Life Cycle Associates

Carbon Intensity of Marginal Petroleum and Corn Ethanol Fuels: Appendix

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DISCLAIMER

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Terms and Abbreviations

ANL	Argonne National Laboratory
API	American Petroleum Institute
ARB	California Air Resources Board
Btu	British thermal unit
bbl	Barrel of Oil
Boe	Barrel of Oil Equivalent
Bbbl	Billion Barrels of Oil
CA	California
CARBOB	California Reformulated gasoline blendstock for oxygen blending
CEC	California Energy Commission
CI	Carbon Intensity
cP	CentiPose
DOE	Department of Energy
DGS	Distillers Grains with Solubles
DDGS	Dry Distillers Grains with Solubles
DOGGR	Department of Oil, Gas and Geothermal Resources
EOR	Enhanced oil Recovery
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
IOGCC	Interstate Oil and Gas Compact Commission
kW	kilowatt
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 Barrel's of oil
NG	Natural gas
NREL	National Renewable Energy Laboratory
NETL	National Energy Technology Laboratory
OOIP	Original Oil in Place
ppm	Parts per million
RBOB	Reformulated gasoline blendstock for oxygen blending
RFG	Reformulated gasoline
RFS	Renewable Fuel Standard (U.S.)
SAGD	Steam Assisted Gravity Drainage

scf	Standard Cubic Feet
SI	System International
SRP	Sucker Rod Pump
STB	Stock Tank Barrels
TEOR	Thermally Enhanced Oil Recovery
TTW	Tank-to-wheels
ULSD	Ultra low sulfur diesel
U.S.	United States
VOC	Volatile Organic Compound
WDGS	Wet Distillers Grains with Solubles
WOR	Water to Oil Ratio
WTT	Well-to-tank
WTW	Well-to-wheels

1. Petroleum Production Technologies

1.1 Petroleum

Petroleum is a complex mixture of hydrocarbons (typically alkanes; linear, branched, cyclo-, or aromatic), various organic compounds (asphaltenes) and associated impurities (Sulfur). The crude product exists as deposits in the earth's crust, and the chemical composition varies by geographic location and deposit formation contributors (algae, plant, minerals, etc.).

Conventional oil is traditionally seen as oil that is "easily" extracted and refined, whilst unconventional oils tend to be heavy, complex, carbon laden, and heavily impregnated into layers of sand, tar, or rock.[1,2] Crude oil can be divided into categories, these are:

• **Conventional Oil:** Petroleum with a viscosity less than 100 centipoise (cP)[i]. If viscosity data is not available, conventional oil is defined as that with API[ii] gravity values greater than 22º.
• **Heavy Oil:** Petroleum with a viscosity between 100 and 10,000 cP. If viscosity data is not available, heavy oil has API gravity values between 10º and 22º.
• **Bitumen:** Petroleum in the semi-solid or solid state. Its viscosity should be greater than 10,000 cP. If viscosity data is not available, bitumen has API gravity values of less than 10º API.[3]

Sulfur content

Crude oil is defined as "sweet" if the sulfur content is 0.5% or less by weight and "sour" if the sulfur content is greater than 1.0%. Sulfur compounds in crude oil are chemically linked to hydrocarbon chains and require additional equipment and energy during refining to remove from crude oil, intermediate and finished products. Transportation fuel specifications require extremely low sulfur contents, usually less than 80 parts per million (ppm).[4]

1.2 Crude Oil Recovery Techniques

This section describes the data used to quantify the recovery energy necessary for each type of crude and its dominant recovery technique. Petroleum recovery has traditionally been grouped into three categories, primary, secondary and tertiary recovery based on when they are likely to be implemented in a commercial production field. Table 1.1 provides an overview of the crude oil recovery options available.

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[i] A centipoise (cP) is a non-SI (non-System International) measurement unit of dynamic viscosity in the centimeter gram second (CGS) system of units. It is multiple of the CGS base viscosity unit named poise (P). Centipoise is measured at atmospheric pressure and original reservoir temperature and on a gas-free basis.

[ii] Specific gravity is the ratio of the density of the crude oil to the density of water. Specific gravity is expressed on the API (American Petroleum Institute) scale, calibrated in terms of degrees API (°API). The API gravity is inversely proportional to the density of the crude oil; hence lighter oils have higher degrees API. The relationship between the API gravity and the specific gravity of an oil is:

$$\text{API gravity} = \frac{141.5}{\text{specific gravity @60oF}} - 131.5$$

Table 1.1. Typical crude oil recovery options

Category	Options	Description
Conventional: Primary recovery	Natural water drive	The rise of the water layer below the oil column displaces oil upward into the well.
	Gas-cap drive	Energy from the expansion of compressed natural gas forces the oil from the reservoir to the well.
	Dissolved gas drive	The dissolution and expansion of dissolved gas in the crude drives the liquid from the reservoir to the well.
	Gravity drainage	The movement of oil within the reservoir from upper to the lower parts, driven by gravitational forces.
Conventional: Secondary recovery	Water flooding	Water is injected into the well to increase the reservoir pressure and displace oil deposits
	Natural gas	Natural Gas is injected into the well to increase the reservoir pressure and displace oil deposits
Tertiary Recovery	Thermal EOR (TEOR)	Thermal energy (Steam or hot water injection and in-situ combustion) is used to raise the temperature of the oil, thus reducing its viscosity and enhancing flow rates.
	Nitrogen Flooding	Similar to Natural Gas injection, Nitrogen gas is injected into the well and creates a gas pressure drive towards the bore head
	CO_2 Flooding	CO_2 is injected into oil wells under supercritical conditions and the flood acts as a solvent to recover oil trapped in the reservoir rock whilst providing a gas pressure drive
Off Shore	Deepwater	Offshore oil production involves the exploration, drilling, and production of oil resources under ocean waters. Exploration and production activities include seismic investigations, exploration drilling, and rig operation
Oil Sands	SAGD	Oil sands consist of heavy oil, or bitumen mixed with sand and are mined with large scale equipment. The bitumen is extracted with steam and solvents, and the remnants pumped into pits. Oil sands can also be recovered using a thermal process, with the Steam Assisted Gravity Drainage (SAGD) process. Oil sands from mining are typically processed in up-graders. Oil sands form SAGD are blended to dilbit (diluted bitumen) and pumped in oil pipelines.
Oil Shale (tight)	Fracking	Hydraulic fracturing, or "*fracking*", is the process of drilling and injecting fluid into the ground at a high pressure in order to fracture shale rocks to release in-situ deposits of oil
Shale Oil	Pyrolysis (retort) Thermal dissolution Hydrogenation	Oil shale is an unconventional oil deriving from an inorganic rock deposit containing kerogen, a precursor to bitumen, oil sands and conventional crude. Oil is extracted by subjecting the crushed shale to high temperatures usually followed by reactive chemical processes to synthetic crude.
GTL (Gas to Liquids)	Direct Conversion Fischer Tropsch (syngas)	GTL is a refinery process to convert natural gas or other gaseous hydrocarbons into longer-chain hydrocarbons such as gasoline or diesel fuel. Methane-rich gases are converted into liquid synthetic fuels either via direct conversion or via syngas as an intermediate, using Fischer Tropsch catalysts.
CTL (Coal to Liquids)	Liquefaction	There are two different methods for converting coal into liquid fuels: 1. Direct liquefaction works by dissolving the coal in a solvent at high temperature and pressure. 2. Indirect liquefaction gasifies the coal to form a 'syngas' which is condensed over a Fischer-Tropsch catalyst.

1.2.1 Conventional Oils

Conventional oil recovery methods use in situ reservoir pressure, physical lift, water flooding, and/or pressure from water or natural gas to force the flow of oil towards the well head. These methods are classified as either primary or secondary recovery depending on the methods used. The recovered oil is generally free flowing and accounts for the majority of all oil production.

1.2.2 Primary Recovery

According to the U.S. Department of Energy primary recovery typically accounts for only 10% of a reservoir's original oil in place (OOIP) reserves.[5] Primary recovery is applied during the initial production phase of an oilfield by exploiting the natural pressure difference between the reservoir and the well bore head, forcing oil towards the surface, or by using pumps to artificially lift the oil to the surface. These processes contribute to the natural pressure of the well, also called the reservoir drive.

1.2.3 Secondary Recovery

Secondary recovery begins when the well the pressure drops to insufficient levels to maintain a flow of oil to the surface. An external fluid (typically water or natural gas) is injected into the reservoir to create an artificial pressure, thus replacing or increasing the natural reservoir drive. Secondary recovery practices are halted when too much of the injected fluid is being returned at the well head and it is uneconomical to continue. Oil recovery is generally limited to 20 - 40% of the OOIP.[3]

1.2.4 Water flooding

This is the principal method of secondary recovery, whereby water is injected through dedicated vertical injection wells located at the periphery of the oil reservoir or through a network of wells distributed throughout the reservoir.[6] Water is an efficient agent for displacing oil of light to medium API gravity and is relatively easy to inject into oil-bearing formations. It is generally available, inexpensive and typically involves lower capital investments and operating costs compared to alternative recovery methods. Energy inputs are similar to those required for primary recovery (diesel in surface equipment, electric power for pumping, separation equipment, etc.) but also water handling requirements for recovery operations. The water for flooding may come from the well itself, from other oil reservoirs or non-potable saline water, from treated domestic waste water or fresh water sources.[7] A typical recovery factor from water-flood operations is about 30%, depending on the properties of the oil and the characteristics of the reservoir rock.[8]

In areas of shallow, under-pressured, and naturally heavily fractured rock (e.g. sandstone) vertically injected water is not feasible because the water is too easily channelled away through the natural fractures before it can flush out residual oil. Recent advances in water flooding techniques have led to the use of horizontal injection wells to enhance oil recovery prospects.[7-8] The process consists of a central horizontal injection well with adjacent and parallel horizontal producing wells. The basic concept is that a large amount of water can be directed into the horizontal injector at pressures that are below the fracture-parting pressure of the rock thus flushing out the oil without fracturing the rock.

Recently, work conducted by Grand Resources, Inc. (Grand) with the support of the U.S. Department of Energy on enhanced oil recovery by horizontal water flooding successfully demonstrated the use of horizontal water flooding in a production field. The project was implemented in the Wolco Field, located in Osage County, Oklahoma. Grand successfully drilled the three horizontal wells and oil production stabilized at approximately 15 barrels of oil per day (bbl/d). An estimated 6,000 stock tank barrels (stb) have been recovered from the project to-date. Based upon this success, the project was expanded outside the scope of the DOE project into nearby acreage. The combined production from expanded areas was approximately 50 bbl/d. Cumulative oil recovery to-date has been approximately 15,000 stb and considered a technical and economic success.[9]

1.2.5 Natural Gas

Natural gas is injected into the reservoir to create an artificial pressure drive in the same manner as water flooding. Gas injection is not as efficient as water flooding and thus is commonly injected in alternating steps with water to improve recovery. Gas injected into the well exhibits similar behaviour to in situ gas-cap drive: i.e. the gas expansion forces additional quantities of oil to the well bore head. Natural gas injection on average renders lower oil recovery when compared to water flooding projects, however in situations of low permeability oil formations (i.e. shales), it may be the only practical method of recovery.

The energy inputs include the use of diesel in surface equipment, electric power for pumping, separation equipment and other utilities, specialized compression and gas injection equipment. Natural gas can be produced from the well itself or nearby wells and captured for re-injection.

