment impacts represent different quantities of biofuel production, we then divide the total impact estimates in Table 9.1.4.1-1 by the total production estimated by each of the studies from which the estimates were derived in million ethanol equivalent gallons. These calculations produced estimates of the impact in terms of jobs per million ethanol equivalent gallons for each renewable fuel. These estimates are reported in Table 9.1.4.1-2. Ethanol has the highest direct and total effects on rural employment per million gallons of ethanol equivalent.

Table 9.1.4.1-2: Agricultural Employment Impacts per Million Ethanol Equivalent Gallons (FTE)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	3.2	2.9	3.5		9.6
BBD	Oilseed production	1.8			5.4	7.2
Ethanol	Feedstock (mostly corn)	3.7	8.2	5.0		17.0

We next estimate the agricultural employment impacts associated with the Analyzed Volumes by multiplying the applicable volumes in our projections by the jobs per million gallons of ethanol equivalent. We report two sets of the projections, one based on the direct effects only and the other based on all effects (*i.e.*, direct, indirect, and induced effects). These estimates are presented in Table 9.1.4.1-3 and 9.1.4.1-4 respectively. Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on agricultural employment, mainly due to substantially higher projected production increases relative to the baseline (see Chapter 3 for more details).

Table 9.1.4.1-3: Agricultural Employment Impacts of the Projected Production Increases Based on Direct Effects Only Under the Analyzed Volumes (FTE)

	Direct	
	2026	2027
RNG	2,569	2,694
Biodiesel	6,469	7,509
Ethanol	864	916
All Fuels	9,902	11,119

Table 9.1.4.1-4: Agricultural Employment Impacts of the Projected Production Increases Based on All Effects Under the Analyzed Volumes (FTE)

	Direct + Indirect + Induced	
	2026	2027
RNG	7,708	8,084
Biodiesel	25,876	30,034
Ethanol	3,916	4,153
All Fuels	37,500	42,272

9.1.4.2 Agricultural Employment Impacts Using NLR's JEDI model for Dry Mill Corn Ethanol

In this subsection, we apply the estimates discussed in Chapter 9.1.2 to the incremental amount of corn ethanol projected in the Analyzed Volumes, compared with the No RFS Baseline. From this, we were able to obtain estimates of the number of gross jobs (indirect and induced effects) that were added to the agricultural sector and allied industries.⁶⁴⁵ As stated in Chapter 9.1, some of these biofuels bear similarities in terms of their backward and forward linkages to other sectors of the economy and as such the nature of the impacts (type of impacted sectors) are going to be similar. The magnitude of the impacts will be guided by the size of the initial policy shock.

We also carried out a sensitivity analysis on these projected estimates using research from a previously published Model Comparison Exercise.⁶⁴⁶ Different modeling approaches yield different answers to the question of the source of corn to support production of a higher volume of corn ethanol. In 2022, EPA carried out a "Model Comparison Exercise" (MCE) where the performance of five different models was compared in terms of their ability to account for the impact of the RFS program on indirect emissions (a requirement of the CAA). One of the scenarios that was modeled to facilitate model comparison was a corn ethanol shock, and the results of that analysis revealed (among other things) the source of the higher corn to fuel this shock. As expected, the results were vastly different across the competing models. Two of these models (GCAM and GLOBIOM) were used in this rule to support the consequential components of the Life Cycle Analysis of biofuels (see Chapter 5). We used the sourcing estimates from those same two models in the previously published MCE to carry out the sensitivity analysis. This will allow us to compare how changing the JEDI model's default assumption (25% of this corn to support the higher production is to be sourced from new cropland) with the values obtained from GCAM (47.4%) and GLOBIOM (1%) will impact the different sectors. Table 9.1.4.2-1 shows the number of gross cumulative indirect operations jobs that are added to agriculture and allied industries and the number of gross induced operations jobs for the Analyzed Volumes, under the assumption that: (1) incremental volumes come from additional production at existing facilities, and (2) incremental volumes come from multiple facilities where the largest facility corresponds to the average size of an ethanol plant in the U.S.

⁶⁴⁵ Standard limitations associated with the limitations of the JEDI model are also applicable in this case. As with the estimates of direct jobs, please refer to the limitations of the JEDI model when it comes to interpreting these results: NLR, "Limitations of JEDI Models." <https://www.nlr.gov/analysis/jedi/limitations.html>

⁶⁴⁶ EPA, "Model Comparison Exercise Technical Document," EPA-420-R-23-017, June 2023. <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf>.

Table 9.1.4.2-1 Annual Cumulative Indirect and Induced (Gross) Jobs in Agriculture, Industry and Other Sectors for Analyzed Volumes (FTE)

Year	Indirect Operations Jobs (Agriculture)		Indirect Operations Jobs (Industry)		Induced Operations Jobs	
	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities
2026	706	706	467	624	520	632
2027	1,445	1,445	935	1,279	1,051	1,293

As we did for the DRIA, we carried out a sensitivity analysis on these projected estimates. By default, the JEDI model assumes 25% of the additional corn sourced to support the incremental corn ethanol projected to be produced under the Analyzed Volumes is to be sourced from new cropland. We supplemented this central estimate with two bookend cases to bound uncertainty. These cases assume approximately 47% and 1% respectively of the corn ethanol is sourced from new production on new cropland, which will impact job creation in the affected sectors. We applied this sensitivity to the case of continuing production at existing facilities. Since the job impacts to the economy from the addition of multiple smaller facilities is significantly higher, the results from the sensitivity analysis when applied to those numbers will generate a wider range for the estimated jobs. Table 9.1.4.2-2 shows the number of gross indirect operations jobs that emerge out of this sensitivity analysis for agriculture, industry, and gross induced operations jobs sectors.

Table 9.1.4.2-2: Results of Sensitivity Analysis on Cumulative (Indirect & Induced) Jobs for the Analyzed Volumes (FTE)

Indirect Operations Jobs (Agriculture) Cumulative FTE			
Year	High Sourcing Value (47%)	JEDI Default Value ^a (25%)	Low Sourcing Value (1%)
2026	1,339	706	28
2027	2,740	1,445	58
Indirect Operations Jobs (Industry) Cumulative FTE			
2026	467	467	467
2027	935	935	935
Induced Operations Jobs Cumulative FTE			
2026	717	520	308
2027	1,455	1,051	809

^a The results in this column correspond to the incremental output coming entirely from one single facility using JEDI's default sourcing assumption estimates.

9.1.5 Rural Economic Development

Changes in biofuel production can have economic development impacts on rural communities and financial impacts on farmers. In this final rule, we project that our Analyzed Volumes will lead to greater consumption of ethanol, BBD (including biodiesel and renewable diesel), and RNG used as CNG/LNG in 2026–2027 relative to the No RFS Baseline. When

considered relative to 2025 production and consumption of renewable fuels, most of the production growth (and therefore consumption growth) is projected to come from renewable diesel. As discussed in Chapter 3, the impacts of the RFS volumes for 2026 and 2027 on domestic ethanol production are uncertain. In their absence, domestic ethanol production could continue at a level at or near current production volumes with increasing ethanol exports, or alternatively, domestic ethanol production could decrease. However, even if only the renewable diesel projections are associated with incremental additional jobs created relative to the state of the industry in 2025, all the renewable fuel production under the 2026 and 2027 Analyzed Volumes continues to sustain economic output in rural communities. In the face of uncertainty regarding the continued production of many of these fuels in the absence of the RFS program, it is worthwhile to quantify the entirety of this economic impact on rural communities.

9.1.5.1 Rural Economic Development Impacts using the Rule-of-Thumb Approach

The Rule-of-Thumb approach and results discussed in Chapters 9.1.1 and 9.1.2, respectively, provide a basis for estimating the impact of renewable fuels on rural economic development. From these results, we have estimated impacts of the projected crop-based renewable fuel volumes on rural economic development measured by GDP. These estimated impacts on rural GDP are summarized in Table 9.1.5.1-1.

Table 9.1.5.1-1: Rural GDP Impacts of Production

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG (million 2024\$)	Agricultural waste	657	380	358		1,395
BBD (million 2021\$)	Oilseed production	1,853			5,558	7,410
Ethanol (million 2023\$)	Feedstock (mostly corn)	3,137	14,299	10,488		27,916

We divide the total impact estimates in Table 9.1.5.1-1 by the total production of each category of fuel in million ethanol equivalent gallons in each of the relevant studies to estimate the impact per million ethanol equivalent gallons for each renewable fuel category. These results are reported in Table 9.1.5.1-2.

Table 9.1.5.1-2: Rural GDP Impacts (million dollars per million ethanol-equivalent gallons)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG (2024\$)	Agricultural waste	0.75	0.43	0.41		1.59
BBD (2021\$)	Oilseed production	0.47			1.42	1.89
Ethanol (2023\$)	Feedstock (mostly corn)	0.20	0.92	0.67		1.79

The GDP impacts in Table 9.1.5.1-2 are based on data from different years. We use the GDP price index from the Federal Reserve Economic Data (FRED)⁶⁴⁷ to compute the ratio of the GDP price index in base year (2024) to the GDP price index in year t (2021–2024), as shown in Table 9.1.5.1-3.

Table 9.1.5.1-3: GDP Price Index Ratios (Base Year is 2024)

Year	GDP Price Index	GDP Price Index Ratio
2021	110	1.137
2022	118	1.061
2023	122	1.024
2024	125	1.000

We then use the ratios to compute the GDP impacts in 2024 dollars as shown in Table 9.1.5.1-4. For example, to derive 0.54 (the real value measured in 2024 dollars in Table 9.1.5.1-4), we multiply 0.47 (the nominal value in Table 9.1.5.1-2) by 1.137 (the ratio for 2021 in Table 9.1.5.1-3). We note that, compared with RNG, BBD and ethanol have higher impacts per million ethanol equivalent gallons on rural economic development.

Table 9.1.5.1-4: Rural GDP Impacts (million 2024\$ per million ethanol-equivalent gallons)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	0.75	0.43	0.41		1.59
BBD	Oilseed production	0.54			1.61	2.15
Ethanol	Feedstock (mostly corn)	0.21	0.94	0.69		1.84

We next estimate the impacts of the Analyzed Volumes by multiplying the projected production increases under these volumes with the impact per million ethanol equivalent gallons estimates shown in Table 9.1.5-2. In Table 9.1.5.1-5, we report two sets of projections, one based on the direct effects only and the other based on all effects (*i.e.*, direct, indirect, and induced effects). Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on rural economic development, largely due to substantially higher production increases relative to the baseline. In addition, we have discounted these impacts using discount rates of 3% and 7%. We report the results of our discounting calculations in Table 9.1.5.1-7. Without discounting and based only on the direct impacts, the Analyzed Volumes are projected to create \$2.58 billion and \$2.92 billion in 2026 and 2027, respectively. If we discount these direct impacts at 3%, the total impact is \$5.26 billion over the two-year horizon, or \$2.63 billion per year. If we also account for indirect and induced effects, the total impact without discounting is \$9.43 billion and \$10.76 billion in 2026 and 2027; with discounting, it is \$19.29 billion over the two-year horizon, or \$9.65 billion per year. In addition, if we amortize \$19.29 billion over the two-year horizon, the annualized value is \$10.08 billion.⁶⁴⁸

⁶⁴⁷ Federal Reserve Economic Data, “Gross domestic product (implicit price deflator),” February 20, 2026. <https://fred.stlouisfed.org/series/A191RD3A086NBEA>.

⁶⁴⁸ An annualized value is the amount one would have to pay (or receive) at the end of each time period so that the sum of all payments in present value terms equals the original stream of values. Computing annualized costs and

Table 9.1.5.1-5: Rural GDP Impacts of the Projected Production Increases (million 2024\$)

	Direct		All Effects (Direct + Indirect + Induced)	
	2026	2027	2026	2027
RNG	599	628	1,272	1,334
BBD	1,933	2,243	7,731	8,974
Ethanol	48	51	424	450
All Fuels	2,580	2,922	9,427	10,757
Present Value at 3%	2,504	2,755	9,152	10,139
All Fuels for Two Years	5,259		19,292	
All Fuels per Year	2,629		9,646	
Present Value at 7%	2,411	2,552	8,810	9,396
All Fuels for Two Years	4,963		18,206	
All Fuels per Year	2,482		9,103	

9.1.5.2 Rural Economic Development Impacts using NLR's JEDI Model for Dry Mill Corn Ethanol

We also estimated rural economic development impacts associated with corn ethanol using the NLR JEDI model. These estimates assume the ethanol volumes are associated with new domestic production and are presented as annual cumulative earnings impacts. Relying on the JEDI model to compute the employment impacts stemming from such an increase in production, we were able to assess the economic impacts to the rural economy under the same scenario specifications as in Chapter 9.1.2.1.2, firstly in a situation where this higher production comes from existing facilities and, secondly, in another situation where this higher production comes from multiple new smaller facilities. Based on our analysis, Table 9.1.5.2-1 shows the economic impacts of continued operations at higher volumes from existing facilities and from multiple new average sized facilities for the Analyzed Volumes.

Table 9.1.5.2-1: Annual Cumulative Earnings from All Indirect and Induced Jobs for the Analyzed Volumes (million 2024\$)

Year	Indirect Operations Earnings (Agriculture)		Indirect Operations Earnings (Industry)		Induced Operations Earnings	
	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities	Single Large Facility	Multiple Smaller Facilities
2026	38	37	45	57	39	46
2027	78	75	89	116	79	96

benefits from present values spreads the costs and benefits equally over each period, taking account of the discount rate.

As in Chapter 9.1.5, we were able to conduct a sensitivity analysis where the percentage of new cropland that was sourced to produce the additional ethanol was the parameter that was given alternate values (see Chapter 9.1.4.2 and the DRIA for more details on this analysis). Table 9.1.5.2-1 shows the impact on earnings that emerge out of this sensitivity analysis for agriculture, industry and other sectors (induced jobs) where the second column in Table 9.1.5.2-1 shows the outcome when 47% of this corn (for ethanol) is sourced from new agricultural production/new plantings, the third column shows the results if 25% is from new production, and the last column shows the impacts when 1% is from production.

Table 9.1.5.2-1: Results of Sensitivity Analysis on Cumulative (Indirect & Induced) Earnings (million 2024\$)

Indirect Earnings (Agriculture)			
Year	High Sourcing Value (47%)	JEDI Default Value (25%)	Low Sourcing Value (1%)
2026	70	39	2
2027	114	77	3
Indirect Earnings (Industry)			
2026	44	45	44
2027	99	89	88
Induced Earnings			
2026	53	39	22
2027	108	79	45

9.1.6 Summary of Employment and Economic Impacts

In this section, we summarize our main results for the employment, agricultural employment, and rural economic development for the Analyzed Volumes. As discussed above, the “Rule-of-Thumb” approach produces estimates for the impacts of the quantities of all three categories of renewable fuel we analyzed—ethanol, BBD, and RNG—under the Analyzed Volumes relative to the No RFS Baseline. The JEDI model approach provides estimates for dry mill corn ethanol only, which we apply to the volumes of that fuel for the Analyzed Volumes relative to the No RFS Baseline. The summary below includes the estimated potential employment impacts, agricultural employment impacts, and rural GDP impacts associated with the volumes of ethanol, BBD, and RNG attributable to the Analyzed Volumes.

With the “Rule-of-Thumb” approach, we estimate that all three categories of renewable fuel we analyzed—ethanol, BBD, and RNG—are associated with increases in employment to varying degrees. We observe that (1) RNG appears to be associated with the highest number of direct and total jobs created per unit of biofuel (9.1 and 27.2, respectively) and (2) BBD and ethanol have higher indirect and induced impacts relative to their direct impacts. See Table 9.1.6-1.

Table 9.1.6-1: Job Creation Impacts per Million Ethanol-Equivalent Gallons (FTE)

	Direct	Indirect + Induced			Total	Multiplier
		Indirect	Induced	Combined		
RNG	9.1	8.5	9.6		27.2	3.0
BBD	4.8			14.4	19.2	4.0
Ethanol	4.6	13.0	7.5		25.2	5.5

However, BBD is projected to have the highest job creation impact overall, primarily due to substantially higher production increases relative to the baseline, for the Analyzed Volumes (Table 9.1.6-2a).

Using the JEDI model for corn ethanol, we created the following two scenarios to estimate the impacts of the Analyzed Volumes on the economy: (1) we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the Analyzed Volumes (relative to the No RFS Baseline) is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline) and (2) a second case, in which we assume the increased ethanol volumes (relative to the No RFS Baseline) come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances. Tables 9.1.6-2b reports the cumulative number of total jobs (in FTE) that would result under the Analyzed Volumes.

Table 9.1.6-2a: Employment Impacts of the Analyzed Volumes using the Rule-of-Thumb Approach (FTE)

	2026	2027
Ethanol	5,810	6,162
BBD	68,912	79,986
RNG	21,765	22,827
Total	96,487	108,975

Table 9.1.6-2b: Employment Impacts of the Analyzed Volumes using NLR's JEDI Model for Dry Mill Corn Ethanol (FTE)

	2026	2027
Ethanol	1,698-2,665	3,436-4,911

Note: The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the range and the multi facility outcome as the upper bound of the range.

In terms of agricultural employment specifically, with the “Rule-of-Thumb” approach, we use the job creation impacts associated with agricultural feedstocks to infer the effects on agricultural employment. Ethanol has the highest direct and total effects per million gallons of ethanol equivalent, as shown in Table 9.1.6-3.

Table 9.1.6-3: Agricultural Employment Impacts per Million Ethanol Equivalent Gallons (FTE)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	3.2	2.9	3.5		9.6
BBD	Oilseed production	1.8			5.4	7.2
Ethanol	Feedstock (mostly corn)	3.7	8.2	5.0		17.0

Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on agricultural employment, mainly due to substantially higher production increases relative to the baseline, for the Analyzed Volumes. See Table 9.1.6-4a.

Once again, using the JEDI model for corn ethanol, we created the following two scenarios to estimate the impacts of the Analyzed Volumes on the economy: (1) we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the Analyzed Volumes (relative to the No RFS Baseline) is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline) and (2) a second case, in which we assume the increased ethanol volumes (relative to the No RFS Baseline) come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances. Table 9.1.6-4b reports the cumulative number of total indirect operations (in agriculture and industry) jobs and the total induced operations jobs that would result under the Analyzed Volumes. For the results of the sensitivity analysis, please refer to Tables 9.1.4.2-1 and 9.1.4.2-2.

Table 9.1.6-4a: Agricultural Employment Impacts of the Analyzed Volumes Using the Rule-of-Thumb Approach (FTE)

	2026	2027
Ethanol	3,916	4,153
BBD	25,876	30,034
RNG	7,708	8,084
Total	37,500	42,272

Table 9.1.6-4b: Agricultural Employment Impacts of the Analyzed Volumes Using NLR's JEDI Model for Dry Mill Corn Ethanol (FTE)

	2026	2027
Ethanol	1,693-1,962	3,431-4,017

Note: The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the range and the multi facility outcome as the upper bound of the range.

With the “Rule-of-Thumb” approach, we also estimate that ethanol, BBD, and RNG are all associated with increased rural economic development, again to varying degrees. Since renewable fuels rely on agricultural feedstocks, we use the GDP impacts associated with agricultural feedstocks to infer the effects on rural economic development. We estimate that

BBD and ethanol have higher total impacts per million ethanol equivalent gallons on rural economic development than does RNG. See Table 9.1.6-5.

Table 9.1.6-5: Rural GDP Impacts per Million Ethanol Equivalent Gallons (million 2024\$)

	Feedstock	Direct	Indirect	Induced	Indirect + Induced	Total
RNG	Agricultural waste	0.75	0.43	0.41		1.59
BBD	Oilseed production	0.54			1.61	2.15
Ethanol	Feedstock (mostly corn)	0.21	0.94	0.69		1.84

Relative to the No RFS Baseline and accounting for direct, indirect, and induced effects, BBD is projected to have the highest impact on rural economic development, largely due to substantially higher production increases relative to the baseline. See Table 9.1.6-6a. The total impact without discounting is \$9.43 billion and \$10.76 billion in 2026 and 2027; with discounting at a 3% discount rate, it is \$19.29 billion over the two-year horizon, or \$9.65 billion per year. In addition, if we amortize \$19.29 billion over the two-year horizon, the annualized value is \$10.08 billion.

Once again, using the JEDI model for corn ethanol, we created the following two scenarios to estimate the impacts of the Analyzed Volumes on the economy: (1) we assume there is no new construction of ethanol facilities and the increased ethanol volume associated with the Analyzed Volumes (relative to the No RFS Baseline) is met by increasing production levels at existing facilities (or in the alternative the avoidance of reduced corn ethanol production that would occur in the No RFS Baseline) and (2) a second case, in which we assume the increased ethanol volumes (relative to the No RFS Baseline) come from new construction. To the extent that retiring ethanol production capital is replaced with new and more efficient facilities in 2026 and 2027, this analysis would be relevant to those circumstances. Table 9.1.6-6b reports the cumulative earnings from the number of total indirect operations (in agriculture and industry) jobs and the total induced operations jobs (in FTE) that would result under the Analyzed Volumes. For the results of the sensitivity analysis, please refer to Tables 9.1.5.2-1 and 9.1.5.2-2.

Table 9.1.6-6a: Rural Economic Development Impacts of the Analyzed Volumes (million 2024\$)

	All Effects (Direct + Indirect + Induced)	
	2026	2027
RNG	1,272	1,334
BBD	7,731	8,974
Ethanol	424	450
All Fuels	9,427	10,757
Present Value at 3%	9,152	10,139
All fuels for two years	19,292	
All fuels per year	9,646	
Present Value at 7%	8,810	9,396
All fuels for two years	18,206	
All fuels per year	9,103	

Table 9.1.6-6b: Rural Economic Development Impacts of the Analyzed Volumes Using NLR’s JEDI Model for Dry Mill Corn Ethanol (million 2024\$)

	2026	2027
Ethanol	123-140	246-288

Note: The estimates are presented as ranges corresponding to the single facility outcome as the lower bound of the range and the multi facility outcome as the upper bound of the range.

These estimates in Chapter 9.1 for the various categories of biofuels are subject to the limitations and assumptions of the methods employed. They are not meant to be exact estimates, but rather to provide an estimate of general magnitude. In addition, while we estimate that production and consumption of these biofuels will lead to higher jobs and rural GDP in some sectors of the economy, this will likely involve some migration in jobs and rural GDP from other sectors. As such, we anticipate that there would be job and rural GDP losses as well in some sectors. Likewise, investments in rural development may involve some shifting of capital from one sector to another. We do not account for any such losses in our analysis. In other words, our estimates for jobs and rural development impacts are gross and not net estimates. While we have also not been able to quantify the impacts of this rule on small entities in rural areas, we note that we do anticipate that small entities (such as farms and supporting industries) will experience benefits from this rule.

The existing literature also shows, in the long run, environmental regulation such as the RFS program typically affects the distribution of employment among industries rather than the general employment level.^{649,650} The expectation is that there will be a movement of labor

⁶⁴⁹ Arrow, Kenneth J., Maureen L. Cropper, George C. Eads, Robert W. Hahn, Lester B. Lave, Roger G. Noll, Paul R. Portney, et al. “Benefit-Cost Analysis in Environmental, Health, and Safety Regulation,” *American Enterprise Institute, The Annapolis Center, and Resources for the Future*, 1996. https://www.aei.org/wp-content/uploads/2014/04/-benefitcost-analysis-in-environmental-health-and-safety-regulation_161535983778.pdf.

⁶⁵⁰ Hafstead, Marc a. C., and Robertson C. Williams. “Jobs and Environmental Regulation.” *Environmental and Energy Policy and the Economy* 1 (January 1, 2020): 192–240. <https://doi.org/10.1086/706799>.

towards jobs that are associated with greater environmental protection, and away from those that are not. Even if impacts are small after long-run market adjustments to full employment, many regulatory actions move workers in and out of jobs and industries, which are potentially important distributional impacts of environmental regulations.⁶⁵¹

9.2 Supply of Agricultural Commodities

Changes in biofuel production can have an impact on the supply of agricultural commodities. The Analyzed Volumes in this rule suggest the potential for associated increases in underlying crop production; however, the magnitude of any potential impact cannot be estimated with any certainty. EPA notes that biogas is not produced from agricultural commodities and therefore is not expected to affect their supply or price.

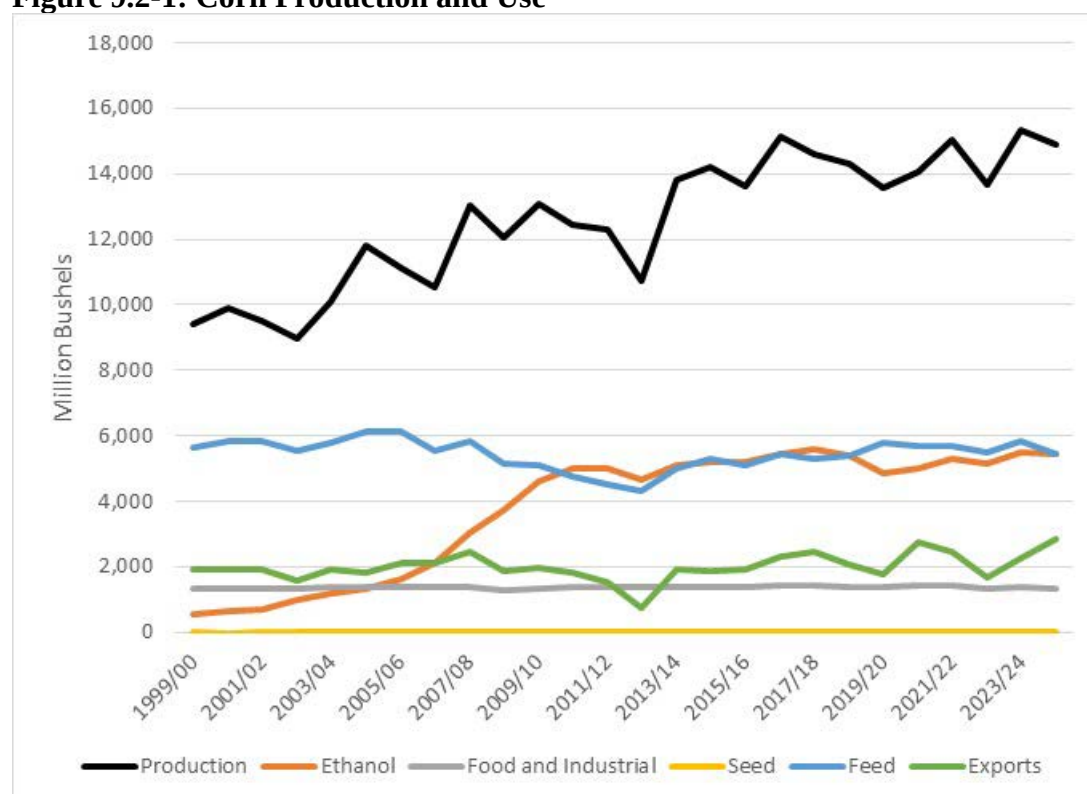
For historical context, Figure 9.2-1 shows trends in corn production and uses from 1999/2000–2024/2005.^{652,653} This data suggests domestic corn production has grown steadily at a 25-year average rate of around 2% year over year, or 220 million bushels added annually.

⁶⁵¹ Walker, W. Reed. “The Transitional Costs of Sectoral Reallocation: Evidence From the Clean Air Act and the Workforce*.” *The Quarterly Journal of Economics* 128, no. 4 (August 15, 2013): 1787–1835. <https://doi.org/10.1093/qje/qjt022>.

⁶⁵² USDA, “Feed Grains Yearbook Tables,” February 11, 2026, Table 4. <https://www.ers.usda.gov/data-products/feed-grains-database/feed-grains-yearbook-tables>.

⁶⁵³ USDA, “U.S. Bioenergy Statistics,” January 21, 2026, Table 5. <https://www.ers.usda.gov/data-products/us-bioenergy-statistics>.

Figure 9.2-1: Corn Production and Use



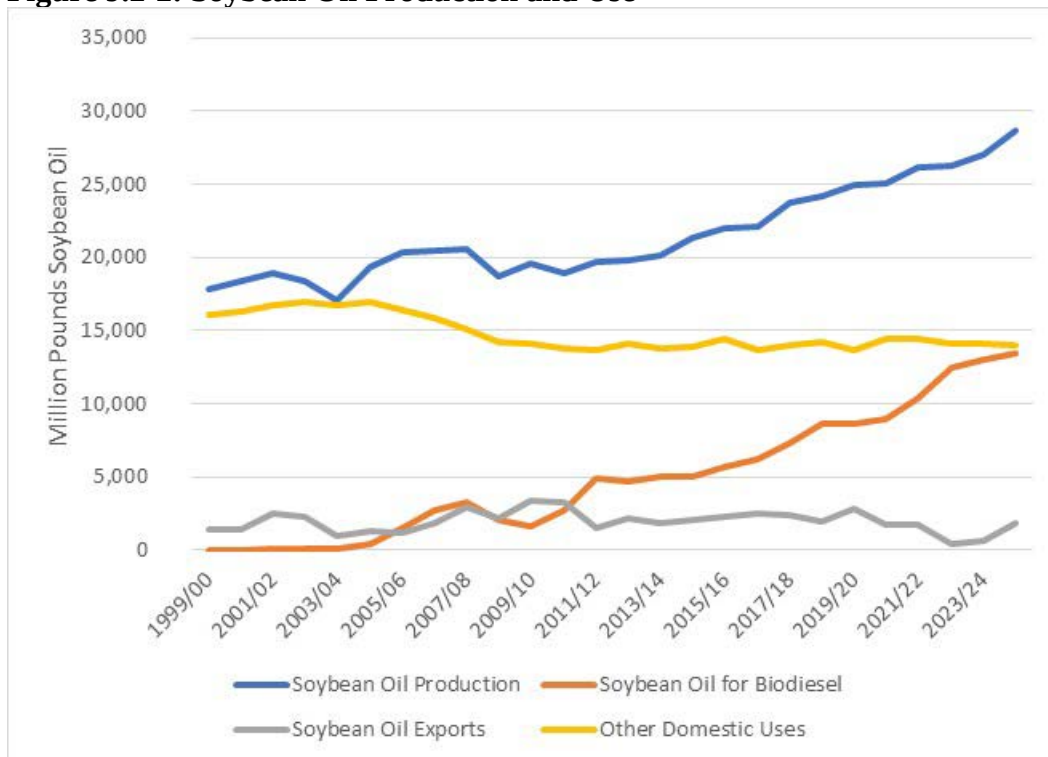
Between 2005–2010, additional corn required to satisfy increasing ethanol production was sourced primarily by diversion from animal feed until overall production caught up. Supply of corn to food uses showed modest but consistent growth at historical rates during this period, despite increased consumption as ethanol feedstock. Exports also remained relatively steady, except for a drop corresponding to weather-related supply disruptions and elevated prices in 2011–2012. Animal feed use began to rebound after 2014 when growth in ethanol use slowed and prices stabilized. Another factor contributing to the longer-term shift of animal feed away from whole corn was the increasing substitution with DDGS, a byproduct of ethanol production. Considering historical trends over the past two decades indicating the ability of production to rise to meet demand, the relatively modest changes in ethanol volumes associated with this rule relative to 2025 are likely to have minimal impact on the supply of corn to food, exports, or other uses.

Soybean production has risen steadily over time, similar to the trend for corn production, according to data from USDA.⁶⁵⁴ Roughly 80% of growth in soybean production since 2005 has been associated with rising exports of soybeans, which have nearly doubled over that period. Domestic crushing of soybeans has grown by about 25% since 2005, which is mirrored in growth of crush products, soybean meal, and soybean oil. These data also show that exports of soybean meal nearly doubled during this time, which together with the growth in whole soybean exports, presents a picture consistent with expansion of meat production internationally. For context, over 95% of soybeans worldwide are eventually crushed for meal and oil.

⁶⁵⁴ USDA, “Oil Crops Yearbook,” March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

Figure 9.2-2 shows the evolution of soybean oil production and disappearance in the U.S. since 2001. Growth in soybean oil production over the past decade has been enabled by both increasing crush capacity and increasing yields of oil per bushel of soybean input. The use of soybean oil for biofuel production has also increased steeply since about 2014, with a further uptick since 2020. In this final rule we are projecting that even greater quantities of soybean oil will be used for biofuel production in 2026 and 2027. With the strong incentives provided by the RFS program and the structure of the CFPC which favors the domestic production of biofuel from North American feedstocks we may see a shift of in the quantity of soybean oil used in non-biofuel markets to enable greater production of biofuel from domestic soybean oil. We do not expect that this shift will result in vegetable oil shortages in the U.S. due to the wide range of vegetable oils used in non-biofuel markets and available to U.S. consumers. However, as discussed further in Chapter 9.3 an increase in demand for soybean oil for biofuel production is projected to result in higher soybean oil prices and could shift the relative value relationship between the oil and meal crush products.

Figure 9.2-2: Soybean Oil Production and Use



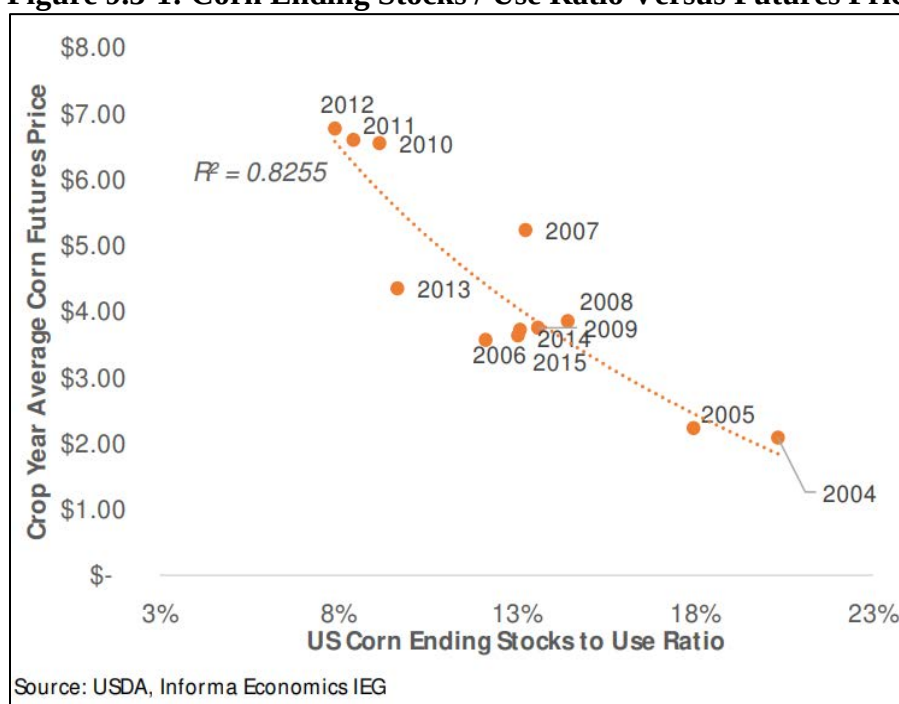
9.3 Price of Agricultural Commodities

Agricultural commodities are bought and sold on the international market, where prices are determined by trends and upsets in worldwide production and consumption. Renewable fuels are only one factor among many (*e.g.*, droughts and storm damage) in determining commodity prices. Thus, models that attempt to project prices at specific times in the future, or in reaction to specific demand perturbations, necessarily contain high levels of uncertainty. This section reviews historical trends and presents key observations from the relevant literature.

In the U.S., corn and soybeans are generally only harvested once per year, and therefore storage is a critical factor in the supply chain. After harvest, grain stores are replenished and then drawn down throughout the year. In recent years, 10–15% of the previous year’s overall corn production is typically still in storage at the time of the new harvest.⁶⁵⁵ If demand rises after harvest, stocks may be drawn down faster than expected. Conversely, if demand decreases, stocks accumulate into the next season.

Storage also has the effect of dampening price shocks in years when harvests are smaller than expected. In 2012, a drought year, corn stocks fell to the lowest levels since 2000, putting upward pressure on futures prices, which in turn served as a market signal to induce more corn planting in the upcoming season. Work done by Informa Economics for the Renewable Fuels Association in 2016 examined the historical relationship between corn usage, stocks, and futures prices.⁶⁵⁶ Figure 9.3-1 shows the strong correlation between futures prices and the stock-to-usage ratio, illustrating that the latter is a key driver of market signals. More generally, crop prices are influenced by an array of factors from worldwide weather patterns to biofuel policies to international tariffs and trade wars.

Figure 9.3-1: Corn Ending Stocks / Use Ratio Versus Futures Price



To make more specific quantitative estimates of the impact of increased biofuel production on corn prices, we considered two meta-studies. Condon, et al., reviewed 29 published papers in 2015 and found a central estimate of 3–5% increase in corn prices per billion

⁶⁵⁵ USDA, “Feed Grains Yearbook,” May 2025. <https://www.ers.usda.gov/data-products/feed-grains-database/feed-grains-yearbook-tables>.

