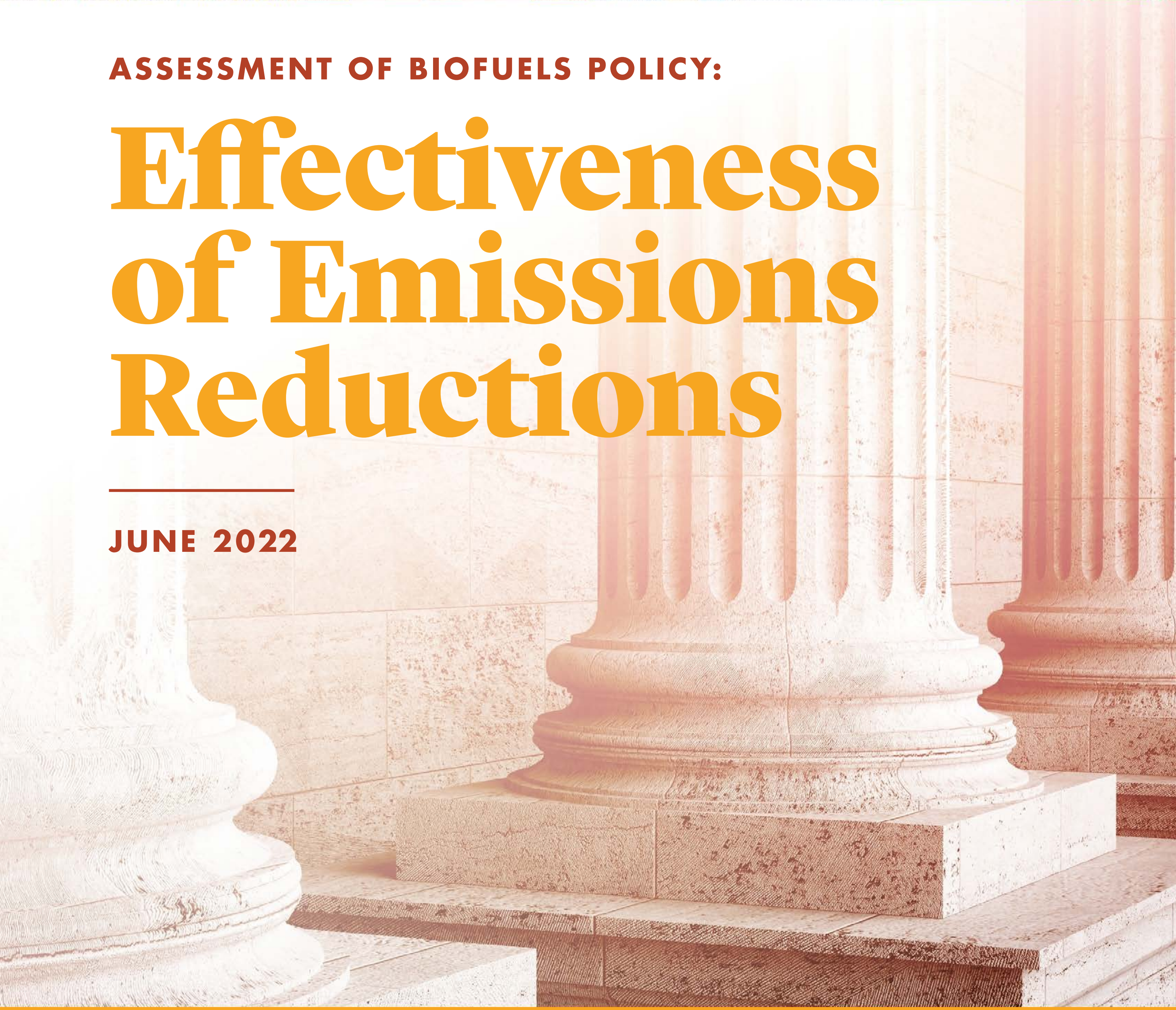
Fuels Institute

ASSESSMENT OF BIOFUELS POLICY:

Effectiveness of Emissions Reductions

JUNE 2022



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Contents

Executive Summary

Assessment of Biofuels Policy: Effectiveness of Emissions Reductions

Reducing emissions from the U.S. transportation section will be a challenge requiring the utilization of a range of solutions. Biofuels represent one of the most practical solutions to lowering U.S. transportation emissions in the near-term.

Corn-based fuel ethanol's carbon intensity (CI) is typically around 45% lower compared to gasoline and has reduced CO_2 emissions by about 75 million metric tons (MMT) in 2019 at its current blend rate of about 10% by volume.[1] An increase to a 15% blend by volume, E15, could save about 111 MMT of CO_2 emissions in 2022, but current regulations regarding ethanol storage compatibility and U.S. Environmental Protection Agency (EPA) limits on Reid vapor pressure during the summer practically prevent an expansion to E15, and the renewable fuel standard's mandated volumes have historically coincided with a 10% blend of ethanol by volume in gasoline.[2]

In the diesel pool, biodiesel and renewable diesel (RD) contributed about 23 MMT of emissions reductions in 2019, and RD's use is expected to increase substantially, owing to its ease of adoption in existing infrastructure and engines. Moreover, the increasing CI obligations of California's Low Carbon Fuel Standard (LCFS) are expected to increase refiners' appetite to blend RD in their diesel pool.

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[1] See the section in this report on "Fuel Ethanol"

[2] The Biden Administration has instituted an emergency waiver to allow E15 sales during the summer months 2022, but under 1.7% of retail stations currently offer E15 with a market share of about 2.5% of the gasoline pool.

However, the limited supply of feedstock available for biodiesel and RD production has increased costs significantly for both biofuel producers and other industries competing for these feedstocks. Therefore, assessing the viability of expanding support for RD as a source of future emissions reductions requires considering the relative cost effectiveness and potential disruption to other industries.

Currently, most biofuels and other alternative fuels are more costly than petroleum fuels absent governmental policy and generally have relied on support from governmental programs to expand their use and achieve emissions reductions. A major exception is ethanol, which can generally compete with gasoline. Corn ethanol has seen its CI reduced through technology and efficiency, and this trend is expected to continue through more sustainable farming practices as well as through carbon capture and sequestration (CCS) incentives such as Internal Revenue Code Section 45Q (IRC 45Q). Application of CCS to corn fuel ethanol production would address roughly one-third of the emissions associated with this biofuel, whereas the reduced application of fertilizer, herbicide, and insecticide can further reduce U.S. corn ethanol CI by 15% to 20%. A stronger focus on CI at the federal level has the potential to trigger U.S.-wide investment in such low-carbon corn ethanol and can further increase the positive climate impact biofuels have in the U.S.

Biofuels have helped to significantly reduce CO_2 emissions in the U.S. transportation sector and represent practical options for carbon emissions reduction today. Taken as a whole, the renewable fuel standard (RFS), blender's tax credit (BTC), and LCFS programs cost about $22.6 billion in 2019 while total U.S. emissions reductions from ethanol, biodiesel, and RD were just over 98 MMT, which is equal to about a $231/metric ton of CO2e emissions reductions in 2019.[3] While there are many other alternative fuel options, practicality, timeline, and costs should be considered when evaluating the best options to avert carbon emissions and their negative impact on the environment. Within this framework, fuel ethanol stands out as a promising means to achieve further emission reductions in the U.S. transportation sector. Current policy incentives make the adoption of low-carbon fuel ethanol likely in California and Oregon, and increased emphasis on CI in other state- or federal-level decarbonization policies can expand the wider uptake of low-carbon fuels in the U.S.

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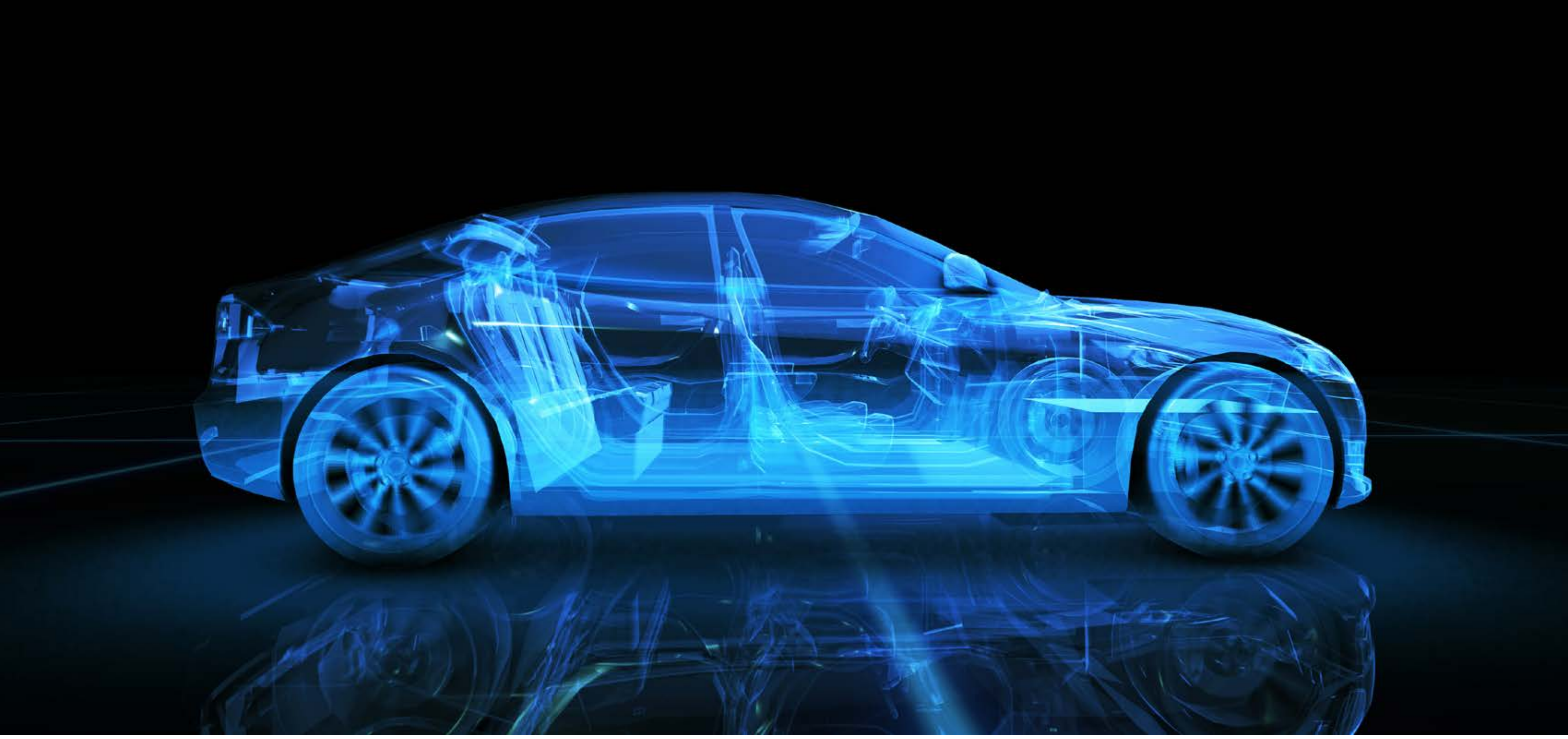
[3] See the section in this report on "Emissions Reductions from Policies and Costs"



Life Cycle Analysis

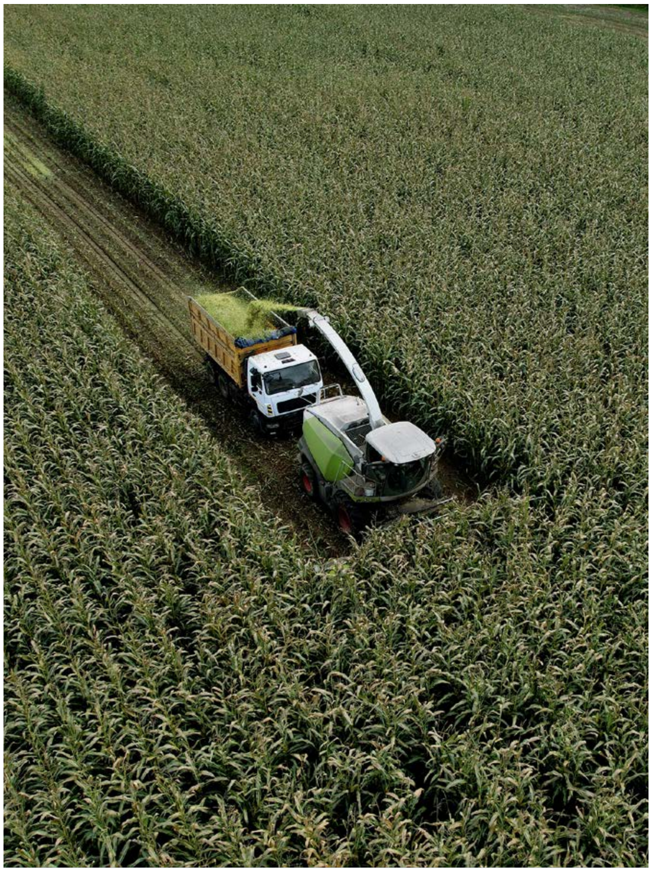
COMPARISON OF LIFE CYCLE ANALYSIS METHODOLOGIES

There are multiple ways to account for fuel emissions. The well-to-wheel approach is the most comprehensive method to calculate life cycle analysis (LCA) emissions of a given fuel as it considers emissions associated with the entire process, including well-to-tank (feedstocks, conversion, and distribution) and tank-to-wheel (tailpipe emissions). Even within the LCA framework, however, outcomes can differ significantly depending on the methodological model used. The U.S., Canada, and China borrow more from the Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) and GHGenius LCA models while in Europe, BioGrace and New EC are more influential.

In the U.S. market, the Department of Energy's Argonne National Laboratory (ANL) publishes CI ratings using the GREET model and makes these models available for public use. In addition, the California Air Resources Board (CARB) publishes its own CI ratings under the LCFS using a version of the GREET model to award LCFS credits. These CI ratings are generally sought out by producers of alternative fuels due to California's market size and the lucrative LCFS credits. However, many market observers contend that the CARB CI ratings are biased by requiring more stringent emissions data from biofuel pathways and less from electricity pathways. For this report, we have averaged the two ratings to provide a more objective view on carbon intensities for our emissions-reduction calculations.

CI scores for biofuels differ widely in the literature, even for similar feedstocks and production processes.[4] For example, for corn ethanol, some studies point to a range of 57 to 65 gCO2e/MJ while others go as high as 142 gCO2e/MJ or as low as 6 gCO2e/MJ.[5] Similarly, for soybean-based biodiesel, some authors estimated emissions to be between 187 and 257 gCO2e/MJ, others indicate a much lower 21 gCO2e/MJ, and more center-leaning studies point towards a range of 41 to 67 gCO2e/MJ.[6] Some of these variations can be explained by differences between the samples studied as emissions released change over time and depend on the dominant production processes in the specific region. That said, a significant share of the diverging CI scores described above can be attributed to mere methodological choices, such as the treatment of indirect land-use change.

When a piece of land is converted into a field for producing biofuel crops, it's relatively easy to calculate the difference in CI of the old land use versus that associated with growing the biofuel crops and thus account for the direct land-use change emissions. However, growing biofuels can also drive emissions arising from indirect land-use changes (ILUC). For example, if biofuels displace cattle, and the animals are instead put out to pasture on a piece of recently deforested land, the ILUC emissions will be high. Because waste products like used cooking oil (UCO) have neither direct nor indirect land-use change associated with them, their emissions are generally much more favorable than for crop-based biofuels. Despite those crop-based biofuels having been around for decades, there is still little consensus between or even within jurisdictions for accounting for ILUC.



The difficulty in accounting for ILUC emissions and methodological choices associated with ILUC are largely because of the diverging carbon intensities summarized above, as well as the need to assess changes in farming activity across the globe.[7] This can be exemplified by comparing California to Germany, the world's largest purely LCFS-driven markets.

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[4] Greenhouse gas emissions for biofuels are measured in grams (g) of CO2 equivalent per megajoule (MJ), or gCO2e/MJ.

[5] Jerome Dumortier et al., "Sensitivity of Carbon Emission Estimates from Indirect Land-Use Change." *Applied Economic Perspectives and Policy* 33, no. 3 (September 2011), retrieved from http://www.card.iastate.edu/products/publications/pdf/09wp493.pdf; Richard J. Plevin et al., "Greenhouse Gas Emissions from Biofuels' Indirect Land Use Change Are Uncertain but May Be Much Greater than Previously Estimated," *Environmental Science & Technology* 44, no. 21 (October 2010): 8015–8021, retrieved from http://pubs.acs.org/doi/pdf/10.1021/es101946t; and David Laborde Debucquet, *Assessing the Land Use Change Consequences of European Biofuel Policies* (Washington, DC: International Food Policy Research Institute, 2011).

