

Greenhouse gas impact of marginal fossil fuel use



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Summary

Biofuels represent a major option to reduce greenhouse gas emissions from the transportation sector. When assessing the benefits of biofuels, they are compared to the fossil fuels they replace. In the framework of the European Renewable Energy Directive and the Fuel Quality Directive, this is done by comparing the lifecycle greenhouse gas emissions of biofuels to a 'fossil comparator'. This fossil comparator is based on the average greenhouse gas intensity of fossil fuels brought on the EU transportation market.

Unconventional oils such as extra heavy oil and bitumen (tar sands), kerogen oil (oil shale), light tight oil (shale oil), deep sea oil and synthetic products such as gas-to-liquids and coal-to-liquids, typically have higher carbon footprints than conventional oil mainly because the effort required to extract, refine and/or synthesize them is much larger than for conventional oil. As the share of these unconventional oil-based fuels gradually rises in the total fuel supply over time, the greenhouse gas footprint of the average fuel consumption also rises. Even for conventional oil production fields, because larger existing fields get depleted, the extraction efforts increase while smaller fields are taken in operation. Both effects increase the carbon footprint of conventional oil. Therefore the fossil comparator should be adjusted upward to reflect these changes.

Furthermore, in reality biofuels do not displace the average of fossil fuels brought on the market, but the marginal ones: those fossil fuels that are ultimately not produced because of a relatively lower and enduring demand following the introduction of biofuels. The marginal fuels are the resources that are most sensitive to long-term marginal price reduction, which is the main mechanism through which biofuels displace fossil fuels. The main non-price drivers that may limit or stimulate the exploration and development of certain types of oils include strategic drivers (mainly security of energy supply) and the related desire to level the trade balance for oil-importing countries, technological developments, the peaking of conventional oil production and access to resources. Today OPEC controls the vast majority of conventional oil reserves, while international private oil companies pioneer new technologies that are required to extract unconventional sources. This is mainly because they have access to capital and closer ties to innovation centres. The lack of access to conventional oil fields, combined with breakthrough technological developments have lead international oil companies to dominate the exploration of unconventional oil fields, in regions where states play a smaller role in investment decisions, and profits (and therefore the oil price) a determining role. This combination of factors have spurred economically-driven investments in large part to North America (USA and Canada), where large resources of oil sands, oil shale and tight oil are available in business-friendly environment. Furthermore, these resources seem to be more economically viable than gas-to-liquids and coal-to-liquids, which are restricted by their access to low-cost resources and high capital costs respectively.

Based on our assessment that the marginal oil displaced by biofuels is a combination of oil sands, kerogen oil (oil shale) and light tight oil, we estimated that the marginal greenhouse gas emissions avoided by the introduction of biofuel are approximately **115 gCO_{2eq}/MJ** of energy delivered by

biofuels. This is 31.7 g/MJ above the average fossil fuel emissions as represented by the fossil comparator used in the European directives on Renewable Energy and on Fuel Quality. This difference is in the same order of magnitude as the ILUC factors currently proposed for biofuels. The upper boundary, should biofuels displace an average mix of all unconventional fuels by 2030, is higher at 137 gCO₂eq/MJ. The 'marginal' approach clearly shows that the true benefit of introducing biofuels is larger than is currently reflected through the use of the fossil comparator.

We recommend that the fossil comparator be adjusted to reflect the continuous shift in the fossil fuel market towards unconventional fuels, and that a fair comparison with fossil fuels should refer to the emissions of the fossil fuels being displaced, i.e. the marginal fossil fuels. Also, the emission factors of various types of unconventional fossil fuels differ significantly and are changing fast with technological developments. Proper implementation of Article 7a of the Fuel Quality Directive could provide a strong incentive to avoid the fuels with the worst greenhouse gas performance and thereby reduce the average emission factor of EU transportation fuels. Full implementation of this policy would likely lead to a relatively reduced investment in and production of the most carbon intensive fossil resources, since they heavily depend on the European market. This would lead to significant reductions in both average and marginal emissions of fossil fuels, while at the same time driving improvements in the greenhouse gas performance of biofuels.

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1 Introduction

Biofuels represent a major option in the EU's strategy to reduce greenhouse gas emissions of the transportation sector. When assessing the benefits of biofuels, they are compared to the fossil fuels they replace. In the framework of the Renewable Energy Directive (2009/28/EC, known as RED) and the Fuel Quality Directive (2009/30/EC, known as FQD), this is done by comparing the lifecycle greenhouse gas emissions of biofuels to a 'fossil comparator'. This fossil comparator is based on the average carbon intensity of fossil fuels brought on the EU transportation market. As we discuss below in Section 3, the current comparator does not reflect the increasing emissions of conventional fuels that are becoming more difficult to extract.

Moreover, the introduction of biofuels reduces the expansion of fossil fuels. Therefore, biofuels should not just be compared with the average performance of the gasoline or diesel they replace but with the fossil fuel that is ultimately (marginally) "not produced". Certainly when biofuels are evaluated for indirect impacts, the same should be done for the fossil fuel they avoid.

We first analyse the cause-effect relations of the marginal decrease of EU fossil fuel consumption (effect of introducing biofuels) on the development and exploitation of new fossil fuel sources globally. In a second step we analyse the carbon intensity and environmental effects of the four fossil fuel types that are most sensitive to a marginal reduced global demand for oil as well as the effect of recent developments on the average fossil fuel carbon intensity. We conclude with policy implications and recommendations.

2 Marginal EU fossil fuel consumption

This section discusses the cause-effect relationship of avoided marginal increase in EU fossil fuel demand due to the introduction of biofuels, and how this translates to a reduced exploration and exploitation of "new fossil fuel sources". We conclude that the fossil fuel resources most sensitive to a marginally reduced demand towards 2030 are extra heavy oil and bitumen, light tight oil, kerogen oil (oil shale) and frontier oil.

The main question we are trying to answer is: which type(s) of crude production is most likely to be displaced by biofuels, and in what distribution? The timeframe up to 2030 is chosen because carbon stock changes related to biofuels are discounted against the same timeline (typically over 20 years).

The application of biofuels is currently the most important option to replace fossil fuels with renewable alternatives and to reduce greenhouse gas emissions of transport fuels, in line with targets of the Renewable Energy Directive and the Fuel Quality Directive. The result of the introduction of biofuels in the transport sector - whether driven by policy or not - is effectively a decreased demand for fossil fuels in the EU market, and as a result a reduced global demand for crude oil. This effect may be small (in comparison to the total market) and difficult to notice in a turbulent and still growing world market for fossil fuels. Nevertheless, the ultimate result is that the global demand curve for fossils changes in comparison to a business-as-usual scenario without biofuels (see Figure 1), leading to a new equilibrium at a lower crude oil volume and a marginally lower price.

The supply curve of fossil crude oils is, in reality, more complex than sketched here, and is made up of various types of crude production fields and projects that are sensitive not only to international oil prices, but also to a wide range of political, technological, and market factors, that play a role in determining their viability.

Since capital costs for oil exploration are high, and the demand for oil is increasing over the time horizon of this study (2030), we assume that once an investment is made to exploit a particular oil field, it will be fully exploited, i.e. there is no idling capacity, with exception of some OPEC measures which we discuss below. We can therefore look at the drivers of investment decisions for each type of crude oil production in order to understand how the development of that resource will react to a relatively lower oil price than in a scenario without biofuels.

