Life Cycle Associates

Carbon Intensity of Marginal Petroleum and Corn Ethanol Fuels

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Prepared by:
Susan Boland
Stefan Unnasch

DISCLAIMER

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Contact Information:

Stefan Unnasch
Life Cycle Associates, LLC
1.650.461.9048
unnasch@LifeCycleAssociates.com
www.LifeCycleAssociates.com

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Terms and Abbreviations

ANL	Argonne National Laboratory
ARB	California Air Resources Board
Btu	British thermal unit
bbl	Barrel of Oil
boe	Barrel of Oil Equivalent
CA	California
CARBOB	California Reformulated gasoline blendstock for oxygen blending
CEC	California Energy Commission
CI	Carbon Intensity
DOE	Department of Energy
DGS	Distillers Grains with Solubles
DDGS	Dry Distillers Grains with Solubles
DOGGR	Department of Oil, Gas and Geothermal Resources
EPA	Environmental Protection Agency
EIA	Energy Information Agency
GHG	Greenhouse gas
GREET	Greenhouse gas, Regulated Emissions and Energy Use in Transportation (Argonne National Laboratory's well-to-wheels model)
IPCC	Intergovernmental Panel on Climate Change
kWh	kiloWatt-hour
LCA	Life cycle assessment
LCFS	Low Carbon Fuel Standard
LCI	Life cycle inventory
LHV	Lower heating value
MGY	Million gallons per year
MJ	Mega joule
ml	Milliliters
mmBtu	Million Btu
mmbbl	Million Barrels of oil
NG	Natural gas
NREL	National Renewable Energy Laboratory
NETL	National Energy Technology Laboratory
RBOB	Reformulated gasoline blendstock for oxygen blending
RFG	Reformulated gasoline
RFS	Renewable Fuel Standard (U.S.)
TTW	Tank-to-wheels
TEOR	Thermally Enhanced Oil Recovery
ULSD	Ultra low sulfur diesel
U.S.	United States
VOC	Volatile Organic Compound
WDGS	Wet Distillers Grains with Solubles
WTT	Well-to-tank
WTW	Well-to-wheels

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Executive Summary

Greenhouse gas (GHG) emissions from petroleum and alternative fuels have been the subject of research for several decades. Petroleum gasoline and corn ethanol are the most widely used automotive fuels and arguably the most closely examined. From production and refining to end use in vehicles, each stage of the fuel supply chain contributes to the fuel's carbon footprint. These well to wheel GHG emissions are expressed in grams of carbon dioxide emitted per megajoule of fuel (g CO_2 e/MJ). Substitution and blending of renewable fuels into petroleum gasoline is one key strategy to reduce the carbon footprint of transportation fuels. However, both the methods for examining GHG emissions as well as the technologies for resource and fuel production have evolved over the decades. In order to better understand the evolving trends in GHG emissions from petroleum gasoline and corn ethanol, this study examines the trends in crude oil based gasoline and corn ethanol in the U.S. and California.

In 2010, the U.S. EPA published the updated analysis of GHG emissions for the Renewable Fuel Standard (RFS2). Under the regulation, U.S. transportation fuel suppliers are required to include specified volumes of renewable fuels in transportation fuels through 2022. The RFS2 established mandatory emission reduction thresholds for renewable fuel categories based on reductions from a 2005 baseline[i]. California and other states introduced Low Carbon Fuel Standards (LCFS), which require a declining carbon intensity (CI) of the average on-road transportation fuel. The California Air Resources Board established a 2006 petroleum baseline gasoline blending component in 2009. Since that time, the emissions from crude oil production have been examined further by the Air Resources Board to reflect the changing mix of crude oil resources utilized in the state.

As unconventional[ii] sources of crude oil have grown in recent years, the CI of petroleum fuels has increased above the baseline levels initially identified in the above fuel polices. This study examines the resource mix of petroleum options over time encompassing conventional and unconventional crude oil sources. Resource types are ranked by cost and CI in order to show the effect of marginal crude oil resources. As the average CI of petroleum is gradually increasing, the CI of corn ethanol is declining. Corn ethanol producers are motivated by economics to reduce the energy inputs and improve product yields. Incentives for lower CI also motivate the industry to adopt new technologies, including feedstock and technological innovations as they roll out.

Figure S.1 shows the volume weighted carbon intensities (g CO_2 e/MJ) of U.S. petroleum gasoline and corn ethanol over time based on the historical crude oil and ethanol plant resource mixes and future projections. The mix of crude oil resources is based on Energy Information Administration estimates combined with crude oil type by country. The mix of corn

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[i] The 2005 baseline is used to calculate emission reductions based on the language in the Energy Independence and Security Act Statute.

[ii] Unconventional oils cannot be produced, transported, and/or refined using traditional techniques. They require energy intensive production techniques and new processes to deal with their inaccessible placements or unusual compositions.

technologies includes stover based ethanol contributing to RFS2 targets. Additionally, projections of stover used as corn replacement feed (CRF) and corn oil used as feed are included as a co-product credit. The baseline values used in the RFS2 and LCFS are presented alongside for comparison.

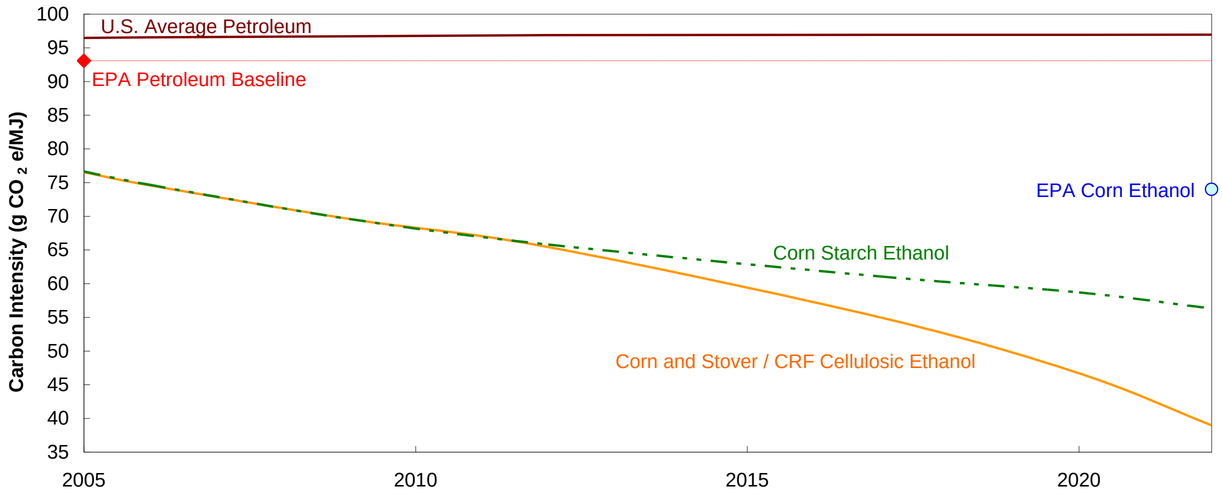

Figure S.1. Carbon intensity (g CO_2 e/MJ) of petroleum gasoline and corn ethanol consumed in the U.S. over time.

The weighted emissions are based on the CI of groups of crude oil production type combined with projections of crude oil resource mix over time. The effect of crude oil type on refining emissions is also taken into account. Similarly, the CI of corn ethanol plants was grouped into technology categories and the weighted CI reflect the chancing resource mix over time. The CI for corn ethanol reflects the most recent estimates of land use conversion from the University of Illinois and Argonne National Laboratory. The CI for corn ethanol reflects starch based ethanol alone as well as the total corn crop, where CRF and cellulosic ethanol are produced from the same crop as starch ethanol. Corn ethanol has advanced to the stage where the 2005 to 2012 average GHG shows a 26% reduction on petroleum levels as shown in Table S.1. These reductions in emissions compared to petroleum baselines under all scenarios evaluated in this study verify the effect of policy mandates and serve to quantify industry advancements in terms of GHG emissions.

Table S.1. Advancements in corn ethanol in relation to petroleum gasoline GHG emissions.

	2005	2012	2022	2005 to 2012 Average
Avg. Crude Oil (or Gasoline)	96.46	96.87	96.95	96.64
Avg. Corn Starch Ethanol (w/ILUC)	76.34	65.54	55.53	71.54
% Baseline Reduction	-20.9%	-32.3%	-42.7%	-26.0%
Avg. Corn and Stover CRF Ethanol (w/ILUC)	76.23	65.18	38.49	71.40
% Baseline Reduction	-21.0%	-32.7%	-60.3%	-26.1%

Substitution and blending of renewable fuel sources for crude oil is one strategy to reduce the carbon footprint of transportation fuels. However, the impact of corn ethanol on the U.S. and

California petroleum slates has not been examined with the best estimates of crude oil production, refining, and aggregation by production type. The question arises as to whether policy and industry efforts to reduce the CI of transportation fuels by substitution and blending has had any impact at all? When alternative fuels are viewed as an incremental resource, several marginal petroleum options represent the effect of these new energy resources. These scenarios for the year 2022 are presented in Figure S.2. Extrapolating from current policy and production scenarios to determine drivers for future growth, generates two potentially significant scenarios. These are the approval of the Keystone XL pipeline and the continuance of the U.S. shale boom. Both of these scenarios would increase the shares of unconventional oil in the domestic slates and shift the weighted GHG emissions accordingly. Under these drivers, significant quantities of marginal oil would be fed into U.S. refineries, generating corresponding emissions penalties, that would be further aggravated in the absence of renewable fuel alternatives. Projecting towards 2022, the effect of stripping renewable fuels from the slates immediately earns emissions penalties and leads to an increase in the overall weighted GHG emissions from petroleum fuels.

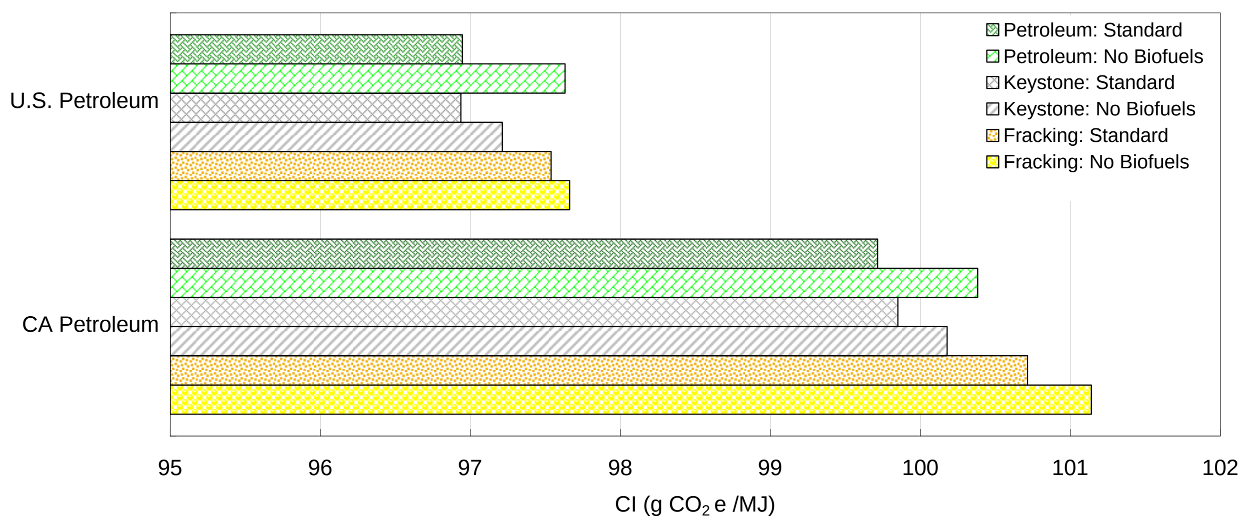

Figure S.2. Weighted carbon intensity (g CO_2 e/MJ) of petroleum fuels under current projections and alternate likely scenarios.

Under these scenarios, the impact of renewable fuels is reflected by an increase in the GHG emissions from petroleum options. Thus, absent alternative fuels, the higher CI petroleum options would contribute further to the aggregate U.S. and California mix.

In practical terms, the emissions that can be saved by the use of corn ethanol in place of the emissions that are generated from marginal petroleum fuels can be used to derive a “marginal petroleum GHG avoidance” situation as a positive indirect effect of these fuels. Indeed, the forgone increase in GHG emissions could even be considered an indirect effect of biofuels and could even be credited to the CI of biofuels.

Conclusions and Recommendations

This study shows the trend in GHG emissions from the aggregate mix of petroleum gasoline and corn ethanol in the U.S. and California. GHG emissions based on a weighted average of crude oil resource by production type are higher than those originally estimated for baseline values under the RFS2 and the LCFS and they continue to grow with a decline in conventional crude oil and growth in high CI petroleum options.

Meanwhile, GHG emissions from corn based ethanol continue to decline over time. Several factors contribute to this reduction in emissions. Notably, estimates of land use conversion have declined with recently published studies from Purdue University and Argonne National Laboratory. Energy efficiency and fuel switching as well as an expansion of co-products reduce the CI of corn ethanol. The GHG savings from CRF offset the land use conversion (LUC) from corn ethanol. Other feed options such as corn oil also displace products with high LUC emissions. The production of cellulosic ethanol from stover will further reduce the average CI of ethanol from the corn crop.

