Ministry of Economic Development
Manatū Ōhanga

Alternative Liquid Fuels: Global Availability, Economics and Environmental Impacts

March 2007

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Foreword

If conventional oil gets to be too expensive, what are the alternatives? This is an important question for New Zealand for three reasons.

- First, the production of conventional oil has been struggling to keep pace with rapidly rising world demand, and there are concerns that even the current levels of production may not be sustainable in the longer-term. Reflecting these realities, world oil prices have more than doubled since 2002.
- Second, New Zealand depends upon oil for over half of its consumer energy and for 99% of its transport energy. Most of this oil is imported, meaning that the New Zealand economy is very much exposed to any shocks that might develop in the world oil market.
- Third, the challenges posed by New Zealand's dependence on imported oil are further complicated by the growing recognition of the additional challenges posed by climate change. Even if there are economic alternatives to oil, will they be environmentally acceptable?

In order to address this question, the Ministry of Economic Development engaged Michael Taylor to survey liquid fuels that might provide an alternative to conventional oil. For each alternative fuel, Michael was asked to describe the current state of the technology and to examine the economics, the extent of the resource, and its environmental impacts.

Michael comes well-qualified for this assignment. He is a New Zealander who has over 13 years experience in energy modelling, energy sector economic analysis, and energy policy development. Since 2001, he has been heavily involved with the International Energy Agency (IEA) in Paris, as both as an employee and as a consultant. He contributed to the IEA's World Energy Outlooks for both 2003 and 2004. He was also one of the authors of the IEA's *Energy Technology Perspectives: Scenarios and Strategies to 2050* and edited the IEA's *Prospects for Hydrogen and Fuel Cells*, both of which had a strong focus on technology and alternative fuels. On the environmental side, Michael has recently been helping to draft the Transport chapter of the soon-to-be-released Intergovernmental Panel on Climate Change (IPCC) *Fourth Assessment Report on the Mitigation of Climate Change*.

The story Michael presents here has good news and bad news. The good news is that there appear to be several alternative liquid fuels that could be available in abundant quantities at a cost competitive with today's oil prices. The bad news is that they come with significant environmental challenges and risks that will need to be carefully addressed and managed. Since these risks tend to be global in scale, New Zealand will need to be aware of them, and become involved in international efforts to mitigate them, even if the fuel is produced overseas.

While there are no easy answers here, Michael's report does a great service in laying out the challenges and the opportunities of alternative liquid fuels.

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March 2007

1 Introduction

Interest in alternative liquid fuels is once again high given that oil prices remain at historically high levels. In the United States of America, President George W. Bush used his State of the Union speech in February 2006 to highlight that “America is addicted to oil” and must develop technologies to address soaring gasoline prices. Given the reliance of all countries on oil products for transportation demand, the same could perhaps be said of any developed economy.

However, alternatives to liquid fuels derived from conventional oil are expensive. As a result, their production has in the past, and today, only contributed a tiny fraction of production. However, if oil prices remain at historically high levels this picture could change. Current high oil prices and concerns about the rate at which conventional oil supplies can expand to meet demand growth are encouraging research and investment in alternative liquid fuel supplies. If prices remain high, they could begin to play a significant role in liquid fuel supply.

Given that alternative liquid fuels face very different technological, economic and in some cases environmental problems, it is important to identify their individual characteristics and the challenges they face in order to understand their potential role in future liquid fuel supply. This paper provides a brief discussion of a number of alternative liquid fuels, their availability, costs and environmental impacts.

2 Alternative Liquid Fuels

This paper presents an analysis of the resource availability, costs and environmental implications of five alternative liquid fuel sources. The prospects for heavy oil (predominantly in Venezuela), tar sands and bitumen (predominantly in Canada), oil shales (predominantly in the United States), biofuels (ethanol and biodiesel) and synfuels from coal and gas are examined in turn.