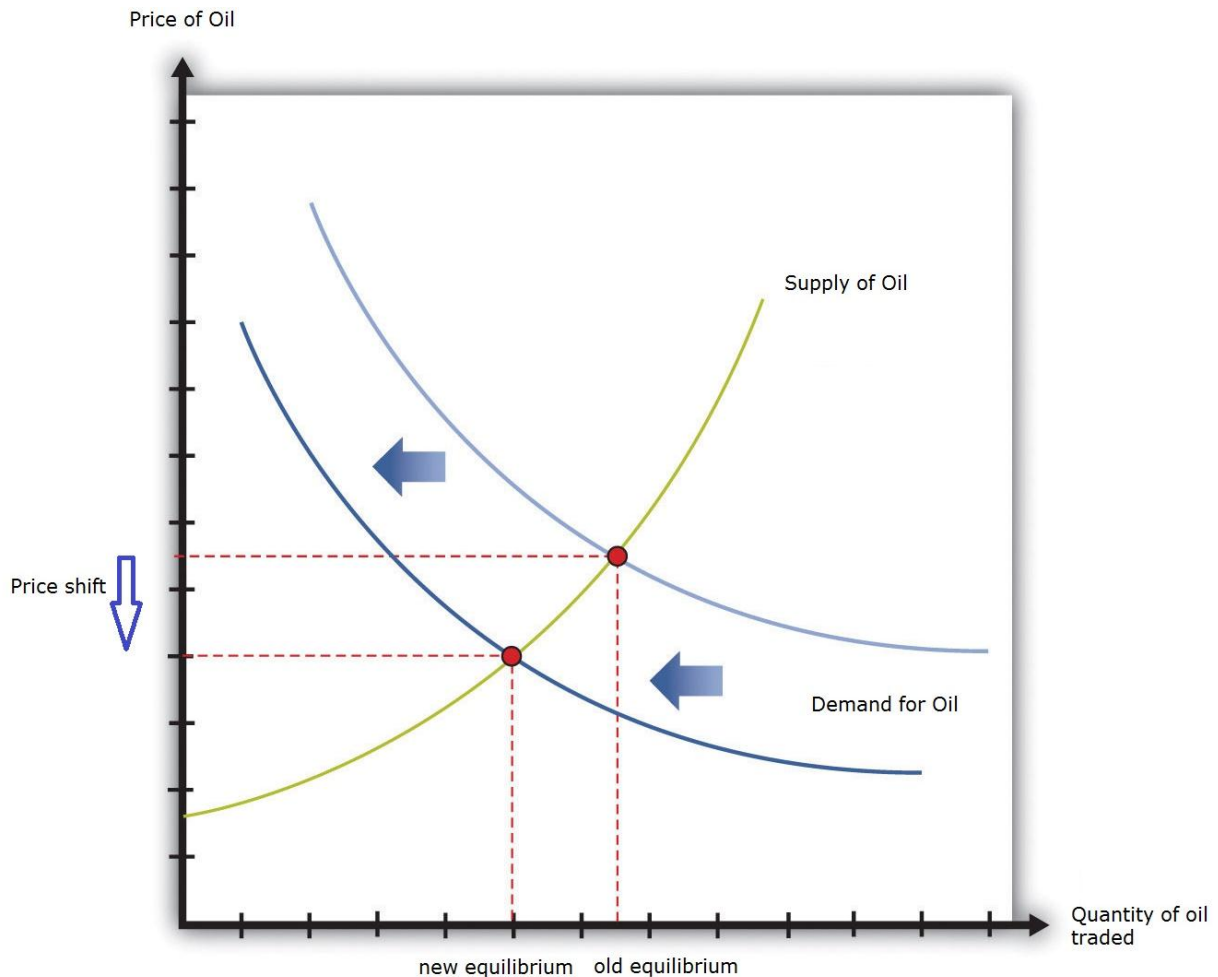


Figure 1 Effect of biofuel and energy efficiency policies on oil demand and price.

2.1 Non-price drivers of investments/developments

Since there are still significant reserves of low-cost conventional reserves, one can ask why more expensive unconventional reserves are being developed at all. We see that although the feasibility of a crude oil production project depends to a large extent on the oil price, it also depends on many non-price drivers. The main non-price drivers that push exploration of unconventional crudes include:

- Lack of access of the international oil companies (IOCs) to the remaining conventional oil. In the 1960s, IOCs had access to around 85 percent of global oil reserves: today that has shrunk to only 6 percent (IEA 2011). OPEC controls the vast majority of the world's remaining conventional oil, which means the majority of future non-OPEC production growth will be in unconventional oil (FOE 2011, IEA WEO 2013, BP 2014);
 - This insecurity of access has been exacerbated by the accelerating depletion of oil fields located in politically stable territories that used to provide a large share of the

- production of the oil companies (e.g. North Sea, the United States and conventional resources in Canada);
- The access to resources is also largely restricted by political factors, like OPEC countries who want to control production volumes and reap the corresponding benefits;
 - Technological developments. Developments of non-conventional oil sources are primarily driven by the major international oil companies since they have generally developed the technology to enable them to do so. For example, the developments of horizontal drilling that have led to the American shale gas boom have entirely be driven by private companies, and are now also benefitting extraction of light tight oil;
 - In some cases, such as the pre-salt ultra-deepwater resources of Brazil or extra heavy oil in Venezuela, national oil companies are playing a leading role;
 - Strategic drivers, mostly security of supply. In many oil-importing countries, economies are heavily burdened by the high costs of importing oil, but also carry a high risk should the supply be interrupted. This was the main driver behind the creation of the International Energy Agency amongst OECD countries, and has recently been a major driver for government support for unconventional resources in Canada, where locally produced oil-sands has been rebranded to 'ethical oil', as opposed to 'conflict oil' from OPEC countries.¹

Fiscal Regime

In most countries, the mineral reserves belong to the state, and oil companies that extract oil pay fixed or variable fees (royalties) to the host government, as usually determined by the fiscal regime. When prices are low, available capital is reduced and states are in a weaker position, as competition for resources among oil companies is limited. States tend to agree to easier terms to encourage inward investment. However, when international oil prices rise, governments may renegotiate these contracts to share in the profits or to have their reserves last longer (Roland Berger 2013).

Regarding fiscal regimes, the areas of most sensitivity are in license regimes and production based production sharing contracts (PSCs), especially those with higher costs, and therefore higher operating leverage (Roland Berger 2013).

Though the impacts of fiscal regimes on the viability of oil projects can be larger, we consider that the impact of biofuels on oil markets is too small to have any noticeable effect on fiscal regimes.

Subsidies

Subsidies are mostly intended to have structural impacts, which play out over the long term. However, they can also change very quickly, and could therefore also bear significant short-term effects.

¹ See for example <http://www.ethicaloil.org>

There are at least 63 subsidy programmes targeted at the oil industry in Canada (IISD 2010). Most subsidies seek to increase exploration and development activity, with a focus on reducing the costs of exploration, drilling and development through a mix of tax breaks and royalty reductions. The rationale for subsidising the industry is in general to bring new production online, which leads to employment and tax income for the state. Furthermore, energy independence plays an increasingly important role, also demonstrated by the rebranding of Canadian tar sands to 'Ethical oil'.