Due to the continued importance of understanding the GHG impact of petroleum and corn- based fuels, the authors provide the following recommendations:

- Refine the GHG emissions from petroleum pathways
    - Continue to monitor crude oil production by resource type
    - Compare local emission inventory reports to LCA model inputs
    - Refine emission estimates from fracking
    - Improve integration of oil refining with crude oil type
    - Include crude oil upstream results for diesel in crude oil LCA
    - Examine methane emissions from crude oil production

- Consider avoidance of marginal petroleum GHG emissions as an indirect effect of biofuels substitution.
    - Incorporate co-product effects of CRF and soy oil into RFS2 and LCFS ratings for corn ethanol
    - Continue to monitor corn ethanol production by production technology

- Consider corn from starch and cellulose as a single feedstock/fuel pathway when assessing the national impact of renewable fuels

1. Introduction

1.1 Life Cycle Analysis of Transportation Fuels

Traditional life cycle analyses (LCAs) of transportation fuels provides an assessment of the emissions associated with petroleum derived fuels and their related uncertainties. Broad studies such as those completed by General Motors Corporation in collaboration with Argonne National Laboratory (ANL), the European Union (E.U.), and others compare a wide range of fuels and technologies to a gasoline baseline.[1-4] Other studies[5-6] have focused on petroleum fuels in more detail by investigating the range in emissions associated with petroleum fuels in order to assess the impacts of petroleum production on the margins of conventional fuel. The greenhouse gas (GHG) impacts that are examined are limited primarily to the set of traditional direct and upstream fuel cycle impacts, the Well-To-Tank (WTT) emissions.[7] The fuel combustion emissions, i.e. Tank-To Wheel (TTW) emissions are treated as invariant amongst the different pathways, and thus generally not examined.[8] The total fuel life cycle is termed the Well-To-Wheels (WTW) and is the sum of the WTT and TTW emissions. [9]

There is general consensus that conventional crude oil supplies have globally peaked and we have entered a transitional phase from conventional to unconventional sources.[10] Many current forms of oil that were once considered unconventional are now grouped into the conventional category. New oils derived from non-flowing oils,[iii] biological materials, natural gas liquids or coal are becoming more prevalent, while technological advancements have made previously uneconomical or inaccessible oil reserves now viable options.

These "new" crude oil sources are termed unconventional or marginal oils and require energy intensive production and refining techniques including water, gas or steam flooding, and other methods to deal with their inaccessible placements or unusual compositions.[10]

Transportation fuels are rated based on their GHG impacts, termed the carbon intensity (CI). The CI of a fuel is quantified as the grams of carbon dioxide equivalent emitted for every megajoule of energy produced for their full life cycle (g CO_2 e/MJ). These CI values apply to all fuels (gasoline, diesel, natural gas, electricity, etc), and to the fuel or to the fuel mix (crude oils and biofuels).[11] The U.S. EPA established the baseline RBOB (Reformulated gasoline Blendstock for Oxygen Blending) CI for gasoline at 93.08 g CO_2 e/MJ in the year 2005. California, in 2006, established a baseline CARBOB (California Reformulated gasoline Blendstock for Oxygen Blending) CI of 95.86 g CO_2 e/MJ. However, this value was updated to the 2012 value of 99.18 g CO_2 e/MJ to reflect the steady shift to higher intensity crude oils fed into U.S. refineries.[12] EPA has not re-examined the CI of petroleum.

Petroleum as a transportation fuel (i.e. gasoline) is typically a blend of refined crude oil and ethanol. Current EPA emission constraints limit ethanol to 10% by volume un gasoline cars, although flexible fuel vehicles can operate with 85% ethanol. This study examines petroleum transportation fuels as a whole by looking at the sources and production methods of crude oil and ethanol that are blended to make gasoline. The major sources and types of crude oil, and the

[iii] Oil sands, Shale oil, kerogen based crudes

recovery and refining stages of each were examined. In addition, the major production methods of ethanol were identified with a specific focus on corn as the predominant feedstock for ethanol production.

EIA data provides the basis for aggregation of petroleum fuels into categories based on predominant production methods. Emissions trends from volumetric weighted categorization of these are modeled. Table 1.1 presents the modeled categories alongside the estimated global reserves. Global reserves are estimated from oil producers' data, government reports and other independent statistics.[13-14]

Table 1.1. Transportation Fuel Category and Global Resources (Bbbl)

Category [6-12]	Global Resource (Bbbl)
Conventional	800
Biofuels[a] (Gboe)	28
TEOR	350
Oil Sands (SAGD, Dilbit)	800
Stripper Wells	50
Fracking (Tight)	300
GTL	500
Oil Shale	100

[a]Biofuels are modeled as barrel of oil equivalents (boe) based on standard calculations; the boe is a unit of energy based on the approximate energy released by burning one barrel (42 U.S. gallons) of crude oil.

The concerted global effort for sustainable renewable fuels (i.e. biofuels) production is a recent one. Total quantitative biofuels estimates are difficult to ascertain, due to the nature and variety of feedstocks. However, estimates have been developed based on leading global producers' data, legislative mandates,[15-16] and were projected these on a 30 year timescale to establish a representative metric for analysis. It should be noted that with the emergence of new technologies and feedstocks, the global resource endowment can be expected to grow and estimates will need to be revised upwards regularly.

Table 1.2. Global Biofuel Resource Estimates

Global Leading Producers	2022 Biofuels demand (Billion gallons)
India	6.8
Brazil	8
US	36
EU-27	6.7
China	3
Total	60.5
30 year projection	1815

Peer reviewed LCA models and methods have been used to establish the time and volume weighted CI for petroleum and corn ethanol. Emissions are compared to policy (EPA and California) baselines and projections are made towards future growth

1.2 Objective

The objective of this study is to examine the current and future trends in the CI of marginal petroleum fuels and corn ethanol. This analysis has been accomplished using the modeling tools used by the U.S. Environmental Protection Agency (EPA) and the California Air Resources Board (ARB). The changing mix of petroleum resources, as well as the growth and advancements in the corn ethanol industry, with extrapolated trends based on penetration and emissions intensities are examined.

1.3 Fuel Policy Initiatives

The paradigm shift from conventional to unconventional fuel sources has led to a concerted effort by many world governments and environmental organizations to legislate and incentivize for a reduction in the full WTW GHG emissions of transportation fuels. The International Energy Agency (IEA) predicts that global consumption of crude oil will increase by 27% over the next two decades, from 83 million barrels per day (mmbbl/d) in 2009 to 105 mmbbl/d in 2030.[17] Petroleum and biofuel alternatives are the largst source of transportation fuel today, and in California, approximately 38% of greenhouse gas (GHG) emissions are due to the transportation sector, compared to approximately 27% for the national U.S. average.[18-19] Life cycle emissions over the entire fuel cycle are the metric of choice when addressing transportation GHG emissions because both the direct vehicle emissions and the upstream fuel cycle emissions can vary considerably among alternative fuel options. Table 1.3 outlines a selection of U.S. and California specific initiatives aimed at reducing the carbon intensity of transportation fuels.

Table 1.3. Policy Initiative Involving Life Cycle GHG Emissions From Fuels

Initiative	Requirement
U.S. EISA, RFS2	36 billion gal of renewable fuel by 2022 20%, 50% and 60% GHG reduction categories
California, LCFS	Reduction in CI of transportation fuels ending with 10% in 2020

1.3.1 EPA RFS2

The U.S. Renewable Fuel Standard 2 requires the addition of 36 billion gallons of renewable transportation fuels to the U.S. slate by 2022. The RFS2 established mandatory CI emission thresholds for renewable fuel categories based on% reductions from an established 2005 petroleum baseline. Within the total volume requirement, RFS2 established separate annual volume standards for cellulosic biofuels, biomass-based diesel, advanced biofuels, and renewable fuels. Figure 1.1 illustrates the RFS2 volume requirements per fuel category. To comply with the standard, obligated parties must sell their annual share (as calculated by EPA) of each type of renewable fuel.

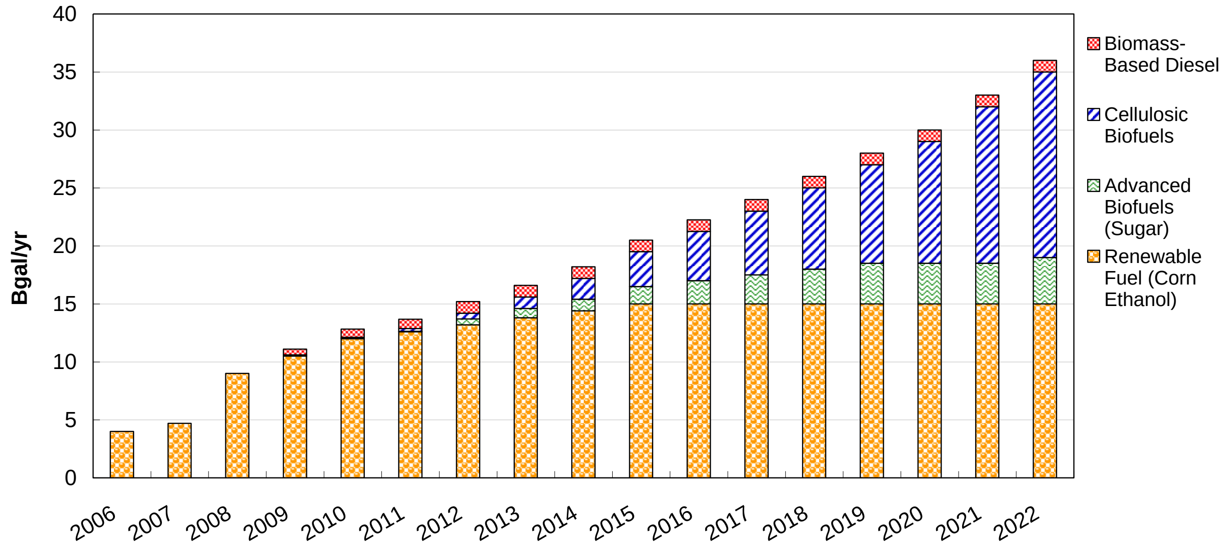

Figure 1.1. RFS2 renewable fuel volume requirements for the United States.

1.3.2 California LCFS

Under the California Assembly Bill AB 32 (Governor Schwarzenegger 2007 Executive Order) the State set a limit on GHG emissions in the State by establishing the Low Carbon Fuel Standard (LCFS) regulations[18,20-21] The LCFS regulations include provisions to reduce transportation emissions by 10% on a 2011 baseline. The LCFS baseline (CARBOB) was calculated to be 95.86 g CO_2 e/MJ to reflect the CI of CARBOB [22] in 2006, with a projected compliance schedule. However, subsequent analysis of crude oil production types led to ARB's analysis of the 2010 CARBOB mix at 99.18 g CO_2 e/MJ. This analysis only examined crude oil production and excluded refining. Thus, the LCFS compliance schedule was re-evaluated in 2012 and greater CI reductions are necessary to reach compliance by 2020, Figure 1.2.

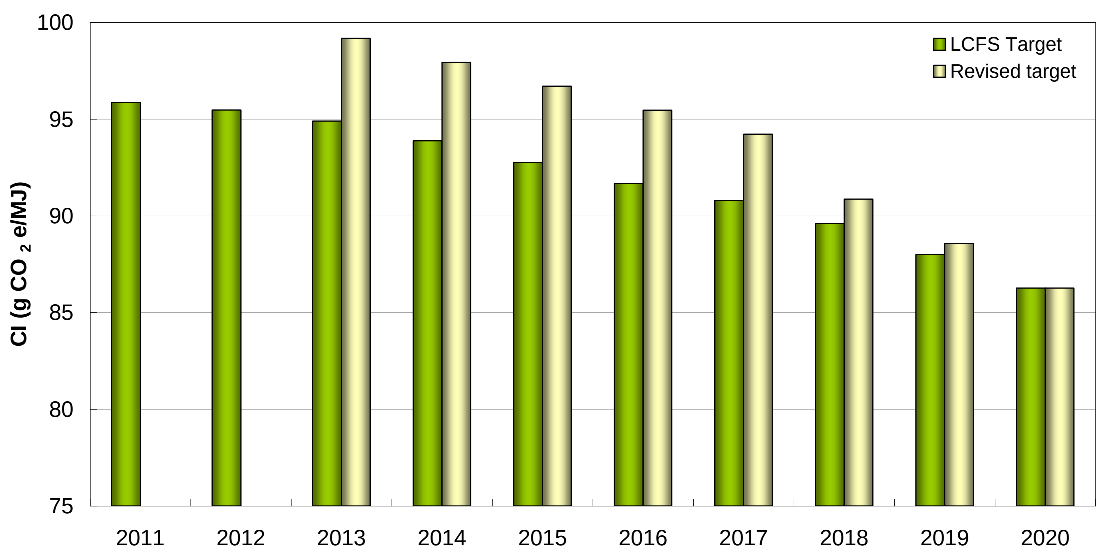

Figure 1.2. California LCFS compliance schedule

2. Petroleum Flows

EIA data provides the basis for determination of sources of petroleum used in the U.S. The EIA provides a time series of data of crude oil and product imports and exports globally. The information is organized by Petroleum Authorization Defense District (PADD). Identifying the uses of crude oil in the U.S. is complicated because the overall balance depends on net imports of crude oil as well as exports of finished products. Establishing the overall crude flow associated with exports is also complex due to the transfer of crude oil and products between refineries and from PADD to PADD. The trends have been examined and modeled to provide the basis for our analysis.

2.1 Crude Oil Production Trends

Global crude oil production (including lease condensate) in 2012 averaged roughly 76 mmbbl/d, and U.S. production was roughly 11 mmbbl/d. Trends in global supply and consumption highlight an increasing demand on petroleum products, particularly from China and India, pressuring oil production to match demand.

2.2 U.S. Consumption Trends

Total U.S. energy is depicted in Figure 2.1. Consumption of oil and other combustible liquids is expected to decrease by approximately 4% on current levels by 2040. This reduction will be primarily driven by the use of renewable biofuels, changing fuel policies and efficiency advancements in production and combustion technologies.