⁶⁵⁶ Informa Economics IEG, “The Impact of Ethanol Industry Expansion on Food Prices: A Retrospective Analysis,” 2016. <https://d35t1syewk4d42.cloudfront.net/file/975/Retrospective-of-Impact-of-Ethanol-on-Food-Prices-2016.pdf>.

gallons of ethanol.⁶⁵⁷ Focusing only on scenarios where a supply response is included gives a result of 3%. A supply response refers to scenarios where farmers can respond to price signals in subsequent year(s) and plant additional crops to meet a larger demand. This is appropriate, as the scope of the analysis is biofuel policy (rather than something unforeseen like weather shocks). A similar meta-analysis was done in 2016 by FAPRI-Missouri that considered other studies.⁶⁵⁸ This paper found an increase of \$0.19 per bushel per billion gallons, or \$0.15 if a supply response is included, a figure that is generally consistent with the 3% impact above if applied to the corn price in 2016.⁶⁵⁹

EPA is projecting a marginal increase in ethanol volumes for years 2026–2027 relative to the No RFS Baseline. We note, however, that in recent years domestic ethanol production has exceeded consumption, with significant volumes being exported. This trend appears very likely to continue during 2026–2027, as our projected consumption volumes remain below USDA’s projected domestic production volumes for these years.⁶⁶⁰ A history of significant export volumes complicates predicting the impact of the projected volumes on agricultural commodity prices. It is possible that an increase in domestic corn ethanol consumption may result in decreased exports and minimal change in overall domestic production volumes. Were this to occur, we would expect little to no net change in domestic corn demand, and thus corn prices, which we would expect to maintain their current levels. Alternatively, lower U.S. net corn exports could reduce supply to international markets and put upward pressure on global corn prices. It is also possible (though less likely) that an increase in consumption would result in an increase in domestic corn ethanol production. In this case we would expect a correlated change in corn demand and corn prices.

To illustrate the potential impact of the volumes on corn prices, we have calculated the projected impact in 2026–2027 if the Analyzed Volumes result in increased corn ethanol production relative to the No RFS Baseline. The projected price impacts are calculated using a value from the literature of 3% increase in the price of a bushel of corn per billion gallons of corn ethanol produced, as described above. The projected impact of the Analyzed Volumes on corn prices relative to the No RFS Baseline are shown in Table 9.3-1.

⁶⁵⁷ Condon, Nicole, Heather Klemick, and Ann Wolverton. “Impacts of Ethanol Policy on Corn Prices: A Review and Meta-analysis of Recent Evidence.” *Food Policy* 51 (January 13, 2015): 63–73. <https://doi.org/10.1016/j.foodpol.2014.12.007>.

⁶⁵⁸ FAPRI, “Literature Review of Estimated Market Effects of U.S. Corn Starch Ethanol.” FAPRI-MU Report #01-16, February 2016. <https://ethanolrfa.org/file/2007/FAPRI-Report-01-16.pdf>.

⁶⁵⁹ These two studies are both based on older market conditions that may no longer hold. They also examine a one-billion-gallon shock size, which is larger than the volume of corn ethanol attributable to this final rule.

⁶⁶⁰ USDA, “USDA Agricultural Projections to 2034,” OCE-2025-1, February 2025. <https://doi.org/10.32747/2025.9015815.ers>.

Table 9.3-1: Projected Impact on Corn Prices Relative to No RFS Baseline

	Units	2026	2027
Corn Price ^a	\$ per bushel	\$3.97	\$4.07
Corn Price Response	(%) per billion gallons of ethanol	3%	3%
Corn Ethanol Volume Increase Relative to No RFS Baseline	billion gallons	0.231	0.245
Corn Price Increase Relative to No RFS Baseline	\$ per bushel	\$0.03	\$0.03

^a Corn prices are from: USDA, “USDA Agricultural Projections to 2034,” OCE-2025-1, February 2025. <https://doi.org/10.32747/2025.9015815.ers>. Prices represent the average price for a calendar year. For corn, the price is calculated using 1/3 of the price for the first agricultural marketing year (*e.g.*, 2025/2026 for 2026) and 2/3 of the price for the second agricultural marketing year (*e.g.*, 2026/2027 for 2026).

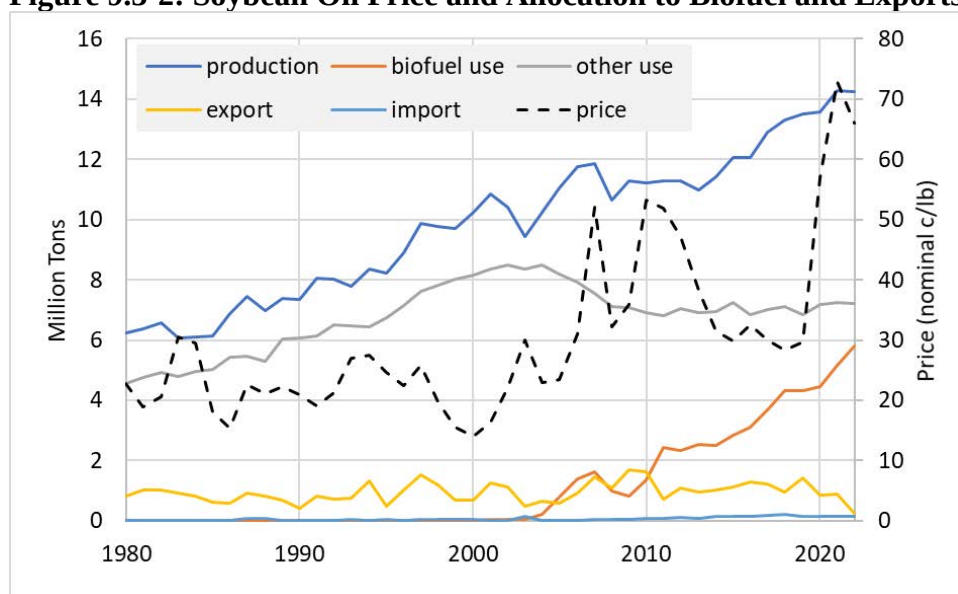
For biodiesel and renewable diesel production, the primary commodity input of interest is soybean oil, which has an indirect link to soybean production. Soybean oil is produced by crushing soybeans, a process which coproduces soybean meal. The supply and prices of soybean oil and soybean meal can move independently from each other. The crush quantities vary from year to year, depending on the crush margin, which is defined as the sum of soybean oil and meal prices minus the soybean price. Oversupplying either oil or meal markets can cause prices to fall, decreasing the crush margin. Figure 9.3-2 shows historical trends in soybean oil prices alongside allocation to biofuel and other uses, based on data taken from the USDA Oil Crops Yearbook.⁶⁶¹ Use of soybean oil in domestic biofuel rose from 0.8 million tons in 2005 to 7 million tons in 2024. Other domestic uses besides biofuel increased steadily through 2005, decreased slightly from 2005–2010, and have remained relatively consistent since 2010. Exports of soybean oil are a minor demand and remained consistent for many years until falling following steep price increases since 2020.

While additional research examining the correlation between soybean oil price and its use in biofuel production historically would be beneficial, soybean oil prices have been reactive in recent years to anticipated and announced biofuel policy developments. These price fluctuations have contributed to a rising share of soybean value derived from soybean oil over time. However, the price of soybean oil is influenced by many factors occurring in the broader economy, including petroleum prices, supply chain disruptions on a range of inputs (*e.g.*, fertilizer), prices of other vegetable oils, weather-related shortages of vegetable oils internationally, as well as general price inflation. While increased soybean oil demand for biofuel production was likely a contributing factor to the sharp price increase in soybean oil prices in 2020 and 2021, poor weather conditions in South America and Malaysia were also likely a significant factor.⁶⁶²

⁶⁶¹ USDA, “Oil Crops Yearbook,” March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

⁶⁶² Wilson, Nick. “Oil prices surge — vegetable oil, that is,” *Marketplace*, February 17, 2022. <https://www.marketplace.org/story/2022/02/17/oil-prices-surge-vegetable-oil-that-is>.

Figure 9.3-2: Soybean Oil Price and Allocation to Biofuel and Exports



There are relatively few quantitative studies on the impacts of BBD production on soybean oil and soybean prices, and they show a range of results.^{663,664,665} This is in part because these studies have included a variety of different policy combinations, none of which isolated the impact of the RFS program on BBD demand. Ethanol demand could impact the soybean markets even in the absence of increased demand for BBD from the RFS program due to increased competition for cropland and other inputs. The largest impacts are estimated when the BBD obligations are modeled jointly with the conventional and cellulosic ethanol obligations.

To illustrate the potential impact of the Analyzed Volumes on soybean prices, we calculate the projected price effects for the 2026 to 2027 period relative to the No RFS Baseline. As in the Set 1 Rule, our projections are primarily based on a linear equilibrium displacement model by Lusk, which estimates the price impact of a 20% shock to current biofuel volumes.⁶⁶⁶ This model links such a shock to changes in prices of soybean oil and related commodities.

Several aspects of this study are important to note to properly understand and apply its findings. First, the model of soybean oil price changes in response to shocks described in the Lusk paper (hereafter “the Lusk model”) expresses results in terms of percentage changes. For example, as presented in the paper, a 20% exogenous increase in the quantity of soybean oil demanded for biofuel use, combined with relatively inelastic supply and downward-sloping

⁶⁶³ Kim, Hyunseok, and GianCarlo Moschini. “The Dynamics of Supply: U.S. Corn and Soybeans in the Biofuel Era.” *Land Economics* 94, no. 4 (October 3, 2018): 593–613. <https://doi.org/10.3368/le.94.4.593>.

⁶⁶⁴ Santeramo, Fabio Gaetano. “Cross-Price Elasticities for Oils and Fats in the US and the EU.” International Council on Clean Transportation, 2017. https://theicct.org/sites/default/files/publications/Cross-price-elasticities-for-oils-fats-US-EU_ICCT_consultant-report_06032017.pdf.

⁶⁶⁵ Williams, Brian R., and Gayle Pounds-Barnett. “Producer Supply Response for Area Planted of Seven Major U.S. Crops.” U.S. Department of Agriculture, Economic Research Service, 2023. <https://doi.org/10.32747/2023.8134361.ers>.

⁶⁶⁶ Lusk, Jayson L. “Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil,” November 10, 2022. https://ag.purdue.edu/cfdas/wp-content/uploads/2022/12/report_soymodel_revised13.pdf.

demand, requires a higher equilibrium price to clear the market; solving the system yields an 8.17% increase in the soybean oil price. Second, the Lusk model is linear. If one shock is a scalar multiple of another, the resulting price and quantity changes scale accordingly. For example, doubling the shock from 20% to 40% doubles the price response. Thus, a 40% shock implies a soybean oil price increase of 16.34% ($2 \times 8.17\% = 16.34\%$). Third, the Lusk model calculates percentage changes as deviations from a baseline (reference) year. Absolute shocks should be converted back to percentage deviations using the same baseline quantities. If the baseline changes materially, or elasticities vary with price levels, linearity may not hold. Consequently, results should be interpreted as local comparative-static approximations around the reference equilibrium rather than large structural changes. Our calculations use 2025 as the baseline (reference) year.

The following illustrates how the soybean oil price impacts in Table 9.3-2 are derived:

(1) The soybean oil prices for 2026 and 2027 in the No RFS Baseline are not observed and are inferred using Lusk's linear percentage-change model. In the Lusk model, for soybean oil, a 20% demand increase yields an 8.17% price increase, so price changes scale at 8.17/20. For 2026, the estimated demand change is -58%. This is computed as the percentage difference between the quantity of soybean oil projected to be used in 2026 without the RFS volume requirements (573 million gallons) and the quantity of soybean oil used for biofuel production in 2025 (1,355 million gallons), *i.e.*, $(573 - 1,355) / 1,355 \approx -58\%$. Taking this -58% estimate as a given assumption, the implied price change is approximately -24% ($-58\% \times [8.17/20] \approx -24\%$). Using the 2025 base price of \$0.49/lb, this gives a No RFS price of approximately \$0.38/lb ($0.49 \times [1-24\%] \approx 0.38$) in 2026. For 2027, the estimated demand change is -78%. This is computed as the percentage difference between the quantity of soybean oil projected to be used in 2027 without the RFS volume requirements (302 million gallons) and the quantity of soybean oil used for biofuel production in 2025 (1,355 million gallons), *i.e.*, $(302 - 1,355) / 1,355 \approx -78\%$. Taking this -78% estimate as a given assumption, the implied price change is -32% ($-78\% \times [8.17/20] \approx -32\%$). Using the 2025 base price of \$0.49/lb, this gives a No RFS price of \$0.33/lb ($0.49 \times [1-32\%] \approx 0.33$) in 2027.

(2) The soybean oil prices in 2026 and 2027 with the RFS volume requirements in place must similarly be projected using Lusk's linear percentage-change model. In the Lusk model, for soybean oil, a 20% demand increase yields an 8.17% price increase, so price changes scale at 8.17/20. For 2026, the estimated demand change is +84%. This is computed as the percentage difference between the quantity of soybean oil projected to be used in 2026 with the RFS volume requirements (2,495 million gallons) and the quantity of soybean oil used for biofuel production in 2025 (1,355 million gallons), *i.e.*, $(2,495 - 1,355) / 1,355 \approx +84\%$. Taking this +84% estimate as a given assumption, the implied price change is +34% ($+84\% \times [8.17/20] \approx +34\%$). Using the 2025 base price of \$0.49/lb, this gives a projected soybean oil price of \$0.66/lb ($0.49 \times [1+34\%] \approx 0.66$) in 2026. For 2027, the estimated demand change is +95%. This is computed as the percentage difference between the quantity of soybean oil projected to be used in 2027 with the RFS volume requirements (2,639 million gallons) and the quantity of soybean oil used for biofuel production in 2025 (1,355 million gallons), *i.e.*, $(2,639 - 1,355) / 1,355 \approx +95\%$. Taking this +95% estimate as a given assumption, the implied price change is +39% ($+95\% \times [8.17/20]$

$\approx +39\%$). Using the 2025 base price of \$0.49/lb, this gives a projected soybean oil price of \$0.68/lb ($0.49 \times [1+39\%] \approx 0.68$) in 2027.

Comparing (1) and (2), the soybean price differences between the No RFS Baseline and the scenario with the RFS volume requirements are \$0.28/lb for 2026 ($0.66 - 0.38 = 0.28$) and \$0.35/lb for 2027 ($0.68 - 0.33 = 0.35$). See Table 9.3-2.

Furthermore, our soybean meal price impact calculations are based on the Lusk model's cross-price relationship that an 8.17% increase in soybean oil price is associated with a 1.93% decrease in soybean meal price. Using 2025 as the common reference year, we first convert the absolute soybean oil price shocks to percentage deviations from the 2025 oil price of \$0.49/lb: a \$0.28/lb increase in 2026 corresponds to 58% ($\approx 0.28/0.49$) and a \$0.35/lb increase in 2027 corresponds to 70% ($\approx 0.35/0.49$). We then map soybean oil price changes to soybean meal price changes using the Lusk ratio, $-1.93\%/8.17\%$, which implies a linear relationship over the range considered. We conclude that a 58% increase in oil price is associated with a 14% ($\approx 58\% \times [-1.93\%]/8.17\%$) decrease in soybean meal price, and a 70% increase in soybean oil price is associated with a 17% ($\approx 70\% \times [-1.93\%]/8.17\%$) decrease in soybean meal price. Given a 2025 soybean meal market price of \$291.34/ton, a 14% decrease corresponds to a reduction of approximately \$40/ton, and a 17% decrease corresponds to a reduction of approximately \$49/ton, as shown in Table 9.3-2.

The projected impacts of the Analyzed Volumes on soybean oil and soybean meal prices at the time of this rule based on the Lusk model are shown in Tables 9.3-2. Note that, a positive soybean oil shock yields a negative soybean meal response under this model; results reflect a proportional (linear) application of the Lusk relationship; and minor differences may arise from rounding.

Table 9.3-2: Projected Impact of the Analyzed Volumes on Soybean Oil and Meal Prices Relative to the No RFS Baseline

	Units	2026	2027
Soybean Oil Increase Relative to No RFS Baseline ^a	million gallons	1,922	2,337
Projected Soybean Oil Price (under RFS) ^b	\$ per pound	\$0.66	\$0.68
Soybean Oil Price Increase Relative to No RFS Baseline ^b	\$ per pound	\$0.28	\$0.35
Soybean Meal Price Change Relative to No RFS Baseline ^b	\$ per ton	-\$40	-\$49

^a Soybean oil volumes in this table are 3.1% higher than the volume of biofuels produced from soybean oil attributable to this rule from Table 3.2.2. This 3.1% increase accounts for the fact that it takes slightly more than one gallon of soybean oil to produce one gallon of renewable diesel.

^b Prices are calculated using estimates from the Lusk paper, with 2025 as the baseline (reference) year when the soybean oil market price was \$0.49/lb and soybean meal market price was \$291.34/ton. Business Insider, "Soybean Oil Spot Price Chart," <https://markets.businessinsider.com/commodities/soybean-oil-price>, and "Soybean Meal Spot Price Chart," <https://markets.businessinsider.com/commodities/soybean-meal-price>.

The changes in the prices of soybean oil and soybean meal presented in Table 9.3-2 are calculated considering only the increase in the quantity of soybean oil used for biofuel production. This is consistent with the Lusk model, which modeled the impacts of increased soybean oil demand for biofuel production assuming demand for other commodities used for biofuel production remained constant. However, we project that to meet the volumes we are finalizing for 2026 and 2027 in this rule we will see significant increases in the use of both soybean oil and canola oil for biofuel production. This is an important consideration, as canola oil is a relatively common substitute for soybean oil. Simultaneously increasing the demand for both soybean oil and canola oil for biofuel demand could have an even greater impact on the prices of soybean oil and soybean meal than if we were only increasing demand for soybean oil.

We were unable to find any estimates of the price impact of simultaneous increasing demand for soybean oil and canola oil for biofuel production in the published literature. To estimate the potential price impacts of this scenario we once again used the price responses from the Lusk model. However, rather than considering only the increase in the use of soybean oil for biofuel production for this scenario we also considered the increase in canola oil relative to the 2025 baseline. These larger quantities of vegetable oils used for biofuel production (3,720 million gallons in 2026 and 3,980 million gallons in 2027) result in larger projected increases in the soybean oil prices and larger projected decreases in the soybean meal prices. These results are summarized in Table 9.3-3.

Table 9.3-3: Projected Impact of the Analyzed Volumes on Soybean Oil and Meal Prices Relative to the No RFS Baseline (High Price Sensitivity)

	Units	2026	2027
Soybean Oil Biofuel Increase Relative to No RFS Baseline	million gallons	3,088	3,647
Projected Soybean Oil Price (High Price Sensitivity)	\$ per pound	\$0.86	\$0.90
Soybean Oil Price Increase Relative to No RFS Baseline	\$ per pound	\$0.48	\$0.57
Soybean Meal Price Change Relative to No RFS Baseline	\$ per ton	-\$68	-\$79

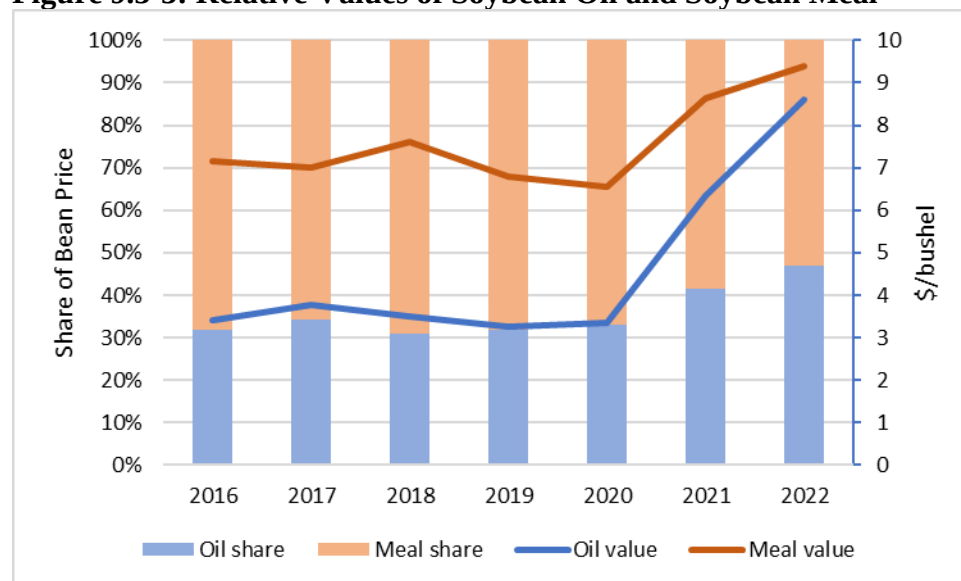
The results of the Lusk modeling, on which our price impacts for soybean oil and soybean meal are based, are supported by empirical data. Analysis published by Irwin at the University of Illinois indicates that soybean oil prices often move separately from meal and bean prices, and that the latter two are closely correlated.⁶⁶⁷ In recent years soybean oil prices appear to have increased significantly relative to soybean meal prices, as shown in Figure 9.3-3. From 2016 through the end of 2020, the value of soybean oil relative to soybean meal was relatively stable, with soybean oil representing around 33% of the value of a soybean on average.⁶⁶⁸ Starting in 2021, the relative value of the soybean oil has increased significantly, averaging 47% in the 21/22 crop year. Examining the \$/bushel value contribution of the components, we see that

⁶⁶⁷ Irwin, Scott, “The Value of Soybean Oil in the Soybean Crush: Further Evidence on the Impact of the U.S. Biodiesel Boom.” *farmdoc daily* (7):169, September 14, 2017. <https://farmdocdaily.illinois.edu/2017/09/the-value-of-soybean-oil-in-the-soybean-crush.html>.

⁶⁶⁸ USDA, “Oil Crops Yearbook,” March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

the oil value has more than doubled while the meal has increased by around 30%. These trends suggest the value of the soybean is shifting more toward the oil than the meal in recent years. The supply of soybean oil may be tightening relative to soybean meal, with rising soybean oil prices exerting some downward pressure on soybean meal prices.

Figure 9.3-3: Relative Values of Soybean Oil and Soybean Meal



In addition to the price impacts on corn, soybean oil, and soybean meal, we also estimated price changes for other feed grains (grain sorghum, barley, and oats) and dried distillers grains. We adjusted the prices of these commodities, as they historically compete with corn in the feed market, and to a lesser extent for acreage. The price adjustments for grain sorghum, barley, oats, and DDG are based on historical price relationships of these commodities with corn. As with corn and soybean oil, we assumed that the prices in the USDA Agricultural Projections to 2034 represent projected prices of the Analyzed Volumes and adjusted the projected prices for these commodities lower in our price projections for the No RFS Baseline. The projected impact of the Analyzed Volumes on sorghum, barley, oat, and DDG prices are shown in Table 9.3-3.

Table 9.3-3: Projected Impact of the Analyzed Volumes on Prices of Other Commodities Relative to No RFS Baseline

	2026	2027
Price Change Factor Relative to Corn Price Change^a		
Corn; \$/bushel	\$1.00	\$1.00
Sorghum; \$/bushel	\$0.93	\$0.93
Barley; \$/bushel	\$0.88	\$0.88
Oats; \$/bushel	\$0.72	\$0.72
Distillers Grains; \$/Pound	\$0.02	\$0.02
Projected Price Impact Relative to No RFS Baseline		
Corn; \$/bushel	\$0.03	\$0.03
Sorghum; \$/bushel	\$0.02	\$0.03
Barley; \$/bushel	\$0.02	\$0.02
Oats; \$/bushel	\$0.02	\$0.02
Distillers Grains; \$/ton	\$0.90	\$0.99

^a These factors were developed in conjunction with USDA in the 2012 evaluation of the use of the general waiver authority. See “Methodology for Estimating Impacts on Food Expenditures, CPI for Food and CPI for All Items,” Docket Item No. EPA-HQ-OAR-2012-0632-2546. <https://www.regulations.gov/document/EPA-HQ-OAR-2012-0632-2546>.

9.4 Food Prices

The above impact on commodity prices may in turn have a ripple impact on food prices and the many other products produced from these commodities. Because the Analyzed Volumes are projected to have a relatively small impact on the overall world commodity markets, and since the cost of these commodities tends to be a relatively small component in the cost of food, the projected impact of this rule on food prices is relatively modest. Further, we note that the projected impact of the Analyzed Volumes on food prices does not represent a cost, but rather a transfer, since higher food prices that result from higher commodity prices represent increased income for feedstock producers (*e.g.*, corn and soybean farmers).⁶⁶⁹

To project the impact of the Analyzed Volumes on food prices, we used a methodology developed in conjunction with USDA in assessing requests from the governors of several states to reduce the 2012 RFS Rule volumes using the general waiver authority.⁶⁷⁰ This methodology generally uses estimates of the impact of biofuel volumes on commodity prices (*e.g.*, corn, soybean oil, etc.) to calculate the estimated impacts on total food expenditures. This estimated change in food expenditures is then compared to total food expenditures. Finally, the ratio of the estimated change in food expenditures to the total food expenditures is used to estimate the change in food expenditures for the average consumer unit.

⁶⁶⁹ In other words, food price impacts represent the movement of money within society (from consumers of foods to the producers of foods) as opposed to additional costs that society as a whole incurs. We note that while the CAA specifically directs EPA to calculate the impacts on “food prices,” as opposed to calculating the impact on the cost to consumers of food. We acknowledge that these market interactions are affected by deadweight losses, but we have not estimated the proportion of deadweight losses to transfers in this rule.

⁶⁷⁰ 77 FR 70752 (November 27, 2012).

In Chapter 9.3, we presented estimates of the impact of the Analyzed Volumes on commodity prices relative to the No RFS Baseline. These estimates are the starting point for our estimate of the impact of the RFS volumes on food prices. EPA used those price impacts in combination with the projected use of commodities for food to project the impact of commodity prices on total food expenditures, which are shown in Table 9.4-1. This analysis assumes changes in commodity prices are fully passed on to consumers at the retail level and therefore changes in total food expenditures may be estimated by multiplying the quantity of these commodities used for food and feed. Feed use is included to capture the effects of the change in the price of the commodity on livestock agriculture production costs, and ultimately the effects on retail prices of foods produced from livestock.⁶⁷¹

EPA recognizes that projecting that the price of distillers grains (DDG) increases proportionally to the price of corn may overstate the impact of this rule on these commodities and ultimately on food prices. It is possible increasing demand for biofuels may result in an oversupply of DDG as a co-product of biofuel production. Thus, while biofuel production may increase the prices of corn and food produced from corn, it may not increase the price of DDG. This could mitigate the overall impact of this rule on food prices. There is not sufficient data to project how increasing demand for corn for biofuel production would impact the price of DDG. If the price for distillers grains increases less than the price of corn (or if it decreases) in response to increased demand for biofuels, a smaller impact on food prices than what we have estimated for the volumes could be expected.

This methodology assumes no response from consumers to changes in commodity prices (*i.e.*, perfect inelasticity of demand to changes in price) and therefore may overstate the change in food expenditures. However, previous research suggests that demand for food is very inelastic and therefore this methodology should provide a close approximation of the change in food expenditures.⁶⁷² Our estimates of the increase of food expenditures only reflect expenditures in the U.S. Due to the integrated nature of agricultural commodity markets, the projected increases in agricultural commodity prices may also impact food prices and expenditures globally. EPA has not attempted to quantify these global impacts.

⁶⁷¹ This methodology includes the expected price impact on all crops used as animal feed and does not account for the livestock produced for the export market or imported meat or animal products.

⁶⁷² USDA, "The Demand for Disaggregated Food-Away-From-Home and Food-at-Home Products in the United States." *Economic Research Report* 139, August 2012.
https://ers.usda.gov/sites/default/files/_laserfiche/publications/45003/30438_err139.pdf?v=69115.

Table 9.4-1: Changes in Food Expenditures of the Analyzed Volumes Relative to the No RFS Baseline

Year	Commodity	Commodity Price Change	Quantity Used for Food and Feed ^a	Change in Expenditures
2026	Corn	\$0.03 per Bushel	7,415 million Bushels	\$187 million
	Grain Sorghum	\$0.02 per Bushel	110 million Bushels	\$3 million
	Barley	\$0.02 per Bushel	157 million Bushels	\$3 million
	Oats	\$0.02 per Bushel	125 million Bushels	\$2 million
	Soybean Oil	\$0.28 per Pound	14,438 million Pounds	\$4,100 million
	Soybean Meal	-\$39.88 per Short Ton	42,344 thousand Short Tons	-\$1,689 million
	DDG	\$0.90 per Short Ton	47 million Short Tons	\$42 million
	Total			\$2,649 million
2027	Corn	\$0.03 per Bushel	7,463 million Bushels	\$207 million
	Grain Sorghum	\$0.03 per Bushel	110 million Bushels	\$3 million
	Barley	\$0.02 per Bushel	158 million Bushels	\$4 million
	Oats	\$0.02 per Bushel	128 million Bushels	\$3 million
	Soybean Oil	\$0.35 per Pound	14,488 million Pounds	\$5,013 million
	Soybean Meal	-\$48.51 per Short Ton	42,950 thousand Short Tons	-\$2,083 million
	DDG	\$0.99 per Short Ton	47 million Short Tons	\$47 million
	Total			\$3,193 million

^a Quantity used for food and feed was calculated from: USDA, “USDA Agricultural Projections to 2034,” OCE-2025-1, February 2025. <https://doi.org/10.32747/2025.9015815.ers>. In general, this quantity is the sum of Feed & Residual & Food, and Seed & Industrial. For corn, we subtracted the quantity used for Ethanol & By-products from this total. DDG was calculated based on the production of 17 pounds of DDG for every bushel of corn used to produce ethanol. Finally, soybean oil is equal to the amount listed for food, feed & other industrial and soybean meal is the total quantity of domestic disappearance.

Finally, we compared the estimated change in food expenditures to total food expenditures as reported by the Bureau of Labor and Statistics in their 2024 survey.⁶⁷³ Specifically, we used 2024 values for the number of consumer units and average food expenditures per consumer unit as the baseline, assuming no material change from 2024–2027; accordingly, we held these inputs constant at their 2024 levels. We then applied the ratio of the estimated change in total food expenditures to total food expenditures to estimate the corresponding change in average food spending per consumer unit, as shown in Tables 9.4-2.

Table 9.4-2: Change in Food Expenditures per Consumer Unit of the Analyzed Volumes Relative to No RFS Baseline

	2026	2027
Number of Consumer Units (thousands)	135,760	135,760
Food Expenditures per Consumer Unit	\$10,169	\$10,169
Total Food Expenditures (millions)	\$1,380,543	\$1,380,543
Change in Food Expenditures (millions)	\$2,649	\$3,193
Percent Change in Food Expenditures	0.19%	0.23%
Projected Food Expenditure Increase	\$19.51	\$23.52

⁶⁷³ Bureau of Labor and Statistics, “Consumer Expenditures – 2024,” USDL-25-1586, December 19, 2025. <https://www.bls.gov/news.release/pdf/cesan.pdf>.

Chapter 10: Estimated Fuel Costs and Fuel Price Impacts

The statute directs EPA to assess the impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods in using the set authority.⁶⁷⁴ In this chapter, we assess the social costs of renewable fuels, the social costs of the petroleum fuels which the biofuels replace, the fuel economy effect based on each fuel's energy density, and the impacts of this rule on social costs, the costs to consumers of transportation fuel, and the costs to transport goods. Other nonfuel costs and price impacts attributed to the RFS program are estimated elsewhere.

We are establishing RFS volume requirements for 2026 and 2027 after we have evaluated different possible volume requirements for the proposed rule. In this chapter, we present our assessment of costs for the Analyzed Volumes relative to the No RFS Baseline, as well as incremental to the 2025 Baseline. In projecting the costs and fuel price impacts in this chapter, we rely on AEO2025, which was the most recently published version at the time the analyses were conducted, and the most recent agricultural projections.

The Analyzed Volumes are projected to cause a large increase in the consumption of domestic vegetable oil and animal fats used by producers of BBD to generate credits under the RFS program. This will likely pose a challenge for the agricultural sector to provide the required volumes of these domestically sourced feedstocks. Thus, we expect to experience price increases for these feedstocks. We project higher prices for the BBD and its feedstocks in response to this likely increase in demand and have conducted sensitivity analyses at higher and lower vegetable oil prices to bound these projections.

The estimated costs for the Analyzed Volumes at the different price sensitivities are all summarized in this chapter. Chapter 10.1 provides estimates of the renewable fuel costs, including feedstock costs, renewable fuel production, blending, fuel economy and distribution costs. Chapter 10.2 contains estimates of petroleum production and distribution costs. Chapter 10.4 contains subsections that summarize the changes in renewable fuel and petroleum volumes relative to the No RFS and 2025 Baselines, as well as the estimated total and per-gallon costs associated with the change in fuel volumes.⁶⁷⁵ In all cases, costs are reported in 2024 dollars.

10.1 Renewable Fuel Costs

10.1.1 Feedstock Costs

For most renewable fuels, the feedstock costs are a primary contributing factor to the cost to produce and use the renewable fuels. We first describe our estimates of changes in the production cost for these feedstocks and then provide information describing our estimates for the production, distribution and blending costs for the various renewable fuels.

⁶⁷⁴ CAA section 211(o)(2)(B)(ii)(V).

⁶⁷⁵ The calculation of the cost estimates for the Analyzed Volumes relative to the No RFS and 2025 Baselines can be found in "Estimated Fuel Costs for Set 2 Final Rule," available in the docket for this action.

For estimating feedstock costs, we used projections of feedstock prices for 2026 and 2027 from multiple sources, including EIA and USDA.⁶⁷⁶ We also adjusted our estimates to account for differences between these projections. Crude oil prices affect the cost of growing renewable fuel feedstocks, the cost of transporting them to the renewable fuel production plants, the cost of transporting the produced renewable fuel from the plant to market, and may also impact the cost of producing the renewable fuel. Because USDA agricultural price projections were based on lower crude oil price projections than those by EIA, the USDA agricultural price projections may have underestimated the agricultural prices that would be consistent with the EIA petroleum price projections. Therefore, we adjusted the USDA price projections for both corn and soybean oil to align these inputs to our cost analysis to common crude oil price assumptions. We also adjusted the projected nominal prices to constant year 2024 dollars.

10.1.1.1 Corn and Corn Ethanol Plant Byproducts

The price of corn is the most important input to estimating the cost of corn ethanol. Table 10.1.1.1-1 shows the derivation of the corn prices used in this cost analysis, which adjusts the projected crop prices for crude oil price differences and for inflation. To help to explain the derivation in the discussion below, we refer to the relevant row number in Table 10.1.1.1-1.

As a starting point we used future corn price projections from USDA. We started with the 2026 to 2027 USDA projected corn prices (row #1).⁶⁷⁷ However, the USDA corn prices are reported in nominal dollars, reflecting the inflated value of the dollars in those years. The first adjustment we made was to convert those USDA corn prices reported in nominal dollars into the 2024 dollars used across this cost analysis (row #2).⁶⁷⁸

Next, we made an adjustment to account for the different crude oil price projections that USDA used (row #3) compared to those projected by EIA (row #5) because crude oil prices affect agricultural commodity prices.^{679,680} Because EIA is the U.S. reference organization for projecting petroleum prices, we adjusted the USDA inflation-adjusted corn prices to put them on the same basis with the petroleum costs which are based on EIA crude oil prices. To do so, we first adjusted the crude oil prices used by USDA (row #3) to 2024 dollars (row #4). Then we used a regression of corn prices and crude oil prices to estimate the corn prices at USDA crude oil prices adjusted to 2024 dollars (row #6) and the corn prices at the EIA crude oil prices (row #6), to enable an adjustment of USDA corn prices to be consistent with the EIA crude oil prices.

⁶⁷⁶ USDA, “USDA Agricultural Projections to 2034,” OCE-2025-1, February 2025. <https://ers.usda.gov/sites/default/files/laserfiche/outlooks/110966/OCE-2025-1.pdf>.

⁶⁷⁷ Id.

⁶⁷⁸ USDA reports estimated future inflation rates that are used for adjusting nominal dollar values to 2024\$.

⁶⁷⁹ There seems to be an association between the renewable fuel feedstock costs and crude oil prices (regression analysis reveals an R-squared of 0.55 for corn and crude oil). Since USDA estimated renewable fuel feedstock prices based on lower crude oil prices, adjusting their renewable fuel feedstock prices higher to be consistent with EIA crude oil prices better syncs the two price projections and leads to a better estimate of costs.

⁶⁸⁰ Camp, Kevin M., “The relationship between crude oil prices and export prices of major agricultural commodities,” *Global Economy*, Bureau of Labor Statistics, April 2019. <https://www.bls.gov/opub/btn/volume-8/pdf/the-relationship-between-crude-oil-and-export-prices-of-major-agricultural-commodities.pdf>.

The regression of corn prices and crude oil prices is based on monthly corn prices between January 2012 and November 2024, which yielded the following equation:^{681,682,683}

$$\text{Corn Price (\$/bushel)} = \text{Crude Oil Price (\$/bbl)} \times 0.0445 + 1.54$$

The corn prices estimated by this regression were not used directly for the cost analysis. We made this choice because we observe that farmers are more efficient at producing corn today than in the past, as evidenced by improving corn yields over time.⁶⁸⁴ As corn productivity continues to increase in 2026 and 2027, production of corn is likely to be on a different supply/demand point on the corn price curve relative to 2024 and prior years. Instead of using the regressed corn prices directly, the difference in regressed corn prices (row #8) was added to the USDA projected corn prices adjusted to 2024 dollars (row #2) to derive the final adjusted corn prices (row #9) subsequently used as an input value for estimating corn ethanol costs as shown in Table 10.1.1.1-1.

Table 10.1.1.1-1: Derivation of Corn Feedstock Production Costs (\$/bushel for corn, \$/bbl for Crude Oil)

		Row #	2026	2027
Corn Prices	USDA Nominal \$	1	3.90	4.00
	USDA 2024\$	2	3.75	3.76
Crude Oil Prices	USDA Nominal \$	3	71.6	70.2
	USDA 2024\$	4	68.8	66.1
	EIA 2024\$	5	77.6	76.6
Regressed Corn Prices	Based on USDA 2024\$	6	4.60	4.48
	Based on EIA 2024\$	7	4.99	4.95
Corn Prices	Difference in Regressed Corn Prices EIA - USDA	8	+0.39	+0.47
Corn Prices	Adjusted USDA 2024\$	9	4.14	4.23

Both the inflation and crude oil price adjustment are modest, and their effects cause offsetting effects. Regardless, we believe these corrections improve the rigor of our estimates.

