ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 80 and 1090

[EPA–HQ–OAR–2024–0505; FRL–11947–01–OAR]

RIN 2060–AW23

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: Under the Clean Air Act (CAA), the Environmental Protection Agency (EPA) is required to determine the applicable volume requirements for the Renewable Fuel Standard (RFS) for years after those specified in the statute. EPA is proposing the applicable volumes and percentage standards for 2026 and 2027 for cellulosic biofuel, biomass-based diesel (BBD), advanced biofuel, and total renewable fuel. EPA is also proposing to partially waive the 2025 cellulosic biofuel volume requirement and revise the associated percentage standard due to a shortfall in cellulosic biofuel production. Finally, EPA is proposing several regulatory changes to the RFS program, including reducing the number of Renewable Identification Numbers (RINs) generated for imported renewable fuel and renewable fuel produced from foreign feedstocks and removing renewable electricity as a qualifying renewable fuel under the RFS program (eRINs).

DATES:

Comments. Comments must be received on or before August 8, 2025.

Public Hearing. EPA will announce information regarding the public hearing for this proposal in supplemental **Federal Register** document.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2024–0505, at *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from the docket. EPA may publish any comment received to its public docket. Do not submit to EPA's docket at *https://www.regulations.gov* any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). Please visit *https://www.epa.gov/dockets/commenting-epa-dockets* for additional submission methods; the full EPA public comment policy; information about CBI or multimedia submissions; and general guidance on making effective comments.

EPA is specifically soliciting comment on numerous aspects of the proposed rule. To facilitate comment on those portions of the rule, EPA has indexed each comment solicitation with a unique identifier (*e.g.,* ''A–1'', ''A–2'', ''B–1'' . . .) to provide a consistent framework for effective and efficient provision of comments. Accordingly, we ask that commenters include the corresponding identifier when providing comments relevant to that comment solicitation. We ask that commenters include the identifier either in a heading or within the text of each comment, to make clear which comment solicitation is being addressed. We emphasize that we are not limiting comment to these identified areas and encourage submission of any other comments relevant to this proposed action.

FOR FURTHER INFORMATION CONTACT: Dallas Burkholder, Assessment and Standards Division, Office of Transportation and Air Quality, Environmental Protection Agency, 2000 Traverwood Drive, Ann Arbor, MI 48105; telephone number: 734–214–4766; email address: *RFS-Rulemakings@epa.gov.*

SUPPLEMENTARY INFORMATION:

Does this action apply to me?

Entities potentially affected by this action are those involved with the production, distribution, and sale of transportation fuels (*e.g.,* gasoline and diesel fuel) and renewable fuels (*e.g.,* ethanol, biodiesel, renewable diesel, and biogas). Potentially affected categories include:

Category	NAICS [a] codes	Examples of potentially affected entities
Industry	111110	Soybean farming.
Industry	111150	Corn farming.
Industry	112111	Cattle farming or ranching.
Industry	112210	Swine, hog, and pig farming.
Industry	211130	Natural gas liquids extraction and fractionation.
Industry	221210	Natural gas production and distribution.
Industry	324110	Petroleum refineries (including importers).
Industry	325120	Biogases, industrial (*i.e.,* compressed, liquified, solid), manufacturing.
Industry	325193	Ethyl alcohol manufacturing.
Industry	325199	Other basic organic chemical manufacturing.
Industry	424690	Chemical and allied products merchant wholesalers.
Industry	424710	Petroleum bulk stations and terminals.
Industry	424720	Petroleum and petroleum products wholesalers.
Industry	457210	Fuel dealers.
Industry	562212	Landfills.

[a] North American Industry Classification System (NAICS).

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities potentially affected by this action. This table lists the types of entities that EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be affected. To determine whether your entity would be affected by this action, you should carefully examine the applicability criteria in 40 CFR part 80. If you have any questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section.

Preamble Acronyms and Abbreviations

Throughout this document the use of "we," "us," or "our" is intended to refer to EPA. We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, EPA defines the following terms and acronyms here:

AEO Annual Energy Outlook
AFDC Alternative Fuels Data Center
ATJ alcohol-to-jet
BBD biomass-based diesel
CAA Clean Air Act
CARB California Air Resources Board
CKF corn kernel fiber
CNG compressed natural gas
CWC cellulosic waiver credit
DOE Department of Energy
DRIA Draft Regulatory Impact Analysis
EIA Energy Information Administration
EMTS EPA Moderated Transaction System
EU European Union
FOG fats, oils, and greases
GHG greenhouse gas
LCFS Low Carbon Fuel Standard
LNG liquified natural gas
MSW municipal solid waste
OPEC Organization of Petroleum Exporting Countries
RFS Renewable Fuel Standard
RIN Renewable Identification Number
RNG renewable natural gas
RVO Renewable Volume Obligation
STP standard temperature and pressure
UCO used cooking oil
USDA United States Department of Agriculture
WTI West Texas Intermediate

Outline of This Preamble

I. Executive Summary

EPA initiated the RFS program in 2006 pursuant to the requirements of the Energy Policy Act of 2005 (EPAct), which were codified in CAA section 211(o). Congress subsequently amended the statutory requirements in the Energy Independence and Security Act of 2007 (EISA). The statute sets forth annual, nationally applicable volume targets for three of the four categories of renewable fuel (cellulosic biofuel, advanced biofuel, and total renewable fuel) through 2022 and for BBD through 2012. For subsequent calendar years, CAA section 211(o)(2)(B)(ii) directs EPA to determine the applicable volume targets for each of the four categories of renewable fuel in coordination with the Secretary of Energy and the Secretary of Agriculture, based on a review of the implementation of the RFS program for prior years and an analysis of specified statutory factors.

In this action, EPA is proposing the volume targets and applicable percentage standards for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel for 2026 and 2027.[1] We are also proposing a number of regulatory changes, including reducing the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks and removing renewable electricity as a qualifying renewable fuel under the RFS program (commonly referred to as eRINs). This preamble describes our rationale for the proposed volume requirements and regulatory changes and requests comment on the proposals and supporting rationales, including on EPA's proposed changes to the RFS program and any legitimate reliance interests that EPA should consider during this rulemaking.

The volume requirements and regulatory changes proposed in this action would strengthen the RFS program and sharpen the program's focus on a central goal of the policy: supporting domestic production of renewable fuels. Ensuring a growing

[1] EPA previously established volume requirements and applicable percentage standards for 2023–2025 on July 12, 2023 (88 FR 44468) (the "Set 1 Rule").

supply of domestically produced renewable fuels, particularly those produced from domestically sourced feedstocks, is a key component in meeting the statutory goals of increasing the energy independence and security of the United States. Increasing domestic production of renewable fuel also contributes to unleashing American energy production towards the goal of achieving energy dominance, consistent with the Administration's ''Unleashing American Energy'' Executive Order [2] and the energy dominance pillar of EPA's ''Powering the Great American Comeback'' initiative.[3] The proposed modifications and requirements in this action are responsive to input from key agricultural and energy stakeholders on ways to bolster the RFS program, and EPA looks forward to engaging with these and additional interested stakeholders on the proposed changes.

A. Summary of the Key Provisions of This Action

1. Volume Requirements for 2026 and 2027

Based on our analysis of the factors required in the statute, and in coordination with the United States Department of Agriculture (USDA) and Department of Energy (DOE), EPA is proposing the volume requirements for 2026 and 2027, as shown in Table I.A.1–1. The proposed volumes represent significant increases from those established for 2023–2025, especially after accounting for the proposal to reduce the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks.

TABLE I.A.1–1—VOLUME REQUIREMENTS FOR 2023–2027

[Billion RINs] [a]

	Volume requirement established in Set 1 Rule			Proposed volume requirement	
	2023	2024	2025	2026	2027
Cellulosic biofuel	0.84	[b] 1.01	[c] 1.19	1.30	1.36
Biomass-based diesel [d]	4.51	4.86	5.36	7.12	7.50
Advanced biofuel	5.94	6.54	7.33	9.02	9.46
Total renewable fuel	[e] 20.94	21.54	22.33	24.02	24.46

[a] One RIN is equivalent to one ethanol-equivalent gallon of renewable fuel. Throughout this preamble, RINs are generally used to describe total volumes in each of the four renewable fuel categories, while gallons are generally used to describe volumes for individual types of biofuel (*e.g.,* ethanol, biodiesel, renewable diesel, etc.).

[b] EPA originally established a cellulosic biofuel volume requirement of 1.09 billion gallons for 2024 in the Set 1 Rule. EPA subsequently reduced this volume requirement to 1.01 billon RINs in a separate action.

[c] EPA originally established a cellulosic biofuel volume requirement of 1.38 billion gallons for 2025 in the Set 1 Rule. As described in Section VII, we are proposing to reduce this volume requirement to 1.19 billion RINs in this action.

[d] Through 2025, the BBD volume requirement was established in physical gallons rather than RINs. As described in Section X.C, we are proposing to now specify the BBD volume requirement in RINs, consistent with the other three renewable fuel categories, rather than physical gallons. For the sake of comparison, we have converted the BBD volume requirements for 2023–2025 from physical gallons to RINs using the BBD conversion factor in 40 CFR 80.1405(c) of 1.6 RINs per gallon.

[e] The total renewable fuel volume requirement for 2023 does not include the 0.25 billion RIN supplemental standard.

In this action, we are proposing to specify the BBD volume requirement in billion RINs, rather than billion gallons as in previous RFS rules. To demonstrate the impact of this change, and to allow for easier comparison to previous RFS rules, the BBD volume requirements (in billion RINs) and the volume of BBD (in billion gallons) we project would be supplied to satisfy the volume requirements are shown in Table I.A.1–2. Finally, the quantities of renewable fuel we project would be supplied to satisfy the volume requirements, after accounting for the nested nature of the RFS volume requirements and the proposed import RIN reduction provisions, are shown in Table I.A.1–3.

TABLE I.A.1–2—BBD VOLUME REQUIREMENTS FOR 2023–2027

	Volume requirement established in the Set 1 Rule			Projected volume requirement	
	2023	2024	2025	2026	2027
BBD volume requirement (billion RINs)	[a] 4.51	[a] 4.86	[a] 5.36	7.12	7.50
Projected volume of BBD (billion gallons)	2.82	3.04	3.35	[b] 5.61	[b] 5.86

[a] Billion RINs estimated assuming the average gallon of BBD generates 1.6 RINs.

[b] Billion gallons estimated after accounting for the projected impacts of the proposed RIN reduction for imported renewable fuel and renewable fuel produced from foreign feedstocks and the proposed revised equivalence value for renewable diesel. We project that the average number of RINs generated for BBD will be 1.27 and 1.28 RINs per gallon in 2026 and 2027, respectively. These numbers are not proposed standards and are presented for illustrative purposes only.

[2] Executive Order 14154, ''Unleashing American Energy,'' January 20, 2025 (90 FR 8353; January 29, 2025).

[3] EPA, ''EPA Administrator Lee Zeldin Announces EPA's 'Powering the Great American Comeback' Initiative,'' February 4, 2025. *https://www.epa.gov/newsreleases/epa-administrator-lee-zeldin-announces-epas-powering-great-american-comeback.*

TABLE I.A.1–3—PROJECTED SUPPLY OF RENEWABLE FUELS TO SATISFY THE VOLUME REQUIREMENTS FOR 2023–2027

[Billion gallons]

	Projected volume in the Set 1 Rule			Projected volume to meet the proposed volume requirements	
	2023	2024	2025	2026	2027
Cellulosic biofuel	0.84	1.09	1.38	1.30	1.36
Biomass-based diesel	3.71	3.85	4.24	6.83	7.16
Other advanced biofuel [a]	0.23	0.23	0.23	0.19	0.19
Conventional renewable fuel	[b] 13.85	13.96	13.78	13.78	13.66
Total renewable fuel	[b] 18.63	19.12	19.63	22.10	22.37

[a] Other advanced biofuel includes all advanced biofuels that to not qualify as cellulosic biofuel or BBD.

[b] Volumes do not include the 0.25 billion RIN supplemental standard established for 2023.

As discussed above, CAA section 211(o) requires EPA to analyze a specified set of factors in making our determination of the appropriate volume requirements. Many of those factors, particularly those related to economic and environmental impacts, are difficult to analyze in the abstract. To facilitate a more robust analysis of the statutory factors, we identified a set of renewable fuel volumes to analyze prior to determining the appropriate volume requirements to establish under the statute. We began by identifying two volume scenarios and then analyzed the potential impacts of these volume scenarios on the factors listed in the statute. The derivation of these volume scenarios is discussed in Section III. Section IV discusses the analysis of the volume scenarios for the statutory factors. Section V discusses our conclusions regarding the appropriate volume requirements to propose in light of the analyses conducted. Finally, Section VI discusses the formulas and values used to calculate the proposed percentage standards.

The BBD and advanced biofuel volumes we are proposing for 2026 and 2027 reflect the significant growth observed in the production of these fuels over the past several years and build off the volumes already achieved in the marketplace in 2024. The proposed volumes reflect the projected growth in the domestic supply of feedstocks, primarily soybean oil, with smaller projected increases in other feedstocks including used cooking oil and animal fats. Our focus on the growth in domestic feedstocks when projecting the supply of BBD for 2026 and 2027 is in part due to the uncertainty in the quantity of imported fuels and feedstocks that will be available to U.S. markets given various factors, including the available supply of qualifying feedstocks and demand for these feedstocks and fuels in other countries.

The cellulosic biofuel volumes we are proposing for 2026 and 2027 are slightly lower than the volumes we finalized for 2025.[4] The primary reasons for the decrease in the proposed volumes are limitations on the quantities of compressed natural gas (CNG) and liquified natural gas (LNG) derived from biogas projected to be used as transportation fuel in these years. CNG/LNG derived from biogas comprise most of the qualifying cellulosic biofuel we project will be supplied through 2027. However, the proposed cellulosic biofuel volumes also include projections of cellulosic ethanol from corn kernel fiber (CKF) produced at existing corn starch ethanol production facilities.

The proposed volumes for total renewable fuel in 2026 and 2027 reflect an implied conventional biofuel volume of 15 billion gallons each year. This is consistent with the implied conventional renewable fuel volumes in the statutory tables for 2015–2022,[5] as well as the implied conventional biofuel volumes established for 2023–2025. We recognize that while the supply of conventional biofuel in 2026 and 2027 will likely fall short of the implied 15-billion-gallon volume, the proposed total renewable fuel volumes are still achievable through the use of additional volumes of advanced biofuel beyond the volume requirement for that category.

The volume requirements that we are proposing in this action are the basis for the calculation of percentage standards applicable to producers and importers of gasoline and diesel unless they are waived in a future action using one or more of the available waiver authorities in CAA section 211(o)(7).

We believe that it is appropriate to propose volume requirements for two years instead of a longer timeframe due to the increased uncertainty of trying to project out further in the future, which increases the likelihood of needing to adjust volumes in the future. Adjustments to volume requirements create uncertainty in the RFS program and hinder the purpose of projecting future years, which is meant to provide certainty to the market. However, EPA is requesting comment on whether it would be appropriate to set standards for more than two years.

2. Partial Waiver of the 2025 Cellulosic Biofuel Volume Requirement

EPA is proposing to partially waive the 2025 cellulosic biofuel volume requirement and revise the associated percentage standard due to a shortfall in cellulosic biofuel production. As discussed in Section VII, we currently project a 0.19 billion RIN shortfall in available cellulosic biofuel in 2025. As such, we are proposing to use our CAA section 211(o)(7)(D) ''cellulosic waiver authority'' to reduce the 2025 cellulosic biofuel volume from 1.38 billion RINs to 1.19 billion RINs. The use of such waiver authority, if finalized, would also make cellulosic waiver credits (CWCs) available for the 2025 compliance year.

3. Reduction in the Number of RINs Generated for Imported Renewable Fuel and Renewable Fuel Produced From Foreign Feedstocks

EPA is proposing to reduce the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks. In simple terms, we are proposing regulatory changes that would mean a gallon of imported renewable fuel, or fuel produced from foreign feedstocks, would generate half the number of RINs that the same gallon of fuel would generate if produced in the U.S. from domestic feedstocks. These proposed changes, described in Section VIII, are in response to the dramatic increase in imported biofuels and feedstocks used to produce biofuels in the U.S. observed

[4] As discussed in Section VII, we are also proposing to reduce the previously established cellulosic biofuel volume requirement for 2025 in this action.

[5] CAA section 211(o)(2)(B)(i).

in recent years and align with the statutory goals of bolstering national energy independence. Imported renewable fuel and renewable fuel produced from foreign feedstocks do not further energy independence and are projected to result in fewer employment and rural economic development benefits relative to renewable fuels produced in the U.S. from domestic feedstocks.

4. Removal of Renewable Electricity From the RFS Program

As described in Section IX, EPA is proposing to remove renewable electricity as a qualifying renewable fuel under the RFS program (commonly referred to as eRINs), thereby making it ineligible to generate RINs. The proposed changes would find that renewable electricity does not meet the definition of renewable fuel under CAA section 211(o)(1)(J). On this basis, we are proposing to remove the regulations related to the production and use of renewable electricity as a transportation fuel, including the regulations related to facility registration for renewable electricity producers and the provisions for generating RINs for use of renewable electricity as a transportation fuel. We are also proposing to remove the definition of ''renewable electricity'' and the renewable electricity pathways in Table 1 of 40 CFR 80.1426 in connection with this policy change.

5. Other Regulatory Changes

EPA is also proposing additional regulatory changes in several areas to strengthen our implementation of the RFS program. These regulatory changes are discussed in greater detail in Section X and include:

- Specifying new equivalence values for renewable diesel, naphtha, and jet fuel.
- Updating RIN generation and assignment provisions.
- Clarifying that RINs cannot be generated on pure or neat biodiesel that is used as process heat or for power generation.
- Changing the percentage standards equations, including specifying the BBD standard in RINs rather than physical gallons.
- Updating existing renewable fuel pathways and adding new ones.
- Adding definitions for terms used throughout the regulations and updating other definitions.
- Adding a joint and several liability provision applicable to importers of renewable fuel.
- Revising compliance reporting and registration provisions, including clarifying that small refineries that receive an exemption from their RFS obligations must still submit an annual compliance report.
- Clarifying certain testing requirements for biodiesel and renewable diesel.
- Other minor changes and technical corrections.

B. Impacts of This Rule

CAA section 211(o)(2)(B)(ii) requires EPA to assess several factors when determining volume requirements for calendar years after 2022. These factors are described in the introduction to this Executive Summary, and each factor is discussed in detail in the Draft Regulatory Impact Analysis (DRIA) accompanying this rule.[6] However, the statute does not specify how EPA must assess each factor. For two of these statutory factors—costs and energy security—we provide monetized estimates of the impacts of the proposed volume requirements. For the other statutory factors, we are either unable to quantify impacts or we provide quantitative estimated impacts that nevertheless cannot be easily monetized. Thus, we are unable to quantitatively compare all the evaluated impacts of this rulemaking.

EPA considered all statutory factors in developing this proposal, including factors for which we provide monetized impacts, otherwise quantified impacts, or provide a qualitative assessment of relevant impacts, and we find that the proposed volumes are appropriate under EPA's statutory authority as an outcome of balancing all relevant factors. This approach is consistent with CAA section 211(o)(2)(B)(ii), which requires the EPA Administrator to ''determin[e]'' volumes based on ''an analysis of'' the statutory factors and does not require that analysis to monetize or quantify all relevant considerations. A summary of our assessment of the impacts of this proposed rule can be found in Section V.H. Table ES–1 in the DRIA provides a list of all the impacts that we assessed, both quantitative and qualitative. Additional detail for each of the assessed factors is provided in DRIA Chapters 4 through 10. For this proposed rule, we used data and projections from the U.S. Energy Information Administration's (EIA's) Annual Energy Outlook 2023, which was the most recent version available at the time we conducted our analyses supporting this action.[7] For the final rule, we intend to update our analyses using the most recent available data and projections from EIA and other sources.[8]

C. Policy Considerations

The RFS program is a critical policy tool to support the domestic production of renewable fuels. This action seeks to get the RFS program back on track by establishing renewable fuel volumes for 2027 by the statutory deadline and aligning the incentives provided by the RFS program with the statutory goals of increasing energy independence and energy security. The proposed volumes for 2026 and 2027 reflect the significant growth potential for renewable fuel production in the United States using domestic feedstocks.

EPA is requesting comment on multiple aspects of this action, including the proposed volume requirements, our technical analyses supporting those volumes, our proposal to reduce the number of RINs generated for imported renewable fuels and renewable fuels produced from foreign feedstocks, the removal of renewable electricity as a qualifying renewable fuel under RFS program, and the other proposed regulatory amendments. We also recognize that while this proposal in an important first step in getting the RFS program back on track, opportunities remain to improve the RFS program. To that end, we are requesting comment on a variety of potential changes to the RFS program that EPA could consider in future actions that would increase the program's ability to achieve the goals of EPAct and EISA. Our request for comment includes, but is not limited to:

- A general pathway for the production of renewable jet fuel from corn ethanol, including the consideration of ways to reduce emissions for this pathway such as the use of carbon capture and storage, renewable natural gas for process energy and low-carbon farming practices.
- The definition of ''produced from renewable biomass.''
- Additional program amendments to ensure that imported renewable fuels are produced from qualifying feedstocks and enhance our ability to track feedstocks to their point of origin. These comments may include input on methods and data to improve our evaluation of the environmental impacts associated with imported feedstocks such as used cooking oil and tallow.
- Program enhancements to increase the use of qualifying woody-biomass to

[6] ''RFS Program Standards for 2026 and 2027: Draft Regulatory Impact Analysis,'' EPA–420–D–25–001, June 2025.

[7] EIA, ''Annual Energy Outlook 2023'' (AEO2023). *https://www.eia.gov/outlooks/archive/aeo23.*

[8] On April 15, 2025, EIA issued ''Annual Energy Outlook 2025'' (AEO2025). *https://www.eia.gov/outlooks/aeo.*

produce renewable transportation fuel. We specifically request comment on the extent to which the renewable biomass definition in 40 CFR 80.2 aligns with current wildfire risk potential and corresponds to wildfire ignition behavior science and how to best maximize the eligibility of woody biomass residues generated at sawmills and other forest products manufacturing businesses that have not been adulterated by chemicals or other non-wood contaminants.

- An option to apply the import RIN reduction provisions to imported renewable fuel and renewable fuel produced domestically from foreign feedstock from only a subset of countries to reflect the reduced economic, energy security, and environmental benefits of imported renewable fuel and feedstock from those countries.
- Any other modifications to the RFS program designed to unleash the production of American energy.

D. Endangered Species Act

Section 7(a)(2) of the Endangered Species Act (ESA), 16 U.S.C. 1536(a)(2), requires that federal agencies such as EPA, in consultation with the U.S. Fish and Wildlife Service (USFWS) and/or the National Marine Fisheries Service (NMFS) (collectively ''the Services''), ensure that any action authorized, funded, or carried out by the action agency 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. Under relevant implementing regulations, the action agency is required to consult with the Services for actions that ''may affect'' listed species or designated critical habitat.[9] Consultation is not required where the action would have no effect on such species or habitat.

Consistent with ESA section 7(a)(2) and relevant implementing regulations at 50 CFR part 402, EPA engaged in informal consultation with the Services and completed a Biological Evaluation (BE) for the Set 1 Rule.[10] Supported by the analysis in the Set 1 Rule BE, EPA determined that the Set 1 Rule was ''not likely to adversely affect'' listed species and their habitats. NMFS concurred with EPA's determination on July 27, 2023, and FWS concurred with EPA's determination on August 3, 2023, thereby concluding the agencies' consultation obligations.[11] For the rulemaking finalizing this proposed action, EPA intends to develop a biological evaluation to inform our assessment of the effects of this action, and in turn our ESA consultation obligations.

II. Statutory Authority

A. Directive To Set Volumes Requirements

Congress enacted the RFS program for the purpose of increasing the use of renewable fuel in transportation fuel over time. Congress specified statutory volumes for the initial years of the program, including for BBD through 2012, and for the total renewable fuel, advanced biofuel, and cellulosic biofuel through 2022, but allowed EPA to waive the statutory volumes in certain circumstances. For years after 2022, Congress provided EPA with the directive and authority to establish the applicable renewable fuel volume requirements, as described in this section.[12] This section discusses EPA's statutory authority and additional factors we have considered due to the timing of this rulemaking, as well as the severability of the various portions of this rule.

B. Statutory Factors

CAA section 211(o)(2)(B)(ii) establishes the processes, criteria, and standards for setting the applicable annual renewable fuel volumes. That provision provides that the EPA Administrator shall, in coordination with USDA and DOE,[13] determine the applicable volumes of each renewable fuel category, based on a review of the implementation of the program during the calendar years specified in the tables in CAA section 211(o)(2)(B)(i) and an analysis of the following factors:

- The impact of the production and use of renewable fuels on the environment, including on air quality, climate change, conversion of wetlands, ecosystems, wildlife habitat, water quality, and water supply;
- The impact of renewable fuels on the energy security of the United States;
- The expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (cellulosic biofuel and biomass-based diesel);
- The impact of renewable fuels on the infrastructure of the United States, including deliverability of materials, goods, and products other than renewable fuel, and the sufficiency of infrastructure to deliver and use renewable fuel;
- The impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods; and
- The impact of the use of renewable fuels on other factors, including job creation, the price and supply of agricultural commodities, rural economic development, and food prices.

Congress provided EPA flexibility by enumerating factors that the Administrator must consider without mandating any particular forms of analysis or specifying how the EPA Administrator must weigh the various factors against one another. Thus, as the CAA ''does not state what weight should be accorded to the relevant factors,'' it ''give[s] EPA considerable discretion to weigh and balance the various factors required by statute.'' [14] These factors were analyzed in the context of the 2020–2022 RFS Rule that modified volumes under CAA section 211(o)(7)(F),[15] which requires EPA to comply with the processes, criteria, and standards in CAA section 211(o)(2)(B)(ii). EPA's assessment of the factors in that rule was recently upheld by the D.C. Circuit in *Sinclair* v. *EPA*.[16] EPA has also considered these factors in establishing the applicable volumes for 2023–2025 under CAA section 211(o)(2)(B)(ii) in the Set 1 Rule. Consistent with our past practice in evaluating the factors,[17] we have again determined that a holistic balancing of the factors is appropriate.[18]

In addition to those factors listed in the statute, the EPA Administrator also has authority to consider ''other'' factors, including both the implied

[9] 50 CFR 402.14.

[10] EPA, ''Biological Evaluation of the Renewable Fuel Standard Set Rule and Addendum,'' EPA–420–R–23–029, May 2023 (the ''Set 1 Rule BE'').

[11] The outcome of the Set 1 Rule ESA consultation is the subject of pending litigation; oral argument was held on November 1, 2024, and we are awaiting the court's decision. See *CBD* v. *EPA, et al.,* Case No. 23–1177 (D.C. Cir.).

[12] We refer to CAA section 211(o)(2)(B)(ii) as the ''set authority.''

[13] In furtherance of this requirement, we will continue periodic discussions with USDA and DOE on this action.

[14] *Nat'l Wildlife Fed'n* v. *EPA,* 286 F.3d 554, 570 (D.C. Cir. 2002) (analyzing factors within the Clean Water Act); *accord Riverkeeper, Inc.* v. *U.S. EPA,* 358 F.3d 174, 195 (2d Cir. 2004) (same); *BP Exploration & Oil, Inc.* v. *EPA,* 66 F.3d 784, 802 (6th Cir. 1995) (same); *see also Brown* v. *Watt,* 668 F.3d 1290, 1317 (D.C. Cir. 1981) (''A balancing of factors is not the same as treating all factors equally. The obligation instead is to look at all factors and then balance the results. The Act does not mandate any particular balance, but vests the Secretary with discretion to weigh the elements. . . .'') (addressing factors articulated in the Out Continental Shelf Lands Act).

[15] 87 FR 39600 (July 1, 2022).

[16] 101 F.4th 871, 888–889 (D.C. Cir. 2024).

[17] 87 FR 39600, 39607–08 (July 1, 2022).

[18] EPA, ''RFS Annual Rules: Response to Comments,'' EPA–420–R–22–009, June 2022 (''2020–2022 RFS Rule RTC''), at 10.

authority to consider factors that inform our analysis of the statutory factors and the explicit authority under CAA section 211(o)(2)(B)(ii)(VI) to consider ''the impact of the use of renewable fuels on other factors.'' Accordingly, we have considered several other relevant factors beyond those enumerated in CAA section 211(o)(2)(B)(ii), including:

- The interconnected nature of the volume requirements for 2026 and 2027, including the nested nature of those volume requirements and the availability of carryover RINs (Section V.E).[19]
- The ability of the market to respond given the timing of this rulemaking (DRIA Chapter 7).[20]
- The supply of qualifying renewable fuels to U.S. consumers (Section III.B).[21]
- Soil quality (DRIA Chapter 4.3).[22]
- Ecosystem services (DRIA Chapter 4.6).[23]
- A consideration of costs and benefits (Section V.H).[24]

C. Statutory Conditions on Volume Requirements

As indicated above, the CAA affords the EPA Administrator flexibility to consider and weigh each of the enumerated factors. However, the CAA contains three overarching conditions that affect our determination of the applicable volume requirements:

- A constraint in setting the applicable volume of total renewable fuel as compared to advanced biofuel, with implications for the implied volume requirement for conventional renewable fuel.
- Direction in setting the cellulosic biofuel applicable volume regarding potential future waivers.
- A floor on the applicable volume of BBD.

We discuss these conditions in further detail below.

1. Advanced Biofuel as a Percentage of Total Renewable Fuel

While the statute generally provides broad discretion in setting the applicable volume requirements for advanced biofuel and total renewable fuel, it also establishes a constraint on the relationship between these two volume requirements. CAA section 211(o)(2)(B)(iii) provides that the applicable advanced biofuel requirement must ''be at least the same percentage of the applicable volume of renewable fuel as in calendar year 2022,'' meaning that EPA must, at a minimum, maintain the ratio of advanced biofuel to total renewable fuel that was established for 2022 for all future years in which EPA itself sets the applicable volume requirements. In effect, this proportional requirement limits the proportion of the implied volume of conventional renewable fuel within the total renewable fuel volume for years after 2022 based on the proportion that existed for calendar year 2022.

The applicable advanced biofuel volume requirement established for 2022 was 5.63 billion gallons.[25] The total renewable fuel volume requirement established for 2022 was 20.63 billion gallons, resulting in an implied conventional volume requirement of 15 billion gallons. Thus, advanced biofuel represented 27.3 percent of total renewable fuel for 2022, and EPA must maintain at least that percentage of the advanced biofuel volume requirement as compared to the total renewable fuel volume requirement for all subsequent years. The volume requirements we are proposing in this action for 2026 and 2027, shown in Table I.A.1–1, exceed this 27.3 percent minimum, and thus they satisfy this statutory requirement for each year.

2. Cellulosic Biofuel

CAA section 211(o)(2)(B)(iv) requires that EPA set the applicable cellulosic biofuel requirement ''based on the assumption that the Administrator will not need to issue a waiver . . . under [CAA section 211(o)](7)(D)'' for the years in which EPA sets the applicable volume requirement. We have historically interpreted this requirement to mean that the cellulosic biofuel volume requirement should be set at a level that is achievable such that EPA does not anticipate a need to further lower the requirement through a waiver under CAA section 211(o)(7)(D).[26] CAA section 211(o)(7)(D) provides that if ''the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under paragraph (2)(B),'' EPA ''shall reduce the applicable volume of cellulosic biofuel required under paragraph (2)(B) to the projected volume available during that calendar year.'' Therefore, we are proposing the cellulosic biofuel volume requirements such that a waiver of those requirements is not anticipated to be necessary for those future years. Operating within this limitation, and in light of our consideration of the statutory factors explained in Section V, we are proposing cellulosic volumes for 2026 and 2027 at the projected volume available in each year, respectively, consistent with our past actions in determining the cellulosic biofuel volume.[27] These projections, discussed further in Sections III.B.1 and V.A, represent our best efforts to project the potential for growth in the volume of cellulosic biofuel that can be achieved in 2026 and 2027.

We recognize that, for 2024 and 2025, the volume of cellulosic biofuel available was less than the volume required, and we have partially waived the 2024 cellulosic biofuel volume requirement and are proposing to partially waive the 2025 cellulosic biofuel volume requirement in this action as discussed in Section VII. Nevertheless, we have considered the cellulosic biofuel available in those years and adjusted our methodology as discussed in Sections III.B.1 and V.A and DRIA Chapter 7.1 to account for the prior shortfalls in the standards. Retroactive waivers of the volume requirements under the RFS program decrease certainty for the market and undermines confidence in the volumes and standards EPA sets, which could negatively impact investment in renewable fuel production in future years. In this action, we propose changes to the methodology used to project cellulosic biofuel volumes to avoid the need for waivers of the RFS standards in the future.

[19] This also informs our analysis of the statutory factor ''review of the implementation of the program'' in CAA section 211(o)(2)(B)(ii).

[20] This also informs our analysis of the statutory factor ''the expected annual rate of future commercial production of renewable fuels'' in CAA section 211(o)(2)(B)(ii)(III).

[21] This is based on our analysis of the statutory factor the expected annual rate of future commercial production of renewable fuel as well as of downstream constraints on biofuel use, including the statutory factors relating to infrastructure and costs.

[22] Soil quality is closely tied to water quality and is also relevant to the impact of renewable fuels on the environment more generally, such that this analysis also informs our analysis of the statutory factor ''the impact of the production and use of renewable fuels on the environment'' in CAA section 211(o)(2)(B)(ii)(I).

[23] 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. Ecosystem services are discussed in DRIA Chapter 4 due to linkages to potential environmental impacts from this rule.

[24] The consideration of costs and benefits includes our quantitative analysis of several statutory factors, including costs and monetizable impacts on energy security.

[25] 87 FR 39601 (July 1, 2022).

[26] The cellulosic waiver authority applies when the projected volume of cellulosic biofuel production is less than the minimum applicable volume, per CAA section 211(o)(7)(D).

[27] See, *e.g.*, 2020–2022 RFS Rule (87 FR 39600; July 1, 2022).

3. Biomass-Based Diesel

EPA has established the BBD volume requirement under CAA section 211(o)(2)(B)(ii) for the years since 2013 because the statute only provides BBD volume requirements through 2012. CAA section 211(o)(2)(B)(iv) also requires that the BBD volume requirement be set at, or greater than, the 1.0-billion-gallon volume requirement enumerated by statute for 2012, but it does not provide any other numerical criteria that EPA must consider. In the years since 2012, EPA has steadily increased the BBD volume requirement beyond 1.0 billion gallons to 3.35 billion gallons in 2025. In this action, we are proposing BBD volume requirements for 2026 and 2027 of 7.12 and 7.50 billion RINs respectively.[28] These numbers are not directly comparable with the BBD volume requirements in previous years, as they express the required volume of BBD in RINs rather than gallons and reflect our proposal that imported renewable fuels and renewable fuels produced from foreign feedstocks would generate fewer RINs.[29] Nevertheless, the proposed BBD volume requirements guarantee that at least 4.45 and 4.69 billion gallons of BBD would be used in 2026 and 2027 respectively,[30] far greater than 1.0-billion-gallon minimum requirement.

D. Authority To Establish Volume Requirements and Percentage Standards for Multiple Years

In this action, EPA is proposing applicable volume requirements and percentage standards for 2026 and 2027. We have a statutory obligation to promulgate volume requirements under CAA section 211(o)(2)(B)(ii) and are addressing that requirement in this proposed action. The statutory deadline for the 2026 applicable volume requirements passed on October 31, 2024. The statutory deadline for promulgating the 2027 applicable volume requirements is October 31, 2025. We are proposing this action with the intent to meet that statutory deadline for the 2027 applicable volume requirements and to fulfill our outstanding obligation to establish the 2026 applicable volume requirements ahead of the 2026 compliance year.

As to the percentage standards with which obligated parties must comply, CAA section 211(o)(A)(i) and (iii) requires EPA to promulgate regulations that, regardless of the date of promulgation, contain compliance provisions applicable to refineries, blenders, distributors, and importers that ensure that the volumes in CAA section 211(o)(2)(B)—which includes volumes set by EPA after 2022—are met. As in the Set 1 Rule, EPA is also proposing to establish corresponding percentage standards in this action.[31]

In summary, we are proposing applicable volume requirements and associated percentage standards for 2026 and 2027, as further described in Sections V and VI.

E. Considerations Related to the Timing of This Action

In this action, we are proposing applicable volume requirements for the 2026 compliance year after the statutory deadline to establish such requirements.[32] That deadline was October 31, 2024. EPA has in the past also missed statutory deadlines for promulgating RFS standards, including the 2023 and 2024 standards established in the Set 1 Rule, and the BBD volume requirements for 2014–2017, which were established under CAA section 211(o)(2)(B)(ii), the same provision under which we are proposing to establish the 2026 standards in this action. In its review of EPA's 2015 action establishing BBD volume requirements for 2014–2017,[33] the D.C. Circuit found that EPA retains authority beyond the statutory deadlines to promulgate volumes and annual standards, even those that apply retroactively, so long as EPA exercises this authority reasonably.[34] EPA had missed the statutory deadline under CAA section 211(o)(2)(B)(ii) to establish an applicable volume requirement for BBD no later than 14 months before the first year to which that volume requirement will apply for all years. The D.C. Circuit held that when EPA exercises this authority after the statutory deadline, EPA must balance the burden on obligated parties of a delayed rulemaking with the broader goal of the RFS program to increase renewable fuel use.[35] In specifically upholding the portion of that rulemaking that was late but not retroactive, the court considered whether there was sufficient lead time and adequate notice for obligated parties.[36] The court found that EPA properly balanced the relevant considerations and had provided sufficient notice to parties in establishing the applicable volume requirements for 2014–2017.[37]

In this action, we are proposing to exercise our authority to set the applicable renewable fuel volume requirements for 2026 after the statutory deadline to promulgate such volume requirements under CAA section 211(o)(2)(B)(ii). We intend to finalize the 2026 standards prior to the beginning of the 2026 compliance year (*i.e.,* before January 1, 2026) and do not expect those standards to apply retroactively. In this proposal, we are providing obligated parties notice of the proposed 2026 standards. Under the RFS regulations, demonstrating compliance with the 2025 standards will not be required until the next quarterly reporting deadline after the 2026 standards are effective.[38] Additionally, obligated parties will continue to have the ability to use existing compliance flexibilities to comply with the 2026 RFS standards, such as the use of carryover RINs and carrying forward a deficit from one compliance year into the next.

F. Impact on Other Waiver Authorities

While we are proposing applicable volume requirements in this action for future years that are achievable and appropriate based on our consideration of the statutory factors, we retain our legal authority to waive volumes in the future under the waiver authorities should circumstances so warrant.[39] For example, the general waiver authority under CAA section 211(o)(7)(A) provides that EPA may waive the volume requirements in ''paragraph (2),'' which provides both the statutory

[28] As noted in Section I.A.1 and explained further in Section X.C, we are proposing to specify the BBD volume requirement in RINs, rather than gallons, as was the case in establishing the 2025 BBD volume requirement of 3.35 billion physical gallons.

[29] See Section VIII for more detail on the proposed RIN reduction for renewable fuels and renewable fuels produced from foreign feedstocks.

[30] These volumes represent the lowest possible volume of BBD that could be used to meet the proposed BBD volume requirements for 2026 and 2027. These numbers are calculated by dividing the proposed BBD RIN requirements by 1.6, which is the number of RINs generated for renewable diesel if produced by a domestic renewable fuel producer using domestic feedstocks.

[31] 88 FR 44468, 44519–21 (July 14, 2023).

[32] See CAA section 211(o)(2)(B)(ii), requiring EPA promulgate applicable volume requirements no later than 14 months prior to the first year in which they will apply.

[33] 80 FR 77420, 77427–28, 77430–31 (December 14, 2015).

[34] *Americans for Clean Energy* v. *EPA,* 864 F.3d 691 (D.C. Cir. 2017) (*ACE*) (EPA may issue late applicable volumes under CAA section 211(o)(2)(B)(ii)); *Monroe Energy, LLC* v. *EPA,* 750 F.3d 909 (D.C. Cir. 2014); *NPRA* v. *EPA,* 630 F.3d 145, 154–58 (D.C. Cir. 2010). *See also Sinclair* v. *EPA,* 101 F.4th 871 (D.C. Cir. 2024).

[35] *NPRA* v. *EPA,* 630 F.3d 145, 164–65.

[36] *ACE,* 864 F.3d at 721–22.

[37] *ACE,* 864 F.3d at 721–23.

[38] 40 CFR 80.1451(f)(1)(i)(A).

[39] *See J.E.M. Ag Supply, Inc.* v. *Pioneer Hi-Bred Intern., Inc.,* 534 U.S. 124, 143–44 (2001) (holding that when two statutes are capable of coexistence and there is not clearly expressed legislative intent to the contrary, each should be regarded as effective).

applicable volume tables and EPA's set authority (the authority to set applicable volumes for years not specified in the table). Therefore, similar to our exercise of the waiver authorities to modify the statutory volumes in past annual standard-setting rulemakings, EPA has the authority to modify the applicable volumes for 2023 and beyond in future actions through the use of our waiver authorities.

We note that, as described above, CAA section 211(o)(2)(B)(iv) requires that EPA set the cellulosic biofuel volume requirements for 2023 and beyond based on the assumption that EPA will not need to waive those volume requirements under the cellulosic waiver authority. Because we are, in this action, proposing the applicable volume requirements for 2026 and 2027 under the set authority, we do not believe we could also waive those requirements using the cellulosic waiver authority in this same action in a manner that would be consistent with CAA section 211(o)(2)(B)(iv), since that waiver authority is only triggered when the projected production of cellulosic biofuel is less than the ''applicable volume established under [211(o)(2)(B)].'' In other words, it does not appear that EPA could use both the set authority and the cellulosic waiver authority to establish volumes at the same time in this action.

Proposing the volume requirements for 2026 and 2027 using our set authority apart from the cellulosic waiver authority has important implications for the availability of CWCs in these years. When EPA reduces cellulosic volumes under the cellulosic waiver authority, EPA is also required to make CWCs available under CAA section 211(o)(7)(D)(ii). In this rule we are proposing cellulosic biofuel volume requirements without utilizing the cellulosic waiver authority. We interpret CAA section 211(o)(7)(D)(ii) such that CWCs are only made available in years in which EPA uses the cellulosic waiver authority to reduce the cellulosic biofuel volume. Because of this, CWCs would not be available as a compliance mechanism for obligated parties in these years absent a future action to exercise the cellulosic waiver authority. Despite the absence of CWCs, we expect that obligated parties will be able to satisfy their cellulosic biofuel obligations for these years because we are proposing to establish the cellulosic biofuel volume requirement based on the quantity of cellulosic biofuel we project will used as transportation fuel in the U.S. each year.

G. Severability

We intend for the volume requirements and percentage standards for each single year covered by this rule (*i.e.,* 2026 and 2027) to be severable from the volume requirements and percentage standards for the other year. Each year's volume requirements and percentage standards are supported by analyses for that year.

We intend for the revised cellulosic biofuel volume requirement and percentage standard for 2025 in Section VII to be severable from the volume requirements and percentage standards for the other years. The cellulosic biofuel volume requirement and percentage standard for 2025 is supported by the analysis for that year.

We intend for the import RIN reduction in Section VIII to be severable from the volume requirements and percentage standards for 2026 and 2027. While the regulatory amendments in Section VIII propose to modify the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks, our basis for proposing the amendments in Section VIII is independent from the volume requirements themselves. Additionally, we do not anticipate that invalidation of the import RIN reduction would jeopardize compliance with the volume requirements and percentage standards.

We also intend for the removal of renewable electricity from the RFS program in Section IX and the regulatory amendments in Section X to be severable from the volume requirements and percentage standards. These regulatory amendments are intended to improve the RFS program in general and are not part of EPA's analysis for the volume requirements and percentage standards for any specific year. Further, each of the regulatory amendments in Sections IX and X is severable from the other regulatory amendments because they all function independently of one another.

If any of the portions of the rule identified in the preceding paragraph (*i.e.,* volume requirements and percentage standards for a single year, the individual regulatory amendments) is invalidated by a reviewing court, we intend the remainder of this action to remain effective as described in the prior paragraphs. To further illustrate, if a reviewing court were to invalidate the volume requirements and percentage standards, we intend the other regulatory amendments to remain effective. Or, as another example, if a reviewing court invalidates the proposed removal of renewable electricity as a qualifying renewable fuel under the RFS program, we intend the volume requirements and percentage standards as well as other regulatory amendments to remain effective.

III. Alternative Volume Scenarios for Analysis and Baselines

In establishing volumes for 2026 and 2027, the statute requires that EPA review the implementation of the RFS program in prior years and analyze a specified set of factors (see Section II.B). Many of those factors, particularly those related to economic and environmental impacts, are difficult to analyze in the abstract; it is challenging to assess impacts without understanding the scale of the volume changes that are the driving force behind those impacts. In light of this, we have opted to develop alternative volume scenarios to analyze for each category of renewable fuel. This section describes the factors we considered when developing the volume scenarios for analysis. The analyses of the impacts of the volume scenarios are summarized in Section IV, and the volumes we are proposing based on these analyses and a review of the implementation of the RFS program to date are described in Section V. Note that neither of the volume scenarios we developed for analytical purposes include the impacts of the proposed import RIN reduction provisions described in Section VIII.

To develop the alternative volume scenarios for analysis, we first assessed two fundamental factors: (1) The potential supply of these fuels from both imports and domestic production; and (2) The ability for these fuels to be used as qualifying transportation fuel in the United States. Throughout this preamble, 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). The projected domestic production and importation of renewable fuel and the use of renewable fuel as transportation fuel closely align with two of the explicit statutory criteria: expected annual rate of future commercial production of renewable fuel and sufficiency of infrastructure to deliver and use renewable fuels. For cellulosic biofuel and conventional renewable fuel, the volume scenarios we chose to analyze are equal to the projected volumes of these fuels we project will be used as qualifying transportation fuel in 2026 and 2027. Our projections of the use of these fuels assumes current ongoing incentives for the production and use of these fuels provided by the RFS program and by other state and federal programs remain in place for the periods of time currently described in their respective statutes and regulations.

For non-cellulosic advanced biofuel (including BBD and other advanced biofuel), the projected supply of these fuels in future years is highly dependent on the incentives for these fuels provided by the RFS program, other state and federal incentives in the U.S., and actions by foreign countries. Unlike cellulosic biofuel and conventional renewable fuel, we do not expect that the supply of non-cellulosic advanced biofuel will be limited by the ability for the market to use these fuels as qualifying transportation fuel. Instead, we project that the available supply of non-cellulosic advanced biofuel will depend on a number of interrelated factors, including the supply of feedstocks to produce these fuels, demand for these feedstocks in non-biofuel markets, and the available incentives for the production and use of these fuels in the U.S. and other countries. Further, unlike cellulosic biofuel and conventional renewable fuel, which are primarily produced from a single feedstock (biogas and corn starch, respectively), non-cellulosic advanced biofuel can be produced from a variety of different feedstocks, and the projected impacts of the production of these fuels can vary depending on the feedstock used to produce the fuel. Considering these complexities, we have developed two different volume scenarios of non-cellulosic advanced biofuel for analysis rather that attempt to identify a single volume scenario for the projected supply of these fuels. These assessments are described in greater detail in Sections III.B and C and DRIA Chapter 6.

We acknowledge that we are adopting a slightly different approach to developing the volume scenarios for analysis in this action than we did in the Set 1 Rule, in which EPA first identified ''candidate volumes'' to analyze for each category of renewable fuel. These candidate volumes were based primarily on a consideration of supply-related factors, with a consideration of other relevant factors as noted in the Set 1 Rule. The approach taken in this action, in which multiple volume scenarios are analyzed, is designed to provide additional information about the potential impacts of a broader range of renewable fuel volume requirements.[40] The analysis of multiple scenarios allows EPA to consider different volumes scenarios for non-cellulosic advanced biofuel, where the impacts may be more heterogenous (*e.g.,* the impacts are not expected to be consistent on a per-gallon basis) across a range of potential qualifying fuels and volume requirements.

The volume scenarios we analyzed for this action, as well as the data that informed these volume scenarios, can be found in Sections III.B and C. Sections III.D and E describe the baselines we considered as points of reference for the analysis of the other statutory factors (*i.e.,* the ''No RFS'' baseline and the 2025 baseline) and the volume changes calculated in comparison to that baseline, respectively.

A. Scope of Analysis

In Section II.D we discuss our statutory authority to establish RFS volume requirements and percentage standards for multiple years in a single action. As discussed in that section, we are proposing to establish volume requirements and percentage standards for two years: 2026 and 2027. When developing the scenarios described in this section, however, EPA had not yet determined either the number of years for which to establish volumes in this action or the exact levels of the proposed volumes. To preserve the opportunity to consider proposing an action that would establish volumes for a greater number of years, we developed scenarios for analysis through 2030. We also assessed a range of potential fuel volumes to provide stakeholders with a more comprehensive sense for the potential impacts of different volume levels. The volume scenarios discussed in this section, as well as the results of our analysis of these scenarios discussed in Section IV, therefore consider a range of renewable fuel volumes through 2030. More information on the projected impacts of the renewable fuel volume requirements we are proposing for 2026 and 2027 can be found in Section V and the DRIA.

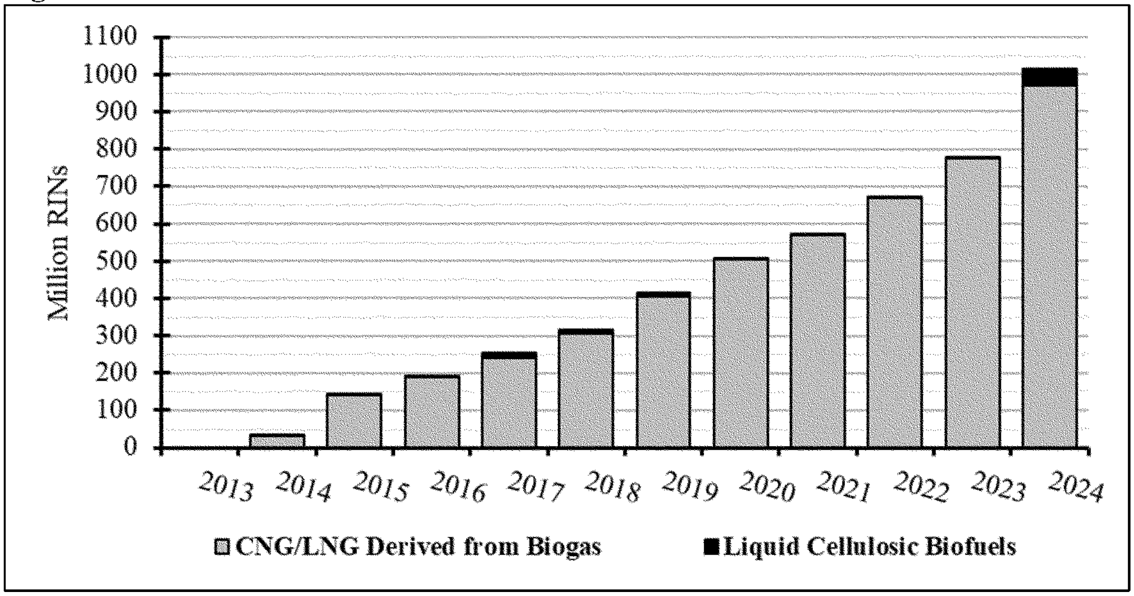
B. Production and Importation of Renewable Fuel

1. Cellulosic Biofuel

CAA section 211(o)(1)(E) defines cellulosic biofuel as renewable fuel derived from any cellulose, hemi-cellulose, or lignin that has lifecycle greenhouse gas (GHG) emissions that are at least 60 percent less than the baseline lifecycle GHG emissions. Since the inception of the RFS program, cellulosic biofuel production has steadily increased, reaching record levels in 2024. This growth has primarily been driven by biogas-derived CNG/LNG, although small volumes of liquid cellulosic biofuels, particularly ethanol produced from corn kernel fiber (CKF), have also played a contributing role. In this section, we discuss our analysis for projecting the production of qualifying cellulosic biofuel for 2026–2030, along with key uncertainties associated with these estimates. Additional details on our volume projections for cellulosic biofuel can be found in DRIA Chapter 7.1.

[40] We note that the two scenarios analyzed for this action differ only in the BBD volumes. Considering different BBD volumes is of the most interest due to the high degree of uncertainty in the potential supply of this fuel through 2027 and the differences in the projected impacts between different types of BBD.

Figure III.B.1-1: Cellulosic RINs Generated



a. CNG/LNG Derived From Biogas

Biogas-derived CNG/LNG from qualifying sources must first be collected and upgraded for vehicle use. The upgraded process varies depending on the final application but typically involves removing undesirable components and contaminants from the raw biogas. Biogas that has been upgraded and distributed through a closed distribution system, either as a biointermediate or for the production of renewable fuel, is defined as ''treated biogas,'' whereas biogas that has been upgraded to be suitable for injection into the commercial natural gas pipeline system and is used to produce renewable fuel is defined as ''renewable natural gas'' (RNG).[41] Although they are defined differently in the regulations, we use the term ''RNG'' to collectively refer to both treated biogas and RNG in this document. Likewise, we use ''biogas-derived CNG/LNG'' to refer to both treated biogas and RNG when used as a transportation fuel in CNG/LNG vehicles.

To project future volumes of biogas-derived CNG/LNG, we analyzed two limiting factors: the estimated volume of RNG that could be produced or captured and the estimated amount of biogas-derived CNG/LNG that could be consumed as a transportation fuel. Our analysis indicates that consumption (*i.e.,* use as a transportation fuel), rather than production, is likely to be the primary constraint on determining volumes during 2026–2030.

To estimate consumption, we developed a projection of total CNG/LNG transportation use based on vehicle sector data, including fuel consumption rates, vehicle miles traveled, and fuel efficiency. Because biogas-derived CNG/LNG can generate RINs only when used as a transportation fuel, total CNG/LNG consumption—whether fossil- or biogas-derived—represents the upper volume limit for biogas-derived CNG/LNG RIN generation. However, full replacement of total CNG/LNG usage with biogas-derived fuel is unlikely due to infrastructure limitations, costs, and other challenges. To account for this, we applied an efficiency factor to estimate the portion of total CNG/LNG consumption that could realistically be met with biogas-derived fuel and, in turn, the number of cellulosic RINs that could be generated. Based on data from California's Low Carbon Fuel Standard (LCFS) program, we assume that even in a fully saturated market,[42] only 97 percent of total CNG/LNG transportation demand would be met with biogas-derived CNG/LNG. As a result, we applied a 97 percent adjustment to our total CNG/LNG consumption estimate to calculate the potential total biogas-derived CNG/LNG volume. The results of this analysis are shown in Table III.B.1.a–1 and are further described in DRIA Chapter 7.1.4.1.

TABLE III.B.1.a–1—ESTIMATED CONSUMPTION OF TOTAL CNG/LNG AND THE ESTIMATED QUANTITY OF BIOGAS-DERIVED CNG/LNG

[Million ethanol-equivalent gallons]

Year	Total CNG/LNG consumption	Total biogas-derived CNG/LNG consumption
2026	1,210	1,174
2027	1,277	1,239
2028	1,349	1,309
2029	1,426	1,384
2030	1,509	1,464

[41] 40 CFR 80.2.

[42] We use the term ''saturated market'' to describe a market that consumes the maximum feasible amount of biogas-derived CNG/LNG relative to its CNG/LNG vehicle population.

Initial evidence of this shift towards a consumption-limited baseline is already apparent. In 2023, RNG volumes were insufficient to meet the cellulosic biofuel volume requirement established in the Set 1 Rule. This shortfall resulted in a 0.09 billion cellulosic RIN deficit carried forward from 2023 into 2024. For 2024, RNG production—and hence cellulosic RIN generation—again fell short of the required volume. This led EPA to propose a partial waiver of the 2024 cellulosic biofuel volume requirement.[43] Similarly, as described in Section VII, EPA currently projects a shortfall in cellulosic biofuel production for 2025 and is proposing to again partially waive the cellulosic biofuel volume requirement for 2025. Thus, while EPA is still projecting continued growth in cellulosic biofuel production, growth in cellulosic RIN generation is likely to face significant constraints for the foreseeable future, limited by the ability of fuel consumers to use RNG as a qualifying transportation fuel.

As a means of cross-checking this expected limitation on cellulosic RIN generation, we also projected future RNG production. To estimate this, we used an industry-wide projection methodology that has been employed in the RFS standard-setting rules since 2018. This methodology applies an industry-wide year-over-year growth rate to the current biogas production rate. Specifically, we used RIN generation data from the most recent 24 months and multiplied the observed growth rate during that period by the most recent full calendar year of data available. This growth rate was then repeatedly applied to each progressive year to project future production. This approach was previously used in the 2018,[44] 2019,[45] 2020–2022,[46] and Set 1 (2023–2025) Rules. However, unlike the 2018–2022 Rules, the Set 1 Rule relied on data from 2015–2022 rather than the previous 24 months. This adjustment was made to account for the expected impact of the COVID–19 pandemic, which was believed at the time to have negatively affected the market in 2020 and 2021. At the time of the Set 1 Rule analysis, pre-pandemic growth rates were considered a more accurate reflection of future biogas production potential, a view supported by stakeholders. However, with the benefit of post-pandemic data, we have returned to our prior methodology, basing projections on the most recent 24 months of data instead of the data from 2015–2022, as described in DRIA Chapter 7.1.4.2. Performing this analysis and comparing RNG production to the consumption of RNG-derived CNG/LNG highlights a key point: for all years from 2026–2030, projected RNG production is expected to exceed the projected consumption of RNG-derived CNG/LNG, providing further evidence that future cellulosic RIN generation is limited by the ability of fuel consumers to use RNG as a qualifying transportation fuel.

While RNG production is not expected to be a limiting factor in determining volumes, the future production of RNG will ultimately depend on market demand. Because of this, there is significant uncertainty overall for the production of RNG. One notable source of uncertainty is the potential for significant competing demands for RNG, such as to produce RNG-based ammonia (*e.g.,* for use as fertilizer) and to produce RNG-based hydrogen for use in various process energy applications. While the demand for these products over the 2026–2030 period is highly uncertain, substantial growth in these competing demands for RNG have the potential to further limit the available supply of RNG as a qualifying transportation fuel.