Development subsidies primarily directed at encouraging companies to bring new oil resources into production comprised 59% of total subsidies (US\$1.68 billion). These subsidies typically reduce capital expenditures through accelerated write-offs, tax credits, royalty reductions or allowances. Subsidies to support exploration, drilling, operations and research and technology comprised the remaining share of subsidies in about equal proportion (IISD).

On average, IISD-GSI estimated that across Canada, the subsidy as a share of average production value be about 5.2%. The study also found that non-conventional production is experiencing the greatest benefit from the subsidies, followed by new drilling. With targeted programmes for the oil sands, as well as a large share of total production, the oil sands are disproportionately benefiting. IISD-GSI indicate that the subsidies are adding 6% to 7% more production to the sector and about 12% more emissions. Most of the targeted programmes are for more exploration activity and drilling in the provinces.

2.2 Impact of oil price on production of various crude oils

Break-even prices and supply curves

The non-economic drivers result in some oil developments being either prohibited or forced in certain regions, in a way that is relatively independent of the international oil price. This drives more economic-driven developments to areas where the oil price does play a more significant role as an enabler for investment decisions.

The minimum price for a project to become financially viable is also called the break-even price, and depends on a lot of factors, including the minimum rate of return for the various investors, risk premiums, expected reserves etc. The break-even price therefore varies significantly from one project to another, but for different oil resources, break-even price ranges have been estimated by various experts and institutes. Figure 2 shows a supply curve for various conventional and non-conventional oil types, showing the production potentials and corresponding break-even prices. The graph shows that significant reserves exist for extra heavy oil and bitumen, light tight oil, kerogen oil, and CTL and GTL that are all potentially viable at oil prices below USD 100/bbl.

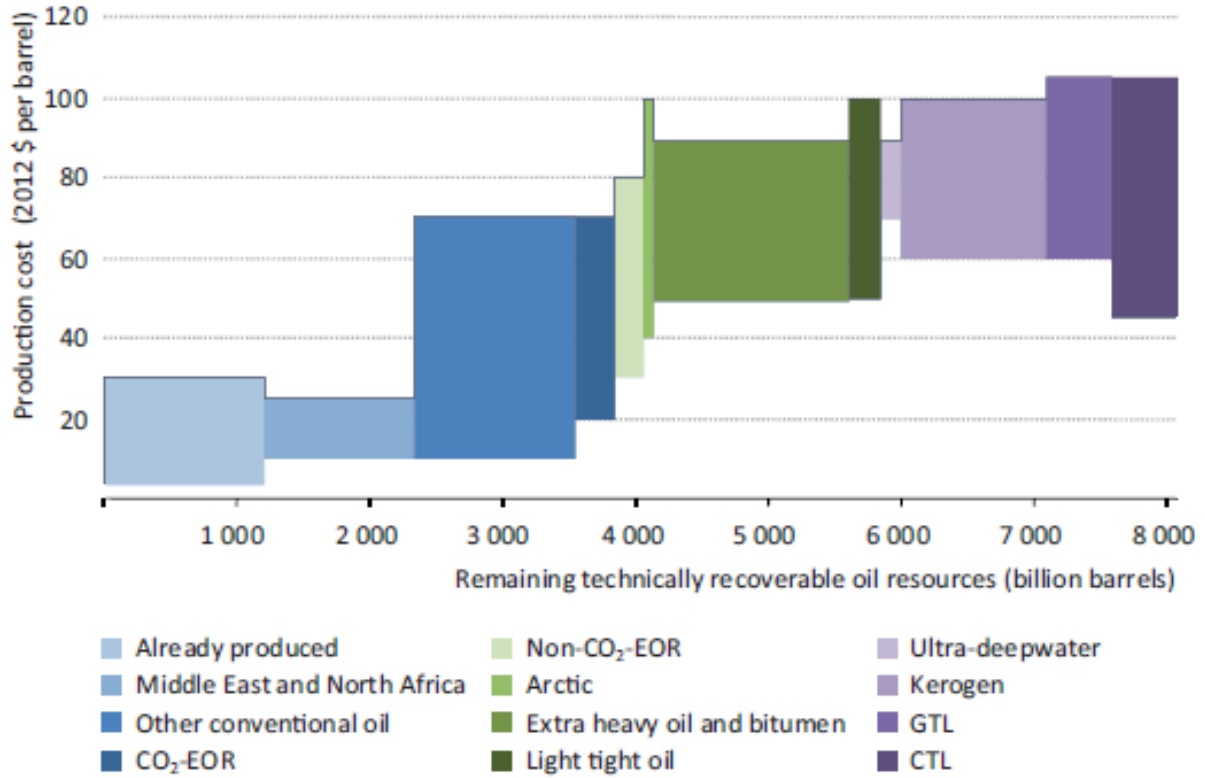


Figure 2 Supply curve of recoverable oil resources. Source: Resources to Reserves (IEA 2013)

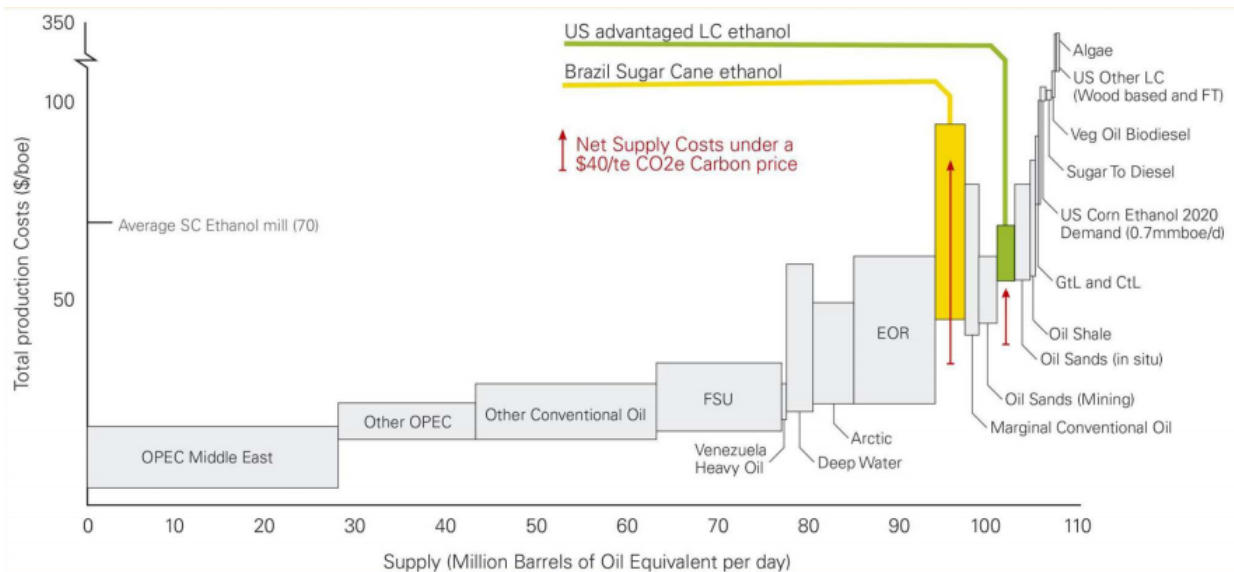


Figure 3 Transportation fuels supply curve (Tongaat Hulett, 2012). Production costs of biofuels are shown for comparison; note that they do not compete on pure economic terms (subsidies and mandates).