1.2.6 Tertiary Recovery

Tertiary oil recovery also known as "Enhanced Oil Recovery" (EOR) refers to a number of recovery operations typically carried out towards the end of life of an oilfield in order to maintain production at economical levels. Sophisticated techniques are used to increase pressure and improve reservoir drive by altering the original properties of the oil. Common tertiary recovery methods are CO_2 flooding and thermal enhanced oil recovery (TEOR) achieved via steam-flooding or combustion.[4]

1.2.7 Thermal EOR (TEOR)

TEOR methods are generally applicable to heavy, viscous crudes, whereby thermal energy is used to raise the temperature of the oil, thus reducing its viscosity and enhancing flow rates. Steam (or hot water) injection and in-situ combustion are the most common thermal recovery methods. Traditionally, U.S. domestic TEOR was fueled with direct combustion of crude oil. This practice ended in the 1980s due to air quality concerns surrounding the combustion of unrefined crudes with high sulfur and metal content.[10]

Steam flooding involves injecting steam into heavy oil reservoirs to heat the crude oil underground, reducing its viscosity and allowing its extraction through wells. One of the largest applications of steam flooding is at Kern River, California, where the field properties of high oil viscosity, low reservoir pressure, shallow depth, and high oil saturation are all favorable for steam flood recovery. The Kern steam flood project field consists of 10 inverted injection patterns, with 32 producing wells covering 61 acres. Kern River is of the largest heavy oil fields in the U.S. producing about 78,000 bbl/d.[4,10]

The associated energy inputs include diesel in surface equipment, electric power for pumping, separation equipment, etc., and other utilities, specialized steam injection equipment, and steam generation for injection. Steam can be produced from conventional steam generators, combustion turbines with cogeneration, or from the combustion of heavy oil residue. The range of energy intensities represented by historical steam flood projects is 0.21 to 0.43 MJ per MJ of incremental crude oil produced. Since these are operating steam-oil ratios, losses in generation, steam condensation in transport lines, and heat conduction outside of the formation are included. More recent Kern River field data illustrates the impact of accounting for co-produced electricity.[10] In 2006, 92 Mbbl of water as steam was injected into the Kern River field, approximately 73 Mbbl of which were generated in electricity co-generation plants. Incremental production from steam injection was 30 Mbbl, giving a steam-oil ratio of 3.06. Steam/oil ratios in other fields were over 5 indicating greater energy requirements for oil recovery.[10]

The steam injection rates and fuel use from the DOGGR data allow for the calculation of energy inputs for thermal EOR. For every MJ put into the oilfield as steam, 2 to 3.2 MJ of natural gas was burned, but 0.5 to 1 MJ of electricity was also produced in addition to the steam.[10]

1.2.8 Nitrogen Flooding

Nitrogen flooding is used for the recovery of "light oils" (API gravity higher than 35^{o}). Gaseous nitrogen (N_2) is attractive for flooding this type of reservoir because it can be manufactured on site (cryogenic separation) at less cost than other alternatives. In general, when nitrogen is injected into a reservoir, it forms a miscible front by vaporizing some of the lighter components from the oil which become miscible with the crude oil. Continued injection of nitrogen pushes the miscible front through the reservoir toward production wells. Similar to natural gas injection, water is injected alternately with the nitrogen to increase the sweep efficiency and oil recovery. At the surface, the produced reservoir fluids are separated, not only for the oil but also for natural gas liquids and injected nitrogen.

The associated energy inputs are similar to those for natural gas injection, however as nitrogen can be produced on site, the energy intensity increases but the overall costs decrease accordingly.

1.2.9 CO_2 Flooding

CO_2 is injected into oil wells under supercritical conditions (high pressure and low temperature). The CO_2 flood acts as a solvent to recover oil trapped in the reservoir rock and provides a gas pressure drive as well as reducing viscosity to drive the crude flow toward the well bore head. Alternating water slugs can also be injected with the nitrogen to increase the sweep efficiency and oil recovery. CO_2 injection has been used successfully throughout the Permian Basin of West Texas and eastern New Mexico, and is now being pursued to a limited extent in Kansas, Mississippi, Wyoming, Oklahoma, Colorado, Utah, Montana, Alaska, and Pennsylvania.[11]

Several technical feasibility CO_2 miscible flood pilot projects have been undertaken in recent years, the Hall-Gurney field, the largest Lansing-Kansas City oilfield in Kansas, is a typical example. The reservoir zone is an oomoldic limestone located at a depth of approximately

2,900 ft. The pilot consisted of one CO_2 injection well and three production wells. Continuous CO_2 injection was applied for approximately 2 years, and approximately 16 million lbm (liters per minute displacement) of CO_2 was injected into the pilot area. Injection was then converted to water to reduce operating costs to a break-even level with the expectation that sufficient CO_2 was injected to displace the oil bank to the production wells by water injection.[12]

Approximately 8,700 bbl of oil was produced from the pilot, however, production from wells to the northwest of the pilot region indicated that oil displaced by CO_2 injection was produced from five wells outside of the pilot area. Approximately 19,200 bbl of incremental oil was estimated to have been produced from these wells as of March 2010. The majority of the injected CO_2 remained in the pilot region, which was maintained at or above the minimum miscibility pressure (MMP). Although the four-well pilot was uneconomical, the estimated oil recovery attributed to the CO_2 flood is 27,902 bbl, which is equivalent to a gross CO_2 usage of 4.8 Mcf/bbl.[13]

1.2.10 Stripper wells

"Stripper wells" or "marginal wells" are terms defined by the Interstate Oil and Gas Compact Commission[14] (IOGCC) and used to describe wells that produce natural gas or oil at very low rates; less than 10 barrels per day of oil or less than 60 thousand cubic feet per day (Mcf/d) of natural gas per day. These wells have been already been through conventional primary, secondary and tertiary recovery, and it is beyond economic feasibility to continue, even though the reservoirs are not necessarily depleted. It has been estimated that in many cases marginal wells may be accessing a reservoir which stills holds up to two-thirds of its potential value[15]. However, a major problem associated with stripper wells is the loss in efficiency due low flow of oil into the well and the need to start and stop pumping.

In the U.S. in 2004 there were 397,362 marginal oil wells, producing an average of 2.14 bbl/d. Combined, these wells produced ~ 310 million barrels of oil, and comprised ~ 84% of domestic oil wells, and equating to ~ 20% of all domestic oil – an amount roughly equal to imports from Saudi Arabia[16]. Marginal gas wells represented ~ 8% of the total natural gas produced in the United States with production of about 1 Trillion cubic feet (Tcf).

Marginal production from either oil or natural gas occurs in 29 states from Alabama to Wyoming. Texas has more than 134,000 marginal oil wells and more than 49,000 marginally producing natural gas wells. Arizona, on the other hand, reported only 16 stripper oil wells and 2 natural gas wells that were producing marginally[15]. Over 17% of California oil production in 2008 was produced from stripper wells with some 59% of operating wells in California now classified as stripper wells.

Given the significance of marginal well production, a recent U.S. D.O.E National Energy Technology Laboratory (NETL) study[17] forecasted the marginal well counts and associated production through 2025. Forecast production volumes and well counts determined are summarized in Figure 1.1. Results from the analysis reveal that:

- Natural gas marginal well counts will increase over time while oil well counts will decrease, assuming no significant technological breakthroughs.

- The fraction of marginal production compared to total onshore production will continue to increase for oil and natural gas.
- A significant increase in marginal natural gas wells is expected in the Rocky Mountain region.
- By 2025, an increase of nearly 20% is expected compared to 2003 volumes.

The energy inputs for marginal oil well recovery are difficult to estimate and solid data is scarce to come by. Inputs include the use of diesel in surface drilling equipment, electric power for pumping; separation equipment and other utilities. However, given that marginal wells are essentially capitalizing on inputs from previous recovery stages, the pumping and lifting requirements are seen as the most relevant inputs. A baseline estimate of the power requirement for pumping and lifting is that it needs around 0.2 kwh/bbl/1000 ft to lift the oil to the surface (66% efficiency) and deeper wells are reported to require from 0.27 to 0.81 kwh/bbl/1000 ft.[18]

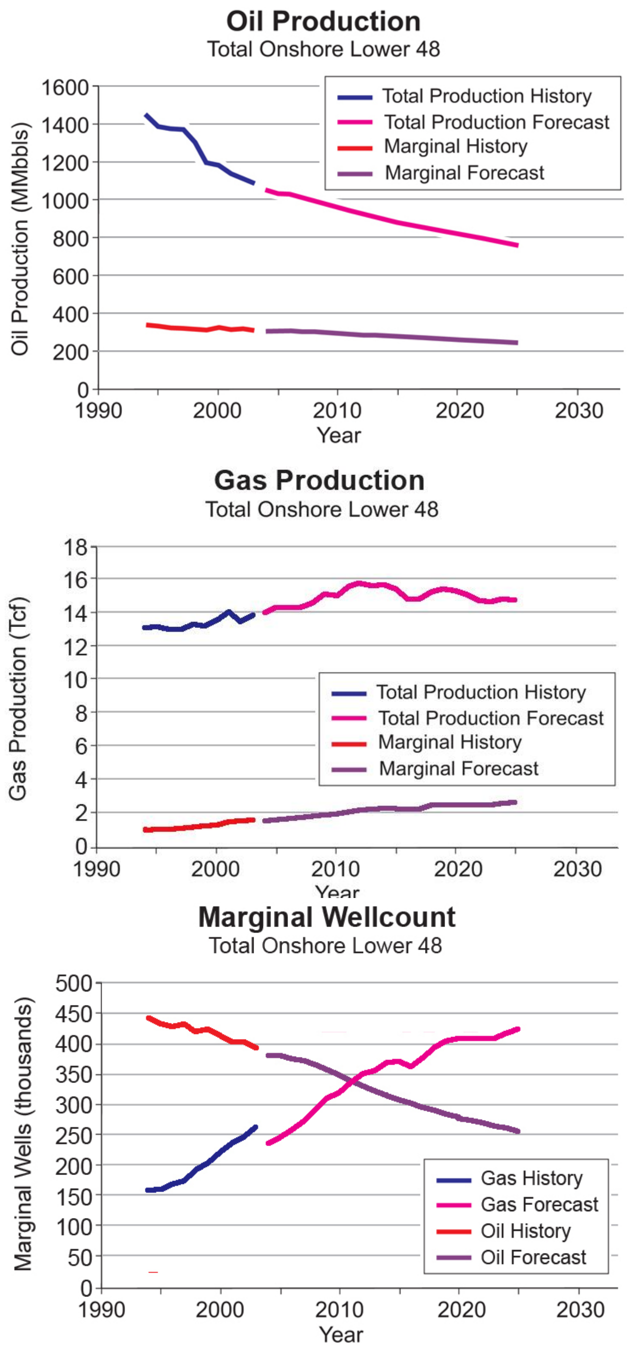

Figure 1.1. Forecast production volumes and well counts determined from National Energy Technology Laboratory study.

Source: Marginal Wells: Contribution to Future Supply FactSheet (2005) Covatch, G., Duda, J. R., Long, R. and Tomer, B. National Energy Technology Laboratory (NETL)

1.2.11 Deep Off Shore

Offshore oil production involves the exploration, drilling, and production of oil resources under ocean waters. Exploration and production activities include seismic investigations, exploration drilling, and rig operation such as the one shown in Figure 1.2.

No readily available sources of information were found to break out energy inputs between offshore exploration and production or between offshore and onshore production. The differences are difficult to discern because marine vessels are used both in exploration activities and oil rig support activities with no readily available data on energy use. Additional sources of information would include project developers and operators as well as information sites such as Rigzone.[10,19]

Figure 1.2. Typical offshore oil platform

Energy inputs for off-shore activities are difficult to estimate as the authors have not found aggregate statistics of energy inputs and oil throughput. More interviews with developers or producers would be needed to estimate energy inputs for specific projects. Off shore oil production can be expected to require more energy inputs than conventional oil production because of the requirements for marine vessel and equipment operation in exploration and rig operation. Extracting oil from deeper wells will also require additional pumping energy. The GHG emissions correspond to about 1 g CO_2 e/MJ or 1% of the energy in petroleum. Since this calculation does not represent all of the energy inputs for offshore activity and the inputs are just coarse estimates, it suggests that the marine vessel operation is a relatively small fraction of total oil production energy. The contribution towards oil production is probably less than 1 g CO_2 e/MJ. The primary sources of emissions are likely to be marine diesel fuel for exploration and production rigs as well as associated gas fuel used to power turbines on production rigs.

1.2.12 Spills

Deep-water offshore drilling is associated with oil spills; both major and minor oil spills harm the surrounding environment greatly. Spills most often occur when oil is being transported to land via oil tanker, but damaged pipelines or the platform itself may also cause spills. Such spills are a drain on both resources and energy, as well as a real and pressing danger to the environment. Oil spills, despite improved technologies, are still common and predicted occurrences. At current extraction rates, it is predicted that in the Gulf of Mexico there will be one oil spill per year of approximately 1000 bbls over the next 40 years.[20]

1.2.13 Oil Sands

Oil sands are sources of petroleum heavy oil. Oil sands consisted of heavy oil, or bitumen, mixed with sand. Oil sands are mined with large scale equipment. The bitumen is extracted with steam and the sand remnants pumped into tailing pits. Oil sands are also recovered underground using a thermal process. With the Steam Assisted Gravity Drainage (SAGD) process, the bitumen in collected in a network of pipes. Bitumen is piped to an upgrader for further refining. Diluent, with the properties of light naphtha, is blended with the bitumen to enable transport to the upgrader. The upgrader produces diluent amounts comparable to the incoming supply, which is returned back to the extraction operation.[10]

Energy requirements include use of diesel in surface mining equipment, electric power for pumping, separation equipment and other utilities, and steam for SAGD operations or separation of bitumen from oil sands. Steam can be produced from conventional steam generators, combustion turbines with cogeneration, or from the combustion of heavy oil residue. Energy inputs for unconventional oil resources and the processing of heavy oils are higher than those of conventional resources. The GREET model[21] also performs calculations for Canadian oil sands. The GREET model inputs reflect both in-situ and surface mining operations with steam generation from natural gas. The energy inputs for oil sands recovery are typically characterized by the steam/oil ratio. Surface mining equipment, results in a smaller share of the total energy inputs (about 3%) than the energy required for thermal recovery of the oil. Steam/oil ratios of 3 are considered typical for SAGD operations, which appear consistent with the GREET model inputs.[10] Emissions would be higher for projects where the source of energy is bitumen or coke. However, the trend is to use natural gas and not combust heavy oil residue. The GHG emissions from oil sands operations are reported by oil sands producers in Canada. In addition, several studies have estimated the emissions associated with oil sands production and as well as shale oil. The emissions impact ranges from 15 to 35 g/MJ depending on the study assumptions and the technology.