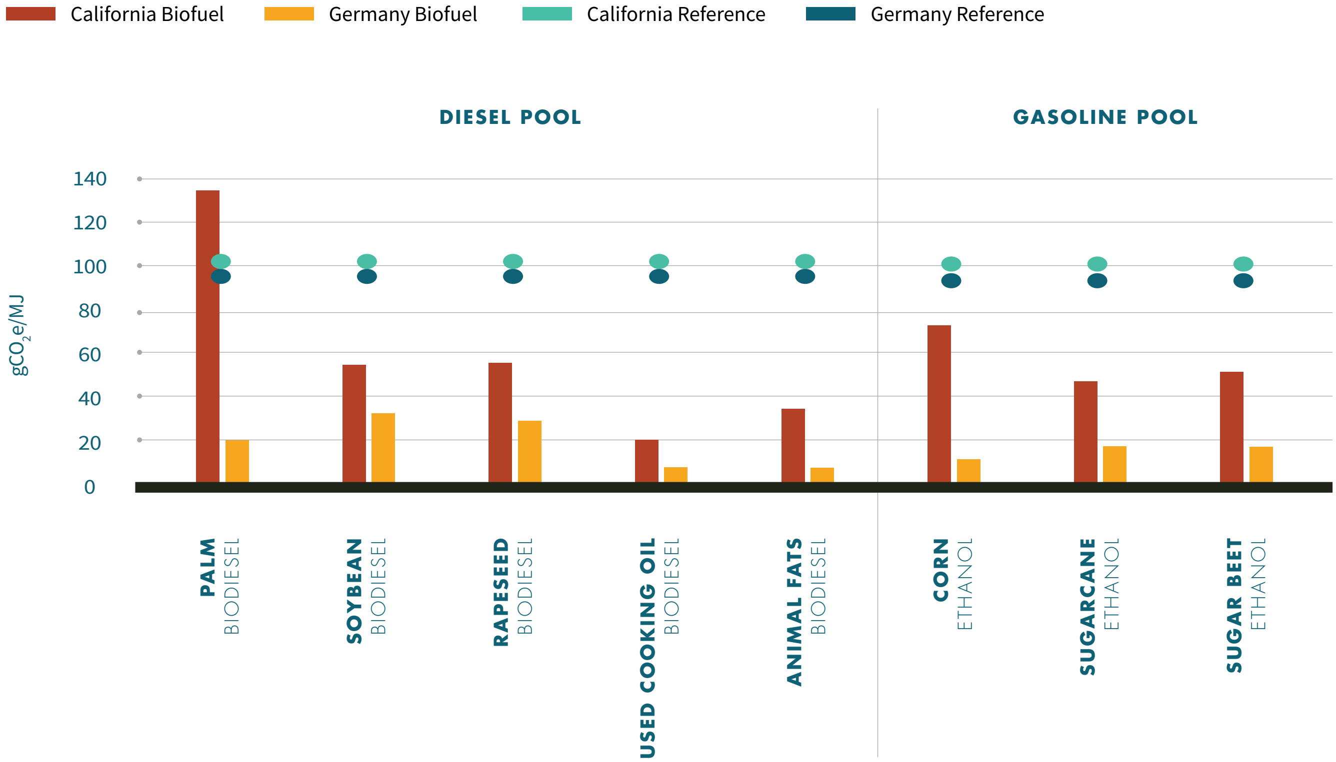
[6] Monica Padella et al., *Estimates of Indirect Land Use Change from Biofuels Based on Historical Data* (Ispra, Italy: Joint Research Centre, European Union Institute for Energy and Transport, 2015), http://doi.org/10.2790/3647; Adolf Acquaye et al., "Biofuels and Their Potential to Aid the UK Towards Achieving Emissions Reduction Policy Targets," *Renewable and Sustainable Energy Reviews* 16, no 7: 5414–5422, DOI:10.1016/j.rser.2012.04.046; and Uwe R. Fritsche, Klaus Hennenberg, and Katja Hünecke, "Sustainability Standards for Internationally Traded Biomass: The "iLUC Factor" as a Means to Hedge Risks of GHG Emissions from Indirect Land Use Change" (working paper, Öko-Institut, Energy & Climate Division, Darmstadt, Germany, July 2010), https://www.oeko.de/oekodoc/1030/2010-082-en.pdf.

[7] See Annex for a full overview by feedstock and biofuels from European Commission: Geert Woltjer et al., *Study Report on Reporting Requirements on Biofuels And Bioliquids Stemming from the Directive* (EU) 2015/1513 (Brussels, Belgium: Wageningen University & Research, Economic Research and Environmental Research; Netherlands Environmental Assessment Agency; and National Renewable Energy Centre, August 2017), https://ec.europa.eu/energy/sites/ener/files/documents/20170816_iluc_finalstudyreport.pdf.

While California factors in ILUC, Germany does not. As a result of this and other methodological differences (e.g., allocating co-products differently), almost identical products can have CIs that widely differ. Biodiesel from Southeast Asian palm oil that is reported as reducing emissions by 75% in Germany is not consumed at all in California because it scores worse than fossil diesel.[8] Sugarcane ethanol reduced emissions by over 50% in both geographies, but corn ethanol was seven times more carbon intensive in California (fossil reference fuels are comparable). Germany imports a lot of its UCO methyl ester (UCOME) from coal-dependent and distant China; California sources its used UCO domestically. Yet UCOME's CI is three times lower in Germany. (figure 1)

Political biases could play a role in explaining different methodologies, but they certainly do not tell the full story. Germany has strong rapeseed and sugar beet lobbies but not many vested palm oil or corn interests. Nevertheless, rapeseed biodiesel or sugar beet ethanol score worse than palm-based biodiesel or corn ethanol. There is not much rapeseed production in California, yet rapeseed/canola methyl ester (RME)'s CI is below average there and above average in Germany. At least part of the differences are random results of methodological choices. Global coordination in agreeing on one common framework could go a long way in avoiding arbitrary feedstock and product flows between jurisdictions and reaching emission reductions in the most cost-effective manner.

FIGURE 1: AVERAGE REPORTED CARBON INTENSITY SCORES IN 2019



Source: Stratas Advisors based on officially reported carbon intensities by CARB and Bundesanstalt für Landwirtschaft und Ernährung (Federal Agency for Agriculture and Food)

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[8] Bundesanstalt für Landwirtschaft und Ernährung, *Evaluationsund Erfahrungsbericht für das Jahr 2019: Biomassestrom-Nachhaltigkeitsverordnung, Biokraftstoff-Nachhaltigkeitsverordnung,* November 2020, https://www.ble.de/SharedDocs/Downloads/DE/Klima-Energie/Nachhaltige-Biomasseherstellung/Evaluationsbericht_2019.pdf?__blob=publicationFile&v=4.

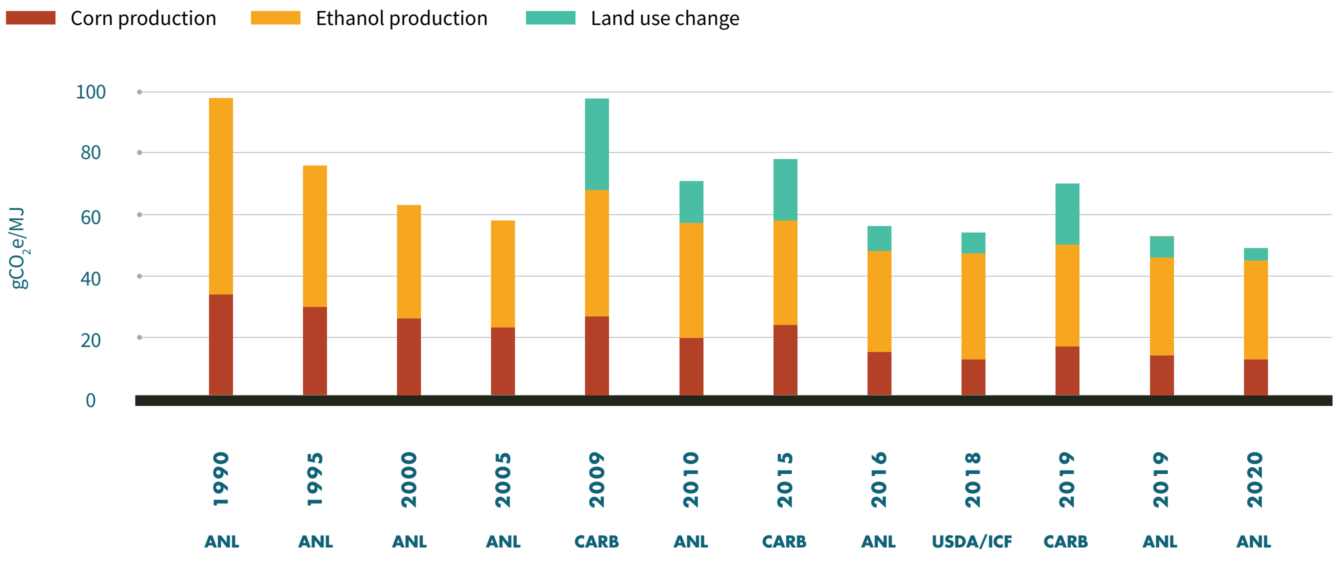
CURRENT AND EXPECTED FUEL-LEVEL CARBON INTENSITIES IN THE U.S.

FUEL ETHANOL

Ethanol is the most consumed renewable fuel in the U.S. (14.4 billion gallons in 2019); it has a market share in the gasoline pool just over 10%.[9] The overwhelming majority of ethanol consumed in the U.S. is from U.S. corn ethanol blended at just about 10% by volume in gasoline (E10).[10] Small volumes of higher blends are consumed by the small flex-fuel vehicle fleet, and California's LCFS attracts volumes of lower-CI sugarcane ethanol, mainly from Brazil. Ethanol's use is largely constrained by regulations that effectively prevent blends of ethanol beyond E10. Recent attempts, by industry groups and the current Administration, to implement E15 have been thwarted by court rulings on Reid vapor pressure limits during the summer months and an additional regulatory requirement to prove the compatible storage, labeling, and dispensing of ethanol blends above E10.[11] As corn ethanol is the most consumed alternative fuel that makes up a relatively large portion of the U.S. gasoline pool, any improvement in its CI or expansion of its use would have a large impact in further reducing emissions from the U.S. transportation sector.

Figure 2 illustrates changes in corn ethanol's CI ratings over the past years as well as differences between ANL and CARB's usage of the GREET model. Averaging the CARB and Department of Energy ratings gives a CI score of 53.3 gCO2e/MJ, representing a 45% reduction in CI versus gasoline's 96.6 gCO2e/MJ. This aligns with a recent study by Scully et al. that concluded a best current estimate of corn ethanol's CI at 51.4 gCO2e/MJ.[12] In all cases, the CI of corn ethanol has dropped significantly, although CARB's CI scores are still higher as a result of higher land-use change penalties.

FIGURE 2: U.S. CORN ETHANOL CARBON INTENSITY OVER TIME BETWEEN DIFFERENT MODELS



Source: Stratas Advisors

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[9] Stratas Advisors

[10] Ibid

[11] The Biden Administration has instituted an emergency waiver to allow E15 sales during the summer months 2022, but under 1.7% of retail stations currently offer E15 with a market share of about 2.5% of the gasoline pool.

[12] Melissa J. Scully et al., "Carbon Intensity of Corn Ethanol in the United States: State of the Science," *Environmental Research Letters* 16, no. 4 (March 2021), https://iopscience.iop.org/article/10.1088/1748-9326/abde08.

The displayed CI breakdown is slightly simplified in the figure; corn production also includes the net benefit of corn ethanol's by-products as well as feedstock transportation.

There is significant potential for additional improvements in corn ethanol's CI, both on the feedstock production and fuel production sides. On the feedstock side, CARB and the Oregon Department of Environmental Quality are now allowing individual farms to submit an evaluation of their production practices to market their corn or other feedstocks to ethanol producers as low-CI, which will contribute to lowering the overall ethanol CI score. Farming energy, fertilizers, and chemicals used during agricultural production contributes about 40% of ethanol's CI. The possibility of individual farms submitting pathway applications can potentially allow for additional greenhouse gas (GHG) savings from fuel ethanol and other crop-based biofuels. Farmers who use less fertilizer, herbicides, and insecticides could sell their low-CI feedstocks to fuel ethanol producers, who could then benefit from a lower CI score, translating into a higher subsidy value in California and Oregon. A recent study by ANL surveyed the farming practices of 71 corn growers in South Dakota and found that the emissions of the most carbon-efficient grower were roughly one-fourth of the least efficient grower (118.6 gCO_2e/kg versus 407.5 gCO2e/kg).[13]

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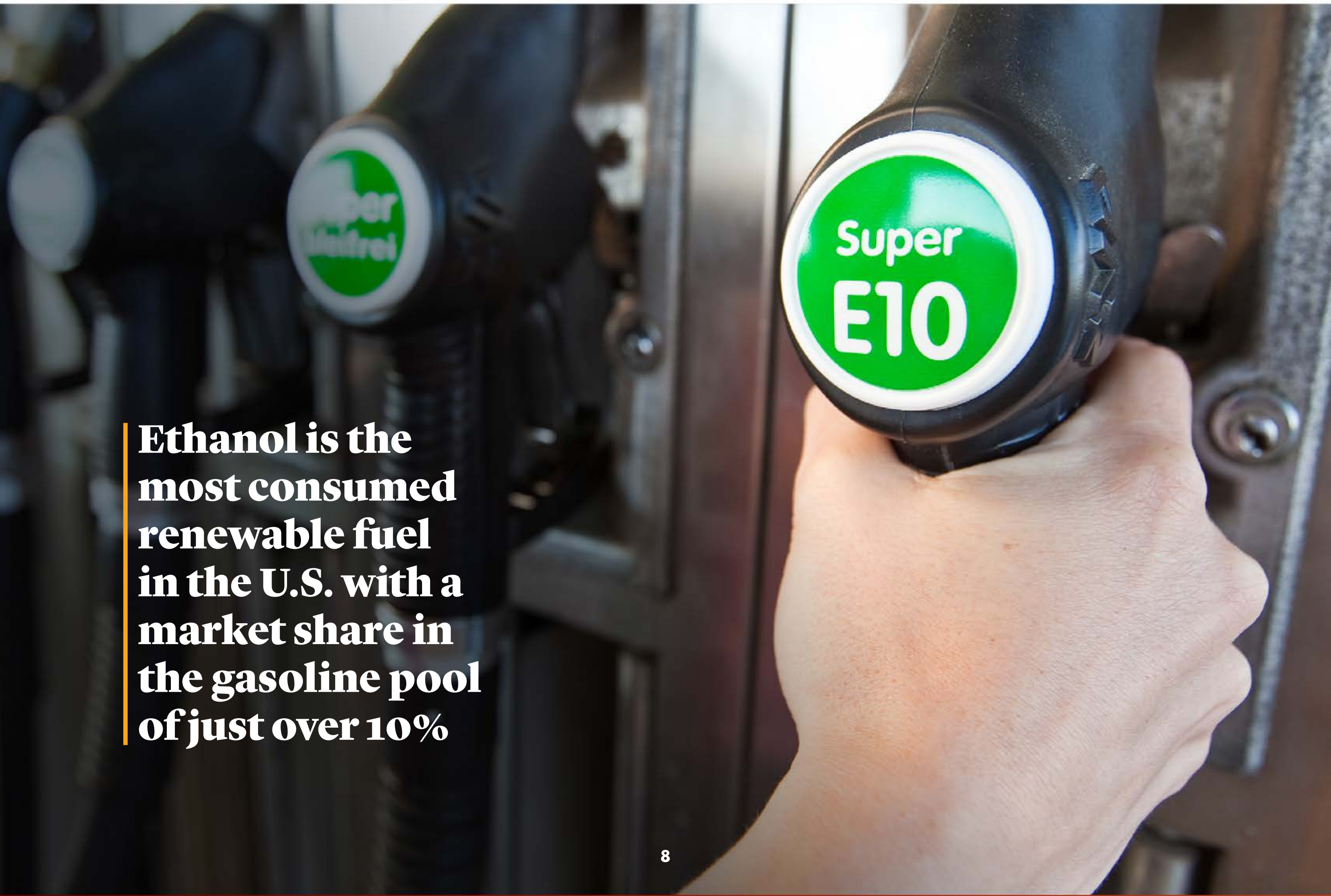
[13] M. Wu, M. Wang, J. Liu, and H. Huo, *Life-Cycle Assessment of Corn-Based Butanol as a Potential Transportation Fuel* (Washington, D.C., Argonne National Laboratory, November 2007): 32, https://afdc.energy.gov/files/u/publication/Argonne_Butanol_Paper.pdf.