For each alternative fuel there is a brief discussion of the following topics:

- *Fuel overview:* This sub-section briefly introduces the characteristics of each fuel and any relevant technology issues or challenges.
- *Resource availability and distribution*: this sub-section looks at the level and distribution of reserves and resources. It will briefly discuss the technological considerations in production and transformation where appropriate. It will discuss the uncertainties surrounding the data and if there are any developments that would yield greater reserves.
- *Production costs* : this sub-section presents a potential supply curve for each alternative fuel and identifies the current costs of production. It will look at what future technological developments might lower these costs or make more resources available at competitive rates. It will also discuss the uncertainties surrounding the cost estimates.
- *Environmental impacts*: This sub-section will discuss the environmental impacts of the production and use of the alternative fuel. This will include specific reference to and quantification of greenhouse gas emissions. It will also discuss any technological options for mitigating the negative environmental impacts and their impact on costs.

3 Non-Conventional Oil

There is no standard definition of non-conventional oil and it is a concept that evolves over time. Deepwater offshore oil reserves were once considered to be technically too difficult to bring to production and they were not considered conventional oil reserves. However, over time production experience and improvements in technology have lowered the costs of deepwater exploration and production, despite the huge technological challenges faced. Generally speaking, non-conventional oil resources are currently defined as heavy oil, tar/oil sands and oil shales.[1]

Non-conventional oil resources have played a relatively minor role in oil supply to-date, because relatively abundant conventional oil resources have not justified large-scale investments in these, more expensive sources. However, the potential resource base is very large and at current oil prices some of these resources are extremely attractive.

Medium heavy oil and extra heavy oil have a density ranging from 25º API to 7 ºAPI, and a viscosity ranging from 10 to 10 000 centiPoise (cP).[2] These oil resources are mobile at reservoir conditions, that is to say, they flow at the reservoir level, albeit at rates much less than conventional oil resources and may need some thermal stimulation. Generally speaking, the higher an oil's API gravity, the more valuable it is. The reason for this is that it yields higher proportions of the valuable "light" petroleum products - such as petrol, diesel and jet kerosene - without upgrading.

Tar sands and bitumen have a density ranging from 12º API to 7 ºAPI, and a viscosity above 10 000 cP. They are not mobile in the reservoir itself and need additional efforts in order to access them. Tar sands generally contain around 10% to 15% bitumen by weight.

3.1 Resources and Reserves of Non-Conventional Oil

Total non-conventional oil resources in place are thought to be around 7 000 billion barrels.[3] [4] Tar sands and bitumen account for 39% of the total, heavy oil 23% and oil shales 38%. However, the potential level of reserves that could be extracted is highly uncertain. Given these resources are more expensive to produce than conventional oil, only 10 billion barrels have been produced to date and this industry is therefore still in its infancy. Recovery rates are currently low for in-situ

[1] The terms "oil sands" and "tar sands" are used somewhat interchangeably in this paper. Confusingly, "oil shales" are not in fact oil or shale, but a type of rock that contains a large portion of solid organic compounds, known collectively as "kerogen".

[2] The API Gravity, in degrees, is a specific gravity scale that was developed by the American Petroleum Institute (API) for measuring the relative density of various petroleum liquids. API gravity is graduated in degrees on a scale so that most values fall between 10 and 70 API gravity degrees. Crude oil is classified as light, medium or heavy, according to its measured API gravity. Light crude oil is defined as having an API gravity higher than 31.1 °API, medium oil is defined as having an API gravity between 22.3 °API and 31.1 °API, and heavy oil is defined as having an API gravity below 22.3 °API.

[3] Oil demand in 2006 is currently estimated to average 85 mb/d or around 31 billion barrels over the entire 2006.

[4] IEA (2005), *Resources to Reserves: Oil and Gas Technologies for the Energy Markets of the Future*, IEA, Paris.

production, while mining is restricted to the relatively small percentage of resources that are close to the surface.

Given that production of non-conventional oil is still in its the infancy, ultimately recoverable reserves will depend critically on technology developments. Potentially very large quantities of non-conventional oil resources could be considered reserves, given that as cumulative production grows, production methods and the economics of production will improve. However, they generally have higher costs than conventional oil reserves and their development to date has been driven by the periods in the past 30 years when high oil prices have made them attractive. However, price volatility makes these resources quite risky. Producers, particularly in Canada, have therefore undertaken a lot of work to improve the production economics.