Steam production from oil sands operations also result in the production of several hundred MW of electric power. The Alberta grid is very coal intensive so the effect of a co-product credit based on the grid resource mix would represent an apparent GHG savings. However, the use of natural gas effectively eliminates a natural gas resource that could be used for power generation, creating the possible indirect, market-mediated effect of increasing the demand for coal or residual oil for electricity production. This possible indirect effect of oil sands production should be considered closely given the great magnitude of natural gas reserves required to produce petroleum from oil sands. As such, a credit for any co-product power should be selected on a conservative basis[22] and perhaps not until the corollary indirect effects analysis has been conducted. The GREET model provides no co-product electric power credit for oil sands operations.

Approximately 1.0 to 1.25 gigajoules (280 to 350 kWh) of energy is needed to extract a barrel of bitumen and upgrade it to synthetic crude. As of 2006, most of this is produced by burning natural gas[23]. Since a barrel of oil equivalent is about 6.117 gigajoules (1,699 kWh), efficiency is expected to improve to average of 900 cubic feet (25 m^3) of natural gas or 0.945 gigajoules (263 kWh) of energy per barrel by 2015.[24]

1.2.14 Oil Shale

U.S. Western oil shale is a finely-grained sedimentary canbonate rock (generally marlstone) which is very rich in organic sedimentary material called "kerogen." Eastern shales are generally derived from silica based formations. Oil shale is actually a confusing misnomer because kerogen isn't crude oil. Oil shale deposits are derived from inorganic rock deposit containing kerogen, a precursor to bitumen, oil sands and conventional crude.
In order to extract the oil, the shale ore is heated to separate the kerogen from the rock (a process knowns as retorting) followed by reactives chemical processes to upgrading and refining and the oil. The kerogen content of the shale ore can range from 10 to 60 or more gallons of oil per ton. The resultant extracted kerogen liquid is converted to superior quality jet fuel, #2 diesel, kerosene, and other high value products[25].

Data form the DOE suggests that America's total oil shale resources could exceed 6 trillion barrels of oil equivalent.[25] However, most of the shale is in deposits of insufficient thickness or richness to access and produce economically. The richest, most concentrated deposits in the U.S. are found in the Green River Formation in western Colorado, eastern Utah, and southern Wyoming. Other significant, less concentrated deposits exist in the Devonian, Antrim, and Chattanooga shale formations in several eastern and southern states and parts of Alaska, Figure 1.3 The CO_2 emissions from oil shale fuels are emitted during three production stages: retorting of shale, upgrading and refining of raw shale oil, and combustion of the finished transportation fuels. Reported emissions estimates from these stages represent approximately 25 to 40%, 5 to 15%, and 50 to 65% of total fuel-cycle emissions, respectively.[28]

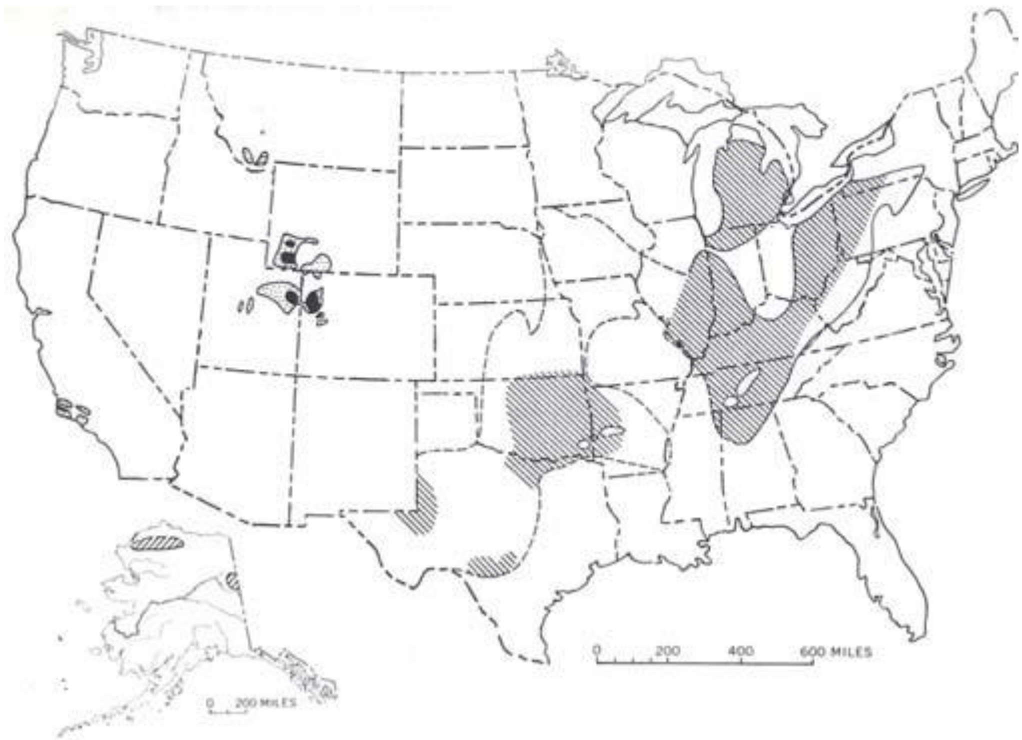

Figure 1.3. Major U.S. Oil Shale Deposits
Source: Office of Petroleum Reserves – Strategic Unconventional Fuels, Fact Sheet: U.S. Oil Shale Resources

Depending on technology and economics, as much as 1 trillion barrels of oil equivalent could be recoverable from oil shale resources yielding greater than 25 gallons per ton. The Institute for Energy Research has estimated that 1 trillion barrels is nearly 4 times the amount of proven oil reserves in Saudi Arabia.[26] The energy potential from our vast resources of oil shale could substantially shift the balance of America's oil supply away from the Persian Gulf. [27]

Oil shale production has been accelerating in U.S., growing from 111,000 bbl/d in 2004 to 553,000 barrels per day in 2011 (equivalent to a growth rate of around 26% per year). As a result, oil imports are forecast this year to fall to their lowest levels for over 25 years.[31]

GHG Implications

GHG emissions from Oil Shale are not well characterized. Brandt et al.[28-29] has conducted several major studies on the GHG implications of oil shale. Without mitigation or technology improvements, full-fuel cycle CO_2 emissions from oil shale derived liquid fuels are likely to be 25 to 75% higher than those from conventional liquid fuels, depending on the details of the process used. The most uncertain source of emissions is the retorting stage, due to variation in emissions with shale quality and retorting technology used, estimates of well establishment are uncertain due to the steep decline curve. A estimate of the range in GHG emissions from the Shale oil is from 113 to 159 g CO_2 e/MJ.

1.2.15 Fracking

Shale oil is liquid oil is stored in micropores of shale formations, fracking, (or hydraulic fracturing) is used to break up the oil laden microporous rock by injecting high pressure liquid into the rock bed. EIA estimates suggest that fracking production in the U.S. will rise to around 1.2 mmbbl/d by 2035 (equivalent to 12% of projected U.S. production at that date).[30] However, these projections seem conservative relative to other market analysts who forecast U.S. shale oil production of up to 3 - 4 mmbbl/d by that date. EIA estimates of the scale of total shale oil resources in the U.S. have been revised upwards from 4 billion bbl in 2007 to 33 Bbbl in 2010.[31] The most significant find of shale oil is in North Dakota and Montana, in the Williston basin, of which Bakken is the largest producing field.

The growth of oil shale has resulted in oil exports from the U.S. The trend is so strong that the price spread between Brent and West Texas Intermediate has turned to a premium for Brent as illustrated in Figure 1.4 and the production of U.S. oil has been cited as one of the key factors in the change in the price spread.[32]

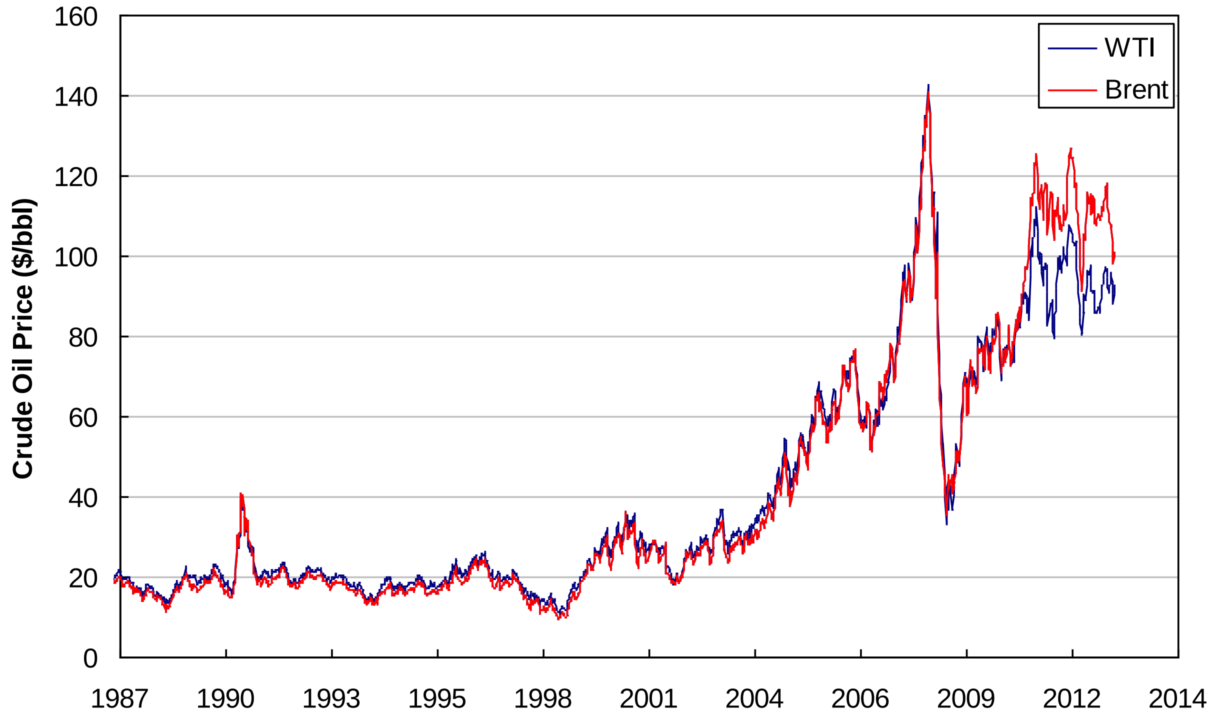

Figure 1.4. Price history of West Texas Intermediate and Brent crude oil showing the recent price premium for Brent due to expanded U.S. oil production.

GHG Implications

GHG emissions from fracking are not well characterized, however, efforts are being made by the ARB with the latest OPGEE model. The emphasis so far has been on shale gas, with few major studies**Error! Bookmark not defined.** on oil from fracking have been performed, thus we have developed custom simulations for this study using published data on well performance and comparable production data.

Oil from the Bakken reservoir is liberated through a hydraulic fracturing process. The oil is light (30^o API gravity) and low in sulfur, but is high in naphthinic acid which can cause operational problems with refinery equipment.