From our analysis of both RNG consumption and production, we believe that cellulosic RIN generation from biogas-derived CNG/LNG during 2026–2030 will be constrained by the total usage of CNG/LNG as transportation fuel (*i.e.,* the total amount of CNG/LNG that can be used in the fleet of CNG- and LNG-powered vehicles). Accordingly, the volumes presented in Table III.B.1.a–2 were used as the volume scenario for biogas-derived CNG/LNG during this period. That said, we recognize that there is considerable uncertainty in these volumes and that the methodology used to determine these volumes are different than what we have done in prior rules. Therefore, we request comment on our projections for cellulosic biofuel production for 2026–2030, specifically regarding our assessment of future CNG/LNG consumption. We also request any additional data or information that could further inform our projections for cellulosic biofuel production during this period.

TABLE III.B.1.a–2—ESTIMATED VOLUME OF BIOGAS-DERIVED CNG/LNG

[Million ethanol-equivalent gallons]

Year	Volume
2026	1,174
2027	1,239
2028	1,309
2029	1,384
2030	1,464

b. Ethanol From Corn Kernel Fiber

Several technologies are currently being developed to produce liquid fuels from cellulosic biomass. However, most of these technologies are unlikely to yield significant volumes of cellulosic biofuel by 2030. One notable exception is the production of ethanol from CKF, for which several companies have developed processes. Many of these processes involve 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 using approved methodologies. 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.[47]

EPA has also 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 could be feasible at all existing corn ethanol facilities, with minimal additional processing units or modifications. To generate cellulosic RINs for ethanol produced from CKF, a facility would need to demonstrate the converted fraction consistent with appropriate test methods. For the purposes of this analysis, we assume that 90 percent of facilities will produce cellulosic ethanol over this period due to potential facility-specific challenges that may prevent 100 percent adoption.

Additionally, while technology providers have indicated that using analytical methods consistent with EPA

[43] 89 FR 100442 (December 12, 2024).

[44] 82 FR 58486 (December 12, 2017).

[45] 83 FR 63704 (December 11, 2018).

[46] 87 FR 39600 (July 1, 2022).

[47] 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.

guidance can demonstrate that approximately 1.5 percent of ethanol produced at existing corn ethanol facilities comes from cellulosic biomass, data submitted to EPA by renewable fuel producers generating cellulosic RINs for CKF ethanol shows that the current industry-wide average among registered facilities is closer to 1 percent. Therefore, for the purposes of this analysis, we are using a 1 percent conversion rate.

The projected production of cellulosic ethanol from CKF, as shown in Table III.B.1.b–1, is based on projections of total corn ethanol production, with a 90 percent facility participation rate and a 1 percent conversion efficiency applied.[48] We request comment on these projected volumes, including our projections of the percentage of ethanol producers that will generate cellulosic RINs for CKF ethanol through 2027 and the proportion of ethanol from cellulose vs. starch at these facilities.

TABLE III.B.1.b–1—PROJECTED PRODUCTION OF ETHANOL FROM CKF

[Million ethanol-equivalent gallons]

Year	Volume
2026	124
2027	123
2028	122
2029	120
2030	119

c. Other Cellulosic Biofuels

We expect that commercial scale production of cellulosic biofuel in the U.S. beyond CNG/LNG derived from biogas and ethanol produced from CKF will be very limited in 2026–2030. There are several cellulosic biofuel production facilities in various stages of development, construction, and commissioning that may be capable of producing commercial scale volumes of cellulosic biofuel by 2030. These facilities primarily focus on producing cellulosic hydrocarbons from feedstocks such as separated municipal solid waste (MSW), precommercial thinnings, and tree residues, which can be blended into gasoline, diesel, and jet fuel. Since no parties have achieved consistent production of liquid cellulosic biofuel in the U.S. or consistently exported liquid cellulosic biofuel to the U.S., production and import of liquid cellulosic biofuel in 2026–2030 is highly uncertain and likely to be relatively small. For the volume scenarios we are analyzing, we have projected no production of these fuels in 2026–2030.

2. Biomass-Based Diesel

CAA section 211(o)(1)(D) defines biomass-based diesel as renewable fuel that is biodiesel and that has GHG emissions reductions of at least 50 percent from the baseline. It also excludes biodiesel that is co-processed with petroleum feedstocks. The BBD standard is nested within the advanced biofuel standard. Historically, the BBD supply under the RFS program has exceeded the BBD standard, with the additional supply used by obligated parties to meet their advanced biofuel volume requirements. Thus, the advanced biofuel standard has incentivized the use of BBD beyond just the BBD standard.

Since 2010, when the BBD volume requirement was added to the RFS program, production of BBD has generally increased annually. 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 including the RFS program; the availability of imported BBD; the demand for BBD (and feedstocks used to produce BBD) in foreign markets; and several other economic factors.

Most renewable fuel that qualifies as BBD is biodiesel or renewable diesel. Both of these fuels are replacements for petroleum diesel and are produced from the same lipid-based feedstocks, a diverse category that includes animal fats, used cooking oil, and vegetable oil feedstocks. Biodiesel and renewable diesel differ in their production processes and chemical composition. Biodiesel is an oxygenated fuel that is generally produced using a transesterification process. Renewable diesel, on the other hand, is a hydrocarbon fuel that closely resembles petroleum diesel and that is generally produced by hydrotreating renewable feedstocks. From 2010–2018, the vast majority of BBD supplied to the U.S. was biodiesel. Production and imports of renewable diesel emerged in the U.S. in the early 2010s. Market share for renewable diesel began a steady upward trend in 2019, and U.S. domestic supply of these fuels has increased significantly over the past several years. The supply of biodiesel has been relatively stable since 2016 amidst the expansion of renewable diesel supply.

In 2023, the supply of renewable diesel exceeded the supply of biodiesel for the first time (see Figure III.B.2–1). Unlike biodiesel, which is often produced at relatively small facilities, renewable diesel is generally produced at large facilities. While some renewable fuel producers have built new production facilities, much of the renewable diesel produced in the U.S. uses petroleum refining infrastructure that has been converted to produce renewable diesel. Because renewable diesel is more chemically similar to petroleum, it is generally not subject to the same blending limits as biodiesel. This has allowed very large volumes of renewable diesel to be supplied to California and other states with incentives for biofuel use in addition to the incentives provided by the RFS program. In future years we expect to continue to see large increases in the supply of renewable diesel due to the advantages in the economy of scale and the ability to access markets with higher incentives, and a relatively steady supply of biodiesel from established facilities with favorable local markets.

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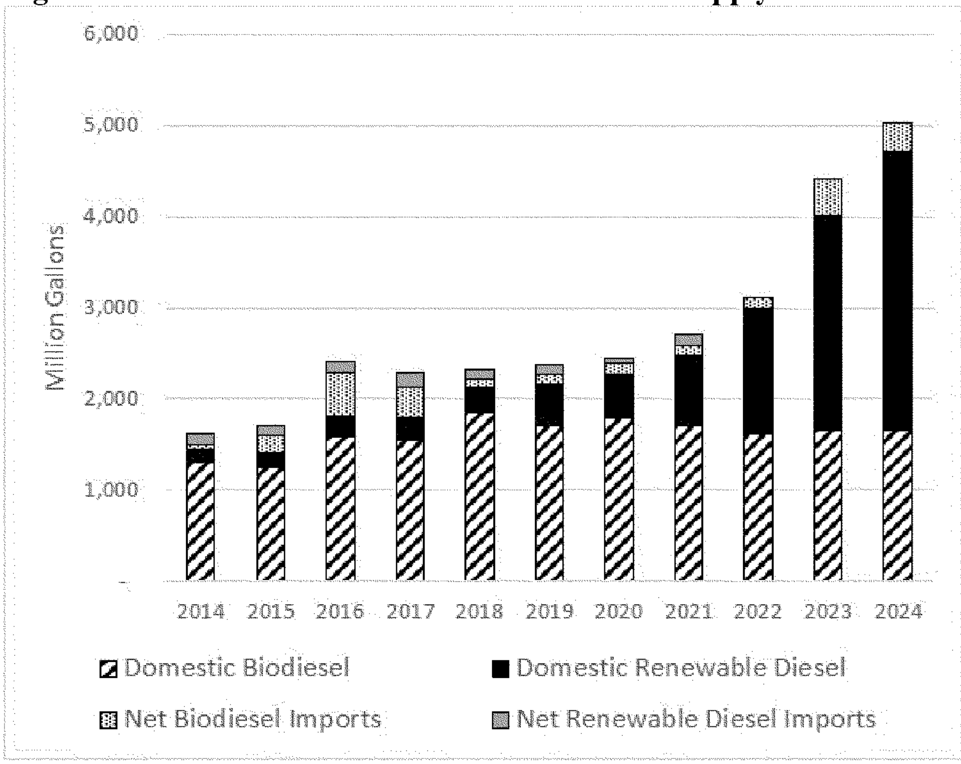
[48] A detailed discussion of the methodology used to project cellulosic ethanol production from CKF can be found in DRIA Chapter 7.1.5.

Figure III.B.2-1: Biodiesel and Renewable Diesel Supply[a]



[a] Numbers are based on data from EMTS. Note that the domestic biodiesel and renewable biofuels represented in this figure include biofuels produced from imported feedstocks. This figure does not include the small quantity of jet fuel that was produced (less than 150 million gallons each year) or fuels that did not generate RINs. This figure also does not include advanced (D5) or conventional (D6) biodiesel and renewable diesel, which are discussed in Sections III.B.3 and III.B.4.b and DRIA Chapters 7.4 and 7.7. Historically, biodiesel has generally generated 1.5 RINs per gallon and renewable diesel has generally generated 1.7 RINs per gallon. As described in Sections VIII and X.A, we are proposing multiple changes that could impact how many RINs are generated per gallon of these fuels.

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There are also small volumes of renewable jet fuel and heating oil that qualify as BBD.[49] Renewable jet fuel has qualified as a RIN-generating BBD and advanced biofuel under the RFS program since 2010 and must achieve at least a 50 percent reduction in GHGs in comparison to petroleum-based fuels. The technology and feedstocks that can currently be used to produce renewable jet fuel are often the same as those used to produce renewable diesel. For example, the same process that produces renewable diesel from lipids generally produces hydrocarbons in the distillation range of jet fuel that can be separated and sold as renewable jet fuel instead of being sold as renewable diesel. While relatively little renewable jet fuel has been produced since 2010—20 million gallons or less per year through 2023, increasing to approximately 110 million gallons in 2024—opportunities for increasing this category of advanced biofuel exist.

A tax credit for renewable jet fuel for tax years 2023 and 2024, often referred to as the ''sustainable aviation fuel credit'' or ''40B credit,'' may have resulted in increasing volumes of renewable jet fuel produced from existing renewable diesel production facilities. Another low carbon transportation fuel tax credit, the ''clean fuel production credit'' or ''45Z credit,'' is available for tax years 2025–2027, and provides up to $1.75 per gallon of renewable jet fuel, provided the relevant wage and apprenticeship requirements are met by the producer. The 45Z credit may provide continued support for renewable jet fuel production. Renewable jet fuel production from existing renewable diesel facilities, however, would likely result in a decrease in renewable diesel production, with little or no net change in their overall production of RIN-generating fuels.[50]

In this rule we have not separately projected growth in renewable jet fuel production, but we recognize that some of the projected growth in renewable diesel production may instead be renewable jet fuel from the same production facilities. Other renewable jet fuel production technologies and production facilities (discussed briefly in Section III.B.2.b) also being developed could enable the future production of renewable jet fuel from new facilities and feedstocks that are not expected to impact renewable diesel production.

The remainder of this section provides historical data on biodiesel and renewable diesel production and production capacity, briefly discusses potential feedstock limitations for

[49] According to EMTS data renewable jet fuel supply ranged from 0–20 million gallons per year from 2014–2023 and increased to approximately 110 million gallons in 2024. Renewable jet fuel is eligible to generate RINs per 40 CFR 80.1426(a)(1)(iv), provided all other regulatory requirements are met.

[50] The equivalence values for renewable diesel and jet fuel are similar. As discussed in Section X.A, we are proposing to revise the renewable diesel equivalence value to be 1.6 RINs per gallon, while also proposing to establish the renewable jet fuel equivalence value to be 1.5 RINs per gallon.

biodiesel and renewable diesel production in future years, and summarizes our assessment of the rate of production and use of qualifying BBD for 2026–2030, along with some of the uncertainties associated with those volumes.[51]

a. Biodiesel

For most of the history of the RFS program, the largest volume of BBD and advanced biofuel supplied in the program each year have been from biodiesel. Domestic biodiesel production increased from approximately 1.3 billion gallons in 2014 to approximately 1.8 billion gallons in 2018. Since 2018, domestic biodiesel production decreased slightly, to approximately 1.7 billion gallons in 2024.[52] The U.S. has also imported significant volumes of biodiesel in previous years and has been a net importer of biodiesel since 2013. Biodiesel imports reached a peak in 2016, with the majority of the imported biodiesel coming from Argentina.[53] In August 2017, the U.S. announced tariffs on biodiesel imported from Argentina and Indonesia.[54] These tariffs were subsequently confirmed in April 2018 and remain in place.[55] Biodiesel imports started dropping in 2017 but have increased again in recent years, reaching approximately 500 million gallons in 2023 and reduced to 420 million gallons in 2024.[56] More generally, overall biodiesel supply in the U.S. has remained between 1.6 and 1.8 billion gallons since 2016 (see Figure III.B.2–1).

Available data suggests that there is significant unused biodiesel production capacity in the U.S., and thus domestic biodiesel production could grow without the need to invest in additional production capacity. Data reported by EIA shows that domestic biodiesel production capacity in November 2024 was approximately 2.00 billion gallons per year, roughly 0.3 billion gallons more than was utilized.[57] According to this data, annual average biodiesel production capacity grew relatively slowly from about 2.1 billion gallons in 2012 to a peak of approximately 2.6 billion gallons in 2019. EIA reports that domestic biodiesel production capacity was approximately 2.5 billion gallons as recently as October 2021. This facility capacity data is collected by EIA in monthly surveys, which suggests that this capacity represents the production at facilities that are currently producing some volume of biodiesel and likely does not include facilities that are inactive or have closed, as these facilities are far less likely to complete a monthly survey.

EPA separately collects facility capacity information through the RFS program facility registration process. This data includes both facilities that are currently producing biodiesel and those that are inactive. EPA's data shows a total domestic biodiesel production capacity of 2.9 billion gallons per year in April 2025, of which 2.6 billion gallons per year was at biodiesel facilities that generated RINs in 2024.[58] These estimates of domestic production capacity strongly suggest that domestic biodiesel production capacity is unlikely to limit domestic biodiesel production through 2030.

b. Renewable Diesel and Renewable Jet Fuel

Renewable diesel and renewable jet fuel are currently produced using the same feedstocks and very similar production technologies, and in most cases are produced at the same production facilities. For example, Montana Renewables produced both renewable diesel and renewable jet fuel at their Great Falls, Montana facility in 2024.[59] Historically, greater incentives have been available for renewable diesel production than for renewable jet fuel production, which has meant that in practice most production facilities chose to maximize renewable diesel production. In this section we have focused on renewable diesel production, but we acknowledge that an increasing portion of this fuel may be used as renewable jet fuel in future years.

In the near term, we expect that any increase in renewable jet fuel production will result in a corresponding decrease in renewable diesel production. We recognize that new technologies are being developed to produce renewable jet fuel from a wider variety of feedstocks, some of which are not suitable for use in the hydrotreating process that dominates renewable diesel production. For example, several companies are developing new technologies intended to produce renewable jet fuel from ethanol or other alcohols, through a technology often referred to as the ''alcohol-to-jet'' (or ''ATJ'') process. To date EPA has not approved a generally applicable pathway for these fuels, but we have approved a facility specific pathway for the production of renewable jet fuel from ethanol to generate BBD RINs.[60] While ATJ has the potential to produce significant volumes of renewable jet fuel in future years, there is a high degree of uncertainty related to the production of these fuels through 2030 as commercial scale production of these fuels has been limited and no RINs have yet been generated for these fuels. Production of renewable jet fuel using these emerging technologies may not negatively impact renewable diesel production to the extent that they do not compete for feedstocks. Through 2027, however, we expect that only relatively modest volumes of fuels might be produced through these emerging technologies. We request comment on the potential production volume of such renewable jet fuel through 2027 and any technical and economic data that would help inform our understanding of the potential impacts of the production of renewable jet fuel through the ATJ process on the statutory factors.

Renewable diesel has historically been produced and imported in smaller quantities than biodiesel, as shown in Figure III.B.2–1. In recent years, however, domestic production of renewable diesel has increased significantly. Renewable diesel production facilities generally have higher capital costs and production costs relative to biodiesel, which likely accounts for the historically higher volumes of biodiesel production relative to renewable diesel production prior to 2023. The higher cost of renewable diesel production can largely be offset through the benefits of economies of scale, since renewable diesel facilities tend to be much larger than biodiesel production facilities.[61] For example, according to EMTS data, in 2024, there were 23 renewable diesel facilities that produced an average of 157 million gallons of renewable diesel per facility, compared to 71 biodiesel facilities that

[51] Further details on these volume projections can be found in DRIA Chapter 7.2.

[52] Id.

[53] In 2016 and 2017, 67 percent of all biodiesel imports were from Argentina. 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.*

[54] 82 FR 40748 (Aug. 28, 2017).

[55] 83 FR 18278 (April 26, 2018).

[56] EIA, ''U.S. Imports of Biodiesel,'' Petroleum & Other Liquids, April 30, 2025. *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=m_epoordb_im0_nus-z00_mbbl&f=a.*

[57] EIA, ''U.S. Biodiesel Production Capacity,'' Petroleum & Other Liquids, April 30, 2025. *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPOORDB_8BDPC_NUS_MMGL&f=M.*

[58] See ''BBD Registered Facility Capacity,'' available in the docket for this action.

[59] Montana Renewables, ''Products.'' *https://montanarenewables.com/products.*

[60] See EPA, ''Letter from EPA to LanzaJet, Inc.,'' January 12, 2023.

[61] See DRIA Chapter 10 for more detail on our assessment of the cost to produce biodiesel and renewable diesel.

produced an average of 29 million gallons of biodiesel per facility.[62]

More importantly, because renewable diesel more closely resembles petroleum diesel than biodiesel (both renewable diesel and petroleum diesel are hydrocarbons while biodiesel is a methyl-ester), renewable diesel can be blended at much higher concentrations with diesel than biodiesel (it is for this reason that renewable diesel is sometimes referred to as a ''drop-in'' fuel). This allows renewable diesel to more easily be blended into diesel at higher rates and enables renewable diesel producers to sell greater volumes of renewable diesel in California, benefiting from the LCFS credits in California in addition to RFS incentives and the federal tax credit.[63] The greater ability for renewable diesel to generate credits under California's LCFS program provides a significant advantage over biodiesel. Biodiesel blends in California containing 6–20 percent biodiesel require the use of an additive to comply with California's Alternative Diesel Fuels Regulations, making the use of higher-level biodiesel blends more challenging in California.[64] The Washington and Oregon programs modeled from the California LCFS have generally mirrored this incentive structure, and the emerging New Mexico program may do so as well. If additional States were to adopt clean fuels programs using a similar structure, these programs could provide an additional advantage to renewable diesel production relative to biodiesel production in the U.S.

Total domestic renewable diesel production capacity has increased significantly in recent years from approximately 280 million gallons in 2017 [65] to approximately 4.6 billion gallons at the end of 2024.[66] Additionally, a number of parties have announced plans to build new renewable diesel production capacity with the potential to begin production in future years. This new capacity includes new renewable diesel production facilities, expansions of existing renewable diesel production facilities, and the conversion of units at petroleum refineries to produce renewable diesel.

EIA currently projects that renewable diesel production capacity will continue to expand and could reach nearly 6 billion gallons by the end of 2025.[67] A recent report published by the National Renewable Energy Laboratory found that by 2028 the domestic production capacity for renewable diesel and renewable jet fuel through the hydrotreating process alone could increase to 9.6 billion gallons per year.[68] In previous years, domestic renewable diesel production has increased in concert with increases in domestic production capacity, with renewable diesel facilities generally operating at high utilization rates. In future years we expect that competition for affordable qualifying feedstocks may result in renewable diesel and biodiesel facilities operating below their production capacity. Competition for qualifying feedstocks could also result in reductions in overall biodiesel production if larger renewable diesel facilities are able to out-compete smaller biodiesel producers for feedstock. Further, even if these facilities operate at levels close to their production capacity, demand for renewable diesel and renewable jet fuel in other countries may impact the quantity of these fuels available to U.S. markets.

In addition to domestic production of renewable diesel, the U.S. has also imported renewable diesel, with nearly all of it produced from fats, oils, and greases (FOG) and imported from Singapore.[69] In more recent years, the U.S. has also exported increasing volumes of renewable diesel. In 2022–2024, renewable diesel exports exceeded renewable diesel imports based on data collected through EMTS (see Table III.B.2.b-1). This situation, wherein significant volumes of renewable diesel are both imported and exported, is likely the result of a number of factors, including the design of the biodiesel tax credit (which is available to renewable diesel that is either produced or used in the U.S. and thus eligible for exported volumes as well), the varying structures of incentives for renewable diesel (with the level of incentives varying depending on the feedstocks used to produce the renewable diesel varying as well as by country), and logistical considerations (renewable diesel may be imported and exported from different parts of the country). Starting in 2025, the 45Z credit, which consolidates and replaces the previous $1 per gallon credit for blending biodiesel and renewable diesel into diesel fuel under 40A, also provides a production credit for alternative fuels and sustainable aviation fuel. Since the new 45Z credit is only available for fuel produced in the United States, it may result in significantly decreased renewable fuel imports and may in turn also decrease renewable fuel exports as domestic producers seek to satisfy demand previously met by imported renewable fuels.

TABLE III.B.2.b–1—RENEWABLE DIESEL IMPORTS AND EXPORTS

[Million gallons]

Year	Renewable diesel imports	Renewable diesel exports	Net imports
2015	120	21	99
2016	165	40	125
2017	191	37	154

[62] See ''Analysis of BBD RIN Generation by Facility Size,'' available in the docket for this action.

[63] For example, when LCFS credits are worth $100/metric ton, blending renewable diesel into California generates LCFS credits worth approximately $0.25 to $0.90 per gallon (assuming carbon intensities of 70 and 20 gCO_2e/MJ respectively). Renewable fuel producers that sell qualifying renewable fuel in California can generate both RINs under the RFS program and LCFS credits.

[64] CARB, ''Frequently Asked Questions on the Alternative Diesel Fuels Regulation,'' November 2017. In 2021, nearly all renewable diesel consumed in the U.S. was consumed in California. Together renewable diesel and biodiesel represented approximately 65–70 percent of all diesel fuel consumed in California in the second half of 2024.

[65] Renewable diesel capacity based on facilities registered in EMTS.

[66] EIA, ''U.S. Total Biofuels Operable Production Capacity,'' Petroleum & Other Liquids, April 30, 2025. *https://www.eia.gov/dnav/pet/pet_pnp_capbio_dcu_nus_m.htm.*

[67] 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.*

[68] 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.*

[69] EIA, ''U.S. Imports by Country of Origin—Renewable Diesel Fuel,'' Petroleum & Other Liquids, April 30, 2025. *https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDO_im0_mbbl_a.htm.*

TABLE III.B.2.b–1—RENEWABLE DIESEL IMPORTS AND EXPORTS—Continued

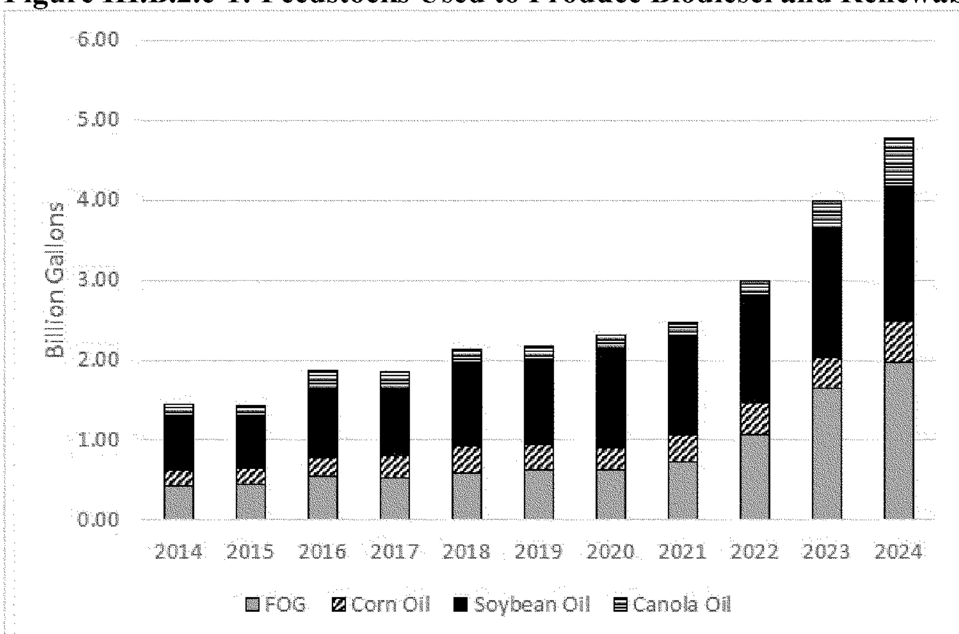
[Million gallons]

Year	Renewable diesel imports	Renewable diesel exports	Net imports
2018	176	80	96
2019	267	148	119
2020	280	223	57
2021	262	241	121
2022	311	326	−15
2023	361	414	−53
2024	430	581	−151

c. Domestic BBD Feedstocks

When considering the potential production and import of biodiesel and renewable diesel in future years and the likely impacts of renewable diesel production, the availability of feedstocks is a key consideration. Currently, biodiesel and renewable diesel in the U.S. are produced from a number of different feedstocks, including FOG, distillers corn oil, and virgin vegetable oils such as soybean oil and canola oil.

Figure III.B.2.c-1: Feedstocks Used to Produce Biodiesel and Renewable Diesel in the U.S.



Source: EMTS. Includes biodiesel and renewable diesel produced in the U.S. from imported feedstocks.

Use of soybean oil to produce biodiesel grew from approximately 10 percent of all domestic soybean oil production in the 2009/2010 agricultural marketing year to 48 percent in the 2023/2024 agricultural marketing year.[70] In the intervening years, the total increase in domestic soybean oil production and the increase in the quantity of soybean oil used to produce biodiesel and renewable diesel were similar, indicating that the increase in oil production was likely driven by the increasing demand for biofuel. However, as the production of renewable diesel has increased in recent years it appears that demand for soybean oil is growing faster than demand for soybean meal. Notably, the percentage of the soybean value that came from the soybean oil (rather than the meal and hulls) had been relatively stable and averaged approximately 33 percent from 2016–2020. The percentage of the soybean value that came from the soybean oil increased significantly starting in 2021, however, reaching a high of 53 percent in October 2021, before declining slightly to 39 percent in August 2024 (the most recent date for which data are available).[71]

Through 2020, most of the renewable diesel produced in the U.S. was made from FOG and distillers corn oil, with smaller volumes produced from soybean oil.[72] While some biodiesel production facilities are unable to use FOG and distillers corn oil without additional capital investment, renewable diesel production facilities are generally able to use them. Additionally, through 2024 the vast majority of renewable diesel consumed in the U.S. is used in

[70] USDA, "Oil Crops Yearbook," March 2025. *https://www.ers.usda.gov/data-products/oil-crops-yearbook.*

[71] *Id.*

[72] In December 2022, EPA approved generally applicable pathways for renewable diesel produced from canola oil (87 FR 73956; December 2, 2022). Use of canola oil to produce renewable diesel for consumption in the U.S. was therefore rare before 2023, but has gradually become more common in recent years.

California due to the combined value of RFS and LCFS incentives (together with the blenders' tax credit). Under California's LCFS program, renewable diesel produced from FOG and distillers corn oil receive more credits than renewable diesel produced from soybean oil and canola oil.

Available volumes of FOG (including used cooking oil and animal fats) and distillers corn oil from domestic sources are expected to continue to increase in future years, but these increases are expected to be limited. FOG are the byproducts of other activities (*e.g.,* food production and rendering operations), and production of FOG is not responsive to increasing demand for biofuel production. Because the production of FOG is generally not responsive to increased demand and most of the available domestic FOG is currently used for biofuel production or in other industries, we expect the availability of FOG to increase slowly, consistent with the observed trend in recent years. Similarly, distillers corn oil is a byproduct of ethanol production. Since we do not anticipate significant growth in ethanol production in future years (see Section III.B.4), we do not project significant increases in the production of distillers corn oil for biofuel production, as most ethanol production facilities currently produce distillers corn oil. Therefore, if renewable diesel production in future years increases rapidly as suggested by the large production capacity announcements, it will likely require increased use of vegetable oils such as soybean oil and canola oil, either from new production or diverted from other markets, or increased use of imported feedstocks.

Greater volumes of soybean oil are projected to be produced from new or expanded soybean crushing facilities through 2030. Several parties have announced plans to expand existing soybean crushing capacity or build new soybean crushing facilities. Public announcements of new and expanded soybean crushing capacity suggest that domestic soybean crush capacity could increase by approximately 1.5 million bushels of soybeans per day from 2024 through 2026.[73] An increase in the domestic crush capacity of this magnitude would result in an increase in domestic soybean oil production sufficient to produce approximately 750 million additional gallons of BBD per year and suggests a 250 million gallon per year annual increase in soybean oil production through 2026.[74] Similarly, an assessment of potential BBD feedstocks in future years prepared for the National Oilseed Processors Association by S&P Global estimated that increases in domestic soybean oil production could support the production of an additional 1 billion gallons of BBD from 2023 to 2027.[75] Most of the publicly announced expansion in soybean crush capacity is scheduled to occur in the next few years, through 2027. Recent data suggests that the domestic soybean crushing industry is capable of continuing to add significant capacity in future years, but that any investment in domestic soybean crushing is highly dependent on demand for soybean oil (and soybean meal) from biofuel producers and other markets.[76]

If domestic crushing of soybeans increases at the expense of soybean exports, domestic vegetable oil production could increase without the need for increasing domestic soybean acreage. Alternatively, increased demand for soybeans from new or expanded crushing facilities could be met through increased soybean production in the U.S. Increased demand for BBD feedstock could also be met through diversion of increasing volumes of qualifying feedstocks (*e.g.,* soybean oil and canola oil) from existing markets to produce renewable diesel. Were this diversion to occur, non-qualifying feedstocks (*e.g.,* palm oil or other virgin vegetable oils) could be used in larger quantities in place of soybean and canola oil in food and oleochemical markets. Diverting feedstocks from existing uses would be projected to result in higher prices for these feedstocks, as biofuel producers would have to outbid the current users of these feedstocks.

d. Imported BBD Feedstocks

In addition to processing domestic feedstocks such as distillers corn oil and soybean oil, a number of domestic BBD producers produce BBD from imported feedstocks. In recent years, and as multiple stakeholders have noted to EPA, the market has seen a significant increase in the quantity of imported BBD feedstocks. Imports of feedstocks that are often considered wastes or by-products of other industries, such as used cooking oil and tallow, have seen the greatest increase in recent years. Figure III.B.2.d–1 shows total imports of common BBD feedstocks through 2024. Figure III.B.2.d–2 shows the total volumes of domestic BBD produced from domestic feedstocks, domestic BBD produced from imported feedstocks, and imported BBD.

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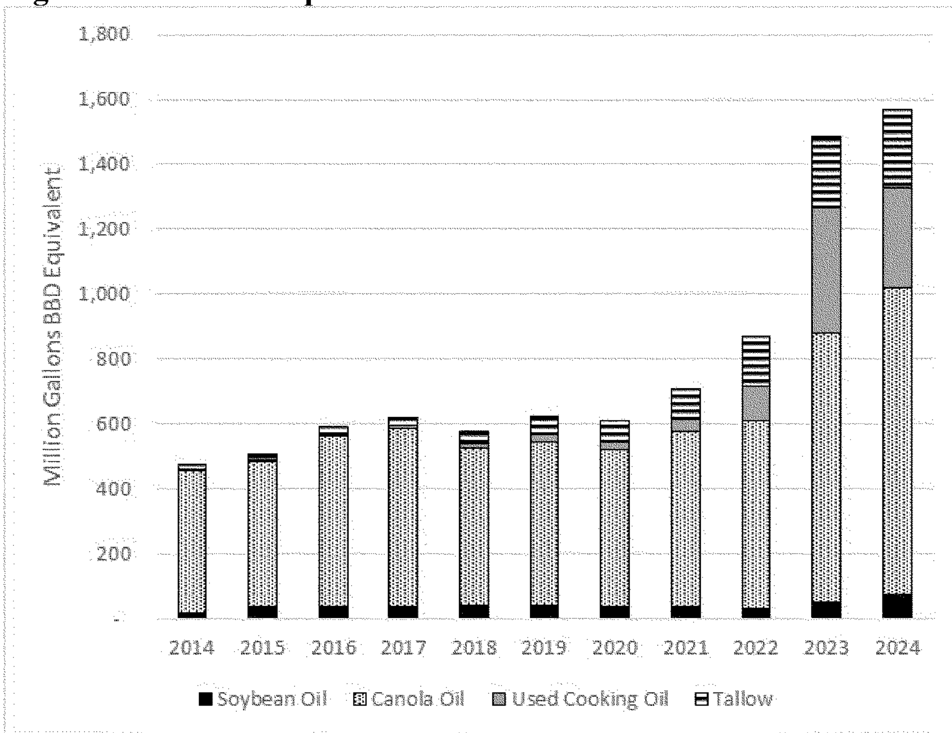
[73] Futrell, Crystal, ''US Soybean Crush Capacity on the Rise,'' World-Grain.com, January 5, 2024. *https://www.world-grain.com/articles/19463-us-soybean-crush-capacity-on-the-rise.*

[74] This estimate assumes a soybean oil yield of 11 lbs per bushel of soybeans and 1 gallon of BBD per 7.75 lbs of soybean oil.

[75] S&P Global, ''Availability of Feedstocks for Biofuel Use—Key Highlights,'' July 2024.

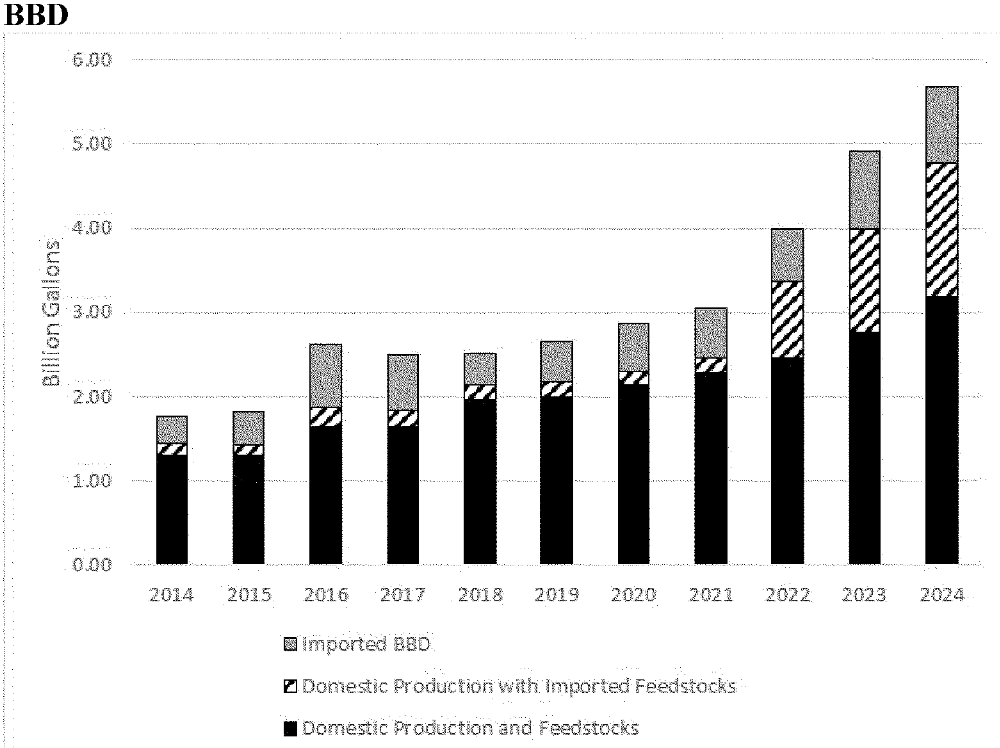
[76] See DRIA Chapter 7.2 for a further discussion of this topic.

Figure III.B.2.d-1: Imports of BBD Feedstocks



Source: UN ComTrade.

Figure III.B.2.d-2: Domestic BBD from Domestic and Imported Feedstocks and Imported BBD



Source: EMTS. Includes all BBD for which RINs are generated; does not account for exported BBD.

There are several factors that have likely contributed to the recent increases in imports of certain BBD feedstocks to the U.S. Three key factors contributing to the increase in imported feedstocks are increasing domestic demand for these feedstocks, increasing available supply of these feedstocks in other countries, and the structure of incentive programs for biofuels in the U.S. relative to other countries' polices. As noted in Section III.B.2.b, the production capacity for renewable diesel and renewable jet fuel has increased rapidly and is expected to continue to grow in future years. As the total production capacity for these fuels has grown, the demand for feedstocks for renewable fuel production has grown along with the production capacity. While some of this demand has been met by the increasing production of domestic feedstocks, domestic feedstock production has not grown as quickly as has the production capacity for renewable diesel and renewable jet fuel. Renewable diesel and renewable jet fuel producers have thus turned to imports to source the feedstocks needed to support increased BBD production.

At the same time domestic demand for these feedstocks has been increasing, the supply available to import from other countries has also been increasing. For example, we project that production of canola oil will increase in future years due to expanding canola crushing capacity in Canada.[77] Similar to the investments in soybean crushing in the U.S., a number of companies have announced investment in additional canola crushing capacity in Canada, and some of these projects are already under construction. Increasing canola oil production in Canada could provide an opportunity for domestic renewable diesel producers to import canola oil for biofuel production. We note that these parties will face competition for this feedstock from Canadian biofuel producers as well as food and other non-biofuel markets. For example, in 2023, Canada began implementing their Clean Fuels Requirements, requiring that the carbon intensity of transportation fuel decrease by 1.5 gCO_2e/MJ per year each year from 2023 to 2030.[78] These regulations are expected to increase demand for biofuels and biofuel feedstocks in Canada, and therefore also impact the quantities of canola oil and other feedstocks available for export to the U.S.

The incentives available in foreign countries to encourage the production and use of BBD are also changing. In response to the increase in the prices of energy and agricultural commodities caused by the Russian invasion of Ukraine in February 2022, a number of countries, including Croatia, Czech Republic, Finland, Latvia, Poland, and Sweden, temporarily reduced biofuel mandates and/or the penalties for not fulfilling the mandates.[79] The reduction in demand from these countries resulted in an increase in the available feedstock supply to the U.S.

At the same time, the European Union (EU) in recent years took actions to discourage the importation of used cooking oil (UCO) and biodiesel produced from UCO from China, which had previously been supplied in significant volumes. On December 20, 2023, the EU announced an anti-dumping investigation on biodiesel imported from China.[80] This investigation resulted in provisional duties on biodiesel from China sold in the EU, which were announced in July 2024.[81] The anti-dumping investigation and resulting fiscal duties on biodiesel imported from China from the EU opened up an opportunity for increased exports of UCO (the primary feedstock used to produce biodiesel in China previously exported to the EU) from China to the U.S.

Finally, incentive programs for biofuels in the U.S. have contributed to the recent observed increases in biofuel feedstock imports. State low carbon fuel standards or clean fuels programs, such as California's LCFS, provide greater incentives for fuels with lower carbon intensities. In general, fuels produced from wastes or by-products such as UCO or tallow have lower carbon intensity values under these programs and thus generate greater credits relative to virgin vegetable oils such as soybean oil and canola oil. In recent years additional States such as Oregon, Washington, and New Mexico have adopted programs that similarly provide higher incentives for fuels with lower carbon intensity.

While these State programs do not explicitly favor imported fuels and/or feedstocks over domestic fuels and feedstocks, most of the available waste and by-product feedstocks such as UCO and tallow available in the U.S. are already being used for biofuel production. The nature of these programs has likely played a role in biofuel producers seeking to import UCO and tallow from foreign countries rather than increasing their use of domestic soybean oil to maximize their generation of credits under these programs.

Changes to the RFS program have also contributed to the observed increase in feedstock imports. In December 2022, EPA approved generally applicable pathways for certain fuels, including renewable diesel, that are produced from qualifying canola oil.[82] The ability for renewable diesel producers to generate RINs for renewable diesel produced from canola oil created a new demand for canola oil in the U.S.

Together, the trends and policy factors described above collectively contributed to increasing imports of BBD feedstocks since 2021. We discuss the impact of these dynamics, and a proposed response to them in the RFS program, in Section VIII.

e. Summary

BBD (including biodiesel, renewable diesel, and renewable jet fuel) has been the fastest growing category of renewable fuel in the RFS program since 2021, with nearly all of the growth coming from renewable diesel. While the domestic supply of BBD feedstocks continues to grow, in recent years imported BBD and BBD produced from imported feedstocks have accounted for an increasing share of the total supply of BBD. BBD production capacity currently exceeds actual production and imports of these fuels by a significant margin, and ongoing investment is expected to result in significantly higher production capacity in future years, particularly for renewable diesel and renewable jet fuel. Further, because of the high blending rates for BBD in general and renewable diesel in particular, the use of BBD in the U.S. is unlikely to be constrained by limitations related to the ability to distribute these fuels or consume them in existing and future diesel engines.

In the absence of constraints related to the production capacity and the ability for the market to distribute and use BBD, the factors most likely to have the largest impact on the quantity of BBD required under the RFS program—in light of our analysis of the statutory factors—is the availability of affordable qualifying feedstocks, competition for those feedstocks for other uses, and competition for them abroad. The

[77] Some of the projected expansion in soybean crushing capacity discussed in Section III.B.2.c is from facilities also capable of crushing canola and other oilseeds. Domestic production of canola is limited, however, and the majority of canola oil supplied to biofuel producers through 2027 is expected to be imported from Canada.

[78] Government of Canada, "What are the Clean Fuel Regulations?" July 7, 2022. *https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-regulations/about.html.*

[79] USDA, "Biofuel Mandates in the EU by Member State—2024," June 27, 2024.

[80] European Commission, "European Commission to Examine Allegations of Unfairly Traded Biodiesel from China," December 20, 2023. *https://policy.trade.ec.europa.eu/news/european-commission-examine-allegations-unfairly-traded-biodiesel-china-2023-12-20_en.*

[81] Reuters, "EU to Set Tariffs on Chinese Biodiesel in Anti-Dumping Probe," July 19, 2024. *https://www.reuters.com/business/energy/eu-set-tariffs-chinese-biodiesel-imports-anti-dumping-probe-2024-07-19.*

[82] 87 FR 73956 (December 2, 2022).

sources of the feedstocks used to produce BBD also indirectly impact other factors, as the environmental and economic impacts of supplying additional volumes of BBD to the U.S. differ depending on the feedstocks used to produce the BBD and the likely alternative use of those feedstocks. For example, the projected economic and environmental impacts of increasing BBD production vary depending on whether the feedstock used to produce the BBD was UCO that would not otherwise have been collected, soybean oil from additional production and processing of soybeans, or the diversion of feedstocks or biofuels that would otherwise have been used in other countries.

In developing the volume scenarios for analysis in this action, we have therefore not attempted to identify the absolute maximum quantity of BBD that could be produced utilizing all potentially available production capacity and used in the U.S. Instead, we have developed two volume scenarios that reflect different growth rates for the quantity of BBD used in the U.S. based on our projections of the potential growth in available feedstocks. Both scenarios start with an updated projection of the supply of BBD to the U.S. which reflects the expected market conditions for 2025 based on the most recent available data at the time these scenarios were developed.[83] The low growth scenario increases the supply of BBD by 500 million RINs each year, a quantity approximately equal to our projection of the potential for growth in waste and byproduct feedstocks such as UCO and tallow, primarily from foreign sources. The high growth scenario increases the supply of BBD by 1 billion RINs each year, a quantity approximately equal to our projection of the potential growth for waste and byproduct feedstocks (primarily imported) and potential growth in virgin vegetable oil production that could be available to biofuel producers from the U.S. and Canada. These two scenarios are summarized in Table III.B.2.e–1 (in billion RINs) and III.B.e–2 (in billion gallons). More detail on the development of these scenarios can be found in DRIA Chapters 3 and 6.

TABLE III.B.2.e–1—BBD VOLUME SCENARIOS

[Billion RINs]

Scenario	2025	2026	2027	2028	2029	2030
Low Growth	7.91	8.41	8.91	9.41	9.91	10.41
High Growth	7.91	8.91	9.91	10.91	11.91	12.91

TABLE III.B.2.e–2—BBD VOLUME SCENARIOS

[Billion gallons]

Scenario	2025	2026	2027	2028	2029	2030
Low Growth	5.08	5.39	5.70	6.01	6.33	6.64
High Growth	5.08	5.70	6.33	6.95	7.58	8.20

3. Other Advanced Biofuel

In addition to BBD, other renewable fuels that qualify as advanced biofuel have been consumed in the U.S. in the past and are expected to contribute to compliance with applicable RFS volume requirements in the future. These other advanced biofuels include imported sugarcane ethanol, domestically produced advanced ethanol, RNG used in CNG/LNG vehicles not produced from cellulosic biomass, and heating oil, naphtha, and renewable diesel that does not qualify as BBD.[84] However, these biofuels have been consumed in much smaller quantities than biodiesel and renewable diesel in the past or have been highly variable.

To estimate the volumes of these other advanced biofuels that may be available in 2026–2030, we used the same general methodology as in the Set 1 Rule, which EPA originally presented in the Set 1 Rule. We projected the supply of these other advanced biofuels by including data on the supply of these fuels from 2023 (the most recent data available at the time the volume scenarios were defined). This methodology addresses the historical variability in these categories of advanced biofuel while recognizing that consumption in more recent years is likely to provide a better basis for making future projections than consumption in earlier years. Specifically, we applied a weighting scheme to historical volumes wherein the weighting was higher for more recent years and lower for earlier years. The result of this approach is shown in Table III.B.3–1. Details of the derivation of these estimates can be found in RIA Chapter 5.4. As the available data varies significantly from year to year, it does not allow us to identify an upward or downward trend in the historical consumption of these other advanced biofuels. Therefore, we have used the volumes in Table III.B.3–1 for all years in the volume scenarios for analysis (*i.e.,* 2026–2030).

TABLE III.B.3–1—ESTIMATE OF ANNUAL CONSUMPTION OF OTHER ADVANCED (D5) BIOFUEL

[Million RINs] [a]

Fuel	Volume
Imported sugarcane ethanol	58
Domestic ethanol	28

[83] Note that the quantity of BBD expected to be supplied in 2025 based on the available data (7.91 billion RINs) is significantly higher than the quantity of BBD projected to be used in 2025 in the Set 1 Rule (6.88 billion RINs). See DRIA Chapter 7.2 for more detail on the projected BBD supply for 2025.

[84] Renewable diesel produced through coprocessing vegetable oils or animal fats with petroleum cannot be categorized as BBD but remains advanced biofuel. 40 CFR 80.1426(f)(1).

TABLE III.B.3–1—ESTIMATE OF ANNUAL CONSUMPTION OF OTHER ADVANCED (D5) BIOFUEL—Continued

[Million RINs] [a]

Fuel	Volume
CNG/LNG	6
Heating oil	3
Naphtha [b]	43
Renewable diesel [c]	111
Total	249

[a] This table does not include fuels that qualify as cellulosic biofuel or BBD.

[b] While renewable naphtha is generally a co-product of renewable diesel production, the supply of renewable naphtha has not increased in line with the observed increases in renewable diesel production.

[c] Includes renewable diesel that is co-processed with petroleum, which does not qualify as BBD.

4. Conventional Renewable Fuel

Conventional renewable fuel includes any renewable fuel that is made from renewable biomass as defined in 40 CFR 80.1401, does not qualify as advanced biofuel (including cellulosic biofuel and BBD), and meets one of the following criteria:

• Is demonstrated to achieve a minimum 20 percent reduction in lifecycle GHG emissions in comparison to the gasoline or diesel which it displaces; or

• Is exempt (''grandfathered'') from the 20 percent minimum GHG reduction requirement due to having been produced in a facility or facility expansion that commenced construction on or before December 19, 2007, as described in 40 CFR 80.1403 and pursuant to CAA section 211(o)(2)(A)(i).

Under the statute, there is no volume requirement for conventional renewable fuel. Instead, conventional renewable fuel may fill that portion of the total renewable fuel volume requirement that is not required to be advanced biofuel. In some cases, this portion of the total renewable fuel requirement that can be met with conventional renewable fuel is referred to as an ''implied'' volume requirement. However, obligated parties are not required to comply with it per se, since any portion of it can be met with advanced biofuel volumes exceeding what is needed to meet the advanced biofuel volume requirement.

To project volumes of conventional renewable fuel for 2026–2030, we focused primarily on projecting volumes of corn ethanol consumed via motor gasoline use across all gasoline blends with varying concentrations of ethanol (*i.e.,* E10, E15, E85). We also investigated potential volumes of non-advanced biodiesel and renewable diesel.

a. Corn Ethanol

Ethanol made from corn starch has dominated the renewable fuels market on a volume basis in the past and is expected to continue to do so for the years addressed by this rulemaking.[85] Corn starch ethanol is prohibited by CAA section 211(i)(1)(B)(i) from being an advanced biofuel regardless of its lifecycle GHG emissions performance in comparison to gasoline.

Total domestic corn ethanol production capacity increased dramatically between 2005 and 2010 and increased at a slower rate thereafter. As of early 2024, domestic corn ethanol production capacity exceeded 18 billion gallons.[86] [87] Actual production of corn ethanol in the U.S. was approximately 16.2 billion gallons in 2024, up from approximately 15.6 billion gallons in 2023.[88]

The expected annual rate of future commercial production of corn ethanol will continue to be driven primarily by gasoline demand in 2026–2030, as most gasoline is expected to continue to contain 10 percent ethanol during this period. Commercial production of corn ethanol is also a function of exports of ethanol and the demand for E0, E15, and E85. There is evidence that some fuel retailers sell higher volumes of E15 than E10, leveraging lower prices at the pump and marketing higher-level ethanol blends to their customers as a cheaper fuel option with only negligible effects on fuel economy (a 1–2 percent reduction compared to E10). In addition to government incentives, industry-led efforts such as Prime-the-Pump have enjoyed great success in growing markets for higher ethanol gasoline blends by providing technical and financial assistance to fuel retailers.[89] Acknowledging the potential for growth in these fuel markets, we have incorporated projected growth in opportunities for sales of E15 and E85 blends into our assessment.

Despite this steady growth, there remains excess of production capacity of ethanol and corn feedstock in comparison to the ethanol volumes that we estimate will be consumed domestically during 2026–2030, given constraints on U.S. ethanol consumption as described in Section III.B.5. Thus, as was the case with the Set 1 Rule, we do not expect production capacity to be a limiting factor for meeting the volume scenarios analyzed in this action.

b. Biodiesel and Renewable Diesel

Other than corn ethanol, the only other conventional renewable fuels that have been used at significant levels in the U.S. in recent years have been conventional biodiesel and renewable diesel. Conventional biodiesel and renewable diesel are produced at facilities grandfathered under 40 CFR 80.1403 because there are no currently valid RIN-generating pathways for their production. Almost all conventional biodiesel and renewable diesel historically used in the U.S. was imported, with the only exceptions being less than 15 million gallons per year produced domestically between 2014 and 2024. The use of conventional biodiesel and renewable diesel did grow marginally in 2024 after a period of very low volume (less than 1 million gallons per year from 2018–2022), though the overall supply remained negligible (less than 0.1 percent of total biofuel supply

[85] Conventional ethanol from feedstocks other than corn starch have been produced in the past, but at significantly lower volumes. Production of ethanol from grain sorghum reached 125 million gallons in 2019, representing just less than 1 percent of all conventional ethanol in that year; grain sorghum ethanol in 2024 was only 46 million gallons. Waste industrial ethanol and ethanol made from non-cellulosic portions of separated food waste have been produced more sporadically and at even lower volumes. These other sources do not materially affect our assessment of volumes of conventional ethanol that can be produced.

[86] Renewable Fuels Association, ''2024 Ethanol Industry Outlook,'' February 19, 2024.

[87] EIA, ''U.S. Fuel Ethanol Plant Production Capacity,'' Petroleum & Other Liquids, August 15, 2024. *https://www.eia.gov/petroleum/ethanolcapacity.*

[88] EIA, ''Monthly Energy Review,'' Total Energy, March 2025. *https://www.eia.gov/totalenergy/data/monthly/archive/00352503.pdf.*

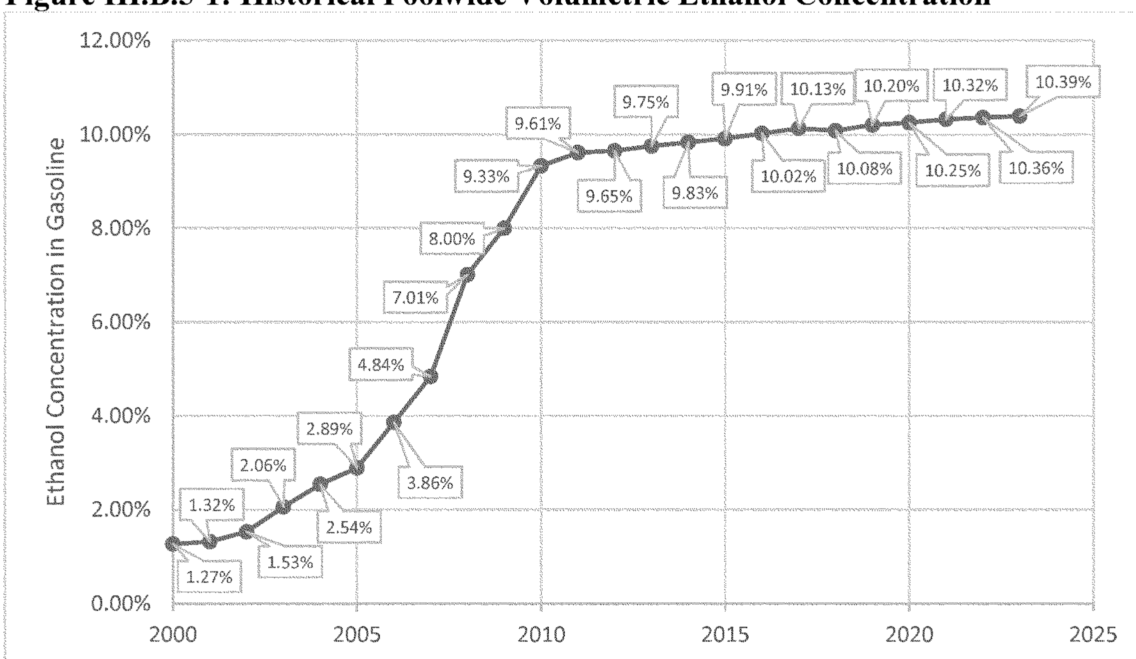
[89] Transportation Energy Institute, ''The Case of E15,'' February 2018.

to the U.S.). While some sparse generation of D6 RINs [90] for these fuels have been observed in recent years, nearly all these RINs were retired for being designated for use in any application other than transportation fuel and therefore do not represent qualifying fuel under the RFS program. As discussed in DRIA Chapter 7.7, there exists much greater potential for domestic production and use of conventional biodiesel and renewable diesel than has actually been supplied in prior years, suggesting the use of these fuels in the U.S. is largely a function of domestic demand versus other markets. While there exists some potential for growth across the period covered by this proposed rule, we are not projecting any increased volumes of these fuels will be used in 2026–2030.

5. Ethanol Consumption

Ethanol consumption in the U.S. is dominated by E10, with higher-level ethanol blends such as E15 and E85 being used in much smaller quantities. The total volume of ethanol that can be consumed—including ethanol produced from corn, grain sorghum, cellulosic biomass, the non-cellulosic portions of separated food waste, and sugarcane—is a function of demand for these three ethanol blends and for E0. The distribution of consumption for these different gasoline blends is best reflected by measuring the observed poolwide ethanol concentration. Ethanol concentration across the entire gasoline pool can exceed 10 percent only insofar as the incremental ethanol in E15 and E85 volumes more than offsets the lack of ethanol in E0 volume. Poolwide ethanol concentration increased dramatically from 2003 through 2010 and has continued to grow more slowly since 2010. As the average ethanol concentration approached and then exceeded 10 percent, the gasoline pool became saturated with E10, with a small, likely stable volume of E0 and small but gradually increasing volumes of E15 and E85. We expect this trend to continue during 2026–2030.

Figure III.B.5-1: Historical Poolwide Volumetric Ethanol Concentration



Source: Derived from ethanol and gasoline consumption in EIA, "Monthly Energy Review," Total Energy, March 2025.

For this action, new volume data from USDA's Higher Blends Infrastructure Incentive Program (HBIIP) [91] and additional volume data acquired directly from six States with high volumes of higher-level ethanol blends (California, Kansas, Iowa, Minnesota, New York, and North Dakota) has enabled a data-driven, bottom-up approach to projecting ethanol volumes into the future that differs from the way these projections were calculated in previous years.[92] In the Set 1 Rule, we projected ethanol concentration in the national gasoline pool using a least-squares regression model using then-current E15 and E85 fueling station population data.[93] This was due to lack of data and a subsequent inability to aggregate sales volumes by ethanol volume at the retail fuel station level. Now, greater availability of sales volume data from the six aforementioned States, HBIIP, and industry partners has enabled an updated and simplified methodology for producing the ethanol volume projections in this action.

