Draft Regulatory Impact Analysis: RFS Annual Rules

United States Environmental Protection Agency

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Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

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Executive Summary

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

The statute includes annual, nationally applicable volume targets for each of the four categories of renewable fuel. It also directs EPA to modify or establish volume targets in certain circumstances. EPA must also translate the volume targets into compliance obligations that obligated parties must meet every year. In this action we are proposing the applicable volumes for cellulosic biofuel, advanced biofuel, and total renewable fuel for 2020, 2021, and 2022, and the biomass-based diesel (BBD) applicable volume for 2022, as well as a supplemental standard for 2022 to address the remand of the 2016 annual rule by the D.C. Circuit Court of Appeals, in *Americans for Clean Energy v. EPA*, 864 F.3d 691 (2017) (hereafter "*ACE*"). We are also proposing the annual percentage standards for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel that would apply to gasoline and diesel produced or imported by obligated parties in 2020, 2021, and 2022, as well as the percentage standard for the 2022 supplemental standard.

This draft Regulatory Impact Analysis (DRIA) supports our proposed rulemaking in several ways. First, this DRIA addresses our statutory obligations under CAA section 211(o)(7)(F) for resetting the 2020, 2021, and 2022 cellulosic biofuel, advanced biofuel, and total renewable fuel volumes. This section of the statute directs us to modify the statutory volumes based upon a review of the implementation of the program and an analysis of various environmental, economic, and other factors. We provide this analysis here, in conjunction with the analysis in the preamble and several technical memoranda to the docket. Second, this DRIA addresses our statutory obligations under CAA section 211(o)(2)(B)(ii) for setting the 2022 BBD volume. This section of the statute requires a similar analysis as our reset authority. Chapter 10 of this document specifically focuses on the 2022 BBD volume; however, other chapters are also relevant as they more generally address BBD and its constituent fuels (advanced biodiesel and renewable diesel).

Overview

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

Chapter 2: Baselines and Volume Scenarios
This chapter identifies the specific biofuel types and associated feedstocks that are projected to be used to meet the proposed volume requirements, and the appropriate baselines for comparison.

Chapter 3: Environmental Impacts
This chapter discusses the environmental factors EPA analyzed in developing the proposed volume requirements.

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This chapter reviews the literature on energy security impacts associated with petroleum consumption and imports and summarizes EPA's estimates of the benefits that would result from the proposed volume requirements.

Chapter 5: Rate of Production of Renewable Fuel
This chapter discusses the expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (cellulosic biofuel and BBD).

Chapter 6: Infrastructure
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This chapter provides greater detail on our evaluation of impacts of renewable fuels on job creation, rural economic development, supply and price of agricultural commodities, and food prices.

Chapter 8: Environmental Justice
This chapter describes potential environmental justice impacts associated with the production and use of renewable fuels.

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This chapter assess the impact of the use of renewable fuels on the social cost, the cost to consumers of transportation fuel, and on the cost to transport goods.

Chapter 10: Biomass-Based Diesel Standard for 2022
This chapter analyzes the required statutory factors specifically with respect to the proposed 2022 BBD volume requirement, in comparison to other advanced biofuels.

Chapter 11: Screening Analysis
This chapter discusses EPA's screening analysis evaluating the potential impacts of the proposed RFS standards on small entities.

Note: Unless otherwise stated, all documents cited in this document are available in the docket for this action (EPA-HQ-OAR-2021-0324).

List of Acronyms and Abbreviations

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

AAA	American Automobile Association
ACE	*Americans for Clean Energy v. EPA*, 864 F.3d 691 (2017)
AEO	Annual Energy Outlook
ASTM	American Society for Testing and Materials
BBD	Biomass-Based Diesel
CAA	Clean Air Act
CAFE	Corporate Average Fuel Economy
CBI	Confidential Business Information
CBOB	Blendstock for Oxygenate Blending
CG	Conventional Gasoline
CNG	Compressed Natural Gas
CO	Carbon Monoxide
CWC	Cellulosic Waiver Credit
DOE	U.S. Department of Energy
DRIA	Draft Regulatory Impact Analysis
EIA	U.S. Energy Information Administration
EISA	Energy Independence and Security Act of 2007
EMTS	EPA-Moderated Transaction System
EO	Executive Order
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 2005
EV	Electric Vehicle
FFV	Flex-Fuel Vehicle
FOG	Fats, Oils, and Greases
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model
LCA	Lifecycle Analysis
LCFS	Low Carbon Fuel Standard
LNG	Liquified Natural Gas
MSW	Municipal Solid Waste
MTBE	Methyl Tertiary Butyl Ether
MY	Model Year
NEMS	National Energy Modeling System
NHTSA	National Highway Transportation Administration
NOx	Nitrogen Oxides
OPEC	Organization of Petroleum Exporting Countries
OPIS	Oil Price Information Service
ORNL	Oak Ridge National Laboratory
PHEV	Plug-in Hybrid Electric Vehicle

PM	Particulate Matter
RFF	Resources for the Future
RFG	Reformulated Gasoline
RFRA	Renewable Fuels Reinvestment Act
RFS	Renewable Fuel Standard
RIA	Regulatory Impact Analysis
RIN	Renewable Identification Number
RVO	Renewable Volume Obligation
RVP	Reid Vapor Pressure
SOx	Sulfur Oxides
SRE	Small Refinery Exemption
STEO	Short Term Energy Outlook
ULSD	Ultra-Low-Sulfur Diesel
USDA	U.S. Department of Agriculture
VEETC	Volumetric Ethanol Excise Tax Credit
VOC	Volatile Organic Compounds
WTI	West Texas Intermediate

Chapter 1: Review of the Implementation of the Program

The statute directs EPA to establish volumes based on several factors, including "a review of the implementation of the program…." This chapter reviews the implementation of the RFS program in previous years, focusing on renewable fuel production and use in the transportation sector since the RFS program began. Of particular interest is a comparison of what the expectations were when the RFS program was initially designed and implemented to what actually occurred, and an investigation into the reasons that the renewable fuels market developed as it did. To this end, the focus of this chapter is on factors related to the production and use of renewable fuels:

- Feedstock availability, production, and collection
- Renewable fuel production technology and capacity
- Distribution, storage, blending, and dispensing of renewable fuels
- The consumption of renewable fuels in vehicles and engines

1.1 Progression of the Fuels Market

At the time that the RFS program was initially created by EPAct, the transportation fuels market was already undergoing changes. Multiple state bans on the use of methyl tertiary butyl ether (MTBE) in gasoline, due to concerns about leaking underground storage tanks and groundwater contamination, had caused refiners to look for replacement sources of high octane gasoline blendstocks. Crude oil prices had also begun to rise over the lower levels seen in the previous decade, improving the relative economic value of alternative fuels. Both of these factors provided some incentive for the increased use of ethanol in gasoline even before the RFS program went into effect.

Congressional activity related to MTBE also had an impact on ethanol use in the years leading up to EPAct. For instance, Congress had considered providing liability protection to refiners using MTBE under the premise that they had no choice but to use an oxygenate in the reformulated gasoline (RFG) and oxyfuels programs.[1] Congressional consideration of some sort of liability protection for refiners, as well as the lack of sufficient infrastructure between 2000 and 2005 for distributing and blending ethanol, likely contributed to the continued use of MTBE despite state bans and concerns expressed by EPA and the public about MTBE in the years prior to and including 2005.[2]

Ultimately, however, Congress rejected any form of liability protection for MTBE in EPAct. While EPAct did not include a nationwide ban on the use of MTBE, it did remove the RFG oxygen mandate, eliminating any argument that MTBE use was necessary to comply with the statute. In combination with the removal of the RFG oxygen mandate, the creation of the RFS program, and the increased economic value of ethanol in light of increasing crude oil prices, refiners now had a disincentive to continue using MTBE after 2005. In addition, although the oxygen requirement for RFG was removed in EPAct, the emission standards for RFG were

[1] "Timeline - A Very Short History of MTBE in the US."
[2] "Clinton-Gore Administration Acts To Eliminate MTBE, Boost Ethanol."

neither eliminated nor modified.[3] Without MTBE, something would be needed to replace the lost volume and octane that had been provided by MTBE while also ensuring that the RFG emission standards would continue to be met. The net result of these factors is that the market made a dramatic shift away from MTBE to ethanol in a very short period of time. By the end of 2006, MTBE use in gasoline had fallen by about 80% in comparison to 2005 levels and by 2007 was essentially zero, while ethanol replaced MTBE on an almost one-for-one energy-equivalent basis over those same two years, growing by 56%.[4] The sudden demand for ethanol use in RFG areas, representing about one-third of all gasoline, was so great that its use was temporarily reduced in much of the rest of the country (conventional gasoline (CG) areas) where ethanol was not needed to meet state fuel program requirements until additional ethanol supply could be brought online. This occurred despite the fact that E10 in CG areas benefitted from a 1 psi RVP waiver, while RFG's emission standards precluded that waiver.

After the RFS program first went into effect in 2006, other factors continued to affect the biofuels market. Crude oil prices continued to rise, state mandates for ethanol and biodiesel use expanded, California's Low Carbon Fuel Standard (LCFS) program was implemented, and foreign demand for biofuels increased. At the same time, the federal ethanol tax subsidy expired at the end of 2011,[5] and the federal oxygenated fuels (oxyfuels) program was largely phased out as areas came into attainment with ambient wintertime carbon monoxide (CO) standards. Furthermore, the statutory requirements were amended by the Energy Independence and Security Act of 2007 (EISA), replacing the single total renewable fuel standard under the RFS1 program with four nested standards (cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel). EPA implemented these changes through the RFS2 program, which began in the midst of these other changes, first with a single but considerably higher total renewable fuel standard in 2009 compared to previous years, and then with the addition of separate standards for cellulosic biofuel, BBD, and advanced biofuel beginning in 2010. In the following years, cellulosic ethanol production struggled to develop despite Congressional aspirations, and increases in ethanol use slowed as the nationwide average ethanol concentration approached 10%.[6] BBD volume, in contrast, expanded beyond the Congressional targets, outcompeting other advanced biofuels with the help of an ongoing tax incentive, and EPA reflected this by setting higher BBD volume requirements for years after 2012.

The history of the progression of the fuels market indicates that consumption of renewable fuels has been a function of many factors, of which the RFS program was only one. Many of these factors can be expected to contribute to renewable fuel production and consumption in the future, including other federal and state fuels programs and incentives, the octane value of ethanol, and foreign demand for renewable fuel.

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[3] See 40 CFR 80.41(e) and (f).

[4] Based on EPA batch data, available at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/gasoline-properties-over-time (excludes California).

[5] The Volumetric Ethanol Excise Tax Credit (VEETC) was instituted through the American Jobs Creation Act of 2004 and the deadline was extended to December 31, 2011, through the Renewable Fuels Reinvestment Act (RFRA).

[6] Here and elsewhere in this DRIA, "ethanol concentration" refers to the concentration of denatured ethanol in gasoline.

1.2 In-Use Consumption of Renewable Fuels

There are several reasons why actual renewable use may differ from the renewable fuel volume targets specified in the statute or even the volumes required through the RFS regulations. First, the statutory provisions of the RFS program provide EPA with several waiver authorities to reduce the statutory volumes under particular circumstances.[7] The statutory volumes minus waived volumes equal applicable volumes; the applicable percentage standards, which are the mechanism through which the obligations of an individual "obligated party" are determined under the RFS program, are based on the applicable volumes.[8]

The "general waiver" authority at CAA section 211(o)(7)(A) was enacted by EPAct and maintained in EISA. It permits EPA to reduce any of the four applicable volume targets in the statute if EPA makes one of the following findings:

> (i) based on a determination by the Administrator, after public notice and opportunity for comment, that implementation of the requirement would severely harm the economy or environment of a State, a region, or the United States; or
>
> (ii) based on a determination by the Administrator, after public notice and opportunity for comment, that there is an inadequate domestic supply.

The "cellulosic waiver" authority at CAA section 211(o)(7)(D) was introduced by EISA and is specific to cellulosic biofuel. It requires (not merely permits) EPA to reduce the statutory cellulosic volume in years that the projected volume of cellulosic biofuel production is less than the statutory volume target. When making such a reduction, EPA may also reduce the statutory volume targets for total renewable fuel and advanced biofuels by the same or a lesser volume.

The "biomass-based diesel waiver" authority at CAA section 211(o)(7)(E) was also introduced by EISA and is specific to BBD. It requires a reduction from the statutory BBD volume for up to 60 days if EPA determines that there is a significant renewable feedstock disruption or other market circumstances that would make the price of BBD increase significantly. When making such a reduction in BBD volume, EPA may also reduce the statutory volume targets for total renewable fuel and advanced biofuels by the same or a lesser volume, similar to the cellulosic waiver authority. Both the cellulosic and BBD waiver authorities include additional criteria for how the waived volumes are to be determined and/or applied.

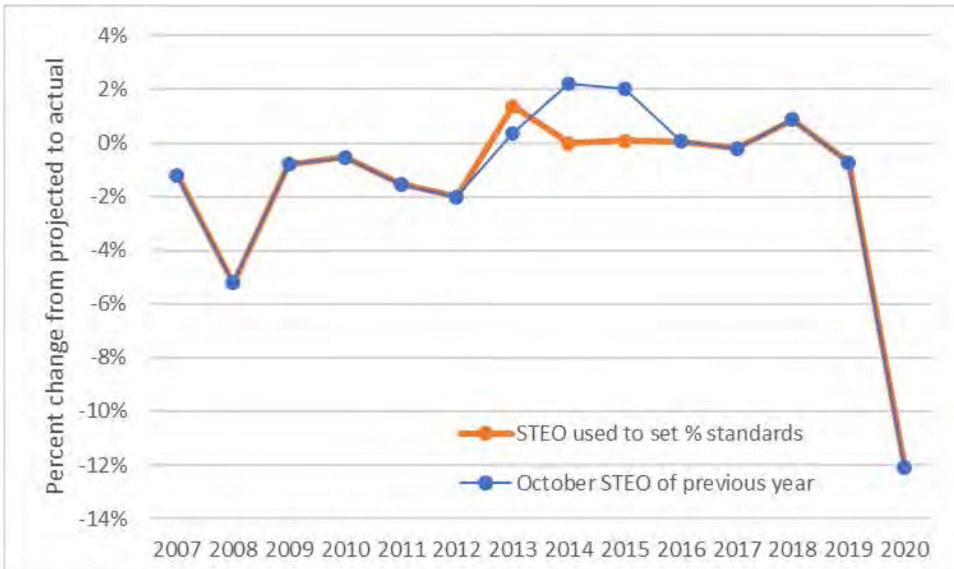
The statute only specifies volume targets for BBD for 2009 through 2012, and EPA did not reduce the statutory target for any of those years under either the general or BBD waiver authorities. Under the cellulosic waiver authority, however, EPA has reduced the statutory target for cellulosic biofuel in every year since 2010 and the statutory targets for advanced biofuel and total renewable fuel in every year since 2014.

[7] See CAA section 211(o)(7).
[8] Obligated parties are producers and importers of gasoline and diesel. See 40 CFR 80.1406.

EPA has used the general waiver authority on only one occasion, in the 2016 annual rule based on a finding of inadequate domestic supply.[9] However, the D.C. Circuit Court of Appeals vacated EPA's use of this waiver authority in *ACE*. Specifically, the court found that EPA had impermissibly considered demand-side factors in its assessment of inadequate domestic supply, rather than limiting that assessment to supply-side factors. The court remanded the rule back to EPA for further consideration in light of the court's ruling.

In addition to the waiver authorities mentioned above, there are five other reasons why actual renewable fuel use may differ from either the statutory or applicable volume requirements. The first is that the percentage standards are based on projected volumes of gasoline and diesel consumption which typically deviate to some degree from what actually occurs. EPA relies on projections provided by the U.S. Energy Information Administration (EIA) in the Short Term Energy Outlook (STEO).[10] In the context of the RFS program, the sum of non-renewable gasoline and diesel demand is relevant. Since the first percentage standard was applied in 2007, this projection has sometimes overpredicted and sometime underpredicted actual consumption as shown below.

Figure 1.2-1: Percent Change from Projected to Actual Sum of Non-Renewable Gasoline + Diesel[a,b,c]



[a] From 2007 to 2009, the RFS1 regulatory structure was in effect, and the applicable percentage standards were based on non-renewable gasoline projections only. Therefore, the values for these three years represent non-renewable gasoline.
[b] For purposes of demonstrating the error in projections, the blue line uses projected volumes derived from the October edition of the STEO for the following year. The orange line, in contrast, uses projected volumes derived from the version of the STEO that was actually used to calculate the percentage standards, which in some years was not the October edition of the preceding year (e.g., the 2014 standards were established in December 2015, well after the 2014 compliance year was over).
c See data and calculations in "Calculation of Percent Change from Projected to Actual Gasoline and Diesel," available in the docket.

[9] 80 FR 77420 (December 14, 2015).
[10] See CAA section 211(o)(3)(A).

In the event that the actual consumption of non-renewable gasoline and diesel is lower than the projection that EPA used to set the applicable percentage standards (negative values in the figure above), the obligations applicable to individual obligated parties are likewise lower, and, all other things being equal, the actual volumes of renewable fuel used as transportation fuel will fall short of the volumes EPA used in setting the percentage standards. Likewise, if the actual consumption of non-renewable gasoline and diesel is higher than the projection that EPA used to set the applicable percentage standards (positive values in the figure above), the actual volumes of renewable fuel used as transportation fuel will be higher. Despite the fact that the statute directs EPA to set standards that ensure that transportation fuel sold or introduced into commerce contains the applicable volumes of renewable fuel, the statute also directs EPA to use projections of gasoline and diesel for this purpose, and does not mandate that EPA correct the volume requirements based on deviations in those projections from the volumes actually consumed.

Another reason that the volume requirements may not be reached by the market in a particular year is related to the credit system that is used to demonstrate compliance with the RFS program.[11] These credits are called Renewable Identification Numbers, or "RINs." Obligated parties have the flexibility to use RINs representing renewable fuel produced in a previous year, often called "carryover RINs" or "banked RINs," to demonstrate compliance rather than by using RINs representing current year renewable fuel production.[12,13] The nationwide total of banked RINs grew dramatically in the early years of the RFS program, and obligated parties have at times drawn down this bank to help fulfill their obligations. For instance, in 2013 consumption of renewable fuels fell more than 500 mill ethanol-equivalent gallons short of the applicable volume requirement, and obligated parties used banked RINs to make up the shortfall. Similarly, while compliance demonstrations for 2019 have not yet fully occurred, we estimate that obligated parties will use approximately 1.5 billon banked RINs to make up for a shortfall in actual consumption.

The third reason that the applicable volume requirements may vary from actual renewable fuel use is the difficulty in projecting the future market's ability to make available and consume renewable fuels. For instance, in several cases producers of cellulosic biofuel made plans that did not come to fruition, such as Cello Energy, Range Fuels, and KiOR.[14] There has also been considerable uncertainty associated with estimating the ability of the RFS standards to incentivize increases in the consumption of ethanol above the E10 blendwall.[15] Other unforeseen circumstances such as the drought in 2012 that adversely affected crops yields and the impacts of the COVID-19 pandemic in 2020 have also contributed to shortfalls in renewable fuel production in comparison to the intended volume requirements. By contrast, in some other years, the market used more renewable fuel than what EPA projected, typically when the economics of doing so were favorable.

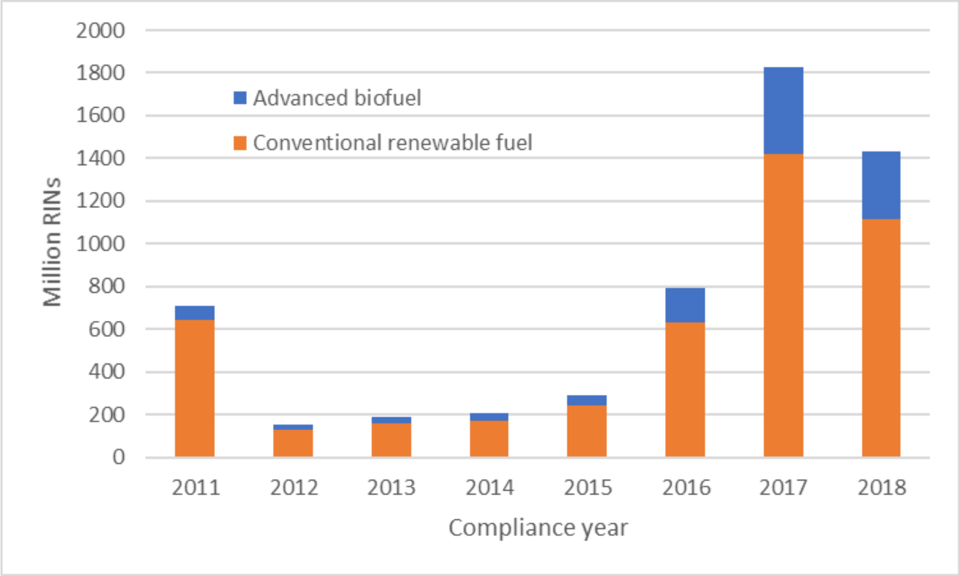
[11] CAA section 211(o)(5) establishes the provisions for credits under the RFS program. This system is discussed in more detail in Chapter 1.9.
[12] This flexibility is a function of the two-year life of RINs as discussed more fully in Chapter 1.9.
[13] The use of previous year RINs for compliance with the applicable standards is limited to 20% of an obligated party's Renewable Volume Obligation (RVO) as indicated in 40 CFR 80.1427(a)(5).
[14] 80 FR 77506 (December 14, 2015).
[15] 80 FR 77457 (December 14, 2015).

A fourth reason that the applicable volume requirements may vary from actual renewable fuel use is that there are other drivers for renewable fuel use besides the RFS program. For instance, as discussed in Chapter 1.1, in the early years of the program, renewable fuel use significantly outpaced the RFS requirements spurred by the transition from MTBE to ethanol as an oxygenate. We discuss numerous other, non-RFS economic drivers for renewable fuel use throughout this section.

Finally, exemptions for small refineries due to disproportionate economic hardship may result in actual consumption of renewable fuels falling short of the volume requirements. These exemptions are permitted under CAA section 211(o)(9)(B) and are evaluated on a refinery-by-refinery basis. In cases where a small refinery exemption (SRE) was granted after the applicable percentage standards were set, the percentage standards remained unchanged but were then applicable to a smaller number of parties.

As described in the 2011 annual rule and repeated in every subsequent annual rule through 2019, once the percentage standards were established for a given year, EPA did not adjust them to account for SREs that were subsequently granted. In essence, this meant that non-exempt obligated parties did not have to make up for volumes that would not be attained by the exempt small refineries.[16] This approach is consistent with that taken for the projected non-renewable gasoline and diesel volumes used to calculate the percentage standards, where errors in projected volumes could likewise result in actual consumption of renewable fuel falling short of the intended volume requirements.

Figure 1.2-2: Volume of SREs Granted After the Applicable Percentage Standards Were Set, By Compliance Year[a]



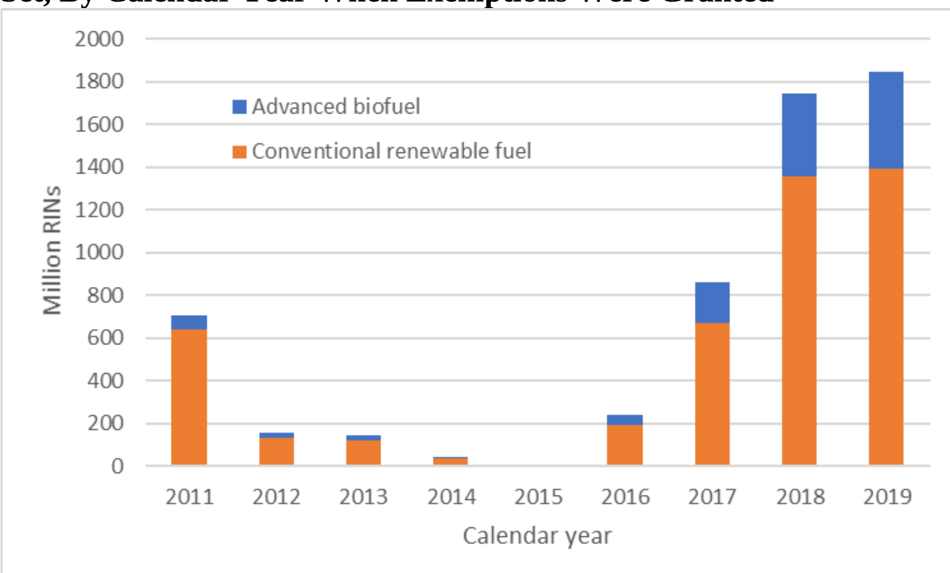
[a] As of this writing, no SREs have been granted after compliance year 2018.

As shown in Figure 1.2-2, SREs granted after the standards were set varied significantly by compliance year. However, these SREs did not necessarily translate into an equivalent

[16] 75 FR 76805 (December 9, 2010).

reduction in actual consumption. Other factors also played a role in determining whether and when actual consumption was affected by SREs. For instance, the combination of the economic attractiveness of marketing ethanol to consumers as E10 and the infrastructure to blend, distribute, and dispense E10, along with longer-term contracts for ethanol blending, meant that the nationwide average ethanol concentration remained very near or above 10.00% ethanol even when large volumes of SREs were granted. By contrast, SREs may have had a greater impact on depressing biodiesel and renewable diesel consumption and potentially consumption of ethanol as E15 or E85. With regard to the timing of the impacts, SREs generally affected consumption of renewable fuel in the calendar year in which they were granted and/or the following years, rather than in the compliance year to which they applied, as shown in Figure 1.2-3.

Figure 1.2-3: Volume of SREs Granted After the Applicable Percentage Standards Were Set, By Calendar Year When Exemptions Were Granted[a]



[a] As of this writing, no SREs have been granted after calendar year 2019.

However, it was not always the case that SREs affected consumption of renewable fuel only in the calendar year in which they were granted and/or the following years. For instance, some small refineries adjusted their RIN acquisition efforts to reflect anticipated grants of their SRE petitions, effectively resulting in SREs having a market impact before they were actually granted. In other cases, a small refinery that was granted an exemption may not have reduced its acquisition of RINs as a result, but may instead have continued to blend renewable fuel into its own gasoline and/or diesel due to the economic attractiveness of doing so. In such cases, the total number of RINs generated may not have been reduced by the SRE, but the carryover RIN bank may have increased. Finally, as discussed above, higher-than-projected gasoline and diesel demand could offset the effect of SREs to some degree.

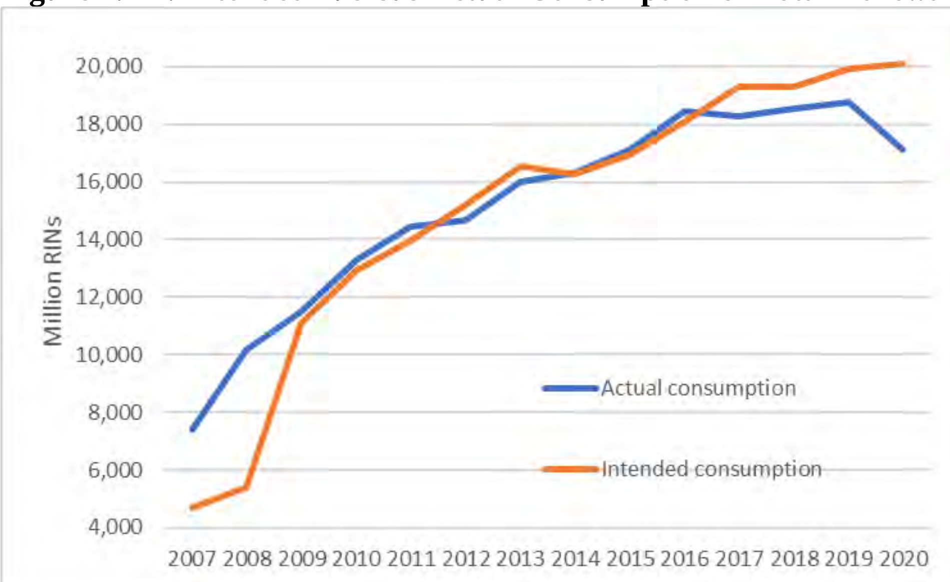
In the 2020 rule, EPA revised the RFS regulations to account for a projection of exempt small refinery volumes, increasing the 2020 percentage standards applicable to non-exempt refineries.[17] Thus, if EPA exempts volumes of gasoline and diesel equal to the projected exempt

[17] 85 FR 7016 (February 6, 2020).

volumes, then the market would (all other things being equal) attain the renewable fuel volumes in the 2020 rule. However, if EPA exempts greater or lesser volumes of gasoline and diesel than the projected exempt volumes, then the market would attain lesser or greater renewable fuel volumes than those in the 2020 rule.[18]

In sum, due to the many factors that affect renewable fuel consumption, including its cost-competitiveness in comparison to petroleum-based gasoline and diesel, actual consumption was sometimes higher and sometimes lower than the volumes that were originally intended to be consumed (i.e., the volumes used to calculate the applicable percentage standards).

Figure 1.2-4: Intended[a] Versus Actual Consumption of Total Renewable Fuel



Source for actual consumption: EPA-Moderated Transaction System (EMTS)
[a] Intended volumes represent the volumes used to calculate the applicable percentage standards. As such, the intended volumes do not account for the effects of SREs granted after the percentage standards were established, errors in projected demand for gasoline and diesel, or the use of carryover RINs for compliance.

The total volume of renewable fuel that was intended to be used between 2007 and 2020 (i.e., the volume that was used to calculate the applicable percentage standards) was almost 210 billion ethanol-equivalent gallons. In comparison, actual consumption was about 212 billion ethanol-equivalent gallons over the same time period. Thus, actual consumption actually exceeded what was intended over the life of the RFS program through 2020. In 2007 and 2008, the significant oversupply was due primarily to the expansion of E10 when the market as a whole had not yet reached the E10 blendwall and blending ethanol as E10 was economically attractive relative to gasoline. The significant undersupply in more recent years affected all types of renewable fuel more equitably, and was precipitated by a combination of the approval of SREs after the applicable percentage standards had been set, lower than projected gasoline and diesel consumption, and other economic factors.

[18] EPA extended the 2020 compliance deadline for obligated parties to January 31, 2022. EPA has also not yet granted any SREs for 2020.

Economic factors impact conventional renewable fuel and non-cellulosic advanced biofuel differently. These factors include crude oil prices, renewable fuel production costs (which are in turn a function of feedstock, process heat, and power costs), tax subsidies, and the market pressures created by the RFS standards to increase ethanol use above the E10 blendwall. Economic factors are coupled with the use of carryover RINs for compliance, the size of the carryover RIN bank, and deficit carry-forwards. In 2013, for instance, the implied conventional renewable fuel standard was 13.8 billion gallons, which was considerably higher than the E10 blendwall. The market responded by producing less conventional renewable fuel but more non-cellulosic advanced biofuel than required. The net effect of these two outcomes nevertheless still fell short of the applicable volume requirements, and the market thus relied on some carryover RINs for compliance.

1.3 2010 Biofuel Projections Versus Reality

In the 2010 rule that established the RFS2 program, EPA projected volumes of each type of renewable fuel that in the aggregate would meet the applicable volume targets in the statute for cellulosic biofuel, BBD, advanced biofuel, and total renewable fuel.[19] These projections did not include any consideration of potential future waivers or any other factor that might cause the statutory volumes not to be met. In reality, actual consumption of renewable fuel typically fell short of the statutory targets for all renewable fuel categories except for BBD. Moreover, the specific types of renewable fuel that were projected in 2010 to be used to fulfill the mandates differed from what was actually used, most notably in regard to the relative amounts of ethanol and non-ethanol renewable fuels.

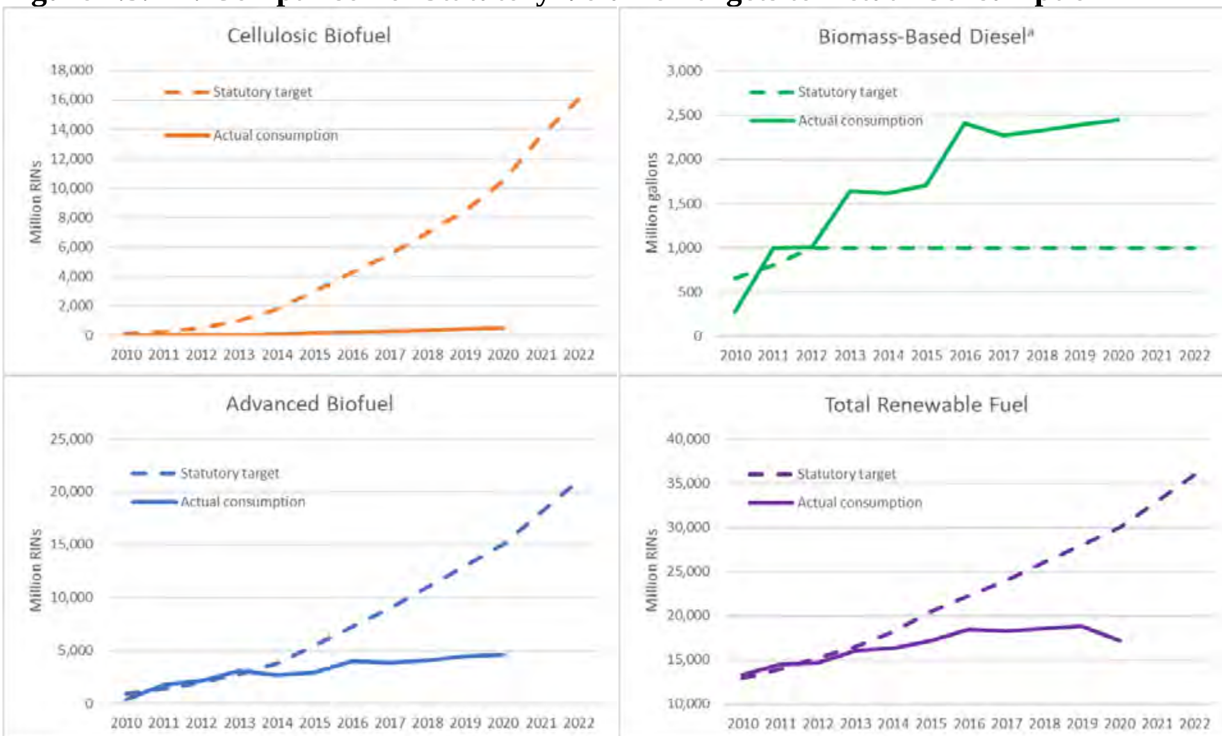
This section highlights the aspirational nature of the statutory volume targets, especially for cellulosic biofuel and its carry through impact on advanced biofuel and total renewable fuel. This section also highlights the difficulty in projecting the ability of the market to meet applicable standards as well as the specific mix of biofuels that will be produced, imported, and consumed.

1.3.1 Shortfalls in Comparison to Statutory Targets

As explained in Chapter 1.2, there are many reasons why actual use of renewable fuels fell short of the statutory targets. Figure 1.3.1-1 compares the statutory targets to actual consumption for the four categories of renewable fuel.

[19] 75 FR 14670 (March 26, 2010)

Figure 1.3.1-1: Comparison of Statutory Volume Targets to Actual Consumption

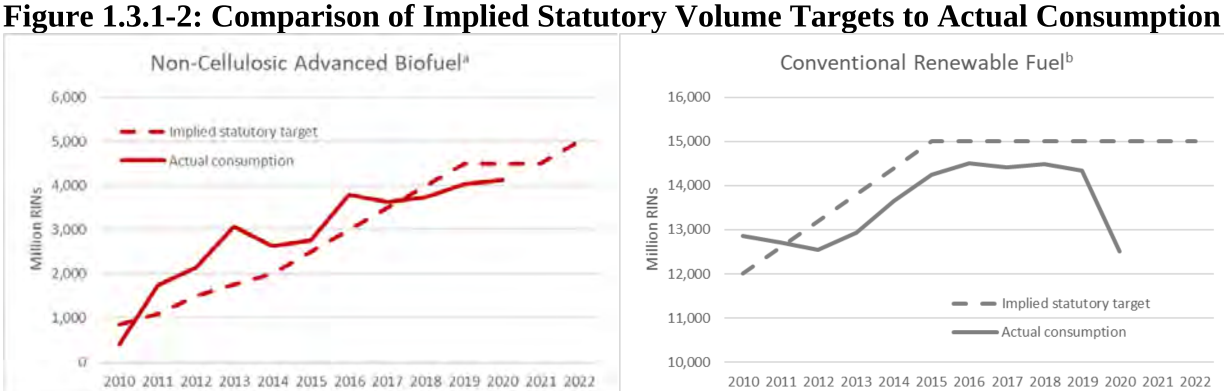


Source for actual consumption: EMTS

[a] The statute specifies BBD volume targets only through 2012. Thereafter, the required BBD volume can be no less than 1.0 billion gallons, but can be more based on an analysis of specified factors.

The significant shortfalls in advanced biofuel and total renewable fuel for more recent years are primarily the result of shortfalls in cellulosic biofuel. This fact is more evident in Figure 1.3.1-2, which shows that consumption is considerably closer to the implied statutory volume targets for non-cellulosic advanced biofuel and conventional renewable fuel.

Figure 1.3.1-2: Comparison of Implied Statutory Volume Targets to Actual Consumption



Source for actual consumption: EMTS

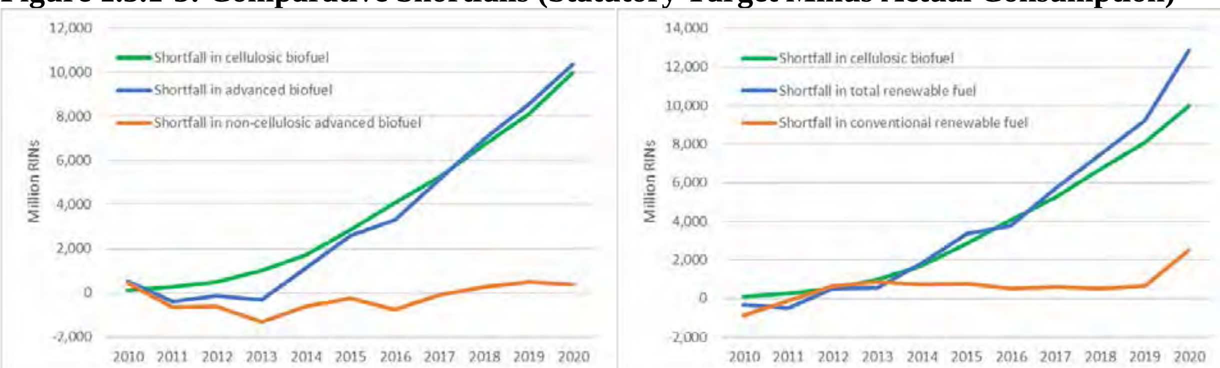
[a] Non-cellulosic advanced biofuel represents RINs with a D-code of 4 or 5.

[b] Conventional renewable fuel represents RINs with a D-code of 6.

The oversupply in non-cellulosic advanced biofuel between 2011 and 2017 partially offset some of the shortfall in conventional renewable fuel in the same years, and also contributed to increases in the carryover RIN bank in some years.

A direct comparison of shortfalls in consumption of cellulosic biofuel to shortfalls in the other categories of renewable fuel makes it clear that consumption of advanced biofuel and total renewable fuel was directly affected by the shortfall in cellulosic biofuel, while the consumption of non-cellulosic advanced biofuel and conventional renewable fuel was not. This is to be expected since the cellulosic biofuel category is nested within advanced biofuel and total renewable fuel categories, but cellulosic biofuel is independent of non-cellulosic advanced biofuel and conventional renewable fuel.

Figure 1.3.1-3: Comparative Shortfalls (Statutory Target Minus Actual Consumption)

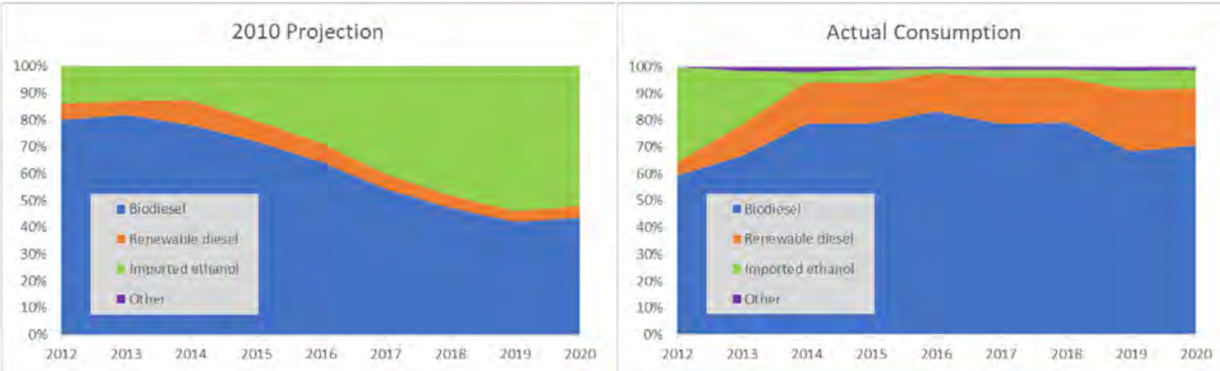


Source for actual consumption: EMTS

1.3.2 Relative Proportions of Ethanol and Non-Ethanol Renewable Fuel

In the 2010 RFS2 rule, non-cellulosic advanced biofuel through 2022 was projected to be composed of biodiesel, renewable diesel, and imported sugarcane ethanol. This has proved largely true as volumes of renewable jet fuel, biogas, heating oil, domestic advanced ethanol, and naphtha, the only other eligible advanced biofuels, have represented only a very small fraction of non-cellulosic advanced biofuel consumption. However, the relative proportions of biodiesel, renewable diesel, and imported sugarcane ethanol have been far different in actual consumption than in the projections from the 2010 rule which established the RFS2 program.

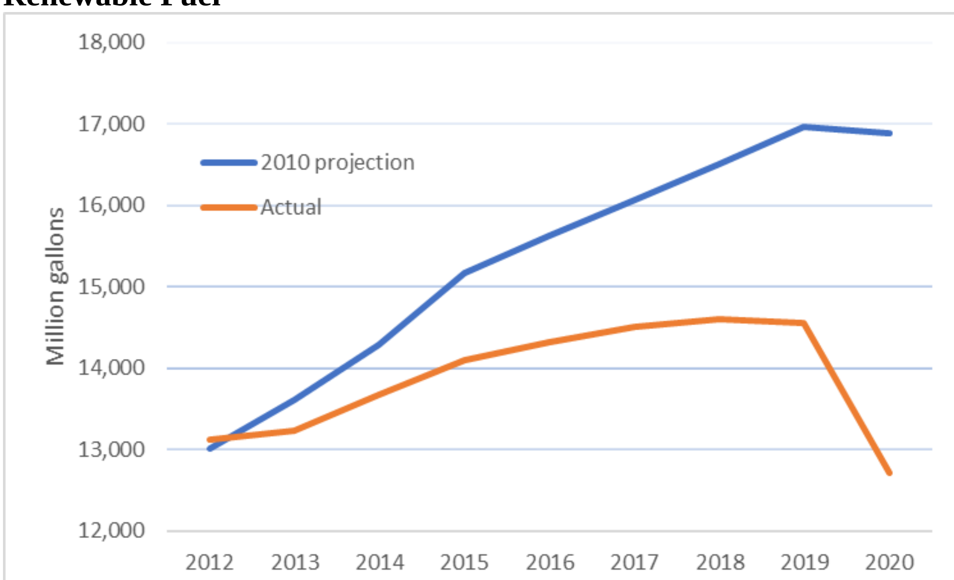
Figure 1.3.2-1: Volumetric Proportions of Each Fuel Type in Non-Cellulosic Advanced Biofuel



Source: "2010 projection" is from the 2010 final rule which created the RFS2 program. See Table 1.2-3 in the RIA for that rule. "Actual consumption" is from EMTS.

Actual consumption of imported sugarcane ethanol has been considerably lower than in the 2010 projection, and consumption of advanced biodiesel and renewable diesel has been higher. This outcome for imported sugarcane ethanol is mirrored in the outcome for total ethanol: actual consumption of ethanol has been lower than the 2010 projection and actual biodiesel and renewable diesel has been higher.

Figure 1.3.2-2: Actual Versus 2010 Projection of Ethanol Consumption in Non-Cellulosic Renewable Fuel[a]



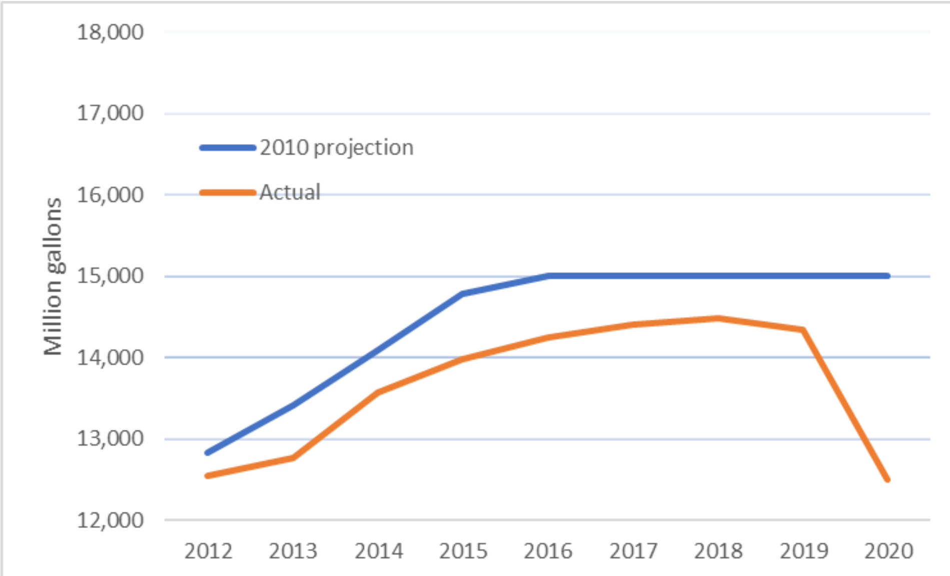
Source: "2010 projection" is from the 2010 final rule which created the RFS2 program. See Table 1.2-3 in the RIA for that rule. "Actual consumption" is from EMTS.
[a] The 2010 projection of ethanol shown here represents the "primary control case." EPA also analyzed a "low ethanol control case" and a "high ethanol control case."

Figure 1.3.2-3: Actual Versus 2010 Projection of Biodiesel + Renewable Diesel Consumption in Non-Cellulosic Renewable Fuel

Source: "2010 projection" is from the 2010 final rule which created the RFS2 program. See Table 1.2-3 in the RIA for that rule. "Actual consumption" is from EMTS.

This pattern of lower ethanol and higher non-ethanol in comparison to expectations appears to be linked to the E10 blendwall and the difficulty that the market has had in increasing sales of higher ethanol blends such as E15 and E85. The 2010 projections included a significant volume of E85 that did not materialize. The result is that, rather than being met entirely with corn ethanol as projected in 2010, the implied conventional renewable fuel volume requirement has included volumes of ethanol up to and just slightly greater than the E10 blendwall, while biodiesel and renewable diesel have made up the difference.

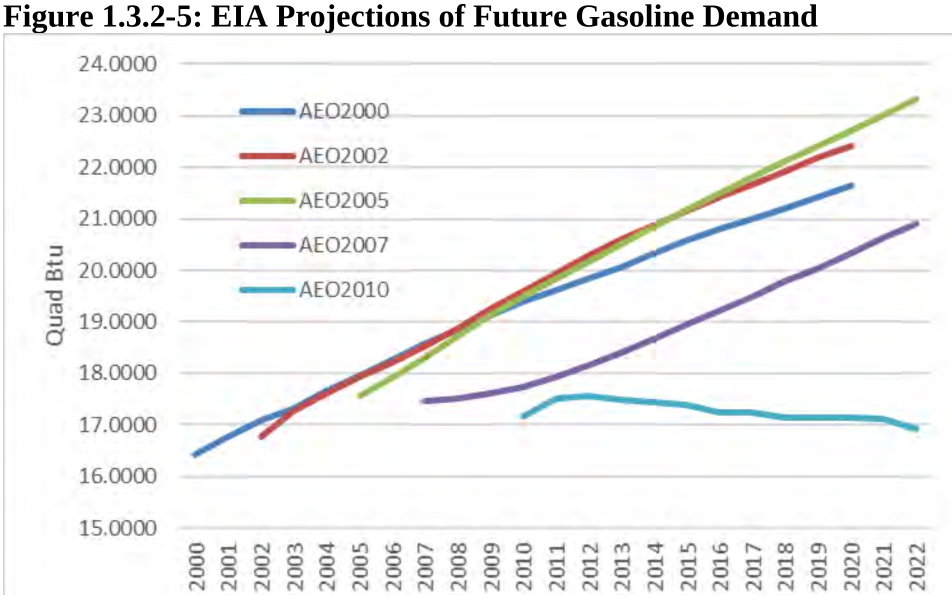
Figure 1.3.2-4: Actual Versus 2010 Projection of Ethanol Consumption in Conventional Renewable Fuel



Source: "2010 projection" is from the 2010 final rule which created the RFS2 program. See Table 1.2-3 in the RIA for that rule. "Actual consumption" is from EMTS.

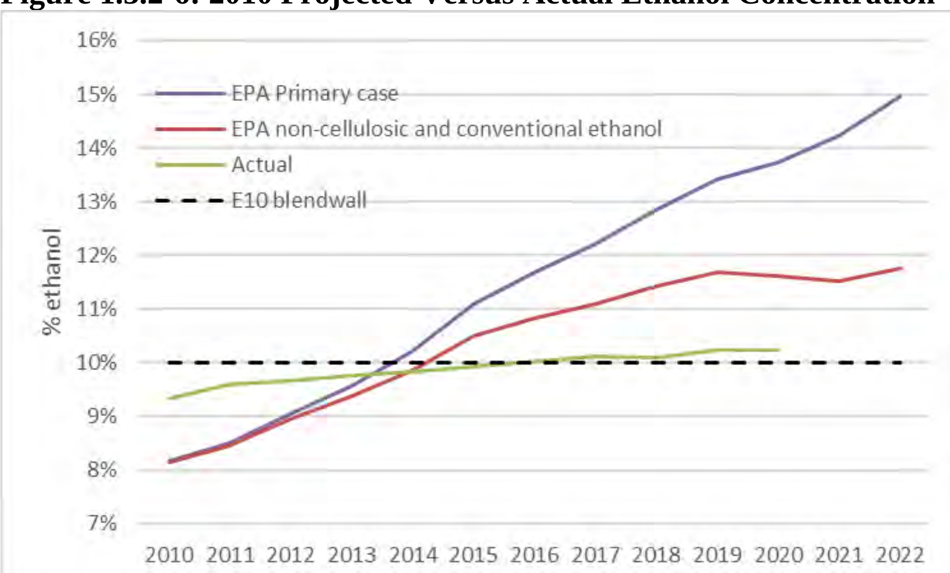
The expectation at the time that EISA was enacted in 2007 was that the implied conventional renewable fuel volume requirement could be met entirely with ethanol as E10 without the nation as a whole exceeding an average ethanol content of 10.00%, and without the need for E15 or E85. This expectation was based on the assumption that gasoline demand would continue to increase in the future, as had been projected by EIA since 2000. By the time RFS2 regulations were finalized in 2010, however, EIA's Annual Energy Outlook (AEO) projected that future gasoline demand was likely to decrease rather than increase.

Figure 1.3.2-5: EIA Projections of Future Gasoline Demand



While EPA's projections in the 2010 rule for how the statutory targets through 2022 might be met included significant volumes of drop-in renewable diesel, it also included total ethanol volumes in excess of the implied statutory conventional renewable fuel volume targets; EPA's projections assumed that substantial volumes of ethanol would also be used to meet the cellulosic biofuel and implied non-cellulosic advanced biofuel volume targets. These projections were based on what EPA believed at that time was reasonable to expect for production and consumption of all renewable fuel types under the influence of the RFS standards, as well as the growth in the availability of E85 at retail service stations that would be needed in order for the projected ethanol volumes to be consumed (E15 had not been approved at that time). Based on EPA's projections of total ethanol volume in the 2010 rule and EIA's projection of gasoline demand in AEO 2010, the nationwide average ethanol content would have first exceeded 10.00% in 2014 in the primary case and would have continued upwards to 15.5% by 2022. In reality, the actual increase in the nationwide average ethanol concentration over time has been considerably slower; the same is true even when ignoring cellulosic ethanol (i.e., when comparing actual ethanol use to the projected volume of all non-cellulosic ethanol (conventional ethanol and non-cellulosic advanced ethanol such as imported sugarcane ethanol)).

Figure 1.3.2-6: 2010 Projected Versus Actual Ethanol Concentration[a]



[a] Here and elsewhere in this DRIA, "ethanol concentration" refers to the concentration of denatured ethanol in gasoline.
Source for actual ethanol concentration: Gasoline and ethanol consumption from EIA's Monthly Energy Review

The considerably slower-than-projected approach to and exceedance of the E10 blendwall suggests that increasing sales of E85 were more difficult to achieve than either EPA or ethanol proponents had projected it would be when the RFS program was established.

1.4 Gasoline, Diesel, and Crude Oil

This section compares crude oil prices with crude oil price projections, and discusses observed changes in petroleum imports, refinery margins, and transportation fuel demand prior to and during the years of the implementation of the RFS program.

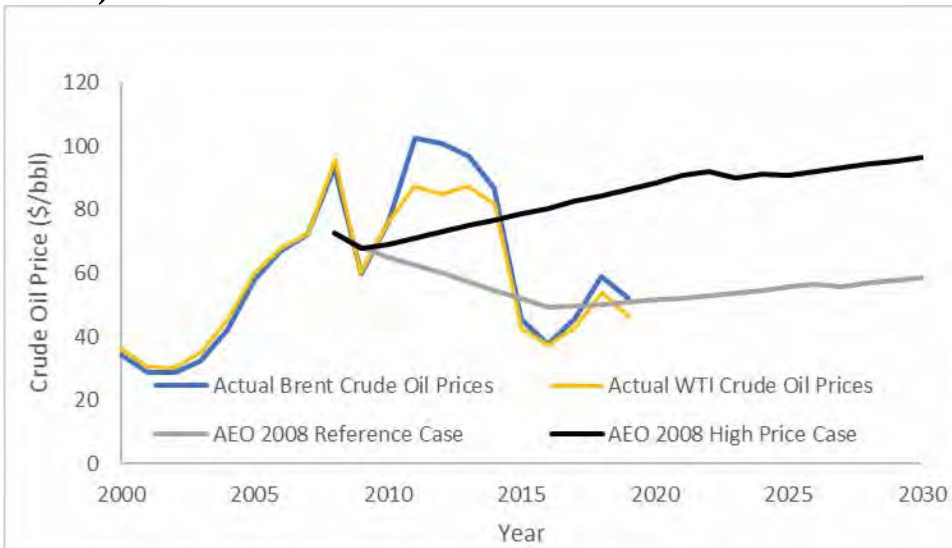
1.4.1 Crude Oil Prices vs. Crude Oil Price Projections

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

When EPA was projecting the cost of future renewable fuels for the RFS2 rule,[20] crude oil prices were very high compared to historical crude oil prices. For estimating the cost of rulemakings, EPA uses projections for the future prices of petroleum products. The cost analysis for the RFS2 rule was based on crude oil, gasoline, and diesel fuel prices projected by EIA in AEO 2008, which projects crude oil prices for decades into the future. Figure 1.4.1-1 shows AEO 2008 projected crude oil prices, as well as actual crude oil prices, for both West Texas Intermediate (WTI, a light, sweet crude produced in the U.S.) and Brent (a light, sweet European crude oil).[21,22,23,24] When there was separation in Brent and WTI crude oil prices and Brent prices were higher than WTI, Brent crude oil prices likely represented the marginal price of crude oils purchased by U.S. refiners and set the marginal price of U.S. refined products, while WTI tended to reflect crude purchase price for many U.S. refiners.

[20] 75 FR 14670 (March 26, 2010).
[21] Light crude oils are comprised of more lower temperature boiling, shorter chain hydrocarbons, while heavy crude oils are comprised of more higher temperature boiling, longer chain hydrocarbons. Sweet crude oils have less sulfur, while sour crude oils have more sulfur. Increased sulfur in crude oils make them more expensive to refine to meet gasoline and diesel fuel sulfur specifications – thus sour crude oils are typically priced lower than sweet crude oils.
[22] AEO 2008 – Petroleum Product Prices; Reference Case; EIA; June 2008.
[23] AEO 2008 – Petroleum Product Prices; High Price Case; EIA: June 2008.
[24] Petroleum and Other Liquids – Spot Prices WTI – Cushing and Brent - Europe; EIA; https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm.

Figure 1.4.1-1: AEO 2008 Projected Crude Oil Prices and Actual Crude Oil Prices (2007 dollars)[a]



[a] Actual crude oil prices have been adjusted to 2007 dollars to be consistent with the value of money used in AEO 2008.

Figure 1.4.1-1 shows actual crude oil prices beginning to increase in 2004 and reaching an average price of nearly $100 per barrel in 2008. Furthermore, some reports at that time projected even higher crude oil prices than the prices in 2008 attributed to crude oil production not keeping up with demand, indicating that the market was anticipating very high crude prices.[25] Nevertheless, EIA crude oil price projections during this time were much lower, and it was during this time that the RFS2 rule was written. The AEO 2008 reference case projected crude oil prices decreasing to under $60 per barrel and remaining that low all the way out to 2030. Because the AEO 2008 reference case projected much lower crude oil prices than actual prices and many other independent predictions at that time, EPA also analyzed the cost of the RFS2 program based on AEO 2008 high crude oil prices. The AEO 2008 high price case estimated crude oil prices rising from $70 per barrel to mid-$90s per barrel out to 2030. Actual crude oil prices decreased in 2014 back down to the $40 to $60 per barrel price range (after adjusting the prices back to 2007 dollars – the dollar value used in AEO 2008), which were much lower than the peak prices, but higher than the typical historical crude oil prices prior to 2004. In retrospect, the reference case and high crude oil price projections of AEO 2008 essentially represented the range of crude oil prices since the RFS2 program was promulgated.

1.4.2 Petroleum Imports

As discussed further in Chapter 4, energy security is an important goal of the RFS program. Importing a significant amount of crude oil and finished petroleum products from abroad creates an energy security concern if the foreign petroleum supply is disrupted. A good example is the oil embargo by the Organization of Petroleum Exporting Countries (OPEC) against the U.S. in 1973 and 1974, which drove up prices, reduced supply, and is attributed to

[25] Hirsch, Robert L.; Peaking of World Oil Production: Impacts, Mitigation & Risk Management; Report to the Department of Energy; February 2005.

causing the U.S. economy to slide into a recession.[26] It also led to Congress banning the export of U.S. oil from 1975 to 2015.[27]

At the time Congress passed EPAct and EISA and EPA was promulgating the RFS1 and RFS2 rulemakings, the U.S. was importing a large portion of its crude oil and refined petroleum products. That trend was expected to continue because the eventual increase in U.S. crude oil production due to fracking was not known at that time. Below we consider the petroleum trade imbalance during that time and what has transpired since.

EIA collects data on imports of crude oil and petroleum products, receives data on crude oil and petroleum product exports from the U.S. Bureau of the Census, and calculates net imports of petroleum into the U.S.[28] The EIA-reported net imports of petroleum values account for imports and exports of crude oil, petroleum products, and biofuels.[29] For the net imports figures shown below in Figure 1.4.2-1, the renewable fuel volumes were removed to only show the U.S. net imports of petroleum for the years from 2000 to 2018. Because the production volume of U.S. tight oil (fracked oil) impacted the net petroleum imports in such a significant way, those volumes are also shown in the figure, along with the individual net imports of gasoline and diesel fuel.

Figure 1.4.2-1: U.S. Net Petroleum Imports and U.S. Tight Oil Production

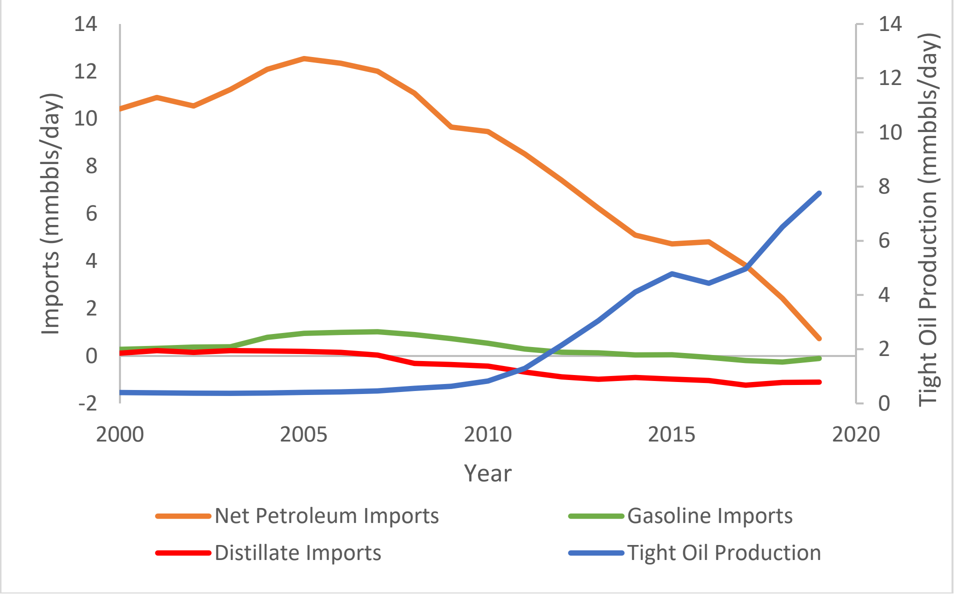


Figure 1.4.2-1 shows that net petroleum imports increased from just over 10 million barrels per day in 2000 to a maximum of about 12.5 million barrels per day in 2005. After

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[26] Verrastro, Frank A., The Arab Oil Embargo-40 Years Later; Center for Strategic & International Studies; October 16, 2013.
[27] 1975 Energy Policy and Conservation Act; Consolidated Appropriations Act of 2016.
[28] U.S. Net Imports by Country; Petroleum and Other Liquids; EIA; https://www.eia.gov/dnav/pet/pet_move_neti_a_EP00_IMN_mbblpd_m.htm
[29] To calculate net petroleum imports EPA subtracted net biofuel imports from the U.S. Net Imports reported by EIA.

peaking in 2005 when EPAct was passed, net petroleum imports started to decrease, very slowly at first, in 2006 and 2007. Starting in 2008, net petroleum imports declined each year by roughly 1 million barrels per day.

Increased tight oil production and changes in gasoline and distillate (comprised largely of diesel fuel) net imports were responsible for reducing net petroleum imports. Figure 1.4.2-1 clearly shows that tight oil production, which increased from about zero in 2009 to 8 million barrels per day in 2018, had a very large impact on net petroleum imports. Distillate exports began to increase starting in 2006 and they continued to increase through 2017. As a result, net distillate imports, which were somewhat positive at 0.2 million barrels per day initially, trended downward starting in 2006 to a negative 1.1 million barrels per day in 2017. Gasoline net imports reached a maximum of over 1 million barrels per day in 2007. Like distillate, gasoline exports also began to increase, which likewise corresponded with a reduction in net gasoline imports. By 2017, gasoline net imports were 1.1 million barrels per day lower than in 2007.

Renewable fuels likely contributed to reducing net petroleum imports, but even if so, it would have been a relatively modest amount. Corn ethanol volume increased from about 2 billion gallons per year in 2000 to over 14 billion gallons per year in 2015. [30,31] Biodiesel consumption increased from 10 million gallons per year in 2001 to over 1 billion gallons in 2013, and biodiesel and renewable diesel consumption totaled over 2 billion gallons in 2019.[32, 33] Assuming that this total renewable fuel volume displaced an energy-equivalent volume of petroleum imports, in 2019 corn ethanol and biodiesel/renewable diesel fuel combined would have displaced about 0.75 million barrels per day of petroleum equivalent volume – which is equivalent to 6% of the highest import volume.

Not only do petroleum imports create energy security vulnerabilities, they also contribute to a monetary trade imbalance. What made the continued increase of net petroleum imports until 2005 a particular concern was that crude oil prices were increasing at the same time.[34] Crude oil spot prices (both WTI and Brent) had doubled in 2005 to over $50/bbl compared to the average of crude oil spot prices prior to 2004. Crude oil prices continued to increase, nearly doubling again in 2008 compared to 2005. Thus, the U.S. imported petroleum trade imbalance quadrupled in monetary terms.

The total U.S. trade imbalance increased to just under $800 billion in 2005 and increased further to over $800 billion per year in 2006 through 2008.[35] The increasing crude oil prices on top of the increasing petroleum imports contributed to this increasing trade imbalance. The 12

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[30] EIA, Monthly Energy Review, Table 10.3, Fuel Ethanol Review; https://www.eia.gov/totalenergy/data/monthly/pdf/sec10_7.pdf

[31] Note that "corn ethanol" also includes small amounts of ethanol produced from other sources of starch such as wheat and grain sorghum.

[32] Biodiesel consumption data from EIA, Monthly Energy Review, Table 10.4, Biodiesel and Other Renewable Fuels Overview; https://www.eia.gov/totalenergy/data/monthly/pdf/sec10_8.pdf

[33] Renewable consumption data from Public Data for the Renewable Fuel Standard; EPA Moderated Transaction System; https://www.epa.gov/fuels-registration-reporting-and-compliance-help/public-data-renewable-fuel-standard

[34] Spot Prices - Petroleum and Other Liquids; EIA; https://www.eia.gov/dnav/pet/pet_pri_spt_s1_a.htm

[35] U.S. Trade in Goods with World, Seasonally Adjusted; United States Census Bureau; https://www.census.gov/foreign-trade/balance/c0004.html

million barrel per day net petroleum import volume combined with the approximately $70 per barrel crude oil price in 2006 contributed to about $300 billion of the total U.S. trade imbalance. While petroleum imports directly comprised a large portion of the increasing trade imbalance, higher crude prices also increased the prices of many other goods that were imported into the U.S., which likely indirectly contributed to the trade imbalance.[36] In 2009, the U.S. trade imbalance dropped to $500 billion. Since then, the U.S. trade imbalance increased back into the $600 to $700 billion per year range until 2018 and 2019, when it increased again back above $800 billion per year. Then, in 2020, the U.S. trade imbalance further increased above $900 billion, although increased U.S. petroleum supply has removed petroleum as the cause.

However, we recognize that because the U.S. is a participant in the world market for petroleum products, our economy cannot be shielded from world-wide price shocks.[37] But, the potential for petroleum supply disruptions due to supply shocks has been significantly diminished due to the increase in tight oil production, and to a lesser extent renewable fuels, which has shifted the U.S. to being a modest net petroleum importer in the world petroleum market in the time frame of this rule, 2021-2022. The potential for supply disruptions has not been eliminated, though, due to the continued need to import petroleum to satisfy the demands of the U.S. petroleum industry.[38]

1.4.3 Refinery Margins

Refinery margins reveal the economic health of refineries. High margins show that refineries are economically viable and potentially making a profit, but very low margins indicate that a refinery is not making much, if any, profit and could even be losing money. Since refiners are one of the types of obligated parties responsible for complying with the RFS program requirements, tracking their economic health over the time period of the implementation of the program may reveal whether increasing volumes of renewable fuels blended into petroleum increases is correlated with financial stress of refineries.

Publicly available refinery margin data from BP is shown in Figure 1.4.3-1 for three different types of refineries: (1) a U.S. Gulf Coast coking refinery; (2) a Northwest European sweet crude oil cracking refinery; and (3) a medium crude oil hydrocracking refinery in Singapore.[39] The refinery margin data is for three refineries owned by BP; thus, it may not represent the margins of other refineries in the same regions. The margin data is on a semi-variable basis, accounting for all variable costs and fixed energy costs.

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[36] U.S. Trade Deficit and the Impact of Changing Oil Prices; Congressional Research Service; February 24, 2020; https://fas.org/sgp/crs/misc/RS22204.pdf

[37] Bordoff, Jason; The Myth of US Energy Independence has Gone Up in Smoke; Foreign Policy; September 18, 2019; https://foreignpolicy.com/2019/09/18/the-myth-of-u-s-energy-independence-has-gone-up-in-smoke

[38] Foreman, Dean; Why the US must Import and Export Oil; American Petroleum Institute; June 14, 2018; https://www.api.org/news-policy-and-issues/blog/2018/06/14/why-the-us-must-import-and-export-oil

[39] Quarterly Oil Refinery Margins - Regional; Quandl; https://www.quandl.com/data/BP/OIL_REF_MARG-Oil-Refining-Margins-Regional

Figure 1.4.3-1: Refinery Margins in Three Different Regions ($/bbl)

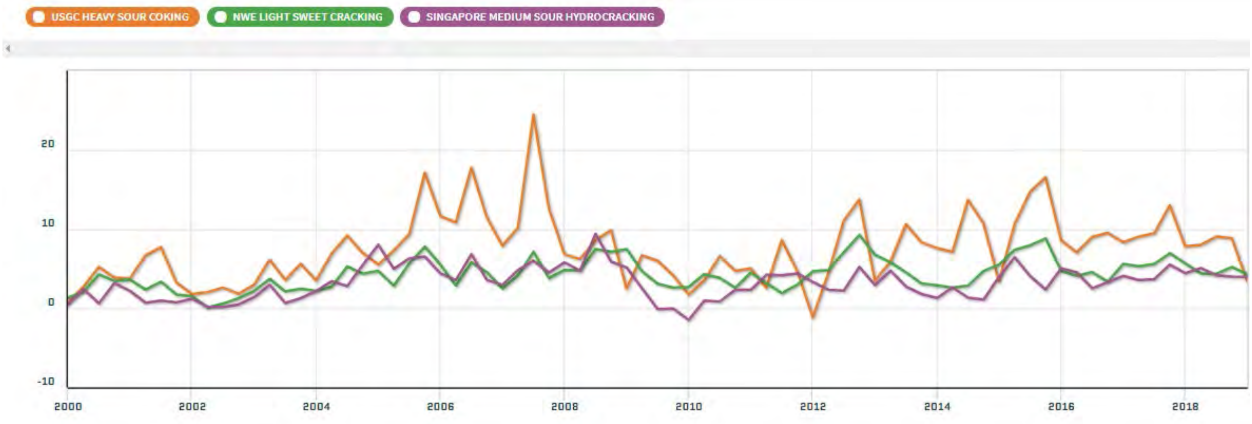


Figure 1.4.3-1 shows that from 2000 to 2004, refinery margins were poor, and the Singapore refinery experienced zero or near-zero margins over much of this time period. In the period from 2004 to 2009, crude oil prices were rising and it was a much better period for these refineries' margins, particularly for the Gulf Coast refinery. The Gulf Coast refinery's margins were likely much higher due to the heavy sour crude oil processed there being much less expensive than the crude oils processed at the other two refineries. All three refineries' margins decreased dramatically after 2008, likely due to the large decrease in refined product demand associated with the Great Recession. As the world emerged from the Great Recession, the three refineries' margins started improving in 2010, and in particular, the refinery margins improved more dramatically for the heavy sour coking refinery in the Gulf Coast. However, refinery margins for U.S. refineries that refine light, sweet crude oil are not represented in Figure 1.4.3-1. As shown in Figure 1.4.1-1, but not reflected in Figure 1.4.3-1, light sweet crude oil prices were depressed in the U.S. during 2011 to 2014. Lower prices of sweet crude oil provided high margins for U.S. refineries that processed sweet crude oil during this time period.

1.4.4 Transportation Fuel Demand

At the time the RFS2 program was being promulgated, there had been a consistent increase in U.S. petroleum demand. However, transportation fuel demand fell short of historical demand increases starting in 2008 and has remained relatively stable since that time. Figure 1.4.4-1 shows the actual volume of gasoline, distillate, and jet fuel consumed in the U.S. from 2000 to 2018, as well as the projected demand of gasoline and distillate if transportation fuel demand growth had continued at the historic rate based on EIA's AEO 2008.[40] [41]

[40] Product Supplied; Petroleum and Other Liquids, Energy Information Administration, https://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.
[41] Annual Energy Outlook 2008; Energy Information Administration; June 2008; https://www.eia.gov/outlooks/archive/aeo08/index.html.

Figure 1.4.4-1: Actual and Projected Transportation Fuel Demand (Source: EIA; includes renewable fuel volumes)

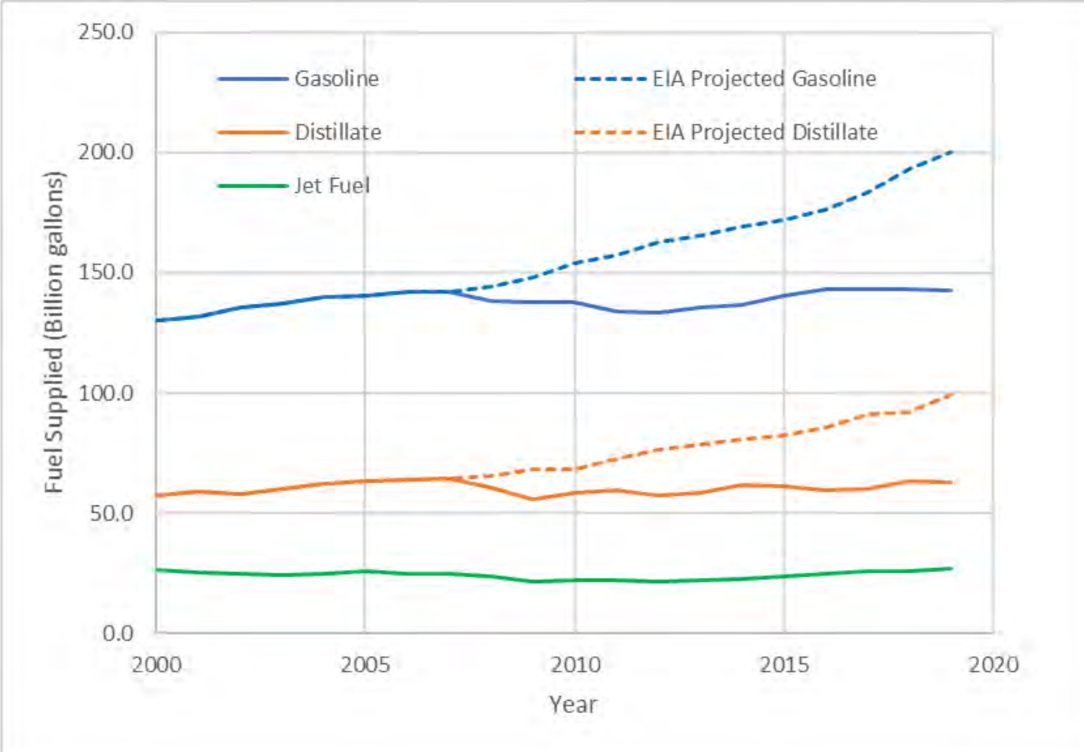


Figure 1.4.4-1 shows that both gasoline and distillate demand increased up to 2007. During previous years, gasoline and distillate demand was increasing 1.3% and 1.7% per year on average, respectively. The dashed lines in Figure 1.4.4-1 show projected gasoline and distillate demand if they had continued to increase at the same rate as that prior to 2008. The figure clearly shows that actual gasoline and distillate demand fell far short of projected demand after 2007. Conversely, jet fuel demand was essentially flat during the entire period.

Several factors led to the decrease of transportation fuel demand after 2007:

- The Great Recession – The Great Recession began in 2008 and officially lasted for 18 months, although employment did not return to pre-recession levels until over 6 years after the onset of the recession. The Great Recession caused a large impact on economic activity, which reduced transportation fuel demand during these years.

- Increased crude oil prices – Sustained, higher crude oil prices resulted in increased transportation fuel prices over this time period, which affected consumer behavior by impacting the number of miles traveled and vehicle purchase decisions. After 2014, crude oil prices decreased to the $40 to $50 price range, which brought gasoline prices back down and likely reversed some of the consumer behavior changes.

- Increasing fuel economy of the motor vehicle fleet - EPA and the National Highway Transportation Administration (NHTSA) finalized standards which reduced light-duty motor vehicle greenhouse gas (GHG) emissions and increased the Corporate

Average Fuel Economy (CAFE) of motor vehicles. The GHG/CAFE standards applied to light-duty vehicles sold in 2012 to 2025 and thereafter.[42] EPA and NHTSA also established GHG/CAFE standards for new heavy-duty vehicles and their trailers.[43] The phase 1 and phase 2 heavy-duty GHG standards began to phase-in in 2014 and will continue to do so through 2027.[44] The GHG standards only affect new internal combustion vehicles; thus, as consumers purchase new motor vehicles, these new vehicles consume less gasoline and diesel fuel compared to the vehicles sold in previous years, reducing overall petroleum demand.

- Electric vehicle penetration and fuel displacement – electric vehicles (EVs) and plug-in hybrid electric vehicles (PHEVs) reduce consumption of petroleum fuel by either partially displacing petroleum fuels (in the case of PHEVs) or completely displacing petroleum demand (in the case of EVs). Data on annual electrified vehicle sales indicates that EVs and PHEVs displaced an estimated 5 million gallons of fuel in 2011 and increased to over 400 million gallons in 2019.[45]

1.5 Cellulosic Biofuel

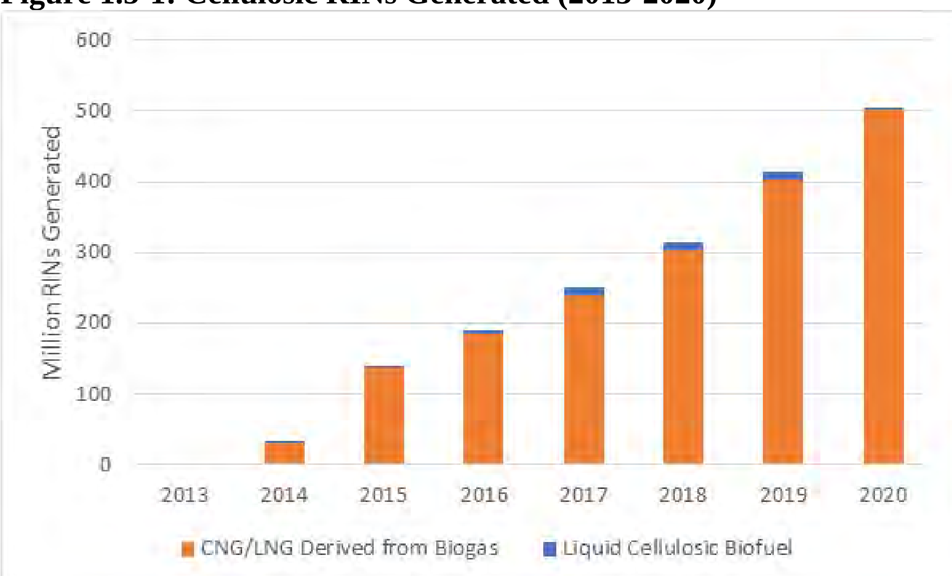
Actual production of cellulosic biofuel through 2020 has been significantly less than the statutory volumes, which reached 16 billion gallons in 2022. Minimal volumes of cellulosic biofuel were produced through 2013. Since 2013, volumes of the types of liquid cellulosic biofuels projected in the RFS2 rule have remained limited. There are numerous reasons that liquid cellulosic biofuel production has not developed as anticipated. The lower than anticipated crude oil prices discussed in Chapter 1.4.1 certainly impacted the market's ability to produce liquid cellulosic biofuels at competitive prices. While the issues associated with each individual company and facility are unique, and the reasons facilities fail to consistently produce cellulosic biofuel at the expected volumes are not always publicly disclosed, there appear to be several common challenges across the liquid cellulosic biofuel industry. These challenges include: (1) feedstock quality and handling issues; (2) higher than anticipated feedstock and capital costs; and (3) difficulty scaling up technology to commercial scale. The inability of several first-of-a-kind cellulosic biofuel production facilities to continue operating has also likely impacted investment in the commercialization of similar technologies.

Although production of liquid cellulosic biofuel from commercial scale production facilities has been far lower than projected in the RFS2 rule, smaller volumes of qualifying cellulosic biofuel has been produced using technologies not discussed in that rule. The production of CNG/LNG derived from biogas, which was not one of the cellulosic biofuel production technologies discussed in the RFS2 rule, has accounted for the vast majority of the cellulosic biofuel produced since 2010. The RFS2 rule contained a pathway[46] for the production

[42] 75 FR 25324 (May 7, 2010) and 85 FR 24174 (April 30, 2020).
[43] 76 FR 57106 (September 15, 2011).
[44] 81 FR 73478 (October 25, 2016).
[45] Transportation Research Center at Argonne National Laboratory, https://www.anl.gov/es/light-duty-electric-drive-vehicles-monthly-sales-updates
[46] A pathway is a combination of feedstock, production process, and fuel type. EPA has evaluated a number of different pathways to determine the category of renewable fuel that fuel produced using the various pathway qualifies for. The list of generally applicable pathways can be found in 40 CFR 80.1426(f).

of biogas from landfills, sewage and waste treatment plants, and manure digesters to generate advanced biofuel (D5) RINs.[47] In response to questions from multiple companies, EPA subsequently evaluated whether biogas from several different sources could be considered not just an advanced biofuel, but also a cellulosic biofuel. In the Pathways II rule, EPA added a pathway for CNG/LNG derived from biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated MSW digesters, as well as biogas from the cellulosic components of biomass processed in other waste digesters, to generate cellulosic biofuel (D3) RINs when used as a transportation fuel.[48] Following this decision, production of CNG/LNG derived from biogas increased rapidly, from approximately 33 million RINs in 2014 to over 500 million RINs in 2020.[49] Through 2020, over 97% of all of the cellulosic biofuel RINs generated in the RFS program have been for CNG/LNG derived from biogas. We anticipate that CNG/LNG derived from biogas will continue to be the source of the vast majority of cellulosic biofuel in the RFS program through 2022. Actual cellulosic biofuel production for each year from 2014 through 2019 is shown in Figure 1.5-1.

Figure 1.5-1: Cellulosic RINs Generated (2013-2020)



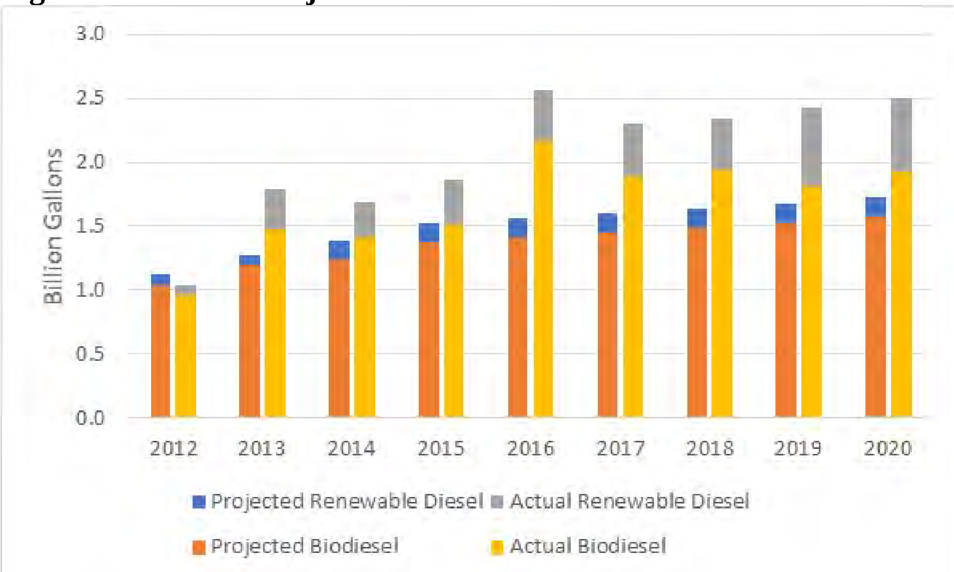
1.6 Biodiesel and Renewable Diesel

The actual supply of biodiesel and renewable diesel has significantly exceeded the supply projected by EPA in the RFS2 rule. In that rule RIA, EPA projected that in 2020,[50] 1.57 billion gallons of biodiesel and 0.15 billion gallons of renewable diesel would be supplied, all of which was projected to be produced in the U.S. The actual supply of biodiesel and renewable diesel in 2020 was 1.92 billion gallons and 0.85 billion gallons, respectively. While the majority of these volumes were produced domestically, significant volumes were imported. Further, while the vast

[47] 75 FR 14872 (March 26, 2010).
[48] 79 FR 42128 (July 18, 2014).
[49] One RIN can be generated for each ethanol-equivalent gallon of renewable fuel. One gallon of ethanol is eligible to generate one RIN; other types of fuel generate RINs based on their energy content per gallon relative to ethanol. For CNG/LNG derived from biogas, every 77,000 BTU of qualifying biogas generates one RIN.
[50] 2020 is the most recent year for which data are available for comparison.

majority of biodiesel and renewable diesel supplied since 2010 has met the requirements for BBD or advanced biofuel, smaller volumes were produced from grandfathered facilities using renewable biomass that does not qualify for BBD or advanced biofuel RINs and therefore only qualify to generate conventional renewable fuel RINs. The most likely feedstock used to produce grandfathered biodiesel and renewable diesel is palm oil; however, other types of renewable biomass that have not been approved to generate advanced or BBD RINs could also be used.

Figure 1.6-1: 2010 Projected vs. Actual Biodiesel and Renewable Diesel Supply (2012-2020)



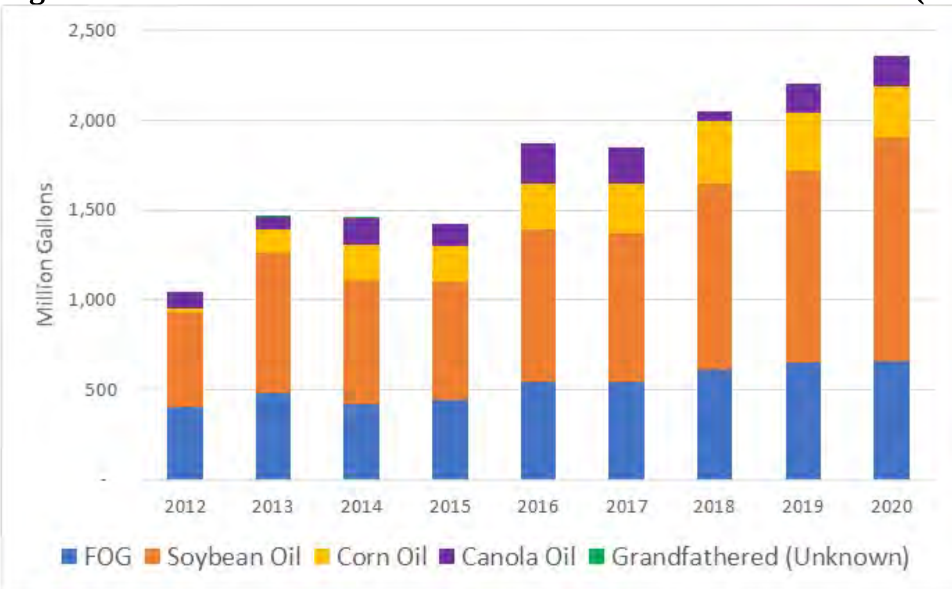
Projected volumes are from the 2010 RFS2 final rule. Actual volumes are from EMTS data.

The reason that the supply of biodiesel and renewable diesel has been much higher than projected in the RFS2 rule is primarily related to challenges associated with consuming ethanol as higher-level blends with gasoline (i.e., greater that 10% ethanol), which we discuss further in Chapter 1.7. The limited use of higher-level ethanol blends, together with lower than projected gasoline demand, resulted in total ethanol consumption in 2019 and 2020 (14.55 and 12.63 billion gallons, respectively) that was lower than the projected ethanol consumption volume in 2022 even the low ethanol case from the 2010 final rule (17.04 billion gallons).[51] Since the primary fuels available to meet the advanced biofuel requirements are biodiesel, renewable diesel, and sugarcane ethanol, the challenges associated with increasing ethanol consumption is a significant factor in a much smaller than projected supply of sugarcane ethanol, with greater volumes of biodiesel and renewable diesel being used to meet the advanced biofuel requirement and at times even the total renewable fuel requirement.

The feedstocks used to produce biodiesel and renewable diesel each year from 2012 through 2020 for domestically produced and imported biodiesel and renewable diesel are shown in Figures 1.6-2 and 1.6-3.

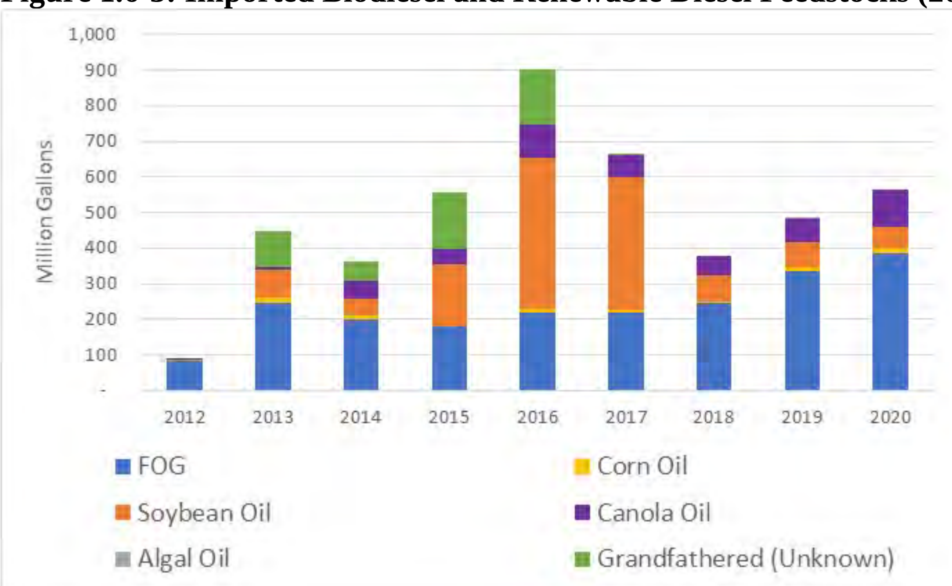
[51] Ethanol consumption volume are from EIA's Monthly Energy Review, while the ethanol projections are from the 2010 RFS2 final rule. Ethanol consumption in 2020 was significantly impacted by the COVID-19 pandemic. Ethanol consumption in the U.S. reached a peak of 14.49 billion gallons in 2017, still far short of the volumes projected in the RFS2 rule.

Figure 1.6-2: Domestic Biodiesel and Renewable Diesel Feedstocks (2010-2020)



Source: EMTS

Figure 1.6-3: Imported Biodiesel and Renewable Diesel Feedstocks (2010-2020)



Source: EMTS

There are several notable differences between the quantities of feedstock projected to be used to produce biodiesel and renewable diesel in the RFS2 rule and the actual feedstocks used to produce these fuels in 2020. Domestic biodiesel production in 2020 was fairly similar to the volume of biodiesel projected in the RFS2 rule for that year (all of which was projected to be produced domestically), but there were significant differences in the feedstocks used to produce this biodiesel. Relative to the quantities projected in the RFS2 RIA, the use of soybean oil, fats, oils, and greases (FOG), and other sources were all higher than projected, while the use of corn oil from ethanol plants was lower than projected. These differences largely reflect the greater than anticipated demand for biodiesel as a result of the limitations on ethanol consumption (see

Chapter 1.7). The lower than expected use of corn oil is likely the result of production of non-food grade corn oil being a relatively new feedstock at the time of the RFS2 rule, EPA's projections being over-ambitious, and demand for this feedstock in animal feed and other sectors.

Domestic renewable diesel production in 2020 was significantly higher than projected in the RFS2 rule, in which EPA projected that all of the renewable diesel would be produced domestically from FOG. While the majority of domestic renewable diesel was produced from FOG in 2020, significant volumes were also produced from soybean oil and corn oil from ethanol plants. The U.S. also imported significant volumes of biodiesel and renewable diesel in 2020, as well as in previous years. By 2020, the majority of the imported biodiesel and renewable diesel was produced from FOG; however, in earlier years the U.S. also imported large volumes of biodiesel produced from soybean oil.[52]

1.7 Ethanol

The predominant form of biofuel used to meet the standards under the RFS program, and in particular the total renewable fuel standard, has been ethanol. In 2005, just prior to implementation of the RFS1 program, ethanol accounted for 97% of all biofuels consumed in the U.S. transportation sector.[53] Over the following years, the total volume of ethanol used in the U.S. has more than tripled from 5.5 million gallons in 2006 to 14.5 million gallons in 2019.[54,55] By 2010, ethanol use in the U.S. was approaching the "E10 blendwall" for the nation as a whole, as represented by the nationwide average ethanol concentration, and actually exceeded 10.00% in 2016. By 2020, ethanol accounted for 81% of the 15.7 billion gallons of biofuels consumed in the U.S.[56]

In all years since ethanol was approved for use in gasoline in 1979, the vast majority of ethanol consumed in the U.S. has been produced domestically from corn starch with small amounts from other starches. Cellulosic ethanol has represented at most 0.07% (2019) of all ethanol consumed in the U.S., while the proportion of imported sugarcane ethanol has been small but highly variable.

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[52] Source: EMTS

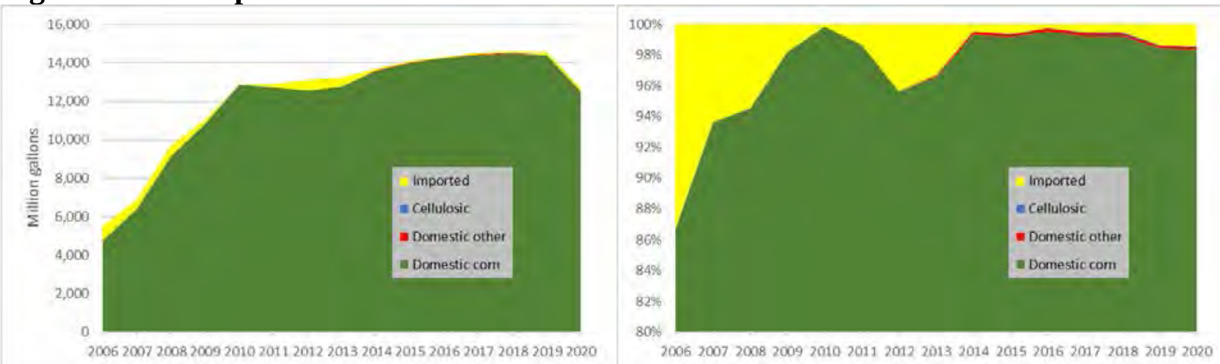
[53] EIA's Monthly Energy Review, April 2021, Tables 10.3 and 10.4. Comparison is based on ethanol-equivalence.

[54] Id.

[55] In 2020, total ethanol consumption dropped to 12.7 billion gallons as a result of the COVID-19 pandemic.

[56] "RIN supply as of 3-22-21," available in docket EPA-HQ-OAR-2021-0324.

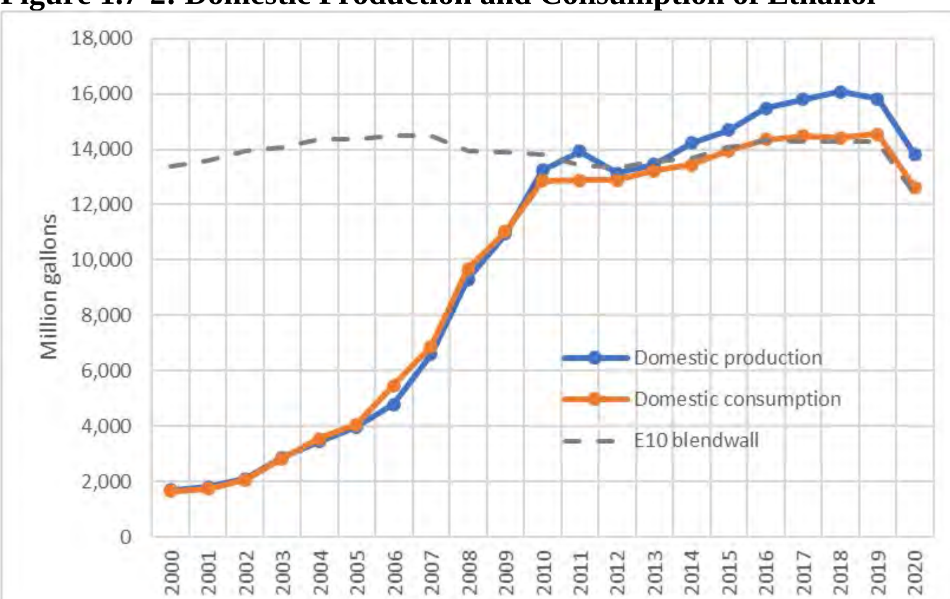
Figure 1.7-1: Proportions of Ethanol Fuel Sources



Source: EMTS

As shown in Figure 1.7-2, actual consumption of ethanol in the U.S. was very close to domestic production through 2009. Thereafter, domestic production began exceeding domestic consumption, indicative of an increase in exports.

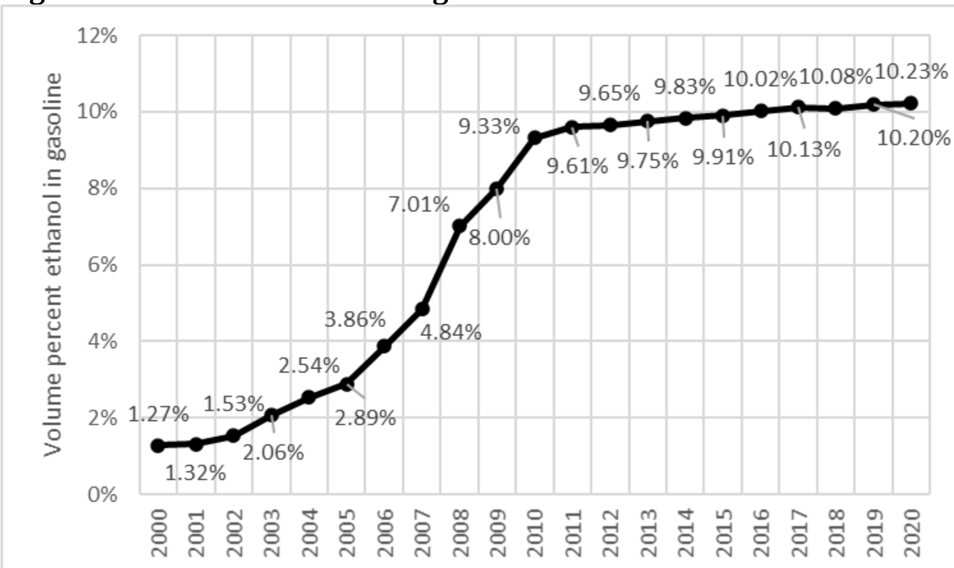
Figure 1.7-2: Domestic Production and Consumption of Ethanol



Source: Domestic consumption from EIA's Monthly Energy Review. The E10 blendwall was derived from total gasoline energy demand. Domestic production = domestic consumption - imports + exports.

The E10 blendwall appears to have been a deciding factor in limiting growth in domestic consumption of ethanol. As illustrated in Figure 1.7-3, the nationwide average ethanol concentration did not increase at the same pace after 2010 as it did in previous years, but instead slowed significantly, approaching and then slightly exceeding 10.00% at a comparative crawl after 2010.

Figure 1.7-3: Nationwide Average Concentration of Ethanol in Gasoline[a]



[a] Here and elsewhere in this DRIA, "ethanol concentration" refers to the concentration of denatured ethanol in gasoline.
Source: Derived from EIA's Monthly Energy Review - ethanol consumption divided by motor gasoline consumption

After E10 was approved for use in all vehicles in 1979, consumers had a choice between E0 (gasoline without ethanol) and E10. Consumers likely made their choice based on knowledge of what fuels were available based on pump labeling, relative price, perceptions (or lack thereof) of impacts on vehicle fuel economy, vehicle operability or longevity, comfort with an unfamiliar fuel, and perceived benefits to the environment or economy. Since approaching and exceeding the E10 blendwall between 2010 and 2016, virtually all gasoline nationwide contains 10% ethanol and there is often little or no indication on the fuel pump of ethanol content. As a result, most consumers today have little choice but to use E10. However, with the expansion of retail service stations offering E15 and E85, the choice for consumers has now shifted to between E10 and these higher-level ethanol blends. For higher-level ethanol blends, consumers likely consider all of the factors they considered when the choice was between E0 and E10, plus whether the fuel is legally permitted to be used in their vehicle and whether the manufacturer has warranted their vehicle for its use.