The risk profile for non-conventional oil production is somewhat different from that for conventional oil projects, as most heavy oil and tar sand resources are reasonably well defined. This means that there is little exploration risk, but non-conventional oil projects are much more exposed to price risk. This will restrict their development to low-risk projects that have relatively robust economic prospects.

The estimated resources in place of heavy oils are concentrated in Venezuela, while the tar sands and bitumen are concentrated in Canada, although estimates suggest there might be 1 350 billion barrels in Russia that is not taken into account.[5] Although natural bitumen and extra-heavy oil occur worldwide, in each case one single deposit in each category dominates the known resources. The natural bitumen deposits in Alberta Canada are estimated to contain at least 85% of the total global bitumen in place, however the remaining deposits are so small and widely distributed that the Canadian deposits are virtually the only economically recoverable resources for conversion to oil.[6] The deposits amount to something between 1 630 and 1 700 billion barrels of bitumen in place.[7]

The extra-heavy crude oil in the Orinoco Oil Belt, in Eastern Venezuela, represents nearly 90% of the known extra-heavy oil resources (Figure 3.1). The amount of heavy oil in Venezuela is thought to be between 1 200 and 1 360 billion barrels, although maybe as high as 1 700 billion barrels.[8] The potential oil in place of tar sands and bitumen in Canada is thought to be around 1 630 billion barrels. Currently, the ultimately recoverable resource component of Canada's tar/oil sands and bitumen reserves are thought to be around 310 billion barrels, while the fraction of Venezuela's heavy oil that is thought to be recoverable at this point is around 270 Billion barrels.[9] Canada's proven remaining reserves of non-conventional oil are around 174 billion barrels, making Canada's non-conventional oil reserves the second largest concentration of oil reserves after Saudi Arabia's conventional reserves (250-260 Billion barrels).[10]

[5] Gielen, D. and Unander, F. (2005), *Alternative Fuels: An Energy Technology Perspective*, IEA/ETO Working Paper. There maybe significant heavy oil reserves in Russia, however, estimates for Russia remain highly uncertain and are generally excluded from oil in place estimates.
[6] World Energy Council (2001), *Survey of Energy Resources*, WEC.
[7] IEA (2006), *Energy Technology Perspectives: Scenarios and Strategies to 2050*, IEA, Paris and WEC (2001).
[8] IEA (2006) and WEC (2001).
[9] IEA (2006).
[10] National Energy Board (2006); *Canada's Oil Sands, Opportunities and Challenges to 2015: An Update*; National Energy Board (NEB), Calgary.

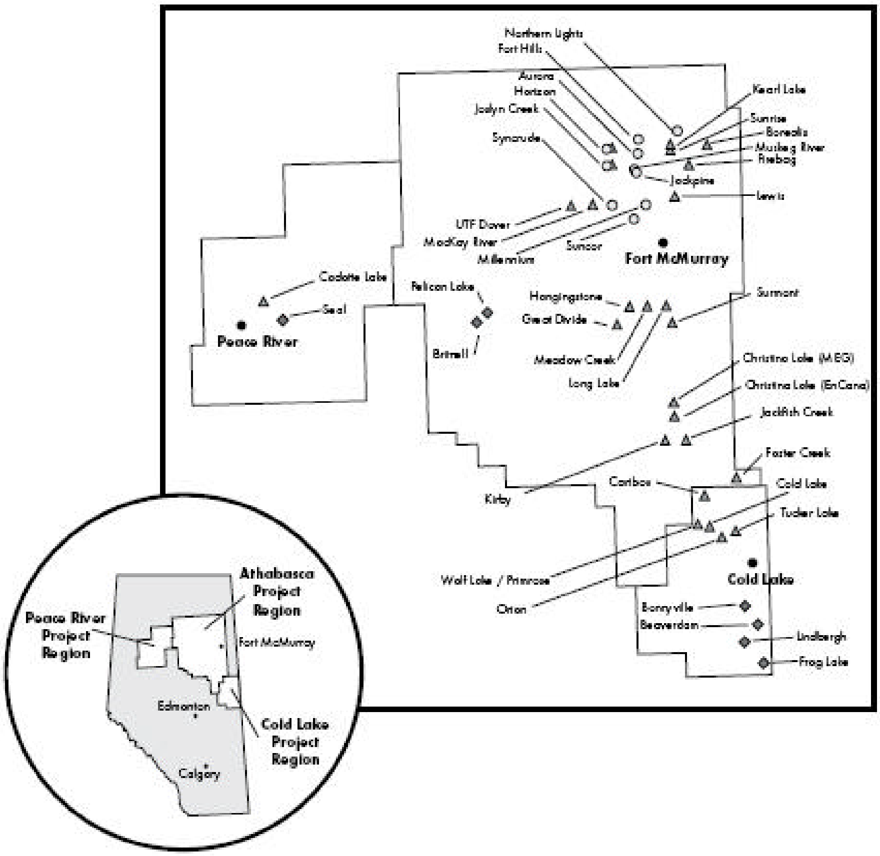
Figure 3.1: Venezuela's Heavy Oil Deposits: The Orinoco Belt[11]