Using the average sales of each gasoline-ethanol blend per retail fueling station, as well as updated station populations from DOE's Alternative Fuels Data Center (AFDC) [94] and the California Air Resources Board (CARB) [95] for 2021–2023, we produced

[90] The D codes given for each component category are defined in 40 CFR 80.1425(g). D codes are used to identify the statutory categories that can be fulfilled with each component category according to 40 CFR 80.1427(a)(2). D6 RINs satisfy only the "renewable fuel" category.

[91] USDA, "Higher Blends Infrastructure Incentive Program," May 2023. *https://www.rd.usda.gov/hbiip.*

[92] See DRIA Chapter 7.5.1 for more information on our projections of ethanol concentration in the gasoline pool.

[93] See "Renewable Fuel Standard (RFS) Program: Standards for 2023–2025 and Other Changes Regulatory Impact Analysis," EPA–420–R–23–015, June 2023 ("RFS Set 1 RIA"), Chapter 7.5.1.

[94] AFDC, "Historical Alternative Fueling Station Counts." *https://afdc.energy.gov/stations/states.*

[95] CARB, "Annual E85 Volumes," April 11, 2025.

forecasts of expected growth in station counts and throughputs out to 2030 for each gasoline-ethanol blend other than E10. We then used these forecasts to project the total fuel volume for these gasoline-ethanol blends (E0, E15, and E85) for 2026–2030 using the following relation: for gasoline-ethanol blends at each concentration, the total fuel volume consumed in any given year is equal to the product of the number of retail fueling stations offering that blend for sale and the volume of that fuel blend sold at a fueling station (*i.e.,* throughput) on average during that year. Finally, we projected E10 as the remainder of the gasoline pool, after accounting for the projected volumes of E0, E15, and E85.

Total ethanol consumption is the sum of ethanol blended with gasoline (E0) to create E10, E15, and E85.[96] The ethanol portion of the projected total consumption for each fuel blend (*i.e.,* total ethanol consumption) is shown in Table III.B.5–1. While we project that the ethanol concentration in the gasoline pool will increase in future years, total ethanol consumption is projected to decrease due to decreases in total gasoline consumption in future years.

TABLE III.B.5–1—PROJECTED ETHANOL CONCENTRATION AND CONSUMPTION

Year	Projected ethanol concentration (%)	Projected ethanol consumption (million gallons)
2026	10.54	13,993
2027	10.58	13,871
2028	10.60	13,724
2029	10.67	13,558
2030	10.71	13,377

C. Volume Scenarios for 2026–2030

Based on the analyses described in Section III.B, we developed two different volume scenarios for 2026–2030 that we then used to analyze the expected impacts of the statutory factors. This section describes the volume scenarios, while Section IV summarizes the results of the analyses we performed. The volumes we are proposing in this action based on the analysis of the statutory factors are described in Section V.

Both of the volume scenarios developed for this action represent growth in the advanced biofuel and total renewable fuel categories relative to the volume of these fuels we expect to be supplied in 2025. Further, both scenarios are identical in the quantities of cellulosic biofuel, advanced biofuel other than BBD, and conventional renewable fuel we project will be supplied. Where the scenarios differ is in the quantity of BBD we project will be supplied in each year. Throughout this action we refer to these two scenarios as the Low Volume Scenario and the High Volume Scenario (or collectively, ''the Volume Scenarios''), though we note that even the Low Volume Scenario represents an annual growth rate of 500 million RINs per year of BBD.

In developing the Volume Scenarios, we have considered the implied volumes for each component category of renewable fuel (cellulosic biofuel, non-cellulosic advanced biofuel, and conventional renewable fuel) in the statutory tables through 2022. While these volumes are not binding on the volume requirements in future years, they do provide an indication of statutory intent. We also considered the statutory intent of the RFS program to increase renewable fuel volumes over time, along with other factors enumerated in the statute to inform the proposed volumes.

Given the nested nature of the statutory renewable fuel categories, we have largely framed our assessment of volumes in terms of the component categories rather than in terms of the statutory categories (cellulosic biofuel, advanced biofuel, total renewable fuel). The statutory categories are those addressed in CAA section 211(o)(2)(B)(i)–(iii), and cellulosic and advanced biofuel are nested within the overall total renewable fuel category. The component categories are the categories of renewable fuels that make up the statutory categories, but which are not nested within one another. They possess distinct economic, environmental, technological, and other characteristics relevant to the factors we must analyze under the statute, making our focus on them rather than the nested categories in the statute technically sound. Finally, an analysis of the component categories is equivalent to analyzing the statutory categories, since doing so would effectively require us to evaluate the difference between various statutory categories (*e.g.,* assessing ''the difference between volumes of advanced biofuel and total renewable fuel'' instead of assessing ''the volume of conventional renewable fuel''), adding unnecessary complexity to our analysis. In any event, were we to frame our analysis in terms of the statutory categories, we believe that our substantive approach and conclusions would remain materially the same.

1. Cellulosic Biofuel

In determining the cellulosic biofuel volume scenario, we started by considering the statutory volume targets for 2010–2022. The statutory volumes for cellulosic biofuel increased rapidly, from 100 million gallons in 2010 to 16 billion gallons in 2022 with the largest increases in the later years. While notable on its own, it is even more notable in comparison to the implied statutory volumes for the other renewable fuel volumes. Statutory BBD volumes did not increase after 2012, implied conventional renewable fuel volumes did not increase after 2015, and non-cellulosic advanced biofuel volume increases tapered off in recent years with a final increment in 2022. Thus, the clear focus of the statute, and CAA section 211(o)(1)(E) in particular, by 2022 was on growth in cellulosic biofuel volumes, which have the greatest GHG reduction threshold requirement in the statute.[97]

This increasing emphasis in the statute on cellulosic biofuel over time is likely due to some or all of the following factors:

• Expectations that cellulosic biofuel has significant potential to reduce GHG emissions (cellulosic biofuels are required to reduce GHG emissions by 60

[96] See DRIA Chapter 7.5.1 for a more comprehensive discussion of the methodology employed to produce the total ethanol consumption projection.

[97] *Cf.* CAA section 211(o)(1)(B)(i), (D), (2)(A)(i). See also definition of ''cellulosic biofuel'' in 40 CFR 80.2.

percent relative to the gasoline or diesel fuel they displace);

- That cellulosic biofuel feedstocks could be produced or collected with relatively few negative environmental impacts;
- That the feedstocks would be comparable or cheaper in cost relative to other fuel feedstocks, allowing for lower cost biofuels to be produced than those produced from feedstocks without other primary uses such as food; and
- That the technological breakthroughs needed to convert cellulosic feedstocks into biofuel were likely imminent.

As discussed in Section II.C, CAA section 211(o)(2)(B)(iv) requires that EPA determine the cellulosic biofuel volume requirement such that EPA will not need to waive the volumes under CAA section 211(o)(7)(D).

The cellulosic biofuel volumes are the same for both the Low and High Volume Scenarios and represent the projected amount of qualifying biofuel expected to be used as transportation fuel in the U.S. for 2026–2030, accounting for incentives provided by the RFS program and other state and federal programs. The cellulosic biofuel volume scenario for 2026–2030 is shown in Table III.C.1–1. Because the technical, economic, and regulatory challenges related to cellulosic biofuel production vary significantly between the various types of cellulosic biofuel, we have shown the volumes for ethanol from corn kernel fiber and CNG/LNG derived from biogas separately.

TABLE III.C.1–1—CELLULOSIC BIOFUEL VOLUME SCENARIO

[Million RINs]

	2026	2027	2028	2029	2030
RNG use as CNG/LNG	1,174	1,239	1,309	1,384	1,464
Ethanol from CKF	124	123	122	120	119
Total cellulosic biofuel	1,298	1,362	1,431	1,504	1,583

2. Non-Cellulosic Advanced Biofuel

Although there are no volume targets in the statute for years after 2022, the statutory volume targets for prior years represent a useful point of reference in the consideration of volumes that may be appropriate for 2026–2030. For non-cellulosic advanced biofuel, the implied statutory requirement in CAA section 211(o)(2)(B) increased in every year between 2009 and 2019. It then remained at 4.5 billion gallons for three years before finally rising to 5.0 billion gallons in 2022. In the Set 1 Rule, EPA further increased the implied volume of non-cellulosic advanced biofuel over the course of three years to a total of 5.95 billion RINs in 2025. However, the market has outperformed these standards to date primarily through higher than anticipated imports of non-cellulosic advanced biofuels and their feedstocks. In recognition of this, the volumes for non-cellulosic advanced biofuel in the Volume Scenarios are higher than the non-cellulosic biofuel volumes in the Set 1 Rule, starting with an updated projection of supply for 2025.

For 2026–2030, we anticipate that a key factor in the growth in the production of advanced biodiesel and renewable diesel (the two non-cellulosic advanced biofuels projected to be available in the greatest quantities through 2030) will be the availability of feedstocks as discussed in Section III.B.2. In light of the significant uncertainties related to the supply of qualifying feedstock in these years, we developed two scenarios for the potential supply of advanced biodiesel and renewable diesel: a low growth scenario and a high growth scenario. These two volume scenarios, when combined with our projection of the available supply of other advanced biofuels discussed in Section III.B.3, are the bases for the two non-cellulosic advanced biofuel volume scenarios that differentiate the Low Volume Scenario from the High Volume Scenario.

TABLE III.C.2–1—TOTAL NON-CELLULOSIC ADVANCED BIOFUEL VOLUME SCENARIOS

[Billion RINs]

	2025 (Set 1) [a]	2025 (Proj.) [b]	2026	2027	2028	2029	2030
Low Volume Scenario							
BBD	6.88	7.91	8.41	8.91	9.41	9.91	10.41
Other advanced biofuel	0.29	0.25	0.25	0.25	0.25	0.25	0.25
Total con-cellulosic advanced biofuel	7.17	8.16	8.66	9.16	9.66	10.16	10.66
High Volume Scenario							
BBD	6.88	7.91	8.91	9.91	10.91	11.91	12.91
Other advanced biofuel	0.29	0.25	0.25	0.25	0.25	0.25	0.25
Total con-cellulosic advanced biofuel	7.17	8.16	9.16	10.16	11.16	12.16	13.16

[a] Volumes of BBD and other advanced biofuels projected to be used to meet the RFS volume requirements in the Set 1 Rule
[b] Volumes of BBD and other advanced biofuels projected to be used in 2025 based on data available through May 2024.

3. Conventional Renewable Fuel

The conventional renewable fuel volume scenario represents the volume of these fuels we project would be supplied to the market when considering the incentives that could be available through the RFS program and other state and national incentives. Since the supply of ethanol is projected to be limited by the ability for the market to consume ethanol in gasoline blends, the supply of conventional ethanol from 2026–2030 can be estimated from the total ethanol consumption projections from Table III.B.5–1 and our projections for other forms of ethanol as discussed earlier in this section. Our projected volumes of ethanol consumption are presented in Table III.C.3–1. We do not currently project that non-ethanol conventional renewable fuels will be supplied to the U.S. under the RFS program in 2026–2030.

TABLE III.C.3–1—ETHANOL CONSUMPTION VOLUME SCENARIO

[Million gallons]

	2026	2027	2028	2029	2030
Cellulosic ethanol	126	125	124	122	120
Imported sugarcane ethanol	58	58	58	58	58
Domestic advanced ethanol	28	28	28	28	28
Conventional ethanol	13,781	13,660	13,514	13,350	13,170
Total ethanol consumption	13,993	13,871	13,724	13,558	13,377

4. Summary

Many of the factors we are statutorily obligated to analyze under CAA section 211(o)(2)(B)(ii) when setting volume standards for the RFS program are difficult to analyze in the abstract, particularly those related to economic and environmental impacts. For this reason, we opted to develop volume scenarios to analyze for each category of renewable fuel, which are summarized in Tables III.C.4–1 and 2. Note that neither of these volume scenarios include the impacts of the proposed import RIN reduction provisions described in Section VIII.

TABLE III.C.4–1—LOW VOLUME SCENARIO

[Million RINs]

	2026	2027	2028	2029	2030
Cellulosic biofuel (D3 & D7)	1,298	1,362	1,431	1,504	1,583
Biomass-based diesel (D4)	8,410	8,910	9,410	9,910	10,410
Other advanced biofuel (D5)	249	249	249	249	249
Conventional renewable fuel (D6)	13,783	13,662	13,516	13,352	13,172

TABLE III.C.4–2—HIGH VOLUME SCENARIO

[Million RINs]

	2026	2027	2028	2029	2030
Cellulosic biofuel (D3 & D7)	1,298	1,362	1,431	1,504	1,583
Biomass-based diesel (D4)	8,910	9,910	10,910	11,910	12,910
Other advanced biofuel (D5)	249	249	249	249	249
Conventional renewable fuel (D6)	13,783	13,662	13,516	13,352	13,172

To inform the volumes we are proposing for 2026 and 2027, we analyzed these volume scenarios according to the factors required under the statute in CAA section 211(o)(2)(B)(ii). A summary of several of these analyses is described in Section IV and discussed in greater detail in the DRIA. Details of the individual biofuel types and feedstocks that make up these volume scenarios are provided in the DRIA Chapter 3. In Section V, we discuss the proposed volume requirements based on a consideration of all the factors that we analyzed.

D. Baselines

To estimate the impacts of the Volume Scenarios, we must identify an appropriate baseline(s). The baseline reflects the use of renewable fuels absent the proposed action or RFS program (*i.e.,* the alternative collection of biofuel volumes by feedstock, production process (where appropriate), biofuel type, and use that would be anticipated to occur after 2025 in the absence of proposed standards), and acts as the point of reference for assessing the impacts. To this end, we have developed a ''No RFS'' scenario that we used as the baseline for analytical purposes (hereafter the ''No RFS Baseline''), which reflects a world without the RFS program. Many of the same supply-related factors that we used to develop the Volume Scenarios were also relevant in developing the No RFS Baseline.

We also consider a 2025 baseline that in some cases may be more informative in understanding the impacts of the Volume Scenarios relative to the status quo. We further discuss alternative baselines to describe our reasoning for the public and interested stakeholders, and because we understand there are differing, informative baselines that could be used in this type of analysis.

1. No RFS Baseline

Broadly speaking, the RFS program is designed to increase the use of renewable fuels in the transportation sector beyond what would occur in the absence of the program. It is appropriate, therefore, to use a scenario representing what would occur if the RFS program did not continue to exist as the baseline for estimating the costs and impacts of the Volume Scenarios. Such a ''No RFS'' baseline is consistent with the Office of Management and Budget's Circular A–4, which says that the appropriate baseline would normally ''be a 'no action' baseline: what the world will be like if the proposed rule is not adopted.'' [98]

Importantly, a ''No RFS'' baseline would not be equivalent to a market scenario wherein no renewable fuels were used at all. Prior to the RFS program, both biodiesel and ethanol were used in the transportation sector, whether due to state or local incentives, tax credits, or a price advantage over conventional petroleum-based gasoline and diesel. This same situation would exist in 2026–20230 in the absence of the RFS program. Federal, State, and local tax credits, incentives, and support payments will continue to be in place for these fuels, as well as State programs such as blending mandates and LCFS programs. Furthermore, now that capital investments in renewable fuels have been made and markets have been oriented towards their use, there are strong incentives in place for continuing their use even if the RFS program were to disappear. As a result, it would be improper and inaccurate to attribute all use of renewable fuel in 2026–2030 to the applicable standards under the RFS program.

To inform our assessment of the volume of renewable fuels that would be used in the absence of the RFS program for the years 2026–2030, we began by analyzing the trends in the economics for renewable fuels blending in prior years. Assessing these trends is important because the economics for blending renewable fuels changes from year to year based on renewable fuel feedstock and petroleum product prices and other factors that affect the relative economics for blending renewable fuels into petroleum-based transportation fuels. A renewable fuel facility investor and the financiers who fund their projects will review the historical (*e.g.,* did they lose money in a previous year), current, and perceived future economics of the renewable fuel market when deciding whether to continue to operate their renewable fuel facilities, and our analysis attempted to account for these factors.

The No RFS Baseline economic analysis for 2026–2030 compares the projected renewable fuel cost with the projected cost for the fossil fuel it displaces, at the point that the renewable fuel is blended with the fossil fuel, to assess whether the renewable fuel provides an economic advantage to blenders. The comparison is performed at the point that the renewable fuel is blended with the fossil fuel to assess whether the renewable fuel provides an economic advantage to blenders. If the renewable fuel is lower cost than the fossil fuel it displaces, it is assumed that the renewable fuel would be used absent the RFS program (within the constraints described below). The No RFS Baseline economic analysis that we conducted mirrors the cost analysis described in Section IV.C, but there are several differences. The primary difference is that the No RFS Baseline economic analysis was conducted from the fuels industry's perspective, whether they would find it economically advantageous to blend renewable fuel into petroleum fuel in the absence of the RFS program. Conversely, the social cost analysis reflects the overall cost impacts on society at large.[99] A primary example of a social cost not considered for the No RFS Baseline economic analysis is the fuel economy effect due to the lower energy density of the renewable fuel, as this cost is generally borne by consumers, not the fuels industry. Other ways that the No RFS Baseline economic analysis is different from the social cost analysis include:

- In the context of assessing production costs, we amortized the capital costs at a higher rate of return more typical for industry investment instead of the rate of return used for social costs.
- We assessed renewable fuel distribution costs to the point where it is blended into petroleum fuel, not all the way to the point of use, which is necessary for estimating the fuel economy cost.[100]
- While we generally do not account for the fuel economy disadvantage of most renewable fuels for the No RFS Baseline economic analysis, the exception is E85 where the lower fuel economy of using E85 is so obvious to vehicle owners that they demand a lower price to make up for this loss of fuel economy. As a result, retailers must price E85 lower than the primary alternative E10 to account for this bias and they must consider this in their decisions to blend and sell E85.[101]

To estimate the relative cost of a renewable fuel compared to the fossil fuel being displaced, we considered several different cost components (*i.e.,* production cost, distribution cost, any blending cost, retail cost) together to reflect the relative cost of each renewable fuel to its respective fossil fuel. We also considered any applicable federal or state programs, incentives, or subsidies that could reduce the apparent blending cost of the renewable fuel at the terminal, including the 45Z credit. The exact amount of credit under 45Z is more variable and depends on a range of factors. However, generally speaking, the amount of credit that fuel producers are able to claim under 45Z is less than the previous $1 per gallon credit that biodiesel and renewable diesel producers were able to claim under 40A.[102] In the case of higher ethanol blends, the retail cost associated with the equipment or use of compatible materials needed to enable the sale of these newer fuels is assumed to be reduced by 50 percent due to the HBIIP program.

In addition, there are a number of State programs that create subsidies for biodiesel and renewable diesel fuel, the largest being offered by California and Oregon through their LCFS programs.[103] We accounted for State and local biodiesel mandates by including their mandated volume regardless of the economics. Several States offer tax credits for blending ethanol at 10 percent. Other States offer tax credits for E85, of which the largest is New York. We are not aware of any State tax credits or subsidies for E15.[104] To account for the various State assumptions, it was necessary to model the cost of using these biofuels on a State-by-State basis.

For most renewable fuels, the economic analysis provided consistent results, indicating that they are either

[98] Office Management and Budget, ''Circular A–4,'' September 17, 2003.

[99] See Section IV.C and DRIA Chapter 10 for descriptions of the social cost analysis.

[100] For several renewable fuels (*e.g.,* ethanol blended as E10, biodiesel, and renewable diesel), the fuel economy cost is paid by the consumer. Because it is the fuels industry (*i.e.,* refiners, terminals, and retailers) that decides whether to blend renewable fuels into petroleum fuels, they are only concerned about the relative cost at the point in which the renewable fuel is blended into the petroleum fuel, not the costs downstream of that blending point.

[101] See DRIA Chapter 2 for further discussion of this topic.

[102] See DRIA Chapter 1 for a further discussion of the 45Z tax credit.

[103] At the time the analysis for the No RFS Baseline was completed, there was insufficient data to project the impacts of LCFS programs in New Mexico on biofuel consumption in these states in the absence of the RFS program.

[104] In light of the fluid situation with respect to a 1-psi RVP waiver for E15 or actions to remove the 1-psi wavier for E10 in eight midwestern states, our analysis did not specifically assume either of these potential changes. These assumptions can affect the relative cost of E15; however, adopting these assumptions would not have impacted the overall conclusions with respect to blending E15 in the absence of the RFS program.

economical in all years or are not economical in any year. However, this was not true for biodiesel and renewable diesel, where the results varied from year to year. Such swings in the economic attractiveness of biodiesel and renewable diesel confound efforts on the part of investors to project future returns on their investments to determine whether to continue to operate their facilities, or shutdown. Thus, to smooth out the swings in the economics for using biodiesel and renewable diesel and look at it the way facility operators and their investors would have in the absence of the RFS program, we made two key assumptions. First, the economics for biodiesel and renewable diesel were modeled starting in 2009 and the trend in its use was made dependent on the relative economics in comparison to petroleum diesel over distinct four-year periods. As a result, the first four-year period modeled the costs over 2009–2012 to estimate the volume of biodiesel and renewable diesel that would be used in 2012 in the absence of the RFS program. Second, the estimated biodiesel and renewable diesel volumes were limited in the analysis to no greater volume than what occurred under the RFS program in any year, since the existence of the RFS program would be expected to create a much greater incentive for using these fuels than if the RFS program was not in place.

We also conducted an economic analysis for cellulosic biofuels, including cellulosic ethanol, corn kernel fiber ethanol, and biogas. Since the volumes of these biofuels were much smaller, a more generalized approach was used in lieu of the detailed state-by-state analysis conducted for corn ethanol, biodiesel, and renewable diesel fuel.

The No RFS Baseline for 2026–2030 is summarized in Table III.D.1–1.[105]

TABLE III.D.1–1—NO RFS BASELINE

[Million RINs]

	2026	2027	2028	2029	2030
Cellulosic biofuel (D3 & D7)	582	619	659	702	749
Biomass-based diesel (D4)	3,156	3,310	3,429	3,614	3,753
Other advanced biofuel (D5)	197	197	197	197	197
Conventional renewable fuel (D6)	13,571	13,434	13,278	13,099	12,906

Our analysis shows that conventional ethanol is economical to use in 10 percent blends (E10) without the presence of the RFS program. Conversely, higher-level ethanol blends are only partially economic without the RFS program. E85 is economic in some of the years before, during, and after the years 2026–2030 in the State of California;[106] thus, we assumed that E85 would be consumed in California without the RFS program.[107] While E85 is economic in New York, which offers a large E85 blending subsidy, the volume of E85 sold in New York is very small even with the RFS program in place; therefore, we ignored E85 sales in New York. Conversely E15 is not economic without the RFS program due to the high cost associated with the equipment needed to be installed at retail stations, even if these costs are partially subsidized by government funding, and the lack of octane blending value. Some volume of biodiesel is estimated to be blended based on state mandates in the absence of the RFS program, and some additional volume of both biodiesel and renewable diesel is estimated to be economical to use without the RFS program, particularly in California and Oregon due to the LCFS incentives. The volumes of CNG from biogas and imported sugarcane ethanol are projected to be consumed in California due to the economic support provided by their LCFS.

2. 2025 Baseline

The applicable volume requirements established for one year under the RFS program do not roll over automatically to the next, nor do the volume requirements that apply in one year become the default volume requirements for the following year in the event that no volume requirements are set for that following year. Nevertheless, the volume requirements established for the previous year represent the most recent set of volume requirements that the market was required to meet.

Since the previous year's volume requirements represent the starting point for any adjustments that the market may need to make to meet the next year's volume requirements, they represent another informational baseline for comparison. For this reason, in previous RFS annual standard-setting rulemakings we have used previous year standards as a baseline against which to compare the projected impacts of the proposed volumes and are also doing so here in addition to the No RFS Baseline for some of the factors (*e.g.,* the cost of this action). We note that in developing the proposed volume requirements in this action, we considered updated projections of biofuel production in 2025, which are significantly higher than the 2025 Baseline shown below that is used as a point of comparison in some of our analyses.

The 2025 volume requirements were finalized in the Set 1 Rule and the volumes we projected to be used to satisfy these requirements are shown in Table III.D.3–1.[108]

[105] See DRIA Chapter 2 for a more complete description of the No RFS Baseline and its derivation.

[106] Our analysis indicated that E85 was also economic compared to gasoline in Oregon; however, because there are only five stations offering E85 in Oregon, we did not include E85 sold in Oregon in the No RFS Baseline.

[107] Since E85 is borderline economic in California in the No RFS Baseline when we do not assume any increase in California's LCFS credit, a likely increase in the LCFS credit under the No RFS Baseline increases the certainty that E85 would be economic. Additionally, we did not consider the possibility that cellulosic ethanol, which receives a larger LCFS credit, could be used to produce E85 and may be more economic than corn ethanol.

[108] More details on the 2025 Baseline can be found in DRIA Chapter 2.

TABLE III.D.3–1—2025 BASELINE

[Million RINs]

	Volume
Cellulosic biofuel (D3 & D7)	1,376
Biomass-based diesel (D4)	6,881
Other advanced biofuel (D5)	290
Conventional renewable fuel (D6)	13,939

E. Volume Changes Analyzed

In general, our analysis of the impacts of the Volume Scenarios was based on the differences between the No RFS Baseline and our assessment of how the market would respond to the Low and High Volume Scenarios. Those differences are shown in Tables III.E–1 and 2.[109] Note that this approach is squarely focused on the differences in volumes between the No RFS Baseline and the Volume Scenarios; our analysis does not, in other words, assess impacts from total renewable fuel use in the U.S. As noted above, we also consider the impacts of this action relative to the 2025 Baseline for some of our analyses. The changes in renewable fuel consumption relative to the 2025 Baseline are shown in in Tables III.E–3 and 4.

TABLE III.E–1—CHANGES IN RENEWABLE FUEL CONSUMPTION—LOW VOLUME SCENARIO VS. NO RFS BASELINE

[Million RINs]

	2026	2027	2028	2029	2030
Cellulosic biofuel (D3 & D7)	716	743	772	802	834
Biomass-Based Diesel (D4)	5,255	5,600	5,981	6,297	6,658
Other Advanced Biofuel (D5)	52	52	52	52	52
Conventional Renewable Fuel (D6)	212	228	238	252	266

TABLE III.E–2—CHANGES IN RENEWABLE FUEL CONSUMPTION—HIGH VOLUME SCENARIO VS. NO RFS BASELINE

[Million RINs]

	2026	2027	2028	2029	2030
Cellulosic biofuel (D3 & D7)	716	743	772	802	834
Biomass-Based Diesel (D4)	5,755	6,600	7,481	8,297	9,158
Other Advanced Biofuel (D5)	52	52	52	52	52
Conventional Renewable Fuel (D6)	212	228	238	252	266

TABLE III.E–3—CHANGES IN RENEWABLE FUEL CONSUMPTION—LOW VOLUME SCENARIO VS 2025 BASELINE

[Million RINs]

	2026	2027	2028	2029	2030
Cellulosic biofuel (D3 & D7)	−78	−14	55	128	207
Biomass-Based Diesel (D4)	1,529	2,029	2,529	3,029	3,529
Other Advanced Biofuel (D5)	−41	−41	−41	−41	−41
Conventional Renewable Fuel (D6)	−156	−277	−423	−587	−767

TABLE III.E–4.—CHANGES IN RENEWABLE FUEL CONSUMPTION—HIGH VOLUME SCENARIO VS. 2025 BASELINE

[Million RINs]

	2026	2027	2028	2029	2030
Cellulosic biofuel (D3 & D7)	−78	−14	55	128	207
Biomass-Based Diesel (D4)	2,029	3,029	4,029	5,029	6,029
Other Advanced Biofuel (D5)	−41	−41	−41	−41	−41
Conventional Renewable Fuel (D6)	−156	−277	−423	−587	−767

IV. Analysis of Volume Scenarios

As described in Section II.B, the statute specifies a number of factors that EPA must analyze in making a determination of the appropriate volume requirements to establish for years after 2022 (and for BBD, years after 2012).[110] In this section, we provide a summary of the analysis of a selection of factors, including climate change, energy security, costs, employment, and economic impacts for

[109] See DRIA Chapter 2 for more details of this assessment, including a more precise breakout of those differences.

[110] A full description of the analysis for all factors is provided in the DRIA.

the Volume Scenarios, along with some implications of those analyses. We provide a summary of our consideration of all factors in determining the proposed volume requirements in Section V.

A. Energy Security

Changes in the required volumes of renewable fuel can affect the financial and security-related risks associated with U.S. trade in crude oil and petroleum products, including both imports and exports (hereafter referred to collectively as ''net petroleum imports''), which, in turn, would have a direct impact on the national energy security of the U.S. Likewise, the required volumes of renewable fuel may lead to changes in imports and exports of renewable fuels and renewable fuel feedstocks that can also impact U.S. energy security.

U.S. energy security is often defined as the continued availability of energy sources at an acceptable price.[111] Energy independence can be achieved by reducing the sensitivity or reliance of an economy to energy imports and foreign energy markets to the point where the costs of depending on foreign energy are so small that they have minimal effects on economic, military, or foreign policies.[112] A central goal of U.S. energy policy for decades has been to lower U.S. oil imports and, thus, become less reliant on foreign oil suppliers. Similarly, as described in Section VIII, we are also proposing to reduce the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks, which is intended to reduce America's reliance on such fuels in future years consistent with the statutory goals of energy security and independence.

The U.S. has witnessed a significant change in its exposure to the world oil market since the initiation of the RFS2 program in 2010, which has implications for U.S. energy security. In 2010, U.S. net imports of petroleum were roughly 9.4 million barrels a day (MMBD).[113] However, over the past decade, mainly as a result of the increased domestic production of oil, particularly ''tight'' (*i.e.,* shale) oil, as well as increases in renewable fuels, the U.S. has gradually shifted from a large net petroleum importer to a modest net petroleum exporter.[114] By 2023, U.S. net petroleum exports were roughly 1.7 MMBD of petroleum.[115] For 2026–2030, EIA anticipates that the U.S. will continue the long-term shift from being a large net petroleum importer, as it was in the 2010 decade, to a modest net petroleum exporter of roughly 2.4 MMBD.[116]

In recent years, however, a substantial quantity of imports of renewable fuels and renewable fuel feedstocks have been used to meet the RFS volume obligations. In particular, there has been a recent expansion of imports of BBD feedstocks since 2021, as can be seen in Figure III.B.2.d–2. This shift, which has been driven by a confluence of factors (as discussed in Section III.B.2), can have implications for the U.S.'s energy security and energy independence.

Despite the long-term shift in the U.S.'s net petroleum trade position, energy security risks remain for the U.S. There are three main reasons why energy security is still a concern. First, oil and renewable fuels and renewable fuel feedstocks are globally traded commodities. As a result, price shocks for these commodities can be transmitted globally even if a country is a net exporter of a commodity. For example, since the U.S. is a large consumer of oil, an oil price shock would raise the price of oil and oil products and could cause broad adverse effects on the economy, even though the U.S. is an overall net petroleum exporter. Second, many U.S. refineries rely significantly or exclusively on imports of heavy crude oil, which could be subject to international supply disruptions. In 2024, gross petroleum imports totaled roughly 8.4 MMBD.[117] Likewise, there has been an expansion in imported feedstocks for BBD in recent years. Third, oil exporters with a large share of global production can raise or lower the price of oil by exerting their market power through the Organization of Petroleum Exporting Countries (OPEC) to alter oil supply relative to demand. All three of the factors listed above contribute to the vulnerability of the U.S. economy to episodic fuel supply shocks and price spikes, even though EIA projects the U.S. will continue to be a net petroleum exporter through 2026–2030.

Oil markets can be subject to episodic periods of price instability due to world oil market disruptions. The most recent world oil price shock started in the beginning of 2022, when world oil prices and price volatility rose fairly rapidly, in large part as a response to oil supply concerns with Russia's invasion of Ukraine beginning on February 24, 2022.[118] For example, the West Texas Intermediate (WTI) crude oil price rose from roughly $76 per barrel on January 3, 2022, to roughly $124 per barrel on March 8, 2022, a 63 percent increase.[119] Conversely, by September 9, 2024, the WTI crude oil price had fallen back to $70/barrel, a somewhat lower price than before the Russian invasion of Ukraine.[120] Oil prices at present are relatively low mainly because of projected slowdown in world oil demand growth, particularly in China.[121] Crude oil prices (*i.e.,* the WTI crude oil price) are projected to be mostly flat over 2026–2027, in the $85–86 per barrel (2022$) range.[122]

EPA has worked with Oak Ridge National Laboratory (ORNL) to understand the energy security implications of reducing U.S. net petroleum imports and, more generally, exposure of the U.S. economy to global oil markets. ORNL has developed approaches for evaluating the social costs/impacts and energy security implications of oil imports, labeled the ''oil import premium'' or ''oil security premium.'' ORNL's methodology estimates two distinct costs/impacts of importing petroleum into the U.S., in addition to the purchase price of petroleum itself: (1) The risk of reductions in U.S. economic output and disruption to the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (*i.e.,* the macroeconomic disruption/adjustment costs); and (2) The impacts that changes in U.S. net oil imports have on overall U.S. oil demand and subsequent

[111] IEA, ''Energy Security.'' *https://www.iea.org/topics/energy-security.*

[112] 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.*

[113] 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.*

[114] EIA, ''Where our oil comes from,'' Oil and petroleum products explained, June 11, 2024. *https://www.eia.gov/energyexplained/oil-and-petroleum-products/where-our-oil-comes-from-in-depth.php.*

[115] EIA, ''U.S. Net Imports of Crude Oil and Petroleum Products,'' Petroleum & Other Liquids, May 30, 2025. *https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=mttntus2&f=a.*

[116] AEO2023, Table 11—Petroleum and Other Liquids Supply and Disposition.

[117] EIA, ''U.S. Supply and Disposition,'' Petroleum & Other Liquids, May 30, 2025. *https://www.eia.gov/dnav/pet/pet_sum_snd_d_nus_mbblpd_a_cur.htm.*

[118] EIA, ''Crude oil prices increased in first-half 2022 and declined in second-half 2022,'' Today in Energy, January 4, 2023. *https://www.eia.gov/todayinenergy/detail.php?id=55079.*

[119] EIA, ''Spot Prices,'' Petroleum & Other Liquids, May 14, 2025. *https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.*

[120] *Id.*

[121] EIA, ''Short-Term Energy Outlook,'' September 2024. *https://www.eia.gov/outlooks/steo/archives/sep24.pdf.*

[122] AEO2023, Table 12—Petroleum and Other Liquids Prices.

changes in the world oil price (*i.e.,* the ''demand'' or ''monopsony'' impacts).[123]

As has been the case for past RFS rulemakings, we consider the monopsony impacts estimated by the ORNL methodology to be a transfer payment, and thus exclude it from the estimated quantified benefits of the Volume Scenarios.[124] Thus, we only consider the macroeconomic disruption/adjustment cost component of the net oil import premiums (*i.e.,* labeled ''macroeconomic oil security premiums'' below) estimated using ORNL's methodology.

For this action, EPA and ORNL have worked together to revise the U.S. oil import premiums based upon recent energy security literature and oil price projections and energy market and economic trends from AEO2023.[125] EPA and ORNL have continuously updated oil import premium estimates to account for increasing domestic shale oil production, as well as other evolving U.S. and world oil market trends, since the RFS2 Rule in 2010. We do not consider military cost impacts from reduced oil use from the Volume Scenarios due to methodological issues in quantifying these impacts.[126]

To calculate the energy security benefits of the Volume Scenarios, we are using the ORNL macroeconomic oil security premiums combined with estimates of annual reductions in U.S. net petroleum imports attributable to the changes in renewable fuel volumes.[127] Table IV.A–1 presents the macroeconomic oil security premiums and the total energy security benefits for the Volume Scenarios. The macroeconomic oil security premiums range from $3.65 per barrel in 2026 to $3.92 per barrel in 2030. In terms of cents per gallon, the macroeconomic oil security premiums range from 8.6 cents per gallon in 2026 to 9.3 cents per gallon in 2030.

TABLE IV.A–1—MACROECONOMIC OIL SECURITY PREMIUMS AND TOTAL UNDISCOUNTED ENERGY SECURITY BENEFITS FOR THE VOLUME SCENARIOS [a]

Year	Macroeconomic oil security premiums (2022$/barrel of reduced imports)	Total energy security benefits—Low Volume Scenario (millions 2022$)	Total energy security benefits—High Volume Scenario (millions 2022$)
2026	$3.65 ($0.47–$6.89)	$138 ($18–$261)	$151 ($19–$284)
2027	3.73 (0.51–7.02)	150 (21–283)	176 (24–331)
2028	3.78 (0.51–7.15)	162 (22–307)	201 (27–380)
2029	3.87 (0.54–7.31)	175 (24–331)	228 (32–430)
2030	3.92 (0.51–7.46)	187 (24–357)	254 (33–484)

[a] Top values in each cell are the mean values, while the values in parentheses define 90 percent confidence intervals.

B. Costs

1. Methodology

This section provides a brief discussion of the methodology used to estimate the cost impacts for the renewable fuels expected to be used for the Volume Scenarios, as well as for the proposed volume standards, all relative to the No RFS Baseline. A more detailed discussion of how we estimated the renewable fuel costs, as well as the fossil fuel costs being displaced, can be found in DRIA Chapter 10.

The cost analysis compared the cost of biofuels attributable to the RFS program to the cost of the fossil fuel it displaces. The net estimated cost impacts are total social costs, excluding any subsidies and transfer payments, and thus are incrementally added to all other societal costs. They do not include benefits and other factors, such as the potential impacts on soil and water quality or potential GHG reduction benefits. The cost of each biofuel and fossil fuel being displaced can be divided into various subcomponents:

- *Production cost:* biofuel feedstock cost is usually the most prominent factor.
- *Distribution cost:* because a given biofuel often has a different energy density than the petroleum fuel it is replacing, the distribution costs are estimated all the way to the point of use to capture the full fuel economy effect of using these fuels.
- *Blending value:* in the case of ethanol blended as E10, there is a blending value that mostly incorporates ethanol's octane value realized by lower gasoline production costs, but also a volatility cost that accounts for ethanol's blending volatility in RVP-controlled gasoline.
- *Retail infrastructure cost:* in the case of higher-level ethanol blends, there is a retail cost since retail stations usually need to add equipment or use compatible materials to enable the sale of these newer fuels.
- *Fuel economy cost:* different fuels have different energy content, leading to different cost levels of fuel economy, which impacts the relative fossil fuel volume being displaced and the cost to the consumer.

We added these various cost components together as appropriate for each renewable fuel to reflect the cost of that fuel. We conducted a similar cost estimate for the fossil fuels being displaced since their relative cost to biofuels is used to estimate the net cost of the increased use of biofuels. Unlike for biofuels, however, we did not calculate production costs for the fossil fuels since their production costs are inherent in the wholesale price projections provided in AEO2023.[128]

2. Estimated Cost Impacts

In this section, we summarize the overall results of our cost analysis based on changes in the use of renewable fuels that displace fossil fuel use for the Volume Scenarios; the costs for the proposed volume standards are

[123] Monopsony impacts stem from changes in the demand for imported oil, which changes the price of all imported oil.

[124] See DRIA Chapter 6.4.2 for more discussion of EPA's assessment of monopsony impacts of this action. Also, for a discussion of monopsony oil security premiums, 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.

[125] See DRIA Chapter 6.4.2 for how the macroeconomic oil security premiums have been updated based upon a review of recent energy security literature on this topic.

[126] See DRIA Chapter 6.3 for a discussion of the difficulties in quantifying military cost impacts.

[127] See DRIA Chapter 6.4.1 for a discussion of the methodology used to estimate changes in U.S. annual net petroleum imports from the Volume Scenarios.

[128] Estimating production costs for renewable fuels facilities is possible because the plants are generally single purpose production processes producing a predictable, limited array of feedstocks into products, while petroleum refineries are each configured differently and each is refining a different mix of feedstocks of varying quality and each refinery is producing a unique number and volume of products.

summarized in Section V.H.4). The renewable fuel costs estimated and presented here and in Section V.H.4 are the societal costs ultimately borne by the consumers and do not reflect transfer payments between parties in the market (*e.g.,* tax subsidies for renewable fuels and RFS compliance costs), which are not relevant under a societal cost analysis.[129] A detailed discussion of the renewable fuel costs relative to the fossil fuel costs can be found in DRIA Chapter 10.

Table IV.B.2–1 provides the total estimated annual cost of the Volume Scenarios while Table IV.B.2–2 provides the per-unit cost (*e.g.,* per gallon or per thousand cubic feet) of the biofuel. For both the total and per-unit cost, the cost of the total change in renewable fuel volume is expressed over the gallons of the respective fossil fuel in which it is blended. For example, the costs associated with corn ethanol relative to that of gasoline are reflected as a cost over the entire gasoline pool, and biodiesel and renewable diesel costs are reflected as a cost over the diesel fuel pool. Biogas displaces natural gas use as CNG in trucks, so it is reported relative to natural gas supply. Since the entire gasoline and diesel fuel pool of each refinery is subject to the RFS program, we also amortize the entire renewable fuels cost over the combined gasoline and diesel fuel pool.

TABLE IV.B.2–1—TOTAL SOCIAL COSTS RELATIVE TO NO RFS BASELINE

[Millions 2022$] [a]

	Low Volumes Scenario		High Volumes Scenario	
	2026	2027	2026	2027
Gasoline	188	206	188	206
Diesel	5,030	4,436	5,615	5,642
Natural Gas	−150	−165	−150	−165
Total	5,068	4,477	5,653	5,683

[a] Total cost of the renewable fuel expressed over the fossil fuel it is blended into.

TABLE IV.B.2–2—PER-UNIT COSTS RELATIVE TO NO RFS BASELINE

[2022$]

	Units	Low Volumes Scenario		High Volumes Scenario	
		2026	2027	2026	2027
Gasoline	¢/gal	0.14	0.16	0.14	0.16
Diesel	¢/gal	9.59	8.54	10.71	10.86
Natural Gas	¢/thousand ft^3	−0.50	−0.57	−0.50	−0.57
Gasoline and Diesel	¢/gal	2.76	2.46	3.07	3.12

[a] Per-gallon or per thousand cubic feet cost of the renewable fuel expressed over the fossil fuel it is blended into; the last row expresses the cost over the obligated pool of gasoline and diesel fuel.

The biofuel costs are higher than the costs of the gasoline, diesel, and natural gas that they displace as evidenced by the increases in fuel costs shown in Table IV.B.2–2.[130] As described more fully in DRIA Chapter 10, our assessment of costs did not yield a specific threshold value below which the incremental costs of biofuels are reasonable and above which they are not. Given the significant inherent uncertainty in both the crude and agricultural feedstock price forecasts, any attempt to identify such a threshold value is extremely difficult. Nevertheless, in Section V we consider the directional cost inferences along with the other factors that we analyzed in the context of our discussion of the proposed volumes for 2026 and 2027.

The costs presented in this section are solely for the Volume Scenarios relative to the No RFS Baseline, whereas Section V.H.4 contains the estimated costs for the proposed volume standards. DRIA Chapter 10 contains summaries of the costs of all the scenarios modeled, including the Volume Scenarios relative to the 2025 Baseline, which are not summarized here.

C. Climate Change

CAA section 211(o)(2)(B)(ii) provides that when determining the applicable volumes of each renewable fuel category after the year 2022, EPA shall include ''an analysis of . . . the impact of the production and use of renewable fuels on . . . climate change.'' As such, we have undertaken an assessment of the potential climate impacts of volume standards consistent with the Volume Scenarios. This analysis considers impacts of such volume standards for three years—2026, 2027, and 2028—relative to the No RFS Baseline.

Cumulative emissions impact estimates for a thirty-year analytical time period are presented in Table IV.C–1. This section of the preamble contains only a brief synopsis of the results of our analysis; a full description of the methods of analysis, models, scenarios, estimated GHG emissions impacts by year, and uncertainties considered is presented in DRIA Chapter 5.

[129] Note that in developing the No RFS Baseline we did consider available subsidies other than those provided by the RFS program in determining the volume of renewable fuels that would be used in the absence of the RFS program.

[130] Natural gas shows a cost savings despite the fact that renewable natural gas is more expensive than fossil natural gas. This is because the proposed cellulosic volume standard is estimated to cause a smaller RNG volume in 2026 and 2027 compared to either the No RFS Baseline or the 2025 Baseline.

TABLE IV.C–1—CUMULATIVE NET EMISSIONS THROUGH 2055 FOR THE VOLUME SCENARIOS RELATIVE TO NO RFS BASELINE

[Millions of metric tons CO_2e emissions]

Scenario	Cumulative Emissions
Low Volume	−672 to −339
High Volume	−759 to −247

Scenarios in the climate change analysis produce annual emissions estimates for a 30-year analytical scenario duration. Additional information about analytical methods for estimating GHG emissions impacts can be found in DRIA Chapter 5; we note that the analysis for this rulemaking relies on an updated methodology for assessing climate change impacts under CAA section 211(o)(2)(B)(ii)(I), details of which can also be found in DRIA Chapter 5. We request comment on our analysis of the GHG emissions impacts of the proposed volume standards, and whether factors in addition to GHG emissions, such as other drivers of climate change and other considerations fitting within the term ''climate change,'' are relevant to the analysis. In addition to requesting comment on this analysis in general, including the updated methodology, we specifically request comment on the following aspects:

- The methods for evaluating crop-based fuels and waste- and byproduct-based fuels.
- The use of economic models for assessing the potential market-mediated impacts associated with crop-based fuels.
- The scenarios used in this analysis, including the analytical duration, and assumed future (post-2027) biofuel consumption levels for both the policy and baseline scenarios.

D. Jobs and Rural Economic Development

In this section, we summarize our estimates of the impacts of the Volume Scenarios on jobs and rural economic development (both include direct, indirect, and induced impacts).[131] This includes details regarding potentially offsetting impacts to the economy that may stem from the expansion of renewable fuels. While we acknowledge these impacts, an attempt at formally quantifying or modeling them to generate an estimate of the net impacts to the entire U.S. economy is beyond the scope of this analysis.

To estimate the impacts on jobs, we applied two analytical approaches common in the literature. The first is a basic ''rule-of-thumb'' type approach that uses job and income impact estimates from previous studies, expressed in jobs and/or dollars per unit of biofuel production, and multiplies these estimated impacts by the projected volumes to arrive at employment estimates. This approach is taken to produce estimates for the impacts of the quantities of ethanol, BBD, and RNG fuels in the Volume Scenarios relative to the No RFS Baseline.

The second is a slightly more nuanced approach that relies on the use of an input-output modeling methodology developed specifically for analysis of dry mill corn ethanol, which is applied only to the volumes of that fuel in the Volume Scenarios relative to the No RFS Baseline. These estimates are summarized in Tables IV. D–1 and 2. In some cases, we have developed ranges of impacts for fuel volumes based on uncertainty regarding how the volumes will be provided. For example, volumes associated with new production capacity would also be associated with some number of temporary construction jobs, while expanded capacity utilization at existing facilities would not. These ranges of potential impacts are summarized in tables in DRIA Chapter 9, along with detailed explanations of the associated methodology. For the corn ethanol case alone, we present the results of these two analyses coequally here and request comment regarding approaches to estimating the employment impacts of ethanol for the final rule. Both sets of estimates (*i.e.,* our rule-of-thumb analysis and our analysis using an input-output model for the case of ethanol) have been computed based on changes from the No RFS Baseline and the results we present should be interpreted as additive gross jobs relative to that baseline. However, were these analyses to be carried out relative to the 2025 Baseline, some of these computed estimates would then be interpreted as jobs at risk were the RFS program discontinued.

We estimate that all three categories of renewable fuel we analyzed—ethanol, BBD, and RNG—are associated with increases in jobs to varying degrees. We observe that RNG appears to be associated with the highest number of direct jobs created per unit of biofuel. However, BBD is projected to have the highest job creation impact overall, primarily due to substantially higher production increases relative to the baseline. In terms of rural employment specifically, ethanol has the highest direct and total effects per million gallons of ethanol equivalent. 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.

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 impacts per million gallons of ethanol equivalent on rural economic development than does RNG. 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.

Tables IV.D–1 and 2 summarize the estimated economy-wide job impacts and rural GDP impacts (both include direct, indirect, and induced impacts) associated with the volumes of ethanol, BBD, and RNG attributable to the Low Volume Scenario and High Volume Scenario, respectively. The estimates of rural GDP impacts are actual values as opposed to discounted values, implying that they do not reflect the time value of money.

[131] These analyses are described in detail in DRIA Chapter 9.

TABLE IV.D–1—ECONOMY-WIDE JOBS AND RURAL ECONOMIC DEVELOPMENT IN THE LOW VOLUME SCENARIO RELATIVE TO NO RFS BASELINE

[Number of jobs in full-time equivalents; million 2022$, undiscounted]

Year	RNG		BBD		Ethanol [a]	
	Jobs	Rural economic development	Jobs	Rural economic development	Jobs	Rural economic development
2026	19,504	$1,072.16	64,793	$6,840.04	5,332	$366.19
2027	20,240	1,112.59	68,931	7,276.90	5,735	393.83
2028	21,030	1,156.02	73,491	7,758.25	5,986	411.10
2029	21,847	1,200.94	77,265	8,156.68	6,338	435.29
2030	22,718	1,248.86	81,576	8,611.74	6,690	459.47

[a] For the corn ethanol case alone, using NREL's JEDI module for dry mill corn ethanol we were able to generate employment and income estimates under alternative scenarios and also carry out a sensitivity analysis. See DRIA Chapter 9 for more details.

TABLE IV.D–2—ECONOMY-WIDE JOBS AND RURAL ECONOMIC DEVELOPMENT IN THE HIGH VOLUME SCENARIO RELATIVE TO NO RFS BASELINE

[Number of jobs in full-time equivalents; million 2022$, undiscounted]

Year	RNG		BBD		Ethanol [a]	
	Jobs	Rural economic development	Jobs	Rural economic development	Jobs	Rural economic development
2026	19,504	$1,072.16	70,790	$7,473.08	5,332	$366.19
2027	20,240	1,112.59	80,905	8,540.95	5,735	393.83
2028	21,030	1,156.02	91,461	9,655.34	5,986	411.10
2029	21,847	1,200.94	101,213	10,684.78	6,338	435.29
2030	22,718	1,248.86	111,520	11,772.88	6,690	459.47

[a] For the corn ethanol case alone, using NREL's JEDI module for dry mill corn ethanol we were able to generate employment and income estimates under alternative scenarios and also carry out a sensitivity analysis. See DRIA Chapter 9 for more details.

We request comment on our approaches to estimating jobs and rural economic development impacts associated with renewable fuels.

These estimates 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 estimates and not net estimates.

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.[132] [133] The expectation is that there will be a movement of labor 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.[134]

For the final rule, we intend to carry out a more robust modeling exercise that may capture more of these nuances. We request comments on the types of approaches which would be appropriate to apply in conducting such an analysis.

E. Agricultural Commodity Prices and Food Price Impacts

In this section, we summarize the projected impacts of the Volume Scenarios on agricultural commodity and food prices. A detailed explanation of the methods used to estimate these impacts can be found in DRIA Chapter 9.

To assess the potential impact on corn prices, we used a literature-based estimate that corn prices increase by 3 percent for every additional billion gallons of corn ethanol produced.[135] We multiplied the projected corn price by the 3 percent per-billion-gallon increase to estimate the price change per bushel. This value was then applied to the difference in corn ethanol volumes between each Volume Scenario and the No RFS Baseline. Table IV.E–1 summarizes the results of the projected impact of increased corn ethanol production on corn prices under the Volume Scenarios.[136]

[132] 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.

[133] Hafstead, Marc a. C., and Roberton 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.*

[134] 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.*

[135] 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.*

[136] The volume of corn ethanol is the same under the Low and High Volume Scenarios; therefore, the

Continued

TABLE IV.E–1—PROJECTED IMPACT OF VOLUME SCENARIOS ON CORN PRICES RELATIVE TO NO RFS BASELINE

	Units	2026	2027	2028	2029	2030
Baseline Corn Price [a]	$/Bushel	$3.97	$4.07	$4.17	$4.27	$4.30
Corn Price Increase Relative to No RFS Baseline	$/Bushel	0.03	0.03	0.03	0.03	0.03

[a] Corn prices are from the USDA Agricultural Projections to 2034 (February 2025). Prices represent the average price for a calendar year. For corn, the price is calculated using ⅓ of the price for the first agricultural marketing year (*e.g.,* 2025/2026 for 2026) and ⅔ of the price for the second agricultural marketing year (*e.g.,* 2026/2027 for 2026).

To determine the potential impact of the Volume Scenarios on soybean oil and meal prices, we calculated projected price effects for 2026–2030 relative to the No RFS Baseline. These projections assume a 35.7 percent increase in the price of a pound of soybean oil per billion gallons of biofuel produced and a 7.94 percent decrease in the price of a short ton of soybean meal per billion gallons of biofuel produced.[137] We multiplied the projected soybean oil and meal prices by their respective percentage changes per billion gallons of biofuel to estimate the price impact per unit. These values were then applied to the difference in biofuel volumes between each Volume Scenario and the No RFS Baseline. This analysis provides an estimate of how increased soy-based biofuel production impacts soybean oil and soybean meal prices under each Volume Scenario. The results from this analysis are presented in Tables IV.E–2 and 3 for the Low and High Volume Scenarios, respectively.

TABLE IV.E–2—PROJECTED IMPACT OF THE LOW VOLUME SCENARIO ON SOYBEAN OIL AND MEAL PRICES RELATIVE TO THE NO RFS BASELINE

	Units	2026	2027	2028	2029	2030
Baseline Soybean Oil Price [a]	$/Pound	$0.39	$0.37	$0.37	$0.36	$0.36
Soybean Oil Price Increase Relative to No RFS Baseline.	$/Pound	0.26	0.26	0.26	0.26	0.26
Baseline Soybean Meal Price [a]	$/Ton	324	331	339	347	355
Soybean Meal Price Change Relative to No RFS Baseline.	$/Ton	−49	−51	−53	−55	−58

[a] Soybean oil and meal prices are from the USDA Agricultural Projections to 2034 report. Prices represent the average price for a calendar year. For soybean oil, the price is calculated using ¼ of the price for the first agricultural marketing year (*e.g.,* 2025/2026 for 2026) and ¾ of the price for the second agricultural marketing year (*e.g.,* 2026/2027 for 2026).

TABLE IV.E–3—PROJECTED IMPACT OF THE HIGH VOLUME SCENARIO ON SOYBEAN OIL AND MEAL PRICES RELATIVE TO THE NO RFS BASELINE

	Units	2026	2027	2028	2029	2030
Baseline Soybean Oil Price [a]	$/Pound	$0.39	$0.37	$0.37	$0.36	$0.36
Soybean Oil Price Increase Relative to No RFS Baseline.	$/Pound	0.29	0.31	0.34	0.37	0.40
Baseline Soybean Meal Price [a]	$/Ton	324	331	339	347	355
Soybean Meal Price Change Relative to No RFS Baseline.	$/Ton	−54	−62	−70	−79	−88

[a] Soybean oil and meal prices are from the USDA Agricultural Projections to 2034 report. Prices represent the average price for a calendar year. For soybean oil, the price is calculated using ¼ of the price for the first agricultural marketing year (*e.g.,* 2025/2026 for 2026) and ¾ of the price for the second agricultural marketing year (*e.g.,* 2026/2027 for 2026).

In addition to estimating the price impacts on corn, soybean oil, and soybean meal, we also assessed price changes for other feed grains—grain sorghum, barley, and oats—as well as distillers grains. These commodities were included in this analysis because they have historically competed with corn in the feed market and, to a lesser extent, for planted acreage. These price changes were estimated using historical price relationships with corn, and the analysis found only minimal impacts on the other grains.[138]

Additionally, the impact on commodity prices described above may, in turn, have downstream effects on food prices and other products derived from these commodities. To estimate the effect on total food expenditures, we combined these projected price changes with forecasts of commodity use for food production.[139] Because commodity costs typically represent a small portion of total food prices, the anticipated effect of this action on food prices is relatively modest, as shown in Table IV.E–4.

results shown in Table IV.E–1 are the same for both Volume Scenarios.

[137] Lusk, Jayson L. ''Food and Fuel: Modeling Food System Wide Impacts of Increase in Demand for Soybean Oil,'' November 10, 2022.

[138] See DRIA Chapter 9 for more information.

[139] Commodity use for food production estimated using USDA Agricultural Projections to 2034. See DRIA Chapter 9 for further detail on this analysis.

TABLE IV.E–4—IMPACT OF VOLUME SCENARIOS ON TOTAL FOOD EXPENDITURES [a]

	Units	2026	2027	2028	2029	2030
Low Volume Scenario						
Change in Food Expenditures	Million $	$1,938	$1,802	$1,723	$1,648	$1,601
Projected Food Expenditure Increase	$ per Consumer Unit	$14.41	$13.40	$12.80	$12.25	$11.90
Percent Change in Food Expenditures	Percent	0.14	0.13	0.13	0.12	0.12
High Volume Scenario						
Change in Food Expenditures	Million $	$2,129	$2,141	$2,187	$2,213	$2,260
Projected Food Expenditure Increase	$ per Consumer Unit	$15.82	$15.92	$16.25	$16.45	$16.79
Percent Change in Food Expenditures	Percent	0.16	0.16	0.16	0.16	0.17

[a] Data from the U.S. Bureau of Labor Statistics, Consumer Expenditures—2023, Table A. Average income and expenditures of all consumer units, 2021–23.

V. Proposed Volume Requirements for 2026 and 2027

As required by CAA section 211(o)(2)(B)(ii), we have reviewed the implementation of the RFS program in prior years and have analyzed a specified set of factors. The proposed volume requirements for 2026 and 2027 (the ''Proposed Volumes'') are informed by our technical analyses of the Volume Scenarios, which are summarized in Section IV. Further details of all analyses performed for this action are provided in the DRIA.

In this section, we summarize and discuss the implications of our analyses and any other relevant information that apply to each of three different component categories of biofuel: cellulosic biofuel, non-cellulosic advanced biofuel, and conventional renewable fuel. These three components combine to produce the statutory categories: the advanced biofuel volume requirement is equal to the sum of cellulosic biofuel and non-cellulosic advanced biofuel, while the total renewable fuel volume requirement is equal to the sum of advanced biofuel and conventional renewable fuel.[140] In Section V.C we discuss our approach to the BBD standard in light our analysis of the non-cellulosic advanced biofuel component category, the vast majority of which we project will be comprised of BBD.