Figure 3 shows a similar curve that shows the break-even oil prices for various transportation fuels, but looking at the current production *capacities* (per day) instead of reserves. This graph clearly shows that current production capacities for unconventional oils are very low when compared to the reserves reported by IEA, while the break-even prices are somewhat more optimistic than what IEA found. Because extraction technologies for unconventional oils are restricted by technical (water availability), administrative (permitting), environmental and other contextual factors etc., it remains the question whether they can reach the production levels of unconventional oil.

A recent study by CTI (2013) shows that the development of significant shares of kerogen oil (oil shale), oil sands (tar sands) and deep water oil depends on high oil prices (above USD 80/bbl and sometimes as high as USD 120-150/bbl).

The main conclusion is that large amounts of unconventional fuels can be produced, but that a large share of the potential depends on an oil price above USD 80 /bbl. It also shows that varying oil prices will render at least part of (the top layers) of unconventional oil supply economically unviable.

OPEC and control of supply

The Organization of the Petroleum Exporting Countries (OPEC) is an economic cartel that was created in 1960 to secure a steady income to its member states through optimal use of their resources. By controlling the production levels of an important share of global supply, they aim at

maintaining the price of oil at a price that is beneficial to its members without causing too much reduction in demand.

For many OPEC countries, oil exports represent a major share of the state income, and the price of oil is therefore an important factor for closing their national budget. Although OPEC governments could run their yearly budgets at a deficit, this is not sustainable on the long term, and for each country one can determine a 'break-even' price of oil, at which the state can close its budget at no deficit. APIC (2013) has modelled what would be the breakeven oil price for OPEC countries, and finds that it ranges from \$US 40-75/bbl for Qatar to about \$US 110-170/bbl for Iran, with \$US 90-120/bbl for the largest producer Saudi Arabia. Outside of OPEC, for Russia, the budget breakeven oil price, set forth by the Ministry of Finance of the Russian Federation, ranges from \$US 100/bbl to \$US 117/bbl for the next three years (Grushevenko 2012).

These high budgetary breakeven prices provide a strong incentive to reduce the production of oil in OPEC countries should the price fall below about \$US110/bbl. This implies that in case of a global drop in demand (for example due to a major economic crisis), the marginal oil could temporarily become OPEC crude, with a relatively low carbon intensity. However, with the expected long-term global demand growth and high oil prices (above \$US110/bbl), it is unlikely that OPEC will restrict production.

Regarding OPEC's capacity to limit oil price increase, only Saudi Arabia has spare capacity that can be called upon to buffer the short-term variations in global oil supply but even that is limited as was shown in the supply crisis of July 2008, when Saudi spare capacity stood at only 1.1 Mbpd (in November 2013 it was 2.7 Mbpd). Since this control mechanism is limited in scale and only intended to limit short-term fluctuations, it plays a negligible role on the time horizon of our analysis (20 years).

2.3 Most marginal oil sources

For some crude oil sources the response to international oil prices is stronger than for others. They will develop relatively slower than the rest when the global demand for crude oil declines.

Regarding the definition of the different oil resources, there are many classifications possible, since oil comes in an infinite variation of compositions (molecule length, non-hydrocarbon content etc). For clarity we chose the definitions and classification as proposed by the International Energy Agency, as shown in Figure 4 from the World Energy Outlook 2013.

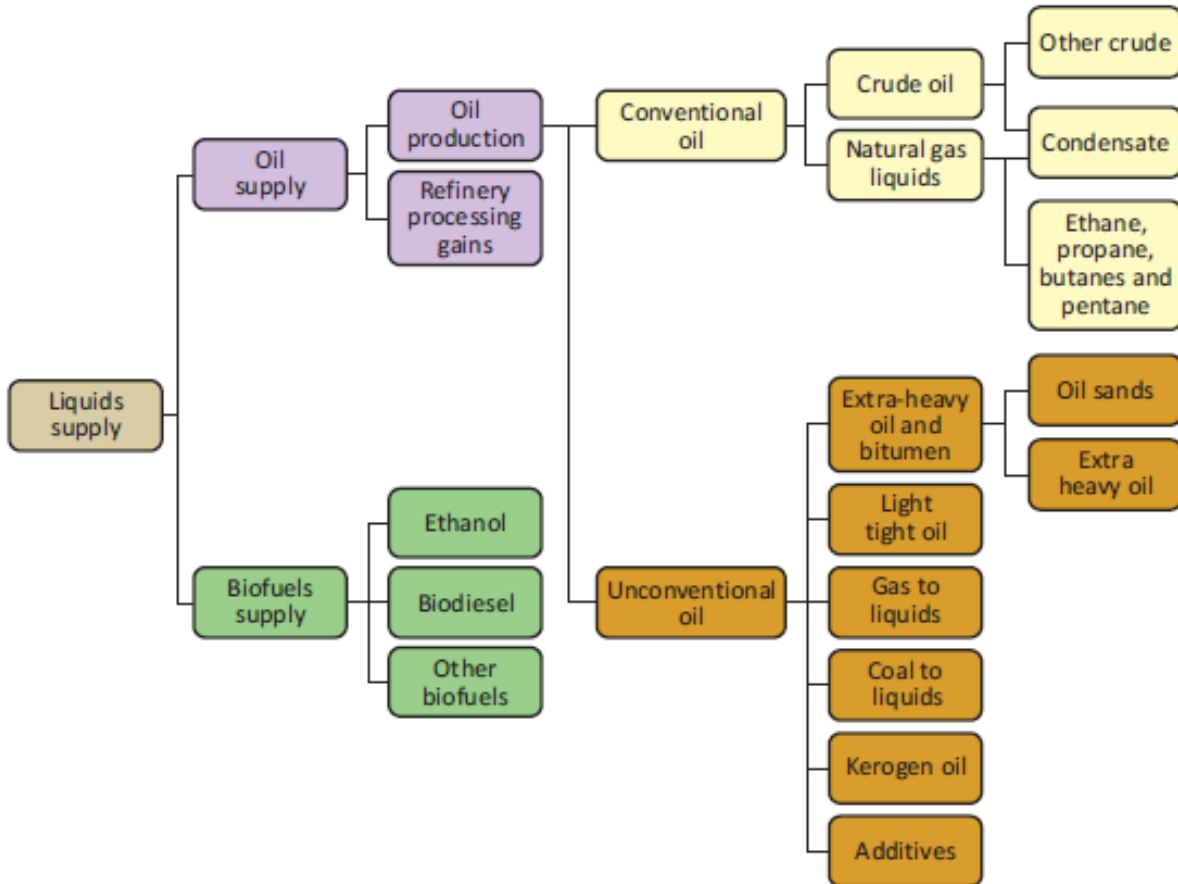


Figure 4 Classification of liquid fuels according to IEA (World Energy Outlook 2013).