3.2 Tar Sands and Bitumen

Tar sands can be mined at the surface, similarly to open-cast coal, if they are sufficiently close to the surface, or accessed using in-situ production techniques. Around 10% of oil sands are located within 50 metres of the surface and can be mined in open pits. Oil recovery from surface mined oil sands can be as high as 90%, and offers favourable economics. Open-cast mining therefore accounts for the majority of Canada's production which occurs in Alberta (Figure 3.2). However, the share of output from surface mining is likely to decline over time if production is to be expanded significantly.

[11] Based on C, Kopper *et al* (2002), *Heavy-Oil Reservoirs*, Oil Field Review, Vol.14, No.3.

Figure 3.2: Canadian Oil Sand Projects and Location[12]



The mined sand is transported to a processing plant where the bitumen is separated using a mixing and cleaning process that uses water, caustic soda and agitation. The bitumen is then diluted with naphthalene or condensate to make it ready for pipeline delivery to a refinery or to an upgrader.[13] The bitumen is heated at the upgrader to around 500°C, the bitumen then yielding about 70-75% syncrude.[14] This "synthetic crude oil" has similar properties to light crudes and can be piped to a refinery, where it has good yields of kerosene and other middle distillates. The remaining 30% thermally cracks to form gaseous products or is converted into petcoke.[15]

Open-cast mining is extremely profitable at today's oil prices, with total production costs for existing projects estimated to be in the vicinity of $10/bbl.[16][17] Incremental capacity increases at

[12] NEB (2006).
[13] The level and type of dilutent can be tailored to create a product acceptable to different refineries needs.
[14] IEA (2006).
[15] Petroleum coke (petcoke) is a carbonaceous solid residual by-product of the oil refining process. Maximising the yield of high-value products such as gasoline and jet fuel yields significant residues, transforming these into petcoke provides an alternative fuel and reduces disposal problems. The petcoke is used as a fuel, with high-grade petcoke having a higher heating value of around 15% greater than coal
[16] All figures used in this report are US dollars.

existing mining sites are likely to be more expensive than this, but not substantially. However, greenfield integrated mining and upgrading capacity additions will have total costs substantially higher than this, as higher natural gas prices, skills shortages, increasing capital costs and inflation in the oil services sector has pushed up project costs in recent years. This is true of many large engineering projects around the world, where increases in the costs of skilled labour and basic raw materials have pushed up project costs.[18]

In the longer-term, although significant incremental capacity will be added to existing mining operations, new capacity will increasingly come from in-situ mining projects. This is due to advances in technology lowering costs for in-situ techniques, their smaller environmental footprint, and reduced freshwater needs. However, in-situ mining typically recovers a much smaller percentage of bitumen, with recovery factors of 10% to 20% being typical. Five in-situ mining techniques are in operation: cyclic steam stimulation (CSS), pressure cycle steam drive (PCSD), cold heavy oil production with sand (CHOPS) and steam or solvent assisted gravity drainage (SAGD).[19]

SAGD is a particularly interesting approach, although it is only at the pilot plant stage at this time, because it could dramatically alter the reserves and production outlook for oil sands. SAGD uses two horizontal wells, one on top of the other, with the top well being used to inject steam or organic solvent, and the bottom well recovering the liquid bitumen (Figure 3.3). This has the potential to raise recovery rates from 10% to 40%, and if this can be proved to be commercially viable could raise global tar sands and heavy oil recoverable reserves to the level of conventional oil reserves.[20]

[17] UTILIS Energy (2004), *Oil Sands – Alberta 2004*, UTILIS Energy, New York.
[18] Corinthus, T. (2006), *The Impact of Synfuels on World Petroleum Supply*, Presentation to the 2006 EIA Energy Outlook and Modeling Conference, March, 2006.
[19] IEA (2006).
[20] IEA (2006).