In general, the volume requirements we are proposing for 2026 and 2027 are designed to provide significant support for the continued growth in the production and use of renewable fuels. While the Proposed Volumes (expressed in billion RINs) are similar to the Low Volume Scenario and lower than the High Volume Scenario, we project that the Proposed Volumes would result in significantly higher renewable fuel production and consumption in the U.S. than either the Low or High Volume Scenario, particularly for domestic renewable fuel, due to the proposed import RIN reduction provisions.[141] Our assessment of the expected annual rate of future commercial production of renewable fuels indicates that continued growth in the production and use of renewable fuels is not only possible but expected if supported through the RFS program. Increasing the production of renewable fuels furthers the goals of the RFS program by increasing the energy independence and energy security of the U.S. Further, increasing production of renewable fuels, particularly those produced from domestic feedstocks, can have significant positive impacts on employment and economic activity in rural areas.

We note that while we do not separately discuss each of the statutory factors for each component category in this section, we have analyzed all the statutory factors. However, it was not always possible to precisely identify the implications of the analysis of a specific factor for a specific component category of renewable fuel. For instance, while we analyzed the impact of biodiesel and renewable diesel on the cost to consumers of transportation fuel, biodiesel and renewable diesel can be used to satisfy multiple biofuel requirements (*e.g.,* BBD, advanced biofuel, and total renewable fuel) and this analysis therefore does not apply to a single standard in that regard. Air quality impacts are driven primarily by biofuel type (*e.g.,* ethanol, biodiesel) rather than by biofuel category (*e.g.,* advanced biofuel, cellulosic biofuel), and energy security impacts are driven by the amount of fossil fuel energy displaced. Moreover, except for CAA section 211(o)(2)(ii)(III), the statute does not require that the requisite analyses be specific to each category of renewable fuel. Rather, the statute directs EPA to analyze certain factors, without specifying how that analysis must be conducted. In addition, the statute directs EPA to analyze the ''program'' and the impacts of ''renewable fuels'' generally, further indicating that Congress intended to provide EPA with the discretion to decide how and at what level of specificity to analyze the statutory factors. This section supplements the analyses discussed in Sections III and IV by providing a narrative summary of how we used the results of our analyses of the Volume Scenarios to derive the volumes we are proposing in this action.

A. Cellulosic Biofuel

In EISA, Congress set increasing targets for cellulosic biofuel, aiming to reach 16 billion gallons by 2022. After 2015, all growth in the mandated total renewable fuel volume was designated for advanced biofuels, with the majority of that growth focused on cellulosic biofuels. This indicates that Congress intended the RFS program to strongly incentivize cellulosic biofuels, placing a particular emphasis on their development after 2015. While cellulosic biofuel production has not reached the levels envisioned by Congress in 2007, EPA remains committed to supporting the advancement and commercialization of these fuels.

Cellulosic biofuels, particularly those produced from waste or residue materials, have the potential to significantly reduce GHG emissions from the transportation sector. In many cases cellulosic biofuel can be produced without impacting current land use and with little to no impact on other environmental factors, such as air and

[140] These combinations are set forth in CAA section 211(o)(2)(B)(i)(I)–(III). In addition, the determination of the appropriate volume requirements for BBD is treated separately in Section V.C.

[141] See DRIA Chapter 3 for more detail on the quantities and types of renewable fuel we project would be supplied to meet the Proposed Volumes and the Volume Scenarios.

water quality. The proposed cellulosic biofuel volumes are intended to support the continued development and commercial-scale deployment of cellulosic biofuels while steadily increasing production, consistent with the growth envisioned by EISA and our evaluation of the relevant statutory factors.

As outlined in Section III, the Volume Scenarios reflect the projected growth in cellulosic biofuel production and use in the transportation sector through 2030, accounting for potential constraints in both the production and use of cellulosic biofuel. We then evaluated the Volume Scenarios using additional statutory factors. The results of these evaluations are summarized here and detailed further in the DRIA. Our analysis suggests that cellulosic biofuels offer several significant benefits, including the potential for exceptionally low lifecycle GHG emissions that meet or exceed the 60 percent GHG reduction threshold for cellulosic biofuel.[142] These benefits largely arise because the majority of feedstocks projected for use in cellulosic biofuel production are either waste materials (*e.g.,* CNG/LNG derived from biogas) or residues (*e.g.,* cellulosic diesel and heating oil from tree residue). The processing of these otherwise unused feedstocks into transportation fuel is also likely to result in increased employment and have a positive economic impact, particularly in the communities where the cellulosic biofuel production facilities are located.

The feedstocks currently used and expected to be used through 2027, particularly biogas used for CNG/LNG production, are not anticipated to cause substantial land use changes that could lead to negative environmental impacts. None of the cellulosic biofuel feedstocks expected to be used to produce liquid cellulosic biofuels through 2027 (including corn kernel fiber, mill residue, and separated MSW) are produced with the intention that they be used as feedstocks for cellulosic biofuel production. Because of this, using these feedstocks to produce liquid cellulosic biofuel is not expected to have significant adverse impacts related to several of the statutory factors, including the conversion of wetlands, ecosystems and wildlife habitat, soil and water quality, the price and supply of agricultural commodities, and food prices through 2027.

Cellulosic biofuels are also expected to provide significant economic development benefits. The production of these fuels supports local economies, creating jobs in biofuel facilities and related distribution networks. By encouraging the cellulosic biofuel market, the U.S. strengthens its energy independence and reduces reliance on foreign fuels, while fostering economic resilience.

Although both liquid cellulosic biofuels and CNG/LNG from biogas are produced from wastes or by-product feedstocks, they differ significantly in terms of production costs and market competitiveness. Liquid cellulosic biofuels face high production costs due to low fuel yields per ton of feedstock and the substantial capital investment required for production facilities. Consequently, their economic viability, at least in the short term (through 2027), will likely depend on high cellulosic RIN prices and supportive programs such as California's LCFS program and the 45Z tax credit to enable them to compete with petroleum-based fuels. In contrast, CNG/LNG derived from biogas sourced from landfills, wastewater treatment facilities, and agricultural digesters can be more cost competitive with fossil fuels. In certain cases, such as larger landfills, CNG/LNG production costs can even approach those of conventional natural gas. Nonetheless, most biogas-derived fuels, and particularly those from new sources, rely on financial incentives to remain competitive. Given their relatively lower production costs and mature technology, and in combination with the high financial incentive created by the RFS program in addition to that from State LCFS programs and tax credits, CNG/LNG from biogas is expected to remain the dominant form of cellulosic biofuel through 2027. The combination of high RIN prices and the growing volume of CNG/LNG used as transportation fuel and the high cellulosic RIN prices that refiners must recover through fuel sales leads to an expected increase in gasoline and diesel prices.

Our analysis of the statutory factors indicates that the benefits of increasing cellulosic biofuel volumes outweigh the potential downsides. To maximize these advantages, we are proposing cellulosic biofuel volumes through 2027 at levels that align with projected growth in the consumption of CNG/LNG as transportation fuel from 2026 to 2027. These proposed volumes, based on the most current data at the time of this action, represent a well-informed estimate of the achievable growth in cellulosic biofuel production during this period. We believe that these volumes would continue to encourage investment in and development of cellulosic biofuels while adhering to statutory requirements, including those under CAA section 211(o)(2)(B)(iv).

TABLE V.A–2—PROPOSED CELLULOSIC BIOFUEL VOLUMES [a]

[Million RINs]

	2026	2027
CNG/LNG Derived from Biogas	1,170	1,360
Ethanol from CKF	120	120
Total Cellulosic Biofuel	1,300	1,360

[a] All volumes rounded to the nearest 10 million RINs.

We also acknowledge the uncertainty in forecasting cellulosic biofuel volumes. If actual cellulosic biofuel production and imports fall significantly below the required volume, resulting in a RIN shortfall, obligated parties may lack sufficient cellulosic RINs to meet their RFS obligations. This could lead to some parties carrying forward compliance deficits, and if production and imports continue to lag targets, non-compliance could become a risk. Conversely, if cellulosic biofuel production and imports exceed the required volumes, resulting in a RIN surplus and lower prices for cellulosic biofuels and cellulosic RINs. This scenario could undermine investments in cellulosic biofuel production, with the simple possibility of such a surplus potentially discouraging future investments. Using the best available data, we believe the proposed cellulosic biofuel volumes are reasonable and achievable, as well as consistent with the statutory requirement in CAA section 211(o)(2)(B)(iv) that EPA

[142] CAA section 211(o)(1)(E).

determine the cellulosic biofuel volume such that EPA need not waive the cellulosic biofuel standard under CAA section 211(o)(7)(D).[143] Therefore, we are proposing volumes that represent the projected volume available in 2026 and 2027. We request comment on our proposed cellulosic biofuel volumes for 2026 and 2027, especially regarding our assessment of future CNG/LNG consumption. In addition, we recognize that the methodology used to determine the proposed cellulosic biofuel volumes in this rulemaking differs from past approaches, so we also request comment on the methodology used to arrive at those volumes. We also request any further data or insights that could enhance our projections for cellulosic biofuel production in 2026 and 2027.

B. Non-Cellulosic Advanced Biofuel

The volume targets established by Congress through 2022 anticipated volumes of advanced biofuel beyond what would be needed to satisfy the cellulosic standard. The statutory target for advanced biofuel in 2022 (21 billion gallons) allowed for up to five billion gallons of non-cellulosic advanced biofuel to be used towards the advanced biofuel volume target, with additional quantities of non-cellulosic advanced biofuel able to contribute towards meeting the total renewable fuel requirement. The applicable standards for 2022 similarly include five billion gallons of non-cellulosic advanced biofuel. In the Set 1 Rule, EPA continued to grow the implied non-cellulosic advanced biofuel category, which reached 5.95 billion gallons in 2025.

As discussed in Sections III.B.2 and 3, we developed volume scenarios for non-cellulosic advanced biofuel based on a consideration of the quantities of these fuels potentially able to be supplied to the U.S. market. This process included consideration of the supply of these fuels in 2023 and the months in 2024 for which data were available and the projected future projection and import of non-cellulosic advanced biofuels in future years. The non-cellulosic advanced biofuel volumes in the Volume Scenarios reflect significantly different growth rates for this category (500 million RINs per year vs. 1 billion RINs per year). These volume scenarios were designed to enable us to consider the likely impacts of different volume requirements for non-cellulosic advanced biofuel. They also reflect the significant uncertainty in the volume of these fuels that could be supplied to the U.S. in future years. We then analyzed the Volume Scenarios according to the statutory factors.

In this action we are proposing volume requirements for 2026 and 2027 that reflect 500 million RIN annual increases in the projected supply of non-cellulosic advanced biofuel. These increases are relative to the volume of non-cellulosic advanced biofuel we project will be supplied to the U.S. in 2025 based on available data, which is significantly higher than the volumes of these fuels we projected would be supplied in 2025 in the Set 1 Rule. Our decision to propose volumes consistent with Low Volume Scenario is based on our assessment of the impacts of biofuels produced from domestic feedstocks on the statutory factors and our projection of the quantity of qualifying feedstocks available to biofuel producers. Our assessment of the statutory factors, and how these assessments support the proposed non-cellulosic advanced biofuel volumes, are summarized in the remainder of this section, and are discussed in greater detail in the DRIA.

A key consideration in determining the proposed non-cellulosic advanced biofuel volumes is our proposal in this action to reduce the number of RINs generated for imported renewable fuels and renewable fuels produced from foreign feedstocks by 50 percent, as discussed in Section VIII. While much of the renewable fuel eligible to generate RINs under the RFS program is produced by domestic producers from domestic feedstocks—including the vast majority of all cellulosic biofuel and conventional renewable fuel—we estimate that nearly 50 percent of all non-cellulosic advanced biofuel was imported or produced from foreign feedstocks in 2024.[144] The 500 million RIN annual growth rate that forms the basis for our proposed non-cellulosic advanced biofuel volumes is approximately equal to our projection of the annual increase in the production of domestic feedstocks that can be used to produce these fuels. This approach provides a strong incentive to increase the production of domestic renewable fuels from domestic feedstocks. It also allows for domestic biofuel producers to continue to use foreign feedstocks where it is advantageous to do so, while incentivizing these producers to source increasing quantities of domestic feedstocks over time.

To date, the vast majority of non-cellulosic advanced biofuel in the RFS program has been biodiesel and renewable diesel, with relatively small volumes of sugarcane ethanol and other advanced biofuels. While the impacts of non-cellulosic advanced biofuels on the statutory factors vary depending on the fuel type, production process, where the fuel is produced (*e.g.,* domestically vs. in a foreign country), and the feedstock used to produce the fuel, all advanced biofuels have the potential to provide significant GHG reductions. These potential GHG reductions suggest that higher non-cellulosic advanced biofuel volumes than those established by Congress for 2022 (5.0 billion RINs) or established by EPA for 2025 (5.95 billion RINs) may be appropriate.

Advanced biodiesel and renewable diesel together accounted for 95 percent or more of the total supply of non-cellulosic advanced biofuel over the last several years, and together the two fuels are expected to continue to do so through 2027 due to the limited production and import of other types of non-cellulosic advanced biofuels.[145] We have therefore focused our attention on the impacts of these fuels in relation to the statutory factors in determining appropriate levels of non-cellulosic advanced biofuel for 2026 and 2027.[146]

As in past RFS rulemakings, our analyses indicate that for some of the statutory factors the projected impacts of increasing consumption of biodiesel and renewable diesel are expected to be generally positive or neutral, while for other factors the impacts are expected to be generally negative. For other factors, the projected impacts vary significantly depending on whether the feedstock used to produce the fuel is a waste or byproduct (*e.g.,* used cooking oil) or an agricultural commodity (*e.g.,* soybean oil) and whether it is sourced domestically or imported.

All qualifying biodiesel and renewable diesel is expected to diversify the transportation fuel supply and thus have a positive impact on the energy security of the U.S. Similarly, because we project that all of the increase in the supply of biodiesel and renewable diesel through 2027 will be supplied from domestic biofuel producers using domestic feedstocks, we expect these fuels to positively impact employment and rural economic development. We

[143] See DRIA Chapter 7.1 for further information on the methodology EPA used to project the supply of cellulosic biofuel in 2026 and 2027.

[144] See DRIA Chapter 3.2 for more detail on EPA's estimate of domestic vs. imported biofuels and feedstocks in 2024.

[145] See DRIA Chapters 7.2 through 7.4.

[146] We have also considered the potential for increasing volumes of renewable jet fuel. Given its similarity to renewable diesel, for purposes of projecting appropriate volume requirements for 2026 and 2027, in most cases we consider renewable jet fuel to be a component of renewable diesel.

do not anticipate the availability of infrastructure to distribute or use biodiesel and renewable diesel will limit the consumption of these fuels in future years, nor do we anticipate that increasing supplies of these fuels will negatively impact the deliverability of materials, goods, and products other than renewable fuel. Together, these statutory factors suggest that higher volumes of biodiesel and renewable diesel may be appropriate in future years.

Other statutory factors suggest that lower volumes of biodiesel and renewable diesel may be appropriate. Biodiesel and renewable diesel have historically had higher costs than the diesel fuel they displace and are expected to continue to cost more into the future, primarily due to relatively high feedstock costs. These higher costs are expected to ultimately be passed through to consumers, resulting in higher costs for transportation fuel and higher costs to transport goods.[147] Biodiesel and renewable diesel produced from vegetable oils are expected to directionally result in higher prices for these oils and the crops from which they are derived (*e.g.,* soybeans and canola). These higher vegetable oil prices are projected to have both positive and negative impacts. Higher vegetable oil prices are expected to drive increased investment in the domestic oilseed crushing industry, resulting in increased employment and economic impact, as well as higher revenue for feedstock producers. Higher vegetable oil prices are also expected to result in higher prices for products that use them as inputs.

Finally, the projected impacts on some of the statutory factors are expected to vary significantly depending on the feedstock used to produce the biodiesel or renewable diesel. We have generally assumed that biofuels produced from wastes or byproducts such as UCO and tallow do not drive the conversion of land to cropland, increase the intensity of farming practices, or raise agricultural commodity or food prices.[148] Because of this assumption, biofuels produced from wastes or byproducts are also generally expected to result in greater GHG emission reductions. However, commodities such as UCO and tallow now command prices comparable to those of crop-derived vegetable oils. We request comment on the potential impact of increased demand for these feedstocks on global crop production, and the implications for the estimated GHG emissions of biofuels produced from these feedstocks.

Increases in domestic sources of waste or byproduct feedstocks in future years are projected to be limited as much of the available feedstocks are already being used for biofuel production with smaller quantities collected for other productive uses. Significant volumes of these feedstocks may be available from foreign countries, though there is significant uncertainty in the quantities of these feedstocks that will be available to the U.S. in future years.

1. Assessment of Available Feedstocks

Biodiesel and renewable diesel produced from agricultural commodities such as soybean oil and canola oil are more likely to have negative impacts on wetlands, wildlife habitat and ecosystems, and water quality, as demand for these feedstocks can result in increased conversion of native lands to cropland. This land conversion (whether land is converted directly to produce biofuel crops or induced through higher commodity prices) generally results in GHG emissions, and therefore biofuels produced from these feedstocks are expected to have lower GHG emission benefits than biofuels produced from wastes or byproducts. Significant opportunities exist for increasing domestic production of soybean oil (which would be expected to positively impact job creation and rural economic development), as well as imported canola oil from Canada. Because the supply of these feedstocks is less dependent on imports and there are relatively fewer incentives and lower demand for biofuels produced from vegetable oils, we have greater confidence in projecting the potential supply of these feedstocks in future years.

Our analysis of the Volume Scenarios indicated likely differences in impacts on the statutory factors between growth in the supply of biodiesel and renewable diesel produced from wastes or byproducts such as UCO and tallow (primarily imported from foreign countries) and those produced from virgin vegetable oils (primarily from the U.S.). Thus, the availability and likely use of these feedstocks for biofuel production and use in the U.S. is a key factor in our consideration of the proposed non-cellulosic advanced biofuel volumes. As discussed further in the remainder of this section, there is relatively less uncertainty in the projected availability of vegetable oils than there is in the projected availability of wastes or byproducts such as UCO and tallow. The higher uncertainty in the projected availability of the waste and byproduct feedstocks is not only a function of the quantity of these feedstocks that can be collected globally, but also of demand for these feedstocks for biofuel production and other productive uses in other countries.

a. Vegetable Oils

The available supply of vegetable oils to domestic biofuel producers is generally a function of the potential for increased production of these feedstocks in the U.S. and Canada, though some small imports from other countries do occur. The available supply of distillers corn oil is primarily a function of corn ethanol production, as most corn ethanol facilities currently extract and sell distillers corn oil. The available supply of soybean oil and canola oil is primarily a function of the quantity of these oils produced by oilseed crushing facilities. Based on the observed increases in soybean and canola crush capacity in recent years and publicly available information on expansions underway, we can reasonably project the rate of growth in the soybean and canola crush industry through 2027, assuming continued demand for the vegetable oils produced from these facilities is sufficient to support ongoing investment in crush capacity.

For distillers corn oil, soybean oil, and canola oil, the primary source of uncertainty in the supply of these feedstocks to domestic biofuel producers is the demand for these feedstocks in markets other than biofuel production in the U.S. With the exception of imports of canola oil from Canada, imports of distillers corn oil, soybean oil, and canola oil from countries other than Canada have been

[147] This discussion refers to societal costs. We recognize that with the incentives provided by the RFS program and other state and local programs, the price for biodiesel and renewable diesel (net available incentives) may be lower than the price of petroleum fuels. See DRIA Chapter 10 for a further discussion of our cost estimates.

[148] This is particularly true if the feedstocks used to produce these biofuels would otherwise be landfilled or not productively used. It is not the case, however, that all feedstocks assumed to be wastes or byproducts would otherwise be landfilled or not productively used. For example, UCO and animal fats such as tallow have historically had a variety of productive uses, include use as animal feed and use as a feedstock to produce soaps, detergents, and other oleochemicals. Historically, such demands have been outstripped significantly by product supply, leading to unproductive disposal of excess supply in the absence of a productive use opportunity. However, increasing levels of demand for these feedstocks for biofuel production could not only fully consume this previously excess supply, but also result in the diversion of these feedstocks from existing markets. In turn, markets that previously used these waste and byproduct feedstocks may seek alternatives, and any impacts on cropland, GHG emissions, or other factors that result from the sourcing of these alternative feedstocks should then be attributable to biofuel production.

relatively small in recent years and are not expected to increase through 2027. Consistent with the observed historical trends, we currently project the potential for increasing imports of canola oil from Canada but do not project any significant changes to the import of distillers corn oil, soybean oil, or canola oil from countries other than Canada due to limited global production, relatively high tariffs on imports, and high demand in food markets respectively. Any increases to the supply of these feedstocks to biofuel producers would require diverting these feedstocks from current markets. While this is possible, we project any shifts of these vegetable oils from current markets through 2027 to be limited. Since 2015, the use of soybean oil and canola oil in the U.S. in markets other than biofuel production has remained fairly consistent despite the significant increase in the use of these oils for biofuel production.[149] This suggests that these oils have a higher value in non-biofuel markets (*e.g.,* food) and are unlikely to be diverted from these markets in significant quantities due to higher demand for biofuel production in the near term. While the U.S. has historically been a net exporter of soybean oil, data for the 2023/24 agricultural marketing year indicates that net exports of soybean oil were near zero [150] and therefore opportunities to divert soybean oil from export markets are very limited.

b. Animal Fats and UCO

In addition to vegetable oils, the other primary sources of feedstocks for biodiesel and renewable diesel production are animal fats (such as tallow) and UCO. In the U.S., collection and productive use of these feedstocks is well established. Most of the economically recoverable UCO and animal fats in the U.S. are currently collected and productively used, primarily for biofuel production.[151] We project that the supply of these feedstocks will continue to grow, but that the rate of growth in the availability of these feedstocks from domestic markets will be modest, growing with domestic meat production and the use of vegetable oil for food production.

In contrast, there is both significant growth potential and a high degree of uncertainty surrounding the supply of animal fats and UCO that could be imported into the U.S. and used for biofuel production. The uncertainty is associated both with the quantity of these materials that can be economically collected and competition for available feedstocks and biofuels produced from these feedstocks in other countries.

The global supply of animal fats is expected to increase with global meat consumption. Global meat production increased 53 percent from 2000 to 2021 and is expected to continue to increase in future years.[152] Like other biodiesel and renewable diesel feedstocks, animal fats have historically been used in other markets such as for oleochemical production and livestock feed. We project that strong incentives for biofuels produced from animal fats in the U.S. (from both state and federal incentive programs) will result in increasing quantities of these feedstocks being used for biofuel production. Thus, we project that the available supply of animal fats to biofuel producers will increase in future years due to both increasing animal fat production (as a byproduct of increasing meat production) and the diversion of animal fats for existing uses to biofuel production. We note, however, that the environmental benefits associated with biofuels produced from diverting animal fats (or any feedstock) diverted from existing markets are likely less than the environmental benefits associated with biofuels produced from feedstocks that would not otherwise be productively used.[153]

The global supply of UCO is primarily a function of UCO collection rates, which are themselves a function of the total quantity of vegetable oils used in food production and the infrastructure in place to collect and productively use UCO. UCO collection rates vary significantly by country, from virtually nothing in many countries to approximately 2.5 pounds per capita in the U.S.[154] Demand for UCO as a feedstock for biofuel production in recent years has resulted in a rapid increase in the global collection of UCO, from approximately 2.3 billion gallons in 2018 to approximately 3.7 billion gallons in 2022.[155] A recent study projected that the increase in global UCO collection from 2022 to 2027 could range from 1.4 billion gallons (based on projected increases in population and GDP) to 6.1 billion gallons (based on increasing collection rates in countries that currently have some UCO collection infrastructure in place).[156] The study noted that even greater UCO collection is possible by 2027 with economic incentives sufficient to encourage the collection of UCO in countries where it is currently not being collected.[157]

In addition to the uncertainty related to the global collection of animal fats and UCO, there is also significant uncertainty related to the markets where these feedstocks and biofuels produced from them will be used. Because biodiesel and renewable diesel generally cost more to produce than the petroleum fuels they displace, demand for these fuels is primarily driven by the incentives available to the producers and/or blenders of these fuels. Many countries around the world offer incentives or have imposed mandates for the use of biodiesel and renewable diesel. These incentives vary significantly from country to country, both in magnitude and in structure. For example, some countries provide the same incentive for all gallons of qualifying biofuel, while other countries provide increasing incentives for biofuels that provide greater GHG reductions, such as the waste feedstock derived fuels.

Because incentives are often greatest for animal fats and UCO feedstocks and biofuels produced from them, the market for these fuels is subject to greater volatility based on changes in biofuel policies than are vegetable oils and biofuels produced from vegetable oils. For example, in California's LCFS program, biofuels produced from animal fats and UCO generally have a lower carbon intensity and thus generate more credits than biofuels produced from vegetable oils such as soybean oil and canola oil. The EU's RED II places no restrictions on the crediting of biofuels produced from animal fats and UCO while the crediting of biofuels produced from food and feed crops is limited to a maximum of 7 percent of the consumption in the road and rail transport sector in each member state.[158] Because biofuels and biofuel feedstocks are globally traded commodities, the incentives available for the production and use of these

[149] USDA, ''Oil Crops Yearbook,'' March 2025. *https://www.ers.usda.gov/data-products/oil-crops-yearbook.*

[150] *Id.*

[151] Global Data, ''UCO Supply Outlook,'' August 2023.

[152] Food and Agriculture Organization of the United Nations, ''World Food and Agriculture—Statistical Yearbook 2023,'' 2023. *https://doi.org/10.4060/cc8166en.*

[153] When feedstocks are diverted from existing uses, the markets that previously used these feedstocks generally seek alternative feedstocks. Potential alternatives could include petroleum-based feedstocks or palm oil. Increased use of these feedstocks in non-biofuel markets could reduce or negate the intended environmental benefits from increased biofuel production.

[154] Global Data, ''UCO Supply Outlook,'' August 2023.

[155] *Id.*

[156] *Id.*

[157] *Id.*

[158] European Commission, ''Renewable Energy—Recast to 2030 (RED II).''

biofuels can and historically have had a significant impact on where these products are used. A greater or smaller portion of the available global supply of animal fats and UCO could be available to U.S. biofuel producers depending on whether the incentives available to biofuel producers are higher or lower than those offered by other countries.

Recent changes in the trade flows of UCO from China illustrate the changing nature of incentive programs and the impact these changes can have on the supply of biofuel feedstocks. From 2018–2023, exports of UCO from China increased significantly, from approximately 0.6 million metric tons in 2018 to about 2.1 million metric tons in 2023. From 2018–2022, the primary destination of these exports was Europe, accounting for approximately 60 percent of all exports of UCO from China, while less than 1 percent of all exports of UCO from China were exported to the U.S.[159] In 2023, however, the market dynamics changed significantly. Exports of UCO from China to Europe fell to just 23 percent of total exports, while exports to the U.S. increased to 41 percent.[160] The decline in European UCO imports was due to a combination of factors, including reduced demand for biodiesel and renewable diesel in some EU member states and concerns that imported UCO from China may include palm oil. These concerns resulted in decreased demand for UCO sourced from China in the EU and simultaneous increased demand for this feedstock in the U.S. There is potential for increased consumption of these fuels and feedstocks domestically in China in future years, should the government, for example, choose to increase incentives for the production and use of renewable jet fuel. The unpredictable nature of changes to biofuel incentives in both the U.S. and other countries in future years, combined with the potentially significant impact of these changes, makes it very difficult to predict the supply of these feedstocks to U.S. biofuel producers with a high degree of certainty.

2. Proposed Non-Cellulosic Advanced Biofuel Volumes

Based on our analyses of all the statutory factors, we are proposing volumes for 2026 and 2027 that reflect 500 million RIN annual increases in the projected supply of non-cellulosic advanced biofuel relative to the projected supply of these fuels in 2025. These volumes reflect our consideration of the impacts of these fuels on the statutory factors, including the potential increases in employment and economic impacts associated with the increased production of these fuels (particularly those produced from domestic feedstocks) and the potential for GHG reductions that may result from their use. The proposed non-cellulosic advanced biofuel volumes also reflect our consideration of the projected potential increases in biodiesel and renewable diesel production and supply based primarily on our assessment of the supply of feedstocks used to produce these fuels (including the uncertainties associated with these projections), the projected high costs for these fuels relative to the petroleum fuel they displace, and the potential negative impacts associated with increasing demand for vegetable oils or diverting feedstocks from existing uses to biofuel production.

We project that the feedstocks needed to produce the proposed non-cellulosic advanced biofuel volumes could be supplied from domestic sources and therefore are not dependent on increases in the quantity of imported feedstocks in future years. The proposed reduction in the number of RINs generated for imported renewable fuels and renewable fuels produced from foreign feedstocks significantly increase the likelihood that the increase in the supply of non-cellulosic biofuels through 2027 will be supplied by domestic biofuel producers using domestic feedstocks. Through 2027, we project that imported renewable fuels and feedstocks will continue to contribute towards the total supply of non-cellulosic advanced biofuels, but that the relative share of imported renewable fuels and feedstocks will decrease in future years as domestic supplies increase in response to the incentives provided by the RFS program. We acknowledge, however, that the impact of the proposed import RIN reduction provisions on imports of biodiesel, renewable diesel, and feedstocks used to produce these fuels is uncertain. We request comment on the impact of the proposed import RIN reduction provisions on imports of biodiesel, renewable diesel, and feedstocks used to produce these fuels.[161]

We recognize that there are potential negative impacts likely to result from non-cellulosic advanced biofuel volume requirements that are too high or too low. If we establish volume requirements for these fuels that are too low, the market will likely supply lower volumes of these fuels to the U.S. than could be achieved with higher volume requirements. This could negatively impact biofuel producers and result in lower employment, economic impacts, and GHG emission reductions than could be achieved with higher volume requirements. Conversely, if we establish volume requirements for these fuels that are too high, the costs of these fuels would be expected to rise, increasing the prices of food, fuel, and other goods for consumers. It is also possible that the market would be unable to supply higher volumes, requiring EPA to reduce the volume requirements in the future, undermining the market stability the RFS program is designed to provide. Finally, increasing demand for feedstocks could result in the diversion of qualifying feedstocks from existing uses and increased demand for substitutes such as palm oil. We request comment on whether higher or lower volumes of non-cellulosic advanced biofuel may be appropriate for 2026 and 2027.

While we have determined that it is reasonable to propose volumes for 2026 and 2027 that reflect 500 million RIN annual increases in the projected supply of non-cellulosic advanced biofuel, we are not proposing the advanced biofuel volume requirements for 2026 and 2027 at a level equal to the sum of cellulosic biofuel and non-cellulosic advanced biofuel volumes in this scenario. Consistent with the approach taken by EPA in the Set 1 Rule, and as discussed in greater detail in Section V.D, we are proposing volume requirements in this action that reflect an implied conventional renewable fuel requirement of 15 billion gallons in each year. Since we project that the quantity of conventional renewable fuel available in these years will be limited, significant volumes of non-ethanol biofuels will be needed to meet the proposed conventional renewable fuel volume of 15 billion gallons.

We project that the most likely source of non-ethanol biofuel will be biodiesel and renewable diesel that qualifies as BBD. Biodiesel and renewable diesel cannot be used to satisfy the projected shortfall in conventional renewable fuel if we already require the use of these fuels to meet the proposed non-cellulosic advanced biofuel volumes. Therefore, the proposed non-cellulosic advanced biofuel volumes are equal to the Low Volume Scenario less the volume projected to be needed to meet the shortfall in the proposed conventional renewable fuel volume. The proposed non-cellulosic advanced

[159] UN Comtrade Database, Trade Data, HS Code 1518.

[160] *Id.*

[161] See DRIA Chapter 3.2 for our assessment of the likely impacts of this proposed rule, including the impact of the proposed import RIN reduction.

biofuel volumes for 2026 and 2027 are summarized in Table V.B.2–1.

TABLE V.B.2–1—PROPOSED NON-CELLULOSIC ADVANCED BIOFUEL VOLUMES

[Million RINs] [a]

	2026	2027
Non-cellulosic biofuel volume (total supply)	8,940	9,440
Needed to meet the implied conventional volume	1,220	1,340
Available for the advanced biofuel standard	7,720	8,100

[a] All volumes rounded to the nearest 10 million RINs.

C. Biomass-Based Diesel

In previous RFS rulemakings, we have adopted an approach of increasing the BBD volume requirement in concert with the change, if any, in the implied non-cellulosic advanced biofuel volume requirement. This approach provides ongoing support for BBD producers, while maintaining an opportunity for other advanced biofuels to compete for market share. In reviewing the implementation of the RFS program to date, we determined that this approach successfully balanced a desire to provide support for BBD producers with an increasing guaranteed market, while at the same time maintaining an opportunity for other advanced biofuels to compete within the advanced biofuel category. Our assessment of the impacts of BBD on the statutory factors is discussed further in the DRIA.

As in recent years, we believe that excess volumes of BBD beyond the BBD volume requirements will be used to satisfy the advanced biofuel volume requirement within which the BBD volume requirement is nested. Historically, the BBD standard has not independently driven the use of BBD in the market. This is due to the nested nature of the standards and the competitiveness of BBD relative to other advanced biofuels. Moreover, BBD can also be driven by the implied conventional renewable fuel volume requirement as an alternative to using increasing volumes of corn ethanol in higher-level ethanol blends such as E15 and E85. We believe these trends will continue through 2027.

We also believe it is important to maintain space for other advanced biofuels to participate within the advanced biofuel standard of the RFS program. Although the BBD industry has matured over the past decade, the production of advanced biofuels other than biodiesel and renewable diesel continues to be relatively low and uncertain. Maintaining this space for other advanced biofuels can in the long-term facilitate increased commercialization and use of other advanced biofuels, which may have superior environmental benefits, avoid concerns with food prices and supply, and have lower costs relative to BBD. Furthermore, rather than only supporting BBD, the new 45Z credit may support the production and use of non-BBD advanced biofuels as well. Despite the potential impacts of the 45Z credit, we do not think increasing the size of this space is necessary through 2027 given that only small quantities of these other advanced biofuels have been used in recent years relative to the space we have provided for them in those years.

The proposed BBD volumes represent significant growth from the volumes established in the Set 1 Rule. At the same time, these volumes preserve an opportunity for non-cellulosic advanced biofuels other than BBD to compete for market share within the advanced biofuel category. We are proposing BBD volumes that maintain a 600 million RIN opportunity for non-cellulosic advanced biofuels other than BBD, which is approximately equal to the opportunity for these fuels from 2023–2025. We request comment on this 600 million RIN amount and whether a higher or lower number would be appropriate. The proposed BBD volumes are shown in Table V.C–1.

Note that, unlike in previous years, the BBD volume requirement is expressed in RINs rather than physical gallons. As discussed in Section X.C, we are proposing to make this change to better align the BBD requirement with the requirements for the other three categories of renewable fuel, which are expressed in RINs rather than gallons. This change also reflects the increasing uncertainty in the relationship between the number of gallons of BBD that will be needed to satisfy the percentage standards due to the proposed reduction in the number of RINs generated for imported renewable fuels and renewable fuels produced from foreign feedstocks.[162]

TABLE V.C–1—PROPOSED BBD VOLUMES

[Million RINs] [a]

	2026	2027
BBD	7,120	7,500
Opportunity for advanced biofuel other than BBD	600	600
Total non-cellulosic advanced biofuel	7,720	8,100

[a] All volumes rounded to the nearest 10 million RINs.

D. Conventional Renewable Fuel

Although Congress had intended cellulosic biofuel to become the most widely used renewable fuel by 2022, conventional renewable fuel has continued to account for the majority of renewable fuel supply since the RFS program began in 2005. The favorable economics of blending corn ethanol at 10 percent into gasoline, even without the incentives created by the RFS

[162] See Section VIII.

program, caused it to quickly saturate the gasoline supply shortly after the RFS program began. Indeed, corn ethanol has been added to nearly every gallon of gasoline used for transportation in the United States ever since.

The implied statutory volume target for conventional renewable fuel rose annually between 2009 and 2015 until it reached 15 billion gallons, where it remained through 2022. EPA has used 15 billion gallons of conventional renewable fuel in calculating the applicable percentage standards for several recent years, most recently for 2023–2025 in the Set 1 Rule.

As discussed in Section III.B.5, constraints on ethanol consumption have prevented the volume of ethanol used in transportation fuel from reaching 15 billion gallons, even with the incentives provided by the RFS program and after accounting for the projected increase in the availability of higher-level ethanol blends such as E15 and E85. Such higher-level ethanol blends are an avenue through which higher volumes of renewable fuel can be used in the transportation sector to reduce GHG emissions and improve energy security over time. Incentives created by the implied conventional renewable fuel volume requirement contribute to the economic attractiveness of these fuels. However, we expect the constraints that currently limit adoption of these blends, and ethanol consumption as a whole, to continue to exist through 2027. The difficulty in reaching 15 billion gallons with ethanol is compounded by the fact that gasoline demand for 2026 and 2027 is expected to continue to decline over time in line with likely vehicle efficiency improvements.

We do not believe that constraints on ethanol consumption should be the single determining factor in the appropriate level of conventional renewable fuel to establish for 2026 and 2027. The implied volume requirement for conventional renewable fuel is not a requirement for ethanol, nor even for conventional renewable fuel. Instead, conventional renewable fuel is the portion of total renewable fuel that is not required to be advanced biofuel. The implied volume requirement for conventional renewable fuel can be satisfied by any approved renewable fuel. Examples of non-ethanol renewable fuels that regularly contribute to this volume include conventional biodiesel and renewable diesel, as well as advanced biodiesel and renewable diesel beyond what is required by the advanced biofuel volume requirement. For these reasons, we choose to propose the appropriate level of conventional renewable fuel on a broader basis than just the amount of conventional ethanol likely to be consumed each year.

While this segment of the RFS program creates opportunities for all approved renewable fuels to contribute, EPA's analysis of several of the statutory factors also highlights, in our view, the importance of ongoing support for corn ethanol generally and for an implied conventional renewable fuel volume requirement that helps to incentivize the domestic consumption of corn ethanol. Moreover, sustained and predictable support of higher-level ethanol blends through consistent implied conventional renewable fuel volume requirements help provide some longer-term incentives for the market to invest in the necessary infrastructure. The benefits of this approach include potential increases in employment and economic impact, most notably for corn farmers, but also positive impacts on ethanol producers and related ethanol blending and distribution activities. The rural economies surrounding these industries also benefit from strong demand for ethanol. Increased demand for higher-level ethanol blends could also increase employment and economic impact more broadly if retail station owners respond to the incentives created by the RFS program and other federal actions by investing in infrastructure necessary to increase the availability of higher-level ethanol blends at their stations. In addition, the consumption of renewable fuels, including domestically produced ethanol, reduces our reliance on foreign sources of petroleum imports and increases the energy security status of the U.S. as discussed in Section IV.B.

Most corn ethanol production occurs in facilities that commenced construction prior to December 19, 2007. This fuel is ''grandfathered'' under the provisions of 40 CFR 80.1403 and thus is not required to achieve a 20 percent reduction in GHGs in comparison to gasoline, pursuant to CAA section 211(o)(2)(A)(i). Nevertheless, based on both our assessment of corn ethanol in the RFS2 Rule and our assessment of GHG impacts for this rule, summarized in Section IV.A, corn ethanol provides GHG reductions in comparison to gasoline. Greater volumes of ethanol consumed thus correspond to greater GHG reductions than would be the case if gasoline was consumed instead of ethanol.

We are projecting that total ethanol consumption will be lower in 2026 and 2027 than it was in previous years despite the increase in consumption of E15 and E85, as discussed in Sections III. At the same time, we are projecting that sufficient BBD and other non-ethanol advanced biofuels will be available in 2026 and 2027 to compensate for this reduction in ethanol consumption and to enable an implied volume requirement for conventional renewable fuel of 15 billion gallons to be met. We are thus proposing to set the implied conventional renewable fuel volume requirement for 2026 and 2027 at 15 billion gallons.

TABLE V.D–1—PROPOSED CONVENTIONAL RENEWABLE FUEL VOLUMES

[Million RINs] [a]

	2026	2027
Conventional ethanol	13,780	13,660
Non-cellulosic advanced biofuel (beyond what is needed to meet the advanced biofuel volume requirement)	1,220	1,340
Total conventional renewable fuel	15,000	15,000

[a] All volumes rounded to the nearest 10 million RINs.

E. Treatment of Carryover RINs

In our assessment of supply-related factors, we focused on those factors that could directly or indirectly impact the consumption of renewable fuel in the U.S. and thereby determined the potential number of RINs generated in each year that could be available for compliance with the applicable standards in those same years. However, carryover RINs represent another source of RINs that can be used for compliance. We therefore investigated whether and to what degree carryover RINs should be considered in the context of determining appropriate levels for the volume scenarios and, ultimately, the Proposed Volumes.

CAA section 211(o)(5) requires that EPA establish a credit program as part of its RFS regulations, and that the credits be valid for obligated parties to show compliance for 12 months as of the date of generation. EPA implemented this requirement through the use of RINs, which are generated for the production of qualifying renewable fuels. Obligated parties can comply by blending renewable fuels into the transportation fuel supply themselves, or by purchasing RINs that represent the renewable fuels that other parties have blended into the supply. RINs can be used to demonstrate compliance for the year in which they are generated or the subsequent compliance year. Obligated parties can obtain more RINs than they need in a given compliance year, allowing them to ''carry over'' these excess RINs for use in the subsequent compliance year, although the RFS regulations limit the use of these carryover RINs to 20 percent of the obligated party's renewable volume obligation (RVO).[163] For the collective supply of carryover RINs to be preserved from one year to the next, individual carryover RINs are used for compliance before they expire and are essentially replaced with newer vintage RINs that are then held for use in the next year. For example, vintage 2025 carryover RINs must be used for compliance with 2026 compliance year obligations, or they will expire. However, vintage 2026 RINs can then be saved for use toward 2027 compliance.

As noted in past RFS annual rules, carryover RINs are a foundational element of the design and implementation of the RFS program.[164] Carryover RINs play an important role in providing a liquid and well-functioning RIN market upon which success of the entire program depends, and in providing obligated parties compliance flexibility in the face of substantial uncertainties in the transportation fuel marketplace.[165] Carryover RINs enable parties ''long'' on RINs to trade them to those ''short'' on RINs, instead of forcing all obligated parties to comply through physical blending. Carryover RINs also provide flexibility and reduce spikes in compliance costs in the face of a variety of unforeseeable circumstances—including weather-related damage to renewable fuel feedstocks and other circumstances potentially affecting the production and distribution of renewable fuel—that could limit the availability of RINs.

Just as the economy as a whole is able to function efficiently when individuals and businesses prudently plan for unforeseen events by maintaining inventories and reserve money accounts, we believe that the RFS program is best able to function when sufficient carryover RINs are held in reserve for potential use by the RIN holders themselves, or for possible sale to others that may not have established their own carryover RIN reserves. Without sufficient RINs in reserve, even minor disruptions causing shortfalls in renewable fuel production or distribution, or higher-than-expected transportation fuel demand (requiring greater volumes of renewable fuel to comply with the percentage standards that apply to all volumes of transportation fuel, including the unexpected volumes) could result in deficits and/or noncompliance by parties without RIN reserves. Moreover, because carryover RINs are individually and unequally held by market participants, a non-zero but nevertheless small number of available carryover RINs may negatively impact the RIN market, even when the market overall could satisfy the standards. In such a case, market disruptions could force the need for a retroactive waiver of the standards, undermining the market certainty so critical to the RFS program. For all these reasons, carryover RINs provide a necessary programmatic buffer that helps facilitate compliance by individual obligated parties, provides for smooth overall functioning of the program to the benefit of all market participants, and is consistent with the statutory provision requiring the generation and use of credits.

Carryover RINs have also provided flexibility when EPA has considered the need to use its waiver authorities to lower volumes. For example, in the context of the 2013 RFS rulemaking we noted that an abundance of carryover RINs available in that year, together with possible increases in renewable fuel production and import, justified maintaining the advanced and total renewable fuel volume requirements for that year at the levels specified in the statute.[166]

1. Projected Number of Available Carryover RINs

The projected number of available carryover RINs after compliance with the 2023 standards (*i.e.,* the number of carryover RINs available for compliance with the 2024 standards) is summarized in Table V.E.1–1.[167] This is the most recent year for which complete RFS compliance data was available at the time of this proposal.

TABLE V.E.1–1—PROJECTED 2023 CARRYOVER RINS

[Million RINs]

RFS standard	RIN type	Absolute 2023 carryover RINs [a]	Effective 2023 carryover RINs [b]
Cellulosic Biofuel	D3+D7	30	0
Non-Cellulosic Advanced Biofuel [c]	D4+D5	740	410
Conventional Renewable Fuel [d]	D6	400	0
Total Renewable Fuel	All D Codes	1,170	[e] 0

[a] Represents the absolute number of 2023 carryover RINs that are available for compliance with the 2024 standards and does not account for deficits carried forward from 2023 into 2024.

[b] Represents the effective number of 2023 carryover RINs that are available for compliance with the 2024 standards after accounting for deficits carried forward from 2023 into 2024. Standards for which deficits exceed the number of available carryover RINs are represented as zero.

[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.

[163] 40 CFR 80.1427(a)(5).

[164] See, *e.g.,* 72 FR 23904 (May 1, 2007).

[165] See 80 FR 77482–87 (December 14, 2015), 81 FR 89754–55 (December 12, 2016), 82 FR 58493–95 (December 12, 2017), 83 FR 63708–10 (December 11, 2018), 85 FR 7016 (February 6, 2020), 87 FR 39600 (July 1, 2022), 88 FR 44468 (July 12, 2023).

[166] 79 FR 49793–95 (August 15, 2013).

[167] The calculations performed to project the number of available carryover RINs can be found in DRIA Chapter 1.8.

[e] This total reflects the fact that for some categories deficits exceed the absolute number of available carryover RINs such that the total volume of effective carryover RINs is zero.

Assuming that the market exactly meets the 2024 and 2025 standards with new RIN generation, these are also the number of carryover RINs that would be available for 2026 and 2027. While we project that the volume requirements in 2024 and 2025 and the volume scenarios for 2026 and 2027 could be achieved without the use of carryover RINs, there is nevertheless some uncertainty about how the market would choose to meet the applicable standards. The result is that there remains some uncertainty surrounding the ultimate number of carryover RINs that will be available for compliance with the 2026 and 2027 standards. In particular, as discussed in DRIA Chapter 1.8, the number of available carryover RINs has decreased significantly in recent years. While on an absolute basis there should still be RINs available to purchase in the marketplace, as shown in Table III.C.4.a–1, in reality the magnitude of compliance deficits is even larger, making their availability less certain. Furthermore, we note that there have been enforcement actions in past years that have resulted in the retirement of carryover RINs to make up for the generation and use of invalid RINs and/or the failure to retire RINs for exported renewable fuel. To the extent that there are enforcement actions in the future, they could have similar results and require that obligated parties or renewable fuel exporters settle past enforcement-related obligations in addition to complying with the annual standards. In light of these uncertainties, the number of available carryover RINs could be larger or smaller than the number projected in Table V.E.1–1.

We continue to believe that carryover RINs serve a vital programmatic function, but also acknowledge that the effective number of cellulosic and conventional renewable fuel carryover RINs is zero, and that the effective number of non-cellulosic advanced biofuel carryover RINs is significantly lower than it has been in recent years and may be necessary to make up for the significant conventional biofuel deficits. Should the market fall short of the volumes we are finalizing, obligated parties will continue to be able to carry forward a RIN deficit from one year into the next, although they may not carry forward a deficit for consecutive years. Conversely, should the market over-comply with the standards we are finalizing, the number of available carryover RINs could again grow.

2. Treatment of Carryover RINs for 2026 and 2027

We evaluated the number of carryover RINs projected to be available and considered whether we should include any portion of them in the determination of the volume scenarios that we analyzed or the volume requirements that we are proposing for 2026 and 2027. Doing so would be equivalent to intentionally drawing down the number of available carryover RINs in setting those volume requirements. After due consideration, we do not believe that this would be appropriate and we propose to avoid intentionally drawing down any portion of the projected number of available carryover RINs in the Proposed Volumes. In reaching this determination, we considered the functions of carryover RINs, the projected number available, the uncertainties associated with this projection, the potential impact of carryover RINs on the production and use of renewable fuel, the ability and need for obligated parties to draw on carryover RINs to comply with their obligations (both on an individual basis and on a market-wide basis), and the impacts of drawing down the number of available carryover RINs on obligated parties and the fuels market more broadly. As previously described, carryover RINs provide important and necessary programmatic functions—including as a cost spike buffer—that will both facilitate individual compliance and provide for smooth overall functioning of the program. We believe that a balanced consideration of the possible role of carryover RINs in achieving the volume requirements, versus maintaining an adequate number of carryover RINs for important programmatic functions, is appropriate when EPA exercises its discretion under its statutory authorities.

Furthermore, in this action we are proposing to prospectively establish volume requirements for multiple years. This inherently adds uncertainty and makes it more challenging to project with accuracy the number of carryover RINs that will be available for each of these years. Given these factors, and the uneven holding of carryover RINs among obligated parties, we believe that further increasing the volume requirements for 2026 and 2027 with the intent to draw down the number of available carryover RINs could lead to significant deficit carryforwards and noncompliance by some obligated parties. We do not believe this would be a desirable outcome. Therefore, consistent with the approach we have taken in recent annual rules, we are not proposing to set the 2026 and 2027 volume requirements at levels that would intentionally draw down the projected number of available carryover RINs.

We are not determining that the number of carryover RINs projected in Table V.E.1–1 is a bright-line threshold for the number of carryover RINs that provides sufficient market liquidity and allows carryover RINs to play their important programmatic functions. As in past years, we are instead evaluating, on a case-by-case basis, the number of available carryover RINs in the context of the RFS standards and the broader transportation fuel market. Based upon this holistic, case-by-case evaluation, we are concluding that it would be inappropriate to intentionally reduce the number of carryover RINs by establishing higher volumes than what we anticipate the market can achieve in 2026 and 2027. Conversely, while a larger number of available carryover RINs may provide greater assurance of market liquidity, we do not believe it would be appropriate to set the standards at levels specifically designed (*i.e.,* low) to increase the number of carryover RINs available to obligated parties.

F. Summary of Proposed Volume Requirements

For the reasons described above, we are proposing RFS volume requirements based on the three component categories discussed above. The volumes for each of the component categories (sometimes referred to as implied volume requirements) are summarized in Table V.F–1. Table V.F–1 also includes the proposed volume requirements for BBD, which is not a component category of renewable fuel but is based on our evaluation of non-cellulosic advanced biofuel and other considerations described in Section V.C.

TABLE V.F–1: PROPOSED VOLUME REQUIREMENTS FOR COMPONENT CATEGORIES AND BBD

[Billion RINs] [a]

	2026	2027
Cellulosic biofuel	1.30	1.36
Biomass-based diesel	7.12	7.50
Non-cellulosic advanced biofuel	7.72	8.10
Conventional renewable fuel	15.00	15.00

[a] All volumes rounded to the nearest 0.01 billion RINs.

The proposed volumes for each of the four component categories shown in the table above can be combined to produce volume requirements for the four statutory renewable fuel categories on which the applicable percentage standards are based. The results are shown in Table V.F–2.

TABLE V.F–2—PROPOSED VOLUME REQUIREMENTS FOR STATUTORY CATEGORIES

[Billion RINs] [a]

	2026	2027
Cellulosic biofuel	1.30	1.36
Biomass-based diesel	7.12	7.50
Advanced biofuel	9.02	9.46
Total renewable fuel	24.02	24.46

[a] All volumes rounded to the nearest 0.01 billion RINs.

We believe that these volume requirements will preserve and substantially build upon the gains made through biofuels in previous years. These proposed volume requirements, in combination with the proposed import RIN reduction provisions, would continue to support the domestic renewable fuel industry and help move the U.S. towards greater energy independence and energy security. These proposed volume standards are expected to drive increased employment and economic impact in the U.S. and are projected to achieve additional reductions in GHG emissions from the transportation sector. The proposed volume requirements would also promote ongoing development within the biofuels and agriculture industries as well as the economies of the rural areas in which biofuels production facilities and feedstock production reside.

G. Request for Comment on Alternatives

We request comment on alternative volume requirements for each of the statutory categories of renewable fuel for 2026 and 2027, including volumes both higher and lower than we are proposing and appropriate volumes if the proposed provisions to reduce the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks are not finalized. Our analysis of the Low and High Volume Scenarios summarized in Section IV and presented in greater detail in the DRIA provides an indication of the potential impacts of alternative volumes. Note that while the Proposed Volumes (expressed in billion RINs) are similar to the Low Volume Scenario and lower than the High Volume Scenario, we project that the Proposed Volumes would result in significantly higher renewable fuel production and consumption in the U.S. than either the Low or High Volume Scenario, particularly for domestic renewable fuel, due to the proposed import RIN reduction provisions.

We also request that commenters provide any data or analysis that would support alternative volumes for these years. In particular, we request comment on our proposed approach of accounting for the projected shortfall in the supply of conventional renewable fuel relative to the 15-billion-gallon implied volume when establishing the volume requirements for advanced biofuel and BBD (see Section V.B for a description of this approach). We request comment on the advantages and disadvantages of establishing BBD and advanced biofuel volume requirements at levels at or closer to the projected supplies of these fuels, as has been suggested by some stakeholders, and the implications of doing so on the implied volume of conventional renewable fuel if such an approach were adopted.

H. Summary of the Assessed Impacts of the Proposed Volume Standards

CAA section 211(o)(2)(B)(ii) requires EPA to assess specific factors when determining volume requirements for calendar years after 2022. These factors are described in Section I and each factor is discussed in detail in the DRIA. However, the statute does not specify how EPA must assess each factor or address whether the EPA Administrator should monetize particular factors, quantify particular factors, or analyze particular factors qualitatively in reaching a determination. For several of these statutory factors—costs and energy security—we provide estimates of the monetized impacts of the proposed volume standards. For the other statutory factors, we are either unable to quantify impacts, or we provide quantitative estimated impacts that nevertheless cannot be easily monetized. Thus, we are unable to quantitatively compare all the evaluated impacts of this rulemaking and are also unable to compare all quantitative impacts on a consistent basis. Our assessments of the impacts of the proposed volume standards mirrors our assessment of the Volume Scenarios discussed in Section IV. That is, we compared the difference in estimated outcomes under the proposed volume standards to the estimated outcomes under the No RFS Baseline.

Assessed effects of the proposed volume standards on the factors enumerated below differ in the directions of their respective impacts. That is, some assessments show benefits of the proposed volume standards from the factor(s) in question, others show negative impacts, while still others show impacts with ambiguous or different directional effects. Factors with analyses showing benefits of the proposed volume standards include impacts on jobs, rural economic development, energy security benefits, and the potential for climate benefits. Assessed factors with analyses indicating costs or directionally negative effects of the proposed volume standards include impacts on fuel costs, water and soil resources, and impacts of induced land use change on ecosystems. Our assessment of the effects of the proposed volume standards on other factors show ambiguous or mixed directional impacts. These factors include effects on the supply and price of some agricultural commodities, air quality impacts, and impacts on infrastructure. All the statutory factors are taken under consideration, as is required by the statute, regardless of whether we were able to quantify or monetize the impact under the proposed volume standards on each of the statutory factors.

1. Jobs and Rural Economic Development

In this section, we summarize our estimates of the impacts of the Proposed Volumes on economy-wide employment and rural economic development (both include direct, indirect, and induced impacts). These analyses are described in detail in DRIA Chapter 9.

To estimate the impact of this proposed rule on jobs (relative to the No RFS baseline), we applied the same two analytical approaches described in Section IV.D—the ''rule-of-thumb'' approach and the use of input-output modeling where feasible. These results are summarized in Table V.H.1–1. For the corn ethanol case, using the results from the IO analysis we have developed ranges of impacts for fuel volumes based on uncertainty regarding how the volumes will be provided. For example, volumes associated with new production capacity would also be associated with some number of temporary construction jobs, while expanded capacity utilization at existing facilities would not. These ranges of potential impacts are summarized in tables in Chapter 9 along with detailed explanations of the associated methodology.

We estimate that all three categories of renewable fuel we analyzed—ethanol, BBD, and RNG—are associated with increases in jobs to varying degrees. We observe that RNG appears to be associated with the highest number of direct jobs created per unit of biofuel. However, BBD is projected to have the highest job creation impact overall, primarily due to substantially higher production increases relative to the baseline. In terms of rural employment specifically, ethanol has the highest direct and total effects per million gallons of ethanol equivalent. 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.

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 impacts per million gallons of ethanol equivalent on rural economic development than does RNG. 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.

Table V.H.1–1 summarizes the estimated economy-wide job impacts and rural GDP impacts (including direct, indirect, and induced impacts) associated with the proposed volumes of ethanol, BBD, and RNG. These estimates of rural GDP impacts are actual values as opposed to discounted values, implying that they do not reflect the time value of money.

TABLE V.H.1–1—JOB CREATION AND RURAL GDP IMPACTS OF PROPOSED VOLUMES

[FTE; million 2022$]

Fuel type	2026		2027	
	Jobs	Rural economic development	Jobs	Rural economic development
RNG	19,504	1,072.16	20,240	1,112.59
BBD	92,285	9,742.30	96,749	10,213.54
Ethanol [a]	5,332	366.19	5,735	393.83
Total	117,121	11,180.66	122,723	11,719.96

[a] For the corn ethanol case alone, using NREL's JEDI module for dry mill corn ethanol we were able to generate employment and income estimates under alternative scenarios and also carry out a sensitivity analysis. Please refer to DRIA Chapter 9 for more details.

Our estimates 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, our estimates for jobs and rural development impacts are gross estimates and not net estimates. To be more accurate, the job estimates are labor demand in the directly regulated industry. We also acknowledge that, in the long run, environmental regulations such as the RFS program typically affect the distribution of employment among industries rather than the general employment level.