Since corn ethanol plants also produce byproducts which can be sold for additional value, we also estimated the prices for those byproducts, specifically DDGS and corn oil, which is estimated in Chapter 10.1.1.2. Since USDA does not estimate future prices for DDGS, these were obtained by agricultural price projections made by the University of Missouri, Food and Agricultural Policy Research Institute (FAPRI).⁶⁸⁵ The FAPRI DDGS projected prices are

⁶⁸¹ We chose the years from 2012–2024 because of the wide range in crude oil and corn prices that existed over this time period.

⁶⁸² USDA, “Corn Prices Received by Farmers,” *Quick Stats*, 2024.
<https://quickstats.nass.usda.gov/results/3538FFA4-F207-383E-A9CF-09A1F1408C77>.

⁶⁸³ EIA, “U.S. Crude Oil Composite Acquisition Cost by Refiners,” *Petroleum & Other Liquids*, May 1, 2025.
https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=R0000_3&f=a.

⁶⁸⁴ USDA, “Corn: Yield by Year, US,” January 12, 2026.
https://www.nass.usda.gov/Charts_and_Maps/Field_Crops/cornyld.php.

⁶⁸⁵ FAPRI, “2025 U.S. Agricultural Market Outlook,” FAPRI-MU Report #01-25, April 2025.
<https://fapri.missouri.edu/wp-content/uploads/2025/04/2025-Baseline-Outlook.pdf>.

reported in nominal dollars, so we adjusted the price projections to 2024 dollars. Table 10.1.1.1-2 summarizes DDGS prices used in the cost analysis.

Table 10.1.1.1-2: DDGS Prices (\$/dry ton)

	2026	2027
Nominal	\$156.2	\$156.7
2024\$	\$150.0	\$147.5

10.1.1.2 Soybean Oil, Corn Oil, and Fats, Oils, and Greases Prices

Soybean oil, FOG, corn oil, and canola oil were identified in Chapter 2 as the feedstocks for producing virtually all biodiesel and renewable diesel fuels expected to contribute to the Analyzed Volumes for 2026 and 2027. For the cost analysis, canola oil volumes are combined with soybean oil volumes to estimate a single volume of virgin vegetable oil feedstock price estimate; we refer to this solely as soybean oil in the remainder of this analysis.

Different sets of prices were estimated and used depending on the cost scenario being modeled. Table 10.1.1.2-1 summarizes the categories of prices that we modelled.

Table 10.1.1.2-1: Categories of Prices used in Modeling Costs

Case	Baseline		Control Cases
	No RFS	2025	
Principal Case	USDA BAU	2025 Average	High Prices
High Price Case	USDA BAU	2025 Average	Very High Prices
Low Price Case	USDA BAU	2025 Average	Low Prices - Same as Baseline

Because both soybean and canola have similar levels of hydrogen unsaturation, it is reasonable to assume that canola and soybean oils would have similar production costs.⁶⁸⁶ Soybean oil price projections made by USDA are used as a starting point for our baseline cost analysis.⁶⁸⁷ We followed the same methodology we used for soybean oil prices as described above for corn prices; this process is summarized in Table 11.1.1.2-2 and the description that follows references the rows in that Table to aid in understanding. The first step required converting USDA projected soybean oil prices in nominal dollars (row #1), converting to 2024 dollars (row #2), and adjusting for the differences in crude oil prices (row #4 for USDA in 2024 dollars) and EIA (row #5). When adjusting for the differences in crude oil prices, a regression of

⁶⁸⁶ Kim, Juyoung, Deok Nyun Kim, Sung Ho Lee, Sang-Ho Yoo, and Suyong Lee. "Correlation of Fatty Acid Composition of Vegetable Oils With Rheological Behaviour and Oil Uptake." *Food Chemistry* 118, no. 2 (May 14, 2009): 398–402. <https://doi.org/10.1016/j.foodchem.2009.05.011>.

⁶⁸⁷ USDA, "USDA Agricultural Projections to 2034," OCE-2025-1, February 2025. <https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2033.pdf>.

monthly soybean oil and crude oil prices between January 2012 and November 2024 yielded the following equation:^{688,689,690}

$$\text{Soybean Oil Price (\$/lb)} = \text{Crude Oil Price (\$/bbl)} \times 0.259 + 19.06$$

The soybean oil prices (row #6) based on USDA crude oil prices and the soybean oil prices (row #7) based on EIA crude oil prices were not used in the cost analysis directly. Rather the difference in regressed soybean oil prices (row #8) was added to the adjusted USDA soybean prices (row #2) to derive the adjusted soybean oil prices (row #9).

Table 10.1.1.2-2: Derivation of Soybean Oil Feedstock Production Costs (cents/pound for soybean oil, \$/bbl for crude oil)

		Row #	2026	2027
Soybean Oil Prices	USDA Nominal \$	1	0.40	0.38
	USDA 2024\$	2	0.38	0.36
Crude Oil Prices	USDA Nominal \$	3	71.6	70.2
	USDA 2024\$	4	68.8	66.1
	EIA 2024\$	5	77.6	76.6
Regressed Soybean Oil Prices	Based on USDA 2024\$	6	0.421	0.410
	Based on EIA 2024\$	7	0.454	0.451
Soybean Oil Prices	Difference in Regressed Soybean Oil Prices EIA - USDA	8	+0.034	+0.041
Soybean Oil Prices	Adjusted USDA 2024\$	9	0.42	0.40

Neither USDA nor FAPRI project future corn oil or FOG prices. Instead, future prices for these oils were estimated based on the historical differences between them and soybean oil's spot prices.⁶⁹¹ Corn oil and FOG spot prices were compared to soybean oil spot prices between January 2016 and December 2022. Over that time period, soybean oil averaged about 40¢ per pound, ranging from 29–68¢ per pound. Corn oil and FOG prices were compared to soybean oil prices, and these were found on average to be priced at 82.7% and 75.4% of soybean oil price respectively. A good reason why corn oil and FOG tend to be priced lower is because they are waste oils requiring some processing before they can be feedstocks for biodiesel and renewable diesel production facilities. These percentages were then applied to the soybean oil prices used in this cost analysis to derive the prices for FOG and corn oil used in this cost analysis.

⁶⁸⁸ There seems to be an association between the renewable fuel feedstock costs and crude oil prices (regression analysis reveals an R-squared of 0.73 for soybean oil and crude oil). Since USDA estimated renewable fuel feedstock prices based on lower crude oil prices, adjusting their renewable fuel feedstock prices higher to be consistent with EIA crude oil prices better synchronizes the two price projections and leads to a better estimate of costs.

⁶⁸⁹ Federal Reserve Economic Data, "Global price of Soybeans Oil," May 13, 2025. <https://fred.stlouisfed.org/series/PSOILUSDM>.

⁶⁹⁰ EIA, "U.S. Crude Oil Composite Acquisition Cost by Refiners," *Petroleum & Other Liquids*, May 1, 2025. https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=R0000_3&f=a.

⁶⁹¹ USDA, "Oil Crops Yearbook," March 2025. <https://www.ers.usda.gov/data-products/oil-crops-yearbook>.

It was necessary to derive the vegetable prices for the 2025 baseline and control cases which are based on high and very high vegetable oil prices. Chapter 9.3 describes the methodology used and lists the estimated prices for soybean oil prices.

The projected soybean oil, FOG, and corn oil prices used for the baseline cost analysis are summarized in Table 10.1.1.2-3. Similar to the estimate of USDA baseline estimate for vegetable oil prices, the relative lower prices for corn oil and FOG are maintained for all the price estimates.

Table 10.1.1.2-3: Projected Vegetable Oil Prices (2024\$/lb)

Year	Case	Feedstock	Baseline		Control Case
			No RFS	2025	
2026	Principal Case	Soybean Oil	0.42	0.49	0.66
		Corn Oil	0.35	0.41	0.55
		FOG	0.32	0.37	0.50
	High Price Case	Soybean Oil	Same as Principal Baseline Case	Same as Principal Baseline Case	0.86
		Corn Oil			0.71
		FOG			0.65
	Low Price Case	Soybean Oil	Same as Principal Baseline Case	Same as Principal Baseline Case	Baseline price
		Corn Oil			Baseline price
		FOG			Baseline price
2027	Principal Case	Soybean Oil	0.40	0.49	0.68
		Corn Oil	0.33	0.41	0.56
		FOG	0.30	0.37	0.51
	High Price Case	Soybean Oil	Same as Principal Baseline Case	Same as Principal Baseline Case	0.90
		Corn Oil			0.74
		FOG			0.68
	Low Price Case	Soybean Oil	Same as Principal Baseline Case	Same as Principal Baseline Case	Baseline Price
		Corn Oil			Baseline Price
		FOG			Baseline Price

10.1.1.3 Biogas

For this analysis we assume that biogas is produced at landfills and collected to prevent the release of methane gas as required by regulation, and then flared, burned to produce electricity, or upgraded for use as natural gas. Since biogas is a waste gas from existing landfills, we assumed no feedstock cost for biogas. The cost of the necessary steps to collect, purify, and distribute biogas are all discussed under the sections discussing fuel production and distribution costs.

10.1.2 Renewable Fuels Production Costs

This section assesses the production costs of renewable fuels, including the feedstock costs described above as well as fixed capital costs, fixed operating costs, and variable utility and fuel operating costs. We generally express the production costs on a per-gallon basis for the renewable fuels being produced. The one exception is biogas which is reported on a per-million

British thermal units (Btu) basis and also on a per ethanol-equivalent volume basis. The detailed cost summaries presented for each renewable fuel in this section are based on projected cost inputs for the year 2026.⁶⁹²

10.1.2.1 Cost Factors

10.1.2.1.1 Fixed Capital and Operating Costs

For this production cost analysis, we developed estimates of the capital costs and other fixed costs of biofuel production, which were then applied to the production volume of renewable fuels. We estimated these fixed costs in two parts. First, we used specific economic assumptions to develop capital cost amortization factors. These assumptions are summarized in Table 10.1.2.1.1-1. These capital cost amortization factors are used in the following section for converting the one-time, total capital cost of a biofuel-related facility to an equivalent per-gallon cost.⁶⁹³ The resulting 0.11 capital cost amortization factor is the same factor used by EPA in the cost estimation calculations made for other rulemakings and technical papers.^{694,695,696,697,698}

Table 10.1.2.1.1-1: Economic Cost Factors Used in Calculating Capital Amortization Factors

Amortization Scheme	Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
Societal Cost	10 Years	15 Years	0%	7%	0.11

Capital costs were adjusted to 2024 dollars for this analysis. The Chemical Engineering Plant Index (CEPI) capital cost index was used to adjust capital costs to 2024 dollars.⁶⁹⁹ Consistent with the increased inflation observed over recent years, the CEPI capital cost index for 2024 represents a large increase in capital costs when adjusting capital costs to the year 2024.

Second, we estimated the fixed operating costs of biofuel production; these include

⁶⁹² All the costs summarized in this chapter are calculated in “Estimated Fuel Costs for Set 2 Final Rule,” available in the docket for this action.

⁶⁹³ The capital amortization factor is applied to the aggregate capital cost to create an amortized annual capital cost that occurs each year for the 15 years of the economic and project life of the unit. The depreciation rate of 10% and economic and project life of 15 years are typical for these types of calculations. The 7% return on investment and the zeroing out of Federal and State taxes is specified by OMB Circular A-4 for these calculations.

⁶⁹⁴ EPA, “Regulatory Impact Analysis – Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements,” EPA-420-R-99-023, December 1999; .

⁶⁹⁵ EPA, “Technical Support Document for the Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements: Air Quality Modeling Analyses,” EPA-420-R-00-028, December 2000.

⁶⁹⁶ Wyborny, Lester. “Cost Estimates of Long-Term Options for Addressing Boutique Fuels,” EPA, October 22, 2001.

⁶⁹⁷ EPA, “Final Regulatory Analysis – Control of Emissions from Nonroad Diesel Engines,” EPA-420-R-04-007, May 2004.

⁶⁹⁸ RFS2 Rule RIA.

⁶⁹⁹ Chemical Engineering, “The Chemical Engineering Plant Cost Index,” <https://www.chemengonline.com/pci-home>.

maintenance costs, insurance costs, rent, laboratory charges and miscellaneous chemical supplies.⁷⁰⁰ Maintenance costs can range from 1% to 8% for industrial processes.⁷⁰¹ We estimated the aggregated annual fixed operating costs to be 5.5% of the capital costs for all renewable fuels production facilities.

10.1.2.1.2 Variable Utility and Fuel Operating Costs

Utility and fuel inputs are variable operating costs incurred to run the renewable fuel production plants on a day-to-day basis and are based on the unit throughput. The most obvious of the variable costs are utilities (electricity, natural gas, and water) which are required to operate the renewable fuels plants. Natural gas is consumed for heating process streams, including feedstocks which must be heated prior to being sent to reactors and distillation columns for separating coproducts. Electricity is necessary to run pumps, compressors, plant controls and other plant operations. Water can be necessary as part of the process (reaction medium) or used in heat exchangers and cooling towers.

Projected electricity and natural gas prices are based on national average values from AEO2025. The cost of process water is generally quite minimal, but a cost is estimated for it nonetheless since renewable fuel technologies can use fairly large quantities.^{702,703} The utility costs used for the cost analysis are summarized in Table 10.1.2.1.2-1.

Table 10.1.2.1.2-1: Summary of Utility Cost Factors (2024\$)

Year	Natural Gas (\$/MMBtu)	Electricity (¢/kWh)	Water (\$/1000 gals)
2026	4.29	7.98	3.0
2027	4.45	8.08	3.0

10.1.2.2 Corn Ethanol Production Costs

Most corn ethanol plant input and output information used in our analysis were based on a 2019 survey of corn ethanol plants.⁷⁰⁴ However, some plant information was sourced from an older analysis.⁷⁰⁵ Coproduct output levels were based on newer analysis of 2022 data. Corn ethanol plants have become more efficient over time; however, these improvements require

⁷⁰⁰ Peters, Klaus D., Max S. Timmerhaus, and Ronald E. West. *Plant Design and Economics for Chemical Engineers*. 5th ed. McGraw Hill, 2003.

⁷⁰¹ McNair, Sam. "Budgeting for Maintenance: A Behavior-Based Approach," *Life Cycle Engineering*, 2011. <https://www.wethegoverned.com/wp-content/uploads/2019/07/110912-Life-Cycle-Engineering-budgeting-maintenance.pdf>.

⁷⁰² Haas, Michael J, Andrew J McAloon, Winnie C Yee, and Thomas A Foglia. "A Process Model to Estimate Biodiesel Production Costs." *Bioresource Technology* 97, no. 4 (June 3, 2005): 671–78. <https://doi.org/10.1016/j.biortech.2005.03.039>.

⁷⁰³ DOE, "Water and Wastewater Annual Escalation Rates for Selected Cities across the United States," September 2017. <https://doi.org/10.2172/1413878>.

⁷⁰⁴ Lee, Uisung, Hoyoung Kwon, May Wu, and Michael Wang. "Retrospective Analysis of the U.S. Corn Ethanol Industry for 2005–2019: Implications for Greenhouse Gas Emission Reductions." *Biofuels Bioproducts and Biorefining* 15, no. 5 (May 4, 2021): 1318–31. <https://doi.org/10.1002/bbb.2225>.

⁷⁰⁵ Mueller, Steffen. "2012 Corn Ethanol: Emerging Plant Energy and Environmental Technologies." April 29, 2013.

increased capital and maintenance costs which largely offset the efficiency cost savings. Thus, the estimated corn ethanol costs are fairly stable over time.

Capital costs were based on a review of corn ethanol construction costs for a 100 million gallon per year dry mill corn ethanol plant in 2016. For this analysis the capital costs were scaled to the U.S. average sized corn ethanol plant with a nameplate capacity of 85 million gallons per year and assumed to operate at 90% of nameplate capacity, therefore producing 76 million gallons of ethanol per year.⁷⁰⁶ Since the capital cost is based on the total construction cost of already constructed corn ethanol plants, no contingency cost factors are applied to the capital costs. Corn prices are farm gate prices and a transportation spreadsheet was used to estimate an average cost of 6¢ per bushel to transport the corn to corn ethanol plants.⁷⁰⁷ Of the dry mill corn ethanol plants in the 2012 survey, 74% were separating and selling corn oil; however, we believe that by now all corn ethanol plants are separating and selling corn oil due to the increased demand for vegetable oil for producing biofuel.

The quantity of dried distillers grain with solubles (DDGS) produced by corn ethanol plants was estimated from USDA DDGS production data from February to October 2022. USDA reports DDGS production for four different categories of DDGS: dried distillers grain (DDG), dried distillers grain with solubles (DDGS), distillers wet grain (DWG) with 65% or more moisture, and distillers wet grain (DWG) with 40–64% moisture.⁷⁰⁸ The production quantity of DWG is adjusted to an equivalent of dried DDG. The DWG with 65% or more moisture is assumed to have 75% moisture, while the DWG with 40–65% moisture is assumed to have 52% moisture. Both wet distiller grain categories are adjusted to dry distiller grain quantities assuming that dried distiller grains contain 11% moisture.⁷⁰⁹ Table 10.1.2.2-1 summarizes and averages the quantity of distiller grains by category, reporting the quantity of wet distiller grains both before and after adjusting them to equivalent dry grains amounts.

⁷⁰⁶ Irwin, Scott. “Weekly Output: Ethanol Plants Remain Barely Profitable,” *Successful Farming*, March 16, 2018. <https://www.agriculture.com/news/business/weekly-outlook-ethanol-plants-remain-barely-profitable>.

⁷⁰⁷ Edwards, William. “Estimating Grain Transportation Costs,” *Ag Decision Maker* File A3-41, August 2017. <https://www.extension.iastate.edu/agdm/crops/html/a3-41.html>.

⁷⁰⁸ USDA, “Grain Crushings and Co-Products Production Monthly,” February 2, 2026. <https://esmis.nal.usda.gov/sites/default/release-files/795755/cagc0226.pdf>.

⁷⁰⁹ Shurson, Jerry. “DDGS present handling and storage considerations,” *National Hog Farmer*, May 29, 2019. <https://www.nationalhogfarmer.com/hog-nutrition/ddgs-present-handling-and-storage-considerations>.

Table 10.1.2.2-1: USDA-Reported DDG (tons) and Corn Ethanol (million gallons) Production for a Portion of 2022

	February	March	April	May	June	July	August	September	October	Average
DWG 65%+ Wet	1,293,312	1,382,790	1,321,275	1,328,402	1,283,359	1,279,210	1,322,744	1,249,996	1,397,867	-
DWG 40-65 Wet	492,839	562,599	517,270	468,772	494,792	495,386	544,168	498,142	490,060	-
DWG 65%+ Dry	363,290	388,424	371,145	373,147	360,494	359,329	371,557	351,122	392,659	370,130
DWG 40-65 Dry	287,951	328,710	302,225	273,889	289,092	289,439	317,941	291,049	286,327	296,291
DDG	303,788	372,813	328,691	322,855	346,591	334,122	335,885	281,984	388,993	335,080
DDGS	1,693,253	1,877,338	1,704,698	1,896,665	1,918,611	1,934,355	1,867,735	1,613,088	1,745,419	1,805,685
Total DDG/DDGS	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132	2,626,132
Ethanol Volume	1,189	1,327	1,217	1,315	1,314	1,322	1,280	1,139	1,321	1,269
Pounds DDGS/gal ethanol	4.42	4.43	4.41	4.33	4.40	4.38	4.48	4.42	4.23	4.39

After averaging the production volume of each grain type over the 9 months, they are totaled and divided by the average ethanol production volume. This analysis estimates DDGS production to be 4.4 pounds per gallon of ethanol produced (12.5 pounds per bushel of corn).

Corn oil production from ethanol plants was estimated using a similar analysis as that conducted for DDGS. The corn oil production by month is summarized and averaged in Table 10.1.2.2.-2.

Table 10.1.2.2-2: USDA-Reported Corn Oil Production for a Portion of 2022 (tons)

	February	March	April	May	June	July	August	September	October	Average
Corn Oil	154,933	174,657	163,024	177,158	184,350	187,853	180,062	159,873	186,770	174,298

To estimate the corn oil production from corn ethanol plants, the average corn oil production is divided by the average corn ethanol production volume summarized in Table 10.1.2.2-1. Based on this analysis, corn oil production from corn ethanol plants is estimated to be 0.27 lbs per gallon of ethanol (0.79 pounds per bushel of corn).

Table 10.1.2.2-3 contains the plant demand and outputs and capital costs for corn ethanol plants and provides an estimate of the estimated corn ethanol production cost for year 2023.

Table 10.1.2.2-3: Corn Ethanol Plant Demands, Production Levels, and Capital Costs for 2026 (2024\$)

Category of Plant Input/Output	Plant Inputs/Outputs	Cost per Input	Cost (MM\$)	Cost (\$/gal)
Ethanol Yield	2.86 gal/bushel	\$4.20/bushel	112	1.47
DDG Yield	4.4 lb/gal	\$150/ton	-25.1	-0.33
Corn Oil Yield	0.27 lb/gal	34.6/lb	-7.1	-0.09
CO2 Yield	1 lb/gal	\$12/ton		
Thermal Demand	22,480 Btu/gal	\$4.21/MMBtu	7.0	0.09
Electricity Demand	0.63 kWh/gal	8.37¢/kwh	4.0	0.05
Water Use	2.7 gal/gal	\$3/1000 gals	0.6	0.01
Labor Cost	\$0.07/gal	-	5.3	0.07
Capital Cost (2024\$, 76 million Gals/Yr)	\$3.27/gal Plant Capital Cost		31.9	0.42
Annual Fixed Cost	5.5% of Total Capital Cost		16.0	0.21
Denaturant	2 vol%		0.5	0.01
Total Cost			143	1.88

The projected corn ethanol production cost for an 85-million-gallon capacity ethanol plant producing 76 million gallons per year of ethanol is \$1.88 per gallon of denatured ethanol for 2026 and \$1.92 per gallon for 2027. For a basis of comparison, these corn ethanol wholesale cost estimates are slightly higher than the AEO2025 projections of \$1.81/gallon and \$1.84/gallon for 2026 and 2027, respectively.

10.1.2.3 Biodiesel Production Costs

Biodiesel production costs for this rule were estimated using an ASPEN cost model developed by USDA for a 38 million gallon-per-year (MGY) transesterification biodiesel plant processing degummed soybean oil as feedstock. Details on the model are given in a 2006 technical publication by Haas.^{710,711} Although dated, this model likely still provides representative cost estimates because the process is fairly simple and unlikely to have changed over time, and consequently its cost are likely to be fairly stable over time as well. Furthermore, the biodiesel costs are primarily (>80%) determined by the feedstock prices.

The biodiesel process comprises three separate subprocesses:

1. Transesterification to produce fatty acid methyl esters (biodiesel) and coproduct glycerol (glycerine);
2. Biodiesel purification to meet biodiesel purity specifications; and
3. Glycerol recovery.⁷¹²

⁷¹⁰ Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.

⁷¹¹ Since 2006 when the HAAS biodiesel plant survey was conducted, biodiesel plants may have achieved improved energy efficiency, but also experienced increased costs to improve product quality and expand the quality of feedstocks they can process.

⁷¹² Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.

For the transesterification process modeled by Haas, soybean oil is continuously fed along with methanol and a catalyst sodium methoxide to a stirred tank reactor heated to 60 °C. After a residence time of 1 hour, the contents exit the reactor and the glycerol is separated using a centrifuge and sent to a glycerol recovery unit. The methyl ester stream, which contains unreacted methanol and catalyst, is sent to a second reactor along with additional methanol and catalyst. Again, the reactants reside in the second stirred tank reactor for 1 hour heated to 60 °C. The products from the second reactor are fed to a centrifuge which again separates the glycerol from the other reactants. The reaction efficiency is assumed to be 90% in each reactor, consistent with published reports, resulting in 99% combined conversion across both reactors.

The methyl ester is purified by washing with mildly acidic (4.5 pH) water to neutralize the catalyst and convert any soaps (sodium or potassium carboxylic acids) to free fatty acids. The solution is then centrifuged to separate the biodiesel from the aqueous phase. The remaining water in the biodiesel is removed by a vacuum dryer to a maximum 0.05% of water by volume.

The glycerol can have a high value if it can be purified to U.S. Pharmacopia (USP) grade to enable using this material for food or medicine. However, this purification process is expensive. Most biodiesel plants create a crude glycerol (glycerine) grade, which is 80% glycerol, and sell the crude glycerol for further refining by others. To create the crude glycerol, the various glycerol streams are combined and treated with hydrochloric acid to convert the soaps to free acids, allowing removal by centrifugation and sending to waste. The glycerol stream is then neutralized (pH brought back up to neutral) with caustic soda. Methanol is recovered from this stream by distillation and the methanol is recycled back into the process. The glycerol stream is distilled to remove it from the remaining water, which is recycled back into the process. The glycerol is now at least 80% pure, adequate to sell as crude glycerol.

We made a series of adjustments to the Haas model output. The capital cost is adjusted from 2006 dollars to 2024 dollars using a ratio of the capital cost index from the Chemical Engineering Cost Index. This adjustment increased installed capital cost from \$11.4 million per 38 MGY plant to \$18.2 million per plant. Fixed operating costs are estimated to comprise 5.5% of the plant cost. Prices were found for methanol,⁷¹³ sodium methoxide,⁷¹⁴ hydrochloric acid,⁷¹⁵ sodium hydroxide,⁷¹⁶ and glycerine.^{717,718} The value of methanol is from a Methanex report, plus 15¢ added on for distribution costs.⁷¹⁹

⁷¹³ Methanex, "Methanex Methanol Price Sheet," January 31, 2023. <https://www.methanex.com/about-methanol/pricing>.

⁷¹⁴ Global Sources, "Sodium Methoxide Bulk Price," June 2025. <https://www.globalsources.com/china-suppliers/methoxy.htm>.

⁷¹⁵ Business AnalytiQ, "Hydrochloric Acid price index," June 2025. <https://businessanalytiq.com/procurementanalytics/index/hydrochloric-acid-price-index>.

⁷¹⁶ Federal Reserve Economic Data, "Producer Price Index by Commodity: Chemicals and Allied Products: Chlorine, Sodium Hydroxide, and Other Alkalies," May 2025. <https://fred.stlouisfed.org/series/WPU06130302>.

⁷¹⁷ Alibaba, "Competitive Price 99.7% Refined Food/USP/Industry Grade Glycerol Glycerine," February 2023. https://www.alibaba.com/product-detail/Competitive-Price-80-99-7-Refined_1600713799582.html.

⁷¹⁸ Irwin, Scott. "2021 Was a Devastating Year for Biodiesel Production Profits." *farmdoc daily* (12):21, February 16, 2022. <https://farmdocdaily.illinois.edu/2022/02/2021-was-a-devastating-year-for-biodiesel-production-profits.html>.

⁷¹⁹ Methanex, "Current Posted Prices," January 31, 2023. <https://www.methanex.com/about-methanol/pricing>.

The value of the glycerin co-product has been volatile due to a large increase in production in biodiesel facilities that has been balanced at times by new uses. Glycerine has traditionally been used for petrochemical-based products, but there is increased demand in personal care and other consumer products as the standard of living increases in many parts of the world. Some facilities are even experimenting with using it as a supplemental fuel.⁷²⁰ We can expect that new uses for glycerin will continue to be found as long as it is plentiful and sufficiently cheap. We use recent cost information of about 32¢ per pound for glycerin.⁷²¹

Table 10.1.2.3-1 also shows the production cost allocation for the soybean oil-to-biodiesel facility. Production cost for biodiesel is primarily a function of feedstock price, with other process inputs, facility, labor, and energy comprising much smaller fractions.

Table 10.1.2.3-1: Soybean-Biodiesel Production Cost for 2026 (2024\$)

	Unit Demands	Cost per Unit	Cost (thousand\$)	Cost (\$/gal)
Soybean Oil Feed	76,875 (1000 lb)	66¢/lb ⁷²²	50,738	5.07
Methanol	7422 (1000 lb)	\$2.54/gal	2932	0.29
Sodium Methoxide	927 (1000 lb)	\$250/ton	116	0.012
Hydrochloric Acid	529 (1000 lb)	\$250/MT	60.1	0.006
Sodium Hydroxide	369 (1000 lb)	\$200/ton	36.9	0.004
Water	2478 (1000 lb)	\$3/1000 gals	1.2	0.00
Glycerine	9000 (1000 lb)	32¢/lb	(2880)	(0.29)
Natural Gas	66.9 million SCF	4.212 \$/MMBtu	282	0.028
Electricity	1008 kW	8.37 ¢/kWh	739	0.074
Labor				0.05
Capital Cost 2006\$	11.35 (\$million)	-	-	-
Capital Cost 2024\$	18.54 (\$million)		1,999	0.20
Fixed Cost		5.5%	1.000	0.10
Total Cost			55,022	5.55

As shown in Table 10.1.2.3-1, biodiesel produced from soybean oil is estimated to cost \$5.55 per gallon in 2026. The estimated biodiesel production cost for all vegetable oil types and for both years is summarized in Table 10.1.2.3-2.

⁷²⁰ Yang, Fangxia, Milford A Hanna, and Runcang Sun. "Value-added Uses for Crude Glycerol--a Byproduct of Biodiesel Production." *Biotechnology for Biofuels* 5, no. 1 (March 14, 2012). <https://doi.org/10.1186/1754-6834-5-13>.

⁷²¹ Alibaba, "Factory Supply Food Grade Tech Grade Cas56-81-5 Glycerol Pure Glycerin," 2026. https://www.alibaba.com/product-detail/Factory-Supply-Food-Grade-Tech-Grade_1601160081092.html?spm=a2700.7724857.0.0.58067c75KA7rvn.

⁷²² See Chapter 10.1.1.2.

Table 10.1.2.3-2: Summary of Estimated Biodiesel Production Costs (2024\$/gal)

	Year	Soybean Oil	Corn Oil	FOG
Control Case	2026	5.55	4.67	4.30
	2027	5.70	4.80	4.42
High Prices	2026	6.71	5.63	5.17
	2027	7.01	5.88	5.40
Low Prices No RFS	2026	3.69	3.14	2.90
	2027	3.54	3.01	2.78
Low Prices 2025	2026	4.25	3.59	3.32
	2027	4.24	3.59	3.31

10.1.2.4 Renewable Diesel Production Costs

The renewable diesel process converts plant oils or rendered fats into diesel or jet fuel using hydrotreating. The process reacts hydrogen over a catalyst to remove oxygen from the triglyceride molecules in the feedstock oils via a decarboxylation (removal of a carbon molecule double-bonded to an oxygen molecule, producing carbon dioxide) and hydro-oxygenation reaction, yielding some light petroleum products, carbon dioxide, and water as byproducts. The byproducts created from the hydrotreating reactor are separated from the renewable diesel in a separation unit. The reactions also saturate the olefin bonds in the feedstock oils, converting them to paraffins, and may also isomerize some paraffins. Depending on process operating conditions, 90–95% of the product yield by volume can be blended into diesel fuel or jet fuel, with the rest being naphtha and light fuel gases (primarily propane). In total, the volumetric yield is greater than 100% of the feed due to the addition of hydrogen and subsequent cracking that occurs over the hydrotreating catalyst.

For this cost analysis we chose to focus on stand-alone renewable diesel production. We found a project cost estimate by Diamond Green, which was \$1.1 billion for a standalone 400 million gallon per year facility.⁷²³ This large plant size and its associated capital costs were scaled down to a 220 million gallon per year plant size which is more typical of the renewable diesel fuel plants being built for start-up through 2024.⁷²⁴ The capital cost for this smaller renewable diesel fuel plant is estimated to be \$768 million.

In addition to feedstock and facility costs, another significant cost input is hydrogen. We used an estimate provided by Duke Biofuels for our hydrogen consumption estimate for producing renewable diesel. On average, vegetable oil and FOG feedstocks require 2,000 standard cubic feet (SCF) of hydrogen per barrel of feedstock processed.⁷²⁵ Hydrogen costs are estimated based on a 50 million SCF (MSCF)/day steam methane reforming hydrogen plant,

⁷²³ Advanced Biofuels USA, “Honeywell Ecofining Technology Helps Diamond Green Diesel Become One of The World’s Largest Renewable Diesel Plants,” October 2, 2019. <https://advancedbiofuelsusa.info/honeywell-ecofining-technology-helps-diamond-green-diesel-become-one-of-the-worlds-largest-renewable-diesel-plants>.

⁷²⁴ The typical renewable diesel plant size is based on volume-weighting renewable diesel capacity. The cost for the smaller sized renewable diesel plant is scaled using a six-tenths factor which captures the higher per gallon cost of a smaller sized plant. The cost scaling is calculated using the following equation: (capital cost of the original plant size) * (new plant size/original plant size)^{0.6}. Perry, Robert H., Don W. Green, and James O. Maloney. *Perry’s Chemical Engineers’ Handbook*. 5th ed. McGraw-Hill Professional Publishing, 1997.

⁷²⁵ Conversation with Mike Ackerson, Duke Biofuels, May 2020.

adjusted to represent a 32 MSCF/day plant, which would be the quantity of hydrogen required for a typical sized 220 million gallon per year renewable diesel plant.⁷²⁶

Table 10.1.2.4-1: Hydrogen Plant Costs for 2026 (2024\$)

	Unit Demands for a 50 MM SCF/day plant	Cost per Unit	Cost for a 32 MMSCF/day plant	
			MM\$	\$/MSCF
Feed Natural Gas	730 MMBtu/hr	\$4.21/MMBtu	17.2	1.47
Fuel Gas for Heat	150 MMBtu/hr	\$4.21/MMBtu	3.5	0.301
Power	1200 KW	8.37/kWh	0.6	0.05
Boiler feed water	160,000 lb/hr	\$3/1000 gal	0.3	0.03
Cooling water	900 gal/min	\$3/1000 gal	0.9	0.08
Export Steam	120,000 lb/hr 600 psi		-3.7	-0.31
Capital Cost	\$70 MM in 2016\$	For a 50 MMSCF/day plant		
	\$81 MM in 2024\$	For a 32 MMSCF/day plant	8.7	0.74
Fixed Cost		6.7%	5.3	0.45
Total Cost			32.9	2.82

Based on our cost analysis, hydrogen is estimated to cost \$2.82/MSCF in 2026. If renewable fuel producers elect to produce and use renewable hydrogen derived from RNG as a feedstock to their renewable diesel plant instead of hydrogen derived from fossil natural gas, we would expect the cost to produce renewable diesel would increase. As summarized in Chapter 10.1.2.6, the cost to produce, clean up and distribute biogas as pipeline-quality RNG is higher than similar costs to produce pipeline-quality fossil-derived natural gas. Thus, the hydrogen produced from the biogas-derived RNG would also be more expensive. And while hydrogen can also be produced from electrolysis, the cost of doing so is greater than steam methane reforming of either fossil or renewable natural gas.⁷²⁷ For these reasons, we anticipate any non-fossil-derived natural gas would be supplied at a cost premium in 2026 or 2027.

Our yield estimates as summarized in Table 10.1.2.4-2 were derived from material presented by UOP and Eni at a 2007 industry conference, which describes producing renewable diesel in a grass roots standalone production process inside a refinery.⁷²⁸ Despite the age of the reference, the underlying chemistry is unlikely to have changed appreciably.

⁷²⁶ Meyers, Robert A. *Handbook of Petroleum Refining Processes, Fourth Edition*. McGraw-Hill Education, 2016.

⁷²⁷ Congressional Research Service, “Hydrogen Production: Overview and Issues for Congress,” R48196, October 3, 2024. <https://www.congress.gov/crs-product/R48196>.

⁷²⁸ Holmgren, Jennifer, Chris Gosling, Rich Mariangeli, Terry Marker, Giovanni Faraci, and Carlo Perego. “A New Development in Renewable Fuels: Green Diesel,” *National Petrochemical & Refiners Association* AM-07-10, 2007.

Table 10.1.2.4-2: Input and Output Streams from Renewable Diesel Plant

Vegetable Oil input	100 gal
Renewable diesel output (main product)	93.5 gal
Naphtha output (co-product)	5 gal
Light fuel gas output (co-product)	9 gal

Notably, these yield estimates assume no separation of jet fuel from renewable diesel. As we note at the beginning of this section, many, if not most, renewable diesel plants also coproduce jet fuel as a separate product. The separation and sale of jet fuel range molecules would be expected to have some impact on the cost to produce renewable diesel relative to the plant described in Table 10.1.2.4-2, but we do not estimate that difference here. We will address costs for renewable jet fuel produced from a unit process inside of a refinery in Chapter 10.1.2.5.

We derived a cost of 6.9¢ per gallon of renewable diesel product to cover other costs: utilities, labor, and other operating costs.⁷²⁹ Finally, the total cost per gallon was estimated at \$4.64. Table 10.1.2.4-3 provides more details for the process assumed in this analysis and summarizes the total and per-gallon costs for the year 2026.

Table 10.1.2.4-3: Renewable Diesel Production Cost Estimate for a Greenfield 220 Million Gallons/Yr Plant Processing Soybean Oil in 2026 (2024\$)

Stream		Estimated value	MM\$/yr	\$/gal
Soybean Oil input	198 MMgals/yr	66¢/lb	1003	5.07
Naphtha output	11.8 MMgals/yr	1.61¢/gal	(19.0)	(0.10)
Light fuel gas output	21.2 MMgals/yr	80.3¢/gal	(17.0)	(0.09)
Hydrogen input	4,760 SCF/100 gals	\$2.82/MSCF	26.6	0.13
Other Operating Costs			15.2	0.07
Capital Costs (2024\$)		\$1,031 million	113.4	0.57
Fixed Costs		5.5%	56.7	0.29
Renewable Diesel Total Costs			921	5.95

The estimated renewable diesel production cost for all vegetable oil types and for the years analyzed is summarized in Table 10.1.2.4-5.