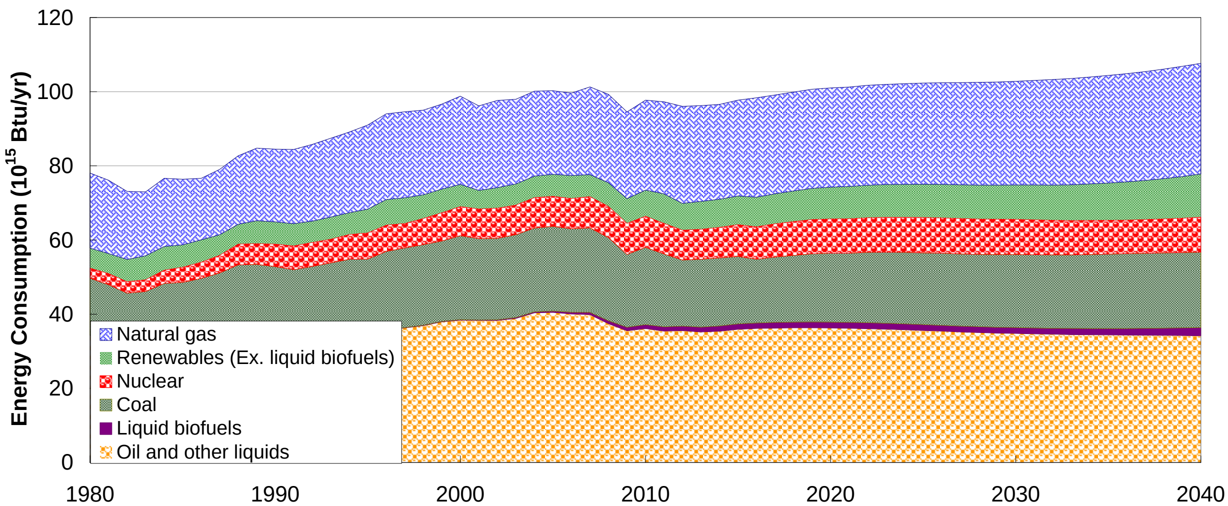

Figure 2.1. U.S. primary energy consumption by fuel, 1980 to 2040 (quadrillion Btu per year)

U.S. consumption of petroleum and other liquids is expected to peak at 19.8 mmbbl/d in 2019 before falling to 18.9 mmbbl/d in 2040.[23] The transportation sector accounts for the largest share of total consumption throughout the projected period, Figure 2.1. This share is expected to decline slowly as a result of improvements in vehicle efficiency and combustion properties. Consumption of petroleum and other liquids is expected to increase in the industrial sector, by 0.6 mmbbl/d from 2011 to 2040, but will decrease in all the other end-use sectors.

Motor gasoline, ultra-low-sulfur diesel fuel, and jet fuel are the primary transportation fuels, supplemented by biofuels and natural gas. An increase in consumption of biodiesel and next generation biofuels, can be directly attributed to the RFS mandates and the LCFS regulations. However, there is no expected increase in the volumetric consumption of ethanol blended into gasoline in the EIA projections, due to an overall declining gasoline consumption and limited penetration of advanced flexible fuel vehicles.[23]

2.3 U.S. Domestic Production and Imports

Approximately 40% of America's oil comes from domestic oil fields in states such as Texas, Alaska, California and North Dakota. Total U.S. proven reserves was approximately 28.9 billion barrels (Bbbl) of crude oil plus lease condensate in 2011.[24] A fraction of this crude oil is exported (approximately 47,000 bbl/day) to countries like Japan and China, the majority that remains is consumed domestically.

In response to rising demand, there has been a fundamental shift in U.S. oil production towards unconventional/marginal resources (tight oil). Tight oil is liquid oil stored in micropores of shale formations; fracking is used to break up the oil laden microporous rock by injecting high pressure liquid into the rock bed. Recent advances are now making the extraction of unconventional oil technologically possible and economically viable at current oil prices.[25] The amount of recoverable oil from one of the largest U.S. reserves, the Bakken Reserve in North Dakota and Montana has increased 25 fold (an additional 3 to 4.3 billion barrels of oil[26]) from early estimates, becoming the largest oil accumulation in the lower 48 states and accounting for 7% of the total U.S. onshore oil production. Due to the location and accessibility limitations of the Bakken and other isolated fields, crude oil is hauled from the field by rail, as with all rail transport there is the danger of spills and other more catastrophic accidents.[27] Other technically accessible shale oil resources in the U.S. include the Eagle Ford formation in South Texas and the Avalon and Bone Springs formations in southeast New Mexico and West Texas.

Advancements in technology have been crucial factors that have allowed producers to economically access these plays. As indicated by Figure 2.2, the development of these new resources is expected to bolster declines in other, more traditional U.S. sources.

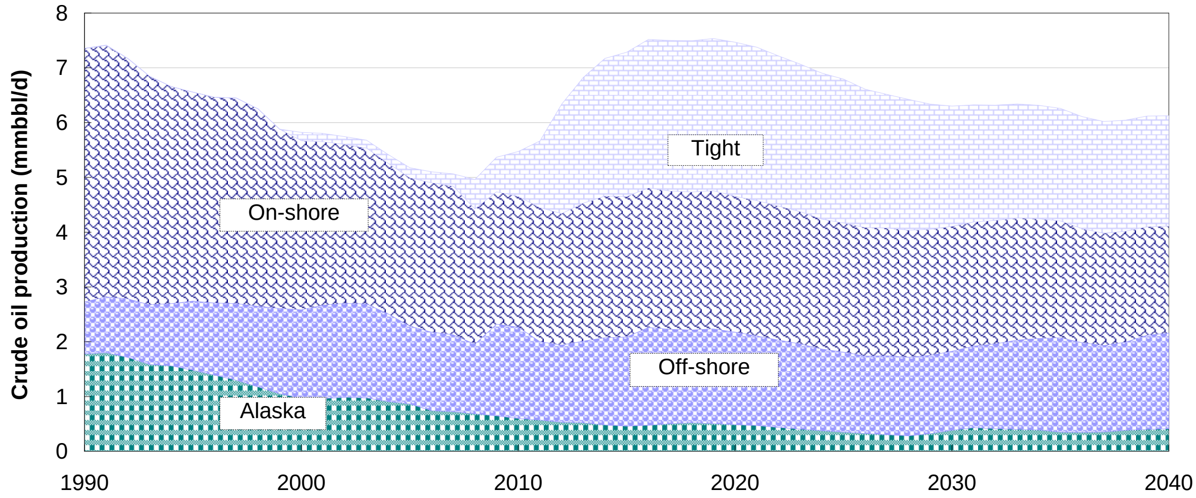

Figure 2.2. U.S. domestic crude production by source

U.S. domestic oil production is not sufficient to meet demand, thus a significant fraction of crude is imported. Figure 2.3 depicts the trend in U.S. domestic production coupled with imports over the last 10 years. On average domestic production has delivered approximately 5.8 mmbbl/d and the shortfall has been made up by imported crude, with the largest portions coming from Canada, Nigeria, the Middle East and Mexico.

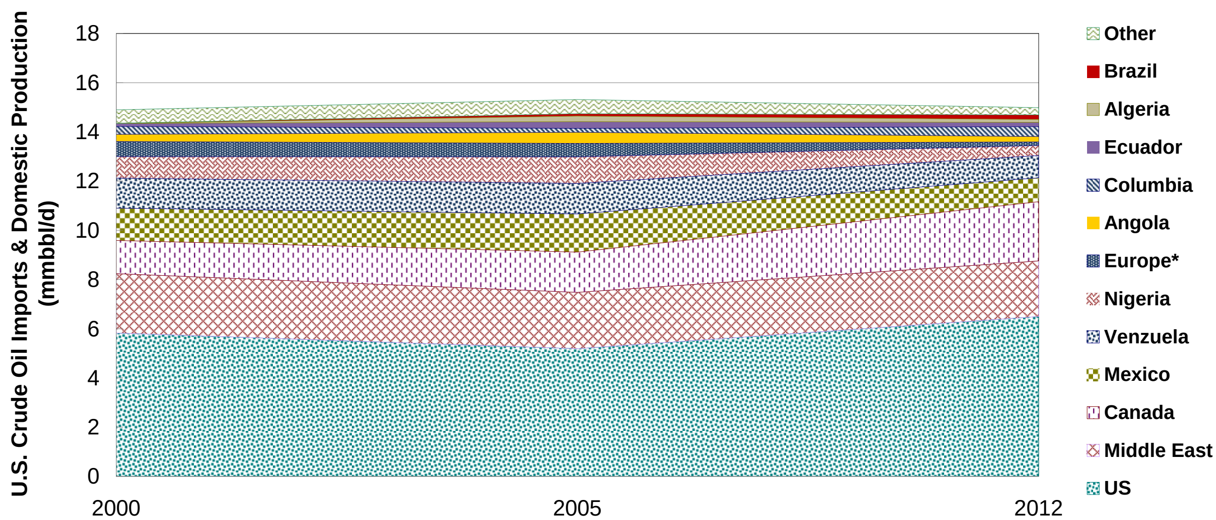

Figure 2.3. U.S. crude oil domestic production and imports by country of origin

2.4 California Crude Oil

Californian crude oil production in 2012 was 0.5 mmbbl/day continuing a slow downward trend in state crude production from a maximum of approximately 1.1 mmbbl/d in 1985.[28] Californian state production has been declining by approximately 3.5% per year and is expected to continue despite higher prices and increases in drilling activity.[29] With the decline in conventional well production, there will be a corresponding increase in stripper (wells producing less than 10 bbl/d) production.

California commonly uses Thermally Enhanced Oil Recovery (TEOR) techniques to help maintain crude oil production.[8,43] The majority of remaining Californian crude is a heavy, viscous oil that requires heating to reduce viscosity and enhance flow rates. Energy inputs and emissions generated are proportional to this. California's heavy oil production is dominated by four large, steam-enhanced oil production projects in Kern County.[30] These are the Midway-Sunset, Kern River and Cymric Fields, and the Tulare Sand in South Belridge Field, accounting for approximately 70% of California's heavy oil production. All of these fields are declining in production, with the exception of Cymric, which has had its life extended by the development of a deeper reservoir, the Etchegoin.[30]

California's heavy oil and oil sands fields have not been developedbecause of economics and politics. The Foxen oil Sand in the Santa Maria Basin is estimated to have 2 Bbbl of oil while other oil sands at Oxnard, Arroyo Grande and Paris Valley have less than 1 Bbbl of oil in aggregate. This compares to estimated 6.2 Bbbl for the Midway-Sunset Field and 4.1 Bbbl for the Kern River Field.[31] A relatively small fraction of California's offshore fields have been developed, leaving considerable exploration potential of the remaining sites.

Figure 2.4 depicts the trend in Californian (included in U.S. domestic production) coupled with imports over the last 10 years. On average domestic production has delivered approximately 0.8 mmbbl/d and the shortfall has been made up by imported crude coming from Canada, South America, the Middle East, Ecuador and Alaska. Imports of Alaska crude oil declined a total of 47% between 2000 and 2010, at an annual rate of 6.2%, corresponding to a decline in overall Alaskan oil production.

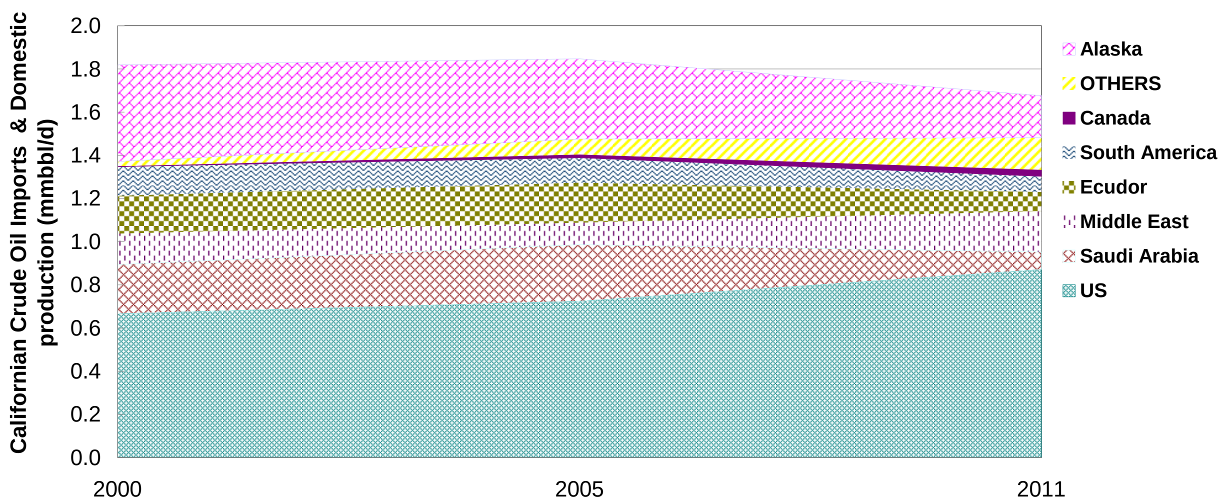

Figure 2.4. California crude oil imports and domestic production by country of origin

2.5 Trends in Ethanol Consumption

The U.S. is currently the world's leader in ethanol production and consumption.[32-33,] In the U.S, ethanol fuel is mainly used as an oxygenate and octane booster in gasoline in the form of low-level blending (10 to 15%), and even up to 85% for flexible fuel vehicles.

The ethanol market share in the U.S. gasoline supply grew by volume from just over 1% in 2000 to more than 3% in 2006 to 10% in 2011.[34-35] Domestic production capacity has increased fifteen times since 1990, from 750 million gallons to 13.3 billion gallons in 2012, Table 2.1.

The Renewable Fuels Association (RFA) reports 210 ethanol biorefineries in operation located in 29 states, with the annual capacity to produce 14.8 billion gallons. In addition, five facilities are under construction or expansion as of November 2013[36] which upon completion, would bring U.S. total installed capacity to 15 billion U.S. gallons. Most expansion projects are aimed to update the refinery's technology to improve ethanol production, energy efficiency, and the quality of the livestock feed they produce.