We request comment on our approaches to estimating jobs and rural economic development impacts associated with renewable fuels.

2. Energy Security

Our analysis shows that the Proposed Volumes would have a positive impact on energy security by reducing U.S. reliance on foreign sources of energy. Monetized energy security impacts of the Proposed Volumes are summarized in Table V.H.2–1. Energy security and methods of quantifying energy security impacts are discussed in Section IV.A and DRIA Chapter 6.

TABLE V.H.2–1—ENERGY SECURITY IMPACTS ESTIMATES OF THE PROPOSED VOLUMES

[Million 2022$]

	3% Discount rate	7% Discount rate
Present value (2025)	$387	$366
Annualized value [a]	202	202

[a] 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.

3. Climate Change

Our analysis of the effects of the Proposed Volumes on climate change shows a range of potential GHG emissions impacts, from 29 million metric tons of cumulative CO_2e reductions through 2055 (1 million metric tons annual average reductions) to 491 million metric tons of cumulative CO_2e reductions through 2055 (16 million metric tons annual average reductions). Although these reductions are notable, the uncertainties involved in implementation and the causal relationship between these emissions and climate change considerations make it difficult to evaluate the extent to which such reductions will meaningfully impact climate change. Methods for estimating climate impacts are discussed in DRIA Chapter 5.

4. Fuel Costs

The methodology used to estimate fuel costs is summarized in Section IV.B, while a detailed summary of the methodology is contained in DRIA Chapter 10. The estimated fuel costs for the Proposed Volumes (including the impacts of the proposed import RIN reduction provisions) are presented in Tables V.H.4–1 through 3, while the estimated fuel costs for the Volume Scenarios are summarized in Section IV.B.2.[168] Fuel costs represent the costs of producing and using biofuels relative to the petroleum fuels they displace. The net estimated cost impacts are total social costs, excluding any subsidies and transfer payments, and thus are incrementally added to all other societal costs. They do not include benefits and other factors, such as the potential impacts on soil and water quality or potential GHG reduction benefits. See DRIA Chapter 10.4.2 for more detail on the estimated costs of this action.

TABLE V.H.4–1—AGGREGATED TOTAL SOCIAL COSTS RELATIVE TO THE NO RFS BASELINE

[Million 2022$] [a]

	2026	2027
Gasoline	188	206
Diesel	7,456	5,871
Natural Gas	−150	−142
Total	7,494	5,936

[a] Total cost of the renewable fuel expressed over the fossil fuel it is blended into.

TABLE V.H.4–2—PER-UNIT COSTS RELATIVE TO NO RFS BASELINE

[2022$] [a]

	Units	2026	2027
Gasoline	¢/gal	0.14	0.16
Diesel	¢/gal	14.22	11.30
Natural Gas	¢/thousand ft^3	−0.50	−0.49
Gasoline and Diesel	¢/gal	4.07	3.26

[a] Per-gallon or per thousand cubic feet cost of the renewable fuel expressed over the fossil fuel it is blended into; the last row expresses the cost over the obligated pool of gasoline and diesel fuel.

TABLE V.H.4–3—ESTIMATED DISCOUNTED FUEL COSTS IMPACTS OF THE PROPOSED VOLUMES

[Million 2022$]

	3% Discount rate	7% Discount rate
Present value (2025)	$12,871	$12,188
Annualized value [a]	6,726	6,741

[a] 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.

5. Cost to Transport Goods

We also estimated the impact of the Proposed Volumes on the cost to transport goods. However, it is not appropriate to use the social cost for this analysis as the fuel prices include a number of other factors, such as state and federal incentives, that we do not consider in our social cost estimates. The per-unit costs from Table V.H.4–2 are adjusted to reflect RIN price impacts and account for the biofuel subsidies and other market factors, and the resulting values can be thought of as retail costs. Consistent with our assessment of the fuels markets, we have assumed that obligated parties pass through their RIN costs to consumers and that fuel blenders reflect the RIN value of the renewable fuels in the price of the blended fuels they sell.[169] Table V.H.5–1 summarizes the estimated impacts of the Proposed Volumes (including the impacts of the proposed import RIN reduction provisions) on gasoline and diesel fuel prices at retail when the costs of each biofuel is amortized over the fossil fuel it displaces. We note that while the Proposed Volumes for 2026 and 2027 are higher than the 2025 baseline, the projected costs of this proposed rule are less than the 2025 baseline. This is primarily due to lower feedstock prices resulting in lower projected costs of production for renewable fuels in 2026 and 2027 relative to 2025.

[168] More detailed information on the costs for the Proposed Volumes is available in DRIA Chapter 10.4.2.

[169] See DRIA Chapter 10.5 for more detailed information on our estimates of the fuel price impacts of this action.

TABLE V.H.5–1—ESTIMATED EFFECT OF PROPOSED VOLUMES ON RETAIL FUEL PRICES
[¢/gal]

	2026	2027
Relative to No RFS Baseline:		
Gasoline	4.4	4.7
Diesel	9.1	10.6
Relative to 2025 Baseline:		
Gasoline	0.0	0.0
Diesel	−1.0	−0.2

For estimating the cost to transport goods, we focus on the impact on diesel fuel prices since trucks that transport goods are normally fueled by diesel fuel. Reviewing the data in Table V.H.5–1, the largest projected price increase is 10.6¢ per gallon for diesel fuel in 2027 for the No RFS Baseline.

The impact of fuel price increases on the price of goods can be estimated based on a USDA study that analyzed the impact of fuel prices on the wholesale price of produce.[170] Applying the price correlation from the USDA study indicates that the 10.6¢ per gallon diesel fuel cost increase raises retail prices by about 2.7 percent, which would then increase the wholesale price of produce by about 0.7 percent. If produce being transported by a diesel truck costs $3 per pound, the increase in that product's price would be $0.02 per pound.[171] If the estimated price impacts are averaged over the combined gasoline and diesel fuel pool, the impact on produce prices would be proportionally lower based on the lower per-gallon cost.

6. Conversion of Natural Lands, Water, Soil, and Ecosystem Impacts

Increases in volumes—particularly BBD volumes—attributable to this action could lead to potential increases in agricultural land conversion to produce biofuel feedstocks. Such land use changes could subsequently contribute to negative impacts to water and soil quality, water quantity, and ecosystems and habitat. This is discussed further in DRIA Chapters 4.2 through 4.5.

7. Infrastructure

We evaluated the Proposed Volumes and how they may impact the existing renewable fuels infrastructure required for product distribution. This includes whether the current infrastructure system is sufficient to accommodate the increases in the Proposed Volumes and potential changes that could occur with volume increase and future demand. Based on our analysis, we project that the proposed renewable fuel volumes will be compatible with existing infrastructure and that the supply of these fuels will not adversely impact the infrastructure required for product distribution. A more detailed summary of this analysis can be found in DRIA Chapter 8.

8. Commodity Supply

We project that the supply of commodities used for biofuel production, such as corn and soybeans, will continue to increase in future years primarily due to yield increases, consistent with historic trends. It is possible that increasing demand for biofuel feedstocks such as soybean oil will divert these feedstocks from other markets; however, we project that most of the increase in the use of agricultural commodities used for biofuel production will be met by increased production of these feedstocks rather than diversion from existing markets. See DRIA Chapter 9.2 for more detail on our analysis of the impact of biofuel production on the supply of commodities.

9. Air Quality

We expect some localized increases in some air pollutant concentrations due to the Proposed Volumes, particularly at locations near biofuel production and transport routes. Overall, considering end use, transport, and production, emission changes are expected to have variable impacts on ambient concentrations of pollutants in specific locations across the U.S. Air quality impacts are discussed further in DRIA Chapter 4.1.

10. Food and Commodity Prices

Our analysis indicates that the Proposed Volumes would have only a minimal impact on agricultural commodity and food prices, with any resulting price increases expected to be small. A summary of the estimated impacts is provided in Table V.H.10–1, and further discussion can be found in DRIA Chapters 9.3 and 9.4.

TABLE V.H.10–1—ESTIMATED EFFECT OF PROPOSED VOLUMES ON FOOD AND AGRICULTURAL COMMODITY PRICES

	Units	2026	2027
Corn Price Increase	$ per bushel	$0.03	$0.03
Soybean Oil Price Increase	$ per pound	0.33	0.36
Soybean Meal Price Change	$ per short ton	−63	−71
Projected Food Expenditure Increase	$ per Consumer Unit	17.97	18.00

VI. Proposed Percentage Standards for 2026 and 2027

EPA implements the nationally applicable volume requirements by establishing percentage standards that apply to obligated parties.[172] The obligated parties to which the percentage standards apply are producers and importers of gasoline and diesel, as defined by 40 CFR 80.2. Each obligated party multiplies the percentage standards by the sum of all

[170] USDA, ''How Transportation Costs Affect Fresh Fruit and Vegetable Prices,'' Economic Research Report 160, November 2013.

[171] Coupons.com, ''Comparing Prices on Groceries,'' May 4, 2021.

[172] See 40 CFR 80.1407 and 75 FR 14670 (March 26, 2010). As discussed in the Set 1 Rule, EPA determined that continuing to use percentage standards as the implementing mechanism for years after 2022 was effective and reasonable. 88 FR 44519 (July 12, 2023).

non-renewable gasoline and diesel they produce or import to determine their RVOs. The RVOs are the number of RINs that the obligated party is responsible for procuring to demonstrate compliance with the applicable standards for that year. Since there are four separate standards under the RFS program, there are likewise four separate RVOs applicable to each obligated party for each year. As described in Section II.D, EPA establishes applicable percentage standards for multiple future years after 2022 in a single action for as many years as it establishes volume requirements. The renewable fuel volumes used to determine the 2026 and 2027 percentage standards are shown in Table V.F–2.

A. Calculation of Percentage Standards

The formulas used to calculate the percentage standards applicable to obligated parties are provided in 40 CFR 80.1405(c). In addition to the required volumes of renewable fuel, the formulas also require estimates of the volumes of non-renewable gasoline and diesel, for both highway and nonroad uses, that are projected to be used in the year in which the standards will apply. Consistent with previous RFS rulemakings, we are using gasoline and diesel projections provided by EIA—specifically AEO2023, as this is the most recent projection from EIA that covers 2026 and 2027.[173] However, these projections include volumes of renewable fuel (*e.g.,* ethanol, biodiesel, renewable diesel) used in gasoline and diesel. Since the percentage standards apply only to the non-renewable portions of gasoline and diesel, the volumes of renewable fuel are subtracted out of the EIA projections of gasoline and diesel as part of the percentage standard equations.[174]

B. Treatment of Small Refinery Volumes

In CAA section 211(o)(9), Congress provided for qualifying small refineries to be temporarily exempt from RFS compliance through December 31, 2010. Congress also provided in CAA section 211(o)(9)(A)(ii)(II) and (B)(i) that small refineries could receive an extension of the exemption beyond 2010 based either on the results of a required Department of Energy (DOE) study or in response to individual petitions demonstrating that the small refinery suffered ''disproportionate economic hardship.''

There is currently significant uncertainty regarding the number of small refinery exemption (SRE) petitions that could be granted for 2026 and 2027. While we stated that ''we anticipate that no SREs will be granted for these future years'' in the Set 1 Rule (referring to 2023–2025) due to the SRE Denial Actions that had recently been issued,[175] subsequent court cases invalidated those actions.[176] As a result, the SRE Denial Actions were vacated and the majority of the SRE petitions decided therein were remanded back to EPA. We have yet to take further action on these petitions and are still determining how we will evaluate and decide those petitions, which would then inform how we would evaluate and decide any SRE petitions received for 2026 and 2027. We expect to communicate our policy regarding SRE petitions going forward before finalization of this rule.

While there remains uncertainty in the volume of gasoline and diesel that will be exempt in 2026 and 2027, we have developed an upper- and lower-bound estimate of this exempt volume. We currently project that there are approximately 34 qualifying and operational small refineries producing up to approximately 18 billion gallons of gasoline and diesel each year, or about 10 percent of the total reported volume of obligated gasoline and diesel. Therefore, the potential range of exempt volumes from SREs that could be included in the calculation specified by 40 CFR 80.1405(c) for 2026 and 2027 ranges from zero gallons (if EPA denied all SRE petitions) to 18 billion gallons (if EPA granted all SRE petitions).

We have used these estimates to calculate both an upper- and lower-bound on the potential percentage standards for 2026 and 2027. While we are still developing our new approach to evaluating SRE petitions, for purposes of the proposed percentage standards in this action, we have used a volume of 18 billion gallons of exempt gasoline and diesel (*i.e.,* all small refineries would be exempt from having to comply with their 2026 and 2027 RFS obligations). We have also calculated what the percentage standards would be if there were zero gallons of exempt gasoline and diesel (*i.e.,* all small refineries would have to comply with their 2026 and 2027 RFS obligations). We expect that by the time we finalize the standards for 2026 and 2027, we will have determined our new approach to evaluating and deciding SRE petitions and will use that new approach to inform our projection of the exempt volumes of gasoline and diesel. In the meantime, these upper- and lower-bound estimates provide stakeholders with a range of plausible outcomes on which to provide comment. We note that a higher projection of exempt volumes of gasoline and diesel would increase the percentage standards and thus the individual RVOs for non-exempt obligated parties. Finally, we note that regardless of the new approach for evaluating SRE petitions, we do not plan to revise the percentage standards once finalized to account for any subsequent changes to that policy or other inaccuracies in the projection of exempt volumes of gasoline and diesel.[177]

This proposed rule, consistent with our regulations, proposes to project the exempt volume of gasoline and diesel associated with SREs for the 2026 and 2027 compliance years only. This proposed rule does not address any exempt volume from the potential grant of SREs for prior compliance years (*i.e.,* 2025 and earlier). Comments on exemptions for compliance years other than 2026 and 2027 will be treated as beyond the scope of this action.

C. Percentage Standards

The formulas used to calculate the percentage standards applicable to obligated parties as a function of their gasoline and diesel fuel production or importation are provided in 40 CFR 80.1405(c).[178] Using the volumes shown in Table V.F–2 and assuming 18 billion gallons of exempt gasoline and diesel to represent the upper-bound estimate, we have calculated the proposed percentage standards for 2026 and 2027, as shown in Table VI.C–1.[179] These percentage standards are included in the proposed regulations at 40 CFR 80.1405(a) and would apply to producers and importers

[173] EIA recently issued AEO2025 on April 15, 2025. We intend to use these updated projections in the final rule.

[174] Further adjustments of these projections are discussed in ''Calculation of Proposed 2026 and 2027 RFS Percentage Standards,'' available in the docket for this action. Discussion of the overall gasoline and diesel projection adjustment factor is discussed in RFS Set 1 RIA Chapter 1.11. We may update this adjustment factor for the final rule after further evaluating the projections and methodologies used in AEO2025.

[175] EPA, ''April 2022 Denial of Petitions for RFS Small Refinery Exemptions,'' EPA–420–R–22–005, April 2022; EPA, ''June 2022 Denial of Petitions for RFS Small Refinery Exemptions,'' EPA–420–R–22–011, June 2022.

[176] *Calumet Shreveport Refining, LLC et al.* v. *EPA,* 86 F.4th 1121 (5th Cir. 2023); *Sinclair Wyoming Ref. Co.et al.* v. *EPA,* 114 F.4th 693 (D.C. Cir. 2024).

[177] For further discussion on our approach if the actual volume of exempt gasoline and diesel differs from our projection, see 2020–2022 RFS Rule RTC Section 7.1.

[178] As described in Section X.C, we are proposing revisions and clarifications to the percentage standard equations.

[179] See ''Calculation of Proposed 2026 and 2027 RFS Percentage Standards,'' available in the docket for this action.

of gasoline and diesel. We have also calculated what the percentage standards for 2026 and 2027 would be assuming zero gallons of exempt gasoline and diesel, representing the lower-bound estimate of the standards, also as shown in Table VI.C–1.

TABLE VI.C–1—PROPOSED PERCENTAGE STANDARDS FOR 2026 AND 2027

	Lower-bound estimate (0 gal exempt G+D)		Upper-bound estimate (18 bil gal exempt G+D)	
	2026 (%)	2027 (%)	2026 (%)	2027 (%)
Cellulosic biofuel	0.77	0.82	0.87	0.92
Biomass-based diesel	4.24	4.52	4.75	5.07
Advanced biofuel	5.37	5.70	6.02	6.40
Renewable fuel	14.30	14.74	16.02	16.54

VII. Partial Waiver of the 2025 Cellulosic Biofuel Volume Requirement

In the Set 1 Rule, EPA promulgated RFS volume requirements and percentage standards for 2023–2025. As part of that rulemaking, EPA projected that 1.38 billion cellulosic RINs would be generated in 2025 and used that volume to establish the 2025 cellulosic biofuel percentage standard of 0.81 percent.[180] This projection was largely based on the assumption that cellulosic RIN generation was primarily constrained by cellulosic biofuel production and was therefore set equal to projected production. However, we have now determined that the main limitation for cellulosic RIN generation is the number of vehicles capable of using cellulosic biofuel as transportation fuel.[181] Consequently, we have updated our cellulosic biofuel projection methodology to be constrained by the total consumption of vehicles capable of using cellulosic biofuel. Based on this change, we now project that only 1.19 billion cellulosic RINs will be generated in 2025, a shortfall of 0.19 billion RINs from the 1.38 billion RINs projected in the Set 1 Rule. Due to this shortfall and reasons further explained in Sections VII.A through C, we are proposing to partially waive the 2025 cellulosic biofuel volume requirement to 1.19 billion RINs (the projected cellulosic RIN generation in 2025) using the CAA section 211(o)(7)(D) ''cellulosic waiver authority.''

We currently project that the supply of advanced biofuel and total renewable fuel in 2025 will exceed the required volumes by a significant margin, despite the projected shortfall in cellulosic biofuel. Given the projected surplus of 2025 advanced RINs, we are not proposing to waive the volume requirements for any of the other categories of renewable fuel (*i.e.,* BBD, advanced biofuel, and total renewable fuel).

A. Cellulosic Waiver Authority Statutory Background

The cellulosic waiver authority at CAA section 211(o)(7)(D)(i) provides that ''[f]or any calendar year for which the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under [CAA section 211(o)](2)(B)], as determined by the Administrator based on the estimate provided under paragraph (3)(A),'' EPA ''shall reduce the applicable volume of cellulosic biofuel required under paragraph (2)(B) to the projected volume available during that calendar year'' and that this reduction shall be made ''not later than November 30 of the preceding calendar year.'' For those years in which EPA ''makes such a reduction,'' the statute further provides that EPA may also ''reduce the applicable volume of renewable fuel and advanced biofuels requirement . . . by the same or a lesser volume.'' As such, even when EPA exercises its cellulosic waiver authority, the determination of whether to correspondingly reduce the total renewable fuel or advanced biofuel requirements is discretionary.

When EPA determines that the projected volume of cellulosic biofuel production for a given year will be less than the annual applicable volume established under CAA section 211(o)(2)(B), EPA is then required to reduce the applicable volume of cellulosic biofuel for that calendar year. Pursuant to this provision, EPA set the cellulosic biofuel volume requirement lower than the CAA section 211(o)(2)(B)(i)(III) statutory volumes enumerated by Congress for each year from 2010–2022. EPA was challenged regarding its interpretation of this statutory provision, leading the D.C. Circuit to evaluate various aspects of EPA's implementation of its cellulosic waiver authority.[182] In 2013 in *API,* the court held that EPA must take a ''neutral aim at accuracy'' in determining the projected volume of cellulosic biofuel available.[183] In *API* and *Alon Refining Krotz Springs, Inc.* v. *EPA,* the D.C. Circuit upheld EPA's decision to use the Energy Information Administration's (EIA's) projected volume of cellulosic biofuel production to inform EPA's projection, without requiring ''slavish adherence by EPA to the EIA estimate.'' [184] In *Sinclair Wyoming Refining Co. LLC, et al.* v. *EPA,* the D.C. Circuit upheld EPA's reading of the statutory phrase ''projected volume available'' to exclude carryover RINs.[185]

EPA is proposing to implement the cellulosic waiver authority to reduce the 2025 cellulosic biofuel volume after the deadline articulated in the statute; CAA section 211(o)(7)(D)(i) directs EPA to act ''by November 30 of the preceding calendar year'' to determine whether cellulosic biofuel production is likely to fall short of the volume requirements in a given year, and then reduce the standard to the projected volume available. EPA has implemented the cellulosic waiver authority to reduce the cellulosic biofuel volume after the November 30 deadline on several

[180] 40 CFR 80.1405(a).

[181] See Section VII.B and DRIA Chapter 7.1.3.

[182] See, *e.g., American Petroleum Institute* v. *EPA,* 706 F.3d 474, 479 (D.C. Cir. 2013) (''*API*'') (interpreting the ''projected volume available'' and indicating that ''the most natural reading of the provision is to call for a projection that aims at accuracy, not at deliberately indulging a greater risk of overshooting than undershooting'' in projecting the available cellulosic biofuel volume); *Americans for Clean Energy* v. *EPA,* 864 F.3d 691, 730 (D.C. Cir. 2017) (''*ACE*'') (determining EPA's use of the cellulosic waiver authority to reduce advanced and total renewable fuel was reasonable); *Sinclair Wyoming Refining Co. LLC, et al.* v. *EPA,* 101 F.4th 871, 883 (2024) (''*Sinclair*'') (rejecting biofuels producers' challenge that EPA must include carryover cellulosic RINs in its determination of '' projected volume available during that calendar year'').

[183] *API,* 706 F.3d at 476.

[184] *Alon Refining Krotz Springs, Inc.* v. *EPA,* 396 F.3d 628, 660 (D.C. Cir. 2019); *API,* 607 F.3d at 478.

[185] *Sinclair,* 101 F.4th at 883–86.

occasions.[186] No party has specifically challenged EPA's use of the cellulosic waiver authority after the November 30 deadline, but petitioners have unsuccessfully challenged EPA's late issuance of standards under other RFS provisions. The D.C. Circuit has concluded that EPA retains the ability to issue late standards even when it acts after the statutory deadlines have passed.[187] We therefore rely on our past practice in implementing the RFS program and favorable case law to implement the cellulosic waiver authority to waive the volume requirements for a given year even when the November 30 deadline in the preceding year has passed, as it has in this instance.

CAA section 211(o)(7)(D)(i) also refers to the ''projected volume of cellulosic biofuel production'' and the ''projected volume available,'' which some parties have suggested is another indication that the provision should or could only be used prospectively. EPA believes the best reading of the statute is instead that there are projections necessary to determine the ''volume of . . . production'' and the ''volume available,'' both when EPA acts in a timely manner by November 30 of the preceding year and when EPA waives the volume requirement after the November 30 date. The use of the term ''projected'' in the statute does contemplate the need for forward-looking estimates; however, it does not follow that the statutory language prohibits EPA from acting after November 30.[188]

We note that the statutory language indicates that the use of the cellulosic waiver authority is mandatory. That is, whenever the projected volume of cellulosic biofuel production is less than the minimum applicable volume established under CAA section (o)(2)(B), CAA section 211(o)(7)(D)(i) provides that EPA ''shall reduce the applicable volume of cellulosic biofuel required under paragraph (2)(B) to the projected volume available during that calendar year.'' EPA implemented this provision for every year from 2010–2022 and again in 2024 to reduce the cellulosic biofuel volume consistent with the statutory directive that EPA shall reduce the volume when the requisite conditions are met.[189]

CAA section 211(o)(7)(D)(ii) directs EPA to make cellulosic waiver credits (CWCs) available whenever it reduces the cellulosic biofuel volume under CAA section 211(o)(7)(D). CWCs—which are offered for sale to obligated parties at a price established by regulation[190] per CAA section 211(o)(7)(D)(iii)—provide compliance flexibility for obligated parties. However, it should be noted that CWCs only satisfy an obligated party's cellulosic biofuel obligation; unlike a cellulosic RIN, a CWC cannot be used to satisfy an obligated party's advanced biofuel or total renewable fuel obligation.[191] To obtain the same compliance value as a cellulosic RIN, an obligated party using a CWC for compliance with the cellulosic biofuel standard needs to also acquire an advanced or BBD RIN to use towards meeting its advanced biofuel and total renewable fuel obligations. When CWCs are made available, they generally limit or cap the price of cellulosic RINs.[192]

CAA section 211(o)(7)(D) provides that EPA may reduce the applicable volume of total renewable fuel and advanced biofuel in years when EPA reduces the applicable volume of cellulosic biofuel under that provision. That reduction must be less than or equal to the reduction in cellulosic biofuel. The D.C. Circuit explained:

> There is no requirement to reduce these latter quotas, nor does the statute prescribe any factors that EPA must consider in making its decision. . . . In the absence of any express or implied statutory directive to consider particular factors, EPA reasonably concluded that it enjoys broad discretion regarding whether and in what circumstances to reduce the advanced biofuel and total renewable fuel volumes under the cellulosic waiver provision.[193]

Using this discretion, EPA has, in the past, declined to reduce the advanced biofuel and total renewable fuel volumes in certain circumstances.[194] In other circumstances, EPA has reduced the advanced biofuel and total renewable fuel volumes using this authority.[195] It is worth noting that EPA's practice of reducing the advanced biofuel and total renewable fuel volumes utilizing the cellulosic waiver authority in past years served to carry through the partial waiver necessitated by the shortfall in cellulosic biofuel to the other nested renewable fuel categories when reducing the statutory cellulosic biofuel volumes established by Congress in 2007. In many cases reductions to the advanced biofuel and total renewable fuel volumes were necessary to enable compliance by obligated parties. For example, EPA reduced the cellulosic biofuel volume by over 15 billion gallons for 2022. Had EPA not also reduced the 2022 advanced biofuel and total renewable fuel volumes, these requirements would have been 15 billion gallons higher, far exceeding the market's ability to supply qualifying renewable fuels, even after considering available carryover RINs. In contrast, for 2025, a year for which EPA set the volume requirements using our set authority, the partial waiver of the cellulosic biofuel volume requirement is significantly smaller than in prior years (0.19 billion gallons), in part due to the fact that instead of starting with a statutory table volume set by Congress many years ago, EPA itself established the volume requirements in 2023 under the set authority. As discussed further in Section VII.B, we are not proposing to adjust the 2025 total renewable fuel and advanced biofuel volumes because those volumes are likely to be achieved in the market.

B. Assessment of Cellulosic RINs Available for Compliance in 2025

Currently, nearly all cellulosic RINs are generated from the production and use of biogas-derived CNG and LNG.[196] To project total cellulosic RIN generation for 2025, we first estimated the number of CNG/LNG vehicles and their corresponding average consumption. Because biogas-derived CNG/LNG generates RINs only when used as transportation fuel, total CNG/LNG consumption—whether fossil- or biogas-derived—sets the upper limit for potential RIN generation from biogas-derived CNG/LNG. However, full replacement of total CNG/LNG usage with biogas-derived fuel is unlikely due to infrastructure limitations, costs, and

[186] See, *e.g.,* 79 FR 25025 (May 2, 2014) (direct final rule reducing the 2013 cellulosic biofuel volume in May 2014), 80 FR 77420 (December 14, 2015) (final rule reducing the 2014 and 2015 cellulosic biofuel volumes in December 2015), 87 FR 39600 (July 1, 2022) (final rule reducing the 2020 and 2021 volumes in July 2022).

[187] *See ACE,* 864 F.3d at 721.

[188] *See Loper Bright Enterprises* v. *Raimondo,* 603 U.S. 369, 400 (2024) (in overruling *Chevron* deference, the Court observed that it ''makes no sense to speak of a 'permissible' interpretation [of a statute] that is not the one the court, after applying all relevant interpretive tools, concludes is best. In the business of statutory interpretation, if it is not the best, it is not permissible.'').

[189] EPA acknowledges that it did not waive the 2023 cellulosic biofuel volume requirement. See *https://www.epa.gov/renewable-fuel-standard-program/epa-denial-petition-partial-waiver-2023-cellulosic-biofuel.*

[190] 40 CFR 80.1456.

[191] 72 FR 14726–27 (March 26, 2010).

[192] See, *e.g.,* 85 FR 7025 (February 6, 2020); 87 FR 39616 (July 1, 2022).

[193] *Monroe* v. *EPA,* 750 F.3d 909, 915 (2014). See, also, *ACE* at 721.

[194] See, *e.g.,* 78 FR 49794, 49811 (August 15, 2013).

[195] See, *e.g.,* 80 FR 77420 (December 14, 2015). 81 FR 89746 (December 12, 2016).

[196] More than 95 percent of all cellulosic RINs generated in 2024 were attributed to CNG/LNG derived from biogas. See ''Total Net Generation'' RIN data table at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.*

other challenges. To account for this, we applied an efficiency factor to estimate the portion of total CNG/LNG consumption that could realistically be met with biogas-derived fuel and, in turn, the number of cellulosic RINs that could be generated.[197] While the majority of cellulosic biofuel comes from biogas-derived CNG/LNG, small volumes of liquid cellulosic biofuel have also contributed to total cellulosic volumes and were therefore included in this estimate.[198] Based on this updated projection methodology, we estimate that cellulosic RIN generation for 2025 will be 1.19 billion RINs.[199]

C. Proposed Partial Waiver of the 2025 Cellulosic Biofuel Volume Requirement

1. Implementation of the Cellulosic Waiver Authority

The cellulosic waiver authority is specific regarding when it is available and how the volume reduction should be determined when acting under the authority, as discussed in Section VII.A. EPA has determined that ''the projected volume of cellulosic biofuel production is less than the minimum applicable volume'' for 2025. In the Set 1 Rule, EPA established the ''minimum applicable volume'' of cellulosic biofuel for 2025 to be 1.38 billion RINs and used that volume to calculate the 2025 cellulosic biofuel percentage standard of 0.81 percent.[200] The actual number of cellulosic RINs that obligated parties will ultimately need to retire for compliance with the current standard will not be known until after the 2025 compliance deadline,[201] when obligated parties report to EPA their 2025 gasoline and diesel production and import volumes.[202] However, for the purpose of making a decision to partially waive the 2025 cellulosic biofuel volume requirement, we have assumed that the actual total 2025 cellulosic biofuel obligation, if not reduced, will be 1.38 billion RINs.[203] We currently estimate that only 1.19 billion cellulosic RINs are projected to be generated in 2025, representing the projected volume of cellulosic biofuel available in 2025.[204] This is 0.19 billion fewer RINs than the 1.38 billion RINs needed to comply with the original 2025 cellulosic biofuel standard, a shortfall of approximately 14 percent. We therefore find that the circumstances have triggered the need for implementation of the cellulosic waiver authority for 2025.

When EPA determines that a waiver of the cellulosic biofuel volume requirement is appropriate under CAA section 211(o)(7)(D)(i), EPA must then reduce the required cellulosic biofuel volume to ''the projected volume available.'' We have previously interpreted the phrase ''projected volume available'' to exclude carryover RINs when determining the volume adjustment to be made; this interpretation was affirmed by the D.C. Circuit in *Sinclair*.[205] EPA has consistently interpreted the ''projected volume available'' as ''the volume of qualifying cellulosic biofuel projected to be produced or imported and available for use as transportation fuel in the U.S. in that year.'' [206] In determining the ''projected volume available,'' EPA must take a ''neutral aim at accuracy.'' [207]

As discussed in Section VII.B, the projected volume of cellulosic biofuel available in 2025 is 1.19 billion RINs. Thus, when the cellulosic waiver authority is applied, EPA is only able to reduce the 2025 cellulosic biofuel volume to the projected volume available of 1.19 billion RINs. However, in accordance with the statute, EPA is also required to make CWCs available to obligated parties, which can be used—along with additional BBD or advanced RINs—to cover any remaining shortfall.[208] The availability of CWCs helps ensure RFS program stability by reducing the likelihood that obligated parties may be forced into non-compliance with their RFS obligations; any obligated party that is unable to acquire sufficient cellulosic RINs to comply with their 2025 cellulosic biofuel obligations—plus any cellulosic RIN deficit carried from 2024—would be able to purchase CWCs to cover the shortfall.[209]

Given that ''the projected volume of cellulosic biofuel production is less than the minimum applicable volume'' for 2025, we are proposing to implement the cellulosic waiver authority to waive the 2025 cellulosic biofuel volume requirement to 1.19 billion RINs, a reduction of 0.19 billion RINs from the original volume requirement of 1.38 billion RINs. This proposed volume requirement matches the projected cellulosic RIN generation for 2025 of 1.19 billion RINs.[210]

Finally, CAA section 211(o)(7)(D) provides that EPA may reduce the applicable volume of total renewable fuel and advanced biofuel in years when EPA reduces the applicable volume of cellulosic biofuel under that provision. That reduction must be less than or equal to the reduction in cellulosic biofuel. The D.C. Circuit concluded that the cellulosic waiver authority provides EPA ''broad discretion'' to consider a variety of factors in determining whether to reduce the total renewable fuel and advanced biofuel volumes under this provision.[211] We currently have insufficient data from 2025 to adequately project the supply of advanced biofuel and total renewable fuel in 2025. Data from previous years, however, indicate that there will likely be a sufficient supply of RINs to meet the advanced biofuel and total renewable fuel volume requirements. In 2023, advanced and total RIN generation (8.99 billion RINs and 23.82 billion RINs, respectively) significantly exceeded the required volumes (5.94 billion RINs and 21.54 billion RINs, respectively).[212] Similarly, advanced

[197] See DRIA Chapter 7.1.3 and 7.1.4 for information on the analysis for 2025 biogas-derived CNG/LNG volumes.

[198] See DRIA Chapter 7.1.3 and 7.1.5 for information on the analysis for 2025 liquid cellulosic biofuel volumes.

[199] We intend to consider additional cellulosic RIN generation data throughout the remainder of 2025 as it becomes available to inform any final action.

[200] 88 FR 44470–71 (July 12, 2023).

[201] The compliance deadline for the 2025 standards will be the first quarterly reporting deadline after the 2026 standards are effective. 40 CFR 80.1451(f)(1)(i)(A).

[202] 40 CFR 80.1451 and 80.1427(a).

[203] Because the compliance obligation is calculated on a percentage basis, if the actual gasoline and diesel volumes reported by obligated parties differ from the projected gasoline and diesel volumes that were used to derive the percentage standard, then the actual number of RINs required for compliance will differ from the projected volume that was used to calculate the percentage standard. Although we rely on the 1.38-billion-RIN projection for 2025 in the Set 1 Rule that was the basis for the 2025 cellulosic biofuel percentage standard, EPA would reach the same conclusion to waive the 2025 cellulosic biofuel volume requirement, for the reasons stated below, using a higher RIN obligation (*i.e.,* a higher gasoline and diesel projection).

[204] See DRIA Chapter 7.1.3.

[205] *Sinclair,* 101 F.4th at 883–86.

[206] See, *e.g.,* 87 FR 39600 (July 1, 2022); *see also Sinclair,* 101 F.4th at 883–86.

[207] *API* v. *EPA,* 706 F.3d 474, 479 (D.C. Cir. 2013).

[208] Pursuant to 40 CFR 80.1405(d), the CWC price is calculated using the methodology specified in 40 CFR 80.1456(d) and posted on EPA's website at: *https://www.epa.gov/renewable-fuel-standard-program/cellulosic-waiver-credits-under-renewable-fuel-standard-program.*

[209] Unlike cellulosic RINs—which apply towards an obligated party's cellulosic biofuel, advanced biofuel, and total renewable fuel obligations—CWCs only apply towards an obligated party's cellulosic biofuel obligation and not toward their nested advanced biofuel and total renewable fuel obligation. Obligated parties that satisfy their cellulosic biofuel obligations with CWCs would therefore also have to purchase additional BBD or advanced RINs to meet their associated advanced biofuel and total renewable fuel obligations.

[210] We intend to consider additional cellulosic RIN generation data throughout the remainder of 2025 as it becomes available to inform any final action.

[211] *ACE,* 864 F.3d at 730–734; *see also Monroe Energy, LLC* v. *EPA,* 750 F.3d 909 (D.C. Cir. 2014).

[212] See ''Total Net Generation'' RIN data table at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.*

and total RIN generation in 2024 (10.42 billion RINs and 25.30 billion RINs, respectively) exceeded not only the 2024 volume requirements (6.54 billion RINs and 21.54 billion RINs, respectively) but also the 2025 volume requirements (7.33 billion RINs and 22.33 billion RINs, respectively).[213] These RIN generation numbers indicate that the market is capable of meeting the 2025 advanced biofuel and total renewable volume requirements after accounting for the projected shortfall in cellulosic biofuel. Further, even if the market falls short of the volume requirements in 2025, the significant oversupply of RINs in previous years indicates that there will be sufficient carryover RINs to make up for any shortfall in 2025.

We believe reductions to the 2025 advanced biofuel and total renewable fuel volumes are not necessary or warranted based on the available supply data, given that the market is projected to provide volumes of these fuels in excess of the requirements established in the Set 1 Rule. Reductions in these volume requirements at this time would only serve to increase the number of advanced and total carryover RINs. Historically, we have declined to take actions that would inflate the number of available carryover RINs.[214]

2. Economic Impact

The proposed partial waiver of the 2025 cellulosic biofuel volume requirement is expected to have an economic impact. However, quantitatively projecting the economic impact of this reduction is challenging for several reasons. First, the proposed partial waiver is due to a shortfall in the projected volume of cellulosic biofuel in 2025. Because of this, higher volumes of cellulosic RINs cannot simply be made available at greater prices; instead, obligated parties will be unable to purchase additional quantities of 2025 cellulosic RINs at any price. The potential economic impact of this action is further complicated by the fact that while some obligated parties can defer some or all of their 2025 cellulosic biofuel obligation to 2026, other obligated parties that carry cellulosic RIN deficits from 2024 into 2025 will be required to fully satisfy their cellulosic biofuel obligations in 2025, including the cellulosic RIN deficits carried forward from 2024. Any party that fails to do so would likely be in non-compliance and could be subject to penalties.[215]

Despite the complications associated with estimating the economic impacts of this action, we can determine that it would result in cost savings. We are proposing to reduce only the 2025 cellulosic biofuel volume. Because we are not proposing to reduce the 2025 advanced biofuel and total renewable fuel volumes, this action would effectively replace the reduced cellulosic biofuel volume with additional volumes of advanced biofuel, which generally has a lower marginal cost than cellulosic biofuel.[216]

Finally, we can reasonably project that because this action would reduce demand for cellulosic RINs, it is expected to directionally decrease cellulosic RIN prices. The exact magnitude of this price reduction depends on a wide range of market factors that prevent us from quantitively projecting a RIN price impact. At the same time, because this action incrementally increases demand for advanced RINs, it is projected to directionally increase BBD and advanced RIN prices. We note, however, that this price impact is expected to be relatively small, as this action would increase demand for advanced biofuel by the magnitude of the proposed partial waiver of the 2025 cellulosic biofuel volume requirement (0.19 billion RINs).

D. Calculation of Proposed 2025 Cellulosic Biofuel Percentage Standard

As described in Section VII.C, we are proposing to implement the cellulosic waiver authority to partially waive the 2025 cellulosic biofuel volume requirement from 1.38 billion RINs to 1.19 billion RINs. As described in Section VI, the formula used to calculate the cellulosic biofuel percentage standard applicable to obligated parties as a function of their gasoline and diesel fuel production or importation is provided in 40 CFR 80.1405(c). Using the same values from the Set 1 Rule for the variables in this formula other than RFV_{CB} (the cellulosic biofuel volume),[217] we have calculated the proposed revised cellulosic biofuel percentage standard for 2025 to be 0.70 percent, down from 0.81 percent.[218] This percentage standard is included in the proposed regulations at 40 CFR 80.1405(a) and would apply to producers and importers of gasoline and diesel.

VIII. Reduction in the Number of RINs Generated for Imported Fuels and Feedstocks

A. Introduction and Rationale

In this action, we are proposing an "import RIN reduction" for imported renewable fuel and renewable fuel produced domestically from foreign feedstocks.[219] Under this proposed approach, renewable fuel producers and importers would generate 50 percent fewer RINs than they generate for the same volume of import-based renewable fuel under the current RFS regulations for RINs generated in 2026 and later years. The proposed approach would not affect RINs generated in 2025 or earlier years. Renewable fuel produced by domestic renewable fuel producers using domestic feedstocks would continue to generate the same number of RINs that they currently do. The import RIN reduction would apply to all foreign-produced renewable fuel, regardless of whether those fuels are produced from domestic or foreign feedstocks. The reduction of RINs generated for import-based renewable fuel reflects the reduced economic, energy security, and environmental benefits provided by these fuels relative to renewable fuels produced domestically using domestic feedstocks.

This proposal is intended to support the statutory goals of energy independence and the Administration's broader economic vision of strengthening American energy independence and bolstering domestic agricultural markets. By implementing an import RIN reduction, EPA aims to reduce America's reliance on import-based renewable fuels, enhance energy

This table includes all reported RINs that were generated and not otherwise retired due to RIN generation error (*i.e.,* an invalid RIN). Thus, the volume of RINs in this table is the volume of RINs that have been made available for compliance with the RFS standards.

[213] *Id.*

[214] 87 FR 39600, 39621 (July 1, 2022) ("While EPA has previously set the RFS standards at what the market actually used (like for 2014 and 2015 in the 2014–2016 rule), we have never intentionally reduced the standards with the express intent to inflate the size of the carryover RIN bank."); 2020–2022 RFS Rule RTC Section 2.6.1.

[215] We recognize that the cellulosic waiver authority is mandatory, and thus would avoid the potential noncompliance and lack of RINs described herein. Nevertheless, we describe these potential outcomes to illustrate the difficulty in calculating the cost savings of the action.

[216] The nested nature of the RFS program allows cellulosic biofuel to be used to meet the advanced biofuel and total renewable fuel volume requirements. Any cellulosic biofuel that can be supplied beyond the required volume can be used in place of advanced biofuel.

[217] 88 FR 44519–21 (July 12, 2023).

[218] See "Calculation of Proposed 2025 Cellulosic Biofuel Percentage Standard," available in the docket for this action.

[219] Throughout this section we refer to imported renewable fuel and renewable fuel produced domestically from foreign feedstocks collectively as "import-based renewable fuel" and RINs generated for these types of renewable fuel as "import RINs." We also refer to renewable fuel produced domestically from domestic feedstocks as "domestic-based renewable fuel."

security, promote domestic-based renewable fuel production, and keep more of the economic benefits of the RFS program within the U.S., while accomplishing the broader goals of the RFS program. We believe that an import RIN reduction would align the RFS program with these goals. We are also requesting comment on whether a higher or lower import RIN reduction factor (*i.e.,* more or less than the proposed 50 percent reduction) would be appropriate.

The RFS program began in 2006 pursuant to the requirements of EPAct, the stated purpose of which was to ''ensure jobs for our future with secure, affordable, and reliable energy.'' [220] The statutory requirements of EPAct were codified in CAA section 211(o) and were subsequently amended by EISA, the purpose of which was to ''move the United States toward greater energy independence and security, to increase the production of clean renewable fuels, to protect consumers, to increase the efficiency of products, buildings, and vehicles, to promote research on and deploy greenhouse gas capture and storage options, and to improve the energy performance of the Federal Government, and for other purposes.'' [221] From the purpose statements in these two enactments, where Congress' focus is clearly on American jobs, American energy independence and security, and increasing the production of American clean renewable fuels, it is evident that Congress intended the RFS program to be a program for the benefit of the American people generally and for certain important segments of the American domestic economy specifically. We believe it is consistent with this Congressional intent to take steps to ensure that most of the economic value of the RFS program flows to American fuel and feedstock producers rather than their foreign competitors.

From the inception of the RFS program, EPA has allowed for imported renewable fuel and renewable fuel produced domestically from foreign feedstocks to generate RINs, provided EPA is assured that certain statutory criteria have been met. EPA thus acknowledges that we have historically placed import-based renewable fuel on an equal footing with domestic-based renewable fuel. The number of RINs generated for import-based renewable fuel has been the same as the number of RINs generated for domestic-based renewable fuel.

While EPA has historically treated import-based renewable fuel as equal to domestic-based renewable fuel, there is nothing in CAA section 211(o) that requires providing the same benefits to foreign entities as domestic entities. CAA section 211(o)(5)(A) simply provides that EPA's regulations must provide ''for the generation of an appropriate amount of credits'' by entities covered by the RFS program, without further specifying how ''an appropriate amount of credits'' should be determined. The term ''appropriate'' necessarily leaves agencies with flexibility to implement statutory programs, so long as that discretion is exercised consistent with the context and structure in which the term appears.[222]

In this action, EPA is proposing to modify the treatment of import-based renewable fuels under the RFS program for the reasons discussed below and in Section VIII.B. EPA requests comment on this issue and on any relevant statutory interpretation issues that bear on EPA's authority to differentiate among suppliers when assigning RINs for reasons based on the statutes' language, legislative history, and purposes.

1. Aligning the RFS Program With America's Economic Interests To Support Domestic Agriculture and Rural Economies

As noted above, the purpose statements of both EPAct and EISA make it clear that Congress intended the RFS program to, among other goals discussed further below, support American agriculture and strengthen rural economies in the U.S. While the RFS program has furthered these goals, the recent influx of imported renewable fuels and feedstocks threatens those gains and the RFS program's ability to build on them.

In 2021, import-based renewable fuel accounted for approximately 25 percent of the total biodiesel and renewable diesel supply. By 2024, such imports surged to nearly 45 percent of the U.S. biodiesel and renewable diesel market.[223] By volume and value, much of this supply comes from countries such as China and Brazil rather than supporting American feedstock producers.

EPA is concerned that the increasing amounts of foreign feedstocks, such as UCO and animal fats from China, Southeast Asia, and South America, may be displacing U.S.-produced feedstocks like corn and soybean oil in the renewable fuels market. This shift comes at a time when American farmers are already struggling due to declining revenues. According to USDA, net farm income is projected to fall by approximately $32 billion from 2022 to 2024.[224] Without EPA intervention, these relatively cheap imports will continue to undercut U.S. producers, reducing the economic value of the RFS program to American feedstock and fuel producers, weakening support for rural economies, and further harming U.S. farmers.

The import RIN reduction proposed in this action would help American farmers by ensuring demand for domestic-based renewable fuels. Renewable fuel producers would be able to generate more RINs (and thus realize greater RIN value) for renewable fuels produced from domestic feedstocks relative to foreign feedstocks. This dynamic would increase the willingness for domestic renewable producers to pay higher prices for domestic feedstocks relative to foreign feedstocks because, all else equal, they would be able to generate higher revenue for fuels produced from domestic feedstocks. In turn, the higher prices offered for domestic feedstocks would increase the revenue of domestic feedstock producers and provide incentives for increased production of domestic feedstocks. By ensuring support for domestic feedstocks and fuels, it is our expectation that the proposed approach will revitalize domestic demand for American crops, stabilize farm incomes, and stimulate economic growth in rural communities.

Consistent with our understanding of the original Congressional intent for the RFS program, EPA believes any economic benefits derived from the RFS program should be retained in the U.S. to the maximum extent practicable. We do not believe that Congress intended to create a program to benefit foreign producers. However, there is significant concern that the increased importation of feedstocks and fuels observed above may indicate that such foreign producers are benefiting from the economic incentives intended to stimulate rural American communities. As a U.S. federal program, the RFS program was designed to promote American agricultural prosperity. The proposed import RIN reduction provisions further that goal and ensures American farmers and domestic

[220] Public Law 109–58, 119 Stat. 594.

[221] Public Law 110–140, 121 Stat. 1492.

[222] *Michigan* v. *EPA,* 576 U.S. 743, 752 (2015).

[223] See Section III.B.2 and DRIA Chapter 3.2 for more information on EPA's estimate of imported vs. domestic supplies of BBD in 2024.

[224] USDA, ''Net Cash Income,'' Farm Income and Wealth Statistics, February 6, 2025. *https://data.ers.usda.gov/reports.aspx?ID=4024.*

renewable fuel producers remain the primary beneficiaries of the RFS program.

2. Strengthening U.S. Energy Security and Energy Independence

Reducing U.S. dependence on foreign energy sources is a cornerstone of this Administration's energy policy. As discussed in detail in Section IV and DRIA Chapter 6, it is also a foundational goal of the RFS program. Although import-based renewable fuels contribute to U.S. energy supply and help to hedge against reliance on foreign fossil fuel producers, reliance on these imports risks creating the exact vulnerabilities that the RFS program was intended to forestall. Global supply chain disruptions, trade disputes, and geopolitical instability can impact the renewable fuel and feedstock markets, leading to increased price volatility across the RIN market, renewable fuel and feedstock markets, and gasoline and diesel markets.

The import RIN reduction would encourage greater investment in domestic-based renewable fuel production. By putting America's farmers and renewable fuel producers first, the proposed import RIN reduction provisions would also strengthen America's energy independence and resilience by reducing exposure to global market disruptions and securing self-reliance in the supply of domestic-based renewable fuels.

3. Protecting the Environment

The core objective of EPA—to protect human health and the environment—is also the focus of our administration of the RFS program. We believe that allowing import-based renewable fuels to have equal RIN generation potential undermines this goal, particularly when there are concerns over the validity of imported feedstocks.

One of the most widely used feedstocks used to produce import-based renewable fuels is UCO. Substantial challenges already exist regarding EPA's ability to verify whether the requirements for imported UCO under the RFS program have been satisfied. Recently, industry experts have raised additional concerns that some UCO shipments may be fraudulently labeled or adulterated with unused palm oil. Propagation of palm trees for oil production has devastating environmental costs and undermines the GHG emissions-reduction goals of the RFS program.[225] These concerns contributed to the decision by the U.S. Department of Treasury and Internal Revenue Service to not include pathways for imported UCO in the initial 45ZCF–GREET model, making these fuels ineligible to generate tax credits under that program.[226] Similar concerns have led the EU to consider suspending the mandatory recognition of the certification of waste-based biofuels by the International Sustainability and Carbon Certification.[227]

The proposed import RIN reduction provisions would not prohibit imports but would instead signal to market participants that domestic-based renewable fuels—manufactured under closely monitored U.S. environmental standards—are preferable. By rewarding domestic-based renewable fuels with full RIN generation potential, EPA would reinforce environmental protection and strengthen the integrity of the RFS program without sacrificing the flexibility to utilize import-based renewable fuels when necessary.

4. Safeguarding the Original Intent of the RFS Program

In sum, the RFS program was designed with clear objectives: to reduce GHG emissions, expand the U.S. renewable fuel sector in support of domestic producers and rural economies, and decrease reliance on foreign energy. However, the rising share of import-based renewable fuel undermines these goals by:

- Redirecting the economic benefits of the program away from American farmers and rural communities.
- Increasing America's exposure to volatile global fuel and commodity trade dynamics.
- Increasing America's reliance on foreign sources of fuel and supplies necessary to produce fuel domestically.

By implementing the proposed import RIN reduction, EPA seeks to restore the benefits of the RFS program to its originally intended recipients. This approach would ensure that the program continues to achieve these important goals while prioritizing domestic economic prosperity.

B. Legal Authority

Historically, EPA used ''equivalence values'' to determine how many RINs a given quantity of renewable fuel generates.[228] In doing so, we relied on CAA section 211(o)(5) to justify our method for allocating RIN values for different renewable fuels. The equivalence values were calculated based on the renewable fuel's energy content relative to a gallon of ethanol, such that renewable fuels with a greater energy potential were allowed to generate a more than one RIN per gallon.[229]

We propose using the same statutory language to justify reduced RIN generation for import-based renewable fuel. Section 211(o)(5)(A) states that EPA ''shall provide'' for ''the generation of an appropriate amount of credits by any person that refines, blends, or imports . . . a quantity of renewable fuel'' and ''for the generation of an appropriate amount of credits for biodiesel.'' In establishing equivalence values, EPA highlighted these statutory provisions as ''evidence that Congress did not limit this program solely to a straight volume measurement of gallons in the context of the RFS program.'' [230] Similarly, in this action we propose to find that the statutory language ''appropriate amount of credits'' alongside the same subsection's differentiation among parties who ''refine[ ], blend[ ], or import[ ]'' renewable fuel allows EPA to determine that imported renewable fuel (and renewable fuel made from foreign feedstocks) may be assigned a lesser amount of credits as EPA determines is appropriate. We additionally rely on the language in CAA section 211(o)(5)(A)(ii) to determine that imported biodiesel (and biodiesel made from foreign feedstocks) may be assigned a lesser amount of credits as EPA determines is appropriate. As noted above, the term ''appropriate'' is broad and flexible, and courts have recognized that Congress uses it to leave agencies with flexibility to administer statutory programs consistent with relevant context and structure.[231]

In doing so, EPA is not advancing a new interpretation of CAA section 211(o)(5)(A). Rather, we are proposing a change in policy consistent with EPA's existing understanding of that provision's delegation of discretion. This new policy would further delineate the amount of credits (*i.e.,* RINs) that are ''appropriate'' for volumes of renewable fuel depending on whether they are

[225] S&P Global, ''New Biofuel Data Triggers Fresh Fraud Concerns Over EU Imports,'' December 14, 2023.

[226] Notice 2025–10, 2025–6 I.R.B. 682 (Feb. 3, 2025).

[227] The Maritime Executive, ''EU Scrutinizes Fraud in Certification of Biofuels,'' March 30, 2025.

[228] See, *e.g.,* 72 FR 23900, 23918–23922 (May 1, 2007) and 75 FR 14670, 14709–10, 14716–18 (March 26, 2010).

[229] *Id.* We note that in this action we are not reopening our approach to providing equivalence values established in the RFS2 Rule, nor any other equivalence values (other than those discussed in Section X.A). Comments about equivalence values more generally will be treated as beyond the scope of this action.

[230] 72 FR 23900, 23919 (May 1, 2007).

[231] See, *e.g., Michigan,* 576 U.S. at 752.

imported—a factor the statute explicitly names as relevant to that consideration.[232] CAA section 211(o)(5)(A) is the kind of clear Congressional delegation of discretion that ''leaves [the] agenc[y] with flexibility'' signaled by specific terms such as ''appropriate.'' [233] Although EPA has previously chosen to use this discretion to assign equivalence values for RIN generation based on a fuel's energy content, this was not an exclusive understanding of how EPA might determine the ''appropriate'' amount of credits to award. EPA may also determine that the ''appropriate amount of credits'' awarded for ''a quantity of renewable fuel'' should vary on other bases, including whether the credits are awarded to a ''person that refines, blends, or imports'' the fuel. Consistent with that understanding, we are proposing to appropriately reduce the RIN value for imported renewable fuel and renewable fuel made from foreign feedstocks.

In proposing this policy change, EPA is observing the relevant procedural standards by acknowledging how the new policy departs from the status quo; by demonstrating the new policy is permissible under the statute and that ''there are good reasons for it;'' and by asserting, as this section does, that the agency believes the new policy is an improvement upon the status quo.[234] EPA requests comment on this change in policy, including on any legitimate reliance interests on the prior policy that EPA should consider during this rulemaking.[235]

C. Implementation

To implement the proposed import RIN reduction for import-based renewable fuel, we are proposing to specify under 40 CFR 80.1426(a) that the following parties must reduce the number of RINs generated for the specified renewable fuel by 50 percent:

- RIN-generating foreign producers, for all renewable fuel produced.
- RIN-generating importers of renewable fuel, for all imported renewable fuel.
- Domestic renewable fuel producers, for all renewable fuel produced from foreign feedstocks or foreign biointermediates.

We believe this is the most straightforward way to implement the proposed import RIN reduction, rather than proposing a separate set of RIN generation equations for import RINs. We request comment on the proposed import RIN generation requirement, and whether there are alternative RIN generation approaches that we should consider for implementing the import RIN reduction.

Since we are proposing that the import RIN reduction would apply to all foreign-produced renewable fuel, regardless of whether it is produced from domestic or foreign feedstocks, we are not proposing any additional requirements for RIN-generating importers of renewable fuel and RIN-generating foreign renewable fuel producers. They would only be able to generate import RINs for the renewable fuel they produce or import, and thus no changes would be necessary in their registration, recordkeeping, reporting, or attest engagement requirements.

However, there remain potential concerns regarding mislabeling of foreign feedstocks under the RFS program. We are concerned that bad actors may try to claim foreign feedstock as domestic to gain a financial benefit. Thus, to ensure that domestic renewable fuel producers are generating the appropriate number of RINs for each batch of renewable fuel they produce, we are proposing several changes to their recordkeeping, reporting, attest engagement, and quality assurance plan (QAP) requirements that we believe are minimally onerous while protecting domestic feedstock producers. First, we are proposing that all domestic renewable fuel producers be required to keep records of feedstock purchases and transfers (*e.g.,* bills of sale, delivery receipts) that identify the feedstock point of origin for each feedstock (*i.e.,* domestic or foreign). We expect that most domestic renewable fuel producers already keep such records as part of their existing business practices or other existing RFS recordkeeping requirements, and thus there should be no additional recordkeeping burden for most of these producers.

Feedstock point of origin would depend on the feedstock type but would generally be considered to be the location, either domestic or foreign, where a feedstock is grown, produced, generated, extracted, collected, or harvested. More specifically, we are proposing the following specific provisions related to what is considered the ''feedstock point of origin'' for each feedstock type:

- For planted crops, cover crops, or crop residue (including starches, cellulosic, and non-cellulosic components thereof), the location of the feedstock supplier that supplied the feedstock to the renewable fuel producer or biointermediate producer (*e.g.,* grain elevator).
- For oil derived from planted crops, cover crops, or algae, the location where the oil is extracted from the planted crop, cover crop, or algae (*e.g.,* crushing facility).
- For biogenic waste oils/fats/greases, separated yard waste, separated food waste, or MSW (including the components thereof), the location of the establishment where the waste is collected (*e.g.,* restaurant, food processing facility).
- For biogas, the location of the landfill or digester that produces the biogas.
- For planted trees, tree residue, slash, pre-commercial thinnings, or other woody biomass, the location where the woody biomass is harvested.
- For all other feedstocks, the location where the feedstock is grown, produced, or generated, as applicable.

Second, we are proposing that domestic renewable fuel producers would need to report the feedstock point of origin (*i.e.,* domestic or foreign) as part of their renewable fuel batch reports under 40 CFR 80.1451(b)(1)(ii)(L). This would help ensure that domestic renewable fuel producers are generating the correct number of RINs for their renewable fuel.