Ethanol is the most consumed renewable fuel in the U.S. with a market share in the gasoline pool of just over 10%

Ethanol production contributes about 43% of fuel ethanol's CI.[14] Ethanol producers are investing heavily in CCS technology and utilizing green energy to reduce the emissions from ethanol production and lower the fuel's CI while also generating tax credits under IRC 45Q. Ethanol industry groups are targeting zero CI or negative CI ethanol by 2050, but much of the CI reduction is expected within the next decade as CCS projects race to meet the 2026 cutoff for 45Q credits and receive more LCFS credits from lower-CI ethanol.[15]

During the ethanol production process, about one-third of the corn kernel is converted into ethanol, one-third into corn meal, and one-third is released as CO_2.[16] CCS technology investments aim to capture and sequester these CO_2 emissions, which are considered biogenic and do not contribute to the CI. This will provide a negative CI for this step of the lifecycle analysis and thus lower the CI of corn ethanol. One of the many recently announced CCS projects is a $4.5 billion investment in the Midwest Carbon Express. It is expected to be the single largest CCS project in the world, connecting more than 30 ethanol plants and capturing about 12 million tons of CO_2 per year.[17] Current announced CCS ethanol production projects would reduce CO_2 emissions by about 32 MMT per year if completed. For context, about 48 MMT of CO_2 were released from producing about 16 billion gallons of ethanol production in 2019.[18] CCS is expected to lower ethanol's CI by about 25 gCO2e/MJ, which would give U.S. corn ethanol a lower CI score than imported sugarcane ethanol as well as most biodiesel and RD under CARB. This reduction of ethanol's CI will likely lead to an elimination of Brazilian ethanol imports unless or until Brazilian sugarcane ethanol reduces its CI. Brazilian ethanol production is expected to follow in CCS investments to maintain their export volumes and capture more credits under their own, domestic low-carbon fuel program, RenovaBio.[19] According to research by the International Energy Agency, the total costs of capturing and storing 1 MT of CO_2 from the fuel ethanol production process would be between $15 and $30.[20]

BIODIESEL

Biodiesel, also referred to as fatty acid methyl ester (FAME), is currently the second-most consumed biofuel in the U.S. with a market share of about 2.8% of the total diesel pool and a volume of 2.4 billion gallons in 2019.[21] Biodiesel is made from the transesterification of oils such as vegetable oils and animal fats, is commonly sold in blends of 5% by volume in diesel fuel (B5), and has an effective maximum blend of B20 without engine modifications. However, volumes of B20 remain under 1% of those of B5 as it is mainly confined to Midwestern states and California with incentives for its use.[22] Biodiesel's market share is likely to peak in 2021 at about 3.5% by volume and decrease thereafter as feedstock prices rise due to an increase in the more lucrative production of RD, which is chemically almost identical to petroleum diesel and can be blended in higher percentages.

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[14] Ibid

[15] Stratas Advisors

[16] Ibid

[17] Des Moines Register, *Terry Branstad: Carbon-capture investments will drive economic growth in rural Iowa and beyond*, accessed August 25, 2021 https://www.desmoinesregister.com/story/opinion/columnists/iowa-view/2021/07/04/carbon-capture-investments-drive-rural-economic-growth/7819597002/

[18] Stratas Advisors

[19] Ibid

[20] IEA, *Is carbon capture too expensive*, February 17, 2021, accessed August 26, 2021 https://www.iea.org/commentaries/is-carbon-capture-too-expensive

[21] Stratas Advisors

[22] Ibid

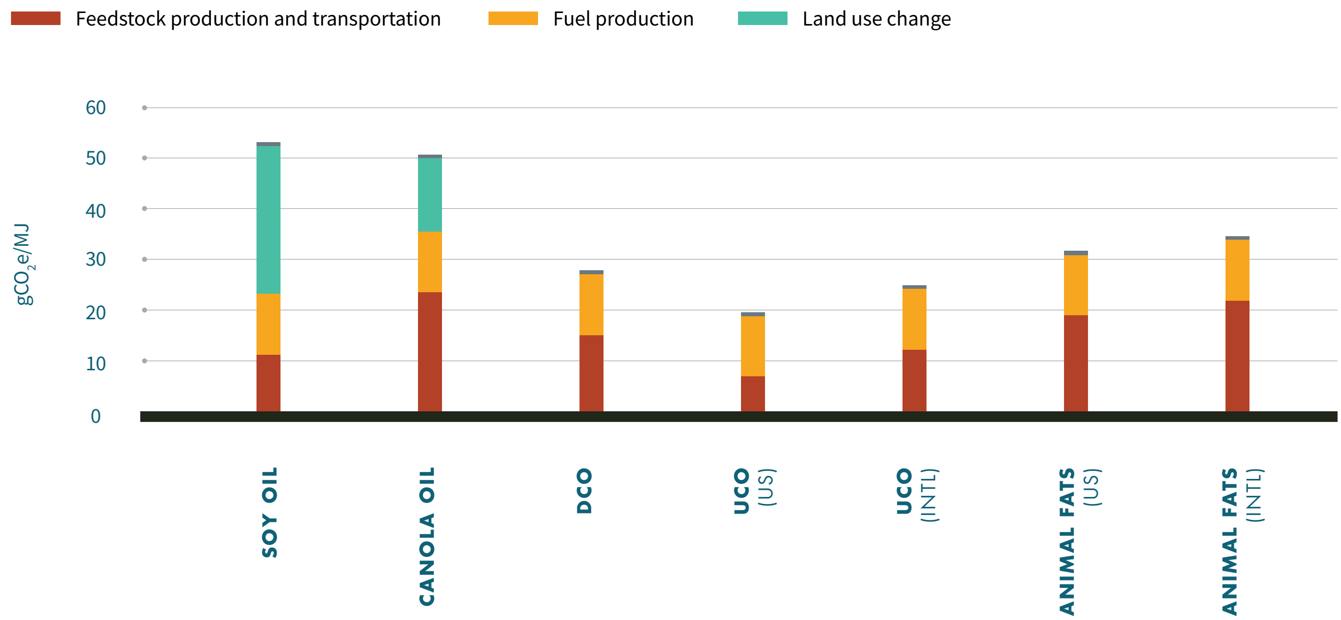
RENEWABLE DIESEL

RD, including hydrotreated vegetable oil (HVO), uses the same feedstocks as biodiesel but with a different production process that generates a fuel almost identical to petroleum diesel and can be used as a "drop-in" fuel replacement. This advantage of RD has led to a rapid growth in its adoption in regional low-carbon fuel markets and a flurry of production investment announcements. In 2019, RD had a market share of about 1.2% of the total U.S. diesel pool at about 0.73 billion gallons.[23] Most of this demand comes from California, where RD has a market share of about 16.3%.[24] This market share in California is expected to reach over 40% by 2024 due to the incentives and obligations of the LCFS program.[25]

RD's CI depends on a number of factors, mostly regarding feedstock use and plant location. As shown in Figure 3, so-called waste feedstocks, including UCO, animal fats, and distiller's corn oil, benefit from the fact that they are not allocated a land-use change penalty in the GREET model used for these calculations. The opposite is true for crop feedstocks such as soy oil and canola oil. As a result, RD producers have been scrambling to secure access to waste feedstocks because the RD produced from this offers higher margins.

Unlike during ethanol fermentation, CCS technology cannot capture direct CO_2 emissions from the production of biodiesel and RD and lower the carbon intensity. However, potential CI reductions can come from improving hydrogen production, which is an important input to most RD production processes. Farming practices and process energy use are expected to become less carbon intensive as sustainable and lower emission farming practices are increasingly rewarded and cleaner energy sources become more available. However, biodiesel and RD

FIGURE 3: RENEWABLE DIESEL— CARBON INTENSITY PER FEEDSTOCK



Source: Stratas Advisors

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[23] Stratas Advisors

[24] Ibid

[25] Ibid

feedstocks are more prone to impacting land-use changes, especially ILUC in the global market for feedstocks. Global soy oil and palm oil production have been heavily linked with deforestation, and the rise in prices for all these commodities from the increase in RD production will indirectly incentivize more deforestation. While U.S. soy oil does not present much deforestation risk and palm oil has largely been shunned by the biodiesel and RD industries in the U.S., the increasing competition for feedstocks will likely create more cases of feedstock fraud and push other end users, such as food and cosmetic producers, to the feedstocks with significantly higher CIs. In addition, RD and other biofuels are mostly transported to California by rail or ship, further increasing the fuel's CI depending on the plant location and transport infrastructure.

RENEWABLE SYNFUEL APPLICATIONS (HYDROGEN FUEL CELLS)

Application of renewable synthetic fuels in the road, marine, and aviation sectors is currently very limited. Green and blue hydrogen for immediate use in fuel cells also plays a marginal role in these transportation sectors. Development of synthetic fuels is dependent on installed capacities of sustainable hydrogen as it is a main component for production via water electrolysis. By 2022, the total installed capacity of renewable hydrogen electrolyzers is expected to account for about 2.5 gigawatts, and thanks to carbon-capture technology, blue hydrogen capacity would constitute around 3 gigawatts globally. This represents less than 1% of the total installed hydrogen production capacity.[26]

Application of fuel cells and thus hydrogen in road transport has seen an uptick in recent years as the number of new fuel cell vehicles nearly doubled in the last two years, although there are still only approximately 30,000 total vehicles globally.[27] Renewable synthetic road fuels such as gasoline and diesel are being produced as part of demonstration or small-scale projects with limited production capacity. Most announced synfuel projects have targeted aviation and shipping, as electrification is not a viable option in these sectors. Stratas Advisors expects volumes of renewable synthetic fuels in the fuel mix to remain marginal compared to biofuels in the next decade.

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[26] Stratas Advisors

[27] Ibid

RENEWABLE GASOLINE

Renewable gasoline, also called bio naphtha or renewable naphtha, is obtained as a by-product of RD production. Like RD, renewable gasoline is a drop-in fuel and can be blended in higher proportions more easily than ethanol. In addition, renewable gasoline's energy content is more in the range of gasoline, which makes it a suitable replacement from a chemical perspective. Renewable gasoline yields are typically around 0.005 gallon per gallon of tallow-based RD produced.[28,29] For feedstocks that are higher in free fatty acids, like pine oil or certain palm oil derivatives, the yields of renewable gasoline can be up to 0.08 gallon per gallon of RD produced.[30] However, U.S. RD producers typically rely on low free fatty acids feedstocks, meaning that renewable gasoline supply will likely not reach the levels necessary to have a meaningful impact on the decarbonization of the U.S. gasoline pool.

Renewable gasoline's CI depends mostly on the feedstock used, and the CI score will be the same as for RD and renewable propane that is produced from the same feedstock, in the same facility.

R80B20

In 2018, CARB approved the sales of a new renewable fuel blend consisting of roughly 80% RD and 20% biodiesel.[31] In most cases, 0.1% of fossil diesel will also be added to guarantee the fuel's eligibility for the BTC. Renewable Energy Group, one of the most prominent suppliers of this blend, is cooperating with 19 truck stop operators around California to offer R80B20. Other than Renewable Energy Group, there has been limited movement around R80B20, and the impact this blend has on overall biofuels demand is very modest as a result.[32] As California moves to increase RD blending, however, R80B20 may become a more popular fuel with retailers.

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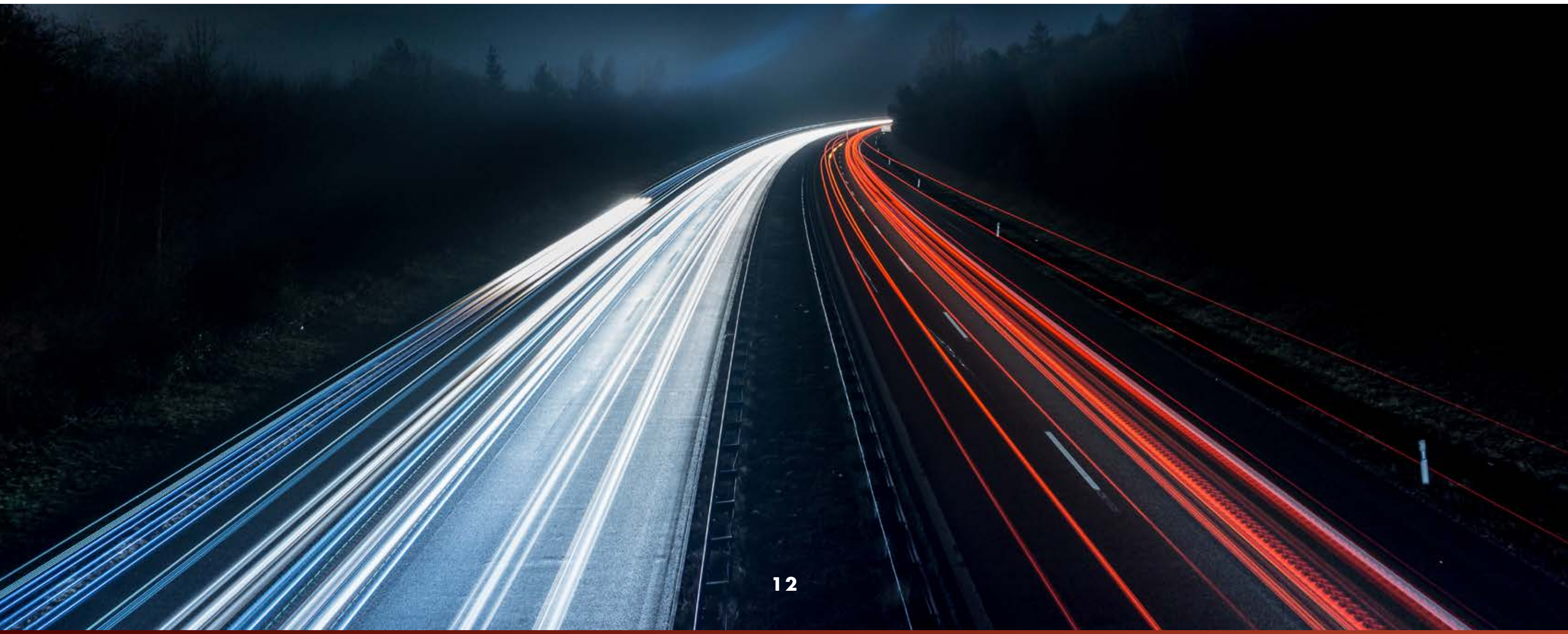
[28] Neste, *Neste Singapore Renewable Diesel: Pathway Description*, June 4, 2021, available at https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0179_report.pdf.

[29] Yields can be even higher if the RD production facility changes its configuration to produce more sustainable aviation fuel (SAF), but RD production is expected to be prioritized for the next decade. (Stratas Advisors)

[30] Jaakko Nousiainen, Petri Kukkonen, Jari Kotoneva, Teemu Lindberg, and Timo Äijälä, Process for Producing Hydrocarbons from Crude Tall Oil and Tall Oil Pitch, international publication number WO 2015/055896 (European Patent Office), filed October 16, 2014, published April 23, 2015, https://data.epo.org/publication-server/document?iDocId=5781685&iFormat=2.

[31] California Air Resources Board, CalEPA Fuels Guidance Document, accessed August 8, 2021 https://ww2.arb.ca.gov/sites/default/files/2018-10/CalEPA_Fuels_Guidance_Document_10-2-18.pdf

[32] Stratas Advisors



Current and Proposed Policy Environment

FEDERAL-LEVEL POLICIES

RENEWABLE FUEL STANDARD

The U.S. has the largest biofuels market of any nation-state in the world. The market is promoted and incentivized by federal regulation, mainly the RFS, and state regulations, namely the LCFS in California and some similar measures passed by smaller states. Much of the RFS' renewable volume obligations (RVOs) are met through domestically produced E10 ethanol blends and B2 and B5 biodiesel blends that produce renewable identification numbers (RINs).[33] RINs are generated and attached to biofuels domestically produced or imported. The RIN can be separated and sold once the fuel has been blended with transportation fuel, heating oil, or jet fuel. These RIN credits can be bought and sold in an open market to fulfill obligations and support biofuel producers.[34]

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[33] Stratas Advisors

[34] "Overview for Renewable Fuel Standard", U.S. Environmental Protection Agency, accessed August 18, 2021, https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard.

US biofuel mandates usually involve a proposed volume or percentage of specific biofuels needed to be blended, as under the RFS, or set an overall mandated GHG reduction percentage, and then the market is left to comply with the reduction, as under the California LCFS and Oregon Clean Fuels Program (CFP). (table 1)

RFS RVOs are expressed in terms of a volume percentage of gasoline and diesel sold or introduced into U.S. commerce and consist of a single applicable percentage that applies to all categories of refineries, blenders, and importers. The RVOs are calculated by dividing each RFS target by the total estimated supply of nonrenewable gasoline and diesel fuel in each year that the Energy Information Administration provides to the EPA.

Refiners and importers that supply gasoline or diesel for the 48 contiguous states plus Hawaii (Alaska has not opted in yet) are responsible for complying with the RFS and must show that a required volume of renewable fuel is used—their RVO—to meet the RFS. The required volume is determined by multiplying their annual gasoline and diesel production (both highway and non-road) by a percentage standard specified by the EPA. This means the agency takes the applicable volume for a particular year, converts it to a percentage of gasoline and diesel production, and then determines a party's individual obligation based on this percentage and the total gasoline and diesel production or import volume in a calendar year.