⁷²⁹ Estimated based on the utility cost for an FCC naphtha hydrotreater. EPA, “Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards Final Rule – Regulatory Impact Analysis,” EPA-420-R-14-005, March 2014. <https://nepis.epa.gov/Exe/ZyPDF.cgi/P100ISWM.PDF?Dockey=P100ISWM.PDF>.

Table 10.1.2.4-5 Summary of Estimated Renewable Diesel Production Costs (\$/gal; 2024\$)

	Year	Soybean Oil	Corn Oil	FOG
Control Case	2026	5.95	5.07	4.70
	2027	5.97	5.07	4.69
High Prices	2026	7.10	6.03	5.57
	2027	7.28	6.15	5.67
Low Prices No RFS	2026	4.09	3.54	3.30
	2027	3.81	3.28	3.06
Low Price 2025	2026	4.64	3.99	3.72
	2027	4.51	3.86	3.59

10.1.2.5 Renewable Jet Fuel

As explained in Chapter 10.1.2.4, the production process for renewable diesel can also be used to produce jet fuel. There are two primary ways of doing so using lipids as feedstocks. The first and lowest cost way is to simply install a distillation column and distill off the lighter hydrocarbons, which boil in the jet fuel distillation range, that are produced by the renewable diesel production process. The second, more expensive way, which can produce a larger amount of jet fuel, is to hydrocrack the renewable diesel hydrocarbons which fall in the diesel fuel range so that the hydrocarbon chains are shortened and then distill within the jet fuel distillation range.

Another emerging pathway for producing jet fuel is to use a recently developed chemical reaction pathway called alcohol-to-jet (ATJ). In this case, alcohol compounds are reacted together to form hydrocarbon chains which fall in the jet fuel boiling range. Ethanol and isobutanol alcohols are possible reactants for this process. Since corn ethanol is widely available domestically available renewable fuel in the U.S., we will estimate the cost of this technology using corn ethanol as the feedstock.

10.1.2.5.1 Distillation

A simple distillation column can be installed to separate the jet fuel boiling range hydrocarbons from the diesel boiling range hydrocarbons in renewable diesel. This simple distillation column, often called a stabilizer column, is designed to separate the lighter hydrocarbons from the heavier hydrocarbons and make only a rough cut between the two hydrocarbon ranges. This type of distillation column would not be designed to boil off many of the heavier hydrocarbon compounds which would allow for a smaller diameter column. Also, because of the need for only a rough cut between the light and heavy hydrocarbons, the column would require fewer trays and therefore not be very tall. EPA obtained cost information from Mobil Oil for such a column for the 1999 Tier 2 gasoline sulfur regulation which was designed for a similar case of separating the light and heavy gasoline naphtha compounds to minimize the cost to desulfurize gasoline.⁷³⁰

⁷³⁰ EPA, “Regulatory Impact Analysis – Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements,” EPA-420-R-99-023, December 1999. <https://nepis.epa.gov/Exe/ZyPDF.cgi/P100F1UV.PDF?Dockey=P100F1UV.PDF>.

The capital and operating cost information, and cost to produce jet fuel, for a stabilizer column to separate the jet fuel hydrocarbons from the rest of the renewable diesel compounds is summarized in Table 10.1.2.5.1-1. The capital cost estimates from Mobil Oil are for a 50 thousand bbl/day unit from the year 2000. We have adjusted the costs to 2024 dollars and base it on 14.4 thousand barrels per day (220 million gallon per year). A 20% factor is added to account for contingency costs, and a 40% factor is added to account for offsite costs. Jet fuel comprises hydrocarbons which range from 8 to 16 carbons in length. Analysis of the hydrocarbon chain lengths of renewable diesel produced soybean and corn vegetable oils and animal fat triglycerides reveals that the renewable diesel from vegetable oils typically contain about 20% 8 to 16 carbon hydrocarbons, while renewable diesel and animal fats typically contain 30% 8 to 16 carbon hydrocarbons. Since most renewable diesel is produced from vegetable oil, we assume that 20% of the renewable diesel produced would be separated as jet fuel by this distillation column, and we amortized the costs over only the jet fuel volume.

Table 10.1.2.5.1-1: Distillation Cost of Separating Jet Fuel from Renewable Diesel (2024\$)

			Annual Cost (MM\$)	Cost to Jet Fuel (¢/gal)
Capacity Basis	50,000 bbl/day			
Capital Cost 2000\$	\$4.1 million			
Capital Cost for a 14.5 bbl/day unit	\$2.2 million		0.25	0.56
Fixed Cost	5% of Capital		0.11	0.24
Electricity	0.17 kWh/bbl	6.69¢/kWh	0.06	0.14
HP Steam	36 lb/bbl	\$4.48/MMBtu	1.27	2.8
Cooling Water	3 gal/bbl	\$3/1000 gal	0.20	0.46
Total cost to jet (2900 bbl/day)			1.88	4.3

Table 10.1.2.5.1-1 summarizes our estimated cost to produce renewable jet fuel from renewable diesel oil in 2026 as 4.30¢ per gallon. Thus, adding a distillation column at a renewable diesel production facility would raise the \$5.95 renewable diesel production cost to \$5.99 per gallon when using distillation to produce renewable jet fuel.

10.1.2.5.2 Hydrocracking

The hydrocracking process utilizing a cracking catalyst can be used to convert some of the renewable diesel to jet fuel. Since this is a mild hydrocracking operation, it is estimated to only require a single stage hydrocracking reactor added after the renewable diesel hydrotreating reactor. The hydrocracking facility includes a distillation column which separates the hydrocracking reactor products into various streams, including jet fuel, renewable diesel, renewable naphtha and other light products. Table 10.1.2.5.2-1 summarizes the capital and operating cost information, input and output product information, and the estimated cost for the added hydrocracker unit.⁷³¹ A hydrocracker can produce a range of products depending on the operating conditions and catalyst used. For this analysis, a hydrocracker processing used cooking

⁷³¹ Meyers, Robert A. *Handbook of Petroleum Refining Processes, Fourth Edition*. McGraw-Hill Education, 2016.

oil, which the study termed a waste oil, is estimated to produce 64% jet fuel, 20% naphtha, 6% light hydrocarbons, and 10% unreacted renewable diesel. However, hydrocrackers are quite flexible in their operations due to operating conditions and the catalyst used, so the product mix can be quite different from that used in this study.⁷³² The mild hydrocracking reaction is estimated to cause the product to swell 3 vol% relative to the feed volume.

The cost of the process is reflected in final cost of the renewable jet fuel being produced. The byproducts of the hydrocracking reaction were assigned monetary values to allow estimating the cost of the jet fuel produced. The unreacted renewable diesel is assigned the same price as the renewable diesel feedstock. The naphtha and light naphtha are assigned a discounted price relative to gasoline to reflect their expected low octane value. However, these streams could have higher value based on their renewability. As a sensitivity on the hydrocracking cost of producing jet fuel, naphtha is also valued the same as the renewable diesel feedstock, which could reflect its value as a renewable fuel.

Table 10.1.2.5.2-1 Estimated Renewable Jet Production Cost from Hydrocracked Renewable Diesel (2024\$)

			Annual Cost (MM\$)	Cost to Jet Fuel (¢/gal)
Capacity Basis	14.4 kbbbl/day			
Capital Cost 2016\$	\$5000/bbl/day			
Capital Cost 2024\$	\$120 million		13.2	10.1
Fixed Cost	5% of capital		6.01	4.6
Feedstock	12,916 bbl/day	\$4.40/gal	871.2	667.4
Hydrogen	250 SCF/bbl	\$3.32/MSCF	3.32	2.5
Natural Gas	90,000 Btu/bbl	\$4.37/MMBtu	1.85	1.4
Electricity	8.4 kWh/bbl	8.37 ¢/kWh	3.32	2.5
Cooling Water	2 gal/bbl	\$3/1000 ft ³	0.03	0.02
Steam Export	10 lb/bbl	\$4.37/MMBtu	-0.16	-0.12
Byproducts				
Other	798	\$1.61/gallon	-19.7	-15.1
Naphtha – Low		\$1.61/gallon	-65.8	-50.4
Naphtha - High	2,661	\$4.64/gallon	-189.445	-145.1
Renewable Diesel	1,330	\$4.44/gallon	-94.7	-72.5
Total Cost – Naphtha Low Price			718.5	550.5
Total Cost – Naphtha High Price			594.9	455.7

The analysis shows that if the hydrocracked naphtha price is significantly reduced to a value less than gasoline based on an assumption that its octane value is significantly lower than gasoline, the estimated production cost of renewable jet fuel is estimated to be \$1.1 per gallon

⁷³² El-Araby, R., E. Abdelkader, G. El Diwani, and S. I. Hawash. “Bio-aviation Fuel via Catalytic Hydrocracking of Waste Cooking Oils.” *Bulletin of the National Research Centre/Bulletin of the National Research Center* 44, no. 1 (October 12, 2020). <https://doi.org/10.1186/s42269-020-00425-6>.

more expensive than renewable diesel. If the hydrocracked naphtha is assumed to be valued at the same price as renewable diesel, perhaps associated with a higher octane value, the estimated production cost of the hydrocracked jet fuel falls to 15¢ per gallon above the assumed renewable diesel price. Hydrocracked naphtha is typically low in octane; however, it is possible for the hydrocracking reactor to include catalyst which could raise the octane of the hydrocracked naphtha.

10.1.2.5.3 Alcohol-to-Jet

Three different reaction steps are involved in converting ethanol into jet fuel. First the alcohol is dehydrated by removing the hydroxyl (-OH) group, creating an olefin with the base hydrocarbon molecule. Thus, dehydrating ethanol produces ethylene as the intermediate product. Second, the hydrocarbons are oligomerized, which essentially daisy-chains the individual hydrocarbons molecules together. An obvious challenge of this second step is reacting enough of the short hydrocarbons together such that they boil in the jet fuel range, without combining too many together and producing diesel or an even heavier hydrocarbon. For the third step, the double carbon-carbon bonds of the oligomerized hydrocarbons are hydrogenated to saturate the double bonds.

We estimated the cost for converting ethanol to jet fuel based on a study which developed an Aspen Plus technical model for the cost analysis which likely includes both onsite and offsite costs.⁷³³ The model assumed a smaller-sized ATJ plant of 185 tons per day (20 million gallons per year) of alcohol feedstock, which seems appropriate for an emerging technology. The model estimates that the process produces mostly jet fuel but also produces renewable diesel and naphtha. We credit the renewable diesel exiting the ATJ process at the feedstock price since the renewable diesel is unreacted by the process. The model estimates a total installed capital cost, but a 20% contingency factor is added to the reported capital cost. Table 10.1.2.5.3-1 summarizes the cost information and resulting estimated costs for the ATJ process.

⁷³³ Geleynse, Scott, Kristin Brandt, Manuel Garcia-Perez, Michael Wolcott, and Xiao Zhang. “The Alcohol-to-Jet Conversion Pathway for Drop-In Biofuels: Techno-Economic Evaluation.” *ChemSusChem* 11, no. 21 (September 13, 2018): 3728–41. <https://doi.org/10.1002/cssc.201801690>.

Table 10.1.2.5.3-1 Estimated Cost to Convert Corn Ethanol to Renewable Jet Fuel (2024\$)

			Annual Cost (MM\$)	Cost to Jet and Diesel Fuels (¢/gal)
Capacity Basis				
Capital Cost 2024\$	\$20.3 million		3.0	0.30
Fixed Cost	6% of capital		1.6	0.16
Corn Ethanol	185 tons/day (20.5 million gals/yr)	\$1.83/gal	38.5	3.92
Hydrogen	1.1 tons/day	\$2.82/MSCF	0.41	0.04
Utilities	\$2.7 million/yr	-	2.7	0.28
Catalyst	\$0.5 million/yr	-	0.5	0.05
Naphtha	1.29 million gal/yr	\$1.61/gal	-2.1	-0.21
Diesel	2.26 million gal/yr		-	
Jet Fuel	7.55 million gal/yr		-	
Total cost to jet and diesel (2900 bbl/day)			44.6	4.54

The cost analysis estimates that producing jet fuel from corn ethanol using the ATJ process costs \$4.54/gallon. This is less expensive than producing jet fuel from soybean oil at the estimated high soybean oil prices, although more expensive than producing jet fuel from used cooking oil or corn oil at low prices.

10.1.2.6 Renewable Natural Gas

RNG is generally understood to describe biogas which has been upgraded for use in place of fossil natural gas.⁷³⁴ The RFS regulations at 40 CFR 80.2 provides a more detailed definition, stipulating that RNG “is produced from biogas...does not require removal of additional components to be suitable for injection into the natural gas commercial pipeline system...[and] is used to produce renewable fuel.” Biogas, in turn, is a methane and carbon-dioxide-rich gas resulting from the decomposition of organic matter under anaerobic conditions; significant sources of biogas include municipal solid waste, animal manure, agricultural waste, and food waste.⁷³⁵ The RFS program provides a more detailed definition of “Biogas” at 40 CFR 80.2, which includes additional program-specific stipulations. The primary product of this anaerobic digestion of these materials is methane, which is the primary component of natural gas. Thus, once biogas is cleaned up by removing various contaminants, it can be used by processes that normally use natural gas.⁷³⁶

The largest source of biogas, which is already being collected to avoid releasing methane into the environment, is from landfills.⁷³⁷ Since landfill gas is the largest source of biogas

⁷³⁴ EPA, “Renewable Natural Gas,” <https://www.epa.gov/lmop/renewable-natural-gas>.

⁷³⁵ Id.

⁷³⁶ LeFevers, Daniel. “Landfill Gas to Renewable Energy,” *Waste Management*, April 26, 2013. https://www.eesi.org/files/042613_Daniel_LeFevers.pdf.

⁷³⁷ EIA, “Biomass explained – Landfill gas and biogas,” November 19, 2024. <https://www.eia.gov/energyexplained/biomass/landfill-gas-and-biogas.php>.

available for the motor vehicle fleet, this cost analysis makes the simplifying assumption that the biogas will solely be provided by landfills.⁷³⁸

While in some cases RNG can be used in local fleet vehicles which are operated at the landfill site, in most cases the fuel must be transported to the final consumer by pipeline. It is our understanding that most new RNG production facilities require the construction of a new pipeline to transport the RNG to a nearby common carrier pipeline. RNG is then pulled off the pipeline at downstream locations and compressed into CNG or liquified into LNG for use in motor vehicles. Tracking the use of RNG in motor vehicles occurs by proxy through contracts and/or affidavits rather than through a system designed to ensure that the same methane molecules produced at the landfill are used in CNG/LNG vehicles.

One of the costliest aspects of using biogas to produce RNG is its cleanup. Biogas contains large amounts of carbon dioxide, nitrogen, and other contaminants such as siloxanes which cannot be tolerated if it is to be put into a natural gas pipeline or used by fleet vehicles at the landfill site. We estimated a cost for cleaning up landfill biogas to pipeline quality using Version 3.5 of the Landfill Gas Energy Cost Model (LFGcost-Web).^{739,740} The throughput volume of landfill gas was estimated to be 1,500 SCF/min, which is about an average production volume from biogas production facilities.⁷⁴¹ The equations from the LFGcost-Web model for biogas clean-up and interconnection to a natural gas pipeline are summarized in Table 10.1.2.6.1-1. We included a cost for biogas collection at a typical sized landfill which amounts to \$0.09/MSCF.⁷⁴² The estimated production and clean-up costs for landfills are summarized in Table 10.1.6.2-2. Distribution and retail costs are estimated for RNG in Chapter 10.1.4.3.

Table 10.1.2.6-1: Biogas Cleanup Cost Information

	Cost Factors (2019\$)
Pipeline Interconnection	\$400,000
Capital Costs	$6,000,000 * e^{(0.0003 * \text{SCF/min})}$
Operating and Maintenance	$250 \times \text{SCF/min} + 148,000$
Electricity Costs	0.009 kWh/SCF

Note: Excludes any new offsite pipeline costs and retailing costs.

⁷³⁸ Landfill biogas is expected to be the supplier in the near term due to its lower cost because of its greater economy scale and closer access to markets.

⁷³⁹ The current version of this model and user's manual are available at: <https://www.epa.gov/lmop/lfgcost-web-landfill-gas-energy-cost-model>.

⁷⁴⁰ This cost estimate does not include the cost for complying with California's more stringent natural gas pipeline specifications designed to address harmful contaminants in some sources of biogas.

⁷⁴¹ The Coalition for Renewable Natural Gas, "Economic Analysis of the U.S. Renewable Natural Gas Industry," December 2021. <https://guidehouse.com/-/media/www/site/insights/energy/2022/guidehouse-esirng-coalition-final-report122022.pdf>.

⁷⁴² EPA, "LFG Energy Project Development Handbook," January 2024, Chapter 4. https://www.epa.gov/system/files/documents/2024-01/pdh_full.pdf.

Table 10.1.2.6-2 Biogas Collection and Cleanup costs (2024\$)

	Average (1500 scf/min)		Large (8000 scf/min)		Small (250 scf/min)	
	Cost MM\$/yr	Cost \$/MMBtu	Cost MM\$	Cost \$/MMBtu	Cost MM\$	Cost (\$/MMBtu
Capital Cost	1.36	3.34	3.72	1.71	0.47	6.83
Operating and Maintenance	0.52	1.28	2.15	0.99	0.21	3.09
Electricity Costs	0.85	2.08	4.54	2.08	0.14	2.08
Total Clean-up Cost	2.74	6.70	10.41	4.78	0.82	12.00
Interconnection	0.06	0.14	0.06	0.03	0.06	0.85
Collection Cost	0.20	0.49	0.20	0.09	0.20	2.95
Collection and Clean-up Cost	3.00	7.33	10.67	4.89	1.08	15.81

The combined biogas collection and cleanup costs for an average sized landfill amount to \$7.33 per million Btu of RNG. For larger and smaller landfills, the costs are estimated to be \$4.89/mmBTU of RNG and \$15.8/mmBTU of RNG, respectively.

10.1.2.7 Sugarcane Ethanol

Unlike the starch in corn kernels which first must be depolymerized using enzymes, sugarcane contains free sugar which, after extraction from the sugarcane, can be directly fermented into ethanol. The fibrous portions of the sugarcane plant, known as sugarcane bagasse, are typically combusted to produce the energy needed for the process.

We estimated the cost to produce sugarcane ethanol in two different ways. The first method we used is based on recent data on sugarcane ethanol prices which we receive in EMTS. These are as-received prices, so they include the cost to ship the ethanol from Brazil to the U.S. Generally, ethanol from sugarcane produced in tropical areas is cheaper to produce than ethanol from cellulose and is similar in cost to corn starch ethanol. This is due to favorable growing conditions resulting in relatively low-cost feedstock, low energy input costs due to the abundance of combustible bagasse residues, and other cost reductions gained from years of experience. The average of sugarcane ethanol prices from EMTS was \$2.73 per gallon. Other price data which EPA receives from OPIS have shown a similar average price over the same period, which helps to corroborate the price data from EMTS.

The second method we used is taken from a study by OECD (2008) entitled “Biofuels: Linking Support to Performance,” which provides a set of assumptions and an estimate of production costs. Our estimate of sugarcane production costs shown in Table 10.1.2.6-1 primarily relies on the analysis described in that study.⁷⁴³ Our original cost estimate reported in the RFS2 Rule assumed an ethanol-dedicated mill and is based off an internal rate of return of 12%, a debt/equity ratio of 50% with an 8% interest rate, and a selling of surplus power at \$57 per MWh. We adjusted the capital and operating costs taken from OECD (2008) for the effects

⁷⁴³ EPA, “RFS2 Regulatory Impact Analysis,” EPA-420-R-10-006, February 2010.

of inflation from 2006 to 2024, as shown in Table 10.1.2.7-1. As we did for most of the other fuel costs estimated in Chapter 10.1.2, when estimating the amortized per-gallon capital costs we also added a 20% capital cost contingency factor to account for other costs not accounted for in the cost analysis. We then applied our capital cost amortization parameters described in Chapter 10.1.2.1.1 above to complete the estimates. Table 10.1.2.7-1 provides the updated production cost estimate for sugarcane ethanol.

Table 10.1.2.7-1: Sugarcane Ethanol Production Cost

Cost Basis	Sugarcane Productivity	71.5 tons/hectare	
	Sugarcane Consumption	2 million tons/year	
	Harvesting days	167	
	Ethanol productivity	85 L/ton feedstock (22.5 gal/ton feedstock)	
	Ethanol Production	170 million L/yr (45 million gals/yr)	
	Surplus power produced	40 kWh/ton sugarcane	
		RFS2 Reported Cost (\$2006)	Revised Costs (\$2024)
Capital Costs (\$ million)	Investment cost in million\$	97	155
	Investment cost for sugarcane production	36	58
Per Gallon Costs (\$/gal)	Operating & maintenance costs	0.26	0.42
	Variable sugarcane production costs	0.64	1.02
	Capital costs	0.49	0.62
	Total production costs	1.39	2.07
	Shipping Costs to U.S.		0.15
	Delivered Cost		2.22

The average FOB ethanol price of \$2.73/gallon in Brazil is somewhat higher than the estimated sugarcane ethanol production cost of \$2.22/gallon. This cost/price difference can mostly be attributed to the low (0.11) before-tax capital amortization factor that we use which reflects the social cost of capital, and the shipping costs incorporated in the price data. As noted in Chapter 10.1.2.1.1, EPA has a standard factor which we have used across numerous rulemakings. However, if we were to use a more typical 0.16 after-tax capital amortization factor used by industry, the per-gallon costs increase to \$2.50 per gallon. Normally we would use the bottom-up cost estimate described in Table 10.1.2.7-1; however, the EMTS price data may capture some inflation effects which the bottom-up cost estimate may not capture regardless of the applied inflation adjustment. For this reason, we used the \$2.73 per gallon price data from EMTS to represent the production and distribution costs for sugarcane ethanol.

10.1.2.8 Corn Kernel Fiber Ethanol

In addition to converting corn starch to ethanol, some of the fiber contained in the corn kernel can also be converted to ethanol. This additional ethanol from CKF is considered cellulosic ethanol and earns D3 RINs. Historically, this step of converting the cellulosic fibers to ethanol was thought of as a separate unit process from the starch to ethanol conversion process, in which DDGS would be reacted a second time in a separate reactor vessel. This process would have additional associated fixed and variable costs. However, one or more companies have found

that a small portion of the cellulosic fiber is converted to ethanol along with the starch in the existing starch to ethanol facilities. We project that most producers will use this single reactor design to produce the cellulosic ethanol volumes in 2026 and 2027.^{744,745} Anticipating that this cellulosic ethanol would be produced in an existing starch to ethanol reactor provides cost efficiency that would lower the overall production cost. But this also presents a challenge for how to identify the quantity of ethanol produced from cellulose versus that produced from the starch. To remedy this EPA published guidance on how to identify the portion of ethanol being produced from cellulose.⁷⁴⁶

Anticipating that the cellulosic ethanol will be produced along with corn starch in an existing reactor allows us to estimate the cost of producing this cellulosic ethanol in a straightforward manner. Since we already estimate the capital, fixed, and variable operating cost of producing ethanol from corn starch on a dollars-per-gallon basis, we begin by applying those same cost estimates to the corn fiber ethanol. There are other additional cost factors to consider on top of these initial costs, specifically the potential cost for the additional enzyme added to convert corn fiber to ethanol and potential cost savings due to increased corn oil production.⁷⁴⁷ We estimate that the cost of the additional enzyme is approximately equally offset by the cost savings of additional corn oil production. Therefore, for the purposes of this chapter, we simply use the cost for producing ethanol from corn starch for the cost of producing ethanol from cellulosic ethanol. As described in Table 10.1.2.2-3 of this chapter, this cost is estimated to be \$1.88 per gallon of denatured ethanol for 2026 and \$1.92 per gallon for 2027.

10.1.3 Blending and Fuel Economy Cost

Certain renewable fuels, namely ethanol, biodiesel, and renewable diesel, are typically blended into petroleum fuels. There are costs, and in some cases, cost savings associated with such blending. In addition, these renewable fuels have relatively lower energy per gallon leading to lower fuel economy (miles driven per gallon). In this section, we consider blending and fuel economy costs for ethanol blended as E10, E15, and E85, as well as for biodiesel and renewable diesel.

10.1.3.1 Ethanol

10.1.3.1.1 E10

Ethanol has physical properties when blended into gasoline which affect its value as a fuel or fuel additive. Ethanol has a very high octane content, a high blending RVP when blended into gasoline at low concentrations, and is low in energy content relative to the gasoline pool that

⁷⁴⁴ Kacmar, Jim. “Intellulose: An Innovative Approach to Your Plant’s Profitability,” *Edeniq* 2019 Distillers Grains Symposium, May 15, 2019. <https://distillersgrains.org/wp-content/uploads/2019/05/7-Kacmar-Intellulose.pdf>.

⁷⁴⁵ National Corn to Ethanol Research Center, “Conversion of Corn-Kernel Fiber in Conventional Fuel-Ethanol Plants,” Project No. 0340-19-03, November 11, 2018.

⁷⁴⁶ EPA, “Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch,” EPA-420-B-22-041, September 2022. <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1015Q8V.pdf>.

⁷⁴⁷ Kacmar, Jim. “Intellulose: An Innovative Approach to your Plant’s Profitability,” *Edeniq* 2019 Distillers Grains Symposium, May 15, 2019. <https://distillersgrains.org/wp-content/uploads/2019/05/7-Kacmar-Intellulose.pdf>.

it is blended into. Ethanol has essentially zero sulfur or benzene, adding to ethanol's value because refineries must meet sulfur and benzene fuel standards. Each of these properties can have a different cost impact depending on the gasoline it is being blended into (*e.g.*, RFG versus CG), winter versus summer gasoline, premium versus regular, blended at 10% versus E15 or E85). These physical properties are also valued differently from a refiner's perspective compared to that of the consumer. Refiners value ethanol's octane because they can lower the octane of the gasoline the ethanol is being blended into, reducing their refining costs. Refiners dislike ethanol's high blending RVP when blending ethanol in gasoline (usually RFG) at 10% because they must remove some low-cost gasoline blendstock material (usually butane) to accommodate the ethanol if the gasoline they are producing does not receive a 1 psi RVP waiver.

Refiners are generally not concerned about ethanol's low energy content when blending it into gasoline since they sell gasoline on volume, not energy content, and consumers do not appear to demand a discount for E10. Rather, this is usually only an issue for the consumers who do not travel as far on a gallon of fuel with lower energy content. Depending on the fuel they are purchasing, the lower energy content will be either obvious to consumers (*i.e.*, E85), impacting their purchase decisions, or not (*i.e.*, E10; most consumers do not notice its lower energy content in comparison to E0, particularly now that almost all gasoline is E10). Since the ultimate finding of this chapter is a social cost analysis which incorporates all the costs to society, the fuel economy effect is included in the overall cost estimates in Chapter 10.4. For the reasons described above, this fuel economy effect is not included with the blending value estimated in this section.

Ethanol's total blending value is estimated based on the output from refinery modeling cases conducted by ICF/Mathpro for a projected 2020 year case assuming that crude oil would be priced at \$72/bbl.⁷⁴⁸ By averaging the costs separately for conventional and reformulated gasolines, the refinery modeling output from the first case allowed us to estimate ethanol's volatility cost for blending ethanol into E10 reformulated gasoline.⁷⁴⁹ Due to the options available to refiners to replace ethanol's octane, ICF/Mathpro ran two ethanol replacement cases.

In the first cost case, the refinery model principally relied on increased alkylate production. But to be able to replace all of ethanol's octane, the refinery model estimates that refiners would also increase the octane of reformate (through increased reformer severity) and increase production of isomerate, even if the primary octane replacement is alkylate. The refinery model estimates that for this alkylate-centric case over 7.6 million barrels per day of new refinery unit capacity would need to be added by refiners.

In the second case, instead of representing refiner reliance on large butane purchases for producing alkylate, ICF/Mathpro modeled increased throughput to, and increased severity of, existing reforming units to increase the octane of reformate, the product stream of the reformer. This case still relied on other octane producing unit additions, including alkylate and isomerate,

⁷⁴⁸ The crude oil price has a first order effect on the blending value and volatility cost for blending ethanol into gasoline. Since the crude oil price used in the refinery modeling cost analysis is about the same as the projected crude oil price for 2021 and 2022, it was not necessary to adjust ethanol's estimated blending cost to any other dollar value.

⁷⁴⁹ EPA's contract was with ICF Incorporated, LLC, which in turn retained Mathpro for some aspects of the work.

but increased reformat volume was the principal method to increase octane. This second reformat-centric refinery modeling case was less capital-intensive, but still added 3.7 million barrels per day of additional refinery unit capacity and was more costly on a per-gallon basis relative to the first cost case. Increasing the severity of reformers is relatively more expensive because of the cost associated with the production of two by-products of the reforming process which increase as the severity of the reformer is increased. Hydrogen is a by-product of reforming, but reformer-produced hydrogen is much more expensive than hydrogen produced from natural gas because natural gas has been priced much lower than crude oil. Fuel gas is another reformer by-product which is usually used for refinery process heat but displaces much cheaper purchased natural gas. For short-term octane needs, refiners would likely need to rely on increasing reformat severity to avoid or minimize the amount of new refining unit capacity additions, but given the higher overall cost, this would not be a preferable long-term solution.

Table 10.1.3.1.1-1 summarizes gasoline's marginal costs for the reference case (all gasoline with ethanol) and ethanol's marginal costs for these two ethanol removal cases across different gasoline types and refinery regions. In the table, Low Biofuel #1 is the reformat-centric case while Low Biofuel #2 is the alkylate-centric case. The lower marginal values for PADD 1 (low Biofuel #1) can be explained because Mathpro forced PADD 3 refineries to satisfy PADD 1's need for replacing ethanol's volume and octane through PADD's 3 exports into the PADD 1 after initial refinery model runs showed PADD 1's marginal costs for replacing ethanol were exceedingly high.

Table 10.1.3.1.1-1: Gasoline Marginal Values for Reference Case and Ethanol Marginal Values for the Low Biofuel Cases (\$/bbl)

PADD of Gasoline Origin	Type	Grade	Gasoline Marginal Values		Ethanol Marg Val Low Biofuel #1		Ethanol Marg Val Low Biofuel #2	
			Summer	Winter	Summer	Winter	Summer	Winter
PADD 1	RFG	Prem	95.74	83.94	108.37	100.88	0	0
		Reg	91.45	81.35	115.98	105.97	0	0
	CG	Prem	92.68	83.89	123.02	100.87	0	0
		Reg	88.93	81.35	136.43	105.88	0	0
PADD 2	RFG	Prem	88.09	81.68	132.42	110.28	113.45	96.62
		Reg	84.80	79.77	145.38	116.02	122.86	101.61
	CG	Prem	85.55	81.25	149.08	110.41	126.74	96.25
		Reg	82.46	79.45	161.21	115.79	135.55	100.93
PADD 3	RFG	Prem	85.42	78.31	121.69	94.72	118.51	89.77
		Reg	81.86	76.39	134.67	98.45	131.29	94.48
	CG	Prem	83.64	78.78	133.95	95.13	129.37	89.91
		Reg	79.97	76.76	146.78	98.46	142.00	94.55
PADD 4	CG	Prem	79.8	77.0	135.5	115.2	150.1	103.1
		Reg	77.4	75.1	149.0	124.0	168.1	110.0
	Low RVP	Prem	94.5	-	136.5	-	151.2	
		Reg	98.3	-	150.1	-	169.2	
PADD 5	RFG	Prem	96.89	83.68	37.68	96.05	0	0
		Reg	91.61	82.01	62.46	97.37	0	0
	CG	Prem	77.63	83.00	118.14	98.01	0	0
		Reg	73.38	81.12	126.14	97.68	0	0

Note: The option for additional alkylation was not available for PADDs 1 and 3, which is why there are no marginal costs reported for the Low Biofuel #2 case.

The gasoline-ethanol difference in marginal values is calculated and summarized in Table 10.1.3.1.1-2. Note that the values in Table 10.1.3.1.1-1 are in dollars per barrel, while the values in Table 10.1.3.1.1-2 are in cents per gallon.⁷⁵⁰

⁷⁵⁰ The ethanol replacement cost is calculated by subtracting the gasoline marginal value from the ethanol marginal value, and then converting the cost difference from dollars per barrel to cents per gallon. For example, the PADD 2 premium summertime RFG ethanol replacement value for the Low Biofuel Case #2 is calculated as \$113.45 – \$88.09 = \$25.36 per barrel = 60.39¢ per gallon.

Table 10.1.3.1.1-2: Marginal Ethanol Replacement Cost by Gasoline Type and Season (¢/gal)

PADD of Gasoline Origin	Type	Grade	Low Biofuel #1 Reformate-centric		Low Biofuel #2 Alkylate-centric		Gasoline Volume thousand bbl/day	
			Summer	Winter	Summer	Winter	Summer	Winter
PADD 1	RFG	Prem	30.07	40.35	0	0	56	56
		Reg	58.41	58.62	0	0	330	332
	CG	Prem	72.23	40.43	0	0	19	18
		Reg	113.10	58.42	0	0	200	189
PADD 2	RFG	Prem	105.56	68.08	60.39	35.55	32	33
		Reg	144.23	86.31	90.61	52.00	269	275
	CG	Prem	151.27	69.44	98.08	35.73	146	156
		Reg	187.51	86.52	126.41	51.15	1,663	1,786
PADD 3	RFG	Prem	86.35	39.08	78.77	27.29	131	114
		Reg	125.74	52.52	117.69	43.07	785	638
	CG	Prem	119.78	38.93	108.86	26.50	369	366
		Reg	159.07	51.68	147.69	42.38	2,685	2,649
PADD 4	CG	Prem	132.70	90.86	167.45	62.16	58	60
		Reg	170.67	116.41	216.07	83.19	283	289
	Low RVP	Prem	100.19	0.00	135.02	0.00	3	3
		Reg	123.27	0.00	168.77	0.00	0	0
PADD 5	RFG	Prem	-140.97	29.46	0	0	218	214
		Reg	-69.39	36.56	0	0	823	810
	CG	Prem	96.44	35.73	0	0	57	52
		Reg	125.61	39.43	0	0	309	285

The regional ethanol replacement costs are volume-weighted together to develop national-average ethanol replacement costs by gasoline grade and season. These costs are only presented for the conventional gasoline pool. Table 10.1.3.1.1-3 summarizes these estimated ethanol-replacement costs.

Table 10.1.3.1.1-3: National Average Ethanol Replacement Cost by Gasoline Grade and Season (¢/gal)

	Gasoline Grade	Reformate-centric		Alkylate-centric	
		Summer	Winter	Summer	Winter
Conventional	Premium	124.6	50.8	112.0	32.7
	Regular	165.1	66.8	144.2	48.2

To estimate the volatility cost, ethanol's marginal values in Table 10.1.3.1.1-1 for RFG are subtracted from those for CG, although the values are calculated separately for premium and regular grade gasolines. These calculated values are summarized in Table 10.1.3.1.1-4. Although this analysis could have separately analyzed RVP-controlled conventional gasoline without a waiver, it did not since its gasoline volume was less than 2% of the total gasoline pool.

Table 10.1.3.1.1-4 Ethanol's RVP Blending Cost in Reformulated Gasoline in 2020 by PADD (\$/gal)

Gasoline PADD	Gasoline Grade	RFG-CG Marginal Values (\$/bbl)
PADD 1	Premium	9.74
	Regular	10.53
PADD 2	Premium	9.59
	Regular	9.32
PADD 3	Premium	9.31
	Regular	9.25
PADD 5 (CA)	Premium	58.79
	Regular	62.59

The ethanol RVP blending cost estimated by the refinery model are volume-weighted together to develop national-average values, and ethanol's RVP blending costs are calculated separately for premium and regular grades of summertime RFG, and summarized in Table 10.1.3.1.1-5. The PADD 5 RFG, which is California RFG, is modeled to have a volatility cost which is five times higher than other RFG areas. The cost of complying with California RFG standards may be higher than that for other RFG areas, but a factor of five seemed much too high and was considered an outlier.⁷⁵¹ Therefore, the modeled California RFG ethanol marginal costs, which should reflect ethanol's volatility cost, were omitted from this analysis and the PADD 1 – 3 costs were volume-weighted together and used for all RFG areas, including California.

Table 10.1.3.1.1-5: Calculated RVP Blending Costs by Fuel Grade

	Gasoline Grade	Cost (¢/gal)
Nationwide Aggregated Cost	Premium	22.5
	Regular	22.8

Although the ethanol replacement cost was based on a refinery modeling case when ethanol was solely removed from conventional gasoline, it would likely be about the same for RFG as well, so we assumed that they were the same for RFG.⁷⁵² However, it is necessary to add in ethanol's volatility cost for RFG, which for ethanol's removal would be a cost savings. The 23¢ per gallon volatility cost for regular and premium gasoline, respectively, is subtracted from ethanol's replacement cost to estimate the ethanol replacement cost for RFG. The ethanol replacement costs for both CG and RFG are shown in Table 10.1.3.1.1-6. The ethanol replacement costs are then further aggregated to national, year-round averages for each octane replacement scenario and summarized at the bottom of the table.

⁷⁵¹ The volatility cost of complying with California RFG standards would be based on the lower price it could get for pentane less than the price of gasoline. Pentane is the likely light hydrocarbon that California refiners remove to comply with the California RFG volatility standards with ethanol blended into RFG. The lowest price California could get for the removed pentane is if it had to rail it back to the Gulf Coast. That transportation cost will not be more than twice the price difference of Gulf Coast pentane to the price of California RFG. Thus, we would not expect the volatility cost to exceed twice that outside of California.