Table 2.1. U.S. Fuel Ethanol Summary

U.S. fuel ethanol (Billion gallon)			
Year	**Production**	**Net Imports**	**Consumption**
1990	0.75	0	0.75
2000	1.62	0.03	1.65
2007	6.52	0.44	6.96
2008	9.31	0.53	9.68
2009	10.94	0.2	11.14
2010	13.3	-0.38	12.92
2011	13.93	-1.02	12.91
2012	13.3	-0.25	13.05

Ethanol consumption in California has grown rapidly, driven by the State and national energy policies. California is the top consumer of fuel ethanol in the U.S., consuming one billion gallons in 2012, Table 2.2.

Table 2.2. California Fuel Ethanol Consumption

Year	**California consumption of ethanol (Billion gallon)**	**U.S. ethanol consumption (%)**
1990	0.05	6.34%
2000	0.07	4.04%
2007	0.98	14.06%
2008	0.99	10.28%
2009	0.98	8.80%
2010	1.28	9.91%
2011	1.02	7.90%
2012	1.00	7.66%

3. GHG Analysis

Many studies have examined the GHG emissions from petroleum fuels. Published data[1-21,42-42] provide the basis to estimate the weighted CI's of crude oil and ethanol in this study. Where data was incomplete or in need of refinement, custom analyses have been developed. The main life cycle analysis tool used in this study was GREET. GREET (The Greenhouse gases, Regulated Emissions, and Energy use in Transportation) is a full life-cycle model developed by researchers at ANL (Argonne National Laboratory) that evaluates energy and emission impacts of advanced and new transportation fuels.38 The inputs have been modified with various process specific parameters per fuel production scenario as outlined in the Appendix.

U.S. RBOB and Californian CARBOB baselines are calculated from the volume weighted WTW CI emissions. Using the production parameters per fuel type and source, the full WTW fuel cycle emissions were calculated. These emissions estimates were then applied to the fuel volumetric consumption data from EIA to develop the volume weighted emissions intensity. The following sections detail how weighted CI values for petroleum and ethanol fuels were established.

3.1 Life Cycle Analysis

Oil and feedstock production are typically the first step in fuel life cycle assessments. Oil production covers a range of technologies depending on the reservoir type, extraction technology, and oil field equipment. Before beginning a life cycle analysis, it is necessary to confine the processes by developing a System Boundary Diagram (SBD). Figure 3.1 outlines the simplified generic SBD's for the production of petroleum from crude oil and ethanol from corn. The Appendix provides detailed accounts on production methodologies for petroleum and corn ethanol.

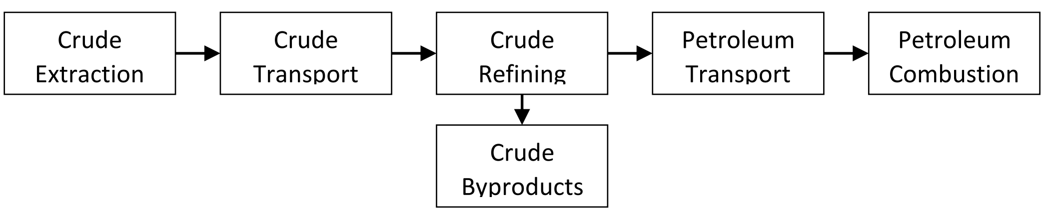

Figure 3.1. Simplified system boundary for petroleum production from crude oil

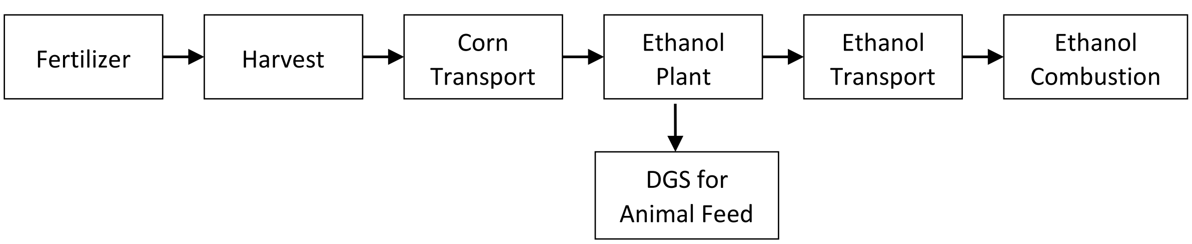

Figure 3.2. Simplified corn ethanol system boundary diagram.

The system boundary diagrams are broken into segments that outline the direct activities within the industry that have the potential to emit GHG. Integrated petroleum companies or ethanol

refineries may also have operations associated with energy generation (electricity, heat/steam generation, or cooling), mining and minerals, petrochemical manufacturing, and/or carbon capture and geological storage. For the purposes of this document, the oil and ethanol industry includes all direct activities related to producing, refining, transporting, and marketing of intermediate and refined products.
The key life cycle steps include:

- Exploration, production, and gas processing
- Transportation and distribution
- Refining
- Retail and marketing
- Vehicle use

Various storage and distribution logistics steps are involved at each stage in the process to move and store both crude oil and gasoline. Energy requirements for each stage are calculated using a "Well-to-wheels" (fuel cycle) analysis.

3.2 Petroleum Fuel LCA

Several modeling approaches are used in assessing the life cycle GHG emissions from petroleum fuels under the RFS2, LCFS, and other initiatives. The WTW results for diesel fuel, and to a lesser extent gasoline are also Life Cycle Inventory (LCI) data for fuel pathways such as corn ethanol and power generation.

Modeling of the petroleum life cycle is complicated by the variations in crude resources and oil refineries discussed in this study. The treatment of crude oil types and oil refining for various fuel LCA models is shown in Table 3.1.

Crude oil production involves many unit operations that use energy from different resources depending upon the oil field and production method. The types of energy inputs and emission sources include the following:

- Produced gas
- Produced crude oil
- On-site power from diesel or natural gas (net import or export)
- Diesel from oil refinery
- Pipeline natural gas
- Grid power
- Chemicals from other sources
- Flared produced gas
- Vented produced gas
- Fugitive hydrocarbons

Crude oil is then refined and the emission sources include the following:

- Refiner heaters fueled by fuel gas, natural gas, or other fuels
- Fluid Catalytic Cracker (FCC) coke combustion
- On-site power from natural gas, fuel gas, or other fuels (net import or export)
- Flared process gas
- Chemicals
- Reformer sour gas (CO_2)
- Fugitive hydrocarbons

Collecting data or modeling each of these sources is challenging. Data are often overly aggregated in environmental impact reports and permits and the data reflect allowable emissions. WTW models such as GREET aggregate all of the parameters into a few inputs for simplification.

Ideally, WTW studies use the best available information and calculate the results on a life cycle basis using appropriate regional detail. For example the LCI data for diesel and pipeline gas will vary by region based on the resource mixes and crude oil refinery types. The effect on the LCA result may be small but WTW models provide very precise calculations and a mismatch between inputs erodes confidence in the models.

A more important issue is the treatment of co-products. Crude oil production results in both oil and gas production. In some instances the gas is flared and this activity is hopefully included in the LCA result. The treatment of gas production also needs to be examined.

Table 3.1 shows the treatment of key steps in the petroleum fuel pathway for fuel LCA modeling studies. The Jacobs studies[5-6] and the OPGEE model[37] provide the greatest degree of detail on crude oil production. These studies take into account crude oil reservoir characteristics. None of these studies matches LCI data by region with crude oil production type, however, the uncertainty due to this omission may be small.

Table 3.1. Treatment of Petroleum Processing in Fuel LCA

Model	**CA GREET1.8b**[38]	**GREET 2012 & 2013**[38]	**Jacobs**[5,6]
Crude Oil Production	Aggregate data combined with TEOR energy and cogeneration power credit	Aggregate data	Based on generic production type
Crude LCI Data	CA_GREET, Petroleum configuration	GREET model average	GREET 1.8d, NG Mix
Venting and Flaring	GREET default, scaled to CA mix	U.S. Flaring data, adjusted for imports	Region specific
Transport distance	Location weighted	US Average	Region specific
Tanker ship (DWT)	250,000	100,000	Based on canal limit
Refinery eficiency	84.50%	90.60%	Varies with crude type, efficiency not reported
Product Allocation	Based on GREET 1.7 with additional hydrogen input	Based on EIA Data. Gasoline and diesel assigned same efficiency. Emissions shared with asphalt production	Tracked emissions and product flows through all refinery units. Assigned emissions from pet coke production to liquid fuel products.

Oil refineries produce many products including gasoline, diesel, kerosene, LPG, naphtha, residual oil, waxes, lubricants, and petroleum coke. The distribution of energy inputs and emissions to each product has a significant effect on the LCA result. The approaches differ considerably between the GREET model,[38] JRC,[39] and Jacobs studies.[5-6] The Jacobs studies provide the greatest detail on crude oil refining and take into account the oil composition as well as refinery type. These studies also treat petroleum coke, residual oil and sulfur as co-products whereas GREET allocates emissions to coke, asphalt and residual oil.

The GHG emissions from crude oil were based on the OPGEE model, developed by Stanford University,[37] combined with the results from the Jacobs studies[5-6] by crude oil type. This approach is the most accurate available among fuel LCA models. A range of GHG results are compared for different crude oil types. The WTW emissions correspond to crude production plus refining from the Jacobs studies.[5-6]

3.3 Carbon Intensity of Petroleum Fuels

Petroleum is produced from crude oil. Crude oil is a complex mixture of hydrocarbons, various organic compounds and associated impurities. The crude product exists as deposits in the earth's crust, and the composition varies by geographic location and deposit formation contributors. Its physical consistency varies from a free flowing liquid to nearly solid. Crude oil is extracted from geological deposits by a number of different techniques. When comparing transportation fuel carbon emissions, both the TTW emissions, and the upstream WTT emissions are considered. Extracting, transporting, and refining of crude oil on average accounts for approximately 20 to 30% of WTW emissions with the majority of emissions generated during end use combustion in the vehicle phase (TTW).[39]

The quality and consistency of the raw crude fed into refineries determines the complexity of processing required. It also dictates the percentages of products that can be produced per barrel of crude and the energy intensity required. For example, lower quality crude oil is more difficult to refine into transportation fuels, thus the carbon intensity for refining lower quality crudes is higher than for high quality crude.

An overview of the technologies associated with crude oil extraction with detailed descriptions of each is presented in the Appendix. The total energy expended to recover crude oil and the resulting GHG emissions vary depending upon the crude characteristics and the recovery methods used. The ARB[40] has published the range of WTT CI emission values obtained for various sources of crude oil ending up in U.S. petroleum refineries in a series of lookup tables.[41-42] These lookup tables yield the emissions from crude oil plus transport but negate to establish a relationship between refining and vehicle emissions to develop the total WTW GHG emissions. ARB estimates the emissions from crude oil production using OPGEE. The model developed GHG estimates based on key oil field parameters such as well depth, water to oil ratio, and thermal energy inputs, which is similar to the approach followed by Jacobs consulting for an analysis of petroleum emissions.[5] The methodology for thermal oil production follows the energy accounting established by Brandt and Unnasch.[43]

The carbon intensities per production method in Table 3.2 have been calculated, using a combination of GREET, OPGEE and standard accounting methods[43] The WTT emissions are calculated form the crude oil plus transport, added to the refining. Yield factors, determined from the Jacobs methodology, have been applied to the crude oil plus transport to compensate for differences in crude quality. The TTW emissions are obtained from GREET.[iv]

[iv] The EPA has calculated the TTW emissions for the 2005 gasoline baseline at 74.9 g CO_2 e/MJ, which is a approximately 1 g CO_2 e/MJ higher than the GREET TTW emissions at 73.5 g CO_2 e/MJ.

Table 3.2. Petroleum Gasoline Carbon Intensity

Petroleum Source	Carbon Intensity ($g\ CO_2\ e/MJ$) Low	High	Average
Primary	84.50	94.6	89.55
Secondary	93.58	98.18	95.88
TEOR	100.58	120.00	110.29
Stripper Wells	101.95	116.44	109.20
Mining Upgrader	100.42	104.91	102.67
SAGD, Dilbit	105.00	115.36	110.18
Fracking	97.48	111.54	104.51
GTL	77.00	100.00	88.50
Oil Shale	113.00	159.00	136.00

Conventional oil includes primary and secondary sources of oil and these are the most well defined and accessible sources of crude and hence the most drawn upon, the carbon intensity of extraction of these crudes ranges from approximately 84 to 98 g CO_2 e/MJ. TEOR (Thermally Enhanced Oil Recovery) methods are generally implemented where the crude characteristics (viscosity, API gravity) dictate and also to extend the life of a production well. Heating water to produce the steam or other *in-situ* TEOR techniques require additional energy inputs and can increase emissions by an additional 8 to 9% over conventional production. Oil sands, the colloquial name for highly viscous deposits of oil and bitumen, are expected to become a major source of global oil supplies over the next few decades. The largest known deposits in the world, are estimated to hold 170 Bbbl of oil reserves and as much as 2 trillion bbl of oil in place, are concentrated in and around the Canadian province of Alberta.[44] The quantity that is commercially viable to extract depends on the global price of crude. Compared to conventional oil deposits, oil sands require production techniques that are associated with greater environmental impacts. Shallow deposits are typically accessed using strip-mining techniques, while deeper deposits are generally accessed using in situ techniques whereby steam is injected into the reservoir to heat the bitumen until its viscosity decreases sufficiently to allow it to flow out of the reservoir. On a WTW basis, the GHG emissions from oil sands are generally between 5 to 15% higher than from most conventional oils. Heating water to produce the steam used for in situ techniques and bitumen-sand separation uses large amounts of energy, typically natural gas, and produces correspondingly large amounts of emissions. In addition, bitumen produced from tar sands must go through more extensive refining than conventional oil, producing additional emissions. Upgraded mining techniques have led to advances in emissions reductions by approximately 2% over other oil sands ranges.