Following the discussion in Section 2.1 and 2.2, we have summarised the main drivers and barriers behind the developments in unconventional oil types in Table 1 below.

Table 1 Summary of drivers behind developments of unconventional oil resources

	Prospects	Investment factors	Sensitivity to oil price
Extra heavy oil and bitumen	<ul style="list-style-type: none"> • Very large resource base 	BE price around USD 50- 90/bbl	high
Light tight oil	<ul style="list-style-type: none"> • Significant resource base • Fast response to prices 	Price is main driver. US crude export restriction policy is a barrier, but could be lifted soon	very high
Gas to Liquids (GTL)	<ul style="list-style-type: none"> • Most interesting for stranded gas, if environmental regulations (flaring are tightened) 	Sensitive to high gas prices, and low oil prices, fiscal instability	medium
Coal-to-Liquids (CTL)	<ul style="list-style-type: none"> • Resource base very large • Developments slower than expected 	<ul style="list-style-type: none"> • Economics and environmental acceptability are constraints • Very high capital costs • Competition with other applications (chemical and electricity) 	medium
Kerogen Oil	<ul style="list-style-type: none"> • Significant resource base, but prospects limited in the medium term • Technology relatively immature 	Oil prices between USD 50-80/bbl	medium
Frontier oil (e.g. deep sea)	<ul style="list-style-type: none"> • Resource base small compared to other unconventional • Technology relatively immature 	High environmental and political risks	low
Natural Gas Liquids	<ul style="list-style-type: none"> • Set to play a large role in future developments. 	<ul style="list-style-type: none"> • Some constraints due to refinery capacity • Strongly linked to developments of natural gas or other conventional oil sources • Depend on developments of natural gas 	low

Extra heavy oil and bitumen, light tight oil and kerogen oil are now analysed in more detail because they all show a significant resource base, and their development are sensitive to marginal changes in the international oil price, and therefore to the introduction of biofuels.

Extra heavy oil and bitumen (tar sands or oil sands)

Tar sands (also known as oil sands) are deposits of sand and clay saturated with bitumen. The tar sands in Alberta, Northern Canada, are the second largest oil deposits in the world. Bitumen is oil in a

(semi) solid state and requires unconventional extraction methods (either mining or, in the case of the deeper deposits, steam injection to get it to flow to the surface) and then processing or “upgrading” to convert it into synthetic crude. This process requires much energy and water.

Drivers for exploration

Exploration of tar sands is driven by higher oil prices, and the desire to increase energy security. The breakeven international oil price required to make tar sand development economically viable range from USD 50 to 90 per barrel (Roland Berger 2013, IEA 2013).

Other drivers for the developments of tar sands from the Alberta region include infrastructure needed to deliver the derived products to markets in the United States, in which pipelines play an important role. An example of such a pipeline is the fourth phase of the Keystone pipeline, also known as ‘Keystone XL’ (See Figure 5).



Figure 5 Keystone pipeline routes, including the yet to be approved phase 4 (keystone XL). Source: Wikimedia 2012

Environmental impact

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 is 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 (Boland and Unnasch 2014).

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 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. 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 (Boland and Unnasch 2014). 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.

There is significant variation between current estimates of GHG emissions from oilsands-derived fuels. This variation has a number of causes, including:

1. Differences in scope and methods of estimates: some studies model emissions from specific projects, while others generate average industry-wide emissions estimates;
2. Differences in assumed efficiencies of extraction and upgrading, especially with respect to the energy efficiency of steam-assisted gravity drainage (SAGD);
3. Differences in the fuel mix assumed to be consumed during oil sands extraction and upgrading;
4. Treatment of secondary non-combustion emissions sources, such as venting, flaring and fugitive emissions;
5. Treatment of ecological emissions sources, such as land-use change (LUC) associated emissions.

Kerogen oil (oil shale)

Kerogen is the solid organic matter contained in shales that is the source of oil and gas. When heated under the right conditions, over geological time, kerogen is transformed into liquid or gaseous hydrocarbons. Shales containing kerogen are ubiquitous around the world. Some outcropping kerogen-rich shales have been exploited for centuries and burned for heat or power. If kerogen-containing shale is retorted (i.e. heated at a controlled rate), the kerogen can be transformed into liquid hydrocarbons (IEA WEO 2013).

Kerogen oil is produced today in this way in small quantities in Estonia, China and Brazil. The easiest kerogen shales to exploit are those near the surface, accessible with mining techniques. In principle, one can also exploit deeper deposits through in-situ heating, but the near-surface resources are already enormous. The largest known such kerogen shales are in the Utah, Colorado, Wyoming area of the United States. These have been studied in detail by the USGS and are thought to contain kerogen resources equivalent to 4, 285 billion barrels of oil, of which more than 1,000 billion barrels is contained in the richest deposits that are more likely to be economically developed (IEA WEO 2013, citing data from United States Geological Survey 2012).

Drivers and barriers

Several pilot projects have been demonstrating the technical feasibility of exploiting these deposits over the last 30 years, though there are significant environmental concerns related to water and land use.

Typically, the oil recovery rate for shale oil is between 1% and 10%, and the cost of production ranges between USD 50-80 per barrel produced (Roland Verger 2013, IEA 2013).

Environmental impact

Developing oil shale and providing power for oil shale operations and associated activities requires significant amounts of water, which could pose problems in areas where water is limited, and where water cleaning may be an issue. According to GAO (2012), oil shale development could have significant impacts on the quantity of surface and groundwater resources, but the magnitude of these impacts is unknown because of uncertainties in technological developments, scale and knowledge of current water conditions and groundwater flow. The possibility of competing municipal and industrial demands for future water, a warming climate, future needs under existing compacts, and additional water needs for the protection of threatened and endangered fishes, may eventually limit the size of a future oil shale industry.

Light tight oil (also known as shale oil)

IEA's World Energy Outlook (2013) use the term light tight oil (LTO) to designate oil produced from shales or other very low permeability formations, using multi-stage hydraulic fracturing in horizontal wells, as pioneered in the United States over the last few years. The interchangeable term "shale oil" is often used as well, by analogy with shale gas; but the term LTO reduces the risk of confusion with oil produced from "oil shales", that is, shales containing kerogen that needs to be heated up, or retorted, to be transformed into oil (which the World Energy Outlook designates as kerogen oil).

Light tight oil resources worldwide are still relatively poorly known but, on current estimates, represent some 6% of total remaining recoverable resources (WEO 2013).

Drivers and barriers

Oil flows relatively easily through the porous rocks that make up a conventional reservoir, so a conventional well can tap a large area. As a result, the volume of oil pumped each day declines slowly, on average at 6% per year. By contrast, oil flows much more sluggishly through impermeable tight rock. A well will tap a much smaller area and production declines quite rapidly, typically by 30% a year for the first few years (Economist, 2014). Maintaining a field's production levels means constant drilling. The International Energy Agency reckons maintaining production at 1 million barrels per day in the North American Bakken field² requires 2,500 new wells a year. In comparison, a large conventional field in southern Iraq needs just 60 (Economist 2014).