⁷⁵² Both RFG and CG must meet many of the same gasoline property specifications, including sulfur and benzene, as well as ASTM D4814, and octane costs are based on the same gasoline blendstocks in either case. PADD 4 is not included in the cost tables because there is no RFG sold there.

Table 10.1.3.1.1-6: Aggregated Ethanol Marginal Replacement Cost (¢/gallon)

Gasoline	Grade	Low Biofuel #1 Reformate-centric		Low Biofuel #2 Alkylate-centric	
		Summer	Winter	Summer	Winter
Conv.	Prem	124.58	50.79	112.04	32.65
	Reg	165.11	66.83	144.23	48.19
RFG	Prem	105.58	50.79	93.04	32.65
	Reg	144.11	66.83	123.23	48.19
Annual Average		82.23		68.65	

Refiners would pursue the lowest cost means to produce their fuels, which in this case would be the alkylate-centric method. Therefore, for evaluating the cost of using ethanol in gasoline at 10%, we used the cost of 68.65¢ per gallon estimated for that method to represent the cost of blending ethanol as E10. This 68.65¢ per gallon cost represents ethanol’s average nationwide blending replacement cost in U.S. gasoline when crude oil is priced at \$72/bbl, since that is the crude price ICF/Mathpro used in their original analysis. However, for AEO2025, EIA projects crude oil prices to average about \$81/bbl across 2026 and 2027. We used this higher projected crude oil price to ratio ethanol’s blending value to \$77.4 per gallon in 2026 and 2027. This estimate can be thought of as the additional value or cost savings to gasoline refiners per gallon of ethanol that results from blending 10% ethanol into gasoline today.

10.1.3.1.2 Higher Level Ethanol Blends

While there is a considerable blending cost savings associated with blending ethanol as E10, there currently is not a blending cost savings for blending ethanol as E15 or E85. The blending costs for higher level ethanol blends are considerably different from E10 in large part due to the inability in most instances to take advantage of the octane benefit associated with the additional ethanol.⁷⁵³ Furthermore, the congressional 1 psi RVP waiver which applies for blending E10 gasoline in summer conventional gasoline does not apply to blending E15, requiring a lower RVP and therefore higher cost gasoline blendstock. However, this is only an added cost in the summer and only in conventional gasoline areas.

There have been, and there continue to be, steps taken to facilitate the blending of E15 into summertime conventional gasoline. EPA granted E15 a 1 psi waiver that took effect in the summer of 2019; however, this waiver was struck down by a federal court in 2021. For the summers of 2022–2025, EPA granted numerous emergency waivers to allow E15 to continue to be sold with a 1 psi RVP waiver. In addition, eight states petitioned EPA to allow them to remove the 1 psi waiver for blending E10 gasoline. EPA issued a final rulemaking granting those petitions effective in 2025, although through a regulatory action requested by the 8 states, the

⁷⁵³ See RIA Chapter 2.1.1 for further details.

removal of the E10 1 psi waiver for those 8 states was delayed until 2026.^{754,755,756} Additionally, EPA granted E15 a nationwide 1 psi waiver for the summer of 2025.⁷⁵⁷

E15 could potentially realize a blending cost benefit based on the increased octane for the additional ethanol if refiners could create and distribute a low RVP, low octane E15 blendstock for oxygenate blending (BOB). However, this would require a widespread shift by refineries, pipelines, and terminals in an entire geographical region to produce and distribute another even lower octane BOB specially designed for producing E15 instead of E10.⁷⁵⁸ This would most likely only occur if E15 becomes the predominant gasoline used in that region because of the limitations of the distribution system and experience with the historic conversion to E10. Since this could not feasibly happen during the time period of this rulemaking, we have not included any octane blending benefit for the additional ethanol blended into E15 in excess of the ethanol blended in E10 (the additional 5%).⁷⁵⁹ Thus, the gasoline BOB used to produce E15 in the winter months is the same as that used for producing E10, resulting in a higher octane fuel which cannot generally be priced to represent the full value of that octane. In the summer months, E15 would also incur the additional RVP control costs, except in those states which have rescinded the E10 1 psi waiver.

There also is not a blending cost benefit for ethanol blended as E85 resulting from its high octane beyond that which is already being realized when blending E10. When producing E85, ethanol's high octane results in significant overcompliance with the minimum octane standard. Refiners do not produce a low octane BOB for producing E85 to realize a cost savings. Conversely, ethanol plants produce E85 by adding a denaturant to ethanol, which typically is a low cost, low octane, high RVP hydrocarbon commonly known as NGLs. The corn ethanol plants add an additional quantity of the NGLs, above the quantity needed to denature the ethanol, to produce the E85. Thus, E85 produced from NGLs does realize a cost savings. But NGLs are also lower in energy density, offsetting the potential cost savings to consumers. Regardless, there is no RVP blending cost for E85 because the high portion of ethanol results in lower RVP instead of higher RVP; therefore, a lower RVP blendstock is not needed for producing E85. In fact, to adjust for the lower RVP of E85 blends, E85 is actually blended at roughly 74% ethanol

⁷⁵⁴ 89 FR 14760 (February 29, 2024).

⁷⁵⁵ 90 FR 13093 (March 20, 2025).

⁷⁵⁶ EPA, "EPA Addresses E-10 Standards, Allows for Nationwide Year-Round E15 Sales," April 28, 2025. <https://www.epa.gov/newsreleases/epa-addresses-e-10-standards-allows-nationwide-year-round-e15-sales>.

⁷⁵⁷ EPA, "Fuel Waivers." <https://www.epa.gov/gasoline-standards/fuel-waivers>.

⁷⁵⁸ Some refiners may have extra tankage available to allow producing and storing a lower octane E15 blendstock to enable selling E15 over its own terminal rack to local retail stations. Refinery rack gasoline sales, however, are usually a small portion of a refinery's gasoline sales.

⁷⁵⁹ The RFG pool always took advantage of ethanol's high octane as it was needed to cause a reduction in aromatics to reduce the emissions of air toxics under the Complex Model—the former compliance tool of the RFG program. When ethanol replaced methyl tertiary butyl ether (MTBE) as the oxygenate in 2005 when the RFG oxygen requirement was rescinded, refiners took advantage of ethanol's high octane content. The CG pool, however, could not take advantage of ethanol's high octane until an entire U.S. gasoline market (*i.e.*, Midwest) was blended with ethanol, and then that gasoline market shifted over all at once to a sub-octane blendstock for oxygenate blending (CBOB). Reviewing CG aromatics levels (high octane aromatics decrease when refiners produce sub-octane CBOB), refiners switched the CG pool over to low octane CBOB from 2008–2013, which is around the time when the U.S. reached the E10 blendwall.

on average over both the summer and winter, instead of 85%, to have sufficiently high RVP to avoid RVP minimum limits.⁷⁶⁰

The societal cost of using ethanol must include ethanol's lower energy density (fuel economy effect). Ethanol has about 33% lower energy density than gasoline blendstock (CBOB and RBOB).⁷⁶¹ Accounting for ethanol's lower energy density adds about 80 cents per gallon of ethanol for all the ethanol blends to account for the additional cost to consumers for having to purchase a greater volume of less energy dense fuel to travel the same distance.⁷⁶²

10.1.3.2 Biodiesel and Renewable Diesel

Biodiesel and renewable diesel fuel have properties that could cause a cost savings or incur a cost. Both fuels have higher cetane value relative to petroleum diesel.^{763,764} Although ICF/Mathpro considered the possibility of the petroleum refining industry taking advantage of that property, they concluded that most markets are not cetane-limited and that as a result refiners likely would not take advantage of this property of biodiesel and renewable diesel.⁷⁶⁵ At this time, we do not have any evidence that refiners are capitalizing on biodiesel and renewable diesel's higher cetane value.

Conversely, a blending cost could be incurred for biodiesel due to the addition of additives to prevent oxidation and lower pour or cloud point. The need to add pour point additives is primarily a cold weather issue and likely contributes to the lower observed blending rates of biodiesel into diesel fuel in the winter compared to the summer, particularly in northern areas. However, for our analysis, no additive costs were included for biodiesel because we do not have a good estimate for them.

As with ethanol, the societal cost of using biodiesel and renewable diesel must include their lower energy density in comparison to petroleum-based diesel fuel, which impacts fuel economy. Accounting for this fuel economy effect adds about 27¢ and 17¢ per gallon to the societal cost of biodiesel and renewable diesel, respectively.⁷⁶⁶

⁷⁶⁰ E85 can have RVP levels that are too low, which makes starting a parked car difficult. When blended at about 70% ethanol, the RVP of the ethanol-gasoline blend is a little higher than E85 blends, improving cold starts.

⁷⁶¹ EIA, "Frequently Asked Questions – How much ethanol is in gasoline, and how does it affect fuel economy?" April 1, 2024. <https://www.eia.gov/tools/faqs/faq.php?id=27&t=10>.

⁷⁶² The fuel economy cost is calculated by subtracting the density of ethanol from the density of gasoline, all divided by the density of gasoline and multiplied by the price of gasoline.

⁷⁶³ Farm Energy, "Animal Fats for Biodiesel Production," January 31, 2014. <https://farm-energy.extension.org/animal-fats-for-biodiesel-production>.

⁷⁶⁴ McCormick, Robert, and Teresa Alleman. "Renewable Diesel Fuel," *NREL*, July 18, 2016. https://cleancities.energy.gov/files/u/news_events/document/document_url/182/McCormick_Alleman_RD_Overyiew_2016_07_18.pdf.

⁷⁶⁵ "Not cetane-limited" means that refiners are normally producing diesel that meets the cetane standard. Thus, refiners will not achieve any diesel fuel production savings by blending in high cetane biodiesel and renewable diesel. ICF, "Modeling a 'No-RFS' Case," EPA Contract No. EP-C-16-020, July 17, 2018.

⁷⁶⁶ The fuel economy cost for biodiesel is calculated by subtracting the density of biodiesel from the density of diesel fuel, all divided by the density of diesel fuel and multiplied by the price of diesel fuel; for renewable diesel, substitute renewable diesel for biodiesel.

10.1.4 Distribution and Retail Costs

In this section, we evaluate the costs of distributing biofuels from the places where they are produced to retail stations as well as the costs of dispensing these fuels at those retail stations.

10.1.4.1 Ethanol

10.1.4.1.1 Distribution Costs

Distribution costs are the freight costs to distribute the ethanol, although the total distribution costs could also include the amortized capital costs of newly or recently installed distribution infrastructure. A significant amount of capital has already been invested to enable ethanol to be blended nationwide as E10, and a small amount of ethanol as E85 and E15. Virtually all terminals, including those co-located with refineries, standalone product distribution terminals, and port terminals, have made investments over the last 15-plus years to enable the distribution and blending of ethanol. Thus, these capital costs may be sunk. However, in the part of the analysis where we estimate ethanol's distribution costs using spot ethanol prices, as described below, we may inherently be including some distribution capital costs which are still being recovered.

As part of the effort by ICF/Mathpro to estimate use of renewable fuels in the absence of the RFS program, ICF estimated distribution costs for ethanol and biodiesel. We used these cost estimates for this rulemaking.⁷⁶⁷ ICF estimated ethanol's distribution costs based on ethanol spot prices that are available from the marketplace. The spot prices likely represent the operating and maintenance costs, and any capital costs which are being recovered. Certain publications, including OPIS and Argus, publish ethanol spot prices for certain cities, and these spot prices were consulted for estimating ethanol's distribution costs. These spot prices are tracked because they represent unit train origination and receiving locations where the custody of the ethanol changes hands in the distribution system. For the ethanol consumed in the Midwest, the ethanol is likely to be moved by trucks directly to the terminals in the Midwest. For the areas adjacent to the Midwest, the ethanol is assumed to be moved by truck for the areas nearest to the Midwest (eg., to Colorado and Wyoming), and by manifest train for the adjacent areas further out (eg., to Utah and Idaho). These various means for distributing ethanol and their associated costs were accounted for when estimating the ethanol's distribution cost to and within each region. For the ethanol being shipped by unit train out of the Midwest, the ICF distribution cost analysis assumed that the ethanol is collected in Chicago by truck or manifest rail at an average cost of 7¢ per gallon and then moved out of the Midwest to other areas mostly using unit trains. Since ICF completed its analysis, we discovered that most corn ethanol plants are capable of sourcing unit trains from their plants.⁷⁶⁸ Thus, the 7¢ per gallon transportation cost from corn ethanol plants to Chicago is not necessary and this cost was removed from the estimated cost to each destination.

Once the ethanol is moved to a unit train or manifest train receiving terminal, there are many other terminals in these areas which must also receive the ethanol. Ethanol must then be

⁷⁶⁷ Id.

⁷⁶⁸ EIA, "Rail congestion, cold weather raise ethanol spot prices," *Today in Energy*, April 3, 2014, <https://www.eia.gov/todayinenergy/detail.php?id=15691>.

moved either by truck or, if further away, by manifest train from the unit train receiving terminals to the other terminals. Since many of these other terminals do not have sidings for rail car offloading, the manifest train ethanol must be offloaded to trucks at tank car-truck transfer locations before it can be received by these other terminals. ICF estimated that, on average, the further distribution of ethanol from these unit train receiving terminals to the rest of the terminals would cost an additional 9¢ or 11¢ per gallon, depending on the PADD. Table 10.1.4.1.1-1 provides the estimate of ethanol distribution costs for the various parts of the country estimated by ICF, both the original estimates and our revised estimate, which removes ICF’s original assumed 7¢ per gallon transportation cost to Chicago.

Table 10.1.4.1.1-1: Ethanol Distribution Costs for Certain Cities or Areas (2017\$)

Location		Distribution Cost (¢/gal) to:			Total (¢/gal)	
		Hub/Terminal		Blending Terminal		
PADD	Area	To Chicago	From Chicago			ICF Estimate
PADD 1	Florida/Tampa	7.0	17.8	11.0	35.8	28.8
	Southeast/Atlanta		11.7	11.0	29.7	22.7
	VA/DC/MD		9.7	11.0	27.7	20.7
	Pittsburgh		6.2	11.0	24.2	17.2
	New York		7.7	11.0	25.7	18.7
PADD 2	Chicago		0.0	11.0	18.0	11.0
	Tennessee		9.7	11.0	27.7	20.7
PADD 3	Dallas		4.5	11.0	22.5	15.5
PADD 4			6.2	11.0	24.2	17.2
PADD 5	Los Angeles		16.4	9.0	32.4	25.4
	Arizona		16.4	9.0	32.4	25.4
	Nevada		12.4	9.0	28.4	21.4
	Northwest		12.4	9.0	28.4	21.4

We volume-weighted the various revised regional distribution cost estimates for PADDs 1 through 5 to derive a PADD-average ethanol distribution cost for all PADDs. Table 10.1.4.1.1-2 summarizes the estimated average ethanol distribution cost by PADD, and the average for the U.S. adjusted to 2024 dollars.

Table 10.1.4.1.1-2: Average Ethanol Distribution Cost by PADD and the U.S. (2024\$)

Region	Gasoline Volume (kgal/day)	Average Ethanol Distribution Cost (¢/gal)
PADD 1	123,700	22.2
PADD 2	102,400	11.0
PADD 3	68,500	15.5
PADD 4	15,100	17.2
PADD 5	63,400	24.4
U.S. Average (2017\$)	373,100	18.1
U.S. Average 2024\$		20.1

10.1.4.1.2 Retail Costs

This analysis assigns no infrastructure costs to E10 but does assign infrastructure costs to E15 and E85. However, infrastructure investments and improvements are needed on an ongoing basis to maintain the retail availability of all fuels (*i.e.*, E10, E15, and E85). The preponderance of HBIIP investments, for instance, support new dispensers for all fuel types and E10 sales at these locations far outweigh those of higher-level ethanol blends. However, we believe that the primary reason for the revamps, and the reason why retailers are receiving an HBIIP subsidy, is to facilitate the sales of higher-level ethanol blends. By apportioning all infrastructure costs to higher-level ethanol blends and none to the E10 that would be sold from the same dispenser, this approach is the best estimate of the marginal costs of higher-level ethanol blends consistent with a social cost estimate. The E15 and E85 volumes that we are using in this cost analysis are summarized in Chapter 6.5.2.

The retail costs for E15 and E85 are estimated based on the investments that must be made to offer such ethanol blends. For this final rule, a more objective means was used to estimate the E15 and E85 retail upgrading costs compared with the method used at the proposal stage. The HBIIP program provides reports on the number of retail outlets for which the station owners have requested and received grants to upgrade their retail stations enabling them to offer E15 and E85, in addition to E10. We reviewed one of the reports which provided grants for a total of 58 projects, which upgraded the refueling equipment of 78 retail stations. Of the 78 retail stations, 39 retail stations were installing E15 compatible refueling equipment, while 42 retail stations were installing E85 compatible refueling equipment.

To this end, we reviewed literature and conferred with EPA's Office of Underground Storage Tanks on what might be considered "typical" for E15 and E85 equipment installations for a typically sized retail station selling these blends.^{769,770,771,772}

For the typical retail station being revamped to sell E15, the station was installing 0.9 underground storage tanks and installing 2.8 new dispensers. While in reality a station cannot install fractions of a storage tank or dispenser, the use of these fractional values allows us to apply the resulting cost estimates across all retail outlets as a simple average cost. The manager of HBIIP estimated that each E15- and E85-compatible dispenser costs \$53,000, and each E15-compatible underground storage is estimated to cost \$168,000, for a total cost of \$305,000 per revamped retail station wanting to sell E15. We assume that HBIIP recipients are installing equipment to sell E15 or E85 but not both.

The typical retail station being revamped to sell E85 add 0.8 underground storage tanks and 2.8 E85-compatible dispensers. Using the same costs for USTs and for E15- and E85-

⁷⁶⁹ Moriarty, K., and J. Yanowitz. "E15 And Infrastructure," *National Renewable Energy Laboratory*, NREL/TP-5400-64156, May 27, 2015. <https://doi.org/10.2172/1215238>.

⁷⁷⁰ EPA, "E15's Compatibility with UST Systems," January 2020. <https://www.epa.gov/sites/default/files/2020-01/documents/e15-ust-compatibility-statement-1-23-20.pdf>.

⁷⁷¹ EPA, "UST System Compatibility with Biofuels," EPA-510-K-20-001, July 2020. https://www.epa.gov/sites/default/files/2020-07/documents/ust_compatibility_booklet_formatted_final_7-13-2020_508.pdf.

⁷⁷² Conversations with Ryan Haerer, Office of Underground Storage Tanks; Spring 2022.

compatible dispensers, the total revamp cost to revamp a typical retail station to provide E85 is estimated to cost \$283,000 per retail station.

Retail stations can incur costs which are higher or lower than the retail revamp costs we estimate for offering E15 and E85. If the retail station already has dispensers, tanks and other equipment that can offer E15 or E85 fuel, then perhaps only a few thousand dollars would need to be spent to make some dispenser parts compatible with the higher concentration ethanol. On the other hand, if a large, high throughput retail station needs new dispensers and also needs to install one or more separate storage tanks and other equipment to store and dispense E15 or E85, then the installation costs would be much higher—potentially over a million dollars. A small percentage of retail stations each year must undergo a significant overhaul once their retail station equipment (tank piping, dispensers, and other associated equipment) has significantly deteriorated, and when they do so the newly installed equipment is compatible with the higher ethanol blends. In this case, the station renovation cost for higher ethanol blends is solely the incremental cost of the ethanol-compatible equipment over non-ethanol-compatible equipment because the replacement cost for the equipment can be attributed to normal maintenance. The retail revamp costs to offer higher ethanol blends estimated here attempts to find a middle ground for representative costs of stations that need to replace dispensers and add tanks to offer E15 and E85.

To estimate the per-gallon cost, it is necessary to estimate the volume of E85 and E15 sold at each station which offers these blends. These per-station volume estimates were based on data collected by USDA through their BIP program and made available to EPA.⁷⁷³ The total volumes of E15 and E85 sold were divided by the estimated number of E15 and E85 retail stations to estimate the volume per retail station. As a result, retail stations offering E15 are estimated to sell 217 thousand gallons of E15 per year while retail stations offering E85 are estimated to sell 85 thousand gallons of E85 per year. Using the amortization factor shown in Table 10.1.2.1.1-1 and amortizing these retail costs over the volume of ethanol in E15 and E85 (15% for E15 and 74% for E85), covering the cost of capital for the retail equipment adds \$1.02 and \$50 per gallon to the ethanol portion of E15 and E85, respectively.⁷⁷⁴ When solely amortizing this retail cost solely over the 5% and 64% of ethanol that is incremental to E10, the cost is \$3.08 and 57¢ per gallon of ethanol in E15 and E85 in excess of E10, respectively.

Another potential retail cost that could apply for E85 is the increased time spent refueling. Since a motor vehicle travels fewer miles on a tankful of E85 compared to refueling with E10, the driver will need to refuel more often when running their vehicle on E85. This additional time is a cost to the driver. Such a refueling cost was not estimated for E85 for this rule.

⁷⁷³ “Communication with USDA on the BIP program 1-19-22,” Docket Item No. EPA-HQ-OAR-2021-0324-0734. <https://www.regulations.gov/document/EPA-HQ-OAR-2021-0324-0734>.

⁷⁷⁴ The amortized cost is calculated by multiplying the retail station revamp cost by the capital amortization factor in Table 10.1.2.1.1-1 (0.11) and then dividing by the annual throughput volume of ethanol contained in E15 or E85 at a typical retail station.

10.1.4.2 Biodiesel and Renewable Diesel Distribution Costs

Biodiesel distribution costs were determined by ICF under contract to EPA based on an estimate of biodiesel being moved by rail and by truck within each PADD and between PADDs.⁷⁷⁵ While biodiesel production is more spread out across the country than ethanol, a significant amount must still be moved long distances to match production to demand. The internal PADD rail costs were estimated to be 15¢ per gallon and truck movements for shorter fuel movements were estimated based on distance moved. Movement of these fuels between PADDs was assumed to be made by rail for most areas and by ship from the Gulf Coast to the West Coast. ICF relied on EIA reports for biofuel movements between PADDs. Based on these analyses, the inter-PADD movements were estimated to cost 15–32¢ per gallon, depending on the distance that the biodiesel must travel.

Renewable diesel fuel distribution costs are assumed to be the same as biodiesel. Because renewable diesel is very similar in quality as diesel fuel, it can more readily be blended in more places in the diesel fuel distribution system, including at refineries, where the renewable diesel fuel would be moved by the same distribution system as diesel fuel. Thus, if renewable diesel is used locally its distribution costs would likely be lower than biodiesel. However, much of the renewable diesel is expected to be distributed to the West Coast to help meet the Low Carbon Fuel Standard programs there.

Table 10.1.4.2-1 summarizes the biodiesel and renewable diesel distribution costs for each PADD, taking into account the amount of fuel that is distributed within PADDs and between PADDs, and shows the national average distribution cost and that average cost adjusted to 2024 dollars.

Table 10.1.4.2-1: Estimated Biodiesel and Renewable Diesel Fuel Distribution Cost by PADD (2024\$)

Destination Location	PADD Total Transportation Cost (¢/gal)
PADD 1	21.6
PADD 2	15.0
PADD 3	16.0
PADD 4	25.0
PADD 5	23.8
U.S. Avg.	17.7
U.S. Average 2024\$	20.5

10.1.4.3 Renewable Natural Gas

10.1.4.3.1 Distribution Costs

We assume for the purposes of this cost analysis that all RNG is gathered from landfill off-gassing and cleaned up before being transported to where it can be used. Typically, in such

⁷⁷⁵ ICF, “Modeling a ‘No-RFS’ Case,” EPA Contract No. EP-C-16-020, July 17, 2018.

cases, this RNG will end up in a nearby natural gas pipeline, but in some rare cases it also could be compressed or liquified for dispensing into the onboard CNG or LNG tanks of a local truck fleet at or near the landfill site.

Information on the length of pipeline needed to bring landfill gas to a nearby natural gas pipeline is not readily available, but we made some assumptions to estimate this distance. Landfills are generally located near to, although generally not in, urban areas to keep the transportation costs lower for hauling the municipal waste to the landfill. The landfill gas is estimated to be moved 5 miles to access a commercial natural gas pipeline. Each mile of pipeline is estimated to cost \$1 million to install, adding up to \$6.6 million for the entire 5 mile pipeline after adjusting from 2019 to 2024 dollars.⁷⁷⁶ We modeled a typical volume example case of 750 SCF of biogas being captured per minute and then cleaned up to pipeline-grade RNG to represent the cost for a typically sized landfill.⁷⁷⁷ When the pipeline capital costs are amortized over that typical volume of landfill biogas-based RNG, the pipeline capital cost is estimated to be \$1.84 per million Btu.⁷⁷⁸ While we focus on the case of landfill biogas-based RNG in this instance, if the biogas generation and/or RNG upgrading facility is located far from an existing natural gas pipeline, such as a farm generating biogas from animal waste, the pipeline cost from distributing the RNG can be very expensive and maybe prohibitive.

Once the RNG is transported through the new pipeline to the natural gas pipeline, it incurs a cost for distribution through the existing natural gas pipeline. Landfills are generally located near urban areas, which are destinations for natural gas pipelines. This means that the distribution costs for RNG into the natural gas pipeline would likely be less than that for fossil natural gas, which is generally distributed longer distances from natural gas production areas. Fossil natural gas will incur both variable and fixed operating costs in the upstream pipelines, which RNG will avoid by being injected downstream. Furthermore, the addition of RNG downstream in the natural gas pipeline system can help the natural gas distribution system avoid capital investments that would otherwise be necessary to debottleneck the upstream natural gas pipeline system to meet commercial and industrial sector demand increases. If we assume that RNG would be injected into a natural gas pipeline at least large enough to serve commercial consumers, the RNG distribution cost can be based on commercial natural gas distribution costs which are represented by the natural gas prices to commercial consumers. As summarized in Table 10.2.2-2, distribution of natural gas to commercial consumers is estimated to cost \$6.07/MSCF in 2026. We could not find detailed cost information for the distribution of commercial natural gas through different parts of the distribution system that would allow us to scale the commercial natural gas distribution costs to the portion of the natural gas pipeline used by RNG. For this reason, half of the commercial natural gas distribution cost, or about

⁷⁷⁶ EPA, “LFGcost-Web – Landfill Gas Energy Cost Model.” <https://www.epa.gov/lmop/lfgcost-web-landfill-gas-energy-cost-model>.

⁷⁷⁷ The Coalition for Renewable Natural Gas, “Economic Analysis of the U.S. Renewable Natural Gas Industry,” December 2021. <https://guidehouse.com/-/media/www/site/insights/energy/2022/guidehouse-esirng-coalition-final-report122022.pdf>.

⁷⁷⁸ The 5.3 million capital cost is amortized over the biogas volume by first multiplying it by the capital cost amortization factor (0.11) to derive an annual average cost, and then dividing this volume by the annual volume of biogas which is estimated to be flowing at 600 SCF/min.

\$2.53/MSCF, is assumed to apply to biogas for distribution to the natural gas pipeline.⁷⁷⁹

While this cost analysis assumes the biogas is being produced entirely at landfills, it is worthwhile to consider the situation other RNG producers are likely to face to distribute their biogas. Like landfills, RNG production at wastewater treatment plants and municipal waste digesters are located near cities and thus would likely have distribution costs similar to landfills. Conversely, agricultural waste digesters are much more likely to be located in rural areas further away from both natural gas pipelines and urban areas. The distribution costs for RNG producers using agricultural waste digesters would likely be higher. Many of these rural locations may be so remote that the RNG could be considered stranded and not readily available for use as transportation fuel, although such stranded locations could perhaps still provide RNG to local truck fleets which distribute agricultural products.⁷⁸⁰

10.1.4.3.2 Retail Costs

Retail facilities to dispense RNG are more expensive compared to other transportation fuel retail costs. One information source provided an estimate that a larger sized CNG retail facility would cost about \$4.61 per million Btu, so this was used for the RNG retail cost.⁷⁸¹ When adjusted to 2024 dollars, the estimated retail cost to dispense RNG is estimated to be \$6.40 per million Btu.

10.2 Gasoline, Diesel Fuel and Natural Gas Costs

10.2.1 Production Costs

As renewable fuel use increases or decreases, the volume of petroleum-based products, such as gasoline and diesel fuel, would decrease or increase, respectively. This change in finished refinery petroleum products results in a change in refinery industry costs. The change in costs would essentially be the volume of fuel displaced multiplied by the cost for producing the fuel.

In addition, there could be a situation where we may need to account for capital investments made by the refining industry. For example, increasing renewable fuel standards could reduce capital investments refiners would otherwise make to increase refined product production above previous levels. In this case increased renewable fuel capital investments would offset decreased refining industry investments. However, we have not assumed for this analysis that there would be any reduction in refining industry investments considering the current situation. After the economic impact of the Covid-19 pandemic, EIA data shows that the

⁷⁷⁹ Biogas producers tell us that they are being charged an equivalent distribution price that natural gas producers are being charged which essentially assumes that they are using the entire natural gas pipeline. This pricing scheme, though, does not represent the true social cost for distributing biogas, and a separate distribution cost is estimated for biogas.

⁷⁸⁰ The term “stranded” means the cost to recover and use the biogas is too high to justify installing the equipment collect upgrade and distribute it for commercial use. The facility may more easily be able to use the biogas onsite to generate electricity.

⁷⁸¹ Clean Fuel Connection, Inc. “Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities.”

demand for gasoline and diesel fuel is stable or somewhat in decline.⁷⁸² Thus, we would not anticipate there to be refined product investment regardless of the renewable fuel volumes and thus no savings that would offset renewable fuel investments.

10.2.1.1 Gasoline and Diesel Fuel Production Costs

The production cost of gasoline and diesel fuel are based on the projected wholesale price for gasoline and diesel fuel provided in AEO2025.⁷⁸³ The projected Brent crude oil prices and gasoline and diesel fuel wholesale prices in 2026 and 2027 are summarized in Table 10.2.1.1-1.

10.2.1.1-1: Estimated Gasoline Production Costs

		2026	2027
Brent Crude Oil Prices (\$/bbl)		81.5	80.4
Wholesale Prices (Assumed to be Production Costs) (\$/gal)	Gasoline	2.18	2.14
	Diesel Fuel	2.28	2.29

Since the EIA modeling for its AEO includes a representation of the RFS program, some price impact of the RFS program is likely represented in these wholesale gasoline and diesel fuel prices. The AEO modeling includes the most recent RFS standards promulgated at the time of analysis, so the wholesale price estimates in AEO2025 would be optimal for modeling the final rule RFS standards incremental to the 2025 Baseline. The RFS impact on the AEO gasoline and diesel fuel prices will slightly bias the cost analysis conducted for the No RFS Baseline. However, the impact on the estimated costs is expected to be minimal and within the accuracy of the cost analysis.

10.2.1.2 Natural Gas Production Cost

For the most part, the increased consumption of RNG has been displacing fossil natural gas, although that is starting to change as new CNG trucks are displacing diesel fuel fueled trucks. Because our primary analysis is relative to the No RFS Baseline, the majority of trucks converting to using RNG have displaced fossil natural gas, thus, our cost analysis will assume that RNG is displacing fossil natural gas. For estimating the cost of RNG relative to natural gas, it is necessary to estimate the production cost of fossil natural gas. The natural gas production cost can be estimated using natural gas spot prices. In AEO2025, EIA projects the natural gas spot price for Henry Hub to average \$2.78/MSCF in 2026 and decrease slightly in 2027.⁷⁸⁴ The Henry Hub spot price most closely represents the natural gas field price, and thus is a proxy for its production cost.

⁷⁸² AEO2025, Table 12 – Petroleum and Other Liquid Prices, and Table 57 – Component of Selected Petroleum Product Prices.

⁷⁸³ AEO2025, Table 57 – Components of Selected Petroleum Product Prices.

⁷⁸⁴ AEO2025, Table 13 – Natural Gas Supply, Disposition, and Prices.

10.2.2 Gasoline, Diesel Fuel and Natural Gas Distribution and Blending Cost

10.2.2.1 Gasoline and Diesel Fuel

Gasoline and diesel fuel distribution costs from refineries to terminals are estimated as the difference between wholesale prices and terminal prices (which we estimated based on historical sales-for-resale prices). This results in estimated gasoline and diesel fuel distribution costs to the terminal of 5¢ and 8¢ per gallon, respectively.

We also estimated the distribution costs from terminals to retail stations, which also contains the retailing costs. To do so, we first calculated the retail costs of gasoline, less taxes. We calculated this by subtracting average federal and state taxes, which are 55¢ per gallon for gasoline and 64¢ per gallon for diesel fuel, from historical gasoline and diesel fuel retail prices.⁷⁸⁵ Then, we calculated the difference between historical retail prices (less taxes) and historical terminal prices (estimated as sales for resale prices) to estimate the distribution costs from the terminal to retail and retail costs. Price data for 2017 to 2019 was used to estimate the distribution and retail costs—these years were chosen because they avoided the price distortions associated with the Covid-19 pandemic and war in Ukraine.⁷⁸⁶ The resulting distribution costs for gasoline and diesel fuel are 5¢ and 8¢ per gallon, respectively. The retail costs for gasoline and diesel fuel are estimated to be 20¢ and 40¢ per gallon, respectively. These various prices and estimated costs are summarized in Table 10.2.2.1-1.⁷⁸⁷

Table 10.2.2.1-1: Estimated Gasoline and Diesel Fuel Distribution and Retail Costs (\$/gal)

	Gasoline				Diesel Fuel			
	2017	2018	2019	Average	2017	2018	2019	Average
Bulk Price	1.64	1.94	1.74	1.77	1.62	2.05	1.86	1.85
Sales for Resale	1.69	1.98	1.81	1.83	1.69	2.13	1.96	1.93
Retail Price	2.42	2.72	2.60	2.58	2.65	3.18	3.06	2.96
Taxes	0.55	0.55	0.55	0.55	0.64	0.64	0.64	0.64
Distribution Costs	0.05	0.04	0.07	0.05	0.07	0.08	0.08	0.08
Retail Costs	0.18	0.19	0.24	0.20	0.32	0.41	0.46	0.40

We then apply the estimated gasoline and diesel fuel distribution and retail costs, adjusted to 2024 dollars, to the projected wholesale gasoline and diesel fuel prices in Table 10.2.1.1-1 for each year to estimate the gasoline and diesel fuel prices from refinery to retail. These gasoline and diesel fuel prices are summarized in Table 10.2.2.1-2.

⁷⁸⁵ American Petroleum Institute, “Gasoline and Diesel Taxes,” January 1, 2022. <https://www.api.org/-/media/files/statistics/state-motor-fuel-notes-summary-january-2022.pdf>.

⁷⁸⁶ EIA, “Refiner Gasoline Prices by Grade and Sales Type,” *Petroleum & Other Liquids*, June 1, 2022. https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_a.htm.

⁷⁸⁷ After completing our cost analysis, we learned that AEO2025 also projects what they refer to as “distribution costs,” which in Table 10.2.2.1-2 corresponds to the sum of (1) Terminal and Retail Costs (which represents the difference between wholesale and retail prices) and (2) Distribution Cost. As a basis for comparison, the gasoline and wholesale prices reported in Table 10.2.2.1-2 are lower than those reported in AEO2025. In 2026, Table 10.2.2.1-2 reports AEO2025-defined “distribution costs” as \$0.26/gallon and \$0.54/gallon for gasoline and diesel, respectively. In AEO2025, these corresponding projections are \$0.33/gallon and \$0.56/gallon, respectively. We may use these AEO estimates for future rulemakings.

Table 10.2.2.1-2: Projected Gasoline and Diesel Production Costs (2024\$; \$/gal)

		2026	2027
	Brent Crude Oil Prices	\$81.5	\$80.4
Gasoline	Retail Cost minus taxes	\$2.46	\$2.41
	Terminal and Retail Costs	\$0.23	\$0.23
	Terminal Costs	\$2.24	\$2.19
	Distribution Cost	\$0.06	\$0.06
	Production Cost (from Table 10.2.1.1-1)	\$2.18	\$2.13
Diesel Fuel	Retail Cost minus taxes	\$2.79	\$2.80
	Terminal and Retail Costs	\$0.45	\$0.45
	Terminal Costs	\$2.36	\$2.37
	Distribution Cost	\$0.09	\$0.09
	Production Cost (from Table 10.2.1.1-1)	\$2.28	\$2.29

10.2.2.2 Natural Gas

EIA projects natural gas prices downstream of natural gas production fields which can be used to estimate natural gas distribution costs.⁷⁸⁸ The three principal natural gas consumers are industrial, commercial, and residential. Industrial consumers consume the largest natural gas volumes per facility, and due to the very large consumption, the distribution costs are lowest. Commercial entities are medium sized consumers, and their distribution costs are higher than industrial consumers. Residential consumers, because of their very low consumption, must pay a much larger distribution cost to maintain the distribution system for much lower consumption to each home. EIA also provides a price for natural gas sold into the transportation sector, although this price includes road taxes which would need to be omitted for the purposes of this cost analysis, so we did not use EIA’s natural gas to transportation sector cost.⁷⁸⁹

The varying costs for these different natural gas categories permit estimating natural gas distribution costs for natural gas consumed by motor vehicles. Natural gas produced and distributed to retail outlets to refuel natural gas trucks and cars most likely falls in the category of midsized consumers, or commercial users. The distribution costs of natural gas can therefore be estimated by subtracting the projected Henry Hub prices from the projected commercial prices. Thus, Henry Hub prices projected in AEO2025 were subtracted from the commercial prices for 2026 and 2027. Table 10.2.2.2-1 summarizes the calculation of natural gas distribution costs. To put the natural gas costs on the same footing as the RNG, we also add \$6.40 per million Btu for retail costs.⁷⁹⁰

⁷⁸⁸ AEO2025, Table 13 – Natural Gas Supply, Disposition, and Prices.