TABLE 1: US ACTIVE LOW CARBON FUEL PROGRAMS

JURISDICTION	BIOFUEL TYPE	MANDATE TYPE	2020	2021	2022	2030
Nationwide	Biomass-based diesel	Billion gallons	2.43*	2.43*	2.76*	TBD
Nationwide	Overall	Billion gallons	17.13*	18.52*	20.77*	TBD
California	Overall	GHG reduction percentage	7.5	8.75	10	20**
Oregon	Overall	GHG reduction percentage	2.5	3.5	5	20

* *Current proposed volume requirements by EPA*

** *CARB announced plans to propose increased GHG reduction targets*

TABLE 2: RFS CATEGORIES AND RIN CODES

RIN CODE	APPLICABLE CATEGORY	EXAMPLE	MINIMUM GHG REDUCTION
D3 or D7	Cellulosic Biofuel	Cellulosic Ethanol	60%
D4	Biomass-Based Diesel	Biodiesel, Renewable Diesel	50%
D5	Advanced Biofuel	Sugarcane Ethanol	50%
D6	Renewable Fuel	Corn Ethanol	20%

Source: EPA

When Congress passed renewable fuels legislation and the EPA issued the rulemaking implementing the original RFS in 2007, the agency established the RIN system to allow obligated participants (refiners and fuel formulators) the option to buy biofuel credits from parties that could over-comply with actual renewable fuel volumes.[35] The EPA used a typical compliance framework with a self-reporting system in which biofuels producers transferred RINs with biofuels sales. Building off the framework, the RIN unit is equal to the energy content in one gallon of ethanol. In the case of biodiesel, one gallon is valued at 1.5 RINs; RD can be either 1.6 or 1.7 RINs. (table 2)

The total volume requirement of the RFS is broken into two major categories based on the biofuel's GHG emissions versus a petroleum-equivalent baseline. The minimum qualifying "renewable fuels" for the RFS2 must have a 20% GHG reduction over their petroleum counterparts, and the specialized "advanced biofuels" must reduce GHG production by at least 50%. Corn-based ethanol, the most widely used biofuel in the U.S., currently only qualifies for the "renewable fuels" portion of the mandates and is explicitly excluded from qualifying as an advanced biofuel, D5 RIN.[36] Biodiesel and RD made from palm oil do not qualify for D4 RIN generation because they do not meet EPA's threshold for GHG emissions reductions of 50% compared to the baseline diesel fuel. All obligated parties must acquire enough RINs to comply with their individual volume obligation and can trade RINs as credits. The annual rulemaking by the EPA can change the mandate schedule as set in the RFS.

In addition, the EPA authorized an "eRIN" pathway for electric vehicle (EV) charging from biogas in 2014, but to date the EPA has not approved any eRIN pathway applications. There is a debate over whether the producer of the renewable electricity or the distributor should receive the eRIN, and the EPA has yet to decide on the topic.[37] An approval of eRIN pathways to generate D3/D7 RINs would likely depress D3/D7 prices, hurting biogas and cellulosic biofuel producers unless the EPA expands the D3/D7 submandate to limit the effect on the D3/D7 RIN price.

Cellulosic biofuels, ethanol, and diesel made from the stringy plant fiber of a plant have struggled to become commercially viable, and only about 15 million gallons of such fuels were consumed in 2019. As such, the EPA offers cellulosic waiver credits (CWC) for purchase that can be combined with a D5 RIN to meet a D3/D7 RIN obligation. In addition, biogas can also generate D3 RINs.[38]

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[35] "Overview for Renewable Fuel Standard"

[36] Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program, Subpart M - Renewable Fuel Standard, 75 FR 14863, March 26, 2010, as amended at 85 FR 78467, December 4, 2020, https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-80/subpart-M.

[37] Jarrett Renshaw and Stephanie Kelly, "White House Asks EPA to Study How EVs Can Generate Renewable Fuel Credits," Reuters, April 1, 2021, https://www.reuters.com/article/us-usa-biden-biofuels-exclusive-idUSU.S.KBN2BO57H.

[38] "Overview for Renewable Fuel Standard"

The Trump administration hampered much of the biofuel industry by expanding Small Refinery Exemptions (SREs) that decreased the actual RVOs required to be met by the market, lowering biofuel demand and depressing RIN credit prices. With the change in administration, RIN prices increased and then dropped on reports that the 2021 and 2022 RVOs were going to be lowered.[39] The official announcement in December of the 2021 and 2022 RVOs and a retroactive lowering of the 2020 RVOs had a small downward effect on RIN prices as they were largely in-line with the earlier reports from August. In addition, strong biofuel feedstock prices, an increase for the 2022 RVO and the EPA proposing to deny all 65 pending small refinery exemptions (SREs) are also expected to support RIN prices in the near-term if upheld.[40] However, drafts of the Biden administration's touted Green New Deal only mention biofuels as mere "transition fuels" and the Biden administration has pushed for the electrification of the vehicle fleet through executive orders and legislative proposals.[41] This electrification shrinks the transport fuel pools and potential biofuel market in the U.S. (table 3)

Refiners and importers of gasoline and diesel generally bear the costs of compliance under the RFS because they are designated as obligated parties that must purchase the renewable fuel to obtain their designated RVO volumes of RINs or purchase RINs directly in the market if they did not purchase enough biofuels to meet their RVO. However, numerous studies have found these obligated parties generally pass along the costs of compliance to the consumer to recoup the costs of the RINs.[42]

Estimating the cost of the RFS as a program is complicated given the various fuel categories, mandate adjustments, and passing of compliance costs through the supply chain. At the top of the supply chain, U.S. crop farmers and ethanol producers generally receive the benefits of the RFS subsidies as the prices for their products have increased because of the program. The benefit to the U.S. agriculture sector is said to be about

TABLE 3: RFS RENEWABLE VOLUME OBLIGATIONS (RVOS)

RENEWABLE FUELS**** (ethanol equivalent billion gallons)
Numbers in parentheses are final rulemaking volumes after EPA adjustment

YEAR	ADVANCED BIOFUELS				ADDITIONAL RENEWABLE FUELS	TOTAL**
	CELLULOSIC BIOFUELS	BIOMASS-BASED DIESEL	ADDITIONAL ADVANCED BIOFUELS	TOTAL ADVANCED	CONVENTIONAL BIOFUELS	
2019	8.5 (0.418)	1.5* (3.15)	3.0 (1.352)	13.0 (4.92)	15.0 (15.0)	28.0 (19.92)
2020	10.5 (0.51)	1.5* (2.43)	3.0 (2.2)	15.0 (4.63)	15.0 (12.5)	30.0 (17.13)
2021	13.5 (0.62)	1.5* (2.43)	3.0 (2.77)	18.0 (5.2)	15.0 (13.32)	33.0 (18.52)

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[39] Reuters, *Biden administration mulls big cuts to biofuel mandates in win for oil industry*, accessed August 6, 2021 https://www.reuters.com/business/energy/exclusive-us-epa-considering-cuts-biofuel-blending-obligations-2020-2021-2022-2021-09-22/

[40] Stratas Advisors

[41] "The Biden Plan for a Clean Energy Revolution and Environmental Justice," Democratic National Committee, accessed August 9, 2021, https://joebiden.com/climate-plan/.

[42] Christopher R. Knittel, Ben S. Meiselman, and James H. Stock, "The Pass-Through of RIN Prices to Wholesale and Retail Fuels under the Renewable Fuel Standard," *Journal of the Association of Environmental and Resource* 4, no. 4 (2017), available at https://scholar.harvard.edu/files/stock/files/knittel_meiselman_stock_jaere_2017.pdf.

$14.1 billion a year, a rough proxy for the cost of the RFS program.[43] The higher feedstock prices support the U.S. agriculture industry but also raise prices for consumers, including international consumers as the U.S. has a large volume of agricultural exports.

NEXT GENERATION FUELS ACT OF 2021

As an example of efforts to expand market opportunities for biofuels, Congress introduced legislation for higher blends of ethanol in 2021.[44] The Next Generation Fuels Act of 2021 would establish high-octane (95 and 98 RON) certification test fuels and supports ethanol blends of up to 30% by volume while requiring automobile manufacturers to design and warrant their vehicles for the use of these fuels beginning with model year 2026. The bill would also include a low-carbon requirement, specifying that the source of the octane boost must reduce lifecycle GHG emissions by an average of at least 40% compared to a 2021 gasoline baseline, as measured by the Department of Energy's GREET model. The legislation also includes a restriction on the aromatics content of gasoline, ensures parity in the regulation of gasoline volatility (Reid vapor pressure), corrects key variables used in fuel economy testing and compliance, requires an update to the EPA's MOtor Vehicle Emission Simulator, or MOVES, model, ensures infrastructure compatibility, and addresses many other regulations impeding the deployment of higher-octane blends at the retail level.[45] The obligated parties including vehicle manufacturers, fuel blenders, and retailers would likely oppose this measure and thus far the bill has not made significant legislative progress.[46]

CLEAN TRUCKS PLAN

In August 2021, the EPA announced plans to reduce emissions and pollutants from heavy-duty trucks through yet-to-be finalized rulemakings. The first would apply to heavy-duty vehicles from model year 2027, increasing pollutant and emissions standards, and a second, more stringent GHG emission standard for heavy-duty vehicles would be for model year 2030 and beyond.[47] The finalized rules must be published to see the potential impact; however, biodiesel and RD will likely play a significant role in meeting the standard as more RD is introduced into the U.S. market and its lower CI reduces the emissions from diesel vehicles.

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[43] GianCarlo Moschini, Harvey Lapan, and Hyunseok Kim, "The Renewable Fuel Standard in Competitive Equilibrium: Market and Welfare Effects" (Working Paper 17-WP 575, Center for Agricultural and Rural Development, Iowa State University, Ames, Iowa, June 2017), https://www.card.iastate.edu/products/publications/pdf/17wp575.pdf.

[44] Next Generation Fuels Act of 2021, H.R.5089, 117th Congress, (introduced August 24, 2021), https://www.congress.gov/bill/117th-congress/house-bill/5089/text.

[45] Ibid

[46] Stratas Advisors

[47] "Clean Trucks Plan," U.S. Environmental Protection Agency, accessed September 14, 2021 https://www.epa.gov/regulations-emissions-vehicles-and-engines/clean-trucks-plan.

IRS TAX CREDITS

BLENDER'S TAX CREDIT

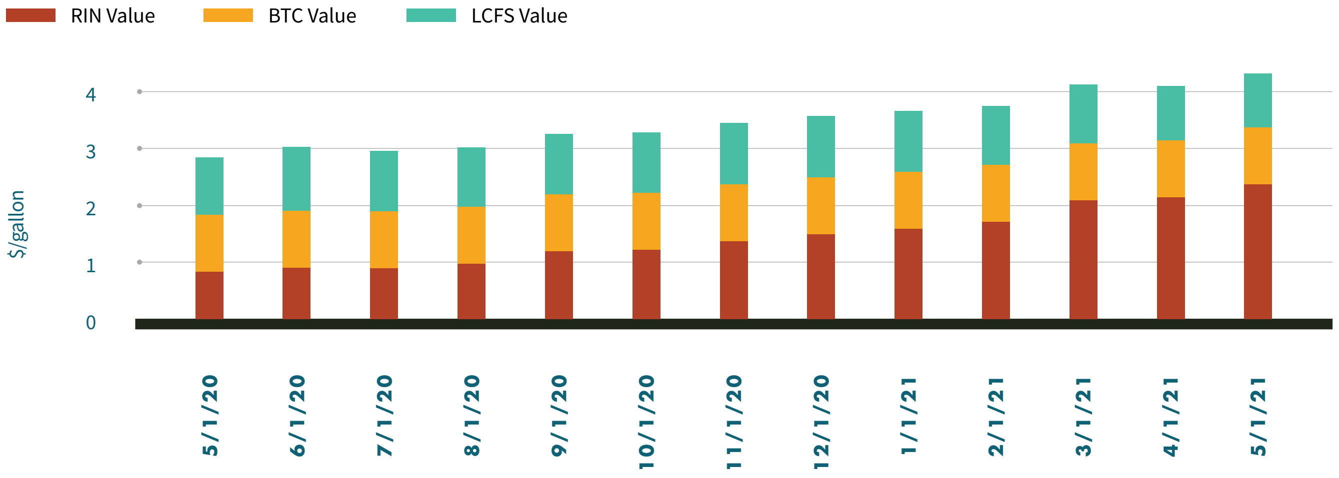
The BTC was instituted by the American Jobs Creation Act of 2004 and has been amended to its current form of $1 per gallon for blenders of biodiesel or RD if at least 0.1% of the biofuel is blended with petroleum diesel for sale or use. This value is passed along to biodiesel and RD producers. The BTC expired at the end of 2017 but was retroactively extended through the end of 2022 by a government spending bill passed at the end of 2019.[48] The BTC is important to ensure favorable economics for biodiesel and RD producers. As of August 24, 2021, the BTC represented approximately 19% of the total subsidy value of soybean-based RD sold in California with LCFS credits and cap-and-trade making up around 25% and RINs the remaining 56%.[49] (figure 4)

Historically, however, the BTC has been more important in guaranteeing positive margins for biodiesel producers. Legislation was introduced in May 2021 to extend the BTC to 2025.[50] The latest analysis on the BTC conducted by the U.S. Energy Information Administration (EIA) at Congress' request found a cost of $2.7 billion in fiscal year 2016.[51]

CARBON SEQUESTRATION TAX CREDIT (45Q)

Projects completed before 2027 that capture and sequester carbon oxides that would otherwise be released into the atmosphere can generate a tax credit under IRC 45Q.[52] The Bipartisan Budget Act of 2018 made numerous changes to the Section 45Q tax credit, including expanding the sequestration of qualified carbon oxides (previously only the sequestration of CO_2 qualified).[53] The credit is worth

FIGURE 4: SUBSIDY VALUE SOY-BASED RENEWABLE DIESEL



Source: Stratas Advisors

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[48] Energy Information Administration, *U.S. biomass-based diesel tax credit renewed through 2022 in government spending bill*, accessed August 24, 2021, https://www.eia.gov/todayinenergy/detail.php?id=42616

[49] Stratas Advisors

[50] "Biodiesel Mixture Excise Tax Credit," Alternative Fuels Data Center, U.S. Department of Energy, accessed August 24, 2021, https://afdc.energy.gov/laws/395.

[51] U.S. Energy Information Administration, *Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2016*, April 2018, https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf.

[52] Congressional Research Service, *The Tax Credit for Carbon Sequestration* (Section 45Q), In Focus series, updated June 8, 2021, https://fas.org/sgp/crs/misc/IF11455.pdf.

[53] Congressional Research Service

$35.42 per ton of carbon oxide sequestered in 2021, rising annually to $50 in 2026 and will be adjusted for inflation thereafter.[54] The value of the credit for carbon sequestration for enhanced oil recovery (fracking) is lower at $23.18 and rises annually to $35 in 2026.[55] Ethanol producers are beginning to invest heavily in CCS technology to reduce the CI of their ethanol production and gain these additional tax credits.

In May 2021, the U.S. Congress introduced the Coordinated Action to Capture Harmful, or CATCH, Emissions Act to raise the 45Q tax credit from $50/MT to $85/MT for industrial and power generation facilities and from $35 to $60/MT for oil and gas carbon capture.[56] Passage of this legislation would likely make the economic case for CCS technology viable at almost all U.S. ethanol production facilities, totaling about 48 MMT of CO_2 emissions abated given current U.S. ethanol production capacity. The legislation would also incentivize CCS investments at other industrial facilities. In contrast to other policies reducing emissions, as tax credits, 45Q and the BTC do not have any obligated parties to bear the costs or pass them along to customers; rather, the U.S. government receives less tax revenue. The Joint Committee on Taxation estimated the cost of 45Q to be less than $50 million from 2020 to 2024 while the Department of the Treasury estimated a cost of $600 million from 2019 to 2023 and $2.3 billion from 2020 to 2029. The variance in cost is due to uncertainty of the speed and scale of potential CCS project development.

STATE-LEVEL POLICIES

CALIFORNIA LOW CARBON FUEL STANDARD

The California LCFS sets emission reduction obligations through 2030 for the transportation sector. It works in coordination with other programs established by CARB, such as the Cap-and-Trade and Advanced Clean Cars programs, to reduce such emissions. Under the original guidelines adopted in 2009, the LCFS set CI benchmarks for each fuel type to reduce emissions a total of 10% by 2020, and subsequently added requirements of an additional 10% by 2030.[57] Stratas Advisors expects the program to be renewed before 2030, ensuring its continuity.

The CI scores are based on the life cycle of the fuel and account for all GHG emissions that are a by-product of the production, transport, and consumption of the fuel. Producers can decide which fuel blends they will utilize to meet the CI requirements. In addition, a 2018 amendment allows for the generation of credits on a capacity basis for zero-emissions vehicles (ZEV) infrastructure.[58] To incentivize the build-out of this infrastructure, hydrogen and fast-charging EV stations receive credits for their capacity minus actual fuel dispensed.[59] The allowance of ZEV credits and other infrastructure credits such as those from innovative crude and implementing solar energy at crude oil production facilities, will lead to more LCFS credit generation. Increasing credit generation makes complying with the obligations of the LCFS program easier and will likely lower LCFS credit prices, lowering the financial incentives and revenues for low-carbon fuel producers.[60]

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[54] Ibid

[55] Ibid

[56] A Bill to Amend the Internal Revenue Code of 1986 to Enhance the Carbon Oxide Sequestration Credit, S.2230, 117th Congress, (introduced June 24, 2021), https://www.congress.gov/bill/117th-congress/senate-bill/2230.