This all means that when oil prices rise, producers can quickly drill more holes and ramp up supply. When prices fall, they simply stop drilling, and production soon declines. Economist 2014 cites an example, where in early 2009, after prices collapsed with the global financial crisis, Pioneer (an LTO developer) shut down all its drilling in the Permian Basin. Within six months, output in the affected areas dropped by 13%.

Tight oil is therefore much more responsive to world prices than other sources of oil. Some economists think this could turn America into a swing producer, helping to moderate the booms and busts of the global market (Economist, 2014).

Greenhouse gas implications

Greenhouse gas emissions from fracking are not well characterized, however, efforts are being made by the California Air Resource Board (ARB) with the latest OPGEE model. The emphasis so far has been on shale gas, with few major studies on oil from fracking. Boland and Unnasch (2014) have developed custom simulations using published data on well performance and comparable production data.

² Geological formation covering large parts of Saskatchewan and Manitoba provinces in Canada and Montana and North Dakota in the US

Oil from the Bakken reservoir is liberated through a hydraulic fracturing process. The oil is light 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 and 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) (OPGEE 2013).

The inputs to the fracking process 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 (Boland and Unnasch 2014). Fracking for crude oil also releases significant volumes of 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 (Boland and Unnasch 2013 quoting New Scientist 2013). Boland and Unnasch 2014 estimate flaring emissions from 5.2 to 12 g CO₂ 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 sulphur result in the low end of refining carbon intensity.

Gas-to-Liquids (GTL)

There are currently five GTL plants operating globally, with capacities ranging from 2,700 barrels per day (bbl/d) to 140,000 bbl/d (EIA 2014). Shell operates two in Malaysia and one in Qatar, Sasol operates one in South Africa, and the fifth is a joint venture between Sasol and Chevron in Qatar. One plant in Nigeria is currently under construction. Three plants in the United States—in Lake Charles, Louisiana; Karns City, Pennsylvania; and Ashtabula, Ohio—are proposed. Of these, only the Lake Charles facility is a large-scale GTL plant.

GtL plants have a different economic basis. Gas is available in a variety of locations, often co-produced with crude oil. This basically means that for GtL studies the gas feedstock is typically taken at very low values, 0.5 to 2 \$ per MMSCFD. The cost of the natural gas feedstock is essentially the extraction and treatment costs. Little public data is available for GtL, and even less published production costs. The Shell Pearl project reports revenues of 4500 M\$ per year for a 19,000 M\$ investment based on an oil price of 70 \$ per barrel. This suggests that the feedstock plays a limited role in the product cost structure. The reported feed gas costs are essentially production costs of 6 \$ per barrel of oil equivalent. The results of the survey are presented in Table 8. Natural gas is often co-produced with condensate and crude oil. When exporting by pipeline is not possible and flaring becomes undesired, liquefaction (LNG) and GtL become interesting options. The low costs of the stranded gas encouraged oil companies to invest in very large plants; examples are modern plants such as the Pearl and Oryx plants in Qatar (Haarlemmer et al 2014).

Drivers and barriers

In December 2013, Shell cancelled plans to build a large-scale GTL facility in Louisiana because of high estimated capital costs and market uncertainty regarding natural gas and petroleum product prices. The Annual Energy Outlook 2014 (EIA 2014b) Reference case projection does not include any large-scale GTL facilities in the United States through 2040. Other uses for available natural gas in industry, electric power generation, and exports of pipeline and liquefied natural gas are more economically attractive than GTL under the reference case facility cost assumptions and energy prices.

Coal-to-Liquids (CTL)

Countries with large, low cost coal resources and significant oil import needs, such as China or India, will lead the investments in this technology. Although not strictly speaking CTL, rapid development of coal-to-chemicals is taking place in China, displacing demand for oil as feedstock. Therefore this technology is not seen as being developed on international markets.

The US Energy Information Agency projected the startup of the first CTL plants in the United States to be in 2023, "with penetration of the technology far more modest" when compared with previous estimates (Quinones 2013).

An extensive study by Sweden's Uppsala University questioned the prospects of CTL around the world, and particularly in the United States: "The economic analysis shows that many CTL studies assume conditions that are optimistic at best. In addition, the strong risk for a CTL plant to become a financial black hole is highlighted".

Drivers and barriers:

Economics and environmental acceptability are the main constraints on CTL development (IEA 2013). Capital costs can run into USD 3 to 4 billion per plant according to Steve Jenkins, quoted in Economist (2014) and financing is therefore a significant barrier.

The economic driver only becomes relevant when the margin between the feedstock (coal) and the price of the sold product (transportation fuel) is really high. However, even at very low costs of coal, oil prices would need to be extremely high for CTL to become interesting, in which case other oil options are economically more interesting. Therefore, the developments of CTL are primarily driven by (political) concerns on energy security, and are unlikely to be motivated by relatively small reduction in oil prices caused by the introduction of biofuels.

Frontier oil

Frontier oil means exploring for resources in new geological areas where costs and risks (technical and financial, although it can also mean political) are high. For instance, a report cited in FOE 2011 named the following as being the next “new oil frontiers”: West Africa (Sierra Leone, Liberia, Sao Tomé and Príncipe), ultra-deepwater in the Gulf of Mexico, Western Sahara, the Falkland Islands, Uganda, the Bahamas, and the Arctic. The term “frontier oil” is usually used to cover exploration for conventional rather than unconventional resources, whether onshore or offshore

Drivers and barriers

Frontier oil developments are attractive because they produce light crude oil, which fits well in the existing refinery infrastructure.

However, besides the very large capital investments required, an important number of non-economic barriers are limiting the developments of this resource type, namely the long lead times, new production techniques, as well as the operations in environmental and politically sensitive areas.

Moreover, the Deepwater Horizon incident has led to renewed concerns about safety and environmental protection and specifically to increased insurance premiums for companies (King 2010). Some analysts also cautioned that the accident would result in a slowing of deepwater investment globally, with governments shying away from opening them up, or companies deeming them too risky, as increased technical and regulatory risks were added onto other geopolitical and fiscal uncertainties.

Hence, though the international oil price does play a role in investments in frontier oil developments, the non-economic drivers are so important that the sensitivity to small oil price variations is negligible, and therefore biofuels do not displace frontier oil-derived fuels.

3 Greenhouse gas impacts

This section discusses the carbon intensity of selected fossil fuels that are most likely to be displaced by biofuels. The analysis shows that by displacing marginal fossil-based liquid fuels, biofuels avoid significant greenhouse gas emissions that are not currently accounted for in the RED. These avoided emissions are in addition to the emissions reductions relative to average petroleum fuels that are already counted in traditional analysis. We estimate that by taking the marginal approach, biofuels displace fossil fuels with an average of 114 gCO₂eq/MJ. In the case where unconventional fuels with higher emissions (tar sands and CTL) are being displaced, the number is potentially a lot higher, at 134.3 gCO₂eq/MJ. Even in the unlikely scenario where only conventional fuels are being displaced, the emission factor should be at least 90 g CO₂eq/MJ.

3.1 Methodology

Greenhouse gas footprints of fossil fuel supply chains are comparable to what is done to calculate the greenhouse gas impact of biofuels in the frame of the EU Renewable Energy Directive. A simplified supply chain is depicted in Figure 6, showing the flows of energy (E), materials (M) and greenhouse gas emissions.