⁷⁸⁹ Taxes are not included in social cost estimates because they are not true costs, only transfer payments.

⁷⁹⁰ Clean Fuel Connection, Inc. “Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities.

Table 10.2.2.2-1: Natural Gas Distribution Cost (2024\$, \$/MSCF)

	2026	2027
Commercial Prices	\$8.85	\$8.90
Henry Hub Prices \$/MMBtu	\$2.88	\$2.74
\$/MSCF	\$2.78	\$2.64
Pipeline Distribution Costs	\$6.07	\$6.26
Retail Station Costs	\$6.40	\$6.40
Total Average Distribution & Retail Station Costs	\$12.47	\$12.66

10.3 Fuel Energy Density and Fuel Economy Cost

To estimate the change in fossil fuel volume that would occur with these changes in renewable fuel volumes and to estimate the fuel economy cost summarized in Chapter 10.4.1, it was necessary to estimate the energy density of each fuel. Table 10.3-1 contains the estimated energy densities for the various renewable fuels and petroleum fuels analyzed for this cost analysis; all values are taken from the GREET 2024 model unless otherwise noted.⁷⁹¹ The table is organized to show the relative energy density of a fuel type relative to the baseline fuel, which we assume is E10 gasoline and B5 diesel fuel.

Table 10.3-1: Lower Heating Value (LHV) Energy Densities (GREET 2024)

		LHV Energy Density (Btu/gal)	Percent of Baseline Fuel
Energy Density Relative to E10 Gasoline	E10 Gasoline	110,428	-
	Gasoline (E0) ^a	114,200	103.1
	E15 Gasoline	108,542	98.3
	E85 ^b	86,285	78.1
	Denatured Ethanol	76,477	69.2
Energy Density Relative to B5 Diesel Fuel	B5 Diesel Fuel	128,009	-
	Diesel Fuel	128,450	100.3
	Renewable Diesel ^c	123,800	0.967
	Biodiesel	119,550	0.934
Other Products	Crude Oil	129,670	
	Pure Ethanol	76,330	
	Natural Gas Liquids	83,686	

^a From Diesel Fuels Technical Review; Chevron Global Marketing; 2007.

^b Assumed to contain 74% ethanol.

^c Energy content of renewable diesel reported to EMTS.

⁷⁹¹ Wang, Michael, Cai, Hao, Ou, Longwen, Elgowainy, Amgad, Alam, Md Rakibul, Benavides, Pahola T., Benvenuti, Livia, Burnham, Andrew, Do, Thai N., Farhad, Masum, Gan, Yu, Gracida-Alvarez, Ulises R., Hawkins, Troy R., Iyer, Rakesh K., Kar, Saurajyoti, Kelly, Jarod C., Kim, Taemin, Kolodziej, Christopher, Kwon, Hoyoung, Lee, Uisung, Lim, Juin Y., Liu, Xinyu, Lu, Zifeng, Morales, Michele, Ng, Clarence, Pandey, Ishan, Shukla, Siddharth, Siddique, Nazib, Sun, Pingping, Sykora, Tom, Vyawahare, Pradeep, and Zhou, Jo. "Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model ® (2024 Excel)." Computer software. December 20, 2024. <https://doi.org/10.11578/GREET-Excel-2024/dc.20241203.1>.

As discussed in Chapter 10.1, when a lower density fuel replaces a higher density fuel one-for-one on a volumetric basis, there is a loss of energy value to society in the form of lower fuel economy. To account for this fuel economy effect in the cost analysis, the change in fossil fuel volume displaced by a change in renewable fuel volume is estimated by the relative energy content of the renewable and fossil fuels. If the energy density is not the same between the fossil fuel and renewable fuel displacing it, the energy equivalent replacement is not one-for-one on a volume basis. For example, ethanol contains about 33% lower energy per volume than the gasoline it is displacing, such that 100 gallons of ethanol would displace 67 gallons of gasoline. By calculating these impacts on an energy basis rather than a volume basis, the loss of energy to society associated with the fuel economy effect is incorporated into the cost analysis. We do not report this estimated fuel economy cost separately.

For the individual fuel cost summary in Chapter 10.4.1, it is desirable to report out a specific fuel economy effect. To do so, the difference in energy density between the renewable fuel and fossil fuel is divided by the fossil fuel energy density and then multiplied times the fossil fuel cost at retail, before taxes, to estimate the fuel economy effect.

10.4 Costs

In this section, we describe the overall societal costs of the final renewable Fuel Volumes in this rule. Costs are estimated for six of the categories of renewable fuel discussed in Chapter 10.1: corn starch ethanol, biodiesel, renewable diesel, other advanced ethanol, RNG, and CKF ethanol. For corn starch ethanol, we have separately estimated costs for this fuel blended as E10, E15, and E85. For biodiesel and renewable diesel, we have calculated production costs for the quantities of fuel we project in Chapter 3 would be produced from soybean oil, corn oil, and FOG, and then totaled them to comprise total production costs for biodiesel and renewable diesel respectively; all other biodiesel and/or renewable diesel costs downstream of production are assumed to be identical for fuels produced from each of these three feedstock types. Other advanced ethanol is assumed to be sugarcane ethanol. RNG is assumed to be produced from landfill biogas and be sold as CNG. While sugarcane ethanol and CKF ethanol could be blended as E10, E15 or E85, we do not estimate separate costs for these blended products; instead, we assume all sugarcane ethanol and CKF ethanol are blended as E10. For our cost analysis we use renewable diesel cost for renewable jet fuel costs for the very small volume change which we analyze. However, we do estimate a cost for separating renewable jet fuel from renewable diesel fuel, and a cost for using cracking to produce a larger volume of renewable jet fuel.

Costs are presented in several different ways. First, a per-gallon, individual renewable fuels cost summary presents our analysis of the societal cost of each renewable fuel analyzed for this rulemaking relative to the fossil fuel being displaced.

Second, aggregate societal costs are presented for the Analyzed Volumes relative to the No RFS and 2025 Baselines. These estimates combine the costs for all types of renewable fuel analyzed for this rulemaking. For each case comparison, we first present the change in volume for each renewable fuel and the quantity of fossil fuel that volume is estimated to displace. Then we present the costs for those volume changes by cost category (production, distribution,

blending) for each renewable fuel and the fossil fuel displaced by the renewable fuel. Finally, we present total annual cost and total per-gallon costs.

Third and finally, we estimate the per-gallon cost on the total gasoline, diesel, and natural gas pools. To do so, we used the projected total U.S. consumption volumes for each of these fuels estimated in AEO2025 for the years 2026 and 2027. These estimates are summarized in Table 10.4-1.

Table 10.4-1: Total Gasoline, Diesel Fuel, and Natural Gas Volumes for 2026 and 2027

	2026	2027	Units
Gasoline Volume	137.05	136.13	Billion gallons
Diesel Volume	58.71	57.95	Billion gallons
Natural Gas Volume	32.38	32.84	Trillion cubic feet

Source: AEO2025, Table 11 – Petroleum and Other Liquids Supply and Disposition and Table 13 – Natural Gas Supply, Disposition, and Prices.

10.4.1 Individual Fuels Cost Summary

Table 10.4.1-1 summarizes the estimated overall societal costs (including production, distribution, blending, and fuel economy) individually for each of the renewable fuels analyzed for this rulemaking for the years 2026 and 2027. These costs do not account for the federal section 45Z Clean Fuel Production Credit (hereafter the “45Z credit” or “45Z”) tax subsidies, nor do they consider taxes or tax subsidies more generally, as these are transfer payments which are not relevant in the estimation of societal costs. Nor do these costs consider state or local infrastructure support funding or the funding from USDA’s Blends Infrastructure Incentive Program (HBIIP) which offsets half of the investment costs for revamping retail stations to be compatible with E85 and E15.⁷⁹² A separate illustrative line item is added for E15 and E85, equal to ½ of their retail cost, to help demonstrate the impact that the HBIIP program would have on the price for these fuels to consumers. The costs of renewable fuels other than RNG are primarily influenced by the feedstock costs, which can vary significantly depending on a wide range of factors domestically and internationally, especially since many of them are also globally traded agricultural commodities. On the other hand, the costs of RNG are primarily associated with upgrading, transporting, and compressing or liquefying the RNG for use as transportation fuel.

To put the different fuels on an equivalent basis for the miles driven, the societal cost analysis also needs to account for each fuel's energy content and impact on fuel economy, which is first discussed in Chapter 10.3. While these costs may not always be reflected in the sales prices among the market participants (*e.g.*, if refiners sell, and consumers buy, gasoline based on volume, not energy content), the varying impacts on fuel economy among the fuels nevertheless still result in different costs to consumers in operating their vehicles, and to society as a whole, and therefore must be accounted for in a social cost analysis. The costs associated with the impact of renewable fuels on fuel economy are determined relative to the fuels they are assumed to displace; ethanol displaces gasoline, biodiesel and renewable diesel displace diesel fuel, and

⁷⁹² USDA, Higher Blends Infrastructure Incentive Program. <https://www.rd.usda.gov/hbiip>.

RNG displaces natural gas.⁷⁹³ To the extent that RINs representing RNG incentivize some incremental growth in sales of CNG/LNG trucks at the expense of diesel fueled trucks, then some RNG could also displace diesel fuel. However, this is expected to be a relatively minor occurrence in 2026 and 2027 when analyzed relative to the No RFS Baseline and so is not included in this cost analysis. It is important to note that in estimating the social cost for this rulemaking the fuel economy cost for ethanol blended into E10 is included since this is a cost that consumers will bear. However, when refiners are considering whether to blend ethanol, such as for estimating volumes for the No RFS Baseline, they do not consider the fuel economy effect. This distinction is important for understanding ethanol's relative economic viability in the marketplace.

The cost shown for renewable compressed natural gas (RCNG) is shown in two different units. RCNG is shown as dollars per million Btu and dollars per ethanol-equivalent gallon. Table 10.4.1-1 is divided into three subparts, "a," "b" and "c", which present production costs, blending, retail, and fuel economy costs, and total costs, respectively.

Table 10.4.1-1a: Renewable Fuels Production Costs Estimated for 2026 and 2027 (2024\$; \$/gal unless otherwise noted)

		2026	2027
Corn Starch Ethanol ^a	E10	\$1.88	\$1.92
	E15 w/ ½ Retail Costs	\$1.88	\$1.92
	E15 w/ Retail Costs	\$1.88	\$1.92
	E85 w/ ½ Retail Costs	\$1.88	\$1.92
	E85 w/ Retail Costs	\$1.88	\$1.92
Biodiesel	Soybean Oil	\$5.55	\$5.70
	Corn Oil	\$4.67	\$4.80
	FOG	\$4.30	\$4.42
Renewable Diesel	Soybean Oil	\$5.95	\$5.97
	Corn Oil	\$5.07	\$5.07
	FOG	\$4.70	\$4.69
Other Advanced	Sugarcane E10 Ethanol	\$2.73	\$2.73
Cellulosic Biofuel	RCNG (\$/Gal Ethanol)	\$0.37	\$0.37
	RCNG (\$/MMBtu)	\$7.33	\$7.33
	Corn Kernel Fiber E10 Ethanol	\$1.88	\$1.88

⁷⁹³ Fuel economy costs are calculated by multiplying the total of petroleum fuel production, distribution and retail costs by the difference in energy density (Btu per gallon) between the petroleum fuel being displaced and the renewable fuel, and the result of that operation is divided by the energy density of the petroleum fuel. For ethanol blended as E10 as an example: (denatured ethanol production + distribution + blending cost) * (E10 gasoline energy density - denatured ethanol energy density)/denatured ethanol energy density.

Table 10.4.1-1b: Renewable Fuels Blending, Distribution, Retail and Fuel Economy Costs Estimated for 2026 and 2027 (2024\$; \$/gal unless otherwise noted)

		Blending Cost	Distribution Cost	Retail Cost	Fuel Economy Cost
Corn Starch Ethanol	E10	-\$0.77	\$0.44		\$0.72
	E15 w/ ½ Retail Costs		\$0.44	\$1.54	\$0.72
	E15 w/ Retail Costs		\$0.44	\$3.08	\$0.72
	E85 w/ ½ Retail Costs		\$0.44	\$0.29	\$0.72
	E85 w/ Retail Costs		\$0.44	\$0.57	\$0.72
Biodiesel	Soybean Oil		\$0.76		\$0.21
	Corn Oil		\$0.76		\$0.21
	FOG		\$0.76		\$0.21
Renewable Diesel	Soybean Oil		\$0.76		\$0.09
	Corn Oil		\$0.76		\$0.09
	FOG		\$0.76		\$0.09
Other Advanced	Sugarcane E10 Ethanol	-\$0.77	\$0.44		\$0.72
Cellulosic Biofuel	RCNG (\$/Gal Ethanol)		\$0.46	\$0.49	-
	RCNG (\$/MMBtu)		\$6.02	\$6.40	-
	Corn Kernel Fiber E10 Ethanol	-\$0.77	\$0.42		\$0.72

Note: Fuel economy cost is per fuel being displaced; ethanol displaces gasoline, renewable diesel and biodiesel displaces diesel fuel, and renewable compressed natural gas (RCNG) displaces natural gas.

For modeling the societal costs of E15 and E85 shown in Chapters 10.4.2 and 10.4.3, the cost analysis is conducted for the entire volume of E15 and E85 and includes the blending cost savings for the E10 BOB used to blend with E15 and E85. For the cost analysis shown here, the cost for E15 and E85 is solely for the ethanol volume above that blended at 10% and therefore does not include any blending value for E10 BOBs to represent the marginal cost for the ethanol volume above E10.

Table 10.4.1-1c: Renewable Fuels Total Costs Estimated for 2026 and 2027 (2024\$/gal unless otherwise noted)

		2026	2027
Corn Starch Ethanol	E10	\$2.26	\$2.30
	E15 w/ ½ Retail Costs	\$4.58	\$4.62
	E15 w/ Retail Costs	\$6.12	\$6.16
	E85 w/ ½ Retail Costs	\$3.32	\$3.36
	E85 w/ Retail Costs	\$3.61	\$3.65
Biodiesel	Soybean Oil	\$6.52	\$6.67
	Corn Oil	\$5.64	\$5.77
	FOG	\$5.27	\$5.39
Renewable Diesel	Soybean Oil	\$6.80	\$6.83
	Corn Oil	\$5.93	\$5.92
	FOG	\$5.56	\$5.54
Other Advanced	Sugarcane E10 Ethanol	\$3.11	\$3.11
Cellulosic Biofuel	RNG (\$/Gal Ethanol)	\$1.32	\$1.32
	RNG (\$/MMBtu)	\$19.75	\$19.75
	Corn Kernel Fiber E10 Ethanol	\$2.26	\$2.30

The distribution costs for the biofuels are nationwide averages, which do not capture the substantial difference depending on the destination. For example, ethanol distribution costs from the ethanol plants to terminals can vary from under 10¢ per gallon for local distribution in the Midwest, to over 30¢ per gallon for moving the ethanol to the coasts. Thus, total ethanol cost blended as E10 can vary from around \$2.23–2.45 per gallon. RNG distribution includes both the amortized capital cost of transporting the RNG to a nearby pipeline as well as the amortized retail distribution capital costs, since the retail facilities for natural gas trucks are relatively expensive.

Tables 10.4.1-2a and Table 10.4.1-2b summarize the production, distribution, retail and total costs for each category of fossil transportation fuel—gasoline, diesel fuel, and natural gas. For gasoline and diesel, production costs are based on wholesale prices in AEO2025.⁷⁹⁴ Projected natural gas spot prices from AEO2025 are used to represent both feedstock and production costs of fossil natural gas.

The distribution costs for gasoline and diesel fuel are typical for these fuels. While they can vary depending on the transportation distance, the differences between high and low distribution costs for gasoline and diesel fuel are likely lower than that for renewable fuels due to the well-established pipeline distribution system for petroleum fuels. The natural gas distribution costs are based on the difference between the projected price for natural gas sold to commercial entities and the projected natural gas spot price, which reflects the price at the point of production.

⁷⁹⁴ AEO2025, Table 57 – Components of Selected Petroleum Product Prices.

Table 10.4.1-2a: Gasoline, Diesel Fuel, and Natural Gas Production, Distribution and Retail Costs for 2026 and 2027 (2024\$)

	2026	2027	Distribution Cost	Retail Cost
Gasoline (\$/gal)	\$1.92	\$1.86	\$0.29	
Diesel Fuel (\$/gal)	\$2.03	\$2.02	\$0.53	
Natural Gas \$/gal ethanol	\$0.32	\$0.31	\$0.46	\$0.49
Natural Gas (\$/MMBtu)	\$4.21	\$4.14	\$6.07	\$6.40

Table 10.4.1-2b: Gasoline, Diesel Fuel, and Natural Gas Total Costs for 2026 and 2027 (2024\$)

	2026	2027
Gasoline (\$/gal)	2.21	2.14
Diesel Fuel (\$/gal)	2.57	2.55
Natural Gas \$/gal ethanol	1.27	1.26
Natural Gas (\$/MMBtu)	16.68	16.61

Table 10.4.1-3 compares the data from Tables 10.4.1-1c and Table 10.4.1-2b to show the relative cost of the renewable fuels with the fossil fuels they are assumed to displace.

Table 10.4.1-3: Renewable Fuel Costs Relative to Fossil Fuel Costs for 2026 and 2027 (2024\$/gal unless otherwise noted)

		2026	2027
Corn Starch Ethanol	E10	-\$0.14	-\$0.05
	E15 w/ ½ Retail Costs	\$2.10	\$2.19
	E15 w/ Retail Costs	\$3.57	\$3.66
	E85 w/ ½ Retail Costs	\$0.93	\$1.02
	E85 w/ Retail Costs	\$1.22	\$1.31
Biodiesel	Soybean Oil	\$1.95	\$1.79
	Corn Oil	\$1.40	\$1.26
	FOG	\$1.16	\$1.03
Renewable Diesel	Soybean Oil	\$2.15	\$1.99
	Corn Oil	\$1.59	\$1.46
	FOG	\$1.36	\$1.23
Other Advanced	Sugarcane E10 Ethanol	\$0.71	\$0.76
Cellulosic Biofuel	RNG (\$/gal ethanol)	\$0.05	\$0.06
	RNG (\$/MMBtu)	\$3.07	\$3.14
	Corn Kernel Fiber E10 Ethanol	-\$0.14	-\$0.05

10.4.2 Costs for the Analyzed Volumes

In this section, we estimate the costs for the Analyzed Volumes relative to both the No RFS Baseline as well as the 2025 Baseline. The costs are primarily driven by projected higher vegetable oil feedstock prices due to the very high increase in vegetable oil demand to meet the large increase in BBD volumes. Later in this chapter we also estimate costs at both much higher

and lower vegetable oil prices. See Chapter 10.1.1.3 for a description of the vegetable oil prices used in the cost analysis.

10.4.2.1 Analyzed Volumes Relative to the No RFS Baseline

In this section, we summarize the estimated costs for the changes in renewable fuel volumes described in Chapter 3.2 (changes relative to the No RFS Baseline volumes are described in Chapter 2). For this analysis we considered all societal costs, including production, blending, and distribution costs, and differences in energy density.

10.4.2.1.1 Volumes

The renewable fuel and fossil fuel volume changes under the Analyzed Volumes relative to the No RFS Baseline are summarized in Tables 10.4.2.1.1-1a and 1b, respectively. For estimating the volume of petroleum fuel being displaced by the biofuel which is being blended into the petroleum fuel, we rely on the energy densities from Table 10.3-1 for determining the relative volumes.

Table 10.4.2.1.1-1a: Analyzed Volumes – Renewable Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volumes	
	2026	2027
<i>Cellulosic Biofuel</i>		
RNG as CNG - Landfill Biogas (MMSCF)	58,925	61,801
Corn Kernel Fiber Ethanol	0	0
<i>Non-cellulosic Advanced</i>		
Biodiesel - Soybean	627	850
Biodiesel - FOG	-79	-116
Biodiesel - Corn Oil	191	124
Biodiesel - Canola	160	236
Renewable Diesel - Soybean	1,320	1,460
Renewable Diesel - FOG	604	945
Renewable Diesel - Corn	61	128
Renewable Diesel - Canola	981	1,101
Sugarcane Ethanol	0	0
<i>Conventional</i>		
Ethanol - E10	336	384
Ethanol - E15	150	169
Ethanol - E85	172	174
Change in RNG Volume	58,925	61,801
Change in Ethanol Volume	657	727
Change in Biodiesel Volume	899	1,094
Change in Renewable Diesel Volume	2,963	3,631

Table 10.4.2.1.1-1b: Analyzed Volumes – Fossil Fuel Volume Changes Relative to the No RFS Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volumes	
		2026	2027
Natural Gas Gasoline	<i>Cellulosic Biofuel</i>		
	RNG as CNG - Landfill Biogas (MMSCF)	-58,925	-61,801
	Corn Kernel Fiber Ethanol	0	0
Diesel Fuel Diesel Fuel Diesel Fuel Diesel Fuel Diesel Fuel Diesel Fuel Diesel Fuel Diesel Fuel Gasoline	<i>Non-cellulosic Advanced</i>		
	Biodiesel - Soybean	-576	-781
	Biodiesel - FOG	73	107
	Biodiesel - Corn Oil	-175	-114
	Biodiesel - Canola	-147	-217
	Renewable Diesel - Soybean	-1,272	-1,407
	Renewable Diesel - FOG	-579	-908
	Renewable Diesel - Corn	-59	-123
	Renewable Diesel - Canola	-945	-1,061
	Sugarcane Ethanol	0.0	0.0
Gasoline Gasoline Gasoline	<i>Conventional</i>		
	Ethanol - E10	-225	-257
	Ethanol - E15	-100	-113
	Ethanol - E85	-115	-116
-	Change in Gasoline Volume	-440	-487
-	Change in Diesel Fuel Volume	-3,681	-4,504
-	Change in Natural Gas Volume	-58,925	-61,801

The change in gasoline and diesel volume for each year is used to estimate the change in imported crude oil, based on its relative energy content, and imported gasoline and diesel fuel. The change in petroleum demanded, and its effect on both imported crude oil and imported petroleum products, is mainly projected based on a comparison of two separate economic cases: the Low Economic Growth Case and the Reference Case, modeled by EIA in AEO2025.⁷⁹⁵ The AEO Low Economic Growth Case for the years 2026–2027 estimates lower refined product demand than that of the Reference case, and due to the reduced refined product demand, AEO estimates changes in reduced imports of crude oil refined products. The two AEO cases project that for a volume of reduced U.S. consumption of gasoline or diesel fuel, 97.5% of that gasoline or diesel reduction would be attributed to reduced crude oil imports and reduced imports of refined products, while only 2.5% of the reduced U.S. product demand would be due to reduced consumption of domestically produced crude oil and refined products.

Based on these correlations, Table 10.4.2.1.1-2 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels relative to the No RFS Baseline. The change in crude oil volume and imported petroleum products is used for the energy security analysis contained in Chapter 6.

⁷⁹⁵ See “Change in Product Demand on Imports AEO2025 for Set 2 Final Rule,” available in the docket for this action.

Table 10.4.2.1.1-2: Analyzed Volumes – Projected Change in Imported and Domestic Crude Oil Due to Increases in Renewable Fuel Consumption - Relative to the No RFS Baseline (million gallons)

	2026	2027
Change in Domestic Crude Oil	-106	-83
Change in Imported Crude Oil	-4,111	-5,017

We are particularly concerned with petroleum imports due to historical incidents of imported petroleum supply shortfalls, which have since guided U.S. foreign policies to prevent such shortfalls. However, some of the renewable fuels or commodities used as feedstocks to produce renewable fuels (*e.g.*, vegetable oils, oilseeds) may also be imported. Because renewable fuel demand continues to comprise a much smaller portion of the U.S. fuels market relative to petroleum products, and any imports and changes of imports of these fuels and feedstocks has not attracted as much concern as petroleum imports, we would not expect the same level of concern for increases in imports of renewable fuels and their feedstocks. However, we will nevertheless discuss possible changes in imports of renewable fuels or their feedstocks.

The 45Z credit was revised in 2025 to incentivize the production of domestic renewable fuels in the U.S. from North American feedstocks. Due to this change in Federal incentives, imported feedstocks will be financially disadvantaged in 2026 and 2027. We anticipate any renewable fuel-related imports in these years would most likely be vegetable oil and FOG feedstocks, not finished fuels. As a result, we might expect reduced imports of canola oil from Canada, since it is disadvantaged relative to domestically produced soybean oil. We would expect significantly reduced imports of used cooking oil from China for the same reasons. For this reason, we project a smaller amount, just over one quarter, of the vegetable oil consumed to produce biodiesel and renewable diesel will be imported in 2026 and 2027. These factors are discussed in more detail in Chapter 7.

10.4.2.1.2 Cost Impacts

The component cost (production, distribution, retail and blending; retail costs were combined with the rest of the distribution costs) of each biofuel type compared to the fossil fuel it is displacing under the Analyzed Volumes relative to the No RFS Baseline is summarized in Tables 10.4.2.1.2-1. These cost estimates based on the Analyzed Volumes relative to the No RFS baseline, are the primary costs associated with this rulemaking. Since we are projecting increased vegetable oil prices due to significant increases in vegetable oil-based fuel volumes over the baseline volumes, there is an additional cost due to increased vegetable oil prices for the baseline volumes as well. For fuels that we do not project will be supplied in the No RFS Baseline (*e.g.*, renewable diesel from soybean oil and canola oil), there is no cost increase for the baseline volumes. This additional cost for BBD is a separately estimated line item (Increase in Baseline Price) and included in the total costs.

Table 10.4.2.1.2-1: Analyzed Volumes – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2024\$)

		Renewable Fuel			Increase in	Petroleum Fuel		Total
		Prod.	Distrib.	Blending	Baseline Price	Prod.	Distrib.	
2026	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	448	742	0		-248	-898	44
	Corn Kernel Fiber Ethanol	0	0	0		0	0	0
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	3481	408	0	879	-1313	-307	3149
	Biodiesel - FOG	-340	-51	0	321	165	39	134
	Biodiesel - Corn Oil	893	124	0	29	-400	-94	553
	Biodiesel - Canola	888	104	0	297	-335	-78	877
	Renewable Diesel - Soybean	7853	860	0	0	-2901	-678	5134
	Renewable Diesel - FOG	2826	393	0	1488	-1327	-310	3085
	Renewable Diesel - Corn	309	40	0	948	-134	-31	1131
	Renewable Diesel - Canola	5836	639	0	0	-2156	-504	3816
	Sugarcane Ethanol	0	0	0		0	0	0
	<i>Conventional</i>							
	Ethanol - E10	631	147	-260		-490	-65	-37
	Ethanol - E15	281	219	-77		-219	-29	176
	Ethanol - E85	323	160	-18		-251	-33	181
2027	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	470	778	0		-256	-942	50
	Corn Kernel Fiber Ethanol	0	0	0		0	0	0
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	4847	554	0	541	-1788	-416	3737
	Biodiesel - FOG	-512	-76	0	434	244	57	147
	Biodiesel - Corn Oil	595	81	0	154	-261	-61	508
	Biodiesel - Canola	1346	154	0	182	-496	-116	1069
	Renewable Diesel - Soybean	8718	951	0	0	-3222	-750	5697
	Renewable Diesel - FOG	4414	615	0	1507	-2086	-485	3980
	Renewable Diesel - Corn	649	83	0	984	-283	-66	1367
	Renewable Diesel - Canola	6575	717	0	0	-2430	-566	4296
	Sugarcane Ethanol	0	0	0		0	0	0
	<i>Conventional</i>							
	Ethanol - E10	737	168	-297		-548	-74	-15
	Ethanol - E15	323	247	-87		-240	-33	210
	Ethanol - E85	333	162	-18		-248	-34	196

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.2.1.2-2.

Table 10.4.2.1.2-2: Total Annual and Per Unit Costs Relative to the No RFS Baseline (2024\$)

Year	Fuel Type	Total Cost (million \$)	Per-Unit Cost	Units
2026	Gasoline	320	0.23	¢/gal gasoline
	Diesel Fuel	17,877	30.45	¢/gal diesel
	Natural Gas	44	0.13	\$/MSCF natural gas
	Total	18,241	9.32	¢/gal gasoline and diesel
2027	Gasoline	392	0.29	¢/gal gasoline
	Diesel Fuel	20,802	35.90	¢/gal diesel
	Natural Gas	50	0.15	\$/MSCF natural gas
	Total	21,244	10.95	¢/gal gasoline and diesel

10.4.2.2 Analyzed Volumes Relative to 2025 Baseline

In this section, we summarize the estimated costs for the changes in renewable fuel volumes described in Chapter 3.2 (changes relative to the 2025 Baseline volumes described in Chapter 2). For this analysis we considered all societal costs (production, blending, distribution...), and differences in energy density.

10.4.2.2.1 Volumes

The renewable fuel and fossil fuel volume changes under the Analyzed Volumes relative to the 2025 Baseline are summarized in Tables 10.4.2.2.1-1a and 1b, respectively. For estimating the volume of petroleum fuel being displaced by the biofuel which is being blended into the petroleum fuel, we rely on the energy densities from Table 10.3-1 for determining the relative volumes.

Table 10.4.2.2.1-1a: Analyzed Volumes – Renewable Fuel Volume Changes Relative to the 2025 Volumes (million gallons, except where noted)

Fuel Type	Change in Renewable Fuel Volumes	
	2026	2027
<i>Cellulosic Biofuel</i>		
RNG as CNG - Landfill Biogas (MMSCF)	4,867	10,104
Corn Kernel Fiber Ethanol	66	137
<i>Non-cellulosic Advanced</i>		
Biodiesel - Soybean	307	307
Biodiesel - FOG	-4	-4
Biodiesel - Corn Oil	166	166
Biodiesel - Canola	210	210
Renewable Diesel - Soybean	766	906
Renewable Diesel - FOG	-269	-159
Renewable Diesel - Corn	235	235
Renewable Diesel - Canola	759	879
Sugarcane Ethanol	15	15
<i>Conventional</i>		
Ethanol - E10	118	6
Ethanol - E15	15	34
Ethanol - E85	24	50
Change in RNG Volume	4,867	10,104
Change in Ethanol Volume	114	46
Change in Biodiesel Volume	679	679
Change in Renewable Diesel Volume	1,491	1,861

Table 10.4.2.2.1-1b: Analyzed Volumes – Fossil Fuel Volume Changes Relative to the 2025 Baseline (million gallons, except where noted)

Fuel Type	Fuel Displaced	Change in Fossil Fuel Volumes	
		2026	2027
Natural Gas	<i>Cellulosic Biofuel</i>		
	RNG as CNG - Landfill Biogas (MMSCF)	-4,867	-10,104
Gasoline	Corn Kernel Fiber Ethanol	34	34
Diesel Fuel	<i>Non-cellulosic Advanced</i>		
	Biodiesel - Soybean	282	282
	Biodiesel - FOG	-4	-4
	Biodiesel - Corn Oil	152	152
	Biodiesel - Canola	193	193
	Renewable Diesel - Soybean	-738	-873
	Renewable Diesel - FOG	259	153
	Renewable Diesel - Corn	-226	-226
	Renewable Diesel - Canola	-732	-847
	Gasoline	10	10
Gasoline	<i>Conventional</i>		
	Ethanol - E10	-16	59
	Ethanol - E15	-10	-23
Gasoline	Ethanol - E85	-16	-33
-	Change in Gasoline Volume	2	48
-	Change in Diesel Fuel Volume	-813	-1,170
-	Change in Natural Gas Volume	-4,867	-10,104

Similar to the analysis conducted in Chapter 10.4.2.1.1, the change in gasoline and diesel volume for each year is used to estimate the change in petroleum demand and its effect on both imported crude oil, domestic crude oil, and imported petroleum products. Table 10.4.2.2.1-2 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels relative to the 2025 Baseline.

Table 10.4.2.2.1-2: Analyzed Volumes – Projected Change in Petroleum Imports Due to Increase in Renewable Fuel Consumption Relative to the 2025 Baseline (million gallons)

	2026	2027
Change in Domestic Crude Oil	-21	-18
Change in Imported Crude Oil	-798	-1,109

10.4.2.2.2 Cost Impacts

The component cost (production, distribution, blending) of each biofuel type compared to the fossil fuel it is displacing under the Analyzed Volumes relative to the 2025 Baseline is summarized in Table 10.4.2.2.2-1. Similar to the No RFS baseline case, we are projecting increased vegetable oil prices due to significant increases in vegetable oil-based fuel volumes over the baseline volumes. Thus, there is an additional cost due to increased BBD costs for the

baseline volumes. This additional cost is a separately estimated line item (Increase in Baseline Price) and included in the total costs.

Table 10.4.2.2-1: Analyzed Volumes – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2024\$)

		Renewable Fuel			Increase in	Petroleum Fuel		Total
		Prod.	Distrib.	Blending	Baseline Price	Prod.	Distrib.	
2026	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	37	61	0		-20	-74	4
	Corn Kernel Fiber Ethanol	96	15	39		-74	-10	66
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	1705	200	0	1036	-643	-150	2147
	Biodiesel - FOG	-17	-3	0	152	-348	-81	142
	Biodiesel - Corn Oil	776	108	0	48	-440	-103	503
	Biodiesel - Canola	1166	137	0	144	0	0	904
	Renewable Diesel - Soybean	4557	499	0	723	-1683	-394	3703
	Renewable Diesel - FOG	-1265	-175	0	3107	-516	-121	2396
	Renewable Diesel - Corn	1192	153	0	478	-1668	-390	1186
	Renewable Diesel - Canola	4516	494	0	290	0	0	3242
	Sugarcane Ethanol	41	7	-12		-22	-3	11
	<i>Conventional</i>							
	Ethanol - E10	44	10	-18		-34	-5	-3
	Ethanol - E15	28	22	-8		-22	-3	18
	Ethanol - E85	46	23	-3		-36	-5	26
2027	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	77	127	0		-42	-154	8
	Corn Kernel Fiber Ethanol	98	15	39		-73	-10	69
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	1751	200	0	1158	-646	-150	2313
	Biodiesel - FOG	-18	-3	0	170	8	2	160
	Biodiesel - Corn Oil	796	108	0	53	-349	-81	527
	Biodiesel - Canola	1197	137	0	161	-442	-103	950
	Renewable Diesel - Soybean	5410	590	0	808	-2000	-465	4344
	Renewable Diesel - FOG	-745	-104	0	1736	351	82	1320
	Renewable Diesel - Corn	1191	153	0	535	-519	-121	1239
	Renewable Diesel - Canola	5249	572	0	324	-1940	-452	3754
	Sugarcane Ethanol	41	7	-12		-21	-3	12
	<i>Conventional</i>							
	Ethanol - E10	-170	-39	69		127	17	3
	Ethanol - E15	65	50	-17		-48	-7	42
	Ethanol - E85	95	46	-5		-71	-10	56

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.2.2-2.

Table 10.4.2.2-2: Analyzed Volumes – Total Annual and Per-Unit Costs Relative to the 2025 Baseline (2024\$)

Year	Fuel Type	Total Cost (million \$)	Per-Unit Cost	Units
2026	Gasoline	118	0.09	¢/gal gasoline
	Diesel Fuel	14,223	24.22	¢/gal diesel
	Natural Gas	4	0.01	\$/MSCF natural gas
	Total	14,344	7.33	¢/gal gasoline and diesel
2027	Gasoline	183	0.13	¢/gal gasoline
	Diesel Fuel	14,606	25.21	¢/gal diesel
	Natural Gas	8	0.02	\$/MSCF natural gas
	Total	14,797	7.62	¢/gal gasoline and diesel

10.4.3 Sensitivity Cases

This chapter provides alternative cost estimates as sensitivity analyses to the primary cost analysis described in Chapter 10.4.2. The two primary sensitivity analyses are high and low vegetable oil price estimates to bound the projected vegetable prices estimated for our primary cost analysis. We also present a sensitivity cost analysis for alternate petroleum pricing scenarios examining the possibility of lower crude oil prices compared to those projected in AEO2025.

10.4.3.1 High Vegetable Oil Prices Sensitivity Analyses

As summarized in Table 10.4.2.2.1-1a, this rule is estimated to cause more than 2.1 billion-gallon increase in biodiesel and renewable diesel consumption in 2026 relative to 2025, which we estimate will largely be supplied by domestic feedstock sources. For our primary cost case, we estimate higher vegetable oil prices as a result. However, if the agricultural market struggles more than expected to respond to these volume requirements, prices could increase even more than what we estimate in our projections. For this reason, we conducted sensitivity cost analyses at much higher vegetable oil prices for those feedstocks. For 2026 we assumed a soybean oil price of 81¢ per pound, and for 2027 we assumed a soybean oil price of 85¢ per pound, respectively, as summarized in Chapter 10.1.1.3. These prices were estimated based on a methodology developed by Lusk et al. (2022).⁷⁹⁶ See Chapter 9.3 for more details about these estimates. We estimated that inedible corn oil and FOG, both of which are less refined than virgin soybean and canola oil, are estimated to be priced somewhat lower than virgin soybean oil and canola oil.

10.4.3.1.1 High Vegetable Oil Price Scenario Relative to the No RFS Baseline

The component cost (production, distribution, blending, retail) of each biofuel type compared to the fossil fuel it is displacing under the Analyzed Volumes at High Prices relative to the No RFS Baseline is summarized in Table 10.4.3.1.1-1. Due to the high price increase caused by the large increase in vegetable oil demand, we also estimate the same price increase of the

⁷⁹⁶ Lusk, Jayson L. “Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil,” November 10, 2022. https://ag.purdue.edu/cfdas/wp-content/uploads/2022/12/report_soymodel_revised13.pdf.

baseline volume of BBD and report that in the table, and include that additional cost in the total costs.