Bakken Oil is extracted from over 6600 wells,[33] each may produce 1000 bbl/d at peak before declining rapidly to an average of 30 bbl/d with an exceptionally steep decline curve (as rapidly as 100 days). Recently the North Dakota Industrial Commission (NDIC) presented results from dynamic simulations for a "typical" tight oil well in the Bakken field, Figure 1.5. The simulation was modeled from production data from 240 wells that were reported to have initiated production from June through December 2011 and are highly representative.[34]

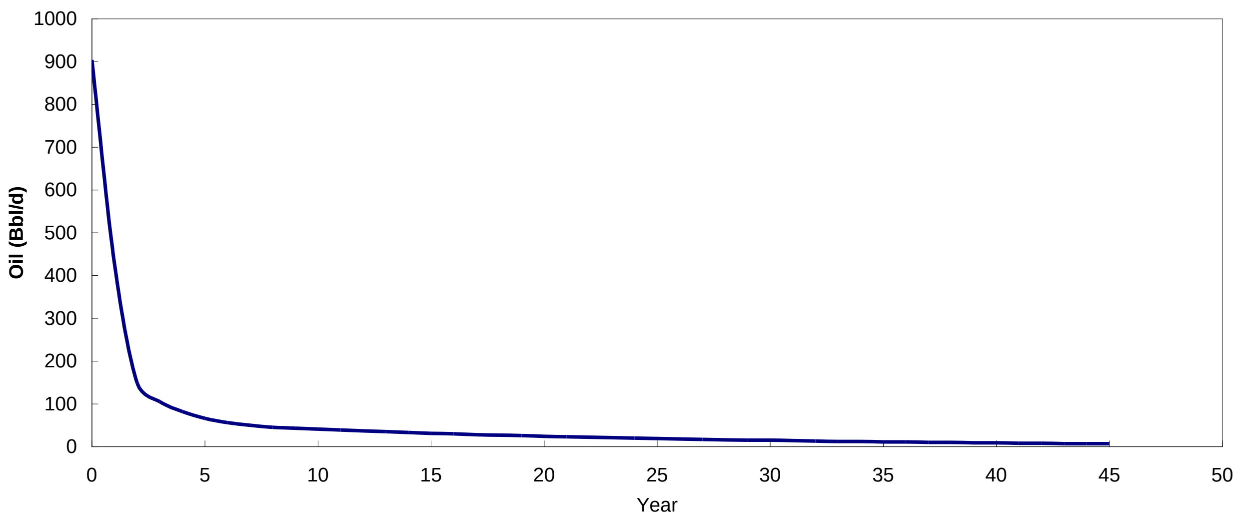

Figure 1.5. Typical Bakken well expected average daily oil production by year (NDIC).

Well establishment involves pumping fracking sand, ceramic beads, chemicals, and water into the well. Water and high pressure cause the formations to fracture, while the sand and beads hold the fractures open, allowing the oil to pool for collection. The inputs include diesel for hauling water and material and energy for pumping. Pumping energy is derived from produced gas or diesel fuel. 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.[35] The scale of rail hauling is described by Burlington Northern[36] with capacity to haul one million bbl/d out of the Williston Basin in North Dakota and Montana. Fracking for crude oil also releases significant volumes of natural gas. This high level of produced gas is not surprising since the fracking process is also used to produce natural gas. However the Williston basin is a relatively new development lacking of infrastructure to capture the released gas. Venting and flaring of the gas is commonplace to reduce emissions. The quantities of flared gas is so significant that it can be observed from low earth orbit, Figure 1.6 shows the extent of flaring from the Bakken region from satellite images.[37]

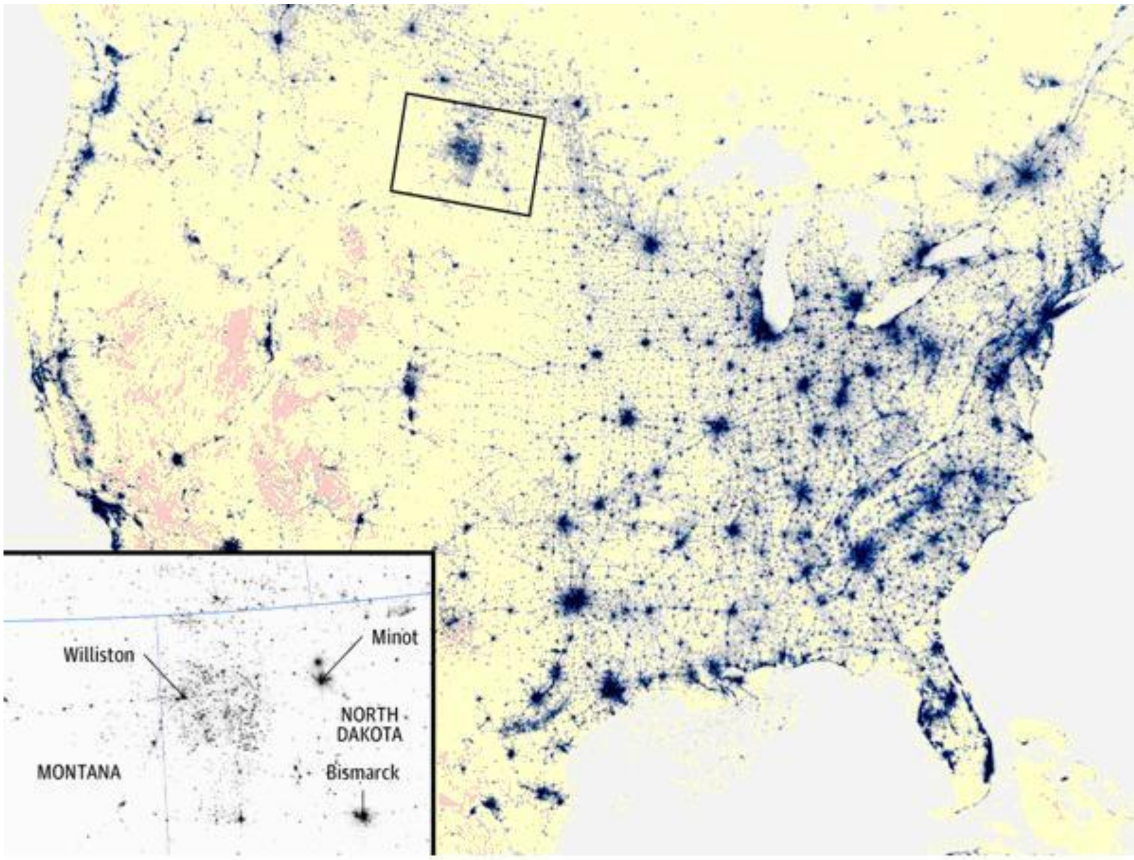

Figure 1.6. Gas flares from Bakken fracking
Source: Sklar, J. (2013) Gas flares from Bakken fracking are visible from space. New Scientist. January 2013
http://www.newscientist.com/blogs/shortsharpscience/2013/01/julia-sklar-reporter.html

Estimates[38] of the produced gas from North Dakota (Bakken) are 380 scf/bbl, this compares to 16 scf/bbl for standard U.S. continental oil, Figure 1.7 presents the volume ranges of flared gas (scf/bbl) by source for a select crude entering the U.S. Slate.

Other significant emissions include flaring, which would range from 5.2 to 12 g CO_2 e/MJ of gasoline depending on the use of the produced gas and flaring efficiency. Apparently most of the gas is flared because it has no path to market. Transport emissions are also significant. Oil can be transported by truck or developing pipeline network to rail, where it is distributed all the way to California or East coast refineries. The low API gravity and low sulfur result in the low end of refining carbon intensity.

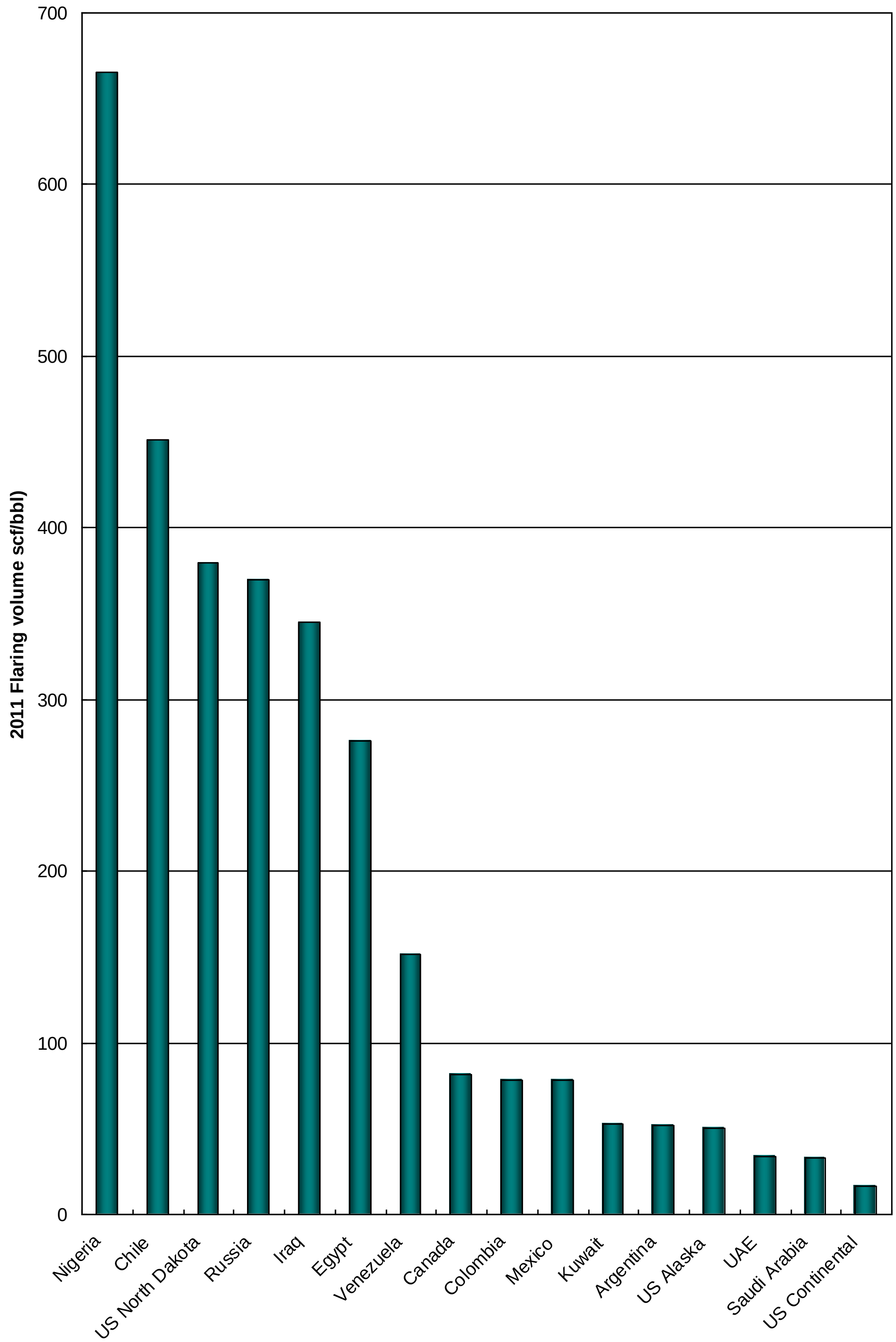

Figure 1.7. Flared gas (scf/bbl) by country of origin.

Flaring results in air emissions from combustion of methane and other Volatile Organic Carbon (VOC), when a flare pilot is extinguished due to high winds or harsh weather conditions, uncombusted raw gas is vented directly to the atmosphere. The Williston basin is a relatively exposed field with an annual average wind speed of 10.3 mph,[39] while no data was found on the rate of flare extinguishment, although it can be expected to occur.

Crude transport emissions from the Williston basin are also significant. Oil can be transported by truck or developing pipeline network to rail, where it is distributed all the way to California or East coast refineries. The low API gravity and low sulfur result in the low end of refining carbon intensity, however the naphthinic nature of the oil can lead to increased operational refining emissions. Estimates of well establishment are uncertain due to the steep decline curve. Other significant emissions include flaring, which would range from 7 to 16 g CO_2 e/MJ of gasoline depending on the use of the produced gas and flaring efficiency. A preliminary estimate of the range in GHG emissions from the Bakken reservoir would be from 97.5 to 111.5 g CO_2 e/MJ.

2. Petroleum Refining

Modern oil refineries produce a variety of fuels and other co-products. Gasoline, diesel, and kerosene (jet fuel), are the primary transportation fuel products, while LPG and residual oil products can also be used as fuels for heating, power generation, and transport. Refineries also produce coke and sulfur as co-products and some refineries produce asphalt. Attributing energy inputs to refined products and co-products is a challenging exercise complicated by the large number of product, co-product, and refinery processes involved. Several approaches have been considered for attributing refinery energy inputs and emissions to fuel products, as discussed in the following subsections.