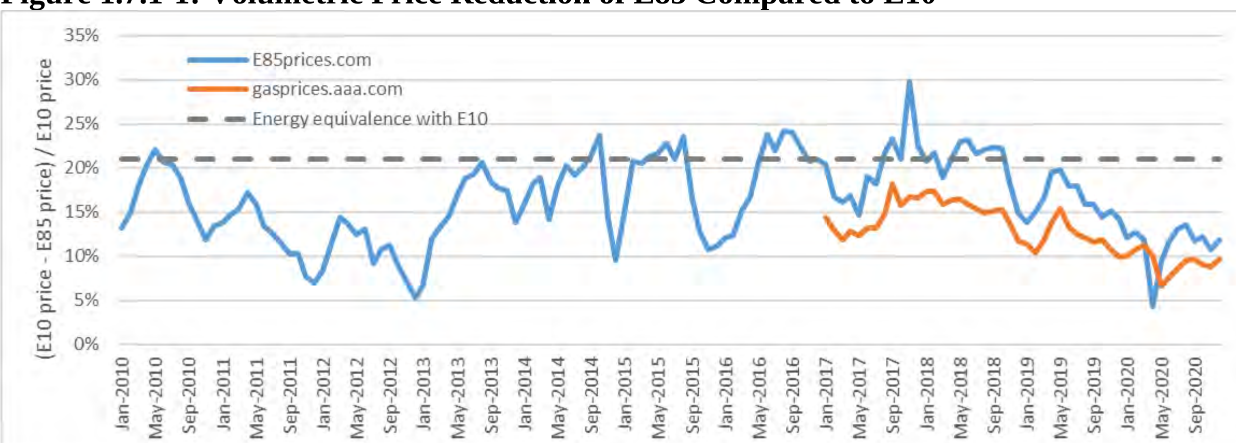
1.7.1 E85

The earliest form of a higher-level ethanol blend was E85. In 1996, the first flex-fuel vehicle (FFV) was produced that could operate on fuel containing up to 85% ethanol.[57] Starting in 2007, the American Society for Testing and Materials (ASTM) limited the maximum ethanol content of E85 to 83% in specification D5798, with a minimum content of 51%. EIA assumes that the annual, nationwide average ethanol concentration of E85 is 74%.[58]

[57] "Alternative Fuel Ford Taurus" available in the docket for this action.
[58] EIA's AEO 2021, Table 2, footnote 11.

E85 is not considered gasoline under EPA's regulations, and as such is permitted to be used only in designated FFVs. However, FFVs can operate on either gasoline or E85. Under basic economic theory, and assuming all other factors are equal, FFV owners are more likely to purchase E85 if they believe that doing so reduces their fuel costs. E85 reduces fuel economy in comparison to E10, and E85 must sell at a discount to E10 if it is to represent an equivalent value in terms of energy content. For an average E85 containing 74% ethanol, its volumetric energy content is approximately 21% less than E10 (or 24% lower than that of E0, though E0 is rarely the point of comparison as sales volumes of E0 are considerably lower than sales volumes of E10).[59,60,61] In order for E85 to be priced equivalently to gasoline on an energy-equivalent basis, then, its price must be on average 21% lower than that of E10. As shown in Figure 1.7.1-1, the nationwide average price of E85 compared to E10 has only rarely achieved the requisite energy equivalent pricing needed for FFV owners who are aware of and concerned about the fuel economy impacts of E85. Furthermore, E85 purchasers generally have no way of knowing whether their fuel contains 83% ethanol, 51% ethanol, or something in-between.

Figure 1.7.1-1: Volumetric Price Reduction of E85 Compared to E10[a]



[a] The 21% energy equivalence level of E85 compared to E10 assumes that E85 contains 74% ethanol.
Note: While E85prices.com is a decentralized system consisting of voluntary submissions from motorists, the American Automobile Association (AAA) data is based on a daily collection of credit card swipe and direct feed price data from up to 130,000 retail stations. Moreover, the data collection by AAA is done in cooperation with the Oil Price Information Service (OPIS) and Wright Express to ensure reliability of the results.

EPA has estimated the nationwide volume of E85 consumed in recent years using two different methods.[62] The results of those analyses are shown in Figure 1.7.1-2.

[59] 74% is the average E85 ethanol concentration used by EIA (e.g., see footnote 1 in Table 6.36 of AEO 2020).
[60] Assumes ethanol energy content is 3.555 mill Btu per barrel and gasoline energy content is 5.222 mill Btu per barrel. EIA Monthly Energy Review for April 2021, Tables A1 and A3.
[61] A comparison to E0 would be more relevant prior to 2010 when there remained significant volumes of E0 for sale at retail stations.
[62] "Estimate of E85 consumption in 2020," memorandum from Akshay Delity to the docket.

Figure 1.7.1-2: Estimated E85 Consumption

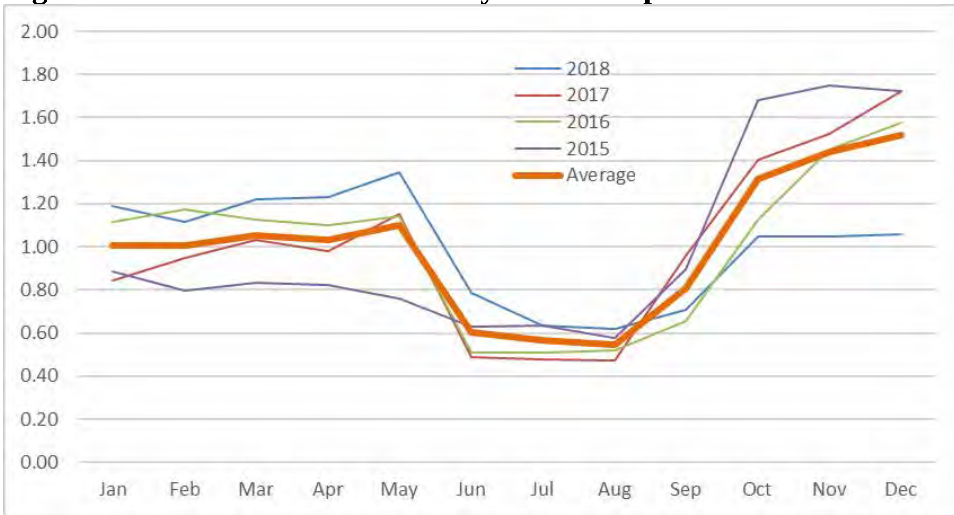
1.7.2 E15

Following a 2011 waiver action, gasoline containing up to 15% ethanol was permitted to be used in model year (MY) 2001 and newer vehicles.[63] E15 has since been offered at an increasing number of retail service stations (see Chapter 6.4.3). There is currently no publicly available data on actual E15 sales volumes for the nation as a whole.

Sales of E15 prior to 2019 were seasonal due to the fact that E15 did not qualify for a 1 psi Reid Vapor Pressure (RVP) volatility waiver for summer gasoline in CG areas that has been permitted for E10 since the summer volatility standards were implemented in 1989.[64] Monthly E15 sales in Minnesota from 2015 to 2018, presented below in Figure 1.7.2-1, demonstrate that sales volumes of E15 in summer months were notably lower than in non-summer months in this time period.

[63] 76 FR 4662 (January 26, 2011).
[64] 54 FR 11883(March 22, 1989).

Figure 1.7.2-1: Normalized Monthly E15 Sales per Station in Minnesota[a]



Source: Minnesota Commerce Department

[a] Normalized values derived by dividing the monthly E15 sales volume per station by the annual average E15 sales volume per station.

In 2019, EPA extended the 1-psi RVP waiver to E15.[65] EPA estimated that the annual average E15 sales per station in Minnesota would have been 16% higher than they were in reality had the 1-psi waiver been in place in 2015 to 2018.[66] On July 2, 2021, the U.S. Court of Appeals for the D.C. Circuit ruled that EPA's extension of the 1-psi waiver to E15 was based on an impermissible reading of the statute and vacated it. Insofar as the 1-psi waiver for E15 had an impact on summer sales of E15, therefore, it did so only for 2019 - 2021 and would have no impact in 2022 or later years.

1.8 Other Biofuels

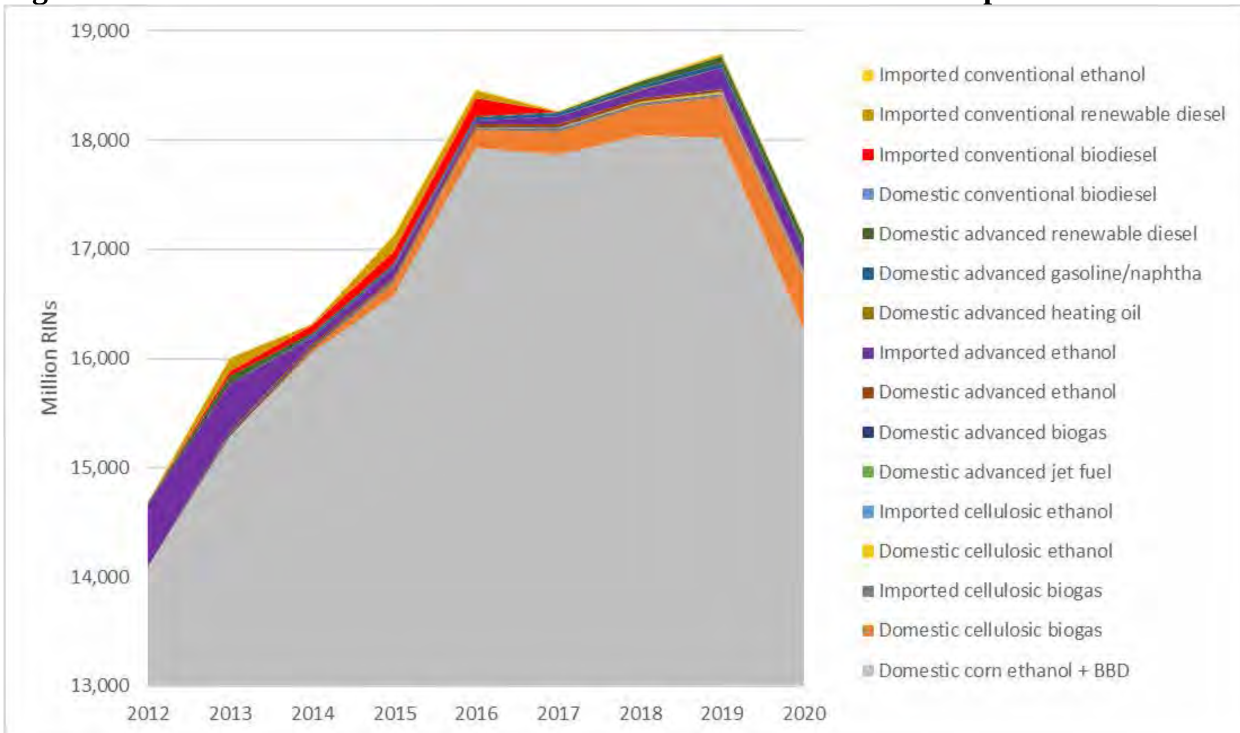
Although domestic corn ethanol and BBD have dominated the biofuels landscape since implementation of the RFS program began in 2006, other biofuels have also contributed to the total renewable fuel pool, sometimes providing the marginal volumes needed to meet the other applicable standards. As shown in Figure 1.8-1, biofuels besides corn ethanol and BBD represented between 2% and 5% of total renewable fuel between 2012 and 2020.[67]

[65] 84 FR 26980 (June 10, 2019).

[66] "Estimating the impacts of the 1psi waiver for E15," memorandum from David Korotney to EPA docket EPA-HQ-OAR-2019-0136.

[67] Detailed data prior to 2012 on RIN generation, adjustments to account for invalid RINs, and exports is less robust and is therefore not presented here.

Figure 1.8-1: Contribution of Biofuels to Total Renewable Fuel Consumption[a,b]



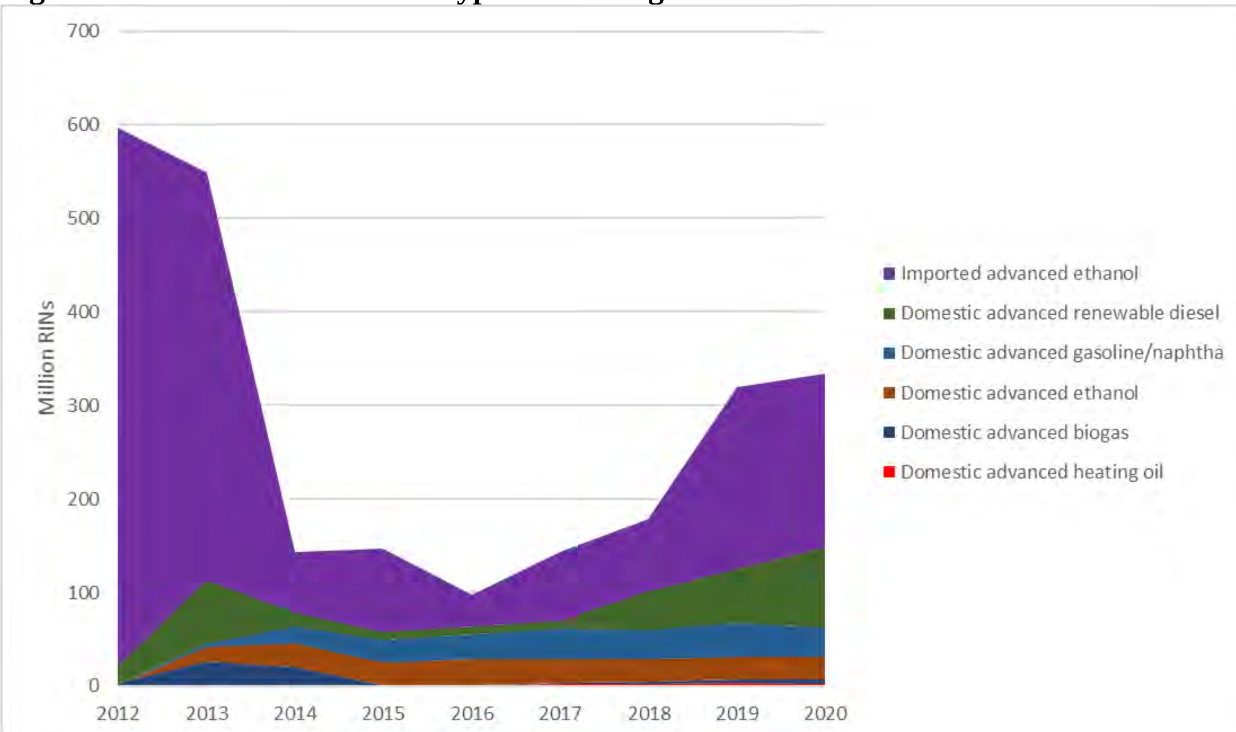
Source: EMTS

[a] Ignores any biofuels that contributed less than 1 million RINs in aggregate over all years shown. This affects domestic cellulosic gasoline/naphtha, domestic cellulosic diesel, and domestic conventional butanol.

[b] Fuel type and D-code of exports is known, but whether the exported fuel was originally produced domestically or was imported is not known. For purposes of this chart, exports were assumed to be distributed to domestic production and imports in proportion to the relative production volumes of each.

As illustrated by Figure 1.8-2, advanced biofuel exclusive of cellulosic biofuel or BBD (i.e., renewable fuel having a D-code of 5) has been met with the greatest variety of fuel types compared to the other statutory categories.

Figure 1.8-2: Advanced Biofuel Types Excluding Cellulosic Biofuel and BBD



Source: EMTS

These sources of advanced biofuel varied widely in both their overall contributions to the advanced biofuel pool from 2012 to 2020, as well as in each individual year. As the largest overall contributor, imported advanced ethanol produced from sugarcane in Brazil is discussed separately in Chapter 5.3. Production of domestic advanced renewable diesel,[68] gasoline/naphtha, and ethanol were of approximately similar magnitude and demonstrated no consistent increasing or decreasing trends between 2012 and 2020. Domestic advanced biogas fell to near zero in 2015 after biogas from landfills was recategorized as cellulosic biofuel in 2014.[69] Domestic advanced heating oil has grown steadily since 2012 but has never generated more than 3 million RINs in a single year.

As described in Chapter 1.5, cellulosic biofuel has been composed predominately of biogas-based CNG/LNG, with smaller volumes of ethanol and heating oil and very small volumes of gasoline/naphtha and renewable diesel also contributing.

1.9 RIN System

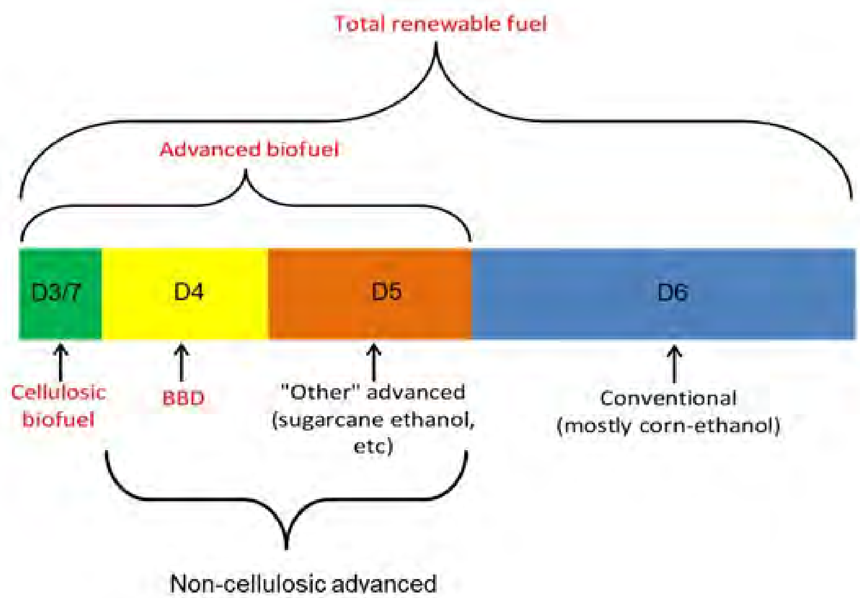
Renewable Identification Numbers (RINs) were created by EPA under the authority of CAA section 211(o)(5) as a flexible mechanism to enable obligated parties under the RFS program across the country to meet their renewable fuel blending obligations without having to

[68] Small quantities of renewable diesel are not BBD but are nonetheless advanced biofuel.
[69] 79 FR 42128 (July 18, 2014).

blend the renewable fuels themselves.[70] RINs allow: (1) The refining industry to comply with the RFS program without producing, purchasing, or blending the renewable fuels themselves; (2) The non-obligated blenders of renewable fuels to maintain their preexisting blending operations; and (3) The ethanol and other biofuel industries to continue to produce biofuels, now with the support of the RIN value. Obligated parties, of course, can and do produce, purchase, and blend their own renewable fuels, but the RIN system allows them the option of not doing so and instead relying on the business practices of other market participants that are already set up to do so. RINs are generated by renewable fuel producers (or in some cases renewable fuel importers) and are assigned to the renewable fuels they produce. These RINs are generally sold together with the renewable fuel to refiners or fuel blenders. RINs can be separated from renewable fuel by obligated parties or when renewable fuel is blended into transportation fuel. Once separated, RINs can be used by obligated parties to demonstrate compliance with their RFS obligations or can be traded to other parties.

In the RFS regulations, EPA created five different types of RINs: cellulosic biofuel (D3) RINs, BBD (D4) RINs, advanced biofuel (D5) RINs, conventional renewable fuel (D6) RINs, and cellulosic diesel RINs (D7).[71] The type of RIN that can be generated for each gallon of renewable fuel depends on a variety of factors, including the feedstock used to produce the fuel, the type of fuel produced, and the lifecycle GHG reductions relative to petroleum fuels. The obligations under the RFS regulations are nested, so that some RIN types can be used to satisfy obligations in multiple categories. A graphic of the nested nature of the RFS obligations is shown in Figure 1.9-1.

Figure 1.9-1: Nested Structure of the RFS Program



[70] The RIN system was created in the RFS1 rule (72 FR 23900, May 1, 2007) and modified in the RFS2 rule (75 FR 14670, March 26, 2010).
[71] 40 CFR 80.1425(g).

1.9.1 Carryover RIN Bank

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 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 surplus RINs for use in the subsequent compliance year. In order to ensure reasonably consistent demand for new renewable fuel use in the ensuing year, however, our regulations limit the use of these carryover RINs to 20% of an obligated party’s renewable volume obligation (RVO). For the bank 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 2020 carryover RINs must be used for compliance in 2021, or they will expire. However, vintage 2021 RINs can then be “banked” for use in 2022.

In the context of setting the annual volume standards, the relative number of carryover RINs projected to be available compared to the projected total renewable fuel volume requirement has helped inform EPA’s decisions regarding the extent to which it should exercise its waiver authorities. During the first several years of the RFS2 program, the total number of RINs generated far exceeded the total number of RINs needed for obligated parties to demonstrate compliance. This resulted in a dramatic increase in the carryover RIN bank, up to an estimated 2.67 billion total carryover RINs in 2013, which represented over 16% of the total renewable fuel volume standard for that year.[72] As a result, EPA determined that sufficient carryover RINs existed such that it was not necessary for EPA to use its cellulosic or general waiver authority to reduce the total or advanced biofuel volume requirements specified in the statute.[73] At the time, EPA recognized that this decision may result in a reduction in the carryover RIN bank, and this in fact occurred, as the total number of carryover RINs dropped by over 900 million RINs to an estimated 1.74 billion total carryover RINs in 2014.[74] As seen in Table 1.9.1-1, at the time the annual standards for individual years were established (i.e., the information available to EPA when the standards were finalized for the subsequent year), the relative size of the projected total carryover RIN bank compared to the projected total renewable fuel volume requirement ranged from a high of over 16% in 2013 to a low of 8% in 2017. However, the magnitude of the RIN bank deviated from these projections sometimes significantly based on the decisions of the market players that only became known after the rule were finalized. With the benefit of hindsight, EPA can calculate the number of carryover RINs that were actually available for compliance for a given year. As seen in Table 1.9.1-1, the actual size of the carryover RIN bank compared to the actual volume obligation for 2013 through 2019 has ranged from a high of nearly 17% in 2018 to a low of 9% in 2016.

[72] EPA first began projecting the size of the carryover RIN bank in the 2013 RFS annual rule.
[73] 78 FR 49820-22 (August 15, 2013).
[74] 80 FR 77482-87 (December 14, 2015).

Table 1.9.1-1: Total Renewable Fuel Carryover RINs Compared to Total Renewable Fuel Volume Requirement[a]

Compliance Year	Total Renewable Fuel Carryover RINs Available (billion RINs)		Total Renewable Fuel Volume Requirement (billion gal)		Carryover RINs as % of Volume Requirement	
	Projected[b]	Actual[c]	Projected[b]	Actual[c]	Projected	Actual
2013	2.67	2.47	16.55	16.92	16.1%	14.6%
2014	1.74	1.58	16.28	16.31	10.7%	9.7%
2015	1.74	1.69	16.93	17.00	10.3%	9.9%
2016	1.74	1.65	18.11	17.93	9.6%	9.2%
2017	1.54	2.48	19.28	18.49	8.0%	13.4%
2018	2.22	3.13	19.29	18.61	11.5%	16.8%
2019	2.59	3.42	19.92	20.80	13.0%	16.5%
2020	1.86	n/a	17.13	n/a	10.8%	n/a
2021	1.86	n/a	18.52	n/a	10.0%	n/a
2022	1.86	n/a	20.77	n/a	8.9%	n/a

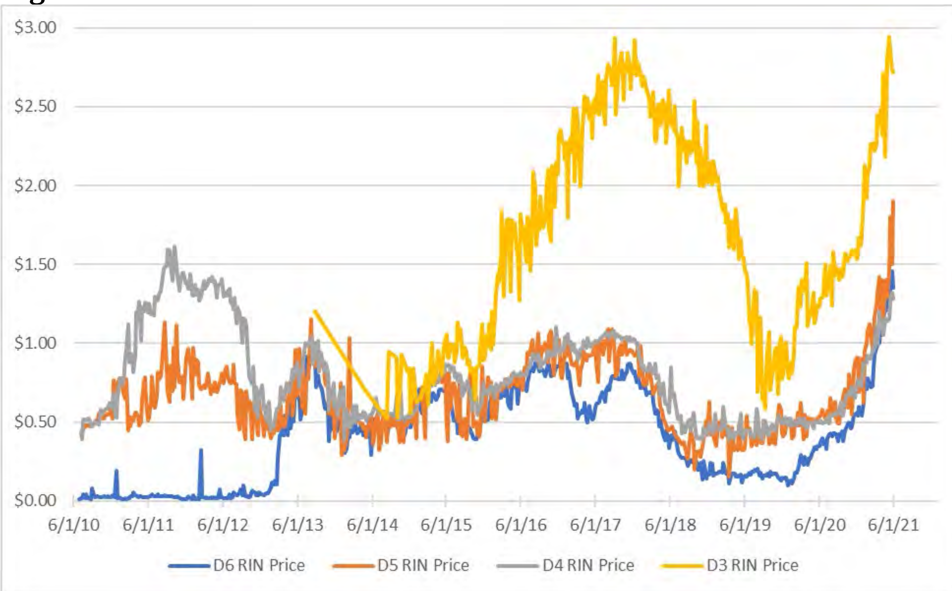
[a] For further discussion of these calculations, see “Carryover RIN Bank Calculations for 2020, 2021, and 2022 Proposed Rule,” available in the docket for this action.
[b] Projected volumes and number of carryover RINs reflect the values projected in the rules establishing the standards for those years. For 2013, see 78 FR 49794 (Aug. 15, 2013); for 2014-2016, see 80 FR 77422 (Dec. 14, 2015); for 2017, see 81 FR 89746 (Dec. 12, 2016); for 2018, see 82 FR 58486 (Dec. 12, 2017); for 2019, see 83 FR 63704 (Dec. 11, 2018); for 2020, 2021, and 2022, see Section IV.A of the preamble.
[c] Data current as of November 10, 2020, and compiled from Tables 2 and 3 at https://www.epa.gov/fuels-registration-reporting-and-compliance-help/annual-compliance-data-obligated-parties-and. Actual Volume Obligation = Reported Volume Obligation (Table 2) + Total End-of-Year Compliance Deficit (Table 5).

1.9.2 RIN Prices

RIN prices have varied significantly since 2010. There have also been significant and notable differences between the prices of each of the four major RIN types. A chart of RIN prices, as reported to EPA through EMTS is shown in Figure 1.9.2-1 below.[75] While there are a wide variety of factors that impact RIN prices, including both market-based and regulatory factors, a review of RIN prices reveals several notable aspects of the RFS program.

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

Figure 1.9.2-1: RIN Prices



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

Beginning in 2013, D6 RIN prices rose sharply. 2013 marked the first time the implied conventional renewable fuel requirement (the difference between the total renewable fuel requirement and the advanced biofuel requirement) exceeded the volume of ethanol that could be consumed as E10. While it has generally been cost-effective to blend ethanol as E10, higher-level ethanol blends (such as E15 or E85) have generally not been cost effective, even with the incentives provided by the RFS program. This is largely because: (1) Fuel blends that contain greater than 10% ethanol are currently not able to be optimized to take advantage of the very high-octane value of ethanol; (2) The lower energy content of ethanol is more noticeable as the amount of ethanol increases; and (3) Infrastructure limitations have restricted the availability of higher-level ethanol blends (see Chapter 6.4).

In subsequent years, D6 RIN prices have varied significantly, but they have never returned to the low prices observed prior to 2013. It is also notable that, from 2013 through 2016, D6 RIN prices remained close to, but slightly less than, D4 and D5 RIN prices. Thus, during this time period obligated parties were purchasing D4 and D5 RINs in excess of their BBD and advanced biofuel obligations to make up for the shortfall in conventional biofuel volume and used them to meet their total renewable fuel obligation. Essentially, given the inability to successfully introduce higher-level ethanol blends into the market in sufficiently large quantities, the market relied upon biodiesel and renewable diesel (primarily advanced biofuel and BBD, but also some volume of conventional biodiesel and renewable diesel) as the marginal RFS compliance option when other sources of conventional biofuel were not available at competitive prices. After 2018, D6 RIN prices were, for some time, significantly lower than D4 and D5 RIN prices, but still higher than the D6 RIN prices observed prior to 2013. These lower D6 RIN prices are largely the result of: (1) SREs granted in 2018, reducing the quantity of D6 RINs needed for compliance with the RFS obligations to a number that was below the E10 blendwall; and (2) The very large number of carryover RINs available, as discussed in Chapter 1.9.1). More recently, D4, D5, and D6 RIN prices have risen dramatically, and come close to converging at just under $2 each. These prices reflect the cost of biodiesel and renewable diesel production (the marginal supply) at a time of unusually high commodity prices for soybean and other oil feedstocks, less the value of other subsidies and credits (e.g., the $1.00/gal federal tax subsidy and state LCFS credits).

While D6 RIN prices have remained relatively high in recent years, these price levels have not translated into higher ethanol prices for ethanol producers. After examining market data, EPA found no correlation between D6 RIN prices and ethanol prices (or between RIN prices and the price differences between ethanol and gasoline, on either a volumetric- or energy-equivalent basis). Instead, higher D6 RIN prices have resulted in lower effective prices (the price after subtracting the RIN value from the price of the fuel with the attached RIN) for ethanol after the RINs have been separated and sold. Higher D6 RIN prices have thus served to subsidize fuel blends that contain higher proportions of conventional biofuels (e.g., E85) and increased the cost of fuel blends that contain little or no conventional biofuel (e.g., E0).

Figure 1.9.2-2: Ethanol Prices and D6 RIN Prices

D5 RINs were priced at a level between D4 and D6 RINs from 2010 through 2013. However, since 2013, D5 RIN prices have been nearly identical to D4 RIN prices. This shift in the relative pricing of D5 and D4 RINs also corresponds with the market reaching the E10 blendwall. This is because there are two primary fuel types that have been used to satisfy the advanced biofuel requirements: sugarcane ethanol and BBD. From 2010 through 2012, obligated parties generally met their implied requirements for “other advanced biofuel” (the difference between the advanced biofuel requirement and the sum of the cellulosic biofuel and BBD requirements, both of which are nested within the advanced biofuel category) with sugarcane ethanol. This is apparent in the volumes of sugarcane ethanol and BBD used in the U.S. in these years.[76] It is also indicated by the prices for D5 RINs, which were significantly lower than the price of D4 RINs during this time, suggesting that it was more cost effective for the market to meet their compliance obligations with D5 RINs (generated for sugarcane ethanol) than D4 RINs (generated for biodiesel and renewable diesel). When the E10 blendwall was reached in 2013, however, it became much more expensive to increase the volume of ethanol blended into the gasoline pool. While obligated parties could still import sugarcane ethanol to satisfy their advanced biofuel obligations, doing so would reduce the volume of corn ethanol that could be used as E10. Available non-ethanol renewable fuels were almost entirely advanced biodiesel and renewable diesel, so obligated parties generally used these fuels (rather than sugarcane ethanol) to meet the advanced biofuel requirements so that they could use corn ethanol to satisfy the remaining total renewable fuel requirements. RIN prices responded, and since 2013 the price of D4 and D5 RINs have been nearly identical.

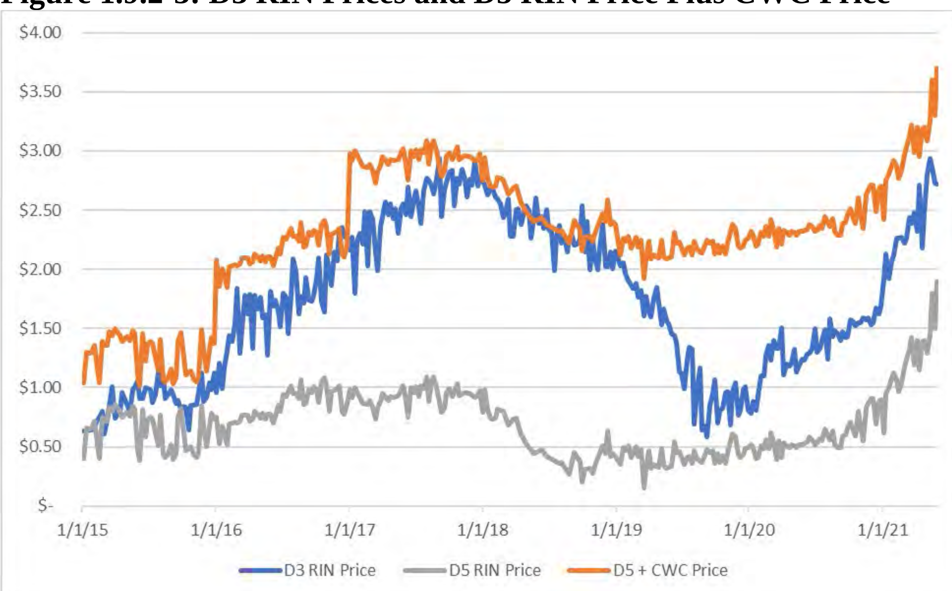
D4 RIN prices, much like all RIN prices, have varied significantly since 2010. The pricing of these RINs, however, has been fairly straightforward. D4 RINs are generally priced to account for the price difference between biodiesel and diesel fuel (which in turn are largely a function of the pricing of their respective oil supplies). Other factors can also impact this relationship; most significantly are the presence or absence of the biodiesel tax credit and the impact of other subsidies and credits (e.g., the $1.00/gal federal tax subsidy and state LCFS credits).[77] Most recently, in 2021, D4 RIN prices have increased quite significantly, tracking with an increase in feedstock (e.g., soybean oil) commodity prices, which comprise greater than 80% of the cost of production of BBD. Generally, D4 RIN prices have increased to a level that allows BBD to be cost-effective with petroleum-based fuels to increase BBD production and use. A December 2018 paper exploring the relationship between the price of D4 RINs and economic fundamentals concluded that “movements in D4 biodiesel RIN price at frequencies of a month or longer are well explained by two economic fundamentals: (a) the spread between the biodiesel and ULSD prices and (b) whether the $1 per gallon biodiesel tax credit is in effect.”[78] This same paper discusses in greater detail the strong correlation between weekly D4 RIN prices and predicted D4 RIN price values using a model based on economic fundamentals. As state LCFS programs have come online and increased in stringency, the value of these credits is now another increasingly important factor.

Data on cellulosic RIN (D3 and D7) prices were not generally available until 2015. This is likely due to the fact that prior to 2015, the market for cellulosic RINs was too small to support commercial reporting services; very few cellulosic RINs were generated and traded in years prior

[76] See Chapters 5.3 and 5.2 for volumes of sugarcane ethanol and BBD used in the U.S., respectively.
[77] A $1 per gallon biodiesel blenders tax credit has been available to biodiesel blended every year from 2010 through the end of 2022. However, at various times this credit has expired and been reinstated retroactively. The biodiesel tax credit expired at the end of 2009 and was not reinstated until December 2010, applying to all biodiesel blended in 2010 and 2011. The biodiesel tax credit has since been again reauthorized semi-regularly, including in January 2013 (applying to biodiesel produced in 2012 and 2013), December 2014 (applying to biodiesel produced in 2014), December 2015 (applying to biodiesel produced in 2015 and 2016), and February 2018 (applying to biodiesel produced in 2017). In December 2019 the tax credit was retroactively reinstated for 2018 and 2018 and put in place prospectively through 2022.
[78] Irwin, S.H, K. McCormack, and J. H. Stock (2018). “The price of biodiesel RINs and economic fundamentals.” NBER working paper series, working paper 25341.

to 2016. From 2015, when D3 RIN prices were first regularly available, through 2018, the price of these RINs was very closely related to the sum of the D5 RIN price plus the price of the cellulosic waiver credit (CWC).[79] This is as expected, since obligated parties can satisfy their cellulosic biofuel obligations through the use of either cellulosic RINs or CWCs plus D5 RINs. The slight discount for D3 RINs (as opposed to the combination of a CWC and a D5 RIN) is also as expected, as CWCs can be purchased directly from EPA when obligated parties demonstrate compliance and carry no risk of RIN invalidity.[80] This discount tends to be larger at the beginning of the year, before narrowing near the end of the year as the RFS compliance date nears for obligated parties. Starting in 2019, the D3 RIN price was significantly lower than the CWC plus D5 RIN price. This is likely due to an over-supply of D3 RINs caused by EPA granting a relatively large number of SREs for the 2017 and 2018 compliance years, lowering the effective RFS standards (see Chapter 1.2). The average D3 RIN price fell to near the D5 RIN price, before slowly increasing relative to the D5 RIN price starting in the second half of 2019.

Figure 1.9.2-3: D3 RIN Prices and D5 RIN Price Plus CWC Price



Source: RIN price data from EMTS

The fact that the price of D3 RINs, with very few exceptions, has not exceeded the CWC plus D5 RIN price has potentially significant consequences for both the cellulosic biofuel and petroleum fuel markets. This statutory ceiling on the CWC price (which effectively sets a ceiling

[79] Pursuant to CAA section 211(o)(7)(D)(ii), EPA makes CWCs available for sale to obligated parties at a price determined by a statutory formula in any year in which EPA reduces the required volume of cellulosic biofuel using the cellulosic waiver authority. A CWC satisfies an obligated party's cellulosic biofuel obligation. However, unlike a cellulosic RIN, which also helps satisfy an obligated party's advanced biofuel and total renewable fuel obligations, a CWC does not help satisfy an obligated party's advanced biofuel and total renewable fuel obligations. A cellulosic RIN (which can be used to meet all 3 obligations) has similar compliance value as a CWC (which can only be used to satisfy the cellulosic biofuel obligation) and an advanced RIN (which can be used to satisfy the advanced biofuel and total renewable fuel obligations).

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

on the D3 RIN price) limits the price cellulosic biofuel producers can expect to receive for their fuels. If the projected cost of production of a particular cellulosic biofuel is higher than the sum of the RIN value of that fuel, the price of the petroleum fuel it displaces, and any tax credits or other incentives available for the fuel, then it will likely not be possible for the cellulosic biofuel to be produced profitably.

At the same time, the relatively high value of the CWC plus D5 RIN price, in conjunction with EPA's statutory obligation since 2010 to set the required volume of cellulosic biofuel at the volume expected to be produced each year,[81] has resulted in generally high D3 RIN prices. These RIN prices are realized for all cellulosic RINs, even those generated for biofuels such as CNG/LNG derived from biogas that can often be produced at a cost that is competitive with the petroleum fuels they displace even without the RIN value. While some of this excess RIN value may be passed on to consumers who use CNG/LNG derived from biogas as transportation fuel in the form of lower cost fuel and/or longer term fixed-price fuel contracts, a significant portion of the RIN value may remain with the biofuel producer, the parties that dispense CNG/LNG derived from biogas, and any other parties involved in the generation of this type of cellulosic biofuel.[82] Unlike other RIN costs that are generally transfered within the liquid fuel pool (e.g., from consumers of fuels with relatively low renewable fuel content such as E0 or B0 to consumers of fuels with relatively high renewable fuel content such as E85 or B20), much of the RIN value for CNG/LNG derived from biogas may be transferred from consumers who purchase gasoline and diesel fuel to parties outside of the liquid fuel pool (e.g., landfill owners).[83]

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[81] CAA section 211(o)(7)(D).

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

[83] E0 and B0 respectively refer to gasoline and diesel without any renewable fuels blended in, that is, gasoline with 0% ethanol content and diesel with 0% biodiesel content. E85 refers to gasoline blended with 51%-83% ethanol. B20 refers to diesel blended with 20% biodiesel.

Chapter 2: Baselines and Volume Scenarios

This DRIA contains a collection of analyses prescribed by the CAA. For analyses in which we have chosen to quantify the impacts of the proposed volume requirements for 2020, 2021, and 2022 (including the 2022 supplemental standard), we have identified the specific biofuel types and associated feedstocks that are projected to be used to meet the volume requirements, and the appropriate baselines for comparison. While we acknowledge that there is significant uncertainty about the types of renewable fuels that would be used to meet the proposed volume requirements in this rule, we believe that the mix of biofuel types described in this chapter are reasonable projections of what could be supplied in response to the proposed volume requirements for the purpose of assessing the potential impacts. We also acknowledge that the choice of baseline affects the estimated impacts of the proposed volume requirements. This section describes both the methodology for identifying the mix of biofuels that could result from the proposed volume requirements and the baseline that we have identified as a reference point for comparison, as well as a discussion of alternative baselines.

2.1 Mix of Renewable Fuel Types for Proposed Volume Requirements

The volume requirements that we are proposing to establish for 2020, 2021, and 2022 (including the 2022 supplemental standard) are presented in Section III of the preamble. We estimate the constituent mix of renewable fuel types and feedstocks that could be used to meet those proposed volume requirements in Table 2.1-1.

Table 2.1-1: Volumes Assessed for 2020, 2021, and 2022 (million RINs)

	2020 Volume	2021 Volume	2022 Volume[a]
Cellulosic Biofuel	505	621	765
CNG/LNG derived from biogas	503	619	762
Liquid Cellulosic Biofuel	2	2	3
Total Biomass-Based Diesel	3,791	4,265	5,615
Biodiesel	2,885	2,870	2,880
Renewable Diesel	900	1,390	2,730
Other	6	5	5
Other Advanced Biofuels	334	289	289
Renewable Diesel	86	64	64
Imported Sugarcane Ethanol	185	161	161
Domestic Ethanol	23	24	24
Other	40	40	40
Total Advanced Biofuel	4,630	5,175	6,669[a]
Conventional Renewable Fuel	12,500	13,453	14,096
Ethanol	12,500	13,453	13,788
Imported Renewable Diesel	0	0	308
Imported Renewable Diesel to address the Supplemental Standard	0	0	250
Other	0	0	0
Total Renewable Fuel	17,129	18,628	20,765

[a] Includes the volume representing the proposed 2022 supplemental standard. For the purposes of this analysis, this volume is assumed to be supplied as imported conventional renewable diesel.
[b] Includes 904 million advanced biofuel RINs in excess of the proposed advanced biofuel volume requirement of 5,765 million RINs.

The analyses leading to the mix of renewable fuel types and feedstocks shown in Table 2.1-1 are presented in later parts of this DRIA as follows:

- Chapter 5.1: Cellulosic biofuel
- Chapter 5.2: BBD
- Chapter 5.3: Sugarcane ethanol
- Chapter 5.4: Other advanced biofuels
- Chapter 5.5: Corn ethanol

The volume of conventional renewable diesel for 2022 was projected based on the difference between the sum of our projections of all the other types of renewable fuel discussed in Chapter 5 and our proposed volumes for 2022. That is, we determined that 308 million RINs of conventional renewable diesel would be needed in order to meet the proposed total renewable fuel volume requirement of 20,765 million RINs after consideration of the volumes of other renewable fuels that can be supplied in 2022. We projected grandfathered renewable diesel as the most likely fuel to be used to meet the proposed total renewable fuel volume as grandfathered renewable diesel can be produced from cheaper feedstocks that are not eligible to be used to produce BBD under the RFS program.[84] The production capacity of foreign grandfathered renewable diesel production facilities is also significant. In previous years when the implied conventional biofuel volume could not be satisfied with ethanol blended as E10 (i.e., 2013, 2015, 2016), we have seen some volumes of grandfathered renewable diesel supplied to the U.S. Moreover, because it can be conventional and because of domestic production limitations, we project that all of this conventional renewable diesel would be imported and sourced from palm oil.

2.2 Volume Changes Analyzed

In assessing the impact of a proposed action EPA's preferred baseline for comparison is generally the world as it would exist in the absence of the rulemaking action. In the case of the RFS program, determining the volume of renewable fuel that would be produced and consumed in the absence of RFS volume requirements is particularly challenging given the many other market and policy drivers for the use of renewable fuels. Consequently, we have not been able to determine a "No-RFS" baseline for 2020-2022 at this time. We have, however, included a brief overview of what a No-RFS baseline for 2020-2022 might look like at the end of this section.

In recent RFS annual rules, we have presented an illustrative cost assessment relative to two different baselines; the statutory volumes and the required RFS volume from the previous year. We considered using the statutorily mandated volumes as the baseline for this proposed rule, but this proved to be unworkable given that the statutory volumes were infeasible and therefore any assessment of the impacts relative to it would be hypothetical and would not be informative. The simplified assumptions and limited scope of the analyses (such as only calculating illustrative costs for a limited set of fuels) that enabled the use of the statutory baseline in past RFS rules would not be appropriate in this rule given the far more extensive costs and impacts analyzed in this rule. The other baseline considered as a point of comparison in recent annual rules was the previous year's volume requirements. This approach was reasonable when the new volume requirements at issue were only prospective and we were only attempting to quantify the cost impacts of a few representative types of renewable fuel. For this rule, in contrast, we are proposing to establish volume requirements both retrospectively and prospectively. We are also proposing to revise the most recently established volume requirements for 2020.

As a result, for those factors that we have quantified, we have chosen to assess the impacts of the proposed volume requirements for 2020, 2021, and 2022 against a baseline consisting of the actual consumption of renewable fuel in 2020. This approach is consistent with that taken in the rulemaking which established the volume requirements for 2014, 2015, and 2016.[85] In that rule, the impacts of the volume requirements for all three years were assessed against a baseline consisting of the actual consumption of renewable fuel in 2014. Additionally, we note that we also considered using the original volume requirements established for 2020 as the baseline. However, the original volume requirements established for 2020 did not specify the particular fuel types we projected would be used to meet the broad categories of renewable fuel.

[84] Note that this grandfathered volume does not have a GHG reduction requirement, and the mix of feedstocks used to produce this fuel will be determined by future market conditions that we are unable to predict at this time.
[85] 80 FR 77420 (December 14, 2015).

These specific fuel types are a necessary element of our baseline. Additionally, the impacts of this proposal using the original 2020 volumes would likely be less informative than the actual volume of renewable fuel used in 2020. The proposed volumes for 2021 are lower than the original volume requirements for 2020. Using the original 2020 RFS volumes (or the actual renewable fuel volumes in 2019) as a baseline would imply a decrease in renewable fuel use in 2021 when in reality renewable fuel use in 2021 is anticipated to be significantly higher than in 2020. Finally, we do not think that using the original volume requirements established for 2020 as a baseline is appropriate given that we are proposing to change those volume requirements in this rule.

Furthermore, we have made the simplifying assumption for analysis purposes for this proposal that the projected volume increases in 2021 and 2022 will result in increases in renewable fuel production on a gallon-for-gallon basis. For example, we have assumed that increases in corn ethanol used to meet the proposed 2021 and 2022 volume requirements would result in an equivalent increase in ethanol production. However, this may not be the case as increased consumption in the U.S. could come from a reduction in exports, which have been at historical highs in recent years. Furthermore, some of the increase in volume analyzed for 2021 and 2022 relative to 2020, and corn ethanol in particular, are associated with the market recovering from the impacts of the COVID-19 pandemic in 2020.

The use of actual consumption in 2020 as the baseline and the treatment of production as being equivalent to consumption are two factors that, while appropriate in their own right, nevertheless make it difficult to attribute all of the impacts assessed for 2021 and 2022 to the proposed volumes. Moreover, a number of factors other than the RFS volume requirements also influence the volumes of renewable fuel consumed and thus the volume changes associated with the volume requirements that we are proposing. For instance, with regard to the biofuel with the largest increase in 2022, ethanol, its predominant use is as E10. As E10 use has saturated the gasoline market, and, as discussed in Chapter 9, is economical in comparison to gasoline, total consumption of ethanol rises and falls with gasoline demand, which is independent of the RFS program. Similarly, the overlapping requirements of state incentives, mandates, and low-carbon fuel programs suggest that some of the increases in cellulosic biogas and advanced renewable diesel use may occur even without the proposed RFS standards, albeit without the financial support of RINs. Furthermore, even where the proposed RFS standards may directly drive increased renewable fuel volume use, it is unclear to what extent those volumes may drive changes in feedstock production in the U.S. or abroad given the many factors that impact those decisions. This is especially an issue when the feedstocks used (e.g., soybean oil) are not the primary source of value for the agricultural product from which it is derived (e.g., soybeans). This is particularly an important consideration when evaluating the many statutory factors discussed in Chapter 3 that relate to impacts on crop production and associated land and water use. As a result of these non-RFS factors and drivers, there are numerous uncertainties associated with the environmental and economic impacts we have analyzed for the proposed volume requirements. The quantitative impact assessments carried out in subsequent chapters simply assume that the proposed standards are driving the volume changes described below.

With that understanding, for those factors for which we quantified the impacts of the proposed volume requirements for 2020, 2021, and 2022, the impacts were based on the difference in the volumes of specific renewable fuel types between the proposed volume requirements and the baseline. These differences are shown in Tables 2.2-1 and 2.2-2 in terms of both RINs and physical volumes, respectively.

Table 2.2-1: Volume Changes for 2020, 2021, and 2022 Relative to the Baseline (million RINs)

	2020	2021	2022
Cellulosic Biofuel	0	+117	+261
CNG/LNG derived from biogas	0	+117	+260
Liquid Cellulosic Biofuel	0	0	+1
Total Biomass-Based Diesel	0	+474	+1,824
Biodiesel	0	–15	–5
Renewable Diesel	0	+490	+1,830
Other	0	–1	–1
Other Advanced Fuels	0	–45	–45
Renewable Diesel	0	–22	–22
Sugarcane Ethanol	0	–24	–24
Domestic Ethanol	0	+1	+1
Other	0	0	0
Total Advanced Biofuel	0	+546	+2,040
Conventional Renewable Fuel	0	+953	+1,596
Ethanol	0	+953	+1,288
Imported Renewable Diesel	0	0	+308
Imported Renewable Diesel to address the Supplemental Standard	0	0	+250
Other	0	0	0
Total Renewable Fuel	0	+1,499	+3,636

Table 2.2-2: Volume Changes for 2020, 2021, and 2022 Relative to the Baseline (million gallons)

	2020	2021	2022
Cellulosic Biofuel	0	+117	+261
CNG/LNG derived from biogas	0	+117	+260
Liquid Cellulosic Biofuel	0	0	+1
Total Biomass-Based Diesel	0	+270	+1,066
Biodiesel	0	–10	–3
Renewable Diesel	0	+280	+1,070
Other	0	–1	–1
Other Advanced Fuels	0	–36	–36
Renewable Diesel	0	–13	–13
Sugarcane Ethanol	0	–24	–24
Domestic Ethanol	0	+1	+1
Other	0	0	0
Total Advanced Biofuel	0	+351	+1,291
Conventional Renewable Fuel	0	+953	+1,469
Ethanol	0	+953	+1,288
Imported Renewable Diesel	0	0	+181
Imported Renewable Diesel to address the Supplemental Standard	0	0	+147
Other	0	0	0
Total Renewable Fuel	0	+1,304	+2,761

For the purposes of our analyses, we made some simplifications to the volume changes shown in Tables 2.2-1 and 2.2-2. We generally grouped fuels with very small changes in volumes with similar fuels with much larger volume changes. We did this both because of the more limited data on the impacts of those renewable fuel types with smaller volume changes, and because we expect small volume changes to have little material impact on the analyses. These simplifications were to assume that:

- All changes in cellulosic biofuel were CNG/LNG derived from biogas.
- All changes in BBD were renewable diesel.
- All changes in other advanced fuels were sugarcane ethanol.

For some of the fuel types, the impacts of increasing (or decreasing) volumes of the fuel vary depending on the feedstock used to produce the fuel. It was therefore necessary to project the feedstocks used to produce the renewable fuels expected to increase (or decrease) in 2021 and 2022. In cases where the vast majority of the fuel type has historically been produced from a single feedstock, as is the case for many of the fuels we are projecting to increase in 2021 and 2022, we assumed that the entire volume change was produced from that feedstock. The fuel that has historically been produced from a variety of feedstocks for which we are projecting appreciable volume increases in 2021 and 2022 is renewable diesel that qualifies as BBD. For this fuel we projected the feedstocks that would be used to produce increasing volumes in 2021 and 2022 according to the trends we have observed in previous years.[86] The changes in renewable fuel production that we assessed in this DRIA (after making the simplifications described above) and the feedstocks used to produce these fuels, are shown in Table 2.2-3.

Table 2.2-3: Renewable Fuel Volume Changes and Feedstocks Analyzed Relative to the Baseline (million gallons of fuel)

Fuel	Feedstock	Change in 2021	Change in 2022
CNG/LNG derived from biogas	Separated MSW	+117	+261
Domestic Renewable Diesel	FOG	+30	+60
Domestic Renewable Diesel	Soybean Oil	+240	+1,006
Imported Ethanol	Sugarcane	–23	–23
Domestic Ethanol	Corn	+953	+1,288
Imported Renewable Diesel	Palm oil	0	+328[a]

[a] Includes 181 million gallons for the proposed 2022 total renewable fuel volume requirement and 147 million gallons for the proposed 2022 supplemental volume requirement.

As discussed briefly above, current guidance to federal agencies on the development of regulatory analysis states that a baseline "should be the best assessment of the way the world would look absent the proposed action."[87] Consistent with this, a baseline that represents what would happen in the absence of the proposed volume obligations (the "No-RFS baseline") has several advantages over the actual volumes of renewable fuel used in 2020. A No-RFS baseline would better estimate the impacts of the proposed action in comparison to not taking the action, including the potential benefits, costs and impacts on other statutory factors. Such a baseline would better assess the changes actually driven by the rule, as opposed to merely assessing changes relative to the 2020 actual volumes, many of which are driven by other factors as noted above. A No-RFS baseline would also avoid the complication of a comparison to previous years that are themselves impacted by past RFS standard-setting rules. Despite these advantages, we have not been able to precisely quantify a No-RFS baseline at this time due to the complex market and regulatory dynamics associated with biofuels. Nonetheless, we present our preliminary views on what such a baseline might look like as many aspects of the qualitative analyses in this DRIA discuss impacts relative to a No-RFS baseline.

We believe that the No-RFS baseline for ethanol may be approximated by using the volumes associated with the E10 blend wall (e.g. ethanol volumes representing 10% of the gasoline pool). In the absence of this or future RFS standard-setting rules, we believe that the fuel market would continue to produce and blend 10 percent ethanol for a variety of economic reasons out into the future, including demand for oxygenates and other high octane blendstocks. Such an approach would not directly account for the relatively small volume of ethanol consumed in higher level ethanol blends such as E15 or E85, but it would implicitly assume some ongoing use of these higher-level ethanol blends that is offset by the continued use of gasoline that does not contain ethanol (E0). We expect that the vast majority of the ethanol volume would be conventional biofuel produced from corn starch, with much smaller quantities of sugarcane ethanol and cellulosic ethanol.

[86] These feedstock trends for BBD production are discussed in greater detail in Chapter 5.2.4.
[87] “”68 FR 58366 (October 9, 2003).

In regards to biodiesel and renewable diesel, we believe that the volume that would be produced, imported, and used without any RFS mandates would be substantially lower than the approximately 2.5 billion gallons used in 2020. Since 2010, biodiesel and renewable diesel prices have consistently been far higher than the price of petroleum-based diesel, even after accounting for the $1 per gallon federal tax credit. This suggests that little if any biodiesel and renewable diesel would be driven by relative fuel prices. However, several states have adopted regulations to incentivize the use of biodiesel and renewable diesel. These incentives range from mandates for biodiesel and renewable diesel use, to tax credits or tax exemptions, to carbon intensity-based incentives such as California’s LCFS. While we expect that the use of biodiesel and renewable diesel in the U.S. would decrease in the absence of the RFS program, these state incentives, in combination with the federal tax credit, would likely result in the continued use of some volumes of these fuels even in the absence of the RFS program.

As for other advanced biofuels and cellulosic biofuel, we expect that in the absence of the RFS program some volumes of these fuels would continue to be used, but likely a lower volume than was used in 2020. State programs such as California’s LCFS and Oregon’s Clean Fuels Program are expected to support the continued use of advanced and cellulosic biofuels, especially in light of the generally low carbon intensities assigned to these fuels, but volumes are still expected to decrease without the significant financial incentive provided by the RFS program.

Chapter 3: Environmental Impacts

The statute requires EPA to analyze a number of environmental factors in its determination of the appropriate volumes to establish under the reset authority. This Chapter discusses those environmental factors required by the statute. Due to its close association with water quality, which is a factor listed in the statute, we also investigated soil quality even though it is not listed in the statute. The second triennial Biofuels Report to Congress provides additional information on environmental impacts.[88]

3.1 Air Quality

Air quality, as measured by the concentration of air pollutants in the ambient atmosphere, can be affected by increased production and use of biofuels. Some air pollutants are emitted directly (e.g., nitrogen oxides (NOx)), other air pollutants are formed secondarily in the atmosphere (e.g., ozone), and some air pollutants have directly emitted and secondarily formed components (e.g., particulate matter (PM) and aldehydes). Health and environmental effects of criteria pollutants and air toxics which can be impacted by biofuel use are discussed in a memorandum to the docket. Air quality can be affected by emissions from combustion of biofuels in vehicles, as well as emissions from production and transport of feedstocks, conversion of feedstocks to biofuels, and transport of the finished biofuels.

In addition to the type of biofuel, other factors affect air quality, including but not limited to the blend level, the vehicle technology, emissions control technology, and operating conditions. Overall, the impacts on air quality resulting from the biofuel volume changes due to this rule are expected to be relatively minor and thus, provide little basis in favor of higher or lower volumes. This conclusion is based on analyses of impacts from much higher volumes.[89, 90] In addition, while we are assessing the impacts of additional volumes of corn ethanol in 2021 and 2022 primarily as a result of changes in gasoline volume, the concentration of ethanol in gasoline in the vast majority of gasoline is expected to remain constant at 10%.

Table 2.3-3 summarizes the changes in renewable production volume assessed for this rule. The largest volume changes are for corn ethanol and renewable diesel, primarily produced from soybean oil, with a small volume from fats, oil and grease (FOG) and biogas. The discussion below focuses on potential impacts for these fuel/feedstock combinations.

3.1.1 Corn Ethanol Emissions

Air quality impacts of corn ethanol are associated with each step in the supply chain: (1) agricultural feedstock production and storage, (2) feedstock transport to the biorefinery, (3)

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[88] EPA. Biofuels and the Environment: Second Triennial Report to Congress (Final Report, 2018). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-18/195, 2018. https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=IO&dirEntryId=341491

[89] EPA (2020). Clean Air Act Section 211(V)(1) Anti-Backsliding Study. https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100ZBY1.pdf

[90] Hoekman, S. K., Broch, A., & Liu, X. (2018). Environmental implications of higher ethanol production and use in the U.S. Renewable and Sustainable Energy Reviews, 81, 3140-3158.

ethanol production at the biorefinery, (4) ethanol distribution, blending and storage, and (5) end use.

There is little recent literature that addresses cumulative impacts of processes upstream of emissions from corn ethanol. A 2009 analysis using the GREET model concluded that criteria pollutant emissions for corn ethanol production are substantially higher than for gasoline on a mass per gasoline equivalent gallon basis.[91] A significant source of upstream emissions from corn ethanol is production facilities.[92,93] Table 3.1.1-1 summarizes corn ethanol plant emissions in 2016, from EPA's 2016 emissions modeling platform version 1.[94] Only 10 plants used coal or coal in combination with other energy sources, although they contributed disproportionately to emissions, especially sulfur dioxide.

Table 3.1.1-1: Pollutant emissions (short tons) from biodiesel and corn ethanol biorefineries in U.S. in 2016.

Finished Fuel	Number of Facilities	CO	NH_3	NOx	PM_{10}	$PM_{2.5}$	SO_2	VOCs
Corn Ethanol (total)	180	7913.0	292.6	9955.1	5420.3	4096.0	5830.2	9964.0
Coal; Dry Mill	2	31.8	0	25.9	7.5	7.1	0.2	26.6
Coal; Wet Mill	2	453.1	7.1	907.8	390.1	302.0	4,397.4	837.6
Natural Gas; Dry Mill	164	7,053.5	276.5	8,510.1	4704.8	3,602.6	1,092.1	8,572.7
Natural Gas; Wet Mill	3	197.0	9.0	150.7	206.0	108.2	68.1	269.6
Unknown; Unknown	9	177.6	0.0	360.6	111.9	76.1	272.4	257.5
Biodiesel[6]	172	1,148.3	39.4	1,962.2	986.1	675.2	4,894.4	5,681.1
Total	352	9,061.3	332.0	11,917.3	6406.3	4,771.2	10,724.6	15,645.1

Source: EPA 2016 version 1 modeling platform (https://www.epa.gov/air-emissions-modeling/2016v1-platform)

Once the ethanol is produced at biorefineries, it is transported to terminals for blending and storage. At the blending terminal, ethanol is blended with gasoline for various fuel combinations such as E10, E15 or E85. The blended fuel is then sent to retail gasoline outlets where it is sold to the customer. Primary modes of distributing ethanol to the blending terminal

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[91] Hess P, Johnston M, Brown-Steiner B, Holloway T, de Andrade JB, Artaxo P. Chapter 10: air quality issues associated with biofuel production and use. In: Howarth RW, Bringezu S. editors. Biofuels: environmental consequences and interactions with changing land use. Gummersbach, Germany; 2009. p. 169–94. https://ecommons.cornell.edu/bitstream/handle/1813/46218/scope.1245782010.pdf?sequence=2

[92] [92] EPA. Biofuels and the Environment: Second Triennial Report to Congress (Final Report, 2018). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R-18/195, 2018. https://cfpub.epa.gov/si/si_public_record_report.cfm?Lab=IO&dirEntryId=341491

[93] de Gouw, J. A., McKeen, S. A., Aikin, K. C., Brock, C. A., ABrown, S. S., Gilman, J. B., Graus, M., AHanisco, T., Holloway, J. S., Kaiser, J., Keutsch, F. N., Lerner, B. M., Liao, J., Markovic, M. Z., Middlebrook, A. M., Min, K.-E., Neuman, J. A., Nowak, J. B., Peischl, J., Pollack, I. B., Roberts, J. M., et al. (2015). Airborne measurements of the atmospheric emissions from a fuel ethanol refinery. Journal of Geophysical Research: Atmospheres, 120(9), 4385-4397. https://doi.org/10.1002/2015JD023138

[94] https://www.epa.gov/air-emissions-modeling/2016v1-platform

and the blended fuel to the retail outlets are rail, road, or barges. Emissions come from combustion and evaporation during transport by mobile sources, as well as evaporative losses during storage and transport. The largest emission contribution is for VOC due to evaporation. Table 3.1.1-2 presents emissions associated with transport. Air quality impacts associated with changes in ethanol production and transport are expected to be primarily in the local area where the emissions occur.[95] Measurement also indicates concentrations of several pollutants, such as NO, formaldehyde, and SO_2,, are greater directly downwind of production facilities, up to a distance of 30 kilometers.[96] More research is needed on these impacts.

Table 3.1.1-2. Emissions from transportation of ethanol (short tons)

CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
4,225	26	19,270	630	533	340	660,674

Source: EPA 2016 version 1 modeling platform (https://www.epa.gov/air-emissions-modeling/2016v1-platform)

Using the production and transport emissions data, along with total production in 2016, we calculated emission rates in grams per gallon for production of and transport of corn ethanol. We then multiplied the grams per gallon emission rates by the volume impacts for this proposed rule to estimate the impacts on ethanol production and transport (Table 3.1.1-3), assuming additional ethanol use in the U.S. will lead to increased ethanol production in the U.S. However, increased volumes that we are projecting will be used to comply with this rule are still below the historical volumes used in the U.S. and even further below the total U.S. production which also reflects exports. As volumes used domestically could be sourced from exports, it is unclear what overall impacts would be on domestic production and therefore emissions.

Table 3.1.1-3: Pollutant Emission Impact Estimates for Production and Transport of Corn Ethanol of the 2021 and 2022 Ethanol Volumes (short tons)

	CO	NH_3	NO_X	PM_{10}	$PM_{2.5}$	SO_2	VOC
Biorefinery Emissions	7,913	293	9,955	5,420	4,096	5,830	9,964
Transport Emissions	4,225	26	19,270	630	533	340	660,674
Total Emissions	12,128	319	29,225	6,050	4,629	6,170	670,638
Impacts per Million Gallons Ethanol[a]	0.79	0.02	1.90	0.39	0.30	0.40	43.52
2021 Annual Std Impacts	751	20	1,807	374	283	382	41,474
2022 Annual Std Impacts	264	7	365	132	101	134	14,579

[a] Emissions per million gallons ethanol is calculated using total domestic ethanol production in 2016 as reported in the EIA Monthly Energy Review (15.41 billion gallons)

[95] Cook, R., Phillips, S., Houyoux, M., Dolwick, P., Mason, R., Yanca, C., Zawacki, M., Davidson, K., Michaels, H., Harvey, C., Somers, J., Luecken, D.. 2011. Air quality impacts of increased use of ethanol under the United States' Energy Independence and Security Act. *Atmospheric Environment*, 45: 7714-7724. https://www.sciencedirect.com/science/article/pii/S1352231010007375

[96] See, e.g., de Gouw, J. A., McKeen, S. A., Aikin, K. C., Brock, C. A., ABrown, S. S., Gilman, J. B., Graus, M., AHanisco, T., Holloway, J. S., Kaiser, J., Keutsch, F. N., Lerner, B. M., Liao, J., Markovic, M. Z., Middlebrook, A. M., Min, K.-E., Neuman, J. A., Nowak, J. B., Peischl, J., Pollack, I. B., Roberts, J. M., et al. (2015). Airborne measurements of the atmospheric emissions from a fuel ethanol refinery. *Journal of Geophysical Research: Atmospheres*, *120*(9), 4385-4397. https://doi.org/10.1002/2015JD023138

After distribution to the retail outlet stations, end use at the vehicle occurs. This step includes both evaporative losses during dispensing the fuel, and exhaust emissions from combustion during vehicular use. Impacts of ethanol blends on vehicle exhaust emissions are the result of complex interactions between fuel properties, vehicle technologies, and emission control systems. Depending on the pollutant and blend concentration the impacts vary both in direction and magnitude.

Several test programs in recent years have evaluated the impacts of fuel properties, including those of certain ethanol blends on emissions from Tier 2 and Tier 3 compliant vehicles).[97,98,99,100]

However, given the magnitude of the projected changes in volume and the fact that they are dispersed across the country, the overall end use impacts are expected to be small. Also, as noted above, the volume changes we are projecting do not likely result in changes in the percentage of ethanol in gasoline – almost all gasoline will be E10. If there are any significant changes in E10 or E85, they would be highly localized.

3.1.2 Biodiesel/Renewable Diesel Emissions

Although biodiesel is sourced from a variety of feedstocks, domestic soybean and domestic FOGs made up nearly 70% of the biodiesel in 2019, with most of that being domestic soybean. Data are lacking on emission and air quality impacts of either soybean biodiesel or FOGs that address the feedstock production (soybean) or collection (FOGs), storage, and transport stages. In the soybean diesel production phase, emission impacts depend on the oil extraction method used. Mechanical expelling is the least efficient with the highest emissions of NOx, VOCs, CO, and PM2.5, followed by hexane extraction and then enzyme assisted aqueous extraction process (EAEP).[101] Hums et al. (2016) performed a lifecycle comparison of soybean biodiesel with low-sulfur diesel which suggested an increase in NOx with PM decreases.[102]

A smaller amount of biodiesel is derived from FOG. FOGs are waste products of processes like animal rendering. Overall, since FOG is a generally a byproduct, farming

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[97] EPA (2013a). Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards: Analysis of Data from Epact Phase 3 (Epact/V2/E-89).

[98] EPA (2013b). Epact/V2/E-89: Assessing the Effect of Five Gasoline Properties on Exhaust Emissions from Light-Duty Vehicles Certified to Tier 2 Standards - Final Report on Program Design and Data Collection.

[99] Morgan, P., Lobato, P., Premnath, V., Kroll, S., Brunner, K.. Impacts of Splash-Blending on Particulate Emissions for Sidi Engines. Coordinating Research Council (2018). http://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC-E-94-3_Final-Report_2018-06-26.pdf

[100] Morgan, P., Smith, I., Premnath, V., Kroll, S., Crawford, R.. Evaluation and Investigation of Fuel Effects on Gaseous and Particulate Emissions on Sidi in-Use Vehicles. Coordinating Research Council (2017). http://crcsite.wpengine.com/wp-content/uploads/2019/05/CRC_2017-3-21_03-20955_E94-2FinalReport-Rev1b.pdf

[101] Cheng, M., Sekhon, J. J. K., Rosentrater, K. A., Wang, T., Jung, S., Johnson, L. A. “Environmental Impact Assessment of Soybean Oil Production: Extruding-Expelling Process, Hexane Extraction and Aqueous Extraction.” Food and Bioproducts Processing 108 (2018): 58-68. https://www.sciencedirect.com/science/article/abs/pii/S0960308518300014

[102] Hums, M., Cairncross, R., & Spatan, S. (2016). Life-cycle assessment of biodiesel produced from grease trap waste. Environmental Science & Technology, 50(5), 2718–2726. https://doi.org/10.1021/acs.est.5b02667

emissions are not attributed to it, and the effects from FOGs may be expected to be much lower than for soybean biodiesel.

Table 3.1.1-1 provides estimated emissions from biodiesel refineries in the U.S. Given the limited impact of this rule on biodiesel production, national-scale impacts are small. However, there could be localized impacts.

While biodiesel is the predominant advanced biofuel used in diesel engines, renewable diesel is projected to meet increases in biomass-based diesel during the 2021/22 timeframe. While research on renewable diesel impacts is limited, research in California concluded that it reduced vehicle exhaust emissions of PM, NOx, hydrocarbons, and CO. Toxics test results also show reductions in most PAHs and VOCs.[103,104] However, these data were obtained on only two pre-2007 engines.

This rule also projects increases in biogas use. We are not aware of research comparing life cycle emissions of biogas versus compressed natural gas, but we welcome any available information.

3.1.3 Air Quality Modeling

As mentioned above, previous air quality analyses based on much larger volumes indicate that air quality impacts from this rule at the geographic scale used in photochemical air quality modeling are expected to be minimal. Thus, no air quality modeling was done. In general, fossil fuels are assumed to be displaced by biofuel use due to the renewable fuel standard. These fossil fuels also produce air emissions at the production, distribution, combustion stages. Relative to emissions from biofuels, emissions from fossil fuels differ based on the fuel, production process, transport, and other factors. Geographic distribution of emissions also varies, and a comprehensive evaluation of offsetting impacts is very complex. Furthermore, to the extent that the RFS results in reductions in imported refined petroleum products, those upstream emissions and the adverse impacts they cause would be considered outside the scope of an RIA or other analysis used to support a rulemaking.

3.2 Climate Change

The statutory authority used for this proposed rule in CAA section 211(o)(2)(B)(ii) says that EPA must analyze, “The impact of the production and use of renewable fuels on the environment, including on…climate change…” This proposed rule may affect climate change by altering the amount of greenhouse gas (GHG) emissions to the atmosphere. This section of the DRIA discusses our evaluation of the potential effects of this proposed rule on GHG emissions.

[103] California EPA. (2015). *Staff report: Multimedia evaluation of renewable diesel*. https://ww2.arb.ca.gov/sites/default/files/2018-08/Renewable_Diesel_Multimedia_Evaluation_5-21-15.pdf

[104] Na, K., Biswas, S., Robertson, W., Sahay, K., Okamoto, R., Mitchell, A., & S., L. (2015). Impact of biodiesel and renewable diesel on emissions of regulated pollutants and greenhouse gases on a 2000 heavy duty diesel truck. *Atmospheric Environment, 107*, 307-314.

3.2.1 GHG Emissions

One of the goals of the RFS program is to reduce greenhouse gas (GHG) emissions by replacing petroleum-based transportation fuels such as gasoline and diesel with renewable fuels such as ethanol and biodiesel. Renewable fuels composed of biogenic carbon recently sequestered from the atmosphere have the potential to reduce GHGs and influence climate change if their use displaces petroleum derived fuels.

To support the GHG emission reduction goals of EISA, Congress required that biofuels used to meet the RFS obligations achieve certain lifecycle GHG reductions. To qualify as a renewable fuel under the RFS program a fuel must be produced from approved feedstocks and have lifecycle GHG emission that are at least 20% less than the baseline petroleum-based gasoline and diesel fuels.[105] Advanced biofuels and biomass-based diesel are required to have lifecycle GHG emissions that are at least 50% less than the baseline fuels, while cellulosic biofuel is required to have lifecycle emissions at least 60% less than the baseline fuels.[106] Congress also allowed for facilities that existed or were under construction when EISA was passed to be grandfathered into the RFS program and exempt from the lifecycle GHG emission reduction requirements.[107]

In the early years of the RFS program the vast majority of the biofuel volume requirement was comprised of renewable fuel that was not required to be advanced biofuel.[108] In the latter years of the program the vast majority of the growth in the volume obligations were in the cellulosic biofuel and advanced biofuel categories, which are required to achieve greater GHG emission reductions. For instance, over the time period covered by this rulemaking, 2020-22, the statute provides for an 8 billion gallon increase in total renewable fuel relative to 2019, the entirety of which must come from advanced biofuel.[109]

In the March 2010 RFS2 rule (75 FR 14670), EPA estimated lifecycle GHG emissions of different biofuel production pathways; that is, the emissions associated with the production and use of a biofuel, including indirect emissions, on a per-unit energy basis. Since the RFS2 rule, EPA has also conducted numerous (over 140) analyses of new pathways and their lifecycle GHG emissions. Over time, EPA has approved additional pathways for participation in the RFS program. These pathways rely on novel feedstocks (e.g., camelina oil,[110] distillers sorghum

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[105] See 42 USC 7545(o)(1), (2)(A)(i)
[106] See 42 USC 7545(o)(1)(B)-(E)
[107] 42 USC 7545(o)(2)(A)(i).
[108] 42 USC 7545(o)(2)(B)(i)
[109] Compare 42 USC 7545(o)(2)(B)(i)(I), with id. (II). In section III.A of the preamble, we further discuss the potential GHG benefits of different types of biofuels.
[110] March 2013 Pathways I rule. 78 FR 14190. https://www.epa.gov/renewable-fuel-standard-program/final-rule-additional-qualifying-renewable-fuel-pathways-under

oil[111]) and novel production processes involving existing feedstocks (e.g., catalytic pyrolysis and upgrading of cellulosic biomass,[112] gasification and upgrading of crop residues[113]).

EPA maintains a summary of lifecycle greenhouse gas intensities estimated for the Renewable Fuel Standard program, which are available in spreadsheet form in a document titled "Summary Lifecycle Analysis Greenhouse Gas Results for the U.S. Renewable Fuels Standard Program."[114] Our analyses of the LCA of various pathways are also published online.[115] A list of pathways that have been approved by regulation can also be found at 40 CFR 80.1426(f)(1). Today's rulemaking also proposes to expand the pathways that can participate in the RFS program, as discussed further in the preamble to this rulemaking.

Depending on the renewable fuel, the feedstocks used to produce it, and the amount of fossil energy used in growing the feedstocks and producing the fuel, the GHG emission reductions will vary considerably. In general, we have found that renewable fuels that are not expected to have significant impacts on land use, such as fuels produced from wastes, residues, or by-products, have greater GHG emission reductions than renewable fuels produced from crops intended to be used as feedstock for renewable fuel production. For instance, with respect to biodiesel and renewable diesel production, the use of waste fats, oils, and greases (FOG) as feedstocks typically results in lower LCA GHG emissions compared to use of virgin vegetable oils, such as soybean or canola oil.[116] In addition, most cellulosic biofuels—which are required to meet the highest statutory LCA GHG reduction threshold of 60%—are produced from wastes, residues, or by-products, including landfill biogas and agricultural byproducts such as corn stover.[117]

The quantity of energy used to produce the renewable fuel and the source of this energy also affects the LCA GHG emissions. For instance, the use of natural gas, biomass, or biogas for process energy can potentially result in lower LCA GHG emissions than the use of coal or oil for process energy. This can help ensure that a biofuel production process meets certain LCA GHG reduction thresholds.[118]

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[111] August 2018 sorghum oil rule. 83 FR 37735. https://www.gpo.gov/fdsys/pkg/FR-2018-08-02/pdf/2018-16246.pdf
[112] March 2013 Pathways I rule. 78 FR 14190. https://www.epa.gov/renewable-fuel-standard-program/final-rule-additional-qualifying-renewable-fuel-pathways-under
[113] "San Joaquin Renewables Fuel Pathway Determination under the RFS Program." May 11, 2020. https://www.epa.gov/renewable-fuel-standard-program/san-joaquin-renewables-approval
[114] This document is available on EPA's website at: https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results. This summary is also available in docket EPA-HQ-OAR-2021-0324.
[115] See https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel and https://www.epa.gov/renewable-fuel-standard-program/other-actions-renewable-fuel-standard-program
[116] According to EPA's assessment biodiesel produced from yellow grease has lifecycle GHG emissions of 13.8 kg CO_2e/mmBTU while biodiesel produced from soybean oil and canola oil have lifecycle GHG emissions of 42.2 kg CO_2e/mmBTU and 48.1 kg CO_2e/mmBTU respectively. See https://www.epa.gov/fuels-registration-reporting-and-compliance-help/lifecycle-greenhouse-gas-results.
[117] According to data from EMTS in 2020 over 92% of all cellulosic biofuel RINs were produced from biogas from landfills or biogas from municipal wastewater treatment facilities. An additional 7% of cellulosic biofuel was produced from agricultural residues or biogas from agricultural digesters.
[118] See, e.g., 40 CFR 80.1426(f)(1) (describing pathways that require the use of natural gas, biomass, and/or biogas for process energy, e.g., at rows A-C).

In the past decade, estimation of biofuel lifecycle emissions has been an active area of research. While we continue to monitor the literature, fuel-specific lifecycle emissions estimates published in prior EPA actions remain within ranges found in more recent studies.[119,120] Despite extensive research on the lifecycle emissions of biofuels since the start of the RFS program, considerable uncertainty regarding the GHG emission impacts of renewable fuel use remains.[121] Sources of uncertainty in biofuel lifecycle emissions are discussed below.

Estimates of the lifecycle GHG emissions associated with an increase in biofuel use are often broken down into different components, which can be categorized into direct and indirect emissions. Direct emissions are the emissions directly attributable to the production and use of renewable fuel, including emissions from agricultural production for feedstock crops, feedstock and fuel transport, energy use for fuel production, and fuel combustion. Indirect emissions are the emissions that occur as a consequence of indirect effects of increased use of renewable fuel. Indirect effects are often mediated through prices of goods which are traded in global markets. Examples include the effects of increased crop demand and coproduct supply on animal feed markets and the consequent effects on livestock and crop production emissions, price effects on energy markets including rebound effects, and increased agricultural product demand driving expansion of cropland into natural land types.

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119 See Figure 1 in Scully, M. J., Norris, G. A., Alarcon Falconi, T. M., & MacIntosh, D. L. (2021). Carbon intensity of corn ethanol in the United States: state of the science. *Environmental Research Letters*, 16(4), Figure 1. doi:10.1088/1748-9326/abde08

120 See "CA LCFS summary of current fuel pathways.xlsx" in docket EPA-HQ-OAR-2021-0324. Retrieved on 6/11/2021 from https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.

121 The following references report a significant range of lifecycle GHG estimates based on modeling, data and other uncertainties: CARB (2014). Detailed Analysis for Indirect Land Use Change. California Air Resources Board. Sacramento, CA: 113. https://www.arb.ca.gov/fuels/lcfs/iluc_assessment/iluc_analysis.pdf; Carriquiry, M., et al. (2019). "Incorporating Sub-National Brazilian Agricultural Production and Land-Use into U.S. Biofuel Policy Evaluation." Applied Economic Perspectives and Policy. doi: 10.1093/aepp/ppy033; Chen, R., et al. (2018). "Life cycle energy and greenhouse gas emission effects of biodiesel in the United States with induced land use change impacts." Bioresource Technology 251: 249-258; Dunn, J. B., et al. (2013). "Land-use change and greenhouse gas emissions from corn and cellulosic ethanol." Biotechnology for Biofuels 6(1): 51; ICAO (2021). CORSIA Eligible Fuels -- Life Cycle Assessment Methodology. Volume 3. March 2021. 155 pages. https://www.icao.int/environmental-protection/CORSIA/Documents/CORSIA_Supporting_Document_CORSIA%20Eligible%20Fuels_LCA_Methodology_V3.pdf; Laborde, D., et al. (2014). Progress in estimates of ILUC with MIRAGE model. JRC Scientific and Policy Reports. Italy, European Commission Joint Research Centre Institute for Energy and Transport: 46. http://www.doc-transition-energetique.info/GED_CDM/194819191209/ifpri-jrc_report.pdf; Lewandrowski, J., et al. (2019). "The greenhouse gas benefits of corn ethanol – assessing recent evidence." Biofuels: 1-15; Plevin, R. J., et al. (2015). "Carbon Accounting and Economic Model Uncertainty of Emissions from Biofuels-Induced Land Use Change." Environmental Science & Technology 49(5): 2656-2664; Qin, Z., et al. (2016). "Influence of spatially dependent, modeled soil carbon emission factors on life-cycle greenhouse gas emissions of corn and cellulosic ethanol." Global Change Biology Bioenergy 8(6): 1136-1149; Scully, M. J., et al. (2021). Carbon intensity of corn ethanol in the United States: state of the science. *Environmental Research Letters*, 16(4), doi:10.1088/1748-9326/abde08; Taheripour, F., et al. (2017). "The impact of considering land intensification and updated data on biofuels land use change and emissions estimates." Biotechnology for Biofuels 10(1): 191; Valin H, P. D., et al. (2015). The land use change impact of biofuels consumed in the EU: Quantification of area and greenhouse gas impacts. Utrecht, Netherlands, Ecofys: 261; Woltjer, G., et al. (2017). Study Report on Reporting Requirements on Biofuels and Bioliquids Stemming from the Directive (EU) 2015/1513, European Commission: 124. https://dspace.library.uu.nl/handle/1874/358650

While direct emissions can, in theory, be directly measured, data availability and measurement methodologies can introduce uncertainty in estimates of direct emissions. For example, accurately estimating the emissions attributable to production of feedstock crops requires detailed data on not only the energy and chemical inputs of agricultural production, but on soil organic carbon (SOC) and carbon fluxes on cropland. There can be significant heterogeneity in SOC measurements even within small geographic areas, and when combined with different land management practices, estimates of carbon sequestered in or emitted from cropland vary widely. Furthermore, in order to estimate SOC changes directly attributable to feedstock production, a baseline SOC needs to be defined representing what the SOC would have been in the absence of the biofuel feedstock production. As is the case with other categories of emissions, uncertainty is amplified when extending estimates based on local measurements, such as measurements of SOC, to larger geographic regions or timeframes.

Indirect impacts, by definition, cannot be directly measured, and are often global in nature.[122] Indirect effects are often mediated through prices of goods which are traded in global markets. Examples include the effects of increased crop demand and coproduct supply on animal feed markets and the consequent effects on livestock and crop production emissions, price effects on energy markets including rebound effects, and increased agricultural product demand driving expansion of cropland into natural land types. Despite significant research on the lifecycle emissions of biofuels since the start of the RFS program, uncertainty regarding direct and indirect emissions associated with biofuel use remains.

Estimating indirect categories of emissions is particularly challenging, since indirect emissions are driven by market behaviors. It is difficult to look at historical data on, for example, crop prices, and determine which changes are the result of biofuel production rather than other trends that would have existed absent production of biofuels. A prime example of this is estimating how much of the historical growth in U.S. corn and soy production is attributable to biofuel production or to the RFS program specifically. The counterfactual (how much corn and soy would have been produced given a certain level of biofuel production or in the absence of the RFS) cannot be answered directly with historical data.

Quantifying indirect emissions caused by land use change (LUC) has been an especially active area of research over the last decade, with methods typically relying on statistical studies and comparing simulated scenarios.[123] LUC emissions have the potential to constitute a large portion of the total emissions attributable to crop-based biofuels, but such estimates also have significant uncertainty.[124]

The time period over which land use change emissions are quantified can influence whether renewable fuel use is estimated to increase or decrease net GHG emissions relative to petroleum fuels. For example, if increased demand for biofuels leads to land conversion, an

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[122] National Research Council 2011. Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. Washington, DC: The National Academies Press. https://doi.org/10.17226/13105
[123] Plevin, R. J. (2017). Assessing the Climate Effects of Biofuels Using Integrated Assessment Models, Part I: Methodological Considerations. *Journal of Industrial Ecology*, 21(6), 1478-1487. doi:10.1111/jiec.12507
[124] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

initial pulse of emissions would likely be released in the first year.[125] Over time, if that land continues to be used for biofuel production, the GHG benefits of displacing fossil fuels may eventually "pay back" the initial increase in GHG emissions from the first year. Thus, when increased biofuel production is expected to result in land conversion longer time horizons generally result in greater GHG reduction estimates than shorter time horizons. The question of the appropriate time horizon over which to evaluate the net emissions can depend on many factors (e.g., the lifetime of the project, the goals of the program, future projections of renewable fuels use). After considering public comments and the input of an expert peer review panel, in the March 2010 RFS2 rule (75 FR 14670), EPA determined that our lifecycle greenhouse gas emissions analysis for renewable fuels would quantify the GHG impacts over a 30-year period.

EPA continues to believe that 30 years is an appropriate timeframe for evaluating the lifecycle GHG emissions of renewable fuels for purposes of determining which fuel pathways satisfy the statutory GHG reduction thresholds for qualification under each of the four categories of renewable fuel. In this rulemaking, EPA is not reopening the related aspects of the 2010 RFS2 rule or any prior EPA lifecycle greenhouse gas analyses, methodologies, or actions. That is beyond the scope of this rulemaking. With respect to estimating the GHG impacts of this rulemaking specifically, the application of a 30-year time period may or may not be the most appropriate analytical time period over which to evaluate the impact of a rule that covers only three years of volume requirements. On one hand, the annual volume rules are part of the broader RFS program that has been in existence since 2005, so there have been long-term market impacts of standards that were set in past individual years. Furthermore, once the cost of clearing and converting land is incurred, it seems likely that land will continue to be used for agricultural purposes in the future. On the other hand, the volumes proposed in this rule do not extend beyond 2022. Therefore, making projections about future policies and volume requirements and future renewable fuel use are outside the scope of this rulemaking and could be a reason to consider a shorter time horizon. We note, however, that in the illustrative GHG scenario presented in Chapter 3.2.2, the analyses relied upon the assumption that, in each of the 29 years following the introduction of proposed standards, aggregate renewable fuel consumption (and consequent increased demand for agricultural goods) for each category exceeded baseline levels by the same volume as required by the NPRM.

The guidance to federal agencies on development of regulatory analysis discusses the importance of quantifying the benefits of regulatory actions to the extent possible.[126] We recognize this guidance and agree that providing a quantitative estimate of the effects of this proposed rule on GHG emissions could provide valuable information. However, quantifying the GHG benefits of the proposed renewable fuel volumes includes a number of complexities. In addition to the uncertainties discussed above related to estimating the GHG emissions associated with individual biofuel pathways, there are additional complexities associated with estimating

[125] The initial pulse of emissions may actually take longer than one year depending on the fate of the biomass cleared from the land. For example, if the biomass is burned, the emissions will indeed occur in the first year. If it is left on the ground or landfilled the emissions associated with biomass decay may occur over several years. The lifecycle GHG analyses for the March 2010 RFS2 rule allocated international biomass clearing emissions to the first year. We said at the time that this was a simplification that was appropriate for the purposes of the analysis. EPA (2010). Renewable fuel standard program (RFS2) regulatory impact analysis. Washington, DC, US Environmental Protection Agency Office of Transportation Air Quality. EPA-420-R-10-006. Section 2.4.4.2.6.8.
[126] Office of Management and Budget (OMB). *Circular A-4*. September 17, 2003.

the GHG emissions associated with producing multiple biofuels concurrently (e.g., crop-based biofuels compete for land and other resources). Extensive modeling would be necessary to accurately address the uncertainties discussed above and the complexities associated with setting standards for multiple biofuels concurrently. At this time, we are unable to perform such extensive modeling of the GHG effects of the proposed volumes. For these reasons, we are not presenting modeled estimates of the GHG impacts of the combined volumes in this proposed rule. Nevertheless, in order to provide some indication of the potential impacts, in the following section we include an illustrative analysis of GHG emissions that represent a potential stream of GHG emissions over a 30-year period, using existing EPA lifecycle analyses for each individual fuel based on the 2010 lifecycle analysis.

Assessing the GHG impacts of biofuels, including analyzing the lifecycle GHG impacts of individual fuels, is an area of ongoing research. The fact that considerable uncertainty exists in lifecycle analysis (LCA), particularly with respect to ILUC impacts, does not mean that further progress on research in this area cannot be made; arguably the high level of uncertainty means that more work is needed. EPA recognizes that subsequent to the publishing of our original LCA estimates in 2010, various academic and institutional studies on this topic have been published – in addition to work that EPA has done – and that new and relevant data is now available that can help inform future assessments. EPA will engage with various stakeholders, outside of this specific rulemaking action, to improve future assessments.

3.2.2 Illustrative GHG Scenario

As noted above, EPA has not provided a primary estimate of the greenhouse gas impacts of the standards in this proposed rule. This section provides an illustrative scenario of the GHG impacts of biofuel consumption following the implementation of the proposed standards. This scenario is not EPA's assessment of the likely greenhouse gas impacts of this proposed rule.

For this illustrative scenario, we rely on existing EPA biofuel lifecycle GHG emissions estimates and straightforward adjustment of these published analyses where necessary. The specific biofuel volumes and methods of assessment for each fuel / feedstock combination are discussed in Chapter 3.2.2.1. EPA's existing lifecycle GHG assessments consider a 30-year time horizon following an initial change in biofuel production in order to assess temporal dynamics of land use change emissions.[127] In applying these analyses, we assume that for the 30 years following a change in standards, those levels of biofuel consumption are maintained. For this illustrative scenario we assess the proposed standards in each year, 2021 and 2022, separately, and then present the effect on GHGs in Chapter 3.2.2.1 as combined streams of impacts from 2021 through 2051. In Chapter 3.2.2.2 we present the implied annual global social benefit for each year of emissions using interim estimates of the social cost of GHGs. All calculations are available in a spreadsheet in the docket for this proposed rule.[128]

[127] As noted in Chapter 3.2.1, the 30-year time horizon used for biofuel lifecycle GHG emissions was determined after considering public comments and the input of an expert peer review panel in the March 2010 RFS2 rule (75 FR 14670). In this rulemaking, EPA is not asking for comment or reopening the related aspects of the 2010 RFS2 rule or any prior EPA lifecycle greenhouse gas analyses, methodologies, or actions.
[128] See "GHG Scenario for 2020-22 RVO Rule.xlsx," available in the docket for this proposal.

3.2.2.1 Greenhouse Gas Impacts

For this illustrative scenario, we evaluate the simplified biofuel volume changes for biofuels and volumes presented in Table 2.2-3. This includes assumed changes in corn and sugarcane ethanol, changes in domestic soy- and FOG-based renewable diesel, changes in grandfathered renewable diesel, and changes in CNG/LNG derived from biogas. Assumptions about the fuels and quantities analyzed are discussed in Chapter 2.2. We do not include quantified GHG impacts for the projected increase in grandfathered renewable diesel in 2022 for either the annual or supplemental standards. We note that this grandfathered volume may be produced from a mix of feedstocks, as determined by market conditions, for which we have not published lifecycle GHG estimates.[129] For these reasons we do not quantify the GHG impacts of the grandfathered renewable diesel volume as part of this illustrative scenario.

For this illustrative scenario, each biofuel volume change is assumed to displace an energy-equivalent quantity of either baseline gasoline or baseline diesel fuel.[130] These volumes and displacements are carried forward for 30 years following the initial change in volume; that is, for the 2021 standard we account for the effects of the change in biofuel volumes from the 2020 baseline through 2050, and we account for the effects of the 2022 standard compared to the 2021 standard through 2051.[131] Annual changes in emissions are then calculated by comparing the emissions attributable to the increased biofuel consumption with the displaced emissions associated with consumption of a baseline petroleum-based fuel.

3.2.2.1.1 Carbon Intensity Analyses Used

EPA evaluates the lifecycle GHG emissions associated with biofuel pathways to determine which pathways satisfy the statutory GHG reduction requirements to qualify for the RFS renewable fuel categories. These lifecycle GHG estimates are often presented as grams of CO_2e emissions per megajoule of additional renewable fuel consumed. These estimates are often called the “carbon intensity” or “CI” of the fuel. As described in more detail in the March 2010 rule, EPA’s CI estimates for agriculture-based fuels are calculated over 30 years, assuming any land converted to biofuel production in Year 1 would continue to be used to produce biofuels (and displace fossil fuels) for the next 29 years.[132] Thus, EPA’s methodology for calculating CI

[129] Grandfathered fuels also do not have a GHG reduction requirement under the RFS program, increasing the uncertainty of the GHG emissions of these fuels.

[130] We note that this assumption is a source of uncertainty. Increased production and use of renewable fuel may not result in a permanent reduction in an energy equivalent amount of conventional fossil fuels. The RFS’s impact on conventional fossil fuel extraction and refining is necessarily indirect: to the extent the RFS causes conventional fossil fuel use to decline, it will depress prices for gasoline and diesel, which would be expected to reduce petroleum prices. Faced with this price reduction, petroleum extraction and refining would be expected to decrease. However, consumption of fossil fuels, particularly outside the U.S. where the RFS does not apply, would be expected to increase in response to lower prices. We have not estimated the net effect of these market mediated indirect effects. Instead, we use the simplifying assumption of energy equivalent displacement, as has been done in EPA’s past biofuel lifecycle GHG analyses.

[131] This is the same baseline we used for other analyses in the DRIA, and consistent with the baselines used in the illustrative cost analyses in previous RFS annual rules. As discussed further in Chapter 2.2, this baseline is different than current guidance to federal agencies on the development of regulatory analysis states that a baseline “should be the best assessment of the way the world would look absent the proposed action.

[132] 75 FR 14670 (March 26, 2010)

values sums the land use change and other emissions over a 30-year period, and then divides those emissions by 30 years of renewable fuel production volumes to calculate an averaged emission factor per megajoule of renewable fuel consumed. In the discussion of each fuel in the following sections, we provide the estimated CI value as a basis for comparing EPA's past evaluations of different biofuels on a per-megajoule basis. For this illustrative scenario, we rely on the same modeling used to evaluate the CI of individual fuels. However, instead of applying the CI values directly, we show the 30-year stream of emissions from which each of the CI estimates was computed. We do this for two reasons: 1) because the social cost of greenhouse gases (SC-GHG, see Chapter 3.2.2.2.1) differs based on the year in which a gas is emitted, providing a monetized estimate requires a 30-year stream of emission, not just the 30-year averages which EPA's CI values represent; and 2) using EPA's CI values to compare renewable fuels implicitly assumes that a 30-year time horizon is the relevant period over which to analyze that fuel. Presenting the 30-year stream of emissions makes these assumptions explicit to the reader.

Baseline Gasoline and Diesel

For this analysis, we used the baseline assessments of 2005 gasoline (93.1 gCO_2e/MJ) and 2005 diesel (91.9 gCO_2e/MJ) which were used, as required by the Energy Independence and Security Act of 2007, in EPA's assessment of biofuel lifecycle GHG emissions percent reductions for the March 2010 RFS2 rule (75 FR 14670).[133] For comparison, Cooney et al. 2017 reported emissions intensities of 98.1 gCO_2e/MJ for gasoline and 94.1 gCO_2e/MJ for diesel based on an updated assessment of the 2005 baseline, and estimated 2014 average emissions intensities of 96.2 gCO_2e/MJ for gasoline and 92.0 gCO_2e/MJ for diesel.[134] Based on GREET-2020 we calculated intensities of 91.9 gCO_2e/MJ for average U.S. gasoline and 90.0 gCO_2e/MJ for average U.S. diesel.[135,136] These results are all relatively similar, and bracket the estimates used in the March 2010 RFS2 rule.

Starch Ethanol & Sugarcane Ethanol

To assess the impacts of volume changes of corn starch ethanol, we directly use EPA's prior emissions intensity analysis published in the March 2010 RFS2 rule for projected corn starch ethanol produced in 2022 using a natural gas fired dry mill process.[137] For sugarcane ethanol, we similarly use EPA's prior emissions intensity analysis published in the March 2010

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[133] U.S. EPA, (2010). 2005 Petroleum Baseline Lifecycle GHG (Greenhouse Gas) Calculations. U.S. Environmental Protection Agency, EPA-HQ-OAR-2005-0161-3151. Washington DC, January. Available at https://www.regulations.gov/document/EPA-HQ-OAR-2005-0161-3151

[134] Cooney, G., Jamieson, M., Marriott, J., Bergerson, J., Brandt, A., & Skone, T. J. (2017). Updating the U.S. Life Cycle GHG Petroleum Baseline to 2014 with Projections to 2040 Using Open-Source Engineering-Based Models. *Environmental Science & Technology*, 51(2), 977-987. doi:10.1021/acs.est.6b02819

[135] GREET1-2020 Fuel Cycle Model available for download at https://greet.es.anl.gov/greet.models

[136] We use SAR2 global warming potential factors in order to better compare estimates in GREET-2020 with the 2005 gasoline and diesel baselines.

[137] See "EPA-HQ-OAR-2005-0161-3173_Results_6_Corn_EtOH_noCHP.xls," available in the docket for this proposal. The vast majority of corn starch ethanol production in the U.S. (approximately 90% of corn ethanol production in 2020 according to EMTS data) use natural gas as the primary energy source. We note, however, that the projected increase in corn ethanol use could be met by grandfathered facilities which do not have a GHG reduction requirement under the RFS program.

RFS2 rule.[138] These analyses resulted in emissions intensity estimates of 73.2 gCO_2e/MJ and 36.1 gCO_2e/MJ for corn starch and sugarcane ethanol respectively, but also provided estimated annual emissions per MMBTU of ethanol starting with an initial change in fuel volume in 2022 and continuing for 30 years into the future. In this illustrative scenario, we consider these 30-year annual streams of emissions following changes in corn ethanol and sugarcane ethanol consumption.

Soybean Oil Renewable Diesel

To determine the lifecycle GHG intensity of soybean oil based renewable diesel we used a straightforward combination of numerical estimates that EPA has published in previous rulemakings to arrive at an overall carbon intensity value. The lifecycle GHG emissions associated with using soybean oil as a feedstock for biodiesel and renewable diesel production were estimated for the March 2010 RFS2 rule. In the 2012 Pathways I rule (78 FR 14190), we evaluated renewable diesel from camelina oil and reported the GHG emissions associated with the hydrotreating process used to convert the camelina oil to renewable diesel. The same hydrotreating process is used for other virgin vegetable oils and is thus applicable for soybean oil renewable diesel. We also published our analysis of hydrotreating in the 2018 distillers sorghum oil rule (83 FR 37735). We combined the annual stream of GHG emissions per pound of soybean oil as estimated for the March 2010 RFS2 rule with the hydrotreating process modeled for the 2018 distillers sorghum oil rule to estimate an annual stream of emissions for renewable diesel produced from soybean oil.[139] This was a straightforward calculation as the output from the soybean oil analysis (GHGs per pound soybean oil) was readily input into the hydrotreating modeling to estimate the GHGs per MJ of renewable diesel. We also assume the naphtha and LPG co-products replace conventional gasoline and natural gas, respectively, and assign the displacement credit to the renewable diesel. Using the above methodology, we calculate that renewable diesel from soybean oil has a lifecycle emissions intensity of 45.9 gCO2e/MJ.

FOG Renewable Diesel

To determine the lifecycle GHG intensity of renewable diesel produced from waste fats, oils, and greases, we rely upon an existing EPA analysis of a similar pathway. In the March 2010 RFS2 rule, we determined that renewable diesel produced from biogenic waste FOG through a hydrotreating process meets the 50% GHG reduction threshold to qualify as biomass-based diesel and advanced biofuel. However, we did not publish a specific estimate of waste FOG renewable diesel lifecycle GHGs; instead, we made the threshold determination based on a logical extension of our estimate that waste FOG biodiesel results in a greater than 80% lifecycle GHG reduction compared to conventional diesel. In 2018, we approved a facility-specific petition for naphtha and liquefied petroleum gas (LPG) produced from biogenic waste FOG at a hydrotreating facility in Louisiana and included our estimate of the GHG emissions associated with this fuel.[140] Although that petition determination was for naphtha and LPG, the results for renewable diesel would be the same except for small differences for fuel distribution and use.

[138] See "EPA-HQ-OAR-2005-0161-3173_Results_11_Sugarcane_EtOH_NoTrash.xls," available in the docket for this proposal.
[139] See "Soy RD LCA for 2021-22 RVO Rule.xlsx," available in the docket for this proposal.
[140] U.S. EPA, (2018). REG Geismar Approval (PDF). Available at https://www.epa.gov/renewable-fuel-standard-program/reg-geismar-approval-0

Although the petition determination considered data, claimed confidential, for one individual facility, we believe the results, 21.8 gCO2e/MJ, provide a reasonable estimate for the purposes of this illustrative scenario. For comparison, GREET-2020 estimates lifecycle GHG emissions for tallow-based renewable diesel of 21.6 gCO2e/MJ. For these reasons, we are using the LPG results from the 2018 petition approval as the basis for evaluating the GHG emissions associated with waste FOG renewable diesel in this illustrative scenario. We note that since FOG renewable diesel is produced from waste oil rather than an agricultural commodity, this analysis assesses no land use change impacts and thus does not provide a temporal stream of emissions.[141] For consistency with other biofuels analyzed in this illustrative scenario, we assess 30 years of consumption of FOG renewable diesel at levels set by the proposed 2021 and 2022 standards.

Landfill Biogas CNG

The July 2014 pathways II rule (79 FR 42128) included a technical memo to the docket explaining EPA's conclusion that CNG and LNG produced from landfill biogas, when compared to a flaring baseline, results in more than an 80% reduction in GHG emissions compared to petroleum-based diesel.[142] For this illustrative scenario, we use this estimate of an 80% reduction in emissions compared to the 2005 diesel baseline to assess GHG reductions for changed volumes of landfill biogas CNG. The implied CI used in this illustrative scenario is 18.4 gCO2e/MJ for landfill biogas CNG. For comparison, GREET-2020 estimates a CI of 13.5 to 35.1 gCO2e/MJ for landfill biogas CNG depending on whether renewable natural gas or conventional natural gas are used to power equipment for landfill gas processing.