Figure 3.3: Oil Sand Production with Steam Assisted Gravity Drainage[21]

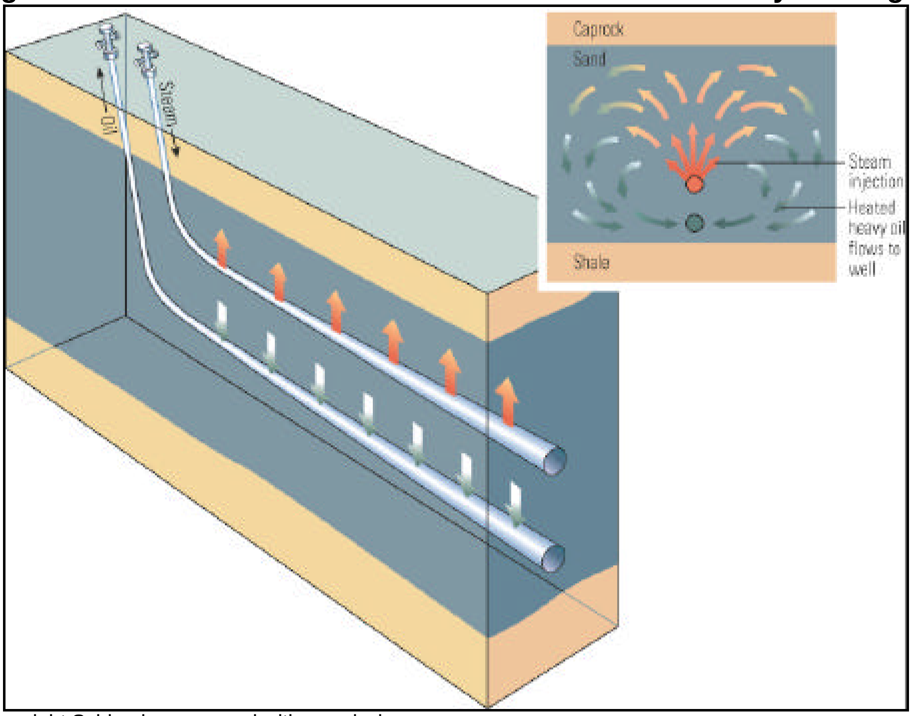


Table 3.1 presents estimated operating and total supply costs for new greenfield capacity. Care needs to be taken in interpreting the differences in costs, as the bitumen is sold as "heavy crude" while the upgraded syncrude trades at little or no differential to light crudes (currently 60% of production is upgraded to syncrude).[22] The operating costs are equivalent to cash costs, and are probably close to marginal costs, while the total supply costs take into account capital charges, royalties, taxes etc. The final column includes an estimate of the WTI (West Texas Intermediate – an extensively traded US crude oil type that is often used as a benchmark crude oil price) crude price necessary for the project to make a 10% rate of return, given the different supply costs for bitumen and upgraded syncrude are not directly comparable per barrel due to their very different market value. Variations in cost take into account reservoir quality, depth of the producing formation and other operating parameters that may vary.

[21] Source: Alboudwarej, H.. *et al* (2006), *Highlighting Heavy Oil*, Oil Field Review.
[22] National Energy Board (2006); *Canada's Oil Sands, Opportunites and Challenges to 2015: An Update*; National Energy Board, Calgary.