2.1 Conventional Petroleum Refining

The method used to assign energy inputs to refined products is challenging because of the complex nature of refineries. The simplest strategy is to assign all refinery emissions and all of the combusted fuel energy to transportation fuel products in proportion to the energy content of the gasoline, kerosene, and diesel produced. This is essentially the energy allocation method, applied to transportation fuels with the understanding that residual oil, petroleum coke, and LPG are not the primary products of the refinery, because substitutes with less energy input are readily available.

Beyond the simple strategy, several approaches could be used to better understand the attribution of refinery energy inputs to fuel products. Linear programming models that yield mass and energy balances based on refinery unit performance data could provide the material balances needed to track the feedstock, fuels, utilities, and emission sources within a refinery.
A linear programming analysis would need to take into account all of the refinery processes, crude oil mixes, and economic factors that affect the refined petroleum products mixes. A linear programming analysis of refineries would need to be coupled with the impact on the crude oil slate. The effect on imported refined products would also need to be considered. Such a comprehensive modeling exercise aimed at assessing the impact of reducing gasoline demand has not been undertaken. This approach could better relate crude oil composition to fuel

specifications, hydrogen requirements, and product yields, but has not been undertaken because of its complexities.

The allocation approach in GREET[21] presents a number of challenges, which tend to understate the GHG emissions of gasoline and diesel fuels associated with refining. The core aspect of the GREET approach is to match EIA data on refinery energy with notional values for the relative energy intensity for gasoline refining. The key challenges with the approach include the following:

- GREET inputs use aggregate data. Thus, it is not possible to examine effect of oil type, API gravity, sulfur, etc.
- Notional gasoline energy intensity does not necessarily apply uniformly to all crude types and refining schemes
- 1 mmBtu of crude oil is assigned to 1 mmBtu of gasoline
- 1 mmBtu of bitumen oil is assigned to 1 mmBtu of gasoline
- Fuel cycle emissions for natural gas are applied only to about one third of the natural gas used to produce hydrogen. Thus, for example, no fuel cycle emissions are applied to the natural gas feeding the hydrogen reformer. This results in a hydrogen carbon intensity that is 6 g CO_2 e/MJ too low. For fuels that use significant amount of hydrogen, the carbon intensity is under reported by 0.5 g CO_2 e/MJ (6 gCO_2 e /MJ H_2 × 0.07 MJ H_2/MJ gasoline product)
- No fuel cycle or WTT emissions are applied to refinery fuel gas (this assumption is not consistent with 1 mmBtu of crude oil assigned to producing 1 mmBtu of gasoline). The fuel cycle emissions associated with gasoline refining appear to be under reported by 0.5 g CO_2 e/MJ
- Coal energy content and WTT emissions are assumed for petroleum coke
- The oil sand crude upgrader burns only natural gas, not fuel gas

Some of the nuances of the GREET approach may be attributed to the allocation scheme. However, on balance, the treatment of oil refining should more closely reflect the process units used to produce products and the impact of crude oil types. Most of the factors identified above affect the upstream energy inputs for the refining process, which correspond to about 10 to 16 g CO_2 e/MJ of GHG emissions in the refining phase. The uncertainty might be another 2 g CO_2 e/MJ (plus an additional 5 to 10 g CO_2 e/MJ for upgrading bitumen or heavy oil). The appropriate range in emissions to use is currently being investigated in several studies. The relative impact may be small on a per MJ basis; but oil refining is the third largest source of GHG emissions in California, behind fuel combustion and power generation. The GHG emissions of this important industry should be better characterized.

2.2 Heavy Oil and Oil Sands Upgrading

Sources of heavy crude oil are also growing in market share. Heavy oil has a lower hydrogen to carbon ratio than lighter oil and requires additional hydrogen to upgrade it for refining. Also, higher levels of residual oil may be produced when heavy oil is refined. Unconventional oils are characterized by an API gravity lower than 10 (including oil sands bitumen). Oil with an API gravity below 18 would still be considered heavy. These oils are characterized by a high viscosity and typically higher levels of sulfur, nitrogen, metals, and asphaltenes. Many technology providers have developed hydrocracking processes that are suited for the conversion and upgrading of a variety of heavy oil materials ranging from conventional vacuum residues up to extra-heavy oils and bitumen.[10]

Upgraders can be configured with a variety of processing units including vacuum distillation, hydrocracking, delayed coking, and hydrotreating of naphtha. Upgraders for oil sands crude require approximately 1,000 scf of hydrogen per bbl of bitumen. The per bbl volume of upgrader product, termed synthetic crude oil (SCO), depends on the technology used and ranges from 85 to 101 bbl SCO per bbl of bitumen. Because of the presence of high density naphthenes, aromatics, and polar compounds, the H/C ratio is very low compared to the gasoline and diesel fuel products. The increase of the H/C ratio is accomplished by rejecting carbon and adding hydrogen. Carbon rejection processes (such as visbreaking and coking) show very high feedstock flexibility, but generate low quality distillates and significant amounts of coke[40]. Hydrocracking technologies result in a higher yield with more hydrogen consumption but these process units are sensitive to feedstock quality.

Current GREET modeling[21] for U.S. refining presumably reflects the impacts of heavy oil from Kern County, California, and Venezuela because the GREET inputs are for aggregate U.S. refinery statistics. However, GREET inputs do not readily allow for the calculation of the impact of heavy oils individually.

The key factors affecting the emissions from processing heavy oil are the hydrogen consumption and the conversion yield to fuel products. Hydroprocessing equipment also requires heaters, fans, pumps, and other utilities. The impact of processing heavy oils is best addressed by examining refinery flow sheets that are configured for light and heavy oil configurations. Linear programming (LP) models could also be used to parametrically examine the effect of oil properties. Such an exercise would need to examine the other impacts, such as the refinery configuration because the LP model generally optimizes on lowest cost. The effect on refinery units would need to be taken into account, so that the modeling represents realistic refineries. Absent a study on refining, many references identify the hydrogen requirements for different refinery processes. The Handbook of Petroleum Refining Processes[41] identifies the hydrogen consumption for heavy oil hydrotreating at 400 to 1,000 scf/bbl oil, and residuum hydrocracking at 1,200 to 1,600 scf/bbl. The GHG impact of hydrogen consumption alone corresponds to 5 to over 10 g CO_2 e/MJ of GHG emissions.

2.3 Carbon Intensity of Petroleum

As previously described, the production and use of transportation fuels includes a wide range of activities that contribute to GHG emissions over their life cycle. The range of activities associated with the production of petroleum fuels have been reviewed in order to assess their life cycle impact on GHG emissions, including both direct petroleum emissions, and to the degree feasible, some indirect effects. Calculations of the average emissions in the GREET model are examined and compared with those associated with marginal and unconventional petroleum resources.

The ARB currently publishes a series of lookup tables[42] outlining the extraction and crude transport emissions for the crudes currently supplied to California and beyond. We have applied the methodology established by Brandt and Unnasch[43] to derive the relationship between refining and GHG emissions and develop carbon intensity ranges for these crudes. Table 2.1 presents our analysis of the ARB published estimate for crude oil.

Table 2.1. Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

		Carbon Intensity (g CO_2 e/MJ)							
Country of Origin	**Crude Identifier**	**Extraction & Transport[a]**	**Refining[b]**	**WTT**	**Vehicle**	**WTW**	**Low**	**High**	**Av.**
Baseline Crude Average[a] CARBOB									99.18
Angola	Dalia	7.86	12.2	20.27	73.5	93.77	93.77	95.66	94.72
	Girassol	10.43	11.6	22.16	73.5	95.66			
	Greater Plutonio	8.82	11.4	20.31	73.5	93.81			
Argentina	Canadon Seco	7.54	12.5	20.29	73.5	93.79	92.69	92.56	92.62
	Escalante	7.51	11.5	19.19	73.5	92.69			
	Hydra	8.03	11	19.06	73.5	92.56			
Australia	Pyrenees	5.96	12.8	18.95	73.5	92.45			92.45
Brazil	Albacora Leste	7.35	12.5	20.08	73.5	93.58	91.79	96.51	94.15
	Frade	6.62	12	18.82	73.5	92.32			
	Marlim	6.75	12.4	19.37	73.5	92.87			
	Marlim Sul	9.69	13	23.01	73.5	96.51			
	Ostra	5.71	12.4	18.25	73.5	91.75			
	Polvo	5.62	12.5	18.29	73.5	91.79			
Canada									
Ex. oil sands	Federated	7.77	11.2	19.00	73.5	92.50			
Ex. oil sands	Koch Alberta	7.61	11	18.65	73.5	92.15	92.15	92.50	92.32
Ex. oil sands	Mixed Sweet Blend	7.75	11.2	18.98	73.5	92.48			
Cameroon	Lokele	24.02	12.5	37.24	73.5	110.74			110.74

Table 2.1. Continued Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

Country of Origin	Crude Identifier	Carbon Intensity (g CO_2 e/MJ)							
		Extraction & Transport[a]	Refining[b]	WTT	Vehicle	WTW	Low	High	Av.
Oil Sands	Albian Heavy Synthetic	21.02	12.5	34.17	73.5	107.67			
Oil Sands	Suncor Synthetic A	24.49	11.5	36.25	73.5	109.75	107.67	109.75	108.71
Oil Sands	Suncor Synthetic C	24.49	12	36.79	73.5	110.29			
Oil Sands	Syncrude Sweet Premium	21.87	11.6	33.77	73.5	107.27			
Colombia	Castilla Blend	6.45	12.6	19.26	73.5	92.76	92.76	92.26	92.51
	Vasconia	6.63	12	18.76	73.5	92.26			
Ecuador	Napo	7.45	12.45	20.14	73.5	93.64	93.64	95.47	94.55
	Oriente	9.34	12.4	21.97	73.5	95.47			
Iraq	Basra Light	12.08	11.4	23.65	73.5	97.15			97.15
Kuwait/Saudi Arabia Partitioned Zone	Eocene	5.59	12.5	18.28	73.5	91.78	91.78	91.81	91.79
	Ratawi	5.77	12.4	18.31	73.5	91.81			
Nigeria	Bonny Light	17.88	11.5	29.56	73.5	103.06			103.06
Oman	Oman	12.3	11.5	23.91	73.5	97.41			97.41
Peru	Loreto	5.82	12.5	18.51	73.5	92.01	92.01	93.34	92.67
Saudi Arabia	Arab Extra Light	6.86	10.8	17.67	73.5	91.17	91.82	91.17	91.50
	Arab Light	6.75	11.5	18.32	73.5	91.82			
Russia	ESPO	12.09	11.71	23.90	73.5	97.40			97.40
Trinidad and Tobago	Calypso	6.95	11.4	18.45	73.5	91.95			91.95
United States	Alaska North Slope	12.81	11.4	24.37	73.5	97.87	97.87	100.58	99.23
	California Average Production	12.9	13.9	27.08	73.5	100.58			

Table 2.1. Continued Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

Country of Origin	Crude Identifier	Carbon Intensity (g CO_2 e/MJ)							
		Extraction & Transport[a]	Refining[b]	WTT	Vehicle	WTW	Low	High	Av.
	California Ex. TEOR	5.7	10.5	15.88	74.5	90.38			
	California TEOR	15.9	12.4	28.26	75.5	103.76			
	North Dakota, Bakken	9.76	10.9	20.66	76.5	97.16			
Venezuela	Boscan	12.53	13.4	26.50	73.5	100.00	100.00	111.68	105.84
	Petrozuata	23.58	13.5	38.18	73.5	111.68			
	Zuata Sweet	23.5	13.5	38.10	73.5	111.60			

[a] Carbon Intensity for Crude Oil plus transport; http://www.arb.ca.gov/fuels/lcfs/lu_tables_11282012.pdf

[b] Relationship between Refining and GHG emissions derived from Brandt and Unnasch, Energy Intensity and Greenhouse Gas Emissions from Thermal Enhanced Oil Recovery, nergy Fuels, 2010, 24 (8), pp 4581–4589

We have built upon data from the ARB[44], Jacobs studies[45],[46] , both North American[47],[48] and EU studies[22,49] and standard GHG emissions models (OPGEE[50] and GREET[21]) to develop our best estimates of the ranges in GHG emissions produced for the various production and refining scenarios. Table 2.2 outlines our analyses of crude oils and provides the emissions ranges that have been used per crude type in this study. U.S. and Californian crude oil consumption statistics and volumes are detailed in Table 2.3 and Table 2.4. These crude volumes have been aggregated alongside the emissions intensity ranges.