The different oil sands extraction technologies produce significant differences in GHG emissions. The low end of oil sands surface mining result falls into the upper end of the range of conventional production and crude oil imports (e.g. Nigeria and Venezuela). This indicates that oil sands projects with high feedstock quality can result in a low end GHG emission range overlapping with conventional heavy oil production.

Strippers are production wells that are nearing the end of economically useful life. Oil wells are generally classified as stripper wells when they produce 10 bbl/ day or less for any twelve-month period. As more conventional wells are depleted, stripper wells will become more prevalent in the future. Stripper oil well production in the U.S. in 2004 comprised ~ 84% of domestic oil wells, equating to ~ 20% of all domestic oil – an amount roughly equal to imports from Saudi Arabia.[45] In order to maintain stripper well production, a high water-to-oil ratio is necessary. This has important considerations in the life cycle analysis driving up the GHG emissions, yielding CI ranges of 101 to 117 g CO_2 e/MJ.

Fracking of tight oil is a source of much debate. ARB is in the process of establishing a WTT CI estimate for inclusion in the next version of the lookup tables[v] and has already published a preliminary estimate represented by U.S. North Dakota.[46]

A preliminary crude oil value of 9.76 g CO_2 e/MJ, is postulated, however, this value does not account for emissions from the fracking process indicating that the value is likely to be lower than the actual value. Some of the incremental emissions can be attributed to:

- Rail transport
- Transport of fracking sand and ceramic
- Pumping energy: Oil will not have significant reservoir pressure
- Venting and flaring of fugitives are unknown for NG from fracking as well as for tight oil.

Emissions from gas venting and flaring from fracked crude oil are expected to be significant, along with transport emissions as oil is transported by truck or rail to refineries. The quality of the oil can also lead to increased refining emissions. By estimating the incremental emissions associated with these stages, an additional emissions estimate of 3 to 15 g CO_2 e/MJ can be added to the proposed ARB value. A preliminary estimate of the range in GHG emissions from the Bakken reservoir of 98 to 112 g CO_2 e/MJ has been derived. (See Appendix for more detail on the calculation and allocation).

Gas to liquids (GTL) products have the potential to replace petroleum-derived products. The resulting WTW emissions of the GTL pathway are generally lower than petroleum diesel references, in the range of 77 to 100 g CO_2 e/MJ.[47]

Oil shale is an unconventional oil deriving from an inorganic rock deposit that contains kerogen, a precursor to bitumen, oil sands and conventional crude. Oil shale is actually a confusing misnomer because kerogen isn't crude oil. To generate liquid oil synthetically from oil shale, the kerogen-rich rock is heated to approximately 950 ^{o}F (500 ^{o}C) in the absence of oxygen (a process known as retorting), generally followed by reactive chemical processing steps. The GHG emissions are correspondingly higher than those associated with conventional oils, due to the high energy demands for extraction and refining. Life cycle GHG emissions of oil shale are the highest of those examined among unconventional fuels, reaching 159 g CO_2 e/MJ.

[v] ARB published a series of lookup tables with the Carbon Intensities of transportation fuels as calculated by the ARB. The 2013 LCFS draft tables are available at:
http://www.arb.ca.gov/fuels/lcfs/regamend13/Draft_Crude_CI_Values_%28OPGEEv1.1_DraftA%29_March_4_2013.pdf

Figure 3.3 presents the CI of gasoline emissions (g CO_2 e/MJ) from the various petroleum production options ranging from conventional crude (primary and secondary) to emergent technologies, i.e. GTL synthetic crude to oil shale extraction. The technologies are ranked according to technological implementation and the breakdown of WTW emissions is allocated according to the TTW, refining and combustion emissions. Emissions related to production (oil exploration and petrochemical processing) are relatively small when compared to the end use itself.

From these trends, one can derive that the production of unconventional oil generally produces more GHG emissions than conventional oil. In terms of net emissions, an ideal way to reduce the volume weighted GHG emissions of gasoline is to blend feedstock of low CI with those of high CI.

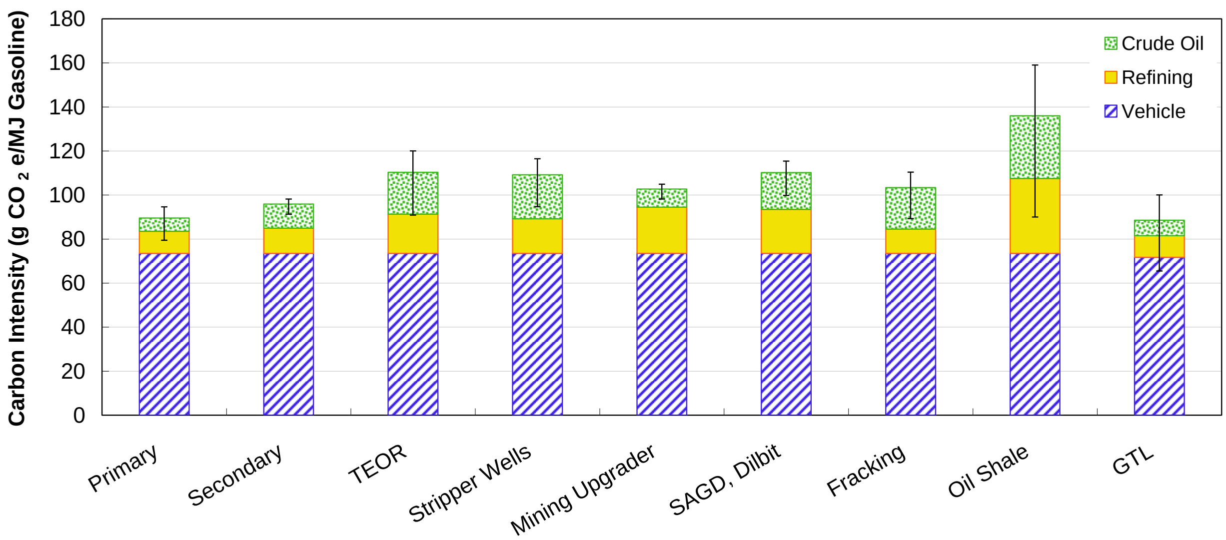

Figure 3.3. CI of gasoline emissions (g CO_2 e/MJ) from various petroleum production options.

3.4 Corn Ethanol LCA

Corn ethanol is produced from a variety of production facilities. The emissions from the corn ethanol plant depend up the energy inputs and co-products.[65] GHG emissions associated with corn ethanol include farming inputs, fertilizer production, changes in soil carbon, N_2O emissions, from fertilizer application soil carbon storage. The ethanol plant emissions include process fuel and electric power. The treatment of the co-products and emission effects of indirect activities remains an issue with all fuel pathways.

Average U.S. corn production provides the basis for LCA studies based on the notion that corn is a widely traded feedstock and that removal of corn from one region would not necessarily result in additional agricultural impacts in that region. This reasoning is extended further for the analyses in the RFS2, where biofuel crop inputs reflect the marginal crop predicted by LUC models. This study uses the GREET approach for agricultural emissions, which assigns average U.S. corn inputs to ethanol production.[38]

Table 3.3 shows several of the modeling approaches that are used to assess the GHG emissions from corn ethanol under the RFS, LCFS, and other initiatives. This study uses the GREET approach, which counts direct WTW emissions plus LUC emissions from GTAP with the CCLUB carbon stock factors. These model configurations are periodically updated by ANL.

Table 3.3. Treatment of Petroleum Processing in Fuel LCA

Model	CA_LCFS	ANL	EPA/RFS2
WTW model	CA GREET1.8b	GREET1 _2013	GREET1.8c
LUC model	GTAP BIO	GTAP ADV BIO	FASOM & FAPRI
Carbon Stock	Woods Hole	CCLUB/Winrock	Winrock
Farm emissions and fertilizer N_2O[a]	CA_GREET	GREET	Marginal crop from FAPRI
DGS Credit	1:1 corn	Corn, Soy substitution	Corn, Soy substitution

[a] GREET and EPA/FAPRI use IPCC Tier 1 calculation method (N_2O = 1.3% of applied chemical fertilizer. EPA estimates U.S. emissions with FASOM based on a county by county analysis using CENTURY.

3.5 Carbon Intensity of Corn Ethanol and Biofuels production

Two primary processes are employed to produce corn ethanol in the U.S. The current ethanol technology ferments the starch fraction of the corn kernel into ethanol, with either a dry or a wet milling process. In the dry mill process, the remainder of the kernel becomes distillers' grains with solubles (DGS) and is either dried (DDGS) to enhance storage and transportability or sold wet DGS (WDGS) to local livestock operations. Dry mill plants correspond to 83% of U.S. capacity and have experienced a 90% growth in production since 2000.

Wet mills today account for 10 to 12% of installed capacity, and less than 10% of the total number of plants. No new wet mill facilities have been constructed in the U.S. since 2005, due largely to high capital expenditure versus production capability. [48]

Figure 3.4 presents an overview of the production pathways for U.S. corn ethanol showing the primary inputs and co-products. Boxes with dashed lines highlight production process improvements developed with the maturation of the technology. Corn ethanol plants produce a variety of co-products that are taken into account with displacement credits in the GREET model. These include DGS, as well as feed products and food grade corn oil from wet mill plants.

Wet mill plants produce corn oil, which is treated with a substitute value of corn oil in the GREET model. The LUC impacts are not included in this credit. Corn oil co-produced from dry mill ethanol plants is extracted from the stillage (back end extraction) following fermentation and distillation, resulting in 2.8 to 3 gallons of corn oil per 100 gallons of ethanol.[49] The extracted oil is treated can be sold for livestock feed or refined into biodiesel. The analysis of corn oil has proven challenging when the oil is used for biodiesel.[50,51] This study treats the corn oil as a substitute for soy oil including both the direct emissions and avoided LUC. The LUC credit for soy oil is not taken into account in the RFS2 or LCFS GTAP analysis.

Corn Stover is also collected as a by-product of ethanol production (typically at a rate of 30% to prevent soil erosion and nutrient loss[52]) and either converted to ethanol via cellulosic fermentation or is treated with alkali and converted to Cattle Replacement Feed (CRF). CRF is used as a substitute feedstock for ruminants. This study treats CRF as a substitute for hay and corn, including both direct emissions and avoided LUC.

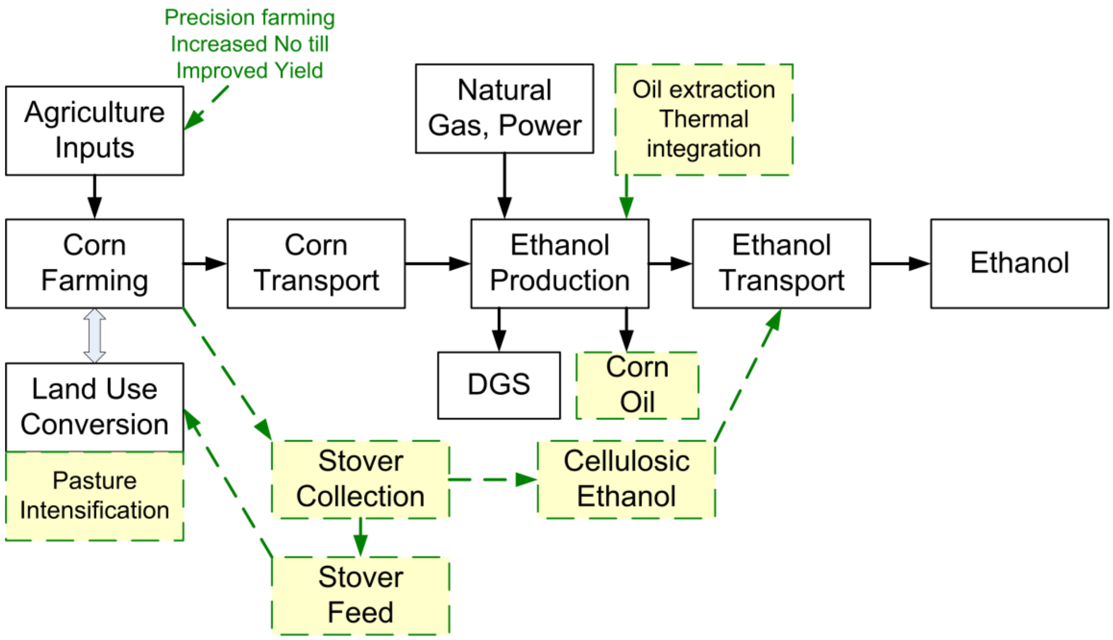

Figure 3.4. Production pathway option for corn ethanol

Land Use Conversion and Indirect Effects

LUC has been included in various fuel LCA studies since the late 1990s.[53]) was and introduced into the policy mainstream by Searchinger et al.[54] in 2008. LUC reflects the net change in carbon stocks associated with crop production as well as indirect effects that are induced by the demand for feedstocks.. LUC is an important element of a biofuels life cycle impact, including the direct emissions associated with land conversion to agricultural fields and indirect emissions associated with economic impacts induced by the change to land use.

Indirect LUC is predicted by economic models that represent food, fuel, feed, fiber, and livestock markets and their numerous interactions and feedbacks. Results from large-scale economic models, depend on a wide range of variables, such as growth rates, exchange rates, tax policies, and subsidies for dozens of countries. Other indirect effects include the effect of fuel inputs such as natural gas for fertilizer or electric power on global energy systems. A final category of indirect effects includes social phenomena that are attributed to fuel production and are not addressed in modeling efforts. Such effects include avoided petroleum production, avoided suburbanization, shifts in labor forces, and other difficult to examine activities.