Finally, we are proposing to add clarifying language for attest engagement auditors and QAP providers regarding verifying feedstock points of origin. For attest engagements, we are proposing to clarify that the existing requirement for auditors to ''[v]erify that feedstocks were properly identified'' in batch reports also includes verifying that the feedstock point of origin was correctly reported.[236] Similarly, for QAP, we are also proposing to clarify that the existing requirements for QAP providers to ''[v]erify that appropriate RIN generation calculations are being followed'' include ensuring that the value applied reflects the feedstock's point of origin.[237] These clarifications would ensure that attest auditors and QAP providers verify that RINs are properly generated by domestic renewable fuel producers with domestic feedstocks.

We request comment on both the proposed recordkeeping, reporting, attest engagement, and QAP requirements and the definition of ''feedstock point of origin,'' particularly

[232] ''[W]hen a particular statute delegates authority to an agency consistent with constitutional limits, courts must respect the delegation, while ensuring that the agency acts within it.'' *Loper Bright Enters.* v. *Raimondo,* 603 U.S. 369, 413 (2024).

[233] *Id.* at 394–95 (quoting *Michigan,* 576 U.S. at 752).

[234] *FCC* v. *Fox Television Stations, Inc.,* 556 U.S. 502, 515 (2009).

[235] *Id.*

[236] 40 CFR 80.1464(b)(1)(v)(B).

[237] 40 CFR 80.1469(c)(3)(vii).

on the proposed origin locations for each feedstock type and whether there are any other feedstock types that should have specified origin locations.

IX. Removal of Renewable Electricity From the RFS Program

While EPA has, in the past, taken actions to allow RIN generation for renewable electricity (commonly referred to as eRINs), in this action we are proposing to remove renewable electricity as a qualifying renewable fuel under the RFS program and the implementing regulations that allow for renewable electricity to generate RINs.

A. Historical Treatment of Renewable Electricity in the RFS Program

The statutory definition of ''renewable fuel'' in CAA section 211(o)(1)(J) requires that renewable fuel be produced from renewable biomass and used to replace or reduce the quantity of fossil fuel present in a transportation fuel. CAA section 211(o)(1)(B)(ii)(B) further indicates that non-liquid biofuels, such as those produced from biogas, may qualify as renewable fuel. Thus, renewable fuels under the RFS program can be broadly categorized as liquid biofuels, such as ethanol or biodiesel, or non-liquid biofuels, such as renewable CNG/LNG that is produced from qualifying biogas (that is in turn produced from qualifying renewable biomass), so long as these fuels are used as transportation fuel. Non-liquid renewable fuels have played a part in the RFS program since the RFS2 Rule was promulgated in 2010. In that final rule, EPA specified that electricity, as well as natural gas and propane, produced from renewable biomass could be a RIN-generating renewable fuel under the RFS program. However, EPA stipulated that electricity could only be a RIN-generating renewable fuel if it could be demonstrated that specific quantities of electricity ''are actually used as a transportation fuel[ ].'' [238] The record for the RFS2 Rule did not further elaborate on how renewable electricity (*i.e.,* electricity that is derived from renewable biomass) satisfies the statutory definition of renewable fuel or is consistent with other applicable statutory requirements.

Pursuant to the determination that renewable electricity is, in certain circumstances, a qualifying renewable fuel, EPA also, in the RFS2 Rule, established regulatory provisions governing the generation of RINs representing renewable electricity in anticipation of a future action that would provide a RIN-generating pathway for electricity made from renewable biomass and used as transportation fuel. In doing so, EPA discussed the relevant differences between liquid and non-liquid renewable fuels and established regulatory provisions for renewable electricity that recognized those distinctions.[239]

In 2010, EPA also promulgated a definition of ''renewable electricity'' to ''clarify that electricity must meet the definition of renewable fuel in order to qualify for RINs.'' [240] In 2014, EPA established novel RIN-generating pathways for electricity produced from biogas from landfills and waste digesters.[241] These pathways currently exist in Rows Q and T of Table 1 to 40 CFR 80.1426. In the same 2014 rulemaking, EPA updated the regulations governing RIN generation for renewable electricity; it is these 2014 RIN generation provisions that currently exist in the regulations at 40 CFR 80.1426(f)(10)(i) and (f)(11)(i). In general, the regulatory requirements were intended to ensure that any RINs generated correspond to electricity that meets the statutory criteria to qualify as renewable fuel. For example, the electricity must be produced from renewable biomass under an approved pathway (demonstrating it meets the required GHG reduction threshold), the electricity must be sold for use as transportation fuel and for no other purpose (and the RIN generator must provide documentation to support its use as transportation fuel), and it must be the case that no other party relied on the renewable electricity for the generation of RINs.[242]

Even though renewable electricity has been part of the RFS program since 2010, and a pathway has existed since 2014 for renewable electricity produced from biogas, EPA has not, to date, registered any party to generate RINs for renewable electricity. Since 2014, several stakeholders have submitted registration requests to generate RINs for renewable electricity produced from biogas. EPA has reviewed these registration requests and met with a range of stakeholders. However, as early as 2016, EPA recognized that structuring a framework to allow for the generation of RINs for renewable electricity produced from biogas under the RFS program presented unique, unanticipated policy and implementation questions that would need to be resolved prior to registering any party, particularly in light of the competing policy preferences of stakeholders.[243] Based on (1) our review of registration requests, (2) information gathered from stakeholders via both comments provided in response to EPA requests and ongoing discussions, and (3) an analysis of how to best incorporate renewable electricity into the RFS program, we concluded that EPA's existing regulations governing the generation of RINs for renewable electricity produced from biogas were insufficient to guarantee overall programmatic integrity, especially in light of the range of different and often competing approaches proposed by registrants.[244] Specifically, because the regulations allow any party that can demonstrate compliance with the applicable requirements to be the RIN generator, it is possible under the current regulations for multiple parties (from independent registrations) to claim RIN generation for the same quantity of renewable electricity. Such double counting is contrary to the regulations themselves and further undermines EPA's ability to ensure that the statutory volumes are met.[245] As a result, we determined that a new regulatory program would be necessary to allow the generation of RINs representing renewable electricity. The ''eRIN'' regulatory program for renewable electricity proposed in December 2022 as part of the Set 1 NPRM was intended to revise the existing regulations governing renewable electricity to allow RIN generation under these pathways.[246] The Set 1 Rule was ultimately finalized without the proposed eRIN regulatory program, leaving the previously existing, inadequate regulations governing renewable electricity in place.

B. Statutory Basis for Removal of Renewable Electricity From the RFS Program

EPA is proposing to remove renewable electricity as a qualifying renewable fuel from the RFS program. As discussed in Section IX.A, although EPA in the RFS2 Rule determined that

[238] 74 FR 14670, 14686 (March 26, 2010).

[239] 75 FR 14670, 14729 (March 26, 2010).

[240] 75 FR 26026, 26031 (May 10, 2010).

[241] 79 FR 42128 (July 18, 2014).

[242] 40 CFR 80.1426(f)(10)(i), (f)(11)(i).

[243] See, *e.g.,* 81 FR 80828, 80890–96 (November 16, 2016).

[244] *Id.; see also* EPA Final Brief defending decision to not include renewable electricity volumes in 2019 Annual Volumes Rule, *Growth Energy* v. *EPA,* D.C. Cir. No. 19–1023, Doc. # 1831996 at 74–77 (filed March 5, 2020).

[245] See CAA section 211(o)(2)(A)(i) (EPA's regulations must ''ensure that transportation fuel sold or introduced into commerce in the United States . . . on an annual average basis, contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel . . .'').

[246] 87 FR 80582 (December 30, 2022).

electricity could participate in the RFS program and promulgated regulations for the generation of RINs for renewable electricity, no RINs representing renewable electricity have ever been generated. In this action, we are proposing to reverse the determination in the RFS2 Rule that renewable electricity is eligible to generate RINs under the RFS program.

We are proposing to remove renewable electricity from the RFS program on the ground that, under the best reading of the statute, renewable electricity is not a renewable fuel. Congress defined renewable fuel in CAA section 211(o)(1)(J) as ''fuel that is produced from renewable biomass and that is used to replace or reduce the quantity of fossil fuel present in a transportation fuel.'' Congress further defined transportation fuel in CAA section 211(o)(1)(L) as ''fuel for use in motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines.'' EPA has consistently interpreted ''renewable fuel'' to encompass three key components: (1) There must be a fuel; (2) The fuel must be produced from renewable biomass; and (3) The fuel must be used to replace or reduce fossil fuel present in a transportation fuel.[247] While EPA previously, in 2010, assumed that renewable electricity could meet this definition, we are now revisiting the statutory analysis based on the text of the statute and consistent with intervening Supreme Court decisions on standards for statutory interpretation.

EPA's analysis focuses on the last component of the renewable fuel definition—that the fuel must be used to replace or reduce the quantity of fossil fuel present in transportation fuel. The best reading of this language is that a renewable fuel must physically displace a volume of fossil fuel that is present in a motor vehicle or motor vehicle engine. The statutory definition uses the phrases ''quantity of fossil fuel'' and ''present in a transportation fuel,'' both of which imply that there must be a measurable physical volume of fossil fuel that is present in a transportation fuel and that volume must be ''replace[d] or reduce[d]'' by the renewable fuel. Because electricity cannot replace or reduce a volume of fossil fuel that is present in a motor vehicle or motor vehicle engine, it does not meet the definition of renewable fuel in the statute. That is, electricity is not fungible with a fossil fuel in a motor vehicle or motor vehicle engine.

In contrast, biogas that is cleaned up into RNG (and then compressed into CNG/LNG) can replace and reduce fossil natural gas that is present in a motor vehicle or motor vehicle engine that runs on CNG/LNG, and therefore satisfies this portion of the renewable fuel definition. But because electricity cannot physically displace fossil fuel present in a motor vehicle or motor vehicle engine, it does not. Biogas-generated electricity does not result in a physical reduction in the ''quantity of fossil fuel present in a transportation fuel,'' nor is the biogas that is replacing fossil natural gas itself present in a transportation fuel in ''motor vehicles, motor vehicle engines, nonroad vehicles, or nonroad engines.'' Instead, the biogas is burned at an electric generating unit, and the resulting electricity is transmitted on the grid for use to charge batteries present in motor vehicles. The use of the term ''present in transportation fuel'' indicates that the requirement intends to increase the renewable fuel contained within fossil-fuel transportation fuel itself, not to substitute electricity for such fuel.

Additionally, we note that ''electricity'' is not mentioned by name in CAA section 211(o), in contrast to over fifty references to liquid fuels. The RFS statutory language in CAA section 211(o) speaks to ''volumes'' and ''gallons'' of renewable fuel. The fact that the CAA explicitly references physical units implies that the RFS program was intended to measure, and thus include, only quantities of liquid or gaseous fuels. Although there is no statutory definition of ''fuel'' under the RFS program, the widely accepted definition is ''a material used to produce heat or power by burning.'' [248] Electricity, which is an energy carrier and not a fuel under this paradigm, cannot be burned nor can it be measured in physical units. The frequent references to physical units in the RFS statutory language, along with the inability of electricity to be quantified by the referenced units, implies that the RFS was intended to only include liquid and gaseous fuels. Thus, we are also proposing to determine that electricity does not qualify as a fuel under the RFS program.

C. Implementation of Proposed Removal of Renewable Electricity From the RFS Program

Our proposed determination that electricity is not a renewable fuel is effectuated in several ways. First, we are proposing to remove the definition of ''renewable electricity'' from the definitions in 40 CFR 80.2. Second, we are proposing to remove the regulations associated with generating RINs for renewable electricity. These actions include removing the renewable electricity pathways in Table 1 to 40 CFR 80.1426, the renewable electricity RIN separation requirements in 40 CFR 80.1429, and all associated registration, reporting, and recordkeeping requirements in 40 CFR 80.1450, 80.1451, and 80.1454.

EPA requests comment on its statutory analyses and on its proposed conclusions that: (1) Renewable electricity does not meet the definition of renewable fuel because it does not ''replace or reduce the quantity of fossil fuel present in a transportation fuel,'' and (2) Electricity is not a fuel under the RFS program. EPA further requests comment on its proposed decision, based on these analyses and conclusions, to remove from the RFS regulations all provisions related to renewable electricity including, but not limited to the definition of and pathways for renewable electricity and the generation of RINs for renewable electricity.

X. Other Changes to RFS Regulations

A. Renewable Diesel, Naphtha, and Jet Fuel Equivalence Values

We are proposing to revise the equivalence values for renewable diesel, naphtha, and jet fuel to account for the non-renewable portion of these fuels, as they are all typically produced using a hydrotreating process. Due to an oversight when initially establishing the equivalence values for these fuels, the existing equivalence values for these fuels do not take into consideration the fact that a portion of the hydrogen in these fuels originates from the hydrogen used in the hydrotreating process, nearly all of which is produced from fossil natural gas. By not accounting for the hydrogen produced from fossil natural gas in these fuels, we are effectively allowing these hydrotreated fuels to generate RINs for non-renewable content. This approach conflicts not only with the statutory direction that fuels must be produced from renewable biomass to be eligible under the RFS program, but also with the approach EPA has taken for other biofuels that contain non-renewable content (*e.g.,* biodiesel, which by standard practice is

[247] 87 FR 80582, 80634 (December 30, 2022); 87 FR 73956–57 (December 2, 2022) (discussing what fuels can generate RINs).

[248] See, *e.g.,* EPA, ''Definition of Fuel,'' September 25, 2024. *https://www.epa.gov/rmp/definition-fuel.* See also, Merriam-Webster definition of fuel, available at *https://www.merriam-webster.com/dictionary/fuel.*

generally comprised partially of fossil fuel-based methanol).[249]

To properly account for the fossil-derived hydrogen found in most renewable diesel, naphtha, and jet fuel, we are proposing to reduce the equivalence values for these fuels. Specifically, we are proposing to reduce the equivalence value for renewable diesel specified in 40 CFR 80.1415(b) to 1.6. We are also proposing to specify equivalence values of 1.4 for renewable naphtha and 1.6 for renewable jet fuel. Equivalence values for these fuels are not currently specified in 40 CFR 80.1415(b), but are instead determined on a facility-by-facility basis using an equation specified in 40 CFR 80.1415(c). Previously approved equivalence values for naphtha range from 1.4 to 1.5 with the majority approved at 1.5, and for renewable jet fuel range from 1.6 to 1.7, with the majority approved at 1.6.[250]

The proposed equivalence values for renewable diesel, naphtha, and jet fuel are based on our technical assessment of the proportion of these fuels that are derived from renewable biomass and would better align the equivalence values of these fuels with the approach used for other biofuels that contain non-renewable content described above.[251] We note, however, that producers or importers would continue to be able to submit an application for an alternative equivalence value pursuant to 40 CFR 80.1415(b)(7).

We recognize that the proportion of these fuels that is produced from renewable biomass will vary slightly depending on a number of factors, such as the feedstock used to produce the renewable diesel, naphtha, or jet fuel. An alternative approach to reducing the equivalence values for these fuels as proposed would be to require each renewable fuel producer to determine the proportion of the renewable diesel, naphtha, or jet fuel that is produced from renewable feedstock on a batch-by-batch basis. This alternative approach would require a significant investment from both EPA and the renewable fuel producer to determine an acceptable methodology for calculating the renewable content of these fuels in the absence of a direct measurement technique and to execute the agreed-upon protocols on an ongoing basis. We do not expect that the number of RINs generated under this alternative approach would vary sufficiently from those under our proposed approach such that the additional burden on the renewable fuel producer would be warranted.

We also acknowledge that the proportion of these fuels that is produced from renewable biomass will vary slightly depending on the definition of ''produced from renewable biomass.'' In this action we are not proposing a definition of produced from renewable biomass. Nevertheless, we believe it is appropriate to propose revised equivalence values for renewable diesel, naphtha, and jet fuel prior to resolving the definition of produced from renewable biomass. The difference in the proportion of these fuels that can be considered produced from renewable biomass using an energy-based approach and a mass-based approach, the two primary approaches to the definition of produced from renewable biomass considered in the Set 1 Rule, are relatively small.[252] In light of the similar outcomes for these fuels between the two approaches, it is not appropriate to continue to allow these fuels to generate a greater number of RINs than would be the case under either approach to the definition of produced from renewable biomass.

We would intend to implement these proposed changes by deactivating any pathways with these impacted equivalence values prior to the effective date of the final rule (typically 60 days after publication of the final rule in the **Federal Register**. To avoid any disruption, currently registered renewable fuel producers utilizing these impacted pathways would need to update their registrations with EPA by the effective date.

We are requesting comment on alternative approaches to recognizing and accounting for the non-renewable content found in most renewable diesel, naphtha, and jet fuel. We are also aware that some producers of renewable diesel, naphtha, and jet fuel have explored producing these fuels using hydrogen that is produced from qualifying renewable biomass rather than from fossil natural gas. We are not proposing new pathways or equivalence values for parties using renewable hydrogen to produce renewable diesel, naphtha, or jet fuel in this action as significant outstanding issues remain. These issues include developing an approach to evaluating the lifecycle GHG emissions for hydrogen used in renewable diesel naphtha, and jet fuel production and how to account for renewable hydrogen used in a hydrotreating process that is not incorporated into the fuel. However, we are requesting comment on how to recognize the potential for greater renewable content that can be achieved using renewable hydrogen in a future action.

B. RIN-Related Provisions

1. RIN Generation and Assignment

Since EPA finalized the biogas regulatory reform provisions in the Set 1 Rule, we have received a significant number of questions from stakeholders regarding when RINs for RNG must be generated and assigned. In response to these inquiries, we are proposing regulations to specify when RINs must be generated and assigned both for renewable fuel and for RNG. Specifically, we are proposing in 40 CFR 80.1426(f)(18) that RINs for most renewable fuels must be generated at:

- For domestic renewable fuel producers, the point of production or point of sale.
- For RIN-generating foreign producers, the point of production or when the renewable fuel is loaded onto a vessel or other transportation mode for transport to the covered location.
- For RIN-generating importers of renewable fuel, the point of importation into the covered location.

We are also proposing in 40 CFR 80.1426(f)(18) that RINs for RNG and renewable fuels that are gaseous at standard temperature and pressure (STP) (*e.g.,* renewable CNG/LNG) must be generated no later than five business days after all applicable requirements for RIN generation under 40 CFR 80.125(b), 80.130(b), and 80.1426(f), as applicable, have been met. An exception would be for foreign produced RIN-less RNG, in which RINs must be generated when title is transferred from the foreign producer to the RIN-generating importer.

Furthermore, we are proposing in 40 CFR 80.1426(e) that, except for RNG and renewable fuels that are gaseous at STP, RINs generated at the point of production or the point of importation into the covered location must be assigned to a volume of renewable fuel when the renewable fuel leaves the renewable fuel production or import facility, while RINs generated at the point of sale or when the renewable fuel was loaded onto a vessel or other transportation mode for transport to the covered location must be assigned prior to the transfer of ownership of the renewable fuel. We are also proposing that RINs for RNG and renewable fuels

[249] See ''Calculation of Equivalence Values for renewable fuels under the RFS program,'' Docket Item No. EPA–HQ–OAR–2005–0161–0046.

[250] See ''Feedstock Summary'' RIN data table at: *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rins-generated-transactions.*

[251] See ''Calculation of Proposed Equivalence Values for Renewable Diesel, Naphtha, and Jet Fuel,'' available in the docket for this action.

[252] *Id.*

that are gaseous at STP must be assigned to a volume of RNG or renewable fuel at the same time the RIN is generated for the RNG or renewable fuel. We request comment on these proposed deadlines for RIN generation and assignment.

2. Pure and Neat Biodiesel Used for Process Heat or Power Generation

The CAA and RFS regulations prohibit RIN generation for fuel that does not replace or reduce the quantity of fossil fuel present in a transportation fuel, heating oil, or jet fuel. Pure biodiesel (*i.e.,* B100) or neat biodiesel (*i.e.,* B99) used for process heat or power generation is not a transportation fuel or jet fuel and does not qualify as heating oil under paragraph (1) of the definition of heating oil under 40 CFR 80.2 because: (1) It is not commonly or commercially known as heating oil, and (2) It is not sold for use in furnaces, boilers, or similar applications.[253] As to the first criterion, pure or neat biodiesel is not commonly known as heating oil and has several natural qualities that make it problematic as a heating oil, the primary issue being that biodiesel gels at low temperatures and could negatively impact the equipment being fueled by biodiesel (*e.g.,* by clogging filters). As to the second criterion, pure or neat biodiesel is not typically sold for use in furnaces, boilers, or similar applications. Therefore, biodiesel producers that use some of the biodiesel they produce for process heat or that sell biodiesel to power plants cannot generate RINs on the volumes used for process heat or power generation. As such, we are proposing to clarify that RINs cannot be generated for pure or neat biodiesel that is used for process heat or power generation by revising the definition of heating oil under 40 CFR 80.2 to state that ''pure biodiesel (*i.e.,* B100) or neat biodiesel (*i.e.,* B99) that is used for process heat or power generation is not heating oil.'' We request comment on the proposed clarification that RINs cannot be generated for pure or neat biodiesel used for process heat or power generation.

C. Percentage Standard Equations

We are proposing several changes to the percentage standard equations in 40 CFR 80.1405(c).[254] First, we are proposing to clarify that the volume requirements used to calculate the percentage standards for cellulosic biofuel, advanced biofuel, and total renewable fuel ($RFV_{CB,i}$, $RFV_{AB,i}$, and $RFV_{RF,i}$, respectively) are based on the number of ''gallon-RINs'' of each fuel, rather than simply ''gallons'' as currently specified. As described in the RFS2 Rule, we have interpreted these volume requirements as being on an energy-equivalent basis (rather than wet or physical gallons of liquid fuel) and that when the volume requirements are used to calculate the applicable percentage standards, it would be through the use of the equivalence value for RIN generation (the ''Equivalence Value'' approach).[255] This energy-equivalent basis for using the volume requirements to calculate the percentage standards is expressed through the use of gallon-RINs, and thus we believe these terms should be defined as such in the regulations.

Second, we are proposing to change the BBD volume requirement ($RFV_{BBD,i}$,) from being expressed in physical gallons to gallon-RINs, consistent with the methodology used to specify the other three renewable fuel volume requirements. Since the BBD volume requirement was first established in the RFS2 Rule, we have interpreted the statutory BBD volume requirements as being in physical gallons.[256] Thus, while the percentage standard equations for cellulosic biofuel, advanced biofuel, and total renewable fuel were established on a gallon-RINs basis, the BBD percentage standard was established on a physical gallon basis. Because the BBD standard was assumed in the RFS2 Rule to be met exclusively with biodiesel, and biodiesel generated 1.5 RINs per gallon, we applied a 1.5 multiplier (the ''BBD multiplier'') to the BBD percentage standard equation to convert from the number of BBD physical gallons in the statutory volume requirements to the equivalent number of gallon-RINs. Since the RFS2 Rule, we have continued to use the energy-equivalent (or gallon-RIN) approach in establishing the cellulosic biofuel, advanced biofuel, and total renewable fuel volume requirement and associated percentage standards. However, the BBD volume requirement has continued to be expressed in physical gallons and then converted to a gallon-RIN equivalent in the BBD percentage standard equation by multiplying the BBD volume requirement by the BBD multiplier (either 1.5 (from 2010–2022) or 1.6 (from 2023–2025)). As discussed in Sections III and V, since the promulgation of the RFS2 Rule, fuels other than biodiesel and with different equivalence values than biodiesel, most prominently renewable diesel, have become significant contributors to the BBD volume requirement. This has led to confusion among stakeholders regarding the correct way to interpret the BBD volume requirement and a perceived lack of clarity regarding how the BBD percentage standard is calculated. Our proposal to reduce the number of RINs generated for imported renewable fuel and renewable fuel produced from foreign feedstocks (discussed in Section VIII) would further complicate this issue.

Acknowledging that the BBD volume requirement is now being met with a more complex mixture of fuels than we anticipated in the RFS2 Rule, we are now proposing to revise the definition of $RFV_{BBD,i}$ to specify that the BBD volume requirement is expressed in gallon-RINs rather than gallons. We believe that specifying the BBD volume requirement in gallon-RINs would reduce confusion among stakeholders regarding how to interpret the BBD volume requirement and how the BBD percentage standard is calculated.

Consistent with this proposed clarification, we are also proposing to revise the BBD percentage standard to remove the 1.6 multiplier. By specifying the BBD volume requirement in RIN gallons, the BBD multiplier would no longer be necessary to convert from physical gallons of BBD to gallon-RINs. This would also eliminate the need to track the average equivalence value of BBD to adjust the BBD multiplier in the future, which EPA recently revised from 1.5 to 1.6 in the Set 1 Rule due to increased production volumes of renewable diesel relative to biodiesel.[257]

We are also proposing to remove the terms GS_i, DS_i, RGS_i, and RDS_i from the percentage standard equations. These terms relate to the use of gasoline, diesel, or renewable fuels contained in gasoline or diesel in Alaska or a U.S. territory if the state or territory opts into the RFS program. However, if Alaska or a U.S. territory were to opt into the RFS

[253] EPA has already made clear that fuel oils used for process heat or power generation do not qualify as heating oil under paragraph (2) of the definition of ''heating oil'' under 40 CFR 80.2. 78 FR 62462 (October 22, 2013).

[254] EPA's proposed changes to the percentage standard formulas are limited to the changes proposed here. We are not seeking comment on or reopening any other aspects of the percentage standard formulas, including the factors that project exempt volumes of gasoline and diesel due to small refinery exemptions.

[255] 75 FR 14709–10, 16–18 (March 26, 2010).

[256] In the RFS2 rule, we stated that ''we are finalizing the energy content approach to Equivalence Values for the cellulosic biofuel, advanced biofuel, and total renewable fuel standards. However, the biomass-based diesel standard is based on the volume of biodiesel. In order to align both of these approaches simultaneously, biodiesel will continue to generate 1.5 RINs per gallon as in RFS1, and the biomass-based diesel volume mandate from EISA is then adjusted upward by the same 1.5 factor.'' 75 FR 14716 (March 26, 2010).

[257] 88 FR 44545–47 (July 12, 2023).

program in the future, we would instead account for gasoline, diesel, and renewable fuel use in the state or territory under the existing G_i, D_i, RG_i, and RD_i terms. These terms refer to the amounts of gasoline, diesel, or renewable fuel used in gasoline or diesel in the covered location, which is defined as ''the contiguous 48 states, Hawaii, and any state or territory that has received an approval from EPA to opt-in to the RFS program under § 80.1443.'' [258] Thus, there is no need to have separate terms in the percentage standards just for Alaska or a U.S. territory that opts into the RFS program in the future.

Finally, we are proposing to revise the definitions of RG_i and RD_i (the amounts of renewable fuel projected to be blended into gasoline and diesel, respectively) to clarify that these projections are for the amounts of renewable fuel contained within the projections of G_i and D_i themselves (the amounts of gasoline and diesel, respectively, projected to be used in the U.S.), rather than a projection of the absolute amount of renewable fuel blended into gasoline and diesel. While the EIA projections of gasoline and diesel used by EPA to calculate the percentage standards have historically contained some volume of renewable fuel (*e.g.,* ethanol in gasoline, biodiesel and renewable diesel in diesel), EIA has recently changed their STEO projection methodology to provide separate projections of petroleum-based diesel and renewable fuels blended into diesel (*e.g.,* biodiesel and renewable diesel). Thus, were we to use these projections to calculate the percentage standards, we would use the petroleum-based diesel projection for D_i and a value of zero for RD_i, as the D_i projection does not contain any renewable fuel.[259] We believe this clarification makes clear how we would calculate the percentage equations under this potential future scenario. We request comment on these proposed changes to the percentage standard equations.

D. Existing Renewable Fuel Pathways

Table 1 to 40 CFR 80.1426 lists generally applicable fuel pathways that have been approved for the RFS program. Fuel producers that produce fuel through a pathway (*i.e.,* a unique combination of a fuel type, feedstock, and process) described in Table 1 may submit a registration application to EPA.[260] Table 1 lists an applicable RIN D code for each approved pathway based on the type of fuel produced, whether it is produced from cellulosic biomass, and whether it satisfies the statutory 20 percent, 50 percent, or 60 percent lifecycle GHG emissions reduction threshold. In Section X.D.1, we are proposing clarifications to certain pathways in Table 1. In Section X.D.2, we are proposing to add pathways to Table 1 for naphtha and liquefied petroleum gas (LPG) produced from biogenic waste oils, fats and greases. We request comment on all these proposed changes to the eligible fuel pathways in Table 1.

1. Table 1 Pathways That Include ''Any'' Production Process

In addition to requiring that renewable fuel be produced from renewable biomass and used to reduce or replace the quantity of fossil fuel in transportation fuel,[261] the CAA also requires that qualifying biofuels meet the lifecycle GHG reduction threshold specified for the applicable category of renewable fuel.[262] The CAA further requires EPA to determine the lifecycle GHG emissions for renewable fuels.[263] EPA has evaluated the lifecycle emissions associated with fuel pathways and listed the pathways it has analyzed that satisfy the statutory GHG reduction criteria in Table 1 to 40 CFR 80.1426. To do so, EPA necessarily evaluates particular feedstocks that are put through particular production processes to produce particular fuels. Thus, an approved pathway in Table 1 signifies that EPA has determined that the specific combination of elements we evaluated meets the applicable GHG reduction threshold.

In 2010 when EPA promulgated the initial set of pathways in Table 1 as part of the RFS2 Rule, the range of commercially available technologies for producing renewable fuels was relatively limited, but there was an expectation that other nascent technologies would be developed over time to the point of commercialization. Given the information available at the time, EPA believed that the lifecycle analyses it had conducted for certain pathways provided sufficient basis to approve other pathways with similar feedstocks, production process technologies, and fuels.[264] For example, based on the biochemical and thermochemical production processes that we modeled for producing ethanol from switchgrass and corn stover, EPA included several other cellulosic feedstocks in Rows K and L of Table 1 and described the production process as ''Any.'' Thus, some of the pathway descriptions in Table 1 are quite broad (*i.e.,* they provide that the approved pathway can include ''any'' production process).

However, over the life of the RFS program, many fuel production processes have been developed that vary from those assumed in the original assessments underlying the pathways listed in Table 1 more than we anticipated in the RFS2 Rule. Indeed, some of the fuel production process technologies that parties are now wishing to register under ''any'' pathways have little connection to the processes EPA evaluated as the basis for including a given pathway in Table 1. In some cases, the GHG emissions performance of such new processes may be significantly worse than the processes we analyzed for the RFS2 Rule or the notional processes we anticipated might be developed in the future. These new processes may therefore not meet the applicable GHG emissions threshold. For example, we have received petitions for cellulosic biofuel production technologies that would use a large amount of conventional natural gas and grid electricity per unit of fuel produced, whereas our 2010 analysis assumed that this type of process would use very little natural gas or grid electricity, relying instead on cellulosic renewable biomass (*e.g.,* lignin) for process energy.

Given the possibility that some pathways fitting the description in Table 1 might not actually meet the corresponding statutory GHG reduction requirement, we believe it is inappropriate to continue allowing ''any'' production process under certain Table 1 pathways. Therefore, we are proposing changes to Table 1 and the RFS regulations to clarify certain fuel pathways in Table 1 and to replace the ''any'' terminology with more precise language.

More specifically, to further clarify the scope of currently approved pathways, we are proposing to add more precise language to the description of rows in Table 1 that include the term ''any'' to describe the production process requirements, which are Rows

[258] 40 CFR 80.2.

[259] Note that the proposed percentage standards in this action are calculated using projections from AEO2023, which does include renewable fuels in its projections of gasoline and diesel.

[260] Note that an individual row in Table 1 can include multiple fuel pathways.

[261] CAA section 211(o)(1)(J).

[262] CAA sections 211(o)(1)(B), (D), (E); 211(o)(2)(A)(i).

[263] CAA section 211(o)(1)(H).

[264] For example, see discussion of ''assessments of similar feedstocks sources'' at 75 FR 14792–14797 (March 26, 2010).

K, L, M, P, Q, and T. Currently, Rows K and L list the production process requirements as ''Any process that converts cellulosic biomass to fuel,'' Row M includes ''any process utilizing biogas and/or biomass as the only process energy sources which converts cellulosic biomass to fuel,'' and Rows P, Q, and T list the production process requirements as ''Any.'' As discussed below, we are proposing to replace some or all of the current language in each of these rows with a description of the production process requirements that EPA evaluated for the corresponding lifecycle GHG assessment and that we determined meet the applicable GHG reduction threshold. Renewable fuel production facilities that do not satisfy the updated production process requirements may petition EPA pursuant to the petition process at 40 CFR 80.1416 to request EPA's evaluation of the lifecycle GHG emissions associated with their fuel.

a. Rows K and L

We are proposing to edit the production process descriptions in Rows K and L to clarify the production process technologies that qualify under these rows. For Row K, we are proposing to clarify that the qualifying production processes are: (1) A biochemical fermentation process that uses cellulosic biomass for all electricity and thermal process energy; (2) A thermochemical gasification process that uses cellulosic biomass for nearly all thermal and electrical process energy needs; or (3) A dry mill fermentation process that converts corn or grain sorghum kernel fiber to ethanol. For Row L, we are proposing to clarify that the qualifying production process technology is a Fischer-Tropsch process that uses cellulosic biomass for nearly all electrical and thermal process energy. Below, we discuss these clarifications in more detail.

For the RFS2 Rule, EPA's evaluation of the emissions associated with the feedstock to fuel conversion stage of the lifecycle was based on process modeling conducted by the National Renewable Energy Laboratory (NREL).[265 266 267 268] The NREL process modeling evaluated conversion of corn stover, switchgrass and hybrid poplar feedstocks through biochemical and thermochemical processes. Instead of conducting process modeling for each possible type of biomass, of which there are a wide variety, NREL categorized the potential feedstocks as crop residue, dedicated biomass crops, and woody biomass. NREL modeled corn stover as representative of all crop residues, switchgrass as representative of all purpose-grown energy grasses, and hybrid poplar as representative of all woody biomass feedstocks. In the RFS2 Rule,[269] the Pathways I Rule,[270] and the Additional Pathways Rule,[271] EPA applied the NREL process modeling to evaluate the biofuel conversion emissions associated with all the feedstocks currently listed in Rows K and L.[272] For the reasons discussed in those rules, EPA is confident that the process technologies evaluated are relevant for all these feedstocks and supports the qualification of fuels produced from these feedstocks and process technologies for D3 or D7 RINs. Thus, we believe it is appropriate for our proposed revisions to the production process requirements for Rows K and L to apply for fuels produced from all the feedstocks listed in those rows.

We are proposing changes to Row K based on the biochemical production processes that we evaluated in the RFS2 Rule. For the RFS2 rule, we evaluated the lifecycle GHG emissions associated with a biochemical cellulosic ethanol production process with four major process steps: (1) Conversion of feedstocks to sugar; (2) Fermentation of sugar to ethanol; (3) Ethanol recovery; and (4) Residue utilization for process energy through a combined heat and power system. A key assumption in the NREL evaluation is that residues from steps 1–3 would be utilized in step 4 to produce heat, steam, and electricity and meet all of the facility's needs for these inputs. The modeling assumed that combusting the residues in a fluidized bed combustor would provide adequate heat, steam, and electricity for steps 1–3, with excess electricity sold to the grid. The residue materials considered in our evaluation were materials left over after the processing of the cellulosic biomass feedstock, including lignin, concentrated syrup, and biogas from wastewater treatment. In particular, the lignin residue was assumed to be the main source of fuel energy to the combined heat and power system.

For the crop residue ethanol via a biochemical process based on analysis assuming corn stover feedstock, we estimated a 129 percent GHG reduction relative to the gasoline baseline (*i.e.,* net negative GHG emissions due to exported electricity displacing grid average electricity). For switchgrass ethanol, the corresponding estimate was a 110 percent GHG reduction. Based on these estimates and considering background data updates since 2010, we remain confident that a biochemical process using the residues of the production process (*e.g.,* lignin, syrup, biogas) for all heat and excess power generation would meet the 60 percent GHG reduction threshold for D3 RINs. However, if we were to change the 2010 analysis to assume natural gas is used for process heat and power, the corresponding GHG reduction estimates would be 56 percent for corn stover ethanol and 41 percent for switchgrass ethanol. Thus, our determination that these pathways satisfy the 60 percent threshold is dependent on the assumption that biomass residues will be used for process energy and power.

For these reasons, we are proposing to revise the production process column of Row K to include, ''Biochemical fermentation process that converts cellulosic biomass to ethanol; only includes processes that use the lignin and other biogenic feedstock residues from the fermentation and ethanol production processes for all thermal and electrical process energy and are net exporters of electricity to the grid.''

We are also proposing changes to Row K of Table 1 to 40 CFR 80.1426 based on the thermochemical production processes that we evaluated in the RFS2 Rule. The RFS2 Rule evaluated pathways for cellulosic ethanol produced via a thermochemical process. Our evaluation of these pathways relied on process modeling by NREL. The process modeled by NREL includes biomass gasification, syngas refining, mixed alcohol synthesis and distillation. The NREL modeling assumed that tar from the biomass gasification and a slipstream of unrefined syngas would be combusted to provide all required process heat, precluding the need to purchase natural gas or other fossil fuels for almost all the energy needs for the process.

[265] Tao, Ling, and Andy Aden. ''Techno-economic Modeling to Support the EPA Notice of Proposed Rulemaking (NOPR),'' NREL, November 3, 2008. Docket Item No. EPA–HQ–OAR–2005–0161–0844.

[266] Aden, Andy. ''Mixed Alcohols from Woody Biomass—2010, 2015, 2022,'' NREL, December 3, 2009. Docket Item No. EPA–HQ–OAR–2005–0161–3034.

[267] Aden, Andy. ''Feedstock Considerations and Impacts on Biorefining,'' NREL, December 10, 2009. Docket Item No. EPA–HQ–OAR–2005–0161–3044.

[268] Davis, Ryan. ''Techno-economic analysis of current technology for Fischer-Tropsch fuels production,'' NREL, August 14, 2009. Docket Item No. EPA–HQ–OAR–2005–0161–3035.

[269] 75 FR 14793–95 (March 26, 2010).

[270] 78 FR 14201–06 (March 5, 2013).

[271] 78 FR 41705–09 (July 11, 2013).

[272] Crop residue; slash, pre-commercial thinnings, and tree residue; switchgrass; miscanthus; energy cane; *Arundo donax; Pennisetum purpureum;* separated yard waste; biogenic components of separated MSW; cellulosic components of separated food waste; cellulosic components of annual cover crops.

Specifically, the NREL modeling assumes that the biomass residue provides 99.8 percent of the process energy with a very small amount of diesel use.

For corn stover ethanol via a thermochemical process, in 2010 we estimated a 92 percent reduction relative to the gasoline baseline. For switchgrass ethanol, the corresponding estimate was a 72 percent GHG reduction. Based on these estimates, we remain confident that a biochemical process using biomass residues for almost all heat and excess power generation will meet the 60 percent GHG reduction threshold for D3 RINs. However, if we were to change the 2010 analysis to assume natural gas is used for process heat and power, the corresponding GHG reduction estimates would be 16 percent for corn stover and 2 percent for switchgrass. Thus, our determination that these pathways satisfy the 60 percent threshold (or even the 20 percent threshold) is dependent on the assumption that biomass residues will be used for process energy and power. For these reasons, we are proposing to revise the production process column of Row K to include, ''Thermochemical gasification process that converts cellulosic biomass to ethanol and uses a portion of the feedstock for over 99% of thermal and electrical process energy.''

We are also proposing changes to Row K of Table 1 to 40 CFR 80.1426 based on the CKF to ethanol process evaluated in the Pathways II Rule.[273] In the 2014 Pathways II rule, EPA evaluated ethanol produced from CKF at dry mill ethanol plants. EPA determined that CKF qualifies as a predominately cellulosic crop residue and ethanol produced from corn kernel fiber through a dry mill process is covered by Row K of Table 1. EPA's evaluation for these pathways was limited to dry mill ethanol plants. This evaluation did not consider the possibility that such plants could be coal fired, which would substantially increase the lifecycle GHG emissions. As part of that rulemaking, EPA also determined that kernel fiber from grain sorghum is a predominately cellulosic crop residue that may be converted to ethanol in the same way as corn kernel fiber. Grain sorghum kernel fiber and CKF are very similar in terms of how they are produced and converted to ethanol such that it is reasonable to extend our lifecycle analysis of ethanol produced from CKF to ethanol produced from grain sorghum kernel fiber. For these reasons, we are proposing to revise the production process column of Row K to include, ''Dry mill process that converts corn or grain sorghum kernel fiber to ethanol and uses natural gas, biogas, or crop residue for all thermal process energy.''

We are proposing changes to Row L of Table 1 to 40 CFR 80.1426 based on the Fischer-Tropsch processes that we evaluated in the RFS2 rule. EPA evaluated the lifecycle GHG emissions associated with diesel, jet fuel, and heating oil produced from corn stover and switchgrass via a Fischer-Tropsch process for the RFS2 Rule. The lifecycle analysis for these pathways relied on process modeling by NREL. The NREL process modeling assumed that the feedstock is dried and gasified, the resulting syngas is cleaned and reformed, wax is sent to a hydrocracker, and the light hydrocarbons and hydrocracker products are sent to a fractionator to separate diesel from other coproducts. The NREL modeling assumed that almost all (99.8 percent) of the steam and power requirements are satisfied internally through biomass and syngas combustion, with the small remainder of energy needs met with grid electricity and conventional diesel.

For diesel fuel produced from corn stover through a Fischer-Tropsch process, in 2010 we estimated a 91 percent reduction relative to the gasoline baseline. For diesel produced from switchgrass through a Fischer-Tropsch process, the corresponding estimate was a 71 percent GHG reduction. Based on these estimates, we remain confident that a Fischer-Tropsch diesel process using residues (*e.g.,* lignin, syrup, biogas) for all heat and excess power generation will meet the 60 percent GHG reduction threshold for D3 RINs. However, if were to change the 2010 analysis to assume natural gas is used for process heat and power, the lifecycle GHG emissions for these fuels would be greater than the lifecycle GHG emissions associated with the diesel baseline: 25 percent greater for switchgrass-based diesel and 5 percent greater for stover-based diesel. Thus, our determination that these pathways satisfy the applicable GHG reductions thresholds are dependent on the assumption that feedstock residues generated during the fuel production process will be used for process energy and power. For these reasons, we are proposing to revise the production process column of Row L to say, ''Fischer-Tropsch process that converts cellulosic biomass to fuel and uses a portion of the feedstock for over 99% of thermal and electrical process energy.''

b. Row M

We are proposing changes to Row M to define the qualifying process technologies more precisely to ensure that fuels produced through Row M satisfy the statutory criteria for RIN generation. In the Pathways I Rule, we approved the pathways in Row M for cellulosic biofuels produced from residue, byproduct and cover crop feedstocks through multiple biochemical and thermochemical processes.[274] These approvals were based on our lifecycle emissions modeling of the following production process technologies: (1) Thermochemical processes including pyrolysis and upgrading; (2) Thermochemical gasification and upgrading; (3) Direct biological conversion, and (4) Biological conversion and upgrading. In that rule, we extended the modeling results of these specific process technologies to ''any process utilizing biogas and/or biomass as the only process energy sources which converts cellulosic biomass to fuel.'' At the time, we explained that extending the modeling in this way was based on the premise that the process assumptions we modeled at the time were relatively conservative, and we expected the industry to improve and potentially exceed the energy efficiencies we modeled. For example, we stated that ''[t]echnology changes in the future are likely to increase efficiency to maximize profits, while also lowering lifecycle GHG emissions.''[275] While these predictions made in 2013 may eventually come to pass, our experience over the 12 years since then has reduced our confidence that ''any'' process using these feedstocks and types of process energy will satisfy the statutory emissions reduction requirements. We are more cautious now because the process configurations we modeled in 2013 to support the Row M pathways have not been commercialized. Furthermore, new fuel pathway petitions submitted pursuant to 40 CFR 80.1416 and pathway screening tool submissions indicated that, rather than exceeding the process efficiencies we modeled in 2013, some projects under consideration may be less energy efficient than we projected. For these reasons, we are no longer confident that the fuel and feedstock combinations listed in Row M produced through ''any process utilizing biogas and/or biomass as the only process energy sources which converts cellulosic biomass to

[273] 79 FR 42128 (July 18, 2014).

[274] 78 FR 14190 (March 5, 2013).

[275] 78 FR 14213 (March 5, 2013).

fuel'' would satisfy the statutory 60 percent GHG reduction requirement to qualify for D3 RINs. Thus, we are proposing to remove the ''any process'' language from Row M, while leaving in place the following processes that convert cellulosic biomass to fuel using natural gas, biogas, or biomass as the only process energy sources: (1) Catalytic pyrolysis and upgrading; (2) Gasification and upgrading; (3) Thermo-catalytic hydrodeoxygenation and upgrading; (4) Direct biological conversion; (5) Biological conversion and upgrading. To our knowledge, this action would not adversely affect any currently operating facilities.

c. Row P

We are proposing changes to Row P based on analyses undertaken by EPA for prior rulemakings. Row P includes ethanol, renewable diesel, jet fuel, heating oil, and naphtha produced from the non-cellulosic portions of separated food waste and non-cellulosic components of annual cover crops. EPA evaluated and approved pathways for ethanol, renewable diesel, jet fuel, heating oil, and naphtha produced from the non-cellulosic portions of separated food waste and non-cellulosic components of annual cover crops assuming that the ethanol would be produced through a fermentation process, and the other fuels would be produced through a hydrotreating or transesterification process. Fermentation processes use a significant amount of thermal energy (*e.g.,* for feedstock heating and distillation) and our evaluation assumed that these facilities would be fired with natural gas or other fuels with similar or lower lifecycle GHG emissions such as biogas or crop residue. For these reasons, we are proposing to revise the production process column of Row P to say, ''Fermentation using natural gas, biogas, or crop residue for thermal energy; Hydrotreating; Transesterification.''

d. Rows Q and T

We are proposing changes to Rows Q and T based on analyses undertaken by EPA for prior rulemakings. EPA's evaluation of renewable CNG produced from biogas assumed the biogas would be treated to increase biomethane concentration and reduce impurities such as carbon dioxide, nitrogen, oxygen, and volatile organic compounds, and the resulting treated biogas would be compressed for vehicle fueling or pipeline injection. Thus, for the renewable CNG pathways, we are proposing to revise the production process column of Rows Q and T to say, ''CNG production from treated biogas via compression.''

EPA's evaluation of renewable LNG produced from biogas assumed the same biogas treatment as the renewable CNG pathways, and the resulting biomethane would undergo liquefaction (*i.e.,* biomethane condensed to liquid form by reducing its temperature to approximately minus 260 degrees Fahrenheit at ambient pressure), producing renewable LNG. Thus, for the renewable LNG pathways, we are proposing to revise the production process column of Row Q to say, ''LNG production from treated biogas via liquefaction.''

Furthermore, the analyses EPA undertook that form the basis for the Rows Q and T pathways assumed the renewable CNG would be transported via pipeline and that the renewable LNG would be used as a transportation fuel within a relatively short time after it was produced. After the LNG is produced there are boil-off emissions of approximately 0.1 to 0.15 percent per day associated with evaporation during transport, storage, and fueling. Thus, renewable LNG that is transported or stored for a long time before use as transportation fuel has higher lifecycle GHG emissions and is outside the bounds of our analysis. We assume that renewable LNG produced in North America would be used relatively soon after production. CNG that is produced outside of North America would involve additional non-pipeline transportation emissions that were not considered in EPA's lifecycle analysis. For these reasons, we are proposing to clarify that the production process requirements for Rows Q and T are limited to processes that occur in North America.[276]

e. Conclusion

These regulatory clarifications to Table 1 to 40 CFR 80.1426 do not affect renewable fuel producers that have successfully registered for any of the existing fuel pathways listed in Table 1. Prior registration applications were reviewed and accepted based on EPA's engineering judgement and interpretation of the fuel pathways in Table 1, including EPA's consideration of the bounds of the lifecycle analysis that formed the basis for the approved pathways. If finalized, the regulatory clarifications proposed in this action would not change the status of any of these prior registrations.

We believe the proposed Table 1 revisions discussed in this section would benefit renewable fuel project developers by giving them additional clarity on what process technologies qualify under the existing renewable fuel pathways. Although we strive to describe the pathways in Table 1 in a precise manner that aligns with the lifecycle analysis that supports each pathway, we recognize that there will likely still be some cases where it is not clear whether a particular process technology qualifies for a particular fuel pathway in Table 1. Fuel producers seeking to determine if their fuel fits within the bounds of a pathway listed in Table 1 can contact EPA through the pathway screening tool for clarification.[277] The pathway screening tool process was designed for the express purpose of providing a means for renewable fuel producers to seek input on whether a fuel fits an existing pathway in Table 1 or whether a new renewable fuel pathway petition, pursuant to 40 CFR 80.1416, is needed prior to generating RINs. To provide additional clarity regarding the criteria that EPA will apply to determine whether a feedstock, fuel, or production technology qualifies for an existing Table 1 pathway, we propose to add the following language to 40 CFR 80.1426(f)(1): ''For purposes of identifying the appropriate approved pathway, the fuel must be produced, distributed, and used in a manner consistent with the pathway EPA evaluated when it determined that the pathway satisfies the applicable GHG reduction requirement.'' Again, producers that are unsure if their fuel qualifies under an existing pathway may use the pathway screening tool process to receive clarification from EPA, and producers of a fuel that does not fit within the bounds of an existing pathway may petition EPA, pursuant to the petition process at 40 CFR 80.1416, requesting EPA's evaluation of the lifecycle GHG emissions associated with their fuel.

2. Adding Waste Fats, Oils, and Greases as Feedstock for Producing Renewable Naphtha and LPG

We are proposing to add generally applicable fuel pathways to Table 1 to 40 CFR 80.1426 for renewable naphtha and liquefied petroleum gas (LPG) produced from biogenic waste oils, fats, and greases through a hydrotreating process to qualify for D5 (advanced

[276] For further information on the lifecycle emissions estimates discussed in this section, see ''Lifecycle Emissions Estimates Related to Clarifications to Table 1 Pathways,'' available in the docket for this action.

[277] EPA, ''Renewable Fuel Pathway Screening Tool.'' *https://www.epa.gov/renewable-fuel-standard-program/forms/renewable-fuel-pathway-screening-tool.*

biofuel) RINs. Specifically, we are proposing to add ''Biogenic waste oils/fats/greases'' to the feedstock column in Row I of Table 1. As discussed below, we are proposing to add these fuel pathways based on our finding that they satisfy the statutory 50 percent GHG reduction threshold to qualify as advanced biofuel.

In the RFS2 Rule, we approved fuel pathways, in Rows F and H, for biodiesel and renewable diesel produced from biogenic waste oils, fats, and greases through a hydrotreating process to qualify for D4 RINs. These pathway approvals were based on our estimate that biodiesel produced from UCO (also called waste grease or yellow grease in the RFS2 Rule) reduced lifecycle GHG emissions by over 80 percent compared to the petroleum baseline.[278] In the Pathways I Rule, we added ''jet fuel'' and ''heating oil'' to the fuel type column of Rows F and H of Table 1. The approval of these jet fuel and heating oil pathways was based on extending the prior determinations to renewable diesel as the same facilities often produce renewable diesel and jet fuel as coproducts.[279] It is also common for hydrotreating facilities to produce naphtha and LPG as coproducts along with renewable diesel and jet fuel. In the Pathways I Rule, we also approved Row I for naphtha and LPG produced from camelina oil through a hydrotreating process based on the lifecycle analysis of camelina oil pathways that was conducted in support of that rule.

In 2018, we approved a facility-specific petition, submitted pursuant to the petition process at 40 CFR 80.1416, for naphtha and LPG produced from biogenic waste oils, fats, and greases at the Renewable Energy Group hydrotreating facility in Geismar, Louisiana, to qualify for D5 RINs.[280] As part of that determination, we estimated that naphtha and LPG produced from UCO at this facility would reduce lifecycle GHG emissions by 76 percent relative to the statutory petroleum baseline. Based on our prior and current evaluations, we believe that, as a general matter, facilities producing renewable naphtha and LPG from biogenic waste oils, fats, and greases, such as UCO and animal tallow, through a hydrotreating process will satisfy the 50 percent GHG reduction threshold for these fuels. Thus, we are proposing to add these pathways to Row I of Table 1 rather than approving them on a more time consuming and burdensome facility-specific basis.

[278] 75 FR 14789 (March 26, 2010).

[279] 78 FR 14201 (March 5, 2013).

[280] EPA, ''Letter from EPA to Renewable Energy Group, Inc.,'' April 13, 2017.

E. Updates to Definitions

1. New Definitions

The RFS regulations currently do not define the terms ''renewable fuel producer,'' ''renewable fuel oil,'' ''renewable naphtha,'' and ''renewable jet fuel;'' however, all these terms are used within the RFS regulations. To provide regulatory clarity, we are proposing to define each of these terms in this action. We are proposing to define a renewable fuel producer as ''any person that owns, leases, operates, controls, or supervises a facility where renewable fuels are produced.'' This proposed definition is consistent with other definitions of regulated parties under the RFS program. We are proposing to define renewable fuel oil as ''heating oil that is renewable fuel and that meets paragraph (2) of the definition of heating oil,'' renewable naphtha as ''naphtha that is renewable fuel,'' and renewable jet fuel as ''jet fuel that is renewable fuel and meets ASTM D7566.'' These proposed definitions are consistent with other definitions of renewable fuels under the RFS program.

We believe these proposed definitions will provide more clarity to both the regulated community and the public. We request comment on the proposed definitions.

2. Revised Definitions

Because we are proposing to reduce the RINs that are generated on foreign renewable fuel and renewable fuel made from foreign feedstocks, and given the complex nature of global supply chains, we believe it is necessary to update the definitions of foreign renewable fuel producers and importers. These proposed revisions will also provide clarity to regulated parties regarding which entities qualify as foreign renewable fuel producers or importers.

Under 40 CFR 80.2, a foreign renewable fuel producer is currently defined as ''a person from a foreign country or from an area outside the covered location who produces renewable fuel for use in transportation fuel, heating oil, or jet fuel for export to the covered location. Foreign ethanol producers are considered foreign renewable fuel producers.'' This definition is ambiguous because renewable fuel produced at a facility in the United States could arguably be considered produced by a ''foreign renewable fuel producer'' if the corporation that produced the renewable fuel is incorporated in a foreign country. We are proposing that a foreign renewable fuel producer instead be defined as ''any person that owns, leases, operates, controls, or supervises a facility outside the covered location where renewable fuel is produced.'' This revised definition is consistent with how foreign biogas producers and foreign RNG producers have been defined under the RFS regulations.

Further, under 40 CFR 80.2 an importer is defined as ''any person who imports transportation fuel or renewable fuel into the covered location from an area outside of the covered location.'' To provide greater clarity to the regulated community as to which entities can be considered an importer, we are proposing to revise the definition of importer to include ''the importer of record or an authorized agent acting on their behalf, as well as the actual owner, the consignee, or the transferee, if the right to withdraw merchandise from a bonded warehouse has been transferred.''

Finally, we are proposing to add a provision in the liability provisions at 40 CFR 80.1461 that specifies that each person meeting the definition of an importer of renewable fuel under the RFS regulations is jointly and severally liable for any violations of the RFS requirements, including the newly proposed import RIN reduction provisions. The proposed change is consistent with the liability framework for other parties participating in the RFS program and the liability framework that applies in EPA's fuel quality program under 40 CFR part 1090. These provisions are also necessary to ensure that importers who import non-qualifying renewable fuel or renewable fuel feedstocks can be held liable.

We request comment on the revised definitions of ''foreign renewable fuel producer'' and ''importer.'' We also request comment on the joint and several liability provision applicable to importers of renewable fuel.

3. New Biointermediates

In the 2020–2022 RFS Rule, we established provisions for biointermediates to be used to produce qualifying renewable fuels and listed in the regulations specific biointermediates that are allowed under the RFS program.[281] We also stated that new biointermediates would be brought into the RFS program via notice-and-comment rulemaking. In the Set 1 Rule, we added biogas as a biointermediate and in this action, we are proposing to add two more biointermediates. These new biointermediates were requested in

[281] 87 FR 39600 (July 1, 2022).

two separate petitions for rulemaking submitted to EPA in 2023 and 2024.[282] First, we are proposing to add activated sludge, which is waste sludge from a secondary wastewater treatment process involving oxygen and microorganisms. One petitioner suggested that activated sludge could initially be used to produce renewable CNG, potentially followed by other fuels such as LNG, ethanol, biobutanol, and methanol in the future. Second, we are proposing to add converted oils, which are glycerides such as monoglycerides and diglycerides that are produced through the glycerolysis of waste oils, fats, or greases with glycerol. Converted oils must exclusively consist of glycerides with fatty acid alkyl groups that originate from waste oils, fats, or greases during the conversion process. One petitioner suggested that converted oils could be used to produce biodiesel, renewable diesel, or jet fuel. We request comment on these proposed additions.

F. Compliance Reporting, Recordkeeping, and Registration Provisions

1. Exempt Small Refinery Compliance Reporting

Under the RFS program, small refineries are eligible to petition for and receive an exemption from their RFS obligations for a given compliance year. The RFS regulations do not, however, exempt these small refineries from having to submit an annual compliance report. We are proposing to clarify that such exempt small refineries must file an annual compliance report.

While an exempt small refinery does not have to retire RINs to comply with an RVO, it still produces gasoline or diesel fuel that is used as transportation fuel in the United States and thus this fuel is included in EIA's projections of nationwide gasoline and diesel fuel consumption. EPA uses these projections as the basis for calculating the annual RFS percentage standards and, as described in the Set 1 Rule, we have recently discovered a discrepancy between the volumes of gasoline and diesel fuel reported by obligated parties in their annual compliance reports and EIA's reported actual volumes of gasoline and diesel fuel consumed.[283] In order for EPA to have a complete picture of the actual volume of gasoline and diesel fuel that was produced by refiners—including fuel produced by exempt small refineries—that would otherwise be reported as obligated fuel in a given compliance year, it is necessary that all refiners submit an annual compliance report regardless of whether they received an exemption from their RFS obligations for the given compliance year. Having this data will improve the accuracy of EPA's gasoline and diesel fuel projections in future standard-setting actions and better ensure that there is not overcompliance by obligated parties.[284] Therefore, we are proposing to clarify under 40 CFR 80.1441(e)(2) and 80.1442(h) that exempt small refineries and small refiners are still subject to RFS reporting requirements under 40 CFR 80.1451(a) and must submit an annual compliance report by the annual compliance reporting deadline. Such exempt small refineries would need to report their actual annual production of gasoline and diesel fuel that would otherwise be obligated fuel. In addition, we are also proposing to clarify under 40 CFR 80.1441(e)(2) and 80.1442(h) that a small refinery or small refiner that receives an exemption for a given compliance year is not exempt from having to comply with any deficit RVOs that were carried forward from the previous compliance year. We request comment on the proposed clarifications.