[57] California Air Resources Board, Low Carbon Fuel Standard Regulation, Accessed August 6, 2021 https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf

[58] *Low Carbon Fuel Standard Regulation*

[59] ‘”LCFS ZEV Infrastructure Crediting,” California Air Resources Board, accessed August 26, 2021, last reviewed October 29, 2021, https://ww2.arb.ca.gov/resources/documents/lcfs-zev-infrastructure-crediting

[60] Stratas Advisors

In the LCFS, fuels that are utilized in the California fuel system that have a CI above the requirement generate a credit deficit whereas fuels that have a CI below the benchmark generate credits. The CI scores established under original LCFS legislation were equivalent to a 6.25% reduction in CI relative to 2010 for compliance year 2019. Amendments made in 2018 to the LCFS continue to decrease the CI scores linearly until a 20% total reduction in CI is achieved by 2030. CI values required in 2030 will remain constant, and compliance requirements will be extended in years beyond 2030. These 2030 average benchmark CI values are 79.55 and 80.36 gCO2e/MJ for gasoline and diesel/jet fuel, respectively, compared to 2019 values of 93.23, 94.17, and 89.37 gCO2e/MJ for gasoline, diesel, and jet fuel, respectively.[61]

Conventional jet fuel is not yet subjected to the LCFS regulations nor does its production generate deficits. However, the jet fuel benchmarks will remain fixed at the initially established 2010 level until the benchmark for diesel substitutes declines below the CI baseline for jet fuel in 2023. The CI benchmarks for jet fuel will then mirror the diesel benchmarks through 2030.[62]

Fuel importers, refiners and wholesalers are regulated parties in the LCFS program, and retailers can opt into the program and become regulated parties to generate credits. In effect, petroleum fuel providers bear the cost of compliance with the program, but as is the case with the RFS program, they typically pass along the costs through increased prices for fuels.[63] CARB estimates that about 2.6 billion gallons of gasoline-equivalent petroleum were displaced in 2019 by alternative fuels supported by the LCFS program.[64] This would equate to about 29.52 MMT of CO2e emissions reduced by the program. Given the 2019 average LCFS credit price of about $191.52/MT of CO2e emissions, the total compliance costs of the LCFS program cost were about$ 5.65 billion in 2019.[65]

As California's LCFS program has had the highest credit price values, most biofuel projects have aimed to serve the California market and receive additional federal subsidies under the RFS and other tax credits such as the BTC. The combination of these credit values allows for modest profit margins for most producers, with only the lowest carbon-intense fuels and best-run operations generating good margins. There has been much consolidation in the ethanol and biodiesel industries as previously low RIN prices and the lapse in the BTC led to many smaller plants ceasing operations or selling their assets.

OREGON CLEAN FUELS PROGRAM

Oregon launched its CFP in 2016; the program is similar to California's LCFS. The original goal of the CFP required companies that import gasoline and diesel to lower carbon emissions from the fuels they sell by 10% below 2015 levels by 2025.[66] On March 10, 2020, Governor Kate Brown issued an executive order that directed multiple state agencies to act in further reducing GHG emissions.[67] As part of this effort, the executive order expands and extends the CFP to increase the availability of low-carbon transportation fuels. Oregon allows approved LCFS pathways to submit their certified CI from CARB with an adjusted value to account for transportation to Oregon.

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[61] *Low Carbon Fuel Standard Regulation*

[62] *Low Carbon Fuel Standard Regulation*

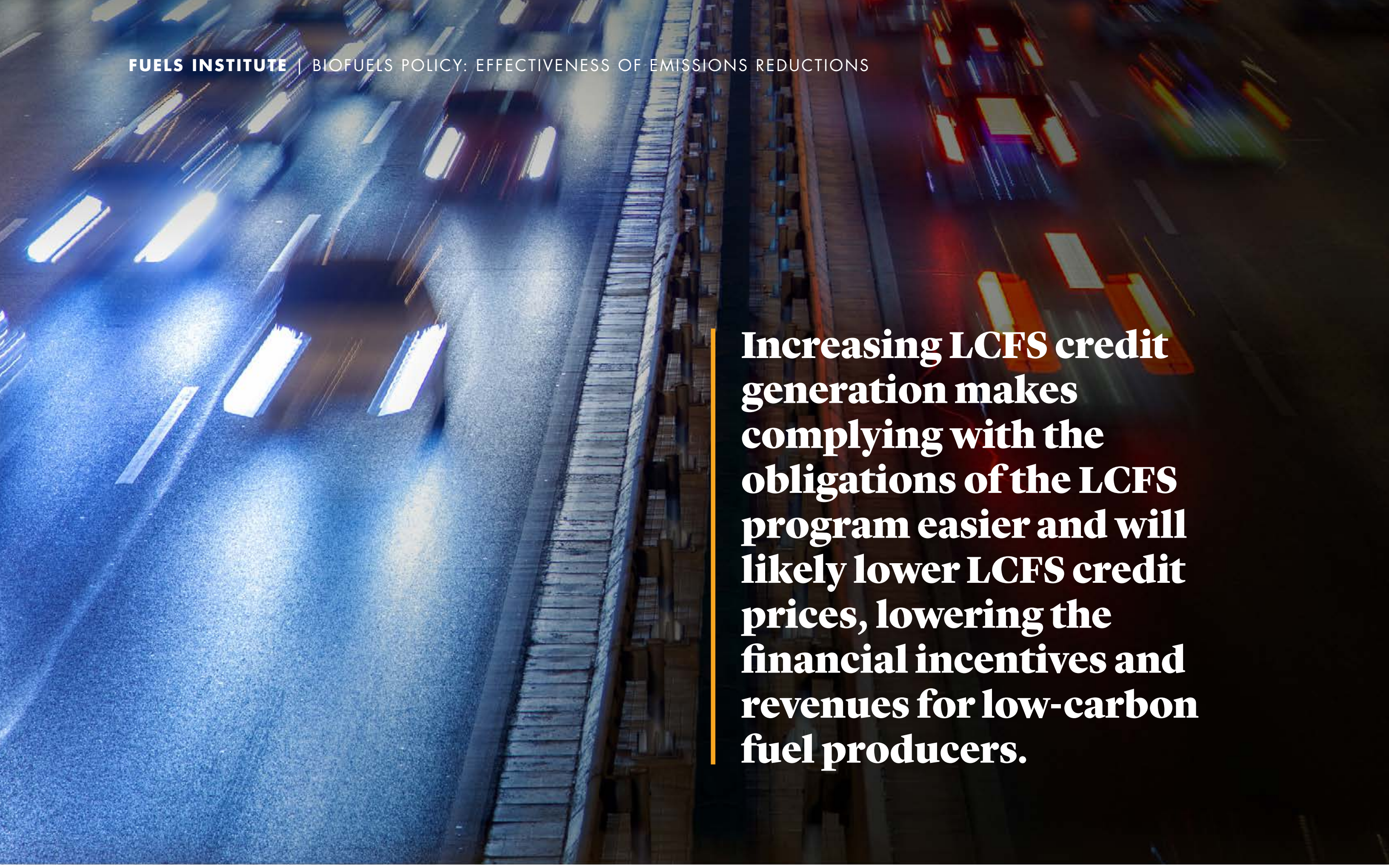
[63] Samir Huseynov and Marco A. Palma, "Does California's Low Carbon Fuel Standards Reduce Carbon Dioxide Emissions?," PLOS ONE 14, no. 1 (September 17, 2018): e0210906, https://doi.org/10.1371/journal.pone.0210906.

[64] "Low Carbon Fuel Standard Reporting Tool Quarterly Summaries," California Air Resources Board, accessed August 26, 2021, last reviewed October 29, 2021, https://ww3.arb.ca.gov/fuels/lcfs/lrtqsummaries.htm.

[65] Stratas Advisors

[66] State of Oregon Department of Environmental Quality, *Overview of the Clean Fuels Program*, Accessed August 6, 2021, https://www.oregon.gov/deq/ghgp/Pages/crprogramoverview.aspx

[67] Ibid



> **Increasing LCFS credit generation makes complying with the obligations of the LCFS program easier and will likely lower LCFS credit prices, lowering the financial incentives and revenues for low-carbon fuel producers.**

OTHER LOW CARBON PROGRAMS

While Oregon may not be a large state market, its program is indicative of growing support for LCFS-style programs in other U.S. states. New York has also proposed an LCFS-style program, the Clean Fuel Standard in committee, but this is not expected to be enacted within the next five years.[68][69] Washington passed their Clean Fuel Standard in 2021 to start by 2023 with goals of reducing transport fuel GHG emissions to 10% below 2017 levels by 2028 and 20% below 2017 levels by 2035; the legislation is conditional on securing $500 million of funding and Washington biofuel producers contributing 25% of credits.[70] In the Northeast, 13 states in the Regional Greenhouse Gas Initiative have passed regulations on emissions from the power generation sector and have launched effects to enact a similar Transportation and Climate Initiative for the transport sector.[71] However, despite 10 years of planning and verbal commitments from governors, none of these states have passed legislation for such a program and several have officially withdrawn from the initiative. Stratas does not expect these programs nor a federal LCFS program to be enacted in earnest in the next five years, but there will likely be additional LCFS-style programs by the end of the decade in which biofuels will likely play an important role because the slow transition to ZEVs and build-out of required charging infrastructure will not be sufficient to meet emissions-reduction goals.

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[68] New York State Senate Senate Bill S2962A, Establishes the clean fuel standard of 2021 (referred to environmental committee January 26,2021) https://www.nysenate.gov/legislation/bills/2021/S2962

[69] Stratas Advisors

[70] Washington State Legislature HB 1091: Reducing greenhouse gas emissions by reducing the carbon intensity of transportation fuel (prefiled January 6, 2021, signed partially vetoed May 17, 2021, effective July 25, 2021), https://app.leg.wa.gov/billsummary?BillNumber=1091&Initiative=false&Year=2021.

[71] The Regional Greenhouse Gas Initiative, Program Overview and Design, accessed August 6, 2021 https://www.rggi.org/program-overview-and-design/elements

MINNESOTA AND IOWA

Outside of low-carbon fuel programs, some states have proposed their own biofuel blend mandates. These states are mainly Midwestern states where most of U.S. biofuel production is located. Minnesota recently proposed an E15 mandate, HF3699 and SF3605 (previously SF 944), that would also require fuel retailers to have one pump of E10 to accommodate older vehicles.[72] Minnesota already has a biodiesel mandate in place varying from 5 to 20% depending on the season.[73] The state has a lot of local and political support for biofuels as it is a key corn-growing and ethanol-producing state. However, the policy will likely depend on a change in the previously mentioned federal judicial decisions and regulations concerning E15.[74] In addition, SF 1178 proposes an E25 mandate in 2031; however, this legislation has currently not advanced in the legislative process and is unlikely to be implemented.[75]

Iowa also has passed a bill requiring all retail fuel stations to offer E15 by 2026 and have proposed a B20 mandate with B5 in the winter. House File 2128, requiring stations to offer E15 by 2026, was approved by the legislature on April 26, 2022, and is expected to be signed into law by Governor Reynolds.[76] Waiver provisions exist for those selling less than 300,000 gallons of fuel per year or if costs to upgrade incompatible equipment exceeds $72,000.

Gasoline fuel providers in Minnesota and Iowa would be required to comply with these policies, but the outcome would likely depend on the actions of federal courts and the EPA concerning E15. According to the Minnesota Service Station and Convenience Stores Association, retail sites in the state would have to spend between $50,000 to $300,000 per site to upgrade infrastructure, in addition to the likely slight rise of retail gasoline prices.[77]

Federal, state, local and EPA rulings allowing E15 use in existing infrastructure would lower compliance costs dramatically and are likely necessary for any state E15 programs to succeed.

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[72] Minnesota Legislature HF 3699 https://www.revisor.mn.gov/bills/bill.php?f=HF3699&b=house&y=2020&ssn=0

[73] Minnesota Statute 239.77 https://www.mda.state.mn.us/environment-sustainability/minnesota-biodiesel

[74] Stratas Advisors

[75] Minnesota Legislature SF 1178 https://www.legis.iowa.gov/legislation/findLegislation/floorVotes?action=result&calendarItemID=15332&useFile=true&chamberID=H

[76] Iowa Legislature SF 549 https://www.legis.iowa.gov/legislation/BillBook?ga=89&ba=SF549

[77] Todd Neeley, "Minnesota Considers E15 Mandate," *Progressive Farmer*, DTN, February 18, 2021, https://www.dtnpf.com/agriculture/web/ag/news/business-inputs/article/2021/02/18/retailers-say-deadline-tight-costs.

Emissions Reductions from Policies and Associated Costs

In 2019, the U.S. gasoline pool was about 142.7 billion gallons (16,868,728 TJ) and ethanol had a market share of about 10.12%, which translated to about 75 MMT of CO_2 emissions savings compared to a hypothetical gasoline pool of 100% gasoline.

Assuming a 2022 U.S. gasoline pool of about 144 billion gallons (17,023,445 TJ), E10 blended gasoline is expected to save over 75.5 MMT of CO_2 emissions, and E15 blended gasoline would save over 111 MMT of CO_2 emissions.[78] On the diesel side, the U.S. diesel pool was about 63 billion gallons (8,503,585 TJ) in 2019, and biodiesel and RD comprised about a 4% market share combined, reducing emissions by about 23 MMT of CO_2e.[79]

Ethanol use is largely mandated by the RFS program, and the emissions reductions from E10 gasoline can be largely attributed to the program. However, disentangling the overlapping incentives from the RFS, LCFS, and BTC on the biodiesel, RD, and other alternative fuels is much more complicated, and Stratas Advisors currently could not find any research attributing the emissions reductions to these low-carbon fuel programs without overlapping accounting for emissions reductions. Taken as a whole, the RFS, BTC, and LCFS programs cost about $22.6 billion in 2019 while total U.S. emissions reductions from ethanol, biodiesel, and RD were about 98 MMT, which is equal to about $231/MT of CO_2e emissions reductions in 2019.[80]

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[78] Stratas Advisors

[79] Ibid

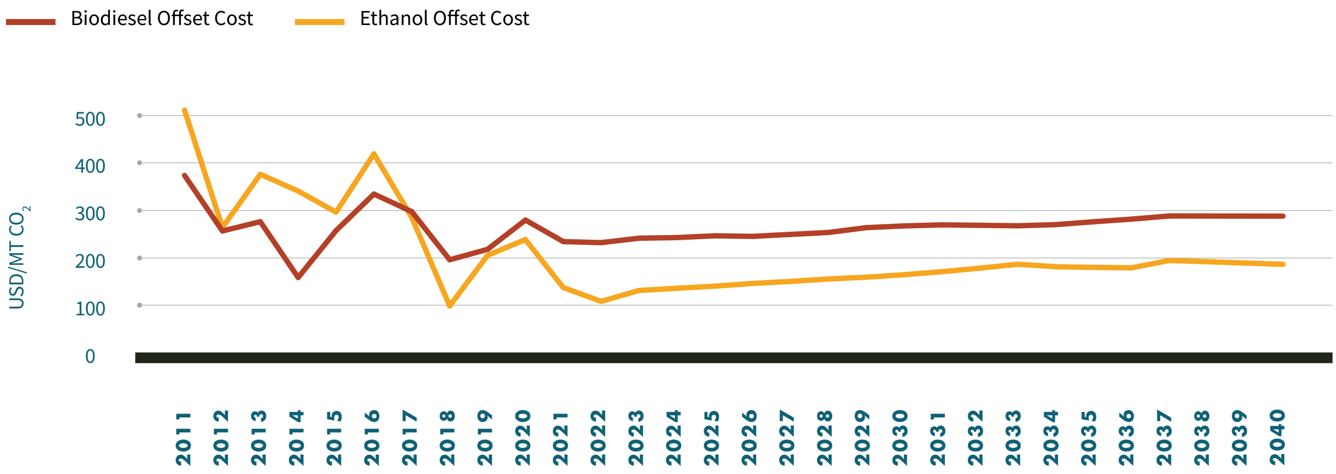
[80] Ibid

Average carbon offsetting costs through ethanol and biodiesel in the U.S. were between \$200-400/MT CO_2 abated between 2015 and 2017.[81] In 2018 and 2019, feedstock prices dropped while fossil fuel prices jumped. This reduced the relative cost of carbon offsets through biofuels. In 2018, the average cost of abating a MT of CO_2 through corn ethanol even fell below \$80. This situation changed radically in 2020. That year, crude oil prices in the U.S. were at record lows due to a sudden drop in demand because of COVID-19 lockdowns. At the same time, increasing biofuel mandates around the world were putting upwards pressure on feedstock prices, increasing the cost of biofuel production. As a result of these diverging trends, the average cost of offsetting carbon through biofuels in the U.S. increased to around \$260/MT of CO_2.[82]

The situation did slightly improve in 2021 as fossil fuel prices picked up again amidst an overall commodity boom. Large new RD capacity coming online in the U.S. has elevated feedstock prices which lowered the impact of higher fossil fuel prices. The gross cost of offsetting carbon through biodiesel decreased to \$235/MT (\$137/MT for ethanol). Feedstock prices look set to remain high in the coming years, as food, feed, and biofuel demands increase while agricultural expansion potential is more limited.