We note that renewable CNG is currently displacing primarily fossil natural gas used in existing CNG/LNG fleets, but it may also be displacing some petroleum-based diesel as its use provides an incentive for the growth in new CNG/LNG vehicle sales. However, since we are relying on existing analyses for this scenario, and past considerations of biogas under the RFS program were for the purpose of lifecycle analysis for pathway approval, we continue to compare against the 2005 diesel baseline for this illustrative scenario. An alternative approach could compare biogas to a fossil natural gas GHG intensity, such as the GHG intensity estimates in the 2016 Phase 2 rule for heavy-duty vehicles (81 FR 73478).[143] Since most estimates for emissions intensities of natural gas are less than the 2005 diesel baseline (91.9 gCO_2e/MJ), the result of using this alternative approach would be similar in scale but would likely result in a smaller reduction in the GHG emissions.[144]

[141] Some of these "waste oils," such as used cooking oil, are currently collected and sold as commodities.
[142] The pathways II rule (79 FR 42128) included a technical memo to the docket (Docket Item No. EPA-HQ-OAR-2012-0401-0243) that discusses EPA's analysis of the GHG emissions of landfill biogas. While that memo did not provide a specific point estimate in terms of gCO_2e/MJ, it did conclude that waste derived biogas would result in over an 80% reduction in GHG emissions compared to the petroleum baseline. For this illustrative scenario analysis, we assume that landfill biogas CNG/LNG reduces GHG emissions by 80% when compared to the 2005 diesel baseline. For comparison, landfill biogas emissions calculated in GREET-2020 achieve an 85% reduction when compared with EPA's 2005 diesel baseline.
[143] U.S. EPA, (2016). Greenhouse Gas Emissions and Fuel Efficiency Standards for Medium- and Heavy-Duty Engines and Vehicles - Phase 2: Regulatory Impact Analysis. U.S. Environmental Protection Agency, EPA-420-R-16-900: Table 13-19, Washington, DC, August.
[144] For comparison, the GHG intensity of landfill biogas CNG used for this analysis would achieve a 76% reduction if it were compared against the fossil CNG intensity used in the 2016 Phase 2 rule for heavy-duty vehicles (81 FR

3.2.2.1.2 Results

For the 2021 and 2022 standards independently we estimate a 30-year stream of changes in GHG emissions for each analyzed fuel using the carbon intensity analyses discussed above. While the NPRM's requirements, if finalized, would only apply in individual years, this analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM. Emissions streams based on the 2021 standard and 2022 standard are presented in Tables 3.2.2.1.2-1 and 3.2.2.1.2-2, respectively. These annual sequences of emissions for the 2021 and 2022 standards are then summed, resulting in a combined stream of estimated annual emissions from 2021 through 2051. This is presented in Table 3.2.2.1.2-3 below. The table includes positive net GHG emissions for the corn ethanol and soy renewable diesel volumes in 2021 and 2022 due to the initial pulse of land use change emissions in the estimates used for this illustrative scenario. The net GHG emissions for these fuels then become negative over time as biofuel production remains in place and continues to replace petroleum-based fuels. As noted above, this scenario assumes that the biofuel production continues for 30 years, irrespective of the RVO mandate in future years. Based on the analysis described above, we estimate that in this illustrative scenario the GHG benefit from biofuel production displacing fossil fuel use is larger than the GHG emissions associated with biofuel production and use, including land use change emissions relative to the baseline scenario. The table includes negative emissions associated with the sugarcane ethanol volume in 2021 because the volume in 2021 decreases in the 2021 standard relative to the baseline.[145] Values for FOG renewable diesel and landfill biogas CNG have no land-use change impact and therefore are always negative.

73478). When compared against the 2005 diesel baseline, as is done in our analysis for this rule, landfill biogas CNG achieves an 80% reduction.

[145] We note that the general trend is of increasing sugarcane area in Brazil, the world's primary producer of sugarcane ethanol. As long as sugarcane area is increasing in the baseline, then reducing sugarcane ethanol production would result in reduced crop expansion. Reducing crop expansion means avoiding a pulse of land clearing emissions.

Table 3.2.2.1.2-1: 30-year stream of emissions for 2021 standard using lifecycle analysis for individual biofuels from EPA's 2010 analysis and subsequent EPA actions, presented in millions of metric tons CO_2e. Parentheses indicate a net reduction in GHG emissions.[a]

Year	Corn Starch Ethanol	Sugarcane Ethanol	Soybean Oil Renewable Diesel	FOG Renewable Diesel	Landfill Biogas CNG	Total
2021	31.5	(0.4)	24.9	(0.3)	(0.2)	55.5
2022	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2023	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2024	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2025	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2026	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2027	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2028	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2029	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2030	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2031	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2032	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2033	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2034	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2035	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2036	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2037	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2038	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2039	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2040	(4.4)	0.1	(2.3)	(0.3)	(0.2)	(7.1)
2041	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2042	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2043	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2044	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2045	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2046	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2047	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2048	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2049	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2050	(5.5)	0.1	(2.4)	(0.3)	(0.2)	(8.3)
2051	-	-	-	-	-	-

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM

Table 3.2.2.1.2-2: 30-year stream of emissions for 2022 standard using lifecycle analysis for individual biofuels from EPA's 2010 analysis and subsequent EPA actions, presented in millions of metric tons CO_2e. Parentheses indicate a net reduction in GHG emissions.[a]

Year	Corn Starch Ethanol	Sugarcane Ethanol	Soybean Oil Renewable Diesel	FOG Renewable Diesel	Landfill Biogas CNG	Total
2021	-	-	-	-	-	-
2022	11.1	-	79.5	(0.3)	(0.2)	90.0
2023	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2024	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2025	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2026	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2027	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2028	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2029	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2030	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2031	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2032	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2033	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2034	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2035	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2036	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2037	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2038	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2039	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2040	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2041	(1.5)	-	(7.3)	(0.3)	(0.2)	(9.4)
2042	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2043	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2044	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2045	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2046	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2047	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2048	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2049	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2050	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)
2051	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM

Table 3.2.2.1.2-3: 30-year stream of emissions for combined 2021 and 2022 standard using lifecycle analysis for individual biofuels from EPA's 2010 analysis and subsequent EPA actions, presented in millions of metric tons CO_2e. Parentheses indicate a net reduction in GHG emissions.[a]

Year	Corn Starch Ethanol	Sugarcane Ethanol	Soybean Oil Renewable Diesel	FOG Renewable Diesel	Landfill Biogas CNG	Total
2021	31.5	(0.4)	24.9	(0.3)	(0.2)	55.5
2022	6.7	0.1	77.2	(0.6)	(0.4)	83.0
2023	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2024	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2025	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2026	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2027	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2028	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2029	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2030	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2031	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2032	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2033	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2034	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2035	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2036	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2037	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2038	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2039	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2040	(6.0)	0.1	(9.6)	(0.6)	(0.4)	(16.4)
2041	(7.0)	0.1	(9.7)	(0.6)	(0.4)	(17.6)
2042	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2043	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2044	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2045	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2046	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2047	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2048	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2049	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2050	(7.4)	0.1	(10.3)	(0.6)	(0.4)	(18.5)
2051	(1.9)	-	(7.8)	(0.3)	(0.2)	(10.2)

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM

3.2.2.2 Monetized Impacts

3.2.2.2.1 Social Cost of Greenhouse Gases

For assessing GHG impacts in this illustrative scenario, we rely upon past biofuel emissions reductions estimates which are available in CO_2e – carbon equivalent emissions using the global warming potentials utilized in those analyses. We estimate the global social benefits of GHG reductions in this illustrative scenario using the SC-CO_2 estimates presented in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990.[146] The SC-GHG is the monetary value of the net harm to society associated with a marginal increase in GHG emissions in a given year, or the benefit of avoiding that increase. SC-GHG estimates individually characterize the social cost of three gases: carbon dioxide (SC-CO_2), methane (SC-CH_4), and nitrous oxide (SC-N_2O). In principle, SC-GHG includes the value of all climate change impacts, including (but not limited to) changes in net agricultural productivity, human health effects, property damage from increased flood risk and natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. The SC-GHG therefore, reflects the societal value of reducing emissions of the gas in question by one metric ton. The SC-GHG is the theoretically appropriate values to use in conducting benefit-cost analyses of policies that affect CO_2, CH_4, and N_2O emissions. As a member of the IWG involved in the development of the February 2021 SC-GHG TSD, the EPA agrees that the interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science.

The SC-GHG estimates presented in the February 2021 technical support document (TSD) were developed over many years, using a transparent process, peer-reviewed methodologies, the best science available at the time of that process, and with input from the public. Specifically, in 2009, an interagency working group (IWG) that included the EPA and other executive branch agencies and offices was established to ensure that agencies were using the best available science and to promote consistency in the SC-CO_2 values used across agencies. The IWG published SC-CO_2 estimates in 2010 that were developed from an ensemble of three widely cited integrated assessment models (IAMs) that estimate global climate damages using highly aggregated representations of climate processes and the global economy combined into a single modeling framework. The three IAMs were run using a common set of input assumptions in each model for future population, economic, and CO_2 emissions growth, as well as equilibrium climate sensitivity (ECS) – a measure of the globally averaged temperature response to increased atmospheric CO_2 concentrations. These estimates were updated in 2013 based on new versions of each IAM.[147,148,149] In August 2016 the IWG published estimates of the social cost of methane (SC-CH_4) and nitrous oxide (SC-N_2O) using methodologies that are consistent with the methodology underlying the SC-CO_2 estimates. In 2015, as part of the response to

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[146] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February. United States Government. Available at: https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.
[147] Dynamic Integrated Climate and Economy (DICE) 2010 (Nordhaus 2010).
[148] Climate Framework for Uncertainty, Negotiation, and Distribution (FUND) 3.8 (Anthoff and Tol 2013a, 2013b)
[149] Policy Analysis of the Greenhouse Gas Effect (PAGE) 2009 (Hope 2013).

public comments received to a 2013 solicitation for comments on the SC-CO_2 estimates, the IWG announced a National Academies of Sciences, Engineering, and Medicine review of the SC-CO_2 estimates to offer advice on how to approach future updates to ensure that the estimates continue to reflect the best available science and methodologies. In January 2017, the National Academies released their final report, *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*, and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process.[150] Shortly thereafter, in March 2017, President Trump issued Executive Order 13783, which disbanded the IWG, withdrew the previous TSDs, and directed agencies to ensure SC-CO_2 estimates used in regulatory analyses are consistent with the guidance contained in OMB's Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). Analyses following E.O. 13783 used SC-CO_2 estimates that attempted to focus on the domestic impacts of climate change as estimated to occur within U.S. borders and were calculated using two discount rates recommended by Circular A-4, 3 percent and 7 percent. All other methodological decisions and model versions used in SC- CO_2 calculations remained the same as those used by the IWG in 2010 and 2013, respectively.

On January 20, 2021, President Biden issued Executive Order 13990, which re-established the IWG and directed it to ensure that the U.S. Government's estimates of the social cost of carbon and other greenhouse gases reflect the best available science and the recommendations of the National Academies. The IWG was tasked with first reviewing the SC-GHG estimates currently used in Federal analyses and publishing interim estimates within 30 days of the E.O. that reflect the full impact of GHG emissions, including by taking global damages into account. The interim SC-GHG estimates published in February 2021 are used here to estimate the climate benefits for this proposed rulemaking. The E.O. instructs the IWG to undertake a fuller update of the SC-GHG estimates by January 2022 that takes into consideration the advice of the National Academies and other recent scientific literature.

The February 2021 TSD provides a complete discussion of the IWG's initial review conducted under E.O. 13990. In particular, the IWG found that the SC-GHG estimates used under E.O. 13783 fail to reflect the full impact of GHG emissions in multiple ways. First, the IWG found that a global perspective is essential for SC-GHG estimates because climate impacts occurring outside U.S. borders can directly and indirectly affect the welfare of U.S. citizens and residents. Thus, U.S. interests are affected by the climate impacts that occur outside U.S. borders. Examples of affected interests include direct effects on U.S. citizens and assets located abroad, international trade, and tourism, and spillover pathways such as economic and political destabilization and global migration. In addition, assessing the benefits of U.S. GHG mitigation activities requires consideration of how those actions may affect mitigation activities by other countries, as those international mitigation actions will provide a benefit to U.S. citizens and residents by mitigating climate impacts that affect U.S. citizens and residents. Therefore, in this illustrative analysis for this proposed rule, EPA centers attention on a global measure of SC-GHG. This approach is the same as that taken in EPA regulatory analyses over 2009 through

[150] National Academies of Sciences, Engineering, and Medicine (National Academies). 2017. Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide. Washington, D.C.: National Academies Press.

2016. As noted in the February 2021 TSD, the IWG will continue to review developments in the literature, including more robust methodologies for estimating SC-GHG values based on purely domestic damages, and explore ways to better inform the public of the full range of carbon impacts, both global and domestic. As a member of the IWG, EPA will continue to follow developments in the literature pertaining to this issue.

Furthermore, the IWG found that the use of the social rate of return on capital (7 percent under current OMB Circular A-4 guidance) to discount the future benefits of reducing GHG emissions inappropriately underestimates the impacts of climate change for the purposes of estimating the SC-GHG. Consistent with the findings of the National Academies and the economic literature, the IWG continued to conclude that the consumption rate of interest is the theoretically appropriate discount rate in an intergenerational context, and recommended that discount rate uncertainty and relevant aspects of intergenerational ethical considerations be accounted for in selecting future discount rates.[151,152,153,154,155] As a member of the IWG involved in the development of the February 2021 TSD, EPA agrees with this assessment and will continue to follow developments in the literature pertaining to this issue.

While the IWG works to assess how best to incorporate the latest, peer reviewed science to develop an updated set of SC-GHG estimates, it set the interim estimates to be the most recent estimates developed by the IWG prior to the group being disbanded in 2017. The estimates rely on the same models and harmonized inputs and are calculated using a range of discount rates. As explained in the February 2021 TSD, the IWG has determined that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates as were used in regulatory analyses between 2010 and 2016 and subject to public comment. For each discount rate, the IWG combined the distributions across models and socioeconomic emissions scenarios (applying equal weight to each) and then selected a set of four values for use in agency analyses: an average value resulting from the model runs for each of three discount rates (2.5 percent, 3 percent, and 5 percent), plus a fourth value, selected as the

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[151] GHG emissions are stock pollutants, where damages are associated with what has accumulated in the atmosphere over time, and they are long lived such that subsequent damages resulting from emissions today occur over many decades or centuries depending on the specific greenhouse gas under consideration. In calculating the SC-GHG, the stream of future damages to agriculture, human health, and other market and non-market sectors from an additional unit of emissions are estimated in terms of reduced consumption (or consumption equivalents). Then that stream of future damages is discounted to its present value in the year when the additional unit of emissions was released. Given the long time horizon over which the damages are expected to occur, the discount rate has a large influence on the present value of future damages.

[152] Interagency Working Group on Social Cost of Carbon (IWG). 2010. Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866. February. United States Government.

[153] Interagency Working Group on Social Cost of Carbon (IWG). 2013. Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. May. United States Government.

[154] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2016a. Technical Support Document: Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866. August. United States Government.

[155] Interagency Working Group on the Social Cost of Greenhouse Gases. 2016b. Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide. August. United Stated Government. Available at: https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf (accessed February 5, 2021).

95th percentile of estimates based on a 3 percent discount rate. The fourth value was included to provide information on potentially higher-than-expected economic impacts from climate change, conditional on the 3 percent estimate of the discount rate. As explained in the February 2021 TSD, this update reflects the immediate need to have an operational SC-GHG that was developed using a transparent process, peer-reviewed methodologies, and the science available at the time of that process. Those estimates were subject to public comment in the context of dozens of proposed rulemakings as well as in a dedicated public comment period in 2013.

Table 3.2.2.2.1-1 summarizes the interim global SC-CO_2 estimates for the years 2021 – 2051.[156] These estimates are reported in 2020 dollars but are otherwise identical to those presented in the IWG's 2016 TSD. The SC-GHG increases over time within the models – i.e., the societal harm from one metric ton emitted in 2030 is higher than the harm caused by one metric ton emitted in 2025 – because future emissions produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to GDP.

[156] The February 2021 TSD provides SC-GHG estimates through emissions year 2050. In this illustrative scenario we held the 2051 SC-CO_2 value for 2051 at the same level as the 2050 value.

Table 3.2.2.2.1-1: Interim Global Social Cost of Carbon Values, 2020-2051 (2020$/Metric Tonne CO_2)[157]

Emissions Year	Discount Rate and Statistic			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2020	$14	$51	$76	$152
2021	$15	$52	$78	$155
2022	$15	$53	$79	$159
2023	$16	$54	$80	$162
2024	$16	$55	$82	$166
2025	$17	$56	$83	$169
2026	$17	$57	$84	$173
2027	$18	$59	$86	$176
2028	$18	$60	$87	$180
2029	$19	$61	$88	$183
2030	$19	$62	$89	$187
2031	$20	$63	$91	$191
2032	$21	$64	$92	$194
2033	$21	$65	$94	$198
2034	$22	$66	$95	$202
2035	$22	$67	$96	$206
2036	$23	$69	$98	$210
2037	$23	$70	$99	$213
2038	$24	$71	$100	$217
2039	$25	$72	$102	$221
2040	$25	$73	$103	$225
2041	$26	$74	$104	$228
2042	$26	$75	$106	$232
2043	$27	$77	$107	$235
2044	$28	$78	$108	$239
2045	$28	$79	$110	$242
2046	$29	$80	$111	$246
2047	$30	$81	$112	$249
2048	$30	$82	$114	$253
2049	$31	$84	$115	$256
2050	$32	$85	$116	$260
2051	$32	$85	$116	$260

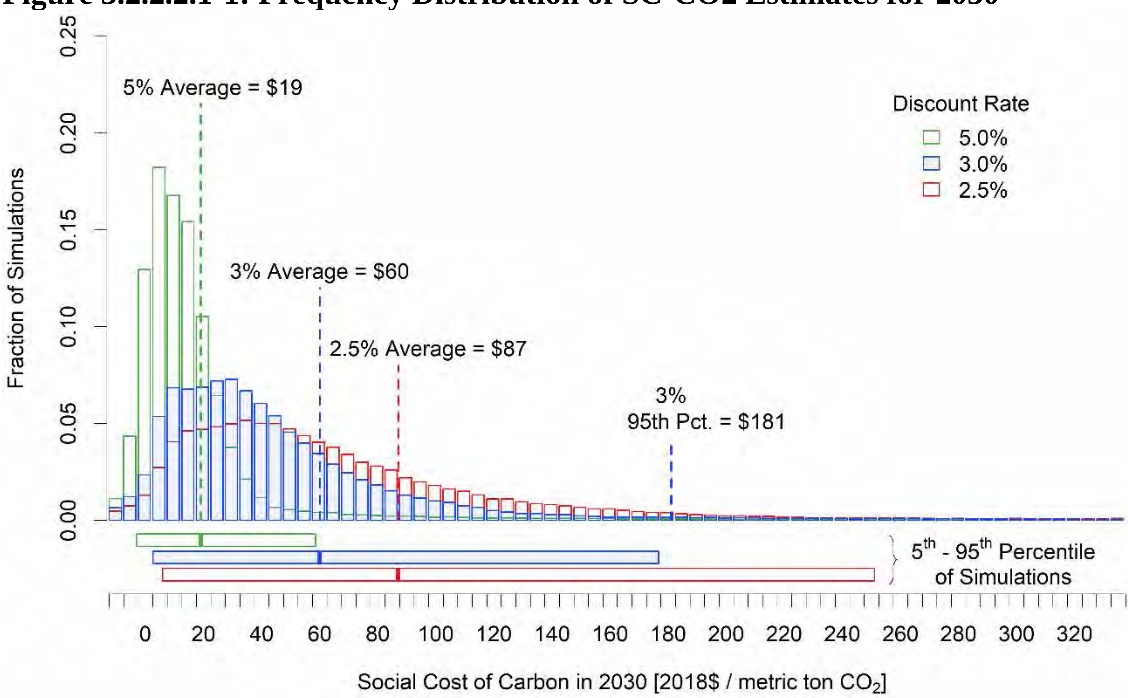
Note: The 2020-2050 SC-CO_2 values are identical to those reported in the 2016 TSD (IWG 2016a) adjusted for inflation to 2020 dollars using the annual GDP Implicit Price Deflator values in the U.S. Bureau of Economic

[157] Interagency Working Group on Social Cost of Greenhouse Gases (IWG). 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990. February.

Analysis' (BEA) NIPA Table 1.1.9 (U.S. BEA 2021). The estimates were extended to 2051 to 2070 using the same value for 2051 as the 2050 value. The values are stated in \$/metric tonne CO_2 and vary depending on the year of CO_2 emissions.

There are a number of limitations and uncertainties associated with the SC-GHG estimates presented in Table 3.2.2.2.1-1. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Figure 3.2.2.2.1-1, presents the quantified sources of uncertainty in the form of frequency distributions for the SC-CO_2 estimates for emissions in 2030 (in 2018\$). The distributions of SC-CO_2 estimate reflects uncertainty in key model parameters such as the equilibrium climate sensitivity, as well as uncertainty in other parameters set by the original model developers. To highlight the difference between the impact of the discount rate and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CO_2 estimates for each discount rate. As illustrated by the figure, the assumed discount rate plays a critical role in the ultimate estimate of the SC-CO_2. This is because GHG emissions today continue to impact society far out into the future, so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. As discussed in the February 2021 TSD, there are other sources of uncertainty that have not yet been quantified and are thus not reflected in these estimates.

Figure 3.2.2.2.1-1: Frequency Distribution of SC-CO2 Estimates for 2030[158]



United States Government. Available at: https://www.whitehouse.gov/briefing-room/blog/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution

[158] Although the distributions and numbers are based on the full set of model results (150,000 estimates for each discount rate and gas), for display purposes the horizontal axis is truncated with 0.02 to 0.68 percent of the estimates falling below the lowest bin displayed and 0.12 to 3.11 percent of the estimates falling above the highest bin displayed, depending on the discount rate and GHG.

The interim $SC\text{-}CO_2$ estimates presented in Table 3.2.2.2.1-1 have a number of other limitations. First, the current scientific and economic understanding of discounting approaches suggests discount rates appropriate for intergenerational analysis in the context of climate change are likely to be less than 3 percent, near 2 percent or lower.**Error! Bookmark not defined.** Second, the IAMs used to produce these interim estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature and the science underlying their "damage functions" – i.e., the core parts of the IAMs that map global mean temperature changes and other physical impacts of climate change into economic (both market and nonmarket) damages – lags behind the most recent research. For example, limitations include the incomplete treatment of catastrophic and non-catastrophic impacts in the integrated assessment models, their incomplete treatment of adaptation and technological change, the incomplete way in which inter-regional and intersectoral linkages are modeled, uncertainty in the extrapolation of damages to high temperatures, and inadequate representation of the relationship between the discount rate and uncertainty in economic growth over long time horizons. Likewise, the socioeconomic and emissions scenarios used as inputs to the models do not reflect new information from the last decade of scenario generation or the full range of projections.

The modeling limitations do not all work in the same direction in terms of their influence on the SC-GHG estimates. However, as discussed in the February 2021 TSD, the IWG has recommended that, taken together, the limitations suggest that the SC-GHG estimates used in this proposed rule likely underestimate the damages from GHG emissions. In particular, the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report, which was the most current IPCC assessment available at the time when the IWG decision over the ECS input was made, concluded that $SC\text{-}CO_2$ estimates "very likely…underestimate the damage costs" due to omitted impacts.[159] Since then, the peer-reviewed literature has continued to support this conclusion, as noted in the IPCC's Fifth Assessment report and other recent scientific

[159] Intergovernmental Panel on Climate Change (IPCC). 2007. Core Writing Team; Pachauri, R.K; and Reisinger, A. (ed.), Climate Change 2007: Synthesis Report, Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, IPCC, ISBN 92-9169-122-4.

assessments.[160,161,162,163,164,165,166,167] These assessments confirm and strengthen the science, updating projections of future climate change and documenting and attributing ongoing changes. For example, sea level rise projections from the IPCC's Fourth Assessment report ranged from 18 to 59 centimeters by the 2090s relative to 1980-1999, while excluding any dynamic changes in ice sheets due to the limited understanding of those processes at the time.[159] A decade later, the Fourth National Climate Assessment projected a substantially larger sea level rise of 30 to 130 centimeters by the end of the century relative to 2000, while not ruling out even more extreme outcomes.[165] The February 2021 TSD briefly previews some of the recent advances in the scientific and economic literature that the IWG is actively following and that could provide guidance on, or methodologies for, addressing some of the limitations with the interim SC-GHG estimates.

Table 3.2.2.2.2-1 and Table 3.2.2.2.2-2 show the estimated global climate benefits from changes in CO_2e for the volumes proposed in 2021 and 2022. This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM. EPA estimated the dollar value of the GHG-related effects for each analysis year between 2021 through 2051 by applying the SC-CO_2 estimates, shown in Table 3.2.2.2.1-1, to the estimated changes in GHG emissions inventories resulting from the proposed volumes, shown in Table 3.2.2.1.2-1 and Table 3.2.2.1.2-2. EPA then calculated the present value and annualized benefits from the

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[160] Intergovernmental Panel on Climate Change (IPCC). 2014. Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp.

[161] Intergovernmental Panel on Climate Change (IPCC). 2018. Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)].

[162] Intergovernmental Panel on Climate Change (IPCC). 2019a. Climate Change and Land: an IPCC special report on climate change, desertification, land degradation, sustainable land management, food security, and greenhouse gas fluxes in terrestrial ecosystems [P.R. Shukla, J. Skea, E. Calvo Buendia, V. Masson-Delmotte, H.-O. Pörtner, D. C. Roberts, P. Zhai, R. Slade, S. Connors, R. van Diemen, M. Ferrat, E. Haughey, S. Luz, S. Neogi, M. Pathak, J. Petzold, J. Portugal Pereira, P. Vyas, E. Huntley, K. Kissick, M. Belkacemi, J. Malley, (eds.)].

[163] Intergovernmental Panel on Climate Change (IPCC). 2019b. IPCC Special Report on the Ocean and Cryosphere in a Changing Climate [H.-O. Pörtner, D.C. Roberts, V. Masson-Delmotte, P. Zhai, M. Tignor, E. Poloczanska, K. Mintenbeck, A. Alegría, M. Nicolai, A. Okem, J. Petzold, B. Rama, N.M. Weyer (eds.)].

[164] U.S. Global Change Research Program (USGCRP). 2016. The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. https://dx.doi.org/10.7930/J0R49NQX.

[165] U.S. Global Change Research Program (USGCRP). 2018. Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.

[166] National Academies of Sciences, Engineering, and Medicine (National Academies). 2016b. Attribution of Extreme Weather Events in the Context of Climate Change. Washington, DC: The National Academies Press. https://doi.org/10.17226/21852.

[167] National Academies of Sciences, Engineering, and Medicine (National Academies). 2019. Climate Change and Ecosystems. Washington, DC: The National Academies Press. https://doi.org/10.17226/25504.

perspective of 2021 by discounting each year-specific value to the year 2021 using the same discount rate used to calculate the SC-CO_2.

3.2.2.2.2 Results

For this illustrative scenario, the interim estimates for carbon dioxide from EO 13990 were used to estimate the global social benefits of the estimated 30-year stream of GHG impacts presented in Chapter 3.2.2.1.2. For each year, the total of emissions changes presented in Tables 3.2.2.1.2-1 and 3.2.2.1.2-2 are multiplied by each of the four SC-CO_2 values in EO 13990 for the same year presented in Table 3.2.2.2.1-1. Values for each year and discount rate statistic are then converted to present value in 2021 using the corresponding discount rates. The resulting streams of estimated global social benefits of the biofuel volume changes assumed in this illustrative scenario for the 2021 standards and the 2022 standards are presented in Tables 3.2.2.2.2-1 and 3.2.2.2.2-2 respectively. Note that in the following tables, volume changes for the 2021 standards are relative to the 2020 standards, while the volume changes for the 2022 standard are relative to the 2021 standards. For this illustrative analysis we summarize the results in two different ways, a net present value and an annualized benefit, both of which assume that, in each of the 29 years following the standards proposed in this rule, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM. The total net present value of the 30-year stream of monetized impacts is calculated by summing the annual stream of discounted benefits presented in each table. An annualized value is also calculated for each discount rate following the methodology presented in EPA guidance document *Guidelines for Preparing Economic Analyses*.[168,169] This annualized benefit is the constant value such that the sum of all thirty years of benefits *in present value terms* equals the net present value, calculated as described above.[170] All calculations are available in a spreadsheet in the docket for this proposed rule.[171] As discussed above, net and annualized impacts are sensitive to both the discount rate and the time horizon used. We note that it would not be appropriate to compare these benefits to the costs or energy security benefits, presented in Chapter 9 and 4, respectively, because this illustrative scenario for GHG analysis covers a different time horizon than those analyses.

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[168] U.S. Environmental Protection Agency. "Chapter 6: Discounting Future Benefits and Costs," equation 4. *Guidelines for Preparing Economic Analyses*. United States Government. Retrieved from: https://www.epa.gov/environmental-economics/guidelines-preparing-economic-analyses#download October 26th, 2021.

[169] Annualized values are calculated using 30-year NPV totals, and so are also sensitive to the 30-year time horizon. Thus, annualized climate benefits are also incomparable to other monetized costs and benefits presented in this dRIA.

[170] This is true assuming there is a benefit or cost in the initial time period, as is the case in this analysis. This corresponds with equation 4 in Chapter 6 of the cited EPA Guidelines for Preparing Economic Analyses.

[171] See "GHG Scenario for 2020-22 RVO Rule.xlsx," available in the docket for this proposal.

Table 3.2.2.2.2-1: Present value of 30-year stream of climate benefits for 2021 standard, using four recommended discount rate statistics for the social cost of greenhouse gases (SC-GHG) (millions of 2020 dollars). Parentheses indicate negative values.[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2021	(830)	(2,893)	(4,312)	(8,606)
2022	104	365	544	1,087
2023	102	361	540	1,079
2024	100	358	535	1,070
2025	98	354	531	1,061
2026	96	350	526	1,052
2027	94	346	521	1,042
2028	92	342	516	1,032
2029	90	338	511	1,021
2030	88	334	506	1,010
2031	86	331	501	1,001
2032	85	327	496	991
2033	83	323	491	981
2034	81	319	486	971
2035	79	315	481	961
2036	78	311	476	950
2037	76	307	471	939
2038	74	303	466	928
2039	72	299	461	917
2040	70	295	455	906
2041	81	341	528	1,048
2042	79	336	522	1,033
2043	77	331	516	1,018
2044	75	327	509	1,003
2045	73	322	503	988
2046	71	317	497	973
2047	69	312	490	959
2048	67	307	484	944
2049	66	302	478	929
2050	64	298	472	914
Total NPV	1,542	6,578	10,201	20,205
Annualized	96	326	476	1,001

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the SC-CO_2 (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using

discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

Table 3.2.2.2.2-2: Present value of 30-year stream of climate benefits for 2022 standard, using four recommended discount rate statistics for the social cost of greenhouse gases (SC-GHG) (millions of 2020 dollars). Parentheses indicate negative values.[a]

Year	Rate: 5%	Rate: 3%	Rate: 2.5%	Rate: 3% 95th percentile
2022	(1,325)	(4,651)	(6,941)	(13,864)
2023	135	479	716	1,430
2024	133	474	710	1,419
2025	130	469	703	1,407
2026	128	464	697	1,394
2027	125	459	690	1,381
2028	122	454	684	1,367
2029	120	448	677	1,353
2030	117	443	671	1,339
2031	115	438	664	1,327
2032	112	433	658	1,314
2033	110	428	651	1,301
2034	108	423	644	1,287
2035	105	418	638	1,273
2036	103	412	631	1,259
2037	101	407	624	1,245
2038	98	402	617	1,230
2039	96	396	611	1,216
2040	93	391	604	1,201
2041	91	385	597	1,184
2042	97	416	646	1,278
2043	95	410	638	1,259
2044	93	404	630	1,241
2045	90	398	622	1,222
2046	88	392	614	1,204
2047	86	386	607	1,186
2048	83	380	599	1,167
2049	81	374	591	1,149
2050	79	368	583	1,131
2051	75	358	569	1,098
Total NPV	1,684	7,457	11,643	22,997
Annualized	104	369	543	1,139

[a] This analysis portrays what might be expected if, in each of the ensuing 29 years, aggregate renewable fuel consumption for each category exceeded baseline levels by the same volume as required by the NPRM. Climate benefits are based on changes (reductions) in CO_2 emissions and are calculated using four different estimates of the

$SC\text{-}CO_2$ (model average at 2.5 percent, 3 percent, and 5 percent discount rates; and 95th percentile at 3 percent discount rate). The IWG emphasized the importance and value of considering the benefits calculated using all four estimates. As discussed in the Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates under Executive Order 13990 (IWG 2021), a consideration of climate benefits calculated using discount rates below 3 percent, including 2 percent and lower, are also warranted when discounting intergenerational impacts.

3.3 Conversion of Wetlands, Ecosystems, and Wildlife Habitats

The Second Triennial Report to Congress on Biofuels[172] summarized the numerous studies that have examined changes in wetlands, ecosystems, and wildlife habitats. The Report noted, for example, there has been an observed increase in acreage planted with soybeans and corn between the decade leading up to enactment of EISA and the decade following enactment. Evidence from observations of land use change suggests that some of this increase in acreage and crop use is a consequence of increased biofuel production. It is likely that the environmental and natural resource impacts associated with land use change are, at least in part, due to increased biofuel production and use. However, at this time we cannot quantify the amount of land with increased intensity of cultivation nor confidently estimate the portion of crop land expansion that is due to the market for biofuels. (see Second Triennial Report to Congress on Biofuels sections 2 and 4.2). Often these changes are ascribed to agricultural expansion for biofuel production, and in some cases even to the RFS program itself, but, in reality, such a causal connection is difficult to make with confidence (see Second Triennial Report to Congress on Biofuels section 2). As with the domestic land use change studies discussed in Chapter 2 of the Second Triennial Report to Congress on Biofuels, these studies vary widely in approach and scope, making comparison inherently difficult. This section focuses on impacts related to the domestic production of renewable fuels and their underlying feedstocks. Effects from the end use of renewable fuel are mostly from air quality effects following combustion (Chapter 3.1), climate effects (Chapter 3.2), and possible leakage from underground storage tanks (Chapter 3.4.4).

3.3.1 Wetlands

There are several federal reports that describe the status and trends of U.S. wetlands,[173] including the U.S. Fish and Wildlife Service (USFWS) Status and Trends of Wetlands in the Conterminous United States,[174] the USFWS and NOAA Status and Trends of Wetlands in the Coastal Watersheds of the Coterminous United States,[175] the USFWS Status and Trends of

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[172] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.
[173] Summarized and listed here: https://www.epa.gov/wetlands/how-does-epa-keep-track-status-and-trends-wetlands-us
[174] Dahl, T.E. 2011. Status and trends of wetlands in the conterminous United States 2004 to 2009. U.S. Department of the Interior; Fish and Wildlife Service, Washington, D.C. 108 pp.
[175] T.E. Dahl and S.M. Stedman. 2013. Status and trends of wetlands in the coastal watersheds of the Conterminous United States 2004 to 2009. U.S. Department of the Interior, Fish and Wildlife Service and National Oceanic and Atmospheric Administration, National Marine Fisheries Service. (46 p.)

Prairie Wetlands in the United States,[176] EPA's National Wetland Condition Assessment[177] (NWCA), and in USDA's Natural Resources Inventory (NRI) described in this chapter.[178] The USGS NWALT series does not model changes in wetlands.[179] Although these federal wetland reports are a wealth of information on wetland status and trends in the U.S., many of them are unfortunately not particularly useful in the context of the RFS annual rules. The most recent versions of the three USFWS reports only cover up to 2009, and, therefore, are of limited utility given that EISA was enacted in 2007 and the RFS2 program was promulgated in 2010. The 2011 NCWA was the first in the series, thus, trends cannot be inferred from that report. The second field sampling for NWCA was conducted in 2016 and may be used to infer trends once the report is available.

The most pertinent federal program that monitors and reports the status and trends of U.S. wetlands in the context of biofuels is the USDA NRI.[180] Wetlands are not an independent land cover class in the NRI, but are overlaid on other land cover types (e.g., wetlands on forested lands made up 66,053,800 acres in 2007). The changes in wetland acres between 2007 and 2017 are shown in Table 3.3.1-1. There was an overall reduction by roughly 52,800 acres between 2007 and 2012, and a further reduction by 64,300 acres between 2012 and 2017, or 0.11% between 2007 and 2017. These reductions were mostly from losses of wetlands on cropland and rangeland, which were partly offset by gains in developed and water areas.[181] The report does not provide the information needed to determine the portion of wetland acres lost in order to grow feedstocks for biofuels.

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[176] Dahl, T.E. 2014. Status and trends of prairie wetlands in the United States 1997 to 2009. U.S. Department of the Interior; Fish and Wildlife Service, Ecological Services, Washington, D.C. (67 pages).

[177] NATIONAL WETLAND CONDITION ASSESSMENT 2011: A Collaborative Survey of the Nation's Wetlands. U.S. Environmental Protection Agency Office of Wetlands, Oceans and Watersheds Office of Research and Development Washington, DC 20460. EPA-843-R-15-005. May 2016

[178] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results.

[179] Falcone JA (2015). U.S. conterminous wall-to-wall anthropogenic land use trends (NWALT), 1974–2012. U.S. Geological Survey: 33 pp. Washington, DC.

[180] *See* Table 7 – Changes in land use/cover between 2012 and 2017, U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results.

[181] "Water areas" are defined in the USDA NRI as "[a] broad land cover/use category comprising water bodies and streams that are permanent open water."

Table 3.3.1-1: Changes in palustrine[182] and estuarine[183] wetlands on different land use/cover types between 2007, 2012, and 2017[184]

	Acres (in thousands)				
Wetlands on	**2007**	**2012**	**2017**	**Change (2017 - 2007)**	**Change (%)**
Cropland, pastureland, & CRP land	17,623.5	17,552.5	17,426.4	–197.1	–1.12
Rangeland	7,969.2	7,913.0	7,876.8	–92.4	–1.16
Forest land	66,053.8	66,035.9	65,983.6	–70.2	–0.11
Other rural land	14,731.1	14,736.6	14,801.5	70.4	0.48
Developed land	1,411.0	1,450.9	1,486.5	75.5	5.35
Water areas	3,556.0	3,602.9	3,652.7	96.7	2.72
Total	111,344.6	111,291.8	111,227.5	–117.1	–0.11

There are several other regional studies examining changes in wetland area, including several from the Prairie Pothole Region.[185] In the only other national assessment to date, Wright et al. (2017) found that within the standard draw of an ethanol biorefinery (50 miles),[186] there was a 14,000-acre loss of wetland between 2008 and 2012. Insofar as a causal connection could be established between proximity to an ethanol biorefinery and loss of wetlands, it nevertheless does not demonstrate a connection to the RFS program specifically. Also, there are many differences between Wright et al. (2017) and the NRI that make direct comparison of these two studies not relevant. These differences stem from numerous sources, including the geographic extent (the entire contiguous U.S. for the NRI versus only areas in the contiguous U.S. within 100 miles of a biorefinery in Wright et al. (2017)), and source data (fixed random points in the NRI versus satellite-derived data from the USDA's Cropland Data Layer in Wright et al. (2017)). Reconciling these estimates is beyond the scope of this rulemaking, but, when taken together,

182 The NRI defines "palustrine wetlands" as "[w]etlands occurring in the Palustrine System, one of five systems in the classification of wetlands and deepwater habitats (Cowardin et al. 1979). Palustrine wetlands include all nontidal wetlands dominated by trees, shrubs, persistent emergent plants, or emergent mosses or lichens, as well as small, shallow open water ponds or potholes. Palustrine wetlands are often called swamps, marshes, potholes, bogs, or fens." *NRI Glossary*, available at https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/processes/?cid=nrcs143_014127 (last accessed May 6, 2021).

183 The NRI defines "estuarine wetlands" as "[w]etlands occurring in the Estuarine System, one of five systems in the classification of wetlands and deepwater habitats (Cowardin et al. 1979). Estuarine wetlands are tidal wetlands that are usually semienclosed by land but have open, partly obstructed or sporadic access to the open ocean, and in which ocean water is at least occasionally diluted by freshwater runoff from the land. The most common example is where a river flows into the ocean." *NRI Glossary*, available at https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/nri/processes/?cid=nrcs143_014127 (last accessed May 6, 2021).

184 U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results.

185 Johnston, C. A. (2013). "Wetland losses due to row crop expansion in the Dakota Prairie Pothole Region." *Wetlands* **33**(1): 175-182. Johnston, C. A. (2014). "Agricultural expansion: land use shell game in the U.S. Northern Plains." *Landscape Ecology* **29**(1): 81-95: 10.1007/s10980-013-9947-0.

186 The "standard draw" defers to the area around a biorefinery where feedstocks are typically drawn. Due to costs of transporting by truck or freight, the standard draw is typically around 50 miles.

these studies demonstrate that agricultural extensification may affect wetlands,[187] but any losses are relatively small compared with all wetland areas and compared with losses of grassland.[188]

In the most recent NRI, the USDA reported that there was a decrease of 24,300 acres in the total wetland and deepwater habitat area, including palustrine and estuarine wetlands and other aquatic habitats, between 2012 and 2017.[189] The bulk of the wetland losses were in the Prairie Pothole region, as reported elsewhere,[190] with some very high rates (i.e., >15%, Wright et al. 2017). The conversion reported by Wright et al. (2017) explicitly included only lands that had not been in cropland for at least 20 years; although these areas may not represent pristine habitats, they are expected to represent habitats that are in a relatively natural state.

The studies discussed above show that total wetland acres in the contiguous U.S. have been decreasing since 2007. However, additional information is needed in order to draw any conclusions with confidence as to whether biofuel production is a driving factor in that loss, as well as the extent to which the annual volume requirements under the RFS program cause changes in biofuel production. The volumes proposed in this action for 2020 and 2021 will not cause any wetland loss, as those volumes will be entirely or largely retroactive. As such, they have no chance of promoting additional production of biofuels fuels or cultivation of biofuel fuel feedstocks. There is a possibility that the volume requirements proposed for 2022 may inspire an increase in feedstock production, which may affect wetlands through conversion to cropland or through agricultural management practices, like fertilizer and pesticide use. More information is needed to assess the degree to which the RFS volume requirements impact land use and management decisions in order to estimate the magnitude of their impacts on wetland loss. However, such analysis would be expansive and could not be performed on the timeline of this rulemaking.

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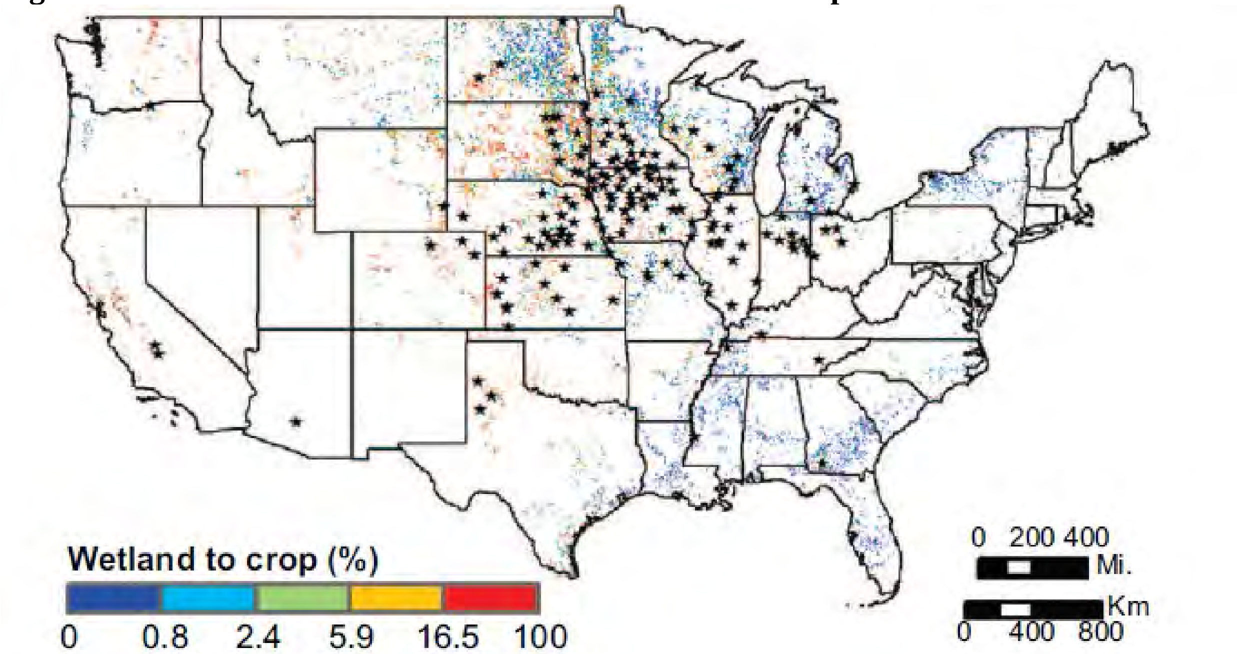
[187] Agricultural extensification is the expansion of agricultural land onto previously uncultivated land. U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[188] See Chapter 3.4.2.1 of this rulemaking for a discussion of grassland losses.

[189] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa, at Table 18. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results/. *See also* USDA, 2017 National Resources Inventory, at https://www.nrcs.usda.gov/Internet/NRCS_RCA/reports/nri_wet_nat.html. (Last accessed on April 12, 2021). The National Wetlands table shows a total area of wetlands and aquatic habitat on water areas and non-federal land as 160,755,900 acres in 2012 and 160,731,600 acres in 2017.

[190] Johnston, C. A. (2013). "Wetland losses due to row crop expansion in the Dakota Prairie Pothole Region." *Wetlands* **33**(1): 175-182. Johnston, C. A. (2014). "Agricultural expansion: land use shell game in the U.S. Northern Plains." *Landscape Ecology* **29**(1): 81-95.

Figure 3.3.1-1: Relative conversion rates from wetland to cropland from 2008 to 2012.



Rates are relativized by type of ecosystem within a 3.5-mile spatial grid (modified from [191]). Stars denote the location of biorefineries in the analysis.

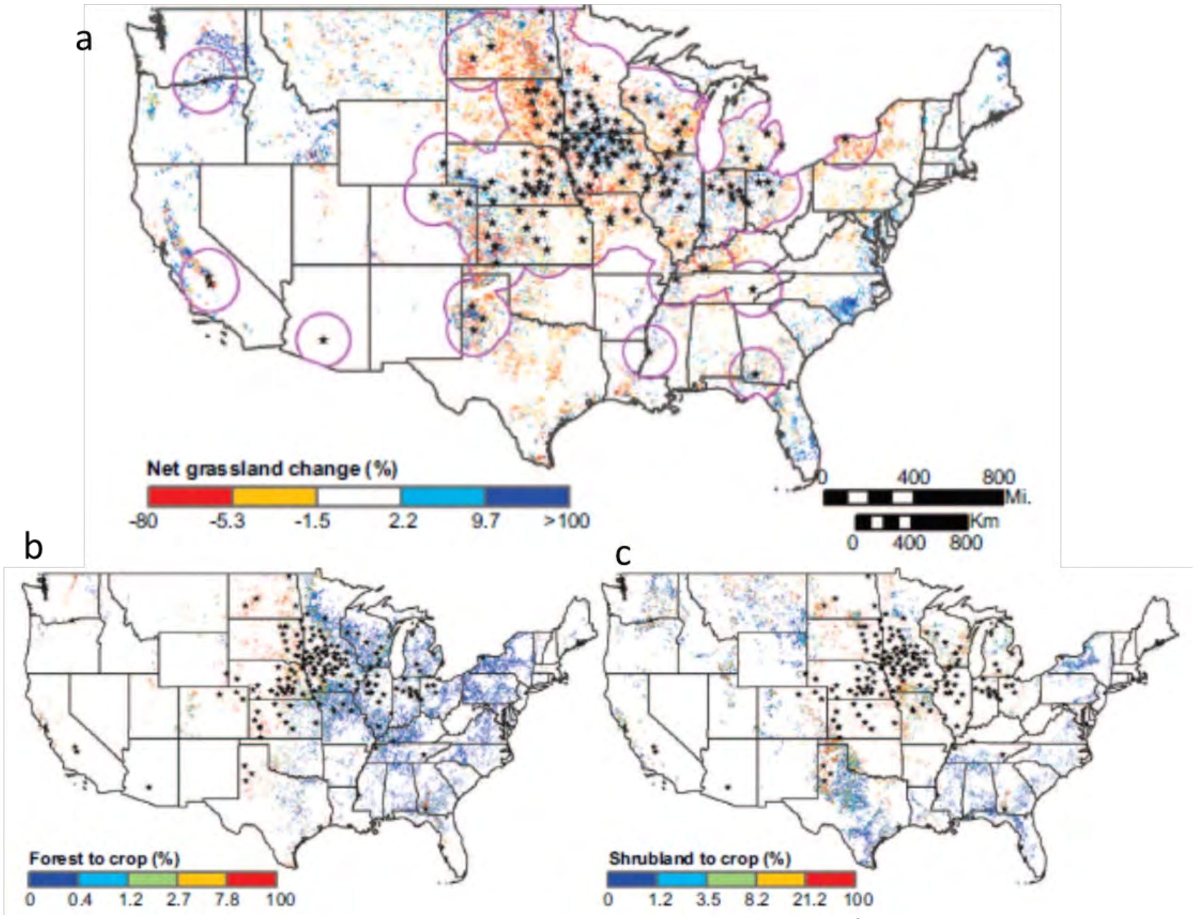
3.3.2 Ecosystems Other Than Wetlands

There are many ecosystems other than wetlands that may be affected by biofuel production and use, including grasslands, forests, and aquatic habitats downstream of corn and soybean production areas. Impacts on aquatic habitats, such as from runoff of fertilizer, pesticides, as well as changes in hydrology from tilling, are discussed in Chapter 3.4. As with other land use changes and associated environmental effects, attributing the fraction of these changes to biofuels is not currently possible with any degree of confidence. Consequently, attribution to the RFS annual volumes is also not currently possible, and such an analysis would be expansive and could not be conducted in time to be included in this rulemaking. The conversion of these ecosystems to other uses, including agriculture, is summarized below.

In addition to wetlands, Wright et al. (2017) also reported on the losses of grasslands, shrublands, and forests within 50 miles of a biorefinery in their study.[192] Wright et al. (2017) estimated much larger reductions of grassland (2 million acres), forests (60,000 acres), and shrublands (52,000 acres), than in wetland reductions (estimated 14,000 acre reduction) (Figure 3.3.2-1). The bulk of the grassland conversions occurred in South Dakota (348,000 acres), Iowa (297,000 acres), Kansas (256,000 acres), Missouri (239,000 acres), Nebraska (213,000 acres), and North Dakota (176,000 acres).[193]

[191] Wright, C. K., et al. (2017). "Recent grassland losses are concentrated around US ethanol refineries." Environmental Research Letters 12(4).
[192] Id.
[193] Id.

Figure 3.3.2-1: Relative conversion rates to cropland from either (a) grassland, (b) forest, or (c) shrubland from 2008 to 2012



Rates are relativized by type of ecosystem within a 3.5-mile spatial grid (modified from [194]). Stars denote the location of biorefineries, and the 100 mile radius from all biorefineries is included in (a) for reference (purple outline).

The 2 million acre reduction in grassland described in Wright et al. (2017) between 2008 and 2012 is comparable to the 1.475 million acre reduction in rangeland reported in the USDA NRI between 2007 and 2012.[195] The NRI defines rangeland as a land use/land cover that is more lightly managed than pastureland,[196] and, as such, is probably the NRI land use/land cover most comparable to the grassland in Wright et al. (2017). The biggest reduction in rangeland was from conversion to cropland (743,400 acres), followed by developed land (535,800 acres), and then conversion to other land uses by smaller amounts. The NRI does not parse out individual crops

[194] Id.

[195] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results

[196] The 2020 NRI defines rangeland as "A broad land cover/use category on which the climax or potential plant cover is composed principally of native grasses, grass-like plants, forbs or shrubs suitable for grazing and browsing, and introduced forage species that are managed like rangeland. This would include areas where introduced hardy and persistent grasses, such as crested wheatgrass, are planted and such practices as deferred grazing, burning, chaining, and rotational grazing are used, with little or no chemicals or fertilizer being applied. Grasslands, savannas, many wetlands, some deserts, and tundra are considered to be rangeland. Certain communities of low forbs and shrubs, such as mesquite, chaparral, mountain shrub, and pinyon-juniper, are also included as rangeland."

within the cropland category, making it impossible to draw specific conclusions about the impact of crop production for biofuels on grassland habitat. This reduction in rangeland acreage between 2007 and 2012 was reported to continue between 2012 and 2017, with an additional reduction of over 2.4 million acres of rangeland, again with the largest conversion to cropland (754,600 acres).[197]

The Conservation Reserve Program (CRP) is especially relevant to the land use change and impacts to ecosystems. CRP lands are often grassland habitat that are entered into contract for 10-15 years, and provide a range of ecosystem services over that period, including carbon sequestration, nutrient capture, and habitat for birds.[198] CRP lands are formerly agricultural lands, and, once they have left the CRP, could be used for the production of biofuel feedstocks. However, they are often not used for production because the lands are often of lower quality, and the guaranteed rental rate from admission to the CRP program is more attractive to farmers than the uncertainty of growing crop on marginal lands.[199] Despite the rental payment incentive to farmers, enrollment in the CRP has been shrinking since 2007.[200] This is due to specifications in the Farm Bills, with a reduction from 36.8 million acres in 2007 to 21.9 million acres in 2020.[201] The 2020 NRI reported a net reduction of CRP land by 8.7 million acres between 2007 and 2012, mostly to cropland (66.5%) and pastureland (38%).[202] These reductions continued from 2012 to 2017, with a reduction of 7.8 million acres between 2012 and 2017, again mostly to cropland (63%) and pasture (37%). A detailed study from a 12-state area in the Midwest found that 30% of the CRP land that left the program between 2010 and 2013 went into five principal crops (i.e., corn, soybean, winter wheat, spring wheat, and sorghum), with the majority of that to corn and soybean.[203] Reconciling these studies suggests that, of the land that leaves the CRP and goes into the generic category of cropland in the NRI, at least half of that cropland is devoted to row crops. The change in CRP enrollment is not uniform across the country (Figure 3.3.2-2), with much of the reduction in the western and northern plains, the same areas experiencing losses of grassland and increases in agriculture.

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[197] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results/.

[198] USDA Farm Services Agency (FSA). 2016. The Conservation Reserve Program: 49th Signup Results, https://www.fsa.usda.gov/Assets/USDA-FSA-Public/usdafiles/Conservation/PDF/SU49Book_State_final1.pdf

[199] Gray, B. J., & Gibson, J. W. (2013). "Actor-networks, farmer decisions, and identity." *Culture, Agriculture, Food and Environment*, **35**(2), 82e101. Brown, J. C., et al. (2014). "Ethanol plant location and intensification vs. extensification of corn cropping in Kansas." *Applied Geography* 53: 141-148.

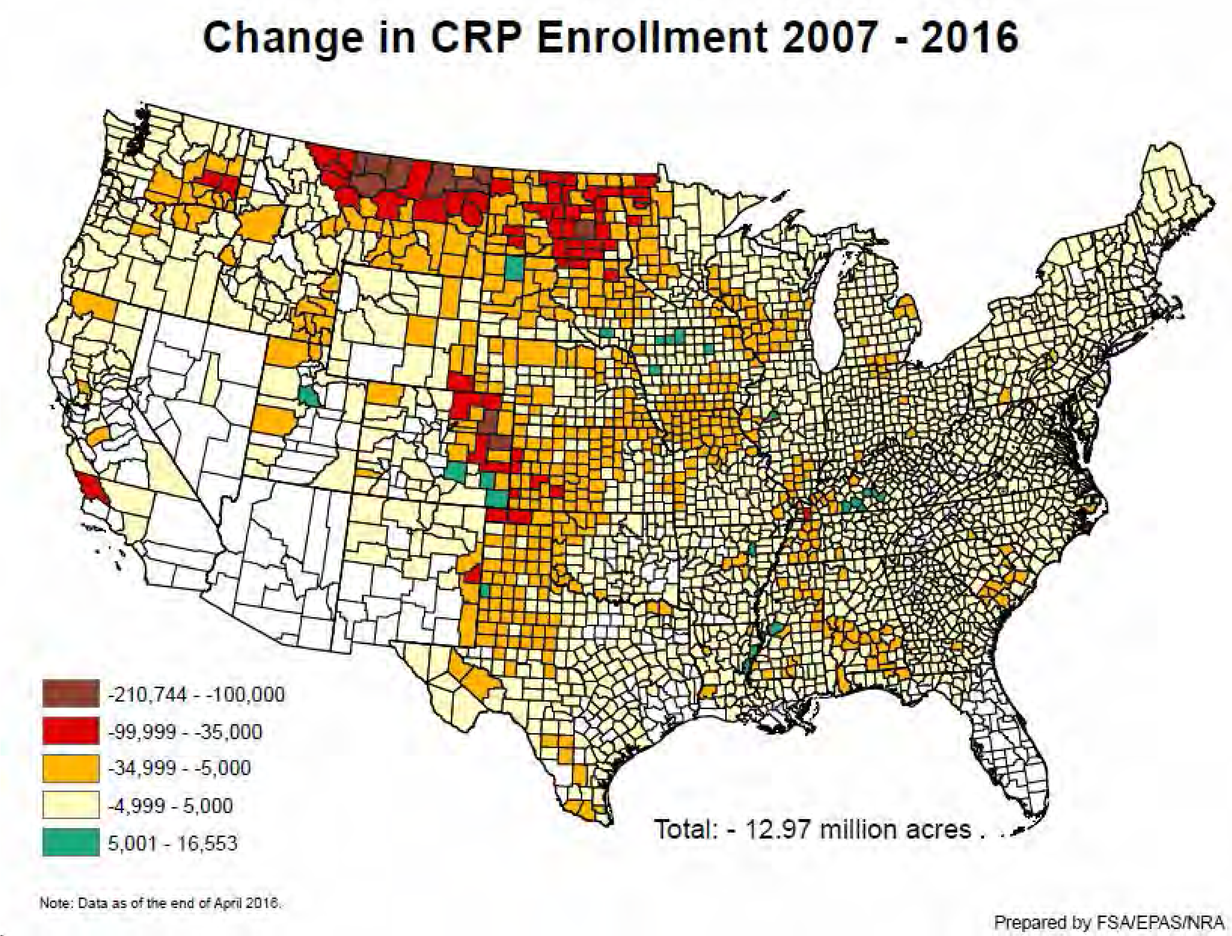
[200] Data from the USDA Farm Service Agency (FSA), available at https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index (last accessed on April 12, 2021).

[201] USDA FSA, FY 2020 Annual Summary. Data from the USDA Farm Service Agency (FSA), available at https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index (last accessed on May 5, 2021).

[202] U.S. Department of Agriculture. 2020. *Summary Report: 2017 National Resources Inventory*, Natural Resources Conservation Service, Washington, DC, and Center for Survey Statistics and Methodology, Iowa State University, Ames, Iowa, at 3-45. https://www.nrcs.usda.gov/wps/portal/nrcs/main/national/technical/nra/nri/results/.

[203] Morefield, P. E., et al. (2016). "Grasslands, wetlands, and agriculture: the fate of land expiring from the Conservation Reserve Program in the Midwestern United States." Environmental Research Letters 11(9): 094005.

Figure 3.3.2-2: Change in CRP enrollment between 2007 and 2016.[204]



Reductions in forested areas to grow corn or soybean does not appear to be occurring in large amounts. As noted above, Wright et al. (2017) reported a net conversion of roughly 60,000 acres of forest within 50 miles of a biorefinery. The NRI reported an overall increase of forestland between 2007 and 2012 (+672,400 acres) which continued between 2012 and 2017 (+1,099,700 acres). Most of the new forest land in both periods came from conversion of pastureland, which offset smaller losses of forest land to predominantly developed lands.[205] Thus, even though some forest land did convert to cropland according to the NRI,[206] these conversions appear small and to be offset by reforestation of pastureland.

Conversion of non-wetland ecosystems to cropland and pastureland has been increasing since 2007. There is indication that grasslands are being converted at the highest rate, and

[204] Data from the from the USDA Farm Services Agency (https://www.fsa.usda.gov/programs-and-services/conservation-programs/reports-and-statistics/conservation-reserve-program-statistics/index).
[205] The increase in forest land between 2007 and 2012 came mostly from addition of pastureland (+2.5 million acres), which offset losses to developed land (-1.4 million acres). These trends continued between 2012 and 2017, with an increase in forestland from pasture (+2.3 million acres) offsetting losses to developed land (-1.2 million acres). There were many other smaller changes that occurred simultaneously.
[206] The 2020 NRI reports that 292,200, and 265,600 acres of forest land converted to cropland between 2007-2012, and 2012-2017, respectively.

primarily to cropland being used to grow corn and soybeans. However, it is difficult to make a causal connection between biofuel production and this loss of grasslands. More information is needed on what the corn and soybeans are being cultivated for before we can state with confidence that they are driving conversion of grasslands to croplands. We can state with confidence that the 2020 and 2021 volumes being proposed in this rulemaking will not cause additional losses in grasslands and other non-wetland ecosystems, as those volumes will be entirely or largely retroactive. The volume requirements being proposed for 2022 have the potential to incent additional production of biofuels, and may affect grasslands and other ecosystems. Additional information on the factors driving grassland to cropland conversion is needed in order to estimate the direction and magnitude of any impact the RFS volumes may have on those land use/land cover changes.

3.3.3 Wildlife

There are many subsequent potential impacts to wildlife from these changes in wetlands and other ecosystems, which were also summarized in the Second Triennial Report to Congress on Biofuels.[207] The potential impacts and their severity vary depending on such factors as crop type, geographic location, and land management practices. The CRP, in particular, provides incentives for maintaining many of these habitats, including practices that target pollinators (e.g., Conservation Practice (CP) 42, and CP2), ducks (e.g., CP 37), and other wildlife (e.g., CP4B, 4D, 33).[208] Here we focus on potential impacts to terrestrial wildlife, including primarily birds and insects, which have been the most studied to date. Impacts to aquatic wildlife are described in Chapter 3.4.2.3.

There are many bird species that use patches of grassland, wetland, pasture, and other lightly managed areas as habitat within largely agricultural areas. Conversion of wetlands to row crops is associated with reduced duck habitat and productivity of duck food sources, including aquatic plants and invertebrates.[209] However, studies of the effects of bioenergy feedstock production suggest that grassland bird species of conservation concern are more likely to be affected by increased corn production than are more common species of birds.[210] Evidence suggests that the direct effects of increasing cultivation of corn and soybean for biofuel production are coming mostly from the conversion of grasslands to cropland, rather than other habitat types (e.g., wetlands, forests, shrublands). Thus, it is likely that the wildlife species with the largest potential risk are grassland species, including bird species and various insect species. However, indirect land use changes may also occur, with evidence from the NRI suggesting roughly 50,000 acres of wetland converted to cropland between 2012 and 2017.

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[207] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[208] Listed here: https://www.fsa.usda.gov/programs-and-services/conservation-programs/crp-practices-library/index.

[209] Gleason, R.A., Euliss, N.H., Tangen, B.A., Laubhan, M.K., and Browne, B.A. (2011). "USDA conservation program and practice effects on wetland ecosystem services in the Prairie Pothole Region." *Ecological Applications* 21: S65–S81.

[210] Fletcher, R.J., Robertson, B.A., Evans, J., Doran, P.J., Alavalapati, J.R.R., and Schemske, D.W. (2011). "Biodiversity conservation in the era of biofuels: risks and opportunities." *Frontiers in Ecology and the Environment* 9(3): 161-168: 10.1890/090091. Blank PJ, Sample DW, Williams CL and Turner MG (2014). "Bird Communities and Biomass Yields in Potential Bioenergy Grasslands." *PLOS ONE* 9(10): e109989: 10.1371/journal.pone.0109989.

While the impacts of land use and management on wildlife have been studied, the impacts of biofuels generally and the annual volume requirements under the RFS program specifically have not. Evans et al. (2015) conducted a detailed assessment of trends in the populations of 22 grassland bird species across an 11-state area using the USGS Breeding Bird Survey.[211] The 22 species examined were a subset of the 28 identified by the USGS as grassland birds. Six species were excluded because their breeding ranges were outside of the 11-state study area. Evans et al. (2015) found that observations of six species were negatively associated with primary crop area, while observations for five species were positively associated with primary crop area.[212] All of the bird species with negative associations were on the U.S. FWS list of species of conservation concern, while none of the species exhibiting positive responses were on the list of conservation concern.[213] Although the above results using Ordinary Least Squares were statistically significant, associations were weaker when random or fixed effects were included. When using random or fixed effects, only two species of conservation concern retained a negative association with crop area (Bobolink [*Dolichonyx oryzivorus*] and Henslow's Sparrow [*Ammodramus henslowii*]). Furthermore, when the marginal trends from primary crop increases were compared with overall trends, the magnitudes of effect were modest. The effects from land use change of primary crops led to a –0.20% to +0.15% effect, compared to the overall trends which ranged from –2.74% to +10.66%, or a 10- to 100-fold larger overall effect.[214]

Potential harm to insects, especially insect pollinators, has also been of particular concern. One study estimated that bees contributed an estimated $14.6 billion toward agricultural production in 2009, or 11% of the nation's agricultural gross domestic product.[215] Roughly 20% of these pollination services are estimated from wild populations which depend on local habitat for food and nesting sites.[216] A recent modeling study suggests that wild bee populations have decreased by 23% across the U.S. between 2008 and 2013.[217] The causes of these reductions are complex, but include land use change, pesticides, and disease.[218] Subsequent effects from reductions in local bee populations are possible, including reductions in pollinator-dependent

[211] Evans, S.G. and Potts, M.D. (2015). "Effect of agricultural commodity prices on species abundance of US grassland birds." *Environmental and Resource Economics*, 62(3), pp.549-565.
[212] Primary crops were defined as corn, soybeans, and wheat.
[213] Evans, S.G. and Potts, M.D. (2015). "Effect of agricultural commodity prices on species abundance of US grassland birds." *Environmental and Resource Economics*, 62(3), pp.549-565.
[214] Id.
[215] Lautenbach, S., Seppelt, R., Liebscher, J., Dormann, C.F. (2012). "Spatial and temporal trends of global pollination benefit." *PLoS One* 7(4):e35954. Morse, R.A., Calderone, N.W. (2000). "The value of honey bees as pollinators of U.S. crops in 2000." *Bee Culture* 128:1–15. Koh, I., Lonsdorf, E.V., Williams, N.M., Brittain, C., Isaacs, R., Gibbs, J., and Ricketts, T.H. (2016). "Modeling the status, trends, and impacts of wild bee abundance in the United States." *Proceedings of the National Academy of Sciences* 113(1): 140-145: 10.1073/pnas.1517685113.
[216] Losey, J.E., Vaughan, M. (2006). "The economic value of ecological services provided by insects." *Bioscience* **56**(4):311–323.
[217] Koh, I., Lonsdorf, E.V., Williams, N.M., Brittain, C., Isaacs, R., Gibbs, J., and Ricketts, T.H. (2016). "Modeling the status, trends, and impacts of wild bee abundance in the United States." *Proceedings of the National Academy of Sciences* 113(1): 140-145: 10.1073/pnas.1517685113.
[218] Goulson, D., Nicholls, E., Botías, C., Rotheray, E.L. (2015). "Bee declines driven by combined stress from parasites, pesticides, and lack of flowers." *Science* 347(6229):1255957.

crops grown in the area,[219] as well as natural pollination services provided to wild habitat and associated ecological effects.

In the most comprehensive study to date, Hellerstein et al. (2017) found that when averaged across the United States, the forage suitability index for pollinators increased from 1982 to 2002 and declined slightly from 2002 to 2012—though in important honey bee regions (such as Central North and South Dakota), the decline from 2002 to 2012 was more pronounced.[220] The Dakota's are the summer grounds for many managed honey bee colonies, and thus the reduction in forage quality in these areas may have impacts. Although the largest stressors to honey bee populations remains the varroa mites, rather than pesticides from nearby crops, the presence of high quality forage nearby colonies is thought to improve the resilience and health of colonies by supplementing feeding.

In a series of recent reviews, researchers concluded that there is evidence of adverse impacts to pollinators due to neonicotinoid exposure.[221] But also that the evidence is mixed, and major gaps remain in our understanding of how pollinator colony-level (for social bees) and population processes may dampen or amplify the lethal or sublethal effects. EPA's preliminary assessment of the risk to bees from imidacloprid, clothianidin, and thiamethoxam found on-field risk to be low for these pesticides applied to corn, which is the dominant use pattern for this crop.[222] For soybeans, risks were considered uncertain at the time and are currently undergoing re-evaluation by EPA. Neonicotinoids, like all pesticides, are approved for use under specific conditions that are designed to protect ecosystems and human health. Recently, EPA expanded its pesticide risk assessment process specifically for bees to quantify or measure exposures and relate them to effects at the individual and colony level.[223] Because of the uncertainty surrounding the impacts of neonicotinoid use in soybean cultivation on pollinators, it is difficult to state with any certainty that the RFS annual volume requirements proposed in this action will have an impact on pollinators.

At present it is not possible to confidently estimate the fraction of wildlife habitat loss or of corn or soy production that is attributable to biofuel production or use. Thus, we cannot

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[219] For example, USDA NASS data for 2017 show that even though most apples (which are highly dependent on pollinators) are grown in Washington (165,000 acres), smaller acreages are also grown in Michigan (33,000 acres), Ohio (4,000 acres) and Illinois (1,700 acres). If 20% of these pollination services are provided by wild insects as estimated by Losey et al. (2006), that could have effects on local apple production.

[220] Hellerstein, Daniel, Claudia Hitaj, David Smith, and Amélie Davis. *Land Use, Land Cover, and Pollinator Health: A Review and Trend Analysis*, ERR-232, U.S. Department of Agriculture, Economic Research Service, June 2017.

[221] Godfray, H., Charles, J., Tjeerd Blacquiere, Linda M. Field, Rosemary S. Hails, Gillian Petrokofsky, Simon G. Potts, Nigel E. Raine, Adam J. Vanbergen, and Angela R. McLean. (2014) "A restatement of the natural science evidence base concerning neonicotinoid insecticides and insect pollinators." *Proceedings of the Royal Society B: Biological Sciences* 281, no. 1786: 20140558.

[222] EPA (2016). Preliminary Aquatic Risk Assessment to Support the Registration Review of Imidacloprid. U.S. Environmental Protection Agency Office of Chemical Safety and Pollution Prevention, EPA-HQ-OPP-2008-0844-1086: 219 pp. Washington, DC, December 22. EPA (2017). Preliminary Bee Risk Assessment to Support the Registration Review of Clothianidin and Thiamethoxam. Office of Pesticide Programs, EPA-HQ-OPP-2011-0865-0173: 414 pp. Washington, DC.

[223] U.S. EPA (2018), "How We Assess Risks to Pollinators." Available at https://www.epa.gov/pollinator-protection/how-we-assess-risks-pollinators (last accessed April 12, 2021).

confidently estimate the impacts to date on wildlife from biofuels generally nor from the annual volume requirements, specifically. Attributing such impacts to RFS annual volume rules specifically, let alone the changes in renewable fuel volumes proposed in this action, is even more difficult (see Second Triennial Report to Congress on Biofuels sections 3.4.3.2 and 2.4.4).

3.3.4 Potential Future Impacts of Annual Volume Requirements

In the future, there may be some increased pressure to convert grasslands and wetlands into cropland, and, therefore, also increased pressure on wildlife habitats due to the proposed volumes, primarily from the 2022 volume's potential ability to incent greater investment in soybean based biofuels. The 2020 and 2021 volumes proposed here, however, will likely have no impact, since these volumes, when they are finalized, will be entirely or largely retroactive . There is substantial uncertainty in projecting changes in land use and management associated with corn, soybean, and other crops. Additional information and modeling are needed to fully assess changes in habitat areas and effects on wildlife, both for crop expansion and pesticide use.

3.4 Soil and Water Quality

Soil and water quality are addressed here in one combined section because they are in many ways intertwined, with effects on soil often directly altering water quality (e.g., soil erosion leading to sedimentation). Soil quality, also referred to as soil health, is the capacity of a soil to function, including the ability to sustain plant growth.[224] It can be affected by biofuel feedstock production through changes in soil erosion, soil organic matter (SOM),[225] and soil nutrients, among other characteristics. Soil erosion can negatively impact soil quality by disproportionately removing the finest soil particles generally higher in organic matter, plant nutrients, and water-holding capacity than the remaining soil. Soil organic matter is critical to soil quality because it provides nutrients to plants, facilitates water retention in the soil, promotes soil structure, and reduces erosion, while also sequestering carbon from the atmosphere. Soil nutrients (e.g., nitrogen, phosphorus) are necessary for plant growth. Too little of these nutrients can reduce crop yields; too much can negatively affect water quality via runoff or leaching.

[224] The USDA Natural Resources Conservation Service (NRCS) defines soil health or soil quality as "The capacity of a specific kind of soil to function, within natural or managed ecosystem boundaries, to sustain plant and animal productivity, maintain or enhance water and air quality, and support human health and habitation. In short, the capacity of the soil to function" (USDA-NRCS 2021). In this section, "soil quality" is used as a general term, independent of area—it is used both to describe effects on single soil types and cumulative effects across large areas and multiple soil types.

[225] Soil organic matter is defined by Brady and Weil (2010) as "[t]he organic fraction of the soil that includes plant and animal residues at various stages of decomposition, cells and tissues of soil organisms, and substances synthesized by the soil population." Brady N and Weil R (2000). Elements of the Nature and Properties of Soils. Upper Saddle River, NJ, USA, Prentice-Hall, Inc. The USDA NRCS similarly defines soil organic matter as "[t]he total organic matter in the soil. It can be divided into three general pools: living biomass of microorganisms, fresh and partially decomposed residues (the active fraction), and the well-decomposed and highly stable organic material. Surface litter is generally not included as part of soil organic material." (USDA-NRCS 2021).

Water quality is the condition of water to serve human or ecological needs.[226] Biofuel feedstock production can affect water quality through associated changes in nutrients, dissolved oxygen, sediment, and chemical loadings.[227] Nutrient releases can result in excessive algal growth (i.e., algal blooms), leading to low dissolved oxygen levels (i.e., hypoxia) in some cases. Increased sediment and total dissolved solids can make water unsuitable for consumption and irrigation, and also have negative impacts on aquatic species. In addition, chemical releases or biofuel leaks and spills from above-ground, underground, and transport tanks can be detrimental to water quality leading to ground, surface, and drinking water contamination (see Chapter 3.4.2).[228] Water quality impacts are presented as either proximal (i.e., geographically close) or downstream, although effects can span both. We discuss sediment and chemical loadings under proximal effects, and nutrients and hypoxia due to algal blooms in both coastal and non-coastal waters under downstream effects.

3.4.1 Drivers

Corn-grain ethanol and soy biodiesel account for most of the biofuel volumes produced to date. As a result, the majority of soil and water quality impacts from biofuels thus far have come from the production of corn and soybeans. Since 2007, grasslands, including CRP grasslands, have been converted to corn and soybeans, in a process termed extensification (see Chapter 3.4.2.1). Corn and soybeans have also replaced other kinds of cropland. By contrast, the use of other feedstocks for biofuel production has been much more limited. Use of corn stover has been attempted at a couple of locations.[229] To date, other feedstocks, such as perennial grasses, woody biomass, and algae, have generally not yet materialized, with a few exceptions (e.g., algal biofuels for the U.S. Navy), though there is a substantial amount of literature available on the impacts of perennial grasses on soil and water quality.[230] For that reason, we have included those feedstocks in this analysis, though they are not widely used. Finally, outside the U.S., palm oil production for biodiesel is an established industry in countries such an Indonesia, Malaysia, and Thailand, with production occurring mainly for export, including to the U.S.

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[226] EPA (2003). National Management Measures to Control Nonpoint Pollution from Agriculture. U.S. Environmental Protection Agency Office of Water, EPA-841-B-03-004. Washington, DC, July.
EPA (2011). Biofuels and the Environment: First Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-10/183F: 220 pp. Washington, DC, December.
[227] The USDA NRCS Environmental Technical Note No. MT-1 (2011) defines these water quality parameters and their significance.
[228] This section focuses on the non-point source, water quality effects of feedstock production and spills. Any direct point source discharges from biofuel production facilities are expected to be effectively controlled by existing environmental statutes under the Clean Water Act (EPA 2011). Biofuels and the Environment: First Triennial Report to Congress. Office of Research and Development, National Center for Environmental Assessment, Washington, DC; EPA/600/R-10/183F).
[229] 81 FR 89746 (December 12, 2016).
[230] Ziolkowska, J.R., and Simon, L. (2014). "Recent developments and prospects for algae-based fuels in the US." *Renewable & Sustainable Energy Reviews* 29: 847-853: 10.1016/j.rser.2013.09.021.

3.4.2 Impacts to Date

3.4.2.1 Soil and Proximal Water Quality Effects

Primarily, the magnitude of the impacts to soil and water quality depend upon the feedstock grown and land use—i.e., the type of land used for growing the biofuel feedstock and the management implemented on that land. On a per acre basis, the extensification of corn and soybeans onto grasslands has greater negative effects on soil and water quality relative to the conversion of other existing cropland, such as wheat, to corn or soybeans. Grassland-to-annual-crop conversion typically impacts soil quality negatively because it increases erosion and the loss of soil nutrients and SOM, including soil carbon loss to the atmosphere.[231] In a meta-analysis, Qin et al. (2016) found that replacing grasslands with corn decreased soil carbon by approximately 20% on average.[232] The effects of converting grasslands to soybeans are likely greater on erosion, SOM, and soil carbon than converting to corn, since corn generally inputs more organic matter and carbon into the soil than soybeans, when both crops are managed using the same tillage practice (tillage practices are discussed in greater detail later in this section).[233] Increased erosion from conversion, in turn, can negatively impact water quality through increased sediment and nutrient loadings to waterways.[234]

Corn and soybeans additionally affect water quality through increased chemical usage, some of which moves as runoff or leaching to surface waterways or groundwater. Table 3.4.2.1-1 summarizes the most recent USDA National Agricultural Statistics Service (NASS) Agricultural Chemical Use Survey results for domestic corn and soybean acreage, as well as domestic wheat acreage for comparison. In general, soybean acreage receives substantially less fertilizer than corn, particularly nitrogen, because soybeans can attain nitrogen from the atmosphere via symbiotic nitrogen fixation whereas corn cannot. Thus, as an example, multiplying 1.94 million acres of extensification in the U.S. attributed to corn[235] by the average nitrogen fertilizer rate corn receives (149 lbs N/acre) yields an increase of approximately 289 million pounds of additional nitrogen added per year. Likewise, from the most recent surveys by the USDA NASS, 97% of planted corn acres were treated with herbicides, 13% with insecticides, and 17% with

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[231] Gregorich, E.G., and Anderson, D.W. (1985). “Effects of cultivation and erosion on soils of four toposequences in the Canadian prairies.” *Geoderma* 36(3-4): 343-354: 10.1016/0016-7061(85)90012-6. Gelfand, I., Zenone, T., Jasrotia, P., Chen, J.Q., Hamilton, S.K., and Robertson, G.P. (2011). “Carbon debt of Conservation Reserve Program (CRP) grasslands converted to bioenergy production.” *Proceedings of the National Academy of Sciences of the United States of America* 108(33): 13864-13869: 10.1073/pnas.1017277108. Qin, Z.C., Dunn, J.B., Kwon, H.Y., Mueller, S., and Wander, M.M. (2016). “Soil carbon sequestration and land use change associated with biofuel production: empirical evidence.” *Global Change Biology Bioenergy* 8(1): 66-80: 10.1111/gcbb.12237. Lal, R. (2003). “Soil erosion and the global carbon budget.” *Environment International* 29(4): 437-450: 10.1016/s0160-4120(02)00192-7.

[232] Qin, Z.C., Dunn, J.B., Kwon, H.Y., Mueller, S., and Wander, M.M. (2016). “Soil carbon sequestration and land use change associated with biofuel production: empirical evidence.” *Global Change Biology Bioenergy* 8(1): 66-80: 10.1111/gcbb.12237.

[233] Johnson, J.M.-F., Allmaras, R.R., and Reicosky, D.C. (2006). “Estimating source carbon from crop residues, roots and rhizodeposits using the national grain-yield database.” *Agronomy Journal* 98:622-636.

[234] Yasarer, L.M.W., Sinnathamby, S., and Sturm, B.S.M. (2016). “Impacts of biofuel-based land-use change on water quality and sustainability in a Kansas watershed.” *Agricultural Water Management* 175: 4-14: 10.1016/j.agwat.2016.05.002.

[235] Lark, T.J., Salmon, J.M., and Gibbs, H.K. (2015). “Cropland expansion outpaces agricultural and biofuel policies in the United States.” *Environmental Research Letters* 10(4): 10.1088/1748-9326/10/4/044003.

fungicides (Table 3.4.2.1-1). Atrazine was the top active ingredient among herbicides applied to the planted corn acres, applied to 65% of planted acres, followed by mesotrione, applied to 42% of planted acres.[236] For planted soybean acres, 99% were treated with herbicides, 16% with insecticides, and 15% with fungicides.[237] Glyphosate isopropylamine salt and glyphosate potassium salt were the top active ingredients among herbicides applied to planted soybean acres.[238] Due to the widespread nutrient and pesticide usage on corn and soybeans, it can be inferred that runoff and/or leaching of these chemicals from corn and soybean acres are contributing in part to proximal water quality impacts. For instance, in a modeling study of the continental U.S., Garcia et al. (2017) estimated that increased corn production (up to 18 billion gallons of corn ethanol) between 2002 and 2022 would increase nitrate groundwater contamination (above or equal to 5 mg/L), particularly in areas with irrigated corn on sandy or loamy soils.[239]

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[236] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Corn. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Corn_2018.pdf (last accessed April 13, 2021).

[237] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf (last accessed April 13, 2021).

[238] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf (last accessed April 13, 2021).

[239] Garcia, V., Cooter, E., Crooks, J., Hinckley, B., Murphy, M., and Xing, X. (2017). "Examining the impacts of increased corn production on groundwater quality using a coupled modeling system." *Science of The Total Environment* 586: 16-24: https://doi.org/10.1016/j.scitotenv.2017.02.009.

Table 3.4.2.1-1: Summary of Chemical Use for Corn, Soybeans, and Wheat Acreage in the U.S. based on 2018 and 2019 USDA NASS Chemical Use Surveys[240,241,242]

	Corn	Soybeans	Winter wheat	Spring wheat	Durum wheat
Nitrogen Fertilizer Applied: % of Planted Acres	98	29	88	97	98
Average Application Rate for Year for Acres with Nitrogen Fertilizer Applied (lbs N/acre)	149	17	73	102	83
Phosphate Fertilizer Applied: % of Planted Acres	79	42	63	89	84
Average Application Rate for Year for Acres with Phosphate Fertilizer Applied (lbs P_2O_5/acre)	69	55	31	39	29
Atrazine Applied: % of Planted Acres	65	Not Reported	Not Reported	Not Reported	Not Reported
Average Application Rate for Year for Acres with Atrazine Applied (lbs/acre)	1.037	Not Reported	Not Reported	Not Reported	Not Reported
Glyphosate Potassium Salt: % of Planted Acres	Not Reported	28	Not Reported	Not Reported	Not Reported
Average Application Rate for Year for Acres with Glyphosate Potassium Salt Applied (lbs/acre)[243]	Not Reported	1.527	Not Reported	Not Reported	Not Reported
Glyphosate Isopropylamine Salt: % of Planted Acres	34	47	Not Reported	Not Reported	46
Average Application Rate for Year for Acres with Glyphosate Isopropylamine Salt Applied (lbs/acre) [244]	0.993	1.202	Not Reported	Not Reported	0.555

There are a couple factors that can mitigate impacts on soil and water quality, at least in part. First, the type of CRP lands, conservation lands, or other grasslands that are converted to cropland can affect soil quality. In a modeling study, LeDuc et al. (2017) simulated that greater erosion and loss of soil carbon and nitrogen occurs from converting low productivity, highly

[240] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Corn. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Corn_2018.pdf (last accessed April 13, 2021).
[241] USDA NASS (2019). 2018 Agricultural Chemical Use Survey: Soybeans. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2018_Peanuts_Soybeans_Corn/ChemUseHighlights_Soybeans_2018.pdf (last accessed April 13, 2021).
[242] USDA NASS (2020). 2019 Agricultural Chemical Use Survey: Wheat. Available at https://www.nass.usda.gov/Surveys/Guide_to_NASS_Surveys/Chemical_Use/2019_Field_Crops/chem-highlights-wheat-2019.pdf (last accessed April 13, 2021).
[243] This is expressed in acid equivalent.
[244] This is expressed in acid equivalent.

sloped CRP grasslands compared to those with higher productivity soils and lower slopes.[245] In turn, higher erosion results in greater sedimentation and nutrient loading to waterways. Second, the effects can also depend upon land management and production practices, like different tilling practices. Most corn and soybeans are grown using conservation tillage, with a smaller percent grown using no-till management.[246] Conservation tillage, including no-till, reduces soil erosion and increases SOM content relative to conventional tillage.[247, 248]

The soil and water quality effects of converting to corn or soybeans from other crops, such as wheat, are generally less than those of the conversion of grasslands.[249] Zuber et al. (2015) observed similar soil effects of no-till, continuous corn rotations, and corn-soybean-wheat rotations on fine textured soils with high organic matter content.[250] From this evidence, Zuber et al. (2015) suggests a movement from wheat to corn may not materially affect soil quality, provided a shift from no-till to conventional tillage does not occur concomitantly. In a meta-analysis, Qin et al. (2016) found that corn replacing other cropland (e.g., soybean, wheat) increased soil organic carbon, whereas the opposite occurred when corn replaced grassland or

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[245] LeDuc SD, Zhang XS, Clark CM and Izaurralde RC (2017). Cellulosic feedstock production on Conservation Reserve Program land: potential yields and environmental effects. Global Change Biology Bioenergy 9(2): 460-468: 10.1111/gcbb.12352.

[246]Conservation tillage is defined as any tillage practice leaving at least 30% of the soil surface covered by crop residues; whereas conventional tillage leaves less than 15% of the ground covered by crop residues (Lal 1997). No-till management, a subset of conservation tillage, disturbs the soil marginally by cutting a narrow planting strip. Nationally, approximately 30% and 45% of the area planted to corn and soybeans, respectively, are under no-till (Wade et al. 2015). Since 2000, there has been a general trend toward greater percent residue remaining after planting for both crops (USDA-ERS 2018 https://data.ers.usda.gov/reports.aspx?ID=17883; data accessed 2/15/2018). Lal R (1997). Residue management, conservation tillage and soil restoration for mitigating greenhouse effect by CO2-enrichment. Soil & Tillage Research 43(1-2): 81-107. USDA-NRCS (2010). Assessment of the effects of conservation practices on cultivated cropland in the Upper Mississippi River Basin. N. R. C. S. United States Department of Agriculture. Available at https://www.nrcs.usda.gov/wps/portal/nrcs/detail/national/technical/nra/ceap/pub/?cid=nrcs143_014161 (last accessed April 13, 2021).
Wade T, Claassen R and Wallander S (2015). Conservation-practice adoption rates vary widely by crop and region, EIB-147, U.S. Department of Agriculture Economic Research Service.

[247] Cassel DK, Raczkowski CW and Denton HP (1995). Tillage effects on corn production and soil physical conditions. Soil Science Society of America Journal 59(5): 1436-1443. West TO and Post WM (2002). Soil organic carbon sequestration rates by tillage and crop rotation: A global data analysis. Soil Science Society of America Journal 66(6): 1930-1946.

[248] Follett RF, Varvel GE, Kimble JM and Vogel KP (2009). No-Till Corn after Bromegrass: Effect on Soil Carbon and Soil Aggregates. Agronomy Journal 101(2): 261-268: 10.2134/agronj2008.0107.
Gelfand I, Zenone T, Jasrotia P, Chen JQ, Hamilton SK and Robertson GP (2011). Carbon debt of Conservation Reserve Program (CRP) grasslands converted to bioenergy production. Proceedings of the National Academy of Sciences of the United States of America 108(33): 13864-13869: 10.1073/pnas.1017277108.

[249] Zuber SM, Behnke GD, Nafziger ED and Villamil MB (2015). Crop Rotation and Tillage Effects on Soil Physical and Chemical Properties in Illinois. Agronomy Journal 107(3): 971-978: 10.2134/agronj14.0465.
Qin ZC, Dunn JB, Kwon HY, Mueller S and Wander MM (2016). Soil carbon sequestration and land use change associated with biofuel production: empirical evidence. Global Change Biology Bioenergy 8(1): 66-80: 10.1111/gcbb.12237. Yasarer LMW, Sinnathamby S and Sturm BSM (2016). Impacts of biofuel-based land-use change on water quality and sustainability in a Kansas watershed. Agricultural Water Management 175: 4-14: 10.1016/j.agwat.2016.05.002.

[250] Zuber SM, Behnke GD, Nafziger ED and Villamil MB (2015). Crop Rotation and Tillage Effects on Soil Physical and Chemical Properties in Illinois. Agronomy Journal 107(3): 971-978: 10.2134/agronj14.0465.

forest land.[251] Notably, the percent increase in soil organic carbon of other cropland moving to corn was exceeded in magnitude by the percent decrease in soil organic carbon by the conversion of grassland to corn. For water quality, an increase in corn at the expense of other crops is likely to lead to greater nutrient loadings. In a global meta-analysis, Zhou and Butterbach-Bahl (2014) found that average nitrate losses from leaching from corn (57.4 kg N/ha) exceeded those of wheat (29 kg N/ha), suggesting that a replacement of wheat by corn would lead to higher nitrate leaching to waterways.[252] Between 2003 and 2010, Plourde et al. (2013) found that the practice of rotating corn and soybeans decreased, while corn mono-cropping, or continuous corn, increased.[253] In a modeling study, Secchi et al. (2011) concluded that this intensification[254] of corn would likely lead to higher nitrogen and phosphorus loads in the Upper Mississippi River Basin.[255]

Beyond corn and soy, the production of cellulosic feedstocks for biofuels, such as corn stover and perennial grasses, may also affect soil and water quality. Partial stover removal can increase corn yields in some locations, in part by reducing nitrogen uptake from the soil by microorganisms and potentially by increasing soil temperatures in no-till systems.[256] Corn stover collection in areas with high rates of production also facilitates no-till land management (compared to conventional tillage), which can reduce erosion, nutrient losses, and thereby improve soil and water quality.[257] Yet too much stover removal can increase soil erosion, decrease SOM and soil nutrients, and ultimately decrease corn yields.[258] Whether corn stover can be harvested sustainably, and at what removal rate, depends on many site-specific factors, including yields, topography, soil characteristics, climate, and tillage practices. In a study across multiple locations in seven states, stover harvesting increased corn grain yields slightly, although the authors cautioned against extrapolating these results to other sites and noted that there is a

[251]Qin ZC, Dunn JB, Kwon HY, Mueller S and Wander MM (2016). Soil carbon sequestration and land use change associated with biofuel production: empirical evidence. Global Change Biology Bioenergy 8(1): 66-80: 10.1111/gcbb.12237.

[252] Zhou and Butterbach-Bahl (2014). "Assessment of nitrate leaching loss on a yield-scaled basis from maize and wheat cropping systems." *Plant Soil* 374: 977-991: 10.1007/s11104-013-1876-9.

[253] Plourde, J.D., Pijanowski, B.C., and Pekin, B.K. (2013). "Evidence for increased monoculture cropping in the Central United States." *Agriculture, ecosystems & environment* 165: 50-59.

[254] Agricultural intensification is the increased production from the land without an increase in acreage. U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[255] Secchi, S., Gassman, P.W., Jha, M., Kurkalova, L., and Kling, C.L. (2011). "Potential water quality changes due to corn expansion in the Upper Mississippi River Basin." *Ecological Applications* 21(4): 1068-1084.

[256] Coulter, J.A. and Naftiger, E.D. (2008). "Continuous Corn Response to Residue Management and Nitrogen Fertilization." *Agronomy Journal* 100(6): 1774-1780: 10.2134/agronj2008.0170. Karlen, D.L., Birrell, S.J., Johnson, J.M.F., Osborne, S.L., Schumacher, T.E., Varvel, G.E., Ferguson, R.B., Novak, J.M., Fredrick, J.R., Baker, J.M., Lamb, J.A., Adler, P.R., Roth, G.W., and Nafziger, E.D. (2014). "Multilocation Corn Stover Harvest Effects on Crop Yields and Nutrient Removal." *Bioenergy Research* 7(2): 528-539: 10.1007/s12155-014-9419-7.

[257] Dale, V.H., Kline, K.L., Richard, T.L., Karlen, D.L., and Belden, W.W. (2017). "Bridging biofuel sustainability indicators and ecosystem services through stakeholder engagement." *Biomass and Bioenergy*. Also available at https://doi.org/10.1016/j.biombioe.2017.09.016 (last accessed April 13, 2021).

[258] EPA (2011). Biofuels and the Environment: First Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-10/183F: 220 pp. Washington, DC, December.

need to conduct site-specific planning with soil testing.[259] Additional research is needed to understand effects on soil and water quality if soil conservation methods are employed while harvesting corn stover.

Perennial grasses are a potential cellulosic feedstock that is not currently used at the commercial scale. But, like other feedstocks, their impacts on soil and water quality would likely depend upon the type of land use replaced and the management practices employed. Replacing grasslands with intensively managed perennial feedstocks could have negative soil and water quality effects, while replacing annual crops would likely lead to improvements.[260] The scientific literature continues to emphasize that perennial grasses or woody biomass grown on marginal lands (e.g., abandoned agricultural land) can help restore soil quality.[261] Notably, however, the effects of these perennial feedstocks can depend upon the plant species grown and the type of land converted.[262] Additionally, the literature definitions of what constitutes marginal land and estimates of its extent vary widely.[263] For water quality, a modeling study found partially replacing annual crops with Miscanthus and switchgrass—two perennial grasses—could reduce inorganic nitrogen loadings by roughly 15% and 20%, respectively, in the Mississippi-Atchafalaya River Basin.[264] Alternative feedstock production (e.g., switchgrass) requires less fertilizer than corn, thereby reducing nutrient runoff.[265] One recent modeling study for the state of Iowa estimated that converting 12% and 37% of cropland to switchgrass would reduce leached nitrate-nitrogen (NO_3-N) by 18% and 38%, respectively, statewide.[266] Another modeling study estimated cropland conversion to switchgrass and stover harvest could greatly reduce suspended sediment, total nitrogen, and phosphorus by 54 to 57%, 30 to 32%, and 7 to 17%, respectively, in the South Fork Iowa River (SFIR) watershed if accompanied by best management practices (e.g., riparian buffers and cover crops).[267]

[259] Karlen, D.L., Birrell, S.J., Johnson, J.M.F., Osborne, S.L., Schumacher, T.E., Varvel, G.E., Ferguson, R.B., Novak, J.M., Fredrick, J.R., Baker, J.M., Lamb, J.A., Adler, P.R., Roth, G.W., and Nafziger, E.D. (2014). "Multilocation Corn Stover Harvest Effects on Crop Yields and Nutrient Removal." *Bioenergy Research* 7(2): 528-539: 10.1007/s12155-014-9419-7.

[260] Ha, M., Z. Zhang, M. Wu (2017). Biomass production in the Lower Mississippi River Basin: Mitigating associated nutrient and sediment discharge to the Gulf of Mexico. Science of the Total Environment, DOI: 10.1016/j.scitotenv.2018.03.184.

[261] Blanco-Canqui H (2016). Growing Dedicated Energy Crops on Marginal Lands and Ecosystem Services. Soil Science Society of America Journal 80(4): 845-858: 10.2136/sssaj2016.03.0080.

[262] Robertson GP, Hamilton SK, Barham BL, Dale BE, Izaurralde RC, Jackson RD, Landis DA, Swinton SM, Thelen KD and Tiedje JM (2017). Cellulosic biofuel contributions to a sustainable energy future: Choices and outcomes. Science 356(6345): 10.1126/science.aal2324.

[263] Emery I, Mueller S, Qin Z and Dunn JB (2016). Evaluating the potential of marginal land for cellulosic feedstock production and carbon sequestration in the United States. Environmental Science & Technology 51: 733-741.

[264] VanLoocke A, Twine TE, Kucharik CJ and Bernacchi CJ (2017). Assessing the potential to decrease the Gulf of Mexico hypoxic zone with Midwest US perennial cellulosic feedstock production. GCB Bioenergy 9(5): 858-875: 10.1111/gcbb.12385.

[265] Parish ES, Hilliard MR, Baskaran LM, Dale VH, Griffiths NA, Mulholland PJ, Sorokine A, Thomas NA, Downing ME and Middleton RS (2012). Multimetric spatial optimization of switchgrass plantings across a watershed. Biofuels, Bioproducts and Biorefining 6(1): 58-72: 10.1002/bbb.342.

[266] Brandes E (2018). Targeted subfield switchgrass integration could improve the farm economy, water quality, and bioenergy feedstock production. GCB Bioenergy 10: 199–212, doi: 10.1111/gcbb.12481.

[267] Ha, M. and M. Wu (2017). Land management strategies for improving water quality in biomass production under changing climate. Environ. Res. Lett. 12 (3), 034015.

3.4.2.2 Downstream Water Quality Effects

Increased corn and soybean cultivation may also affect downstream surface water and aquatic systems, which can lead to aquatic life effects (see Chapter 3.4.2.3).[268] Fertilizer runoff, in addition to other factors (e.g., temperature and precipitation) and conservation practices, influence downstream eutrophication,[269] algal blooms, and hypoxia in fresh and coastal waters. In freshwater systems, weather conditions and agricultural activity can increase nutrient runoff, as observed in 2011 in western Lake Erie with dissolved reactive phosphorus.[270] Total nitrogen in lake water is also strongly correlated to the probability of detecting the cyanobacterium *Microcystis* in lakes, in addition to the percentage of agricultural land cover within a given lake's ecoregion.[271]

In coastal systems, nutrient loadings affect hypoxic zone size, which is also a function of climate, weather (e.g., storms), basin[272] morphology, circulation patterns, water retention time, freshwater inflows, stratification, and mixing, as seen in the Gulf of Mexico.[273] Conservation practices (e.g., filter strips, cover crops, riparian buffers) can help mitigate downstream water quality effects due to nutrients. Additionally, studies suggest that land conversion to perennial grasses such as switchgrass and Miscanthus, even with manure application, could significantly reduce phosphorus runoff into water bodies.[274] Though perennial grasses are not used at the

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[268] LaBeau MB, Robertson DM, Mayer AS, Pijanowski BC and Saad DA (2014). Effects of future urban and biofuel crop expansions on the riverine export of phosphorus to the Laurentian Great Lakes. Ecological Modelling 277: 27-37: https://doi.org/10.1016/j.ecolmodel.2014.01.016. Jarvie HP, Sharpley AN, Flaten D, Kleinman PJA, Jenkins A and Simmons T (2015). The pivotal role of phosphorus in a resilient water–energy–food security nexus. Journal of Environmental Quality 44(4): 1049-1062: 10.2134/jeq2015.01.0030.

[269] EPA defines eutrophication as "[a] reduction in the amount of oxygen dissolved in water. The symptoms of eutrophication include blooms of algae (both toxic and non-toxic), declines in the health of fish and shellfish, loss of seagrass and coal reefs, and ecological changes in food webs." EPA, Vocabulary Catalog: Acid Rain Glossary, available at https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&glossaryName=Acid%20Rain%20Glossary (last accessed April 14, 2021).

[270] Michalak AM, Anderson EJ, Beletsky D, Boland S, Bosch NS, Bridgeman TB, Chaffin JD, Cho K, Confesor R, Daloğlu I, DePinto JV, Evans MA, Fahnenstiel GL, He L, Ho JC, Jenkins L, Johengen TH, Kuo KC, LaPorte E, Liu X, McWilliams MR, Moore MR, Posselt DJ, Richards RP, Scavia D, Steiner AL, Verhamme E, Wright DM and Zagorski MA (2013). Record-setting algal bloom in Lake Erie caused by agricultural and meteorological trends consistent with expected future conditions. Proceedings of the National Academy of Sciences 110(16): 6448-6452: 10.1073/pnas.1216006110.

[271] Taranu ZE, Gregory-Eaves I, Steele RJ, Beaulieu M and Legendre P (2017). Predicting microcystin concentrations in lakes and reservoirs at a continental scale: A new framework for modelling an important health risk factor. Global Ecology and Biogeography.

[272] EPA defines basin as "[a]n area of land that drains into a particular river, lake, bay or other body of water. Also called a watershed." EPA, Vocabulary Catalog: Chesapeake Bay Glossary, available at https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do?details=&glossaryName=Chesapeake%20Bay%20Glossary (last accessed April 14, 2021).