Table 2.2. Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

Category	Carbon Intensity (g CO_2 e/MJ)								Sources	Scenario
	Oil Production	Transport	Crude Oil	Crude Yield	Refining	WTT	Vehicle	WTW		
Primary	9	3	12	1.00	8	21	73.7	94.60	Jacobs 2009	Arab medium
Primary	8	3	11	1.00	8	19	73.7	92.71	Jacobs 2009	Arab medium
Primary	5	4	8	1.00	13	21	72.8	93.91	Jacobs 2012	Arab medium
Primary	5	1	6	1.03	13	18	73.5	91.78	OPGEE, 2012	Kuwait/Saudi Arabia Partitioned Zone, Iraq, Saudi Arabia
Primary	5	1	6	1.02	12	18	73.5	91.81	OPGEE, 2012	Kuwait/Saudi Arabia Partitioned Zone, Iraq, Saudi Arabia
Primary	6	1	7	1.05	12	19	72.9	92.26	Jacobs NA 2010	Iraq light
Primary	3	1	4		11	11	73.5	84.50	NETL, 2009	Middle Eastern Sour
Secondary	5	3	8	1.07	12	21	73.5	94.07	TIAX 2009	Mexico Maya
Secondary	14	2	16	1.00	9	24	73.7	98.19	Jacobs 2009	Mexico Maya
Secondary	5	2	7	1.03	13	20	73.5	93.58	OPGEE 2012	Brazil, Albacora Leste
Alaska	7	3	10	N/A	15	15	73.5	88.50	OPGEE, 2012	Alaska North Slope
Alaska	2	1	3		8	8	73.5	81.20	TIAX 2009	Alaska North Slope
Nigeria	21	2	23	1.03	6	30	73.7	103.33	Jacobs 2009	Nigeria, Bonny light
Nigeria	16	2	18		11	11	73.5	84.20	OPGEE, 2012	Nigeria, Bonny light
Nigeria	14	2	17	1.03	13	31	73.5	104.12	TIAX 2009	Nigeria, Bonny light

Table 2.2. Continued Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

Category	Carbon Intensity (g CO_2 e/MJ) Oil Production	Transport	Crude Oil	Crude Yield	Refining	WTT	Vehicle	WTW	Sources	Scenario
California	12	1	13	1.06	13	27	73.5	100.58	OPGEE, 2012	California Average Production
California Ex TEOR	5	1	6	1.03	11	17	73.5	90.38	OPGEE, 2012	California Ex TEOR
California TEOR	14.9	1	15.9	1.06	13	30	73.5	103.77	OPGEE, 2012	California TEOR
TEOR	13	1	14	1.00	13	27	73.5	100.01	GREET, CA-GREET	California Thermal
TEOR	19	1	20	1.04	15	35	72.9	107.70	Jacobs, 2009	California Thermal
Stripper Wells	13	3	16	1.09	11	28	73.5	101.95	OPGEE, 2012, Jacobs 2009	High WOR
Stripper Wells	16	3	19	1.09	12	33	72.9	105.63	Jacobs 2009	High WOR
Stripper Wells	25	3	28	1.09	12	43	73.9	116.44	Jacobs 2009	High WOR
Off Shore	16	2	17	1.05	9	27	73.7	100.73	Jacobs 2009	Off shore, Mars, Missishippi Canyon
Off Shore	4	2	6	1.05	9	15	73.5	88.68	Energy Redefined, llc	Off Shore, Mad Dogg USA, Deep water integrated
Off Shore	13	2	15	1.05	9	25	73.5	98.13	Energy Redefined, llc	Offshore, Canterall, Mexico, Integrated Platform Drilling
Off Shore	6	2	8	1.05	9	17	73.5	90.57	Energy Redefined, llc	Offshore, Forties, U.K, Integrated Platform Drilling

Table 2.2. Continued Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

	Carbon Intensity (g CO_2 e/MJ)									
Category	Oil Production	Transport	Crude Oil	Crude Yield	Refining	WTT	Vehicle	WTW	Sources	Scenario
Off Shore	4	2	6	1.05	9	15	73.5	88.68	Energy Redefined, llc	Off Shore, Mad Dogg USA, Deep water integrated
Off Shore	13	2	15	1.05	9	25	73.5	98.13	Energy Redefined, llc	Offshore, Canterall, Mexico, Integrated Platform Drilling
Off Shore	6	2	8	1.05	9	17	73.5	90.57	Energy Redefined, llc	Offshore, Forties, U.K, Integrated Platform Drilling
Off Shore	6	2	8	1.03	12	20	73.5	93.77	OPGEE, 2012	Offshore,Dalia, Angola
Off Shore	8	2	10	1.01	12	22	73.5	95.66	OPGEE, 2012	Offshore, Girassol, Angola
Off Shore	8	1	9	1.01	11	20	73.5	93.81	OPGEE, 2012	Offshore, Greater Plutonia, Angola
Canada Ex. Oil Sands	7	1	7	1.00	12	19	73.5	92.50	OPGEE, 2012	Canada, Federated
Canada Ex. Oil Sands	7	1	8	1.00	11	18	73.5	91.59	OPGEE, 2012	Canada, Koch Alberta
Canada Ex. Oil Sands	7	1	7	1.00	11	19	73.5	92.17	OPGEE, 2012	Canada, Mixed Sweet Blend
Canada Oil Sands	20	1	21	1.03	12.5	34	73.5	107.67	OPGEE, 2012	Canada Average Production
Canada Oil Sands	21	3	24	1.01	11.5	36	73.5	109.75	GREET 1.8b	Canada Average Production
Canada Oil Sands	21	3	24	1.01	12	37	73.5	110.29	GREET 1.8b	Canada Average Production
Off Shore	4	2	6	1.05	9	15	73.5	88.68	Energy Redefined, llc	Off Shore, Mad Dogg USA, Deep water integrated

Table 2.2. Continued Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

	Carbon Intensity (g CO_2 e/MJ)									
Category	Oil Production	Transport	Crude Oil	Crude Yield	Refining	WTT	Vehicle	WTW	Sources	Scenario
Off Shore	13	2	15	1.05	9	25	73.5	98.13	Energy Redefined, llc	Offshore, Canterall, Mexico,
Canada Oil Sands	20	2	22	1.01	11.6	34	73.5	107.27	GREET 1.8b	Canada Average Production
Mining Upgrader	21	1	22	1.02	9	32	73.7	105.37	Jacobs 2009	Mining SCO
Mining Upgrader	7	2	9		12	12	73.5	85.50	TIAX 2009	Canadian Oil Sands
Mining Upgrader	20	1	21	1.02	6	27	73.7	100.85	Jacobs 2009	Mining Bitumen
Stripper Wells	13	3	16	1.09	11	28	73.5	101.95	OPGEE, 2012, Jacobs 2009	High WOR
Stripper Wells	16	3	19	1.09	12	33	72.9	105.63	Jacobs 2009	High WOR
Oil Sands, SAGD	21	2	22	1.02	12	35	73.7	108.62	Jacobs 2009	SAGD Bitumen
Oil Sands, SAGD	20	2	22	1.02	12	34	73.5	107.90	Jacobs 2012	SAGD Bitumen
Oil Sands, SAGD	29	1	30	1.02	9	40	73.7	113.49	Jacobs 2009	SAGD SCO – Coker
Oil Sands, SAGD	14	2	16		16	16	73.5	89.50	NETL, 2009	WCSB Oil Sands Average
Oil Sands, SAGD	31	2	32	1.02	9	42	73.7	115.36	Jacobs 2009	SAGD SCO - Eb-Bed
Venezuela	11	2	13	1.06	12	25	73.7	98.98	Jacobs 2009	Venezuela .Bachaquero
Oil Sands, SAGD	21	2	22	1.02	12	35	73.7	108.62	Jacobs 2009	SAGD Bitumen
Venezuela	11	2	13	1.06	12	25	73.7	98.98	Jacobs 2009	Venezuela Bachaquero

Table 2.2. Continued Carbon Intensity Lookup Table for Crude Oil Production and Transport 2012

	Carbon Intensity (g CO_2 e/MJ)									
Category	**Oil Production**	**Transport**	**Crude Oil**	**Crude Yield**	**Refining**	**WTT**	**Vehicle**	**WTW**	**Sources**	**Scenario**
Venezuela	11	2	13	1.06	12	25	73.7	98.98	Jacobs 2009	Venezuela .Bachaquero
Oil Sands, SAGD	21	2	22	1.02	12	35	73.7	108.62	Jacobs 2009	SAGD Bitumen
Venezuela	10	2	13	1.06	15	29	73.5	102.29	Jacobs 2008	Venezuela .Bachaquero
Venezuela	10	2	14	1.06	15	30	73.5	103.35	TIAX 2009	Venezuela .Bachaquero
Fracking	9	4	13	1.06	10	24	73.5	97.48	OPGEE, 2012	North Dakota, Bakken
Fracking	18	7	25	1.06	12	38	73.5	111.54	OPGEE, 2012	North Dakota, Bakken
Oil Shale	13	2	15		10	10	73.5	83.50	NRDC OPGEE 2012	Oil Shale (in situ)
Oil Shale	15	4	19		36	36	73.5	109.50	NRDC OPGEE 2012	Oil Shale (ex situ)
EPA RFS2 RIA				1.00		0	73.5	73.50	EPA	RFS2 RIA

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Energy Redifined, llc	Carbon Intensity of Crude Oil in Europe, Energy-Redefined LLC, (2010), Report prepared for the Europaen Commission, Available at: http://www.climateworks.org/download/?id=363969bc-e45a-4434-8ff5-553abff7e451
GREET 1.8b,	Wang, M. GREET Model 1.8c.0, 1.8c.0; Argonne National Lab, Department of Energy: 2009.
GREET 2012	Wang, M. Q., GREET 2012: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, Version 2, Argonne National Laboratory. 2012
GREET 2013	Wang, M. Q., GREET 2013: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, Version 1, Argonne National Laboratory. 2013
CA GREET	California Air resources board and Life cycle associates (2010) available at: http://www.arb.ca.gov/fuels/lcfs/ca_greet1.8b_dec09.xls).
Sasol	Greenhouse Gas Emission Evaluation of the GTL Pathway, G. S. Forman,T. E. Hahn,.and S. D. Jensen.dx.doi.org/10.1021/es202101b
NRDC	GHG Emission Factors for High Carbon Intensity Crude Oils, Simon Mui, Luke Tonachel, Bobby McEnaney, and Elizabeth Shope Natural Resources Defense Council
EPA	EPA Regulatory Impact Analysis (RIA)for the final Transport Rule, (2010) pp 267 http://www.epa.gov/otaq/renewablefuels/420r10006.pd

Table 2.3. U.S. Crude Oil Consumption (1000 bbl/d)

Source	2000	2012	2022	Carbon Intensity (g CO_2 e/MJ) Low	High	Average
	Volume (1000 bbl/d)					
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
Oilsands	809	1445	1078	105	115	110
Fracking	206	945	1863	97	112	105
Total	14,206	16,196	16,993			

Table 2.4. Californian Crude Oil Consumption (1000 bbl/d)

Source	2000	2012	2022	Carbon Intensity (g CO_2 e/MJ) Low	High	Average
	Volume (1000 bbl/d)					
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	130	71	150	84	99	91
Other Foreign	144	222	183			
Total	1844	1826	1762			

3. Corn Based Biofuels

Corn has been a feedstock for ethanol production since the 1990s. Corn ethanol technologies include dry mill and wet mill facilities. Corn ethanol plants are configured as dry mill or wet mill designs. Wet mills use several processing steps to separate fractions of the corn kernel. Dry mill plants grind corn kernels and ferment the entire corn kernel.[iii]

3.1 Corn Production

Corn is the most widely grown grain crop throughout the Americas, with 10 to 12.5 million bushels grown annually in the United States alone.[51] Approximately 3.5 billion bushels go directly into the production of 13.5 billion gallons of ethanol.[52]

Today's corn grower production has been revolutionized by new technologies from hybrid seeds, herbicides, and commercial fertilizers to tractors and the first self-propelled combines. Modern farming techniques in the U.S. uses dense planting, which produces one ear per stalk.

In 1957, U.S. corn growers set a new yield record at 48.3 bushels per acre. Since then, new technologies have enhanced yield including biotechnology, no-till and low-till, global positioning satellites and precision agriculture, variable rate application, and equipment that will plant 36 rows of corn in one pass. Today's yields approach 147 bushels per acre in 2011, for a total crop of 12.4 billion bushels. By 2020, it is estimated that U.S. farmers will grow more than 17 billion bushels of corn.[53]

3.2 Corn Stover

Corn stover is the portion of the corn crop that remains after harvest. Stover includes the stalk, leaf, husk, and cob. The stover may also include weeds and other grasses. Typically stover is left in the field after the grain harvest. The stover mass is equal to about half of the corn grain mass yield. For biofuel production, a fraction of the stover is removed.