In our default scenario, Stratas Advisors therefore expects offsetting costs through ethanol and biodiesel to stay between \$100-300 for the remainder of the decade. Offsets through biodiesel are expected to be slightly more expensive than through ethanol until 2025. Around the middle of the decade, Stratas Advisors expects soybean oil prices to come down somewhat again, as overcapacity in the U.S. RD segment is expected to lead to some shutdowns around that time. As a result, biodiesel offsets are projected to be slightly cheaper than ethanol offsets in the second half of the 2020s. All costs discussed in this paragraph are gross costs; in reality, the revenues of biofuels credits and tax breaks drastically lower the costs of biofuel blending, although such costs are typically transferred to fuel consumers or taxpayers. (figure 5)

FIGURE 5: U.S. EMISSIONS OFFSET COSTS



Source: Stratas Advisors

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[81] Ibid

[82] Stratas Advisors

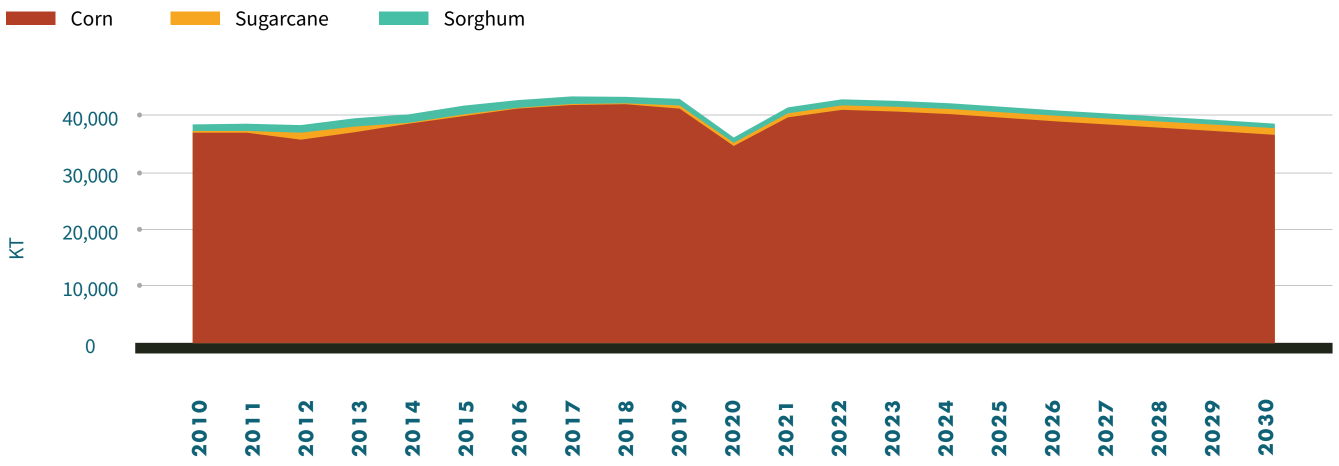
Feedstock and Vehicle Fleet Constraints

FEEDSTOCK AVAILABILITY AND PRODUCTION CAPACITY

FUEL ETHANOL

With over 95% of U.S. fuel ethanol demand met by corn, the corn supply is the most important feedstock to analyze when judging potential availability for ethanol production. Under the current and projected policies effectively limiting ethanol blends to E10, Stratas expects fuel ethanol feedstock demand to have peaked in 2017 at 14.5 billion gallons (43,363 thousand metric tons (KT) of feedstock, including 4.85 billion bushels of corn). This figure is expected to recover to about 14.3 billion gallons (42,590 KT of feedstock, including 4.75 billion bushels of corn) in 2022. Post-2022, Stratas projects ethanol demand to start a slow decline to about 10.5 billion gallons (38,586 KT of feedstock, including 4.25 billion bushels of corn) in 2030, driven mostly by increased efficiency of gasoline light-duty vehicles (LDVs) and, to a lesser extent, by EV-induced gasoline-demand destruction.[83] (figure 6)

FIGURE 6: U.S. FUEL ETHANOL FEEDSTOCK DEMAND E10 SCENARIO



Source: Stratas Advisors

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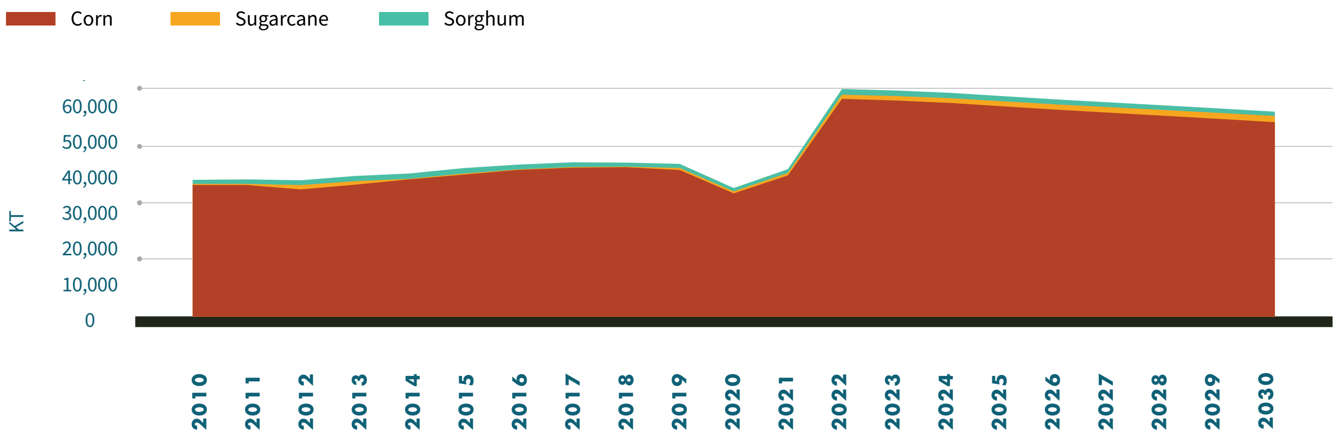
[83] Stratas Advisors

FIGURE 7: U.S. FUEL ETHANOL FEEDSTOCK DEMAND E15 SCENARIO



Source: Stratas Advisors

The U.S. is the world's largest producer, exporter, and consumer of corn grain, with nearly one-third of its cropland used for corn production. While corn is grown in virtually all U.S. states, production volumes are concentrated in the Midwest. U.S. corn harvest ranges from March to December depending on the geography of the growing area, with most of the production occurring in the Midwest from April to December. In 2019, U.S. corn production was about 13.7 billion bushels (347 MMT) with about 47% used for animal feed, 30% for ethanol, 10% for food, and 13% for export.[84] Thus, U.S. fuel ethanol demand has not excessively stretched the U.S. corn market and is not expected to over the next ten years, even under a scenario where E15 were implemented, which would amount to about 21.8 billion gallons and 20.6 billion gallons of ethanol demand in 2022 and 2030, respectively. This would equate to about 7.3 and 6.9 billion bushels of corn, about half of current U.S. corn production volume. Current U.S. fuel ethanol production capacity is about 17.5 billion gallons per year, more than enough to cover current expectations of an effective E10 maintenance.[85]

A strong potential for E15 use would lead to investment in expansion of ethanol capacity, but the market has not received strong signs thus far to make these investments. (figure 7)

The US biofuel industry also imports some feedstocks from Canada. The Canadian corn industry is quite small when compared to the U.S. corn industry, and Canada's corn production is mostly concentrated in Ontario, with Quebec also producing some quantities. In 2019, Canadian production of corn was about 513 million bushels (13 MMT) and, in contrast to the U.S.'s heavy use of corn for ethanol production, Canadian ethanol production is only about 77% corn.[86] However, Canada's new Clean Fuel Standard program is projected to support demand for biofuels, with ethanol expected to reach an expected 8.1% volumetric market share by 2040, up from a current level of about 6.1%.[87] Canadian ethanol production is forecasted to reach 792 million gallons (3 billion liters) in 2030, requiring only about 110 million bushels (2.8 MMT) of corn. The final biofuel demand increases to be expected under the

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[84] Ibid

[85] Renewable Fuels Association, *Essential Energy: 2021 Ethanol Industry Outlook*, February 17, 2021, https://ethanolrfa.org/wp-content/uploads/2021/02/RFA_Outlook_2021_fin_low.pdf.

[86] Stratas Advisors

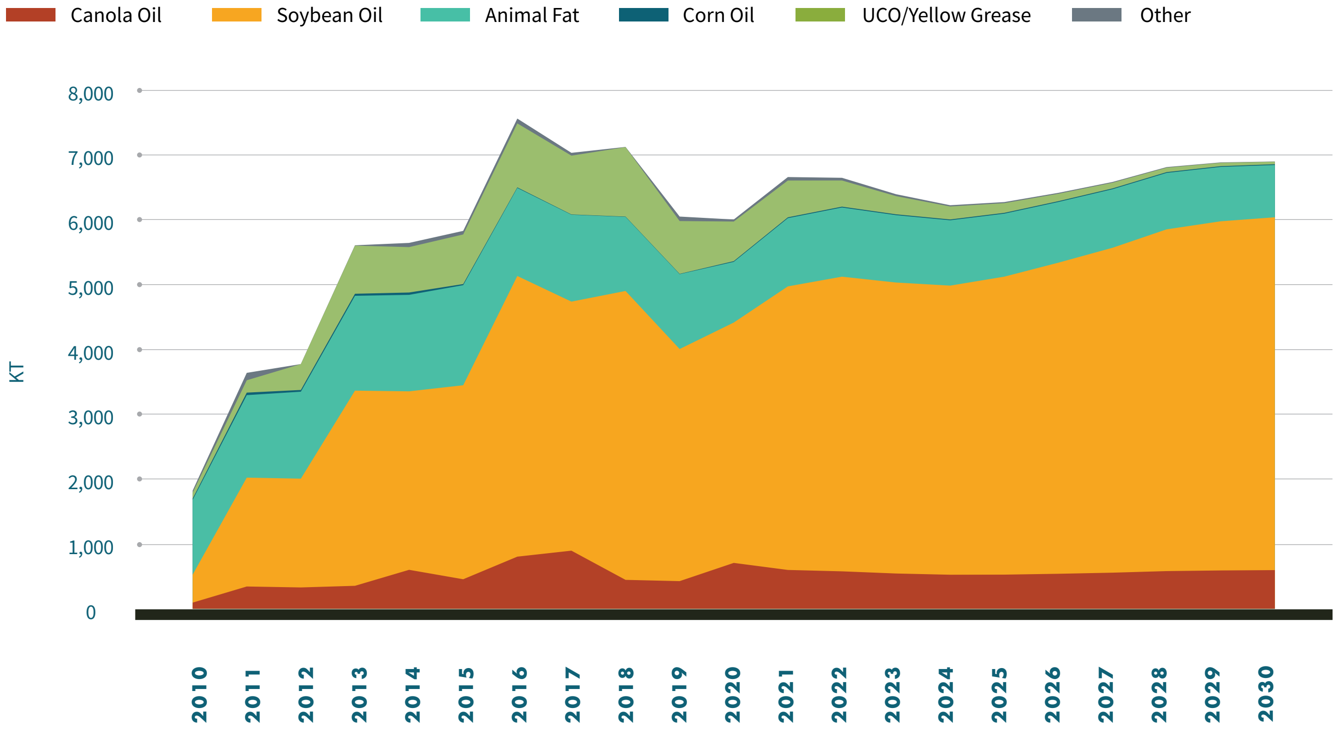
[87] Ibid

Canadian Clean Fuel Standard will depend on the program's final shape, as much of the GHG emissions reductions are expected to be met through upstream oil and gas production efficiency improvements and compliance with existing mandates. As such, U.S. ethanol producers will likely not be short of feedstock in contrast to biomass-based diesel producers.

BIODIESEL

Soybean oil is currently the main feedstock for U.S. biodiesel. Other, lower-CI feedstocks are expected to be drawn towards the increasing production of RD as the economics of RD production produce higher margins due to biodiesel's effective blend wall of B20, constraining about 97% of U.S. biodiesel demand to the B5 blend.[88] Canola oil is currently not approved as a RD feedstock by the EPA for RIN generation under the RFS and thus expected to continue to be used for biodiesel production and by the food industry.[89,90] Total biodiesel demand is expected to have peaked in 2018 at about 2.4 billion gallons (7,924 KT of feedstock demand) and fall to about 1.8 billion gallons (6,156 KT of feedstock demand) by 2030 after recovering from an expected drop in LCFS credit prices in the mid-2020s. Biodiesel production capacity is currently about 3.6 billion and expected to fall slightly by 2030 as some biodiesel plants become uneconomical and are sold to RD producers to be used as feedstock processing and pre-treatment facilities.[91] (figure 8)

FIGURE 8: U.S. BIODIESEL FEEDSTOCK DEMAND



Source: Stratas Advisors

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[88] Ibid

[89] U.S. Environmental Protection Agency, *Approved Pathways for Renewable Fuel*, accessed August 18, 2021, https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel

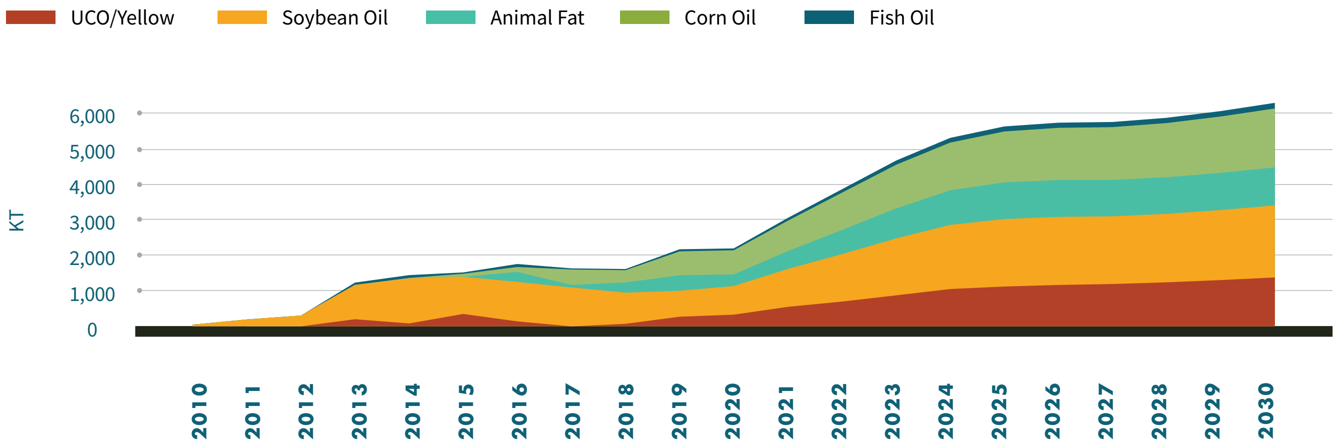
[90] EPA is currently considering canola pathways. See Docket ID No: EPA-HQ-OAR-2021-0845; FRL-9075-03-OAR

[91] U.S. Environmental Protection Agency, *Approved Pathways for Renewable Fuel*, accessed August 18, 2021, https://www.epa.gov/renewable-fuel-standard-program/approved-pathways-renewable-fuel

RENEWABLE DIESEL

RD demand is expected to grow rapidly, and many production projects have been announced, mainly targeting California's LCFS market. Overcompliance in the diesel pool is expected to ensure compliance of the LCFS regulation given the effective blend wall of E10 for ethanol and the expected slow adoption of EVs. RD demand was about 742 million gallons (2,192 KT of feedstock demand) in 2020 and is expected to grow to 2.1 billion gallons (6,285 KT of feedstock demand) by 2030. RD production capacity is currently about 900 million gallons but is expected to grow rapidly. Announced production capacity would amount to over 5.9 billion gallons by 2025, but not all of these projects are likely to be completed or remain operational. A more realistic production capacity number is about 5 billion gallons in 2025, with a similar level in 2030 if no significant policy changes or expansions to current low-carbon fuel markets are made. (figure 9)