[273] Dale VH, Kling C, Meyer JL, Sanders J, Stallworth H, Armitage T, Wangsness D, Bianchi TS, Blumberg A, Boynton W, Conley DJ, Crumpton W, David MB, Gilbert D, Howarth RW, Lowrance R, Mankin K, Opaluch J, Paerl H, Reckhow K, Sharpley AN, Simpson TW, Snyder C and Wright. D (2010). Hypoxia in the Northern Gulf of Mexico. New York, Springer. Turner RE and Rabalais NN (2016). 2016 forecast: Summer hypoxic zone size Northern Gulf of Mexico. Louisiana Universities Marine Consortium: 14 pp.

[274] Muenich RL, Kalcic M and Scavia D (2016). Evaluating the Impact of Legacy P and Agricultural Conservation Practices on Nutrient Loads from the Maumee River Watershed. Environmental Science & Technology 50(15): 8146-8154.

commercial scale to produce biofuels, there is a substantial amount of literature on their impacts on soil and water quality. In the interest of providing as much information as is available on this subject, we have included perennial grasses in this analysis.

3.4.2.3 Aquatic Life Effects

According to the Second Triennial Report to Congress on Biofuels, the impacts of biofuel crop production on aquatic ecosystems is understudied compared to the impacts on terrestrial ecosystems.[275] However, it has been shown that increased corn and soybean cultivation may affect downstream aquatic communities, chiefly through runoff or leaching of nutrients and pesticides, though changes in land use and land cover also impact aquatic ecosystems, particularly through conversion of wetlands that provide ecosystem services like improving surface water flow, groundwater recharge, and sediment control.[276] Aquatic organisms interact within a food web and contribute to many ecosystem services. The aquatic food web includes microorganisms (bacteria, fungi, and algae), macroinvertebrates and macrophytes (submerged and floating aquatic plants), and larger animals such as fish and marine mammals. When increased corn and soybean cultivation changes the flow of water, nutrients, and other chemicals to downstream systems, aquatic communities change in assemblage composition, typically in favor of organisms that can tolerate nutrient and chemical pollution. Sensitive organisms that decrease in abundance in response to these changes may be important food resources or key species in aquatic chemical and biological processes, such as nutrient uptake or fish production.

Inputs of nutrients are a leading cause of impairment of freshwater and coastal ecosystems, in part due to corn and soybean production.[277] Corn production requires greater application of nitrogen fertilizer compared to soy production because soy plants develop root nodules with bacteria that can fix nitrogen from the atmosphere (Table 3.4.2.1-1). EPA's National Aquatic Resource Surveys assess the quality of the nation's freshwater and coastal ecosystems, including biological condition usually derived from the abundance of pollution-tolerant and pollution-sensitive benthic macroinvertebrate taxa[278] and fish.[279] As of 2014, nearly half (44%) of the nation's river- and stream-miles were in poor biological condition and about 30% were in good condition based on benthic macroinvertebrate indicators, and while 37% were

[275] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[276] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[277] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[278] Benthic macroinvertebrate taxa are small, bottom-dwelling, aquatic animals and the aquatic larval stages of insects. EPA, National Aquatic Resource Survey: Indicators: Benthic Macroinvertebrates, available at https://www.epa.gov/national-aquatic-resource-surveys/indicators-benthic-macroinvertebrates#:~:text=What%20are%20benthic%20macroinvertebrates%3F,snails%2C%20worms%2C%20and%20beetles (last accessed April 14, 2021).

[279] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

in poor condition and 26% were in good condition based on fish species indicators.[280] The leading problems contributing to poor biological condition were excess nutrients (especially phosphorus), loss of shoreline vegetation, and excess sediments.[281] For rivers and streams, sites with a condition rating of poor because of excess nutrients were most prevalent in the mid-continent ecoregions[282] of the nation compared to the eastern and western regions.[283] Agriculture is the dominant land use in the Mississippi River basin. As of 2012, 31% of the nation's lakes were rated as having poor biological condition, over 35% had excess nutrient concentrations, and nearly 10% of lakes had greater concentrations of cyanobacterial cells and the algal toxin microcystin compared to 2007.[284] For lakes, disturbance by nutrients varied by ecoregion (Figure 3.4.2.3-1). Northern Plains and Southern Appalachian ecoregions had a higher proportion (67-80% of within-ecoregion lakes) of sites classified as most disturbed by phosphorus pollution and there was a statistically significant increase from 2007 to 2014 in the number of most disturbed lakes in the Northern Appalachian ecoregion. For coastal and Great Lakes nearshore waters (Figure 3.4.2.3-1), phosphorus was again a widespread problem (rating of poor in 21% of sites) and biological condition was poorest along the Northeast coast (rating of poor in 27% of sites), followed by the Great Lakes nearshore waters (rating of poor in 18% of sites).[285] By 2014, the greatest reduction in number of fish species occurred in portions of the Midwest and the Great Lakes, where several watersheds have lost more than 20 species known to occur in those locations prior to 1970.[286]

[280] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

[281] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

[282] The National Rivers and Streams Assessment 2013-2014 defines "ecoregion" as "geographic areas that display similar environmental characteristics, such as climate, vegetation, type of soil, and geology." USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

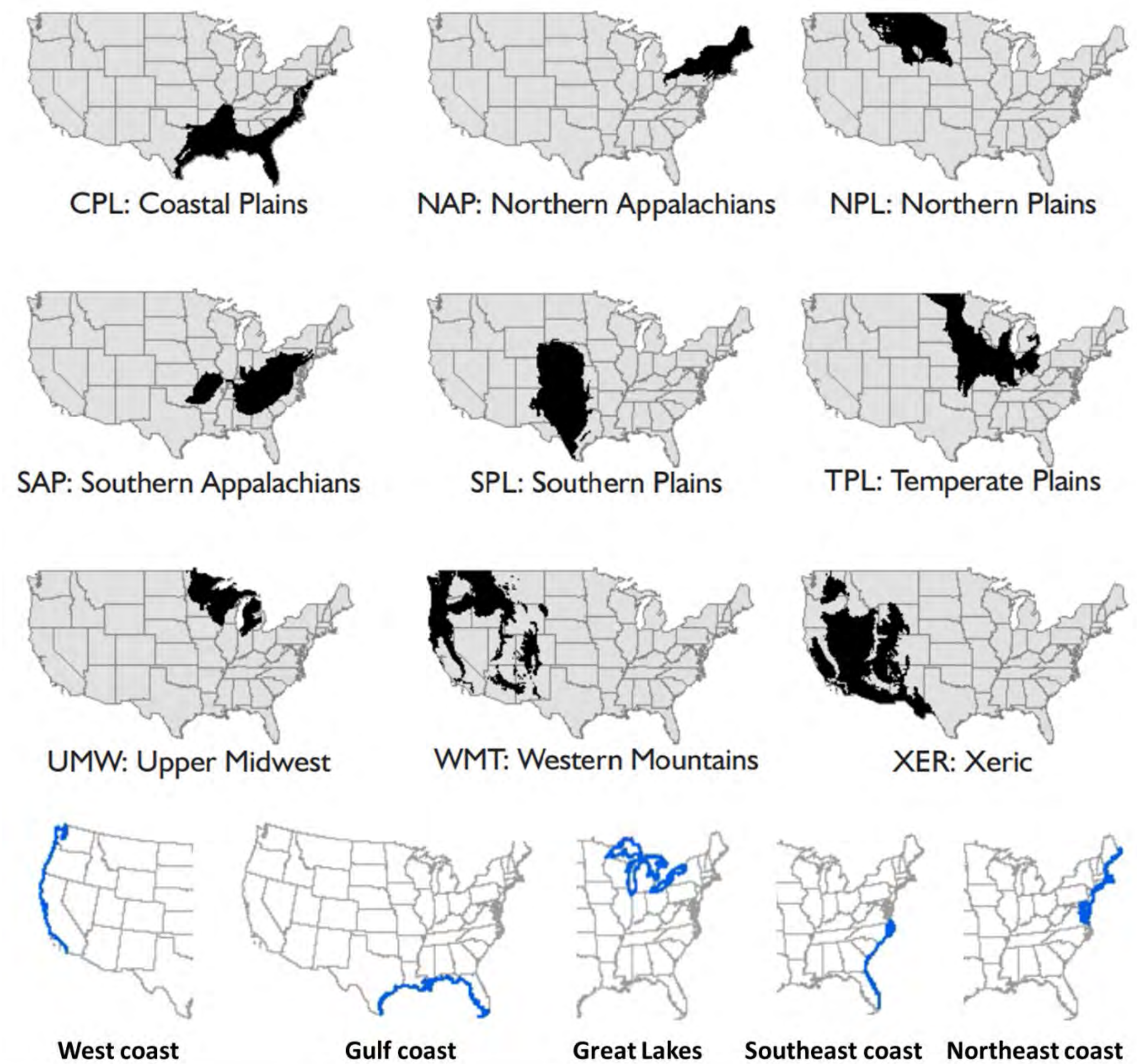
[283] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).

[284] USEPA (2016). National Lakes Assessment 2012: A Collaborative Survey of Lakes in the United States. EPA 841-R-16-113. U.S. Environmental Protection Agency, Washington, DC. Available at https://www.epa.gov/sites/default/files/2016-12/documents/nla_report_dec_2016.pdf (last accessed September 14, 2021).

[285] USEPA (2015). Office of Water and Office of Research and Development. National Coastal Condition Assessment. EPA 841-R-15-006. U.S. Environmental Protection Agency, Washington, DC. Available at TO10_NCCA_2010_Summary_Report_Review_Draft_ES_20101029 (epa.gov) (last accessed September 14, 2021).

[286] USEPA. (2015). Report on the Environment. Fish Faunal Intactness. https://cfpub.epa.gov/roe/indicator.cfm?i=84

Figure 3.4.2.3-1: Locations of ecoregions and coastal areas defined by the USEPA's National Aquatic Resource Surveys.[287]



Excess nutrients (both nitrogen and phosphorus)[288] in waterbodies can also result in harmful algal blooms, some of which can produce toxins. Algal blooms, especially cyanobacteria, can create surface scums that block sunlight and reduce the growth of other algae and aquatic plants. Because of potential toxin production and composition of fatty acids in their cells, cyanobacteria are lower quality food for aquatic insects and fish compared to other algae such as diatoms. Lakes and reservoirs with excess nutrient loads are susceptible to recurring

[287] Figures modified from Figure 5.1 in Ecoregions at a Glance in the National Lakes Assessment 2012. USEPA (2016). National Lakes Assessment 2012. EPA 841-R-16-113 and from USEPA (2015) National Coastal Condition Assessments 2010. EPA 841-R-15-006. U.S. Environmental Protection Agency, Washington, DC.

[288] Paerl, H.W., Scott, J.T., McCarthy, M.J., Newell, S.E., Gardner, W.S., Havens, K.E., Hoffman, D.K., Wilhelm, S.W. and Wurtsbaugh, W.A. (2016). It takes two to tango: When and where dual nutrient (N & P) reductions are needed to protect lakes and downstream ecosystems. Environmental science & technology, 50(20): 10805-10813.

algal blooms. The western Lake Erie is a good example as it receives nutrient loads from a drainage area dominated by agricultural land use. Larger streams and rivers are often associated with nutrient loading from nearby agricultural activities, as well as slower water flow rates and longer residence times favorable for algal blooms.

In both freshwater and coastal marine systems, algal blooms terminate with microbial decomposition of algal cells resulting in oxygen depletion or hypoxic zones. The 2017 Gulf of Mexico hypoxic zone was the largest size measured since 1985, spanning 8,776 square miles.[289] Hypoxic zones result in the death of fish and other organisms that need oxygen to live. Along lake shorelines, blooms of filamentous green algae such as *Cladophora* harbor potentially pathogenic bacteria and foul recreational beaches when the algae proliferate and decay.[290] While fertilizer use by current agricultural practices contribute to much of the nutrient loading that stimulates algal responses in many waterbodies, the total nutrient budgets[291] of some waterbodies also include internal nutrient recycling of legacy inputs.[292]

In addition to nutrients, pesticides from corn and soybeans can also have deleterious effects on aquatic life. Toxicological studies of glyphosate on fish have measured mainly sublethal effects, such as DNA damage[293] in organ tissues and altered muscle and brain function.[294] Some bacteria can use glyphosate for growth, enhancing microbial proliferation.[295] There are cyanobacteria with natural tolerance to glyphosate[296] and certain concentrations of glyphosate can stimulate photosynthesis in a common bloom-forming taxon, *Microcystis aeruginosa*.[297] There is a notable link between glyphosate and phosphorus because more than 18% of glyphosate acid by mass is phosphorus. Glyphosate has chemical similarities with phosphate ions (competing for the same sorption sites in soil), and glyphosate rapidly degrades

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[289] Louisiana Universities Marine Consortium (2017). August 2, 2017 Summary. Shelfwide Cruise: July 24 - July 31. https://gulfhypoxia.net/research/shelfwide-cruise/?y=2017&p=press_release. USNOAA (2019). Large 'dead zone' measured in Gulf of Mexico. Available at https://www.noaa.gov/media-release/large-dead-zone-measured-in-gulf-of-mexico (last accessed April 14, 2021).

[290] Ibsen, M., Fernando, D.M., Kumar, A. and Kirkwood, A.E. (2017). Prevalence of antibiotic resistance genes in bacterial communities associated with *Cladophora glomerata* mats along the nearshore of Lake Ontario. Canadian Journal of Microbiology 63(5): 439–449.

[291] "A nutrient budget quantifies the amount of nutrients imported to and exported from a system []. The budget is considered in balance if inputs and outputs are equal. Nutrient budgets can be calculated at any scale, such as a farm, a county, a watershed, a state, or a country." Amy L. Shober, George Hochmuth, and Christine Wiese (2011). "An Overview of nutrient budgets for use in nutrient management planning." University of Florida IFAS Extension SL361. Available at https://edis.ifas.ufl.edu/pdffiles/SS/SS56200.pdf (last accessed April 14, 2021).

[292] Chen, D., Shen, H., Hu, M., Wang, J., Zhang, Y. and Dahlgren, R.A. (2018). Legacy nutrient dynamics at the watershed scale: principles, modeling, and implications. In: Advances in Agronomy. Ed: Donald L. Sparks. 149: 237-313. Academic Press. Cambridge, MA.

[293] Guilherme, S., Gaivão, I., Santos, M.A. and Pacheco, M. (2012). DNA damage in fish (*Anguilla anguilla*) exposed to a glyphosate-based herbicide–elucidation of organ-specificity and the role of oxidative stress. Mutation Research/Genetic Toxicology and Environmental Mutagenesis, 743(1-2): 1–9.

[294] Modesto, K.A. and Martinez, C.B. (2010). Roundup® causes oxidative stress in liver and inhibits acetylcholinesterase in muscle and brain of the fish *Prochilodus lineatus.* Chemosphere, 78(3): 294–299.

[295] Hove-Jensen B, Zechel DL, and Jochlmsen B. (2014). Utilization of glyphosate as phosphate source: biochemistry and genetics of bacterial carbon–phosphorus lyase. Microbiol Mol Biol R 78: 176–97.

[296] Harris TD and Smith VH. 2016. Do persistent organic pollutants stimulate cyanobacterial blooms? Inland Waters 6: 124–30.

[297] Qiu, H., Geng, J., Ren, H., Xia, X., Wang, X. and Yu, Y. (2013). Physiological and biochemical responses of *Microcystis aeruginosa* to glyphosate and its Roundup® formulation. Journal of hazardous materials, 248:172-176.

in water and releases phosphorus compounds easily used by organisms for growth. Glyphosate-derived phosphorus has now reached levels in aquatic systems similar to phosphorus derived from detergents prior to legislation banning these products, in part because of negative impacts on aquatic life.[298] In 2014, 58% of U.S. rivers and streams were given a rating of poor for the phosphorus indicator of EPA's National Rivers and Streams Assessment.[299] While both corn and soy production use glyphosate, corn production can also use atrazine (Table 3.4.2.1-1). In 2012, EPA detected atrazine in 30% of lakes, but concentrations rarely reached the EPA level of concern for plants in freshwaters (<1% of lakes).[300] In 2016, EPA concluded that in areas where atrazine use is heaviest (mainly in the Temperate Plains ecoregion, Figure 3.4.2.3-1), there are impacts on aquatic plants and potential chronic risk to fish, amphibians, and aquatic invertebrates; there is a high probability of changes to aquatic plant assemblage structure, function, and primary production at a 60-day average concentration of 3.4 ug L^{-1} and reproductive effects to fish exposed for several weeks to 5 ug L^{-1} atrazine.[301] When there are changes to aquatic plant assemblage structure, function, or productivity, other parts of the food web become at risk because there is reduced food and altered habitat for fish, invertebrates, and birds.

3.4.3 Comparison with Petroleum

Biofuel feedstocks are not the only input to energy production affecting soil and water quality. For comparison, petroleum used to produce gasoline and diesel fuel also impacts soil and water quality, but at different spatial and temporal scales than corn and soy. When comparing the two, it is necessary to consider both the spatial extent of the effects (e.g., the acreage of soil or volume of water impacted) and the time or effort to recover from any effects. While petroleum production may have required less land than agriculture in the U.S. between 2007 and 2011, when considering recovery time or effort, a recent study suggested the effects of petroleum production can be longer lasting and harder to mitigate (e.g., brine or oil contamination in soil or groundwater) than those of biofuel feedstocks on soil and water quality.[302] A full comparison between the effects of the two fuel types of energy feedstocks would need to consider both factors (spatial extent and recovery time or effort), but such an assessment would be expansive and could not be performed on the timeline of this rulemaking.

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[298] Hébert, M.P., Fugère, V. and Gonzalez, A. (2019). The overlooked impact of rising glyphosate use on phosphorus loading in agricultural watersheds. Frontiers in Ecology and the Environment. doi: 10.1002/fee.1985.
[299] USEPA (2020). National Rivers and Streams Assessment 2013-2014: A collaborative Survey. EPA 841-R-19-001. Washington, DC. Available at https://www.epa.gov/national-aquatic-resource-surveys/nrsa (last accessed April 14, 2021).
[300] USEPA (2016). National Lakes Assessment 2012: A Collaborative Survey of Lakes in the United States. EPA 841-R-16-113. U.S. Environmental Protection Agency, Washington, DC.
[301] USEPA (2016). Refined Ecological Risk Assessment for Atrazine. EPA-HQ-OPP-2013-0266. U.S. Environmental Protection Agency, Washington, DC.
[302] Parish ES, Kline KL, Dale VH, Efroymson RA, McBride AC, Johnson TL, Hilliard MR (2012). Comparing Scales of Environmental Effects from Gasoline and Ethanol Production. Env Management: 10.1007/s00267-012-9983-6.

3.4.4 Water Quality and Underground Storage Tanks

Releases from underground storage tank (UST) systems can threaten human health and the environment, contaminating both soil and groundwater. As of September 2020, more than 559,900 UST releases have been confirmed across the United States.[303] One possible cause of an UST releasing fuel to the environment is incompatibility of the UST system with the fuel being stored.

Ensuring UST systems are compatible with the substances they store is essential because USTs contain many components made of different materials. In certain percentages petroleum-biofuel blends are more incompatible with certain materials used in UST system construction than petroleum based fuel without biofuels. The whole UST system – including the tank, piping, containment sumps, pumping equipment, release detection equipment, spill prevention equipment, and overfill prevention equipment – needs to be compatible with the fuel stored to prevent releases to the environment. Compatibility with the substance stored is required for all UST systems under EPA regulations, and storing certain biofuels requires additional actions of UST owners and operators.

Equipment or components incompatible with the fuel stored could harden, soften, swell, or shrink, and could lead to release of fuel to the environment. Examples of observed incompatibility between fuels stored and UST materials include equipment or components such as tanks, piping, or gaskets and seals on ancillary equipment that have become brittle, elongated, thinner, or swollen when compared with their condition when initially installed.

Many of the tanks, piping and ancillary components in the market today may only be compatible with up to 10% ethanol or up to 20% biodiesel. Most currently installed UST systems have at least some components that may not be compatible with fuel blends containing more than 10% ethanol or more than 20% biodiesel. EPA's 2015 UST regulation includes requirements for owners and operators of UST systems storing any regulated substances containing greater than 10% ethanol or greater than 20% biodiesel, or any other substance identified by the implementing agency, to demonstrate their UST system is compatible with those blends of biofuels prior to storing them.[304] In 2021, EPA proposed new regulations intended to strengthen the requirements for the underground storage of fuels to ensure compatibility of new systems with high concentrations of biofuels.[305]

3.4.5 Potential Future Impacts of Annual Volume Requirements

Future soil and water quality impacts associated with biofuel volumes will be driven, in large part, by any associated land use/land cover changes. Assumed increases in biofuel production associated with higher RFS volumes would likely lead to an increase in land used for agriculture globally and in the U.S. compared to lower volumes. There are inherent uncertainties with the scenarios we have investigated, but an increase in cropland acreage would generally be

[303] USEPA (2021). Frequent questions about underground storage tanks. Available at https://www.epa.gov/ust/frequent-questions-about-underground-storage-tanks (last accessed April 14, 2021).
[304] 40 CFR Part 280.
[305] 86 FR 5094 (January 19, 2021).

expected to lead to more negative soil and water quality impacts. As outlined previously, the conversion of non-cropland, such as the extensification of corn and soybeans onto grasslands, has greater negative effects on soil and water quality relative to the conversion of other existing cropland.

Although effects may generally be more negative, the cumulative magnitude of such an increase in soil and water quality impacts is uncertain. The magnitude of effects depends on the feedstocks planted, the types of land used, and management practices, all of which are not directly determined by the RFS standards. Additional factors, such as vegetative barriers, and advances in biotechnology and crop yields, can lessen future impacts. Expanded use of soil amendments (e.g., biochar, manure) also could help counterbalance the removal of organic matter and avoid or reduce the potential negative impacts of corn stover harvesting on soil quality.[306] The additional soil and water quality modeling that would be needed to assess the potential cumulative impacts of future land use changes under each scenario would be expansive and could not be performed on the timeline of this rulemaking.

There is a possibility that some increased adverse impacts to soil and water quality could occur due to the proposed volumes, primarily from the 2022 volume's potential ability to incent greater investment in corn and soybean based biofuels. However, the magnitude of this potential impact cannot be estimated at this time, more information is needed regarding the other factors and the magnitude of the impacts on land use and management changes. The 2020 and 2021 volumes proposed here, however, will likely have no impact, since these volumes, when they are finalized, will be entirely or largely retroactive. There is substantial uncertainty in projecting changes in land use and management associated with corn, soybean, and other crops due to the other factors driving biofuel demand. Additional information and modeling are needed to fully assess the degree to which the annual volume requirements drive land use and management changes that would impact soil and water quality. Such analysis would be expansive and could not be performed on the timeline of this rulemaking.

3.5 Water Quantity and Availability

This section assesses the impact of the production and use of renewable fuels and their primary feedstocks on the use and availability of water in the U.S. We first review the drivers of impacts on water use and availability of freshwater resources, summarize impacts to date, highlight more recent work focused on groundwater supplies, and finally discuss the potential future effects of the proposed RFS volume obligation.

3.5.1 Drivers of Impacts on Water Use and Availability

Water quantity, in the context of renewable fuels, refers to the volume of water used in the production of biomass feedstocks (i.e., irrigation of corn, soybeans or other crops) and the conversion of those feedstocks to biofuel (i.e., water use in the biofuel production plant itself). The irrigation of corn and soybeans used to produce biofuels is the predominant driver of water quantity impact and is generally orders of magnitude greater than water use in the biofuel

[306] Blanco-Canqui H (2013). Crop Residue Removal for Bioenergy Reduces Soil Carbon Pools: How Can We Offset Carbon Losses? Bioenergy Research 6(1): 358-371: 10.1007/s12155-012-9221-3.

production process.[307] The water use for the full biofuels supply chain also has been quantified as significantly higher than the water use for petroleum-based fuels, meaning biofuels are more water intensive on a per gallon of fuel basis. Of concern are the impacts that this water use may have on freshwater supplies and availability. Water intensive corn and soybean production occurs on irrigated acres in states such as Nebraska and Kansas, in particular, the western parts of those states. These states also overlap the High Plains Aquifer (HPA)[308] "where groundwater levels have declined at unsustainable rates."[309]

As noted above, the primary driver of impacts to water quantity is the water used for irrigation of the biofuel feedstocks. To the extent that feedstock production expands into regions where irrigation is required, the demand for water will increase, whether the expansion is a direct consequence of production specifically for biofuel feedstocks or an indirect result of increased production for all feedstock uses. Water demand for biofuel production processes can also drive impacts on water use and availability. Although water demands of biofuel production facilities may be much smaller at a national scale than the water demands of irrigated feedstock production, biofuel facility water use may be locally consequential in areas that are already experiencing stress on water availability.

3.5.2 Life Cycle Water Use of Biofuels

In the Second Triennial Report to Congress on Biofuels, the water quantity impacts of biofuels were assessed.[310] Research investigating the water quantity impacts of biofuels started shortly after the passage of the Energy Policy Act of 2005. Several highly cited and visible articles compared the life cycle water use of biofuels relative to petroleum-based fuels on the basis of "gallons of water per mile" or "gallons of water per gallon of fuel."[311] These early studies characterized this issue as biofuel's water intensity,[312] embodied water,[313] and water footprint.[314] Many studies of the water footprint further divide the consumptive water use into

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[307] Wu M, Zhang Z and Chiu Y-w (2014). Life-cycle Water Quantity and Water Quality Implications of Biofuels. Current Sustainable/Renewable Energy Reports 1(1): 3-10.

[308] The High Plains Aquifer is often referred to as the Ogallala Aquifer, which is the largest formation within the High Plains Aquifer.

[309] Smidt, S. J., Haacker, E. M., Kendall, A. D., Deines, J. M., Pei, L., Cotterman, K. A., ... & Hyndman, D. W. (2016). Complex water management in modern agriculture: Trends in the water-energy-food nexus over the High Plains Aquifer. Science of the Total Environment, 566, 988-1001.

[310] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[311] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[312] King, C. W., & Webber, M. E. (2008). Water intensity of transportation. *Environmental Science & Technology*, 42(21), 7866.

[313] Chiu, Y. W., Walseth, B., & Suh, S. W. (2009). Water embodied in bioethanol in the United States. *Environmental Science & Technology*, 43(8), 2688-2692.

[314] Dominguez-Faus, R., Powers, S. E., Burken, J. G., & Alvarez, P. J. (2009). The water footprint of biofuels: A drink or drive issue? Environmental Science & Technology 43(9): 3005-3010: 10.1021/es802162x; Scown, C. D., Horvath, A., & McKone, T. E. (2011). Water footprint of US transportation fuels. *Environmental Science & Technology*. 45(7), 2541-2553.

two components: *blue* water (ground and surface water) and *green* water (rainwater).[315] Most of the focus of life cycle analyses (LCAs) has been on blue water or irrigation requirements for crop production, as well as other freshwater use for biofuel conversion processes. When comparing different transportation energy sources, Scown et al. (2011) found ethanol from corn-based feedstocks to be one of the most significant users of freshwater.[316] The same study calculated the gallons of water consumed per mile of travel and found that the full life cycle water footprint of ethanol produced from corn grain and stover (using average irrigation rates) would require almost seven times as much surface water consumption as any other transportation power source and an order of magnitude more groundwater consumption when compared to other transportation energy sources.[317]

3.5.2.1 Life Cycle Water Use: Feedstock Production

Researchers have continued to refine the LCA-based water footprint of biofuels with a focus on feedstock production – for both current biofuels crops and future feedstocks. Because more than 90% of corn is grown in rain-fed areas where corn production is non-irrigated, Wu et al. (2014) suggested that, at the highly aggregated level, the "national water footprint of corn is consistently low to modest."[318] However, water quantity demands depend on the crops grown, where they are grown, and how they are grown. In terms of differences among feedstocks, Dominguez-Faus et al. (2009) calculated the irrigation water required for corn-based ethanol at an average of approximately 600 liters (approximately 158.5 gallons) of water per liter of ethanol produced (liter/liter).[319] Much of the focus has been on corn ethanol, due to the higher volumes of corn ethanol produced to date. However, in the same article, Dominguez-Faus et al. estimated that irrigated soybean based biodiesel water requirement averaged nearly 1,300 liters of water per liter of ethanol-equivalent biodiesel (based on energy equivalence).[320] These values all represent an upper end estimate of water demands, if fuels are made from irrigated crops.

However, where and how crops are grown also matter because irrigation rates for the same crops can vary enormously based on where they are cultivated: from no irrigation in rain-fed acres in the Midwest to high irrigation rates in more arid regions in the West. Dominguez-Faus et al. (2013) calculated a range of irrigation water use for corn ethanol between 350 and 1400 gal/gal.[321] That study estimated that if 20% of corn production was used to produce 12

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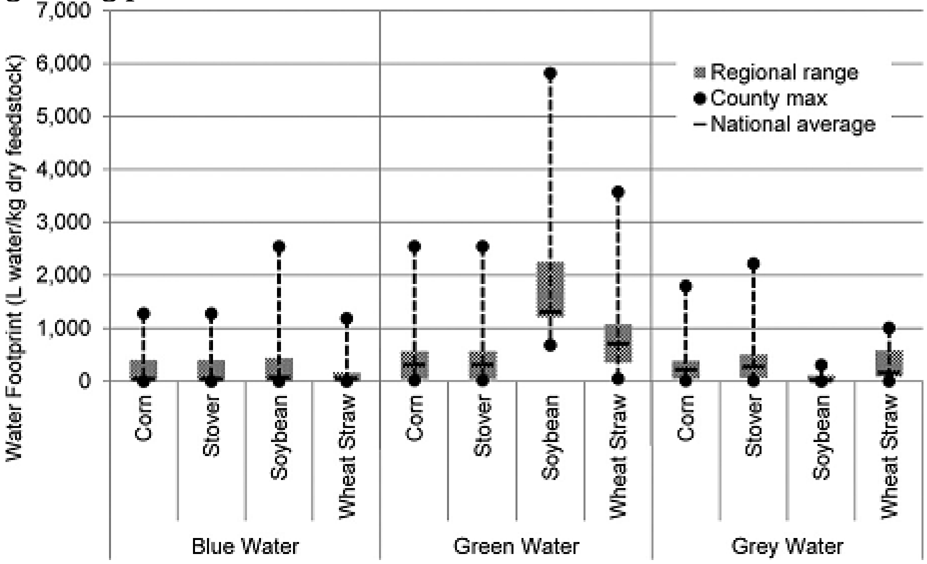
[315] Another category is the *grey* water footprint, which is the volume of water required to assimilate pollutant loads, such as excess nitrogen. Topics relating to grey water are covered in the water quality section. *See* Hoekstra, A. Y., & Mekonnen, M. M. (2012). The water footprint of humanity. *Proceedings of the national academy of sciences*, 109(9), 3232-3237.
[316] Scown CD, Horvath A and McKone TE (2011). Water Footprint of U.S. Transportation Fuels. Environmental Science & Technology 45(7): 2541-2553: 10.1021/es102633h.
[317] Scown CD, Horvath A and McKone TE (2011). Water Footprint of U.S. Transportation Fuels. Environmental Science & Technology 45(7): 2541-2553: 10.1021/es102633h.
[318] Wu, M., Zhang, Z., & Chiu, Y. W. (2014). Life-cycle water quantity and water quality implications of biofuels. *Current Sustainable/Renewable Energy Reports*, 1(1), 3-10.
[319] Dominguez-Faus R, Powers SE, Burken JG and Alvarez PJ (2009). The Water Footprint of Biofuels: A Drink or Drive Issue? Environmental Science & Technology 43(9): 3005-3010: 10.1021/es802162x.
[320] Dominguez-Faus R, Powers SE, Burken JG and Alvarez PJ (2009). The Water Footprint of Biofuels: A Drink or Drive Issue? Environmental Science & Technology 43(9): 3005-3010: 10.1021/es802162x.
[321] Dominguez-Faus, R., Folberth, C., Liu, J., Jaffe, A. M., & Alvarez, P. J. (2013). Climate change would increase the water intensity of irrigated corn ethanol. *Environmental science & technology*, 47(11), 6030-6037.

billion gallons per year of ethanol in 2011 (irrigated at a weighted average of 800 gal/gal), that would amount to 1.8 trillion gallons of irrigation water withdrawals per year. While not an insignificant amount, it represents only 4.4% of all irrigation withdrawals.[322] Other researchers have similarly focused on the wide range of water intensity estimates between rain-fed and irrigated counties and among a variety of crops (see Figure 3.5.2.1-1). Gerbens-Leenes et al. (2012) estimated Nebraska's blue water (irrigation water) footprint at three times higher than the U.S. weighted average blue water footprint.[323] Many other corn producing states have much smaller irrigation demands relative to Nebraska. Yet, it should be noted that, after Iowa, Nebraska is the second largest producer of corn-based ethanol in the U.S., with 25 active ethanol facilities, many concentrated in southern Nebraska.[324] Additionally, the blue water footprint in areas that have already stressed water sources, like the HPA, could experience more severe water quantity impacts. A report by the National Academy of Sciences (NAS 2011) highlighted the groundwater depletion in the HPA, noting that Nebraska is "among the states with the largest water withdrawals for irrigation, and its usage has continued to increase in recent years, largely driven by the need to irrigate corn for ethanol."[325] This suggests that the majority of groundwater consumption would come from areas like Nebraska that are already impacted by over-pumping due to their high blue water footprint for corn production (Gerbens-Leenes et al. 2012).[326]

[322] Dominguez-Faus R, Folberth C, Liu J, Jaffe AM and Alvarez PJJ (2013). Climate Change Would Increase the Water Intensity of Irrigated Corn Ethanol. Environmental Science & Technology 47(11): 6030-6037: 10.1021/es400435n.
[323] Gerbens-Leenes, W., & Hoekstra, A. Y. (2012). The water footprint of sweeteners and bio-ethanol. *Environment international*, 40, 202-211.
[324] EIA (2018). "Six states account for more than 70% of U.S. fuel ethanol production." Available at https://www.eia.gov/todayinenergy/detail.php?id=36892 (last accessed April 14, 2021). *See also* EIA. (2017, February 16). "Nebraska State Profile and Energy Estimates: Profile Analysis." Retrieved June 2, 2017, from https://www.eia.gov/state/analysis.php?sid=NE.
[325] NAS (2011). Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. National Academy of Sciences. Washington, DC.
[326] Gerbens-Leenes, W., & Hoekstra, A. Y. (2012). The water footprint of sweeteners and bio-ethanol. *Environment international*, 40, 202-211.

Figure 3.5.2.1-1: Estimate of the blue/irrigation, green/rainwater and grey/pollution water footprint associated with corn grain, stover, wheat straw and soybean during the crop growing phase.



The national production-weighted average is represented by the horizontal bar, while the regional ranges (this includes all USDA regions such as the Corn Belt, Southern Plains, etc.) are represented by the shaded bars. County-level variation in feedstock water footprints, shown in dashed lines, are driven by differences in irrigation and evapotranspiration (ET). The circles show both "County max" as well as "County min." [Source: Chiu and Wu (2012)].

3.5.2.2 Life Cycle Water Use: Biofuel Conversion

Studies of water use at biofuels conversion facilities have generally quantified water consumption as gallons of water per gallon of biofuel produced, mostly concentrating on ethanol, especially dry mill facilities.[327] Process level engineering studies and surveys of ethanol facilities have shown declines in water requirements from 5.8 gallons of water per gallon of ethanol (gal/gal) in 1998 to 2.7 gal/gal in 2012.[328] These values are typical of a dry mill facility. Wet mill facilities require closer to 4 gallons per gallon of ethanol.[329] Some reports also point to reductions in the water intensity of ethanol facilities through more efficient water use and recovery, and reuse of wastewater after treatment for processes such as fermentation or possibly cooling towers.[330] Some facilities have set goals to both reduce water use and minimize discharges.

[327] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[328] Mueller S (2010). 2008 National dry mill corn ethanol survey. Biotechnology Letters 32(9): 1261-1264: 10.1007/s10529-010-0296-7. and Wu Y and Liu S (2012). Impacts of biofuels production alternatives on water quantity and quality in the Iowa River Basin. Biomass and Bioenergy 36: 182-191: 10.1016/j.biombioe.2011.10.030. *See also* Wu Y and Liu S (2012b). Impacts of biofuels production alternatives on water quantity and quality in the Iowa River Basin. Biomass and Bioenergy 36: 182-191: 10.1016/j.biombioe.2011.10.030.

[329] Grubert, E. A., & Sanders, K. T. (2018). Water use in the US energy system: A national assessment and unit process inventory of water consumption and withdrawals. Environmental science & technology.

[330] Schill, S. R. (2017) Water: Lifeblood of the Process. *Ethanol Producer Magazine*. January 24, 2017. http://www.ethanolproducer.com/articles/14049/water-lifeblood-of-the-process. See also Jessen, H. (2012) Dropping

Biodiesel conversion from oil crops such as soybeans requires water use for multiple stages of the process (crop to oil, and oil to biodiesel). The soybean processing (crop to oil) stage involves crushing, oil extraction and crude soybean oil refining (degumming). Water consumption includes make-up water for cooling towers and other processes. In the biodiesel production stage (oil to biodiesel), following the crushing and oil extraction steps, water is used to remove residual glycerol, a by-product of the transesterification process, and other impurities, while some water is also for additional make-up water for cooling towers.[331] Tu et al. (2016) estimated that the water footprint of soybean based biodiesel to be under 1 gal/gal biodiesel (0.17 for crop to oil and 0.31 for oil to biodiesel).[332]

There are no recently published surveys of water consumption representing all current biofuel facilities, and no comprehensive data on the type of water sources utilized (e.g., groundwater, surface freshwater, public supply, etc.). Grubert and Sanders estimate that the majority of the water used is freshwater. There is also some evidence that groundwater from aquifers is being extracted for use in ethanol production in states such as Iowa and Nebraska,[333] and likely a source of water for facilities along the HPA (see Figure 3.5.3-3 below).

3.5.2.3 Life Cycle Water Use: Summary and Comparison to Petroleum

Improvements in irrigation have brought down the upper range of water use, with updated estimates of irrigation for corn production ranging from 9.7 gal/gal ethanol for USDA Region 5 (Iowa, Indiana, Illinois, Ohio and Missouri) to 220.2 gal/gal ethanol in Region 7 (North Dakota, South Dakota, Nebraska and Kansas) for groundwater.[334] The conversion of corn to ethanol requires 2-10 gal/gal for processing, with most dry mill plants requiring roughly 3 gal/gal. When averaging production over all regions, and accounting for co-products of ethanol production (such as distillers dried grain and solubles), the range for full life cycle consumptive water use for U.S. corn ethanol is 8.7 - 160.0 gal/gal ethanol based on the updated analysis by Wu et al (2018). By comparison, the most recent estimates of the net consumptive water use over the petroleum-based fuel life cycle would be in the range of 1.4 - 8.6 gallons of water per gallon of gasoline based on U.S. conventional crude.[335] The Wu et al (2018) analysis does not include biodiesel. The most recent estimate for the full LCA water consumption for biodiesel provides a range of values for each state: Missouri 21-79 gal water/gal biodiesel, Kansas and Oklahoma 80-

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Water Use. *Ethanol Producer Magazine*. June 12, 2012. Available at http://www.ethanolproducer.com/articles/8860/dropping-water-use (last accessed September 16, 2021).

[331] Tu, Q., Lu, M., Yang, Y. J., and D. Scott (2016) Water consumption estimates of the biodiesel process in the US. *Clean Technologies and Environmental Policy*. 18(2): 507-516.

[332] Tu, Q., Lu, M., Yang, Y. J., and D. Scott (2016) Water consumption estimates of the biodiesel process in the US. *Clean Technologies and Environmental Policy*. 18(2): 507-516.

[333] Schilling, K. E., Jacobson, P. J., Libra, R. D., Gannon, J. M., Langel, R. J., & Peate, D. W. (2017). Estimating groundwater age in the Cambrian–Ordovician aquifer in Iowa: implications for biofuel production and other water uses. Environmental Earth Sciences, 76(1), 2. *See also* Gerbens-Leenes, W., & Hoekstra, A. Y. (2012). The water footprint of sweeteners and bio-ethanol. *Environment international*, 40, 202-211.

[334] Wu, M., & Xu, H. (2018*). Consumptive Water Use in the Production of Ethanol and Petroleum Gasoline—2018 Update* (No. ANL/ESD/09-1 Rev. 2). Argonne National Lab.(ANL), Argonne, IL (United States). https://publications.anl.gov/anlpubs/2019/01/148043.pdf

[335] Id.

150 gal/gal, Nebraska and Texas 150-300 gal/gal.[336] In summary, while values will vary across states and counties, both ethanol and biodiesel are substantially more water intensive than the petroleum fuels they would displace.

3.5.3 Impacts to Date

Because the majority of the growth in biofuels production has come from corn- and soy-based biofuels, the water consumption impacts to date would have come from additional water use for corn and soybean acreage. To our knowledge, there have been no comprehensive studies of the changes in irrigated acres, rates of irrigation, or changes in surface and groundwater supplies attributed specifically to the increased production of corn grain-based ethanol and soybean-based biodiesel. There are, however, studies that can give some indication of how changes in production of these biofuels may have affected water demand and availability. The Second Triennial Report to Congress on Biofuels highlights analyses in Lark et al. (2015) and Wright et al. (2017) that show changes in land use, including cropland expansion in the western Dakotas and Kansas, related to biofuels.[337] These are areas unlikely to have sufficient precipitation to support corn or soybean cultivation.[338] While difficult to attribute how much additional water use might be required as a result of the volumes proposed in this rule, there are several lines of evidence that suggest increased production of corn-based ethanol and soybean-based biodiesel will increase water demands and, potentially, affect limited water supplies.

The USDA Irrigation and Water Management Surveys (formerly the Farm and Ranch Irrigation Survey or FRIS), a supplement to the Census of Agriculture completed every five years, provide a general indication of the changes in water demands between 2013 and 2018.[339] From 2013 to 2018, there was an increase in total irrigated acres of nearly 0.6 million acres in the U.S.[340] Over the same period, irrigated acres of corn for grain and seed decreased from 13.3 million acres to 11.6 million acres harvested, along with a lower irrigation rate of 0.9 acre-feet applied in 2018 compared to 1.1 acre-feet applied in 2013.[341] Over the same time period, irrigated acres of soybeans increased from 7.4 to 8.2 million acres harvested, while average acre-

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[336] Tu, Q., Lu, M., Yang, Y. J., and D. Scott (2016). Water consumption estimates of the biodiesel process in the US. *Clean Technologies and Environmental Policy*. 18(2): 507-516.

[337] U.S. EPA (2018). Biofuels and the Environment: Second Triennial Report to Congress. U.S. Environmental Protection Agency, EPA/600/R-18/195: 159 pp. Washington, DC, June.

[338] Lark TJ, Salmon JM and Gibbs HK (2015). Cropland expansion outpaces agricultural and biofuel policies in the United States. Environmental Research Letters 10(4): 10.1088/1748-9326/10/4/044003. and Wright, C. K., et al. (2017). "Recent grassland losses are concentrated around US ethanol refineries." Environmental Research Letters 12(4).

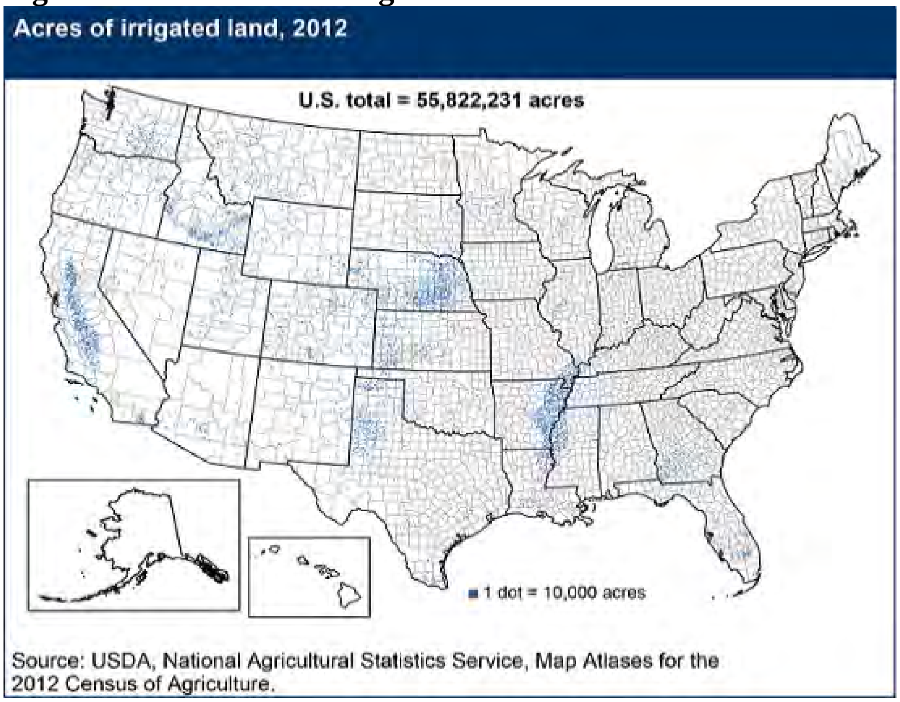
[339] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

[340] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

[341] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

feet applied declined from 0.9 to 0.6 per acre.[342] Figure 3.5.3-1 shows acres of irrigated land in 2012, the most recent year of data for which this figure is available.

Figure 3.5.3-1: Acres of irrigated land in 2012

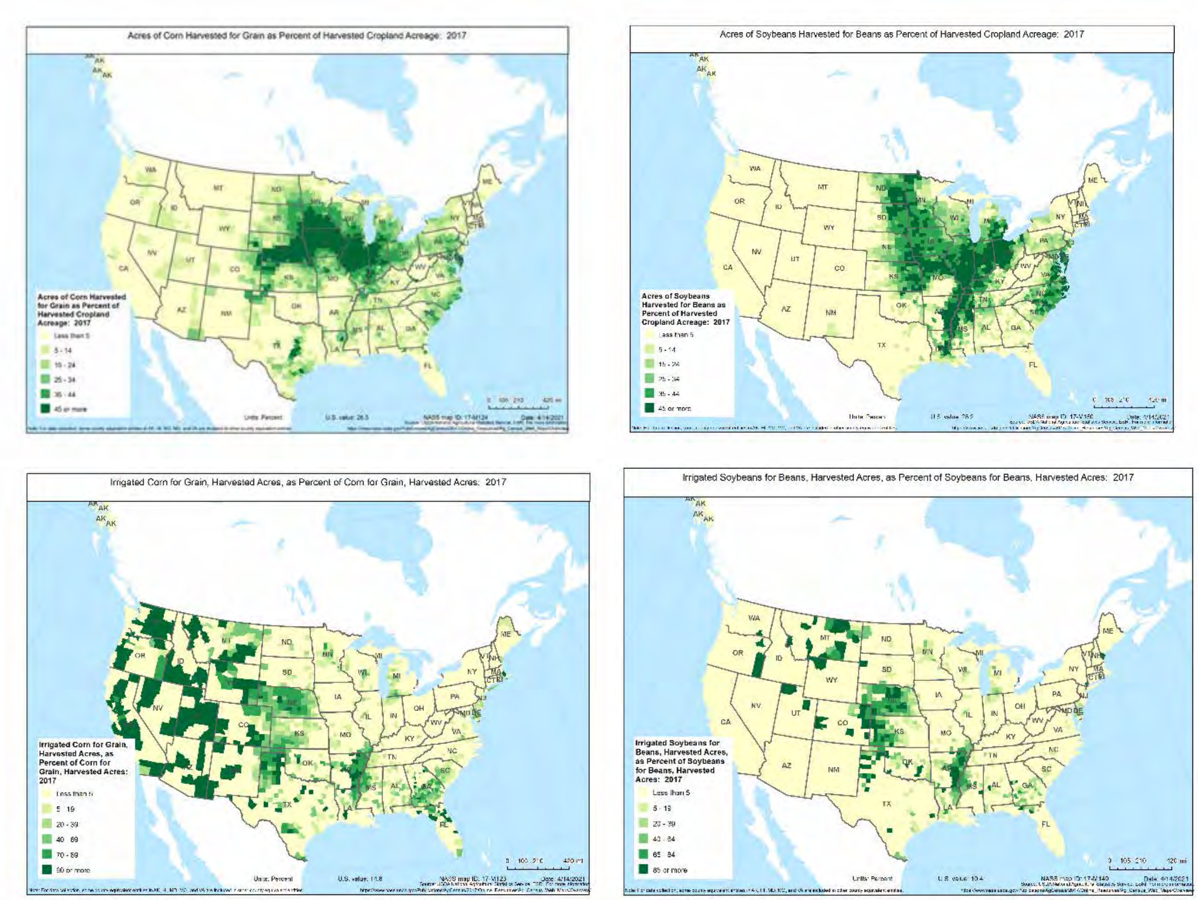


Based on the USDA Farm and Ranch Irrigation Survey. Source: https://www.ers.usda.gov/topics/farm-practices-management/irrigation-water-use/background.aspx

Figure 3.5.3-2 shows corn and soybean areas and share of irrigated acres. Irrigated corn grain/seed acres are heavily concentrated in Nebraska (4.5 million acres) followed by Kansas (1.3 million acres). This is a decrease of 0.9 and 0.2 million acres respectively from 2012 to 2018. Irrigated soybean acres are also found in Nebraska, Kansas, particularly the more western part of those states. Overall soybean production is generally more concentrated (as a share of total harvested cropland) in rainfed areas, whereas corn production reaches further west. There is also a high percentage of soybean acres in Arkansas and Mississippi, with a large share of those soybean acres being irrigated. The top rows of Figure 3.5.3-2 below show the distribution of corn and soybean acres, as a share of total cropland acres, while the bottom rows of Figure 3.5.3-2 shows the percent of irrigated corn and soybean acres relative to total acres for those crops (measures as harvested acres).

[342] USDA NASS (2018). 2018 Irrigation and Water Management Survey. Available at https://www.nass.usda.gov/Publications/AgCensus/2017/Online_Resources/Farm_and_Ranch_Irrigation_Survey/fris.pdf (last accessed April 14, 2021).

Figure 3.5.3-2: Percent of irrigated corn and soybean acres relative to total acres, respectively



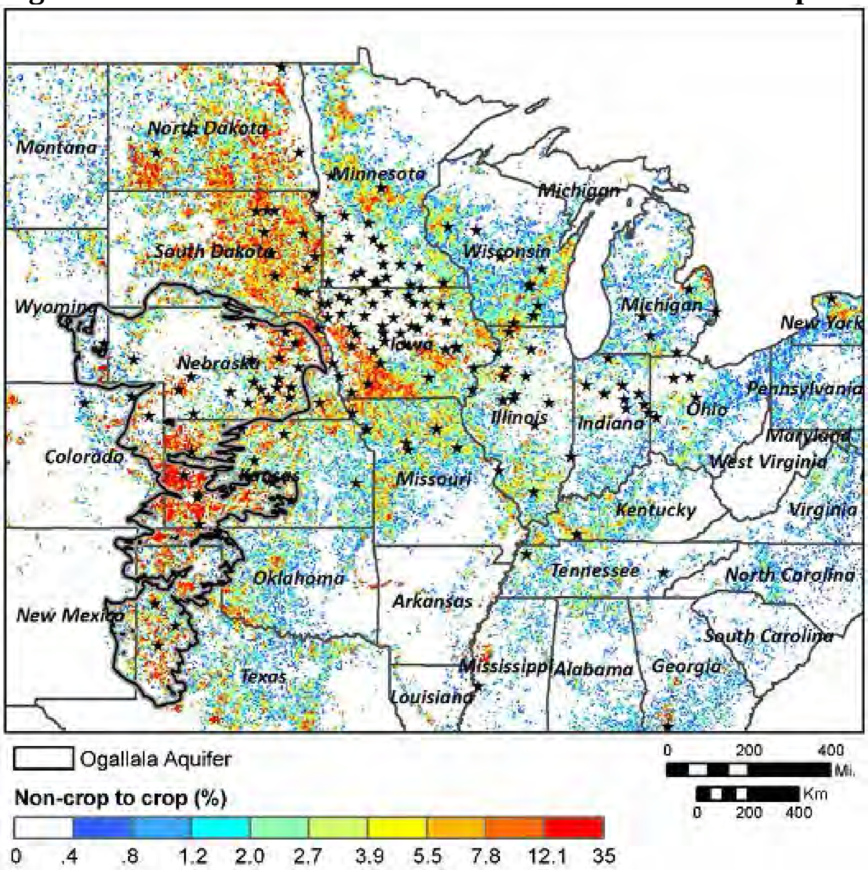
Top Left: Acres of Corn Harvested as a Percent of Harvested Cropland Acreage; Top Right: (b) Acres of Soybean Harvested as a Percent of Harvested Cropland Acreage; Bottom left: Irrigated Corn as a Percent of Total Corn (Harvested Acres), Irrigated Soybeans as a Percent of Total Soybeans (Harvested Acres).
Source: USDA Agricultural Census Web Maps (Accessed April 14, 2021).
https://www.nass.usda.gov/Publications/AgCensus/2012/Online_Resources/Ag_Census_Web_Maps/index.php

Higher irrigation demands may coincide with areas of already-stressed surface and groundwater resources, such as the HPA (also called the Ogallala Aquifer). A 2011 report by the National Academy of Sciences highlighted the groundwater drawdown in the HPA, noting that Nebraska is “among the states with the largest water withdrawals for irrigation, and its usage has continued to increase in recent years, largely driven by the need to irrigate corn for ethanol.”[343] This suggests that the majority of groundwater consumption would come from areas like Nebraska, which are already impacted by over-pumping due to their high blue water footprint for corn production. Changes in irrigation practices are dependent on a number of economic and agronomic factors that affect how land is managed, making it difficult to attribute expanded irrigation to biofuels production and use without more detailed analysis. A study by Wright et al. (2017) of land use change rates noted that “along the Ogallala Aquifer, elevated rates of land use

[343] NAS (2011). Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. National Academy of Sciences. Washington, DC.

change to corn production in Western Kansas, Oklahoma and Texas coincided with areas experiencing groundwater depletion rates ranging from 5-20% per decade" (see Figure 3.5.3-3). However, this does not necessarily establish a direct, causal relationship between biofuel production and groundwater depletion.

Figure 3.5.3-3: Relative conversion rates of arable non-cropland to cropland (2008-2012).



Includes conversion located along the Ogallala aquifer. Stars denote biofuel production facilities. (Source: Wright et al. 2017)

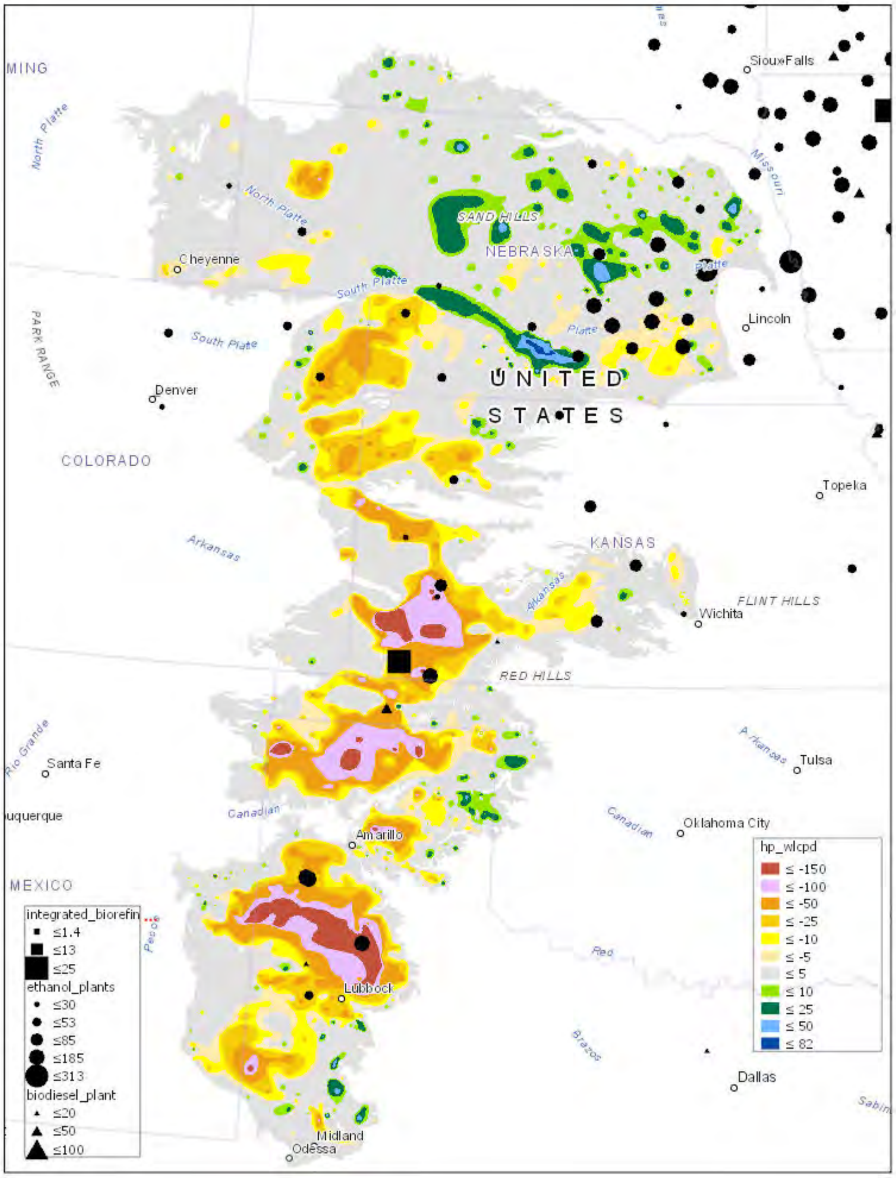
As stated above, there have been no comprehensive studies of the changes in irrigated acres, rates of irrigation, or changes in surface and groundwater supplies attributed specifically to the increased production of corn grain-based ethanol and soybean-based biodiesel. In the absence of analyses that do focus directly on crops for biofuel production, there are studies that look more broadly at the connection between agricultural water use and groundwater levels. For example, Smidt et al. (2016) analyzed the water-energy-food nexus over the HPA to look at the major drivers that have affected and will continue to affect agriculture's water use. That study highlights that, across large portions of the HPA, "groundwater levels have declined at unsustainable rates despite improvements in both the efficiency of water use and water productivity in agricultural practices."[344] Figure 3.5.3-3, above, shows the relative conversion rates of arable cropland to non-cropland, as well as the location of the HPA and biofuel

[344] Smidt, S. J., Haacker, E. M., Kendall, A. D., Deines, J. M., Pei, L., Cotterman, K. A., … & Hyndman, D. W. (2016). Complex water management in modern agriculture: Trends in the water-energy-food nexus over the High Plains Aquifer. Science of the Total Environment, 566, 988-1001.

conversion facilities. Figure 3.5.3-4, below, also shows the HPA, but shows the absolute changes in groundwater levels, from predevelopment to 2017 based on data from USGS.[345] The HPA can be divided into three geographical regions – the Northern, Central, and Southern High Plains. The Northern HPA groundwater supplies have been relatively stable since predevelopment (with some increases shown in green/blue), whereas the Central and Southern HPAs have seen substantial declines, in some areas over 150 ft of declines (shown in yellow/orange/red). Biofuel facility locations (from the National Renewable Energy Laboratory[346]) are overlaid onto the HPA data from USGS to highlight where biofuel production facilities are co-located with areas of changes in the groundwater levels. Again, while the Central and Southern HPAs have seen substantial declines, the Northern HPA has remained relatively stable and even increased in some areas (as shown in Figure 3.5.3-4). This does not demonstrate that biofuel production causes declines in groundwater levels, but it does show that some biofuel facilities operate in areas that are experiencing water-stressed aquifer resources.

[345] The predevelopment water level is defined as "the water level in the aquifer before extensive groundwater pumping for irrigation, or about 1950. The predevelopment water level was generally estimated by using the earliest water-level measurement in more than 20,000 wells." https://ne.water.usgs.gov/projects/HPA/index.html
[346] https://maps.nrel.gov/biofuels-atlas/

Figure 3.5.3-4: Water-level changes in the High Plains Aquifer, predevelopment (about 1950) to 2015.



Water levels changes in feet, yellows and reds represent decreases in groundwater levels while greens and blue represent rises in groundwater levels. Grey indicated no substantial change. Data from U.S. Geological Survey (USGS). Ethanol plants, biodiesel plans, and integrated biorefineries size (based on annual capacity) and location from the Bioenergy Atlas, maintained by NREL. https://maps.nrel.gov/biofuels-atlas/

3.5.3.1 Crop Prices and Value of Irrigation

Recent research has also assessed the linkage between crop prices and irrigation rates to find the irrigation values ($/ha/mm) which reflect the price incentive to irrigate. Comparing the value of irrigation across commodities, Smidt et al (2017) found that the highest value was for corn. The value of irrigation was lower for soybeans.[347] The high value of irrigation for corn is due to the large yield increases that occur with irrigation for corn, as well as the high water-use efficiency. This indicates that higher corn prices will increase the incentives to irrigation, and, conversely, lower corn prices may lead to decreases in acres and rates of irrigation. The same would hold true for soy– higher prices for soybeans incentivizing more irrigation, lower prices leading to less irrigation. Though the impact would be smaller than it would be from an increase in corn cultivation, since soybeans generally require less irrigation than does corn.

Earlier work also looked at the impact of agricultural commodity prices on irrigation demands by taking an economic-based approach that calculated the price elasticities of irrigation water demands.[348] More recent work by Deines et al (2017) utilized satellite images to produce annual maps of irrigation for 1999-2016 to study changes in irrigation over time.[349] In addition to looking at changes in the area and location of irrigated fields, Deines et al (2017) also did statistical modeling to assess how factors such as precipitation and commodity prices influenced the extent of irrigation. That study confirmed that "farmers expanded irrigation when crop prices were high to increase crop yield and profit."[350]

3.5.3.2 Non-Cropland Biofuels and Non-U.S. Crops

The Second Triennial Report to Congress on Biofuels and the published research on the water quantity impacts of biofuels generally do not report or estimate water used for production of non-cropland biofuels or impacts outside of the U.S. However, some of the changes in volumes are associated biogas or palm-based biofuels. We will therefore briefly describe biogas here while palm oil water demands are be discussed in section 2.6 of the Second Triennial Report.

Biogas does not have the irrigation requirements associated with crop-based biofuels. Because their inventory covers all of the U.S. energy system at a high level of detail (including 126 unit processes), Grubert and Sanders (2018) examined whether there were any water consumption and withdrawals for biogas from landfills, wastewater and animal manure digesters.[351] For biogas, they reported no water requirements. Since the biogas is a byproduct of wastes (i.e., landfills, manure, and wastewater), none of the water used for the primary products (e.g., the agricultural operations that produced the manure) is allocated to the produced biogas. In the case of landfill biogas, we therefore assume no significant amounts of water are used. Grubert and Sanders also assume negligible water requirements for the processing and

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[347] Smidt, S. J., Haacker, E. M., Kendall, A. D., Deines, J. M., Pei, L., Cotterman, K. A., ... & Hyndman, D. W. (2016). Complex water management in modern agriculture: Trends in the water-energy-food nexus over the High Plains Aquifer. Science of the Total Environment, 566, 988-1001.
[348] See for example, Scheierling, S. M., Loomis, J. B., & Young, R. A. (2006). Irrigation water demand: A meta-analysis of price elasticities. *Water resources research*, 42(1).
[349] Deines, J.M., Kendall, A.D., and Hyndman, D.W. (2017). Annual Irrigation Dynamics in the U.S. Northern High Plains Derives from Landsat Satellite Data. *Geophysical Research Letters 44*, 9350-9360.
[350] Deines, J.M., Kendall, A.D., and Hyndman, D.W. (2017). Annual Irrigation Dynamics in the U.S. Northern High Plains Derives from Landsat Satellite Data. *Geophysical Research Letters 44*, 9350-9360.
[351] Grubert, E., & Sanders, K. (2018). Water Use in the United States Energy System: A National Assessment and Unit Process Inventory of Water Consumption and Withdrawals. *Environmental Science & Technology* 52(11), 6695-6703.

transportation of biogas, although they note that some water may be used for upgrading biogas if water-intensive amine scrubbing is used.

3.5.4 Potential Future Impacts of Annual Volume Requirements

Most of the available research looks at the past and potential future water quantity and availability impacts associated with increased use of corn ethanol, and in some instances, cellulosic biofuels. Because of the high volumes of corn ethanol produced to date, the water quantity and availability concerns have been focused on corn ethanol, with less focus on soy biodiesel. The changes in mandatory volumes under this rule and future rules are different from the scenarios analyzed in the literature published to date. Studies on future water quantity impacts often project larger changes for corn ethanol[352] or focus on future cellulosic feedstocks.[353] Thus, the water quantity impacts due to this rule are difficult to quantify based on the existing literature. That said, there are several ways to assess the impacts of the volume scenarios, based on the studies reviewed above. We summarize these approaches and how they would be used to estimate the impacts for different scenarios.

First, we can assess potential water demand changes based on volume changes by biofuel type as summarized in section 3.3 of the Second Triennial Report to Congress on Biofuels. All else being equal, the life cycle water consumption of ethanol and biodiesel (derived from soybeans and likely palm) is higher, sometimes orders of magnitude higher, than the petroleum-based fuels they are intended to displace (see Chapter 2.2). However, while the life cycle approach estimates the direction of changes in the water demands associated with shifting from petroleum to biomass-based fuels, how much that translates into increased irrigation or changes in water availability is more difficult to assess.

A second approach to estimate changes in water demands due to the volume changes would rely on scenarios projecting land use changes and changes in crop management practices with a high enough level of precision to also assess or estimate the change in irrigation requirements. Some studies have attempted to project water requirements of increased biofuels production in the U.S.[354] However, the biofuel volumes modeled by Liu et al. (2017) represented an E20 scenario for 2025 and differed greatly in their modeled expansion of crops compared to the volumes proposed here.

[352] Liu, X. V., Hoekman, S. K., & Broch, A. (2017). Potential water requirements of increased ethanol fuel in the USA. *Energy, Sustainability and Society*, *7*(1), 18.
[353] Several studies have estimated water use and availability impacts associated with future scenarios of increased cellulosic biofuel production. These studies often project future land use/management for different scenarios of increased production of cellulosic crops, and then estimate impacts on water use and changes in streamflow for specific watersheds. See for example: Cibin, R., Trybula, E., Chaubey, I., Brouder, S. M., & Volenec, J. J. (2016). Watershed-scale impacts of bioenergy crops on hydrology and water quality using improved SWAT model. Gcb Bioenergy, 8(4), 837-848 or Le, P. V., Kumar, P., & Drewry, D. T. (2011). Implications for the hydrologic cycle under climate change due to the expansion of bioenergy crops in the Midwestern United States. Proceedings of the National Academy of Sciences, 108(37), 15085-15090.
[354] Liu, X., Hoekman, S.K., and Broch, A. 2017. Potential water requirements of increased ethanol fuel in the USA. *Energy, Sustainability and Society*, 7: 18.

A third approach to estimate the changes in water demands is based on changes in crop prices and the associated economic value of irrigation. While the attribution of impacts due to land use changes and associated irrigation requirements is difficult, it may be possible to assess at a broad scale, at least in terms of directionality, the changes in irrigation that may result from the impact of the proposed volumes on crop prices. However, we have not yet been able to perform such an analysis and it remains an area where additional analysis and research is needed to better understand the impacts of the proposed volumes on water demand.

In summary, based on the approaches above, there will likely be some increased irrigation pressure on water resources due to the proposed volumes, primarily from the 2022 volume's potential ability to incent greater investment in corn and soybean based biofuels. The 2020 and 2021 volumes proposed here, however, will likely have no impact, since these volumes, when they are finalized, will be entirely or largely retroactive. There is uncertainty in projecting changes in acreage and irrigation rates associated with corn, soybean, and other crops. Additional information and modeling are needed to fully assess changes in water demands and effects on water stressed regions, both for crop irrigation as well as impacts of biofuel facility water use. Additionally, and as described in Chapter 3.4, we note that there may be potential effects on water and soil quality. While we could not quantify these effects, as described in Chapter 3.4, the potential for negative effects is an area of ongoing concern and research.

Chapter 4: Energy Security Impacts

The CAA directs EPA to analyze "the impact of renewable fuels on the energy security of the United States" in using the reset authority to establish volumes. U.S. energy security is broadly defined as the continued availability of energy sources at an acceptable price.[355] Most discussions of U.S. energy security revolve around the topic of the economic costs of U.S. dependence on oil imports.[356] While energy independence is not a statutory factor in the CAA, Congressional intent and the interpretation of the Courts have stated that one goal of the RFS program is energy independence.[357] Energy independence and energy security are distinct but related concepts, and an analysis of energy independence helps to inform our analysis of energy security.[358]

Since renewable fuels substitute for petroleum-derived conventional fuels, changes in renewable fuel volumes have an impact on U.S. petroleum consumption and imports. All else being constant, a change in U.S. petroleum consumption and imports will alter both the financial and strategic risks associated with sudden disruptions in global oil supply, thus influencing the U.S.'s energy security position. Renewable fuels also may have some energy security risks, for example, as a result of weather-related events (i.e., droughts). To the extent that renewable fuel price shocks are weather-related, their shocks will not be correlated with oil price shocks, providing energy security benefits. However, the energy security risks of using renewable fuels are not well understood, nor well studied. This Chapter reviews the literature on energy security impacts associated with petroleum consumption and imports and summarizes EPA's estimates of the benefits of reduced petroleum consumption and imports that would result from the proposed volumes for 2021 and 2022.

The U.S.'s oil consumption has been gradually increasing in recent years (2015–2019) before dropping dramatically as a result of the Covid pandemic in 2020.[359] The U.S. has increased its production of oil, particularly "tight" (i.e., shale) oil over the last decade. As a result of the recent increase in U.S. oil production, the U.S. became a net exporter of crude oil and product in 2020. The U.S. is projected to be a modest net importer of crude oil and product through 2021-2022, the time frame of this analysis, before becoming a net exporter of crude oil and product for the foreseeable future.[360] This is a significant reversal of the U.S.'s oil trade

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355 Id.

356 The issue of cyberattacks is another energy security issue that could grow in significance over time. For example, one of the U.S.'s largest pipeline operators, Colonial Pipeline, was forced to shut down after being hit by a ransomware attack. The pipeline carries refined gasoline and jet fuel from Texas to New York. *Cyberattack Forces a Shutdown of a Top U.S. Pipeline*. New York Times. May 8th, 2021.

357 The statutory preamble of the RFS that Congress enacted specifically refers to energy independence, and the D.C. Circuit Court has stated that energy independence is a goal of the RFS program. Americans for Clean Energy v. Env't Prot. Agency, 864 F.3d 691, 696 (D.C. Cir. 2017) ("By mandating the replacement—at least to a certain degree—of fossil fuel with renewable fuel, Congress intended the Renewable Fuel Program to move the United States toward greater energy independence and to reduce greenhouse gas emissions."); id. 697 (citing 121 Stat. at 1492).

358 Greene, D. 2010. Measuring energy security: Can the United States achieve oil independence? Energy Policy 38, pp. 1614–1621.

359 U.S. EIA. Total Energy. Annual Energy Review. Table 3.1. Petroleum Overview. April 2021.

360 U.S. Energy Information Administration. 2021. *Annual Energy Outlook* 2021. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

balance position since the U.S. has been a substantial net importer of crude oil and product starting in the early 1950s.[361]

Given that the U.S. is projected to be a modest net importer of crude oil and product for the time frame of this analysis, one could reason that the U.S. does not have a significant energy security problem anymore. However, U.S. refineries still rely on significant imports of heavy crude oil from potentially unstable regions of the world. Also, oil exporters with a large share of global production have the ability to raise or lower the price of oil by exerting the monopoly power associated with a cartel, the Organization of Petroleum Exporting Countries (OPEC), to alter oil supply relative to demand. The degree of market power that OPEC has during the two-year time frame of this analysis is hard to quantify. These factors contribute to the vulnerability of the U.S. economy to episodic oil supply shocks and price spikes, even when the U.S. is projected to be a modest net importer of crude oil and product over the 2021-2022 time frame of this proposed RFS rule.

However, we recognize that because the U.S. is a participant in the world market for petroleum products, our economy cannot be shielded from world-wide price shocks.[362] But, the potential for petroleum supply disruptions due to supply shocks has been diminished due to the increase in tight oil production, and to a lesser extent renewable fuels, which have shifted the U.S. to being a modest net petroleum importer in the world petroleum market in the time frame of this rule, 2021-2022**.** The potential for supply disruptions has not been eliminated, though, due to the continued need to import petroleum to satisfy the demands of the U.S. petroleum industry.[363] In light of the increase in tight oil production, it may be that energy security vulnerabilities have been over-estimated.

4.1 Review of Historical Energy Security Literature

Energy security discussions are typically based around the concept of the oil import premium. The oil import premium is the extra cost of importing oil beyond the price of the oil itself as a result of: (1) Potential macroeconomic disruption and increased oil import costs to the economy from oil price spikes or "shocks"; and (2) Monopsony impacts. Monopsony impacts stem from changes in the demand for imported oil, which changes the price of all imported oil.

The so called oil import premium gained attention as a guiding concept for energy policy in the aftermath of the oil shocks of the 1970s (Bohi and Montgomery 1982, EMF 1982).[364] Plummer (1982) provided valuable discussion of many of the key issues related to the oil import premium as well as the analogous oil stockpiling premium.[365] Bohi and Montgomery (1982)

[361] See EIA https://www.eia.gov/energyexplained/oil-and-petroleum-products/imports-and-exports.php
[362] Bordoff, J. 2019. The Myth of US Energy Independence has Gone Up in Smoke. Foreign Policy. September 18. https://foreignpolicy.com/2019/09/18/the-myth-of-u-s-energy-independence-has-gone-up-in-smoke/
[363] Foreman, D. 2018. Why the US must Import and Export Oil; American Petroleum Institute. June 14. https://www.api.org/news-policy-and-issues/blog/2018/06/14/why-the-us-must-import-and-export-oil
[364] Bohi, D. and Montgomery, D. 1982. Social Cost of Imported and U.S. Import Policy, Annual Review of Energy, 7:37-60. Energy Modeling Forum, 1981. World Oil, EMF Report 6, Stanford University Press: Stanford 39 CA. https://emf.stanford.edu/publications/emf-6-world-oil.
[365] Plummer, J. (Ed.). 1982. Energy Vulnerability, "Basic Concepts, Assumptions and Numerical Results," pp. 13 - 36, Cambridge MA: Ballinger Publishing Co.

detailed the theoretical foundations of the oil import premium and established many of the critical analytic relationships.[366] Hogan (1981) and Broadman and Hogan (1986, 1988) revised and extended the established analytical framework to estimate optimal oil import premia with a more detailed accounting of macroeconomic effects.[367,368] Since the original work on energy security was undertaken in the 1980s, there have been several reviews on this topic by Leiby, Jones, Curlee and Lee (1997) and Parry and Darmstadter (2004).[369,370]

The economics literature on whether oil shocks are the same level of threat to economic stability as they once were, is mixed. Some of the literature asserts that the macroeconomic component of the energy security externality is small. For example, the National Research Council (2009) argued that the non-environmental externalities associated with dependence on foreign oil are small, and potentially trivial.[371] Analyses by Nordhaus (2007) and Blanchard and Gali (2010) question the impact of oil price shocks on the economy in the early 2000 time frame.[372] They were motivated by attempts to explain why the economy actually expanded during the oil shock in the early-2000s timeframe, and why there was no evidence of higher energy prices being passed on through higher wage inflation. One reason, according to Nordhaus and Blanchard and Gali, is that monetary policy has become more accommodating to the price impacts of oil shocks. Another reason is that consumers have simply decided that such movements are temporary and have noted that price impacts are not passed on as inflation in other parts of the economy.

Hamilton (2012) reviews the empirical literature on oil shocks and suggests that the results are mixed, noting that some work (e.g., Rasmussen and Roitman (2011)) finds less evidence for economic effects of oil shocks or declining effects of shocks (Blanchard and Gali (2010)), while other work continues to find evidence regarding the economic importance of oil shocks.[373] For example, Baumeister and Peersman (2011) find that an "oil price increase of a given size seems to have a decreasing effect over time, but noted that the declining price-elasticity of demand meant that a given physical disruption had a bigger effect on price and turned out to have a similar effect on output as in the earlier data."[374] Hamilton observes that "a

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366 Bohi, D. and Montgomery, D. 1982. Social Cost of Imported and U.S. Import Policy, Annual Review of Energy, 7:37-60.

367 Broadman, H. 1986. "The Social Cost of Imported Oil," Energy Policy 14(3):242-252. Broadman H. and Hogan, W. 1988. "Is an Oil Import Tariff Justified? An American Debate: The Numbers Say 'Yes'." The Energy Journal 9: 7-29.

368 Hogan, W. 1981. "Import Management and Oil Emergencies," Chapter 9 in Deese, 5 David and Joseph Nye, eds. Energy and Security. Cambridge, MA: Ballinger Publishing Co.

369 Leiby, P., Jones, D., Curlee, R. and Lee, R. 1997. Oil Imports: An Assessment of Benefits and Costs, ORNL-6851, Oak Ridge National Laboratory, November.

370 Parry, I. and Darmstadter, J. 2004. "The Costs of U.S. Oil Dependency," Resources for the Future, November 17, 2004. Also published as NCEP Technical Appendix Chapter 1: Enhancing Oil Security, the National Commission on Energy Policy 2004 Ending the Energy Stalemate - A Bipartisan Strategy to Meet America's Energy Challenges.

371 National Research Council. 2009. Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use. National Academy of Science, Washington, DC.

372 Nordhaus, W. 2007. "Who's Afraid of a Big Bad Oil Shock?". Brookings Papers on Economic Activity, Economic Studies Program, The Brookings Institution, vol. 38(2), pp. 219-240.

373 Rasmussen, T. and Roitman, A. 2011. Oil Shocks in a Global Perspective: Are We Really That Bad. IMF Working Paper Series.

374 Hamilton, J. 2012. Oil Prices, Exhaustible Resources, and Economic Growth. In Handbook of Energy and Climate Change. Retrieved from http://econweb.ucsd.edu/~jhamilto/handbook_climate.pdf

negative effect of oil prices on real output has also been reported for a number of other countries, particularly when nonlinear functional forms have been employed" (citing as examples Kim (2012) and Engemann, Kliesen, and Owyang (2011)).[375,376] Alternatively, rather than a declining effect, Ramey and Vine (2010) find "remarkable stability in the response of aggregate real variables to oil shocks once we account for the extra costs imposed on the economy in the 1970s by price controls and a complex system of entitlements that led to some rationing and shortages."[377]

Some of the literature on oil price shocks emphasizes that economic impacts depend on the nature of the oil shock, with differences between price increases caused by a sudden supply loss and those caused by rapidly growing demand. Recent analyses of oil price shocks have confirmed that "demand-driven" oil price shocks have greater effects on oil prices and tend to have positive effects on the economy while "supply-driven" oil shocks still have negative economic impacts (Baumeister, Peersman and Robays (2010)).[378] A paper by Kilian and Vigfusson (2014), for example, assigns a more prominent role to the effects of price increases that are unusual, in the sense of being beyond the range of recent experience.[379] Kilian and Vigfussen also conclude that the difference in response to oil shocks may well stem from the different effects of demand- and supply-based price increases: "One explanation is that oil price shocks are associated with a range of oil demand and oil supply shocks, some of which stimulate the U.S. economy in the short-run and some of which slow down U.S. growth (see Kilian 2009a)."[380]

The general conclusion that oil supply-driven shocks reduce economic output is also reached in a paper by Cashin et al. (2014), which focused on 38 countries from 1979–2011.[381] They state: "The results indicate that the economic consequences of a supply-driven oil-price shock are very different from those of an oil-demand shock driven by global economic activity, and vary for oil-importing countries compared to energy exporters." Cashin et al. continues "…oil importers (including the U.S.) typically face a long-lived fall in economic activity in response to a supply-driven surge in oil prices." But almost all countries see an increase in real output for an oil-demand disturbance.

EPA's assessment of the energy security literature finds that there are benefits to the U.S. from reductions in oil imports. But there is some debate as to the magnitude, and even the

[375] Kim, D. 2012. What is an oil shock? Panel data evidence. Empirical Economics, Volume 43, pp. 121-143.
[376] Engemann, K., Kliesen. K. and Owyang, M. 2011. Do Oil Shocks Drive Business Cycles, Some U.S. and International Evidence. Federal Reserve Bank of St. Louis, Working Paper Series. No. 2010-007D.
[377] Ramey, V. and Vine, D. 2010. "Oil, Automobiles, and the U.S. Economy: How Much have Things Really Changed?". National Bureau of Economic Research Working Papers, WP 16067 (June). Retrieved from http://www.nber.org/papers/w16067.pdf
[378] Baumeister C., Peersman, G. and Van Robays, I. 2010. "The Economic Consequences of Oil Shocks: Differences across Countries and Time," RBA Annual Conference Volume in: Renée Fry & Callum Jones & Christopher Kent (ed.), Inflation in an Era of Relative Price Shocks, Reserve Bank of Australia.
[379] Kilian, L. and Vigfusson, R. 2014. "The role of oil price shocks in causing U.S. recessions," CFS Working Paper Series 460, Center for Financial Studies.
[380] Kilian, L. 2009. "Not All Oil Price Shocks Are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market." American Economic Review, 99 (3): pp. 1053-69.
[381] Cashin, P., Mohaddes, K., and Raissi, M. 2014. The Differential Effects of Oil Demand and Supply Shocks on the Global Economy, Energy Economics, 12 (253).

existence, of energy security benefits from U.S. oil import reductions. Over the last decade, differences in economic impacts from oil demand and oil supply shocks have been distinguished. The oil security premium calculations in this analysis are based on price shocks from potential future supply events only. Oil supply shocks, which reduce economic activity, have been the predominant focus of oil security issues since the oil price shocks/oil embargoes of the 1970s. It is not necessarily clear how increased renewable fuel volumes would influence energy security under an oil demand shock. While there is some increase in imported renewable fuels as a result of this proposed RFS rule, the proposed rule results in an overall reduction by the U.S. in imported fuels (i.e., combined total of imported oil and imported renewable fuels), moving the U.S. modestly towards the goal of energy independence.

4.2 Review of Recent Energy Security Literature

There have also been a handful of recent studies undertaken in the last few years that are relevant for the issue of energy security: one by Resources for the Future (RFF), a study by Brown, two studies by Oak Ridge National Laboratory (ORNL), and a couple of studies, Newell and Prest and Bjornland et al., on the responsiveness of U.S. tight oil (i.e., shale oil) to world oil price changes. We provide a brief review and high-level summary of each of these studies below.

The RFF study (2017) attempts to develop updated estimates of the relationship among gross domestic product (GDP), oil supply and oil price shocks, and world oil demand and supply elasticities.[382] In a follow-on study, Brown summarized the RFF study results as well.[383] The RFF work argues that there have been major changes that have occurred in recent years that have reduced the impacts of oil shocks on the U.S. economy. First, the U.S. is less dependent on imported oil than in the early 2000s due in part to the “fracking revolution” (i.e., tight/shale oil), and to a lesser extent, increased production of renewable fuels. In addition, RFF argues that the U.S. economy is more resilient to oil shocks than in the earlier 2000s timeframe. Some of the factors that make the U.S. more resilient to oil shocks include increased global financial integration and greater flexibility of the U.S. economy (especially labor and financial markets), many of the same factors that Nordhaus and Blanchard and Gali pointed to as discussed above.

In the RFF effort, a number of comparative modeling scenarios are conducted by several economic modeling teams using three different types of energy-economic models to examine the impacts of oil shocks on U.S. GDP. The first is a dynamic stochastic general equilibrium model developed by Balke and Brown.[384] The second set of modeling frameworks use alternative

[382] Krupnick, A., Morgenstern, R., Balke, N., Brown, S., Herrara, M. and Mohan, S. 2017. “Oil Supply Shocks, U.S. Gross Domestic Product, and the Oil Security Problem,” Resources for the Future Report.
[383] Brown, S. 2018. New estimates of the security costs of U.S. oil consumption”, Energy Policy, 113 pp. 171-192.
[384] Balke, N. and Brown, S. 2018. “Oil Supply Shocks and the U.S. Economy: An Estimated DSGE Model.” Energy Policy, 116, pp. 357-372.

structural vector autoregressive models of the global crude oil market.[385] The last of the models utilized is the National Energy Modeling System (NEMS).[386]

Two key parameters are focused upon to estimate the impacts of oil shock simulations on U.S. GDP: oil price responsiveness (i.e., the short-run price elasticity of demand for oil) and GDP sensitivity (i.e., the elasticity of GDP to an oil price shock). The more inelastic (i.e., the less responsive) short-run oil demand is to changes in the price of oil, the higher will be the price impacts of a future oil shock. Higher price impacts from an oil shock result in higher GDP losses. The more inelastic (i.e., less sensitive) GDP is to an oil price change, the less the loss of U.S. GDP with future oil price shocks.

For oil price responsiveness, RFF reports three different values: a short-run price elasticity of oil demand from their assessment of the “new literature,” –0.17; a “blended” elasticity estimate; –0.05, and short-run oil price elasticities from the “new models” RFF uses, ranging from –0.20 to –0.35. The “blended” elasticity is characterized by RFF in the following way: “Recognizing that these two sets of literature [old and new] represent an *evolution* in thinking and modeling, but that the older literature has not been wholly overtaken by the new, Benchmark-E [the blended elasticity] allows for a range of estimates to better capture the uncertainty involved in calculating the oil security premiums.”

The second parameter that RFF examines is the GDP sensitivity. For this parameter, RFF’s assessment of the “new literature” finds a value of –0.018, a “blended elasticity” estimate of –0.028, and a range of GDP elasticities from the “new models” that RFF uses that range from –0.007 to –0.027. One of the limitations of the RFF study is that the large variations in oil price over the last fifteen years are believed to be predominantly “demand shocks”: for example, a rapid growth in global oil demand followed by the Great Recession and then the post-recession recovery.

The only supply-side oil shock in the last several years was the attack on the Saudi Aramco Abqaiq oil processing facility and the Khurais oil field (which took place after the publication of RFF’s study). On September 14, 2019, a drone and cruise missile attack damaged the Saudi Aramco Abqaiq oil processing facility and the Khurais oil field in eastern Saudi Arabia. The Abqaiq oil processing facility is the largest crude oil processing and stabilization plant in the world, with a capacity of roughly 7 MMBD or about 7% of global crude oil production capacity.[387] On September 16, the first full day of commodity trading after the attack, both Brent and WTI crude oil prices surged by $7.17/barrel and $8.34/barrel, respectively, in response to the attack, the largest price increase in roughly a decade.

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[385] These models include Kilian, L. 2009. Not All Oil Price Shocks are Alike: Disentangling Demand and Supply Shocks in the Crude Oil Market, American Economic Review, 99:3, pp., 1053-1069; Kilian, L. and Murphy, D. 2013. “The Role of Inventories and Speculative Trading in the Global Market for Crude Oil,” Journal of Applied Economics, https://doi.org/10.1002/jae.2322; and Baumeister, C. and Hamilton, J. 2019. “Structural Interpretation of Vector Autoregressions with Incomplete Identification: Revisiting the Role of Oil Supply and Demand Shocks,” American Economic Review, 109(5), pp.1873-1910.

[386] Mohan, S. 2017. “Oil Price Shocks and the U.S. Economy: An Application of the National Energy Modeling System.” Resources for the Future Report Appendix.

[387] U.S. Energy Information Administration. September 23, 2019. “Saudi Arabia crude oil production outage affects global crude oil and gasoline prices.” Today in Energy.

However, by September 17, Saudi Aramco reported that the Abqaiq plant was producing 2 MMBD, and they expected its entire output capacity to be fully restored by the end of September.[388] Tanker loading estimates from third-party data sources indicated that loadings at two Saudi Arabian export facilities were restored to the pre-attack levels.[389] As a result, both Brent and WTI crude oil prices fell on September 17, but not back to their original levels. The oil price spike from the attack on the Abqaiq plant and Khurais oil field was prominent and unusual, as Kilian and Vigfusson (2014) describe. While pointing to possible risks to world oil supply, the oil shock was short-lived, and generally viewed by market participants as being transitory, so it did not influence oil markets over a sustained time period. Thus, there is little recent empirical evidence to estimate the response of the U.S. economy to an oil supply shock of a significant magnitude.[390]

A second set of recent studies related to energy security are from ORNL. In the first study, ORNL (2018) undertakes a quantitative meta-analysis of world oil demand elasticities based upon the recent economics literature.[391] The ORNL study estimates oil demand elasticities for two sectors (transportation and non-transportation) and by world regions (OECD and Non-OECD) by meta-regression. To establish the dataset for the meta-analysis, ORNL undertakes a literature search of peer reviewed journal articles and working papers between 2000 and 2015 that contain estimates of oil demand elasticities. The dataset consisted of 1,983 observations from 75 published studies. The study finds a weighted short-run price elasticity of world oil demand of –0.07 and a long-run price elasticity of world oil demand of –0.26.

The second relevant ORNL (2018) study from the standpoint of energy security is a meta-analysis that examines the impacts of oil price shocks on the U.S. economy as well as many other net oil-importing economies.[392] Nineteen studies after 2000 were identified that contain quantitative/accessible estimates of the economic impacts of oil price shocks. Almost all studies included in the review were published since 2008. The key result that the study finds is a short-run oil price elasticity of U.S. GDP, roughly one year after an oil shock, of –0.021, with a 68% confidence interval of –0.006 to –0.036.

Only in recent years have the implications of the “tight oil revolution” been felt in the international market where U.S. production of oil is rising to be roughly on par with Saudi Arabia and Russia. Recent economics literature of the tight (i.e., shale/unconventional) oil expansion in the U.S. has a bearing on the issue of energy security as well. It could be that the

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388 Id.
389 Id.
390 The Hurricanes Katrina/Rita in 2005 primarily caused a disruption in U.S. oil refinery production, with a more limited disruption of some crude supply in the U.S. Gulf Coast area. Thus, the loss of petroleum product exceeded the loss of crude oil, and the regional impact varied even within the U.S. The Katrina/Rita Hurricanes were a different type of oil disruption event than is quantified in the Stanford EMF risk analysis framework, which provides the oil disruption probabilities than ORNL is using.
391 Uría-Martínez, R., Leiby, P., Oladosu, G., Bowman, D., Johnson, M. 2018. Using Meta-Analysis to Estimate World Oil Demand Elasticity, ORNL Working Paper.
392 Oladosu, G., Leiby, P., Bowman, D., Uría-Martínez, R., Johnson, M. 2018. Impacts of oil price shocks on the U.S. economy: a meta-analysis of oil price elasticity of GDP for net oil-importing economies, Energy Policy 115. pp. 523–544.

large expansion in shale oil has eroded the ability of OPEC to set world oil prices to some degree, since OPEC cannot directly influence shale oil production decisions. Also, by effecting the percentage of global oil supply controlled by OPEC, the growth in U.S. oil production may be influencing OPEC's degree of market power. But given that the shale oil expansion is a relatively recent trend, it is difficult to know how much of an impact the increase in shale oil is having, or will have, on OPEC behavior.

Two recent studies have examined the characteristics of tight oil supply that have relevance for the topic of energy security. In the context of energy security, the question that arises is: Can tight oil respond to an oil price shock more quickly and substantially than conventional oil?[393] If so, then tight oil could potentially lessen the impacts of future oil shocks on the U.S. economy by moderating the price increases from a future oil supply shock.

Newell and Prest (2019) look at differences in the price responsiveness for oil wells, using a detailed dataset of 164,000 oil wells, during the time frame of 2000–2015 in five major oil-producing states: Texas, North Dakota, California, Oklahoma, and Colorado.[394] They find that unconventional oil wells are more price responsive than conventional oil wells, mostly due to their much higher productivity, but the estimated supply elasticity is still small. Newell and Prest also estimate a medium-run price elasticity of oil supply of 0.12. Newell and Prest note that the shale oil supply response still takes more time to arise than is typically considered for a "swing producer," referring to a supplier able to increase production quickly, within 30–90 days. In the past, only Saudi Arabia and possibly one or two other oil producers in the Middle East have been able to ramp up oil production in a short period of time. From the standpoint of energy security, the most relevant time frame of analysis is roughly a year, considered the short-run responsiveness of oil demand to price.

Another study, by Bjornland et al. (2021), uses a well-level monthly production data set covering more than 15,000 crude oil wells in North Dakota to examine differences in supply responses between conventional and tight oil/shale oil.[395] They find a short-run (i.e., one-month) supply elasticity with respect to oil price for tight oil wells of 0.076, whereas the one-month response of conventional oil supply was not statistically different from zero. Both the results from the Newell and Prest and Bjornland et al. suggest that tight oil may have a larger supply response to oil prices in the short-run than conventional oil, although the estimated short-run elasticity is still small.

Finally, despite continuing uncertainty about oil market behavior and outcomes and the sensitivity of the U.S. economy to oil shocks, it is generally agreed that it is beneficial to reduce petroleum fuel consumption from an energy security standpoint. The relative significance of petroleum consumption and import levels for the macroeconomic disturbances that follow from oil price shocks is not fully understood. Recognizing that changing petroleum consumption will

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[393] Union of Concerned Scientist, "What is Tight Oil?". 2015. "Tight oil is a type of oil found in impermeable shale and limestone rock deposits. Also known as "shale oil," tight oil is processed into gasoline, diesel, and jet fuels—just like conventional oil—but is extracted using hydraulic fracturing, or "fracking."

[394] Newell, R. and Prest, B. 2019. The Unconventional Oil Supply Boom: Aggregate Price Response from Microdata, The Energy Journal, Volume 40, Issue Number 3.

[395] Bjørnland, H., Nordvik, F. and Rohrer, M. 2021. "Supply flexibility in the shale patch: Evidence from North Dakota," Journal of Applied Economics, February.

change U.S. imports, this assessment of oil costs focuses on those incremental social costs that follow from the resulting changes in net imports, employing the usual oil import premium measure.

4.3 Cost of Existing U.S. Energy Security Policies

An additional often-identified component of the full economic costs of U.S. oil imports is the costs to the U.S. taxpayers of existing U.S. energy security policies. The two primary examples are maintaining the Strategic Petroleum Reserve (SPR) and maintaining a military presence to help secure a stable oil supply from potentially vulnerable regions of the world.

The SPR is the largest stockpile of government-owned emergency crude oil in the world. Established in the aftermath of the 1973/1974 oil embargo, the SPR provides the U.S. with a response option should a disruption in commercial oil supplies threaten the U.S. economy. While the costs for building and maintaining the SPR are more clearly related to U.S. oil use and imports, historically these costs have not varied in response to changes in U.S. oil import levels. Thus, while the effect of the SPR in moderating price shocks is factored into the analysis that EPA is using to estimate the macroeconomic oil security premiums, the cost of maintaining the SPR is excluded.

EPA also has considered the possibility of quantifying the military benefits components of energy security but has not done so here for several reasons. The literature on the military components of energy security has described four broad categories of oil related military and national security costs, all of which are hard to quantify. These include possible costs of U.S. military programs to secure oil supplies from unstable regions of the world, the energy security costs associated with the U.S. military's reliance on petroleum to fuel its operations, possible national security costs associated with expanded oil revenues to "rogue states" and relatedly the foreign policy costs of oil insecurity.

Of these categories listed above, the one that is most clearly connected to petroleum use and is, in principle, quantifiable is the first: the cost of military programs to secure oil supplies and stabilize oil supplying regions. There is an ongoing literature on the measurement of this component of energy security, but methodological and measurement issues – attribution and incremental analysis – pose two significant challenges to providing a robust estimate of this component of energy security. The attribution challenge is to determine which military programs and expenditures can properly be attributed to oil supply protection, rather than some other objective. The incremental analysis challenge is to estimate how much the petroleum supply protection costs might vary if U.S. oil use were to be reduced or eliminated. Methods to address both of these challenges are necessary for estimating the effect on military costs arising from a modest reduction (not elimination) in oil use attributable to this proposed rule.

Since "military forces are, to a great extent, multipurpose and fungible" across theaters and missions (Crane et al. 2009), and because the military budget is presented along regional accounts rather than by mission, the allocation to particular missions is not always clear.[396]

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[396] Crane, K., Goldthau, A., Toman, M., Light, T., Johnson, S., Nader, A., Rabasa, A. and Dogo, H. 2009. Imported oil and US national security. RAND, 2009.

Approaches taken usually either allocate “partial” military costs directly associated with operations in a particular region, or allocate a share of total military costs (including some that are indirect in the sense of supporting military activities overall) (Koplow and Martin 1998).[397]

The challenges of attribution and incremental analysis have led some to conclude that the mission of oil supply protection cannot be clearly separated from others, and the military cost component of oil security should be taken as near zero (Moore et al. 1997).[398] Stern (2010), on the other hand, argues that many of the other policy concerns in the Persian Gulf follow from oil, and the reaction to U.S. policies taken to protect oil.[399] Stern presents an estimate of military cost for Persian Gulf force projection, addressing the challenge of cost allocation with an activity-based cost method. He uses information on actual naval force deployments rather than budgets, focusing on the costs of carrier deployment. As a result of this different data set and assumptions regarding allocation, the estimated costs are much higher, roughly 4 to 10 times, than other estimates. Stern also provides some insight on the analysis of incremental effects, by estimating that Persian Gulf force projection costs are relatively strongly correlated to Persian Gulf petroleum export values and volumes. Still, the issue remains of the marginality of these costs with respect to Persian Gulf oil supply levels, the level of U.S. oil imports, or U.S. oil consumption levels.

Delucchi and Murphy (2008) seek to deduct from the cost of Persian Gulf military programs the costs associated with defending U.S. interests other than the objective of providing more stable oil supply and price to the U.S. economy.[400] Excluding an estimate of cost for missions unrelated to oil, and for the protection of oil in the interest of other countries, Delucci and Murphy estimated military costs for all U.S. domestic oil interests of between $24 and $74 billion annually. Delucchi and Murphy assume that military costs from oil import reductions can be scaled proportionally, attempting to address the incremental issue.

Crane et al. considers force reductions and cost savings that could be achieved if oil security were no longer a consideration. Taking two approaches and guided by post-Cold War force draw downs and by a top-down look at the current U.S. allocation of defense resources, they concluded that $75–$91 billion, or 12–15% of the current U.S. defense budget, could be reduced.

Finally, an Issue Brief by Securing America’s Energy Future (SAFE) (2018) found a conservative estimate of approximately $81 billion per year spent by the U.S. military protecting global oil supplies.[401] This is approximately 16% of the recent U.S. Department of Defense’s budget. Spread out over the 19.8 million barrels of oil consumed daily in the U.S. in 2017, SAFE concludes that the implicit subsidy for all petroleum consumers is approximately $11.25 per

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[397] Koplow, D. and Martin, A. 1998. Fueling Global Warming: Federal Subsidies to Oil in the United States. Greenpeace, Washington, DC.
[398] Moore, J., Behrens, C. and Blodgett, J. 1997. “Oil Imports: An Overview and Update of Economic and Security Effects.” CRS Environment and Natural Resources Policy Division report 98, no. 1: pp. 1-14.
[399] Stern, R. 2010. “United States cost of military force projection in the Persian Gulf, 1976–2007.” *Energy Policy* 38, no. 6. June: 2816-2825. http://linkinghub.elsevier.com/retrieve/pii/S0301421510000194.
[400] Delucchi, M. and Murphy, J. 2008. “US military expenditures to protect the use of Persian Gulf oil for motor vehicles.” Energy Policy 36, no. 6. June: 2253-2264.
[401] Securing America’s Energy Future. 2018. Issue Brief. The Military Cost of Defending the Global Oil Supply.

barrel of crude oil, or $0.28 per gallon. According to SAFE, a more comprehensive estimate suggests the costs could be greater than $30 per barrel, or over $0.70 per gallon.[402]

As in the examples above, an incremental analysis can estimate how military costs would vary if the oil security mission is no longer needed, and many studies stop at this point. It is substantially more difficult to estimate how military costs would vary if U.S. oil use or imports are partially reduced, as is projected to be a consequence of this proposed rule. Partial reduction of U.S. oil use surely diminishes the magnitude of the security problem, but there is uncertainty that supply protection forces and their costs could be scaled down in proportion, and there remains the associated goal of protecting supply and transit for U.S. allies and other importing countries, if they do not decrease their petroleum use as well.[403] EPA is unaware of a robust methodology for assessing the effect on military costs of a partial reduction in U.S. oil use. Therefore, we are unable to quantify this effect resulting from the projected reduction in U.S. oil use attributable to this proposed rule.