Table 10.4.3.1.1-1: High Vegetable Oil Prices Scenario – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2024\$)

		Renewable Fuel			Increase in	Petroleum Fuel		Total
		Prod.	Distrib.	Blending	Baseline Price	Prod.	Distrib.	
2026	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	448	742	0		-248	-898	44
	Corn Kernel Fiber							
	Ethanol	0	0	0		0	0	0
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	4445	408	0	1606	-1313	-307	4840
	Biodiesel - FOG	-432	-51	0	586	165	39	308
	Biodiesel - Corn Oil	1136	124	0	53	-400	-94	820
	Biodiesel - Canola	1134	104	0	543	-335	-78	1369
	Renewable Diesel - Soybean	9881	860	0	0	-2901	-678	7162
	Renewable Diesel - FOG	3540	393	0	2720	-1327	-310	5015
	Renewable Diesel - Corn	387	40	0	1731	-134	-31	1993
	Renewable Diesel - Canola	7343	639	0	0	-2156	-504	5322
	Sugarcane Ethanol	0	0	0		0	0	0
2027	<i>Conventional</i>							
	Ethanol - E10	631	147	-260		-432	-65	21
	Ethanol - E15	281	219	-77		-193	-29	202
	Ethanol - E85	323	160	-18		-221	-33	211
	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	470	778	0		-256	-942	50
	Corn Kernel Fiber							
	Ethanol	0	0	0		0	0	0
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	6284	554	0	0	-1788	-416	5598
	Biodiesel - FOG	-660	-76	0	964	244	57	338
	Biodiesel - Corn Oil	768	81	0	274	-261	-61	802
	Biodiesel - Canola	1745	154	0	324	-496	-116	1610
	Renewable Diesel - Soybean	11185	951	0	0	-3222	-750	8164
	Renewable Diesel - FOG	5633	615	0	2684	-2086	-485	6361
	Renewable Diesel - Corn	828	83	0	1752	-283	-66	2315
	Renewable Diesel - Canola	8435	717	0	0	-2430	-566	6156
	Sugarcane Ethanol	0	0	0		0	0	0
	<i>Conventional</i>							
	Ethanol - E10	737	168	-297		-548	-74	-15
	Ethanol - E15	323	247	-87		-240	-33	210
	Ethanol - E85	333	162	-18		-248	-34	196

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.3.1.1-2.

Table 10.4.3.1.1-2: Total Annual and Per-Unit Costs Relative to the No RFS Baseline (2024\$)

Year	Fuel Type	Total Cost (million \$)	Per-Unit Cost	Units
2026	Gasoline	320	0.23	¢/gal gasoline
	Diesel Fuel	26,828	45.69	¢/gal diesel
	Natural Gas	44	0.13	\$/MSCF natural gas
	Total	27,192	13.89	¢/gal gasoline and diesel
2027	Gasoline	392	0.29	¢/gal gasoline
	Diesel Fuel	31,344	54.09	¢/gal diesel
	Natural Gas	50	0.15	\$/MSCF natural gas
	Total	31,786	16.38	¢/gal gasoline and diesel

10.4.3.1.2 High Vegetable Oil Prices Scenario Relative to the 2025 Baseline

The component cost (production, distribution, blending, retail) of each biofuel type compared to the fossil fuel it is displacing under the Analyzed Volumes at High Prices relative to the 2025 Baseline is summarized in Table 10.4.2.3.2-1. The high price increase caused by the large increase in vegetable oil demand is estimated to cause the same price increase for the baseline volume of BBD, which is reported in the table, and included in the total costs.

Table 10.4.3.1.2-1: Analyzed Volumes at High Vegetable Oil Prices – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2024\$)

		Renewable Fuel			Increase in	Petroleum Fuel		Total
		Prod.	Distrib.	Blending	Baseline Price	Prod.	Distrib.	
2026	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	37	61	0		-20	-74	4
	Corn Kernel Fiber Ethanol	96	15	39		-74	-10	66
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	2177	200	0	2256	-643	-150	3839
	Biodiesel - FOG	-22	-3	0	330	-348	-81	316
	Biodiesel - Corn Oil	987	108	0	104	-440	-103	770
	Biodiesel - Canola	1489	137	0	313	0	0	1396
	Renewable Diesel - Soybean	5734	499	0	1574	-1683	-394	5730
	Renewable Diesel - FOG	-1577	-175	0	6762	-516	-121	5740
	Renewable Diesel - Corn	1491	153	0	1041	-1668	-390	2048
	Renewable Diesel - Canola	5681	494	0	631	0	0	4749
	Sugarcane Ethanol	41	7	-12		-22	-3	11
	<i>Conventional</i>							
	Ethanol - E10	44	10	-18		-34	-5	-3
	Ethanol - E15	28	22	-8		-22	-3	18
	Ethanol - E85	46	23	-3		-36	-5	26
2027	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	77	127	0		-42	-154	8
	Corn Kernel Fiber Ethanol	98	15	39		-73	-10	69
	<i>Non-cellulosic Advanced</i>							
		2270						
	Biodiesel - Soybean		200	0	2499	-646	-150	4173
	Biodiesel - FOG	-23	-3	0	3746	8	2	351
	Biodiesel - Corn Oil	1029	108	0	115	-349	-81	821
	Biodiesel - Canola	1553	137	0	347	-442	-103	1491
	Renewable Diesel - Soybean	6941	590	0	1744	-2000	-465	6810
	Renewable Diesel - FOG	-948	-104	0	3746	351	82	3128
	Renewable Diesel - Corn	1519	153	0	1154	-519	-121	2187
	Renewable Diesel - Canola	6734	572	0	699	-1940	-452	5614
	Sugarcane Ethanol	41	7	-12		-21	-3	12
	<i>Conventional</i>							
	Ethanol - E10	-170	-39	69		127	17	3
	Ethanol - E15	65	50	-17		-48	-7	42
	Ethanol - E85	95	46	-5		-71	-10	56

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.3.1.2-2.

Table 10.4.3.1.2-2: Analyzed Volumes at High Prices – Total Annual and Per-Unit Costs Relative to the 2025 Baseline (2024\$)

Year	Fuel Type	Total Cost (million \$)	Per-Unit Cost	Units
2026	Gasoline	118	0.09	¢/gal gasoline
	Diesel Fuel	24,586	41.88	¢/gal diesel
	Natural Gas	4	0.01	\$/MSCF natural gas
	Total	24,708	12.62	¢/gal gasoline and diesel
2027	Gasoline	183	0.13	¢/gal gasoline
	Diesel Fuel	24,575	42.41	¢/gal diesel
	Natural Gas	8	0.02	\$/MSCF natural gas
	Total	24,766	12.76	¢/gal gasoline and diesel

10.4.3.2 Low Vegetable Oil Prices Sensitivity Analyses

We analyzed the costs for the final fuel volumes relative to the No RFS Baseline, as well as incremental to the 2025 Baseline, assuming a lower bound estimate for vegetable oil prices.

10.4.3.2.1 Low Vegetable Oil Prices Relative to the No RFS Baseline

In this section, we summarize the estimated costs for the changes in renewable fuel volumes described in Chapter 10.4.2.1.1 (changes relative to the No RFS Baseline volumes described in Chapter 2) assuming lower vegetable oil prices. The vegetable oil prices are based on soybean oil prices projected by USDA (~40¢/pound range) adjusted from nominal to 2024 dollars as discussed in Chapter 10.1.1.2. The costs presented here could represent the costs for these higher BBD volumes once the vegetable oil market rebalances itself at these higher vegetable oil volumes which likely would occur after 2026 and 2027. For this analysis we considered all societal costs, including production, blending, and distribution costs, and differences in energy density.

The component cost (production, distribution, blending, retail) of each biofuel type compared to the fossil fuel it is displacing under the low vegetable oil prices scenario relative to the No RFS Baseline is summarized in Tables 10.4.2.1.2-1. Since the vegetable oil prices are the same as baseline prices, there is no price increase associated with the baseline BBD volumes.

Table 10.4.3.2.1-1: Low Vegetable Oil Prices Scenario – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2024\$)

		Renewable Fuel			Petroleum Fuel		Total
		Production	Distribution	Blending	Production	Distribution	
2026	<i>Cellulosic Biofuel</i>						
	RNG as CNG - Landfill						
	Biogas	448	742	0	-248	-898	44
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	<i>Non-cellulosic Advanced</i>						
	Biodiesel - Soybean	2316	408	0	-1313	-307	1104
	Biodiesel - FOG	-229	-51	0	165	39	-77
	Biodiesel - Corn Oil	599	124	0	-400	-94	230
	Biodiesel - Canola	591	104	0	-335	-78	282
	Renewable Diesel - Soybean	5402	860	0	-2901	-678	2683
	Renewable Diesel - FOG	1984	393	0	-1327	-310	750
	Renewable Diesel - Corn	216	40	0	-134	-31	90
	Renewable Diesel - Canola	4015	639	0	-2156	-504	1994
	Sugarcane Ethanol	0	0	0	0	0	0
	<i>Conventional</i>						
	Ethanol - E10	631	147	-260	-432	-65	21
	Ethanol - E15	281	219	-77	-193	-29	202
	Ethanol - E85	323	160	-18	-221	-33	211
2027	<i>Cellulosic Biofuel</i>						
	RNG as CNG - Landfill						
	Biogas	470	778	0	-256	-942	50
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0
	<i>Non-cellulosic Advanced</i>						
	Biodiesel - Soybean	3007	554	0	-1788	-416	1356
	Biodiesel - FOG	-323	-76	0	244	57	-98
	Biodiesel - Corn Oil	373	81	0	-261	-61	132
	Biodiesel - Canola	835	154	0	-496	-116	377
	Renewable Diesel - Soybean	5561	951	0	-3222	-750	2540
	Renewable Diesel - FOG	2888	615	0	-2086	-485	932
	Renewable Diesel - Corn	420	83	0	-283	-66	155
	Renewable Diesel - Canola	4194	717	0	-2430	-566	1915
	Sugarcane Ethanol	0	0	0	0	0	0
	<i>Conventional</i>						
	Ethanol - E10	737	168	-297	-478	-74	56
	Ethanol - E15	323	247	-87	-210	-33	241
	Ethanol - E85	333	162	-18	-216	-34	228

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.3.2.1-2.

Table 10.4.3.2.1-2: Total Annual and Per-Unit Costs Relative to the No RFS Baseline (2024\$)

Year	Fuel Type	Total Cost (million \$)	Per-Unit Cost	Units
2026	Gasoline	320	0.23	¢/gal gasoline
	Diesel Fuel	7,056	12.02	¢/gal diesel
	Natural Gas	44	0.13	\$/MSCF natural gas
	Total	7,420	3.79	¢/gal gasoline and diesel
2027.	Gasoline	392	0.29	¢/gal gasoline
	Diesel Fuel	7,309	12.61	¢/gal diesel
	Natural Gas	50	0.15	\$/MSCF natural gas
	Total	7,751	3.99	¢/gal gasoline and diesel

10.4.3.2.2 Low Vegetable Oil Prices Relative to the 2025 Baseline

In this section, we summarize the estimated costs for the changes in renewable fuel volumes described in Chapter 10.4.2.2.1 (changes relative to the 2025 Baseline volumes described in Chapter 2) assuming lower vegetable oil prices. The vegetable oil prices are based on the average soybean oil price in 2025 (~50¢/pound range) as discussed in Chapter 10.1.1.2. The costs presented here could represent the costs for these higher BBD volumes once the vegetable oil market rebalances itself at these higher vegetable oil volumes which likely would occur after 2026 and 2027. For this analysis we considered all societal costs, including production, blending, and distribution costs, and differences in energy density.

The component cost (production, distribution, blending, retail) of each biofuel type compared to the fossil fuel it is displacing under the final renewable fuel volumes relative to the 2025 Baseline is summarized in Tables 10.4.2.2.2-1. Since the vegetable oil prices are the same as baseline prices, there is no price increase associated with the baseline BBD volumes.

Table 10.4.3.2.2-1: Low Vegetable Oil Prices Scenario – Renewable and Petroleum Fuel Costs Relative to the 2025 Baseline (million 2024\$)

		Renewable Fuel			Petroleum Fuel		Total
		Production	Distribution	Blending	Production	Distribution	
2026	<i>Cellulosic Biofuel</i>						
	RNG as CNG - Landfill						
	Biogas	37	61	0	-20	-74	4
	Corn Kernel Fiber Ethanol	96	15	39	-74	-10	66
	<i>Non-cellulosic Advanced</i>						
	Biodiesel - Soybean	1303	200	0	-643	-150	710
	Biodiesel - FOG	-13	-3	0	-348	-81	-6
	Biodiesel - Corn Oil	597	108	0	-440	-103	276
	Biodiesel - Canola	892	137	0	0	0	486
	Renewable Diesel - Soybean	3557	499	0	-1683	-394	1979
	Renewable Diesel - FOG	-1000	-175	0	-516	-121	-446
	Renewable Diesel - Corn	938	153	0	-1668	-390	454
	Renewable Diesel - Canola	3525	494	0	0	0	1961
	Sugarcane Ethanol	41	7	-12	-22	-3	11
	<i>Conventional</i>						
	Ethanol - E10	44	10	-18	-34	-5	-3
	Ethanol - E15	28	22	-8	-22	-3	18
	Ethanol - E85	46	23	-3	-36	-5	26
2027	<i>Cellulosic Biofuel</i>						
	RNG as CNG - Landfill						
	Biogas	77	127	0	-42	-154	8
	Corn Kernel Fiber Ethanol	98	15	39	-73	-10	69
	<i>Non-cellulosic Advanced</i>						
	Biodiesel - Soybean	1302	200	0	-646	-150	706
	Biodiesel - FOG	-13	-3	0	8	2	-5
	Biodiesel - Corn Oil	596	108	0	-349	-81	274
	Biodiesel - Canola	891	137	0	-442	-103	483
	Renewable Diesel - Soybean	4088	590	0	-2000	-465	2213
	Renewable Diesel - FOG	-570	-104	0	351	82	-241
	Renewable Diesel - Corn	907	153	0	-519	-121	421
	Renewable Diesel - Canola	3966	572	0	-1940	-452	2147
	Sugarcane Ethanol	41	7	-12	-21	-3	12
	<i>Conventional</i>						
	Ethanol - E10	-170	-39	69	127	17	3
	Ethanol - E15	65	50	-17	-48	-7	42
	Ethanol - E85	95	46	-5	-71	-10	56

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.3.2.2-2.

Table 10.4.3.2.2-2: Low Vegetable Oil Prices Scenario – Total Annual and Per-Unit Costs Relative to the 2025 Baseline (2024\$)

Year	Fuel Type	Total Cost (million \$)	Per-Unit Cost	Units
2026	Gasoline	118	0.09	¢/gal gasoline
	Diesel Fuel	5,414	9.22	¢/gal diesel
	Natural Gas	4	0.01	\$/MSCF natural gas
	Total	5,536	2.83	¢/gal gasoline and diesel
2027.	Gasoline	183	0.13	¢/gal gasoline
	Diesel Fuel	5,997	10.35	¢/gal diesel
	Natural Gas	8	0.02	\$/MSCF natural gas
	Total	6,188	3.16	¢/gal gasoline and diesel

10.4.3.3 Crude Oil Sensitivity Analyses

10.4.3.3.1 Cost Impacts of Lower Crude Oil Prices

It is common for crude oil prices to deviate from the projected crude oil prices which we use for our economic analysis, and these deviations impact the cost of the RFS program. As an example, crude oil prices finished lower in 2025 compared to the beginning of the year and, as of this writing, crude prices were lower than the 2026 crude oil prices forecasted in AEO2025. This decline is associated with lower demand caused by lower economic activity combined with higher crude oil output and these lower crude oil prices could persist in 2026.⁷⁹⁷ Compared to AEO2025's forecast of \$81.5/bbl crude oil prices in 2026, the end-of-year Brent crude oil spot price averaged about \$65/bbl. We based a crude oil sensitivity case on this \$65/bbl crude oil price in lieu of EIA's forecasted crude oil price to show how lower crude oil prices impact the estimated costs. Because the wholesale price of gasoline and diesel fuel are used for estimating their production costs, we needed to estimate the wholesale gasoline and diesel fuel wholesale prices when crude oil is priced at \$65/bbl. The AEO2025 low crude oil sensitivity case estimates gasoline and diesel fuel wholesale prices at an even lower crude oil price of \$38/bbl and we interpolated the gasoline and diesel fuel wholesale prices between the two AEO cases to estimate the gasoline and diesel fuel wholesale prices at \$65/bbl. Table 10.4.3.3.1-1 summarizes the reference case, low crude oil case and sensitivity case crude oil and wholesale prices.

⁷⁹⁷ EIA, "Crude Oil Prices Fell in 2025 Amid Oversupply, *Today in Energy*, January 5, 2026. <https://www.eia.gov/todayinenergy/detail.php?id=66944>.

Table 10.4.3.3.1-1 Crude Oil and Wholesale Prices at Different AEO2025 Crude Oil Prices (2024\$)

Case	Price	Units	2026	2027
Reference Case	Brent Crude Price	\$/bbl	\$81.5	\$80.4
	Gasoline Wholesale Price	\$/gal	\$2.18	\$2.13
	Diesel Wholesale Price	\$/gal	\$2.28	\$2.29
Low Crude Oil Price Case	Brent Crude Price	\$/bbl	\$38.5	\$39.3
	Gasoline Wholesale Price	\$/gal	\$1.51	\$1.40
	Diesel Wholesale Price	\$/gal	\$1.64	\$1.57
Sensitivity Case Crude Oil Prices	Brent Crude Price	\$/bbl	\$65.0	\$65.0
	Gasoline Wholesale Price	\$/gal	\$1.92	\$1.86
	Diesel Wholesale Price	\$/gal	\$2.03	\$2.02

Based on the lower petroleum prices, the component cost (production, distribution, blending retail) of each biofuel type compared to the fossil fuel it is displacing under the Low Crude Oil Price Scenario relative to the No RFS Baseline is summarized in Tables 10.4.3.3.1-2.

Table 10.4.3.3.1-2: Low Crude Oil Price Scenario – Renewable and Petroleum Fuel Costs Relative to the No RFS Baseline (million 2024\$)

		Renewable Fuel			Increase in	Petroleum Fuel		Total
		Prod.	Distrib.	Blending	Baseline Price	Prod.	Distrib.	
2026	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	448	742	0	0	-248	-898	44
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0	0
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	3481	408	0	879	-1172	-307	3290
	Biodiesel - FOG	-340	-51	0	321	148	39	116
	Biodiesel - Corn Oil	893	124	0	29	-357	-94	596
	Biodiesel - Canola	888	104	0	297	-299	-78	913
	Renewable Diesel - Soybean	7853	860	0	0	-2588	-678	5447
	Renewable Diesel - FOG	2826	393	0	1488	-1184	-310	3228
	Renewable Diesel - Corn	309	40	0	948	-120	-31	1146
	Renewable Diesel - Canola	5836	639	0	0	-1924	-504	4048
	Sugarcane Ethanol	0	0	0		0	0	0
	<i>Conventional</i>							
	Ethanol - E10	631	147	-260	0	-432	-65	21
	Ethanol - E15	281	219	-77	0	-193	-29	202
	Ethanol - E85	323	160	-18	0	-221	-33	211
2027	<i>Cellulosic Biofuel</i>							
	RNG as CNG - Landfill							
	Biogas	470	778	0	0	-256	-942	50
	Corn Kernel Fiber Ethanol	0	0	0	0	0	0	0
	<i>Non-cellulosic Advanced</i>							
	Biodiesel - Soybean	4847	554	0	541	-1577	-416	3948
	Biodiesel - FOG	-512	-76	0	434	215	57	118
	Biodiesel - Corn Oil	595	81	0	154	-230	-61	539
	Biodiesel - Canola	1346	154	0	182	-438	-116	1128
	Renewable Diesel - Soybean	8718	951	0	0	-2843	-750	6076
	Renewable Diesel - FOG	4414	615	0	1507	-1840	-485	4226
	Renewable Diesel - Corn	649	83	0	984	-249	-66	1401
	Renewable Diesel - Canola	6575	717	0	0	-2144	-566	4582
	Sugarcane Ethanol	0	0	0		0	0	0
	<i>Conventional</i>							
	Ethanol - E10	737	168	-297		-478	-74	56
	Ethanol - E15	323	247	-87		-210	-33	241
	Ethanol - E85	333	162	-18		-216	-34	228

The costs are aggregated for each fossil fuel type and shown as annual totals and per-gallon and per MSCF costs in Table 10.4.3.3.1-3.

Table 10.4.3.3.1-3: Low Crude Oil Price Scenario – Total Annual and Per-Unit Costs Relative to No RFS Baseline (2024\$)

Year	Fuel Type	Total Cost (million \$)	Per-Unit Cost	Units
2026	Gasoline	433	0.32	¢/gal gasoline
	Diesel Fuel	18,782	31.99	¢/gal diesel
	Natural Gas	44	0.13	\$/MSCF natural gas
	Total	19,259	9.84	¢/gal gasoline and diesel
2027	Gasoline	525	0.39	¢/gal gasoline
	Diesel Fuel	22,018	38.00	¢/gal diesel
	Natural Gas	50	0.15	\$/MSCF natural gas
	Total	22,593	11.64	¢/gal gasoline and diesel

10.4.3.3.2 Potential Cost Impact of Lower Crude Oil Demand

As estimated previously in this chapter, the increased consumption of renewable fuels will decrease petroleum product fuel demand. Thus, a case could be made that this reduced petroleum demand could lower crude oil prices and therefore lower costs to consumers.

AEO2025 provides a way to estimate how a decrease in petroleum demand affects crude oil prices. When modeling two different demand cases for AEO2025, a low economic growth case relative to the reference case, EIA models a reduction in refined product demand between the two cases, and also estimates a lower crude oil price for the lower demand case relative to the reference case. The low economic growth AEO2025 case shows a 425 thousand barrel per day reduction in refined product demanded relative to the reference case for the years 2027–2030, and also estimates an average of \$0.438/bbl lower crude oil price for the low economic growth case for those same years. Averaged over 2026 to 2027, the Set rule is estimated to cause a 300 thousand barrel per day reduction in gasoline and diesel fuel relative to the No RFS baseline case, and 110 thousand barrel per day in gasoline and diesel fuel relative to the 2025 baseline case. Assuming the EIA correlation is realistic, the Set rule volumes would be estimated to cause a \$0.32/bbl decrease in crude oil prices relative to the No RFS Baseline, and a \$0.12/bbl decrease in crude oil prices relative to the 2025 baseline, when averaged over both 2026 and 2027.

If we adopted this method for estimating the RFS program on crude oil prices, it would increase the cost of the RFS program slightly (if petroleum products become less expensive, the renewable fuels become relatively more expensive). As shown by the crude oil price sensitivity case in Chapter 10.4.3.3.1, a fairly large change in crude oil price had a modest impact on the RFS program cost, thus this potentially much smaller price change would have a de minimis impact on the program cost.

Another possible cost impact to consider is how lower petroleum products prices would affect the U.S. economy as a whole. U.S. crude oil consumption is 16.1 million barrels per day so a cost impact could be estimated by the product of the estimated lower crude oil price and crude oil demand. Relative to the No RFS baseline, there is an estimated cost savings of \$1.87 billion dollars. Relative to the 2025 baseline, there is an estimated cost savings of \$700 million.

For several reasons, we elected not to use this method to adjust crude oil prices for the RFS program cost analysis and maintain it as a sensitivity analysis. One reason is that there is great uncertainty in estimating price changes due to lower demand, particularly since the elasticity is based on EIA's AEO low economic growth case, which could be biased by being based on a lower functioning U.S. economy. Thus, it is not clear if the change in crude oil prices is due to the lower demand or due to the impact of a lower functioning economy being modeled by EIA on crude oil prices (*i.e.*, lower labor rates). Either way, the much larger petroleum market is likely to experience a very, very small price impact due to the relatively much smaller increased volumes of renewable fuels.

A case could also be made that there may not be any price impact at all. Multiple crude oil producers alter their crude oil production volumes to maintain the price of crude oil within a price band. EIA evaluated how Saudi Arabia crude changed its crude oil production to apparently affect crude oil prices.⁷⁹⁸

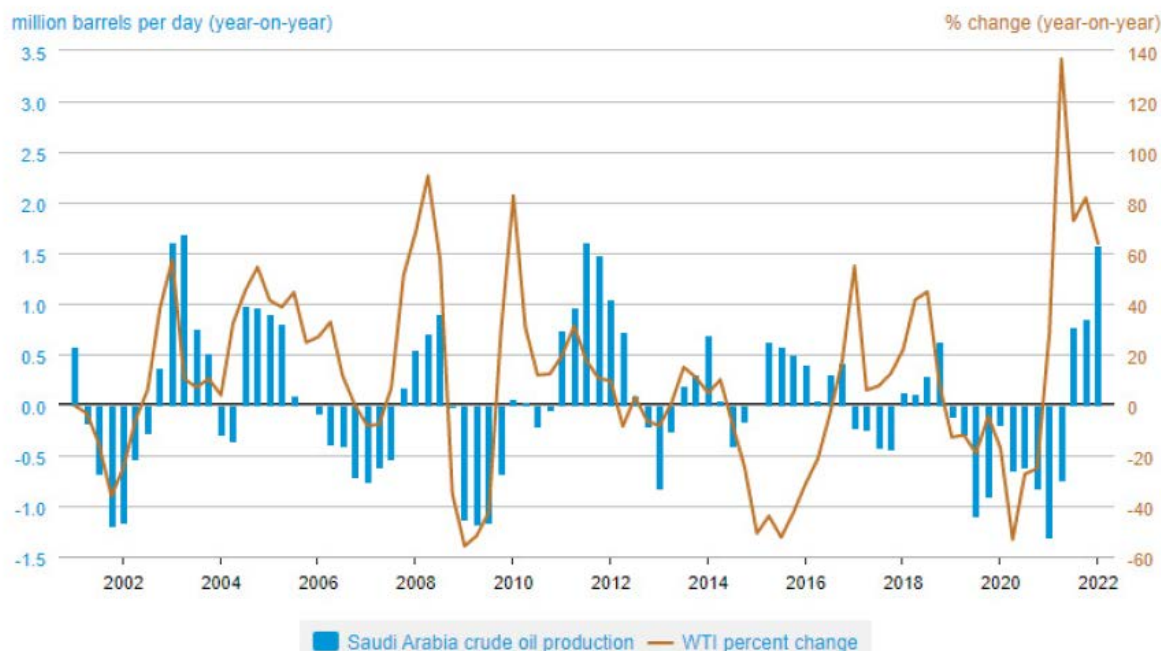
⁷⁹⁸ EIA, "What drives crude oil prices: Supply OPEC," *Energy and Financial Markets*, April 12, 2022. <https://www.eia.gov/finance/markets/crudeoil/supply-opec.php>.

Figure 10.4.3.2-1: Effect of Changing Saudi Arabian Crude Production on Crude Oil Prices

Changes in Saudi Arabia crude oil production can affect oil prices

Changes in Saudi Arabia crude oil production and WTI crude oil prices

DOWNLOAD



Source: U.S. Energy Information Administration, Refinitiv An LSEG Business

Updated: Monthly | Last Updated: 04/12/2022

Oil markets often respond to changing expectations of future supply and demand. This chart shows how projections of changes in Saudi Arabia crude oil production results in changes in WTI crude oil prices.

As shown and described by the figure and its accompanying text, Saudi Arabia is able to “swing” their crude oil production/exports by as much as 2.7 million barrels per day to affect crude oil prices. The 2.7 million barrels per day swing in Saudi Arabian crude oil production change correlates to about 40 billion gallons per year of BBD volume, thus dwarfing the changes in renewable fuels volume changes in the U.S. In addition, Saudi Arabian crude supply is just one of many crude oil supply and demand factors around the world that impact crude prices. Some analysts have concluded that U.S. unconventional crude oil producers are also swing producers which could impact crude oil prices.⁷⁹⁹ Thus, there is a question whether the RFS program would affect crude oil prices at all, and if it did, what the magnitude would be. For this reason, we consider this a speculative analysis.

⁷⁹⁹ Newell, Richard G., and Brian C. Prest. “Is The US the New Swing Producer? The Price-Responsiveness of Tight Oil.” Resources for the Future, June 19, 2017. <https://media.rff.org/documents/RFF-WP-17-15.pdf>.

10.5 Estimated Fuel Price Impacts

In this section, we estimate the impact of the use of renewable fuels on the cost to consumers of transportation fuel and the cost to transport goods. We have estimated cost to consumers of transportation fuel by assessing the fuel price impacts associated with this rulemaking. We do so based on the cost of renewable fuels (less available federal tax credits) and accounting for the cross-subsidy implemented through the RIN system. We have also used estimates of the fuel price impacts of this rule to estimate the cost to transport goods discussed in Chapter 10.5.5.

Unlike the costs presented in Chapter 10.4, the impacts estimated in this set of analyses may not be costs from a societal perspective. For example, revenue from transporting goods benefits the shipping company completing that work. Likewise, each purchase of fuel benefits the seller of that fuel to some extent. Transactions which benefit certain economic participants while costing others are transfers from a societal perspective, not costs. For this reason, the impacts estimated in this section are not used in Chapter 10.6, where we estimate the societal benefits and costs of this rule.

10.5.1 RIN Cost and RIN Value

Before estimating fuel price impacts, we first estimated the RIN cost (*i.e.*, the cost added to the wholesale and/or retail price of each gallon of petroleum fuel to account for the RIN obligation on the fuel) and RIN value (*i.e.*, the value of the RINs associated with the renewable fuel in the fuel blend) associated with producing petroleum and renewable fuels, respectively. Because RIN prices can be impacted by a wide variety of different factors (including the prices of renewable fuels and petroleum-based fuels, crude oil prices, biofuel feedstock commodity prices, etc.), we are not able to project what RIN prices will be in the future. We can, however, use the average RIN prices over the last 12 months (through December 2025) as an estimate of future RIN prices, as shown in Table 10.5.1-1. These estimates are shown alongside the percentage standards for 2025, as well as the percentage standards for 2026 and 2027 finalized in this rule.

Table 10.5.1-1: Average RIN Prices (January 2025 – December 2025)

RFS Standard	RIN Type	Average RIN Price	2025 Standard	2026 Standard	2027 Standard
Cellulosic Biofuel	D3/D7	\$2.40	0.71% ^c	0.79%	0.84%
Biomass-Based Diesel	D4	\$0.95	3.15%	5.24%	5.37%
Other Advanced Biofuel ^a	D5	\$0.99	0.46%	0.39%	0.40%
Conventional Renewable Fuel ^b	D6	\$0.91	8.82%	9.08%	9.17%

^a Other advanced biofuel is not an RFS standard category but is calculated by subtracting the cellulosic biofuel and BBD standards from the advanced biofuel standard.

^b Conventional renewable fuel is not an RFS standard category but is calculated by subtracting the advanced biofuel standard from the total renewable fuel standard.

^c Reflects the partial waiver of the 2025 cellulosic biofuel standard.

We then calculated the RIN cost for petroleum fuel by weighting the RIN price for each D code by their respective RFS standard and summing the total. The results are shown in Table 10.5.1-2.

Table 10.5.1-2: Estimated RIN Costs for Petroleum Fuel for 2025–2027

Year	RIN Cost (\$/Gallon)
2025	\$0.13
2026	\$0.16
2027	\$0.16

Finally, we calculated RIN values for fuels. For gasoline-ethanol blends, we multiplied the average D6 RIN price by the ethanol content of each blend (*i.e.*, 10% for E10, 15% for E15, and an average ethanol content of 74% for E85). For biodiesel and renewable diesel, we multiplied the average D4 RIN price by the equivalence value of each fuel (*i.e.*, 1.5 for biodiesel and 1.5 for renewable diesel). The results are shown in Table 10.5.1-3.

Table 10.5.1-3: Estimated RIN Values for Fuels

Fuel	RIN Value (\$/Gallon)
E10	\$0.09
E15	\$0.14
E85	\$0.67
Biodiesel	\$1.43
Renewable Diesel	\$1.43

10.5.2 Estimated Fuel Price Impacts (Gasoline)

In this section, we estimate the fuel price impacts of the Analyzed Volumes on gasoline relative to the No RFS and 2025 Baselines. First, we estimated the total impact of RIN prices on the price of gasoline-ethanol blends for the Analyzed Volumes. We began with the production cost for each fuel (as specified in Tables 10.4.1-1c (ethanol) and 10.4.1-2b (gasoline)),⁸⁰⁰ to which we added the RIN price impact associated with the gasoline portion of the fuel (as described in Table 10.5.1-2), and then subtracted the RIN value associated with the ethanol portion of each fuel (as described in Table 10.5.1-3), which gave us each fuel’s net price impact per gallon. We then multiplied each fuel’s net price impact by its volume from Table 7.5.1-5 to derive the total price impact for each fuel pool. Finally, we calculated the average gasoline price impact by dividing the total price impact on all fuels by the total volume of all fuels. As shown in Tables 10.5.2-1 and 2, we estimate that the average gasoline price impact ranges from \$2.14 to \$2.20 per gallon.

⁸⁰⁰ Note that for purposes of this fuel price impacts assessment, we only looked at the cost to produce and distribute fuel to retail stations for sale to consumers (*i.e.*, we subtracted out of the fuel economy cost for each fuel).

Note that when estimating the cost to produce ethanol, we make the simplifying assumption that all this ethanol is derived from corn starch⁸⁰¹ and we use only the production cost estimates for corn starch ethanol specified in Table 10.4.1-1c. In reality, some amount of ethanol blended into E10, E15, and E85 is derived from CKF, grain sorghum, separated food waste, and other feedstocks, all of which have different costs to produce relative to ethanol derived from corn starch. However, we believe this simplifying assumption is appropriate because ethanol derived from corn starch represents nearly all the total ethanol blended with gasoline. As described in Chapter 3, we estimate the total ethanol pool shares of corn starch ethanol to be about 99% in both 2026 and 2027 under the Analyzed Volumes. For this reason, we do not believe the gasoline price estimates would vary substantially if we did explicitly include the volume-weighted costs to produce other types of ethanol currently blended into these pools. Therefore, for simplicity and ease of understanding, the following estimates assume all ethanol to be corn starch ethanol.

Table 10.5.2-1: Total Gasoline Costs – 2026

	E0	E10	E15	E85
Cost to Produce (\$/gal)	\$2.21	\$2.14	\$2.30	\$2.58
RIN Cost (\$/gal)	\$0.16	\$0.14	\$0.14	\$0.04
RIN Value (\$/gal)	\$0.00	-\$0.09	-\$0.14	-\$0.67
Tax Credit (\$/gal)	\$0.00	\$0.01	\$0.02	\$0.12
Net Cost (\$/gal)	\$2.37	\$2.20	\$2.32	\$2.07
Volume (mil gal)	2,061	137,404	998	443
Total Fuel Cost (\$bil)	\$4.9	\$302.3	\$2.3	\$0.9
Average Cost (\$/gal)	\$2.20			

Table 10.5.2-2: Total Gasoline Costs – 2027

	E0	E10	E15	E85
Cost to Produce (\$/gal)	\$2.14	\$2.08	\$2.25	\$2.59
RIN Cost (\$/gal)	\$0.16	\$0.14	\$0.14	\$0.04
RIN Value (\$/gal)	\$0.00	-\$0.09	-\$0.14	-\$0.67
Tax Credit (\$/gal)	\$0.00	\$0.01	\$0.02	\$0.12
Net Cost (\$/gal)	\$2.30	\$2.14	\$2.27	\$2.08
Volume (mil gal)	2,075	136,301	1,124	477
Total Fuel Cost (\$bil)	\$4.8	\$291.7	\$2.6	\$1.0
Average Cost (\$/gal)	\$2.14			

Next, we estimated the cost of gasoline-ethanol blends under the No RFS and 2025 Baselines. For the No RFS Baseline, we began with the production cost for each gasoline-ethanol blend, using the relevant estimates described in Chapter 10.1, and multiplied by the volume of each blend under the respective baseline to get the total cost for each fuel.⁸⁰² We then calculated the average gasoline cost by dividing the total cost of all fuels by the total volume of all fuels. As

⁸⁰¹ And also from grain sorghum starch, which we assume throughout this regulatory impact analysis to be identical in cost and other characteristics to corn starch.

⁸⁰² For purposes of the No RFS Baseline analysis, we assumed that E0 volumes were held constant relative to the Analyzed Volumes and that there would not be any volumes of E15 or E85. E10 volumes were calculated by totaling ethanol production for each year from Table 2.1.5-2 and dividing by 0.1.

shown in Tables 10.5.2-3 and 4, we estimate that the average gasoline cost under the No RFS Baseline ranges from \$2.09 to \$2.15 per gallon.

Table 10.5.2-3: Total Gasoline Costs – 2026 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce (\$/gal)	\$2.21	\$2.14	\$2.30	\$2.58
Tax Credit (\$/gal)	\$0.00	\$0.01	\$0.02	\$0.12
Net Fuel Price Impact (\$/gal)	\$2.21	\$2.15	\$2.32	\$2.70
Volume (mil gal)	2,061	138,610	0	169
Total Fuel Cost (\$bil)	\$4.6	\$298.0	\$0.0	\$0.5
Average Cost (\$/gal)	\$2.15			

Table 10.5.2-4: Total Gasoline Costs – 2027 (No RFS Baseline)

	E0	E10	E15	E85
Cost to Produce (\$/gal)	\$2.14	\$2.08	\$2.25	\$2.59
Tax Credit (\$/gal)	\$0.00	\$0.01	\$0.02	\$0.12
Net Fuel Price Impact (\$/gal)	\$2.14	\$2.09	\$2.27	\$2.71
Volume (mil gal)	2,075	137,642	0	190
Total Fuel Cost (\$bil)	\$4.4	\$287.7	\$0.0	\$0.5
Average Cost (\$/gal)	\$2.09			

For the 2025 Baseline, we used the same approach described above for No RFS Baseline.⁸⁰³ As shown in Tables 10.5.2-5 and 6, we estimate that the average gasoline cost under the 2025 Baseline ranges from \$2.14 to \$2.20 per gallon.