FIGURE 9: U.S. RENEWABLE DIESEL FEEDSTOCK DEMAND



Source: Stratas Advisors

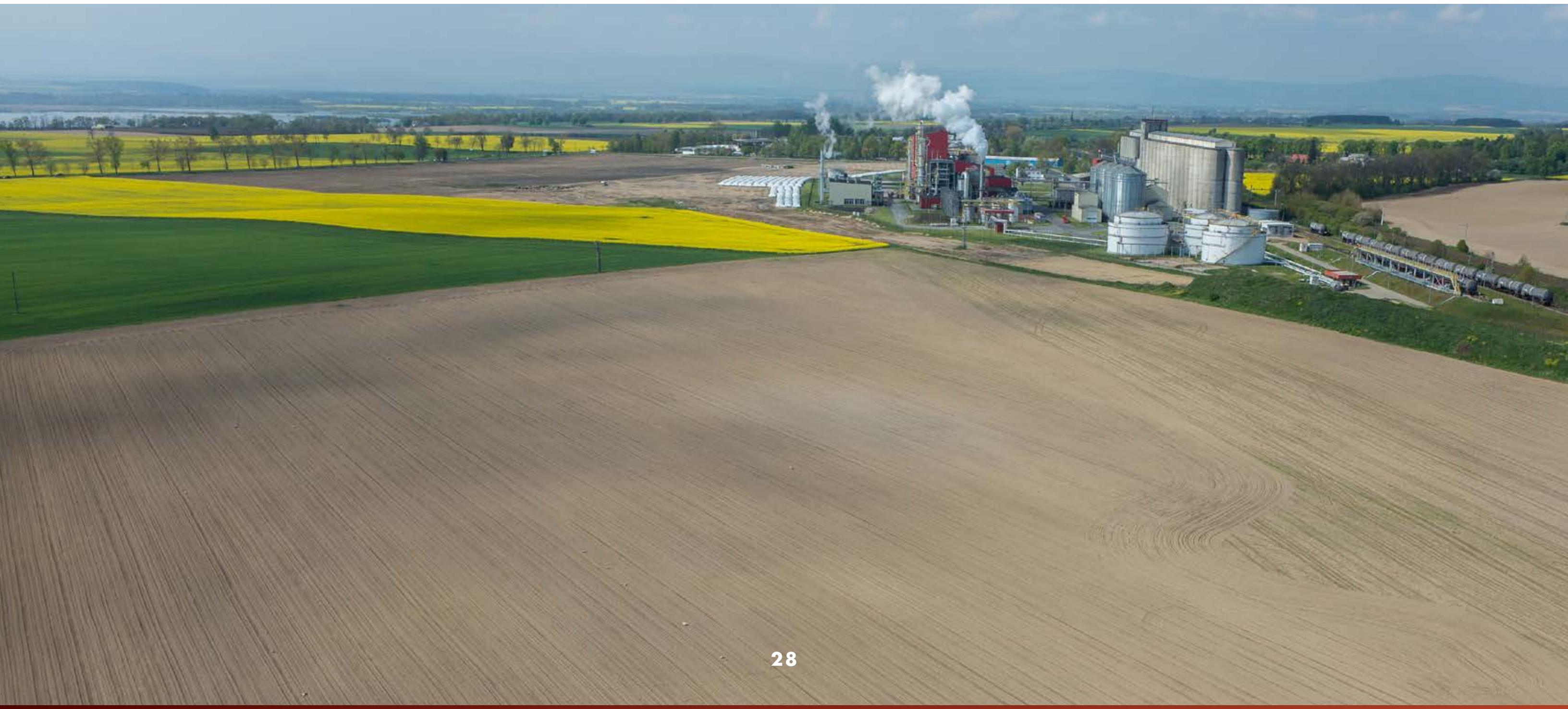
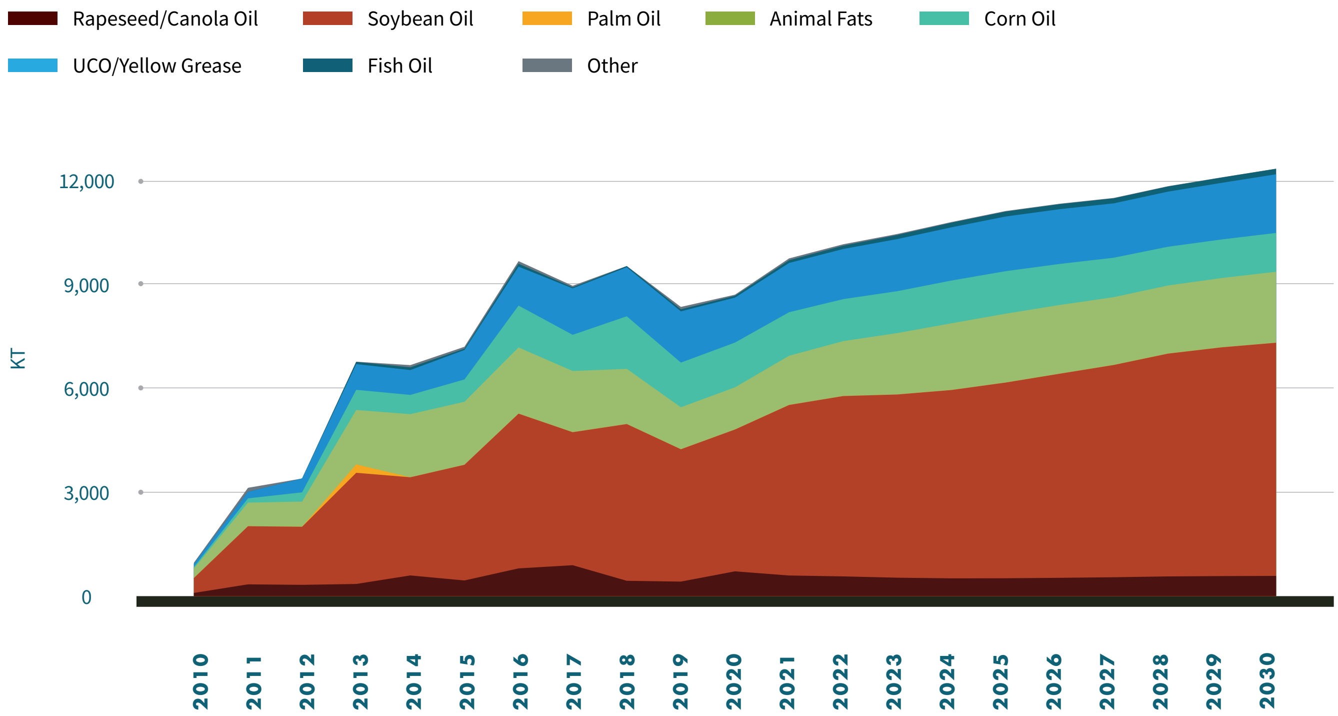


FIGURE 10: U.S. BIODIESEL/RENEWABLE DIESEL FEEDSTOCK PRODUCTION



Source: Stratas Advisors

The U.S. biodiesel and RD feedstock market is already feeling a squeeze as new RD projects come online and demand more feedstock supplies, raising prices. Total U.S. feedstock production is expected to stay ahead of biodiesel and RD demand, but the animal feed and food processing and services industries also use these feedstocks, and there will increasingly be more competition.[92] This is expected to draw more feedstock from Canada and especially Latin America as higher prices encourage more feedstock production and imports. Canada's biodiesel demand is expected to have peaked in 2019 at 143 million gallons (482 KT of feedstock) and is expected to stay below 135 million gallons (467 KT of feedstock) in the next decade.[93]

On the RD side, demand is expected to grow quite substantially due to the Clean Fuel Standard program, from about 15 million gallons (36 KT of feedstock) in 2019 to over 480 million gallons (970 KT of feedstock) by 2030. This will about triple Canada's biomass-based diesel feedstock demands, further adding to feedstock market tightness. Canada will likely use more canola oil, which is still not approved as a pathway for RD production under the RFS.[94] However, U.S. food services and processors are currently the main consumers of Canadian canola oil and thus strain Canadian imports for U.S. biomass-based diesel producers.[95] (figure 10)

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[92] Stratas Advisors

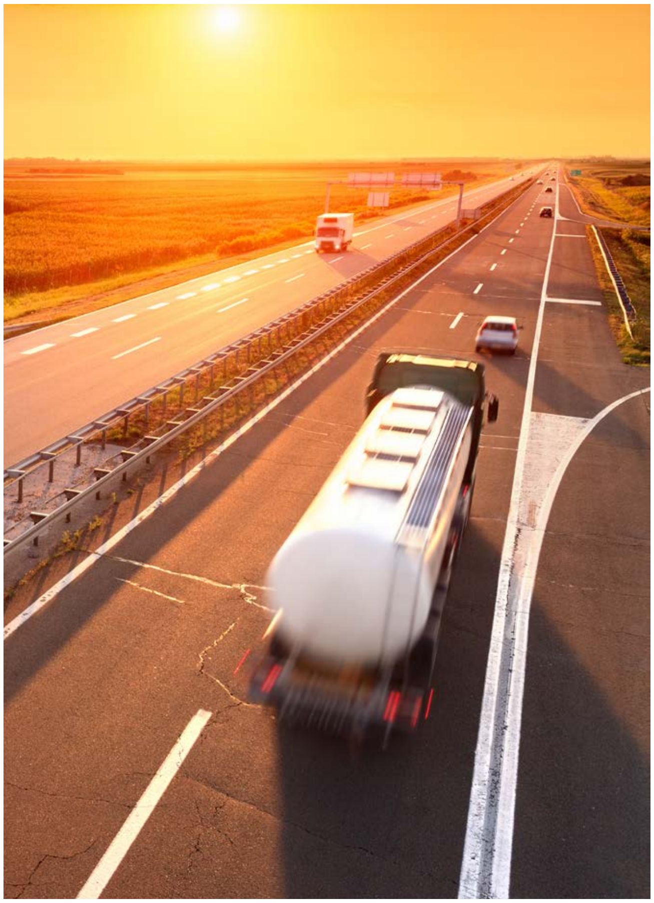
[93] Ibid

[94] EPA is currently considering canola pathways. See Docket ID No: EPA-HQ-OAR-2021-0845; FRL-9075-03-OAR

[95] Ibid

FUEL EFFICIENCY

As compared to global emissions standards, those applied in the U.S. are relatively lax; but the new EPA proposals aim to bridge this gap. In real world conversions, the European Union's Worldwide Harmonized Light Vehicle Test Procedure target is 47.3 mpg in 2025, rising to 62.33 mpg in 2030; the U.S.'s Corporate Average Fuel Economy (CAFE) standard is currently 28.69 mpg in 2025, but the Biden administration's EPA recently proposed a new standard which would require about 48 mpg in 2026 and fine automakers not in compliance.[96] In August 2021, the Biden administration enacted a target for 50% ZEV sales by 2030, but this target has no enforcement, so U.S. fuel efficiency and vehicle fleet are likely to slowly decarbonize.



FUEL COMPATIBILITY AND DISTRIBUTION

The main advantage of biofuels is their relative compatibility with existing infrastructure and vehicle fleets, which has led to their relatively large adoption when compared to other forms of alternative fuels. While ethanol is largely stored and transported separate from gasoline, once it is mixed into a gasoline blend, up to about 10% by volume, it can be used in existing internal combustion engines without any engine modifications. In most modern vehicles, ethanol can be used in up to E15 blends without modifications; in older vehicles, E15 blends have not been approved by most automotive manufactures. Ethanol is usually transported and stored as E10-blended gasoline after blending. For storing and dispensing blends above E10, EPA, state, and local entities require additional regulatory approval and labeling requirements, which further constrain the expansion of E15 and other higher blends of ethanol.[97]

Similarly, biodiesel can be used in existing diesel engines in blends up to about 20% by volume without engine modifications. Biodiesel blends up to B5 are considered petroleum diesel and can be transported and stored in existing diesel infrastructure. Biodiesel blends above B20 are subject to additional storage and labeling regulations that largely limit its use, similar to the case for blends of ethanol above E10.[98] RD has the most compatibility with existing infrastructure and engines. Since it is almost chemically identical to petroleum diesel, it can be transported, stored, and used in existing diesel infrastructure and diesel engines without modification. These compatibility advantages greatly benefit biofuels at these blend levels because vehicle fleets and fueling infrastructure are expected to remain overwhelmingly dominated by internal combustion and diesel engines for the next decade

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[96] "Proposed Rulemaking for Model Years 2024-2026 Light-Duty Vehicle Corporate Average Fuel Economy Standards," NHTSA, U.S. Department of Transportation, accessed January 21, 2021 https://www.nhtsa.gov/sites/nhtsa.gov/files/2021-08/CAFE-NHTSA-2127-AM34-PRIA-Complete-web-8-6-21-tag.pdf

[97] "Ethanol Codes, Standards, and Safety," Alternative Fuels Data Center, U.S. Department of Energy, accessed August 26, 2021, https://afdc.energy.gov/fuels/ethanol_codes.html.

[98] "Biodiesel Codes, Standards, and Safety," Alternative Fuels Data Center, U.S. Department of Energy, accessed August 26, 2021, https://afdc.energy.gov/fuels/biodiesel_codes.html.

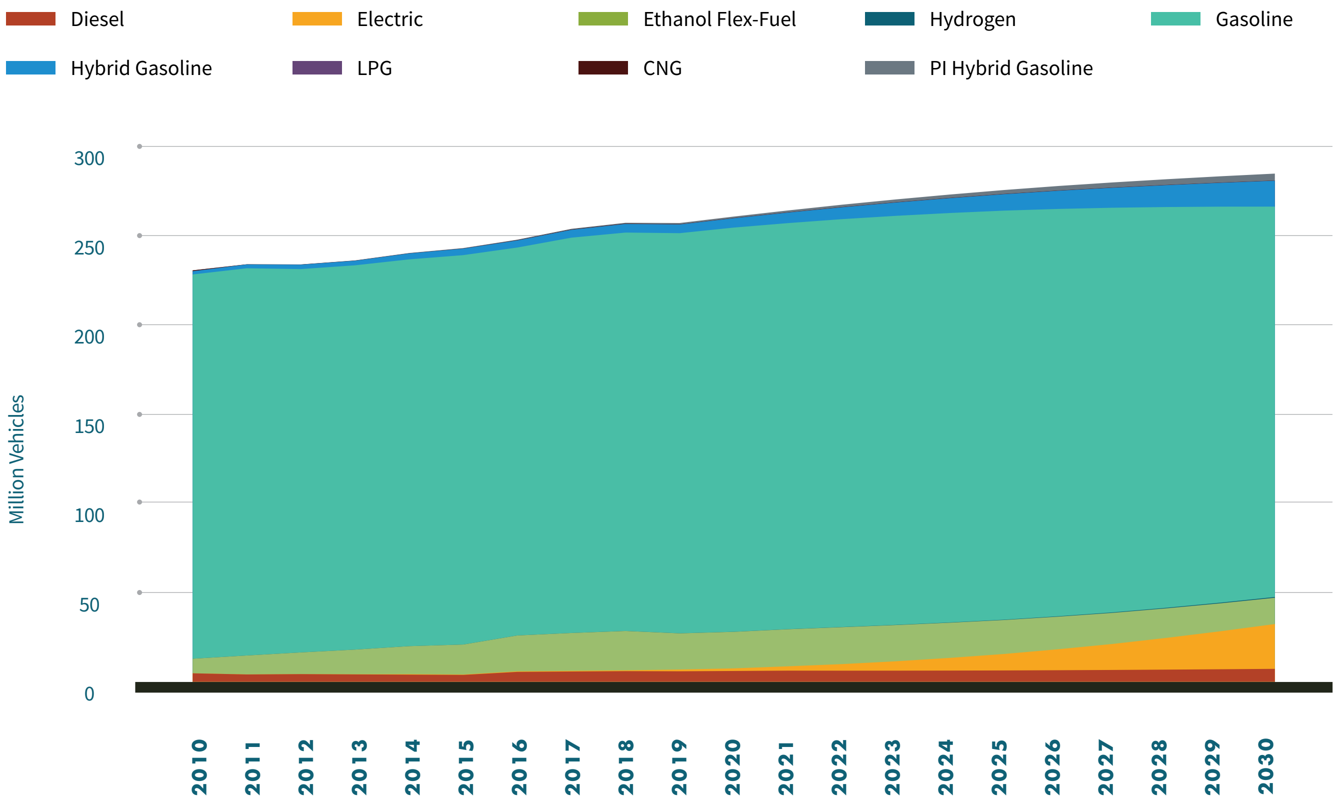
and beyond.