4.4 Energy Security Impacts

4.4.1 U.S. Oil Import Reductions

Over the time frame of this proposed rule, 2021–2022, the U.S. Department of Energy's (DOE) Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2021 (Reference Case) forecasts that the U.S. will be both an exporter and an importer of crude oil.[404] The U.S. produces more light crude oil than its refineries can refine. Thus, the U.S. exports lighter crude oil and imports heavier crude oils to satisfy the needs of U.S. refineries, which are configured to efficiently refine heavy crude oil. U.S. crude oil exports are forecasted to be 3.1 MMBD in 2021 and 2.8 MMBD in 2022. U.S. crude oil imports, meanwhile, are forecasted to be 7.6 MMBD in 2021 and 7.8 MMBD in 2022. The AEO 2021 also forecasts that U.S. net oil product exports will increase from 3.6 MMBD in 2021 to 4.7 MMBD in 2022. Given the pattern of U.S. crude oil exports/imports, and the U.S.'s net oil product exports, the U.S. is forecasted to be a modest net crude oil and product importer of 0.8 MMBD in 2021 and 0.2 MMBD in 2022. After the 2021-2022 time period, the AEO2021 projects that the U.S. will become a net exporter of crude oil and product for the foreseeable future.

U.S. oil consumption is projected to have decreased significantly in 2020 to 18.1 MMBD as a result of social distancing and quarantines that limited personal mobility as a result of the Covid pandemic. U.S. oil consumption is projected to rebound in 2021 and 2022 to 19.9 MMBD. It is not just U.S. crude oil imports alone, but both imports and consumption of petroleum from all sources and their role in economic activity, that exposes the U.S. to risk from price shocks in the world oil price. During the 2021–2022 time frame of this proposal, the U.S. is projected to continue to consume significant quantities of oil and to rely on significant quantities of crude oil

402 Id.
403 Crane, K., Goldthau, A., Toman, M., Light, T., Johnson, S., Nader, A., Rabasa, A. and Dogo, H. 2009. Imported oil and US national security. 2009. RAND.
404 U.S. Energy Information Administration. *Annual Energy Outlook* 2021. Reference Case. Table A11. Petroleum and Other Liquids Supply and Disposition.

imports. As a result, U.S. oil markets are expected to remain tightly linked to trends in the world crude oil market.

In Chapter 9.3.2, EPA estimates changes in U.S. petroleum consumption and U.S. oil imports attributable to this proposed rule. A 99% oil import reduction factor is calculated by examining changes in petroleum demand and its effect on both imported versus domestic crude oil, and imported petroleum products considering two separate economic cases, the Low Economic Growth Case and the Reference Case, modeled by EIA in its 2021 Annual Energy Outlook.[405] In other words, 99% of changes in oil consumption result in reduced U.S. oil imports. Based upon the changes in oil consumption estimated by EPA and the 99% oil import factor, the reduction in U.S. oil imports as a result of the proposed RFS fuel volume cases are estimated in Table 4.4.1-1 below for the 2021–2022 time frame. Included in Table 4.4.1-1 are estimates of U.S. crude oil exports and imports, net oil product exports, net crude oil and product imports and U.S. oil consumption to place the reduction in U.S. oil imports in the context of U.S. oil market trends during the 2021–2022 time frame.

While this proposed RFS annual rule is projected to reduce U.S. oil imports modestly in the 2021-2022 time frame, it also results in some increase in U.S. renewable fuel imports. We do not have a methodology to estimate the energy security impacts of an increased use of imported renewable fuels. To the extent that renewable fuel imports are mainly subject to supply risks from weather, renewable fuel disruptions are not likely to be correlated with oil supply disruptions.

Table 4.4.1-1: Projected Trends in U.S. Crude Oil Exports/Imports, Net Oil Product Exports, Net Crude Oil and Product Imports, Oil Consumption and U.S. Oil Import Reductions Resulting from the Proposed RFS Annual Rule from 2021 to 2022 (Millions of barrels per day (MMBD))[a]

	2021	**2022**
U.S. Crude Oil Exports	3.1	2.8
U.S. Crude Oil Imports	7.6	7.8
U.S. Net Oil Product Exports	3.6	4.7
U.S. Net Crude Oil and Product Imports	0.8	0.2
U.S. Oil Consumption	19.9	19.9
Reduction in U.S. Oil Imports from the Proposed Renewable Fuel Standards[b]	0.05	0.12

[a] The AEO 2021 Reference Case, Table A11. Values have been rounded off from the AEO 2021, so the totals may not add up to the AEO estimates.
[b] Estimated changes in imported crude oil are presented in Table 9.3-2.

4.4.2 Oil Security Premiums Used for this Proposed Rule

In order to understand the energy security implications of reducing U.S. oil imports, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. The energy security estimates provided below are based upon a methodology developed in a peer-reviewed study

[405] AEO 2021 Change in product demand on imports; docketed spreadsheet.

entitled, “The Energy Security Benefits of Reduced Oil Use, 2006-2015,” completed in 2008.[406] This ORNL study is an updated version of the approach used for estimating the energy security benefits of U.S. oil import reductions developed in a 1997 ORNL Report.[407] This same approach was used to estimate energy security benefits for the March 2010 RFS2 final rule (75 FR 14839-14842).[408] ORNL has updated this methodology periodically for EPA to account for updated forecasts of future energy market and economic trends reported in the U.S. EIA’s AEO.

The ORNL methodology is used to compute the oil import premium (concept defined in Chapter 4.1) per barrel of imported oil. The values of U.S. oil premium components (macroeconomic disruption/adjustment costs and monopsony components) are numerically estimated with a compact model of the oil market by performing simulations of market outcomes using probabilistic distributions for the occurrence of oil supply shocks, calculating marginal changes in economic welfare with respect to changes in U.S. oil import levels in each of the simulations, and summarizing the results from the individual simulations into a mean and 90 percent confidence intervals for the import premium. The macroeconomic disruption/adjustment costs import cost component is the sum of two parts: the marginal change in expected import costs during disruption events and the marginal change in gross domestic product due to the disruption. The monopsony component is the long-run change in U.S. import costs as the level of oil import changes.

For this proposed rule, EPA is using oil security premiums that incorporate the oil price forecast and energy market and economic trends, particularly global regional oil supplies and demands (i.e., the U.S./OPEC/rest of the world), from the AEO 2021 into its model.[409] EPA only considered the avoided macroeconomic disruption/adjustment costs oil security premiums (i.e., labeled macroeconomic oil security premiums below), since the monopsony impacts of changes in renewable fuel volumes are considered transfer payments. See the March 2010 RFS2 final rule (75 FR 14841-14842) for a discussion of monopsony oil security premiums.[410] EPA also does not consider the effect of this proposed rule on the costs associated with existing energy security policies (e.g., maintaining the Strategic Petroleum Reserve or strategic military deployments), which are discussed in Chapter 4.3.

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406 Leiby, Paul N. 2008. *Estimating the Energy Security Benefits of Reduced U.S. Oil Imports*, Final Report, ORNL/TM-2007/028, Oak Ridge National Laboratory, Rev. March 14.

407 Leiby, P., Jones, D., Curlee, R. and Lee, R. 1997. *Oil Imports: An Assessment of Benefits and Costs*, ORNL-6851, Oak Ridge National Laboratory, November.

408 See 40 CFR Part 80, Regulation of Fuels and Fuels Additives: Changes to the Renewable Fuel Standard Program; Final Rule, March 26, 2010. https://www.govinfo.gov/content/pkg/FR-2010-03-26/pdf/2010-3851.pdf

409 The oil market projection data used for the calculation of the oil security premiums came from EIA’s Annual Energy Outlook (AEO) 2021, supplemented by the latest EIA international projections from the Annual Energy Outlook (AEO)/International Energy Outlook (IEO) 2019. Global oil prices and all variables describing U.S. supply and disposition of petroleum liquids (domestic supply, tight oil supply fraction, imports, demands) as well as U.S. non-petroleum liquids supply and demand are from AEO 2021. Global and OECD Europe supply/demand projections as well as OPEC oil production share are from IEO 2019. The need to combine AEO 2021 and IEO 2019 data arises due to two reasons: (a) EIA stopped including Table 21 “International Petroleum and Other Liquids Supply, Disposition, and Prices” in the U.S.-focused Annual Energy Outlook after 2019, (b) EIA does not publish complete updates of the IEO every year.

410 Id., pp. 14841–14842.

The macroeconomic oil security premiums arise from the effect of U.S. oil imports on the expected cost of supply disruptions and accompanying price increases. A sudden increase in oil prices triggered by a disruption in world oil supplies has two main effects: (1) it increases the costs of oil imports in the short-run, and (2) it can lead to macroeconomic contraction, dislocation, and GDP losses. Since future disruptions in foreign oil supplies are an uncertain prospect, each of the disruption cost components must be weighted by the probability that the supply of petroleum to the U.S. will actually be disrupted. Thus, the "expected value" of these costs – the product of the probability that a supply disruption will occur and the sum of costs from reduced economic output and the economy's abrupt adjustment to sharply higher petroleum prices – is the relevant measure of their magnitude.

In addition, EPA and ORNL have worked together to revise the oil security premiums based upon recent energy security literature. Based upon EPA and ORNL's review of the recent energy security literature, EPA is updating its macroeconomic oil security premiums for this proposed RFS annual rule. The recent economics literature (discussed in Chapter 4.2) focuses on three factors that can influence the macroeconomic oil security premiums. We discuss each factor below and provide a rationale for how we are updating two out of three of the factors to develop new estimates of the macroeconomic oil security premiums. We are not accounting for how shale oil is influencing the macroeconomic oil security premiums in this proposed rule.

First, we assess the price elasticity of demand for oil. In previous EPA RFS rulemakings, EPA has used a short-run elasticity of demand for oil of –0.045.[411] From the recent RFF study, the "blended" price elasticity of demand for oil is –0.05. The ORNL meta-analysis estimate of this parameter is –0.07. We find the elasticity estimates from what RFF characterizes as the "new literature," –0.175, and from the "new models" that RFF uses, –0.20 to –0.33, somewhat high. Most of the world's oil demand is concentrated in the transportation sector and there are limited alternatives to oil use in this sector. According to the IEA, the share of global oil consumption attributed to the transportation sector grew from 60% in 2000 to 66% in 2018.[412] The next largest sector by oil consumption, and an area of recent growth, is petrochemicals. There are limited alternatives to oil use in this sector, particularly in the time frame of this proposed rule. Thus, we believe it would be surprising if short-run oil demand responsiveness has changed in a dramatic fashion.

The ORNL meta-analysis estimate encompasses the full range of the economics literature on this topic and develops a meta-analysis estimate from the results of many different studies in a structured way, while the RFF study's "new models" results represent only a small subset of the economics literature's estimates. Thus, for the analysis of this proposed rule, we are increasing the short-run price elasticity of demand for oil from –0.045 to –0.07, a 56% increase.[413] This increase has the effect of lowering the macroeconomic oil security premium estimates undertaken by ORNL for EPA.

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[411] For example, see Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule, 40 CFR Part 80 (2010).

[412] IEA, Data and Statistics, https://www.iea.org/data-and-statistics?country=WORLD&fuel=Oil&indicator=OilProductsConsBySector (Accessed March 2021)

[413] EPA and ORNL worked together to develop an updated estimate of the short-run elasticity of demand for oil for use in the ORNL model.

Second, we consider the elasticity of GDP to an oil price shock. For previous EPA rulemakings, a GDP elasticity to an oil shock of –0.032 was used.[414] The RFF "blended" GDP elasticity is –0.028, the RFF's "new literature" GDP elasticity is –0.018, while the RFF "new models" GDP elasticities range from –0.007 to –0.027. The ORNL meta-analysis GDP elasticity is –0.021. We believe that the ORNL meta-analysis value is representative of the recent literature on this topic since it considers a wider range of recent studies and does so in a structured way. Also, the ORNL meta-analysis estimate is within the range of GDP elasticities of RFF's "blended" and "new literature" elasticities.

For this proposed rule, EPA is using a GDP elasticity of –0.021, a 34% reduction from the GDP elasticity used previously (i.e., the –0.032 value).[415] This GDP elasticity is in between the ORNL meta-analysis estimate and the elasticity EPA has used in previous rulemakings. Finally, in the limited time frame to complete this analysis, we have not factored in how increases in U.S. tight oil might influence U.S. oil security values, other than how U.S. tight oil significantly reduces net oil imports.

Table 4.4.2-1 below provides estimates of EPA's macroeconomic oil security premium estimates for 2021 and 2022. The macroeconomic oil security premiums are relatively steady over the time period of this proposed rule at $3.14/barrel in 2021 (7.5 cents/gallon) and $3.27/barrel (7.8 cents/gallon) in 2022 (in 2020 U.S. dollars).

Table 4.4.2-1: Macroeconomic Oil Security Premiums for 2021–2022 (2020$/barrel)[a]

Year	Avoided Macroeconomic Disruption/Adjustment Costs (Range)
2021	$3.14 ($1.09 - $5.62)
2022	$3.27 ($1.03 - $5.85)

[a] Top values in each cell are mean values. Values in parentheses are 90% confidence intervals.

4.4.3 Energy Security Benefits

Estimates of the total annual energy security benefits of the proposed 2021 and 2022 RFS standards are based on the ORNL oil security premium methodology with updated oil security premium estimates reflecting the recent energy security literature and using the AEO 2021. Annual per-gallon benefits are applied to the reductions in U.S. crude oil imports, 856 millions of gallons for 2021, and 2,078 millions of gallons, including the Supplemental Volumes, and

[414] Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule, 40 CFR Part 80. 2010.
[415] EPA and ORNL worked together to develop an updated estimate of the GDP elasticity to an oil shock for use in the ORNL model. This slightly different value also was produced by an earlier draft of the ORNL meta-analysis.

1,939 millions of gallons, excluding the Supplemental Volumes, in 2022, respectively.[416] We do not consider military cost impacts, the monopsony effect of oil import changes. The energy security benefits are estimated to be 64 million dollars in 2021 and 162 million dollars in 2022 (in 2020 dollars), including the Supplemental Volumes, from this proposed rule and 151 million dollars in 2022 (in 2020 dollars), excluding the Supplemental Volumes, from this proposed rule, as presented in Table 4.4.3-1 below.

Table 4.4.3-1: Annual Energy Security Benefits of the Proposed 2021 and 2022 RFS Standards (Millions of 2020$)

Year	Crude Import Reduction [a] (millions of gallons)	Benefits (millions of 2020$)
2021	856	64
2022		
Excluding Supplemental Volumes	1,939	151
Including Supplemental Volumes	2,078	162

[a] Import reductions used for the energy security analysis in this section are a combination of reduced imports in gasoline, diesel, and crude from Table 9.3-4 and 9.3-5 converted to crude oil equivalent gallons.

[416] See Table 9.3-2. Energy security benefits are assessed for volume changes relative to proposed 2020 volumes. Thus the 2022 volume change is assumed to be the sum of the 2021/2020 crude import change and the 2022/2021 crude oil import change. Note that we do not separately assess the energy security implications of renewable diesel volumes which are expected to be imported; we only consider the energy security impacts of the petroleum-based fuel that this imported biofuel is assumed to displace.

Chapter 5: Rate of Production of Renewable Fuel

This chapter discusses the expected annual rate of future commercial production of renewable fuels, including advanced biofuels in each category (cellulosic biofuel and biomass-based diesel), for each of the years addressed in this proposed rule. Projected production of renewable fuel for 2021 and 2022 for each category of renewable fuel is based on historic data and other relevant factors, discussed in more detail in the following sections.

We also project the use (i.e., consumption) of qualifying renewable fuels in the United States. Sometimes, we term this the “supply” of biofuels. This projection is based on our assessment of production, exports and imports, infrastructure constraints on distributing and using biofuels, costs, and other factors explained below and throughout the DRIA. In general, we expect that all cellulosic biofuels produced in the U.S. will be used here. By contrast, some quantities of domestically produced advanced and conventional renewable fuels are exported.

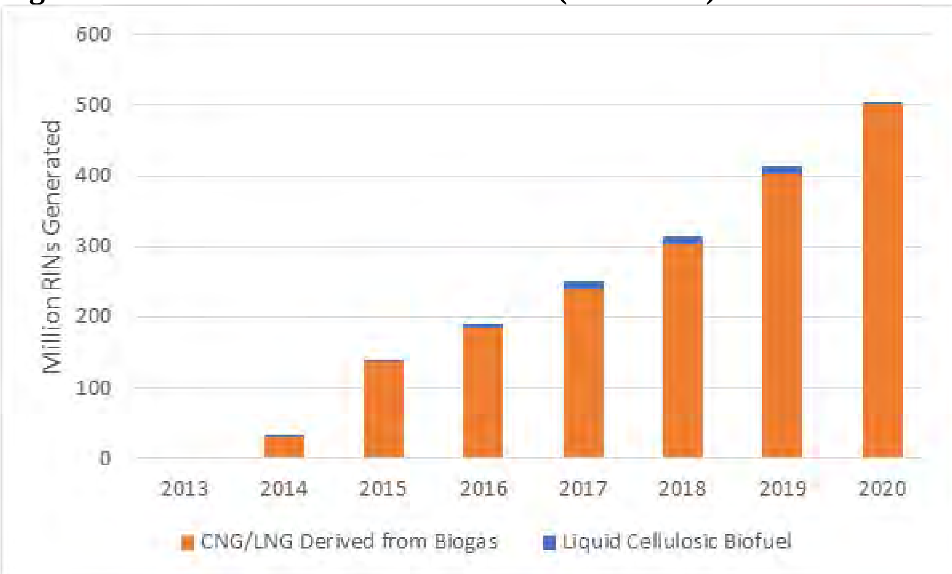
We discuss the production and use of each major type of biofuel in turn: cellulosic biofuel (5.1), biodiesel and renewable diesel (5.2), advanced ethanol (5.3), other advanced biofuels (besides ethanol, biodiesel, and renewable diesel) (5.4), and corn ethanol (5.5).

5.1 Cellulosic Biofuel

In the past several years, production of cellulosic biofuel has continued to increase. Cellulosic biofuel production reached record levels in 2020, driven by CNG and LNG derived from biogas.[417] The projected volumes of cellulosic biofuel production in 2021 and 2022 are even higher than the volume produced in 2020. Production of liquid cellulosic biofuel has remained limited in recent years (see Figure 5.1-1). This section describes our assessment of the rate of production of qualifying cellulosic biofuel in 2021 and 2022, and some of the uncertainties associated with these volumes. These projections address both our obligation to project the amount of cellulosic biofuel under the cellulosic waiver authority, CAA section 211(o)(7)(D)(i), and our obligation to analyze the rate of production of renewable fuel in these years under our reset authority, CAA section 211(o)(2)(B)(ii)(III). We also discuss the potential availability of cellulosic biofuels produced from other sources that are not included in our volume projections for 2021 and 2022.

[417] The majority of the cellulosic RINs generated for CNG/LNG are sourced from biogas from landfills; however, the biogas may come from a variety of sources including municipal wastewater treatment facility digesters, agricultural digesters, separated municipal solid waste (MSW) digesters, and the cellulosic components of biomass processed in other waste digesters.

Figure 5.1-1: Cellulosic RINs Generated (2013-2020)



To project the volume of cellulosic biofuel production in 2021 and 2022, we considered numerous factors, including the accuracy of the methodologies used to project cellulosic biofuel production in previous years, data reported to EPA through EMTS, and information we collected through meetings with representatives of facilities that have produced or have the potential to produce qualifying volumes of cellulosic biofuel in 2021 or 2022. We also based our projection of cellulosic biofuel production in 2021 on EIA's projection. EIA has not yet provided EPA with a projection of cellulosic biofuel production for 2022, but we anticipate this projection will also inform our projection of cellulosic biofuel production for 2022 in the final rule.

To project the range of potential production volumes of liquid cellulosic biofuel for 2021 and 2022 we used the same general methodology as the methodology used in the 2018 – 2020 RFS annual rules. We have adjusted the percentile values used to select a point estimate within a projected production range for each group of companies based on updated information (through 2020) with the objective of improving the accuracy of the projections. To project the production of cellulosic biofuel RINs for CNG/LNG derived from biogas, we used the same general year-over-year growth rate methodology as in the 2018 – 2020 final rules, with updated RIN generation data through March 2021. This methodology reflects the mature status of this industry, the large number of facilities registered to generate cellulosic biofuel RINs from these fuels, and EPA's continued attempts to refine its methodology to yield estimates that are as accurate as possible.

Our discussion of the rate of production of cellulosic biofuel also discusses the availability of potential cellulosic biofuels produced from two other sources: cellulosic ethanol derived from corn kernel fiber (beyond those facilities currently registered with EPA) and renewable electricity used as transportation fuel. At this time, there are outstanding technical, regulatory, and/or implementation issues that must be resolved before cellulosic RINs can be generated using these pathways. In the case of cellulosic ethanol derived from corn kernel fiber, the relevant issues may be resolved on a timeline that allows for cellulosic RIN generation in 2022, but this is not the case for the issues related to renewable electricity.

The balance of this section is organized as follows. Chapter 5.1.1 discusses our current cellulosic biofuel industry assessment, including a review of the accuracy of EPA's projections in prior years and the companies EPA assessed in the process of projecting qualifying cellulosic biofuel production in the U.S. Chapter 5.1.2 discusses the methodologies used by EPA to project cellulosic biofuel production in 2021 and 2022. Chapter 5.1.3 discusses other potential sources of cellulosic biofuel. Chapter 5.1.4 discusses the projected rate of production and import of cellulosic biofuel volume for 2021 and 2022.

5.1.1 Cellulosic Biofuel Industry Assessment

In this section, we first explain our general approach to assessing facilities or groups of facilities (which we collectively refer to as "facilities") that we believe are likely to generate qualifying RINs for cellulosic biofuel in 2021 and 2022. We then review the accuracy of EPA's projections in prior years. Next, we discuss the criteria used to determine whether to include potential domestic and foreign sources of cellulosic biofuel in 2021 and 2022. Finally, we provide a summary table of all facilities that we expect to produce cellulosic biofuel by 2022.

To project the rate of cellulosic biofuel production for 2021 and 2022, we have tracked the progress of a number of potential cellulosic biofuel production facilities, located both in the U.S. and in foreign countries. We considered a number of factors, including information from EMTS, the registration status of potential biofuel production facilities as cellulosic biofuel producers in the RFS program, publicly available information (including press releases and news reports), and information provided by representatives of potential cellulosic biofuel producers. As discussed in greater detail in Chapter 5.1.3.1, our projection of liquid cellulosic biofuel is based on a facility-by-facility assessment of each of the likely sources of cellulosic biofuel in 2021 and 2022, while our projection of CNG/LNG derived from biogas is based on an industry-wide assessment. To make a determination of which facilities are most likely to produce liquid cellulosic biofuel and generate cellulosic biofuel RINs by 2022, each potential producer of liquid cellulosic biofuel was investigated further to determine the current status of its facilities and its likely cellulosic biofuel production and RIN generation volumes. Both in our discussions with representatives of individual companies and as part of our internal evaluation process, we gathered and analyzed information including, but not limited to, the funding status of these facilities, current status of the production technologies, anticipated construction and production ramp-up periods, facility registration status, and annual fuel production and RIN generation targets.

5.1.1.1 Review of EPA's Projection of Cellulosic Biofuel in Previous Years

As an initial matter, it is useful to review the accuracy of EPA's past cellulosic biofuel projections. The record of actual cellulosic biofuel production, including both cellulosic biofuel (which generate D3 RINs) and cellulosic diesel (which generate D7 RINs), and EPA's projected production volumes from 2015-2020[418] are shown in Table 5.1.1.1-1. These data indicate that

[418] 2020 is the last year for which complete data is available at the time of this proposal. In the final rule, we anticipate, as we have done in prior annual rulemakings, also analyzing actual cellulosic biofuel availability in 2021 based on updated data.

EPA's projection was lower than the actual number of cellulosic RINs made available in 2015 and 2018[419] and higher than the actual number of RINs made available in 2016, 2017, 2019, and 2020. The fact that the projections made using this methodology have been somewhat inaccurate, under-estimating the actual number of RINs made available in some years and over-estimating in other years, reflects the inherent difficulty with projecting cellulosic biofuel production. It also emphasizes the importance of continuing to consider refinements to our projection methodology in order to make our projections more accurate.

Table 5.1.1.1-1: Projected and Actual Cellulosic Biofuel Production (2015-2020); Million Gallons[a]

Year	Projected Volume[b]			Actual Production Volume[c]		
	Liquid Cellulosic Biofuel	CNG/LNG Derived from Biogas	Total Cellulosic Biofuel[d]	Liquid Cellulosic Biofuel	CNG/LNG Derived from Biogas	Total Cellulosic Biofuel[d]
2015[e]	2	33	35	0.5	52.8	53.3
2016	23	207	230	4.1	186.2	190.3
2017	13	298	311	11.7	239.4	251.1
2018	14	274	288	10.6	303.9	314.5
2019	20	399	418	11.1	402.8	413.9
2020	16	577	593	2.1	502.5	504.6

[a]EPA has consistently interpreted the term "projected volume of cellulosic biofuel production" to include volumes of cellulosic biofuel likely to be made available in the U.S., including from both domestic production and imports. The volumes in this table therefore include both domestic production of cellulosic biofuel and imported cellulosic biofuel.
[b]Projected volumes for 2015 and 2016 can be found in the 2014-2016 Final Rule (80 FR 77506, 77508, December 14, 2015); projected volumes for 2017 can be found in the 2017 Final Rule (81 FR 89760, December 12, 2016); projected volumes for 2018 can be found in the 2018 Final Rule (82 FR 58503, December 12, 2017); projected volumes for 2019 can be found in the 2019 Final Rule (83 FR 63704, December 11, 2018); projected volumes for 2020 can be found in the 2020 Final Rule (85 FR 7016, February 6, 2020).
[c]Actual production volumes are the total number of RINs generated minus the number of RINs retired for reasons other than compliance with the annual standards, based on EMTS data.
[d]Total cellulosic biofuel may not be precisely equal to the sum of liquid cellulosic biofuel and CNG/LNG derived from biogas due to rounding.
[e]Projected and actual volumes for 2015 represent only the final 3 months of 2015 (October – December) as EPA used actual RIN generation data for the first 9 months of the year.

EPA's projections of liquid cellulosic biofuel were higher than the actual volume of liquid cellulosic biofuel produced each year from 2015 to 2020. In an effort to take into account the most recent data available and make the liquid cellulosic biofuel projections more accurate, EPA adjusted our methodology in the 2018 final rule following the over-projections in 2015-2016 (and anticipated over-projection in 2017).[420] Despite these adjustments, EPA continued to over-project the volume of liquid cellulosic biofuel in each year from 2018 through 2020. 2020, however, was a challenging year for the entire industry due to the impacts of COVID-19, which was an unforeseen event that EPA could not have accounted for in projecting the volume. Given

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[419] EPA only projected cellulosic biofuel production for the final three months of 2015, since data on the availability of cellulosic biofuel RINs (D3+D7) for the first nine months of the year were available at the time the analyses were completed for the final rule.
[420] 82 FR 58486 (December 12, 2017).

this and the fact the liquid cellulosic biofuel volume is a small fraction of the total cellulosic biofuel volume, we are again applying the same general approach we first used in the 2018 final rule: using percentile values based on actual production in previous years, relative to the projected volume of liquid cellulosic biofuel in these years. We believe that the use of the methodology (described in more detail in Chapter 5.1.3.1), results in a projection that reflects a neutral aim at accuracy since it accounts for expected growth in the near future by using historical data.

We next turn to the projection of CNG/LNG derived from biogas. For 2018 - 2020, EPA used an industry-wide approach, rather than an approach that projects volumes for individual companies or facilities, to project the production of CNG/LNG derived from biogas. EPA used a facility-by-facility approach to project the production of CNG/LNG derived from biogas from 2015-2017. Notably the facility-by-facility methodology resulted in significant over-estimates of CNG/LNG production in 2016 and 2017, leading EPA to develop the alternative industry wide projection methodology first used in 2018. This updated approach reflects the fact that this industry is far more mature than the liquid cellulosic biofuel industry, with a far greater number of potential producers of CNG/LNG derived from biogas. In such cases, industry-wide projection methods can be more accurate than a facility-by-facility approach, especially as macro market and economic factors become more influential on total production than the success or challenges at any single facility. The industry-wide projection methodology slightly under-projected the production of CNG/LNG derived from biogas in 2018 and 2019 but over-projected the production of these fuels in 2020. The accuracy of the 2020 projection, however, was likely influenced by the unforeseen and significant impacts of COVID-19.

As further described in Chapter 5.1.3.2, EPA is again projecting production of CNG/LNG derived from biogas using the industry-wide approach in this proposed rule. We calculate a year-over-year rate of growth in the renewable CNG/LNG industry and apply this year-over-year growth rate to the total number of cellulosic RINs generated and available to be used for compliance with the annual standards in 2020 to estimate the production of CNG/LNG derived from biogas in 2021 and 2022.[421] We have applied the growth rate to the number of available 2020 RINs generated for CNG/LNG derived from biogas as data from this year allows us to adequately account for not only RIN generation, but also for RINs retired for reasons other than compliance with the annual standards. While more recent RIN generation data is available, the retirement of RINs for reasons other than compliance with the annual standards generally lags RIN generation, sometimes by up to a year or more.

The production volumes of cellulosic biofuel in previous years also highlight that the production of CNG/LNG derived from biogas has been significantly higher than the production of liquid cellulosic biofuel. This is likely the result of a combination of factors, including the mature state of the technology used to produce CNG/LNG derived from biogas relative to the technologies used to produce liquid cellulosic biofuel, and the relatively low production cost of

[421] To project the volume of CNG/LNG derived from biogas in 2021, we multiply (1) the number of 2020 RINs generated for these fuels and available to be used for compliance with the annual standards by (2) the calculated growth rate to project production of these fuels in 2021. To project the volume of CNG/LNG derived from biogas in 2022 we then (3) multiply the projected volume for 2021 by the growth rate again to project the production of these fuels in 2022.

CNG/LNG derived from biogas (see Chapter 9). These factors are unlikely to change in 2021 or 2022. While we project production volumes of liquid cellulosic biofuel and CNG/LNG derived from biogas separately, ultimately it is overall accuracy of the combined cellulosic biofuel volume projection that is relevant to obligated parties.

5.1.1.2 Potential Domestic Producers

There are several companies and facilities located in the U.S. that have either already begun producing cellulosic biofuel for use as transportation fuel, heating oil, or jet fuel at a commercial scale,[422] or are anticipated to be in a position to do so at by the end of 2022. The RFS program provides a strong financial incentive for domestic cellulosic biofuel producers to sell any fuel they produce for domestic consumption.[423] To date nearly all cellulosic biofuel produced in the U.S. has been used domestically. This, along with the significant incentives provided by the high cellulosic RIN prices, gives us a high degree of confidence that cellulosic biofuel RINs will be generated for all cellulosic biofuel produced by such domestic commercial scale facilities. To generate RINs, each of these facilities must be registered with EPA under the RFS program and comply with all the regulatory requirements. This includes using an approved RIN-generating pathway and verifying that their feedstocks meet the definition of renewable biomass. Most of the domestic companies and facilities considered in our assessment of potential cellulosic biofuel producers through 2022 have already successfully completed facility registration, and have successfully generated RINs.[424] The remainder of this section presents a brief description of each of the domestic companies (or group of companies for cellulosic CNG/LNG producers and the facilities using Edeniq's technology) that EPA believes may produce commercial-scale volumes of RIN generating cellulosic biofuel by the end of 2022. General information on each of these companies or group of companies considered in our projection of the potentially available volume of cellulosic biofuel in 2021 or 2022 is summarized in Table 5.1.1.4-1.

Ace Ethanol

Ace Ethanol has installed technology developed by D3MAX designed to convert the cellulosic portion of the distillers grains produced at their Stanely, Wisconsin facility to ethanol. The D3MAX technology uses heat, acid, and enzymes to convert the cellulosic biomass in the wet cake produced by a corn ethanol production facility to sugars, which are subsequently converted to ethanol.[425] Ace Ethanol began construction to integrate the D3MAX technology

[422] For a further discussion of EPA's decision to focus on commercial scale facilities, rather than research and development and pilot scale facilities, see the 2019 proposed rule (83 FR 32031, July 10, 2018).
[423] According to data from EMTS, the average price for a 2020 cellulosic biofuel RINs sold in 2020 was $1.35. Alternatively, obligated parties can satisfy their cellulosic biofuel obligations by purchasing an advanced (or biomass-based diesel) RIN and a cellulosic waiver credit. The average price for a 2020 advanced biofuel RINs sold in 2020 was $0.59 while the price for a 2020 cellulosic waiver credit is $1.80 (EPA-420-B-20-005).
[424] Most of the facilities listed in Table 5.1.1.4-1 are registered to produce cellulosic (D3 or D7) RINs with the exception of several of the producers of CNG/LNG derived from biogas and Red Rock Biofuels. EPA is unaware of any outstanding issues that would reasonably be expected to prevent these facilities from registering as cellulosic biofuel producers and producing qualifying cellulosic biofuel in 2021 or 2022.
[425] "Technology," D3MAX website. Accessed 4/27/2020. https://www.d3maxllc.com/technology

into their existing corn ethanol production facility in October 2018.[426] Production of ethanol from the distillers grains began in January 2020.[427] In April 2020 this facility completed the process to register as a cellulosic biofuel producer under the RFS program.[428]

Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) Producers

In July 2014 EPA approved, as part of the "Pathways II" rule,[429] a new cellulosic biofuel pathway for CNG and LNG derived from biogas produced at landfills, separated MSW digesters, municipal wastewater treatment facilities, agricultural digesters, and from the cellulosic components of biomass processed in other waste digesters. The production potential for this type of cellulosic biofuel is large and has increased at a rapid pace since 2014 due to the fact that many U.S.-based entities currently capture or produce biogas. This means that in many cases, both historically and in future years, the construction of new facilities capable of capturing and/or producing biogas will not be required for facilities to begin generating cellulosic biofuel (D3) RINs. In many cases, however, new equipment is necessary to upgrade the biogas that is currently captured or produced to meet pipeline specifications and to compress the gas for injection into a pipeline.

Corn Kernel Fiber to Ethanol Technologies

EPA is aware of several companies that are developing technologies to enable existing corn ethanol plants to convert the cellulosic components present in the corn kernel to ethanol. These technologies generally seek to use some combination of pretreatment and enzymatic hydrolysis to convert the cellulose and hemicellulose present in the corn kernel to simple sugars, and to then ferment these sugars to produce ethanol. Some of these technologies are designed to convert the cellulosic components of the corn kernel to sugars and eventually to ethanol simultaneously with the conversion of the corn kernel starch to ethanol. Other technologies first convert the starch to ethanol and then separately convert the cellulosic components remaining in the wet cake co-product of the corn starch ethanol process to sugars and eventually to ethanol. EPA regulations currently contain a pathway (Pathway K in Table 1 to 40 CFR 80.1426(f)) that would allow ethanol produced in either manner to qualify for cellulosic biofuel RINs, if all other regulatory requirements are satisfied.

A significant issue that must be resolved to register a facility to generate cellulosic biofuel RINs for ethanol when both corn starch and corn kernel fiber are processed together is the accurate quantification of the volume of ethanol produced from cellulosic feedstocks rather than non-cellulosic feedstocks such as starch. As discussed in Section III of the preamble, it is uncertain whether the technical issues related to quantifying the portion of ethanol that is produced from cellulosic biomass when it is processed simultaneously with corn starch will be

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[426] "Ace Ethanol Begins D3MAX Plant Construction at Stanley Wisconsin Facility," Ace Ethanol Website. October 17, 2018. https://www.aceethanol.com/news/ace-ethanol-begins-d3max-plant-construction-at-stanley-wisconsin-facility/
[427] "Ace Approved to Generate D3 RINs From Corn Kernel Fiber Ethanol," BBI International. April 1, 2020.
[428] Id.
[429] 79 FR 42128, July 18, 2014.

resolved on a timeline that would allow significantly higher volumes of qualifying cellulosic ethanol to be produced from corn kernel fiber in 2021.

Edeniq

Edeniq has developed a proprietary process technology (Edeniq Pathway) that allows corn ethanol producers to co-produce conventional ethanol from corn starch and cellulosic ethanol from corn kernel fiber at the corn ethanol producers' existing production facilities. Their process involves the addition of cellulase enzymes to convert the cellulosic material in the corn kernel into sugars and ultimately cellulosic ethanol. Edeniq tested the Edeniq Pathway technology, including both their proprietary Cellunator milling technology and the cellulase enzymes, at a demonstration-scale facility in Visalia, California and announced the successful performance of the Edeniq Pathway technology in June 2014. In the July 2014 "Pathways II" rule EPA clarified that processes, such as the one developed by Edeniq, that convert corn kernel fiber into transportation fuel can be approved to produce fuel that qualifies for cellulosic RINs provided all applicable requirements are met.[430] In September 2016, EPA approved Pacific Ethanol's registration update to allow this facility to generate cellulosic biofuel RINs for fuel produced from cellulosic biomass using Edeniq's technology.[431] EPA has since registered other facilities to generate cellulosic RINs for fuel produced from cellulosic biomass using Edeniq's technology.[432]

Fulcrum BioEnergy

Fulcrum BioEnergy has developed a technology to convert separated MSW into a synthetic crude oil using a gasification and Fischer-Tropsch process.[433] Fulcrum intends to transport this synthetic crude oil, which EPA would consider to be a biointermediate, to an existing petroleum refinery where it would be further processed into transportation fuel. Fulcrum is currently constructing a facility designed to produce 11 million gallons of synthetic crude oil in Storey County, Nevada. Construction of this facility started in May 2018,[434] and is expected to be completed in 2021.

Quad County Corn Processors/Syngenta

Quad County Corn Processors (QCCP) have been operating their bolt-on technology called Cellerate™ since July 2, 2014, at their Galva, Iowa facility. The Cellerate Process Technology enables QCCP to produce cellulosic ethanol from corn kernel fiber. The Cellerate Process Technology is a second process, separate from the process that converts corn starch to

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[430] 79 FR 42128, July 18, 2014.
[431] Schroeder, Joanna. "EPA Approves Edeniq Cellulosic Pathway." Energy.Agwired.com. September 13, 2016. Available at: http://energy.agwired.com/2016/09/13/epa-approves-edeniq-cellulosic-pathway
[432] "Edeniq Pathway Technology Renamed to Intellulose" https://www.businesswire.com/news/home/20180503005977/en/Edeniq-Pathway-Technology-Renamed-to-Intellulose
[433] Unless otherwise noted, all information in this paragraph from Fulcrum BioEnergy website: Sierra Biofuels Plant: https://fulcrum-bioenergy.com/facilities
[434] Fulcrum BioEnergy Breaks Ground on Sierra Biofuels Plant: https://fulcrum-bioenergy.com/wp-content/uploads/2018/05/2018-05-16-Sierra-Groundbreaking-FINAL-1.pdf

ethanol. The Cellerate Process Technology pre-treats the remaining cellulosic portion of the corn kernel to produce sugars, and then ferments these sugars to produce ethanol.

Red Rock Biofuels

Red Rock Biofuels intends to use an integration of existing technologies to convert forest residues to diesel and jet fuel using a Fischer-Tropsch process.[435] Construction of their first commercial scale production facility began on July 18, 2018.[436] This facility, located in Lakeview, Oregon, is designed to produce approximately 16 million gallons of cellulosic biofuel per year.[437] Construction of this facility is currently expected to be completed by the end of 2021.[438]

5.1.1.3 Potential Foreign Sources of Cellulosic Biofuel

EPA's projection of cellulosic biofuel production through 2022 also includes cellulosic biofuel that is projected to be imported into the U.S. This means the potential imports from all currently registered foreign facilities under the RFS program. Currently, there are several foreign cellulosic biofuel companies registered with EPA and with the potential to generate RINs for qualifying cellulosic biofuel in 2021 or 2022. These include facilities owned and operated by Enerkem, GranBio, and Raizen. All of these facilities use fuel production pathways that have been approved by EPA for cellulosic RIN generation provided eligible sources of renewable feedstock are used, the fuel is used as transportation fuel in the U.S., and other regulatory requirements are satisfied. Given this, we consider imports from these companies as potential sources of cellulosic biofuel. Nonetheless, we also note that demand for the cellulosic biofuels they produce is expected to be high in their own local markets.

By contrast, we believe that cellulosic biofuel imports from foreign facilities not currently registered to generate cellulosic biofuel RINs are generally highly unlikely through 2022. This is due to the strong demand for cellulosic biofuel in local markets and the time necessary for potential foreign cellulosic biofuel producers to register under the RFS program and arrange for the importation of cellulosic biofuel to the U.S. For purposes of our 2021 and 2022 projections of the rate of production of cellulosic biofuel we have excluded potential volumes from foreign cellulosic biofuel production facilities that are not currently registered under the RFS program.

Cellulosic biofuel produced at two foreign facilities (GranBio's and Raizen's Brazilian facilities) have generated cellulosic biofuel RINs for fuel exported to the U.S. in previous years. Another foreign facility (Enerkem's Canadian facility) has completed the registration process as a cellulosic biofuel producer. Each of these facilities is described briefly below. However, based on data available through EMTS no foreign facilities have generated cellulosic (D3) RINs for

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[435] Red Rock Biofuels website: https://www.redrockbio.com/. Accessed April 30, 2019.
[436] Red Rock Biofuels: Lakeview Site: https://www.redrockbio.com/lakeview-site.html. Accessed April 30, 2019.
[437] Red Rock Biofuels: Lakeview Site: https://www.redrockbio.com/lakeview-site.html. Accessed April 30, 2019.
[438] Winter, Ken. "Work continues at Red Rock despite rumors." *Lake County Examiner*, February 10, 2021. Available at: http://www.lakecountyexam.com/news/work-continues-at-red-rock-despite-rumors/article_7eb9cf92-6b26-11eb-b1a7-47cc48d569ab.html

imported liquid cellulosic biofuel since March 2019. Therefore, while we have included these facilities as potential sources of cellulosic biofuel we are not projecting any imports of cellulosic biofuel through 2022. All of the potential cellulosic biofuel producers for 2021 and/or 2022 are listed in Table 5.1.1.4-1.

Enerkem

Enerkem has developed a commercial-scale technology capable of converting non-recyclable waste to a variety of renewable chemicals and fuels, including both methanol and ethanol.[439] After feedstock preparation, Enerkem's feedstocks are gasified to produce a synthetic gas (or syngas). Enerkem next purifies the syngas and processes it through a catalytic reactor to convert the syngas into the desired products. Enerkem has developed their proprietary technology over a period of 10 years before deploying it at commercial scale in Edmonton, Canada.[440] Enerkem's facility in Edmonton is designed to produce up to 13 million gallons of cellulosic ethanol per year.[441] This facility began production of methanol in 2015, with production switching from methanol to ethanol in 2017.

GranBio

GranBio uses a hydro-thermal pretreatment and enzymatic hydrolysis process to convert cellulosic biomass into ethanol.[442] Construction of their first cellulosic ethanol production facility was announced in mid-2012, and financing was completed in May 2013.[443] In September 2014, GranBio announced that its first cellulosic ethanol facility became operational.[444] The facility uses sugarcane straw or bagasse as a feedstock and produces both ethanol and electricity, depending on market conditions. The facility is located in Sao Miguel dos Campos, Alagoas, Brazil and originally had a production capacity of approximately 21.5 million gallons (82 million liters) of ethanol per year.[445] Since 2016, GranBio has been implementing several equipment and technology modifications at the plant, which will result in a production capacity of approximately 15.8 million gallons (60 million liters) of ethanol per year.

Raizen

Raizen, a joint venture between Shell and Cosan, uses a technology developed by Iogen Energy to convert sugarcane bagasse into ethanol. Raizen has constructed a facility co-located with a first generation ethanol production facility in Piracicaba/SP Brazil designed to be capable of producing approximately 10.5 million gallons of ethanol a year from biomass residues from

[439] "Technology," Enerkem Website. Accessed 5/15/2018. https://enerkem.com/about-us/technology/
[440] Ibid
[441] "Enerkem Alberta Biofuels," Enerkem Website. Accessed 5/15/2018. https://enerkem.com/facilities/enerkem-alberta-biofuels/
[442] "Who We Are," GranBio Website. Accessed May 15, 2018. http://www.granbio.com.br/en/conteudos/who-we-are/
[443] Schill, Susanne R. "Financing Complete on Brazil's first commercial 2G Ethanol Plant," Ethanol Producer Magazine. May 17, 2013.
[444] "Who We Are," GranBio Website. Accessed May 15, 2018. http://www.granbio.com.br/en/conteudos/who-we-are/
[445] Ibid

first generation sugarcane ethanol production.[446] Construction of this facility began in November 2013, and the first phase, allowing for the conversion of C6 sugars into ethanol, was completed in July 2015.[447] Further construction allowing for the conversion of both C5 and C6 sugars into ethanol was completed in May 2016. Raizen began exporting cellulosic ethanol produced at this facility to the United States in 2017, and has exported 32 million liters of cellulosic ethanol to the U.S. through the end of 2019.

5.1.1.4 Summary of Potential Sources of Cellulosic Biofuel in 2021-2022

General information on each of the cellulosic biofuel producers (or group of producers, for producers of CNG/LNG derived from biogas and producers of liquid cellulosic biofuel using Edeniq's technology) that factored into our projection of cellulosic biofuel production through 2022 is shown in Table 5.1.1.4-1. This table includes both facilities that have already generated cellulosic RINs, as well as those that have not yet generated cellulosic RINs, but are expected to do so by the end of 2022. Since we are proposing regulations that would allow for the production of qualifying renewable fuels from biointermediates in this rule, we have included facilities intending to produce cellulosic biofuel from biointermediates in this table, and in our projections of liquid cellulosic biofuel production for 2022. Note that while we believe all these facilities have the potential to produce or import cellulosic biofuel by the end of 2022, our projections of cellulosic biofuel production do not include volumes from all of the listed facilities, as we believe the most likely volume of cellulosic biofuel produced or imported from some of these facilities in 2021 and 2022 is zero.

[446] "A track record of innovation." Iogen website. Accessed May 1, 2018.
[447]Ibid

Table 5.1.1.4-1: Potential Producers of Cellulosic Biofuel for U.S. Consumption in 2021 or 2022

Company Name	Location	Feedstock	Fuel	Facility Capacity (Million Gallons per Year)[448]	Construction Start Date	First Production[449]
Ace Ethanol	Stanley, WI	Corn Kernel Fiber	Ethanol	3	October 2018	January 2020
CNG/LNG Producers	Various	Biogas	CNG/ LNG	Various	Various	Various
Edeniq	Various	Corn Kernel Fiber	Ethanol	Various	Various	October 2016
Enerkem	Edmonton, AL, Canada	Separated MSW	Ethanol	10[450]	2012	September 2017[451]
Fulcrum/ Marathon	Storey County, NV	Separated MSW	Diesel, Jet Fuel	11	May 2018	2021
GranBio	São Miguel dos Campos, Brazil	Sugarcane bagasse	Ethanol	21	Mid 2012	September 2014
QCCP/ Syngenta	Galva, IA	Corn Kernel Fiber	Ethanol	4	Late 2013	October 2014
Red Rock Biofuels	Lakeview, OR	Wood Waste	Diesel, Jet Fuel	16	July 2018	1Q 2022
Raizen	Piracicaba City, Brazil	Sugarcane bagasse	Ethanol	11	January 2014	July 2015

[448] The Facility Capacity is generally equal to the nameplate capacity provided to EPA by company representatives or found in publicly available information. Capacities are listed in physical gallons (rather than ethanol-equivalent gallons). If the facility has completed registration and the total permitted capacity is lower than the nameplate capacity, then this lower volume is used as the facility capacity.
[449] Where a quarter is listed for the first production date EPA has assumed production begins in the middle month of the quarter (i.e., August for the 3rd quarter) for the purposes of projecting volumes.
[450] The nameplate capacity of Enerkem's facility is 10 million gallons per year. However, we anticipate that a portion of their feedstock will be non-biogenic municipal solid waste (MSW). RINs cannot be generated for the portion of the fuel produced from non-biogenic feedstocks. We have taken this into account in our production projection for this facility (See "May 2021 Liquid Cellulosic Biofuel Projections for 2021 and 2022 CBI").
[451] This date reflects the first production of ethanol from this facility. The facility began production of methanol in 2015.

5.1.2 Projected Cellulosic Biofuel Production in 2021 and 2022

5.1.2.1 Liquid Cellulosic Biofuel

For our 2021 and 2022 liquid cellulosic biofuel projections, we use the same general approach as we have in projecting these volumes in previous years. We begin by first categorizing potential liquid cellulosic biofuel producers in 2021 and 2022 according to whether or not they have achieved consistent commercial scale production of cellulosic biofuel to date. For our 2022 projections, these potential producers include one facility (Fulcrum/Marathon) that intends to produce liquid cellulosic biofuel from biointermediates, as we are proposing regulations that would allow for the production of qualifying renewable fuel from biointermediates in this rule. We refer to these facilities as consistent producers and new producers, respectively. Next, we define a range of likely production volumes for 2021 and 2022 for each group of companies. Finally, we use a percentile value to project from the established range a single projected production volume for each group of companies in 2021 and 2022. As in the 2018 – 2020 final rules, we then calculated percentile values for each group of companies based on the past performance of each group relative to our projected production ranges.

We first separate the list of potential producers (listed in Table 5.1.1.4-1) into two groups according to whether the facilities have achieved consistent commercial-scale production and cellulosic biofuel RIN generation. Unlike in previous years, we have not listed the names of the companies that fall into each group due to the small number of companies in some of the categories and the fact that some of the data used to calculated the ends of the range is considered confidential business information by these companies.[452] We next defined a range of likely production volumes for each group of potential producers. The low end of the range for each group of producers reflects actual RIN generation data over the last 12 months for which data were available at the time our technical assessment was completed (April 2020 – March 2021).[453] Because the most recent 12 months for which we have data is the same for our projections of liquid cellulosic biofuel production in 2021 and 2022, the low end of the range for each group of producers is the same for both years. For potential producers that have not yet generated any cellulosic RINs, the low end of the range is zero. For the high end of the range, we considered a variety of factors, including the expected start-up date and ramp-up period, facility capacity, and the number of RINs the producer expects to generate in 2021 and 2022.[454] The high end of the range for each group of producers is potentially different for 2021 and 2022, as we consider factors such as the ramp-up of production and company projections in the high end

[452] More information on the companies included in each group is contained in the memos "May 2021 Liquid Cellulosic Biofuel Projections for 2021 and 2022 CBI"“”.

[453] We recognize that in some years cellulosic biofuel production from facilities that have achieved consistent commercial scale production may be lower than the volume achieved in the previous 12 months. This has happened several times since 2016. In these cases the methodology would suggest that using a negative percentile value (indicating production in the coming year that is lower than the volume produced in the previous 12 months). By considering the use of negative percentile values for facilities that have achieved consistent commercial scale production we believe the proposed methodology adequately accounts for this possibility.

[454] As in our 2015-2020 projections, EPA calculated a high end of the range for each facility (or group of facilities) based on the expected start-up date and a six-month straight-line ramp-up period. The high end of the range for each facility (or group of facilities) is equal to the value calculated by EPA using this methodology, or the number of RINs the producer expects to generate in 2021 or 2022, whichever is lower.

of the range, which may lead to differing estimates for 2021 and 2022. The projected range for each group of companies is shown in Table 5.1.2.1-1.[455]

Table 5.1.2.1-1: 2021 and 2022 Liquid Cellulosic Biofuel Projected Production Ranges (million ethanol-equivalent gallons)[a]

Category	Low End of the Range	High End of the Range
2021		
New Producers	0	0
Consistent Producers	2	3
2022		
New Producers	0	20
Consistent Producers	2	3

[a] Rounded to the nearest million gallons.

After defining likely production ranges for each group of companies, we next determined the percentile values to use in projecting a production volume for each group of companies. We calculate the percentile values by comparing actual production data from 2016 through 2020 with the production ranges projected in the annual rules for those years. We chose the 2016-20 time period because the first full year in which EPA used the current methodology for developing the range of potential production volumes for each company was 2016, while 2020 is the most recent year for which we have data.

As in previous years, to calculate the percentiles within the projected ranges used to project liquid cellulosic biofuel production for 2021 and 2022 we propose to use the average percentile values for each group of companies from 2016 – 2020. We considered weighting recent years more heavily than previous years, however we have not done so in this projection. The disruptions in the cellulosic biofuel industry caused by the COVID pandemic in 2020 suggest that we should not more heavily weigh 2020, even though this is the most recent year for which we have data. Alternatively, we considered only considering the percentile values from 2016-2019 due to the impacts of the COVID pandemic. Excluding the percentiles from 2020 results in slightly higher percentile values than those we calculate when including the 2020 data (the 9th percentile for new producers and the 6th percentile for consistent producers). We note that these slightly higher percentile values have no impact on our projection of cellulosic biofuel production in 2021 and a very small impact (1 million gallons) on our projection of cellulosic biofuel production for 2022.

For each group of companies and for each year from 2016-2020, Table 5.1.2.1-2 shows the projected ranges for liquid cellulosic biofuel production (from relevant annual rules), actual

[455] More information on the data and methods EPA used to calculate each of the ranges in these tables in contained in “May 2021 Liquid Cellulosic Biofuel Projections for 2021 and 2022 CBI” memorandum from Dallas Burkholder to EPA Docket EPA-HQ-OAR-2021-0324. We have not shown the projected ranges for each individual company. This is because the high end of the range for some of these companies are based on the company’s production projections, which they consider confidential business information (CBI). Additionally, the low end of the range for facilities that have achieved consistent commercial scale production is based on actual RIN generation data in the most recent 12 months, which is also claimed as CBI.

production, the percentile values that would have resulted in a projection equal to the actual production volume, and the weighting factor used in each year.

Table 5.1.2.1-2: Projected and Actual Liquid Cellulosic Biofuel Production in 2016-2020 (million gallons)

	Low End of the Range	High End of the Range	Actual Production[456]	Actual Percentile
New Producers[457]				
2016	0	76	1.06	1st
2017	0	33	8.79	27th
2018	0	47	2.87	6th
2019	0	10	0.00	0th
2020	0	30	1.53	5th
Average[a]	N/A	N/A	N/A	8th
Consistent Producers[458]				
2016	2	5	3.28	43rd
2017	3.5	7	3.02	–14th
2018	7	24	7.74	4th
2019	14	44	11.13	–10th
2020	10	36	0.52	–36th
Average[a]	N/A	N/A	N/A	–3rd

[a] We have not averaged the low and high ends of the ranges, or actual production, as we believe it is more appropriate to consider the averages of the actual percentiles from 2016 - 2020 rather than calculating a percentile value for 2016 – 2020 in aggregate.

Based upon this analysis, EPA has projected cellulosic biofuel production from new producers at the 8th percentile of the calculated range and from consistent producers at the –3rd percentile.[459] These percentiles are calculated by averaging the percentiles that would have produced cellulosic biofuel projections equal to the volumes produced by each group of companies in 2016 - 2020. Prior to 2016, EPA used different methodologies to project available

[456] Actual production is calculated by subtracting RINs retired for any reason other than compliance with the RFS standards from the total number of cellulosic RINs generated.

[457] Companies characterized as new producers in the 2014-2016, 2017, 2018, 2019, and 2020 final rules were as follows: Abengoa (2016), CoolPlanet (2016), DuPont (2016, 2017), Edeniq (2016, 2017), Enerkem (2018, 2019, 2020), Ensyn Port Cartier (2018, 2019, 2020), GranBio (2016, 2017), IneosBio (2016), and Poet (2016, 2017) Red Rock Biofuels (2020).

[458] Companies characterized as consistent producers in the 2014-2016, 2017, 2018, and 2019 final rules were as follows: Edeniq Active Facilities (2018, 2019, 2020), Ensyn Renfrew (2016 -2020), GranBio (2018-2020), Poet (2018, 2019), Quad County Corn Processors/Syngenta (2016 - 2020), and Raizen (2019-2020).

[459] The negative percentile we are using to project cellulosic biofuel production from consistent producers in 2021 and 2022 means that we are projecting less cellulosic biofuel will be produced from these facilities than they produced over the last 12 months for which data is available. We observed a similar pattern in 2017 and 2020, where liquid cellulosic biofuel production from consistent producers fell from the prior year. This is generally because producing liquid cellulosic biofuel at a commercial scale remains challenging, and many producers have gone out of business not long after they began production.

volumes of cellulosic biofuel and thus believes it inappropriate to calculate percentile values based on projections from those years.[460]

We then used these percentile values, together with the ranges determined for each group of companies discussed above, to project a volume for each group of companies in 2021 and 2022. These calculations are summarized in Table 5.1.2.1-3.

Table 5.1.2.1-3: Projected Volume of Liquid Cellulosic Biofuel in 2021 and 2022 (million ethanol-equivalent gallons)

	Low End of the Range[a]	High End of the Range[a]	Percentile	Projected Volume[a]
2021				
Liquid Cellulosic Biofuel Producers; Producers without Consistent Commercial Scale Production	0	0	8th	0
Liquid Cellulosic Biofuel Producers; Producers with Consistent Commercial Scale Production	2	3	–3rd	2
Total	N/A	N/A	N/A	2
2022				
Liquid Cellulosic Biofuel Producers; Producers without Consistent Commercial Scale Production	0	20	8th	2
Liquid Cellulosic Biofuel Producers; Producers with Consistent Commercial Scale Production	2	3	–3rd	2
Total	N/A	N/A	N/A	3[b]

[a] Volumes rounded to the nearest million gallons.
[b] Numbers in the table do not add due to rounding

5.1.2.2 CNG/LNG Derived from Biogas

For 2021 and 2022, EPA is using the same industry wide projection approach as used for 2018 – 2020 based on a year-over-year growth rate to project production of CNG/LNG derived from biogas used as transportation fuel.[461] EPA calculated the year-over-year growth rate in CNG/LNG derived from biogas by comparing RIN generation from April 2020 to March 2021 (the most recent 12 months for which data are available) to RIN generation in the 12 months that immediately precede this time period (April 2019 to March 2020). The growth rate calculated using this data is 23.1 percent. These RIN generation volumes are shown in Table 5.1.2.2-1.

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[460] EPA used a similar projection methodology for 2015 as in 2016-2018, however we only projected cellulosic biofuel production volume for the final 3 months of the year, as actual production data were available for the first 9 months. We do not believe it is appropriate to consider data from a year for which 9 months of the data were known at the time the projection was made in determining the percentile values used to project volume over a full year.
[461] Historically RIN generation for CNG/LNG derived from biogas has increased each year. It is possible, however, that RIN generation for these fuels in the most recent 12 months for which data are available could be lower than the preceding 12 months. We believe our methodology accounts for this possibility. In such a case, the calculated rate of growth would be negative.

Table 5.1.2.2-1: Generation of Cellulosic Biofuel RINs for CNG/LNG Derived from Biogas (ethanol-equivalent gallons)

RIN Generation (April 2019 – March 2020)	RIN Generation (April 2020 – March 2021)	Year-Over-Year Increase
417,623,027	514,168,474	23.1%

EPA then applied this 23.1% year-over-year growth rate to the total number of 2020 cellulosic RINs generated and available for compliance for CNG/LNG. This methodology results in a projection of 619 million ethanol-equivalent gallons of CNG/LNG derived from biogas in 2021 and 762 million ethanol-equivalent gallons of CNG/LNG derived from biogas in 2022. In this rule, as in the 2018 – 2020 final rules, we are proposing to apply the calculated year-over-year rate of growth to the volume of CNG/LNG actually supplied in the most recent year for which data is available (in this case 2020), taking into account actual RIN generation as well as RINs retired for reasons other than compliance with the annual volume obligations. This provides a projection of the production of CNG/LNG derived from biogas in 2021. In turn, applying the rate of growth to this 2021 projection yields the projected production of these fuels in 2022.[462]

We then compared these projected volumes with the total volume of CNG/LNG expected to be used as transportation fuel in 2021 and 2022. We are aware of several estimates for the quantity of CNG/LNG that will be used as transportation fuel in 2021 and 2022 that cover a wide range of projected volume. EIA's April 2021 STEO projects that 0.15 and 0.16 billion cubic feet per day of natural gas will be used as transportation fuel in 2021 and 2022 respectively (approximately 720 million ethanol-equivalent gallons and 770 million ethanol-equivalent gallons respectively, assuming 1015 BTU per cubic foot of natural gas and 77,000 BTU per gallon of ethanol).[463] EIA's 2021 AEO projects that 0.11 trillion cubic feet of natural gas and 0.1 trillion cubic feet of natural gas will be used in the transportation sector in 2021 and 2022 respectively (approximately 1.45 billion ethanol-equivalent gallons and 1.3 billion ethanol-equivalent gallons respectively).[464] Finally, according to a paper prepared by Bates White for the Coalition for Renewable Gas[465] Fuels Institute North America projects that 1.8 billion ethanol-equivalent gallons and 2.0 billion ethanol-equivalent gallons of natural gas will be used as transportation fuel in 2021 and 2022 respectively. All of these estimates are greater than (or in the case of the STEO estimate for 2022 equal to) the volume of qualifying CNG/LNG derived from biogas projected to be used in 2021 and 2022. In addition, as discussed in the Bates White report, the projection in the STEO is based on industry surveys, and is highly unlikely to reflect

[462] To calculate the projected production of CNG/LNG derived from biogas in 2021 and 2022, EPA multiplied the number of 2020 RINs generated and available for compliance for CNG/LNG derived from biogas (502.5 million), by 1.231 (representing a 23.1% year-over-year increase) to project production of CNG/LNG in 2021, and multiplied this number (618.6 million RINs) by 1.231 again to project production of CNG/LNG in 2022.
[463] These values are from the projections for Vehicle Use in Table 5a: U.S. Natural Gas Supply, Consumption, and Inventories in the April 2021 STEO.
[464] These values are from the projections for Motor Vehicles, Trains, and Ships in Table 13: Natural Gas Supply, Distribution, and Prices in the 2021 AEO.
[465] *Renewable Natural Gas Supply and Demand for Transportation*. Bates White Economic Consulting, April 5, 2019.

all of the CNG/LNG used as transportation fuel.[466] While there is considerable uncertainty about the quantity of CNG/LNG that will be used in transportation fuel in 2021 and 2022, we believe that the higher estimates made by the Fuels Institute and EIA's Annual Energy Outlook are more representative of the industry capacity to use CNG/LNG as transportation fuel in 2021 and 2022. The projections of natural gas used as transportation fuel in EIA's AEO and the Fuels Institute are significantly greater than the volume of qualifying CNG/LNG derived from biogas projected to be used in 2021 and 2022. Thus, the volume of CNG/LNG used as transportation fuel would not appear to constrain the number of RINs generated for this fuel in these years.

We believe that projecting the production of CNG/LNG derived from biogas in this manner appropriately takes into consideration the actual recent rate of growth of this industry, and that this growth rate accounts for both the potential for future growth and the challenges associated with increasing RIN generation from these fuels in future years. This methodology may not be appropriate to use as the projected volume of CNG/LNG derived from biogas approaches the total volume of CNG/LNG that is used as transportation fuel, as RINs can be generated only for CNG/LNG used as transportation fuel. We do not believe that this is yet a constraint as our projection for 2022 is below the total volume of CNG/LNG that is currently used as transportation fuel.

5.1.3 Additional Potential Sources of Cellulosic Biofuel

As we explain in Section IV of the preamble, EPA has consistently interpreted the statutory phrase "projected volume available" to refer to the volume of qualifying cellulosic biofuel projected to be produced in the U.S. or imported and available for use in the U.S. in that year. This can also be expressed as the quantity of likely cellulosic RINs generated in 2021 and 2022 (i.e., from cellulosic biofuel production that meets statutory and regulatory requirements) that are available for obligated parties to use for compliance. This is the approach we have taken in projecting biogas and liquid cellulosic biofuel in this rule and in prior annual rules. [467]

Although CAA section 211(*o*)(7)(D)(i) does not expressly connect the "projected volume available" with RIN generation, this interpretation is consistent with the statutory context, structure, and purpose.[468] Notably, in *API v. EPA*, the D.C. Circuit explained that CAA section

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[466] Ibid

[467] For example, consider our projection in the 2020 final rule. There as here, we considered RINs generated in 2020 and available for obligated parties to use for compliance in determining the projected volume available. See 85 FR 7023/1 (projecting "the production of cellulosic biofuel RINs for CNG/LNG derived from biogas"), 7024/2 (considering "which facilities are most likely to produce liquid cellulosic biofuel and generate cellulosic biofuel RINs in 2020"); 2020 RTC 32, 31 (declining to include renewable electricity in projected volume available because technical and regulatory obstacles precluded timely registration of facilities "to generate RINs for the production of renewable electricity"; thus, such facilities were not "reasonably likely to produce qualifying cellulosic biofuel in 2020"). Similarly, our projection included an adjustment for RINs not available for compliance. See 85 FR 7028/1 n.53 (in projecting liquid cellulosic biofuel, considering historical actual production, which excludes RINs retired for reasons other than compliance), 7029/1 (in projecting biogas, considering the number of "cellulosic RINs generated and available for compliance"). RINs may be retired for various non-compliance purposes, e.g., they are erroneously or unlawfully generated, associated with spilled biofuel, etc. In addition, RINs may be retired to satisfy the exporter renewable volume obligation and thus not available for compliance by obligated parties, see 40 CFR 80.1430; however, the vast majority of domestically-produced cellulosic biofuel is used domestically.

[468] See *Chevron USA, Inc. v. Natural Resources Defense Council, Inc.*, 467 U.S. 837 (1984).

211(*o*)(7)(D)(i) "serves as a non-discretionary safety valve when the refiners and importers of transportation fuel subject to [§ 211(o)'s] mandate would otherwise be put in an impossible position, or at least a highly punitive one—that is, forced to purchase volumes of cellulosic biofuel greater than total production, or pay fines for failing to do so."[469] The court further held that EPA's methodology for making its cellulosic biofuel projection must take a "neutral aim at accuracy."[470] Thus, the projected volume of cellulosic biofuel available in a given year should reflect the volume that can actually be used to satisfy obligated parties' renewable volume obligations. Obligated parties demonstrate compliance via the procurement and retirement of RINs; a fuel that does not generate RINs cannot be used towards compliance and cannot be said to be "available."

In other words, cellulosic RINs are generated for fuels that meet all the applicable statutory and regulatory requirements to qualify as cellulosic biofuel. A fuel that cannot be demonstrated to meet those requirements, whether due to technical or to regulatory obstacles, is not a qualifying cellulosic biofuel, cannot generate RINs, and is therefore not available. In the case of ethanol produced from corn kernel fiber co-processed with corn starch and renewable electricity, outstanding technical, regulatory, and/or implementation issues currently preclude facilities from registering to generate RINs. In each of these instances, the issues have revolved around demonstrating that the fuel claimed as cellulosic biofuel satisfies the statutory and regulatory requirements to qualify as such. For ethanol produced from corn kernel fiber, the impediments to registering facilities involve demonstrating that the fuel is produced from renewable biomass that is derived from cellulose, hemicellulose or lignin.[471] For renewable electricity, the outstanding technical and regulatory issues include ensuring that the volumes of the fuel claimed as being used to replace or reduce the quantity of fossil fuel present in transportation fuel are in fact used for that purpose without double counting volumes claimable by others.[472]

For renewable electricity, EPA believes that the outstanding technical, regulatory, and/or implementation issues surrounding RIN generation cannot be resolved in a sufficiently timely manner such that significant amounts of fuel from these sources will be available as cellulosic biofuel in 2021 or 2022. We are therefore not including fuel from this source in our projections of the available volume of cellulosic biofuel. For cellulosic ethanol produced from corn kernel fiber, there is significant uncertainty as to whether the remaining technical and other issues will be resolved in a time frame that would allow for significant additional volume of cellulosic biofuel to be available in 2021 or 2022. We have not included volumes from additional facilities

[469] 706 F.3d 474, 479 (D.C. Cir. 2013).

[470] Id. at 476.

[471] "[C]ellulosic biofuel means renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 60% less than the baseline lifecycle greenhouse gas emissions." CAA section 211(*o*)(1)(E). *See also* 40 CFR 80.1401, 80.1450.

[472] 81 FR 80828, 80890-91 ("Vehicle charging data demonstrate the use of electricity as transportation fuel, one of the two main requirements for RIN generation (production from renewable biomass being the other). However, there are several sources of charging data that could be provided to verify the use of electricity as transportation fuel…. Any of these sources of data could conceivably be used as the basis for generating RINs for renewable electricity. Although multiple types of data can be used to demonstrate the use of electricity as transportation fuel, allowing them to be used simultaneously would almost certainly result in the generation of RINs by multiple parties for the same charging event (*i.e.*, double counting).").

that wish to produce cellulosic ethanol from corn kernel fiber co-processed with corn starch in our projections of cellulosic biofuel production in 2021 and 2022.

5.1.3.1 Ethanol Produced from Corn Kernel Fiber

In previous annual rules several commenters have suggested that EPA's projection of cellulosic biofuel production should include additional volume from cellulosic ethanol produced from corn kernel fiber at facilities that are currently producing ethanol from corn starch.[473] Several different companies have developed processes for producing cellulosic ethanol from corn kernel fiber. Many of these processes involve co-processing of both the starch and cellulosic components of the corn kernel. To be eligible to generate cellulosic RINs, facilities that are co-processing starch and cellulosic components of the corn kernel must be able to determine the amount of ethanol that is produced from the cellulosic portion of the corn kernel. EPA has raised concerns about the accuracy and reliability of the methods for calculating the amount of ethanol produced from the cellulosic portion of the corn kernel. In May 2019 EPA published a document providing guidance on analytical methods used to quantify the amount of ethanol produced when co-processing corn kernel fiber and corn starch.[474]

At this time, it is uncertain whether the technical issues raised in EPA's May 2019 guidance document will be resolved on a timeline that would allow significantly higher volumes of qualifying cellulosic ethanol to be produced from corn kernel fiber in 2021 or 2022.[475] These issues must be resolved prior to EPA registering additional facilities to generate cellulosic RINs for ethanol from corn kernel fiber. Even assuming methods for calculating the volume of ethanol produced from cellulose can be timely demonstrated to have satisfied the regulatory requirements, there is also significant uncertainty as to how rapidly production can be scaled up for commercial availability. If the outstanding technical issues described in the May 2019 guidance document are not resolved between now and 2022 there would not be any cellulosic RINs generated for ethanol produced from corn kernel fiber beyond those facilities that are currently registered as cellulosic biofuel producers.

However, progress continues to be made towards developing the necessary analytical methods to accurately and reliably quantify the production of ethanol from cellulosic components when co-processed with starch.[476] In a best-case scenario we estimate approximately half of the facilities currently generating RINs for ethanol produced from corn starch may be able to generate cellulosic RINs for ethanol produced from corn kernel fiber in 2022. This would likely require the development of additional laboratory testing capabilities and the sourcing of

[473] For example, see EPA-HQ-OAR-2019-0136-0208 and EPA-HQ-OAR-2019-0136-0276.
[474] Guidance on Qualifying an Analytical Method for Determining the Cellulosic Converted Fraction of Corn Kernel Fiber Co-Processed with Starch (EPA-420-B-19-022), May 2019.
[475] Prior to issuance of the May 2019 guidance, EPA registered 6 facilities to generate cellulosic RINs for ethanol produced from corn kernel fiber. These facilities are included in our discussion of projected production of liquid cellulosic biofuel. This section discusses the potential for cellulosic biofuel production from facilities not currently registered as cellulosic RIN generators.
[476] EPA's regulations require that data used to calculate the volume of fuel produced from corn kern fiber "be representative and obtained using an analytical method certified by a voluntary consensus standards body, or using a method that would produce reasonably accurate results as demonstrated through peer reviewed references provided to the third party engineer performing the engineering review at registration." 40 CFR 80.1450(b)(1)(xiii)(B)(3).

additional enzymes in addition to the development and deployment of the testing procedures. Based on information submitted to EPA to date, we estimate that up to 3% of the ethanol produced at corn ethanol plants converting corn kernel fiber to cellulosic ethanol may be produced from cellulosic feedstocks (rather than starch). In this best-case scenario, we project that up to 210 million cellulosic RINs could be generated for ethanol produced from corn kernel fiber in 2022.[477] This calculation does not include a ramp-up period, as we expect that little or no additional process changes would be required. Smaller volumes of ethanol from corn kernel fiber may be able to be produced in 2021, but these volumes would be limited as at this time no facilities have demonstrated that they are able to satisfy the requirements outlined in EPA's May 2019 guidance.

5.1.3.2 Electricity Used as Transportation Fuel

Commenters have also suggested that EPA include electricity produced from qualifying cellulosic feedstocks and used for transportation purposes in the projected volume of available cellulosic biofuel for 2021. We stated in the preamble to the 2016 Renewables Enhancement and Growth Support (REGS) proposed rule that the existing regulatory framework for RIN generation with regard to renewable electricity "create[s] an untenable environment for the approval of any single registration request by the EPA to date."[478] Among other technical and regulatory issues discussed in the REGS preamble, under the existing framework EPA cannot ensure that parties registering to generate RINs will be able to demonstrate that the electricity is not claimed by multiple parties attempting to demonstrate transportation use.[479] We have therefore not included electricity in our projection of cellulosic biofuel production for 2021 or 2022 in light of the significant technical and regulatory issues that must be addressed prior to facilities being able to demonstrate that the electricity qualifies as cellulosic biofuel and thus generate cellulosic RINs for electricity used as transportation fuel. As stated in the REGS rule, we believe these are best addressed through a public rulemaking process. We are not addressing the outstanding, substantive technical and regulatory issues here and, at this time, we do not expect that they issues will be resolved in time for a significant volume of cellulosic RINs to be generate for electricity used as transportation fuel for 2021 or 2022.

5.1.4 Projected Rate of Cellulosic Biofuel Production for 2021 and 2022

After projecting production of cellulosic biofuel from liquid cellulosic biofuel production facilities and producers of CNG/LNG derived from biogas, EPA combined these projections to project total cellulosic biofuel production for 2021 and 2022. These projections are shown in Table 5.1.4-1. Using the methodologies described in this section, we project that 0.62 billion ethanol-equivalent gallons of qualifying cellulosic biofuel will be produced in 2021 and 0.77 billion ethanol-equivalent gallons of qualifying cellulosic biofuel will be produced in 2022. We believe that projecting overall production in 2021 and 2022 in the manner described above

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[477] This calculation assumes 13.7 billion gallons of RIN generating ethanol is produced in 2022 (the volume we are projecting for 2022 in Chapter 5.5), and that half of this volume generates cellulosic RINs for ethanol from corn kernel fiber for 3% of their total production.
[478] 81 FR 80891 (November 16, 2016).
[479] Id.

results in a neutral estimate (neither biased to produce a projection that is too high nor too low) of likely cellulosic biofuel production in 2021 and 2022.

Table 5.1.4-1: Projected Volume of Cellulosic Biofuel in 2021 and 2022

Projected Volume in 2021	Projected Volume[a]
Liquid Cellulosic Biofuel Producers; Producers without Consistent Commercial Scale Production (million gallons)	0
Liquid Cellulosic Biofuel Producers; Producers with Consistent Commercial Scale Production (million gallons)	2
CNG/LNG Derived from Biogas (million gallons)	619
Total (billion gallons)	0.62
Projected Volume in 2022	**Projected Volume[a]**
Liquid Cellulosic Biofuel Producers; Producers without Consistent Commercial Scale Production (million gallons)	2
Liquid Cellulosic Biofuel Producers; Producers with Consistent Commercial Scale Production (million gallons)	2
CNG/LNG Derived from Biogas (million gallons)	762
Total (billion gallons)	0.77

[a] Rounded to the nearest million gallons.

As discussed in Chapter 5.1.4, this projection does not include any volume of cellulosic ethanol produced from corn kernel fiber (other than from producers already registered to generate cellulosic biofuel RINs from corn kernel fiber) or renewable electricity used as transportation fuel because we do not expect the relevant technical and regulatory issues will be addressed to enable the generation of a significant number of cellulosic RINs in 2021 or 2022 from these sources. We believe the projection represents a "neutral aim at accuracy" consistent with the court's direction in *API v. EPA.*

While there is currently significant uncertainty related to the demand for transportation fuel in 2021 and 2022, we believe these factors are unlikely to impact the supply of cellulosic biofuel in these years. The vast majority of fuel we project will be produced is CNG/LNG derived from biogas, much of which is sourced from landfills. We do not expect that lower transportation fuel demand will impact the production of this fuel, nor do we expect that the use of CNG/LNG as transportation fuel will decrease to a level below the volume we are projecting will be available in 2021 and 2022. To the degree that the COVID-19 pandemic may continue to impact the production of cellulosic biofuel, we believe that the projection methodologies in this proposed rule, when combined with updated data at the time of the final rule, will adequately account for these impacts.

5.2 Biomass-Based Diesel

Since 2010 when the biomass-based diesel (BBD) volume requirement was added to the RFS program, production of BBD has generally increased. The volume of BBD supplied in any given year is influenced by a number of factors including production capacity, feedstock availability and cost, available incentives, the availability of imported BBD and the demand for BBD in foreign markets, and several other economic factors. From 2010 through 2015 the vast majority of BBD supplied to the U.S. was biodiesel. While biodiesel is still the largest source of BBD supplied to the U.S. since 2015, increasing volumes of renewable diesel have also been supplied. Production and import of renewable diesel are expected to continue to increase in future years. There are also very small volumes of renewable jet fuel and heating oil that qualifies as BBD, however as the vast majority of BBD is biodiesel and renewable diesel we have focused on these fuels in this section. This section describes our assessment of the rate of production and use of qualifying biomass-based diesel biofuel in 2021 and 2022, and some of the uncertainties associated with those volumes.

5.2.1 Production and Use of Biomass-Based Diesel in Previous Years

As a first step in considering the rates of production and use of BBD in future years we review the volumes of BBD produced domestically, imported, and exported in previous years. Reviewing the historic volumes is useful since there are a number of complex and inter-related factors beyond simply total production capacity (including the availability of advanced biodiesel and renewable diesel feedstocks,[480] the extension of the biodiesel tax credit, tariffs on imported biodiesel, import and distribution infrastructure, and other market-based factors) that could affect the supply of advanced biodiesel and renewable diesel. While historic data and trends alone are insufficient to project the volumes of biodiesel and renewable diesel that could be provided in future years, historic data can serve as a useful reference in considering future volumes. Production, import, export, and total volumes of BBD are shown in Table 5.2.1-1.

[480] Throughout this section we refer to advanced biodiesel and renewable diesel as well as advanced biodiesel and renewable diesel feedstocks. In this context, advanced biodiesel and renewable diesel refer to any biodiesel or renewable diesel for which RINs can be generated that satisfy an obligated party's advanced biofuel obligation (i.e., D4 or D5 RINs). While cellulosic diesel (D7) can also contribute towards an obligated party's advanced biofuel obligation, these fuels are discussed in Section III of the preamble rather than in this section. An advanced biodiesel or renewable feedstock refers to any of the biodiesel, renewable diesel, jet fuel, and heating oil feedstocks listed in Table 1 to 40 CFR 80.1426 or in petition approvals issued pursuant to 40 CFR 80.1416, that can be used to produce fuel that qualifies for D4 or D5 RINs. These feedstocks include, for example, soybean oil; oil from annual cover crops; oil from algae grown photosynthetically; biogenic waste oils/fats/greases; non-food grade corn oil; camelina sativa oil; and canola/rapeseed oil (See pathways F, G, and H of Table 1 to 80.1426).

Table 5.2.1-1: BBD (D4) Production, Imports, and Exports from 2012 to 2020[481] (million gallons)[a]

	2012	2013	2014[b]	2015[b]	2016	2017	2018	2019	2020
Domestic Biodiesel (Annual Change)	984 (N/A)	1,364 (+380)	1,297 (–67)	1,245 (–52)	1,581 (+336)	1,552 (–29)	1,841 (+289)	1,706 (–135)	1,802 (+96)
Imported Biodiesel (Annual Change)	39 (N/A)	153 (+114)	130 (–23)	261 (+131)	562 (+301)	462 (–100)	175 (–287)	185 (+10)	209 (+24)
Exported Biodiesel (Annual Change)	66 (N/A)	77 (+11)	72 (–5)	73 (+1)	89 (+16)	129 (+40)	74 (–55)	76 (+2)	88 (+12)
Total Biodiesel (Annual Change)[c]	957 (N/A)	1,440 (+483)	1,355 (–85)	1,433 (+78)	2,054 (+621)	1,885 (–169)	1,942 (+57)	1,815 (–127)	1,923 (+108)
Domestic Renewable Diesel (Annual Change)	38 (N/A)	70 (+32)	149 (+79)	169 (+20)	231 (+62)	252 (+21)	282 (+30)	454 (+172)	472 (+18)
Imported Renewable Diesel (Annual Change)	28 (N/A)	145 (+117)	130 (–15)	120 (–10)	165 (+45)	191 (+26)	176 (–15)	267 (+91)	280 (+13)
Exported Renewable Diesel (Annual Change)	2 (N/A)	5 (+3)	15 (+10)	21 (+6)	40 (+19)	37 (–3)	80 (+43)	145 (+65)	223 (+78)
Total Renewable Diesel (Annual Change)[c]	64 (N/A)	210 (+146)	264 (+154)	268 (+4)	356 (+88)	406 (+50)	378 (–28)	576 (+198)	529 (–47)
Total BBD[d] (Annual Change)	1,021 (N/A)	1,650 (+629)	1,619 (–31)	1,701 (+82)	2,412 (+711)	2,293 (–119)	2,322 (+29)	2,393 (+71)	2,456 (+63)

[a] All data from EMTS. EPA reviewed all advanced biodiesel and renewable diesel RINs retired for reasons other than demonstrating compliance with the RFS standards and subtracted these RINs from the RIN generation totals for each category in the table above to calculate the volume in each year.
[b] RFS required volumes for these years were not established until December 2015.
[c] Total is equal to domestic production (of both biodiesel and renewable diesel) plus imports minus exports.
[d] Total BBD includes some small volumes (>10 million gallons per year) of D4 jet fuel

Since 2012, the year-over-year changes in the volume of advanced biodiesel and renewable diesel used in the U.S. have varied greatly, from a low of 119 million fewer gallons from 2016 to 2017 to a high of 711 million additional gallons from 2015 to 2016. As discussed previously, these changes were likely influenced by multiple factors. This historical information does not indicate that the maximum previously observed annual increase of 709 million gallons of advanced biodiesel and renewable diesel would be reasonable to expect each year in 2020 and 2022. In fact, the years following those with large increases (2013 and 2016) have had negative growth rates. Rather, these data illustrate both the magnitude of the changes in advanced biodiesel and renewable diesel in previous years and the significant variability in these changes.

[481] Similar tables of biodiesel and renewable diesel production, imports, and exports presented in previous annual rules included advanced (D5) biodiesel and renewable diesel. This table only contains volumes of biodiesel and renewable diesel that qualifies as BBD (D4). Advanced (D5) biodiesel and renewable diesel are covered in Chapter 5.4.

This data also shows the increasing importance of renewable diesel in the BBD pool. In 2012 approximately 6% of all BBD was renewable diesel, and the remaining 94% was biodiesel. By 2020 production and imports of renewable diesel had increased not only in absolute terms (from 64 million gallons in 2012 to 529 million gallons in 2020), but also as a percentage of the BBD pool. In 2020 approximately 22% of all BBD was renewable diesel, while the remaining 78% was biodiesel. As discussed further in the following sections, we expect that renewable diesel will represent an increasing percentage of total BBD in future years.

The historic data indicates that the biodiesel tax policy in the U.S. can have a significant impact on the volume of biodiesel and renewable diesel used in the U.S. in any given year. The availability of this tax credit also provides biodiesel and renewable diesel with a competitive advantage relative to other biofuels that do not qualify for the tax credit.

While the biodiesel blenders tax credit has applied in each year since 2010, it has historically only been prospectively in effect during the calendar year in 2011, 2013, 2016, and 2020, while other years it has been applied retroactively. Years in which the biodiesel blenders tax credit was in effect during the calendar year (2013, 2016, and 2020) generally resulted in significant increases in the volume of BBD used in the U.S. over the previous year (629 million gallons, 711 million gallons, and 63 million gallons respectively). It is likely that with the tax credit in place prospectively for 2021 and 2022, the increase in the supply of biodiesel and renewable diesel over these two years will be greater than the average historical increase observed. However, following the large increases in 2013 and 2016, there was little to no growth in the use of advanced biodiesel and renewable diesel in the following years. Data from 2018 and 2019 suggests that while the availability of the tax credit certainly incentivizes an increasing supply of biodiesel and renewable diesel, supply increases can also occur in the absence of the tax credit, likely as the result of the incentives provided by the RFS program, state LCFS programs, and other economic factors.

Another important factor highlighted by the historic data is the tariffs imposed by the U.S. on biodiesel imported from Argentina and Indonesia. In December 2017 the U.S. International Trade Commission adopted tariffs on biodiesel imported from Argentina and Indonesia.[482] According to data from EIA,[483] no biodiesel was imported from Argentina or Indonesia since September 2017, after a preliminary decision to impose tariffs on biodiesel imported from these countries was announced in August 2017. As a result of these tariffs, total imports of biodiesel into the U.S. were significantly lower in 2018 than they had been in 2016 and 2017. The decrease in imported biodiesel did not, however, result in a decrease in the volume of advanced biodiesel and renewable diesel supplied to the U.S. in 2018. Instead, higher domestic production of advanced biodiesel and renewable diesel, in combination with lower exported volumes of domestically produced biodiesel, resulted in an overall increase in the volume of advanced biodiesel and renewable diesel supplied in 2018.

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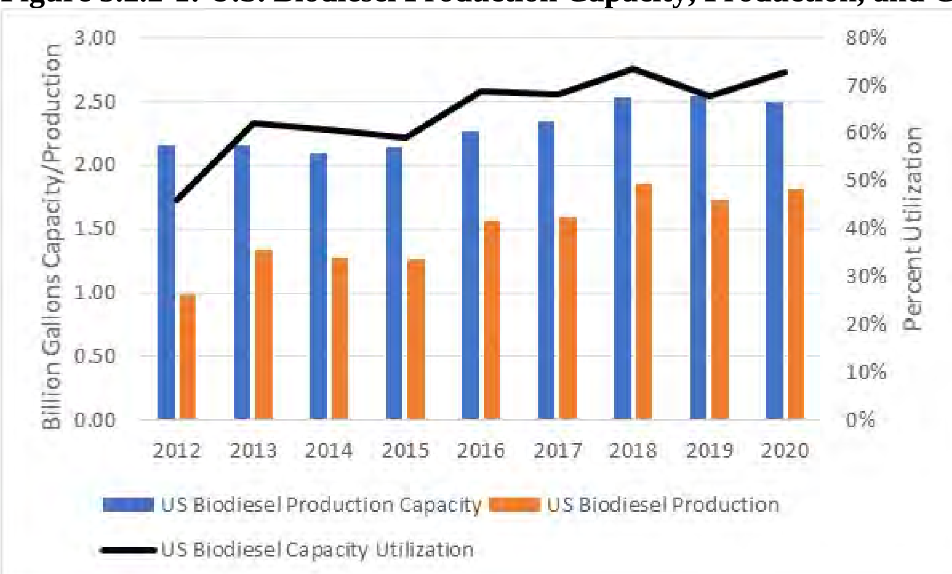
[482] "Biodiesel from Argentina and Indonesia Injures U.S. Industry, says USITC," Available at: https://www.usitc.gov/press_room/news_release/2017/er1205ll876.htm

[483] See "EIA Biomass-Based Diesel Import Data" available in docket EPA-HQ-OAR-2021-0324.

5.2.2 Biomass-Based Diesel Production Capacity and Utilization

One of the factors considered when projecting the rate of production of BBD in future years is the production capacity. Domestic biodiesel production capacity, domestic biodiesel production, and the utilization rate of the existing biodiesel production capacity each year is shown in Figure 5.2.2-1. Active biodiesel production capacity in the U.S. as reported by EIA has experienced modest growth in recent years, from approximately 2.1 billion gallons in 2012 to approximately 2.4 billion gallons in 2020.[484] While production of biodiesel has increased during this time period, significant excess production capacity remains, with facility utilization remaining below 75% through 2020. EPA data on total registered biodiesel production capacity in the U.S., which includes both facilities that are producing biodiesel and idled facilities, is much higher, approximately 3.9 billion gallons. Active biodiesel capacity as reported by EIA is the aggregate production capacity of biodiesel facilities that produced biodiesel in any given month, while the total registered capacity based on EPA data includes all registered facilities, regardless of whether they are currently producing biodiesel or not. These data suggest that domestic biodiesel production capacity is unlikely to limit biodiesel production in future years, and that factors other than production capacity are currently limiting domestic biodiesel production.

Figure 5.2.2-1: U.S. Biodiesel Production Capacity, Production, and Capacity Utilization



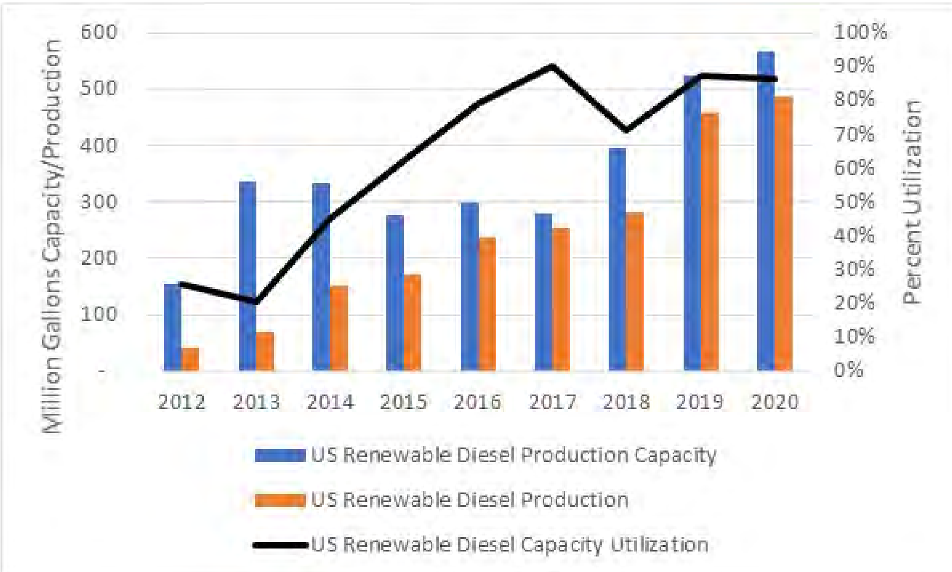
Unlike domestic biodiesel production capacity, domestic renewable diesel production capacity has increased significantly in recent years, from approximately 280 million gallons in 2017 to approximately 565 million gallons in 2020 (Figure 5.2.2-2).[485] Domestic renewable diesel production has increased along with production capacity in recent years, and capacity utilization at domestic renewable diesel production facilities has been high, approximately 84% from 2017-2020. These high utilization rates in recent years suggest that increased renewable diesel production will likely be dependent on the construction of new renewable diesel

[484] Biodiesel production capacity from EIA Monthly Biodiesel Production reports

[485] Renewable diesel capacity is based on RFS facility registration data.

production capacity, and that renewable diesel production is likely to increase along with increases in renewable diesel production capacity.

Figure 5.2.2-2: U.S. Renewable Diesel Production Capacity, Production, and Capacity Utilization



Renewable diesel production capacity and actual production values are from EMTS data. Capacity utilization is calculated by dividing actual production by the total production capacity.

A number of parties have announced their intentions to build new renewable diesel production capacity with the potential to begin production of renewable diesel by the end of 2022. These new facilities include new renewable diesel production facilities, expansions of existing renewable diesel production facilities, and the conversion of units at petroleum refineries to produce renewable diesel. A list of the facilities expected to begin producing renewable diesel by 2022, as well as existing facilities expected to complete expansions by 2022, based on publicly available data is shown in Table 5.2.2-1. In addition to the facilities listed in Table 5.2.2-1, a significant number of renewable diesel facilities have been announced with intended start-up dates after 2022. These facilities are not discussed here since they are not likely to impact renewable diesel production in 2021 or 2022, however they do indicate that there is high interest in expanding renewable diesel production in future years.

Table 5.2.2-1: New Renewable Diesel Production Capacity in the U.S. Through 2022[486]

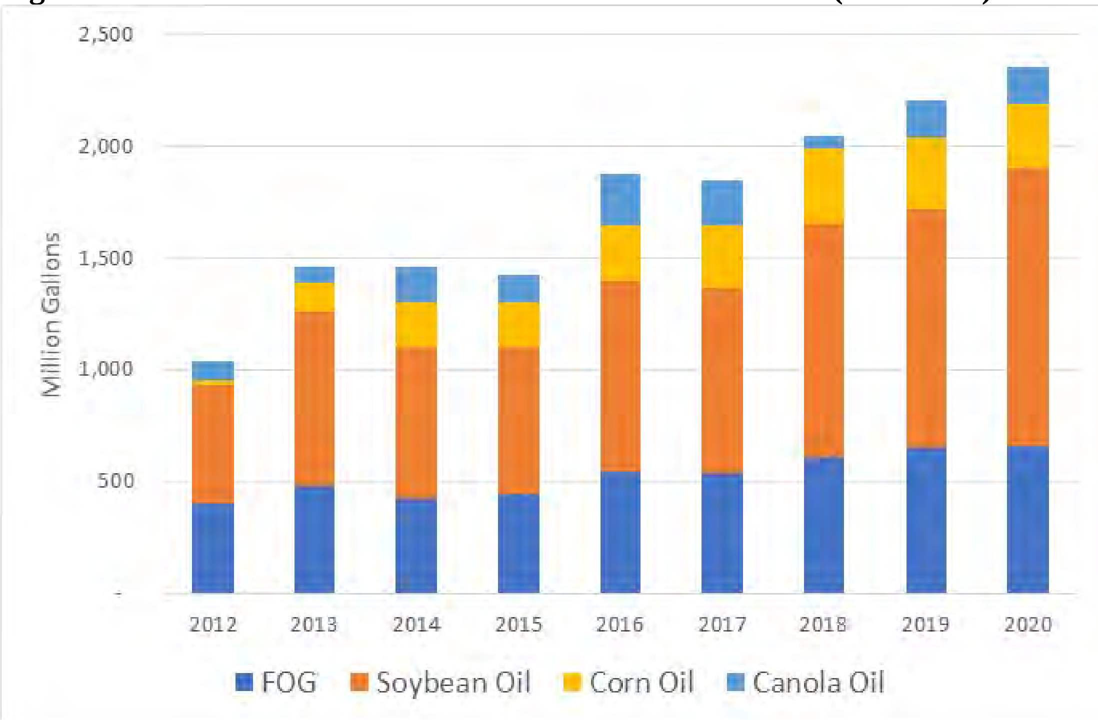
Facility Name	Location	Capacity (MGY)	Expected Start Date
Bakersfield Renewable Fuels	Bakersfield, CA	230	Early 2022
CVR Energy Inc. – Wynnewood	Wynnewood, OK	100	July 2021
Diamond Green Diesel	Norco, LA	Expansion (275 to 675)	2021
HollyFrontier – Artesia	Artesia, NM	110	2022
HollyFrontier – Cheyenne	Cheyenne, WY	90	Early 2022
Marathon – Dickinson	Dickinson, ND	184	Late 2020/Early 2021
Phillips 66	Reno, NV	50	2021
Phillips 66	Rodeo, CA	120	2021

5.2.3 Availability of Biomass-Based Diesel Feedstocks

Another key factor in considering the rate of production of BBD in 2021 and 2022 is the availability of qualifying feedstocks. To assess the availability of feedstocks for producing BBD through 2022 we first reviewed the feedstocks used in previous years. This review of feedstocks used in previous years can provide information about the feedstocks most likely to be used in future years, as well as the likely increase in the availability of these feedstocks in future years. A summary of the feedstocks used to produce BBD from 2012 through 2020 is shown in Figure 5.2.3-1.

[486] Bryan, Tom. *Renewable Diesel's Rising Tide*. Biodiesel Magazine. January 12, 2021. http://www.biodieselmagazine.com/articles/2517318/renewable-diesels-rising-tide

Figure 5.2.3-1: Feedstocks Used To Produce BBD in the U.S. (2012-2020)[487]



BBD production from fats, oils, and greases (FOG) has generally increased from 2012 through 2020 at an average annual rate of approximately 30 million gallons per year. These feedstocks are generally by-products of other industries. We expect that in future years production of BBD from FOG will continue to increase at approximately the historical rate as the availability of FOG increases with population. It is possible that greater demand for feedstocks for BBD production could result in greater collection of FOG that is currently sent to landfills or wastewater treatment systems, but we do not expect significant increases in the collection rates of FOG for BBD production through 2022.

Production of BBD from distillers corn oil has also generally increased through 2020. The most significant increases in the volume of BBD produced from distillers corn occurred through 2017 as more corn ethanol plants installed equipment to produce distillers corn oil and corn ethanol production expanded. However, production of BBD from this feedstock has been fairly consistent at about 300 million gallons per year since 2017. Total production of distillers corn oil in the U.S. in 2020 was approximately 1.7 million tons,[488] or enough corn oil to produce about 500 million gallons of BBD. This suggests that distillers corn oil could be used to produce as much as 200 million gallons of additional BBD, but that this would require shifting distillers corn oil from other existing uses. which would then have to be backfilled with other new sources.[489]

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[487] Based on EMTS data

[488] USDA Grain Crushings and Co-Products Production 2020 Summary. March 2021. Available at: https://www.nass.usda.gov/Publications/Todays_Reports/reports/cagcan21.pdf

[489] For a discussion of backfilling when oil is removed from dried distillers grains, see 83 FR 37735 (August 2, 2018).

The remaining volume of BBD has been produced from canola oil and soybean oil. Production of BBD from canola oil has fluctuated in recent years from a high of over 200 million gallons in 2016 to a low of approximately 50 million gallons in 2018. Total production of canola oil reached a high of approximately 1.9 billion pounds in 2020, or enough canola oil to produce approximately 250 million gallons of BBD.[490] An additional 4 billion pounds of canola oil, or enough to produce approximately 500 million gallons of BBD, were imported in 2020. It is unclear how much of this imported canola oil would be able to qualify as renewable biomass under the statutory definition, and thus available to be used to produce qualifying BBD under the RFS program.[491] Doing so, however, would require shifting it from its other existing uses which would then have to be backfilled with other new sources, the lowest cost of which is currently palm oil, potentially impacting the GHG benefits.

The largest source of BBD production in the U.S. historically has been soybean oil. Due to the potential limitations on the increased availability of the other BBD feedstocks discussed above, we also expect that soybean oil is the most likely source of feedstock used to produce higher volumes of BBD in future years. Use of soybean oil to produce biodiesel increased from approximately 4.9 billion pounds in the 2011/2012 agricultural marketing year to approximately 7.9 billion pounds in the 2019/2020 agricultural marketing year.[492] During this time period the percentage of all soybean oil produced in the U.S. used to produce biodiesel increased from approximately 25% in 2011/2012 to approximately 32% in 2019/2020. As a point of reference, if all the soybean oil produced in the U.S. in 2019/2020 (24.9 billion pounds) were used to produce BBD, this quantity of feedstock could be used to produce approximately 3.2 billion gallons of BBD. Thus, BBD production from soybean oil could more than double if it were shifted from its other existing uses, including food, and backfilled with other new sources such as palm oil, potentially impacting the GHG benefits.

Additional soybean oil production in future years could come from several sources. The first potential source of additional soybean oil is increased planting and production of soybeans. USDA currently projects that soybean planting will increase from 83.1 million acres in 2020 to 90 million acres in 2022.[493] If soybean oil production increased proportionally to soybean planting this would result in an additional 2.1 billion pounds of soybean oil in 2022, or enough soybean oil to produce approximately 270 million gallons of BBD. Another potential source of additional soybean oil could come from a higher soybean crushing rate. Soybean crushing is the process by which whole soybeans are converted into soybean oil and soybean meal. The percentage of U.S. soybean production that has been crushed has varied from a low of 44% in the 2016/2017 agricultural year to a high of 61% in the 2019/2020 marketing year.[494] Higher soybean crushing rates produce greater quantities of soybean oil from the same soybean crop. A

[490] U.S. Canola oil production data sourced from USDA's Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/).
[491] See CAA section 211(o)(1)(I).
[492] U.S. Soybean oil production and use data sourced from USDA's Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/). The agricultural marketing year for soybeans runs from September to August.
[493] Soybean planting projections from USDA's Agricultural Projections Through 2030 (February 2020). Available at: https://www.usda.gov/sites/default/files/documents/USDA-Agricultural-Projections-to-2030.pdf
[494] U.S. Soybean crushing data sourced from USDA's Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/).

third potential source of soybean oil for BBD production would be decreased exports of soybeans and soybean oil. From the 2011/2012 agricultural marketing year through the 2019/2020 agricultural marketing year approximately 47% of the U.S. soybean crop was exported.[495] During this same time period approximately 10% of the soybean oil produced in the U.S. was exported.[496] Reduced exports of soybeans and/or soybean oil could provide additional feedstocks for BBD production through 2022. As with other potential sources of BBD feedstock with existing markets, increasing BBD production by decreasing exports of soybeans and/or soybean oil would require shifting these feedstocks from existing markets including food supply in the U.S. and abroad and then backfilling with other new supplies such as palm oil, potentially impacting the GHG benefits.

Finally, additional vegetable oil feedstocks in future years could come from international sources. The most recent World Agricultural Supply and Demand Estimates from USDA project that global production of vegetable oils will be approximately 209 million metric tons in the 2020/2021 agricultural marketing year.[497] This quantity of vegetable oil, if converted to fuel, would result in approximately 60 billion gallons of biodiesel and/or renewable diesel. Much of this vegetable oil, however, is likely to be from palm oil that does not currently have an approved pathway under the RFS program except for the portion that could be produced under the program's grandfathering provisions. Regardless, it would certainly not be reasonable to assume that all, or even a majority, of global vegetable oil production globally or domestically could be available to produce biodiesel or renewable diesel supplied to the U.S. for a number of reasons.[498] However, the large global production of vegetable oil suggests that increased imports of vegetable oil, or biodiesel and renewable diesel produced from vegetable oil (discussed in the next section), may be available to markets in the U.S. in future years.