The fuel pathway for corn stover includes collection, transport of collected stover, and conversion to fuel or power. When corn stover is collected, the nutrient content supplied to the soil by the otherwise uncollected stover needs to be replaced by increased chemical fertilizer application to the subsequent crop. This requires that additional energy use and emissions to be assigned to the stover collection and use pathway. Upstream emissions associated with corn growing and harvesting are not included in the stover use pathway as these are assigned to corn grain ethanol production. Downstream emissions associated with the corn ethanol transportation and vehicle use as fuel are similarly not included.

3.3 Corn Ethanol Production

Corn ethanol technologies include dry mill and wet mill facilities. There are about 200 corn ethanol plants[54] operate in the U.S., with 10 additional plants are identified as operating on other grains such as milo and barley. Figure 6.1 presents an overview of the production pathways for

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[iii] See corn oil discussion in Section 6.4.3.

U.S. corn ethanol and oil, shaded boxes highlight production process improvements developed with the maturation of the technology.

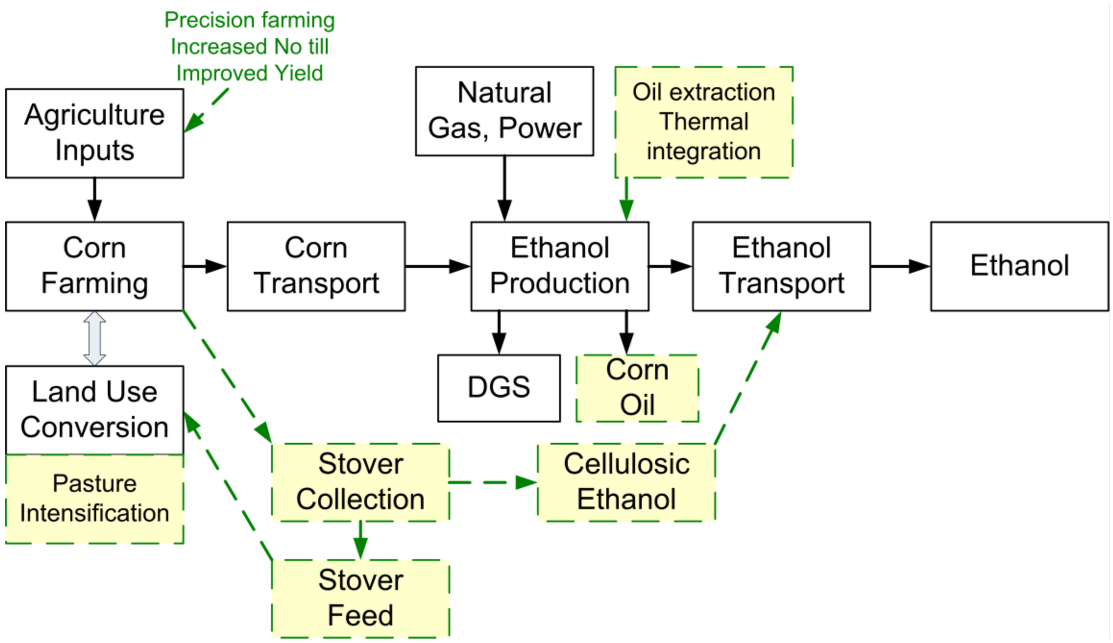

Figure 6.1. Production pathway option for corn ethanol

3.4 Dry Mill Ethanol Process

There are more dry-mill plants than wet-mill plants producing ethanol, although wet-mill plants account for a majority of the capacity. The primary advantages[8,7,55] of the conventional dry mill plant are:

- Lower capital cost per bushel processed;
- Higher ethanol yield per bushel processed; and
- Simplicity in marketing co-products.

The dry mill process can be broken down into four major steps:

- Grain handling and milling,
- Liquefaction and saccharification,
- Fermentation,
- Distillation and co-product recovery.

Grain handling and milling is the step in which the corn is brought into the plant and ground to promote better starch to glucose conversion. Liquefaction and saccharification is where the starch is converted into glucose. Fermentation is the process of yeast converting glucose into ethanol. Co-product recovery is the step in which the alcohol and corn by-products are purified and made market ready.

3.5 Wet Mill Ethanol Process

Wet mills today accounting for only about 10 – 12% of installed capacity, or slightly less than 10% of the total number of plants.[56] In the wet milling process, the corn kernel is steeped in hot water before the kernel is mechanically separated in to its basic constituents, i.e. the protein and oil portions are separated from the carbohydrates in order to process each into a variety of products. The wet milling process can produce a greater variety of products from the corn kernels such as; starch, corn syrup, ethanol, sweeteners, etc., which allows for adaptability to market demands. However, the costs of construction and operation of a wet mill are much greater than those of a dry mill. If ethanol is the target product, then it can be produced at a lower cost and more efficiently in a dry mill plant than in a wet mill plant, under current economic conditions.[8]

Once mechanical separation has taken place, the corn is processed in the same manner as with dry milling:

- Liquefaction and saccharification,
- Fermentation,
- Distillation and co-product recovery

3.6 Corn Oil

Processes for the extraction of corn oil from distillers' grains with solubles (DGS) can be integrated into corn ethanol production facilities with little modification to the plant and no effect on the ethanol production. The extraction process extract corn oil from the thin stillage following fermentation and distillation. The processes use a combination of washing and centrifuging to extract 60 to 75% of the corn oil contained in the stillage. This translates to about 2.8 to 3 gallons of corn oil per 100 gallons of ethanol produced at corn ethanol plants.[57]

The extraction of corn oil requires additional thermal energy that is used to heat the stillage and additional electricity requirements to run the motors on the pumps and centrifuges. However, there are energy savings that exceed the additional thermal and electricity requirements. These savings occur because the removal of the corn oil reduces the mass of the stillage that needs to be dried while also increasing the heat transfer characteristics of the stillage that is dried. Using the publically available information, the ARB has estimated that the installation of corn oil extraction at pre-existing ethanol plants could reduce the energy use at a typical production plant by approximately 5.4%.[58]

The corn oil can be used in several applications, each with different GHG implications. The primary uses of corn oil include animal feed, return corn oil to DGS (to raise fat content and benefit from energy savings at ethanol plant, and biodiesel).

When corn oil is used for animal feed, it displaces oil seeds such as soy and canola as a source of fat in animal feed. Since the productivity per acre is lower than that for corn, the ILUC per kg of oil is much higher than the ILUC per kg of corn. Therefore, when corn oil is used as an animal feed, the avoided ILUC credit is about 2.5 times higher than that for grain corn (See Appendix B). For this study, an additional ILUC credit is included for corn oil used as feed.

Corn oil can also be used to produce biodiesel. The extracted oil is sent to biodiesel production plants where the corn oil is converted to fatty acid methyl esters (FAME) biodiesel using a transesterification process. Several approaches are possible for the co-product treatment. With the displacement method, corn oil biodiesel would receive a credit for the diesel fuel it displaces. This approach has not been widely adopted since both the ethanol and biodiesel are transportation fuels and treating one fuel with a displacement credit does not provide a meaningful assessment of its GHG impact.[59-60]

As corn oil-based biodiesel becomes a more attractive option for compliance with the LCFS, corn oil extraction facilities will be added in this manner to pre-existing corn ethanol plants, with ethanol as the primary fuel produced.

The carbon intensity for the production of biodiesel fuel using corn oil extracted at dry mill corn ethanol plants producing dry distillers' grains with solubles (DDGS). is 5.9 g CO_2 e/MJ of biodiesel produced. This value does not include any emissions due to indirect land use changes (ILUC) since the ILUC contribution is captured in the ethanol pathway. This approach assigns all of the benefits of corn oil extraction to the corn oil, which provides some challenges when certifying ethanol plants under the LCFS. Assigning a CI to an ethanol plant with corn oil extraction equipment becomes challenging with the ARB's method because the energy savings from corn oil extraction are difficult to separate from other process improvements.[59-60]

3.7 Carbon Intensity of Corn Biofuels

Several modeling approaches are used in assessing the life cycle GHG emissions from corn biofuels under the RFS, LCFS, and other initiatives.

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, globally. This study uses the GREET approach for agricultural emissions, which assigns average U.S. corn inputs to ethanol production. [21,]**Error! Bookmark not defined.**

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. Data from GREET[21] and the 2013 National Corn Mill Survey[55] have been used to develop process inputs for the range of ethanol production methods evaluated in this study. Process inputs for the years 2005, 2012 and 2022 are outlines in Table 3.1, Table 3.2 and Table 3.3. Process data has been inputted into GREET1_2013 and customized carbon intensities calculated per plant type, Table 3.4.

Plant mill type, number and production capacity has been extrapolated from the EPA Regulatory Impact Analysis (RIA)[56] and is presented in Table 3.5. The relative carbon intensity per plant type has been weighted against the aggregate plant mill data in Table 3.5 to develop the yearly weighted carbon intensity values for use in the main report, Table 3.6.

Table 3.1. Process and Energy Inputs for Corn Ethanol Production in the year 2005

Parameter	Units	Dry Mill Corn, Average[a]	Wet Mill [b]	Wet Mill[a]	Dry Mill [a]	Dry Mill[a]	Dry Mill, [a]	Dry mill, corn oil [a]	Dry mill, corn oil[a]	Dry Mill CRF[a]	Dry Mill, [a, c&d]
Fuel		NG	Coal	NG	Coal	NG	NG	NG	NG	NG	Biomass
Corn yield	bu/acre	158	158	158	158	158	158	0	0	N/A	148
Stover recovery	Ton/acre	0	0	0	0	0	0	0	0	1.33	0.00
Tillage	Type	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	No Till	Conv.
Ethanol Yield	gal/bu or gal/ton	2.74	2.55	2.55	2.74	2.74	2.74	0	0.00	2.74	2.75
Back End Oil	lb/gal, dry	0	0	0	0	0	0	0	0	0	0
DDGS	lb/gal, dry	4.31	0	0	4.31	5.57	0.19	0	0	4.31	4.31
WDGS	lb/gal, dry	1.27	0	0	1.27	0	5.39	0	0	1.27	1.27
Corn Gluten Meal	lb/gal, dry	0	1.22	1.22	0	0	0	0	0	0	0
Corn Gluten Feed	lb/gal, dry	0	5.28	5.28	0	0	0	0	0	0	0
Corn oil	lb/gal, dry	0	0.98	0.98	0	0	0	0	0	0	0
Total Feed	lb/gal, dry	5.63	7.48	7.48	5.63	5.63	5.63	0	0	5.63	5.63
Natural Gas Use	Btu/gal	24,696	0	0	0	33,330	21,830	0	0	26,248	43,629
Coal Use	Btu/gal	0	50,500	49,542	47,166	0	0	0	0	0	0
Biomass Use	Btu/gal	0	0	0	0	0	0	0	0	0	3,537
Net Electricity Use	kWh/gal	0.74	0	0	1.00	0.75	0.75	0.00	0.00	0.75	1.09
	Btu/kWh	2,533	0	0	3,412	2,559	2,559	0	0	2,559	3,719
Stover Removal	%	0%	0%	0%	0%	0%	0%	0%	0%	30%	0%
Stover Substitution	lb hay/lb stover	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.5	N/A
	lb corn/lb stover	0	0	0	0	0	0	0	0	0.5	0

[a] Wang, M. Q., GREET 2013: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, Version 1, Argonne National Laboratory. 2013.
[b] Wang, M, Updated Energy and Greenhouse Gas Emission Results of Fuel Ethanol, Center for Transportation Research, Argonne National Laboratory, presented at The 15th International Symposium on Alcohol Fuels, 26-28 September 2005, San Diego, CA, USA.
[c] http://www.agmanager.info/marketing/outlook/newletters/archives/GRAIN-OUTLOOK_11-10-11_Feedgrains.pdf
[d] Morey,R. V., Tiffany, D. G., Hatfield, D. L. Biomass for electricity and process heat at ethanol plants, Applied Engineering in Agriculture, Vol. 22(5): 723-728

Table 3.2. Process and Energy Inputs for Corn Ethanol Production in the year 2012