Table 10.5.2-5: Total Gasoline Costs – 2026 (2025 Baseline)

	E0	E10	E15	E85
Cost to Produce (\$/gal)	\$2.21	\$2.14	\$2.30	\$2.58
RIN Cost (\$/gal)	\$0.16	\$0.14	\$0.14	\$0.04
RIN Value (\$/gal)	\$0.00	-\$0.09	-\$0.14	-\$0.67
Tax Credit (\$/gal)	\$0.00	\$0.01	\$0.02	\$0.12
Net Cost (\$/gal)	\$2.37	\$2.20	\$2.32	\$2.07
Volume (mil gal)	2,049	136,239	898	410
Total Fuel Cost (\$bil)	\$4.9	\$299.7	\$2.1	\$0.8
Average Cost (\$/gal)	\$2.20			

⁸⁰³ 2025 Baseline gasoline-ethanol blend volumes from Set 1 Rule RIA Table 6.5.2-3.

Table 10.5.2-6: Total Gasoline Costs – 2027 (2025 Baseline)

	E0	E10	E15	E85
Cost to Produce (\$/gal)	\$2.14	\$2.08	\$2.25	\$2.59
RIN Cost (\$/gal)	\$0.16	\$0.14	\$0.14	\$0.04
RIN Value (\$/gal)	\$0.00	-\$0.09	-\$0.14	-\$0.67
Tax Credit (\$/gal)	\$0.00	\$0.01	\$0.02	\$0.12
Net Cost (\$/gal)	\$2.30	\$2.14	\$2.27	\$2.08
Volume (mil gal)	2,049	136,239	898	410
Total Fuel Cost (\$bil)	\$4.7	\$291.6	\$2.0	\$0.9
Average Cost (\$/gal)	\$2.14			

Finally, we calculated the fuel price impacts of this rule on gasoline for each year by subtracting the average gasoline cost in each baseline scenario from the average gasoline cost for the Analyzed Volumes. As shown in Table 10.5.2-7, we estimate that the fuel price impact on gasoline under the No RFS Baseline ranges from 5.1¢ to 5.2¢ per gallon. As shown in Table 10.5.2-8, we estimate that the fuel price impact on gasoline under the 2025 Baseline is 0.0¢ per gallon.

Table 10.5.2-7: Total Gasoline Fuel Price Impacts (No RFS Baseline)

	2026	2027
Average Cost (No RFS Baseline) (\$/gal)	\$2.15	\$2.09
Average Cost (Analyzed Volumes) (\$/gal)	\$2.20	\$2.14
Fuel Price Impact (¢/gal)	5.1¢	5.2¢

Table 10.5.2-8: Total Gasoline Fuel Price Impacts (2025 Baseline)

	2026	2027
Average Cost (2025 Baseline) (\$/gal)	\$2.20	\$2.14
Average Cost (Analyzed Volumes) (\$/gal)	\$2.20	\$2.14
Fuel Price Impact (¢/gal)	0.0¢	0.0¢

10.5.3 Estimated Fuel Price Impacts (Diesel)

In this section, we estimate the fuel price impacts of the Analyzed Volumes on diesel relative to the No RFS and 2025 Baselines. First, we estimated the total cost of diesel, biodiesel, and renewable diesel for the Analyzed Volumes. We began with the production cost for each fuel (as specified in Tables 10.4.1-1c (biodiesel and renewable diesel) and 10.4.1-2b (diesel)),⁸⁰⁴ and then either added the RIN cost (for diesel) or subtracted the RIN value and tax credit (for biodiesel and renewable diesel) associated with each fuel, which gave us each fuel's net cost per gallon. We then multiplied each fuel's net cost by its volume from Table 3.1-4 (biodiesel and renewable diesel) or Preamble Table VII.C-1 (diesel) to get the total cost for each fuel. Finally, we calculated the average diesel cost by dividing the total cost of all fuels by the total volume of all fuels. As shown in Tables 10.5.3-1 and 2, we estimate that the average diesel cost is \$2.86 per gallon.

⁸⁰⁴ Note that for purposes of this fuel price impacts assessment, we only looked at the cost to produce and distribute fuel to retail stations for sale to consumers (*i.e.*, we subtracted out of the fuel economy cost for each fuel).

Table 10.5.3-1: Total Diesel Costs – 2026

	Diesel	Biodiesel			Renewable Diesel		
		Corn Oil	FOG	Soybean/Canola Oil	Corn Oil	FOG	Soybean/Canola Oil
Cost to Produce (\$/gal)	\$2.57	\$5.43	\$5.06	\$6.31	\$5.84	\$5.47	\$6.71
RIN Cost (\$/gal)	\$0.16	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
RIN Value (\$/gal)	\$0.00	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43
Tax Credit (\$/gal)	\$0.00	-\$0.80	-\$0.80	-\$0.62	-\$0.75	-\$0.66	-\$0.52
Net Cost (\$/gal)	\$2.73	\$3.20	\$2.83	\$4.26	\$3.66	\$3.38	\$4.76
Volume (mil gal)	58,273	210	150	1,420	678	1,365	2,301
Total Fuel Cost (\$bil)	\$159.1	\$0.7	\$0.4	\$6.0	\$2.5	\$4.6	\$11.0
Total Cost (\$/gal)	\$2.86						

Table 10.5.3-2: Total Diesel Costs – 2027

	Diesel	Biodiesel			Renewable Diesel		
		Corn Oil	FOG	Soybean/Canola Oil	Corn Oil	FOG	Soybean/Canola Oil
Cost to Produce (\$/gal)	\$2.55	\$5.56	\$5.18	\$6.46	\$5.83	\$5.45	\$6.74
RIN Cost (\$/gal)	\$0.16	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
RIN Value (\$/gal)	\$0.00	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43
Tax Credit (\$/gal)	\$0.00	-\$0.80	-\$0.80	-\$0.62	-\$0.75	-\$0.66	-\$0.52
Net Cost (\$/gal)	\$2.71	\$3.33	\$2.95	\$4.41	\$3.65	\$3.36	\$4.79
Volume (mil gal)	57,085	210	150	1,420	678	1,475	2,561
Total Fuel Cost (\$bil)	\$154.7	\$0.7	\$0.4	\$6.3	\$2.5	\$5.0	\$12.3
Total Cost (\$/gal)	\$2.86						

Next, we estimated the total cost of diesel under the No RFS and 2025 Baselines. For the No RFS Baseline, we began with the production cost for each fuel and subtracted the tax credit (for biodiesel and renewable diesel) associated with each fuel, which gave us each fuel's net cost per gallon. We then multiplied each fuel's net cost by its volume under the respective baseline to get the total cost for each fuel.⁸⁰⁵ We then calculated the average diesel cost by dividing the total cost of all fuels by the total volume of all fuels. As shown in Tables 10.5.3-3 and 4, we estimate that the average diesel cost under the No RFS Baseline ranges from \$2.64 to \$2.67 per gallon.

⁸⁰⁵ Biodiesel and renewable diesel volumes from Table 2.1.5-2. For purposes of the No RFS Baseline analysis, we assumed that total diesel energy demand was held constant relative to the Analyzed Volumes to calculate petroleum diesel fuel volumes.

Table 10.5.3-3: Total Diesel Costs – 2026 (No RFS Baseline)

	Diesel	Biodiesel			Renewable Diesel		
		Corn Oil	FOG	Soybean/Canola Oil	Corn Oil	FOG	Soybean/Canola Oil
Cost to Produce (\$/gal)	\$2.57	\$5.43	\$5.06	\$6.31	\$5.84	\$5.47	\$6.71
Tax Credit (\$/gal)	\$0.00	-\$0.80	-\$0.80	-\$0.62	-\$0.75	-\$0.66	-\$0.52
Net Cost (\$/gal)	\$2.57	\$4.63	\$4.26	\$5.69	\$5.09	\$4.81	\$6.19
Volume (mil gal)	61,722	19	86	633	617	1,122	0
Total Fuel Cost (\$bil)	\$158.6	\$0.1	\$0.4	\$3.6	\$3.1	\$5.4	\$0.0
Total Cost (\$/gal)	\$2.67						

Table 10.5.3-4: Total Diesel Costs – 2027 (No RFS Baseline)

	Diesel	Biodiesel			Renewable Diesel		
		Corn Oil	FOG	Soybean/Canola Oil	Corn Oil	FOG	Soybean/Canola Oil
Cost to Produce (\$/gal)	\$2.55	\$5.56	\$5.18	\$6.46	\$5.83	\$5.45	\$6.74
Tax Credit (\$/gal)	\$0.00	-\$0.80	-\$0.80	-\$0.62	-\$0.75	-\$0.66	-\$0.52
Net Cost (\$/gal)	\$2.55	\$4.76	\$4.38	\$5.84	\$5.08	\$4.79	\$6.22
Volume (mil gal)	61,083	86	317	334	550	983	0
Total Fuel Cost (\$bil)	\$155.8	\$0.4	\$1.4	\$2.0	\$2.8	\$4.7	\$0.0
Total Cost (\$/gal)	\$2.64						

For the 2025 Baseline, we used the same approach described above for the No RFS Baseline.⁸⁰⁶ As shown in Tables 10.5.3-5 and 6, we estimate that the average diesel cost under the 2025 Baseline ranges from \$2.78 to \$2.80 per gallon.

Table 10.5.3-5: Total Diesel Costs – 2026 (2025 Baseline)

	Diesel	Biodiesel			Renewable Diesel		
		Corn Oil	FOG	Soybean/Canola Oil	Corn Oil	FOG	Soybean/Canola Oil
Cost to Produce (\$/gal)	\$2.57	\$5.43	\$5.06	\$6.31	\$5.84	\$5.47	\$6.71
RIN Cost (\$/gal)	\$0.16	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
RIN Value (\$/gal)	\$0.00	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43
Tax Credit (\$/gal)	\$0.00	-\$0.80	-\$0.80	-\$0.62	-\$0.75	-\$0.66	-\$0.52
Net Cost (\$/gal)	\$2.73	\$3.20	\$2.83	\$4.26	\$3.66	\$3.38	\$4.76
Volume (mil gal)	57,695	44	154	904	417	1,529	730
Total Blend Cost (\$bil)	\$157.5	\$0.1	\$0.4	\$3.8	\$1.5	\$5.2	\$3.5
Average Cost (\$/gal)	\$2.80						

⁸⁰⁶ 2025 Baseline biodiesel and renewable diesel volumes from Table 2.2-2. For purposes of the 2025 Baseline analysis, we assumed that total diesel energy demand was held constant relative to the Analyzed Volumes to calculate petroleum diesel fuel volumes.

Table 10.5.3-6: Total Diesel Costs – 2027 (2025 Baseline)

	Diesel	Biodiesel			Renewable Diesel		
		Corn Oil	FOG	Soybean/Canola Oil	Corn Oil	FOG	Soybean/Canola Oil
Cost to Produce (\$/gal)	\$2.55	\$5.56	\$5.18	\$6.46	\$5.83	\$5.45	\$6.74
RIN Cost (\$/gal)	\$0.16	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
RIN Value (\$/gal)	\$0.00	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43	-\$1.43
Tax Credit (\$/gal)	\$0.00	-\$0.80	-\$0.80	-\$0.62	-\$0.75	-\$0.66	-\$0.52
Net Cost (\$/gal)	\$2.71	\$3.33	\$2.95	\$4.41	\$3.65	\$3.36	\$4.79
Volume (mil gal)	57,695	44	154	904	417	1,529	730
Total Blend Cost (\$bil)	\$156.4	\$0.1	\$0.5	\$4.0	\$1.5	\$5.1	\$3.5
Average Cost (\$/gal)	\$2.78						

Finally, we calculated the fuel price impacts on diesel for each year by subtracting the average diesel cost for each baseline from the average diesel cost for the Analyzed Volumes. As shown in Table 10.5.3-7, we estimate that the fuel price impact on diesel under the No RFS Baseline ranges from 19.5¢ to 22.3¢ per gallon. As shown in Table 10.5.3-8, we estimate that the fuel price impact on diesel under the 2025 Baseline ranges from 6.2¢ to 7.6¢ per gallon.

Table 10.5.3-7: Total Diesel Fuel Price Impacts (No RFS Baseline)

	2026	2027
Average Cost (No RFS Baseline) (\$/gal)	\$2.67	\$2.64
Average Cost (Analyzed Volumes) (\$/gal)	\$2.86	\$2.86
Fuel Price Impact (¢/gal)	19.5¢	22.3¢

Table 10.5.3-8: Total Diesel Fuel Price Impacts (2025 Baseline)

	2026	2027
Average Cost (2025 Baseline) (\$/gal)	\$2.80	\$2.78
Average Cost (Analyzed Volumes) (\$/gal)	\$2.86	\$2.86
Fuel Price Impact (¢/gal)	6.2¢	7.6¢

10.5.4 Fuel Price Impacts of the SRE Reallocation Volumes

As discussed in Preamble Section IV.B, we have concluded that the SRE reallocation volumes will generally have no impact on the statutory factors because we project that the SRE reallocation volumes will be met with carryover RINs. The one statutory factor that we do project will be impacted by the SRE reallocation volumes is the impact on the cost to consumers of transportation fuel and the cost to transport goods. The SRE reallocation volumes will result in higher percentage standards for obligated parties than would otherwise be the case, which in turn require obligated parties to acquire greater quantities of RINs to retire for compliance. We project that, in aggregate, obligated parties will acquire these additional RINs by purchasing carryover RINs from other parties (or alternatively using RINs that would have been retired for compliance but for the 2023–2025 SREs) rather than blending additional quantities of renewable fuel. We further project that obligated parties will pass on the costs of purchasing additional

RINs to consumers, and that the SRE reallocation volumes could therefore increase the cost of transportation fuel to consumers.

In Chapters 10.5.2 and 10.5.3 we present estimates of the price impacts on gasoline and diesel fuel from this rule. These estimates include the price impacts of the SRE reallocation volumes. This is because the estimates of the fuel price impacts use the total percentage standards for 2026 and 2027, which are a function of both the renewable fuel volume requirements and the SRE reallocation volumes. To estimate the impact of the SRE reallocation volumes on fuel price impacts, we must first estimate the impact of the SRE reallocation volumes on the percentage standards for each category of renewable fuel. We did this by calculating what the percentage standards would have been absent SRE reallocation volumes and then taking the difference between the percentage standards with and without the SRE reallocation volumes.⁸⁰⁷ We then multiplied this difference (*i.e.*, the portion of the percentage standards due to SRE reallocation volumes) by the average RIN prices in Table 10.5.1-1. These numbers are summarized in Table 10.5.4-1.

Table 10.5.4-1: Estimated Fuel Price Impacts of the SRE Reallocation Volumes

RFS Standard	RIN Type	RIN Price	SRE Reallocation Percentage		Price Impact	
			2026	2027	2026	2027
Cellulosic Biofuel	D3/D7	\$2.40	0.00%	0.00%	0.0¢	0.0¢
BBD	D4	\$0.95	0.12%	0.14%	0.1¢	0.1¢
Other Advanced Biofuel	D5	\$0.99	0.05%	0.06%	0.0¢	0.1¢
Conventional Renewable Fuel	D6	\$0.91	0.41%	0.41%	0.4¢	0.4¢
Total Renewable Fuel		N/A	N/A	N/A	0.5¢	0.6¢

Note: There is no SRE reallocation volume for cellulosic biofuel as discussed in Preamble Section IV.B.

We recognize that there is a fair amount of uncertainty regarding our estimates of the fuel price impacts of the SRE reallocation volume. In calculating these impacts, we have used the average RIN prices over the past 12 months for which data were available to project RIN prices in 2026 and 2027. Higher or lower RIN prices in these years would directly result in higher or lower estimates of the fuel price impacts of the SRE reallocation volumes respectively. Further, as discussed in Preamble Section IV.B, we project that the entire SRE reallocation volume will be met with carryover RINs attributable to the 2023–2025 exemptions. The cost of these RINs to obligated parties is arguably zero in 2026 and 2027 as the cost of acquiring these RINs was realized in 2023–2025. In the Set 1 Rule, we projected that no SREs would be granted in 2023–2025, and therefore the cost and fuel price estimates for the Set 1 Rule included the cost of acquiring the RINs that we project will be used to meet the compliance obligations associated with the SRE reallocation volumes in this rule. The fuel price impacts we have projected in this chapter are thus something of a high-end estimate where we project that the full cost of acquiring the RINs needed for compliance with the SRE reallocation volume is passed through to consumers despite this cost being realized in previous years.

⁸⁰⁷ See “Calculation of 2026 and 2027 RFS Percentage Standards Without SRE Reallocation Volumes,” available in the docket for this action.

10.5.5 Cost to Transport Goods

In this chapter, we consider the impact of the use of renewable fuels on the cost to transport goods. Since most goods being transported utilize diesel fuel powered trucks (as opposed to gasoline or natural gas vehicles), we focus on the impacts on diesel fuel prices. Reviewing the price estimates in Table 10.5.3-7, the projected price increase for diesel fuel relative to the No RFS Baseline ranged from 19.5¢ per gallon in 2026 to 22.3¢ per gallon in 2027. As a worst-case scenario, we will use the projected diesel fuel price increase of 22¢ per gallon for estimating the impact on the cost to transport goods.

The impact of fuel price increases on the price of goods is based upon a study conducted by USDA. USDA analyzed the impact of fuel prices on the wholesale price of produce from 2000 to 2009 when fuel prices ramped up from an average of \$30/bbl to over \$90/bbl.⁸⁰⁸ Their study found that a 100% increase in fuel prices resulted in a 25% increase in produce prices. Assuming a baseline diesel fuel retail price of \$2.79/gal in 2026 as summarized in Table 10.2.2.1-2 and adding 60¢ per gallon state and federal taxes to it, the projected 22¢ per gallon increase in diesel fuel price in 2027 amounts to a 6% increase in diesel fuel prices. Applying the 25% ratio from the USDA study would indicate that the Analyzed Volumes for 2026 incremental to the No RFS Baseline would then increase the wholesale price of produce by about 1.5%. If produce being transported by a diesel truck costs \$3 per pound, the increase in that products' price due to the projected impact of the candidate volumes would be \$0.045 per pound.⁸⁰⁹ Transport of food by other means such as rail or barge would be expected to impact food prices less than transport by truck since rail and barge transport are both more efficient and fuel costs would likely have a lower impact those modes of transportation costs. This estimate of the impact on food prices is only an order of magnitude type estimate since impacts on food prices vary greatly depending on the distance that the particular food travels by truck.

Relative to the 2025 Baseline, the impact of the Analyzed Volumes is expected to cause a smaller increase in diesel fuel prices, thus causing a smaller increase in the cost to transport goods. Also, our food transport cost analysis assumes that all the BBD costs are amortized over the diesel fuel pool. If refiners amortize the BBD costs over both gasoline and diesel fuel, the cost impact of transporting goods would be lower.

10.6 Comparison of Societal Benefits and Costs

In this section, we summarize the projected societal benefits and costs of the Analyzed Volumes (see Table 10.6-1). This section only considers impacts of the rule that are characterized as societal benefits or costs. Thus, for example, the projected rural economic development impacts are not considered in this section, as many of these impacts represent transfers (*e.g.*, higher food prices paid by consumers to agricultural producers). The economic impact methodologies used in Chapter 9 do not identify incremental societal benefits and costs, so the results are not suitable for a societal benefit-cost comparison. Certain incremental benefits and costs are discussed qualitatively in other chapters but not monetized, so they are not

⁸⁰⁸ USDA, "How Transportation Costs Affect Fresh Fruit and Vegetable Prices," *Economic Research Report* 160, November 2013. https://ers.usda.gov/sites/default/files/laserfiche/publications/45165/41077_err160.pdf.

⁸⁰⁹ Coupons.com, "Comparing Prices on Groceries," May 4, 2021.

presented here. For a full discussion of the impacts of each of these scenarios, including impacts that are not considered societal benefits or costs, see the relevant chapters of this document. In this comparison we have only considered the primary cost projections. Other cost scenarios can be found in Chapter 10.4. The present value of the benefits, costs, and net benefits represent the values in 2026.

Table 10.6-1: Net Benefits of the Analyzed Volumes in 2026 and 2027 (million 2024\$)

Type	Category	2026	2027	Present Value	Annualized Value
Societal Benefits	Energy Security Benefits	\$361	\$438	\$786	\$411
Societal Costs	Fuel Costs	\$18,241	\$21,244	\$38,866	\$20,312
Net Benefits	Total	-\$17,880	-\$20,806	-\$38,080	-\$19,901

Note: Present and annualized values are estimated using a 3% discount rate. Computing annualized costs and benefits from present values spreads the costs and benefits equally over each period, taking account of the discount rate. The annualized value equals the present value divided by the sum of discount factors. For a calculation of present and annualized values from annual impact estimates, see “Set 2 FRM Costs and Benefits Summary,” available in the docket for this action.

Chapter 11: Regulatory Flexibility Act Screening Analysis

This chapter discusses EPA’s screening analysis evaluating the potential impacts of the 2026 and 2027 RFS standards on small entities. The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (referred to as a “No SISNOSE finding”). Pursuant to this requirement, EPA has prepared a screening analysis for this rule.

11.1 Summary

We conducted the screening analyses by looking at the potential impacts on small entities using two different methods and compared the cost-to-sales ratio for each method to a threshold of 1%.⁸¹⁰ For our first method, we compared obligated parties’ cost of compliance (whether they acquire RINs by purchasing renewable fuels with attached RINs and blending these fuels into transportation fuel or by purchasing separated RINs) with the ability for the obligated parties to recover these compliance costs through higher prices for the gasoline and diesel they sell with what would be expected in the absence of the RFS program. Based on our analysis of the data, we have determined that all obligated parties—including small refiners—fully recover the costs of RFS compliance through higher sales prices on gasoline and diesel.⁸¹¹

For our second method, we estimated the cost-to-sales ratios for each small refiner that is an obligated party under the RFS program using refinery-specific data under the worst-case assumption that they could not recover RIN costs. While as noted above we have determined that small refiners fully recover their RIN costs, we have nevertheless included this hypothetical scenario in this analysis to respond to prior concerns from small refiners that they could not recover their RIN costs. Moreover, this method seems more relevant to addressing small refiner-specific concerns. This method emphasizes that even erroneously assuming no RIN cost recovery by small refiners as suggested by some parties, a No SISNOSE finding would still be appropriate.

As shown in Table 11.1-1, both methods result in a cost-to-sales ratio of less than 1%. Therefore, EPA finds that these standards would not have a significant economic impact on a substantial number of small entities.

⁸¹⁰ A cost-to-sales ratio of 1% represents a typical agency threshold for determining the significance of the economic impact on small entities. EPA, “Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act,” November 2006.
<https://www.epa.gov/sites/default/files/2015-06/documents/guidance-regflexact.pdf>.

⁸¹¹ For a further discussion of the ability of obligated parties to recover the cost of RINs, see EPA, “Denial of Petitions for Rulemaking to Change the RFS Point of Obligation,” EPA-420-R-17-008, November 2017.
<https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockkey=P100TBGV.pdf>.

Table 11.1-1: Estimated Cost-to-Sales Ratios of the 2026 and 2027 RFS Standards

Method	Screening Analysis	Cost-to-Sales Ratio	
		2026	2027
1	Cost as Part of RFS2 Rule	N/A	
2	Market Cost Recovery	0.00%	
3	Full RIN Price as Cost for Small Refiners	0.11–0.86%	0.12–0.98%

11.2 Background

11.2.1 Overview of the Regulatory Flexibility Act (RFA)

The RFA was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect those entities. The RFA requires EPA to carefully consider the economic impacts that its rules may have on small entities. The elements of the initial regulatory flexibility analysis accompanying a proposed rule are set forth in 5 U.S.C. § 603, while those of the final regulatory flexibility analysis accompanying a final rule are set forth in section 604. However, section 605(b) of the statute provides that EPA need not conduct the section 603 or 604 analyses if we certify that the rule will not have a significant economic impact on a substantial number of small entities.

11.2.2 Need for the Rulemaking and Rulemaking Objectives

A discussion on the need for and objectives of this action is located in Preamble Section I. CAA section 211(o) requires EPA to promulgate regulations implementing the RFS program, and to establish annual renewable fuel standards that are used by obligated parties to determine their individual RVOs.

11.2.3 Definition and Description of Small Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of a rule on small entities, a small entity is defined as: (1) a small business according to the Small Business Administration’s (SBA) size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

Small businesses (as well as large businesses) would be regulated by this rule, but not small governmental jurisdictions or small organizations as described above. As set by SBA, the categories of small entities that would potentially be directly affected by this rulemaking are described in Table 11.2.3-1. Other entities may be indirectly affected by this rulemaking but are not considered in this screening analysis.⁸¹²

⁸¹² For example, small farms might benefit (see Chapter 9.1.6) whereas small entities in other industries might be adversely affected by commodity and food price increases (see Chapters 9.3 and 9.4) or the increased price to transport goods (see Chapter 10.5.5).

Table 11.2.3-1: Small Business Definitions

Industry	Defined as small entity by SBA if less than or equal to:	NAICS^a code
Gasoline and diesel refiners	1,500 employees ^b	324110

^a North American Industrial Classification System.

^b Under the RFS program, EPA has included a provision that, in order to qualify for small refiner flexibilities, a refiner must also produce no greater than 155,000 barrels per calendar day (bpcd) crude capacity. See 40 CFR 80.1442(a).

EPA used the criteria for small entities developed by SBA under the North American Industry Classification System (NAICS) as a guide. Information about the characteristics of refiners comes from sources including EIA, oil industry literature, and previous rules that have affected the refining industry. In addition, EPA found employment information for companies meeting the SBA definition of “small entity” using publicly available information and the business information database Hoover’s Inc. (a subsidiary of Dun & Bradstreet). These refiners fall under the Petroleum Refineries category, 324110, as defined by NAICS.

Small entities that would be subject to this rulemaking include domestic refiners that produce gasoline and/or diesel. Based on 2025 EIA refinery data,⁸¹³ EPA believes that there are approximately 30 refiners of gasoline and diesel subject to the RFS regulations. Of these, EPA believes that there are currently 6 refiners (owning 7 refineries) producing gasoline and/or diesel that meet the small entity definition of having 1,500 employees or fewer.

Table 11.2.3-2: Small Refiners

Refiner	Refinery Locations	Parent Company	Employees
American Refining Group	Bradford, PA	American Refining Group, Inc.	310
CountryMark	Mount Vernon, IN	CountryMark Cooperative Holding Corp	425
Kern Energy	Bakersfield, CA	Casey Co.	129
Placid Oil	Port Allen, LA	The William Herbert Hunt Trust Estate	251
San Joaquin Refining	Bakersfield, CA	San Joaquin Refining Co., LLC	130
Silver Eagle Refining	Evanston, WY Woods Cross, UT	The International Group, Inc.	100

11.2.4 Reporting, Recordkeeping, and Other Compliance Requirements

Registration, reporting, and recordkeeping are necessary to track compliance with the RFS standards and transactions involving RINs. However, these requirements are already in place under the existing RFS regulations.⁸¹⁴ While EPA is making revisions to the RFS

⁸¹³ EIA, “Refinery Capacity Report 2025,” *Petroleum & Other Liquids*, January 1, 2025.

<https://www.eia.gov/petroleum/refinerycapacity/archive/2025/refcap2025.php>.

⁸¹⁴ Prior to issuing our 2009 proposal for the general RFS regulatory program regulations required to implement the amendments enacted pursuant to EISA, we analyzed the potential impacts on small entities of implementing the full RFS program through 2022 and convened a Small Business Advocacy Review Panel (SBAR Panel) to assist us in this evaluation. This information is located in the RFS2 Rule docket (Docket ID No. EPA-HQ-OAR-2005-0161).

requirements in this action, we do not anticipate that there will be any significant cost on directly regulated small entities.

11.3 Screening Analysis Approaches

This section concerns EPA's screening analyses performed for the 2026 and 2027 RFS standards. For the purposes of this screening analysis, we estimated the costs of the 2026 and 2027 RFS standards relative to a "baseline" of the 2025 RFS standards (*i.e.*, the percentage standards established in the Set 1 Rule for 2025).

We considered two different methods for estimating the cost of the 2026 and 2027 RFS standards to obligated parties using the baseline of the 2025 RFS standards. If, as has been demonstrated, obligated parties recover the costs of RFS compliance through higher prices in the marketplace for the petroleum products they sell, there is no net cost to obligated parties. However, because various parties, including several small refiners, have continued to claim that they are not able to recover the cost of RFS compliance in the marketplace, we also estimated the cost-to-sales ratios for each of the 6 small refiners that are obligated parties under the RFS program using refinery-specific data under the assumption that they could not recover RIN costs.

11.3.1 Method 1: Market Cost Recover Method

One way, and we believe the most appropriate way, to consider the impacts of the 2026 and 2027 RFS standards on obligated parties is to compare their cost of compliance with the ability of the obligated parties to recover these compliance costs through the higher prices for the gasoline and diesel they sell that result from the market-wide impact of the RFS program. EPA has determined that while there is a cost to all obligated parties to acquire RINs (including small refiners), obligated parties recover that cost through the higher sales prices they receive for the gasoline and diesel they sell due to the market-wide impact of the RFS standards on these products.⁸¹⁵ EPA has examined available market data and concluded that the costs of compliance with the RFS program are being passed downstream, as current wholesale gasoline and diesel prices enable obligated parties to recover the cost of the RINs.⁸¹⁶ When viewed in light of this data, there is no net cost of compliance with the RFS standards (cost of compliance with the RFS standards minus the increased revenue due to higher gasoline and diesel prices that result from implementing the RFS program) to obligated parties, including small refiners. This is true whether obligated parties acquire RINs by purchasing renewable fuels with attached RINs or by purchasing separated RINs.

11.3.2 Method 2: Full RIN Price as Cost for Small Refiners Method

For our extreme hypothetical case, we estimated the actual change in the total cost of the 2026 and 2027 RFS standards to the 6 obligated parties that are small refiners if they acquired the RINs necessary for compliance by purchasing separated RINs. We note, however, that in

⁸¹⁵ For a further discussion of the ability of obligated parties to recover the cost of RINs, see EPA, "Denial of Petitions for Rulemaking to Change the RFS Point of Obligation," EPA-420-R-17-008, November 2017. <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100TBGV.pdf>.

⁸¹⁶ *Id.*

doing so we ignored the fact that these parties recover the cost of the RINs they purchase through the higher market-wide prices they receive for the petroleum-based gasoline and diesel that they sell, as discussed in Method 1. This approach would then reflect the cost they would have to pay for compliance at the end of the year if they had spent the added revenue received from the higher gasoline and diesel prices for other purposes.

Furthermore, we have also assumed that these parties would actually have to comply with the 2026 and 2027 RFS standards. As described in Preamble Section V.C, the 2026 and 2027 percentage standards project that some small refineries—including those owned by the 6 obligated parties that are small refiners—receive an SRE and would not have to comply with the 2026 and 2027 RFS standards. Thus, this estimate represents a worst-case scenario for these parties in which EPA establishes higher percentage standards based on a projection that some small refineries will receive an exemption, but they do not receive an exemption and have to comply with their 2026 and 2027 RFS obligations.

Because RIN prices can be impacted by a wide variety of different factors (including the prices of renewable fuels and petroleum-based fuels, oil prices, commodity prices, etc.), EPA is not able to project what RIN prices will be in the future. We can, however, use the average RIN prices over the last 12 months (through December 2025) as an estimate of future RIN prices, as shown in Table 11.3.2-1.

Table 11.3.3-1: Average RIN Prices and RFS Standards for 2026 and 2027

RFS Standard	RIN Type	Avg RIN Price (Jan. 2025 – Dec. 2025)	2025 RFS Standard	2026		2027	
				Standard	Δ ^a	Standard	Δ ^a
Cellulosic Biofuel	D3	\$2.40	0.71% ^d	0.79%	0.08%	0.84%	0.13%
Biomass-Based Diesel	D4	\$0.95	3.15%	5.24%	2.09%	5.37%	2.22%
Other Advanced Biofuel ^b	D5	\$0.99	0.42%	0.39%	-0.03%	0.40%	-0.02%
Conventional Renewable Fuel ^c	D6	\$0.91	8.82%	9.07%	0.25%	9.17%	0.35%

^a Δ represents the change relative to the baseline of the 2025 RFS standards.

^b Other advanced biofuel is not an RFS standard category but is calculated by subtracting the cellulosic biofuel and biomass-based diesel standards from the advanced biofuel standard.

^c Conventional renewable fuel is not an RFS standard category but is calculated by subtracting the advanced biofuel standard from the total renewable fuel standard.

^d Reflects the partial waiver of the 2025 cellulosic biofuel standard.

Using 2024 compliance data and SRE petition materials where available, and assuming that the total gasoline and diesel production for each of these small refiners remains unchanged, we estimated their RVOs for 2026 and 2027. The difference between the estimated RVOs for each year multiplied by the estimated RIN price for each standard then gives us the estimated cost of the 2026 and 2027 RFS standards for each small refiner that chooses to meet their obligations by purchasing separated RINs. The actual calculations for each small refiner are provided in Chapter 11.6; a non-CBI example of these calculations is shown in Tables 11.3.3-2 and 3.

Table 11.3.3-2: Example Small Refiner Costs Calculation for 2026

Refiner	2024 Gas/Diesel Prod (mil gal)	Cellulosic (D3)		BBD (D4)		Other Advanced Biofuel (D5)		Conventional Renewable Fuel (D6)		Total Cost (\$mil)
		Δ (mil RINs)	Cost (\$mil)	Δ (mil RINs)	Cost (\$mil)	Δ (mil RINs)	Cost (\$mil)	Δ (mil RINs)	Cost (\$mil)	
Example	250	0.20	\$0.48	5.23	\$4.96	-0.15	-\$0.15	0.65	\$0.59	\$5.89

Table 11.3.3-3: Example Small Refiner Costs Calculation for 2027

Refiner	2024 Gas/Diesel Prod (mil gal)	Cellulosic (D3)		BBD (D4)		Other Advanced Biofuel (D5)		Conventional Renewable Fuel (D6)		Total Cost (\$mil)
		Δ (mil RINs)	Cost (\$mil)	Δ (mil RINs)	Cost (\$mil)	Δ (mil RINs)	Cost (\$mil)	Δ (mil RINs)	Cost (\$mil)	
Example	250	0.33	\$0.78	5.55	\$5.27	-0.12	-\$0.12	0.87	\$0.80	\$6.73

11.4 Cost-to-Sales Ratio Result

The final step in our methodology is to compare the total estimated costs from each of the methods above to relevant total estimated revenue from the sales of gasoline and diesel in the U.S. in 2026 and 2027. Since the RFS standards are proportional to the volume of gasoline and diesel produced by each obligated party, all obligated parties (including small refiners) are expected to experience costs (and recover those costs) to comply with the RFS standards that are proportional to their sales volumes.

For Method 1, all obligated parties—including small refiners—recover their RFS compliance costs and thus they have no net cost of compliance. For Method 2, we divided the estimated costs for each small refiner by its total estimated annual sales.⁸¹⁷ The resulting cost-to-sales ratios for each method are shown in Table 11.4-1, along with a non-CBI example of these calculations for Method 2 using the data from Tables 11.3.3-2 through 4.

Table 11.4-1: Estimated Cost-to-Sales Ratios of the 2026 and 2027 RFS Standards

Method	Screening Analysis	Total Cost (\$mil)		Total Sale (\$mil)		Cost-to-Sales Ratio	
		2026	2027	2026	2027	2026	2027
1	Market Cost Recovery	\$0		n/a		0.0%	
2	Full RIN Price as Cost for Small Refiners (Actual) ^a	--		--		0.11–0.86%	0.12–0.98%
	Full RIN Price as Cost for Small Refiners (Example)	\$5.89	\$6.73	\$1,000	\$1,000	0.59%	0.67%

^a The actual calculations for Method 2 for each small refiner are provided in Chapter 11.6.

11.5 Conclusion

Based on our outreach, fact-finding, and analysis of the potential impacts of this rule on small businesses, we have concluded that this rule would not have a significant economic impact

⁸¹⁷ Estimated 2024 sales data gathered from SRE petitions and Hoovers, Inc. (available at <https://app.dnbhoovers.com>).

on a substantial number of small entities. As described in Method 1, since obligated parties have been shown to recover their RFS compliance costs through the resulting higher market prices for their petroleum products, there is no net cost to small refiners resulting from the RFS program.

However, as described in Method 2, we also conducted a worst-case sensitivity analysis that ignored the fact that obligated parties recover their costs. Under this extreme assumption, we were able to estimate the costs of this rule on small refiners and then use a cost-to-sales ratio test (a ratio of the estimated annualized compliance costs to the value of sales per company) to assess whether the costs were significant. Under this method, the cost-to-sales analyses indicated that the 6 small refiners would be affected at less than 1% of their sales (*i.e.*, the estimated costs of compliance with the rule would be less than 1% of their sales). The cost-to-sales percentages estimated using Method 2 ranged from 0.10% to 0.98%.

11.6 Small Refiner CBI Data

[Information Redacted – Claimed as CBI]