Table 3.1: Estimated Operating and Supply Costs for Alberta's Oil Sands[23]

	Crude type	Production capacity (kb/d)	Operating costs ($)	Total Supply costs ($)	WTI price to yield 10% rate of return
Mining/extraction	bitumen	n.a.	8-10	15-19	30-35
Integrated mining/upgrading	syncrude	200	15-19	31-34	30-35
SAGD	bitumen	120	9-12	15-19	30-35

The steam component of the operating cost of a SAGD project is estimated to be around $3/bbl if gas is used[24] to generate the steam and $1/bbl if upgrading residues can be used, but at the expense of higher CO_2 emissions. The total estimated cost of large-scale production using SAGD including production and upgrading is thought to be $15-20/bbl of the bitumen produced, which is equivalent to a WTI price of around $30-$35/bbl.

Rising gas prices have resulted in increased interest in using mining and upgrading residues to produce the steam required for oil sands production and upgrading. The gasification of bitumen residues to produce syngas for process fuel use, thereby reducing gas needs is being increasingly examined, although this implies higher CO_2 emissions and capital costs. Another alternative to natural gas is being tested – Multiphase Superfine Atomised Residue[25] – this allows the clean and complete combustion of production residues to fuel the production process. In-situ combustion of the oil within a SAGD production process is also being evaluated.

Significant uncertainties surround the possible production costs for future oil sand projects. Technology is lowering the costs of production, but these have been outweighed in recent years by project cost inflation. If capital costs continue to rise due to rising raw material and labour costs, then new projects will start to look risky given other concerns about lower oil prices and higher gas prices over the life of a project. However, it is possible that costs may fall back, as part of the explanation for rising capital costs is the booming nature of the industry at present. Companies are considering continuous capacity expansion in order to retain skilled workers over next ten years in order to benefit from "learning by doing" benefits and more stable hiring conditions.[26]

Currently, the number of projects proposed exceeds the likely rate at which the industry could expect to expand over the next ten years. If there were no constraints on capacity expansion, current projects would raise production from 1.1 mb/d in 2005 to 4.4 mb/d in 2015. The National Energy Board's base case is for production to rise to 3 mb/d by 2015, 65% of which will be upgraded to syncrude quality. This assumes oil prices remain at $50/bbl or above, that the economic environment remains positive and natural gas prices don't rise further.

3.2.1 Environmental Issues

[23] NEB (2006).

[24] This assumed $3/MMbtu, a more reasonable assumption is that of $7.5/MMbtu used in the NEB (2006) analysis, suggesting that the operating steam cost for current projects could be around $7.5/bbl

[25] This is a second generation emulsion fuel, that is to say it takes bitumen residues and converts them to an oil in water emulsion fuel that has good combustion characteristics. It is similar to "Orimulsion" the fuel originally developed by BP and PDVSA of Venezuela.

[26] Presentation of the National Energy Board's (2006); *Canada's Oil Sands, Opportunites and Challenges to 2015: An Update*; IEA, Paris June 2006.

The economic benefits of oil sands production must be balanced by the environmental concerns raised by production. The main environmental concerns associated with oil sand production are: water conservation, GHG emissions, land disturbance and waste management.

Oil sands mining requires between 2 and 4.5 barrels of water per barrel of syncrude produced, less if the bitumen is not upgraded. Currently most of this is withdrawn from the Athabasca river, but there will not be enough water for all proposed projects to sustainably draw from this river. In-situ production techniques use much less water, around 0.2 barrels per barrel of bitumen or around 1.3 barrels of water per barrel of syncrude.[27] Freshwater demands are minimized by using saline groundwater, but the disposing of the solid waste from treating this groundwater before use in the steam generators is also a problem.

Government agencies are working on a new Water Conservation and Allocation Policy to reduce or eliminate the use of freshwater for in-situ projects. They are planning to only issue water allocation licenses for a two-year period, with subsequent licenses issued for a five-year term; renewal will not be automatic. This is a significant reduction compared to the previous system, where there was a 10-year renewal period.[28]

The production of tar sands is considerably more CO_2 intensive than that of conventional oil. Up to 75 kg of CO_2 is emitted per barrel of bitumen produced using CSS and up to 109 kg of CO_2 per barrel for steam assisted gravity drainage.[29] The CO_2 emissions from gasoline derived from non-conventional oil are estimated to be around a third higher than that for gasoline derived from conventional oil, including mining, upgrading, refining and combustion by the final end-user.[30] In terms of marginal emissions for production, syncrude is estimated to produce emissions of between 22 and 34 kg CO_2/GJ, compared to 10 kg CO_2/GJ for conventional oil refining.[31] Although, there should be ongoing reductions in the amount of emissions per barrel produced due to process improvements, these will be offset by capacity expansion.