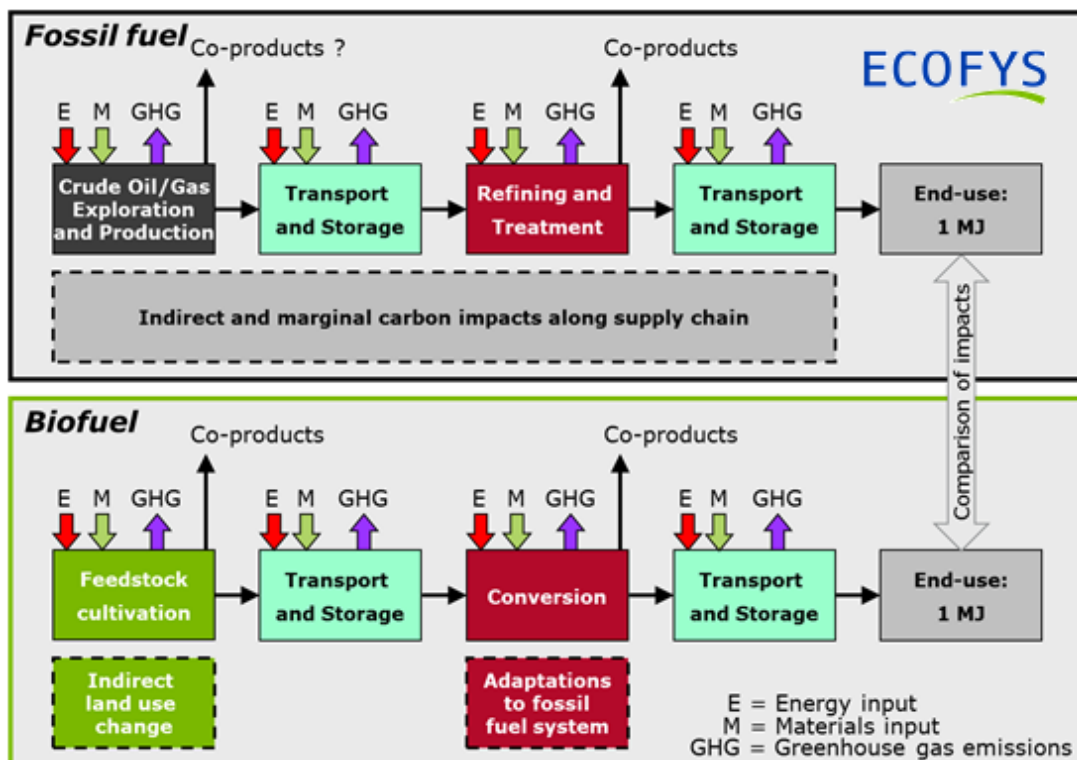


Figure 6 Simplified supply chain and system boundaries for GHG emission calculation for fossil fuels (top) compared with biofuels (bottom).

Modelling of the petroleum life cycle is affected by the variations in crude resources and oil refineries discussed in this study.

After determining the life-cycle emissions of various supply-chains, the results are combined with elements from Chapter 2, where the marginal greenhouse gas impact of introducing 1 MJ of biofuels is assessed in several scenarios. In other words, we ask: what fuel sources would be used if biofuels were not available?

Note on methodology for calculating biofuel GHG emissions according to RED and FQD

It is useful to note that the methodology set out in the EU Renewable Energy Directive³ and Fuel Quality Directive⁴ to calculate the well-to-wheel carbon footprint of biofuels, presents a few anomalies. For instance, the methodology allows a share of the total life-cycle emissions to be allocated to co- and by-products of the biofuel. However, the methodology explicitly prohibits the allocation of emissions to renewable electricity, which should also be regarded as a valuable co-product of certain biofuel production pathways. For example, if a Brazilian sugar and ethanol mill wants to export electricity to the electric grid, the electricity should also share a part of the emission burden with the biofuel output.

Furthermore, many of the default parameters provided by the RED and FQD are outdated and do not represent the average technology level of current biofuel production technologies. The use of outdated data regarding biofuel technologies can be explained by the fact that the biofuel sector was barely involved in the drafting on the legislation.

3.2 Crude oil production

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;

³ Annex V section C

⁴ Annex IV section C

Collecting data or modelling each of these sources is challenging. Data are often overly aggregated in environmental impact reports and permits and the data reflect allowable emissions. For each type of resource, the most relevant impacts on GHG emissions have been listed in their respective description in Section 2.3.

3.3 Refinery Emissions

After crude oil is produced, it is refined in a refinery, which produces refined fuels, and other co-products. 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 (Boland and Unnasch 2014).

During the refinery stage, GHG emission sources include the following:

- Refiner heaters fuelled 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 (CO₂);
- Fugitive hydrocarbons;

An 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 should be included in the LCA result. 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 studies.

The most accurate models are those from the OPGEE model from Stanford University (El Houjeri and Brandt 2013) and studies by Jacobs consultancy (Jacobs and Life Cycle Associates 2012) and cited in Life Cycle Associates 2014. These studies take into account crude oil reservoir characteristics. 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 sulphur as co-products whereas the GREET model allocates emissions to coke, asphalt and residual oil (GREET 2013).

3.4 GHG performance summary

GHG emission have been sourced from literature, where the best and most accurate source was selected for the relevant fuels. A summary of these emissions is given in Figure 7. Here, the RED/FQD fossil comparator is also shown for reference, as well as other references used in the US in the federal renewable fuel standard (RFS) and in the California Low Fuel Standard (LCFS).

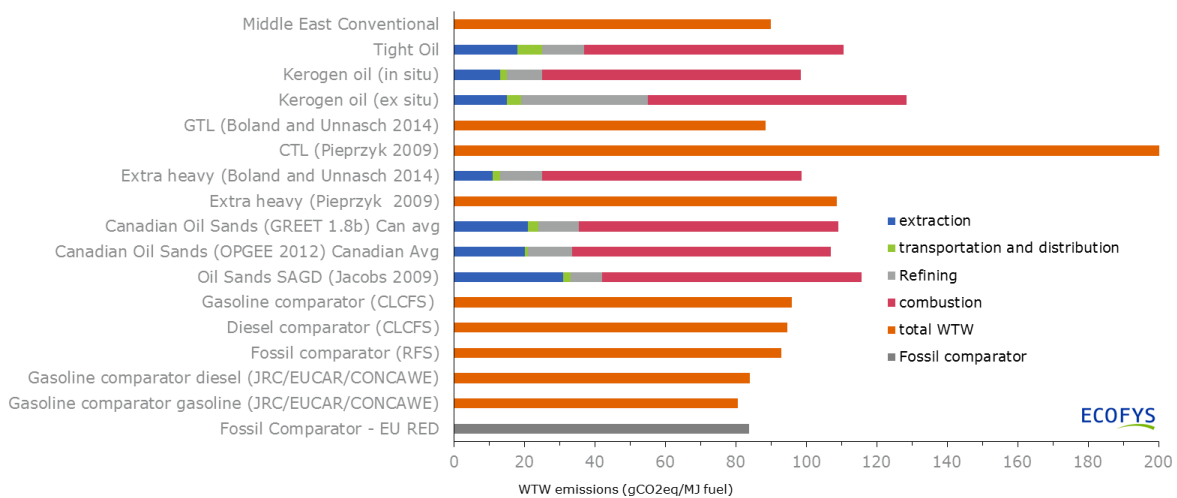


Figure 7 Well-to-Wheel comparison of fuels from various resources

3.5 Weighted substitution

When we assume that one energy unit of biofuel displaces one energy unit of fossil fuels, the question remains what types of fossil fuels are being displaced. Based on our analysis from Chapter 2, we allocated shares to the fuels that are most sensitive to a price change i.e. light tight oil, oil sands and kerogen oil. In order to frame these results, we have also compared them with (1) the extreme situation where only conventional fuels are being displaced and (2) the situation where all emissions are spread over all unconventional fuels in the proportions they will grow according to the EIA in its reference case in its Annual Energy Outlook to 2035. The results are summarised in Table 2 below and visualised in Figure 8.