5.2.4 Imports and Exports of Biomass-Based Diesel

In evaluating the likely rate of production of BBD through 2022 we also examined BBD imports and exports in previous years. While imports and exports of BBD may not directly impact the rate of production of BBD in the U.S., they do impact the volume of these fuels available to obligated parties. We therefore think that a consideration of the volume of these fuels that may be imported and exported in future years is a relevant consideration as we propose required volumes through 2022 under the RFS program.

Since 2013 biodiesel imports have generally ranged from 100 to 200 million gallons per year, with the exception of 2015-2017. During this time (2015-2017) biodiesel imports from Argentina surged, with biodiesel imported from Argentina responsible for 64% of all biodiesel imports in these three years. In August 2017, the U.S. announced preliminary tariffs on biodiesel

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[495] U.S. Soybean exports sourced from USDA's Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/).

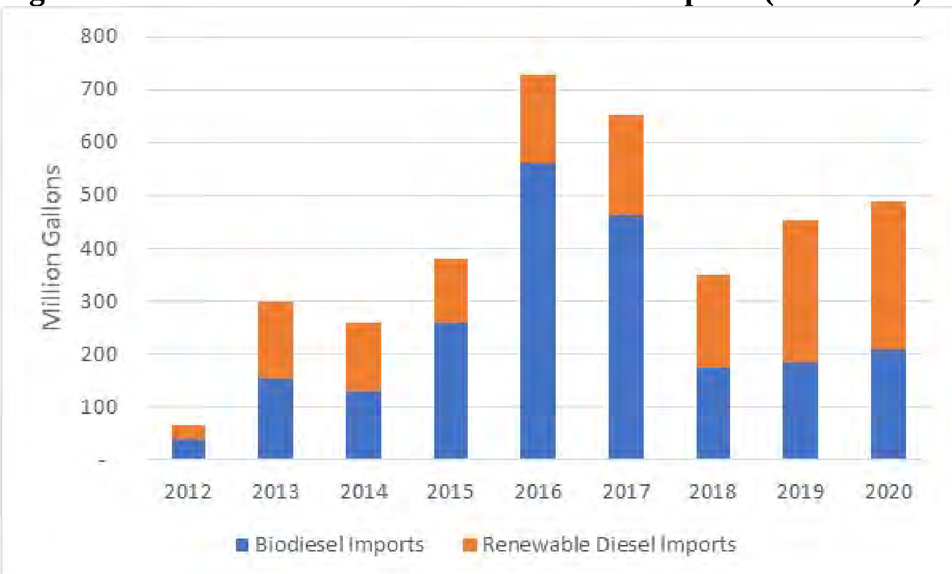
[496] U.S. Soybean oil exports sourced from USDA's Oil Crops Yearbook (https://www.ers.usda.gov/data-products/oil-crops-yearbook/).

[497] United States Department of Agriculture World Agricultural Supply and Demand Estimates. March 9, 2021.

[498] These reasons include the demand for vegetable oil in the food, feed, and industrial markets both domestically and globally; constraints related to the production, import, distribution, and use of significantly higher volumes of biodiesel and renewable diesel; and the fact that biodiesel and renewable diesel produced from much of the vegetable oil available globally may not qualify as an advanced biofuel under the RFS program.

imported from Argentina and Indonesia.[499] These tariffs were subsequently confirmed in April 2018.[500] Since the time the preliminary tariffs were announced, EIA has not reported any biodiesel imported from these countries.[501] After the imposition of these tariffs, imports of biodiesel from other countries has increased marginally; however, the biggest effect of these tariffs has been a decrease in the total volume of imported biodiesel to the levels observed in 2013 and 2014.

Figure 5.2.4-1: Biodiesel and Renewable Diesel Imports (2012-2020)



Biodiesel and renewable diesel imports based on data from EMTS

Renewable diesel imports have generally increased since 2012, with larger increases observed in recent years. A significant factor in the increasing imports of renewable diesel appears to the California's Low Carbon Fuel Standard (LCFS), as the vast majority of the renewable diesel consumed in the U.S. (including both domestically produced and imported renewable diesel) has been consumed in California.[502] We expect that, as the carbon intensity requirements in California's LCFS program continue to decrease, this program, in conjunction with the RFS program and the federal tax credit, will continue to provide an attractive market for domestically produced and imported renewable diesel.

Biodiesel exports have been fairly consistent since 2012, generally ranging between 50 and 100 million gallons per year. Renewable diesel exports have increased significantly in recent years, reaching a high of over 200 million gallons in 2020. Increasing exports of renewable

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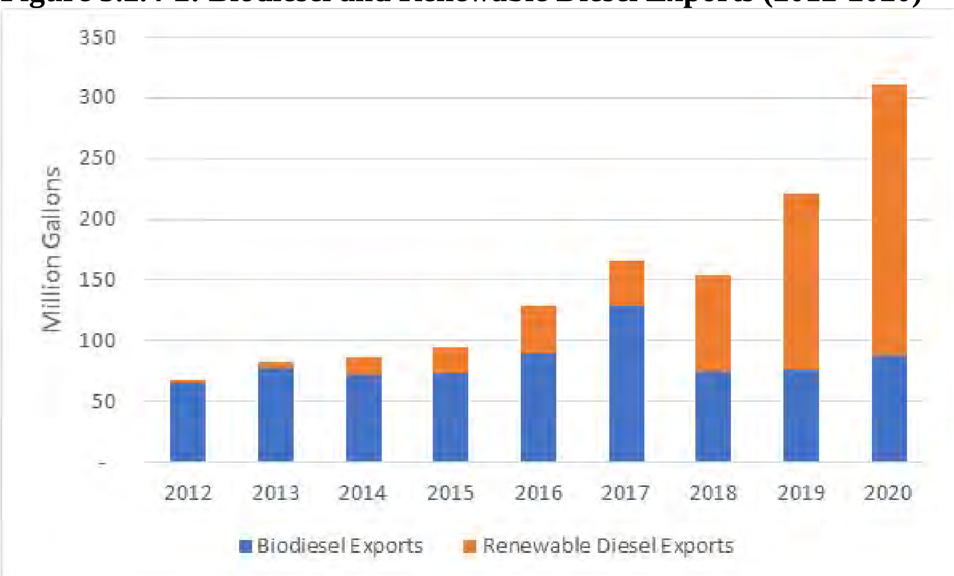
[499] 82 FR 40748 (August 28, 2017).
[500] 83 FR 18278 (April 26, 2018).
[501] See EIA data on biodiesel imports by country, available at: https://www.eia.gov/dnav/pet/pet_move_impcus_a2_nus_EPOORDB_im0_mbbl_a.htm
[502] Data from California's LCFS program indicates that 618 million gallons of renewable diesel were consumed in California in 2019, the most recent year for which data are available (https://ww3.arb.ca.gov/fuels/lcfs/dashboard/dashboard.htm). Data from EMTS indicates that 610 million gallons of renewable diesel were consumed in the U.S. in 2019, including both renewable diesel that generated BBD RINs and advanced RINs.

diesel suggest that there is significant demand for renewable diesel in other countries. At this time it is difficult to project whether renewable diesel exports will continue to increase in future years or alternatively return to the low levels observed through 2017.

The fact that there are both imports and exports of BBD simultaneously also suggests that there are efficiencies associated with importing into and exporting from certain parts of the country as well as economic advantages associated with the use of BBD from different feedstocks in different foreign and domestic markets. One factor likely supporting simultaneous imports and exports of biodiesel and renewable diesel is the structure of the biodiesel tax credit. The tax credit can be claimed for biodiesel or renewable diesel that is either produced or used in the U.S. By importing foreign produced biodiesel and renewable diesel for domestic use and then exporting domestically produced biodiesel and renewable diesel to other countries parties are able to increase the income they receive from the biodiesel tax credit.

Figure 5.2.4-2: Biodiesel and Renewable Diesel Exports (2012-2020)



Biodiesel and renewable diesel exports based on data from EMTS

5.2.5 Projected Rate of Production and Use of Biomass-Based Diesel

Based on the factors discussed in the preceding sections we have projected BBD production in the U.S. through 2022. We have also included projections of BBD imports and exports, as imports and exports of BBD impact the quantity of BBD available to obligated parties. Table 5.2.5-1 shows our projections for 2021 and 2022, along with the observed volumes from 2018-2020 to provide context for our projections. We have focused on data from 2018 through 2020 as this is the most recent data available, and we believe the trends observed in these years are most likely to be predictive of growth in BBD production through 2022. In addition, data from 2017 and earlier years does not reflect the impact of the tariffs on biodiesel from Argentina and Indonesia.

Table 5.2.5-1: BBD (D4) Biodiesel and Renewable Diesel Production, Imports, and Exports through 2022 (Million Gallons)

	2018	2019	2020	2021	2022
Domestic Biodiesel Production (million RINs)	1,841 (2,762)	1,706 (2,559)	1,802 (2,702)	1,780 (2,670)	1,780 (2,670)
Domestic Renewable Diesel Production (million RINs)	282 (479)	454 (772)	472 (802)	770 (1,320)	1,590 (2,710)
Biodiesel Imports (million RINs)	175 (263)	185 (277)	209 (314)	230 (350)	240 (360)
Renewable Diesel Imports (million RINs)	176 (300)	267 (454)	280 (477)	330 (560)	380 (650)
Biodiesel Exports (million RINs)	74 (111)	76 (115)	88 (132)	100 (150)	100 (150)
Renewable Diesel Exports (million RINs)	80 (136)	145 (247)	223 (379)	290 (490)	370 (630)
Total BBD Available (million RINs)	2,320 (3,577)	2,391 (3,700)	2,452 (3,814)	2,720 (4,260)	3,520 (5,610)

Our projections for each of the various potential sources of BBD in 2021 and 2022 in Table 5.2.5-1, and described below, are based on the information presented in the preceding sections.

As discussed in Chapter 5.2.3, since 2016 there has been a consistent relationship between domestic renewable diesel production capacity and domestic renewable diesel production, with consistently high production capacity utilization rates for renewable diesel. A number of new renewable diesel production facilities are currently being commissioned or are under construction with the intention to begin producing fuel in 2021 or 2022. Several of these facilities are conversions of existing refineries, which are good candidates for conversion to renewable diesel production facilities due to the available infrastructure and the similarities between some of the refinery processing units and the equipment needed to produce renewable diesel. Market factors, such as much easier access to markets in states such as California with LCFS programs are also favoring increased production of renewable diesel over biodiesel.

At this time we are unaware of any other factors that are likely to inhibit these facilities from being able to produce renewable diesel at or near their intended facility capacity after a period of commissioning is complete. If domestic renewable diesel production capacity continues to expand at this rate it is possible that the availability and/or cost of feedstock could be a limiting factor in future years, but we do not expect that the availability of feedstock will limit renewable diesel production through 2022. We have therefore projected that domestic renewable diesel production increases consistent with the increases in domestic renewable diesel production capacity through 2022 (shown in Table 5.2.2-1), after accounting for the announced start-up dates for these facilities and a period of facility commissioning[503] and production ramp-up.[504]

Domestic biodiesel production dropped significantly in 2019 from its peak in 2018, only to recover much of its losses again in 2020, providing no discernable trend in recent years. As discussed above, going forward into 2021, and especially into 2022 and beyond, it would appear that future growth in BBD production is more likely to come from increased renewable diesel production rather than increased biodiesel production. Nevertheless, we are not projecting a decrease in biodiesel production during this time period since biodiesel producers can take advantage of existing facility capacity and previously established feedstock supply agreements and downstream markets. Given the high value of BBD, and lacking information to the contrary, we have projected that biodiesel production will continue at the average observed volume from 2018-2020 (1,780 million gallons) through 2022.

For the remaining four categories of potential sources of BBD through 2022 (biodiesel and renewable diesel imports and biodiesel and renewable diesel exports) the observed data from 2018-2020 suggested increasing trends for each of these potential sources of BBD. At this time we are unaware of any information that would suggest these trends are unlikely to continue through 2022. As demonstrated by the observed data presented in Chapter 5.2.5., projecting imports and exports of BBD is challenging as these volumes can be significantly impacted by both market conditions in various countries as well as changing incentives and trade policies in the U.S. and around the world. It is possible that higher RFS volumes, in conjunction with the federal tax credit and other state incentive programs, could result in higher imported volumes of BBD (or lower exports from the U.S. to other countries) than shown in Table 5.2.5-1. In particular, significant expansion of renewable diesel production in foreign countries has also been announced,[505] and the U.S. (particularly California) is likely to be an attractive market for increasing volumes of imported renewable diesel.

5.3 Imported Sugarcane Ethanol

The predominant available source of advanced biofuel other than cellulosic biofuel and BBD has historically been imported sugarcane ethanol. Imported sugarcane ethanol from Brazil is the predominant form of imported ethanol and the only significant source of imported advanced ethanol. In setting the 2020 standards, we estimated that 70 million gallons of imported sugarcane ethanol would be imported in 2020.[506] This was based on a combination of data from recent years demonstrating relatively low import volumes and older data indicating that higher

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[503] Commissioning is the process of planning, documenting, scheduling, testing, adjusting, verifying, and training, to provide a facility that operates as a fully functional system.

[504] To project domestic renewable diesel production capacity we have assumed that facilities announced to begin production “early” in the year start production on January 1 of that year. For facilities that do only specify a year in which they intend to begin production, we assume the facility begins production on July 1 of that year. We have also assumed that these facilities ramp-up production over a 6-month period, producing at 50% capacity 3 months after the start of production and 100% capacity 6 months after the start of production. This results in an average production rate of 50% of their listed facility capacity over this 6-month ramp-up period.

[505] For example, see https://www.futurebridge.com/industry/perspectives-energy/renewable-diesel-the-fuel-of-the-future

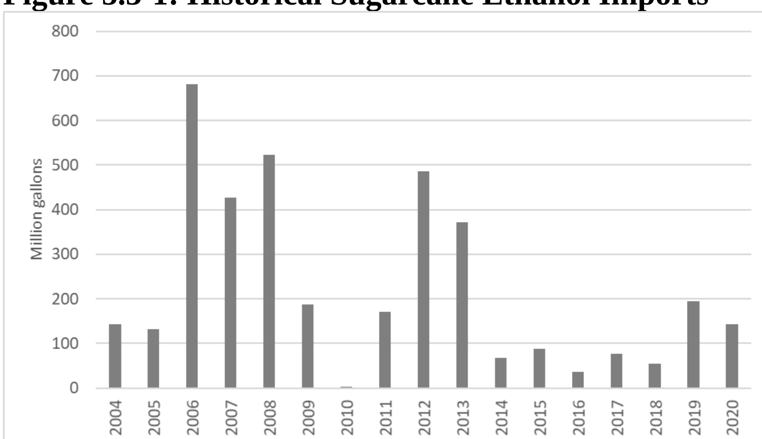
[506] 85 FR 7016, 7032-34 (February 6, 2020).

volumes were possible. We also noted the high variability in ethanol import volumes in the past (including of Brazilian sugarcane ethanol), increasing gasoline consumption in Brazil, and variability in Brazilian production of sugar as reasons why it would be inappropriate to assume that sugarcane ethanol imports would reach the much higher levels suggested by some stakeholders.

At the time of the 2020 standards final rule, we also noted that while sugarcane ethanol imports had stabilized at a relatively low level after 2013, averaging 67 million gallons, partial data from 2019 indicated a notable increase. Nevertheless, at that time we had little evidence that the increase exhibited in 2019 would continue into 2020 as there was no consistent upward or downward trend after 2013, and several factors created disincentives for increasing imports above the levels in recent years. We therefore projected that 70 million gallons of sugarcane ethanol could be supplied in 2020.

Import data for both 2019 and 2020 is now available and indicates that imports of sugarcane ethanol were notably higher than in previous years.

Figure 5.3-1: Historical Sugarcane Ethanol Imports



Source: "US Imports of Brazilian Fuel Ethanol from EIA - March 2021." Includes imports directly from Brazil and those that are transmitted through the Caribbean Basin Initiative and Central America Free Trade Agreement (CAFTA).

Moreover, data from EIA indicates that all 2019 and 2020 ethanol imports entered the U.S. through the West Coast, presumably to help refiners meet the requirements of the California Low Carbon Fuel Standard (LCFS).

It is unclear if the increase in imports in 2019 and 2020 in comparison to previous years represents the beginning of an upward trend that could reasonably be expected to continue in 2021 and 2022. It is likely that the LCFS standards will continue to become more stringent and provide an incentive to increase imports of sugarcane ethanol into California, but the recent reinstatement of the biodiesel tax credit for 2020 through 2022 could provide a preferential incentive for biodiesel and renewable diesel over that of sugarcane ethanol imports for meeting the advanced biofuel volume requirement.[507] On balance, we believe that the substantial increase

[507] "ARB summary of LCFS program." See slide 6.

in ethanol imports in 2019 and 2020 may be indicative of future import volumes and thus should be taken into account in estimating imports that could occur in 2021 and 2022.

As noted in previous annual standard-setting rulemakings, the high variability in historical ethanol import volumes makes any projection of future imports uncertain. However, import volumes for more recent years are likely to provide a better basis for making future projections than import volumes for earlier years, and the higher volumes for 2019 and 2020 disrupted the trend of lower volumes that had occurred between 2014 and 2018. To address these issues, we propose a different methodology for making projections of future ethanol imports than we have used in previous years.[508]

Specifically, we propose a weighted average of import volumes for all years where the weighting is higher for more recent years and lower for earlier years. We propose that the weighting factor for any given year's volume be twice as large as the weighting factor for the previous year's volume. This approach would provide a better predictor of future imports of sugarcane ethanol than either simple averages of historical volumes or a trendline based on historical volumes. While this approach could in theory be used to account for import data from all years, in practice this would not be necessary as data from more than eight years ago would collectively contribute only 0.4% to the weighted average. Given the levels of the volumes in the 2013 - 2020, the addition of 2012 and earlier data would have an impact on the weighted average of less than 1 million gallons, which would not be meaningful in the broader context of the assessment of the volume requirements that we believe would be appropriate to establish.

The volumes and weighting factors we propose using are shown below. The resulting weighted average is 161 million gallons. For both 2021 and 2022, this is the volume of sugarcane ethanol that we project can be supplied.

Table 5.3-1: Annual Advanced Ethanol Imports and Weighting Factors

Year	Imported advanced ethanol[a] (million gallons)	Weighting factor
2013	435	0.0078125
2014	64	0.015625
2015	89	0.03125
2016	34	0.0625
2017	74	0.125
2018	78	0.25
2019	196	0.5
2020	185	1

[a] Based on RINs generated for imported ethanol and assigned a D-code of 5 according to EMTS.

As noted above, the future projection of imports of sugarcane ethanol is inherently imprecise, and actual imports in 2021 and 2022 could be lower or higher than 161 million gallons. Factors that could affect import volumes include uncertainty in the Brazilian political climate, weather and harvests in Brazil, world ethanol demand and prices, constraints associated

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

with the E10 blendwall in the U.S., world demand for and prices of sugar, the cost of sugarcane ethanol relative to that of corn ethanol, and the impact of the novel virus COVID-19 on transportation fuel prices and demand.

5.4 Other Advanced Biofuel

In addition to cellulosic biofuel, imported sugarcane ethanol, and BBD, there are other advanced biofuels that can be supplied in 2021 and 2022. These other advanced biofuels include non-cellulosic CNG, naphtha, heating oil, co-processed renewable diesel, and domestically produced advanced ethanol. However, the supply of these fuels has been relatively low in the last several years.

Table 5.4-1: Historical Supply of Other Advanced Biofuels (million ethanol-equivalent gallons)

Year	CNG/LNG	Domestic Ethanol	Heating Oil	Naphtha	Renewable Diesel (D5)	Total
2013	26	17	0	3	67	87
2014	20	26	0	12	15	73
2015	0	25	1	24	8	58
2016	0	27	2	27	8	64
2017	2	25	2	32	9	70
2018	2	25	3	31	40	101
2019	5	24	3	37	58	127
2020	5	23	3	32	86	149

We propose to use the same weighted averaging approach (see Table 5.3-1) for other advanced biofuels as we are proposing above to use for sugarcane ethanol to project the supply of these other advanced biofuels in 2021 and 2022. Based on this approach, the weighted average of other advanced biofuels would be 128 million gallons.[509] This volume of other advanced biofuel would be composed of 24 million gallons of advanced ethanol and 104 million gallons of non-ethanol advanced biofuel.

We recognize that the potential exists for additional volumes of advanced biofuel from sources such as jet fuel, liquefied petroleum gas (LPG), butanol, and liquefied natural gas (as distinct from CNG), as well as non-cellulosic CNG from biogas produced in digesters. However, since they have been produced, if at all, in only de minimis and sporadic amounts in the past, we do not believe the market will make available substantial volumes from these sources in 2021 or 2022.[510]

[509] Under our prior approach, we would have taken a straight average of 2015-2020, all years following the change in the categorization of landfill biogas from D5 to D3. This approach would yield a volume of 60 million gallons, nearly the same volume we are proposing under the new approach. Moreover, as with sugarcane ethanol, given the relatively small volumes of other advanced biofuels we are projecting (approximately 1% of the advanced biofuel standard), even a significant deviation in its actual availability would likely have negligible impact on the market's ability to meet the advanced biofuel volumes.

[510] No RIN-generating volumes of these other advanced biofuels were produced in 2020, and less than 1 million gallons total in prior years.

5.5 Corn Ethanol

As described in more detail in Chapter 1.6.1.1, total domestic ethanol production capacity increased dramatically between 2005 and 2010, and increased at a slower rate thereafter. In 2020, production capacity had reached 17.4 billion gallons.[511,512] This production capacity was significantly underused in 2020 due to the COVID-19 pandemic, which depressed gasoline demand in comparison to previous years. Actual production of ethanol in the U.S. reached 12.85 billion gallons in 2020, compared to 14.72 billion gallons in 2019.[513]

The expected annual rate of future commercial production of corn ethanol will be driven primarily by gasoline demand as most gasoline is expected to continue to contain 10% ethanol in 2021 and 2022. Commercial production of corn ethanol is also a function of exports of ethanol and to a much smaller degree the demand for E0, E15, and E85. While production of corn ethanol may be limited by production capacity in the abstract, it does not appear that production capacity will be a limiting factor in 2021 or 2022 for meeting the proposed RFS standards.

In previous years when estimating the potential availability of corn ethanol in the context of assessing the appropriateness of total renewable fuel volume requirements, we combined EIA's future projections of gasoline energy demand with the highest historical average ethanol concentration. This approach enabled us to account for both the amount of E15 and E85 in aggregate that we projected would be achievable as well as the volume of E10 that was likely to occur based on the projection of total gasoline demand.[514] For instance, for the 2020 standards we used a 2020 projection of 17.166 Quad Btu gasoline and 10.13% ethanol from 2017.[515] The 10.13% was the highest historical ethanol concentration achieved by the market at the time that the 2020 standards were being developed, and we determined that the market should be able to achieve at least the same ethanol concentration in 2020 since it had done so in the past. That is, the E15 and E85 volumes inherently represented in aggregate by the 0.13% above 10.00% should be achievable in 2020.

In analyzing the volumes of ethanol that may be achievable in 2021 and 2022, we could take the same approach. In this case, the highest historical ethanol concentration would be 10.23% from 2020. However, we note that this ethanol concentration may be less representative of what is achievable in 2021 and 2022 due to very atypical market conditions in 2020 caused by the COVID-19 pandemic. At the same time, the projected nationwide average ethanol concentration for 2021 and 2022 derived from EIA's ethanol and gasoline projections are nearly the same as, but slightly lower than it was in 2020 as shown below.

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[511] "2021 Ethanol Industry Outlook - RFA," available in docket EPA-HQ-OAR-2021-0324.
[512] "Ethanol production capacity - EIA April 2021," available in docket EPA-HQ-OAR-2021-0324.
[513] "RIN supply as of 3-22-21," available in docket EPA-HQ-OAR-2021-0324.
[514] The nationwide average ethanol concentration also includes some volume of E0. However, an ethanol concentration above 10.00% can only occur insofar as the ethanol in E15 and E85 exceeds the amount of ethanol that could have been in E10 but instead was displaced by E0.
[515] "Updated market impacts of biofuels in 2020," available in docket EPA-HQ-OAR-2021-0324.

Table 5.5-1: Average Ethanol Concentration from EIA

Year	Nationwide average ethanol concentration	EIA Report[516]
2017	10.13%	March 2021 MER
2018	10.08%	March 2021 MER
2019	10.20%	March 2021 MER
2020	10.23%	March 2021 MER
2021	10.23%	May 2021 STEO
2022	10.22%	May 2021 STEO

As described in more detail in Section III of the preamble, for 2021 we are proposing to base the applicable volume requirements on a combination of actual consumption for those months for which such data is available, and a projection of likely consumption for remaining months. This is consistent with the approach we took for 2015.[517] The May 2021 edition of the STEO contains actual consumption of gasoline and ethanol through February 2021 and a projection of consumption for the remaining months of 2021. We believe that this combination of actual and projected consumption provides a more appropriate estimate of ethanol concentration for 2021 than assuming that purely historical (e.g. 2020) volumes of ethanol and gasoline consumption will be repeated in the future. Thus for 2021 the ethanol concentration and associated ethanol volume have been derived from the May 2021 STEO.

The ethanol concentration based on EIA's projection of gasoline and ethanol consumption for 2022 is nearly the same as the actual ethanol concentration in 2020 (10.22% versus 10.23%). As a result, the use of the projected ethanol concentration for 2022 rather than the actual ethanol concentration for 2020 would have very little impact on our assessment. Moreover, the use of the projected ethanol concentration for 2022 in determining appropriate volume requirements for 2022 would be more consistent with our approach to 2021. Combined with the fact that there is higher uncertainty in the 2020 value due to the atypical market conditions in that year, we propose to use the projection of ethanol concentration derived from EIA reports for 2022 as a reasonable estimate of what level can be achieved in 2022, rather than the actual ethanol concentration in 2020.

By using the ethanol concentrations shown in Table 5.5-1 for 2021 and 2022, we are by definition using EIA's projections of total ethanol consumption since the ethanol concentration is derived from ethanol volume and gasoline volume. Moreover, this total volume is a combination of corn ethanol, cellulosic ethanol, and advanced ethanol. Our estimate of corn ethanol consumption for 2021 and 2022 for the purposes of estimating the mix of biofuels that could be made available is shown below.

[516] STEO = Short Term Energy Outlook. MER = Monthly Energy Review. While the STEO provides ethanol concentration in %, it does so only to one decimal place. Therefore, ethanol concentration in % was calculated to two decimal places from the ethanol volume and total gasoline volume available in these reports.
[517] 80 FR 77448 (December 14, 2015).

Table 5.5-2: Calculation of Projected Corn Ethanol Consumption for 2021 and 2022 (million gallons)

	2021	**2022**
Total ethanol	13,640	13,975
Cellulosic ethanol	2	2
Imported sugarcane ethanol	161	161
Domestic advanced ethanol	24	24
Corn ethanol	13,453	13,788

Total production of corn ethanol in 2021 and 2022 is likely to be higher than the consumption levels shown in Table 5.5-2 because the U.S. has exported significant volumes in recent years. For instance, in 2020 ethanol export volumes were 1.34 billion gallons.[518]

[518] "Fuel Ethanol Exports by Destination from EIA 4-9-21," available in docket EPA-HQ-OAR-2021-0324.

Chapter 6: Infrastructure

This chapter analyzes the impact of renewable fuels on the distribution infrastructure of the United States. The statute indicates that this assessment must address two aspects of infrastructure:

1. Deliverability of materials, goods, and products other than renewable fuel
2. Sufficiency of infrastructure to deliver and use renewable fuel

This chapter begins by addressing the sufficiency of infrastructure to deliver and use different types of renewable fuels. We then address how the use of renewable fuels affects the deliverability of materials, goods, and products other than renewable fuel.

6.1 Biogas

Infrastructure considerations regarding the use of renewable biogas were not evaluated in the 2010 RFS2 rule because it was only after that time that renewable biogas was used in significant volumes under the RFS program. Renewable biogas infrastructure considerations differ from those for other biofuels not only because it is a gas rather than a liquid, but also because renewable biogas can be processed to be physically identical to natural gas which is used for many purposes including transportation.[519] Natural gas was used in compressed natural gas (CNG) and liquified natural gas (LNG) vehicles for many years prior to the introduction of renewable biogas. The RFS program allows RINs to be generated for renewable biogas that is fungible with the wider natural gas pool provided that a contract is in place to demonstrate that the same volume of natural gas is used for transportation purposes and all other regulatory requirements are met.[520] As the cost of running spur pipelines for anything beyond short distances becomes prohibitively expensive, only those biogas sources that are in relatively close proximity to the existing natural gas pipeline infrastructure are likely to be developed. Once connected, however, renewable biogas utilizes the existing CNG/LNG vehicle fleet, natural gas distribution system, and CNG/LNG vehicle refueling infrastructure. According to data from the Department of Energy Alternative Fuels Data Center, there are currently 1,549 public and private CNG fueling stations and 102 public and private LNG refueling stations in the U.S.[521]

Once the processed biogas is in the gas pipeline it is virtually indistinguishable from natural gas. However, expanding CNG vehicle infrastructure to support growth in the renewable biogas beyond the current level, estimated to be capable of supplying 1.3 to 2.0 billion ethanol-equivalent gallons of CNG/LNG per year in 2022, would represent a substantial challenge.[522] The incentives from the RFS program may be insufficient to cause a substantial increase in the CNG/LNG vehicle fleet and refueling infrastructure. CNG/LNG vehicles are predominately used in fleet applications where there is a unique situational advantage such as a natural gas supplier's

[519] Growth in biogas may require investment in additional gas cleanup operations prior to pipeline injections, particularly in California where pipeline standards currently preclude the injection of most biogas. The potential for such biogas cleanup costs are discussed in Chapter 6.1.2.10 of the DRIA.
[520] See generally 40 CFR 80.1426(f).
[521] Data accessed from the AFDC website (https://afdc.energy.gov/stations/) on April 13, 2021.
[522] See Chapter 5.1.3.2 for further discussion of the estimated use of CNG/LNG as transportation fuel in 2022.

utility fleet or landfill's waste hauler fleet. In addition, it would be more challenging to establish the necessary contacts to demonstrate that natural gas was used in CNG/LNG vehicles outside of fleet operations. The cost associated with removing the impurities in renewable biogas to make it suitable for use in CNG/LNG vehicles and to facilitate its fungible transportation in the natural gas distribution system could also be a barrier to its expanded use.

6.2 Biodiesel

The 2010 RFS2 final rule projected that 1.5 billion gallons of biodiesel would be used in 2017 and 1.82 billion gallons would be used in 2022 to meet the statutory biofuel volume requirements.[523] We noted that biodiesel plants tended to be more dispersed than ethanol plants, thereby facilitating delivery to local markets by tank truck and lessening the need to distribute biodiesel to over long distances. Biodiesel imports also helped to serve coastal markets. We projected that as biodiesel volumes grew, there would be more need for long distance transport of domestically-produced biodiesel. We estimated that such long-distance transport would be accomplished by manifest rail and to a lesser extent barge since the economy of scale would not justify the use of unit trains. We estimated that biodiesel and biodiesel blends would not be shipped by pipeline to a significant extent due to concerns over potential contamination of jet fuel that is also shipped by pipeline.

In 2010 much of the biodiesel blending was taking place at facilities downstream of terminals such as storage facilities operated by individual fuel marketers. We projected that this would take place to a lesser extent as volumes grew with most biodiesel being blended at terminals to the 5% (B5) blend level that is approved for use in diesel engines by all manufacturers for distribution to retail and fleet fueling facilities. We acknowledged that the expansion of biodiesel volumes could pose issues for petroleum terminals, but that these issues could be resolved.[524] Since vehicle refueling infrastructure is compatible with biodiesel blends up to 20% (B20), we estimated that there would be no changes needed at retail and fleet facilities to accommodate the projected increase in biodiesel use.

There are significant instances where actual biodiesel production and use have developed differently than we projected in the 2010 RFS 2 rule. Most importantly, the 1.9 billion gallons of biodiesel used in 2020 already exceeded the 1.82 billion gallons that we projected would be used in 2022. Another significant difference is that much biodiesel blending is taking place downstream of terminals at fuel marketer storage facilities and even at fuel retail facilities.

Somewhat easing biodiesel transportation to terminals is the fact that shipment of low-level biodiesel blends up to 5% is currently taking place on some petroleum product pipelines that do not also carry jet fuel.[525] Jet fuel is a significant product on much of the petroleum pipeline system. Therefore, concern over biodiesel contamination of jet fuel remains a significant limitation on the ability to expand the shipment of biodiesel blends by pipeline. Industry is

[523] See Section 1.2.2 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[524] There is additional difficulty in storing and blending biodiesel because of the need for insulated and/or heated equipment to prevent cold flow problems in the winter. This issue is typically not present for B5 biodiesel blends.
[525] Ethanol, Biofuels, and Pipeline Transportation. Association of Oil Pipelines and American Petroleum Institute. https://www.api.org/~/media/files/oil-and-natural-gas/pipeline/aopl_api_ethanol_transportation.pdf

currently investigating whether jet fuel can tolerate higher levels of biodiesel contamination which may allow low-level biodiesel blends to be shipped on pipelines that also carry jet fuel, however this effort will likely not be completed until after the 2022 timeframe of this proposal.[526] Finally, there appears to be substantial volumes of B20 being used despite the fact that a significant number of vehicle manufacturers only warranty their engines for up to B5.[527] This has resulted in an uneven distribution of biodiesel use across the nation, with some parts using more than 5% while other locales use little or no biodiesel.[528]

In this proposed rule we are not projecting significant increases in the volume of biodiesel produced and imported in the U.S. As such, we do not anticipate any challenges associated with the infrastructure to distribute and use biodiesel through 2022. However, it is possible that domestic biodiesel production and/or biodiesel imports may increase in future years. Domestic biodiesel production capacity is discussed in Chapter 5.2. A review of monthly biodiesel imports suggests that import infrastructure can support significantly higher volumes of imports.[529] For example, 1.3 billion gallons per year of imports could be supported using the existing infrastructure if we were to assume that the 112 million gallons of biodiesel imports that took place in December of 2016 could be maintained year-round. Some additional expansion in import infrastructure might also be anticipated through 2022. Therefore, we do not believe that domestic production capacity or import infrastructure constraints would be a substantial impediment to an expansion in biodiesel volumes at current levels.[530]

We anticipate that if biodiesel production and imports increase significantly investment in the infrastructure to transport biodiesel from the points of production to locations where it can be consumed will be needed. These investments would primarily be associated with securing sufficient downstream biodiesel storage and the requisite number of rail cars and tank trucks suitable for biodiesel transport.[531] Significantly expanding biodiesel blending infrastructure to accommodate the increase in biodiesel volume may also pose significant challenges. Many terminals that have yet to distribute biodiesel would likely need to install the infrastructure necessary to do so in a time frame that may not be possible for them to achieve. All vehicle refueling infrastructure is compatible with B20 blends, thereby easing the expansion to retail of biodiesel blends made at terminals. However, significant infrastructure changes would be needed to biodiesel storage and blending facilities downstream of terminals and at retail facilities if substantial additional volumes of biodiesel blends were to be made downstream of terminals.

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526 An ASTM task group is seeking additional data to address negative comments on a 2018 ballot to increase the limit on biodiesel contamination in jet fuel from 50 mg/kg to 100 mg/kg. The ASTM limit on biodiesel contamination of jet fuel was last revised in 2015. Revised ASTM Standard Expands Limit on Biofuel Contamination in Jet Fuels, ASTM New Release, February 2, 2015.

527 See Pilot Flying J Fuel Offerings, Memorandum to EPA Docket EPA-HQ-OAR-2021-0324.

528 See Average Biodiesel Blend Level By State Based on EIA Data, Memorandum to EPA Docket EPA-HQ-OAR-2021-0324.

529 Energy Information Administration, U.S. Imports of Biodiesel 2009 thorough 2018.

530 The expansion of biodiesel imports to the extent discussed above is for purposes of the infrastructure analyses only. There would be significant challenges in obtaining foreign produced biodiesel volumes to approach such a substantial increase in imported biodiesel. See Chapter 1.4.2.

531 Biodiesel rail cars and to a lesser extent tank trucks must often be insulated and or heated during the cold season to prevent cold flow problems. The use of such insulated/heated vessels is sometimes avoided by shipping pre-heated biodiesel.

Therefore, the infrastructure system may present challenges to increasing volumes of biodiesel in the U.S.

The cold flow of petroleum-based diesel dispensed to vehicles must often be improved in the winter through the addition of #1 diesel fuel and/or cold-flow improver additives. Biodiesel blends tend to have poorer cold flow performance than straight petroleum-based diesel fuel. This requires the use of additional cold-flow improvers and sometimes limits the biodiesel blend ratio that can be used under the coldest conditions.[532] Biodiesel cold flow properties are dependent on the source of the feedstock with biodiesel produced from palm oil being subject to wax formation at higher temperatures than soy-based biodiesel.[533] Thus, additional actions are necessary to ensure adequate cold-flow performance of palm-based biodiesel blends compared to soy-based biodiesel. Such additional actions may be uneconomical in some cases.[534] Therefore, a substantial increase in the use of palm-based biodiesel during the cold weather season may be a challenge.

6.3 Renewable Diesel

The 2010 RFS2 rule projected that the volume of “drop-in” cellulosic and renewable diesel fuel would range from 0.15 billion gallons to 3.4 billion gallons in 2017 and 0.15 billion gallons to 9.5 billion gallons in 2022.[535] Such fuels are referred to as drop-in fuels because their physical properties are sufficiently similar to petroleum-based diesel fuel to be fungible in the common diesel fuel distribution system.[536] Thus, little change is needed to the fuels infrastructure system to support the use of drop-in biofuels. The 2010 RFS 2 rule projected that the distribution infrastructure could expand in a timely fashion to accommodate that projected range of growth in drop-in cellulosic and renewable diesel fuel.[537]

In practice, much of the renewable diesel produced in the U.S. has been transported by truck, rail, and ship rather than by pipelines. This is in part due to the location of the renewable diesel production and demand and the lack of available pipelines to transport renewable diesel from production sites to demand centers. Regulatory challenges have also limited the transportation of renewable diesel via pipeline. Regulatory programs such as the RFS program require renewable diesel to be used as transportation fuel to be eligible to generate RINs. In addition, renewable diesel can generate credits for California and other State biofuel programs only if it is used in those States. Finally, product documentation requirements for product shipped by pipeline and fuel pump labeling requirements often require that the blend level be indicated, but the concentration would often be uncertain in a fungible distribution system. Transportation of renewable diesel via common carrier pipelines can make documenting the use and blend levels of renewable diesel difficult, if not impossible.

[532] B5 blend levels can typically be maintained.
[533] Biodiesel Cold Flow Basics, National Biodiesel Board, 2014.
[534] Evaluation and enhancement of cold flow properties of palm oil and its biodiesel, Puneet Verma, et.al., Biofuel Research Laboratory, Indian Institute of Technology, Elsevier Energy Reports, January 2016.
[535] See Section 1.2.2 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).
[536] Such drop-in fuels are typically blended with petroleum-based diesel fuel prior to use.
[537] See Section 1.6 of the RFS2 Regulatory Impact Analysis (EPA-420-R-10-006).

The projected increase in domestic renewable diesel production through 2022 is significant (see Chapter 4.2). We expect that much of this renewable diesel will be used in states with state incentive programs for fuels with low carbon intensity such as California and Oregon. As both these markets are located on the Pacific coast, much of the renewable diesel produced on or near the Gulf Coast is likely to be transported via ship. The remaining renewable diesel production facilities are not located near the coast, and we therefore project that the fuel they produce will likely be transported via truck and/or rail to markets where the fuel is used. This may require some expansion to the existing infrastructure, such as additional rail cars to transport renewable diesel. The fact that the new or expanding renewable diesel production facilities are generally located in the western U.S. relatively close to California and Oregon likely reduces the impact of distributing these fuels on the transportation infrastructure, though this may be somewhat offset by the need to transport feedstocks to the renewable diesel production facilities. While some adjustments will likely be needed to accommodate the expected increase in renewable diesel production, we do not expect that these adjustments will inhibit the growth of renewable diesel production or appreciably impact transportation networks in the U.S. more broadly.

6.4 Ethanol

The infrastructure needed to deliver ethanol includes that required for distribution of denatured ethanol from production facilities to terminals, storage and blending equipment, and distribution of gasoline-ethanol blends to retail service stations. With regard to infrastructure needed to use ethanol, essentially all retail service stations are certified to offer E10 and all vehicles and equipment are designed to use E10. As a result, any infrastructure-related impacts on the use of ethanol in 2021 and 2022 are associated with service station storage and dispensing equipment for higher ethanol blends such as E15 and E85, and the vehicles that are permitted to use those blends.

Based on our analysis of the sufficiency of infrastructure to deliver and use ethanol as discussion below, we have determined that there are constraints associated with E15 and E85 that limit the rate of future growth in their consumption. These constraints are appropriately reflected in our use of projected ethanol consumption from EIA as discussed in Chapter 4.5 since those projections represent only moderate changes in the nationwide average ethanol concentration in comparison to earlier years.[538]

6.4.1 Ethanol Distribution

To support the 2010 RFS2 rule, Oak Ridge National Laboratories (ORNL) conducted an analysis of potential distribution constraints that might be associated with attaining the statutory volume targets through 2022.[539] The ORNL analysis analyzed ethanol transport pathways from production to blending facilities at terminals by rail, waterways, and roads, and projected that most ethanol would require long distance shipment to demand centers. The primary mode of

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[538] A nationwide average ethanol concentration above 10.00% can only occur insofar as there is consumption of E15 and/or E85. The ethanol volume projections from EIA for 2021 and 2022 from the April 2021 STEO represent ethanol concentrations of 10.20% and 10.22%, respectively.

[539] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints," ORNL, March 2009.

long-distance transport in 2010 was via manifest rail and to a lesser extent by barge although transport by unit train was beginning to spread. ORNL projected that rail would continue to be the predominate means of long-distance ethanol transport through 2022 with a substantial increase in the use of unit trains and continued supplemental transport by barge. ORNL concluded that there would be minimal additional stress on most U.S. transportation networks overall to distribute the increased biofuel volumes.

However, ORNL stated that there would be considerable increased traffic along certain rail corridors due to the shipment of biofuels that would require significant investment to overcome the resulting congestion. We concluded in the 2010 RFS2 rule that these investments could be made to increase the capacity of the effected rail corridors without undue difficulty.[540] Therefore, the 2010 RFS2 rule concluded that the infrastructure system to the blending terminal could accommodate the projected increased volume of ethanol in a timely fashion.

To update and expand upon the analysis of distribution infrastructure upstream of retail that was conducted for the 2010 RFS2 rule, we contracted with ICF International Inc. ("ICF") to conduct a literature review, background research, and stakeholder interviews to characterize the impacts of distributing ethanol and other biofuels.[541] ICF's 2018 report determined that the conclusions from ORNL's 2010 analysis have largely turned out to be accurate based on an absence of indicators of distribution constraints up to and including the blending terminal. ICF noted that there were instances when the ethanol industry went through rapid expansion where the rail industry was not able to fully accommodate the expansion of inter-regional trade in ethanol. However, ICF found no evidence to suggest that rail congestion from shipment of biofuel was a persistent or common problem at the time that the study was completed. Likewise, ICF found no evidence that marine networks, including those used for import and export, were experiencing significant issues in accommodating increased volumes of biofuels. Consistent with the 2010 analysis, ICF stated that the expansion of ethanol and biodiesel volumes could pose issues for petroleum terminals, but that these issues could be resolved. While ICF indicated that there likely had been negative impacts on rural and highway transportation networks surrounding ethanol production facilities, ICF also determined that these impacts could be mitigated with network infrastructure planning and increased funding for road maintenance. ICF noted these increased costs would be small in comparison to broader maintenance costs for roads and that the road network could accommodate substantial growth in the movement of biofuels.

Based on the ICF study and our own assessment of the program's implementation, we conclude that the response of the ethanol distribution infrastructure system upstream of retail has largely unfolded as we projected in the 2010 RFS2 rule. Ethanol imports to coastal demand centers have helped to satisfy local demand. Ethanol transport over long distances is primarily being accomplished by unit train, and to a lesser extent by manifest rail and barge. Materials compatibility issues continue to prevent ethanol and ethanol blends from being shipped in petroleum product pipelines. Tank trucks are used to distribute ethanol to markets close to the ethanol production facility and from rail receipt facilities to more distant markets. Petroleum terminals have installed the necessary ethanol receipt, storage, and blending infrastructure.

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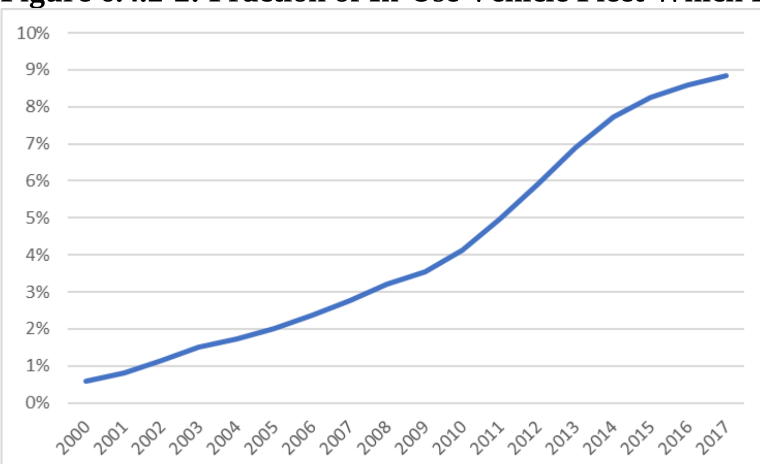
[540] 2010 Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis.
[541] Impact of Biofuels on Infrastructure, Report for EPA by ICF International Inc., January 2018.

Intermodal facilities such as those that transfer ethanol directly from rail cars to tank trucks are also being used to ease the burden on terminals.

6.4.2 Infrastructure for E85

E85 is permitted to be used only in designated flex fuel vehicles (FFVs). As of 2018, there were about 22 million FFVs in operation in the U.S., representing about 8.9% of all spark-ignition vehicles (Figure 6.4.2-2). Although this is the highest FFV fraction of the in-use fleet in history, it appears to have peaked and is expected to begin to decline due to the reduction in annual sales of FFVs in recent years.

Figure 6.4.2-2: Fraction of In-Use Vehicle Fleet Which Is FFVs



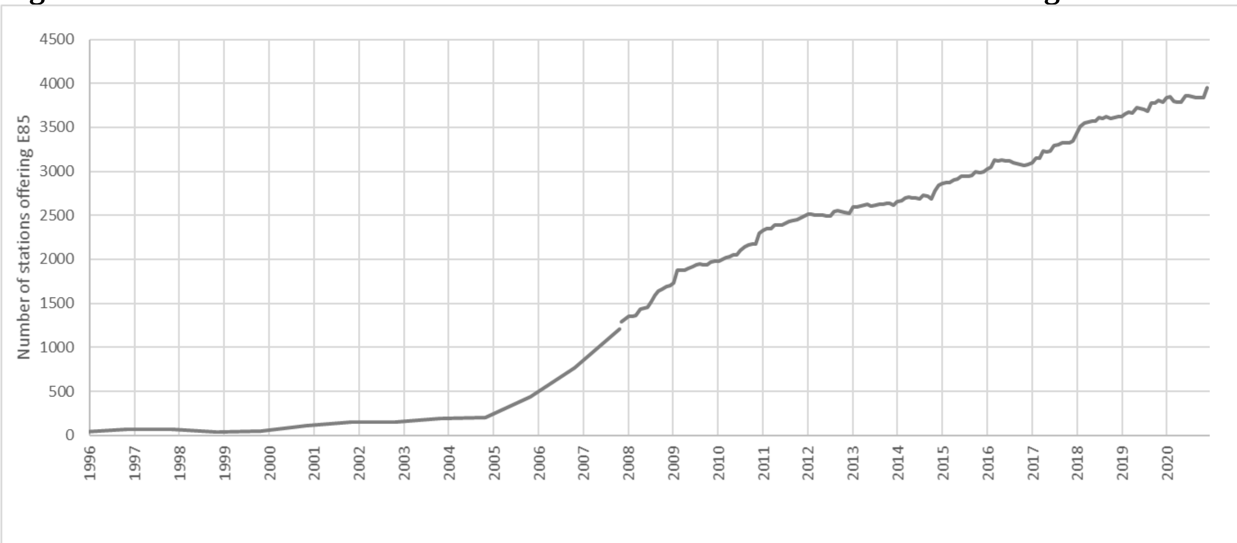
Source: Values calculated using annual retail vehicle sales of cars and trucks (Tables 4.6 and 4.7) and survival rates (Table 6.3.13) from the Transportation Energy Data Book, Edition 38, published by Oak Ridge National Laboratory in August 2020.

As of August 2020, there were about 22.2 million registered light-duty FFVs in-use, out of a total of about 254 million light-duty vehicles, or about 8.7% of the in-use fleet.[542,543]

E85 is sold at retail stations where the pumps, underground storage tanks, and associated equipment has been certified to operate safely with the high ethanol concentrations.[544] As shown below in Figure 6.4.2-3, stations offering E85 have increased steadily since about 2005. By the end of 2020, the total number of stations offering E85 had reached 3,947.

[542] "FFV registrations from AFDC August 2020," available in docket EPA-HQ-OAR-2021-0324.
[543] "DOT National Transportation Statistics Table 1-11," available in docket EPA-HQ-OAR-2021-0324.
[544] "UST System Compatibility with Biofuels," EPA Report number EPA 510-K-20-001, July 2020. Available in docket EPA-HQ-OAR-2021-0324.

Figure 6.4.2-3: Number of Public and Private Retail Service Stations Offering E85[a]

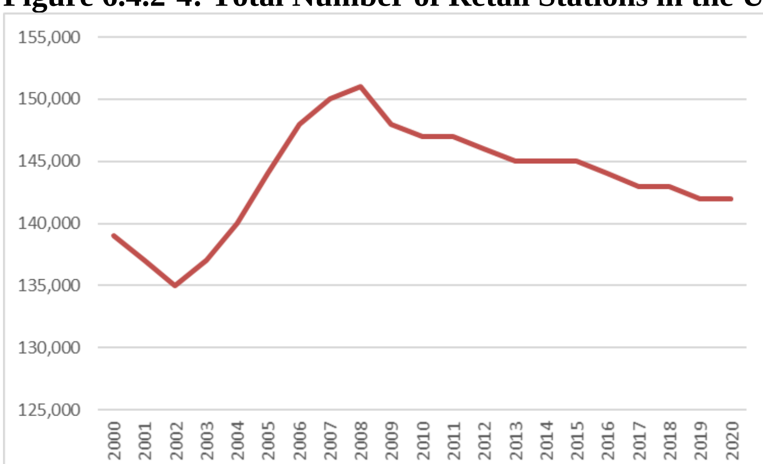


[a] Data through 2007 is annual, whereas data for 2008 and later is monthly
Source: Department of Energy's Alternative Fuels Data Center (AFDC). https://afdc.energy.gov/stations/states.

Grant programs such as the U.S. Department of Agriculture's (USDA) Biofuels Infrastructure Partnership (BIP) and the ethanol industry's Prime the Pump program, in addition to individual company efforts, have helped to fund the expansion of E85 offerings at retail stations. The combined effect of these efforts ensured ongoing growth in the number of stations offering E85.

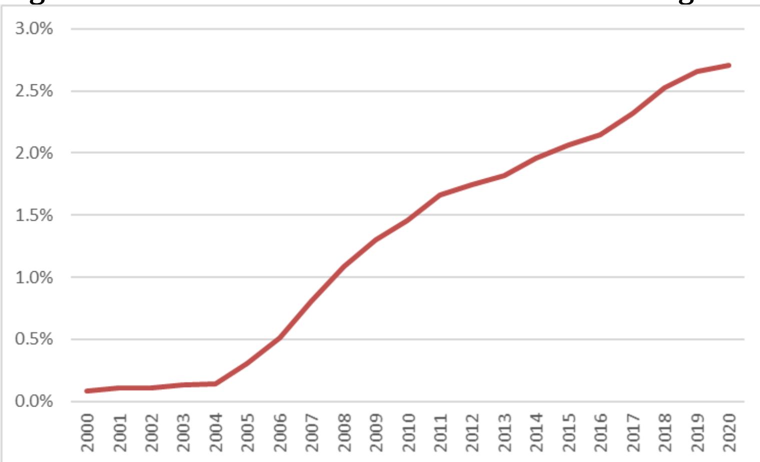
Although the total number of retail stations in the U.S. has varied over this time period as shown in Figure 6.4.2-4, the fraction of those stations offering E85 has steadily increased. By the end of 2020, the fraction of retail stations offering E85 had reached 2.7% as seen in Figure 6.4.2-5.

Figure 6.4.2-4: Total Number of Retail Stations in the U.S.



Source: Table 4.24, Transportation Energy Data Book, Edition 39.

Figure 6.4.2-5: Fraction of Retail Stations Offering E85



6.4.3 Infrastructure for E15

The CAA waiver which permitted all spark ignition highway vehicles of MY 2001 and later to use E15 was published on January 26, 2011.[545] The infrastructure needed to support the use of E15 includes blending and storage equipment at terminals, certified storage and dispensing equipment at retail service stations, and the vehicles that are permitted to use E15.

While the majority of service stations offering E15 today do so through blender pumps which can produce E15 on demand for consumers through the combination of E10 (or E0) and E85,[546] the number of terminals offering preblended E15 directly to service stations has been increasing.[547] The first terminals started to offer E15 in 2016, and today E15 is offered at 262 terminals, accounting for 20% for all U.S. terminals.[548]

The fraction of the in-use highway fleet that is MY2001 or later has increased steadily since E15 was approved in 2011, and with it the fraction of all gasoline consumed by highway vehicles that is consumed by MY2001 or later vehicles (see Figure 6.4.3-1).

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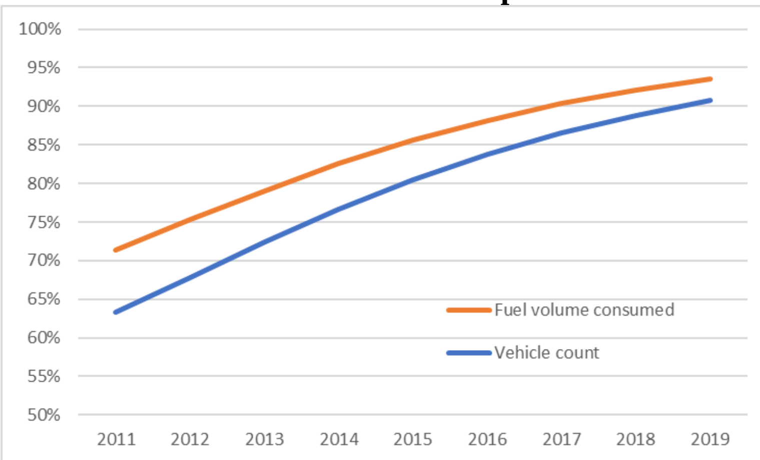
[545] Partial Grant of Clean Air Act Waiver Application Submitted by Growth Energy To Increase the Allowable Ethanol Content of Gasoline to 15 Percent; Decision of the Administrator, 76 FR 4662 (January 26, 2011).
[546] According to Prime the Pump, 1,771 out of 2,302 stations offering E15 at the end of 2020 used blender pumps.
[547] "Terminal Availability of E15 Grows as EPA Prepares to Remove RVP Barrier," available in docket EPA-HQ-OAR-2021-0324
[548] https://growthenergy.org/resources/retailer-hub. See also "Retailer Hub – Growth Energy 9-24-21," available in the docket.

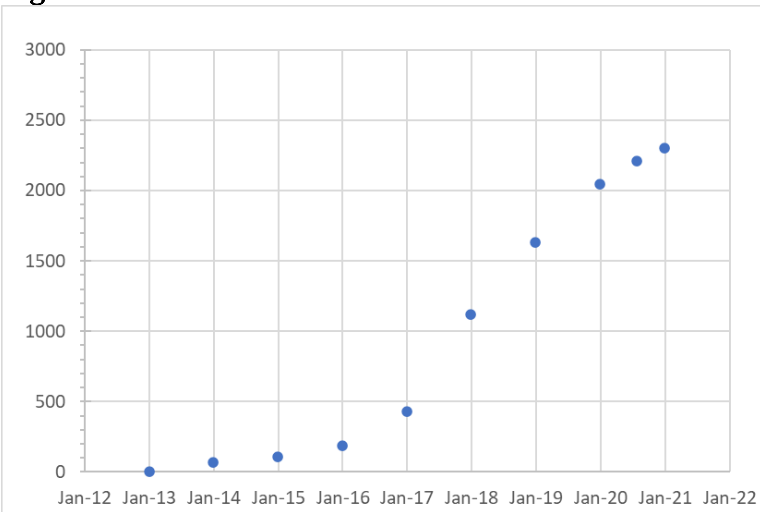
Figure 6.4.3-1: MY2001 Or Later Fraction of In-Use Vehicle Fleet and MY 2001 or Later Fraction of In-Use Gasoline Consumption



Source: Values calculated using annual retail vehicle sales of cars and trucks (Tables 4.6 and 4.7), survival rates (Table 6.3.13), miles per year per vehicle by age (Table 6.3.12), and fuel economy by model year (Table 6.4.12) from the Transportation Energy Data Book, Edition 38, published by Oak Ridge National Laboratory in August 2020.

Based on the two modes of E15 production (terminals and blender pumps at retail stations), and the fact that the majority of in-use vehicles are legally permitted to use E15, it appears that the primary constraint on the consumption of E15 in the near term is likely to be the number of retail stations that offer it. Since E15 was not approved for use until 2011, there were no retail stations offering it before 2011. Since the vast majority of the existing retail infrastructure is not or is not confirmed to be entirely compatible with E15 (the entire system of tanks, pipes, pumps, dispensers, vent lines, and importantly pipe dope), growth in the number of retail stations offering E15 is dependent on investments in retail outlets to convert them to E15 compatibility or make them compatible when newly constructed. However, many retail station owners are unable to pay the cost of such conversions themselves and require assistance. Growth in the number of stations offering E15 was slow until USDA's Biofuels Infrastructure Partnership (BIP) program and the ethanol industry's Prime the Pump program began providing funding for station conversions in about 2016.

Figure 6.4.3-2: Number of Retail Service Stations Offering E15



Source: "Prime the Pump Infrastructure Update Jan 2021," available in docket EPA-HQ-OAR-2021-0324.

USDA has followed up its BIP program with a similar grant program called the Higher Blends Infrastructure Incentive Program (HBIIP) which will also provide funds to help retail service station owners to upgrade or replace their equipment to offer biofuels. This program was initiated in 2020.

Based on comments received in 2016 from the Petroleum Marketers Association of America in response to previous annual standard-setting proposals, there may also be resistance to expanded offerings of E15 due to concerns about liability.[549] These liability concerns fall into two areas: the use of retail storage and dispensing equipment that is not compatible and/or not approved for E15, and consumers that refuel vehicles and engines not designed and/or approved for its use. With regard to equipment compatibility, even if much of the existing equipment at retail is compatible with E15 as argued in studies from the National Renewable Energy Laboratory (NREL) and Stillwater Associates, compatibility with E15 is not the same as being approved for E15 use.[550,551] Recently-amended EPA regulations require that parties storing ethanol in underground tanks in concentrations greater than 10% demonstrate compatibility of their tanks with the fuel, through one of the following methods:[552]

- A certification or listing of underground storage tank system equipment or components by a nationally recognized, independent testing laboratory such as Underwriter's Laboratory
- Written approval by the equipment or component manufacturer
- Some other method that is determined by the agency implementing the new requirements to be no less protective of human health and the environment

[549] See comments from the Petroleum Marketers Association of America on the proposed standards for 2014-2016. Document # EPA-HQ-OAR-2015-0111-1197 available in docket EPA-HQ-OAR-2021-0324.
[550] K. Moriarty and J. Yanowitz, "E15 and Infrastructure," National Renewable Energy Laboratory, May 2015. Attachment 3 of comments submitted by the Renewable Fuels Association.
[551] Stillwater Associates, "Infrastructure Changes and Cost to Increase RFS Ethanol Volumes through Increased E15 and E85 Sales in 2016," July 27, 2015. Submitted with comments provided by Growth Energy.
[552] "UST System Compatibility with Biofuels," available in docket EPA-HQ-OAR-2021-0324.

The use of any equipment to offer E15 that does not satisfy these requirements, even if that equipment is technically compatible with E15, would pose potential liability for the retailer, including concerns related to liability for equipment damage. This issue is of particular concern for underground storage tanks and associated hardware, as the documentation for their design and the types of materials used, and even their installation dates, is often unavailable. As existing underground storage tank systems reach the end of their warranties or are otherwise in need of repair or upgrade it provides an opportunity for retail station owners to install new systems that are compatible with E15.

With regard to retailer concerns about litigation liability for E15 misfueling related to vehicles not designed and/or approved for use with E15, we note that EPA regulations require pump labeling, a misfueling mitigation plan, surveys, product transfer documents, and approval of equipment configurations, providing consumers with the information needed to avoid misfueling.[553] In addition, the portion of vehicles not designed and/or approved for E15 use continues to decline. Vehicles manufactured before EPA's threshold of 2001 represent less than 10% of the vehicle stock, and just slightly over 5% of miles travelled. Vehicles designed and warranted by manufacturers to be fueled on E15 are likewise representing an ever increasing portion of the in-use fleet. It is unclear, however, to what degree these facts will mitigate retailers' concerns.

6.5. Deliverability of Materials, Goods, and Products Other Than Renewable Fuel

The distribution of renewable fuels relies on the same rail, marine, and road infrastructure networks that are used to deliver materials, goods and products other than renewable fuels. Therefore, we evaluated whether the use of renewable fuels would impact the deliverability of other items that rely on these infrastructure networks.

The ORNL study of biofuel distribution for the 2010 RFS 2 rule discussed in Chapter 6.4.1 concluded that there would be minimal additional stress on most U.S. transportation networks overall due to increased biofuel volumes. This indicates that the shipment of the statutory biofuel volumes could be accommodated without impacting the deliverability of other items. However, as discussed above, ORNL noted that significant investment would be needed to overcome congestion on certain rail corridors. The ICF study discussed in Chapter 6.4.1 determined that the conclusions from ORNL's 2010 analysis have largely turned out to be accurate based on an absence of indicators of distribution constraints. However, ICF noted that there were instances when the ethanol industry went through rapid expansion where the rail industry was not able to fully accommodate the expansion in inter-regional trade in ethanol. During these periods, the volume of ethanol permitted to be shipped along the sensitive rail corridors was limited to mitigate the congestion. However, ICF found no evidence to suggest that rail congestion from shipment of biofuel is a persistent or common problem today.

[553] See 40 CFR Part 80, Subpart N: Sections 1500 to 1509.

Likewise, ICF found no evidence that the shipment of biofuels has had a negative impact on marine networks. While ICF indicated that there likely have been negative impacts on rural and highway transportation networks surrounding ethanol production facilities, it also determined that these impacts can be mitigated with network infrastructure planning and increased funding for road maintenance. ICF noted these increased costs are small in relation to broader maintenance costs for roads and that the road network can accommodate substantial growth in the movement of biofuels.

Given the overall minimal impact on transportation infrastructure from the distribution of biofuels and the ability of the system to resolve localized instances of increased stress on the system in a timely fashion, we believe that the volumes under consideration in this proposal would not impact the deliverability of materials and products other than renewable fuel.

With regard to the deliverability of feedstocks used to produce renewable fuel, we do not anticipate constraints that would make proposed volume requirements difficult to achieve. For instance, biogas for CNG/LNG vehicles will be delivered through the same pipeline network used to distribute natural gas. Since that biogas will be displacing natural gas used in CNG/LNG vehicles, we would not expect a net increase in total volume of biogas + natural gas delivered.

We estimate that fats, oils, and greases (FOG) would represent only a small portion of the feedstocks used to produce renewable diesel under our proposed standards for 2021 and 2022. FOG is collected and distributed through a diverse network of trucking companies, and the increase would represent a very small portion of their activities. The estimated increase of 30 million gallons of FOG-based renewable diesel in both 2021 and 2022 would represent only 16% of all the FOG currently produced and collected for renewable diesel production. As a result, we do not anticipate any hindrances to the deliverability of FOG for the production of renewable diesel in 2021 and 2022.

The largest volumes of renewable fuel increases that we are proposing for 2021 and 2022 would be for corn ethanol and soybean oil renewable diesel. However, although corn ethanol would increase in both 2021 and 2022 under our proposed volume requirements as shown in Table 2.3-3, the total volume consumed in both years would remain below that consumed in 2019. Since the corn collection and distribution network functioned without difficulty in 2019, there is no reason to believe that it would not function similarly in 2021 and 2022.

As shown in Table 2.3-3, soybean oil produced for renewable diesel is projected to increase by 240 million gallons in 2021 and 767 million gallons in 2022. To the degree that these volumes are derived from new soybean production rather than soybean oil diverted to renewable diesel production from existing uses, they nevertheless represent moderate increases in feedstock production levels. Domestic soybean oil production is expected to increase by 719 million pounds, according to the USDA ERS Oil Crops Yearbook. As a result, marine, rail, and road infrastructure improvements can be made without undue difficulties. This is consistent with the ORNL study of biofuel distribution for the 2010 RFS 2 Rule, which concluded that increased renewable diesel production would not affect infrastructure, meaning the feedstocks likely will not affect these transportation networks either.[554] Moreover, an ICF study found that, while there

[554] "Analysis of Fuel Ethanol Transportation Activity and Potential Distribution Constraints," ORNL, March 2009.

were instances in the past when the ethanol industry went through such rapid expansion that the rail network was unable to immediately accommodate, there is little evidence that rail, road, or marine congestion from increases in shipments of any biofuel, including renewable diesel, is a persistent problem.[555] It is unlikely that the required feedstock for this renewable diesel would pose problems to existing infrastructure when the fuel transport itself does not.

[555] "Impact of Biofuels on Infrastructure," Report for EPA by ICF International Inc., January 2018.

Chapter 7: Other Factors

The statute directs EPA to consider 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. This chapter addresses the enumerated "other" factors.[556] We focus our analysis on the primary biofuels that this rulemaking is expected to affect, namely, corn ethanol, renewable diesel made from soybean oil, and biogas. While we also expect relatively large increases in renewable diesel from palm, we expect that the palm will be produced in foreign countries and thus will have little impact on the domestic rural economy.

7.1 Job Creation

This section provides greater detail on our evaluation of impacts of renewable fuels on job creation. Attempting to attribute increases or decreases in employment to a single variable such as domestic renewable fuel use is fraught with complexity. Even considering just the biofuel production facilities themselves, there are confounding factors that include biofuel import/export activity, shifts in agricultural commodity prices, and varying demand for coproducts. Assessing the impacts on indirectly-affected industries is even more difficult. Recognizing this challenge, we chose to focus the analysis on economic sectors which have the closest association with biofuel use: biofuel production, petroleum refining, and agriculture. We acknowledge that changes in indirect employment (service sectors, transportation, construction, etc.) can also be associated with renewable fuel use, but due to the amount of effort and uncertainty involved with indirect effects, they were excluded from the scope of our analysis. We recognize that this analysis does not estimate the net employment effects as increases in employment in some sectors may be offset by unemployment in other sectors.

7.1.1 Fuel Production

This subsection provides analysis and discussion on employment aspects of renewable fuel production as they relate to the volumes projected in this rulemaking.

7.1.1.1 Ethanol Production

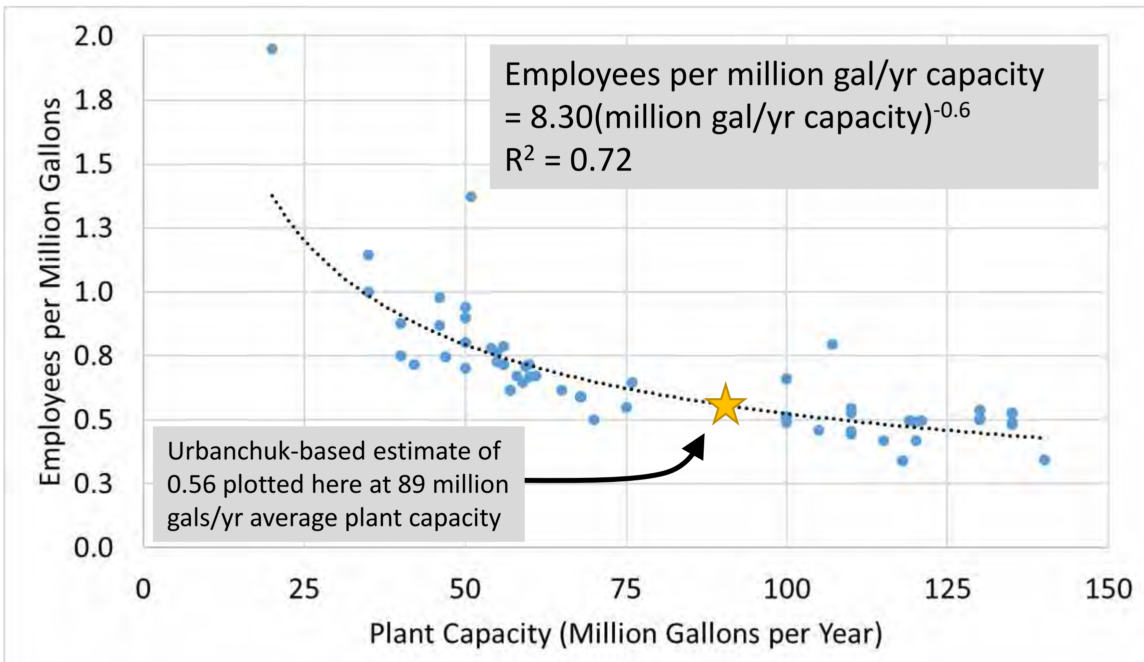
As we explain in Chapter 2, the vast majority of the renewable fuel change in 2021-2022 is due to corn ethanol. Urbanchuk estimates the total number of direct, full-time-equivalent jobs for domestic corn ethanol production in 2019 was 9,500 across the 190 plants that the Renewable Fuels Association found to be operating that year.[557] Since the Census Bureau employment data does not cover ethanol production specifically, Urbanchuk explains that this employment value was generated by multiplying the number of operating facilities by an estimated 50 full-time-equivalent positions at each.

[556] As we explain in Section II of the preamble, we also consider several other factors besides those enumerated in the statute.
[557] From "*Contribution of the Ethanol Industry to the Economy of the United States in 2019*," prepared for the Renewable Fuels Association by John M. Urbanchuk, ABF Economics. February 4, 2020. We have cited the 2019 report for this discussion because of the unusual economic conditions in 2020 caused by the COVID-19 pandemic.

The U.S. Energy Information Administration (EIA) Annual Fuel Ethanol Production Capacity Report provides plant count and total nameplate capacity values for historical calendar years. For 2021, EIA shows 17,546 million gallons (MMgal) produced by 197 plants that reported themselves as operational.[558] The average plant size using these figures is 89 million gallons per year, which gives an average employee concentration of 0.56 jobs per million gallons capacity using Urbanchuk's value of 50 employees per plant.

In 2018, we were able to collect data on the number of employees at each of 65 corn ethanol facilities through the website of Ethanol Producer magazine.[559] A table of this information is provided in the docket. The plant capacities provided by Ethanol Producer generally compare well with those reported by EIA, deviating by less than 3% when averaged on a state-by-state basis. For these 65 facilities, we examined employee concentration as a function of production capacity. The results show a nonlinear decreasing trend in employee concentration with production capacity, suggesting economies of scale are associated with labor in ethanol plants. Figure 7.1.1.1-1 shows this data fit with an exponential trendline, and includes the Urbanchuk-based estimate of employee concentration of 0.56 plotted at the national average facility size of 89 million gallons per year. The Urbanchuk value shows good agreement with the correlation fit line.

Figure 7.1.1.1-1: Correlation between employee concentration and facility size for corn-ethanol facilities



Since the data underlying this analysis was collected at a single point in time and simply associates a plant headcount with its nameplate capacity, we weren't able to estimate the

[558] U.S. EIA. U.S. Nameplate Fuel Ethanol Production Capacity, January 2021. https://www.eia.gov/petroleum/ethanolcapacity/archive/2021/index.php

[559] Ethanol plant employment data obtained via Ethanol Producer Magazine website. Current issue and archives available at http://www.ethanolproducer.com

sensitivity of employment at a particular facility to changes in production volume at that facility. Regardless, it's unlikely that small variations in production volume (e.g., 10-15%) at a particular plant over in the short term would affect employee headcount. Each the unit operations such as feedstock unloading, mashing, fermentation, DDGS drying and pelletizing must remain operational for ethanol production to continue, and each of these areas requires trained operators. Over the longer term, we might anticipate changes consistent with Figure 7.1.1.1-1, and demand that stretches plants above their nameplate capacity for a sustained period could cause construction of new facilities. The corn ethanol volume increases being evaluated in this rulemaking are well below 10% of the current production level and are driven in large part by the recovery in gasoline demand from its depressed level during the pandemic in 2020 (volumes which form the baseline for this rule). Thus, little to no impact on employment and no new construction are expected related to ethanol production.

7.1.1.2 Renewable Diesel and Biogas Production

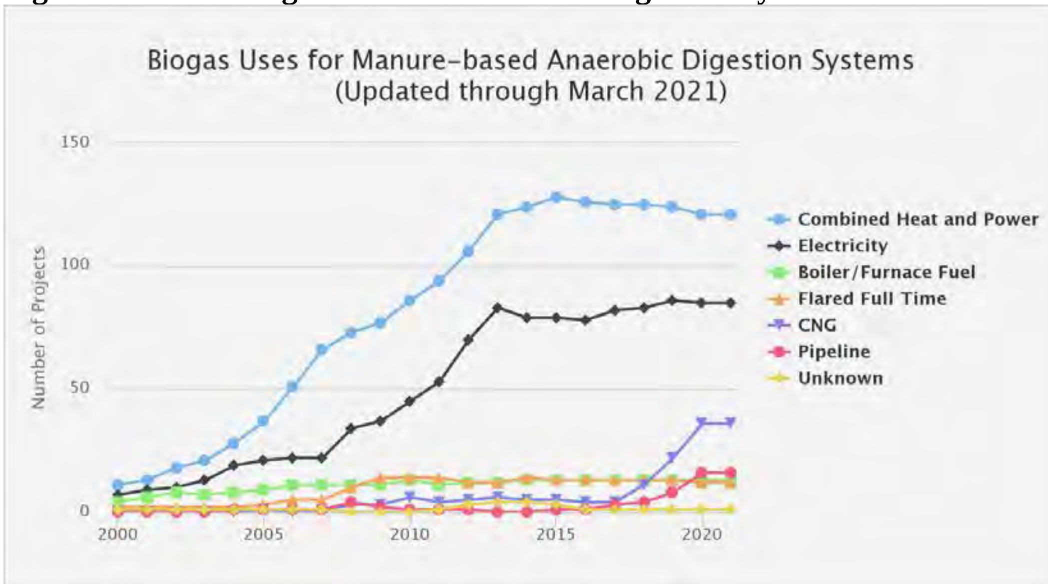
We are projecting significant growth in renewable diesel (RD) production for 2021 (270 MMgal) and 2022 (797 MMgal), as outlined in Chapter 5. Production of this fuel will come from a mix of expansions at existing facilities, construction of new facilities, and conversions of process trains at existing petroleum refineries. We expect employment increases related to this volume expansion, particularly with respect to the new facilities. However, at this time, we lack the data to quantify the impact on employment.

We are also projecting significant growth of biogas CNG/LNG use to meet the proposed standards based on a relatively steady 23% year-on-year growth rate, as outlined in Chapter 5. This fuel is expected to be sourced primarily will be produced via landfill gas collection, but some may also be produced from animal waste digesters. Since collection of landfill gas has been required for decades, increases in production described in this rule will come from existing biogas already captured and put into natural gas pipeline systems, or from operators upgrading the quality of the biogas they are already capturing for onsite electrical generation or flaring and installing the necessary pipeline interconnect and metering equipment to begin earning credits under the RFS program.[560] Thus, we expect little or no new employment from the landfill biogas volume increases described in this rule.

The story is similar for biogas digesters. Figure 7.1.1.2-1 shows that installation of gas-producing digesters increased steadily over the past two decades, with nearly all the output being used for onsite heating and electrical generation through about 2018. Since that time, we see flat or decreasing numbers for onsite consumption (heating, flaring, electrical generation) while gas being directed to pipeline injection and other CNG uses has increased steadily (excluding the economic downturn of 2020). It is expected that this transition will continue given high credit values available for renewable transportation fuel.[561] Since this redirection is similar to the situation for landfill gas, we expect little or no new employment at digester facilities during the timeframe of this rule.

[560] Jaramillo and Matthews, Environmental Science & Technology 2005 39 (19), 7365-7373.
[561] U.S. EPA AgSTAR Data and Trends, June 2021. Available at https://www.epa.gov/agstar/agstar-data-and-trends

Figure 7.1.1.2-1: Biogas Uses for Anaerobic Digestion Systems



7.1.1.3 Fuel Production Summary

Overall, we expect modest increases in fuel production employment due to the annual volume requirements in this rulemaking. These will occur primarily in the renewable diesel production sector. Increased use of renewable fuel displaces a similar amount of fossil petroleum, however, the petroleum refining sector has steadily increased product exports over the past decade and thus little contraction in their actual production volumes is expected despite slightly slower domestic consumption due to the proposed volumes.[562]

7.1.2 Agricultural Employment

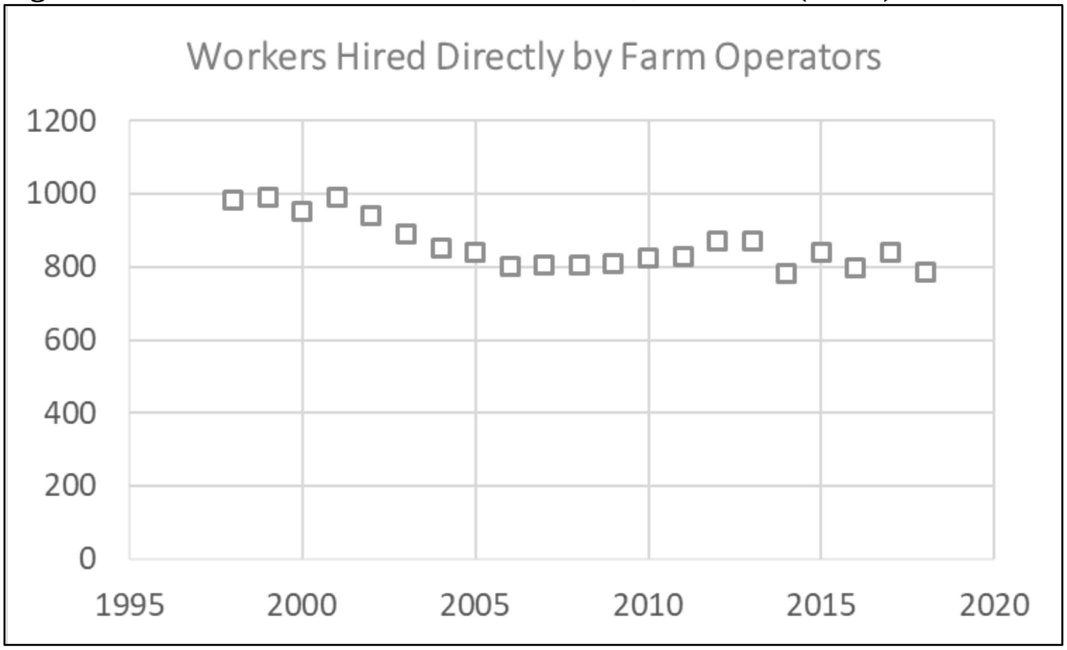
Job creation in the agricultural sector, beyond the fuel production activities discussed above, is expected primarily in the areas of production and transportation of crops serving as biofuel feedstocks. As described in 7.1.1.2 above, we don't expect the projected increases in ethanol or biogas CNG/LNG production to have a quantifiable effect on agricultural employment. As noted above, we are projecting significant growth in renewable diesel production for 2021 and 2022, with nearly all of this feedstock being soybean oil. (This excludes imported renewable diesel, which we expect will be made outside the U.S. from palm oil or other low-cost feedstocks.)

Gauging the impact that increased use of renewable fuels has had on employment in the agricultural sector is challenging for a number of reasons including, but not limited to, seasonality, production of a wide array of products, and the broad nature of employment in the sector which stretches from field hands to equipment production. To try to understand this better, we examined available data on agricultural employment over the past couple of decades, with no pretense of ascribing causation for observed trends to particular volumes of renewable fuels.

[562] Energy Information Administration, Annual Petroleum Export Data.

Some of the most consistently sourced data available on hired farmworkers is made available by the National Agricultural Statistics Service (NASS)[563]. The reports from the month of November on farm labor statistics were used to track the harvest season (October) level of workers hired directly by farm operators over the past two decades. This data is presented in figure 7.1.2-1 below.

Figure 7.1.2-1: Harvest Season Farm Workers, 1998-2018 (1000s)



The trend in the data is that direct employment of hired farmworkers by farm operators has been relatively stable, around the 800 thousand level, since 2003/4. There is variation year-over-year, but it is difficult to conclude from this data that there has been any significant increase or decrease in the employment of farmworkers directly hired by farm operators related to increased production of renewable fuels over the past two decades. Given the broad scope of this data, it is not possible to discern whether, for example, an increase of workers harvesting corn in Iowa has been offset by a reduction in employment of workers harvesting pistachios in California. Were more disaggregated employment data available, perhaps it would be possible to discern changes in the employment of farmworkers for the purposes of producing soy and corn.

An additional set of data on agricultural employment is collected by the United States Department of Agriculture (USDA). The methods for categorizing types of employment are slightly different than those found in the NASS data, but the greater breadth of jobs captured by the employment in agriculture and support industries dataset provides additional insight. Figure 7.1.2-2 presents the data on employment in agriculture and support activities for 2001-2019.[564]

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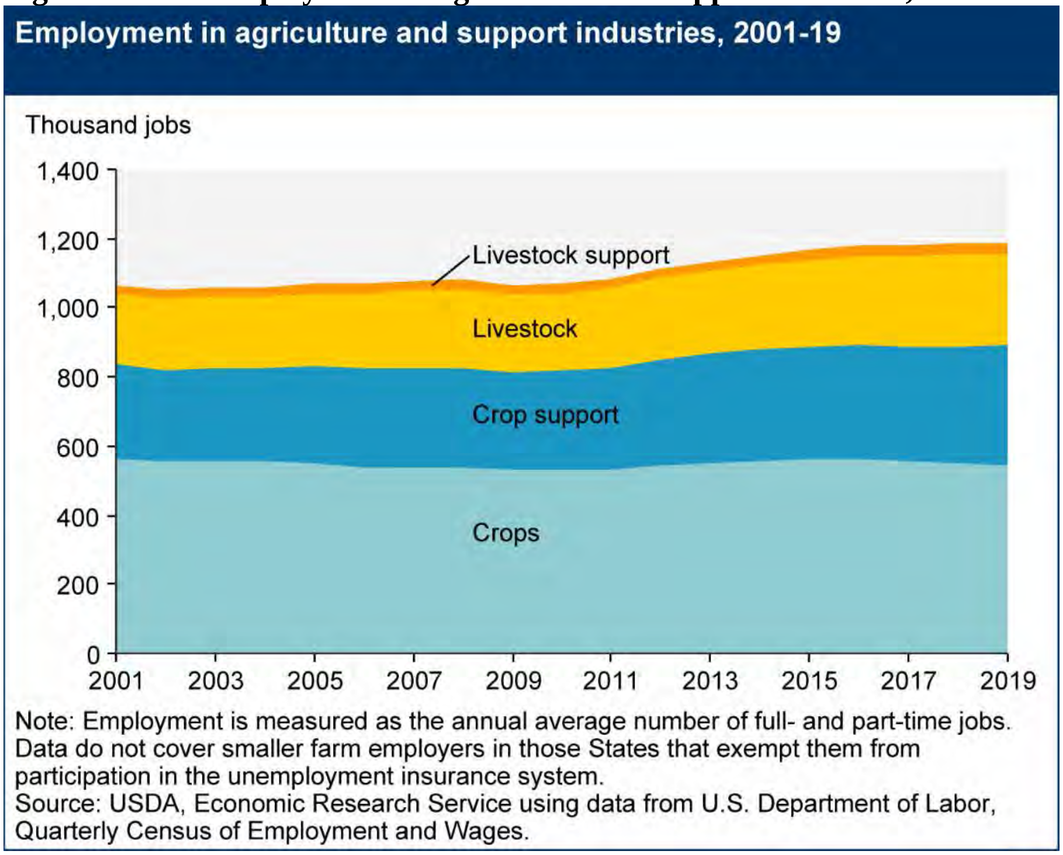
[563] USDA NASS Farm Labor, May 2021. Available at https://usda.library.cornell.edu/concern/publications/x920fw89s

[564] USDA ERS Farm Labor (April 2021). Available at https://www.ers.usda.gov/topics/farm-economy/farm-labor

Figure 7.1.2-2: Employment in Agriculture and Support Activities, 2001-2019



This data from USDA shows that employment in crop production and crop support activities have increased about 3% and 20%, respectively, over the past decade. As with the previous dataset presented in Figure 7.1.2-1, the lack of crop-specific data makes drawing associations with biofuel production very difficult. We see that the lowest employment levels reported in the USDA data for crop production workers coincide with the 2008-2009 recession and that it wasn't until 2015 that the number of such jobs met the pre-recession levels. Looking at this dataset, it is difficult to see any clear impact of increased renewable fuel production among broader economy-wide factors.

7.2 Rural Economic Development

Changes in biofuel production can have economic development impacts on rural communities and financial impacts on farmers. As discussed in 7.1.1 above, the projected increases in ethanol and biogas CNG/LNG production in this rulemaking aren't expected to have quantifiable effects on rural employment, which is a component of rural income and economic development. While additional revenue may be generated from the biogas CNG credit market, the ownership and revenue structures of waste digesters may involve third party investors, and we lack the necessary data to estimate impacts on farm and rural income at this time.

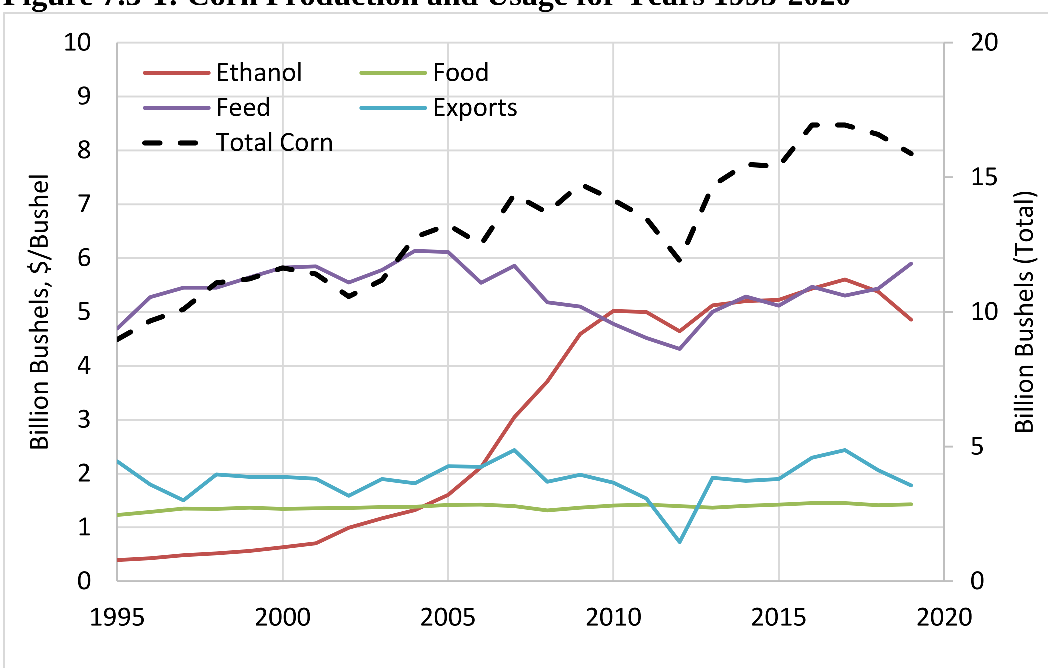
We are projecting significant growth in renewable diesel production for 2021 and 2022, with the vast majority of this feedstock coming from soybean oil. Some of this oil will come from additional soybean production and crushing, which may bring some revenue increases to rural communities. We are also projecting modest growth in ethanol production, though this is measured from a 2020 baseline so much of this volume is getting back to consumption levels before the economic contraction associated with the COVID-19 pandemic. We lack the necessary data to quantify these impacts at this time.

7.3 Supply of Agricultural Commodities

Changes in biofuel production can have an impact on the supply of agricultural commodities. As discussed in 7.1.1 above, we are projecting modest growth in corn ethanol production for 2021-2022. Growth in renewable diesel production will be more substantial, with additional feedstock likely coming from additional soybean crushing as well as diversion from other domestic uses. Biogas is not produced from agricultural commodities and therefore is not expected to affect their supply or price.

For historical context, Figure 7.3-1 shows trends in corn production and uses between 1995-2020. [565] This data suggests domestic corn production has grown steadily at a 25-year average rate of around 2% or 250 million bushels per year, with no apparent correlation to ethanol production volumes.

Figure 7.3-1: Corn Production and Usage for Years 1995-2020



Between 2005-2010, additional corn required to satisfy increasing ethanol production was apparently largely filled by diversion from animal feed in the short term until overall production caught up. Supply of corn to food uses continued to grow steadily during this period,

[565] USDA NASS Agricultural Statistics Annual Report, 2020, 2012, 2002 releases. Available at https://usda.library.cornell.edu/concern/publications/j3860694x

despite increased consumption as ethanol feedstock. Exports also remained steady, except for a drop in exports corresponding to weather-related supply disruptions and elevated prices in 2011-2012. Animal feed use began to rebound after 2014 when growth in ethanol production slowed and prices stabilized. Another factor contributing to the longer-term shift of animal feed away from whole corn was the increasing substitution with dried distillers' grains (DDGS), a byproduct of ethanol production. Considering historical trends over the past two decades indicating the ability of production to rise to meet demand, the modest increases in ethanol volumes associated with this rulemaking, if they have any impact on the supply of corn to food, exports, or other uses, would only be expected to have only a small short-term effect.

With changes in biodiesel and renewable diesel production, the commodity most directly impacted is soy oil, which has an indirect link to bean production (and thus acres planted) via the crushing process. Figure 7.3-2 shows production and use trends for soy oil. Use in domestic biofuel rose from 0.8 million tons in 2005 to roughly 4 million tons in 2020.[566] Other domestic uses have also increased steadily, while exports of soy oil play a minor role.

Figure 7.3-2: Soy Oil Production and Usage for Years 1980-2020

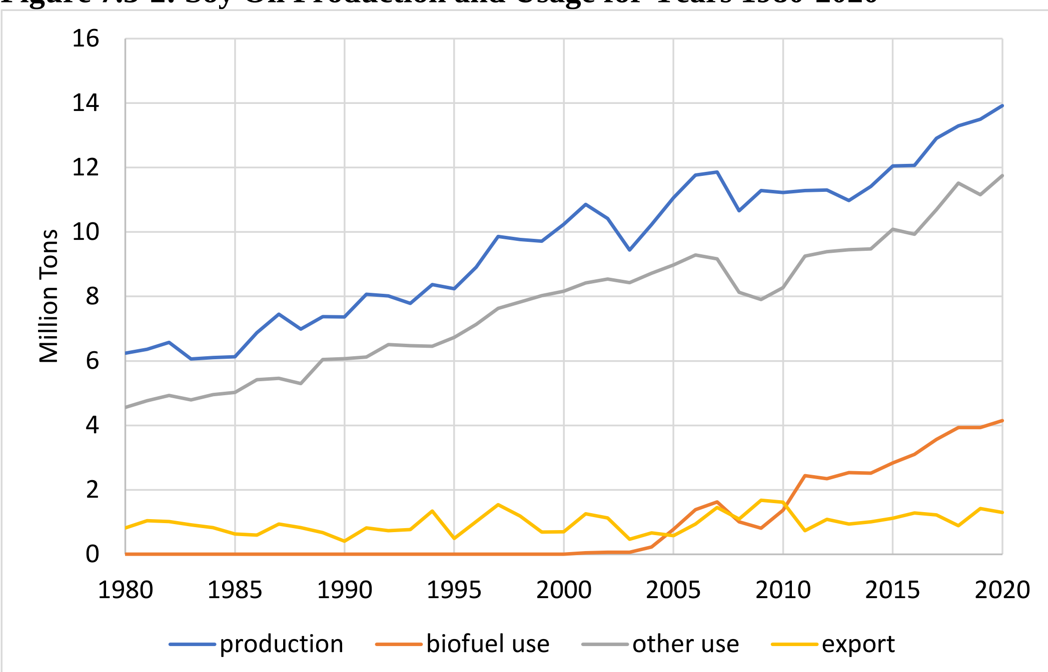


Figure 7.3-3 shows that soybean production has risen steadily over time, similar to the trend for corn production.[566] Roughly 80% of this growth since 2005 is associated with rising exports of soybeans, which have nearly doubled over that period. Domestic crushing of beans has grown by 23% since 2005, which mirrors the same relative growth in production of the crush products, soy meal and oil. As shown in Figure 7.3-4, exports of soy meal also nearly doubled during this time, which together with the growth in whole bean exports, presents a picture consistent with expansion of meat production internationally.[566] (Worldwide, over 95% of beans are eventually crushed for meal and oil.)

566 USDA Economic Research Service. 2021. Oil Crops Yearbook, Soy Tables.

Figure 7.3-3: Soybean Production and Usage for Years 1980-2020

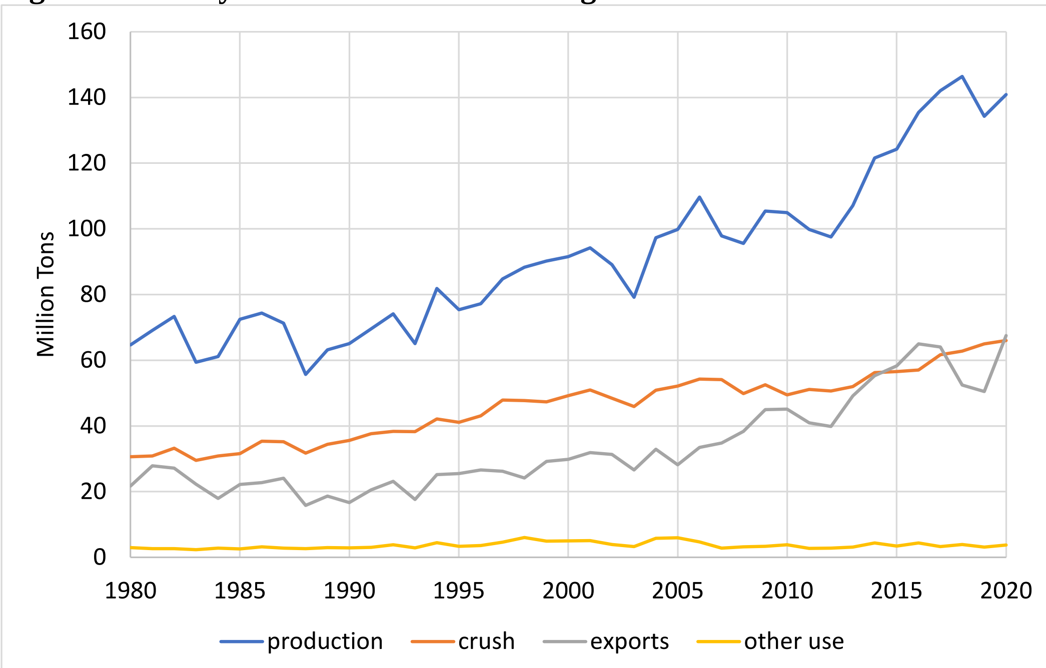
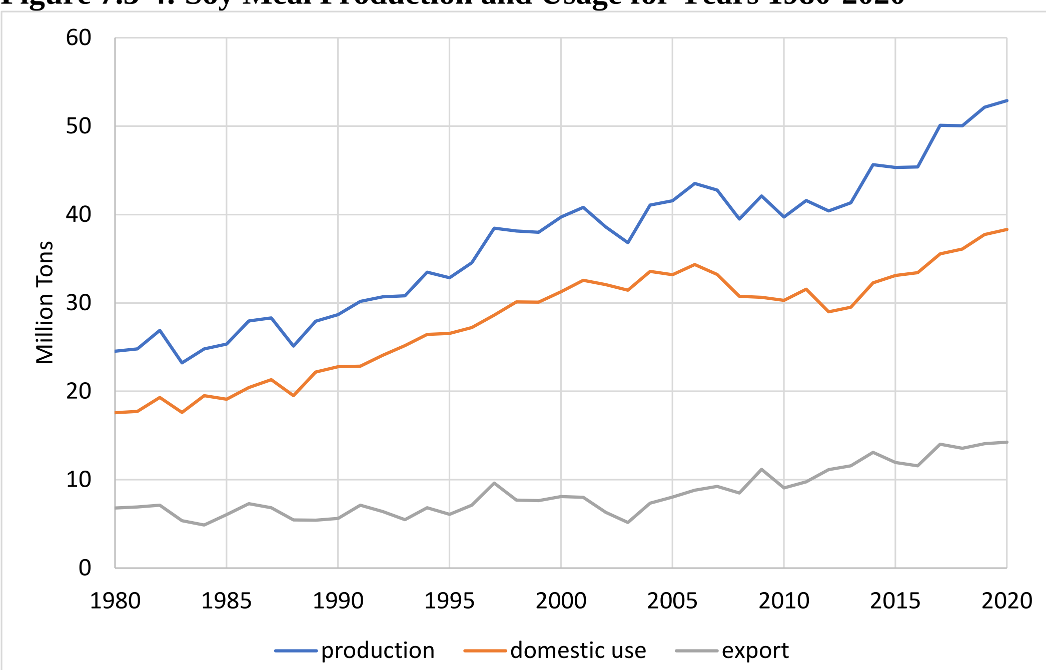


Figure 7.3-4: Soy Meal Production and Usage for Years 1980-2020



Overall, these data indicate that biomass-based diesel represents a major use of domestic soy oil, but that other domestic uses have continued to expand alongside biofuel use, which suggests crushing capacity has kept pace over the past several years. In terms of overall soybean production, and thus demand for planted acres, the primary driver of growth over the past 15 years has clearly been rising exports, with crushing of beans for meal and oil being a distant second.

7.4 Price of Agricultural Commodities

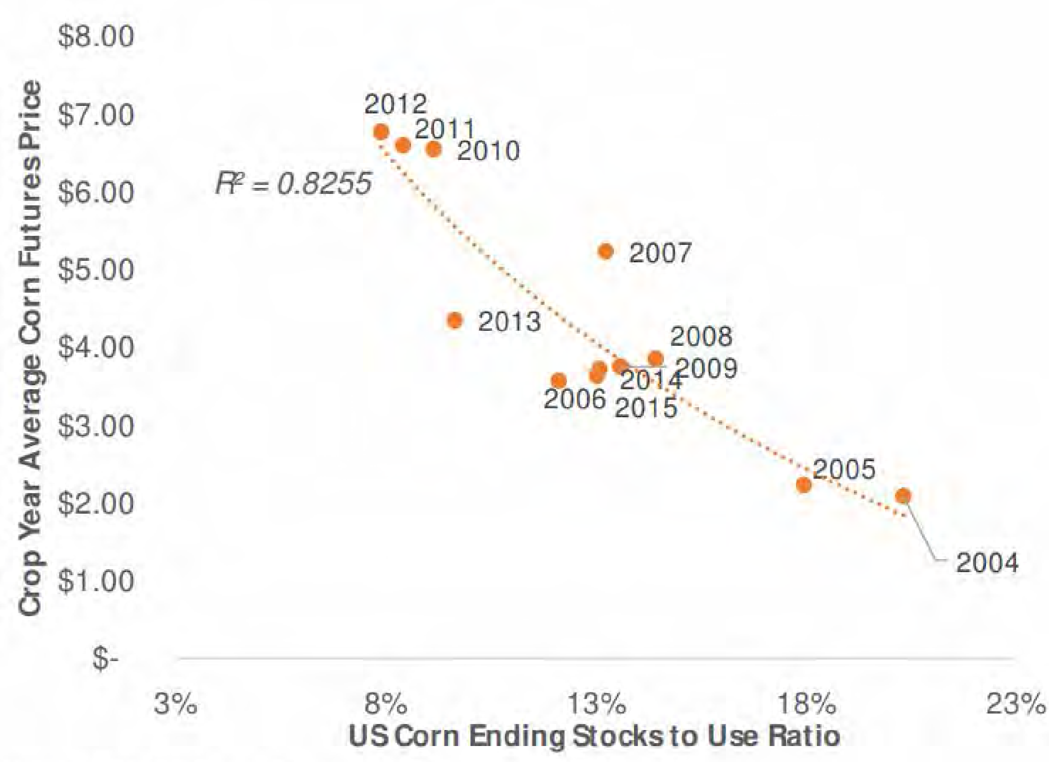
Agricultural commodities are bought and sold on an international market, where prices are determined by trends and upsets in worldwide production and consumption. Drought and storm damage to crops may strike entire regions with only hours' notice and have a major effect on harvest yields. Renewable fuels are only one factor in determining their prices. Thus, models that attempt to project prices at specific times in the future, or in reaction to specific demand perturbations, necessarily contain high levels of uncertainty. This section reviews historical trends and presents key observations from the literature.