The capture and storage of the CO_2 produced in oil sands production is potentially feasible, but would require a CO_2 pipeline from the oil sand producing region to the conventional oil producing region where the captured CO_2 could be used for enhanced oil recovery (EOR) or stored in depleted oil reservoirs. However, a pipeline is unlikely to be economic based just on the benefits of EOR and CO_2 pricing would be required for this option become economic. Incorporating CO_2 capture into a project is estimated to increase costs by around $5-7/bbl.[32] However, the full cost of CO_2 capture and storage, including transport, are as yet unclear and will depend on the project specifics.

The large land-use footprint of open cast mining operations is a significant environmental issue.[33] Very large areas are excavated over the life of a project and given the extreme nature of the environment where production is taking place, it will take many years for land reclamation projects to reduce the visible impact of the mining. There is significant debate about how successful reclamation projects will ever be in this potentially fragile environment.

[27] NEB (2006).
[28] NEB (2006).
[29] Foley, D. (2001), *Fuelling the Climate Crisis, the Continental Energy Plan*, David Suzuki Foundation.
[30] IEA (2005).
[31] IEA (2006).
[32] IEA (2005) and Cupic, F. (2003), Extra Heavy Oil and Bitumen. Impact of Technologies on the Recovery Factor, paper presented to the ASPO Annual Meeting, Rueil-Malmaison, 26-27 May.
[33] Individual mines can cover 150 to 200 square kilometers.

3.3 Heavy Oil

The Venezuelan Orinoco tar sands are somewhat easier and cheaper to produce than Canada's oil sands. They have a lower viscosity than other heavy oils for a given API and the temperature of the reservoirs at a depth of 1 000 m is 55 ºC. This reservoir temperature reduces the viscosity further and means that the oil will flow with very little thermal stimulation (0.3 bbl steam/bbl oil).[34]

The heavy oil that flows, which has an average gravity of 9.5°API, is extracted from wells that are arranged in clusters, using screw pumps. The production costs, are higher than for conventional oil due to the need for some thermal stimulation and pumping, but less than for Canada's oil sands. The oil's are too viscous at the surface to be transported through conventional pipelines. They need heated pipelines, which are only economic over short distances, or they must be either upgraded before transportation or diluted with light hydrocarbons to create a mix closer to crude oil.

The production process currently used results in very low recovery factors, with Venezuela estimating that only 250-270 billion barrels are recoverable reserves with these techniques, if 1 700 billion barrels of oil are in place.[35] Technology therefore has a potentially important role to play. In-situ production techniques that reduce the viscosity of the oil at the level of the reservoir could possibly double the recovery rate.

Venezuela has plans to apply "deep conversion" technology to their heavy oil, essentially very extensive refining, in order to produce the higher value transportation fuels that are driving current oil demand growth. However, this will require higher capital costs. Plans are to produce 622 kb/d of syncrude by 2009, although the capability of the Venezuelan oil company (PDVSA) to fund this investment is questionable, despite high oil prices, given the demands on its balance sheet by the government.[36] The investment climate is also less attractive after increases in the tax and royalty rates, and the forced conversion of operating contracts to joint-ventures with the state oil company PDVSA.

3.4 Oil Shales

Oil shale is the name for any rock that contains significant amounts of solid organic compounds collectively known as kerogen. Kerogen is a type of immature oil, in that it was never exposed to high enough pressures and temperatures to convert it into oil. The quantity of kerogen in the rock varies considerably, from "lean" shale that contains about 4% kerogen to "rich" shale containing about 40% kerogen.

To produce oil, the rock is heated to 350-400 ºC, whereupon it yields anywhere from 20 to 200 litres of oil per ton of shale. However, this is an even more CO_2 intensive process than oil sand production. Even advanced oil shale processing techniques would result in roughly 286 kg

[34] Ali, A. and K. Farouq (2003), *Heavy Oil – Evermore Mobile*, Journal of Petroleum Science and Engineering, No. 37.
[35] IEA (2005).
[36] See for example, "News in Depth", The Wall Street Journal, 2 August 2006.