Table 2 Distribution of 1 MJ over unconventional oil sources and corresponding avoided GHG emissions.

Oil resource	share displaced by 1 MJ of biofuel		
	most likely (our assessment)	equally distributed over unconventional growth	only conventional
Oil sands (tar sands)	30.0%	55.4%	0.0%
Extra heavy oil	10.0%	10.7%	0.0%
Biofuels	0.0%	0.0%	0.0%
Coal-to-Liquids	0.0%	24.3%	0.0%
Gas-to-Liquids	0.0%	5.6%	0.0%
Kerogen oil	20.0%	3.3%	0.0%
Tight oil	40.0%	0.7%	0.0%
Conventional (Middle East)	0.0%	0.0%	100.0%
Total	100.0%	100.0%	100.0%
Average avoided GHG emissions (gCO ₂ eq/ MJ biofuel)	115.5	137.5	90.0
Difference with RED comparator (83.8 gCO ₂ eq/MJ)	31.7	53.7	6.2

Figure 8 below shows a comparison of typical life-cycle emissions of typical biofuels and well-to-wheel emissions from fossil fuels according to the EU RED fossil comparator and using the marginal approach (this study). The figure clearly shows the difference between the EU RED comparator, and the fossil fuel emissions when using the marginal approach. Our assessment is that by taking the marginal approach, the fossil fuels being displaced by biofuels emit 31.7g/MJ more than the current fossil comparator. These figures are in the same order of magnitude as the ILUC factors⁵ currently proposed for biodiesel, that range from 52g/MJ (sunflower) to 54g/MJ (rapeseed and palm fruit) and 56g/MJ (soybean).

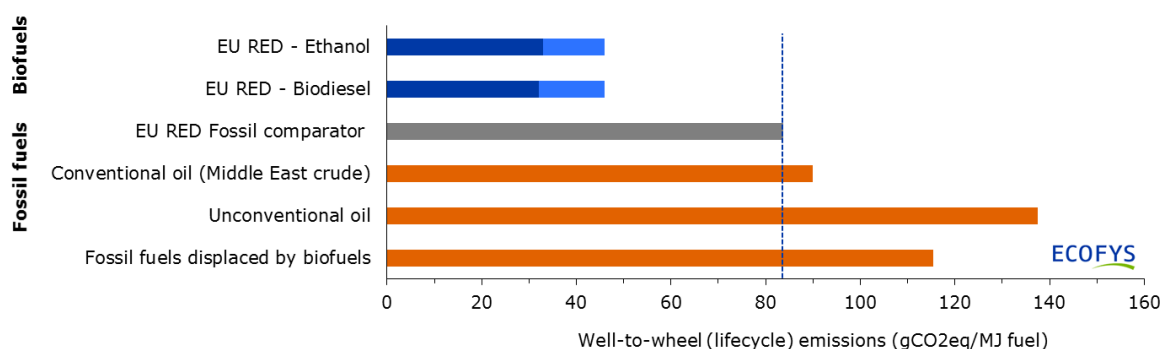


Figure 8 Comparison of well-to-wheel emissions from biofuels with fossil fuels using marginal approach. A range of EU RED typical emissions is plotted for ethanol (sugar beet 33 g/MJ, wheat 46 g/MJ) and for biodiesel (palm oil biodiesel with methane capture 32 g/MJ, rapeseed 46 g/MJ).

⁵ ILUC factors discussed here are the 2011 values as calculated by IFPRI and published by the EC. Note that a new assessment of ILUC factors is being made, based on the latest insights and the Globiom model. For more information visit <http://www.globiom-iluc.eu>

3.6 Conclusion

This analysis shows that substituting biofuels for marginal fossil-based liquid fuels results in the avoidance of significant GHG emissions that are not currently accounted for in the RED. These avoided emissions are in addition to the emissions reductions relative to average petroleum fuels that are already counted in traditional analysis. In our analysis, avoided emissions resulting from displacement of unconventional liquid fuels result in displacing fossil fuels with an average of **115 gCO_{2eq}/MJ** of energy delivered by biofuels. This number remains an estimate, but sensitivity analysis shows that even in the unlikely scenario where only conventional fuels are being displaced, the emission factor should be at least 90 g CO_{2eq}/MJ. In case that also unconventional fuels with higher emissions are being displaced, the number is potentially a lot higher, at 137.5 gCO_{2eq}/MJ. Hence, by taking the marginal approach, the fossil fuels being displaced by biofuels emit **31.7g/MJ** more than the current fossil comparator. These figures are in the same order of magnitude as the ILUC factors currently proposed for biodiesel, that range from 52g/MJ (sunflower) to 54g/MJ (rapeseed and palm fruit) and 56g/MJ (soybean).

4 Policy Implications

The average greenhouse gas emissions of (conventional) fossil transportation fuels are rising, and will keep rising in the foreseeable future, as the share of high-emission fuels based on unconventional resources will increase. The average emission factor has risen to about 90 g/MJ, and the fossil comparator should be adjusted to reflect these changes.

Indirect emissions of biofuels are being assessed by expanding the system boundaries of the fuel system, in order to provide a more accurate representation of the greenhouse gas savings that are achieved by deploying biofuels. Similarly, in order to more accurately reflect the emissions they avoid, biofuels' carbon intensity should be compared with the emissions of the fossil fuels they really displace, i.e. the marginal fossil fuels. We estimate that the emission factor of the marginal fossil fuels being displaced is around 115 g/MJ. This is 31.7 g/MJ above the average fossil fuel emissions to which biofuels are currently being compared (fossil comparator).

The emission factors of various types of unconventional fossil fuels differ significantly and are changing fast with technological developments. Proper implementation of Article 7a of the FQD could provide a strong incentive to avoid the fuels with the worst GHG performance to reach the EU market. Full implementation of this policy would likely lead to a relatively reduced investment in and production of the most carbon intensive fossil resources globally, since they heavily depend on the European market (Buffet 2014⁶). This would lead to significant reductions in both average and marginal emissions of fossil fuels, while at the same time driving improvements in the GHG performance of biofuels.

⁶ Buffet quotes Joe Oliver, then energy minister of Canada, "You can have all the oil and gas in the world, but it's not much good if you can't get it to market [...] Europe is the biggest single market in the world right now."

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