Parameter	Units	Dry Mill Corn, Average[a]	Wet Mill [b]	Wet Mill[a]	Dry Mill [a]	Dry Mill[a]	Dry Mill, [a]	Dry mill, corn oil [a]	Dry mill, corn oil[a]	Dry Mill CRF[a]	Dry Mill, [a, c&d]
Fuel		NG	Coal	NG	Coal	NG	NG	NG	NG	NG	Biomass
Corn yield	bu/acre	158	158	158	158	158	158	158	158	N/A	158
Stover recovery	Ton/acre	0	0	0	0	0	0	0	0	1.33	0.00
Tillage	Type	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	No Till	Conv.
Ethanol Yield	gal/bu or gal/ton	2.82	2.63	2.63	2.82	2.82	2.82	2.82	2.82	2.82	2.82
Back End Oil	lb/gal, dry	0.19	0	0	0.19	0.19	0.19	0.19	0.19	0.19	0.19
DDGS	lb/gal, dry	4.12	0	0	4.12	5.39	0.00	5.39	0.00	4.12	4.12
WDGS	lb/gal, dry	1.27	0	0	1.27	0	5.39	0.00	5.39	1.27	1.27
Corn Gluten Meal	lb/gal, dry	0	1.22	1.22	0	0	0	0	0	0	0
Corn Gluten Feed	lb/gal, dry	0	5.28	5.28	0	0	0	0	0	0	0
Corn oil	lb/gal, dry	0	0.98	0.98	0	0	0	0	0	0	0
Total Feed	lb/gal, dry	5.57	7.48	7.48	5.57	5.57	5.57	5.57	5.57	5.57	5.57
Natural Gas Use	Btu/gal	23,862	0	0	0	27,706	18,702	26,210	18,328	23,862	25,872
Coal Use	Btu/gal	0	47,409	45,039	27,969	0	0	0	0	0	0
Biomass Use	Btu/gal	0	0	0	0	0	0	0	0	0	2,098
Net Electricity Use	kWh/gal	0.75	0	0	1.00	0.75	0.75	0.75	0.75	0.75	0.75
	Btu/kWh	2,559	0	0	3,412	2,559	2,559	2,559	2,559	2,559	2,559
Stover Removal	%	0%	0%	0%	0%	0%	0%	0%	0%	30%	0%
Stover Substitution	lb hay/lb stover	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.5	N/A
	lb corn/lb stover	0	0	0	0	0	0	0	0	0.5	0

[a] Wang, M. Q., GREET 2013: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, Version 1, Argonne National Laboratory. 2013.
[b] Wang, M., Updated Energy and Greenhouse Gas Emission Results of Fuel Ethanol, Center for Transportation Research, Argonne National Laboratory, presented at The 15th International Symposium on Alcohol Fuels, 26-28 September 2005, San Diego, CA, USA.
[c] http://www.agmanager.info/marketing/outlook/newletters/archives/GRAIN-OUTLOOK_11-10-11_Feedgrains.pdf
[d] Morey,R. V., Tiffany, D. G., Hatfield, D. L. Biomass for electricity and process heat at ethanol plants, Applied Engineering in Agriculture, Vol. 22(5): 723-728

Table 3.3. Process and Energy Inputs for Corn Ethanol Production in the year 2020

Parameter	Units	Dry Mill Corn, Average[a]	Wet Mill [b]	Wet Mill[a]	Dry Mill [a]	Dry Mill[a]	Dry Mill, [a]	Dry mill, corn oil [a]	Dry mill, corn oil[a]	Dry Mill CRF[a]	Dry Mill, [a, c&d]
Fuel		NG	Coal	NG	Coal	NG	NG	NG	NG	NG	Biomass
Corn yield	bu/acre	158	158	158	158	158	158	158	158	N/A	158
Stover recovery	Ton/acre	0.00	0	0	0	0	0	0	0	1.33	0
Tillage	Type	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	Conv.	No Till	Conv.
Ethanol Yield	gal/bu or gal/ton	2.93	2.74	2.74	2.93	2.93	2.93	2.93	2.93	2.93	2.93
Back End Oil	lb/gal, dry	0.19	0	0	0.19	0.19	0.19	0.19	0.19	0.19	0.19
DDGS	lb/gal, dry	4.12	0	0	4.12	5.39	0.00	5.39	0.00	4.12	4.12
WDGS	lb/gal, dry	1.27	0	0	1.27	0	5.39	0	5.39	1.27	1.27
Corn Gluten Meal	lb/gal, dry	0	1.22	1.22	0	0	0	0	0	0	0
Corn Gluten Feed	lb/gal, dry	0	5.28	5.28	0	0	0	0	0	0	0
Corn oil	lb/gal, dry	0	0.98	0.98	0	0	0	0	0	0	0
Total Feed	lb/gal, dry	5.57	7.48	7.48	5.57	5.57	5.57	5.57	5.57	5.57	5.57
Natural Gas Use	Btu/gal	21,476	0	0	0	24,935	17,767	23,589	17,412	21,476	23,285
Coal Use	Btu/gal	0	42,668	40,535	25,172	0	0	0	0	0	0
Biomass Use	Btu/gal	0	0	0	0	0	0	0	0	0	1,888
Net Electricity Use	kWh/gal	0.75	0	0	1.00	0.75	0.75	0.75	0.75	0.75	0.75
	Btu/kWh	2,559	0	0	3,412	2,559	2,559	2,559	2,559	2,559	2,559
Stover Removal	%	0%	0%	0%	0%	0%	0%	0%	0%	30%	0%
Stover Substitution	lb hay/lb stover	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.5	N/A
	lb corn/lb stover	0	0	0	0	0	0	0	0	0.5	0

[a] Wang, M. Q., GREET 2013: The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model, Version 1, Argonne National Laboratory. 2013.
[b] Wang, M., Updated Energy and Greenhouse Gas Emission Results of Fuel Ethanol, Center for Transportation Research, Argonne National Laboratory, presented at The 15th International Symposium on Alcohol Fuels, 26-28 September 2005, San Diego, CA, USA.
[c] http://www.agmanager.info/marketing/outlook/newletters/archives/GRAIN-OUTLOOK_11-10-11_Feedgrains.pdf
[d] Morey,R. V., Tiffany, D. G., Hatfield, D. L. Biomass for electricity and process heat at ethanol plants, Applied Engineering in Agriculture, Vol. 22(5): 723-728

Table 3.4. Carbon Intensity of Corn Biofuels

	Carbon Intensity with ILUC ($g\ CO_2\ e/MJ$)		
	2005	**2012**	**2022**
Wet Mill, Coal	101.74	94.94	85.39
Wet Mill, NG	79.93	75.45	66.01
Dry Mill, Coal	108.65	79.35	71.05
Dry Mill, NG, DDGS	74.33	65.69	58.92
Dry Mill, NG, WDGS	63.96	57.54	52.42
Dry mill, corn oil DDGS	0	63.34	56.70
Dry mill, corn oil WDGS	0	56.21	51.10
Dry Mill NG, CRF	67.94	62.21	55.78
Dry Mill, NG, Biomass	51.00	42.77	38.25

Table 3.5. Yearly Production Volumes per Plant Type

Corn Ethanol CI Evolution	**2005**	**2012**	**2022**
Plant Energy Source		**Volumes (Mgal)**	
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, WDGS CRF	303	420	1,475
Dry Mill, NG, Biomass	182	515	2,525
Total Corn Ethanol	9,170	14,999	15,007

Table 3.6. Weighted Carbon Intensities of Corn Biofuels

Weighted CI ($g\ CO_2\ e/MJ$)	**2005**	**2012**	**2022**
Corn Ethanol. CI	76.6	65.8	56.3
Corn and Stover CRF Cellulosic Ethanol	76.5	65.4	39.0

4. Transport Logistics

Changes in fuel use affect the movement of goods globally. For example, crude oil refining results in the co-production of residual oil. Displacing petroleum fuels reduces both the production of fuels as well as the co-product residual oil. Reduced residual oil transport would be an indirect consequence of reducing the use of petroleum fuels. Similarly the production of biofuels affects the global production of crops. These effects are examined in terms of their LUC impact. However, changes in crop production also affect global goods movement. For example a reduction in U.S. corn production could result in additional production in South America. Of course other agricultural goods would also be affected but the first order effect is a shift in the transport of soybeans.

Another transportation issue is the capacity of bulk carriers. The emissions intensity of marine vessel transport depends on the ship capacity. Small carriers can use over 5 times as much fuel as the largest carriers. An indirect effect of changes in fuel production could be shifts in the transport of finished product, which is often moved in smaller cargo vessels.

4.1 Crude Oil and Product Transport

Saudi Arabia is the leading exporter of crude oil, followed by Russia, Iran, Nigeria, U.A.E., Iraq, Angola, Norway, Canada, and Kazakhstan. Total world exports amounted to 42.3 million bbl/d in 2009. Major importers of crude oil are the U.S., Japan, the European Union, China, and India. Figure 4.1 shows the worldwide flows of crude oil in 2009 in million bbl/d.

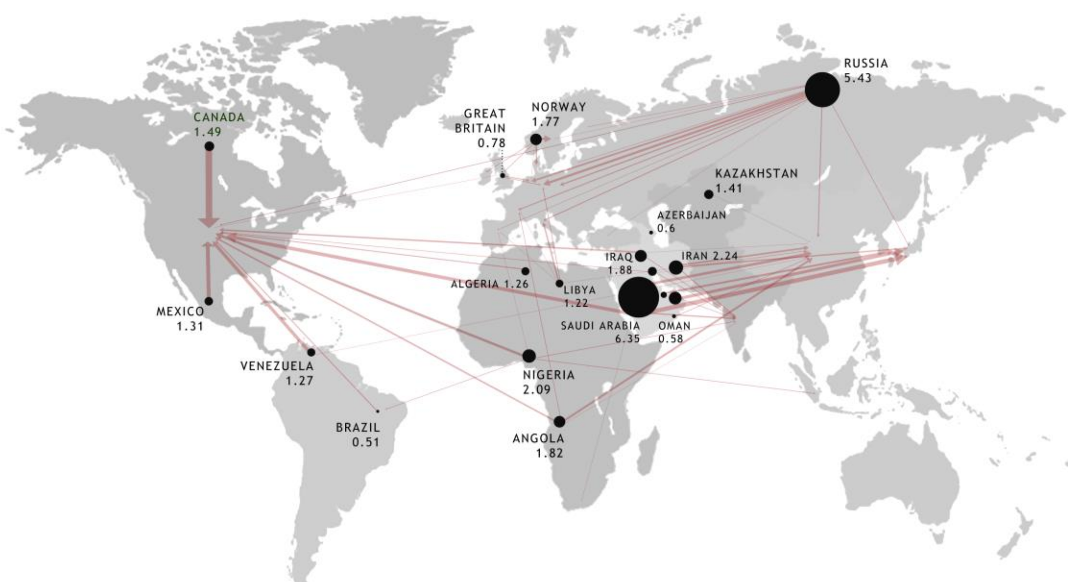

Figure 4.1. Crude Oil Imports and Exports Worldwide

Source: U.S. EIA 2009

Petroleum transport is a relatively small contributor to the petroleum fuel cycle GHG emissions when compared to the total for other processes. However, significant quantities of oil and product are moved in smaller vessels. Oil from stripper wells may even be transported by truck. When the crude oil and product are transported in smaller vessels or equipment, the relative GHG emissions for transportation grow substantially. With a few exceptions, the smallest marine crude carriers have a capacity of 250,000 DWT (deadweight tonnage). However, smaller tankers are often used to transport finished product in the event of shortages. The GHG emissions from crude oil and finished fuel transport are given in Table 4.1.

As noted above, the impact of fuel transportation is generally a small portion of the energy inputs and emissions associated with petroleum fuels. However, higher emission impacts occur on the margin as indicated above. The transportation carbon intensity rises rapidly with smaller cargo capacity transport equipment.

Table 4.1. Impacts of Crude Oil Transportation Mode.

Transport mode	**GHG emissions (g CO_2 e/MJ transported product)**
Overseas oil transport	
1,000,000 to 250,000 DWT crude oil	0.17
50,000 DWT refined product tanker	1.2
Stripper well operation	
100 mi truck transport	0.6

[a]GREET default reflects 1,000,000 DWT super tanker. Most crude carriers are close to 200,000 DWT and product tankers can be even smaller.

Corn is by far the largest component of global coarse-grain trade, accounting for about three-quarters of total volume in recent years. (Coarse grains make up a common trade category that includes corn, sorghum, barley, oats, and rye.). Most of the corn that is traded is used for feed; smaller amounts are traded for industrial and food uses. Processed-corn products and byproducts-including corn meal, flour, sweeteners, and corn gluten feed are also traded, but are not included in this discussion of corn trade. Although the U.S. dominates world corn trade, exports account for a relatively small portion of demand for U.S. corn - approximately 15%.[61]

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