Searchinger's[54] ILUC analysis for corn ethanol resulted in 104 g CO_2 e/MJ. Subsequent analyses have included a more detailed assessment of yield improvement, land cover type, carbon stocks, and other parameters. The intial GTAP analysis for the LCFS resulted in an indirect LUC of 30 g CO_2 e/MJ.[55,59] Tyner et al.[56] revised the GTAP model, including improvements in the nesting of substitute products resulting in an ILUC value of 13.9 g CO_2e/MJ for average corn ethanol. The disparity between analyses is not due to any major conceptual disputes but rather to different parameter estimates, model assumptions, and data treatment, and serve to highlight the volatility of ILUC estimations.[57] Researchers at the University of Illinois,[58] applied more accurate carbon stock factors to the GTAP model resulting in an ILUC of 9.0 g CO_2 e/MJ, which is included in ANL's GREET1_2013.[38]

ARB Treatment of ILUC

In 2009, the ARB approved the carbon intensities for gasoline, diesel, and a variety of biofuel pathways.[59] Global Trade Analysis Project (GTAP) provided the basis for ILUC emissions. The model, developed by researchers at Purdue University, is an econometric model that responds to "shocks" to the system. For example, a demand for ethanol results in a demand for corn and the price of corn increases until global commodity supply and demand is in equilibrium. Table 3.4 summarizes the ARB ILUC results for transportation fuels.[60]

Table 3.4. ARB Treatment of ILUC for Transportation Fuels**.**

Fuel type	**ILUC[a] (g CO_2 e/MJ)**
Corn ethanol	30
Gasoline	0
Diesel	0
Brazilian sugarcane ethanol	46
Biodiesel (B100) Midwest soybeans	62
Renewable diesel Midwest soybeans	62

[a] ILUC from ARB lookup tables.[41]

EPA Treatment of ILUC

The EPA estimated ILUC in the Federal Renewable Fuels Standard (RFS2) in 2010[61] using a consequential analysis with the FASOM and FAPRI models [62]. The EPA arrived at an ILUC for corn ethanol of 28 g CO_2 e/MJ, reflecting a similar value as the ARB analyses. However, EPA and ARB reached their respective ILUC estimates in distinctly different ways. Figure 3.5 presents and overview of the major studies on corn ethanol ILUC.

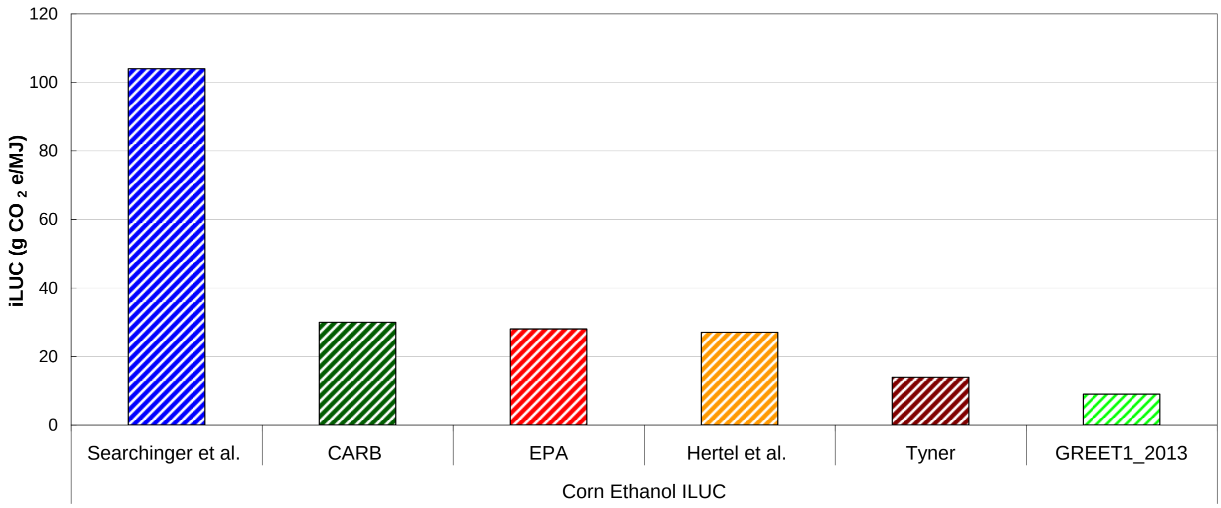

Figure 3.5. Comparison of ILUC from various sources

Biofuel use has increased since the inception of the RFS2 with 13.3 billion gallons of ethanol produced in 2012. This capacity has made U.S. the world's largest ethanol producer.[63] The total capacity is made up from ethanol produced in either wet or dry mills using various technologies for heat and power consumption or other feedstock options. This study takes the total installed production capacity combined with the CI for each technology. The technology mix is based on published literature and consultation with industry experts.[36,63-64]

The EPA in it's Regulatory Impact Analysis, analyzed cases for corn ethanol based on the 2022 scenario. Table 3.5 follows the same technology aggregation to estimate the weighted CI for corn based biofuels. The capacity per plant type (including projections for capacity expansions) was used to model the trend in corn ethanol production for established years of 2005 and 2012 and to make projections towards 2022 (reflecting RFS2 start and end points).

Table 3.5. Corn Ethanol Production Capacity and Technology Aggregation

Plant Energy Source, Aggregated data	**2005[a]**	**2012[a]**	**2022[b]**
		Capacity (MGY)	
Wet Mill, Coal	1,760	2,000	1,500
Wet Mill, NG	100	500	1,000
Dry Mill, Coal	50	20	0
Dry Mill, NG, DDGS	4,535	1,915	1,015
Dry Mill, NG, WDGS	2,240	965	660
Dry mill, corn oil DDGS		5,781	5,081
Dry mill, corn oil WDGS		2,883	1,751
Dry Mill NG, DDGS CRF[c]	303	420	1,475
Dry Mill, Biomass	182	515	2,525
Total Corn Ethanol	9,170	14,999	15,007

[a] EPA Regulatory Impact Analysis (RIA)for the final Transport Rule.[48]
[b] Custom projections in consultation with industry experts.[64]
[c] CRF can be combined with any or all of the above cases, DDGS is illustrative.

The EPA has not updated its analysis of corn ethanol because it would have little or no impact on compliance with the RFS2 as the volumetric requirements are readily achievable. However, improvements to the analysis of corn ethanol would improve the understanding of the environmental impact of this fuel option. These analysis improvements include:

1. Examine cases where corn ethanol achieves a 50% reduction in GHG emissions
2. Examine LUC impact of corn oil from dry mill plants.
3. Examine co-product credit for CRF

The EPA's interpretation of the statue is that no corn ethanol from corn starch can achieve advanced biofuel status, regardless of technological advancements in production and co-product extraction. New, more efficient corn ethanol plants, with advanced technology will still only achieve conventional biofuel status regardless of the carbon intensity of the process. Corn oil associated with dry mill ethanol is sold for animal feed and biodiesel. If corn is oil used as a supplemental animal feed, then soy oil would be a comparable replacement product. Thus the emissions associated with soy oil production and the associated ILUC emissions should be part of the co-product credit for corn oil.

Corn ethanol production technology evolves as new innovations are proven and then rapidly adopted. Figure 3.6 illustrates our analysis of the progression of new corn ethanol technology. Most dry mill plants have improved their energy consumption, thermal integration, and they produce more diverse co-products. These changes have resulted in a reduction of natural gas usage from 30,000 Btu/gal, LHV to less than 24,000 Btu/gal over the past 12 years.[65] The mix of co-product includes corn oil, wet DGS, and corn stover feed. Wet DGS and corn oil extraction result in reduced fuel use for drying. Corn oil and stover feed also result in additional displacement of animal feed and reduced ILUC. The use of biomass fuel as well as excess heat from co-located cellulosic ethanol plants are expected to reduce GHG emissions from corn ethanol even further. Weighting the production capacity with the CI for each technology allows for calculation of the weighted CI for corn ethanol production by year as shown in Table 3.6.

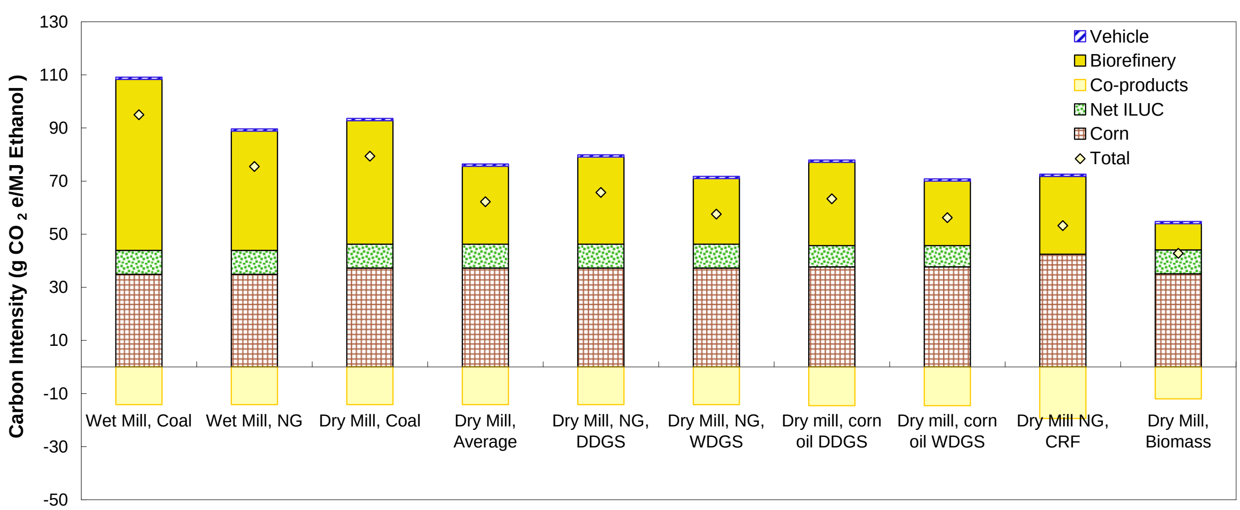

Figure 3.6. Breakdown of the CI emissions (g CO_2 e/MJ) of Corn Ethanol

Table 3.6. Carbon Intensity of Corn Ethanol

	Carbon Intensity (g CO_2 e/MJ)		
	2005	**2012**	**2022[a]**
Wet Mill, Coal	101.74	94.94	85.53
Wet Mill, NG	79.93	75.45	66.15
Dry Mill, Coal	108.65	79.35	71.19
Dry Mill, Average	66.47	62.21	55.93
Dry Mill, NG, DDGS	74.33	65.69	59.06
Dry Mill, NG, WDGS	63.96	57.54	52.56
Dry mill, corn oil DDGS		63.34	56.80
Dry mill, corn oil WDGS		56.21	51.20
Dry Mill NG, CRF	58.99	53.21	46.83
Dry Mill, NG, Biomass	51.00	42.77	38.40

[a] GREET1_2013 has been used for model analysis in the year 2020, these have been projected to 2022. Data form the latest National Corn Mill Ethanol Survey[65] and GREET1_2013, have been applied to these calculations, see Appendix for more detail.

3.6 Global Fuel Resource Endowment

Petroleum flows, resource endowment and carbon intensity of transportation fuels have been analyzed and presented in marimekko type supply charts in order to identify the resource mix and indentify the margins.

Figure 3.7 presents the carbon intensity emissions (g CO_2 e/MJ) versus the global recoverable resource endowment ranked by ease of access or production scenario. The light portion of each resource segment represents a conservative estimate of the amount of that resource available, while the darker portion represents a less certain estimate.

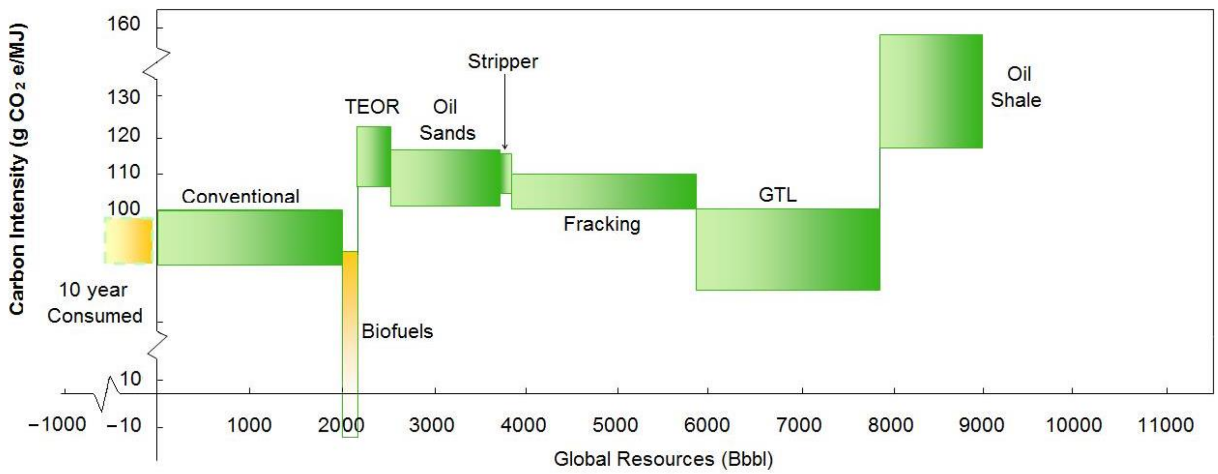

Figure 3.7. Range in of CI of gasoline for different energy resources (g CO_2 e/MJ) (2013)