2. Compliance Report Updates

We are proposing several changes to requirements related to compliance reports. Generally, these changes are intended to reduce burden, support implementation, or to improve the quality of information submitted to EPA under 40 CFR 80.1449, 80.1451, and 80.1452.

Currently, each entity owning RINs must calculate the volume of renewable fuel (in gallons) owned at the end of each quarter and report this on a quarterly basis. The general requirements for RIN distribution specify that the number of assigned RINs owned must be less than or equal to the amount of renewable fuel owned multiplied by 2.5. However, since 2010 there have been no documented compliance issues with entities meeting the distribution requirement for assigned RINs. To reduce reporting burden, we are proposing to remove this quarterly reporting requirement under 40 CFR 80.1451 and to also update the associated requirement under 40 CFR 80.1428(a)(4).

Renewable fuel producers are required to submit an annual ''production outlook report'' that currently includes a monthly or annual projection in future years. We are proposing to only require annual projections. Reducing this reporting requirement to annual projections will reduce burden while maintaining a minimum level of reporting needed to assess future production. We are also proposing to update or remove other outdated language under 40 CFR 80.1449.

Additionally, producers or importers of biogas used for transportation fuel are currently required to report on a quarterly basis the total energy produced and supplied for use as transportation fuel, as well as where the fuel is sold for use as a transportation fuel. These reporting requirements under 40 CFR 80.1451(b)(1)(ii)(P) are similar to other existing reporting requirements under 40 CFR 80.140. We are therefore proposing to remove this separate quarterly reporting requirement to further reduce reporting burden.

Finally, we are taking steps to improve the quality of information when entities generate RINs in EMTS. Currently, each reporting party must enter a ''reason code'' whenever they are reporting a buy, sell, separate or retire transaction in EMTS as described in 40 CFR 80.1452. This information is then used for implementation, compliance and public data postings on EPA's website. We are proposing to also add a ''reason code'' to generate transactions for similar purposes and updating other language under 40 CFR 80.1452 to improve consistency. Examples of new reason codes include feedstock point of origin identification, co-processed batches, and remedial actions.

3. Third-Party Auditor Registration Renewal

We are proposing to change the frequency that independent third-party auditors are required to renew their registrations. Currently, a third-party auditor's registration expires each year on December 31. However, we have found that there is significant burden on both EPA and auditors to review and approve these registrations every year. We believe that it is not necessary to require auditors to renew their registrations annually and that a two-year registration period would be more appropriate. This length of time would still ensure that we are regularly reviewing auditor registrations, while also reducing burden on EPA and auditors. Thus, we are proposing that a

[282] ''Agresti Energy Petition to Add Potential Biointermediates to the Regulatory Definition,'' October 12, 2023; ''DS Dansuk Petition for Addition of New Biointermediate Produced via a New Production Process,'' November 26, 2024.

[283] RFS Set 1 RIA, Chapter 1.11.

[284] Without gasoline and diesel fuel production volumes from exempt small refineries, EPA is more likely to underestimate the actual amount of gasoline and diesel fuel expected to be used in a given compliance year. This would result in overly stringent percentage standards, and thus more RINs would need to be retired than necessary to comply with the annual volume requirements.

third-party auditor's registration would expire on December 31 every other year. We request comment on the proposed change to the registration renewal requirement for independent third-party auditors.

4. Engineering Review Site Visits

Under 40 CFR 80.1450(b)(2), renewable fuel production facilities are required to undergo an independent third-party engineering review prior to registration. As part of that engineering review, the independent third-party engineer is required to conduct a site visit. However, the current regulations do not specify when such site visits need to occur. Recently, EPA has received some engineering reviews where the site visit was over a year old. Therefore, we are proposing to specify that engineering review site visits must be conducted within six months prior to submitting a registration request in order to ensure that the site visit is reflective of the current operation of the facility. We request comment on the proposed change to the engineering review site visit requirement.

5. Biogas Batch Period of Production

As part of the biogas regulatory reform provisions in the Set 1 Rule, a batch of biogas was specified as the volume of biogas measured for a calendar month, with the last day of the month as the production date.[285] Stakeholders have subsequently provided feedback to EPA that allowing biogas producers to produce batches for time periods of less than a month would improve implementation of the biogas regulations. To provide additional flexibility for biogas producers, we are proposing to change the period of production such that a biogas batch may be ''up to'' a calendar month, allowing for more frequent biogas batches as indicated by the business practices of the biogas producer. This change would also provide additional flexibility to RNG producers that use the biogas batches as part of their RNG RIN generation. We request comment on this proposed flexibility, including how this change impacts RNG RIN generation and separation, as well as on the RNG RIN period of production.

G. New Approved Measurement Protocols

We are proposing to add additional measurement protocols to the list of approved methods for measuring the volume of RNG or treated biogas. EPA has already accepted all these methods through alternative measurement protocols. The methods we are proposing to add under 40 CFR 80.155(a) are the following:

- AGA Report No. 3.
- AGA Report No. 9.
- AGA Report No. 11 or API MPMS 14.9.
- ASME MFC–5.1
- ASME MFC–21.2.
- ANSI B109.3.
- ISO 5167–1 and ISO 5167–2, ISO 5167–4, or ISO 5167–5.
- ISO 17089–2.

We are also proposing that flow meters used to measure the volume of RNG or treated biogas must be tested and calibrated under OIML R137–1 and 2. Relatedly, we are proposing that if a given flow meter is calibrated with a fluid other than natural gas, the equivalency to biogas flow or natural gas flow, respectively, must be demonstrated at the time of registration.

In addition, under 40 CFR 80.155(b)(2)(v), we are proposing to add EPA Method TO–15 and ASTM D1945 as additional methods that can be used for hydrocarbon analysis of biogas and RNG samples. Currently, only EPA Method 18 is specified for hydrocarbon analysis.

We request comment on the adding the proposed methods and whether there are any additional methods we should add to the list of approved methods.

H. Biodiesel and Renewable Diesel Requirements

We are not proposing any changes to the sulfur standards for biodiesel or renewable diesel in this action. However, we are again reiterating that biodiesel and renewable diesel producers must comply with all of EPA's regulatory requirements for diesel producers in 40 CFR part 1090 for the biodiesel and renewable diesel they produce (referred to as ''nonpetroleum diesel fuel'' in 40 CFR part 1090), including demonstrating homogeneity for each batch of biodiesel and renewable diesel and testing each batch for sulfur content to ensure the fuel meets the 15 ppm standard.[286] This also includes the requirement that all sulfur test results must be obtained by the producer before shipping biodiesel or renewable diesel from the facility. Requiring measurement before shipping provides assurance of compliance prior to the fuel being mixed and comingled in the fungible distribution system.

Further, the definition of biodiesel under 40 CFR 80.2 requires that the fuel ''meet ASTM D6571,'' which means that each batch of biodiesel must be tested for and meet all parameters specified in ASTM D6751. The ASTM D6751 specification was imposed to ensure that biodiesel for which RINs are generated is of a sufficient quality to be used as transportation fuel. To ensure that all biodiesel for which RINs are generated is fit to be used as transportation fuel, each batch must be tested for and meet ASTM D6751.

To further make clear that all the above requirements apply to biodiesel and renewable diesel, we are proposing clarifying language at 40 CFR 1090.300(a), 1090.305(a), 1090.1310(b)(1), and 1090.1337(e). We request comment on these proposed clarifications in 40 CFR part 1090 relating to biodiesel and renewable diesel.

I. Technical Amendments

We are proposing numerous technical amendments to the RFS regulations. These amendments are being made to correct minor inaccuracies and clarify the current regulations. These changes are described in Table X.I–1.

TABLE X.I–1—MISCELLANEOUS TECHNICAL CORRECTIONS AND CLARIFICATIONS TO RFS REGULATIONS

Part and section of Title 40	Description of revision
§§ 80.2, 80.1425(a)(3), 80.1426(e)(3), 80.1428(a)(3), 80.1429(c), 80.1460(b)(4).	Clarifying the definition of ''Assigned RIN'' and implementing regulations that assigned RINs for RNG have a K code of 3.
§ 80.2	Clarifying the definition of ''Biodiesel'' to state that it must be renewable fuel.
§ 80.2	Clarifying the definition of ''Diesel fuel'' by adding renewable diesel as an example of a non-distillate diesel fuel.

[285] 40 CFR 80.105(j)(1) and 80.140(b)(2).

[286] EPA has previously made clear that biodiesel producers must comply with all of EPA's regulatory requirement for diesel producers. See EPA, ''Guidance for Biodiesel Producers and Biodiesel Blenders/Users,'' EPA–420–B–07–019, November 2007; see also, EPA ''Am I required to register biodiesel? How would I do that?'' April 1, 2025. *https://www.epa.gov/fuels-registration-reporting-and-compliance-help/am-i-required-register-biodiesel-how-would-i-do.*

TABLE X.I–1—MISCELLANEOUS TECHNICAL CORRECTIONS AND CLARIFICATIONS TO RFS REGULATIONS—Continued

Part and section of Title 40	Description of revision
§ 80.2	Clarifying that parties must use ASTM D86 to measure T90 in the definition of "MVNRLM diesel fuel".
§§ 80.2, 80.1426(f)(17), 80.1450(b)(1)(xii), 80.1451(b)(1)(ii)(T), 80.1454(l).	Removing the definition of "Non-ester renewable diesel" and replacing it with a definition of "Renewable diesel".
§§ 80.2 80.1426(c)(7), Table 1 to 80.1426, 80.1450(b)(1)(xi), 80.1453(d), 80.1454(b)(8), 80.1460(g).	Replacing text in existing regulations to use the new definition of "renewable fuel oil."
§§ 80.2, 80.1426(f)(17), Table 1 to 80.1426, 80.1450(b)(1)(xii), 80.1451(b)(1)(ii)(T), 80.1454(l).	Replacing text in existing regulations to use the new definition of "renewable jet fuel."
§§ 80.2, 80.1454, 80.1469, 80.1470, 80.1471, 80.1472, 80.1473, 80.1474, 80.1477, 80.1479.	Removing expired Option A and Option B QAP provisions.
§§ 80.12 and 1090.95	Updating numerous ASTM standards and methods to the latest versions (see Section IX.J for list of methods).
§§ 80.105(j)(3), 80.110(j)(3), and 80.1476(h)(1)	Clarifying that batch numbers for biogas, RNG, biogas-derived renewable fuel, and biointermediates do not need to be numbered sequentially but must be unique in a compliance period.
§ 80.125(d)(4)	Clarifying that RNG RIN separators must separate RINs equal to or less than the total volume of RNG used as renewable CNG/LNG.
§ 80.125(e)(2)	Clarifying when assigned RINs for a volume of RIN must be retired and removing an example that was inconsistent with the specified regulatory requirements.
§ 80.135(c)(10)(vi)(A)(*5*)	Clarifying that biogas is "produced," not "generated."
§ 80.1426(f)(8)	Clarifying that the batch volume standardization equations apply to liquid renewable fuels and liquid biointermediates.
Table 1 to § 80.1426, 80.1453(a)(12)(v)	Replacing text in existing regulations to use the new definition of "renewable naphtha."
§ 80.1449(a)(4)(i)	Replacing existing and planned production capacity with nameplate and permitted production capacity.
§ 80.1452(b) and (c)	Clarifying that EPA may allow a party to submit RIN assignment or transaction information to EMTS outside the applicable 5- or 10-business-day deadline.
§ 80.1454(b)(3)(ix)	Clarifying that records must be kept for all calculations under 80.1426.
§ 1090.80	Replacing references to "NP diesel fuel" with "nonpetroleum diesel fuel."
§ 1090.80	Clarifying the definition of "Responsible corporate officer (RCO)" by removing "operations manager" as an example of an RCO.
§§ 80.2, 80.3, 80.1405, 80.1407, 80.1415, 80.1426, 80.1429, 80.1435, 80.1444, 80.1450, 80.1451, 80.1452, 80.1453, 80.1454.	Correcting typographical, grammatical, and consistency errors.

XI. Request for Comments

We solicit comments on this proposed action. Specifically, we are soliciting comment on the following:

A. Renewable Fuel Volumes and Analyses

- The proposed cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel volume requirements for 2026 and 2027 (A–1).
- Alternative volume requirements for each of the statutory categories of renewable fuel for 2026 and 2027, including any data or analysis that would support alternative volumes for these years (A–2).
- The assessments and methodologies used to project volumes of cellulosic biofuel (A–3).
- The appropriate volume of non-cellulosic advanced biofuel for 2026 and 2027 (A–4).
- The potential production volume and impacts of renewable jet fuel on the statutory factors (A–5).
- Our proposed approach of accounting for the projected shortfall in the supply of conventional renewable fuel relative to the 15-billion-gallon implied volume when establishing the volume requirements for advanced biofuel and BBD (A–6).
- The advantages and disadvantages of establishing BBD and advanced biofuel volume requirements at levels at or closer to the projected supplies of these fuels and the implications of doing so on the total renewable fuel volume if such an approach were adopted (A–7).
- Our analysis of the statutory factors in CAA section 211(o)(2)(B)(ii), including the approaches to estimating jobs and rural economic development impacts associated with renewable fuels and the types of approaches that would be appropriate to apply in analyzing net jobs and rural development impacts (A–8).

B. Import RIN Reduction

- The appropriateness of the proposed import RIN reduction factor (*i.e.,* more or less than the proposed 50 percent reduction) (B–1).
- The proposed import RIN generation requirement, and whether there are alternative RIN generation approaches that we should consider (B–2).
- The proposed import RIN reduction recordkeeping, reporting, attest engagement, and QAP requirements (B–3).
- The proposed definition of "feedstock point of origin," particularly on the proposed origin locations for each feedstock type and whether there are any other feedstock types that should have specified origin locations (B–4).

C. Removal of Renewable Electricity From the RFS Program

- The statutory analyses and proposed conclusions that: (1) Renewable electricity does not meet the definition of renewable fuel because it does not "replace or reduce the quantity of fossil fuel present in a transportation fuel," and (2) Electricity is not a fuel under the RFS program (C–1).
- The proposed removal from the RFS regulations all provisions related to renewable electricity, including but not limited to the definition of and pathways for renewable electricity and

the generation of RINs for renewable electricity (C–2).

D. Other RFS Program Amendments

• The other proposed amendments to the RFS program, including: the equivalence values for renewable diesel, naphtha, and jet fuel; the changes to the percentage standards equations; and the changes and additions to the pathways in Table 1 to 40 CFR 80.1426 (D–1).

E. Policy Considerations

• Where applicable, any legitimate reliance interests impacted by EPA's proposed changes in policy. (E–1)
• A general pathway for the production of renewable jet fuel from corn ethanol, including the consideration of technologies that could reduce the GHG emissions for this pathway such as the use of carbon capture and storage and renewable natural gas for process energy (E–2).
• The definition of ''produced from renewable biomass'' (E–3).
• Additional program amendments to ensure the validity of imported renewable fuels and feedstocks (E–4).
• Program enhancements to increase the use of qualifying woody-biomass to produce renewable transportation fuel (E–5).
• An option to apply the import RIN reduction provisions to imported renewable fuel and renewable fuel produced domestically from foreign feedstock from only a subset of countries to reflect the reduced economic, energy security, and environmental benefits of imported renewable fuel and feedstocks from those countries (E–6).
• Any other modifications to the RFS program designed to unleash the production of American energy (E–7).

XII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review

This action is a ''significant regulatory action,'' as defined under section 3(f)(1) of Executive Order 12866. Accordingly, EPA, submitted this action to the Office of Management and Budget (OMB) for Executive Order 12866 review. Documentation of any changes made in response to the Executive Order 12866 review is available in the docket. EPA prepared an analysis of the potential costs and benefits associated with this action. This analysis is presented in DRIA Chapter 10.6, available in the docket for this action.

B. Executive Order 14192: Unleashing Prosperity Through Deregulation

This action is expected to be an Executive Order 14192 regulatory action. Details on the estimated costs of this proposed rule can be found in EPA's analysis of the potential costs and benefits associated with this action in DRIA Chapter 10.6, available in the docket for this action.

C. Paperwork Reduction Act (PRA)

The information collection activities in this proposed rule have been submitted for approval to the Office of Management and Budget (OMB) under the PRA. The Information Collection Request (ICR) document that the EPA prepared has been assigned EPA ICR number 7804.01. You can find a copy of the ICR in the docket for this rule, and it is briefly summarized here.

The proposed volume standards and associated percentage standards for 2026 and 2027 do not add to the burdens already estimated under existing, approved ICRs for the RFS program. This proposed rule proposes recordkeeping and reporting for domestic renewable fuel producers to implement the proposed RIN reduction for import-based renewable fuel. We anticipate the increase in burden related to identifying feedstock as foreign or domestic will be very small because the parties already are required to keep underlying records and provide reports for the RFS program, generally. General recordkeeping and reporting for the RFS program is contained in the Renewable Fuel Standard program ICR, OMB Control Number 2060–0725 (expires November 30, 2025).

Certain information submitted to EPA may be claimed as confidential business information (CBI) and such information will be handled in accordance with the requirements of 40 CFR parts 2 and 80.

Respondents/affected entities: renewable fuel producers, third party auditors (attest engagements), QAP auditors.

Respondent's obligation to respond: Mandatory, under 40 CFR part 80.

Estimated number of respondents: 2,307.

Frequency of response: Quarterly, annual, on occasion/as needed.

Total estimated burden: 7,244 hours (per year). Burden is defined at 5 CFR 1320.3(b).

Total estimated cost: $20,323, all purchased services and including $0 annualized capital or operation & maintenance costs.

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. The EPA will respond to any ICR-related comments in the final rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs using the interface at *www.reginfo.gov/public/do/PRAMain.* Find this particular information collection by selecting ''Currently under Review—Open for Public Comments'' or by using the search function. OMB must receive comments no later than July 17, 2025.

D. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA.

With respect to the amendments to the RFS regulations, this action makes minor corrections and modifications to those regulations. As such, we do not anticipate that there will be any significant adverse economic impact on directly regulated small entities as a result of these revisions.

The small entities directly regulated by the annual percentage standards associated with the RFS volumes are small refiners that produce gasoline or diesel fuel, which are defined at 13 CFR 121.201. EPA believes that there are currently 6 refiners (owning 7 refineries) producing gasoline and/or diesel that meet the definition of small entity by having 1,500 employees or fewer. To evaluate the impacts of the proposed 2026 and 2027 volume requirements on small entities, we have conducted a screening analysis to assess whether we should make a finding that this action will not have a significant economic impact on a substantial number of small entities.[287] Currently available information shows that the impact on small entities from implementation of this rule will not be significant. We have reviewed and assessed the available information, which shows that obligated parties, including small entities, are able to recover the cost of acquiring the RINs necessary for compliance with the RFS standards through higher sales prices of the petroleum products they sell than

[287] See DRIA Chapter 11.

would be expected in the absence of the RFS program.[288] This is true whether they acquire RINs by purchasing renewable fuels with attached RINs or purchasing separated RINs. The costs of the RFS program are thus being passed on to consumers in a highly competitive marketplace. Even if we were to assume that the cost of acquiring RINs was not recovered by obligated parties, a cost-to-sales ratio test shows that the costs to small entities of the RFS standards established in this action are far less than 1 percent of the value of their sales.[289]

Furthermore, to the degree that small entities may be impacted by this action, these impacts are mitigated by the existing compliance flexibilities in the RFS program that are available to small entities. These flexibilities include being able to comply through RIN trading rather than renewable fuel blending, 20 percent RIN rollover allowance (up to 20 percent of an obligated party's RVO can be met using previous-year RINs), and deficit carry-forward (the ability to carry over a deficit from a given year into the following year, provided that the deficit is satisfied together with the next year's RVO). Additionally, as required by CAA section 211(o)(9)(B), the RFS regulations include a hardship relief provision that allows for a small refinery to petition for an extension of its small refinery exemption at any time based on a showing that the refinery is experiencing a ''disproportionate economic hardship.'' [290] EPA regulations provide the same relief to small refiners that are not eligible for small refinery relief.[291] In the RFS2 Rule, we discussed other potential small entity flexibilities that had been suggested by the Small Business Regulatory Enforcement Fairness Act (SBREFA) panel or through comments, but we did not adopt them, in part because we had serious concerns regarding our authority to do so.[292]

In sum, this rule will not change the compliance flexibilities currently offered to small entities under the RFS program and available information shows that the impact on small entities from implementation of this rule will not be significant.

E. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million (adjusted annually for inflation) or more (in 1995 dollars) as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local, or tribal governments. This action contains a federal mandate under UMRA that may result in expenditures of $100 million (adjusted annually for inflation) or more (in 1995 dollars) for the private sector in any one year. Accordingly, the costs associated with this rule are discussed in Section IV and DRIA Chapter 10.

This action is not subject to the requirements of section 203 of UMRA because it contains no regulatory requirements that might significantly or uniquely affect small governments.

F. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

G. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. This action will be implemented at the Federal level and affects transportation fuel refiners, blenders, marketers, distributors, importers, exporters, and renewable fuel producers and importers. Tribal governments will be affected only to the extent they produce, purchase, or use regulated fuels. Thus, Executive Order 13175 does not apply to this action.

H. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

Executive Order 13045 directs federal agencies to include an evaluation of the health and safety effects of the planned regulation on children in federal health and safety standards and explain why the regulation is preferable to potentially effective and reasonably feasible alternatives. This action is subject to Executive Order 13045 because it is a significant regulatory action under section 3(f)(1) of Executive Order 12866, and EPA believes that the environmental health or safety risks of the pollutants impacted by this action may have a disproportionate effect on children. An assessment of the environmental impacts from this rule is include in DRIA Chapter 4.

I. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. This action proposes to establish the required renewable fuel content of the transportation fuel supply for 2026 and 2027 pursuant to the CAA. The RFS program and this rule are designed to achieve positive effects on the nation's transportation fuel supply by increasing energy independence and security. These positive impacts are described in Section IV and DRIA Chapter 6.

J. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This action involves technical standards. Except for the standards discussed in this section, the standards included in the regulatory text as incorporated by reference were all previously approved for incorporation by reference (IBR) and no change is included in this action.

In accordance with the requirements of 1 CFR 51.5, we are proposing to incorporate by reference the use of certain standards and test methods from the American Gas Association (AGA), American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), ASTM International (ASTM), International Organization for Standardization (ISO), International Organization of Legal Metrology (OIML), and EPA. The standards and test methods may be obtained through the AGA website (*www.aga.org*) or by calling AGA at (202) 824–7000; the ANSI website (*www.ansi.org*) or by calling ANSI at (212) 642–4980; the API website (*www.api.org*) or by calling API at (202) 682–8000; the ASME website (*www.asme.org*) or by calling ASME at (800) 843–2763; the ASTM website (*www.astm.org*) or by calling ASTM at (877) 909–2786; the ISO website (*www.iso.org*) or by calling ISO at +41–22–749–01–11; the OIML website (*www.oiml.org*) or by calling OIML at +33 1 4878 1282; and the EPA website (*www.epa.gov*) or by calling EPA at (202) 272–0167. We are proposing to

[288] 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.

[289] A cost-to-sales ratio of 1 percent represents a typical agency threshold for determining the significance of the economic impact on small entities. See ''Final Guidance for EPA Rulewriters: Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act,'' November 2006.

[290] 40 CFR 80.1441(e)(2).

[291] 40 CFR 80.1442(h).

[292] 75 FR 14858–62 (March 26, 2010).

incorporate by reference the following standards:

Organization and standard or test method	Part and section of Title 40	Summary
AGA Report No. 3 Part 1, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022.	§§ 80.12 and 80.155	This standard describes engineering equations, installation requirements, and uncertainty estimations of square-edged orifice meters in measuring the flow of natural gas and similar fluids.
AGA Report No. 3 Part 2, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016.	§§ 80.12 and 80.155	This standard describes design and installation of square-edged orifice meters for measuring flow of natural gas and similar fluids.
AGA Report No. 3 Part 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021.	§§ 80.12 and 80.155	This standard describes applications using square-edged orifice meters for measuring flow of natural gas and similar fluids.
AGA Report No. 3 Part 4, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019.	§§ 80.12 and 80.155	This standard describes the development of equations for coefficient of discharge, including a calculation procedure, for square-edged orifice meters measuring flow of natural gas and similar fluids.
AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters, 2nd Edition, April 2007.	§§ 80.12 and 80.155	This standard describes procedures and guidelines for measuring natural gas by turbine meters.
AGA Report No. 11, Measurement of Natural Gas by Coriolis Meter, 2nd Edition, February 2013.	§§ 80.12 and 80.155	This standard describes procedures and guidelines for measuring natural gas by Coriolis meters.
ANSI B109.3–2019 (R2024), Rotary-Type Gas Displacement Meters, February 5, 2019, Reaffirmed April 26, 2024.	§§ 80.12 and 80.155	This document describes a basic standard for safe operation, substantial and durable construction, and acceptable performance for rotary-type gas displacement meters.
API MPMS 14.9–2013, Measurement of Natural Gas by Coriolis Meter, 2nd Edition, February 2013.	§§ 80.12 and 80.155	This standard describes procedures and guidelines for measuring natural gas by Coriolis meters.
ASME MFC–5.1–2011 (R2024), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, June 17, 2011, Reaffirmed 2024.	§§ 80.12 and 80.155	This standard describes procedures and guidelines for measuring liquid flow by ultrasonic flowmeters.
ASME MFC-21.2–2010 (R2018), Measurement of Fluid Flow by Means of Thermal Dispersion Mass Flowmeters, January 10, 2011, Reaffirmed 2018.	§§ 80.12 and 80.155	This standard describes guidelines for the quality, description, principle of operation, selection, installation, and flow calibration of thermal dispersion flowmeters for the measurement of the mass flow rate and volumetric flow rate of the flow of a fluid in a closed conduit.
ASTM D86–23ae2, Standard Test Method for Distillation of Petroleum Products and Liquid Fuels at Atmospheric Pressure, approved December 1, 2023.	§§ 80.2, 80.12, 1090.95, and 1090.1350(b).	This updated standard describes how to perform distillation measurements for gasoline and other petroleum products.
ASTM D287–22, Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), approved December 1, 2022.	§§ 1090.95 and 1090.1337(d).	This updated standard describes how to measure the density of fuels and other petroleum products, expressed in terms of API gravity.
ASTM D975–24a, Standard Specification for Diesel Fuel, approved August 1, 2024.	§§ 80.2, 80.12, 80.1426(f), 80.1450(b), 80.1451(b), and 80.1454(l).	This updated standard describes the characteristic values for several parameters to be considered suitable as diesel fuel.
ASTM D976–21e1, Standard Test Method for Calculated Cetane Index of Distillate Fuels, approved November 1, 2021.	§§ 1090.95 and 1090.1350(b).	This updated standard describes how to calculate cetane index for a sample of diesel fuel and other distillate fuels.
ASTM D1945–14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019.	§§ 80.12 and 80.155	This standard describes how to determine the chemical composition of natural gas using gas chromatography.
ASTM D2622–24a, Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, approved December 1, 2024.	§§ 1090.95, 1090.1350(b), 1090.1360(d), and 1090.1375(c).	This updated standard describes how to measure the sulfur content in gasoline, diesel fuel, and other petroleum products.
ASTM D3588–98 (Reapproved 2024)e1, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, reapproved May 1, 2024.	§§ 80.12 and 80.155(b) and (f)..	This updated standard describes the calculation protocol for aggregate properties of gaseous fuels from compositional measurements.
ASTM D3606–24a, Standard Test Method for Determination of Benzene and Toluene in Spark Ignition Fuels by Gas Chromatography, approved November 1, 2024.	§§ 1090.95 and 1090.1360(c).	This updated standard describes how to measure the benzene content of gasoline and similar fuels.
ASTM D4057–22, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, approved May 1, 2022.	§§ 80.8(a) and 80.12	This updated standard describes procedures for drawing samples of fuel and other petroleum products from storage tanks and other containers using manual procedures.

Organization and standard or test method	Part and section of Title 40	Summary
ASTM D4177–22e1, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, approved July 1, 2022.	§§ 80.8(b) and 80.12	This updated standard describes procedures for using automated procedures to draw fuel samples for testing.
ASTM D4737–21, Standard Test Method for Calculated Cetane Index by Four Variable Equation, approved November 1, 2021.	§§ 1090.95 and 1090.1350(b).	This updated standard describes how to calculate cetane index for a sample of diesel fuel and other distillate fuels.
ASTM D4806–21a, Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel, approved October 1, 2021.	§§ 1090.95 and 1090.1395(a).	This updated standard describes the characteristic values for several parameters to be considered suitable as denatured fuel ethanol for blending with gasoline.
ASTM D4814–24b, Standard Specification for Automotive Spark-Ignition Engine Fuel, approved December 1, 2024.	§§ 1090.95, 1090.80, and 1090.1395(a).	This updated standard describes the characteristic values for several parameters to be considered suitable as gasoline.
ASTM D5134–21, Standard Test Method for Detailed Analysis of Petroleum Naphthas through n-Nonane by Capillary Gas Chromatography, approved December 1, 2021.	§§ 1090.95 and 1090.1350(b).	This updated standard describes how to measure benzene in butane, pentane, and other light-end petroleum compounds.
ASTM D5453–24, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence, approved October 15, 2024.	§§ 1090.95 and 1090.1350(b).	This updated standard describes how to measure the sulfur content of neat ethanol and other petroleum products.
ASTM D5842–23, Standard Practice for Sampling and Handling of Fuels for Volatility Measurement, approved October 1, 2023.	§§ 80.8(c), 80.12, 1090.95, and 1090.1335(d).	This updated standard describes procedures for drawing samples of gasoline and other fuels from storage tanks and other containers using manual procedures to prepare samples for measuring vapor pressure.
ASTM D5854–19a, Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products, approved May 1, 2019.	§§ 80.8(d) and 80.12	This updated standard describes procedures for handling, mixing, and conditioning procedures to prepare representative composite samples.
ASTM D6259–23, Standard Practice for Determination of a Pooled Limit of Quantitation for a Test Method, approved May 1, 2023.	§§ 1090.95 and 1090.1355(b).	This updated standard describes procedures to determine how to evaluate parameter measurements at very low levels, including a laboratory limit of quantitation that applies for a given facility.
ASTM D6708–24, Standard Practice for Statistical Assessment and Improvement of Expected Agreement Between Two Test Methods that Purport to Measure the Same Property of a Material, approved March 1, 2024.	§§ 1090.95, 1090.1360(c), 1090.1365(d) and (f), and 1090.1375(c).	This updated standard describes statistical criteria to evaluate whether an alternative test method provides results that are consistent with a reference procedure.
ASTM D6729–20, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100 Metre Capillary High Resolution Gas Chromatography, approved June 1, 2020.	§§ 1090.95 and 1090.1350(b).	This updated standard describes how to determine the benzene content of butane and pentane.
ASTM D6730–22, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100-Metre Capillary (with Precolumn) High-Resolution Gas Chromatography, approved November 1, 2022.	§§ 1090.95 and 1090.1350(b).	This updated standard describes how to determine the benzene content of butane and pentane.
ASTM D6751–24, Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, approved March 1, 2024.	§§ 1090.95, 1090.300(a), and 1090.1350(b).	This standard describes the characteristics of biodiesel.
ASTM D6792–23c, Standard Practice for Quality Management Systems in Petroleum Products, Liquid Fuels, and Lubricants Testing Laboratories, approved November 1, 2023.	§§ 1090.95 and 1090.1450(c).	This updated standard describes principles for ensuring quality for laboratories involved in parameter measurements for fuels and other petroleum products.
ASTM D6866–24a, Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, approved December 1, 2024.	§§ 80.12, 80.155(b), 80.1426(f), and 80.1430(e).	This updated standard describes the radiocarbon dating test method to determine the renewable content of biogas and RNG.
ASTM D7717–11 (Reapproved 2021), Standard Practice for Preparing Volumetric Blends of Denatured Fuel Ethanol and Gasoline Blendstocks for Laboratory Analysis, approved October 1, 2021.	§§ 1090.95 and 1090.1340(b).	This updated standard describes the procedures for blending denatured fuel ethanol with gasoline to prepare a sample for testing.
ASTM D7777–24, Standard Test Method for Density, Relative Density, or API Gravity of Liquid Petroleum by Portable Digital Density Meter, approved July 1, 2024.	§§ 1090.95 and 1090.1337(d).	This updated standard describes how to measure the density of fuels and other petroleum products, expressed in terms of API gravity.
ASTM E711–23e1, Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved April 1, 2023.	§§ 80.12 and 80.1426(f)	This updated standard describes the procedures for determination of the gross calorific value of a prepared analysis sample of solid forms of refuse-derived fuel by the bomb calorimeter method.
ASTM E870–24, Standard Test Methods for Analysis of Wood Fuels, approved October 1, 2024.	§§ 80.12 and 80.1426(f)	This updated standard describes the proximate analysis, ultimate analysis, and the determination of the gross caloric value of wood fuels.

Organization and standard or test method	Part and section of Title 40	Summary
ISO 5167–1:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 1: General principles and requirements, 3rd Edition, June 2022.	§§ 80.12 and 80.155	This standard establishes the general principles for methods of measurement and computation of the flow rate of fluid flowing in a conduit by means of pressure differential devices when they are inserted into a circular cross-section conduit running full.
ISO 5167–2:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 2: Orifice plates, 2nd Edition, June 2022.	§§ 80.12 and 80.155	This standard specifies the geometry and method of use of orifice plates when they are inserted in a conduit running full to determine the flow rate of the fluid flowing in the conduit.
ISO 5167–4:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 4: Venturi tubes, 2nd Edition, June 2022.	§§ 80.12 and 80.155	This standard specifies the geometry and method of use of Venturi tubes when they are inserted in a conduit running full to determine the flow rate of the fluid flowing in the conduit.
ISO 5167–5:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 5: Cone meters, 2nd Edition, October 2022.	§§ 80.12 and 80.155	This standard specifies the geometry and method of use of cone meters when they are inserted in a conduit running full to determine the flow rate of the fluid flowing in the conduit.
ISO 17089–2:2012, Measurement of fluid flow in closed conduits—Ultrasonic meters for gas, Part 2: Meters for industrial applications, 1st Edition, October 2012.	§§ 80.12 and 80.155	This standard specifies requirements and recommendations for ultrasonic gas meters, which utilize acoustic signals to measure the flow in the gaseous phase in closed conduits.
OIML R 137–1 and 2, Gas meters, Part 1: Metrological and technical requirements and Part 2: Metrological controls and performance tests, Edition 2012, Including Amendment 2014.	§§ 80.12 and 80.155	This standard specifies testing and calibration requirements for gas meters.
EPA Compendium Method TO–15, Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS), Second Edition, January 1999.	§§ 80.12 and 80.155	This standard specifies sampling and analytical procedures for identifying and measuring VOCs using gas chromatography/mass spectrometry.

AGA, ASME, ANSI, API, ASTM, ISO, and OIML regularly publish updated versions of their standards and test methods, with the potential that there will be a published version of one or more of the documents listed above before we adopt the final rule that is more recent than the documents we identify in this proposed rule. For any such updated versions, we will consider including a reference to the latest document when we finalize the revisions covered by this proposed rule.

XIII. Amendatory Instructions

Amendatory instructions are the standard terms that the Office of the Federal Register (OFR) uses to give specific instructions to agencies on how to change the CFR. OFR's historical guidance was to include amendatory instructions accompanying each individual change that was being made (*e.g.,* each sentence or individual paragraph). The piecemeal amendments served as an indication of changes EPA was making. Due to the extensive number of technical and conforming amendments included in this action, however, EPA is utilizing OFR's new amendatory instruction ''revise and republish'' for revisions proposed in this action.[293] Therefore, instead of the past practice of piecemeal amendments for revisions to the CFR, EPA is using the ''revise and republish'' instruction to both revise regulatory text and republish in their entirety certain sections of 40 CFR part 80 that contain the regulatory text being revised. To indicate those portions of provisions where changes are being revised, EPA has created a red-line version of 40 CFR part 80 that incorporates the proposed changes. This red-line version is available in the docket for this action. This red-line version provides further context to assist the public in reviewing the proposed regulatory text changes. EPA is not reopening for comment those unchanged provisions. Republishing provisions that are unchanged in this action is consistent with guidance from OFR.

XIV. Statutory Authority

Statutory authority for this action comes from sections 114, 203–05, 208, 211, 301, and 307 of the Clean Air Act, 42 U.S.C. 7414, 7522–24, 7542, 7545, 7601, and 7607.

[293] OFR's Document Drafting Handbook (Chapter 2, 2–38) explains that agencies ''[u]se [r]epublish to set out unchanged text for the convenience of the reader, often to provide context for your regulatory changes.'' *https://www.archives.gov/federal-register/write/handbook.* Additional information on OFR's mandatory use of ''revise and republish'' is available at *https://www.archives.gov/federal-register/write/ddh/revise-republish.*

List of Subjects

40 CFR Part 80

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Oil imports, Petroleum, Renewable fuel.

40 CFR Part 1090

Environmental protection, Administrative practice and procedure, Air pollution control, Diesel fuel, Fuel additives, Gasoline, Imports, Incorporation by reference, Oil imports, Petroleum, Renewable fuel.

Lee Zeldin,

≤*Administrator.*

For the reasons set forth in the preamble, EPA proposes to amend 40 CFR parts 80 and 1090 as follows:

PART 80—REGULATION OF FUELS AND FUEL ADDITIVES

■ 1. The authority citation for part 80 continues to read as follows:

Authority: 42 U.S.C. 7414, 7521, 7542, 7545, and 7601(a).

Subpart A—General Provisions

■ 2. Amend § 80.2 by:

■ a. Adding the definition ''Activated sludge'' in alphabetical order;

■ b. Removing the definition ''A–RIN'';

■ c. Revising the definitions ''Assigned RIN'' and ''Biodiesel'';
■ d. Adding paragraphs (5)(x) and (xi) in the definition ''Biointermediate'';
■ e. Revising paragraph (1)(ii) in the definition ''Biomass-based diesel'';
■ f. Removing the definition ''B–RIN'';
■ g. Revising the definition ''Cellulosic diesel'';
■ h. Adding the definition ''Converted oils'' in alphabetical order;
■ i. Revising the definition ''Co-processed cellulosic diesel'';
■ j. Revising paragraph (1)(ii) in the definition ''Diesel fuel'';
■ k. Adding the definition ''Feedstock point of origin'' in alphabetical order;
■ l. Revising the definitions ''Foreign renewable fuel producer'', ''Heating oil'', and ''Importer'';
■ m. Removing the definition ''Interim period'';
■ n. Revising the definition ''MVNRLM diesel fuel'';
■ o. Removing the definition ''Non-ester renewable diesel'';
■ p. Adding the definition ''Renewable diesel'' in alphabetical order;
■ q. Removing the definition ''Renewable electricity''; and
■ r. Adding the definitions ''Renewable fuel oil'' and ''Renewable jet fuel'' in alphabetical order;
■ s. Revising the definition ''Renewable liquefied natural gas or renewable LNG''; and
■ t. Adding the definition ''Renewable naphtha'' in alphabetical order.

The revisions and additions read as follows:

§ 80.2 Definitions.

* * * * *

Activated sludge means the waste sludge from a secondary wastewater treatment process involving oxygen and microorganisms.

* * * * *

Assigned RIN means a RIN assigned to a volume of renewable fuel or RNG pursuant to § 80.1426(e) or § 80.125(c), respectively, with a K code of 1 for renewable fuel or 3 for RNG.

* * * * *

Biodiesel means diesel fuel that is renewable fuel and that meets ASTM D6751 (incorporated by reference, see § 80.12).

* * * * *

Biointermediate * * *

(5) * * *

(x) Activated sludge.

(xi) Converted oils.

* * * * *

Biomass-based diesel * * *

(1) * * *

(ii) Meets the definition of either biodiesel or renewable diesel.

* * * * *

Cellulosic diesel is any renewable fuel which meets both the definitions of cellulosic biofuel and biomass-based diesel. Cellulosic diesel includes renewable fuel oil and renewable jet fuel produced from cellulosic feedstocks.

* * * * *

Converted oils means glycerides such as monoglycerides and diglycerides that are produced through the glycerolysis of biogenic waste oils/fats/greases with glycerol. Converted oils must exclusively consist of glycerides with fatty acid alkyl groups that originate from biogenic waste oils/fats/greases during the conversion process.

* * * * *

Co-processed cellulosic diesel is any renewable fuel that meets the definition of cellulosic biofuel and meets all the requirements of paragraph (1) of this definition:

(1) (i) Is a transportation fuel, transportation fuel additive, heating oil, or jet fuel.

(ii) Meets the definition of either biodiesel or renewable diesel.

(iii) Is registered as a motor vehicle fuel or fuel additive under 40 CFR part 79, if the fuel or fuel additive is intended for use in a motor vehicle.

(2) Co-processed cellulosic diesel includes all the following:

(i) Renewable fuel oil and renewable jet fuel produced from cellulosic feedstocks.

(ii) Cellulosic biofuel produced from cellulosic feedstocks co-processed with petroleum.

* * * * *

Diesel fuel * * *

(1) * * *

(ii) A non-distillate fuel other than residual fuel with comparable physical and chemical properties (*e.g.,* biodiesel, renewable diesel).

* * * * *

Feedstock point of origin means the location, either domestic or foreign, where a feedstock is produced, generated, extracted, collected, or harvested. This location is determined as follows:

(1) For planted crops, cover crops, or crop residue (including starches, cellulosic, and non-cellulosic components thereof), the location of the feedstock supplier that supplied the feedstock to the renewable fuel producer or biointermediate producer (*e.g.,* grain elevator).

(2) For oil derived from planted crops, cover crops, or algae, the location where the oil is extracted from the planted crop, cover crop, or algae (*e.g.,* crushing facility).

(3) For biogenic waste oils/fats/greases, separated yard waste, separated food waste, or MSW (including the components thereof), the location of the establishment where the waste is collected (*e.g.,* restaurant, food processing facility).

(4) For biogas, the location of the landfill or digester that produces the biogas.

(5) For planted trees, tree residue, slash, pre-commercial thinnings, or other woody biomass, the location where the woody biomass is harvested.

(6) For all other feedstocks, the location where the feedstock is produced, generated, extracted, collected, or harvested, as applicable.

* * * * *

Foreign renewable fuel producer means any person that owns, leases, operates, controls, or supervises a facility outside the covered location where renewable fuel is produced.

* * * * *

Heating oil means a product that meets one of the definitions in paragraph (1) of this definition:

(1)(i) Any No. 1, No. 2, or non-petroleum diesel blend that is sold for use in furnaces, boilers, and similar applications and which is commonly or commercially known or sold as heating oil, fuel oil, and similar trade names, and that is not jet fuel, kerosene, or MVNRLM diesel fuel.

(ii) Any fuel oil that is used to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort. The fuel oil must be liquid at STP and contain no more than 2.5% mass solids.

(2) Pure biodiesel (*i.e.,* B100) or neat biodiesel (*i.e.,* B99) that is used for process heat or power generation is not heating oil.

Importer means any person who imports transportation fuel or renewable fuel into the covered location from an area outside of covered location. This includes the importer of record or an authorized agent acting on their behalf, as well as the actual owner, the consignee, or the transferee, if the right to withdraw merchandise from a bonded warehouse has been transferred.

* * * * *

MVNRLM diesel fuel means any diesel fuel or other distillate fuel that is used, intended for use, or made available for use in motor vehicles or motor vehicle engines, or as a fuel in any nonroad diesel engines, including locomotive and marine diesel engines, except the following: Distillate fuel with a T90, as determined using ASTM D86 (incorporated by reference, see § 80.12), at or above 700 °F that is used only in Category 2 and 3 marine engines is not MVNRLM diesel fuel, and ECA marine fuel is not MVNRLM diesel fuel (note that fuel that conforms to the requirements of MVNRLM diesel fuel is excluded from the definition of ''ECA marine fuel'' in this section without regard to its actual use).

(1) Any diesel fuel that is sold for use in stationary engines that are required to meet the requirements of 40 CFR 1090.300, when such provisions are applicable to nonroad engines, is considered MVNRLM diesel fuel.

(2) [Reserved]

* * * * *

Renewable diesel means diesel fuel that is renewable fuel and that is one or more of the following:

(1) A fuel or fuel additive that meets the Grade No. 1–D or No. 2–D specification in ASTM D975 (incorporated by reference, see § 80.12).

(2) A fuel or fuel additive that is registered under 40 CFR part 79.

* * * * *

Renewable fuel oil means heating oil that is renewable fuel and that meets paragraph (2) of the definition of heating oil.

* * * * *

Renewable jet fuel means jet fuel that is renewable fuel and that meets ASTM D7566 (incorporated by reference, see § 80.12).

Renewable liquefied natural gas or renewable LNG means biogas, treated biogas, or RNG that is liquefied (*i.e.,* it is cooled below its boiling point) for use as transportation fuel and meets the definition of renewable fuel.

Renewable naphtha means naphtha that is renewable fuel.

* * * * *

■ 3. Amend § 80.3 by revising entry LNG to read as follows:

§ 80.3 Acronyms and abbreviations.

* * * * *

LNG Liquefied natural gas.

* * * * *

■ 4. Revise and republish § 80.12 to read as follows:

§ 80.12 Incorporation by reference.

Certain material is incorporated by reference into this part with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. All approved incorporation by reference (IBR) material is available for inspection at U.S. EPA and at the National Archives and Records Administration (NARA). Contact U.S. EPA at: U.S. EPA, Air and Radiation Docket and Information Center, WJC West Building, Room 3334, 1301 Constitution Ave. NW, Washington, DC 20460; (202) 566–1742. For information on the availability of this material at NARA, visit: *www.archives.gov/federal-register/cfr/ibr-locations.html* or email *fr.inspection@nara.gov.* The material may be obtained from the following sources:

(a) American Gas Association (AGA), 400 North Capitol Street NW, Suite 450, Washington, DC 20001; (202) 824–7000; *www.aga.org.*

(1) AGA Report No. 3 Part 1, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022 (''AGA Report No. 3 Part 1''); IBR approved for § 80.155(a).

(2) AGA Report No. 3 Part 2, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016 (''AGA Report No. 3 Part 2''); IBR approved for § 80.155(a).

(3) AGA Report No. 3 Part 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021 (''AGA Report No. 3 Part 3''); IBR approved for § 80.155(a).

(4) AGA Report No. 3 Part 1, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019 (''AGA Report No. 3 Part 4''); IBR approved for § 80.155(a).

(5) AGA Report No. 9, Measurement of Gas by Multipath Ultrasonic Meters, 2nd Edition, April 2007 (''AGA Report No. 9); IBR approved for § 80.155(a).

(6) AGA Report No. 11, Measurement of Natural Gas by Coriolis Meter, 2nd Edition, February 2013 (''AGA Report No. 11); IBR approved for § 80.155(a).

(b) American National Standards Institute (ANSI), 1899 L Street NW, 11th Floor, Washington, DC 20036; (202) 293–8020; *www.ansi.org.*

(1) ANSI B109.3–2019 (R2024), Rotary-Type Gas Displacement Meters, February 5, 2019, Reaffirmed April 16, 2024 (''ANSI B109.3''); IBR approved for § 80.155(a).

(2) [Reserved]

(c) American Petroleum Institute (API), 200 Massachusetts Avenue NW, Suite 1100, Washington, DC 20001–5571; (202) 682–8000; *www.api.org.*

(1) API MPMS 14.1–2016, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluids Measurement Section 1—Collecting and Handling of Natural Gas Samples for Custody Transfer, 7th Edition, May 2016 (''API MPMS 14.1''); IBR approved for § 80.155(b).

(2) API MPMS 14.3.1–2012, Manual of Petroleum Measurement Standards Chapter 14.3.1—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 1: General Equations and Uncertainty Guidelines, 4th Edition, including Errata July 2013, Reaffirmed, July 2022 (''API MPMS 14.3.1''); IBR approved for § 80.155(a).

(3) API MPMS 14.3.2–2016, Manual of Petroleum Measurement Standards Chapter 14.3.2—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 2: Specification and Installation Requirements, 5th Edition, March 2016 (''API MPMS 14.3.2''); IBR approved for § 80.155(a).

(4) API MPMS 14.3.3–2013, Manual of Petroleum Measurement Standards Chapter 14.3.3—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 3: Natural Gas Applications, 4th Edition, Reaffirmed, June 2021 (''API MPMS 14.3.3''); IBR approved for § 80.155(a).

(5) API MPMS 14.3.4–2019, Manual of Petroleum Measurement Standards Chapter 14.3.4—Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids—Concentric, Square-edged Orifice Meters Part 4—Background, Development, Implementation Procedure, and Example Calculations, 4th Edition, October 2019 (''API MPMS 14.3.4''); IBR approved for § 80.155(a).

(6) API MPMS 14.9–2013, Measurement of Natural Gas by Coriolis Meter (''API MPMS 14.9''); IBR approved for § 80.155(a).

(7) API MPMS 14.12–2017, Manual of Petroleum Measurement Standards Chapter 14—Natural Gas Fluid Measurement Section 12—Measurement of Gas by Vortex Meters, 1st Edition, March 2017 (''API MPMS 14.12''); IBR approved for § 80.155(a).

Note 1 to paragraph (a):

API MPMS 14.3.1, 14.3.2, 14.3.3, and 14.3.4, are co-published as AGA Report 3, Parts 1, 2, 3, and 4, respectively.

(d) American Public Health Association (APHA), 1015 15th Street NW, Washington, DC 20005; (202) 777–2742; *www.standardmethods.org.*

(1) SM 2540, Solids, revised June 10, 2020; IBR approved for § 80.155(c).

(2) [Reserved]

(e) American Society of Mechanical Engineers (ASME), Two Park Avenue, New York, NY 10016–5990; (800) 843–2763; *www.asme.org.*

(1) ASME MFC–5.1–2011 (R2024), Measurement of Liquid Flow in Closed Conduits Using Transit-Time Ultrasonic Flowmeters, June 17, 2011, Reaffirmed 2024 (''ASME MFC–5.1''); IBR approved for § 80.155(a).

(2) ASME MFC-21.2–2010 (R2018), Measurement of Fluid Flow by Means of Thermal Dispersion Mass Flowmeters, January 10, 2011, Reaffirmed 2018 (''ASME MFC–21.2''); IBR approved for § 80.155(a).

(f) ASTM International (ASTM), 100 Barr Harbor Dr., P.O. Box C700, West Conshohocken, PA 19428–2959; (877) 909–2786; *www.astm.org.*

(1) ASTM D86–23ae2, Standard Test Method for Distillation of Petroleum Products and Liquid Fuels at Atmospheric Pressure, approved December 1, 2023 (''ASTM D86''); IBR approved for § 80.2.

(2) ASTM D975–24a, Standard Specification for Diesel Fuel, approved August 1, 2024 (''ASTM D975''); IBR approved for § 80.2.

(3) ASTM D1250–19e1, Standard Guide for the Use of the Joint API and ASTM Adjunct for Temperature and Pressure Volume Correction Factors for Generalized Crude Oils, Refined Products, and Lubricating Oils: API MPMS Chapter 11.1, approved May 1, 2019 (''ASTM D1250''); IBR approved for § 80.1426(f).

(4) ASTM D1945–14 (Reapproved 2019), Standard Test Method for Analysis of Natural Gas by Gas Chromatography, approved December 1, 2019 (''ASTM D1945''); IBR approved for § 80.155(b).

(5) ASTM D3588–98 (Reapproved 2024)e1, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels, reapproved May 1, 2024 (''ASTM D3588''); IBR approved for § 80.155(b) and (f).

(6) ASTM D4057–22, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, approved May 1, 2022 (''ASTM D4057''); IBR approved for § 80.8(a).

(7) ASTM D4177–22e1, Standard Practice for Automatic Sampling of Petroleum and Petroleum Products, approved July 1, 2022 (''ASTM D4177''); IBR approved for § 80.8(b).

(8) ASTM D4442–20, Standard Test Methods for Direct Moisture Content Measurement of Wood and Wood-Based Materials, approved March 1, 2020 (''ASTM D4442''); IBR approved for § 80.1426(f).

(9) ASTM D4444–13 (Reapproved 2018), Standard Test Method for Laboratory Standardization and Calibration of Hand-Held Moisture Meters, reapproved July 1, 2018 (''ASTM D4444''); IBR approved for § 80.1426(f).

(10) ASTM D4888–20, Standard Test Method for Water Vapor in Natural Gas Using Length-of-Stain Detector Tubes, approved December 15, 2020 (''ASTM D4888''); IBR approved for § 80.155(b).

(11) ASTM D5504–20, Standard Test Method for Determination of Sulfur Compounds in Natural Gas and Gaseous Fuels by Gas Chromatography and Chemiluminescence, approved November 1, 2020 (''ASTM D5504''); IBR approved for § 80.155(b).

(12) ASTM D5842–23, Standard Practice for Sampling and Handling of Fuels for Volatility Measurement, approved October 1, 2023 (''ASTM D5842''); IBR approved for § 80.8(c).

(13) ASTM D5854–19a, Standard Practice for Mixing and Handling of Liquid Samples of Petroleum and Petroleum Products, approved May 1, 2019 (''ASTM D5854''); IBR approved for § 80.8(d).

(14) ASTM D6751–24, Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, approved March 1, 2024 (''ASTM D6751''); IBR approved for § 80.2.

(15) ASTM D6866–24a, Standard Test Methods for Determining the Biobased Content of Solid, Liquid, and Gaseous Samples Using Radiocarbon Analysis, approved December 1, 2024 (''ASTM D6866''); IBR approved for §§ 80.155(b); 80.1426(f); 80.1430(e).

(16) ASTM D7164–21, Standard Practice for On-line/At-line Heating Value Determination of Gaseous Fuels by Gas Chromatography, approved April 1, 2021 (''ASTM D7164''); IBR approved for § 80.155(a).

(17) ASTM D8230–19, Standard Test Method for Measurement of Volatile Silicon-Containing Compounds in a Gaseous Fuel Sample Using Gas Chromatography with Spectroscopic Detection, approved June 1, 2019 (''ASTM D8230''); IBR approved for § 80.155(b).

(18) ASTM E711–23e1, Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved April 1, 2023 (''ASTM E711''); IBR approved for § 80.1426(f).

(19) ASTM E870–24, Standard Test Methods for Analysis of Wood Fuels, approved October 1, 2024 (''ASTM E870''); IBR approved for § 80.1426(f).

(g) European Committee for Standardization (CEN), Rue de la Science 23, B–1040 Brussels, Belgium; + 32 2 550 08 11; *www.cencenelec.eu.*

(1) EN 17526:2021(E), Gas meter—Thermal-mass flow-meter based gas meter, approved July 11, 2021 (''EN 17526''); IBR approved for § 80.155(a).

(2) [Reserved]

(h) International Organization for Standardization (ISO), Chemin de Blandonnet 8, CP 401, 1214 Vernier, Geneva, Switzerland; +41 22 749 01 11; *www.iso.org.*

(1) ISO 5167–1:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 1: General principles and requirements, 3rd Edition, June 2022 (''ISO 5167–1''); IBR approved for § 80.155(a).

(2) ISO 5167–2:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 2: Orifice plates, 2nd Edition, June 2022 (''ISO 5167–2''); IBR approved for § 80.155(a).

(3) ISO 5167–4:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 4: Venturi tubes, 2nd Edition, June 2022 (''ISO 5167–4''); IBR approved for § 80.155(a).

(4) ISO 5167–5:2022, Measurement of fluid flow by means of pressure differential devices inserted in circular cross-section conduits running full, Part 5: Cone meters, 2nd Edition, October 2022 (''ISO 5167–5''); IBR approved for § 80.155(a).

(5) ISO 17089–2:2012, Measurement of fluid flow in closed conduits—Ultrasonic meters for gas, Part 2: Meters for industrial applications, 1st Edition, October 2012 (''ISO 17089–2''); IBR approved for § 80.155(a).

(i) International Organization of Legal Metrology (OIML), 11 Rue Turgot, F–75009, Paris, France; +33 1 4878 1282; *www.oiml.org.*

(1) OIML R 137–1 and 2, Gas meters, Part 1: Metrological and technical requirements and Part 2: Metrological controls and performance tests, Edition 2012, Including Amendment 2014 (''OIML R 137–1 and 2''); IBR approved for § 80.155(a).

(2) [Reserved]

(i) U.S. Environmental Protection Agency (EPA), 1200 Pennsylvania Avenue NW, Washington, DC 20460; (202) 272–0167; *www.epa.gov.*

(1) EPA/625/R–96/010b, Compendium Method TO–15, Determination Of Volatile Organic Compounds (VOCs) In Air Collected In Specially-Prepared Canisters And

Analyzed By Gas Chromatography/Mass Spectrometry (GC/MS), Second Edition, January 1999 (''EPA Method TO–15''); IBR approved for § 80.155(b).

(2) [Reserved]

Subpart E—Biogas-Derived Renewable Fuel

■ 5. Amend § 80.105 by revising paragraphs (j)(1) and (3) and adding paragraph (j)(4) to read as follows:

§ 80.105 Biogas producers.

* * * * *

(j) * * *

(1) Except for biogas produced from a mixed digester, the batch volume of biogas is the volume of biogas measured under paragraph (f) of this section for a single batch pathway at a single facility for up to a calendar month, in Btu HHV.

* * * * *

(3) The biogas producer must assign a number (the ''batch number'') to each batch of biogas consisting of their EPA-issued company registration number, the EPA-issued facility registration number, the last two digits of the compliance year in which the batch was produced, and a unique number for the batch during the compliance year (*e.g.,* 4321–54321–25–000001).