In the U.S., corn and soybeans are generally only harvested once per year, and therefore storage is a critical factor in the supply chain. After harvest, grain stores are replenished and then drawn down throughout the year. In recent years, about 15% of the previous year's overall corn production is typically still in storage at the time of the new harvest[567]. If demand rises after harvest, stocks may be drawn down faster than expected. Conversely, if demand decreases, stocks accumulate into the next season.

Storage also has the effect of dampening price shocks in years when harvests are smaller than expected. In 2012, a drought year, corn stocks fell to the lowest levels since 2000, putting upward pressure on futures prices, which in turn serve as a market signal that induces more corn planting in the upcoming season. Work done by Informa Economics for the Renewable Fuels Association in 2016 examined the historical relationship between corn usage, stocks, and futures prices.[568] Figure 7.4-1 illustrates the strong correlation between futures prices and the stock-to-usage ratio, illustrating that the latter is a key driver of market signals. More generally, crop prices are influenced by an array of factors from worldwide weather patterns to biofuel policies to international tariffs and trade wars.

[567] USDA Economic Research Service. 2020. Feed Grains Data, Feed Grains: Yearbook Tables.
[568] Informa Economics IEG. The Impact of Ethanol Industry Expansion on Food Prices: A Retrospective Analysis. November 2016. Available at https://ethanolrfa.org/impact-of-ethanol-expansion-on-food-ps_informa_2016/

Figure 7.4-1: Corn Ending Stocks / Use Ratio versus Futures Price



Source: USDA, Informa Economics IEG

To make more specific quantitative estimates of the impact of increased biofuel production on corn prices, we consider two meta-studies. Condon, *et al.*, reviewed 29 published papers in 2015 and found a central estimate of 3-5% increase in corn prices per billion gallons of ethanol.[569] Focusing only on scenarios where a supply response is included gives a result of 3%. A supply response refers to scenarios where farmers can respond to price signals in subsequent year(s) and plant additional crops to meet a larger demand. This is appropriate, as the scope of the analysis is biofuel policy (not something unforeseen like weather shocks). A similar meta-analysis was done in 2016 by FAPRI-Missouri that considered several newer studies.[570] This paper found $0.19 per bushel per billion gallons or $0.15 if a supply response is included, a figure that is consistent with the 3% impact above.

With biodiesel and renewable diesel production, the commodity input of interest is soy oil, which has an indirect link to bean production. Oil is produced by crushing, which also creates soy meal, and the supply and prices of these move independently from each other. The crush quantities vary from year to year, depending on the crush margin, which is defined as the sum of oil and meal price minus the bean price. Oversupplying either oil or meal markets can

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[569] Condon, Nicole, Klemick, Heather and Wolverton, Ann, (2013), Impacts of Ethanol Policy on Corn Prices: A Review and Meta-Analysis of Recent Evidence, No 201305, NCEE Working Paper Series, National Center for Environmental Economics, U.S. Environmental Protection Agency, https://EconPapers.repec.org/RePEc:nev:wpaper:wp201305.

[570] Food and Agricultural Policy Research Institute. Literature Review of Estimated Market Effects of U.S. Corn Starch Ethanol, 2016. FAPRI-MU Report #01-16.

cause prices to fall, decreasing the crush margin. Thus, the degree of pass-through of oil price increases to bean prices, which may then influence acres planted, is not straightforward.

There are relatively few studies on the impacts of biodiesel production on soy oil and bean prices, and they show a wide range of results. This is in part because these studies used a variety of different policy combinations, none of which separated out just the impact of the biomass-based diesel obligations. Ethanol obligations could impact the soybean markets even in the absence of a biomass-based diesel obligation due to increased competition for cropland and other inputs. The largest impacts are estimated when the biomass-based diesel obligations are modeled jointly with the conventional and cellulosic ethanol obligations. Given that actual cellulosic ethanol volumes have been far below those modeled, we focus on the studies that included only a conventional ethanol obligation. The range of soybean price impacts indicated by these studies is 1.8% to 6.5% per billion gallons of biomass-based diesel, from which we derive a single central value of 4.2%.[571, 572, 573] Considering data presented here and in 7.3 above, we see the primary impacts of increases in renewable fuel production have historically been short-term price increases for both corn and soybeans, which have evened out after a period of market and production adjustments.

To project the impact on crude soybean oil prices, we used a value of 16 cents per pound of oil per billion gallons of biomass-based diesel produced from soybean oil. This figure was derived from modeling work published by Babcock, *et al.*, and is the same figure used for other cost estimates in this proposal.[574] Analysis published by Irwin at the University of Illinois indicates that soy oil prices often move separately from meal and bean prices, and that the latter two are closely correlated.[575] From this we made the simplifying assumption that the price impact on soy meal would match the 4.2% per billion gallons described above for beans. Table 7.4-1 summarizes these price impacts for corn, soy oil, and soy meal for the proposed volumes in 2021 and 2022.

[571] Babcock, B. A. 2012. The impact of US biofuel policies on agricultural price levels and volatility. China Agricultural Economic Review 4:407-426.
[572] J. Huang, J. Yang, S. Msangi, S. Rozelle, and A. Weersink. 2012. Biofuels and the poor: Global impact pathways of biofuels on agricultural markets. Food Policy 37:439-451.
[573] U.S. EPA. 2010. Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis. Assessment and Standards Division. EPA Office of Transportation and Air Quality.
[574] Babcock BA, Moreira M, Peng Y, 2013. Biofuel Taxes, Subsidies, and Mandates: Impacts on US and Brazilian Markets. Staff Report 13-SR 108. Center for Agricultural and Rural Development, Iowa State University, Ames, Iowa.
[575] Irwin, S. "The Value of Soybean Oil in the Soybean Crush: Further Evidence on the Impact of the U.S. Biodiesel Boom." *Farmdoc Daily* (7):169, Department of Agricultural and Consumer Economics, University of Illinois at Urbana-Champaign, September 14, 2017.

Table 7.4-1: Projected Impact of Proposed 2021-2022 Volumes on Commodity Prices

	Corn	**Soybean Oil**	**Soybean Meal**
Percent increase per billion gallons of biofuel	**3%**	49%	**4.2%**
Impact of the 2021 Proposed Volumes Relative to Baseline			
Commodity Price[a]	$3.60 per bushel	$0.325 per pound	$335 per short ton
Price increase per billion gallons of biofuel	$0.11 per bushel	$0.16 per pound	$14 per short ton
Volume Increase in 2021 (million gallons)	953	240	240
Price increase in 2021	$0.11 per bushel	$0.04 per pound	$3.4 per short ton
Impact of the 2022 Proposed Volumes Relative to Baseline			
Commodity Price[a]	$3.65 per bushel	$0.34 per pound	$350 per short ton
Price increase per billion gallons of biofuel	$0.11 per bushel	$0.16 per pound	$15 per short ton
Volume Increase in 2022 (million gallons)	1288	1007	1007
Price increase in 2022	$0.14 per bushel	$0.16 per pound	$15 per short ton

[a] Commodity prices are from the February 2021 USDA Agricultural Projections to 2030. Prices listed for 2021 are for the 2020/2021 agricultural marketing year and prices listed for 2022 are for the 2021/2022 agricultural marketing year.

7.5 Food Prices

The above impacts on corn and soy commodity prices may in turn have a ripple impact on food prices and the many other products produced from these commodities. Since the proposed volume changes would have a relatively small impact on the overall world commodity markets and since the cost of the commodity itself tends to be a relatively small component in the cost of food, the impacts are likewise relatively modest. To project the impact of the proposed volumes on food prices we used a methodology developed in conjunction with USDA in assessing requests from the Governors of several states to reduce the 2012 RFS volumes using the general waiver authority.[576] This methodology generally uses estimates of the impact of biofuel volumes on commodity prices (corn, soybean oil, and soybean meal) to calculate the estimated impacts on total food expenditures. For context this estimated change in food expenditures is compared to total food expenditures. Finally, the ratio of the estimated change in food expenditures to the total food expenditures is used to estimate the change in food expenditures for the average consumer unit and the consumer units in the lowest income quintile.

The previous section presented a discussion of literature estimates of changes in biofuel volumes on commodity prices. These estimates are the starting point for our estimate of the impact of the proposed RFS volumes on food prices. From those we projected the impact of commodity prices on total food expenditures, which are shown in Table 7.5-1. In addition to the price impacts on corn, soybean oil, and soybean meal we also estimated price changes for other feed grains (grain sorghum, barley, and oats) and distillers' grains. We adjusted the prices of these commodities as they historically compete with corn in the feed market, and to a lesser

[576] 77 FR 70752 (November 27, 2012).

extent for acreage. The price adjustments for grain sorghum, barley, oats, and distillers grains are based on historical price relationships of these commodities with corn.[577] We assumed that changes in commodity prices are fully passed on to consumers at the retail level, and therefore we can project changes in total food expenditures by multiplying the quantity of these commodities used for food and feed. Feed use is included to capture the effects of the change in the price of the commodity on livestock producers' production costs, and ultimately the effects on retail livestock prices.[578] This methodology assumes no response by producers or consumers to changes in commodity prices and therefore may overstate the change in food expenditures. However, previous research suggests that demand for food is very inelastic and therefore this methodology should provide a close approximation of the change in food expenditures.[579]

[577] Other commodity price impacts were estimated as follows: change in the price of grain sorghum = 0.93 times the change in the price of corn; change in the price of barley = 0.88 times the change in the price of corn; change in the price of oats = 0.72 times the change in the price of corn; change in the price of distillers grains = 1/56 times the change in the price of corn. These factors are from the 2012 evaluation of the use of the general waiver authority. See Methodology for Estimating Impacts on Food Expenditures, CPI for Food and CPI for all Items in EPA-HQ-OAR-2021-0324.
[578] We acknowledge that this approach may over-state the effect of the proposed renewable fuel volumes as it includes the expected price impact on all crops used as animal feed and does not account for the livestock produced for the export market.
[579] Okrent, Abigail M., and Julian M. Alston. The Demand for Disaggregated Food-Away-From-Home and Food-at-Home Products in the United States, ERR-139, U.S. Department of Agriculture, Economic Research Service, August 2012.

Table 7.5-1: Changes in Food Expenditures (Relative to 2020)

	Commodity Price Change	Quantity Used for Food and Feed[a]	Change in Expenditures
Changes in Food Expenditures in 2021			
Corn	$0.11 per bushel	7,200 million bushels	$741 million
Grain Sorghum	$0.10 per bushel	110 million bushels	$11 million
Barley	$0.09 per bushel	168 million bushels	$15 million
Oats	$0.07 per bushel	154 million bushels	$11 million
Soybean Oil	$0.04 per pound	14.9 billion pounds	$572 million
Soybean Meal	$3.40 per short ton	38.3 million short tons	$129 million
Distillers Grains	$3.70 per short ton	43 million short tons	$158 million
Total	N/A	N/A	$1,637 million
Changes in Food Expenditures in 2022			
Corn	$0.14 per bushel	7,375 million bushels	$1,040 million
Grain Sorghum	$0.13 per bushel	110 million bushels	$14 million
Barley	$0.12 per bushel	173 million bushels	$21 million
Oats	$0.10 per bushel	160 million bushels	$16 million
Soybean Oil	$0.16 per pound	15.4 billion pounds	$2,473 million
Soybean Meal	$14.80 per short ton	38.7 million short tons	$573 million
Distillers Grains	$5.00 per short ton	44 million short tons	$219 million
Total	N/A	N/A	$4,358 million

[a] Quantity used for food and feed calculated based on the February 2021 USDA Agricultural Projections to 2030. Quantities listed for 2021 are based on the 2020/2021 agricultural marketing year and quantities listed for 2022 are based on the 2021/2022 agricultural marketing year. In general, the quantity use for food and feed is the sum of the quantities projected for Feed and Residual and Food, Seed & Industrial. For corn we subtracted the quantity used for Ethanol & by-products from this total. The quantity of distillers grains was calculated based on the production of 17 pounds of distillers grains for every bushel of corn used to produce ethanol. Finally, the quantity of soybean oil is equal to the amount listed for food, feed & other industrial and the quantity of soybean meal is the total quantity of domestic disappearance.

Finally, we compared the estimated change in food expenditures to total food expenditures are reported by the Bureau of Labor and Statistics in their 2019 survey.[580] We used the ratio of the estimated change in food expenditures to the total food expenditures to estimate the change in food expenditures for the average consumer unit (household) and the consumer units in the lowest income quintile. These estimates are shown in Tables 7.5-2 and 7.5-3.

Table 7.5-2: Percent Change in Food Expenditures (Relative to 2020)

	2021 Estimate	2022 Estimate
Number of Consumer Units (thousands)	132,242	132,242
Food Expenditures per Consumer Unit	$8,619	$8,619
Total Food Expenditures	$1,080 billion	$1,080 billion
Change in Food Expenditures	$1,637 million	$4,357 million
Percent Change in Food Expenditures	0.15%	0.40%

[580] Bureau of Labor and Statistics Consumer Expenditure Survey, 2019: Table 1, Quintiles of income before taxes: Annual expenditure means, shares, standard errors, and coefficients of variation, 2019.

Table 7.5-3: Change in Food Expenditures per Consumer Unit (Relative to 2020)

	2021	**2022**
All Consumer Units		
Food Expenditures	$8,169	$8,169
Percent Impact on Food Expenditures	0.15%	0.40%
Projected Food Expenditure Increase	$12.38	$32.96
Lowest Quintile Income Consumer Units		
Food Expenditures	$4,400	$4,400
Percent Impact on Food Expenditures	0.15%	0.40%
Projected Food Expenditure Increase	$6.67	$17.75

Chapter 8: Environmental Justice

Executive Order 12898 (59 FR 7629; February 16, 1994) establishes federal executive policy on environmental justice. Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. EPA defines environmental justice as the fair treatment and meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.[581] Executive Order 14008 (86 FR 7619; February 1, 2021) also calls on federal agencies to make achieving environmental justice part of their missions "by developing programs, policies, and activities to address the disproportionately high and adverse human health, environmental, climate-related and other cumulative impacts on disadvantaged communities, as well as the accompanying economic challenges of such impacts." It also declares a policy "to secure environmental justice and spur economic opportunity for disadvantaged communities that have been historically marginalized and overburdened by pollution and under-investment in housing, transportation, water and wastewater infrastructure and health care." EPA also released its "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis" (U.S. EPA, 2016) to provide recommendations that encourage analysts to conduct the highest quality analysis feasible, recognizing that data limitations, time and resource constraints, and analytic challenges will vary by media and circumstance.

When assessing the potential for disproportionately high and adverse health or environmental impacts of regulatory actions on minority populations, low-income populations, tribes, and/or indigenous peoples, EPA strives to answer three broad questions: (1) Is there evidence of potential environmental justice (EJ) concerns in the baseline (the state of the world absent the regulatory action)? Assessing the baseline will allow EPA to determine whether pre-existing disparities are associated with the pollutant(s) under consideration (e.g., if the effects of the pollutant(s) are more concentrated in some population groups). (2) Is there evidence of potential EJ concerns for the regulatory option(s) under consideration? Specifically, how are the pollutant(s) and its effects distributed for the regulatory options under consideration? And, (3) do the regulatory option(s) under consideration exacerbate or mitigate EJ concerns relative to the baseline? It is not always possible to quantitatively assess these questions, though it may still be possible to describe then qualitatively.

[581] Fair treatment occurs when "no group of people should bear a disproportionate burden of environmental harms and risks, including those resulting from the negative environmental consequences of industrial, governmental, and commercial operations or programs and policies" (U.S. EPA, 2011). Meaningful involvement occurs when "1) potentially affected populations have an appropriate opportunity to participate in decisions about a proposed activity [i.e., rulemaking] that will affect their environment and/or health; 2) the population's contribution can influence [EPA's] rulemaking decisions; 3) the concerns of all participants involved will be considered in the decision-making process; and 4) [EPA will] seek out and facilitate the involvement of population's potentially affected by EPA's rulemaking process" (U.S. EPA, 2015). A potential EJ concern is defined as "actual or potential lack of fair treatment or meaningful involvement of minority populations, low-income populations, tribes, and indigenous peoples in the development, implementation and enforcement of environmental laws, regulations and policies" (U.S. EPA, 2015). See also https://www.epa.gov/environmentaljustice.

EPA's 2016 Technical Guidance does not prescribe or recommend a specific approach or methodology for conducting an environmental justice analysis, though a key consideration is consistency with the assumptions underlying other parts of the regulatory analysis when evaluating the baseline and regulatory options. Where applicable and practicable, the Agency endeavors to conduct such an analysis. Going forward, EPA is committed to conducting environmental justice analysis for rulemakings based on a framework similar to what is outlined in EPA's Technical Guidance, in addition to investigating ways to further weave environmental justice into the fabric of the rulemaking process.

8.1 Greenhouse Gas Impacts

In 2009, under the "Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act" (hereafter "Endangerment Finding"), EPA considered how climate change threatens the health and welfare of the U.S. population. As part of that consideration, we also considered risks to minority and low-income individuals and communities, finding that certain parts of the U.S. population may be especially vulnerable based on their characteristics or circumstances. These groups include economically and socially disadvantaged communities; individuals at vulnerable lifestages, such as the elderly, the very young, and pregnant or nursing women; those already in poor health or with comorbidities; the disabled; those experiencing homelessness, mental illness, or substance abuse; and/or Indigenous or minority populations dependent on one or limited resources for subsistence due to factors including but not limited to geography, access, and mobility.

Scientific assessment reports produced over the past decade by the U.S. Global Change Research Program (USGCRP),[582,583] the Intergovernmental Panel on Climate Change

[582] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II* [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.
[583] : USGCRP, 2016: The Impacts of Climate Change on Human Health in the United States: A Scientific Assessment. Crimmins, A., J. Balbus, J.L. Gamble, C.B. Beard, J.E. Bell, D. Dodgen, R.J. Eisen, N. Fann, M.D. Hawkins, S.C. Herring, L. Jantarasami, D.M. Mills, S. Saha, M.C. Sarofim, J. Trtanj, and L. Ziska, Eds. U.S. Global Change Research Program, Washington, DC, 312 pp. http://dx.doi.org/10.7930/J0R49NQX

(IPCC),[584,585,586,587] and the National Academies of Science, Engineering, and Medicine[588,589] add more evidence that the impacts of climate change raise potential environmental justice concerns. These reports conclude that poorer or predominantly non-white communities can be especially vulnerable to climate change impacts because they tend to have limited adaptive capacities and are more dependent on climate-sensitive resources such as local water and food supplies, or have less access to social and information resources. Some communities of color, specifically populations defined jointly by ethnic/racial characteristics and geographic location, may be uniquely vulnerable to climate change health impacts in the United States. In particular, the 2016 scientific assessment on the *Impacts of Climate Change on Human Health*[2] found with high confidence that vulnerabilities are place- and time-specific, that particular lifestages and ages are linked to immediate and future health impacts, and that social determinants of health are linked to greater extent and severity of climate change-related health impacts.

8.1.1 Effects on Specific Populations of Concern

EJ populations of concern, such as individuals living in socially and economically disadvantaged communities (e.g., living at or below the poverty line or experiencing homelessness or social isolation) or those who have been historically marginalized or overburdened are at greater risk of health effects from climate change. This is also true with respect to people at vulnerable lifestages, specifically women who are pre- and perinatal, or are

[584] Oppenheimer, M., M. Campos, R.Warren, J. Birkmann, G. Luber, B. O'Neill, and K. Takahashi, 2014: Emergent risks and key vulnerabilities. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 1039-1099.

[585] Porter, J.R., L. Xie, A.J. Challinor, K. Cochrane, S.M. Howden, M.M. Iqbal, D.B. Lobell, and M.I. Travasso, 2014: Food security and food production systems. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 485-533.

[586] Smith, K.R., A.Woodward, D. Campbell-Lendrum, D.D. Chadee, Y. Honda, Q. Liu, J.M. Olwoch, B. Revich, and R. Sauerborn, 2014: Human health: impacts, adaptation, and co-benefits. In: Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects. Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel,A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L.White (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, pp. 709-754.

[587] IPCC, 2018: Global Warming of 1.5°C.An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. In Press.

[588] National Research Council. 2011. America's Climate Choices. Washington, DC: The National Academies Press. https://doi.org/10.17226/12781

[589] National Academies of Sciences, Engineering, and Medicine. 2017. Communities in Action: Pathways to Health Equity. Washington, DC: The National Academies Press. https://doi.org/10.17226/24624

nursing; *in utero* fetuses; children at all stages of development; and the elderly. Per the Fourth National Climate Assessment, "Climate change affects human health by altering exposures to heat waves, floods, droughts, and other extreme events; vector-, food- and waterborne infectious diseases; changes in the quality and safety of air, food, and water; and stresses to mental health and well-being."[590] Many health conditions such as cardiopulmonary or respiratory illness and other health impacts are associated with and exacerbated by an increase in greenhouse gases and climate change outcomes, which is problematic as these diseases occur at higher rates within vulnerable communities. Importantly, negative public health outcomes include those that are physical in nature, as well as mental, emotional, social, and economic.

To this end, the scientific assessment literature, including the aforementioned reports, demonstrates that there are myriad ways in which these populations may be affected at the individual and community levels. Individuals face differential exposure to criteria pollutants, in part due to the proximities of highways, trains, factories, and other major sources of pollutant-emitting sources to less-affluent and traditionally marginalized residential areas. Outdoor workers, such as construction or utility workers and agricultural laborers, who are frequently part of already at-risk groups, are exposed to poor air quality and extreme temperatures without relief. Furthermore, individuals within environmental justice ("EJ") populations of concern face greater housing and clean water insecurity and bear disproportionate economic impacts and health burdens associated with climate change effects. They tend to have less or limited access to healthcare and affordable, adequate health or homeowner insurance. Finally, resiliency and adaptation are more difficult for economically disadvantaged communities. They have less liquidity, individually and collectively, to move or to make the types of infrastructure or policy changes to limit or reduce the hazards they face. Finally, due to systemic challenges, affected communities may lack the resources necessary to advocate for resources that would otherwise aid in resiliency and hazard reduction and mitigation.

The assessment literature cited in EPA's 2009 and 2016 Endangerment Findings, as well as *Impacts of Climate Change on Human Health,* also concluded that certain populations and people in particular life stages, including children, are most vulnerable to climate-related health effects. The assessment literature produced from 2016 to the present strengthens these conclusions by providing more detailed findings regarding related vulnerabilities and the projected impacts youth may experience. These assessments – including the Fourth National Climate Assessment (2018) and *The Impacts of Climate Change on Human Health in the United States* (2016) – describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to allergens, as well as health effects associated with storms, and floods. More generally, these reports note that extreme weather and flooding can cause or exacerbate poor health outcomes by affecting mental health because of stress; contributing to or worsening

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[590] Ebi, K.L., J.M. Balbus, G. Luber, A. Bole, A. Crimmins, G. Glass, S. Saha, M.M. Shimamoto, J. Trtanj, and J.L. White-Newsome, 2018: Human Health. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 539–571. doi: 10.7930/NCA4.2018.CH14

existing conditions, again due to stress or also as a consequence of exposures to water and air pollutants; or by impacting hospital and emergency services operations.[591] Further, in urban areas in particular, flooding can have significant economic consequences due to effects on infrastructure, pollutant exposures, and drowning dangers. The ability to withstand and recover from flooding is dependent in part on the social vulnerability of the affected population and individuals experiencing an event.[592] Additional health concerns may arise in low-income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity.

The Impacts of Climate Change on Human Health (USGCRP, 2016) also found that some communities of color, low-income groups, people with limited English proficiency, and certain immigrant groups (especially those who are undocumented) live with many of the factors that contribute to their vulnerability to the health impacts of climate change. While difficult to isolate from related socioeconomic factors, race appears to be an important factor in vulnerability to climate-related stress, with elevated risks for mortality from high temperatures reported for Black or African American individuals compared to white individuals after controlling for factors such as air conditioning use. Moreover, people of color are disproportionately exposed to air pollution based on where they live, and disproportionately vulnerable due to higher baseline prevalence of underlying diseases such as asthma, so climate exacerbations of air pollution are expected to have disproportionate effects on these communities.

Native American Tribal communities possess unique vulnerabilities to climate change, particularly those communities impacted by degradation of natural and cultural resources within established reservation boundaries and threats to traditional subsistence lifestyles. Tribal communities whose health, economic well-being, and cultural traditions depend upon the natural environment will likely be affected by the degradation of ecosystem goods and services associated with climate change. The IPCC indicates that losses of customs and historical knowledge may cause communities to be less resilient or adaptable.[593] The Fourth National Climate Assessment (2018) noted that while Indigenous peoples are diverse and will be impacted by the climate changes universal to all Americans, there are several ways in which climate change uniquely threatens Indigenous peoples' livelihoods and economies.[594] In addition, there can be institutional barriers (including policy-based limitations and restrictions) to their management of water, land, and other natural resources that could impede adaptive measures. For example, Indigenous agriculture in the Southwest is already being adversely affected by changing patterns of flooding, drought, dust storms, and rising temperatures leading to increased soil erosion, irrigation water demand, and decreased crop quality and herd sizes. The

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[591] USGCRP, 2018: *Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment*, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, 1515 pp. doi: 10.7930/NCA4.2018.
[592] National Academies of Sciences, Engineering, and Medicine. 2019. *Framing the Challenge of Urban Flooding in the United States*. Washington, DC: The National Academies Press. https://doi.org/10.17226/25381.
[593] Porter et al., 2014: Food security and food production systems.
[594] Jantarasami, L.C., R. Novak, R. Delgado, E. Marino, S. McNeeley, C. Narducci, J. Raymond-Yakoubian, L. Singletary, and K. Powys Whyte, 2018: Tribes and Indigenous Peoples. In Impacts, Risks, and Adaptation in the United States: Fourth National Climate Assessment, Volume II [Reidmiller, D.R., C.W. Avery, D.R. Easterling, K.E. Kunkel, K.L.M. Lewis, T.K. Maycock, and B.C. Stewart (eds.)]. U.S. Global Change Research Program, Washington, DC, USA, pp. 572–603. doi: 10.7930/NCA4.2018.CH15

Confederated Tribes of the Umatilla Indian Reservation in the Northwest have identified climate risks to salmon, elk, deer, roots, and huckleberry habitat. Housing and sanitary water supply infrastructure are vulnerable to disruption from extreme precipitation events. Confounding the general Indigenous response to natural hazards are limitations imposed by policies such as the Dawes Act of 1887 and the Indian Reorganization Act of 1934, which ultimately restrict Tribal peoples' autonomy regarding land-management decisions through Federal trusteeship of certain Tribal lands and mandated Federal oversight of management decisions.

Additionally, NCA4 noted that Indigenous peoples are subject to institutional racism effects, such as poor infrastructure, diminished access to quality healthcare, and greater risk of exposure to pollutants. Consequently, Indigenous people often have disproportionately higher rates of asthma, cardiovascular disease, Alzheimer's disease, diabetes, and obesity. These health conditions and related effects (e.g., disorientation, heightened exposure to PM2.5, etc.) can all contribute to increased vulnerability to climate-driven extreme heat and air pollution events, which may be exacerbated by stressful situations, such as extreme weather events, wildfires, and other circumstances.

NCA4 and IPCC AR5[595] also highlighted several impacts specific to Alaskan Indigenous Peoples. Coastal erosion and permafrost thaw will lead to more coastal erosion, exacerbated risks of winter travel, and damage to buildings, roads, and other infrastructure – these impacts on archaeological sites, structures, and objects that will lead to a loss of cultural heritage for Alaska's Indigenous people. In terms of food security, the NCA discussed reductions in suitable ice conditions for hunting, warmer temperatures impairing the use of traditional ice cellars for food storage, and declining shellfish populations due to warming and acidification. While the NCA also noted that climate change provided more opportunity to hunt from boats later in the fall season or earlier in the spring, the assessment found that the net impact was an overall decrease in food security.

8.1.2 Potential Future Impacts of Annual Volume Requirements

As described in Chapter 3.3, the proposed renewable fuel volumes may to help mitigate the impacts of climate change by potentially reducing GHG emissions. Future impacts of climate change are still expected and will likely be unevenly distributed in ways that uniquely impact communities with EJ concerns.

8.2 Air Quality Impacts

There is evidence that communities with EJ concerns are impacted by non-GHG emissions. Numerous studies have found that environmental hazards such as air pollution are more prevalent in areas where racial/ethnic minorities and people with low socioeconomic status (SES) represent a higher fraction of the population compared with the general

[595] Porter et al., 2014: Food security and food production systems.

population.[596,597,598,599] Consistent with this evidence, a recent study found that most anthropogenic sources of $PM_{2.5}$, including industrial sources, and light- and heavy-duty vehicle sources, disproportionately affect people of color.[600]

Emissions of non-GHG pollutants associated with this proposed rulemaking, including, for example, PM, NOx, CO, SO_2 and air toxics, occur during the production, storage, transport, distribution, and combustion of petroleum-based fuels and biofuels. Communities with EJ concerns may be located near petroleum refineries, biorefineries, and on-road sources of pollution. For example, analyses of communities in close proximity to petroleum refineries have found that vulnerable populations near refineries may experience potential disparities in pollution-related health risk from that source.[601] There is also substantial evidence that people who live or attend school near major roadways are more likely to be of a minority race, Hispanic ethnicity, and/or low socioeconomic status.[602,603,604] For this proposed action, EPA has not quantitatively assessed the demographic characteristics of populations living near biorefineries, but is evaluating the extent to which this type of analysis could be done for future rulemakings.

Although proximity to an emissions source is a useful indicator of potential exposure, it is important to note that the impacts of emissions from both upstream and tailpipe sources are not limited to communities in close proximity to them. As a result of regional transport and secondary formation of pollutants in the air, the effects of both potential increases and decreases in emissions from the sources affected by this proposal might also be felt many miles away, including in communities with EJ concerns downwind of sources. The spatial extent of these impacts from upstream and tailpipe sources depend on a range of interacting and complex factors including the amount of pollutant emitted, atmospheric chemistry and meteorology.

The manner in which producers and markets respond to the provisions in this proposed rule could have non-GHG exposure impacts for communities living near facilities that produce biofuels. Chapter 3.1 summarizes what is known about potential air quality impacts of the changes in renewable fuel volumes assessed for this rule. We expect that small increases in non-GHG emissions from biodiesel production and small reductions in petroleum-sector emissions

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[596] Mohai, P.; Pellow, D.; Roberts Timmons, J. (2009) Environmental justice. Annual Reviews 34: 405-430. https://doi.org/10.1146/annurev-environ-082508-094348

[597] Rowangould, G.M. (2013) A census of the near-roadway population: public health and environmental justice considerations. Trans Res D 25: 59-67. http://dx.doi.org/10.1016/j.trd.2013.08.003

[598] Marshall, J.D., Swor, K.R.; Nguyen, N.P (2014) Prioritizing environmental justice and equality: diesel emissions in Southern California. Environ Sci Technol 48: 4063-4068. https://doi.org/10.1021/es405167f

[599] Marshall, J.D. (2000) Environmental inequality: air pollution exposures in California's South Coast Air Basin. Atmos Environ 21: 5499-5503. https://doi.org/10.1016/j.atmosenv.2008.02.005

[600] C. W. Tessum, D. A. Paolella, S. E. Chambliss, J. S. Apte, J. D. Hill, J. D. Marshall (2021). PM2.5 polluters disproportionately and systemically affect people of color in the United States. Sci. Adv. 7, eabf4491.

[601] U.S. EPA (2014). Risk and Technology Review – Analysis of Socio-Economic Factors for Populations Living Near Petroleum Refineries. Office of Air Quality Planning and Standards, Research Triangle Park, North Carolina. January.

[602] Rowangould, G.M. (2013) A census of the U.S. near-roadway population: public health and environmental justice considerations. Transportation Research Part D; 59-67.

[603] Tian, N.; Xue, J.; Barzyk. T.M. (2013) Evaluating socioeconomic and racial differences in traffic-related metrics in the United States using a GIS approach. J Exposure Sci Environ Epidemiol 23: 215-222.

[604] Boehmer, T.K.; Foster, S.L.; Henry, J.R.; Woghiren-Akinnifesi, E.L.; Yip, F.Y. (2013) Residential proximity to major highways – United States, 2010. Morbidity and Mortality Weekly Report 62(3): 46-50.

would lead to small changes in exposure to these non-GHG pollutants for people living in the communities near these facilities. We do not have the information needed to understand the magnitude and location of facility-specific responses to the biofuel volumes in this proposed rule, and therefore we are unable to evaluate impacts on air quality in EJ communities near these facilities. We therefore recommend caution when interpreting these broad, qualitative observations.

8.3 Water & Soil Quality Impacts

In proposing this rule, we conducted an analysis to estimate the impacts of the proposed volumes on water and soil quality in Chapter 3.4. Though soil quality is not among the statutory factors required to be analyzed under the reset authority in the Clean Air Act,[605] it is discussed in conjunction with water quality because it can have direct impacts on water quality. EPA defines water quality as the condition of water to serve human or ecological needs, while USDA defines soil quality as the ability of soil to function, including its capacity to support plant life. The ways in which this rule could potentially impact water and soil is by creating an incentive for land use and management changes, primarily through the encouragement of biofuels produced from corn and soybeans. An increase in demand for corn and soybeans for biofuel production has historically caused the conversion of natural grasslands to cropland, see Chapter 3.3.2. This land use change has negative consequences for soil quality in that it can increase soil erosion, depletion of SOM, and loss of soil carbon. These negative impacts on soil quality then translate into negative impacts on water quality like increased soil erosion, which causes sedimentation and murky water conditions, and nutrient leaching can result in excessive algae growth and hypoxia (low oxygen levels in the water), which then has negative consequences on aquatic organisms as described in Chapter 3.4.2.3.

For this rule, we estimate that the 2020 and 2021 volumes would have little to no impact on water and soil quality, as we are setting those volume requirements at levels equal to the volumes of renewable fuel projected to be produced in 2020 and 2021. Because the 2020 and 2021 volumes portion of this rule will be late, it will not be able to stimulate any increase in the production of biofuels in 2020 and 2021. Therefore, we do not expect the 2020 and 2021 volume standards to cause any changes in land use or management that could negatively impact soil and water quality. However, the volume targets for 2022 are ambitious, anticipate a large growth in biofuel production, and are being proposed far enough in advance to stimulate renewable fuel production. Therefore, it is possible that the 2022 volume targets could have at least some impact on land use and management through increased crop cultivation, which would have negative impacts on water and soil quality, as discussed in Chapter 3 of this DRIA. The magnitude of this impact is difficult to estimate as it would require more information on the extent to which the proposed renewable fuel standards drove changes in which biofuel volumes, the impact this might have on feedstock production (e.g., corn, soy, palm), where any increases in those feedstocks occur (e.g., domestically vs internationally, and on what acres), the cultivation practices applied to those acres (e.g., fertilizer and pesticide use, use of cover crops in the non-growing season, crop rotations, etc.), as well modeling to evaluate the magnitude of any runoff occurring from those acres. Additionally, we would need additional information on the impacted populations in order to evaluate the environmental justice concerns: where are the populations

[605] CAA § 211(o)(2)(B)(ii).

that are already being impacted most, who resides in those areas, how are they using the water, and how are the changes in water quality and availability impacting those uses and, thereby, those populations. For these reasons, we are unable to assess the degree of impact the annual volume requirements may have. However, we would like to better understand the relationship between the annual RFS volume standards and land use/land management decisions.

Any negative impacts on aquatic life have the potential to also negatively impact populations who rely on fish or other aquatic life, like shrimp or crawfish, for sustenance or income. According to a study by Beveridge, et al., fish is a very nutritious food for humans with high quality animal protein, essential fatty acids and micronutrients.[606] Many American Indian tribes, minority populations, and some low-income populations, rely on local food sources—including fish and other aquatic life—to supplement their diets. To better understand these high-risk populations, we conducted a literature review to identify population groups most likely to fall under the high risk category for mercury exposure based on higher-than-average fish consumption as part of the RIA for the Mercury and Air Toxics Standards rule.[607] These population groups are the same ones who would be most affected by any adverse impact the RFS has on fisheries and aquatic life due to their heavy reliance on fishing for sustenance. This review included six high-risk population groups, including African-American and white low-income recreational and subsistence fishers in the Southeast, female low-income recreational and subsistence fishers, Hispanic and Laotian subsistence fishers, and Chippewa/Ojibwe Tribe members in the Great Lakes area.[608] American Indian tribes also rely on recreational fisheries for income, as explained by the U.S. Department of the Interior.[609] The fish populations depend on healthy water systems to thrive. If these aquatic ecosystems are negatively impacted by agricultural runoff and nutrient leaching, they could suffer from algae blooms or become hypoxic, making it impossible for fish to survive and endangering the human populations who rely on them. Additionally, any increased use of nitrogen rich fertilizers, as are applied to approximately 98% of corn acres (see Table 3.4.2.1-1), could result in nitrates leaching into groundwater that may be used for human consumption, particularly in areas with loamy and sandy soil conditions. Nitrate filtration is an expensive process that low income communities may not have access to. Additionally, where groundwater wells are employed in rural areas, the concern of disproportionate impact on vulnerable populations may increase. In this way, the proposed volumes for 2022 could potentially have disproportionately severe negative impacts on environmental justice communities within American Indian tribes and other low income populations that rely on local fisheries as a source of food or income or that may not be able to afford costly water filtration systems to address nitrate contamination in their drinking water.

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[606] Beveridge, M. C., Thilsted, S. H., Phillips, M. J., Metian, M., Troell, M., & Hall, S. J. (2013). Meeting the food and nutrition needs of the poor: the role of fish and the opportunities and challenges emerging from the rise of aquaculture. Journal of fish biology, 83(4), 1067–1084. https://doi.org/10.1111/jfb.12187

[607] EPA, *Regulatory Impact Analysis for the Final Mercury and Air Toxics Standards,* Dkt. No. EPA-HQ-OAR-2009-0234; EPA-HQ-OAR-2011-0044 (Dec. 2011).

[608] Id.

[609] U.S. Department of the Interior, Working with Native American Tribes, available at https://www.fws.gov/southeast/our-services/native-american-tribes/ (last accessed May 28, 2021), see also U.S. Department of the Interior, Native American Trust Responsibilities, available at https://www.fws.gov/southwest/fisheries/native_american_trust.html (last accessed May 28, 2021), and U.S. Department of the Interior, Indian Affairs, Branch of Fish, Wildlife, and Recreation, available at https://www.bia.gov/bia/ots/division-natural-resources/branch-fish-wildlife-recreation (last accessed May 28, 2021).

8.4. Impacts on Fuel and Food Prices

Costs are also relevant to an EJ analysis when communities are expected to face economic challenges due to impacts of a regulation (E.O. 14008). For instance, if prices for basic commodities such as food and fuel increase as a result of a rulemaking, lower-income households may be differentially affected since these goods and services may make up a relatively larger share of their income, and they are less able to adapt or substitute away from them.

As part of the analyses conducted for this rule we estimated the impact of the proposed volumes on food prices. We estimated that the proposed volumes would have minimal impacts on food prices (increases of total food expenditures of 0.15% and 0.40% in 2021 and 2022 respectively). In part, this is because corn and soy are a relatively small proportion of most foods purchased and consumed in the United States (corn and soy commodity prices exhibit larger increases). We also projected relatively small price impacts of the proposed volumes on the prices of transportation fuel, with slight decreases in the price of gasoline (–0.11 and –0.02 cents per gallon in 2021 and 2022 respectively) and increases in the price of diesel (0.70 and 3.22 cents per gallon in 2021 and 2022 respectively). These impacts are discussed in greater detail in Chapter 7.5 (food price impacts), Chapter 7.4 (price of agricultural commodities), and Chapter 9 (fuel price impacts).

The projections of the impact of the proposed volumes on food and fuel prices for this proposed rule are ultimately derived from projections of the impact of the rule on widely traded commodities such as corn, soybeans, gasoline, and diesel. We therefore do not expect that the impact of this rule on food and fuel prices will vary for different parts of the country. However, changes in food and fuel prices could have a disproportionate impact on populations who spend a larger share of their income on food and fuel. According to data collected via the Consumer Expenditure Survey from the Bureau of Labor and Statistics, consumer units[610] with income in the lowest 20% spend a greater portion of their total expenditures on food and fuel (see Table 8.4-1). Thus, even though we expect that this proposal would have the same effects on the prices for food and fuel for all consumers, we also expect that these price impacts, though small, would have a proportionally larger impact on lower income communities.

[610] Consumer unit members are either related by blood, marriage, or other legal arrangement, or they are financially dependent (i.e., live together and share the responsibility for some main expenditures in housing, food, and other living expenses). In 2019 the average consumer unit was comprised of 2.5 people, of which 0.6 people were children under 18. For more information see Bureau of Labor and Statistics Consumer Expenditure Survey, 2019.

Table 8.4-1: Proportion of Total Expenditures on Food and Fuel

	All Consumer Units	Lowest 20% Income Consumer Units
Total expenditures	$63,036	$28,672
Food expenditures	$8,169	$4,400
Percent of total expenditures on food	13.0%	15.3%
Fuel expenditures	$2,094	$998
Percent of total expenditures on fuel	3.3%	3.5%

Chapter 9: Costs

The statute directs EPA to assess the impact of the use of renewable fuels on the cost to consumers of transportation fuel and on the cost to transport goods in using the reset authority. In this chapter, we assess the social costs of renewable fuels (9.1), the social costs of the petroleum fuels which the biofuels replace (9.2), the fuel economy effect based on each fuel's energy density (9.3), and the impacts of this rule on social costs, the costs to consumers of transportation fuel, and the costs to transport goods (9.4).[611]

9.1 Renewable Fuel Costs

9.1.1 Feedstock Costs

For all renewable fuels, the feedstock costs are a primary contributing factor to the cost to produce and use the renewable fuels. We first estimate the production cost for these feedstocks prior to providing information for the production, distribution and blending costs for the various renewable fuels.

9.1.1.1 Corn and Corn Ethanol Plant Byproducts

The price of corn is the most important input to enable estimating the cost of corn ethanol. Corn price projections are from the United States Department of Agriculture (USDA) which makes projections of future corn prices. However, it is also necessary to estimate the prices for two corn ethanol plant byproducts: dried distiller grains solubles (DDGS) and inedible corn oil. Since USDA does not estimate future prices for DDGS and corn oil, these were obtained by agricultural price projections made by the University of Missouri, Food and Agricultural Policy Research Institute (FAPRI). Table 9.1.1.1-1 summarizes the corn, DDGS and corn oil prices used in the cost analysis.[612] [613] [614] An additional sensitivity analysis is conducted at a much higher corn price to understand how the current higher feedstock costs affect the cost of using renewable fuels. No difference in DDGS and inedible corn oil prices are assumed for the sensitivity analysis.

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[611] Costs are reported as year 2020 costs for capital costs, but left in nominal dollars for operating and feedstock costs, which is how they were reported originally. Since future projected costs are only one and two years into the future, using the operating and feedstock costs nominally has a negligible impact on the cost analysis compared to adjusting them back to a recent prior baseline, such as 2020.

[612] USDA Economic Research Service; US Bioenergy Statistics; Table 14 Fuel ethanol, corn and gasoline prices by month; December 2019.

[613] USDA Economic Research Service; Feed Grains Database: Custom Query Results; DDGS; https://data.ers.usda.gov/FEED-GRAINS-custom-query.aspx#ResultsPanel

[614] USDA Economic Research Service; Oil Crops – all Tables; Table 32; https://www.ers.usda.gov/data-products/oil-crops-yearbook.aspx; Inedible distillers corn oil price used for 2013 - 2018, and the average of the ratio of inedible to edible corn oil price is applied to edible corn oil prices for the years prior to 2013.

Table 9.1.1.1-1 Corn, Dried Distiller Grains Solubles and Inedible Corn Oil Prices (nominal dollars)

Year	Corn Prices ($/bushel)	DDGS Prices ($/dry ton)	Inedible Corn Oil Prices (c/lb)
2021	3.60	165	41.8
2022	3.65	162	39.9
Sensitivity	5.00	-	-

9.1.1.2 Soybean and Waste Vegetable Oil Prices

Soybean oil, waste oil (animal fat, waste oil and grease) and palm oil were identified in Chapter 2 as feedstocks for producing renewable diesel fuel. Soybean oil price projections made by USDA are used for this cost analysis.

Waste oils are expected to comprise a small portion of the feedstock volume of renewable diesel plants, but unfortunately neither USDA nor FAPRI project future waste oil prices. Instead future waste oil prices for this analysis were estimated based on the historical differences between waste oil spot prices and soybean oil's spot prices. Inedible waste oil spot prices were compared to soybean oil spot prices between January 2012 and September 2017.[615] Over that time period, soybean oil averaged 37.6 cents per pound, and waste oil averaged 29.4 cents per pound, respectively. The waste oil to soybean oil ratio is 0.78, and this was used for establishing waste oil prices relative to USDA projected 2021 and 2022 soybean oil prices.

Palm oil is expected to be the other feedstock used for producing a portion of renewable diesel, but again, neither USDA nor FAPRI project future palm oil prices. Instead, like for waste oil, future palm oil prices for this analysis were estimated based on the historical differences between palm oil spot prices and soybean oil's spot prices. Palm oil spot prices were compared to soybean oil spot prices between January 2012 and September 2017.[616,617] Over that time period, soybean oil averaged 37.6 cents per pound, and palm oil averaged 29.4 cents per pound, respectively. The palm oil to soybean oil ratio is 0.78, and this was used for establishing palm oil prices relative to USDA projected 2021 and 2022 soybean oil prices.

The additional demand for vegetable oils caused by this proposed rulemaking is expected to increase the price for those oils. Previous agricultural modeling using the Global Change Analysis Model (GCAM) found that increases of 200 million gallons of soybean oil increased the soybean oil price by 0.032 cents per pound.[618] This price increase estimate was used to adjust the soybean oil prices for this analysis based on estimated increase of soybean oil demand. A similar adjustment was made for the estimated increased demand for waste oil and palm oil. Since the volume of the waste oil market is about 1/10th the size of the soybean oil market, the price increase for increased waste oil demand was estimated to be 10 times higher, or $0.032/lb

[615] USDA Yearbook Tables by the Economic Research Service, downloaded March 2021.
[616] Id.
[617] Palm prices in more recent years will be compared to soybean oil prices for the final rule cost analysis.
[618] Shelby, Michael; Cost Impacts of the Final 2019 Annual Renewable Fuel Standards; Memorandum to EPA Air and Radiation Docket EPA-HQ-OAR-2018-0167.

per 20 million gallons of increased waste oil demand. The volume of the global palm oil market is nearly 6 times greater than the U.S. soybean oil market, so the adjustment to the palm oil prices is much more modest than the adjustment to soybean oil and waste oil projected prices. The projected soy, waste and palm oil prices in the baseline and resulting from the increased demand due to the proposed standards that are used in this cost analysis are summarized in Table 9.1.1.2-1 below.

As this time in the Spring of 2021 when the costs were being modeled for this proposal, soybean oil prices have been at or above $0.60 per pound. It is likely that this is a short-term price spike due to a shortage in soybean production this past year and it will be reversed by a new soybean crop. In fact, high soybean oil prices will prompt farmers to plant more soybeans. Even if this period of high soybean oil prices passes, there is a concern that as vegetable oil demand increases, vegetable oil prices will continue to rise. Thus, to model the cost impact of current or potential future higher vegetable oil prices, higher vegetable oil prices were assumed and modeled to understand their effect on costs. In addition to the principal vegetable oil prices being modeled, Table 9.1.1.2-1 summarizes the vegetable oil prices used for a sensitivity analysis for higher vegetable oil prices.

Table 9.1.1.2-1: Summary of Vegetable Oil Production Costs (nominal dollars/pound)

	Baseline Costs – Prices Before Adjustments			**Modeled Vegetable Oil Prices**		
	USDA Price Projection			**Adjusted for Increased Demand**		
Year	**Soybean Oil**	**Waste Oil**	**Palm Oil**	**Soybean Oil**	**Waste Oil**	**Palm Oil**
2021	0.34	0.265	-	0.370	0.30	-
2022	0.345	0.269	0.275	0.436	0.34	0.285
Sensitivity Analysis				0.60	0.53	0.35

9.1.1.3 Biogas

For this analysis we assume that biogas is the byproduct by landfills and collected by the landfills to prevent the emissions of methane gas as required by regulation and flared, burned to produce electricity, or cleaned up for use as natural gas. Since the biogas is a waste gas from existing landfills, we assumed no feedstock cost for biogas. The necessary steps to collect, purify and distribute the biogas are all discussed under the subsections discussing production and distribution costs.

9.1.1.4 Sugar Cane

The sugar cane feedstock costs are not estimated separately from the rest of the sugar cane processing costs.

9.1.2 Renewable Fuels Production Costs

This section assesses the production costs of renewable fuels, including the feedstock costs described above as well as the capital, fixed and operating costs. For the most part, the production costs are expressed on a per-gallon for the renewable fuels being produced, not on some other basis, such as ethanol-equivalent volume. The one exception is biogas which is reported on a per-million BTU basis and also on a per ethanol-equivalent volume basis.

9.1.2.1 Cost Factors

9.1.2.1.1 Capital and Fixed Costs

The economic assumptions used to amortize capital costs over the production volume of renewable fuels are summarized below in Table 9.1.2.1.1-1. These capital amortization cost factors are used in the following section for converting the one time, total capital cost to an equivalent per-gallon cost.[619] The resulting 0.11 capital cost amortization factor is the same factor used by EPA in the cost estimation calculations made for other rulemakings and technical papers.[620] [621] [622] [623] [624]

Table 9.1.2.1.1-1: Economic Cost Factors Used in Calculating Capital Amortization Factors

Amortization Scheme	Depreciation Life	Economic and Project Life	Federal and State Tax Rate	Return on Investment (ROI)	Resulting Capital Amortization Factor
Societal Cost	10 Years	15 Years	0%	7%	0.11

Capital costs were adjusted to 2017 year dollars for a previous cost analysis. When gathering the information to adjust the capital costs for this more recent cost analysis to a more recent cost basis, it was discovered that capital costs for the most recent year (2020) had decreased down to about 2017 levels after a couple years of increases. This decrease in capital costs in 2020 back down to near 2017 levels was most likely due to the temporary effects of the Covid pandemic on the economy. For this reason, capital costs were left at the 2017 cost basis and reported as year 2020 costs.[625]

Fixed costs include the maintenance costs, insurance costs, rent, laboratory charges and

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[619] The capital amortization factor is applied to the aggregate capital cost to create an amortized annual capital cost which occurs each and every year for the 15 years of the economic and project life of the unit. The depreciation rate of 10% and economic and project life of 15 years are typical for these types of calculations. The 7% return on investment and the zeroing out of Federal and State taxes is specified by the Office of Management and Budget for these calculations (Office of Management and Budget; Circular A-4; Regulatory Impact Analysis: A primer; https://www.reginfo.gov/public/jsp/Utilities/circular-a-4_regulatory-impact-analysis-a-primer.pdf).

[620] Regulatory Impact Analysis - Control of Air Pollution from New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, EPA420-R-99-023, December 1999.

[621] Cost Estimates of Long-Term Options for Addressing Boutique Fuels; Memorandum from Lester Wyborny to the Docket; October 22, 2001.

[622] Regulatory Impact Analysis: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements; EPA420-R-00-028; December 2000.

[623] Final Regulatory Analysis: Control of Emissions from Nonroad Diesel Engines; EPA420-R-04-007; May 2004.

[624] Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis; EPA-420-R-10-006; February 2010.

[625] Jenkins, Scott; 2020 Annual CEPCI Average Value; Chemical Engineering; March 18 2021; wwwchemengonline.com/pci.

miscellaneous chemical supplies.[626] Maintenance costs can range from 1% to 8% for industrial processes.[627] The fixed costs are lowest for the most efficient, well established plants. For the renewable fuels technologies which have not been operating as long (for a decade or two, as opposed to the refining industry which is better established and has been operating for many decades), we assumed that maintenance costs are at the higher end of this range comprising 5.5% of the capital costs.

9.1.2.1.2 Utility and Fuel Costs

Variable operating costs are those costs incurred to run the renewable fuel production plants on a day-to-day basis, and are based on the unit throughput. The most obvious of the variable costs are utilities. Utilities (electricity, natural gas and water) are required to operate the renewable fuels plants. Natural gas is consumed for heating process streams, including feedstocks which must be heated prior to being sent to reactors and distillation columns for separating coproducts. Electricity is necessary to run pumps, compressors, plant controls and other plant operations. Water can be necessary as part of the process (reaction medium), or used in cooling towers.

Projected electricity and natural gas prices are based on national average values from Energy Information Administration's (EIA) 2021 Short Term Energy Outlook for 2021 and 2022.[628] The STEO-projected electricity and natural gas prices for industrial users in the midwest are used because it is the most common location for renewable fuels plants.[629] The cost of process water is generally quite minimal, but a cost is estimated for process water as well since renewable fuels technologies can use fairly large quantities.[630] [631]The utility costs used for the cost analysis are summarized in Table 9.1.2.1.2-1.

Table 9.1.2.1.2-1: Summary of Utility Cost Factors (nominal dollars)[a]

Year	Natural Gas ($/1000 cf)	Electricity (c/kWhr)	Water ($/1000 gals)
2021	5.18	7.05	3.0
2022	5.31	7.11	3.0

[a] c/kWh is cents per kilowatt-hour; $/1000 cf is dollars per thousand standard cubic feet; $/1000 gallons is dollars per thousand gallons.

[626] Peters, Max S., Timmerhaus, Klaus, D.; Plant Design and Economics for Chemical Engineers 3rd Edition; McGraw Hill; 1980.
[627] McNair, Sam Budgeting for Maintenance: A Behavior-Based Approach, Life Cycle Engineering, 2011.
[628] Short Term Energy Outlook 2021, Energy Information Administration, April 2021; https://www.eia.gov/outlooks/steo/
[629] The ratios of the average Midwest natural gas and electricity prices to the national natural gas and electricity prices are applied to the AEO projections of national natural gas and electricity prices to derive Midwest projections for natural gas and electricity prices.
[630] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[631] Water and Wastewater Annual Escalation Rates for Selected Cities across the United States, Office of Energy Efficiency and Renewable Energy, Department of Energy; September 2017.

9.1.2.2 Corn Ethanol

Corn ethanol plant demand and production output information was obtained from a recent survey of corn ethanol plant producers. The operating costs and ethanol plant yields were based on a 2012 survey of corn ethanol plants.[632] Capital costs are based on a review of corn ethanol construction costs for a 100 million gallon per year corn ethanol plant in 2016. For this analysis the capital costs were scaled to the U.S. average sized corn ethanol plant with a nameplate capacity of 85 million gallons per year assumed to operate at 90% of nameplate capacity, therefore producing 76 million gallons of ethanol per year.[633] Since the capital cost is based on the total construction cost of already constructed corn ethanol plants, no contingency cost factors are applied to the capital costs. The survey information estimates the quantity of DDGS produced by corn ethanol plants. Corn prices are farm gate prices and a transportation spreadsheet was used to estimate a cost of 6 cents per bushel to transport the corn to a corn ethanol plant.[634] Of the corn ethanol plants in the 2012 survey, 74% were separating and selling corn oil so selling corn oil was assumed for 70% of the plant capacity. Table 9.1.2.2-1 contains the plant demand and outputs and capital costs for corn ethanol plants.

Table 9.1.2.2-1: Corn Ethanol Plant Demands, Production Levels and Capital Costs (year 2020 dollars and nominal dollars)

			Cost (MM$)	Cost ($/gal)
Ethanol Yield	2.83 Gal/Bushel	3.6 $/bushel	97	1.27
DDG Yield	15.7 Lbs/Bushel	183 $/ton	–38	–0.51
Corn Oil Yield	0.53 Lbs/Bushel	43 cents/lb	–4.5	–0.06
Thermal Demand	23,860 BTU/Gal	5.19 $/1000 cf	9.1	0.12
Electricity Demand	0.75 kWh/Gal	7.0 c/kwh	4.0	0.05
Water Use	2.7 Gal/Gal	$3/1000 gals	0.6	0.01
Labor Cost	0.07 $/Gal	-	5.3	0.07
Capital Cost (2020 dollars, 76 million Gals/Yr)	2.34 $/Gal Plant Capital cost		21	0.40
Annual Fixed Cost	5.5% of Total Capital Cost		10.5	0.14
Denaturant	2 volume percent		1.3	0.02
Total Cost			106	1.51

The projected corn ethanol social production cost for a 85 million gallon capacity ethanol plant is $1.51 and $1.58 per gallon of denatured ethanol for 2021 and 2022, respectively. These modeled costs are similar to the ethanol plant gate spot prices reported in 2018 and therefore appear to be reasonably accurate.[635]

[632] Mueller, Steffen; 2012 Corn Ethanol: Emerging Plant Energy and Environmental Technologies; April 29, 2013.
[633] Irwin, Scott; Weekly Output: Ethanol Plants Remain Barely Profitable; 3/16/2018.
[634] Edwards, William; Grain Truck Transportation Cost Calculator (a3-29graintransportation.xlsx version 1.4_82017); Iowa State University.
[635] Modelling a "No-RFS" Case; ICF Incorporated for EPA, Work Assignment 0-11 and 1-11, EPA contract EP-C-16-020; July 17, 2018.

9.1.2.3 Imported Sugarcane Ethanol Production Costs

Unlike the starch in corn kernels which first must be depolymerized using enzymes, sugarcane contains free sugar which, after extraction from the sugarcane, can be fermented into ethanol. The fibrous portions of the sugarcane plant is typically combusted to produce the energy needed for the process.

We based our imported ethanol fuel costs on a simple cost estimate and compared it to price data for sugarcane ethanol in Brazil. Generally, ethanol from sugarcane produced in tropical areas is cheaper to produce than ethanol from cellulose, and approaches the cost of corn starch ethanol. This is due to favorable growing conditions, relatively low-cost feedstock and energy inputs, and other cost reductions gained from years of experience.

A study by OECD (2008) entitled "Biofuels: Linking Support to Performance," provides a set of assumptions and an estimate of production costs. Our estimate of sugarcane production costs, which is shown in Table 9.1.2.3-1, primarily relies on the analysis made for that study. The original cost estimate reported in the RFS2 rulemaking assumes an ethanol-dedicated mill and is based off an internal rate of return of 12%, a debt/equity ratio of 50% with an 8% interest rate and a selling of surplus power at $57 per MWh. We revised the operating costs higher by 22% to account for the effects of inflation from 2006 to 2017. The capital costs are adjusted 33% higher using Nelson-Farrar capital cost indexes. When we estimated the amortized, per-gallon capital costs we also added a 20% capital cost contingency factor to account for other costs not accounted for in the cost analysis and amortized the capital costs using our capital cost amortization parameters. Table 9.1.2.3-1 provides the updated production cost estimate for sugarcane ethanol.

Table 9.1.2.3-1: Cost of Production for a Standard Sugarcane Ethanol Project in Brazil (2020 dollars)

Cost Basis	Sugarcane Productivity	71.5 tons/hectare	
	Sugarcane Consumption	2 million tons/year	
	Harvesting days	167	
	Ethanol productivity	85 liters/ton feedstock (22.5 gal/ton feedstock)	
	Ethanol Production	170 million liters/year (45 million gals/yr)	
	Surplus power produced	40 kWh/ton sugarcane	
		RFS2 Reported Cost ($2006)	Revised Costs ($2017)
Capital Costs ($ million)	Investment cost in mill	97	129
	Investment cost for sugarcane production	36	48
Per Gallon Costs ($/gal)	O & M (Operating & Maintenance) costs	0.26	0.32
	Variable sugarcane production costs	0.64	0.78
	Capital costs	0.49	0.52
	Total production costs	1.40	1.74

We also reviewed Brazil's market price of the sugar cane ethanol which should approximate the production cost of sugar cane ethanol. The Argus Americas report provides the sugarcane ethanol free on board (FOB) price at Santos, the port of San Paulo, Brazil, from which sugarcane ethanol is typically shipped to the U.S. We reviewed daily price data from the Argus Americas Biofuels Report from September 2015 to August 2017 and taking a weekly sample of prices, sugar cane ethanol averaged $1.98 per gallon, including the shipping costs to the U.S., over that two year period. The ethanol prices varied from about $1.60 to $2.20 per gallon. The average FOB ethanol price of $1.98/gallon in Brazil is somewhat higher than the estimated sugar cane ethanol production cost of $1.74/gallon. This cost/price difference can mostly be attributed to the low (0.11) before-tax capital amortization factor that we use which reflects the social cost of capital, and the shipping costs incorporated in the price data. When we use a more typical 0.17 after-tax capital amortization factor used by industry, the per-gallon costs increase to $2.02 per gallon which is about the middle of the range for the FOB price data.

The price of sugar will also play in setting sugar cane ethanol plant gate prices costs since sugar cane ethanol producers can sell into either the sugar market, or into the ethanol market. The Brazil ethanol FOB prices were regressed against both the spot crude oil price and world sugar prices. There was very little correlation between spot crude oil price and Brazil ethanol prices (R2 below 0.2). There appears to be more correlation between sugar prices, which ranged from 16 to 26 cents per pound over these two years, and the Brazil's ethanol prices (R2 of 0.45), although the correlation is still low.[636]

[636] The correlations shows that with sugar at 16 cents per pound, the ethanol price would be 180 cents per gallon, and with sugar at 26 cents per pound, the ethanol price would be 215 cents per gallon.

The projected sugar price could help us estimate the future likely FOB ethanol price. Based on one projection of sugar prices in the 2020 to 2022 time period, sugar prices will average between 10 and 15 cents per pound which is lower than recent history when sugar prices ranged from 17 to 25 cents per pound.[637] If sugar prices do have a large effect on Brazil ethanol prices as suspected and if future sugar prices are in fact lower, then future sugar cane ethanol production costs could be somewhat lower than $2.00 per gallon.

9.1.2.4 Biodiesel Production Costs

Biodiesel production costs for this rule were estimated using an ASPEN cost model developed by USDA for a 38 million gallon-per-year transesterification biodiesel plant processing degummed soybean oil as feedstock. Details on the model are given in a 2006 technical publication by Haas.[638] This data is likely still representative of biodiesel plant costs because the process is fairly simple and its cost are likely to be fairly stable over time. Furthermore, the biodiesel costs are mainly (>80 percent) determined by the feedstock prices.

The biodiesel process comprises three separate subprocesses: 1) Transesterification to produce fatty acid methyl esters (biodiesel) and coproduct glycerol (glycerine), 2) biodiesel purification section to meet biodiesel purity specifications, and 3) glycerol recovery section.[639] For the transesterification process modeled by Haas, soybean oil is continuously fed along with methanol and a catalyst sodium methoxide to a stirred tank reactor heated to 60C. After a residence time of 1 hour, the contents exit the reactor and the glycerol is separated using a centrifuge and sent to a glycerol recovery unit. The methyl ester stream, which contains unreacted methanol and catalyst, is sent to a second reactor along with additional methanol and catalyst. Again, the reactants reside in the second stirred tank reactor for 1 hour heated to 60C. The products from of the second reactor are fed to a centrifuge which again separates the glycerol from the other reactants. The reaction efficiency is assumed to be 90% in each reactor, consistent with published reports, resulting in 99% combined conversion in both reactors.

The methyl ester is purified by washing with mildly acidic (4.5 pH) water to neutralize the catalyst and convert any soaps (sodium or potassium carboxylic acids) to free fatty acids. The solution is then centrifuged to separate the biodiesel from the aqueous phase. The remaining water in the biodiesel is removed by a vacuum dryer to a maximum 0.05% of water by volume.

The glycerol can have a high value if it can be purified to USP grade, however this process is expensive. Most biodiesel plants create a crude glycerol (glycerine) grade, which is 80% glycerol, and sell the crude glycerol for further refining by others. To create the crude glycerol, the various glycerol streams are combined and treated with hydrochloric acid to convert the soaps to free acids, allowing removal by centrifugation and sending to waste. The glycerol stream is then neutralized (pH brought back up to neutral) with caustic soda. Methanol is recovered from this stream by distillation and the methanol is recycled back into the process. The

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[637] Taylor, Richard D.; 2017 Outlook of the U.S. and World Sugar Markets, 2016 – 2026; Center for Agricultural Policy and Trade Studies, North Dakota State University; March 2017.
[638] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.
[639] Haas, M.J, A process model to estimate biodiesel production costs, Bioresource Technology 97 (2006) 671-678.

glycerol stream is distilled to remove it from the remaining water, which is recycled back into the process. The glycerol is now at least 80% pure, adequate to sell as crude glycerol.

We made a series of adjustments to the Haas model output. The capital cost is adjusted from 2006 dollars to 2017 dollars using a ratio of the capital cost index from Nelson-Farrar. This adjustment increased installed capital cost from $11.9 million to $15.1 million. Fixed operating costs are estimated to comprise 5.5% of the plant cost. Prices were found on the Web for methanol,[640] sodium methoxide,[641] hydrochloric acid,[642] sodium hydroxide,[643] and glycerine.[644] The value of methanol is from a Methanex report plus 15 cents per gallon distribution costs.[645] Prices for sodium methoxide, hydrochloric acid and sodium hydroxide are all bulk prices from a chemicals supplier.[646] Costs were not updated to more recent year costs to avoid the short-term price effects of the economic recession associated with the Covid pandemic.

The value of the glycerin co-product has been volatile due to a large increase in production in biodiesel facilities that has been balanced at times by new uses. Glycerine has traditionally been used for petrochemical-based products, but there is increased demand in personal care and other consumer products as the standard of living increases in many parts of the world. Some facilities are even experimenting with using it as a supplemental fuel.[647] We can expect that new uses for glycerin will continue to be found as long as it is plentiful and cheap. We use recent cost information of about 10 cents per pound for glycerine.[648]

Table 9.1.2.4-1 also shows the production cost allocation for the soybean oil-to-biodiesel facility as modeled for the 2020 to 2022 time period. Production cost for biodiesel is primarily a function of feedstock price, with other process inputs, facility, labor, and energy comprising much smaller fractions.

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[640] Methanex; current North America prices plus 15 c/gal for shipping; https://www.methanex.com/our-business/pricing; August 2018.
[641] Alibaba; https://www.alibaba.com/trade/search?fsb=y&IndexArea=product_en&CatId=&SearchText=sodium+methoxide; August 2018.
[642] Alibaba; https://www.alibaba.com/trade/search?IndexArea=product_en&CatId=&fsb=y&SearchText=hydrochloric+acid; August 2018.
[643] eBioChem; http://www.ebiochem.com/Search/search/cate2/name/cate/0/keywords/sodium%2520hydroxide/; August 2018.
[644] Perez, Leela Landress; US crude glycerine prices could dip as spring nears; https://www.icis.com/explore/resources/news/2018/02/14/10193613/us-crude-glycerine-prices-could-dip-as-spring-nears; February 14, 2018.
[645] Methanex Methanol Price Sheet; US Gulf Coast; May 31, 2018
[646] https://www.alibaba.com.
[647] Yang, Fangxia; Value-added uses for crude glycerol – a byproduct of biodiesel production; Biotechnology for Fuels; March 14, 2012.
[648] US crude glycerine prices could dip as spring nears; ICIS News; February 14, 2018.

Table 9.1.2.4-1: Biodiesel Production Cost (year 2020 dollars and nominal dollars)

			Thousand Dollars	$/gal
Soybean Oil Feed	74,152 (1000 lb)	37 cents/lb	28,643	2.86
Methanol	7422 (1000 lb)	1.64 $/gal	1,893	0.19
Sodium Methoxide	927 (1000 klb)	$2000/ton	927	0.09
Hydrochloric Acid	529 (1000 lb)	$200/MT	48.1	0.005
Sodium Hydroxide	369 (1000 lb)	$420/ton	77.5	0.008
Water	2478 (1000 lb)	$3/1000 gals	1.2	0.00
Glycerine	9000 (1000 lb)	10 cents/lb	(900)	(0.09)
Natural Gas	66.9 million cf	$5.19/1000cf	347	0.05
Electricity	1008 kW	7.05 cents/kWh	622	0.035
Labor				0.062
Capital Cost 2006$	11.35 ($million)	-	-	-
Capital Cost 2020$	15.12 ($million)		1,664	0.17
Fixed Cost		5.5%	832	0.08
Total Cost			34,150	3.46

9.1.2.5 Renewable Diesel Production Costs

The renewable diesel process converts plant oils or rendered fats into diesel or jet fuel using hydrotreating. The process reacts hydrogen over a catalyst to remove oxygen from the triglyceride molecules in the feedstocks oils via a decarboxylation (removal of a carbon molecule double-bonded to an oxygen molecule producing carbon dioxide) and hydro-oxygenation reaction, yielding some light petroleum products, carbon dioxide and water as byproducts. The reactions also saturate the olefin bonds in the feedstock oils, converting them to paraffins, and may also isomerize some paraffins. Depending on process operating conditions, the yield of product which can be blended into diesel fuel is typically between 90-95% by volume, with the rest being naphtha and light fuel gases (primarily propane). In total, the volumetric yield is greater than 100% of the feed due to the cracking that occurs over the hydrotreating catalyst. Besides the renewable diesel product, propane (light gas output), water and carbon dioxide are also produced. The byproducts created from that first reactor are separated from the renewable diesel in a separation unit.

For this cost analysis we chose to focus on stand-alone renewable diesel production. We estimate a total project cost of $150MM for a standalone 80 million gallon per year facility producing 75 million gallons per year based on materials made publicly available by Syntroleum Corp. related to their Geismar, LA, project.[649] Adjusting from 2006 dollars to 2017 dollars increased the capital costs to $200 million.

[649] Capital cost and other details taken from Syntroleum Corp Investor Presentation materials dated November 2009, available in the docket originally from http://www.syntroleum.com/Presentations/SyntroleumInvestorPresentation.November%205.2009.FINAL.pdf

Our yield estimates as summarized in Table 9.1.2.5-1 were derived from material presented by UOP and Eni at a 2007 industry conference, which describes producing renewable diesel in a grass roots standalone production process inside a refinery.[650]

In addition to feedstock and facility costs, another significant cost input is hydrogen. We used an estimate provided by Duke Biofuels for our hydrogen consumption estimate for producing renewable diesel. On average, vegetable and waste oil require 2,000 SCF/bbl of feedstock processed.[651] Hydrogen costs are estimated to be $4.6 per thousand standard cubic feet based on a large steam methane hydrogen plant producing hydrogen for multiple consumers, not just the renewable diesel fuel plant. This is likely because renewable diesel fuel plants generally are located in areas which have access to large third-party hydrogen producers.

Table 9.1.2.5-1: Input and Output from Renewable Diesel Plant

Fat input	100 gal
Hydrogen	4760 SCF
Renewable diesel output (main product)	93.5 gal
Naphtha output (co-product)	5 gal
Light fuel gas output (co-product)	9 gal

gal is gallons; SCF is standard cubic feet

We derived a cost of 6.9 cents/gallon of renewable diesel product to cover other costs: utilities, labor, and other operating costs. Finally, the total cost per gallon was estimated at $3.26 (2017 dollars). Table 9.1.2.5-2 provides more details for the process assumed in this analysis and summarizes the total and per-gallon costs.

Table 9.1.2.5-2: Parameters used in renewable diesel production cost estimates for a 75 million gallons/yr Plant (year 2020 and nominal dollars)

Stream		Estimated value	MM$/yr	$/gal
Oil input	80 MMgals/yr	37.0c/lb	230	3.06
Naphtha output	4.0 MMgals/yr	0.55150 c/gal	(6.0)	(0.08)
Light fuel gas output	7.2 MMgals/yr	73 c/gal	(5.3)	(0.07)
Hydrogen input	4760 scf/100 gals	$4.6/thousand standard cubic feet	18	0.23
Other Operating Costs			5.2	0.07
Capital Costs (2020 dollars)		$200 million	22.0	0.29
Fixed Costs		5.5%	11.0	0.15
Total Costs			274	3.65

A number of announced renewable diesel projects projected to start-up in 2021 and 2022 are conversions of petroleum refineries to produce renewable diesel fuel. The existing hydrotreating units, fired heaters, heat exchangers, control and instrumentation equipment, hydrogen plants and tank storage at these refineries is expected to be repurposed for the storage

[650] A New Development in Renewable Fuels: Green Diesel, AM-07-10 Annual Meeting NPRA, March 18-20, 2007.
[651] Conversation with Mike Ackerson, Duke Biofuels, May 2020.

of feedstocks and the production and storage of renewable diesel. There will likely still need to be some additional engineering and construction costs to adapt the existing refinery equipment to produce renewable diesel fuel. Adapting a hydrotreater to process vegetable oil requires modifications for higher heats of reaction, increased depressurization and perhaps some changes in metallurgy.[652] These modifications are estimated to cost about one third the cost of a new hydrotreater, or $30 million. As an order of magnitude cost estimate, this is estimated to cost these refineries only 15% of the capital costs of a greenfield renewable diesel plant to enable the refinery conversion.[653]

It is very challenging to accurately estimate the portion of the future renewable diesel production which will be produced by these converted refineries because of the number of potential renewable diesel projects and the uncertainty of which of these projects will move forward. Because these refineries will require much less capital investment prior to producing renewable diesel fuel, these refinery conversion projects are more likely to move forward than greenfield projects. As a very rough estimate, half of the future domestic renewable fuel production is estimated to be produced by these converted refineries. Because most of the cost of producing renewable diesel fuel is due to the feedstock cost, these capital cost savings are estimated to have a modest impact on the cost to produce renewable diesel fuel. For example, renewable diesel produced from soybean oil by a converted petroleum refinery is estimated to cost $3.39/gallon versus $3.65/gallon for a greenfield renewable diesel plant.

9.1.2.6 Biogas

Biogas is the result of anaerobic digestion of organic matter, including municipal waste, manure, agricultural waste and food waste.[654] The primary product of this anaerobic digestion of waste is methane, which is the primary component of natural gas. Thus, once biogas is cleaned up it can be used by processes that normally use natural gas.[655]

The largest source of biogas, which is already being collected to avoid methane emissions, is from landfills.[656] Since landfill gas is the most likely source of biogas for the motor vehicle fleet, to estimate the cost of biogas, this analysis assumes that the biogas will solely be provided by landfills. In some situations, the biogas can be made available to a motor vehicle fleet at or nearby the biogas generating site which would enable the biogas to be used directly by the fleet of vehicles. However, due to the difficulty of transporting biogas from the landfill site to motor vehicles which intend to use the biogas, the predominant method is that the biogas is cleaned up to pipeline specifications and injected into a common carrier pipeline at the landfill.

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[652] Chan, Erin; Converting a petroleum diesel refinery for renewable diesel fuel; Hydrocarbon Processing; April 2021.

[653] Recent cost information provided by a refiner for converting an existing refinery over to renewable diesel provides a higher cost estimate of about 28% of the cost for a grassroots renewable diesel plant. We anticipate using this or similar cost information for the final rule cost analysis. We do not expect this change to have a dramatic impact on our renewable diesel cost analysis, as the capital cost is relatively small (less than 10%) compared to the total cost of renewable diesel production.

[654] Wikipedia. Accessed April 2021; https://en.wikipedia.org/wiki/Biogas.

[655] LeFevers, Daniel; Landfill Gas to Renewable Energy; Hill Briefing; April 26, 2013.

[656] Biomass Explained, Landfill Gas and Biogas; US Energy Information Administration; February 1, 2019; www.eia.gov/energyexplained/index.php?page=bioimass_biogas

Gas is then pulled off the pipeline at downstream locations and compressed into CNG or liquified into LNG for use in motor vehicles. Tracking the use of the biogas in motor vehicles occurs through contracts and/or affidavits rather than using the same methane molecules produced at the landfill.

One of the costliest aspects of using biogas is its cleanup. Biogas contains large amounts of carbon dioxide, nitrogen, and other contaminants such as siloxanes which cannot be tolerated if it is to be put into a natural gas pipeline or used by fleet vehicles at the landfill site. We estimated a cost for cleaning up landfill biogas (LFG) by the transportation sector using Version 3.2 of the Landfill Gas Energy Cost Model.[657] The default inputs and cost estimates by LFGcost-Web are based on typical project designs and for typical landfill situations.[658] EPA ran the financial cost calculator for projects with a design flow rate of 1,000 and 10,000 cubic feet per minute which represents two possible flow rates depending on the size of the landfill. The default data was used for these two cases for a project start year of 2018. The cost estimates from the Model excluded the gas collection and control system infrastructure at the landfill, as EPA expects that landfills that begin producing high BTU gas in 2018 are very likely to already have this infrastructure in place, and that this infrastructure would be used regardless to control methane emissions.

We added some costs not estimated by the Landfill cost model. We estimated and included an operating cost for biogas collection at the landfill.[659] While the capital costs for collecting the biogas are assumed to be sunk at existing sites, the operating costs are ongoing and should be attributed to this new use. Distribution and retail costs are estimated for biogas in Chapter 9.1.4.3.

Table 9.1.2.6-1: Biogas Collection and Cleanup Costs (nominal dollars)

	$ per million BTU	**$/gallon ethanol-equivalent**
Biogas Collection Operating Costs	0.63	0.049
Biogas Clean-up	2.66 – 4.06	0.20 – 0.31

9.1.2.7 BTL Diesel Production Costs

Biofuels-to-Liquids (BTL) processes, which includes several possible different thermochemical processes, convert biomass to liquid fuels relying on process heat. The process analyzed here is commonly referred to a Fischer Tropsch process. The primary product produced by this process is similar to diesel fuel, except BTL diesel has less aromatics. This technology is commonly termed biomass-to-liquids (BTL) because of its similarity to gas-to-liquids and coal-to-liquids technology, but rely on biomass as the feedstock. BTL diesel's higher energy density per gallon than ethanol and even biodiesel provides it an inherent distribution and consumption cost advantage over these other fuels. In addition, like renewable diesel, BTL diesel fuel can be easily distributed from production to retail outlets and used by motor vehicles because of its

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[657] The current version of this model and user's manual are downloadable from the LMOP website: https://www.epa.gov/lmop

[658] This cost estimate does not include the cost for complying with California's more stringent natural gas pipeline specifications designed to address harmful contaminants in some sources of biogas.

[659] LFG Energy Project Development Handbook – Project Economics and Financing; Chapter 4.

similarity to diesel fuel. The diesel fuel produced by the BTL process tends to be comprised of paraffins which provide a much higher cetane number than petroleum diesel fuel. However, it also has a poorer cloud point which reduces its widespread use in cold temperatures.

There are many steps involved in a BTL process which makes this a capital-intensive process. The first step, like all the cellulosic processes, requires that the feedstocks be processed, dried and ground to a fine size. The second step is the syngas step, which thermochemically reacts the biomass to carbon monoxide and hydrogen. Since carbon monoxide production exceeds the stoichiometric ideal fraction of the mixture, a water shift reaction must be carried out to increase the relative balance of hydrogen. The syngas products must then be cleaned to facilitate the following Fischer-Tropsch (FT) reaction. The Fischer-Tropsch reaction reacts the syngas to a range of hydrocarbon compounds – a type of synthetic crude oil. This hydrocarbon mixture is then hydrocracked to maximize the production of high cetane diesel fuel, although some low octane naphtha and small amounts of wax are also produced. The many steps of the BTL process contribute to its high capital cost and the associated high per-gallon cost.

A detailed study conducted by NREL analyzed the cost for biomass-to-liquids production plants via the FT gasification route. NREL estimated that diesel fuel made by a 42 million gallon per year FT plant could be produced at $4.26 per gallon estimated (in 2007 dollars).[660] Three adjustments however were needed to make the NREL production cost compatible with the rest of our analysis: 1) Adjust capital costs to recent year dollars 2) reduce the capital amortization charge and 3) reduce the plant size to a more typical plant size given the relative novelty of the production technology.

For capital charges, the NREL costs were based on amortizing capital assuming a 10% rate of return after taxes, using an annual capital charge factor of 0.176. The report's estimate for capital costs was $606 million for the plant, resulting in annual capital cost of $106 million. We adjusted the capital cost to recent year dollars, which increased the total capital costs to $811 million. Amortizing the capital costs based on the before-tax amortization factor we use resulted in a yearly cost of $89 million or $2.14 per gallon of diesel fuel produced. The relatively large plant would not be appropriate for a first generation plant, so the plant size was adjusted using a 0.7 scaling factor to a 15 million gallon per year sized plant – 10 million gallons per year of diesel fuel and 4.9 million gallons per year naphtha. After this adjustment, the capital costs decreased to $396 million. The result is a diesel fuel production cost of $5.77 per gallon from the FT process. Table 9.1.2.7-1 Summarizes the Cost Information for a FT BTL Plant.

[660] Swanson, Ryan; Satrio, Justinus A.; Brown, Robert C; Platon, Alexandru; Hsu, David D.; 2010. Techno-Economic Analysis of Biofuels Production Based on Gasification; National Renewable Energy Laboratory technical report NREL/TB-6A20-4687.

Table 9.1.2.7-1: Production Costs for FT (BTL) Diesel Fuel (year 2020 and nominal dollars)

Plant Size (million gallons/yr) 10 Diesel Fuel 14.9 All Liquid	Cost ($million/yr)	Cost ($/gal)
Capital Cost $million	396	
Capital Cost 10% ROI before taxes ($million/yr)	43.6	2.91
Fixed Costs ($million/yr)	21.8	1.45
Feedstock Cost ($million/yr)	18.5	1.23
Utility and Other Variable Costs	2.2	0.14
Other raw material Costs ($million/yr)	0.5	0.03
Waste Disposal and Catalyst Costs ($million/yr)	0.5	0.03
Co-Product Credit	–2.0	–0.13
Total Costs ($million/yr)	87.5	5.77

9.1.3 Blending and Fuel Economy Cost

9.1.3.1 Ethanol

9.1.3.1.1 E10

Ethanol has physical properties which affect its value as a fuel or fuel additive. Ethanol has a very high octane content, a high blending Reid Vapor Pressure (RVP) at low concentrations, and is low in energy content relative to the gasoline pool that it is blended into. Each of these properties has a different cost impact depending on the gasoline it is being blended into (RFG versus CG, winter versus summer gasoline, premium versus regular, and blended at 10% or blended as E15 or E85). These physical properties are also valued differently from a refiner's perspective compared to that of the consumer. Refiners value ethanol's octane because they can lower the octane of the gasoline the ethanol is being blended into, reducing refining costs. Refiners dislike ethanol's high blending RVP when blending ethanol in RFG at 10% because they must remove some low value gasoline blendstock material (usually butane) to accommodate the ethanol if the gasoline they are producing does not receive a 1 psi RVP waiver. However, refiners are not concerned about ethanol's low energy content when blending it into gasoline at 10% since they sell gasoline on volume, not energy content. Rather, this is usually just an issue for the consumers who do not travel as far on a gallon of fuel with lower energy content. Depending on the fuel they are purchasing the lower energy content will be either obvious to consumers (i.e., E85), impacting their purchase decisions, or not (i.e., E10 – most consumers do not notice its lower energy content, particularly now when almost all gasoline is E10). Since this is a cost analysis which incorporates all the costs to society, the fuel economy effect is included in the cost estimates.

The blending value of ethanol at 10% was estimated based on the output from two different refinery modeling cases conducted by ICF/Mathpro. The refinery modeling output from the first case allowed us to estimate ethanol's volatility cost for blending in reformulated gasoline. The refinery modeling output from the second case, which modeled ethanol's removal from the conventional gasoline pool, allowed us to estimate ethanol's replacement cost – replacing both its volume and octane.

The refinery modeling output from the first modeling case is summarized in Tables 10.1.3.1.1-1 and 2, which summarize the refinery model's marginal blending values for both ethanol and gasoline.

Table 9.1.3.1.1-1: Refinery Model's Ethanol Value (c/gal)[a]

	PADD 1		**PADD 2**		**PADD 3**		**PADD 4**		**PADD 5**	
Ethanol	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
RFG										
Premium	188	196	193	199	193	184			102	202
Regular	197	202	203	206	203	190			108	205
CG with Waiver										
Premium	218	196	214	199	213	184	211	190	225	201
Regular	96	85	94	86	94	80	93	82	233	205
CG No Waiver										
Premium	190	0								
Regular	200	0								
7.8 RVP with Waiver										
Premium			217	0	215	0	216	0	274	0
Regular			225	0	225	0	226	0	268	0
7.8 RVP No Waiver										
Premium	189	222			193	184				
Regular	198	142			202	189				
7.0 RVP with Waiver										
Premium			218	0						
Regular			226	0						
7.0 RVP No Waiver										
Premium										
Regular										

[a] Premium means premium grade gasoline; regular means regular gasoline grade. Values are reported for each gasoline grade/type produced in each PADD – blank cells means that the gasoline type/grade is not produced in that PADD.

Table 9.1.3.1.1-2: Refinery Model's Gasoline Value (c/gallon)[a]

	PADD 1		PADD 2		PADD 3		PADD 4		PADD 5	
	Summer	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**	**Winter**
Gasoline										
RFG										
Premium	196	182	191	179	190	171			199	183
Regular	189	178	186	175	183	168			190	180
CG with Waiver										
Premium	192	182	188	179	187	172	178	167	173	182
Regular	185	178	182	175	181	168	172	163	164	179
CG No Waiver										
Premium	192	181								
Regular	185	177								
7.8 RVP with Waiver										
Premium			190	178	189	171	180	167	192	0
Regular			184	174	183	168	174	163	182	0
7.8 RVP No Waiver										
Premium	195	0			189	172				
Regular	188	0			183	168				
7.0 RVP with Waiver										
Premium			191	179						
Regular			186	175						
7.0 RVP No Waiver										
Premium										
Regular										

[a] Premium means premium grade gasoline; regular means regular gasoline grade. Values are reported for each gasoline grade/type produced in each PADD – cells are blank because that gasoline type/grade is not produced in that PADD.

Ethanol's blending value is calculated by subtracting ethanol's value by gasoline's value for the same category of gasoline in Tables 10.1.3.1.1-1 and 2. For example, ethanol's value for blending with regular grade summertime CG with the waiver is 96.14 dollars per barrel, compared to the gasoline which is 77.89 dollars per barrel. Thus, the refinery model values ethanol 18.25 dollars per barrel more than gasoline, or about 0.43 dollars per gallon. Table 9.1.3.1.1-3 summarizes the calculated blending values for ethanol in summer gasoline after the blending values for the various PADDs were volume-weighted averaged together.[661]

[661] The summertime ethanol blending values for California RFG were very negative, which the contactor thought could be due to low butane prices. Regardless of the cause, these negative ethanol blending costs were considered outliers and, thus, were not included in our average of ethanol blending costs.

Table 9.1.3.1.1-3: Ethanol's Blending Value in Summer Gasoline ($/gal)

		Summer
CG	Regular	0.32
	Premium	0.20
RFG	Regular	0.11
	Premium	0.01

Ethanol's volatility cost for blending ethanol into RFG is estimated by subtracting ethanol's blending value in reformulated gasoline from ethanol's blending value in conventional gasoline. Thus, ethanol's volatility's cost is 21 and 19 cents per gallon in regular and premium grade gasolines, respectively. Ethanol's octane value can also be estimated from the values in Tables 10.1.3.1.1-1 through 3; however, ethanol's blending value increases significantly when refiners are faced with the cost of replacing it in the gasoline pool.

The second refinery modeling case described above, which evaluated ethanol's value when ethanol is removed from the conventional gasoline pool, provided an estimate of ethanol's replacement cost. This second case revealed that ethanol's very high octane and volume would require significant investment at refineries to replace ethanol and this is reflected in ethanol's much higher blending value when accounting for these additional costs.

Table 9.1.3.1.1-4 summarizes ethanol's marginal costs by different gasoline types and refinery regions for both the reference case (all gasoline with ethanol) and the low biofuel cases (conventional gasoline without ethanol) which replaced ethanol in the gasoline pool with refinery sourced alternatives. Two different ethanol replacement cases were modeled: low biofuel #1 is a reformate-centric case while low biofuel #2 is an alkylate centric case.[662] The much lower marginal values for PADD 1 can be explained because Mathpro allowed PADD 3 refineries to satisfy PADD 1's need for replacing ethanol's volume and octane through its exports into the PADD 1 after initial refinery model runs showed PADD 1's marginal costs for replacing ethanol were exceedingly high.

[662] Reformate is a gasoline blendstock produced by a refinery unit named the reformer. Reformers react a low-octane stream from the crude distillation tower which boils in the gasoline boiling range over a catalyst to convert (reform) low octane hydrocarbons to high octane aromatic compounds. Alkylate is a gasoline blendstock produced by a refinery unit named the alkylation unit. The alkylation unit reacts isobutylene with isobutane and normal butane in acid to branched chain paraffins which are high in octane.

Table 9.1.3.1.1-4: Gasoline Marginal Values for Reference Case and Ethanol Marginal Values for the Low-Biofuel Cases ($/barrel)[a]

PADD of Gasoline Origin	Type	Grade	Gasoline Marginal Values		Ethanol Marginal Values			
					Low-Biofuel #1		Low-Biofuel #2	
			Summer	Winter	Summer	Winter	Summer	Winter
PADD 1	RFG	Prem	95.737	83.936	108.37	100.88		
		Reg	91.452	81.349	115.98	105.97		
	Conv.	Prem	92.680	83.890	123.02	100.87		
		Reg	88.927	81.346	136.43	105.88		
PADD 2	RFG	Prem	88.087	81.685	132.42	110.28	113.45	96.62
		Reg	84.803	79.771	145.38	116.02	122.86	101.61
	Conv.	Prem	85.549	81.248	149.08	110.41	126.74	96.25
		Reg	82.457	79.447	161.21	115.79	135.55	100.93
PADD 3	RFG	Prem	85.424	78.308	121.69	94.72	118.51	89.77
		Reg	81.863	76.395	134.67	98.45	131.29	94.48
	Conv.	Prem	83.644	78.784	133.95	95.13	129.37	89.91
		Reg	79.975	76.755	146.78	98.46	142.00	94.55
PADD 4	RFG	Prem	79.756	77.014	135.5	115.2	150.1	103.1
		Reg	77.367	75.066	149.0	124.0	168.1	110.0
	Conv.	Prem	81.785	82.073	136.5		151.2	
		Reg	81.702	81.993	150.1		169.2	
PADD 5	RFG	Prem	96.890	83.676	37.68	96.05		
		Reg	91.607	82.013	62.46	97.37		
	Conv.	Prem	77.631	82.999	118.14	98.01		
		Reg	73.384	81.116	126.14	97.68		
Average					**135.00**	**105.00**	**133.00**	**99.00**

[a] Low biofuel case means no biofuel in the conventional gasoline pool.

The difference between ethanol and gasoline marginal values is calculated, converted to cents per gallon and then volume-weighted to summarize them on national average basis by gasoline grade and season in Table 9.1.3.1.1-5.

Table 9.1.3.1.1-5: Marginal Ethanol Replacement Cost by Gasoline Grade and Season (cents/ethanol gallon)

		Reformate-centric		Alkylate-centric	
		Summer	Winter	Summer	Winter
Conv.	Prem	124.58	50.79	112.04	32.65
	Reg	165.11	66.83	144.23	48.19

Although the ethanol replacement cost was based on a refinery modeling case when ethanol was solely removed from conventional gasoline, it would likely be about the same for reformulated gasoline (RFG) as well, so we assumed that they were the same for RFG.[663] However, it is necessary to add in ethanol's volatility cost, which for ethanol's removal would be a cost savings. The 21 and 19 cent per gallon volatility cost for regular and premium gasoline, respectively, is subtracted from ethanol's replacement cost to estimate the ethanol replacement cost for RFG. The ethanol replacement costs for both CG and RFG are shown in Table 9.1.3.1.1-6.

The ethanol replacement costs are then further aggregated to national, year-round averages each octane replacement scenario and also adjusted for a lower crude oil price and summarized at the bottom of Table 9.1.3.1.1-6. The crude oil price adjustment was a simple ratio of 58/72 - Mathpro modeled ethanol replacement costs based on crude oil priced at $72 per barrel, but EIA projects crude oil prices to average about $58 per barrel 2021 and 2022.[664]

Table 9.1.3.1.1-6: Aggregated Ethanol Marginal Replacement Cost (cents/gallon)

		Reformate-centric		**Alkylate-centric**	
		Summer	**Winter**	**Summer**	**Winter**
Conv.	Prem	124.58	50.79	112.04	32.65
	Reg	165.11	66.83	144.23	48.19
RFG	Prem	105.58	50.79	93.04	32.65
	Reg	144.11	66.83	123.23	48.19
		82.23		68.65	

Refiners would pursue the lowest cost means to produce their fuels. Therefore, for evaluating the cost of using ethanol in gasoline at 10 volume percent, the lower cost, alkylate-centric cost of 68.65 cents per gallon was used for the ethanol blending cost in the cost analysis.

9.1.3.1.2 Higher Ethanol Blends

Compared to E10, the blending costs are different for ethanol blended into E15 and E85 because these fuels are blended differently. Although E15 could potentially realize a blending benefit based on the increased octane for the additional ethanol, this would require a widespread shift by refineries, pipelines, and terminals in an entire geographical region to produce and distribute another even lower octane blendstock for oxygenate blending (BOB) specially for blending E15 instead of E10.[665] This would most likely only occur when E15 becomes the predominant gasoline used in that region based on the limitations of the distribution system and experience with the historic conversion to E10. Since this could not feasibly happen during the time period of this rulemaking, we have not included any octane blending benefit for the

[663] Both RFG and CG must meet many of the same gasoline property specifications, including sulfur and benzene, as well as ASTM standards (ASTM D4814).
[664] Short-Term Energy Outlook; Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption and Inventories; April 6, 2021.
[665] Some refiners may have extra tankage available to allow producing and storing a lower octane, E15 blendstock to enable selling E15 over its own terminal rack to local retail stations. Refinery rack gasoline sales, however, are usually a small portion of the refinery's gasoline sales.

additional ethanol blended into E15 over the ethanol blended in E10 (the additional 5%).[666] The 1 psi waiver that formerly only applied to E10 was extended to E15 for the portion of the gasoline pool which receives the 1 psi waiver, so the gasoline BOB used to blend up E15 is the same as that used for blending into E10.

We also did not assign a blending credit for E85 for its high octane beyond that credit already being realized when blending E10. At higher ethanol blends, the very high octane resulting from the high ethanol content results in significant overcompliance with the minimum octane standard regardless of the octane level of the gasoline portion of the blend. As a result, there is no additional octane value associated with the additional ethanol. But there is no RVP cost for E85 either because the high portion of ethanol results in lower RVP instead of higher RVP in such mixtures, therefore, a lower RVP blendstock is not needed for blending E85. In fact, to adjust for the lower RVP of E85 blends, E85 is actually blended at roughly 74% ethanol on average over both the summer and winter instead of 85% to have sufficiently high RVP to avoid RVP minimum limits.[667]

The cost of using ethanol must include ethanol's lower energy density (fuel economy effect). Ethanol has about 33% lower energy density than gasoline blendstock (CBOB and RBOB).[668] Accounting for ethanol's lower energy density adds about 70 cents per each gallon of ethanol for all the ethanol blends to account for the additional cost to consumers for consuming less energy dense E10 gasoline (see Chapter 6.3 for additional discussion of the fuel economy effect).

9.1.3.2 Biodiesel and Renewable Diesel

Biodiesel and renewable diesel fuel have properties that could cause a cost savings or incur a cost that we should consider. Both fuels have higher cetane value relative to petroleum diesel,[669] [670] although ICF/Mathpro commented on the possibility of the oil industry taking advantage of that property stating that most markets are not cetane limited and the oil industry likely would not take advantage of this property of biodiesel and renewable diesel.[671] We do not have any evidence that the oil industry is capitalizing on biodiesel and renewable diesel's higher

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[666] The reformulated gasoline pool always took advantage of ethanol's high octane as it was needed to cause a reduction in aromatics to reduce the emissions of air toxics under the Complex Model – the compliance tool of the RFG program. So when ethanol replaced methyl tertiary butyl ether (MTBE) as the oxygenate in 2005 when the RFG oxygen requirement was rescinded, refiners took advantage of ethanol's high octane content. The CG pool, however, could not take advantage of ethanol's high octane until an entire U.S. gasoline market (i.e., Midwest) was blended with ethanol, and then that gasoline market shifted over all at once to a suboctane blendstock for oxygenate blending (CBOB). Reviewing CG aromatics levels (high octane aromatics decrease when refiners produce suboctane CBOB), refiners switched the CG pool over to low octane CBOB over the years from 2008 to 2013 which is around the time when the U.S. reached the E10 blendwall.

[667] E85 can have RVP levels which are too low which makes starting a parked car difficult. When blended at about 70% ethanol, the RVP of the ethanol-gasoline blend is a little higher than E85 blends improving cold starts.

[668] Frequently Asked Questions: How much ethanol is in gasoline, and how does it affect fuel economy?; Energy Information Administration; https://www.eia.gov/tools/faqs/faq.php?id=27&t=10

[669] Animal Fats for Biodiesel Production; Farm Energy; January 31, 2014.

[670] McCormick, Robert; Renewable Diesel Fuel; NREL; July 18, 2016.

[671] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.

cetane value. A blending cost could be incurred for biodiesel due to the addition of additives, to prevent oxidation and lower pour or cloud point, for example. Some of the need to add these pour point additives may be avoided, thus avoiding their costs, as blenders could blend more biodiesel in the summer which would allow lower blending rates in the winter, perhaps avoiding the need for pour point additives altogether. For the analysis, no additive costs were included for biodiesel because we do not have a good estimate for additive costs for biodiesel, nor how biodiesel additive costs compares to that for petroleum diesel. Biodiesel and renewable diesel have somewhat lower energy density than petroleum diesel and this fuel economy effect is accounted for in the cost analysis.

9.1.4 Distribution and Retail Costs

9.1.4.1 Ethanol

9.1.4.1.1 Distribution Costs

Distribution costs are the operating costs to distribute the ethanol, although the total distribution costs could also include the amortized capital costs of newly or recently installed distribution infrastructure (the retail costs to offer E15 and E85 are discussed below). A significant amount of capital has already been invested to enable ethanol to be blended nationwide as E10, and a small amount of ethanol as E85 and E15. Virtually all terminals, those co-located with refineries, standalone product distribution terminals, and port terminals, have made investments over the last 15-plus years to enable the distribution and blending of ethanol. Thus, these capital costs are considered sunk and no additional capital cost is explicitly included in our analysis. However, in the part of the analysis where we estimate ethanol's distribution costs using spot ethanol prices, as described below, we may inherently be including some distribution capital costs which are still being recovered. Thus, those capital costs are still being accounted for in these market prices that we use.

As part of the effort by ICF/Mathpro to estimate use of renewable fuels, ICF estimated distribution costs for ethanol and biodiesel. These cost estimates were also used for the distribution cost analysis for this proposed rulemaking.[672] ICF's estimated ethanol's distribution costs based on ethanol spot prices that are available from the marketplace. The spot prices likely represent the operating and maintenance costs, and any capital costs which are being recovered. Certain publications, including OPIS and ARGUS, publish ethanol spot prices for certain cities and these spot prices were consulted for estimating ethanol's distribution costs. These spot prices are tracked because they represent unit train origination and receiving locations where the custody of the ethanol changes hands in the distribution system. Since nearly all the ethanol is being produced in the Midwest, the distribution cost analysis assumes that the ethanol is collected together in Chicago by truck or manifest rail at an average cost of 7 cents per gallon and then moved out of the Midwest to other areas mostly using unit trains. For the ethanol consumed in the Midwest, the ethanol is likely to be moved by trucks directly to the terminals in the Midwest. For the areas adjacent to the Midwest, the ethanol is assumed to be moved by truck for the areas nearest to the Midwest, and by manifest train for the adjacent areas further out.

[672] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.

These various means for distributing ethanol, and their associated costs, were accounted for when estimating the ethanol's distribution cost to and within each region.

Once the ethanol is moved to a unit train or manifest train receiving terminal, there are many other terminals in these areas which must also receive the ethanol. Ethanol must then be moved either by truck or, if further away, by manifest train from the unit train receiving terminals to the other terminals. Since many of these other terminals don't have sidings for rail car offloading, the manifest train ethanol must be offloaded to trucks at tank car-truck transfer locations before it can be received by these other terminals. A simple analysis revealed that each unit train receiving terminal must then service, on average, an area of 31 thousand square miles (equivalent to a 180 x 180 miles) to make the ethanol available to the various terminals in the area. ICF estimated that, on average, that the further distribution of ethanol from these unit train receiving terminals to the rest of the terminals would cost an additional 11 cents per gallon. Table 9.1.4.1.1-1 provides the estimate of ethanol distribution costs for the various parts of the country.