3.7 Trends in U.S. Consumption

The trends in the U.S. transportation fuel consumption and CI have been examined by selecting baseline years of 2000, 2012 and 2022. By looking at a year by year basis, progress and process improvements, legislative and economic impacts and the changing attitudes of the nation are highlighted. The RFS2 and supporting incentives are a major driver for U.S. consumption and have been successful in increasing liquid biofuels consumption, increasing steadily over from approximately 167,000 bbl/d in 2005, to approximately 569,000 bbl/d in 2012. The total biofuels volumes are expected to reach approximately 792,000 bbl/d by 2022.[23]

Biofuels consumption grows through 2022 but falls short of meeting the ambitions RFS2 target of 36 billion gallons by 2022. This will be mainly due to a decline in overall gasoline consumption as a result of improving fuel efficiency and economy and updated expectations for sales of vehicles capable of using higher % ethanol blended gasoline.[66] EIA projects that from 2011 to 2022, demand for motor gasoline ethanol blends will fall from 8.7 million barrels to 8.1 million barrels per day, or by approximately 6.9%.[23]

Table 3.7 presents the carbon intensity emissions (g CO_2 e/MJ) versus the U.S. volumetric petroleum consumption over the timeframe analyzed. The crude oil volumes by production type are based on several government reporting sources (EIA, DOGGR, CEC, oil producers' data and global surveys).[67-68]

Table 3.7. U.S. Volume Requirements and Carbon Intensity Emissions Ranges (g CO_2 e/MJ)

	Volume (1000 bbl/d)			2012 Carbon Intensity Range (g CO2 e/MJ)		
Source	**2000**	**2012**	**2022**	**Low**	**High**	**Average**
Middle East	2415	2257	2336	85	95	90
Alaska	970	526	322	84	99	91
Other Primary and Secondary	3645	4627	4841	84	99	91
California	200	145	40	90	94	92
TEOR	526	381	247	101	120	110
Stripper	1164	1300	1307	102	116	109
Offshore	1526	1314	1391	89	100	94
Nigeria	875	405	405	102	104	103
Venezuela	1223	906	906	98	102	100
Canada	539	963	719	92	93	92
Oil Sands	809	1445	1078	105	115	110
Fracking	206	945	1863	97	112	105
Other Biofuels	62	70	214	40	50	45
Corn Ethanol	46	891	641	47	76	62
Cellulosic Corn Stover	0	11	342	0	12	6
Cellulosic Other	0	11	342	2	14	8
Total	14,206	16,196	16,993			

The environmental impacts of the oil transition can be seen graphically in Figure 3.8 where various estimates of CI emissions (g CO_2 e/MJ) of petroleum fuels by source versus U.S. consumption over the selected timeframe is presented. The resource endowment boxes are ranked according to supply importance and GHG impact. Historically, the U.S. has had a heavy reliance on Middle Eastern oil and this will continue, despite the increased domestic oil production forecasts. Middle Eastern oil generates typically low emissions due to the ease of extraction and refining, and the quantity of supply. However, parameters such as fugitive emissions are unknown. Alaskan oil is in terminal decline and is a dwindling resource. Other conventional (primary and secondary) sources of fuel come from combined domestic and imported production capabilities. California, has a long tradition as an oil producing state, but has now entered a period of steady decline, with a gradual reduction in production capacity of approximately 3.5% per year, as the conventional and TEOR production declines, more and more stripper wells will be commissioned.[29] The biggest impacts to the U.S. crude oil slate can be expected to come from increased oil sands production and the "shale boom" from tight oil. According to the AEO 2013[23] there has been an approximate 6 fold increase in consumption of tight oil from 2000 levels and this is expected to approximately double by 2022. The increase in tight consumption will offset declining domestic conventional crude production (e.g., Alaska, California).

The average price per barrel of crude (WTI spot price) was approximately $30 in the year 2000, this rose steadily in response to global and economic events to $94.87/bbl in 2011, to a current price of $94/bbl although, this is expected to rise again in the future.[69]

Figure 3.8. Carbon Intensity (g CO_2 e/MJ) of petroleum fuels versus consumption for the U.S.

3.8 Californian Consumption

Californians consume nearly 44 million gallons of gasoline and 10 million gallons of diesel every day.[23] California as a low carbon State, is seen as an environmental bellwether and has championed the LCFS regulations by applying CI requirements that affect the feedstocks that are fed into Californian refineries and the fuels sold in the state. The use of renewable fuels as well as alternative fuel sources (electricity and natural gas) is expected to reduce overall consumption in the future. Table 3.8 presents the CI versus the Californian consumption over the timeframe analyzed. Crude oil volumes by production type are based on several government reporting sources (EIA, DOGGR, CEC, oil producers' data and global surveys.[67-70]

Table 3.8. California Volume Requirements and Carbon Intensity Emissions Ranges ($g\ CO_2\ e/MJ$)

	Volume (1000 bbl/d)			2012 Carbon Intensity Range ($g\ CO_2\ e/MJ$)		
Source	**2000**	**2012**	**2022**	**Low**	**High**	**Average**
California	92	62	40	90	94	92
TEOR	542	366	238	101	120	110
Alaska	447	211	20	84	99	91
Middle East	245	371	308	85	95	90
South America	98	155	127	94	102	98
Canada	0	16	8	92	93	92
Oil Sands	0	23	12	105	115	110
Stripper	130	88	57	102	116	109
Fracking	0	100	400	97	112	105
Other Domestic [a]	130	71	150	84	99	91
Other Biofuels	9	10	31	40	50	45
Corn Ethanol	7	127	92	47	76	62
Cellulosic Corn Stover	0	2	49	0	12	6
Cellulosic Other	0	2	49	2	14	8
Other Foreign	144	222	183			
Total	1,844	1,826	1,762			

[a] Not disaggregated by CI

The past and future changes in the carbon intensity of Californian transportation fuels were examined, by selecting baseline years as above and charting the trends in each, Figure 3.9. Resource endowment ranking is allocated by supply importance and GHG emission range.

Historically, California has been relatively self-reliant on petroleum supplies (CA-domestic), however, CA-domestic production has been in steady decline for some time now (approx. 3.5% per year).[29] CA-domestic production is typically achieved by either conventional (primary & secondary) means and TEOR methods, as CA-domestic capacity is reduced, an increasing number of wells will be reclassified as stripper wells, and will continue to produce from the margins. This decline of CA-domestic supply has increased reliance on both U.S. domestic supplies and foreign imports.

Canadian Oil sands, traditionally excluded from Californian refineries have gradually been incorporated in the State's stocks with the advancement in extraction and refining processes. The low-end of oil sands surface mining 97 g CO_2 e/MJ falls into the range of conventional production.

In 2000, the majority of imports were from the Middle East followed closely by South America, with GHG emissions in the range of 89 to 108 g CO_2 e/MJ. No data was found for oil shale consumption within the state and given the comparatively high GHG emissions, incorporation is not readily expected for some time.

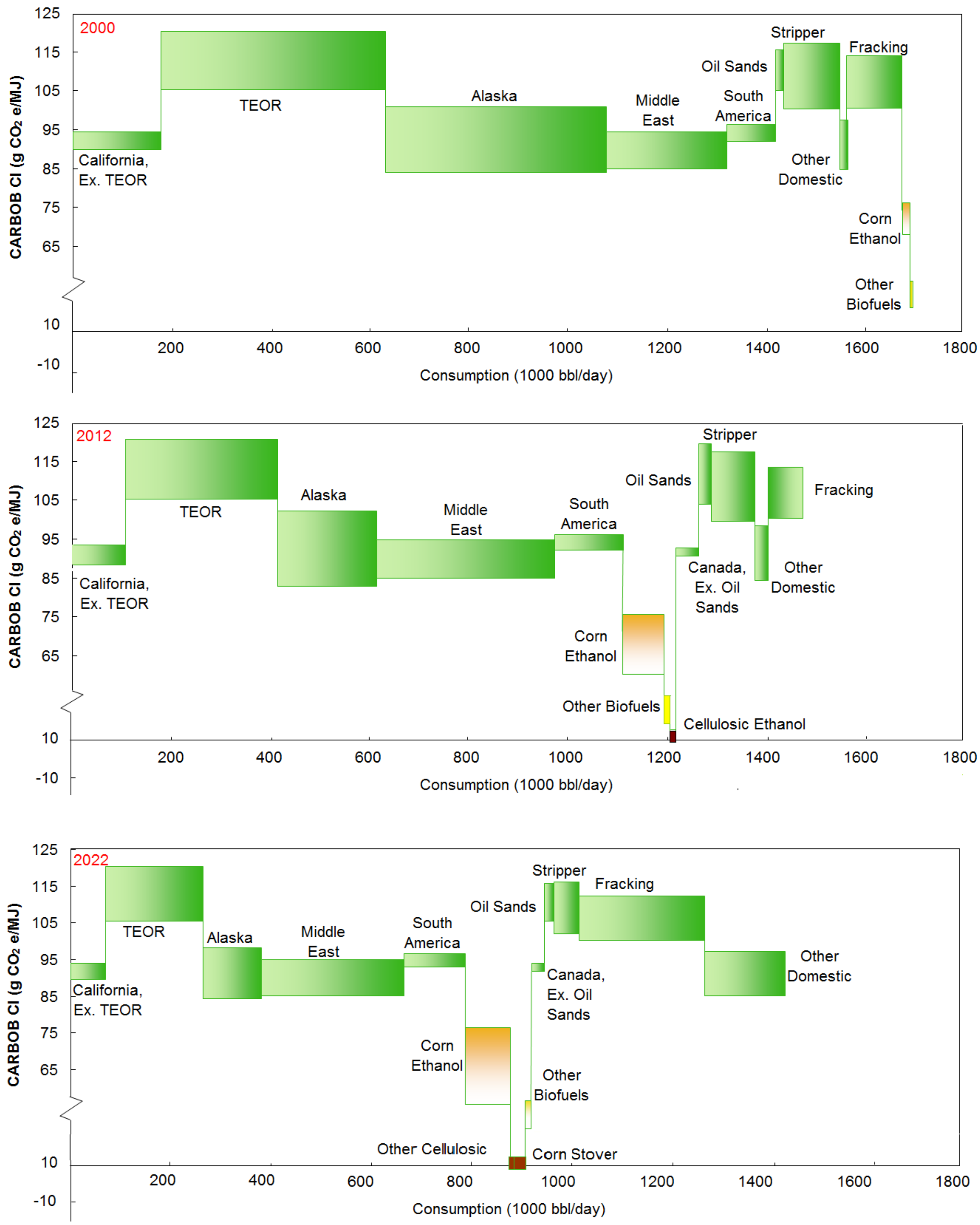

Figure 3.9. Carbon intensity (g CO_2 e/MJ) of petroleum fuels consumed in California

3.9 Weighted Fuel Carbon Intensities

The lifecycle emissions of the fuel sources in the U.S. combined with the volumes provide the volumetric weighted average CI over time. These results are greater than the 2005 EPA average gasoline baseline (93.08 g CO_2 e/MJ). The median CI of U.S. petroleum gasoline is 96.87 g CO_2 e/MJ. while Californian CARBOB is 99.19 g CO_2 e/MJ

The ARB 2012 CARBOB CI value is 99.18 g CO_2 e/MJ following a revision from the original 2006 default baseline of 95.86 g CO_2 e/MJ. This revision to the baseline reflects the changing mix of crude oil resources. This study has closely correlated the 2012 ARB CARBOB CI. The LCFS compliance target is 86.27 g CO_2 e/MJ by 2020. The 2020 CI for petroleum gasoline is 99.58 g CO_2 e/MJ, highlighting an approximate 13.3 g deficit that must be overcome to achieve compliance.

Figure 3.10 depicts the weighted carbon intensities of petroleum fuels consumed in the U.S. and California alongside the current baselines and mandated targets.

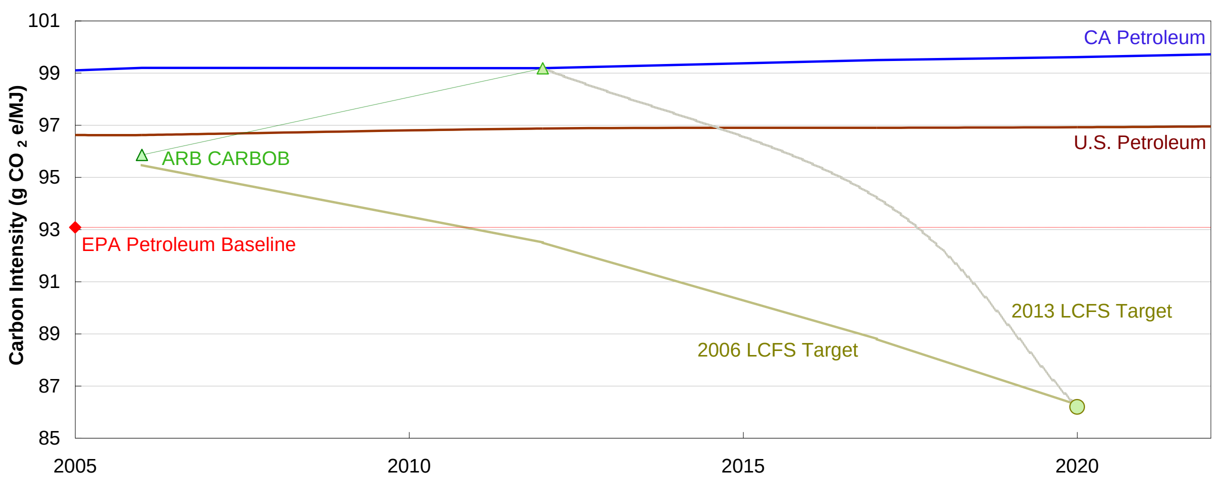

Figure 3.10. Weighted carbon intensity (g CO_2 e/MJ) of petroleum fuels consumed in the U.S. and California

While petroleum fuels have slowly and steadily increased in CI, corn ethanol, on the other hand has steadily declined. Further significant incremental CI savings are expected in the near future with the advancements in fermentation technology and the use of stover as a feedstock. The average Ethanol CI corresponds to the median CI weighted by corn ethanol production type and volumes as previously described. Figure 3.11 shows corn ethanol to steadily decline over time with advances in cellulosic/stover technologies driving the CI to 39.3 g CO_2 e/MJ by 2022.