(4) The production date for a batch of biogas is the last day of the time period that the batch represents. For example, the production date for a batch of biogas for the month of January would be January 31, while the production date for a batch of biogas for February 1–14 would be February 14.

* * * * *

■ 6. Amend § 80.110 by revising paragraph (j)(3) to read as follows:

§ 80.110 RNG producers, RNG importers, and biogas closed distribution system RIN generators.

* * * * *

(j) * * *

(3) The RNG producer, RNG importer, or biogas closed distribution system RIN generator must assign a number (the ''batch number'') to each batch of RNG or biogas-derived renewable fuel consisting of their EPA-issued company registration number, the EPA-issued facility registration number, the last two digits of the compliance year in which the batch was produced, and a unique number for the batch during the compliance year (*e.g.,* 4321–54321–25–000001).

* * * * *

■ 7. Amend § 80.125 by revising paragraphs (d)(4) and (e)(2) to read as follows:

§ 80.125 RINs for RNG.

* * * * *

(d) * * *

(4) A party must only separate a number of RINs equal to or less than the total volume of RNG (where the Btu LHV are converted to gallon-RINs using the conversion specified in § 80.1415(b)(1)) that the party demonstrates is used as renewable CNG/LNG under paragraph (d)(2) of this section.

* * * * *

(e) * * *

(2) A party must retire all assigned RINs for a volume of RNG if the RINs are not separated under paragraph (d) of this section by March 31 of the subsequent calendar year after the RNG RIN was generated.

* * * * *

■ 8. Amend § 80.135 by revising paragraphs (c)(3)(i), (c)(10)(vi)(A)(*5*), and (d)(3)(i) to read as follows:

§ 80.135 Registration.

* * * * *

(c) * * *

(3) * * *

(i) A description of how biogas will be measured, including the specific standards under which the meters are operated, the fluid with which the meters were calibrated, and the equivalency to biogas flow for meters calibrated with a fluid other than biogas, as applicable.

* * * * *

(10) * * *

(vi) * * *

(A) * * *

(*5*) A demonstration that no biogas produced from non-cellulosic biogas feedstocks could be used to generate RINs for a batch of renewable fuel with a D code of 3 or 7. EPA may reject this demonstration if it is not sufficiently protective.

* * * * *

(d) * * *

(3) * * *

(i) A description of how RNG will be measured, including the specific standards under which the meters are operated, the fluid with which the meters were calibrated, and the equivalency to RNG flow for meters calibrated with a fluid other than natural gas, as applicable.

* * * * *

■ 9. Amend § 80.140 by revising paragraph (b)(2) to read as follows:

§ 80.140 Reporting.

* * * * *

(b) * * *

(2) Production date.

* * * * *

■ 10. Amend § 80.155 by:

■ a. Revising and republishing paragraph (a)(2); and

■ b. Revising paragraph (b)(2)(v).

The revisions read as follows:

§ 80.155 Sampling, testing, and measurement.

(a) * * *

(2) Flow meters tested and calibrated under OIML R 137–1 and 2 (incorporated by reference, see § 80.12) and compliant with one of the following:

(i) AGA Report No. 3 Parts 1, 2, 3, and 4 or API MPMS 14.3.1, API MPMS 14.3.2, API MPMS 14.3.3, and API MPMS 14.3.4 (incorporated by reference, see § 80.12).

(ii) API MPMS 14.12 (incorporated by reference, see § 80.12).

(iii) EN 17526 (incorporated by reference, see § 80.12) compatible with gas type H.

(iv) AGA Report No. 9 (incorporated by reference, see § 80.12).

(v) AGA Report No. 11 or API MPMS 14.9 (incorporated by reference, see § 80.12).

(vi) ASME MFC–5.1 (incorporated by reference, see § 80.12).

(vii) ASME MFC-21.2 (incorporated by reference, see § 80.12).

(viii) ANSI B109.3 (incorporated by reference, see § 80.12).

(ix) ISO 5167–1 and ISO 5167–2, ISO 5167–4, or ISO 5167–5 (incorporated by reference, see § 80.12).

(x) ISO 17089–2 (incorporated by reference, see § 80.12).

* * * * *

(b) * * *

(2) * * *

(v) Hydrocarbon analysis using EPA Method 18 (see Appendix A–6 to 40 CFR part 60), EPA Method TO–15, or ASTM D1945 (incorporated by reference, see § 80.12).

* * * * *

Subpart M—Renewable Fuel Standard

■ 11. Amend § 80.1405 by:

■ a. Revising entry 2025 and adding entries 2026 and 2027 in table 1 to paragraph (a); and

■ b. Revising paragraphs (c) and (d).

The revisions and addition read as follows:

§ 80.1405 What are the Renewable Fuel Standards?

(a) * * *

TABLE 1 TO PARAGRAPH (a)—ANNUAL RENEWABLE FUEL STANDARDS

Year	Cellulosic biofuel standard (%)	Biomass-based diesel standard (%)	Advanced biofuel standard (%)	Renewable fuel standard (%)	Supplemental total renewable fuel standard (%)
* * *	*	*		*	*
2025	0.70	3.15	4.31	13.13	n/a
2026	0.87	4.75	6.02	16.02	n/a
2027	0.92	5.07	6.40	16.54	n/a

* * * * *

(c) EPA will calculate the annual renewable fuel percentage standards using the following equations:

$$Std_{CB,i} = 100 * \frac{RFV_{CB,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{BBD,i} = 100 * \frac{RFV_{BBD,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{AB,i} = 100 * \frac{RFV_{AB,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

$$Std_{RF,i} = 100 * \frac{RFV_{RF,i}}{(G_i - RG_i) - GE_i + (D_i - RD_i) - DE_i}$$

Where:

$Std_{CB,i}$ = The cellulosic biofuel standard for year i, in percent.

$Std_{BBD,i}$ = The biomass-based diesel standard for year i, in percent.

$Std_{AB,i}$ = The advanced biofuel standard for year i, in percent.

$Std_{RF,i}$ = The renewable fuel standard for year i, in percent.

$RFV_{CB,i}$ = Annual volume of cellulosic biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, or volume as adjusted pursuant to 42 U.S.C. 7545(o)(7)(D), in gallon-RINs.

$RFV_{BBD,i}$ = Annual volume of biomass-based diesel required by 42 U.S.C. 7545 (o)(2)(B) for year i, in gallon-RINs.

$RFV_{AB,i}$ = Annual volume of advanced biofuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

$RFV_{RF,i}$ = Annual volume of renewable fuel required by 42 U.S.C. 7545(o)(2)(B) for year i, in gallon-RINs.

G_i = Amount of gasoline projected to be used in the covered location for year i, in gallons.

D_i = Amount of diesel projected to be used in the covered location for year i, in gallons.

RG_i = Amount of blended renewable fuel projected to be contained in the projection of G_i for year i, in gallons.

RD_i = Amount of blended renewable fuel projected to be contained in the projection of D_i for year i, in gallons.

GE_i = The total amount of gasoline projected to be exempt for year i, in gallons, per §§ 80.1441 and 80.1442.

DE_i = The total amount of diesel fuel projected to be exempt for year i, in gallons, per §§ 80.1441 and 80.1442.

(d) The price for cellulosic biofuel waiver credits will be calculated in accordance with § 80.1456(d) and published on EPA's website.

■ 12. Amend § 80.1407 by revising paragraph (f)(5) to read as follows:

§ 80.1407 How are the Renewable Volume Obligations calculated?

* * * * *

(f) * * *

(5) Gasoline or diesel fuel exported for use outside the covered location.

* * * * *

■ 13. Amend § 80.1415 by revising paragraphs (a), (b), and (c)(1) to read as follows:

§ 80.1415 How are equivalence values assigned to renewable fuel?

(a)(1) Each gallon (or gallon-equivalent) of a renewable fuel must be assigned an equivalence value by the producer or importer pursuant to paragraph (b) or (c) of this section, as applicable.

(2) The equivalence value is a number that is used to determine how many gallon-RINs can be generated for a gallon of renewable fuel according to § 80.1426.

(b)(1) Equivalence values for certain renewable fuels are assigned as follows:

TABLE 1 TO PARAGRAPH (b)(1)—EQUIVALENCE VALUES FOR CERTAIN RENEWABLE FUELS

Renewable fuel	Amount	Equivalence value
Denatured ethanol	1 gallon	1.0
Biodiesel	1 gallon	1.5
Butanol	1 gallon	1.3
Renewable diesel	1 gallon	1.6

TABLE 1 TO PARAGRAPH (b)(1)—EQUIVALENCE VALUES FOR CERTAIN RENEWABLE FUELS—Continued

Renewable fuel	Amount	Equivalence value
Renewable naphtha	1 gallon	1.4
Renewable jet fuel	1 gallon	1.6
Fuels that are gaseous at STP (*e.g.,* RNG, renewable CNG/LNG)	77,000 Btu LHV	1.0

(2) For all other renewable fuels, a producer or importer must submit an application to EPA for an equivalence value following the provisions of paragraph (c) of this section. A producer or importer may also submit an application for an alternative equivalence value pursuant to paragraph (c) of this section if the renewable fuel is listed in this paragraph (b), but the producer or importer has reason to believe that a different equivalence value than that listed in this paragraph (b) is warranted.

(c) * * *

(1) The equivalence value for renewable fuels described in paragraph (b)(2) of this section must be calculated using the following formula:

$$EqV = (R/0.972) * (EC/77,000)$$

Where:

EqV = Equivalence Value for the renewable fuel, rounded to the nearest tenth.

R = Renewable content of the renewable fuel. This is a measure of the portion of a renewable fuel that came from renewable biomass, expressed as a fraction, on an energy basis.

EC = Energy content of the renewable fuel, in Btu LHV per gallon.

* * * * *

■ 14. Amend § 80.1425 by adding paragraph (a)(3) to read as follows:

§ 80.1425 Renewable Identification Numbers (RINs).

* * * * *

(a) * * *

(3) K has the value of 3 when the RIN is assigned to a volume of RNG pursuant to §§ 80.125(c) and 80.1426(e).

* * * * *

■ 15. Amend § 80.1426 by:

■ a. Adding paragraph (a)(5);

■ b. Revising paragraph (b)(2), (c)(7), and (e);

■ c. In paragraphs (f)(1)(v)(A) and (B), removing the text ''D-code'' and adding in its place the text ''D code'';

■ d. Adding paragraph (f)(1)(vii);

■ e. Revising paragraph (f)(8) introductory text, (f)(8)(iii), (f)(10), (11) and (17);

■ f. Adding paragraph (f)(18); and

■ g. Revising table 1 to § 80.1426.

The additions and revisions read as follows:

§ 80.1426 How are RINs generated and assigned to batches of renewable fuel?

(a) * * *

(5) Starting January 1, 2026, the following parties must reduce the number of RINs generated, as calculated under paragraphs (f) of this section, for the specified renewable fuel by 50 percent:

(i) RIN-generating foreign producers, for all renewable fuel produced.

(ii) RIN-generating importers of renewable fuel, for all imported renewable fuel.

(iii) Domestic renewable fuel producers, for all renewable fuel produced from foreign feedstocks or foreign biointermediates.

(b) * * *

(2) If EPA approves a petition of Alaska or a United States territory to opt-in to the renewable fuel program under the provisions in § 80.1443, then the requirements of paragraph (b)(1) of this section shall also apply to renewable fuel produced or imported for use as transportation fuel, heating oil, or jet fuel in that state or territory beginning in the next calendar year

* * * * *

(c) * * *

(7) For renewable fuel oil, renewable fuel producers and importers must not generate RINs unless they have received affidavits from the final end user or users of the fuel oil as specified in § 80.1451(b)(1)(ii)(T)(*2*).

* * * * *

(e) *Assignment of RINs to batches.* (1)(i) Except as specified in paragraphs (e)(1)(ii) and (g) of this section, the producer or importer of renewable fuel must assign all RINs generated to volumes of renewable fuel as follows:

(A) If RINs were generated for the renewable fuel at the point of production or the point of importation into the covered location, RINs must be assigned when such volumes leave the renewable fuel production or import facility.

(B) If RINs were generated for the renewable fuel at the point of sale or when the renewable fuel was loaded onto a vessel or other transportation mode for transport to the covered location, RINs must be assigned prior to the transfer of ownership of the renewable fuel.

(ii) For RNG and renewable fuels that are gaseous at STP, RINs must be assigned to a volume of RNG or renewable fuel, as applicable, at the same time the RIN is generated.

(2) A RIN is assigned to a volume of renewable fuel when ownership of the RIN is transferred along with the transfer of ownership of the volume of renewable fuel, pursuant to § 80.1428(a).

(3) All assigned RINs must have a K code value of 1 for RINs assigned to renewable fuel or 3 for RINs assigned to RNG.

(f) * * *

(1) * * *

(vii) For purposes of identifying the appropriate approved pathway, the fuel must be produced, distributed, and used in a manner consistent with the pathway EPA evaluated when it determined that the pathway satisfies the applicable GHG reduction requirement

* * * * *

(8) *Standardization of volumes.* In determining the standardized volume of a batch of liquid renewable fuel or liquid biointermediate under this subpart, the batch volume must be adjusted to a standard temperature of 60 °F as follows:

* * * * *

(iii) For other renewable fuels and biointermediates, an appropriate formula commonly accepted by the industry must be used to standardize the actual volume to 60 °F. Formulas used must be reported to EPA and may be determined to be inappropriate

* * * * *

(10) RIN generators may only generate RINs for renewable CNG/LNG produced from biogas that is distributed via a closed, private, non-commercial system if all the following requirements are met:

(i) The renewable CNG/LNG was produced from renewable biomass under an approved pathway.

(ii) The RIN generator has entered into a written contract for the sale or use of a specific quantity of renewable CNG/LNG for use as transportation fuel, or has obtained affidavits from all parties selling or using the renewable CNG/LNG as transportation fuel.

(iii) The renewable CNG/LNG was used as transportation fuel and for no other purpose.

(iv) The biogas was introduced into the closed, private, non-commercial system no later and the renewable CNG/LNG produced from the biogas was used as transportation fuel no later than December 31, 2024.

(v) RINs may only be generated on biomethane content of the renewable CNG/LNG used as transportation fuel.

(11) RINs for renewable CNG/LNG produced from RNG that is introduced into a commercial distribution system may only be generated if all the following requirements are met:

(i) The renewable CNG/LNG was produced from renewable biomass and qualifies for a D code in an approved pathway.

(ii) The RIN generator has entered into a written contract for the sale or use of a specific quantity of RNG, taken from a commercial distribution system (*e.g.,* physically connected pipeline, barge, truck, rail), for use as transportation fuel, or has obtained affidavits from all parties selling or using the RNG taken from a commercial distribution system as transportation fuel.

(iii) The renewable CNG/LNG produced from the RNG was sold for use as transportation fuel and for no other purpose.

(iv) The RNG was injected into and withdrawn from the same commercial distribution system.

(v) The RNG was withdrawn from the commercial distribution system in a manner and at a time consistent with the transport of the RNG between the injection and withdrawal points.

(vi) The volume of RNG injected into the commercial distribution system and the volume of RNG withdrawn are measured by continuous metering.

(vii) The volume of renewable CNG/LNG sold for use as transportation fuel corresponds to the volume of RNG that was injected into and withdrawn from the commercial distribution system.

(viii) No other party relied upon the volume of biogas, RNG, or renewable CNG/LNG for the generation of RINs.

(ix) The RNG was introduced into the commercial distribution system no later than December 31, 2024, and the renewable CNG/LNG was used as transportation fuel no later than December 31, 2024.

(x) RINs may only be generated on biomethane content of the biogas, treated biogas, RNG, or renewable CNG/LNG.

(xi) (A) On or after January 1, 2025, RINs may only be generated for RNG injected into a natural gas commercial pipeline system for use as transportation fuel as specified in subpart E of this part.

(B) RINs may be generated for RNG as specified in subpart E of this part prior to January 1, 2025, if all applicable requirements under this part are met.

* * * * *

(17) *Qualifying use demonstration for certain renewable fuels.* For purposes of this section, any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, or renewable diesel that meets paragraph (1) of the definition of renewable diesel is considered renewable fuel and the producer or importer may generate RINs for such fuel only if all the following apply:

(i) The fuel is produced from renewable biomass and qualifies to generate RINs under an approved pathway.

(ii) The fuel producer or importer maintains records demonstrating that the fuel was produced for use as a transportation fuel, heating oil, or jet fuel by any of the following:

(A) Blending the renewable fuel into gasoline or distillate fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards under this part and 40 CFR part 1090.

(B) Entering into a written contract for the sale of the renewable fuel, which specifies the purchasing party must blend the fuel into gasoline or distillate fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards under this part and 40 CFR part 1090.

(C) Entering into a written contract for the sale of the renewable fuel, which specifies that the fuel must be used in its neat form as a transportation fuel, heating oil, or jet fuel that meets all applicable standards.

(ii) The fuel was sold for use in or as a transportation fuel, heating oil, or jet fuel, and for no other purpose.

(18) *RIN generation timing.* A RIN generator must generate RINs as follows:

(i) Except as specified in paragraph (f)(18)(ii), RINs must be generated at:

(A) For domestic renewable fuel producers, the point of production or point of sale.

(B) For RIN-generating foreign producers, the point of production or when the renewable fuel is loaded onto a vessel or other transportation mode for transport to the covered location.

(C) For RIN-generating importers of renewable fuel, the point of importation into the covered location.

(ii)(A) Except as specified in paragraph (f)(18)(ii)(B), for RNG and renewable fuels that are gaseous at STP, RINs must be generated no later than 5 business days after the RIN generator has met all applicable requirements for the generation of RINs under §§ 80.125(b), 80.130(b), and this paragraph (f), as applicable.

(B) For foreign produced RIN-less RNG, RINs must be generated when title is transferred from the foreign producer to the RIN-generating importer.

* * * * *

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS

Row	Fuel type	Feedstock	Production process requirements	D Code
A	Ethanol	Corn starch	All the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least two advanced technologies from Table 2 to this section.	6
B	Ethanol	Corn starch	All the following: Dry mill process, using natural gas, biomass, or biogas for process energy and at least one of the advanced technologies from Table 2 to this section plus drying no more than 65% of the distillers grains with solubles it markets annually.	6
C	Ethanol	Corn starch	All the following: Dry mill process, using natural gas, biomass, or biogas for process energy and drying no more than 50% of the distillers grains with solubles it markets annually.	6
D	Ethanol	Corn starch	Wet mill process using biomass or biogas for process energy	6
E	Ethanol	Starches from crop residue and annual cover crops.	Fermentation using natural gas, biomass, or biogas for process energy.	6

TABLE 1 TO § 80.1426—APPLICABLE D CODES FOR EACH FUEL PATHWAY FOR USE IN GENERATING RINS—Continued

Row	Fuel type	Feedstock	Production process requirements	D Code
F	Biodiesel; Renewable diesel; Renewable jet fuel; Renewable fuel oil.	Soybean oil; Oil from annual cover crops; Oil from algae grown photosynthetically; Biogenic waste oils/fats/greases; *Camelina sativa* oil; Distillers corn oil; Distillers sorghum oil; Commingled distillers corn oil and sorghum oil.	The following processes that do not co-process renewable biomass and petroleum: Transesterification with or without esterification pre-treatment; Esterification; Hydrotreating.	4
G	Biodiesel; Renewable diesel; Renewable jet fuel; Renewable fuel oil.	Canola/Rapeseed oil	The following processes that do not co-process renewable biomass and petroleum: Transesterification using natural gas or biomass for process energy; Hydrotreating.	4
H	Biodiesel; Renewable diesel; Renewable jet fuel; Renewable fuel oil.	Soybean oil; Oil from annual cover crops; Oil from algae grown photosynthetically; Biogenic waste oils/fats/greases; *Camelina sativa* oil; Distillers corn oil; Distillers sorghum oil; Commingled distillers corn oil and sorghum oil; Canola/Rapeseed oil.	The following processes that co-process renewable biomass and petroleum: Transesterification with or without esterification pretreatment; Esterification; Hydrotreating.	5
I	Renewable naphtha; LPG	*Camelina sativa* oil; Distillers sorghum oil; Distillers corn oil; Commingled distillers corn oil and distillers sorghum oil; Canola/Rapeseed oil; Biogenic waste oils/fats/greases.	Hydrotreating	5
J	Ethanol	Sugarcane	Fermentation	5
K	Ethanol	Crop residue; Slash, pre-commercial thinnings, and tree residue; Switchgrass; Miscanthus; Energy cane; *Arundo donax; Pennisetum purpureum;* Separated yard waste; Biogenic components of separated MSW; Cellulosic components of separated food waste; Cellulosic components of annual cover crops.	Biochemical fermentation process that converts cellulosic biomass to ethanol and uses the lignin and other biogenic feedstock residues from the fermentation and ethanol production processes for all thermal and electrical process energy and are net exporters of electricity to the grid; Thermochemical gasification process that converts cellulosic biomass to ethanol and uses a portion of the feedstock for over 99% of thermal and electrical process energy; Dry mill process that converts corn or grain sorghum kernel fiber to ethanol and uses natural gas, biogas, or crop residue for all thermal process energy.	3
L	Cellulosic diesel; Renewable jet fuel; Renewable fuel oil.	Crop residue; Slash, pre-commercial thinnings, and tree residue; Switchgrass; Miscanthus; Energy cane; *Arundo donax; Pennisetum purpureum;* Separated yard waste; Biogenic components of separated MSW; Cellulosic components of separated food waste; Cellulosic components of annual cover crops.	Fischer-Tropsch process that converts cellulosic biomass to fuel and uses a portion of the feedstock for over 99% of thermal and electrical process energy.	7
M	Renewable gasoline; Renewable gasoline blendstock; Co-processed cellulosic diesel; Renewable jet fuel; Renewable fuel oil.	Crop residue; Slash, pre-commercial thinnings, and tree residue; Separated yard waste; Biogenic components of separated MSW; Cellulosic components of separated food waste; Cellulosic components of annual cover crops.	The following processes that convert cellulosic biomass to fuel using natural gas, biogas, or biomass as the only process energy sources: Catalytic pyrolysis and upgrading; Gasification and upgrading; Thermo-catalytic hydrodeoxygenation and upgrading; Direct biological conversion; Biological conversion and upgrading.	3
N	Renewable naphtha	Switchgrass; Miscanthus; Energy cane; *Arundo donax; Pennisetum purpureum*.	Gasification and upgrading processes that convert cellulosic biomass to fuel.	3
O	Butanol	Corn starch	Fermentation; Dry mill process using natural gas, biomass, or biogas for process energy.	6
P	Ethanol; Renewable diesel; Renewable jet fuel; Renewable fuel oil; Renewable naphtha.	Non-cellulosic portions of separated food waste; Non-cellulosic components of annual cover crops.	Fermentation using natural gas, biogas, or crop residue for thermal energy; Hydrotreating; Transesterification.	5
Q	Renewable CNG; Renewable LNG.	Biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters; Biogas from the cellulosic components of biomass processed in other waste digesters.	The following processes that occur in North America: CNG production from treated biogas via compression; LNG production from treated biogas via liquefaction.	3
R	Ethanol	Grain sorghum	Dry mill process using natural gas or biogas from landfills, waste treatment plants, or waste digesters for process energy.	6
S	Ethanol	Grain sorghum	Dry mill process using only biogas from landfills, waste treatment plants, or waste digesters for process energy and for on-site production of all electricity used at the site other than up to 0.15 kWh of electricity from the grid per gallon of ethanol produced, calculated on a per batch basis.	5
T	Renewable CNG; Renewable LNG.	Biogas from waste digesters	The following processes that occur in North America: CNG production from treated biogas via compression; LNG production from treated biogas via liquefaction.	5

* * * * *

■ 16. Amend § 80.1428 by:

■ a. Revising paragraph (a)(3);

■ b. Removing paragraph (a)(4); and

■ c. Redesignating paragraph (a)(5) as paragraph (a)(4).

The revision reads as follows:

§ 80.1428 General requirements for RIN distribution.

(a) * * *

(3) Assigned gallon-RINs with a K code of 1 or 3 can be transferred to another person based on the following:

(i) No more than 2.5 assigned gallon-RINs with a K code of 1 can be transferred to another person with every gallon of renewable fuel transferred to that same person.

(ii) For RNG, the transferor of assigned RINs with a K code of 3 must transfer RINs under § 80.125(c).

* * * * *

■ 17. Amend § 80.1429 by:
■ a. Revising paragraph (b)(5)(i);
■ b. Removing the text ''only'' in paragraph (b)(5)(ii)(B); and
■ c. Revising paragraph (c)

The revisions read as follows:

§ 80.1429 Requirements for separating RINs from volumes of renewable fuel or RNG.

* * * * *

(b) * * *

(5) (i) Any party that produces, imports, owns, sells, or uses a volume of biogas for which RINs have been generated in accordance with § 80.1426(f) must separate any RINs that have been assigned to that volume of biogas if all the following conditions are met:

(A) The party designates the biogas as transportation fuel.

(B) The biogas is used as transportation fuel.

* * * * *

(c) The party responsible for separating a RIN from a volume of renewable fuel or RNG must change the K code in the RIN from a value of 1 or 3, as applicable, to a value of 2 prior to transferring the RIN to any other party.

* * * * *

§ 80.1435 [Amended]

■ 18. Amend § 80.1435 by, in paragraph (b)(2)(ii), removing the text ''RIN gallons'' and adding in its place the text ''gallon-RINs''.

■ 19. Amend § 80.1441 by adding paragraphs (e)(2)(iv) and (v) to read as follows:

§ 80.1441 Small refinery exemption.

* * * * *

(e) * * *

(2) * * *

(iv) A refinery that is granted a small refinery exemption under this section must still submit reports under § 80.1451(a) for the compliance year for which it was granted an exemption, including annual compliance reports. Such exempt small refineries must submit annual compliance reports containing all the information specified in § 80.1451(a)(1) by the applicable compliance deadline specified in § 80.1451(f)(1)(i).

(v) A refinery that is granted a small refinery exemption under this section must still comply with any deficit RVOs carried forward from the previous year.

* * * * *

■ 20. Amend § 80.1442 by adding paragraphs (h)(6) and (7) to read as follows:

§ 80.1442 What are the provisions for small refiners under the RFS program?

* * * * *

(h) * * *

(6) A refiner that is granted a small refiner exemption under this section must still submit reports under § 80.1451(a) for the compliance year for which it was granted an exemption, including annual compliance reports. Such exempt small refiners must submit annual compliance reports containing all the information specified in § 80.1451(a)(1) by the applicable compliance deadline specified in § 80.1451(f)(1)(i).

(7) A refiner that is granted a small refiner exemption under this section must still comply with any deficit RVOs carried forward from the previous year.

* * * * *

§ 80.1444 [Amended]

■ 21. Amend § 80.1444 by, in paragraph (b), removing the text ''in § 80.1401''.

■ 22. Amend § 80.1449 by:
■ a. Revising paragraphs (a) introductory text, (a)(1), (a)(4)(i), (a)(4)(iii), and (b);
■ b. Removing paragraph (d); and
■ c. Redesignating paragraph (e) as paragraph (d).

The revisions read as follows:

§ 80.1449 What are the Production Outlook Report requirements?

(a) By June 1 of each year, a registered renewable fuel producer or importer must submit and an unregistered renewable fuel producer may submit all of the following information for each of its facilities, as applicable, to EPA:

(1) If currently registered, any planned changes to the type, or types, of renewable fuel expected to be produced or imported at each facility owned by the renewable fuel producer or importer.

* * * * *

(4) * * *

(i) Nameplate production capacity and, if applicable, permitted production capacity.

* * * * *

(iii) If currently registered, any planned changes to feedstocks, biointermediates, and production processes to be used at each production facility.

* * * * *

(b) The information listed in paragraph (a) of this section must include the reporting party's best annual projection estimates for the five following calendar years.

* * * * *

■ 23. Amend § 80.1450 by:
■ a. Revising the last sentence in paragraphs (a);
■ b. Revising paragraphs (b)(1)(v)(D) introductory text, (b)(1)(v)(D)(*1*), (b)(1)(xi), (b)(1)(xii) introductory text, (b)(1)(xii)(A), (b)(2), (g)(10) introductory text, and (g)(10)(i).

The revisions read as follows:

§ 80.1450 What are the registration requirements under the RFS program?

(a) * * * Registration information must be submitted and accepted by EPA at least 60 days prior to RIN ownership.

(b) * * *

(1) * * *

(v) * * *

(D) For all facilities producing renewable fuel from biogas, submit all relevant information in § 80.1426(f)(10) or (11), including:

(*1*) Copies of all contracts or affidavits, as applicable, that follow the track of the biogas/CNG/LNG from its original source, to the producer that processes it into renewable fuel, and finally to the end user that will actually use the renewable CNG/LNG for transportation purposes.

* * * * *

(xi) For a producer of renewable fuel oil:

(A) An affidavit from the producer of the renewable fuel oil stating that the renewable fuel oil for which RINs have been generated will be sold for the purposes of heating or cooling interior spaces of homes or buildings to control ambient climate for human comfort, and no other purpose.

(B) Affidavits from the final end user or users of the renewable fuel oil stating that the renewable fuel oil is being used or will be used for purposes of heating or cooling interior spaces of homes or buildings to control ambient climate for human comfort, and no other purpose, and acknowledging that any other use of the renewable fuel oil would violate EPA regulations and subject the user to civil and/or criminal penalties under the Clean Air Act.

(xii) For a producer or importer of any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, renewable diesel that meets paragraph (1) of the definition of renewable diesel, biogas-derived renewable fuel, or RNG, all the following:

(A) A description of the renewable fuel and how it will be blended to into gasoline or diesel fuel to produce a transportation fuel, heating oil, or jet fuel that meets all applicable standards.

* * * * *

(2) An independent third-party engineering review and written report and verification of the information provided pursuant to paragraph (b)(1) of this section and § 80.135, as applicable.

The report and verification must be based upon a review of relevant documents and a site visit conducted within the six months prior to submission of the registration information. The report and verification must separately identify each item required by paragraph (b)(1) of this section, describe how the independent third-party evaluated the accuracy of the information provided, state whether the independent third-party agrees with the information provided, and identify any exceptions between the independent third-party's findings and the information provided.

* * * * *

(g) * * *

(10) *Registration renewal.* Registrations for independent third-party auditors expire December 31 of every other calendar year. Previously approved registrations will renew automatically if all the following conditions are met:

(i) The independent third-party auditor resubmits all information, updated as necessary, described in § 80.1450(g)(1) through (g)(7) no later than October 31 before the calendar year that their registration expires.

* * * * *

■ 24. Amend § 80.1451 by:

■ a. Revising paragraph (b)(1)(ii)(L);

■ b. Removing and reserving paragraph (b)(1)(ii)(P);

■ c. Revising paragraph (b)(1)(ii)(T);

■ d. Removing paragraph (c)(2)(ii)(D)(14); and

■ e. In paragraph (g)(1)(viii), removing the text ''D-code'' and adding in its place the text ''D code''.

The revisions read as follows:

§ 80.1451 What are the reporting requirements under the RFS program?

* * * * *

(b) * * *

(1) * * *

(ii) * * *

(L) Each process, feedstock, feedstock point of origin, and biointermediate, as applicable, used and proportion of renewable volume attributable to each process, feedstock, feedstock point of origin, and biointermediate, as applicable.

* * * * *

(T) Producers or importers of any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, renewable diesel that meets the paragraph (1) of the definition of renewable diesel, biogas-derived renewable fuel, or RNG, must report, on a quarterly basis, all the following for each volume of fuel:

* * * * *

■ 25. Amend § 80.1452 by

■ a. Revising paragraphs (a), (b) introductory text, (b)(1), (2), (4), and (11);

■ b. Redesignating paragraph (b)(18) as paragraph (b)(19) and adding new paragraph (b)(18); and

■ c. Revising paragraph (c) introductory text.

The revisions and addition read as follows:

§ 80.1452 What are the requirements related to the EPA Moderated Transaction System (EMTS)?

(a) Each party required to submit information under this section must establish an account with the EPA Moderated Transaction System (EMTS) at least 60 days prior to engaging in any RIN transactions.

(b) Each time a RIN generator assigns RINs to a batch of renewable fuel or RNG pursuant to §§ 80.125(c) and 80.1426(e), as applicable, all the following information must be submitted to EPA via the submitting party's EMTS account within five (5) business days of the date of RIN assignment. EPA in its sole discretion may allow a RIN generator to submit information under this paragraph (b) outside the 5-business-day deadline.

(1) The name of the RIN generator.

(2) The EPA company registration number of the renewable fuel producer, RNG producer, or foreign ethanol producer, as applicable.

* * * * *

(4) The EPA facility registration number of the facility at which the renewable fuel producer, RNG producer, or foreign ethanol producer produced the batch, as applicable.

* * * * *

(11) The volume of ethanol denaturant, if applicable, and applicable equivalence value of each batch.

* * * * *

(18) The type of RIN generation protocol (*e.g.,* domestic, import, co-processing, etc) used when assigning RINs to the associated renewable fuel volume.

* * * * *

(c) Each time any party sells, separates, or retires RINs, all the following information must be submitted to EPA via the submitting party's EMTS account within five (5) business days of the reportable event. Each time any party purchases RINs, all the following information must be submitted to EPA via the submitting party's EMTS account within ten (10) business days of the reportable event. The reportable event for a RIN purchase or sale occurs on the date of transfer per § 80.1453(a)(4). The reportable event for a RIN separation or retirement occurs on the date of separation or retirement as described in § 80.1429 or § 80.1434. EPA in its sole discretion may allow a party to submit information under this paragraph (c) outside the applicable 5- or 10-business-day deadline.

* * * * *

■ 26. Amend § 80.1453 by revising paragraphs (a)(12)(v), (vii), and (d) to read as follows:

§ 80.1453 What are the product transfer document (PTD) requirements for the RFS program?

(a) * * *

(12) * * *

(v) Renewable naphtha. ''This volume of neat or blended renewable naphtha is designated and intended for use as transportation fuel or jet fuel in the 48 U.S. contiguous states and Hawaii. This naphtha may only be used as a gasoline blendstock, E85 blendstock, or jet fuel. Any person exporting this fuel is subject to the requirements of 40 CFR 80.1430.''.

* * * * *

(vii) Renewable fuels other than ethanol, biodiesel, heating oil, renewable diesel, naphtha, or butanol. ''This volume of neat or blended renewable fuel is designated and intended to be used as transportation fuel, heating oil, or jet fuel in the 48 U.S. contiguous states and Hawaii. Any person exporting this fuel is subject to the requirements of 40 CFR 80.1430.''.

* * * * *

(d) For renewable fuel oil, the PTD of the renewable fuel oil shall state: ''This volume of renewable fuel oil is designated and intended to be used to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort. Do NOT use for process heat or cooling or any other purpose, as these uses are prohibited pursuant to 40 CFR 80.1460(g).''.

* * * * *

■ 27. Amend § 80.1454 by:

■ a. Revising paragraph (a) introductory text, (b) introductory text, (b)(3)(ix), (b)(8), (c)(1) introductory text, and (d)(1);

■ b. In paragraph (g) introductory text, removing the text ''U.S. agricultural land as defined in § 80.1401'' and adding in its place the text ''agricultural land'';

■ c. Revising and republishing paragraph (k)(1);

■ d. Revising paragraphs (k)(2) introductory text, (l) introductory text, (l)(2), and (l)(3)(iv);

■ e. Removing paragraph (m)(8); and

■ f. Redesignating paragraphs (m)(9) through (11) as paragraphs (m)(8) through (10).

The revisions read as follows:

§ 80.1454 What are the recordkeeping requirements under the RFS program?

(a) *Requirements for obligated parties and exporters of renewable fuel.* Any obligated party or exporter of renewable fuel must keep all the following records:

* * * * *

(b) *Requirements for all producers of renewable fuel.* In addition to any other applicable records a renewable fuel producer must maintain under this section, any domestic or RIN-generating foreign producer of a renewable fuel must keep all the following records:

* * * * *

(3) * * *

(ix) All facility-determined values used in the calculations under § 80.1426 and the data used to obtain those values.

* * * * *

(8) A producer of renewable fuel oil must keep copies of all contracts which describe the renewable fuel oil under contract with each end user.

* * * * *

(c) * * *

(1) Any RIN-generating foreign producer or importer of renewable fuel must keep records of feedstock purchases and transfers associated with renewable fuel for which RINs are generated, sufficient to verify that feedstocks used are renewable biomass.

* * * * *

(d) * * *

(1)(i) Starting January 1, 2026, any domestic producer of renewable fuel that generates RINs for such fuel must keep records of feedstock purchases and transfers (*e.g.,* bills of sale, delivery receipts) that identify the feedstock point of origin for each feedstock (*i.e.,* domestic or foreign).

(ii) Except as provided in paragraphs (g) and (h) of this section, any domestic producer of renewable fuel that generates RINs for such fuel must keep documents associated with feedstock purchases and transfers that identify where the feedstocks were produced and are sufficient to verify that feedstocks used are renewable biomass if RINs are generated.

* * * * *

(k) * * *

(1) *Pathways involving feedstocks other than grain sorghum.* A renewable fuel producer that generates RINs for renewable CNG/LNG pursuant to § 80.1426(f)(10) or (11), or that uses process heat from biogas to produce renewable fuel pursuant to § 80.1426(f)(12) must keep all the following additional records:

(i) Documentation recording the sale of renewable CNG/LNG for use as transportation fuel relied upon in § 80.1426(f)(10), § 80.1426(f)(11), or for use of biogas for process heat to make renewable fuel as relied upon in § 80.1426(f)(12) and the transfer of title of the biogas/CNG/LNG from the point of biogas production to the facility which sells or uses the fuel for transportation purposes.

(ii) Documents demonstrating the volume and energy content of biogas/CNG/LNG relied upon under § 80.1426(f)(10) that was delivered to the facility which sells or uses the fuel for transportation purposes.

(iii) Documents demonstrating the volume and energy content of biogas/CNG/LNG relied upon under § 80.1426(f)(11), or biogas relied upon under § 80.1426(f)(12) that was placed into the commercial distribution.

(iv) Documents demonstrating the volume and energy content of biogas relied upon under § 80.1426(f)(12) at the point of distribution.

(v) Affidavits, EPA-approved documentation, or data from a real-time electronic monitoring system, confirming that the amount of the biogas/CNG/LNG relied upon under § 80.1426(f)(10) and (11) was used for transportation purposes only, and for no other purpose. The RIN generator must obtain affidavits, or monitoring system data under this paragraph (k), at least once per calendar quarter.

(vi) The biogas producer's Compliance Certification required under Title V of the Clean Air Act.

(vii) Any other records as requested by EPA.

(2) *Pathways involving grain sorghum as feedstock.* A renewable fuel producer that produces fuel pursuant to a pathway that uses grain sorghum as a feedstock must keep all the following additional records, as appropriate:

* * * * *

(l) *Additional requirements for producers or importers of any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable diesel, biogas-derived renewable fuel, or RNG.* A renewable fuel producer that generates RINs for any renewable fuel other than ethanol, biodiesel, renewable gasoline, renewable jet fuel, renewable diesel that meets paragraph (1) of the definition of renewable diesel, biogas-derived renewable fuel, or RNG must keep all the following additional records:

* * * * *

(2) Contracts and documents memorializing the sale of renewable fuel to parties who blend the fuel into gasoline or diesel fuel to produce a transportation fuel, heating oil, or jet fuel, or who use the renewable fuel in its neat form for a qualifying fuel use.

* * * * *

(3) * * *

(iv) A description of the finished fuel, and a statement that the fuel meets all applicable standards and was sold for use as a transportation fuel, heating oil, or jet fuel.

* * * * *

■ 28. Amend § 80.1460 by revising paragraphs (b)(4) and (g) to read as follows:

§ 80.1460 What acts are prohibited under the RFS program?

* * * * *

(b) * * *

(4) Transfer to any person a RIN with a K code of 1 or 3 without transferring an appropriate volume of renewable fuel to the same person on the same day.

* * * * *

(g) *Failing to use a renewable fuel oil for its intended use.* No person shall use renewable fuel oil for which RINs have been generated in an application other than to heat or cool interior spaces of homes or buildings to control ambient climate for human comfort.

* * * * *

■ 29. Amend § 80.1461 by adding paragraph (g) to read as follows:

§ 80.1461 Who is liable for violations under the RFS program?

* * * * *

(g) *Importer joint and several liability.* Any person meeting the definition of an importer under this subpart is jointly and severally liable for any violation of this subpart.

■ 30. Amend § 80.1464 by revising paragraph (b)(1)(v)(B) to read as follows:

§ 80.1464 What are the attest engagement requirements under the RFS program?

* * * * *

(b) * * *

(1) * * *

(v) * * *

(B) Verify that feedstocks were properly identified in the reports, including the feedstock point of origin for domestic renewable fuel producers, and met the definition of renewable biomass.

* * * * *

■ 31. Amend § 80.1469 by:

■ a. Removing paragraphs (a) and (b);

■ b. Redesignating paragraphs (c) through (f) as paragraphs (a) through (d); and

■ c. Revising newly redesignated paragraphs (a) introductory text, (a)(1)(vii), (a)(3)(vii), (a)(5), (c)(1), (d)(1) introductory text, and (d)(2).

The revisions read as follows:

§ 80.1469 Requirements for Quality Assurance Plans.

* * * * *

(a) *QAP Requirements.* All components specified in this paragraph (a) require quarterly monitoring, except for paragraph (a)(4)(iii) of this section which must be done annually.

(1) * * *

(vii) Feedstock(s) and biointermediate(s) are not renewable fuel for which RINs were previously generated unless the RINs were generated under § 80.1426(c)(6). For renewable fuels that have RINs generated under § 80.1426(c)(6), verify that renewable fuels used as a feedstock meet all applicable requirements of this paragraph (a)(1).

* * * * *

(3) * * *

(vii) Verify that appropriate RIN generation calculations are being followed under § 80.1426, including the feedstock point of origin.

* * * * *

(5) *Representative sampling.* Independent third-party auditors may use a representative sample of batches of renewable fuel or biointermediate in accordance with the procedures described in 40 CFR 1090.1805 for all components of this paragraph (a) except for paragraphs (a)(1)(ii) and (iii), (a)(2)(ii), (a)(3)(vi), and (a)(4)(ii) and (iii) of this section. If a facility produces both a renewable fuel and a biointermediate, the independent third-party auditor must select separate representative samples for the renewable fuel and biointermediate.

* * * * *

(c) * * *

(1) Each independent third-party auditor must annually submit a general and at least one pathway-specific QAP to the EPA which demonstrates adherence to the requirements of paragraphs (a) and (b) of this section and request approval on forms and using procedures specified by EPA.

* * * * *

(d) * * *

(1) A new QAP must be submitted to EPA according to paragraph (c) of this section and the independent third-party auditor must update their registration according to § 80.1450(g)(9) whenever any of the following changes occur at a renewable fuel or biointermediate production facility audited by an independent third-party auditor and the auditor does not possess an appropriate pathway-specific QAP that encompasses the change:

* * * * *

(2) A QAP ceases to be valid as the basis for verifying RINs or a biointermediate under a new pathway until a new pathway-specific QAP, submitted to the EPA under this paragraph (d), is approved pursuant to paragraph (c) of this section.

§ 80.1470 [Reserved]

■ 32. Remove and reserve § 80.1470.

■ 33. Amend § 80.1471 by:

■ a. Revising paragraph (b)(3);

■ b. Revising and republishing paragraph (e); and

■ c. Revising paragraph (f).

The revisions read as follows:

§ 80.1471 Requirements for QAP auditors.

* * * * *

(b) * * *

(3) The independent third-party auditor must not own, buy, sell, or otherwise trade RINs unless required to replace an invalid RIN pursuant to § 80.1474.

* * * * *

(e) The independent third-party auditor must identify RINs generated from a renewable fuel producer or foreign renewable fuel producer as having been verified under a QAP.

(1) For RINs verified under a QAP pursuant to § 80.1469, RINs must be designated as Q–RINs and must be identified as having been verified under a QAP in EMTS.

(2) The independent third-party auditor must not identify RINs generated from a renewable fuel producer or foreign renewable fuel producer as having been verified under a QAP if a revised QAP must be submitted to and approved by the EPA under § 80.1469(d).

(3) The independent third-party auditor must not identify RINs generated for renewable fuel produced using a biointermediate as having been verified under a QAP unless the biointermediate used to produce the renewable fuel was verified under an approved QAP pursuant to § 80.1477.

(f)(1) Auditors may only verify RINs that have been generated after the audit required under § 80.1472 has been completed. Auditors may only verify biointermediates that were produced after the audit required under § 80.1472 has been completed. Auditors must only verify RINs generated from renewable fuels produced from biointermediates after the audit required under § 80.1472 has been completed for both the biointermediate production facility and the renewable fuel production facility.

(2) Verification of RINs or biointermediates may continue for no more than 200 days following an on-site visit or 380 days after an on-site visit if a previously the EPA-approved remote monitoring system is in place at the renewable fuel production facility.

* * * * *

■ 34. Revise and republish § 80.1472 to read as follows:

§ 80.1472 Requirements for quality assurance audits.

(a) *General requirements.* (1) An audit must be performed by an auditor who meets the requirements of § 80.1471.

(2) An audit must be based on a QAP per § 80.1469.

(3) Each audit must verify every element contained in an applicable and approved QAP.

(4) Each audit must include a review of documents generated by the renewable fuel producer or biointermediate producer.

(b) *On-site visits.* (1) As applicable, the independent third-party auditor must conduct an on-site visit at the renewable fuel production facility, foreign ethanol production facility, or biointermediate production facility:

(i) At least two times per calendar year; or

(ii) In the event an auditor uses a remote monitoring system approved by the EPA, at least one time per calendar year.

(2) An on-site visit specified in paragraph (b)(1)(i) of this section must occur no more than:

(i) 200 days after the previous on-site visit. The 200-day period must start the day after the previous on-site visit ends; or

(ii) 380 days after the previous on-site visit if a previously approved (by EPA) remote monitoring system is in place at the renewable fuel production facility, foreign ethanol production facility, or biointermediate production facility, as applicable. The 380-day period must start the day after the previous on-site visit ends.

(3) An on-site visit must include verification of all QAP elements that require inspection or evaluation of the physical attributes of the renewable fuel production facility, foreign ethanol production facility, or biointermediate production facility, as applicable.

(4) The on-site visit must be overseen by a professional engineer, as specified in § 80.1450(b)(2)(i)(A) and (b)(2)(i)(B).

■ 35. Amend § 80.1473 by:

■ a. Revising paragraph (a);

■ b. Removing paragraphs (c) and (d);

■ c. Redesignating paragraphs (e) and (f) as paragraphs (c) and (d);

■ d. Revising newly redesignated paragraphs (c) introductory text, (c)(1), and (d).

The revisions read as follows:

§ 80.1473 Affirmative defenses.

(a) *Criteria.* Any person who engages in actions that would be a violation of the provisions of either § 80.1460(b)(2) or (c)(1), other than the generator of an invalid RIN, will not be deemed in violation if the person demonstrates that the criteria under paragraph (c) of this section are met.

* * * * *

(c) *Asserting an affirmative defense for invalid Q–RINs.* To establish an affirmative defense to a violation of § 80.1460(b)(2) or (c)(1) involving invalid Q–RINs, the person must meet the notification requirements of paragraph (d) of this section and prove by a preponderance of evidence all the following:

(1) The RIN in question was verified through a quality assurance audit pursuant to § 80.1472 using an approved QAP as specified in § 80.1469.

* * * * *

(d) *Notification requirements.* A person asserting an affirmative defense to a violation of § 80.1460(b)(2) or (c)(1), arising from the transfer or use of an invalid Q–RIN must submit a written report to the EPA via the EMTS support line (*fuelsprogramsupport@epa.gov*), including all pertinent supporting documentation, demonstrating that the requirements of paragraph (c) of this section were met. The written report must be submitted within 30 days of the person discovering the invalidity.

■ 36. Amend § 80.1474 by:
■ a. Removing paragraphs (a)(1) and (2);
■ b. Redesignating paragraphs (a)(3) and (4) as paragraphs (a)(1) and (2);
■ c. Revising paragraphs (b)(5) and (d)(2);
■ d. Removing paragraph (e);
■ e. Redesignating paragraphs (f) and (g) as paragraphs (e) and (f).

The revisions read as follows:

§ 80.1474 Replacement requirements for invalidly generated RINs.

* * * * *

(b) * * *

(5) Within 60 days of receiving a notification from the EPA that a PIR generator has failed to perform a corrective action required pursuant to this section, the party that owns the invalid RIN is required to do one of the following:

(i) Retire the invalid RIN.

(ii) If the invalid RIN has already been used for compliance with an obligated party's RVO, correct the RVO to subtract the invalid RIN.

* * * * *

(d) * * *

(2) The number of RINs retired must be equal to the number of PIRs or invalid RINs being replaced, subject to paragraph (e) of this section if applicable.

■ 37. Amend § 80.1476 by revising paragraph (h)(1) to read as follows:

§ 80.1476 Requirements for biointermediate producers.

* * * * *

(h) * * *

(1) Each biointermediate producer must assign a number (the ''batch number'') to each batch of biointermediate consisting of their EPA-issued company registration number, the EPA-issued facility registration number, the last two digits of the compliance year in which the batch was produced, and a unique number for the batch during the compliance year (*e.g.,* 4321–54321–25–000001).

* * * * *

■ 38. Amend § 80.1477 by revising paragraphs (b) and (c) to read as follows:

§ 80.1477 Requirements for QAPs for biointermediate producers.

* * * * *

(b) QAPs approved by EPA to verify biointermediate production must meet the requirements in § 80.1469, as applicable.

(c) Quality assurance audits, when performed, must be conducted in accordance with the requirements in § 80.1472.

* * * * *

■ 39. Amend § 80.1479 by revising paragraphs (c)(2) to read as follows:

§ 80.1479 Alternative recordkeeping requirements for separated yard waste, separated food waste, separated MSW, and biogenic waste oils/fats/greases.

* * * * *

(c) * * *

(2) The independent third-party auditor must conduct a site visit of each feedstock aggregator's establishment as specified in § 80.1471(f). Instead of verifying RINs with a site visit of the feedstock aggregator's establishment every 200 days as specified in § 80.1471(f)(2), the independent third-party auditor may verify RINs with a site visit every 380 days.

* * * * *

PART 1090—REGULATION OF FUELS, FUEL ADDITIVES, AND REGULATED BLENDSTOCKS

■ 40. The authority citation for part 1090 continues to read as follows:

Authority: 42 U.S.C. 7414, 7521, 7522–7525, 7541, 7542, 7543, 7545, 7547, 7550, and 7601.

Subpart A—General Provisions

■ 41. Amend § 1090.80 by:
■ a. Revising paragraph (2) in the definition ''Diesel fuel'';
■ b. Removing the definition ''Nonpetroleum (NP) diesel fuel'';
■ c. Adding the definition ''Nonpetroleum diesel fuel''; and
■ d. Revising the last sentence in the definition of ''Responsible corporate officer (RCO)''.

The revision and addition read as follows:

§ 1090.80 Definitions.

* * * * *

Diesel fuel * * *

(2) Any fuel (including nonpetroleum diesel fuel or a fuel blend that contains nonpetroleum diesel fuel) that is intended or used to power a vehicle or engine that is designed to operate using diesel fuel.

* * * * *

Nonpetroleum diesel fuel means renewable diesel fuel or biodiesel. Nonpetroleum diesel fuel also includes other renewable fuel under 40 CFR part 80, subpart M, that is used or intended for use to power a vehicle or engine that is designed to operate using diesel fuel or that is made available for use in a vehicle or engine designed to operate using diesel fuel.

* * * * *

Responsible corporate officer (RCO) * * * Examples of positions in non-corporate business structures that qualify are owner, chief executive officer, or president.

* * * * *

■ 42. Amend § 1090.95 by revising paragraphs (c)(1), (2), (4), (8), (11), (15) through (18), (21), (25), (28), and (32) through (38) to read as follows:

§ 1090.95 Incorporation by Reference.

* * * * *

(c) * * *

(1) ASTM D86–23ae2, Standard Test Method for Distillation of Petroleum Products and Liquid Fuels at Atmospheric Pressure, approved December 1, 2023 (''ASTM D86''); IBR approved for § 1090.1350(b).

(2) ASTM D287–22, Standard Test Method for API Gravity of Crude Petroleum and Petroleum Products (Hydrometer Method), approved December 1, 2022 (''ASTM D287''); IBR approved for § 1090.1337(d).

* * * * *

(4) ASTM D976–21e1, Standard Test Method for Calculated Cetane Index of Distillate Fuels, approved November 1, 2021 (''ASTM D976''); IBR approved for § 1090.1350(b).

* * * * *

(8) ASTM D2622–24a, Standard Test Method for Sulfur in Petroleum

Products by Wavelength Dispersive X-ray Fluorescence Spectrometry, approved December 1, 2024 (''ASTM D2622''); IBR approved for §§ 1090.1350(b); 1090.1360(d); 1090.1375(c).

* * * * *

(11) ASTM D3606–24a, Standard Test Method for Determination of Benzene and Toluene in Spark Ignition Fuels by Gas Chromatography, approved November 1, 2024 (''ASTM D3606''); IBR approved for § 1090.1360(c).

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(15) ASTM D4737–21, Standard Test Method for Calculated Cetane Index by Four Variable Equation, approved November 1, 2021 (''ASTM D4737''); IBR approved for § 1090.1350(b).

(16) ASTM D4806–21a, Standard Specification for Denatured Fuel Ethanol for Blending with Gasolines for Use as Automotive Spark-Ignition Engine Fuel, approved October 1, 2021 (''ASTM D4806''); IBR approved for § 1090.1395(a).

(17) ASTM D4814–24b, Standard Specification for Automotive Spark-Ignition Engine Fuel, approved December 1, 2024 (''ASTM D4814''); IBR approved for §§ 1090.80; 1090.1395(a).

(18) ASTM D5134–21, Standard Test Method for Detailed Analysis of Petroleum Naphthas through n-Nonane by Capillary Gas Chromatography, approved December 1, 2021 (''ASTM D5134''); IBR approved for § 1090.1350(b).

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(21) ASTM D5453–24, Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Spark Ignition Engine Fuel, Diesel Engine Fuel, and Engine Oil by Ultraviolet Fluorescence, approved October 15, 2024 (''ASTM D5453''); IBR approved for § 1090.1350(b).

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(25) ASTM D5842–23, Standard Practice for Sampling and Handling of Fuels for Volatility Measurement, approved October 1, 2023 (''ASTM D5842''); IBR approved for § 1090.1335(d).

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(28) ASTM D6259–23, Standard Practice for Determination of a Pooled Limit of Quantitation for a Test Method, approved May 1, 2023 (''ASTM D6259''); IBR approved for § 1090.1355(b).

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(32) ASTM D6708–24, Standard Practice for Statistical Assessment and Improvement of Expected Agreement Between Two Test Methods that Purport to Measure the Same Property of a Material, approved March 1, 2024 (''ASTM D6708''); IBR approved for §§ 1090.1360(c), 1090.1365(d) and (f), and 1090.1375(c).

(33) ASTM D6729–20, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100 Metre Capillary High Resolution Gas Chromatography, approved June 1, 2020 (''ASTM D6729''); IBR approved for § 1090.1350(b).

(34) ASTM D6730–22, Standard Test Method for Determination of Individual Components in Spark Ignition Engine Fuels by 100-Metre Capillary (with Precolumn) High-Resolution Gas Chromatography, approved November 1, 2022 (''ASTM D6730''); IBR approved for § 1090.1350(b).

(35) ASTM D6751–24, Standard Specification for Biodiesel Fuel Blendstock (B100) for Middle Distillate Fuels, approved March 1, 2024 (''ASTM D6751''); IBR approved for §§ 1090.300(a) and 1090.1350(b).

(36) ASTM D6792–23c, Standard Practice for Quality Management Systems in Petroleum Products, Liquid Fuels, and Lubricants Testing Laboratories, approved November 1, 2023 (''ASTM D6792''); IBR approved for § 1090.1450(c).

(37) ASTM D7717–11 (Reapproved 2021), Standard Practice for Preparing Volumetric Blends of Denatured Fuel Ethanol and Gasoline Blendstocks for Laboratory Analysis, approved October 1, 2021 (''ASTM D7717''); IBR approved for § 1090.1340(b).

(38) ASTM D7777–24, Standard Test Method for Density, Relative Density, or API Gravity of Liquid Petroleum by Portable Digital Density Meter, approved July 1, 2024 (''ASTM D7777''); IBR approved for § 1090.1337(d).

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Subpart D—Diesel Fuel and ECA Marine Fuel Standards

■ 43. Amend § 1090.300 by adding paragraph (a)(3) to read as follows:

§ 1090.300 Overview and general requirements.

(a) * * *

(3) Biodiesel that meets ASTM D6751 (incorporated by reference in § 1090.95) is not subject to the cetane index or aromatic content standards in § 1090.305(c). Biodiesel or biodiesel blends that do not meet ASTM D6751 remain subject to the cetane index or aromatic content standards in § 1090.305(c).

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■ 44. Amend § 1090.305 by revising paragraph (a) to read as follows:

1090.305 ULSD standards.

(a) *Overview.* Except as specified in § 1090.300(a), all diesel fuel (including nonpetroleum diesel fuel) must meet the ULSD per-gallon standards of this section.

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Subpart N—Sampling, Testing, and Retention

■ 45. Amend § 1090.1310 by revising paragraph (b)(1) to read as follows:

§ 1090.1310 Testing to demonstrate compliance with standards.

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(b) * * *

(1) *Diesel fuel.* Perform testing for each batch of ULSD (including nonpetroleum diesel fuel), 500 ppm LM diesel fuel, and ECA marine fuel to demonstrate compliance with sulfur standards.

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■ 46. Amend § 1090.1337 by revising paragraph (e) to read as follows:

§ 1090.1337 Demonstrating homogeneity.

* * * * *

(e) For testing of diesel fuel (including nonpetroleum diesel fuel) and ECA marine fuel to meet the standards in subpart D of this part, demonstrate homogeneity using one of the procedures specified in paragraph (d)(1) or (2) of this section.

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