Table 9.1.4.1.1-1: Ethanol Distribution Costs for Certain Cities or Areas

Location		Distribution Cost (¢/g) to:			Total	
		Hub/Terminal		Blending Terminal		
PADD	Area	To Chicago	From Chicago		(¢/g)	($/b)
PADD 1	Florida/Tampa	7.0	17.8	11.0	35.8	15.0
	Southeast/Atlanta		11.7	11.0	29.7	12.5
	VA/DC/MD		9.7	11.0	27.7	11.6
	Pittsburgh		6.2	11.0	24.2	10.2
	New York		7.7	11.0	25.7	10.8
PADD 2	Chicago		0.0	11.0	18.0	7.6
	Tennessee		9.7	11.0	27.7	11.6
PADD 3	Dallas		4.5	11.0	22.5	9.5
PADD 4			6.2	11.0	24.2	10.2
PADD 5	Los Angeles		16.4	9.0	32.4	13.6
	Arizona		16.4	9.0	32.4	13.6
	Nevada		12.4	9.0	28.4	11.9
	Northwest		12.4	9.0	28.4	11.9

We volume-weighted the various state-specific distribution cost estimates for PADD 1 and 5 to derive a PADD-average ethanol distribution cost for those PADDs. Table 9.1.4.1.1-2 summarizes the estimated average ethanol distribution cost by PADD, and the average for the U.S.

Table 9.1.4.1.1-2: Average Ethanol Distribution Cost by PADD and the U.S.

Region	Gasoline Volume (kgals/day)	Average Ethanol Distribution Cost (¢/gal)
PADD 1	123,700	29.2
PADD 2	102,400	11.0
PADD 3	68,500	22.5
PADD 4	15,100	24.2
PADD 5	63,400	31.4
U.S. Average	373,100	23.2

9.1.4.1.2 Retail Costs

Retail costs for E10 have been sunk for many years and no additional retail costs are assumed. However, this is not the case for E15 and E85. Additional investments are needed to make them available at retail. The Energy Information Administration (EIA) estimates E85 volumes for its Annual Energy Outlook (AEO), and the E85 volume estimates for 2020, 2021 and 2022 from AEO 2021 were used for this analysis. E15 volumes are estimated based on the difference between the total ethanol volume estimated in the Short-Term Energy Outlook and volume of ethanol assumed to be blended in E85 and E10.

The retail costs for E15 and E85 are estimated based on the investments that are needed to be made to offer a higher volume of such ethanol blends. Thus, retail costs are only assumed to be incurred when the E15 and E85 volume exceeds the maximum volume of that fuel estimated to have been consumed in any prior year – in this case either 2019 or 2020 can be the previous maximum year depending on the estimated volumes for those years. As summarized in Table 9.1.4.1.2-1, 2019 was the previous high level year for E15, and 2020 was the previous high level year for E85.

For estimating retail costs, the necessary retail station changes and their associated installation costs for offering E15 and E85 must be estimated. To do so, we conferred with EPA's Office of Underground Storage Tanks on what might be considered "typical" for E15 and E85 installations for a typical sized retail station selling higher ethanol blends. The E15 station is assumed to have an underground storage tank already compatible with E15 that it would convert over to store E15, but would still require 4 new dispensers to dispense the E15 - each dispenser is estimated to cost $20,000 for a total cost of $80,000 (assuming only 4 dispensers for E15 at a retail outlet, with other dispensers still devoted to E10 and other fuels). The E85 stations are also assumed to have an existing underground storage it could use for storing E85, but would require some equipment costing $14,500 to allow the very high ethanol concentration to be stored in that tank. The E85 station would also be required install a new E85-compatible dispenser, costing $20,000, for a total cost of $34,500 (assuming only one dispenser at a retail outlet is provided for E85).[673] Service stations can incur costs which are higher or lower than the costs we estimate for offering E15 and E85. If the service station already has dispensers that can offer an additional

[673] Because only a small percentage of the motor vehicle fleet is comprised of fuel flexible vehicles (FFVs) which can refuel on E85, typically a retail station only offers E85 from a single dispenser at the retail station.

fuel, then perhaps only a few thousand dollars would need to be spent to make the dispenser parts compatible with ethanol. On the other hand, if the service station needs the new dispensers and also needs to install a separate storage tank to store the E15 or E85, then the installation costs would be much higher.

To estimate the per-gallon cost, it is necessary to estimate the volume of E85 and E15 sold at each station which can be estimated based on E15 and E85 throughput volumes sold in Iowa.[674] Retail stations offering E15 are estimated to sell 187 thousand gallons of E15 per year while each retail station offering E85 are estimated to sell 80 thousand gallons of E85 per year.[675] Using the amortization factor shown in Table 9.1.2.1.1-1, and amortizing these retail costs over the incremental volume of ethanol in E15 and E85 above the E10 they displace, which is 5% for E15 and 64% for E85, the covering the cost of capital for the retail equipment adds 97 cents per gallon to the cost of E15 and 7 cents per gallon to the cost of E85.

Table 9.1.4.1.2-1 summarizes the increased volume of E15 and E85 the associated estimated capital cost.

Table 9.1.4.1.2-1: Volumes and Capital Costs for E15 and E85 for New Retail Infrastructure

		2019	2020	2021	2022
Volume (MMgals/yr)	E15	5635	5,388	5,791	5,863
	E85	311	330	341	322
Change in Volume (MMgals/yr)	E15			403	72
	E85			11	(19)
Increase Above Maximum Volume (MMgals/yr)	E15			156	72
	E85			11	-
Capital Cost ($million)	E15			68	32
	E85			5	0

9.1.4.2 Biodiesel and Renewable Diesel Distribution Costs

The biodiesel and renewable diesel distribution costs were determined by ICF under contract to EPA based on an estimate of how much biodiesel and renewable diesel was moved by rail and by truck, within each PADD, and between PADDs.[676] While biodiesel and renewable diesel production is more spread out across the country than ethanol, a significant amount must still be moved long distances to match the production to the demand. The internal PADD rail costs were estimated to be 15 cents per gallon and truck movements for shorter fuel movements were estimated based on distance moved. Movement of biodiesel between PADDs was usually assumed to be made by rail, although biodiesel and renewable diesel fuel are moved by ship

[674] Awan, Hamid, Internal Services Division, Iowa Department of Revenue; 2020 Retailers Fuel Gallons Annual Report; April 2021.
[675] The E15 retail station throughput volumes estimated from EIA total ethanol and E85 volume projections suggest a higher E15 throughput than for a typical sized retail station. The cost per retail station throughput still applies since as the station throughput increases, so would the number of dispensers to sell the increased volume of E15.
[676] Modeling a No-RFS Case; ICF Incorporated; Work Assignment 0,1-11, EPA contract EP-C-16-020; July 17, 2018.

from the Gulf Coast, to the West Coast. ICF relied on EIA reports for biofuel movements between PADDs. Based on these analyses, the inter-PADD movements are estimated to cost 15 to 32 cents per gallon, depending on the distance that the biodiesel must travel. Table 9.1.4.2-1 summarizes the biodiesel and renewable diesel distribution costs for each PADD taking into account the amount of fuel which is distributed within PADDs and between PADDs.

Table 9.1.4.2-1: Estimated Biodiesel and Renewable Diesel Fuel Distribution Cost by PADD

Location	PADD Total Transportation Cost (¢/gal)
PADD 1	21.6
PADD 2	15.0
PADD 3	16.0
PADD 4	25.0
PADD 5	23.8
U.S. Avg.	17.7

The renewable diesel fuel distribution costs are assumed to be the same as biodiesel. Because renewable diesel is very similar in quality as diesel fuel, it can more readably be blended in more places in the diesel fuel distribution system, including at refineries, where the renewable diesel fuel would be moved by the same distribution system as diesel fuel. Thus, if renewable diesel is used locally its distribution costs would likely be lower than biodiesel. However, because much of the renewable diesel is expected to be distributed to the West Coast to help meet the Low Carbon Fuel Standard programs there, renewable diesel's distribution costs are estimated to be about the same as biodiesel's estimated costs.

9.1.4.3 Biogas

9.1.4.3.1 Distribution Costs

Biogas which is gathered from the landfill off-gassing and cleaned up must then be transported to where it can be used. Most likely, this gas will end up in a nearby natural gas pipeline, but it also could be in some rare cases compressed or liquified for dispensing into the onboard CNG or LNG tanks of a local truck fleet at or near the landfill site.

Information on the length of pipeline needed to bring landfill gas to a nearby natural gas pipeline is not readily available, but some simple assumptions allowed us to estimate this distance. Landfills are generally located near to, although not in, urban areas to keep the transportation costs lower for hauling the waste to the landfill. The landfill gas is estimated to have to be moved 5 miles to access at least a commercial natural gas pipeline. For installing each mile of pipeline, it is estimated to cost $0.68 million, or $3.4 million for the entire 5 mile pipeline. Two different volume cases were modeled to estimate the cost for a small and a large landfill – the small landfill producing 1000 scf/min and the large landfill producing 10,000 scf/min. When amortized over the volume of landfill gas, the pipeline capital cost is estimated to add $0.72 per million BTU for the 1000 scf/min case, and $0.30 per million BTU for the 10,000 scf/min case. We used the average of these two costs, which is $0.51 per million BTU, to represent the average pipeline costs for moving the biogas from a landfill to a natural gas pipeline.

Once the biogas is transported through the new pipeline to the natural gas pipeline, it incurs a cost for distribution through an existing natural gas pipeline. Landfills are located near urban areas which are destination areas for natural gas pipelines. This means that the distribution costs in the natural gas pipeline would be less than that for natural gas which is being distributed long distances from natural gas production areas. Natural gas will incur both variable and fixed operating costs in the upstream pipelines, which biogas will avoid by being injected downstream. Furthermore, the addition of biogas downstream in the natural gas pipeline system can help the natural gas distribution system avoid capital investments that would otherwise be necessary to debottleneck the upstream natural gas pipeline system to meet commercial and industrial sector demand increases. If we assume that biogas would be injected into a natural gas pipeline at least large enough to serve commercial consumers, the biogas distribution cost can be based on commercial natural gas distribution costs which are represented by the natural gas prices to commercial consumers. As summarized in Table 9.2.2-1, distribution of natural gas to commercial consumers is estimated to cost $4.30 to $4.40 million BTU. We could not find detailed cost information for the distribution of commercial natural gas through different parts of the distribution system that would allow us to scale the commercial natural gas distribution costs to the portion of the natural gas pipeline used by biogas. For this reason, half of the commercial natural gas distribution cost, or about $2.2 per million BTU, is assumed to apply to biogas for distribution to the natural gas pipeline.[677]

While this cost analysis assumes the biogas is being produced at landfills, it is worthwhile to consider the situation other biogas producers are likely to be faced with to distribute their biogas. Like landfills, biogas production at wastewater treatment plants and municipal waste digesters are located near cities and thus would likely have distribution costs similar to landfills. Conversely, agricultural waste digesters are much more likely to be located in rural areas further away from both natural gas pipelines and urban areas. The distribution costs for biogas producers using ag waste digesters would likely be higher, and some of these rural locations may be so remote that the biogas could be considered stranded. Such stranded locations could perhaps still provide biogas to local truck fleets which distribute agricultural products.

9.1.4.3.2 Retail Costs

Retail facilities to dispense biogas are by comparison more expensive compared to transportation fuel retail costs. One information source provided an estimate that a larger sized CNG retail facility would cost about $0.59 per diesel equivalent gallon, or $4.6 per million BTU, so this was used for biogas retail cost.[678]

[677] Biogas producers tell us that they are being charged an equivalent price that natural gas producers are being charged which essentially assumes that they are using the entire natural gas pipeline. This pricing scheme, though, does not represent the true social cost for distributing biogas, and a separate distribution cost is estimated for biogas.
[678] Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities; prepared for The California Statewide Alternative Fuel and Fleets Project by Clean Fuel Connection, Inc.

9.2 Gasoline, Diesel Fuel, and Natural Gas Costs

9.2.1 Production Costs

As renewable fuel use increases or decreases, the volume of petroleum-based products, such has gasoline and diesel fuel, would decrease or increase, respectively. This change in finished refinery petroleum products results in a change in refinery industry costs. The change in costs would essentially be the volume of fuel displaced multiplied by the cost for producing the fuel.

In addition, there could be a situation where we may need to account for capital investments made by the refining industry. For example, increasing renewable fuel standards could reduce capital investments refiners would otherwise make to increase refined product production above previous levels. In this case increased renewable fuel capital investments would offset decreased refining industry investments. However, we have not assumed for this analysis that there would be any reduction in refining industry investments considering the current situation. After the economic impact of the Covid pandemic, Energy Information Administration (EIA) data shows that gasoline and diesel fuel demand are lower now and as of early 2021, only diesel fuel is expected to increase above previous levels in 2022.[679] Furthermore, light-duty and heavy-duty greenhouse gas standards will continue to phase-in, continuing to reduce transportation fuel demand.[680] [681] [682] [683] Thus, we would not anticipate there to be refined product investment regardless of the proposed renewable fuel volumes and thus no savings that would offset renewable fuel investments.

9.2.1.1 Gasoline and Diesel Fuel Production Costs

The production cost of gasoline and diesel fuel are based on the projected retail price of gasoline and diesel fuel provided in EIA's Short-Term Energy Outlook. The state and federal taxes and distribution costs are subtracted from the retail prices to estimate the production costs. API compiles federal and state tax information and estimates gasoline and diesel fuel taxes to be 55 and 62 cents per gallon, respectively.[684] Gasoline distribution costs are estimated by subtracting gasoline bulk prices from gasoline retail minus taxes, which results in an estimated cost of 25 cents per gallon. EIA does not compile bulk price information for diesel fuel, so the estimated gasoline distribution costs are assumed to apply to diesel fuel. Table 9.2.1.1-1

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[679] Short-Term Energy Outlook; Table 4a. U.S. Petroleum and Other Liquids Supply, Consumption and Inventories; April 6, 2021.

[680] Environmental Protection Agency, Department of Transportation; Final rule for Model Year 2012-2016 Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; May 7, 2010.

[681] Department of Transportation, Environmental Protection Agency; The Safer Affordable Fuel-Efficient (SAFE) Vehicles Rule for Model Years 2021 – 2026 Passenger Cars and Light Trucks Final Rule; April 30, 2020.

[682] Environmental Protection Agency, Department of Transportation; Final Rule for Phase 1 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium-Duty and Heavy-Duty Engines and Vehicles; September 15, 2011.

[683] Environmental Protection Agency, Department of Transportation; Final Rule for Phase 2 Greenhouse Gas Emissions Standards and Fuel Efficiency Standards for Medium-Duty and Heavy-Duty Engines and Vehicles; October 25, 2016.

[684] American Petroleum Institute; Notes to State and Excise Taxes; Rates Effective 1/1/2021; https://www.api.org/oil-and-natural-gas/consumer-information/motor-fuel-taxes/gasoline-tax

summarizes the projected gasoline and diesel fuel production costs calculated from the Short-Term Energy Outlook projected retail prices.

Table 9.2.1.1-1: Projected Gasoline and Diesel Production Costs ($/gal)

	Gasoline Costs		Diesel Fuel Costs	
	2021	**2022**	**2021**	**2022**
Retail Cost (Short Term)	2.78	2.72	2.94	2.91
Taxes	0.55	0.55	0.62	0.62
Retail Cost minus Taxes	2.23	2.17	2.32	2.29
Distribution Cost	0.25	0.25	0.25	0.25
Production Cost	1.97	1.91	2.06	2.03

9.2.1.2 Natural Gas Production Cost

For estimating the relative cost of biogas to natural gas, it is necessary to estimate the production cost of fossil natural gas. Like gasoline and diesel fuel, the natural gas production cost can be estimated using natural gas spot prices. In its Short-Term Energy Outlook, EIA projects the natural gas spot price for Henry Hub to average $3.15 and $3.23 per thousand cubic feet for 2021 and 2022, respectively.[685] The Henry Hub spot price most closely represents the natural gas field price, and thus is a proxy for its production cost.

9.2.2 Gasoline, Diesel Fuel and Natural Gas Distribution and Blending Cost

Gasoline and diesel fuel distribution costs were estimated to be 25 cents per gallon as described above in Chapter 9.2.1.1. There are two parts to the gasoline and diesel fuel distribution costs, the distribution cost from the refinery to the terminal and then the distribution from the terminal to retail. These were estimated separately to allow adding the terminal to retail distribution cost to ethanol and renewable diesel costs. Out of the total 25 cents per gallon distribution cost, the terminal to retail distillation cost is estimated to be 20 cents per gallon estimated from the 2017 – 2019 price difference between refiner sales through retail outlets and refiner bulk sales prices, presuming that the sales to retail prices represents gasoline terminal prices.[686]

EIA projects natural gas prices downstream of natural gas production fields which can be used to estimate natural gas distribution costs. The three principal natural gas consumers are industrial, commercial and residential. Industrial consumers consume the largest natural gas volumes per facility, and due to the very large consumption, the distribution costs are lowest. Commercial entities are medium sized consumers, and their distribution costs are higher than industrial consumers. Residential consumers, because of their very low consumption, must pay a much larger distribution cost to maintain the distribution system for much lower consumption to each home. EIA also provides a price for natural gas sold into the transportation sector, although this price includes road taxes which would need to be omitted for the purposes of this cost analysis.[687]

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[685] Short-Term Energy Outlook; Table 5b. US Reginal Natural Gas Prices; Wholesale Spot; April 6, 2021
[686] Energy Information Administration; https://www.eia.gov/dnav/pet/pet_pri_refmg_dcu_nus_a.htm
[687] Taxes are not included in social cost estimates because they are not true costs, only transfer payments.

The varying costs for these different natural gas categories permit estimating natural gas distribution costs for natural gas consumed by motor vehicles. Natural gas produced and distributed to retail outlets to refuel natural gas trucks and cars most likely falls in the category of midsized consumers, or commercial users. The distribution costs of natural gas can therefore be estimated by subtracting the Henry Hub prices from the commercial prices. Thus, the Short-Term Energy Outlook projected Henry Hub prices were subtracted from the commercial prices for 2021 and 2022. Table 9.2.2-1 summarizes the calculation of natural gas distribution cost. To put the natural gas costs on the same footing as the biogas, we also add $4.61 per million BTU for retail costs.[688]

Table 9.2.2-1: Natural Gas Distribution Cost ($/million btu; nominal dollars)

	2021	**2022**
Commercial Prices	7.70	7.61
Henry Hub Prices	3.27	3.35
Pipeline Distribution Costs	4.43	4.26
Retail Costs	+4.61	+4.61
Total Distribution Costs	9.04	8.87

9.3 Energy Density Related Fuel Economy Cost

To estimate the change in petroleum fuel volume that would occur with these changes in renewable fuels volumes and to estimate the fuel economy cost for the summary of individual renewable fuel costs summarized in Chapter 9.4.1, it was necessary to estimate the energy density of each fuel. Table 9.3-1 contains the estimated energy densities for the various renewable fuels and petroleum fuels analyzed for this cost analysis.

[688] Permitting CNG and LNG Stations, Best Practices Guide for Host Sites and Local Permitting Authorities; prepared for The California Statewide Alternative Fuel and Fleets Project by Clean Fuel Connection, Inc.

Table 9.3-1: Lower Heating Value (LHV) Energy Densities

LHV Energy Density (GREET 2017)	
	BTU/gal
Gasoline (E0)[a]	114,200
Diesel Fuel	128,450
Pure Ethanol	76,330
Natural Gas Liquids	83,686
Denatured Ethanol	76,477
E10 Gasoline	110,428
E15 Gasoline	108,542
E85 (E74) Gasoline	86,285
E85 (E74) NGL	78,351
Biodiesel	119,550
Renewable Diesel	122,887
Pyrolysis Naptha	111,520
Crude Oil	129,670

[a] From Chevron Paper.[689]

When accounting for the difference in energy density, changes in ethanol volume affect gasoline volume, changes in renewable diesel volume affect diesel fuel volume, and changes in biogas volume affect natural gas. The gasoline and diesel volumes are estimated based on their energy content relative to the energy content and volumes of renewable fuel which are displacing them, as shown in Table 9.3-2, and in Table 9.3-3 for the supplemental standard. For example, E10 gasoline contains about 3% less energy content than E0 gasoline, and the cost of lower energy dense gasoline is paid by consumers through lower fuel economy and more frequent refueling. When expressed over the cost of using ethanol which comprises only 10% of the E10 volume, the costs are higher. The costs are shown in Chapter 9.4.1.

[689] Diesel Fuels Technical Review; Chevron Global Marketing; 2007.

Table 9.3-2: Renewable Fuel and Fossil Fuel Volume Changes (million gallons)

	Change in Renewable Fuel Volume				Change in Fossil Fuel Volume		
	2021	2022	2021 & 2022		2021	2022	2021 & 2022
Cellulosic biofuel - Total	8,629	10,546	19,175				
CNG - landfill biogas (MMFT3)	8,629	10,546	19,175	Natural Gas	-8,629	-10,546	-19,175
Non-cellulosic adv. - Total	246	797	1043				
Renewable Diesel - soy oil	240	737	977	Diesel Fuel	-230	-705	-935
Renewable Diesel - waste oil	30	60	90	Diesel Fuel	-29	-57	-86
Ethanol - sugarcane	-24	0	-24	Gasoline	16	0	16
Conventional - Total	1,051	275	1,326				
Ethanol - Corn - E10	982	279	1,261	Gasoline	-658	-187	-844
Ethanol - Corn - E85	60	11	71	Gasoline	-40	-7	-48
Ethanol - Corn - E15	8	-14	-6	Gasoline	-5	9	4
Renewable Diesel - Imported	0	181	181	Diesel Fuel	0	-173	-173
Change in Biogas Volume (MMFT3)	8,629	10,546	19,175				
Change in Ethanol Volume	1,027	275	1,302	-	-	-	
Change in Renewable Diesel Volume	270	978	1,248				
Change in Gasoline Volume	-	-		-	-688	-184	-872
Change in Diesel Fuel Volume	-	-		-	-258	-936	-1,194
Change in Natural Gas Volume (MMFT3)					-8,629	-10,546	-19,175

Table 9.3-3 Supplemental Standard Renewable Fuel and Petroleum Fuel Volume Changes

Change in Renewable Fuel Volume				Change in Diesel Fuel Volume			
	2021	2022	2021 & 2022		2021	2022	2021 & 2022
Supplemental Std. Renewable Diesel - Palm	0	147	147	Diesel Fuel	0	-141	-141

The change in gasoline and diesel volume for each case is used to estimate the change in crude oil based on its relative energy content. The change in petroleum demanded and its effect on both imported versus domestic crude oil, and imported petroleum products is projected based on these effects by two separate economic cases, a comparison of the Low Economic Growth Case to the Reference Case, modeled by EIA in its 2021 Annual Energy Outlook.[690] Table 9.3-4 summarizes the projected change in petroleum imports expected from the increased consumption of renewable biofuels, and Table 9.3-5 shows the same information but also accounts for imported renewable diesel fuel due to the Supplemental Standard. The change in crude oil volume and imported petroleum products is used for the energy security analysis contained in Chapter 4 of the DRIA.

[690] AEO 2021 Change in product demand on imports; docketed spreadsheet.

Table 9.3-4: Projected Change in Petroleum Imports Due to Increased Renewable Fuel Consumption (million gallons)

<table>
<tr><th></th><th></th><th>2021</th><th>2022</th><th>2021 & 2022</th></tr>
<tr><td rowspan="5">Projected Change in Imported Petroleum Only</td><td>Change in Imported Gasoline</td><td>-87</td><td>-23</td><td>-110</td></tr>
<tr><td>Change in Imported Diesel Fuel</td><td>-33</td><td>-118</td><td>-151</td></tr>
<tr><td>Total Change in Crude Oil</td><td>-752</td><td>-952</td><td>-1,704</td></tr>
<tr><td>Change in Domestic Crude Oil</td><td>-5</td><td>-7</td><td>-12</td></tr>
<tr><td>Change in Imported Crude Oil</td><td>-747</td><td>-945</td><td>-1,692</td></tr>
<tr><td rowspan="5">Projected Change in Imported Petroleum accounting for Imported Renewable Diesel Fuel</td><td>Change in Imported Gasoline</td><td>-87</td><td>-23</td><td>-110</td></tr>
<tr><td>Change in Imported Diesel Fuel including Imported Renewable Diesel</td><td>-33</td><td>55</td><td>22</td></tr>
<tr><td>Total Change in Crude Oil</td><td>-752</td><td>-952</td><td>-1,704</td></tr>
<tr><td>Change in Domestic Crude Oil</td><td>-5</td><td>-7</td><td>-12</td></tr>
<tr><td>Change in Imported Crude Oil</td><td>-747</td><td>-945</td><td>-1,692</td></tr>
</table>

Table 9.3-5: Projected Change in Petroleum Imports Due to Increased Renewable Fuel Consumption; accounts for the Supplemental Standard imports (million gallons)

<table>
<tr><th></th><th></th><th>2021</th><th>2022</th><th>2021 & 2022</th></tr>
<tr><td rowspan="5">Projected Change in Imported Petroleum Only</td><td>Change in Imported Gasoline</td><td>-87</td><td>-23</td><td>-110</td></tr>
<tr><td>Change in Imported Diesel Fuel</td><td>-33</td><td>-136</td><td>-169</td></tr>
<tr><td>Total Change in Crude Oil</td><td>-752</td><td>-1073</td><td>-1,826</td></tr>
<tr><td>Change in Domestic Crude Oil</td><td>-5</td><td>-7</td><td>-13</td></tr>
<tr><td>Change in Imported Crude Oil</td><td>-747</td><td>-1066</td><td>-1,813</td></tr>
<tr><td rowspan="5">Projected Change in Imported Petroleum accounting for Imported Renewable Diesel Fuel and the Supplemental Standard</td><td>Change in Imported Gasoline</td><td>-87</td><td>-23</td><td>-110</td></tr>
<tr><td>Change in Imported Diesel Fuel including Imported Renewable Diesel (incl. Sup. Std.)</td><td>-33</td><td>178</td><td>145</td></tr>
<tr><td>Total Change in Crude Oil</td><td>-752</td><td>-1,073</td><td>-1,826</td></tr>
<tr><td>Change in Domestic Crude Oil</td><td>-5</td><td>-7</td><td>-13</td></tr>
<tr><td>Change in Imported Crude Oil</td><td>-747</td><td>-1066</td><td>-1,813</td></tr>
</table>

9.4 Costs

9.4.1 Individual Fuels Cost Summary

It is useful to total the production, distribution, blending and fuel economy costs estimated for each fuel to enable a comparison. Table 9.4.1-1 summarizes the estimated costs for the renewable fuels analyzed for this rulemaking for 2021. These costs do not include the per-gallon federal cellulosic and biodiesel tax subsidies, nor do they consider taxes or tax subsidies, as these are transfer payments which are not included in costs. Nor do these costs consider federal state or local infrastructure support funding (e.g., the USDA Higher Blends Infrastructure Incentive Program; HBIIP) supporting E85 and E15 retail station equipment, as these subsidies are also transfer payments.[691] The costs of renewable fuels are primarily influenced by the feedstock costs, which can vary significantly depending on a wide range of factors domestically and internationally, especially since many of them are also agricultural commodities.

[691] Higher Blends Infrastructure Incentive Program; United States Department of Agriculture (USDA); https://www.rd.usda.gov/hbiip

To put the different fuels on an equivalent basis for the miles driven, the cost analysis also needs to account for each fuels impact on fuel economy. While these costs may not always be reflected in the sales prices among the market participants (e.g., refiners sell gasoline based on volume, not energy content), the varying impacts on fuel economy among the fuels result in different costs to consumers in operating their vehicles. The cost associated with the impact of the renewable fuel on fuel economy costs are determined relative to the fuels they are assumed to displace; the ethanol fuels are assumed to displace gasoline, the biodiesel and renewable diesel are assumed to displace diesel fuel, and biogas is assumed to displace natural gas.[692]

For several cases, biofuel costs are included in Table 9.4.1-1 and Table 9.4.1-3 which are not included in the cost analysis summarized in Chapter 9.4.2. To the extent that RINs from biogas incentivize some incremental sales of trucks capable of refueling on biogas (essentially CNG/LNG trucks) at the expense of diesel fueled trucks, then some biogas could also displace diesel fuel, but this is expected to be a relatively minor portion for the volumes and timeframe of this proposal. Nevertheless, we also provide a comparison of the costs of biogas to the costs of diesel fuel. Small volumes of biodiesel and BTL (Fischer Tropsch) diesel/naphtha were estimated in the volumes analysis, but it was decided to assume their very small volumes would be represented by other fuels. The costs of the biodiesel and BTL fuels were included in these fuels comparison cost tables for the benefit of the reader. Soy biodiesel costs are also shown in the table despite representing their costs and other impacts in the cost analysis by changes in soy renewable diesel fuel.

[692] Fuel economy costs are calculated by multiplying the total of petroleum fuel production, distribution and retail costs by the difference in energy density (BTU per gallon) between the petroleum fuel being displaced and the renewable fuel, and the result of that operation is divided by the energy density of the petroleum fuel. For ethanol blended as E10 as an example: (denatured ethanol production + distribution + blending cost) * (E10 gasoline energy density - denatured ethanol energy density)/denatured ethanol energy density.

Table 9.4.1-1: Renewable Fuels Costs ($/gallon unless otherwise noted)

		Production Cost	Blending Cost	Distribution Cost	Retail Cost	Fuel Economy Cost[a]	Total Cost
Corn Starch Ethanol	E10	1.51	(0.65)	0.43		0.74	2.03
	E15 with retail cost	1.51		0.43	0.96	0.74	3.64
	E15 without retail cost	1.51				0.74	2.25
	E85 with retail cost	1.51		0.43	0.09	0.74	2.78
	E85 without retail cost	1.51				0.74	2.25
Renewable Diesel	Soybean Oil	3.51		0.38		0.10	3.99
	Waste Oil	2.94		0.38		0.10	3.42
	Palm Oil	2.79		0.38		0.10	3.27
Sugarcane Ethanol	E10	1.74	(0.65)	0.43		0.74	2.26
Biodiesel	Soybean Oil	3.44		0.38		0.16	3.98
Cellulosic	Biogas ($/gal ethanol)	0.30		0.64		0.90	1.85
	Biogas ($/million BTU)	4.00		2.79	4.61	0.00	11.40
	FT Naphtha	5.77	0.40	0.38		0.05	6.60
	FT Distillate	5.77		0.38		0.10	6.25

[a] Fuel Economy cost is per fuel being displaced – ethanol and FT naphtha displaces gasoline, renewable and FT diesel displaces diesel fuel, and biogas represented as ethanol-equivalent volume is relative to diesel fuel.

The distribution costs for ethanol and biodiesel are averages, which does not capture the substantial difference depending on the destination. For example, ethanol distribution costs can vary from under 10 cents per gallon for local distribution in the Midwest, to over 30 cents per gallon for moving the ethanol to the coasts. Thus, total ethanol cost blended as E10 can vary from around 1.90 to 2.10 per gallon. Biogas distribution includes both the amortized capital cost of transporting the biogas to a nearby pipeline as well as the amortized retail distribution capital costs, since the retail facilities for natural gas trucks are relatively expensive.

Table 9.4.1-2 summarizes production and distribution costs for each category of fossil transportation fuel—gasoline, diesel fuel, and natural gas. For gasoline and diesel, production costs are based on prices in the April 2021 STEO.[693] Natural gas spot prices from the April 2021 STEO are used to represent both feedstock and production costs.

The distribution costs for gasoline and diesel fuel are typical for these fuels. While they can vary depending on the transportation distance, the differences between high and low

[693] EIA, Short Term Energy Outlook 2021, Energy Information Administration, April 6, 2021; https://www.eia.gov/outlooks/steo/archives/Apr21.pdf

distribution costs for gasoline and diesel fuel are likely lower than that for renewable fuels due to the well-established pipeline distribution system for petroleum fuels. The natural gas distribution costs are based on the difference between the projected price for natural gas sold to commercial entities and the projected natural gas spot price, which reflects the price where it is produced.

Table 9.4.1-2: Gasoline, Diesel Fuel, and Natural Gas Costs

	Production Cost	Distribution Cost	Total Cost
Gasoline ($/gal)	1.97	0.26	2.23
Diesel Fuel ($/gal)	2.06	0.26	2.32
Natural Gas ($/million BTU)	3.68	8.45	12.13

Table 9.4.1-3 compares the data from Tables 10.4.1-1 and 2 to show the relative cost of the renewable fuels with the petroleum fuels they displace.

Table 9.4.1-3: Comparison of Renewable Fuel Costs with Petroleum Fuel Costs ($/gal unless otherwise noted)

	Relative to:	Petroleum Fuel Total Cost	Renewable Fuel Total Cost	Relative Cost
E10	Gasoline	2.23	2.03	(0.20)
E15 with retail cost	Gasoline	2.23	3.64	1.41
E15 without retail cost	Gasoline	2.23	2.25	0.02
E85 with retail cost	Gasoline	2.23	2.78	0.55
E85 without retail cost	Gasoline	2.23	2.25	0.02
Sugarcane E10	Gasoline	2.23	2.26	0.03
FT Naphtha	Diesel Fuel	2.32	6.60	4.28
Soybean Oil Renewable Diesel	Diesel Fuel	2.32	3.99	1.67
Waste Oil Renewable Diesel	Diesel Fuel	2.32	3.42	1.10
Palm Oil Renewable Diesel	Diesel Fuel	2.32	3.27	0.95
Soybean Oil Biodiesel	Diesel Fuel	2.32	3.98	1.66
Biogas	Diesel Fuel	2.32	1.85	(0.47)
FT Diesel	Diesel Fuel	2.32	6.25	3.93
Biogas ($/million BTU)	Natural Gas	12.13	11.40	(0.73)

9.4.2 Total Estimated Cost Impacts

In this section, we summarize the results of our analysis estimating the costs for changes in the use of renewable fuels which displace gasoline, diesel fuel and natural gas.[694] For this analysis we considered the production, blending, distribution, and differences in energy density. Table 9.4.2-1 summarizes the cost and cost savings of each biofuel fuel type compared to the

[694] Capital costs are in 2020 dollars, but operating costs are left in nominal dollars. Note that since both renewable fuel and fossil fuel operating costs are in nominal dollars, and one displaces the other, the inflation effects of using nominal dollars offset each other.

fossil fuel it is displacing, and Table 9.4.2-2 provides this information for the supplemental standard.

Table 9.4.2-1: Renewable Fuel and Petroleum Fuel Costs (million dollars; year 2020 and nominal dollars)

		Renewable Fuel			Petroleum Fuel		
		Production	Distribution	Blending	Production	Distribution	Total
2021	Cellulosic biofuel - Total	35.8	66.2	0.0	-27.2	-82.9	-8.1
	CNG - landfill biogas	35.8	66.2	0.0	-27.2	-82.9	-8.1
	Non-cellulosic adv. - Total	901.7	92.2	15.7	-501.5	-62.8	445.3
	Renewable Diesel - soy oil	841.4	91.3	0.0	-474.0	-58.7	400.0
	Renewable Diesel - waste oil	88.2	11.4	0.0	-59.2	-7.3	33.0
	Ethanol - sugarcane	-27.9	-10.4	15.7	31.7	3.3	12.3
	Conventional - Total	1586.4	465.1	-641.1	-1389.3	-179.9	-158.7
	Ethanol - Corn - E10	1483.0	427.2	-641.1	-1298.8	-168.2	-197.8
	Ethanol - Corn - E15	91.3	33.7	0.0	-79.9	-10.3	34.7
	Ethanol - Corn - E85	12.1	4.1	0.0	-10.6	-1.4	4.3
	Renewable Diesel - Imported	0.0	0.0	0.0	0.0	0.0	0.0
2022	Cellulosic biofuel - Total	43.7	81.0	0.0	-34.1	-99.6	-9.0
	CNG - landfill biogas	43.7	81.0	0.0	-34.1	-99.6	-9.0
	Non-cellulosic adv. - Total	3179.4	303.1	0.0	-1551.1	-194.9	1736.4
	Renewable Diesel - soy oil	2983.7	280.3	0.0	-1434.4	-180.3	1649.3
	Renewable Diesel - waste oil	195.7	22.8	0.0	-116.8	-14.7	87.0
	Ethanol - sugarcane	0.0	0.0	0.0	0.0	0.0	0.0
	Conventional - Total	434.7	123.2	-181.8	-353.1	-47.2	-24.1
	Ethanol - Corn - E10	439.5	121.1	-181.8	-357.0	-47.7	-25.8
	Ethanol - Corn - E15	17.0	8.1	0.0	-13.8	-1.8	9.5
	Ethanol - Corn - E85	-21.9	-6.0	0.0	17.8	2.4	-7.8
	Renewable Diesel - Imported	504.4	68.8	0.0	-352.3	-44.3	176.7

Table 9.4.2-2 Renewable Fuel and Petroleum Fuel Costs for the Supplemental Standard (million dollars; year 2020 and nominal dollars)

	Renewable Fuel			Petroleum Fuel		
Year 2022	**Production**	**Distribution**	**Blending**	**Production**	**Distribution**	**Total**
Supplemental Std. RD Palm	409.6	55.9	0.0	-286.1	-36.0	143.5

To estimate the per-gallon cost on the total gasoline, diesel and natural gas pools, the projected total volumes for each of these fuels was obtained from EIA's Short Term Energy Outlook and summarized in Table 9.4.2-3.

Table 9.4.2-3: Total Gasoline, Diesel Fuel and Natural Gas Volumes

	2021	2022	Units
Gasoline Volume	132.45	136.28	Billion gallons
Diesel Volume	62.09	63.93	Billion gallons
Natural Gas Volume	30.16	30.12	Trillion cubic feet

The costs are aggregated for each fossil fuel type and costs expressed as per-gallon and per thousand cubic feet costs in Table 9.4.2-4 for 2021, and the 2022 per-volume costs calculated and shown incremental to 2021 and the combined 2021 and 2022 costs are also shown incremental to the 2020, the baseline year. Table 9.4.2-5 includes similar information, but also includes the supplemental standard costs.

Table 9.4.2-4: Total Proposed Annual Rule Cost without the Supplemental Standard (year 2020 and nominal dollars)

		Total Cost (Million $)	Per Unit Costs	Units
2021	Gasoline	-146	-0.11	c/gallon
	Diesel Fuel	433	0.70	c/gallon
	Natural Gas	-8	-0.00003	$/1000cf
	Total	278	-	
2022 relative to 2021	Gasoline	-24	-0.02	c/gallon
	Diesel Fuel	1,913	2.99	c/gallon
	Natural Gas	-9.0	-0.00003	$/1000cf
	Total	1,880	-	
2021 & 2022 relative to 2020	Gasoline	-171	-0.13	c/gallon
	Diesel Fuel	2346	3.67	c/gallon
	Natural Gas	-17	-0.00006	$/1000cf
	Total	2158		

Table 9.4.2-5: Total Proposed Annual Rule Cost with the Supplemental Standard (year 2020 and nominal dollars)

		Total Cost (Million $)	Per Unit Costs	Units
2021	Gasoline	-146	-0.11	c/gallon
	Diesel Fuel	433	0.70	c/gallon
	Natural Gas	-8	-0.00003	$/1000cf
	Total	278	-	
2022 relative to 2021	Gasoline	-24	-0.02	c/gallon
	Diesel Fuel	2,057	3.22	c/gallon
	Natural Gas	-9.0	-0.00003	$/1000cf
	Total	2,023	-	
2021& 2022 relative to 2020	Gasoline	-171	-0.13	c/gallon
	Diesel Fuel	2490	3.67	c/gallon
	Natural Gas	-17	-0.00006	$/1000cf
	Total	2302	-	

9.4.3 Cost to Consumers and to Transport Goods

The cost to transport goods depends on the cost of the biofuels at retail. Since the retail costs of the biofuels are affected by the cellulosic and biodiesel subsidies, we created a new cost table which includes the cellulosic biofuel (1.01 dollar per gallon) and biodiesel (1.00 dollar per gallon) fuel subsidies. These impacts on the cost of transportation fuel do not include any RIN price impacts, since RIN price impacts are generally transfers within the transportation fuel pool. Table 9.4.3-1 summarizes the incremental retail price impacts of the biofuel volume requirements proposed for 2021 and 2022 on both gasoline and diesel fuel prices.

Table 9.4.3-1: Estimated Effect of 2021 and 2022 Biofuel Volume Requirements (including supplemental standard) on Gasoline and Diesel Fuel Costs including Subsidies (per-unit costs may represent prices, year 2020 and nominal dollars)

		Total Cost (Million $)	Per Unit Costs	Units
2021	Gasoline	(146)	(0.11)	¢/gallon
	Diesel Fuel	163	0.26	¢/gallon
	Natural Gas	(126)	(0.0004)	$/1000cf
	Total	(110)	-	
2022	Gasoline	(24)	(0.02)	¢/gallon
	Diesel Fuel	932	1.46	¢/gallon
	Natural Gas	(153)	(0.0005)	$/1000 cf
	Total	761	-	

Since most goods being transported utilize diesel fuel powered trucks and the diesel price impact is larger, it would make sense to focus more on the impacts on diesel fuel prices.

Reviewing the data in the above table, the highest cost value is the 1.47cents per gallon increase for diesel fuel in 2022.

We further considered the impact of fuel price increases on the price of goods based upon a study conducted by the United States Department of Agriculture (USDA). The USDA analyzed the impact of fuel prices on the wholesale price of produce from 2000 to 2009 when fuel prices ramped up because crude oil prices increased from $30 per barrel to over $90 per barrel.[695] Their study found that a 100% increase in fuel prices resulted in a 25% increase in produce prices. Assuming a baseline diesel fuel price of $2.91/gal in 2022 as summarized in Table 9.2.1.1-1, the 1.46 cent per gallons increase in diesel fuel prices projected in Table 9.4.3-1 amounts to a 0.5% increase in diesel fuel prices. Applying the 25% ratio from the USDA study would indicate that the incremental 2022 RFS volumes would then increase the wholesale price of produce by 0.1 percent. If perishable food products being transported by a diesel truck costs $3 per pound, the increase in that products' prices would be 0.3 cents per pound.[696]

9.4.4 Sensitivity Cost Analysis

As described above in Chapter 9.1.1, a sensitivity analysis that assumes current feedstock prices persist through 2022. The scenario assumes higher corn ($6/bushel), soybean oil (60c/lb), waste oil (53 c/lb) and palm oil (35 c/lb) prices, although all other cost inputs and petroleum prices remained the same. The purpose of the sensitivity analysis is to gain a better understanding about how the current high feedstock prices affect the costs of the RFS program if high feedstock prices were to continue over the next couple of years assuming the proposed volumes are finalized. The higher feedstock costs have a significant impact on production cost of renewable fuels. When the price of corn increases from $3.60 per bushel to $6.00 per bushel, corn ethanol production costs are estimated to increase from $1.51 per gallon to $2.34 per gallon. When the price of soybean oil increases from 37 cents per pound to 60 cents per pound, the soy renewable diesel production costs increase from $3.50 per gallon to $5.40 per gallon. The increase in the cost to diesel fuel resulting from the incremental volumes proposed for 2021 is estimated to be 1.52 cents per gallon, and the combined 2021 and 2022 proposed standards in 2022 is estimated to cost 6.98 cents per gallon. Table 9.4.4-1 summarizes these estimated cost impacts of the proposed volumes based on the sensitivity cost analysis.

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[695] Volpe, Richard; How Transportation Costs Affect Fresh Fruit and Vegetable Prices; United States Department of Agriculture; November 2013.

[696] Comparing Prices on Groceries; May 4, 2021: http://www.coupons.com/thegoodstuff/comparing-prices-on-groceries

Table 9.4.4-1 Results of the Sensitivity Cost Analysis (year 2020 and nominal dollars)

		Total Cost (Million $)	Per Unit Costs	Units
2021	Gasoline	727	0.55	¢/gallon
	Diesel Fuel	944	1.52	¢/gallon
	Natural Gas	(8)	(0.00003)	$/1000 cf
	Total	1,663	-	
2022 relative to 2021	Gasoline	200	0.15	¢/gallon
	Diesel Fuel	3,329	5.21	¢/gallon
	Natural Gas	(9)	(0.00003)	$/1000cf
	Total	3,520	-	
2022 relative to 2020	Gasoline	927	0.68	¢/gallon
	Diesel Fuel	4,272	6.33	¢/gallon
	Natural Gas	(17)	(0.00006)	$/1000 cf
	Total	5,182	-	

Chapter 10: Biomass-Based Diesel Standard for 2022

In setting the BBD volumes in recent annual rules, EPA has recognized that the advanced biofuel volume drives the use of BBD beyond what is required by the BBD volume. Nonetheless, we have continued to ensure space for "other" advanced biofuels (beyond BBD and cellulosic biofuels) to participate in the RFS program given the desire to support biofuels that might be able to further increase biofuel volumes over the longer term and at potentially lower cost. At the same time, given the relatively low rate of participation of other advanced biofuels, we previously maintained approximately the same space for other advanced biofuels in 2021 as in 2020.[697] As we explain in Section III of the preamble, this action maintains this same space in 2022 through commensurate increases in both the 2022 BBD and advanced volumes.

Elsewhere in this DRIA, we analyze the required statutory factors in CAA section 211(o)(2)(B)(ii) for all the biofuel volume requirements we are proposing today, including for BBD. Specifically, we analyze biodiesel and renewable diesel fuels used for RFS compliance, the vast majority of which are BBD. In this section, we conduct further analyses of the statutory factors specifically with respect to the BBD volume, in comparison to other advanced biofuels. This analysis provides additional support for the proposed BBD volume and for EPA's policy of maintaining space for other advanced biofuels.

In general, we think that the size of this space for other advanced biofuels is a policy choice that Congress entrusted to EPA. To date, the BBD industry is the single largest contributor to the advanced biofuel pool, and has been largely responsible for the growth in advanced biofuels envisioned by Congress. However, in establishing the BBD and cellulosic standards as nested within the advanced biofuel standard, Congress clearly intended to support development of BBD and cellulosic biofuels, while also providing an incentive for the growth of other non-specified types of advanced biofuels. That is, the advanced biofuel standard provides an opportunity for other advanced biofuels (advanced biofuels that do not qualify as cellulosic biofuel or BBD) to be used to satisfy the advanced biofuel standard after the cellulosic biofuel and BBD standards have been met. Indeed, since Congress specifically directed growth in BBD only through 2012, leaving development of volume targets for BBD to EPA for later years while also specifying substantial growth in the cellulosic biofuel and advanced biofuel categories, we believe that Congress clearly intended for EPA to evaluate the appropriate rate of participation of BBD within the advanced biofuel standard.

10.1 Review of Implementation of the Program

One of the considerations in determining the BBD volume for 2022 is a review of the implementation of the program to date, as it affects BBD. This review is required by CAA 211(o)(2)(B)(ii), and also provides insight into the capabilities of the industry to produce, import, export, distribute, and use BBD. It also helps us to understand what factors, beyond the BBD standard, may incentivize the availability of BBD. In reviewing the program, we assess numerous regulatory, economic, and technical factors, including the availability of BBD in past years relative to the BBD and advanced standards; the prices of BBD, advanced, and

[697] The 2021 BBD volume was set in the 2020 final rule, while the 2020 BBD volume was set in the 2019 final rule.

conventional RINs; the competition between BBD and other advanced biofuels in meeting the portion of the advanced standard not required to be met by BBD or cellulosic RINs; the maturation of the BBD industry over the course of the RFS program; and the effects of the BBD standard on the production and development of both BBD and other advanced biofuels.

The BBD industry in the U.S. and abroad has matured since EPA first increased the required volume of BBD beyond the statutory minimum in 2013.[698] To assess the maturity of the biodiesel industry, EPA compared information on BBD RIN generation by facility in 2012 and 2020 (the most recent year for which complete RIN generation by company is available). In 2012, the annual average RIN generation per facility producing BBD was about 7.2 million gallons with approximately 53% of facilities producing less than 1 million gallons of BBD a year.[699] Since that time, the BBD industry has matured in a number of critical areas, including growth in the size of facilities, the consolidation of the industry, and more stable funding and access to capital. In 2020, the average BBD RIN generation per facility had climbed to over 29 million gallons annually, more than a 4-fold increase. Only 23% of the facilities produced less than 1 million gallons of BBD in 2020.[700]

Table 10.1-1 shows, for 2011-2020, the number of BBD RINs generated, the number of RINs retired due to export, the number of RINs retired for reasons other than compliance with the annual BBD standards, and the consequent number of available BBD RINs; and for 2011-2022, the BBD and advanced biofuel standards. Note that the 2021-2022 advanced biofuel standards and the 2022 BBD standard are being proposed in this rulemaking; all other standards were finalized in prior rules.

[698] See also generally 84 FR 36794-95 (further explaining our approach in establishing the 2013 BBD volume and our experience since that time).
[699] "BBD RIN Generation by Company in 2012 and 2020," available in EPA docket EPA-HQ-OAR-2021-0324.
[700] Id.

Table 10.1-1: Biomass-Based Diesel (D4) RIN Generation and Advanced Biofuel and Biomass-Based Diesel Standards in 2011-2022 (million RINs or gallons)[701]

Year	BBD RINs Generated	Exported BBD (RINs)	BBD RINs Retired, Non-Compliance Reasons	Available BBD RINs[a]	BBD Standard (Gallons)[b]	BBD Standard (RINs)[b]	Advanced Biofuel Standard (RINs)[b]
2011	1,692	48	102	1,542	800	1,200	1,350
2012	1,738	102	91	1,545	1,000	1,500	2,000
2013	2,740	125	101	2,514	1,280	1,920	2,750
2014	2,710	134	99	2,477	1,630	2,490[c]	2,670
2015	2,796	145	45	2,606	1,730	2,655[c]	2,880
2016	4,009	203	121	3,685	1,900	2,850	3,610
2017	3,849	257	115	3,477	2,000	3,000	4,280
2018	3,873	247	67	3,559	2,100	3,150	4,290
2019	4,147	361	80	3,705	2,100	3,150	4,920
2020	4,489	512	186	3,791	2,430	3,767[c]	5,090
2021	N/A	N/A	N/A	N/A	2,430	3,767[c]	5,200
2022	N/A	N/A	N/A	N/A	2,760	4,278[c]	5,770

[a] Available BBD RINs may not be exactly equal to BBD RINs Generated minus Exported RINs and BBD RINs Retired, Non-Compliance Reasons, due to rounding.
[b] The volumes for each year are those used as the basis for calculating the percentage standards in the final rule. They have not been retroactively adjusted for subsequent events, such as differences between projected and actual gasoline and diesel use and exempted small refinery volumes.
[c] Each gallon of biodiesel qualifies for 1.5 RINs due to its higher energy content per gallon than ethanol. Renewable diesel qualifies for between 1.5 and 1.7 RINs per gallon, but generally has an equivalence value of 1.7. While some fuels that qualify as BBD generate more than 1.5 RINs per gallon, EPA has in the past multiplied the required volume of BBD by 1.5 in calculating the percent standard per 80.1405(c). In 2014 and 2015 however, the number of RINs in the BBD Standard column is not exactly equal to 1.5 times the BBD volume standard as these standards were established based on actual RIN generation data for 2014 and a combination of actual data and a projection of RIN generation for the last three months of the year for 2015, rather than by multiplying the required volume of BBD by 1.5. Some of the volume used to meet the BBD standard in these years was renewable diesel, with an equivalence value higher than 1.5. Moreover, in this action we are proposing that the factor of 1.5 in calculating the percent standard per 80.1405(c) be changed to 1.55 to account for typical mixtures of biodiesel and renewable diesel (see Section VIII.A of the preamble). The number of RINs represented by the BBD standards for 2020, 2021, and 2022 reflects this proposed change.

In reviewing historical BBD RIN generation and use, we see that the number of RINs available for compliance purposes exceeded the volume required to meet the BBD standard in 2011-2013 and 2016-2020.[702] Additional production and use of BBD was likely driven by a number of factors, including demand to satisfy the advanced biofuel and total renewable fuels

[701] Available BBD RINs Generated, Exported BBD RINs, and BBD RINs Retired for Non-Compliance Reasons information from EMTS.
[702] The number of RINs available in 2014 and 2015 was approximately equal to the number required for compliance in those years, as the standards for these years were finalized at the end of November 2015 and EPA's intent at that time was to set the standards for 2014 and 2015 to reflect actual BBD use. See 80 FR 77490-92, 77495 (December 14, 2015).

standards, the biodiesel tax credit,[703] and various other State and local incentives and mandates allowing for favorable blending economics. Moreover, additional production of BBD, beyond the volumes shown in the above table, was exported without generating any RINs.

The prices paid for advanced biofuel and BBD RINs beginning in early 2013 through March 2021 (the last month for which data is available) also support the conclusion that the advanced biofuel, and in some periods the total renewable fuel standards, provide a sufficient incentive for additional BBD volume beyond what is required by the BBD standard. Because the BBD standard is nested within the advanced biofuel and total renewable fuel standards, and therefore can help to satisfy three RVOs, we would expect the price of BBD RINs to exceed that of advanced and conventional renewable RINs.[704] If, however, BBD RINs are being used (or are expected to be used) by obligated parties to satisfy their advanced biofuel obligations, above and beyond the BBD standard, we would expect the prices of advanced biofuel and BBD RINs to converge.[705] Further, if BBD RINs are being used (or are expected to be used) to satisfy obligated parties' total renewable fuel obligation, above and beyond their BBD and advanced biofuel requirements, we would expect the price for all three RIN types to converge.

When examining RIN price data from 2011 through March 2021, shown in Figure 10.1-1, we see that beginning in early 2013 and through March 2021 the advanced RIN (D5) price and BBD (D4) RIN prices were approximately equal. Similarly, from early 2013 through late 2016 the conventional renewable fuel (D6) RIN and BBD RIN prices were approximately equal. This demonstrates that the advanced biofuel standard, and in some periods the total renewable fuel standard, are capable of incentivizing increased BBD volumes beyond the BBD standard. The advanced biofuel standard has incentivized additional volumes of BBD since 2013, while the total standard had incentivized additional volumes of BBD from 2013 through 2016.[706] We do note, however, that in 2011-2012 the BBD RIN price was significantly higher than both the advanced biofuel and conventional renewable fuel RIN prices. At this time, the E10 blendwall had not yet been reached, and it was likely more cost effective for most obligated parties to

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[703] The biodiesel tax credit was reauthorized in January 2013. It applied retroactively for 2012 and for the remainder of 2013. It was once again extended in December 2014 and applied retroactively to all of 2014 as well as to the remaining weeks of 2014. In December 2015 the biodiesel tax credit was authorized and applied retroactively for all of 2015 as well as through the end of 2016. In February 2018 the biodiesel tax credit was authorized and applied retroactively for all of 2017. On December 17, 2019, the biodiesel tax credit was authorized and applied retroactively for all of 2018, 2019, and the majority of 2020 and prospectively for the remainder of 2020 through 2022.

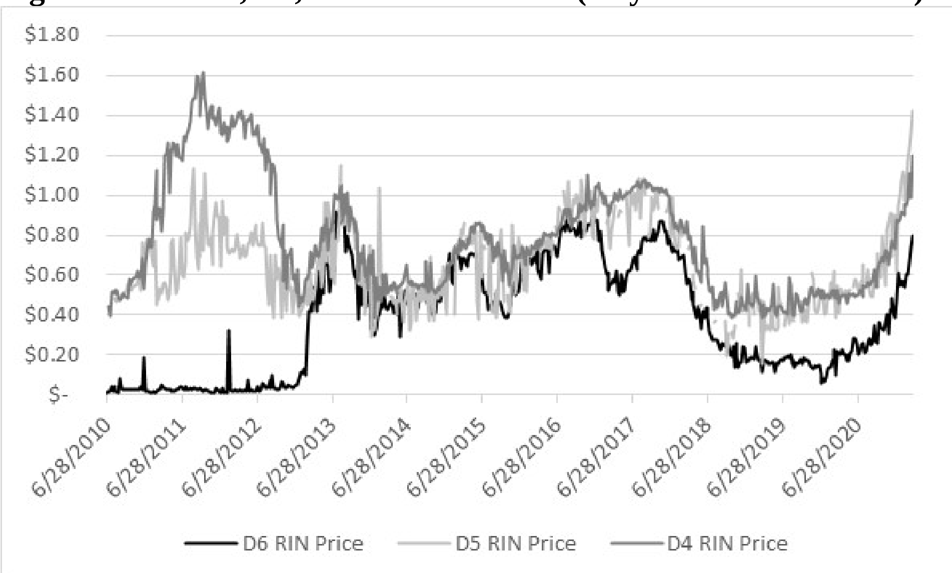
[704] This is because when an obligated party retires a BBD RIN (D4) to help satisfy their BBD obligation, the nested nature of the BBD standard means that this RIN also counts towards satisfying their advanced and total renewable fuel obligations. Advanced RINs (D5) count towards both the advanced and total renewable fuel obligations, while conventional RINs (D6) count towards only the total renewable fuel obligation.

[705] We would still expect D4 RINs to be valued at a slight premium to D5 and D6 RINs in this case (and D5 RINs at a slight premium to D6 RINs) to reflect the greater flexibility of the D4 RINs to be used towards the BBD, advanced biofuel, and total renewable fuel standard. This pricing has been observed over the past several years.

[706] Although we did not issue a rule establishing the final 2013 standards until August of 2013, we believe that the market anticipated the final standards, based on EPA's July 2011 proposal and the volume targets for advanced and total renewable fuel established in the statute. (76 FR 38844, 38843 July 1, 2011). Similarly, for 2014 and 2015, although we issued the final standards in late 2015, the proposed rule incentivized the market to use BBD volumes exceeding the proposed BBD standard to help satisfy the proposed advanced and total standards. See 80 FR 33100 (2014-16 standards proposed June 10, 2015); 78 FR 71732 (2014 standards proposed Nov. 29, 2013).

satisfy the portion of the advanced biofuel requirement that exceeded the BBD and cellulosic biofuel requirements with advanced ethanol.

Figure 10.1-1: D4, D5, and D6 RIN Prices (July 2010 – March 2021)



RIN Price Source: EMTS Data

We also examined the opportunity for advanced biofuels other than BBD and cellulosic biofuels to participate in the RFS program, as shown in Table 10.1-2. We believe it is important to preserve this opportunity for other advanced biofuels, and we are conscious of public comments claiming that BBD volume requirements that are a significant portion of the advanced volume requirements effectively disincentivize the future development of other promising advanced biofuel pathways.[707] A variety of different types of advanced biofuels, rather than a single type such as BBD, would increase energy security (e.g., by increasing the diversity of feedstock sources used to make biofuels, thereby reducing the impacts associated with a shortfall in a particular type of feedstock) and increase the likelihood of the development of lower cost advanced biofuels that meet the same GHG reduction threshold as BBD.

[707] See, e.g., Comments from Advanced Biofuel Association, available in EPA docket EPA-HQ-OAR-2018-0167-1277.

Table 10.1-2: Opportunity for and RIN Generation of "Other" Advanced Biofuels (million RINs)

Year	Opportunity for "Other" Advanced Biofuels[a]	Available Advanced (D5) RINs	Available BBD (D4) RINs in Excess of the BBD Requirement[b]
2011	150	223	342
2012	500	597	45
2013	829	548	594
2014	147	143	–13
2015	102	147	–49
2016	530	98	835
2017	969	144	477
2018	852	178	415
2019	1,352	322	555
2020	855	334	146
2021	862	N/A	N/A
2022	777	N/A	N/A

[a]The opportunity for "other" advanced biofuel is calculated by subtracting the number of cellulosic biofuel and BBD RINs required each year from the number of advanced biofuel RINs required. This portion of the advanced standard can be satisfied by advanced (D5) RINs, BBD RINs in excess of those required by the BBD standard, or cellulosic RINs in excess of those required by the cellulosic standard.
[b]The available BBD (D4) RINs in excess of the BBD requirement is calculated by subtracting the required number of BBD RINs (from Table 10.1-1) from the number of BBD RINs available for compliance in that year. This number does not include carryover RINs, nor do we account for factors that may impact the number of BBD RINs that must be retired for compliance, such as differences between the projected and actual volume of obligated gasoline and diesel. The required BBD volume has not been retroactively adjusted for subsequent events, such as differences between projected and actual gasoline and diesel use and exempted small refinery volumes.

In each year since 2016, there has been significant space for other advanced biofuels, but this space has nonetheless been dominated by excess BBD. While the RFS volumes created the opportunity for up to 530 million, 969 million, 852 million, 1,352 million, and 855 million gallons of "other" advanced for 2016, 2017, 2018, 2019, and 2020 respectively to be used to satisfy the advanced biofuel obligation, only 98 million, 144 million, 178 million, 322 million and 334 million gallons of "other" advanced biofuels were generated. This is significantly less than the volumes of "other" advanced available in 2012-2013. Despite creating space within the advanced biofuel standard for "other" advanced, in recent years, only a small fraction of that space has been filled with "other" advanced, and BBD continues to fill most of the gap between the BBD standard and the advanced standard. Thus, there does not appear to be a compelling reason to increase the "space" maintained for "other" advanced biofuel volumes for 2022.

10.2 Analysis of Other Statutory Factors

In this section, we discuss our consideration of the other statutory factors (besides review of the implementation of the program). As already noted, this analysis supplements the analyses elsewhere in this DRIA and focuses on a comparison between BBD and other advanced biofuels.

Consistent with the historical trends described above as well as the expected availability of BBD in 2022 (see Chapter 5.2), we expect that the actual use of BBD in 2022 will exceed the

BBD standard and that its use will be driven by the 2022 advanced biofuel standard, and potentially the 2022 total renewable fuel standard. Thus, EPA continues to believe that approximately the same overall volume of BBD would likely be used in 2022 even if we were to propose a somewhat lower or higher BBD volume for 2022. Despite this, we think the BBD volume requirement can still have a positive impact on the future development and marketing of BBD by providing a base guaranteed level for investment certainty in BBD.

At the same time, we believe that, over the long-term, maintaining a significant space for other advanced biofuels could result in greater production and use of these other advanced biofuels, which may in turn have positive impacts on several of the statutory factors. Specifically, when viewed in a long-term perspective, BBD can be seen as competing for research and development dollars with other types of advanced biofuels for participation as advanced biofuels in the RFS program. Preserving space within the advanced biofuel standard for advanced biofuels that do not qualify as BBD or cellulosic biofuel provides the appropriate incentives for the continued development of these types of fuels. The increased use of other advanced biofuels in the long-term (which would be less likely if higher BBD volumes were established leaving a smaller market share for other advanced biofuels within the advanced biofuel requirement) leads to potentially favorable outcomes for some statutory considerations, including wetlands, ecosystems, and wildlife habitats; water quality and water supply; energy security; and costs. These potential positive impacts, which are the focus of our discussion in this section, support our continued practice of providing space for other advanced biofuels.

We note that while preserving space for other advanced biofuels facilitates the commercialization of those fuels, whether such commercialization is actually realized or not depends on market and other factors beyond the RFS program. In contrast to BBD, non-cellulosic advanced biofuel volumes other than BBD have not grown to the same extent in recent years. This may or may not be the case in the future. One reason this trend may continue is that in contrast to some prior years the biodiesel blender's tax credit is in place prospectively through 2022. The biodiesel blender's tax credit provides a competitive advantage to BBD over other advanced biofuels. Given this and also because we have not seen significant increases in other advanced biofuels in recent years, we are proposing to increase the BBD volume by the same amount as the increase in the implied volume for non-cellulosic advanced biofuels in 2022. This is similar to what we did in establishing the 2020 BBD volume and is also consistent with our action setting the 2021 BBD volume.

At present, the other advanced biofuels that could fill any gap between the advanced biofuel volume and the BBD volume include the following: sugarcane ethanol; ethanol from grain sorghum using certain processing technologies; naphtha; compressed natural gas/liquefied natural gas (CNG/LNG) from non-cellulosic sources; liquified petroleum gas; renewable diesel co-processed with petroleum diesel fuel; renewable jet fuel; renewable heating oil; and cellulosic biofuel. EPA also continues to consider other potential pathways for producing advanced biofuels. To this end we have published analyses of greenhouse gas emissions attributable to the production and transport of feedstocks used to produce advanced biofuels, including analyses of pennycress oil, carinata oil, cottonseed oil, jatropha oil, and sugar beets.[708] These analyses could help influence the submission of new petitions seeking EPA approval of additional advanced biofuel pathways, and other advanced biofuels that may be affected by the use of BBD.

Following is a discussion of the six sets of factors listed under CAA section 211(o)(2)(B)(ii)(I)–(VI).

10.2.1 Impact on the Environment

10.2.1.1 Air Quality

We describe the impacts of biofuels, including BBD, on air quality in Chapter 3. As we explain further there, some emission increases or decreases might be associated with a change in the use of BBD and other advanced biofuels. Depending on which of the competing advanced biofuels is compared to BBD, the emissions impacts of requiring a larger or smaller portion of the advanced biofuel standard to BBD will vary. However, given that other advanced biofuels also result in air quality impacts (both positive and negative), and that the volume at issue is relatively small when considered in the context of transportation fuel use throughout the geographic area in which the RFS program applies (the continental United States and Hawaii), the overall impacts of marginal shifts between BBD and other advanced biofuels is expected to be small, and air quality impacts do not appear to provide a good reason for setting a higher or lower BBD volume requirement.

10.2.1.2 Climate Change

We describe the greenhouse impacts of biofuels, including BBD, in Chapter 3. As we detail in Chapter 5, the vast majority of increases in both BBD and advanced biofuels in 2022 is expected to come from renewable diesel made from soy, which is a form of BBD. Together with biodiesel made from soy, also a form of BBD, soy biodiesel and renewable diesel are expected to be used to satisfy the majority of the increases in the BBD and advanced biofuel requirements in 2022. Other advanced biofuels, (e.g., ethanol from food waste or CNG/LNG from non-cellulosic feedstock) could also expected to contribute to satisfying the increased 2022 BBD and advanced biofuel volumes. Some of these other biofuels may have superior GHG profiles relative to soy biodiesel and renewable diesel.

A somewhat higher or lower 2022 BBD volume is not expected to significantly change the availability of advanced biofuels with superior GHG profiles in 2022. In the long-term, however, setting the nested BBD volume requirement sufficiently below the advanced biofuel requirement should provide a continuing incentive for the further development and marketing of such fuels, and may result in more GHG reductions.

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[708] See EPA's webpage, Analysis of Lifecycle Greenhouse Gas Emissions Attributable to Production and Transport of Certain Feedstocks; https://www.epa.gov/renewable-fuel-standard-program/other-actions-renewable-fuel-standard-program (last accessed June 6, 2019).

10.2.1.3 Wetlands, Ecosystems, Wildlife Habitats, Water Quality, and Water Supply

In Chapter 3, we describe the impacts of biofuels, including BBD, on wetlands, ecosystems, wildlife habitats, water quality, and water supply. Our comparative assessment of BBD and other advanced biofuels is similar to the above assessment for climate change. Namely, there are some advanced biofuels (e.g., ethanol from food waste, CNG/LNG from non-cellulosic feedstock) that are not made directly from crops and would therefore likely have significantly lower adverse impacts on some or all of these environmental factors relative to soy renewable diesel. By contrast, some other advanced biofuels are made from planted crops (e.g., biodiesel from canola, ethanol from sugarcane) and therefore could potentially have impacts on these environmental factors, which may be roughly comparable to, yet still may differ from, soy biodiesel and renewable diesel.

Setting the BBD volume requirement sufficiently below the advanced biofuel requirement as we are for 2022 should provide a continuing incentive for the further development and marketing of fuels with diminished adverse impacts on these environmental factors. To the extent such fuels become increasingly significant players in the advanced biofuel market, there may be long-term reductions in such adverse impacts as compared to a scenario where the BBD volume requirement is set at a level that does not incentivize production of such fuels.

10.2.2 Impact on Energy Security

In Chapter 4, we assess the impacts of replacing petroleum with biofuels, including BBD. In this section, we further consider the energy security impacts of BBD relative to other advanced biofuels. Having a diversity of biofuels available to displace petroleum is likely to reduce the occurrences and severity of supply disruptions or "supply shocks," since a diversity of fuel supplies means that a disruption to any single supply of fuel will not have as severe of an impact. Setting a BBD standard that requires all (or virtually all) of the anticipated 2022 advanced biofuel requirement be made up of BBD would reduce diversity of the fuel supply and therefore reduce energy security. By contrast, providing space for other advanced biofuels, such as sugarcane ethanol and renewable naptha, contributes to a more diverse fuel mix and thus energy security. In the long-term, preserving this space could increase production and use of other advanced biofuels, which would further enhance energy security.

10.2.3 Rate of Production

We assess the expected rate of production of biofuels, including BBD, in Chapter 5.

10.2.4 Impact of Renewable Fuels on Infrastructure

In Chapter 6, we describe the impacts of biofuels, including BBD, on infrastructure. With respect to the sufficiency of infrastructure to deliver and use renewable fuels, all of the renewable fuels have some infrastructure issues and challenges associated with them to varying degree, some of which are dependent on the feedstock and feedstock location. Some advanced biofuels/feedstock combinations that may offer some advantages and some that may offer some disadvantages relative to BBD (e.g., those dependent on those dependent on retail infrastructure changes and/or new vehicle sales). However, in looking across the various fuels and feedstocks, there does not appear to be a reason on the basis of infrastructure hurdles to set a higher or lower BBD standard.

Similarly, with respect to potential impacts on deliverability of materials other than renewable fuels, we do not anticipate any significant impacts of devoting a larger or smaller portion of the advanced biofuel standard to BBD for 2022. As discussed in Chapter 6, we do not foresee any meaningful impacts from the proposed renewable fuel volumes at all.

10.2.5 Impact of the Use of Renewable Fuels on the Cost to Consumers of Transportation Fuel and on the Cost to Transport Goods

In Chapter 9, we assess the impacts of biofuels, including BBD, on costs. Generally, the market will determine which advanced biofuels are used to meet the portion of the advanced standard that is not dedicated to BBD. To the extent that cost considerations favor BBD, the cost benefit can be obtained either through setting a higher BBD nested standard or allowing the market to choose BBD over competing products in meeting the advanced and total RFS standards. However, to the degree that non-BBD advanced biofuels can be supplied at a lower cost than BBD, requiring the use of a higher volume of BBD would result in higher transportation fuels costs and higher costs to transport goods.

In the long-term, leaving room within the advanced standard for non-BBD advanced biofuels can incentivize the development and production of non-BBD advanced biofuels which may eventually provide a cost benefit as compared to BBD and support the growth in their volumes that will enhance the longer term success of the RFS program. In addition, this approach may temper to some extent BBD prices, by providing competition between the marginal BBD production volumes and other types of advanced biofuels. We note that in general, BBD remains more costly than diesel fuel and some other types of advanced biofuel, primarily driven by feedstock costs, and that this cost represents a significant portion of the costs of the RFS program in general. By preserving space for other advanced biofuels, other advanced biofuels may offer greater potential for costs reductions in the long-term. Therefore, we believe that this factor supports maintaining the BBD volume requirement at a level sufficiently lower than the advanced biofuel volume requirement to incentivize production of non-BBD advanced biofuels, consistent with today’s proposed rule.

10.2.6 Impact of Renewable Fuels on Other Factors

10.2.6.1 Job Creation and Rural Economic Development

In Chapter 7, we assess the impacts of biofuels, including BBD, on job creation and rural economic development. Overall, we believe that BBD will have small but positive impacts on job creation and rural economic development, including due to the construction and operation of new renewable diesel facilities anticipated through 2022. Depending on which other advanced biofuel is compared to BBD, the job creation and rural economic development opportunities will vary. Notably, if we compare advanced biofuels that are predominantly imported (such as imported sugarcane ethanol) with BBD, which is predominantly produced in the U.S., BBD will likely have superior domestic job creation and rural economic benefits. By contrast, if we compare other domestically produced advanced biofuels with BBD, both fuels may provide domestic job creation and economic benefits, albeit potentially for different sectors of the economy or kinds of workers. In general, we think that the marginal shifts in job creation and rural economic benefits do not provide a good reason for setting a higher or lower BBD requirement.

10.2.6.2 Price and Supply of Agricultural Commodities and Food Prices

In Chapter 7, we assess the impacts of biofuels, including BBD, on the price and supply of agricultural commodities and food prices. We do not expect that the proposed volumes would cause adverse impacts on the supply of agricultural commodities. We do expect that the proposed volumes, as analyzed in Chapter 7, could cause small increases in soybean oil and food prices. Depending on which competing advanced biofuel is compared to BBD, the impacts on agricultural commodities and food prices would vary. To the extent that BBD is replaced by biofuels made from other agricultural products (e.g., sugarcane ethanol), there will be different impacts on the associated agricultural commodities and food prices (e.g., increases in the price of sugar as opposed to soybean oil). By contrast, if BBD is replaced by advanced biofuels made from non-agricultural products (e.g., ethanol from food waste), we would expect less impacts on agricultural commodities and food prices. To the extent that such fuels become increasingly significant players in the market, there may be long-term impacts, positive or negative, on the prices for food and agricultural commodities.

Chapter 11: Screening Analysis

11.1 Summary

This chapter discusses EPA's screening analysis evaluating the potential impacts of the RFS standards for 2020, 2021, and 2022 on small entities. The Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute, unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities (referred to as a "No SISNOSE finding"). Pursuant to this requirement, EPA has prepared a screening analysis for this rule.

We conducted the screening analyses by looking at the potential impacts on small entities using five different approaches and compared the cost-to-sales ratio for each approach to a threshold of 1%. For our first approach and the one we consider to be most appropriate, we considered the annual RFS standards as a subset of the overall Renewable Fuel Standard program finalized in 2010[709] (RFS2); for the remainder of our approaches, we considered the annual RFS standards (including the 2022 supplemental standard) to be a separate action.[710] For our second approach, we compared obligated parties' cost of compliance (whether they acquire renewable identification numbers (RINs) by purchasing renewable fuels with attached RINs and blending these fuels into transportation fuel or by purchasing separated RINs) with the ability for the obligated parties to recover these compliance costs through higher prices for the gasoline and diesel fuel they sell than would be expected in the absence of the RFS program. Our remaining approaches are hypothetical worst-case scenarios assuming obligated parties do not recover the RFS compliance costs. Commenters have previously contended that the RIN value is not able to be passed through in the market and that RIN prices represent a net cost for compliance with the RFS program. However, based on our analysis of the data, the record does not support these claims.[711] Nevertheless, for our third and fourth approaches we assumed that obligated parties were unable to recover the cost of renewable fuels relative to petroleum-based fuels or the cost of acquiring RINs in the marketplace. Finally, for our last approach, we analyzed the specific situations of small refiners under the same assumption that RIN costs could not be passed through to consumers.

Viewed from the perspective of the first approach, the annual RFS standards impose no additional cost, since they simply represent the ongoing implementation of a program put into place in 2010. As can be seen in Table 11.1-1 below, all of the approaches that assume this rule is a separate action result in a cost-to-sales ratio of less than 1%. Therefore, EPA finds that these standards would not have a significant economic impact on a substantial number of small entities.

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709 75 FR 14670 (March 26, 2010).

710 Note that throughout the rest of this chapter that when we refer to the 2022 RFS standards, we are also including the 2022 supplemental standard.

711 "A Preliminary Assessment of RIN Market Dynamics, RIN Prices, and Their Effect," Dallas Burkholder, Office of Transportation and Air Quality, U.S. EPA. May 14, 2015.

Chapter 11.2 provides background on the RFA and this rule, including the regulated small entities. For each of the five approaches described above, Chapter 11.3 describes EPA's calculations of the costs of the rule, and Chapter 11.4 sets forth the cost-to-sales ratios. Chapter 11.5 concludes.

Table 11.1-1: Estimated Cost-to-Sales Ratios of the 2021 and 2022 RFS Standards

Approach	Screening Analysis Method	Cost-to-Sales Ratio	
		2021	2022
1	Cost as Part of RFS2 Rule	N/A	
2	Market Cost Recovery	0.00%	
3	Renewable vs. Petroleum Cost (No Cost Recovery)	0.01%	0.06%
4	Full RIN Price as Cost (No Cost Recovery)	0.24%	0.63%
5	Small Refiner-Specific (No Cost Recovery)	0.00% – 0.03%	0.04% – 0.24%

11.2 Background

11.2.1 Overview of the Regulatory Flexibility Act (RFA)

The RFA was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect those entities. The RFA requires us to carefully consider the economic impacts that our rules may have on small entities. The elements of the initial regulatory flexibility analysis accompanying a proposed rule are set forth in 5 U.S.C. § 603, while those of the final regulatory flexibility analysis accompanying a final rule are set forth in section 604. However, section 605(b) of the statute provides that EPA need not conduct the section 603 or 604 analyses if we certify that the rule will not have a significant economic impact on a substantial number of small entities.

11.2.2 Need for the Rulemaking and Rulemaking Objectives

A discussion on the need for and objectives of this action is located in Section I of the preamble. CAA section 211(o) requires EPA to promulgate regulations implementing the RFS program, and to annually establish renewable fuel standards that are used by obligated parties to determine their individual renewable volume obligations (RVOs).

11.2.3 Definition and Description of Small Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of the rule on small entities, a small entity is defined as: (1) a small business according to the Small Business Administration's (SBA) size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; or (3) a small organization that is any not-for-profit enterprise that is independently owned and operated and is not dominant in its field.

Small businesses (as well as large businesses) would be regulated by this rulemaking, but not small governmental jurisdictions or small organizations as described above. As set by SBA, the categories of small entities that would potentially be directly affected by this rulemaking are described in the table below.

Small Business Definitions		
Industry	***Defined as small entity by SBA if less than or equal to:***	***NAICS[a] code***
Gasoline and diesel fuel refiners	1,500 employees[b]	324110

[a] North American Industrial Classification System.

[b] EPA has included in past fuels rulemakings a provision that, in order to qualify for small refiner flexibilities, a refiner must also produce no greater than 155,000 barrels per calendar day (bpcd) crude capacity. See 40 CFR 80.1442(a).

EPA used the criteria for small entities developed by the Small Business Administration under the North American Industry Classification System (NAICS) as a guide. Information about the characteristics of refiners comes from sources including the Energy Information Administration (EIA) within the U.S. Department of Energy, oil industry literature, and previous rulemakings that have affected the refining industry. In addition, EPA found employment information for companies meeting the SBA definition of "small entity" using the business information database Hoover's Inc. (a subsidiary of Dun & Bradstreet). These refiners fall under the Petroleum Refineries category, 324110, as defined by NAICS.

Small entities that would be subject to this rulemaking include domestic refiners that produce gasoline and/or diesel. Based on 2020 EIA refinery data,[712] EPA believes that there are about 35 refiners of gasoline and diesel fuel subject to the RFS regulations. Of these, EPA believes that there are currently 8 refiners (owning 12 refineries) producing gasoline and/or diesel that meet the small entity definition of having 1,500 employees or fewer.

11.2.4 Reporting, Recordkeeping, and Other Compliance Requirements

Registration, reporting, and recordkeeping are necessary to track compliance with the RFS standards and transactions involving RINs. However, these requirements are already in place under the existing RFS regulations. While EPA is making minor revisions to the RFS requirements in this action, we do not anticipate that there will be any significant cost on directly regulated small entities.

11.3 Approaches to the Screening Analyses

This section concerns EPA's screening analyses performed for the 2020, 2021, and 2022 RFS standards only. However, prior to issuing our 2009 proposal for the general RFS regulatory program regulations required to implement the amendments enacted pursuant to the Energy Independence and Security Act of 2007, we analyzed the potential impacts on small entities of implementing the full RFS program through 2022 and convened a Small Business Advocacy

[712] Data available at https://www.eia.gov/petroleum/refinerycapacity/archive/2020/refcap2020.php.

Review Panel (SBAR Panel, or 'the Panel') to assist us in this evaluation. This information is located in the RFS2 rulemaking docket (Docket ID No. EPA-HQ-OAR-2005-0161). We believe that it is most appropriate to consider the annual RFS standards as a subset of the overall RFS2 program finalized in 2010. Viewed from that perspective, the 2020, 2021, and 2022 RFS standards impose no additional cost, since they simply represent the ongoing implementation of a program put into place in 2010. The annual rulemaking standards in fact reflect reductions from the statutory volumes that were evaluated in 2010. However, for the purposes of this screening analysis, we also estimated the costs of the 2020, 2021, and 2022 RFS standards relative to a "baseline" of the proposed 2020 RFS standards (i.e., the amount of biofuel actually used in 2020).

The changes between 2020 and 2022 in required volumes of the four categories of renewable fuel for which standards are established are shown in Table 11.3-1 below. In this table we have included volume increases that result from both the annual RFS volume requirements and the 2022 supplemental standard. In addition, we have also referenced in Table 11.3-1 the implied volumes of conventional renewable fuel (total renewable fuel minus advanced biofuel) and non-cellulosic advanced biofuel (advanced biofuel minus cellulosic biofuel) that may be used to satisfy the 2020, 2021, and 2022 RFS standards.

Table 11.3-1: Changes in RFS Standards from 2020 to 2022 (million RINs)[a]

	2020		2021		2022	
RFS Standard	**Proposed Volumes[b]**	**Δ**	**Proposed Volumes[c]**	**Δ**	**Proposed Volumes**	**Δ**
Cellulosic Biofuel	510	0	620	110	770	260
Biomass-Based Diesel (BBD)[d]	3,770	0	3,770	0	4,280	510
Advanced Biofuel	4,630	0	5,200	570	5,770	1,140
Non-Cellulosic Advanced Biofuel[e]	4,120	0	4,580	460	5,000	880
Total Renewable Fuel	17,130	0	18,520	1,390	20,770	3,640
Conventional Renewable Fuel[f]	12,500	0	13,320	820	15,000	2,500
Supplemental Standard[g]	n/a	n/a	n/a	n/a	250	250

[a] All volumes have been rounded to the nearest 10 million gallons, consistent with our practice in previous annual rules. Δ represents the change relative to the baseline of the proposed 2020 RFS standards.
[b] The 2020 BBD volume requirement was established in the 2019 final rule (83 FR 63704, December 11, 2018).
[c] The 2021 BBD volume requirement was established in the 2020 final rule (85 FR 7016, February 6, 2020).
[d] For ease of comparison, the BBD standards shown in this table are in ethanol-equivalent RINs, rather than physical volume. To convert from BBD volume to ethanol-equivalent RINs, a multiplier of 1.55 was used. See Section VIII.A of the preamble explaining our proposed change to the BBD conversion factor.
[e] Non-cellulosic advanced biofuel is not a fuel category for which a percentage standard is established but is calculated by subtracting the cellulosic biofuel applicable volume from the advanced biofuel applicable volume.
[f] Conventional renewable fuel is not a fuel category for which a percentage standard is established but is calculated by subtracting the advanced biofuel applicable volume from the total renewable fuel applicable volume.
[g] The 2022 supplemental standard is a total renewable fuel requirement and can be satisfied with RINs from any category. For the purpose of this analysis we have assumed that obligated parties use conventional renewable fuel RINs to satisfy their supplemental volume obligation.

As shown in Table 11.3-1, because we are using a baseline of the proposed 2020 RFS standards, there are no impacts of the proposed 2020 RFS standards themselves, and hence, regardless of the approach used, there are no costs on obligated parties. Therefore, for the remainder of this analysis, we have only considered the impacts of the 2021 and 2022 RFS standards.

We next considered various methods for estimating the cost of the 2021, and 2022 RFS standards to obligated parties (refiners of petroleum-based gasoline and diesel) using the baseline of the proposed 2020 RFS standards. If, as has been demonstrated, obligated parties recover the costs of RFS compliance through higher prices in the marketplace for the petroleum products they sell, there is no net cost to obligated parties. However, because various parties, including several small refiners, have continued to postulate that they are not able to recover the cost of RFS compliance in the marketplace, we also conducted sensitivity analyses making worst-case assumptions that ignore or discount the ability for the obligated parties to recover the costs of renewable fuels relative to petroleum-based fuels or the costs of RINs for RFS compliance. After estimating the costs using each of these methods, we compared the costs to the expected revenues from the sale of gasoline and diesel fuel in the U.S. using data from EIA.[713] Finally, we also estimated the cost-to-sales ratios for each of the 8 small refiners that are obligated parties under the RFS program using refinery-specific data under the assumption that they could not recover RIN costs.

11.3.1 Approach 1: Cost as Part of RFS2 Rule

We continue to believe that it is most appropriate to consider the impacts of the annual RFS standards on small businesses as a subset of the overall RFS2 program finalized in 2010, rather than as an unrelated or separate action. When viewed from this perspective, the 2021 and 2022 RFS standards are simply the ongoing implementation of a program finalized in 2010 and therefore add no additional burden. More precisely, to the extent the RFS2 program imposes any net costs on small entities, this rule only reduces net costs relative to the standards analyzed in the RFS2 rule. This is because the RFS2 rule considered the economic impacts of standards based on the statutory volumes, while this rule reduces those volumes using available statutory authorities, with corresponding reductions to the RFS standards.[714]

11.3.2 Approach 2: Market Cost Recovery Method

One way, and we believe the most appropriate way to consider the impacts of the 2021 and 2022 RFS standards on obligated parties if the 2021 and 2022 RFS standards are considered as a separate action, is to compare their cost of compliance with the ability for the obligated parties to recover these compliance costs through the higher prices for the gasoline and diesel fuel they sell that result from the market-wide impact of the RFS program. EPA has determined that while there is a cost to all obligated parties to acquire RINs, including small entities, obligated parties recover that cost through the higher sales prices they receive for the gasoline and diesel fuel they sell due to the market-wide impact of the RFS standards on these

[713] To project revenue from refiners and importers of gasoline and diesel, EPA used projected gasoline and diesel consumption and prices for 2021 and 2022 from the May 2021 STEO.
[714] Although the BBD standards in this action exceed the statutory minimum of 1.0 billion gallons, we do not expect any additional burden due to the BBD standard, as it is nested within the advanced biofuel standard and it is that standard that is driving BBD use.

products.[715] EPA has examined available market data and concluded that the costs of compliance with the RFS program are being passed downstream, as current wholesale gasoline and diesel prices generally enable obligated parties to recover the cost of the RINs.[716] When viewed in light of this data, there is no net cost of compliance with the RFS standards to obligated parities (cost of compliance with the RFS standards minus the increased revenue due to higher gasoline and diesel prices that result from implementing the RFS program). This is true whether obligated parties acquire RINs by purchasing renewable fuels with attached RINs or by purchasing separated RINs.

11.3.3 Approach 3: Renewable vs. Petroleum Cost Method (No Cost Recovery)

While there is no net cost of compliance with the RFS standards to obligated parties in Approach 2, there is an overall cost of the 2021 and 2022 RFS standards to society to the extent they require greater volumes of renewable fuel than in 2020 and to the extent that renewable fuels cost more than the petroleum fuels they displace. These costs, like all other costs associated with fuel production, are passed on to consumers through the pricing of fuels. However, under the extreme hypothetical that obligated parties are unable to pass along these costs, then another sensitivity analysis can be performed to estimate the cost of the 2021 and 2022 RFS standards. In this case, the cost of complying with the 2021 and 2022 RFS standards is estimated to be the difference between the cost of the production of renewable fuels (with associated RIN) and the cost of the petroleum-based fuel that is being replaced by the renewable fuel. In providing cost estimates for the 2021 and 2022 RFS standards, we estimated the cost per gallon (with the associated RINs) of CNG/LNG derived from biogas, soybean renewable diesel, conventional renewable diesel, and corn ethanol.[717] The estimated cost of these fuels, the estimated wholesale price of the petroleum-based fuels they replace, and the difference between the two is shown in Table 11.3.3-1 below.

[715] For a further discussion of the ability of obligated parties to recover the cost of RINs see “Denial of Petitions for Rulemaking to Change the RFS Point of Obligation,” EPA-420-R-17-008, November 2017.
[716] Id.
[717] See Chapter 9.4.

Table 11.3.3-1: Estimated Costs of Renewable Fuels and Petroleum-Based Fuels (Per Ethanol-Equivalent Gallon) in 2021 and 2022

Renewable Fuel	Per Gallon Cost		Price of Petroleum Fuel Displaced[a]		Cost Per Gallon of Renewable Fuel[b]	
	2021	2022	2021	2022	2021	2022
CNG/LNG Derived from Biogas[c]	$0.30	$0.25	$0.24	$0.24	$0.06	$0.01
Soybean Renewable Diesel	$3.51	$4.05	$1.857	$1.869	$1.65	$2.18
Corn Ethanol	$1.38[d]	$1.38[d]	$1.891	$1.801	($0.51)	($0.42)
Conventional Renewable Diesel	n/a	$2.79	n/a	$1.869	n/a	$0.92

[a] CNG/LNG derived from biogas displaces CNG/LNG derived from natural gas, corn ethanol displaces gasoline, and soybean renewable diesel and conventional renewable diesel displace diesel. Wholesale natural gas costs (Henry Hub Spot – dollars per million BTU) and wholesale gasoline and diesel prices are from EIA's May 2021 STEO.
[b] Costs per gallon may not exactly equal the difference between the per gallon cost of renewable fuels and the petroleum fuels they displace due to rounding.
[c] Costs for CNG/LNG derived from biogas are per ethanol-equivalent gallon. EPA used a conversion factor of 77,000 BTU per ethanol equivalent gallon to convert dollars per million BTU to dollars per ethanol equivalent gallon.
[d] For the purposes of this analysis, ethanol costs are expressed on a volumetric basis rather than an energy-equivalent basis as ethanol is blended at the wholesale level based on volume.

We next multiplied the projected biofuel increases (shown in Table 11.3-1) by the estimated cost for each ethanol-equivalent gallon of biofuel. The cost estimate for this approach is shown in Table 11.3.3-2 below.

Table 11.3.3-2: Total Estimated Cost of 2021 and 2022 RFS Standards Fuel Blending Method; Cost Per Gallon Basis

RFS Standard	Cost Per Ethanol-Equivalent Gallon of Renewable Fuel		Expected RIN Change		Total Estimated Cost (Million Dollars)	
	2021	2022	2021	2022	2021	2022
Cellulosic Biofuel	$0.06	$0.01	110	260	$6.6	$2.6
Non-Cellulosic Advanced Biofuel[a]	$1.65	$2.18	460	880	$447.3	$1,129.0
Conventional Renewable Fuel	($0.51)	($0.42)	820	2,500	($419.0)	($1,052.5)
Supplemental Standard[a]	n/a	$0.92	n/a	250	n/a	$135.4
Total	n/a	n/a	1,390	3,890	$34.9	$214.5

[a] To convert the cost per gallon of soybean renewable diesel we divided by 1.7, as each gallon of renewable diesel generates 1.7 RINs.

11.3.4 Approach 4: Full RIN Price as Cost Method (No Cost Recovery)

For another extreme hypothetical case, we estimated the RFS compliance costs if obligated parties acquired the RINs necessary for compliance by purchasing separated RINs and ignored the fact that these parties automatically recover the cost of the RINs they purchase through the higher market-wide prices they receive for the petroleum-based gasoline and diesel fuel they produce.[718] Using these assumptions, we estimated the total cost to obligated parties by multiplying the incremental change for 2021 and 2022 relative to the baseline of the proposed 2020 RFS standards for each type of RIN by the estimated RIN price. We once again note, however, that in doing so we are ignoring the fact that the obligated party recovers the cost of the RINs through higher prices received for the gasoline and diesel fuel that they sell, as discussed in Method 2. Because RIN prices can be impacted by a wide variety of different factors (including the prices of renewable fuels and petroleum-based fuels, oil prices, commodity prices, etc.), EPA is not able to project what RIN prices will be in the future. We can, however, use the average RIN prices over the last 12 months (through April 2021) as an estimate of RIN prices. We can use these estimates, along with the change in the 2021 and 2022 volumes relative to the baseline of the proposed 2020 RFS standards to estimate the cost of the 2021 and 2022 annual rule for parties that choose to meet their obligations by purchasing separated RINs. These calculations are shown in Table 11.3.4-1.

Table 11.3.4-1: Total Estimated Cost of 2021 and 2022 RFS Standards Full RIN Price Method

RFS Standard	RIN Type	Average RIN Price (May 2020 – April 2021)	Expected RIN Change (Million RINs)[a]		Total Estimated Cost to Obligated Parties (Million Dollars)	
			2021	2022	2021	2022
Cellulosic Biofuel	D3	$1.71	110	260	$188.1	$444.6
Non-Cellulosic Advanced Biofuel	D4	$0.73	460	880	$335.8	$642.4
Conventional Renewable Fuel	D6	$0.40	820	2,500	$328.0	$1,000.0
Supplemental Standard	D6	$0.40	n/a	250	n/a	$100.0
Total	n/a	n/a	1,390	3,890	$851.9	$2,187.0

[a] These expected changes reflect the nested nature of the RFS standards (i.e., each cellulosic biofuel RIN counts towards an obligated party's cellulosic biofuel, advanced biofuel, and total renewable fuel RVOs).

11.3.5 Approach 5: Small-Refiner-Specific Method (No Cost Recovery)

Using the same assumptions described above in Approach 4, we can estimate the actual change in the total cost of the 2021 and 2022 RFS standards to the 8 obligated parties that are small refiners. We once again note, however, that in doing so we are ignoring that they recover the cost of the RINs through the higher market-wide prices received for the gasoline and diesel fuel that they sell. This would then reflect the cost they would have to pay for compliance at the end of the year if they had spent the added revenue received from the higher gasoline and diesel prices for other purposes. Because RIN prices can be impacted by a wide variety of different factors (including the prices of renewable fuels and petroleum-based fuels, oil prices, commodity prices, etc.), EPA is not able to project what RIN prices will be in the future. We can, however, use the average RIN prices over the last 12 months (through April 2020) as an estimate of future RIN prices, as shown in Table 11.3.5-1.

[718] If parties were only able to recover a portion of their RIN acquisition costs, their expected costs would be somewhere between the costs calculated in Approach 2 and those calculated in Approach 4.

Table 11.3.5-1: Average RIN Prices and RFS Standards for 2020, 2021, and 2022[a]

RFS Standard	RIN Type	Average RIN Price (April 2020 – March 2021)	2020 Proposed Standard	2021		2022	
				Proposed Standard	Δ	Proposed Standard	Δ
Cellulosic Biofuel	D3	$1.71	0.34%	0.38%	0.04%	0.46%	0.12%
Biomass-Based Diesel	D4	$0.73	2.50%	2.30%	(0.20)%	2.54%	0.04%
Other Advanced Biofuel[b]	D5	$0.81	0.23%	0.50%	0.27%	0.42%	0.19%
Conventional Renewable Fuel[c]	D6	$0.40	8.29%	8.15%	(0.14)%	8.91%	0.62%
Supplemental Standard	D6	n/a	n/a	n/a	n/a	0.15%	0.15%

[a] Δ represents the change relative to the baseline of the proposed 2020 RFS standards. For purposes of this analysis, we are using the high end of the proposed range of percentage standards for 2020, 2021, and 2022. However, we note that the differences between the Δ of the high end of the proposed range vs. the Δ of the low end of the proposed range are negligible.
[b] Other advanced biofuel is not a fuel category for which a percentage standard is established, but is calculated by subtracting the cellulosic biofuel and biomass-based diesel standards from the advanced biofuel standard.
[c] Conventional renewable fuel is not a fuel category for which a percentage standard is established, but is calculated by subtracting the advanced biofuel standard from the total renewable fuel standard.

Using 2019 compliance data and small refinery hardship exemption petition materials where available, and assuming that the total gasoline and diesel production for each of these small refiners remains unchanged, we can also estimate their RVOs for 2020, 2021, and 2022. The difference between the estimated RVOs for each year multiplied by the estimated RIN price for each standard then gives us the estimated cost of the 2021 and 2022 RFS standards for each small refiner that chooses to meet their obligations by purchasing separated RINs. The actual calculations for each small refiner are provided in Chapter 11.6; a non-CBI example of these calculations is shown below in Tables 11.3.5-2 and 3.

Table 11.3.5-2: Example Small Refiner Costs Calculation for 2021

Company	Gas/Diesel Production (gal)	Cellulosic (D3)		BBD (D4)	
		Δ (RINs)	Cost ($)	Δ (RINs)	Cost ($)
Example	100,000,000	40,000	$68,400	(200,000)	($146,000)

Company	Other Advanced Biofuel (D5)		Conventional Renewable Fuel (D6)		Total Cost ($)
	Δ (RINs)	Cost ($)	Δ (RINs)	Cost ($)	
Example	270,000	$218,700	(140,000)	($56,000)	$85,100

Table 11.3.5-3: Example Small Refiner Costs Calculation for 2022

Company	Gas/Diesel Production (gal)	Cellulosic (D3)		BBD (D4)		Other Advanced Biofuel (D5)	
		Δ (RINs)	Cost ($)	Δ (RINs)	Cost ($)	Δ (RINs)	Cost ($)
Example	100,000,000	120,000	$205,200	40,000	$29,200	190,000	$153,900

Company	Conventional Renewable Fuel (D6)		Supplemental Standard (D6)		Total Cost ($)
	Δ (RINs)	Cost ($)	Δ (RINs)	Cost ($)	
Example	620,000	$248,000	150,000	$60,000	$696,300

11.4 Cost-to-Sales Ratio Results

The final step in our methodology is to compare the total estimated costs from each of the approaches above to relevant total estimated revenue from the sales of gasoline and diesel in the U.S. in 2021 and 2022. Since the RFS standards are proportional to the volume of gasoline and diesel produced by each obligated party, all obligated parties (including small refiners) are expected to experience costs (and recover those costs) to comply with the RFS standards that are proportional to their sales volumes. To calculate total revenue for all obligated parties we multiplied the total expected sales volume of gasoline and diesel used in the U.S. in 2021 and 2022 from the EIA's May 2021 STEO by the projected prices for each of these fuels. These calculations are shown in Table 11.4-1 below.

Table 11.4-1: Estimated Revenue from the Sale of Gasoline and Diesel in the U.S. in 2021[a]

Fuel Type	Projected Sales Volume (Billion Gallons)		Price Per Gallon		Total Revenue (Billion Dollars)	
	2021	2022	2021	2022	2021	2022
Gasoline	133.4	136.7	$1.891	$1.801	$252	$138
Diesel	57.6	59.9	$1.857	$1.869	$107	$60
Total	N/A	N/A	N/A	N/A	$359	$358

[a] Gasoline and diesel volumes and prices from EIA's May 2021 STEO.

For Approaches 1-4, we then divided the estimated costs from each of the methods by the total projected revenue for the sale of gasoline and diesel in the U.S. in 2021 and 2022. For Approach 5, we divided the estimated costs for each small refiner by its total estimated annual sales.[719] The resulting cost-to-sales ratios for each approach are shown in Table 11.4-2, along with a non-CBI example of these calculations for Approach 5 using the data from Tables 11.3.5-2 and 3.

Table 11.4-2: Estimated Cost-to-Sales Ratios of the 2021 and 2022 RFS Standards

Approach	Screening Analysis Method	Total Cost (Million Dollars)		Total Sales (Billion Dollars)		Cost-to-Sales Ratio	
		2021	2022	2021	2022	2021	2022
1	Cost Relative to the Statutory Baseline	Volume Reduction – No Net Cost		$359	$358	N/A	
2	Market Cost Recovery	$0		$359	$358	0.00%	
3	Renewable vs. Petroleum Cost (No Cost Recovery)	$34.9	$214.5	$359	$358	0.01%	0.06%
4	Full RIN Price as Cost (No Cost Recovery)	$851.9	$2,269.5	$359	$358	0.24%	0.63%
5	Small Refiner-Specific (Actual)[a]	--		--		0.00% – 0.03%	0.04% – 0.24%
	Small Refiner-Specific (Example)	$0.09	$0.70	$0.25	$0.25	0.03%	0.23%

[a] The actual calculations for Method 5 for each small refiner are provided in Chapter 11.6.

11.5 Conclusions

Based on our outreach, fact-finding, and analysis of the potential impacts of this rule on small businesses, we believe that there is no net cost to small refiners resulting from the RFS program. When considered as a subset of the overall RFS2 program finalized in 2010, the 2021 and 2022 RFS standards are simply the ongoing implementation of the program and therefore add no additional burden. Assuming a baseline of the proposed 2020 RFS standards, since obligated parties have been shown to recover their RFS compliance costs through the resulting higher market prices for their petroleum products, there are still no net costs of the rule on small businesses. However, we also conducted worst-case sensitivity analyses that ignored the fact that

[719] Estimated annual sales data gathered from Hoovers, Inc. (available at https://www.dnb.com/products/marketing-sales/dnb-hoovers.html) and small refinery hardship exemption petition materials.

obligated parties recover their costs. Under these extreme assumptions we were able to estimate costs (or savings) of this rule and then use a cost-to-sales ratio test (a ratio of the estimated annualized compliance costs to the value of sales per company) to assess whether the costs were significant. Costs were analyzed using the methods described above.

Under any of the five approaches, the cost-to-sales analyses indicated that all obligated parties, including the 8 small refiners, would be affected at less than 1% of their sales (i.e., the estimated costs of compliance with the rule would be less than 1% of their sales). The cost-to-sales percentages estimated using the various methods described in the previous section ranged from 0.00% to 0.63%. We note that these cost estimates assume the obligated parties, including small refiners, fully comply with the 2021 and 2022 RFS standards. To the degree that small refiners are granted exemptions from their obligations, their costs associated with the RFS program would be lower than projected in this chapter.

11.6 Small Refiner CBI Data

[Information Redacted – Claimed as CBI]