VEHICLE FLEET PROJECTIONS

In 2020, the U.S. LDV fleet was about 260.58 million vehicles. By 2030, Stratas projects a fleet size of 284.7 million LDVs. Of these, 76.8% will be gasoline, 5.2% will be ethanol flex-fuel, 2.5% will be diesel, 5.1% will be hybrid gasoline, 1.4% will be plug-in hybrid EV gasoline, and 8.8% will be EVs.[99] The massive size of the U.S. LDV fleet and the expected lack of penetration by ZEV electric and hydrogen vehicles will likely leave a large volume of GHG emissions unabated. (figure 11)

The U.S. medium- and heavy-duty fleets are about 2.7% and 2.0% the size of the U.S. light-duty fleet and thus make up a smaller volume of GHG emissions.[100] However, despite their small fleet size, the emissions per medium- and heavy-duty vehicle are much larger and, on average, switching a vehicle in these fleets to lower emissions fuels has a larger emissions impact per vehicle. In these fleets, ZEVs are expected to have an even smaller market penetration. In 2030, Stratas projects total medium-duty vehicles will rise to about 9.1 million, up from 7 million in 2020. Of these, 67.3% will be diesel, 26.2% gasoline, 2.4% EV, 2.4% ethanol flex-fuel, 0.2% natural gas, and 0.8% liquefied petroleum gas. In the heavy-duty fleet, total vehicles are expected to fall slightly from 2020 to 2030 from 5.2 million to 5.1 million. Of these heavy-duty vehicles, 97.5% will be diesel, 0.7% gasoline, 0.5% EV, 0.3% hydrogen, and 1.1% natural gas. (figure 12, figure 13)

FIGURE 11: U.S. LIGHT-DUTY VEHICLE FLEET



Source: Stratas Advisors

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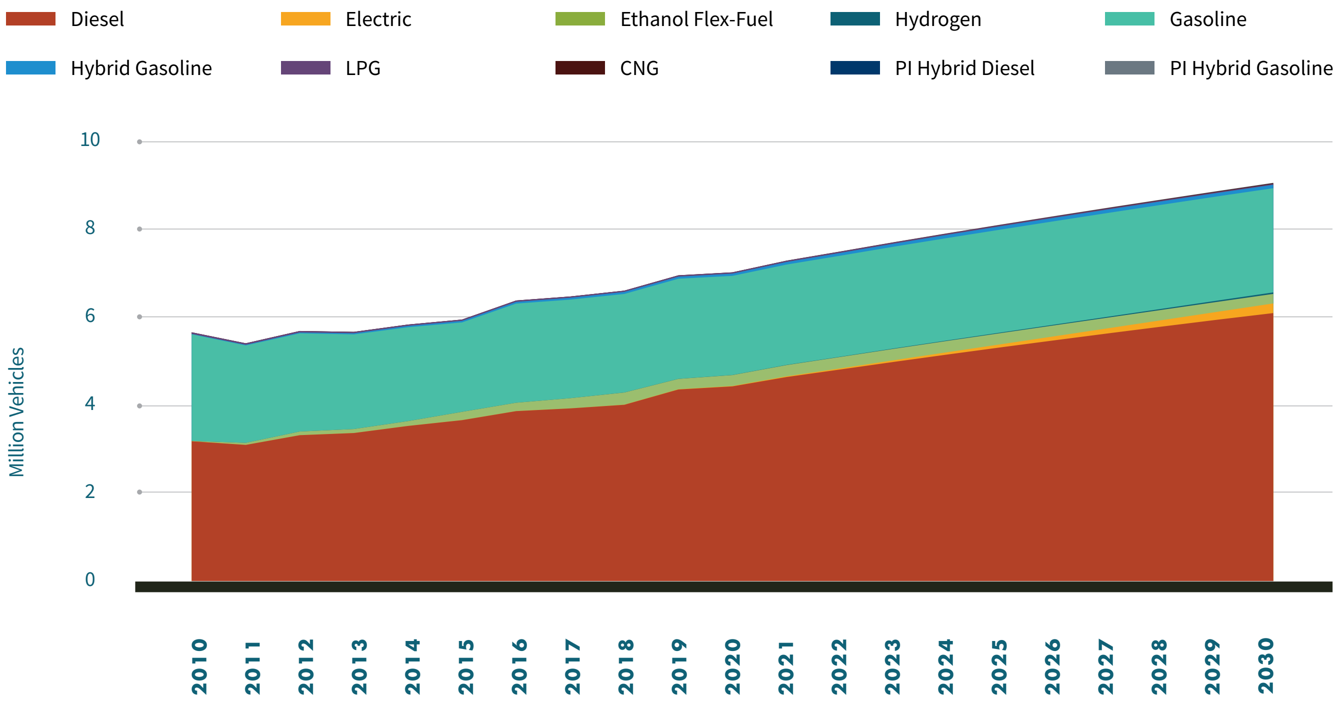
[99] Stratas Advisors

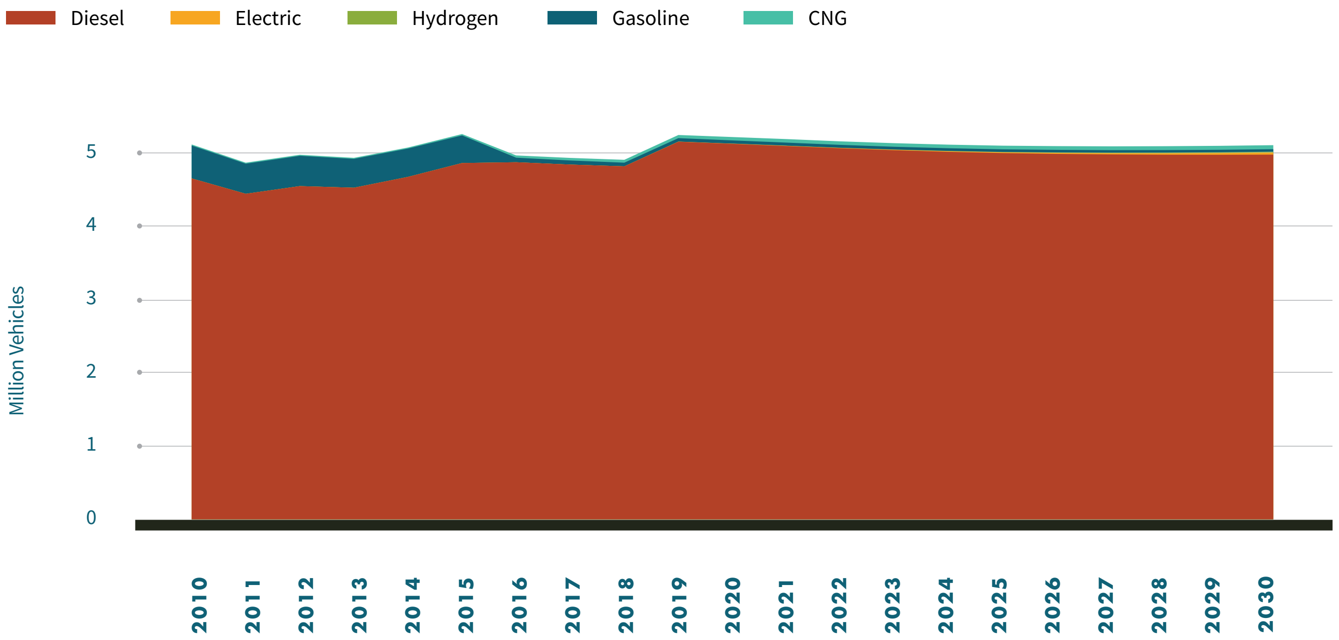
[100] Ibid

FIGURE 12: U.S. MEDIUM-DUTY VEHICLE FLEET



Source: Stratas Advisors

FIGURE 13: U.S. HEAVY-DUTY VEHICLE FLEET



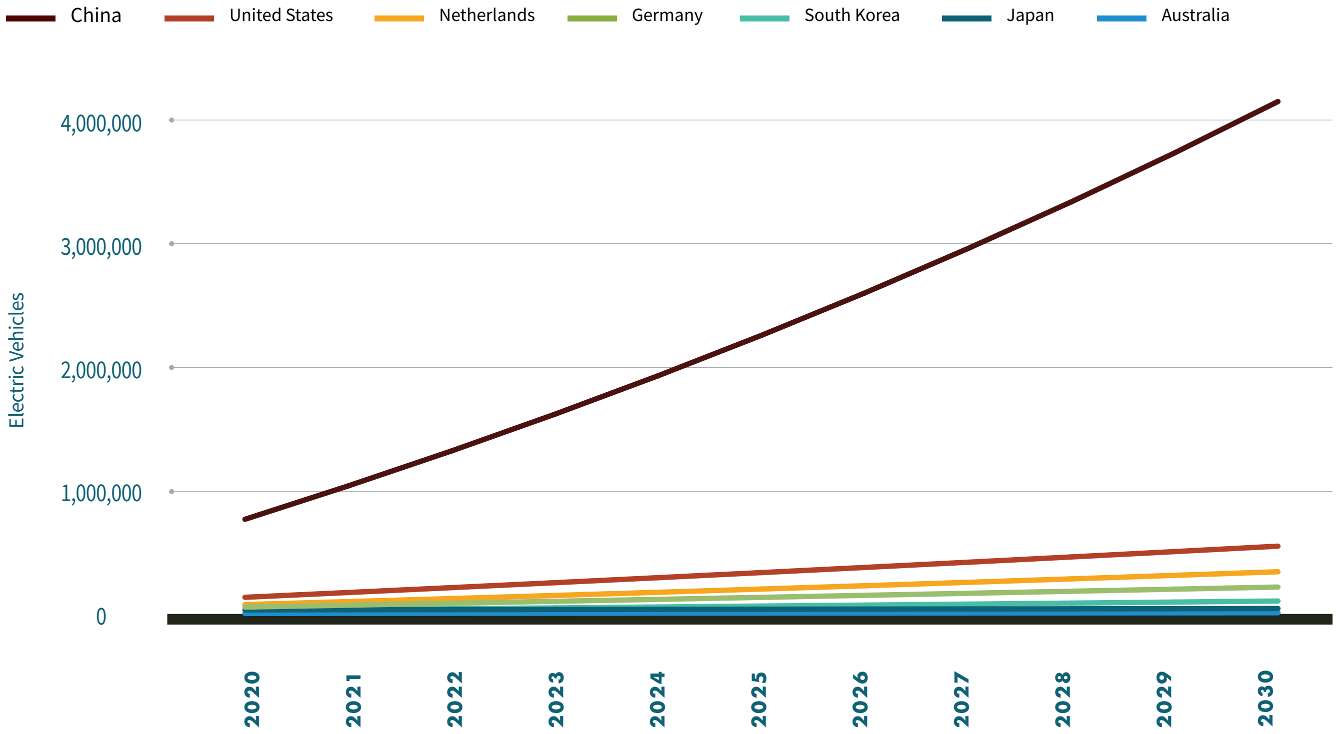
Source: Stratas Advisors

ELECTRIC VEHICLE EXPANSION

In comparison with other developed countries, the U.S. is projected to have a poor uptake in ZEVs given its relatively large population. Hydrogen vehicles are currently expected to remain marginal over the next decade while infrastructure, range anxiety, and prices constrain large EV adoption. As previously mentioned, a lack of EV infrastructure will be one factor preventing a large uptake in the U.S. (figure 14)

Refueling an internal combustion engine vehicle is fast, convenient, and easy given the ubiquity of gasoline retail stations in the U.S. while EV charging stations are much less common and slower to recharge in comparison. The average American lives only four minutes from a gas station but about 31 minutes from a Tesla Supercharger, the most common DC fast-charging station, representing over 55% and 57% of the California and U.S. markets, respectively.[101]

FIGURE 14: ELECTRIC VEHICLE FLEET OUTLOOK BY COUNTRY



Source: Stratas Advisors

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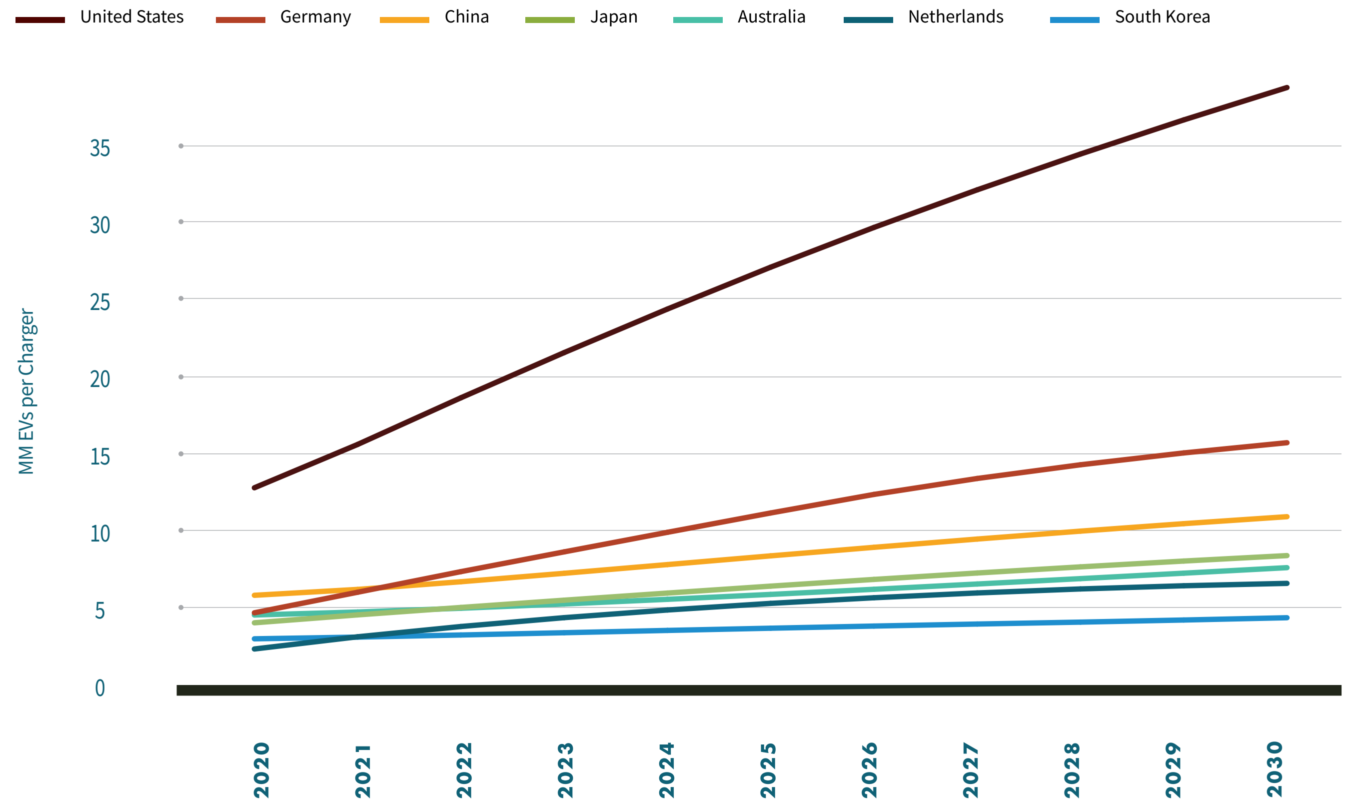
[101] Stratas Advisors

FIGURE 15: ELECTRIC VEHICLES PER CHARGER BY COUNTRY



Source: Stratas Advisors

Also, there are many stretches of interstate highway where there are currently no DC fast-charging stations, or the existing station is not compatible with all EV charging plugs.

Many European countries have mandated CCS[102] plug DC fast-charging stations, leading to its adoption as the standard charging plug type. However, in the U.S., competing EV companies effectively exclude charging from their competitors' EVs.[103] For example, a Tesla EV in the U.S. can use a Tesla Supercharger plug, a J1772 plug with an included adaptor, and a CHAdeMO speed-limited plug with a $540 adaptor. A Tesla EV cannot currently use a CCS plug type, but the company has announced plans for an adaptor. Chevrolet's competing Bolt EV can use CCS and J1772 type plugs, but it cannot use a Tesla Supercharger nor a CHAdeMO plug charger.[104] Therefore, DC fast-charging stations currently need three plug types to effectively accommodate all EVs in the U.S. and better compete with gasoline retail stations. However, most DC fast-charging stations are either Tesla Superchargers or stations with CCS and CHAdeMO plug types and thus not currently compatible with all EVs. This lack of infrastructure compatibility will further constrain the growth of the U.S. EV fleet and limit the expected overall impact EVs on emissions reduction in the transport sector. (figure 15)

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[102] CCS stands for Combined Charging System, which is a standard for charging electric vehicles that uses the Combo 1 and Combo 2 connectors to provide power at up to 350 kilowatts.

[103] Ibid

[104] Ibid

Glossary

AFLEET	Alternative Fuel Life Cycle Environmental and Economic Transportation
ANL	Argonne National Laboratory
BTC	blender’s tax credit
CARB	California Air Resources Board
CCS	carbon capture and sequestration
CFP	Clean Fuels Program
CI	carbon intensity
CWC	cellulosic waiver credits
EPA	Environmental Protection Agency
EV	electric vehicle
FAME	Fatty acid methyl ester
FCEV	fuel cell vehicles
GHG	greenhouse gas
GREET	Gases, Regulated Emissions, and Energy use in Technologies
ILUC	indirect land-use changes
LCA	life cycle analysis
LCFS	Low Carbon Fuel Standard
LDV	light-duty vehicle
MM	million metric tons
RD	renewable diesel
RFS	renewable fuel standard
RIN	renewable identification number
RVO	renewable volume obligations
UCO	used cooking oil
UCOME	UCO methyl ester
ZEV	zero-emissions vehicle

About the Fuels Institute

The Fuels Institute, founded by NACS in 2013, is a 501(c)(4) non-profit research-oriented think tank dedicated to evaluating the market issues related to vehicles and the fuels that power them. By bringing together diverse stakeholders of the transportation and fuels markets, the Institute helps to identify opportunities and challenges associated with new technologies and to facilitate industry coordination to help ensure that consumers derive the greatest benefit.

The Fuels Institute commissions and publishes comprehensive, fact-based research projects that address the interests of the affected stakeholders. Such publications will help to inform both business owners considering long-term investment decisions and policymakers considering legislation and regulations affecting the market. Research is independent and unbiased, designed to answer questions, not advocate a specific outcome. Participants in the Fuels Institute are dedicated to promoting facts and providing decision makers with the most credible information possible so that the market can deliver the best in vehicle and fueling options to the consumer.

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