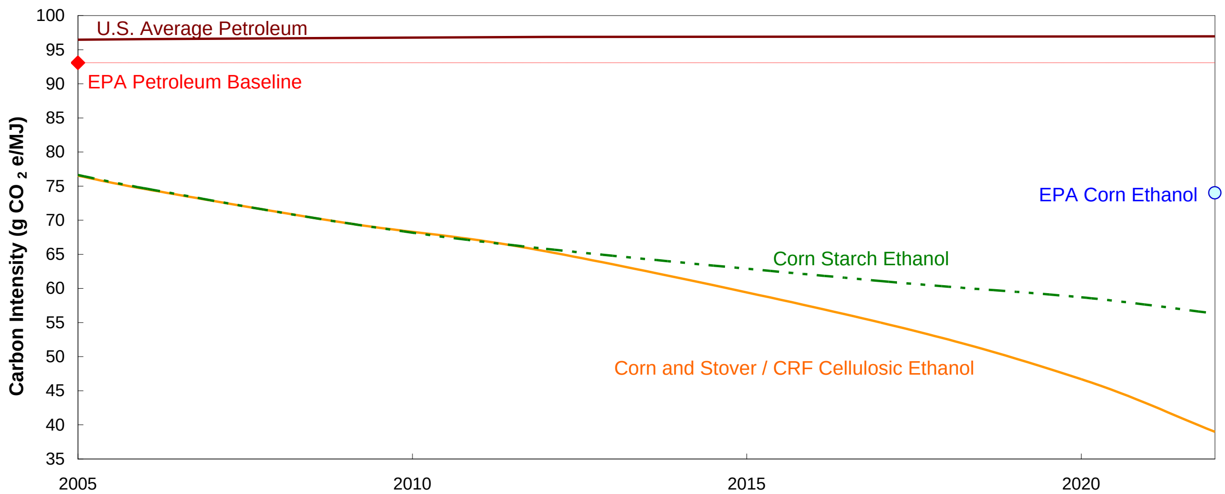

Figure 3.11. Weighted carbon intensity (g CO_2 e/MJ) of petroleum fuels and corn ethanol consumed in the U.S. over time.

3.10 What do biofuels replace and why does it matter?

The majority of unconventional fuel sources discussed here emit significantly more GHG emissions than both biofuels and conventional (primary and secondary) fossil fuel sources, as shown in Figure 3.12. As previously discussed, the biggest future impacts on the U.S. oil slate are expected to come from oil sands (with the keystone XL pipeline) and fracking production (from North Dakota). Oil Shale is a significant GHG contributor, however, capacity is not expected to increase significantly in the near future.

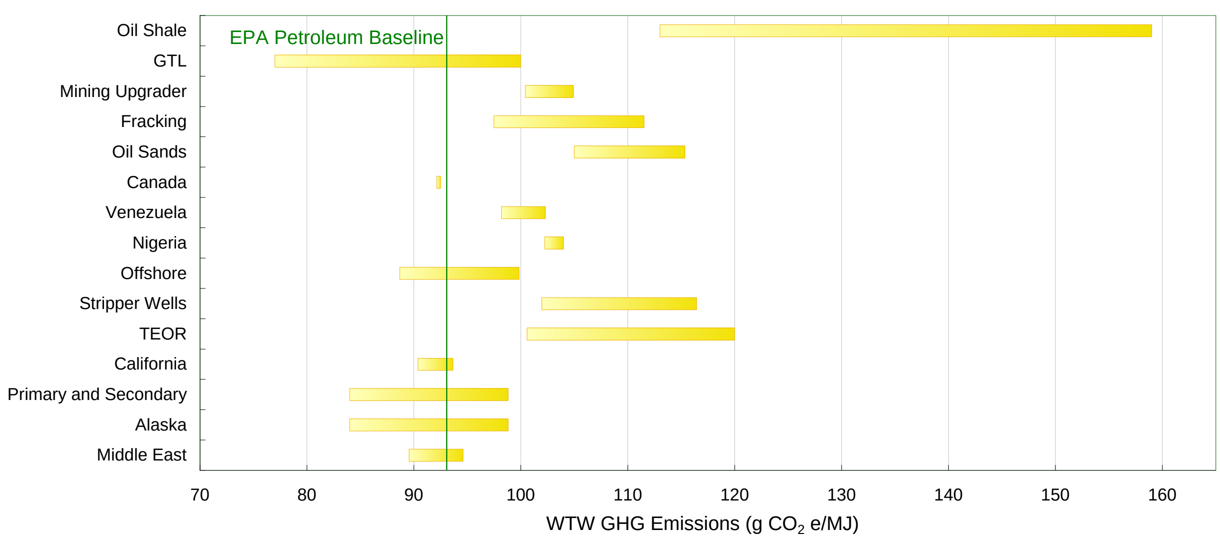

Figure 3.12. Carbon intensity (g CO_2 e/MJ) of petroleum fuels

Biofuels production and consumption in the U.S. are an incentivized encroachment into the transportation fuel slate, driven primarily by government mandates and environmental policies. By 2022, the total share of liquid biofuels consumed in the U.S. is expected to grow by 18% on 2012 levels.[23]

Substitution and blending of cleaner renewable fuel sources for crude oil is one strategy that has been marketed to reduce the carbon footprint of transportation fuels. However, the impact of these cleaner renewable fuels on the U.S. and California petroleum slates has yet to be established. The question arises as to whether policy and industry efforts to reduce the CI of transportation fuels by substitution and blending has had any impact at all?

When alternative fuels are viewed as an incremental resource, several marginal petroleum options represent the effect of these new energy resources. These scenarios for the year 2022 are presented in Figure 3.13. To determine drivers for future growth, this study extrapolates from current policy and production economics, generating two potentially significant scenarios. These are the approval of the Keystone XL pipeline and the continuance of the U.S. shale boom. Both of these scenarios would increase the shares of unconventional oil in the domestic slates and shift the weighted GHG emissions accordingly. Under these drivers, higher CI petroleum would be fed into U.S. refineries, elevating the overall emissions.

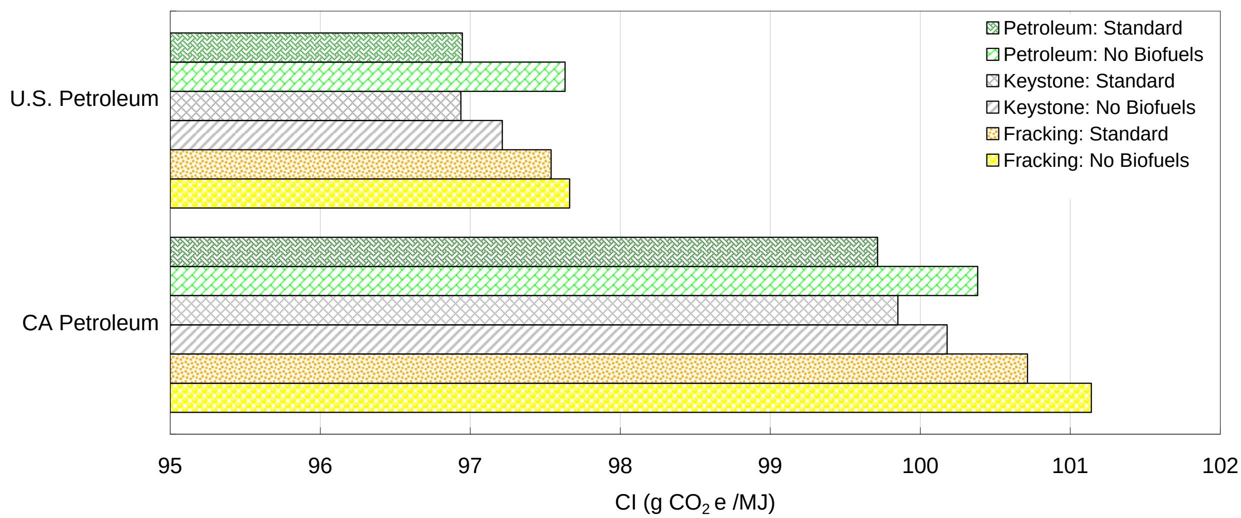

Figure 3.13. Weighted carbon intensity (g CO_2 e/MJ) of petroleum fuels under current projections and alternate likely scenarios.

In practical terms, the emissions that can be saved by the use of corn ethanol in place of the emissions that are generated from marginal petroleum fuels can be used to derive a "marginal petroleum GHG avoidance" situation as a positive indirect effect of these fuels. Indeed, the forgone increase in GHG emissions could even be considered an indirect effect of biofuels and could even be credited to the CI of biofuels. For example, for biofuels displacing petroleum fuels results in a change in U.S. average CI from 97.6 to 96.9 g CO_2 e/$MJ_{gasoline}$, the indirect effect of using biofuels is a savings of 0.7 g CO_2 e/$MJ_{ethanol}$ which could be credited to ethanol on a 1:1 basis.

3.11 What are the policy implications of increased marginal fuels?

Both corn ethanol and petroleum gasoline are treated differently under the RFS2 and LCFS. Table 3.9 summarizes some of the key differences. The RFS2 requires biofuel volumes and establishes CI thresholds. The threshold for conventional biofuels is a 20% reduction in GHG emissions from a 2005 petroleum baseline. Much of the corn ethanol produced today and all new production capacity is below this threshold. The most advanced corn ethanol configurations achieve a 50% reduction in GHG emissions, which would qualify for advanced biofuel status, except that the EISA statue limits fuels made from corn starch to conventional biofuel status.

Table 3.9. Comparison of Governing Fuel Policies

Policy	RFS2	LCFS		
Calculation of corn ethanol CI	Analysis of various corn ethanol technologies using GREET1.8c. 20% reduction in GHG emissions for conventional biofuel status.	CI for each fuel pathway. Default pathways based on CA_GREET. Corn ethanol producers also register facility specific pathways based on operating data.		
LUC and agriculture	Agroeconomic modeling of LUC and farming inputs. (FASOM and FAPRI)	Agro-economic modeling of LUC with GTAP, currently value is 30 g CO_2 e/MJ.		
Petroleum Baseline	2005 baseline, U.S. crude oil mix. Hybrid of NETL and GREET models	2006 baseline, CA crude oil mix, CA GREET refinery inputs.		
Treatment of future year petroleum	Fixed baseline (93 g CO_2 e/MJ)	Average CI calculated by year. CI of crude oil is taken into account. Petroleum refining CI is fixed and does not take into account crude oil properties [a].		
Other indirect effects	Limited analysis of indirect economic effects.	Examined in working groups. Not included in CI.		
Gasoline CI, (g CO_2 e/MJ) [b]	2005 baseline	2006	2012	2022[c]
	93.05	95.86	99.18	99.72

[a] The CI of petroleum refining depends on both the refinery configuration and crude oil type. The LCFS does not distinguish among oil refineries and uses the CA_GREET default CI in order to avoid "shuffling" of crude oils among refiners.

[b] 2006 and 2005 values are baseline values used under RFS2 and LCFS. Look up table for LCFS

[c] This analysis has correlated the 2012 ARB CARBOB baseline, thus it is reasonable to assume that the 2022 CI will show a similar correlation.

The LCFS calculates the CI for each fuel technology, with individual ethanol plants registering their CI based on actual performance. The LCFS requires a reduction in CI for transportation fuels sold in California. The weighted contribution of all fuels contributes to this calculation. ARB is assessing the impact of crude oil production, while they are assuming that changes in oil refining would be covered under the State's GHG cap.

3.12 Recommendations: How should GHG calculations be improved

- **Calculate CI for crude oils and oil refining based on production type.**

The ARB's approach to calculating GHG emissions by crude oil type helps improve the understanding of the different types of crude oil.[71] Analyses of this type should be extended to the U.S., EU, and other regions that strive to manage GHG emissions from transportation. Analyses of GHG emissions from oil refining typically do not take into account crude oil type. A more detailed analysis of oil refining should be carried out following methods laid out in recent studies.[2,4,5,9] The analysis of GHG emissions should also take into account transportation logistics including deliver of finished product by smaller capacity marine vessels and the hauling of small volumes of crude oil from stripper wells. Analysis methods to determine GHG emissions from petroleum fuels should be readily available to inform the public even if the specific results of the analysis are not used in policy calculations. For example, the RFS2 uses a 2005 petroleum baseline. This regulatory approach does not mean that we should abandon the improved calculation of GHG emissions from petroleum.

- **Include indirect effects and co-products in petroleum GHG calculations.**

The treatment of co-products like petroleum coke and residual oil is simplified in most fuel LCA models. Energy inputs and emissions are allocated between all energy products[1]. So, producing more petroleum coke and residual oil effectively lowers the GHG emissions from gasoline and diesel. Heavy refinery products can also be treated by the substitution method[1,4, 17,] which was also examined in this study.

- **Include the ILUC impacts of co-products associated with corn ethanol.**

Advances in corn ethanol technology are resulting in an increase in production of feed quality. Corn oil extraction results in higher quality feed supplements. The substitute value for corn oil should be based on an alternate product like soy oil as well as the avoided ILUC from soy oil production. Similarly, corn stover is co-produced with corn and the avoided feed and ILUC should be included in GHG calculations.

- **Examine scenarios for corn starch based advanced biofuels.**

Advanced corn ethanol scenarios can achieve over 50% reduction in GHG emissions when all of the co-products and indirect effects are taken into account. This study examined corn oil extraction with stover feeding. Other corn starch configurations can also achieve a 50% reduction in GHG emissions and these impacts should be examined even if they are not included in current fuel policy.

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