CO_2/bbl. This compares to 59 kg CO_2/bbl for conventional oil. However, it is possible that CO_2 emissions could be reduced to 169 kg/bbl in the longer term.[37]

The raw shale oil produced would constitute a relatively light crude with a 42° API gravity, and 0.4wt% sulphur. The oil is further processed into hydrotreated naphtha and low sulphur medium shale oil of 27º API.

The world's largest oil shale project, the Stuart shale oil project in Australia, was opposed by environmental NGOs and it was announced in 2004 that Stage 1 of the development, a 4 500 b/d demonstration plant, would be put into care and maintenance. There are some oil shale mining activities in Estonia, Brazil and China, but they are very small.

Most of the global oil shale resource is located in the United States, where it is estimated more than 500 Billion barrels is in place that would yield around 95 litres/tonne in a layer at least 3 metres thick. Perhaps twice this quantity is a lower quality resource.[38] The in-situ mining and upgrading of oil shale to syncrude could cost in the order of $30/bbl (Shell estimate[39]). It is unlikely that oil shale will play a large role in oil supply before 2020 and would need to use CO_2 capture and storage to avoid significant environmental opposition.

3.5 Production Prospects for Non-Conventional Oil

The current production costs of Canadian oil sands and Venezuelan heavy oil are lower than $20/bbl. However, additional greenfield capacity in Canada will require prices in the range of $30-$35/bbl. Canadian production faces capacity expansion constraints in the short-term due to shortages of labour and expertise, but the main issue in the longer term that is likely to restrict expansion in Canada is concern about price risk. This is due to their very high cost of production compared to conventional oil from the Middle East. This is balanced to some extent by the fact that there is little or no exploration risk given that the resources are well defined. They can also be produced using proven techniques, although new techniques potentially offer much improved environmental performance and economics.

Investment in non-conventional oil production involves hundreds of millions, even billions of dollars, and requires a stable regulatory environment.[40] This is the case in Canada, but this cannot be taken for granted in Venezuela. Much of the increase in non-conventional oil production is therefore likely to take place in Canada.

The IEA projects non-conventional oil production in Canada and Venezuela will grow to just under 6 Mb/d in 2030[41], based on assumptions that oil prices drop back to $35/bbl in 2010, before gradually increasing to $39/bbl in 2030. Given that it appears that demand growth is not going to

[37] Innovest Strategic Value Advisors (2001), *The Stuart Oil Shale Project: Implications of Carbon Emissions Constraints for Suncor Shareholders*, study commissioned by Greenpeace. www.greenpeace.org.au
[38] US DOE (2004), *Stratgeic Significance of America's Oil Shale Resource*, US DOE, Washington, DC.
[39] Quoted in IEA (2005).
[40] SAGD is estimated to require capital investment of around CAN$ 15 000 per daily flowing barrel and upgrading CAN$ 32 000 (NEB, 2006).
[41] IEA (2005), *World Energy Outlook*, Paris.

slow in the near future, even at today's current high prices, this may even underestimate the contribution of non-conventional oil.

Non-conventional oil production could grow very strongly over the period to 2030 if oil prices average $40/bbl or above. The IEA projects a maximum contribution of non-conventional oil of 37 Mb/d in 2030 in a low conventional oil resource case. This figure includes gas-to-liquids and coal-to-liquids, but oil sands and heavy oil production might be expected to triple in this scenario compared to the Reference Scenario.

What may cause investment in non-conventional oil resources to lag behind what might be considered their economic rate is concern about the additional CO_2 emissions from these sources and the risk of oil prices dropping below $30/bbl. Although, it is too early to tell, it appears that CO_2 capture and storage could address the first concern by 2030, although significant uncertainty remains. However, there remains the real risk that a repeat of the price collapses experienced in the past could occur again if demand stagnates or falls, just as the oil industry has committed to significantly more capacity than is called for by demand growth given the current high prices. This is not a significant risk over the next few years, but remains a very real risk over the 30 to 40 year lifetime of some of these projects.

Table 3.2: Summary of Non-conventional Oil Costs[42]

	Production cost	Possible CCS cost	Total including CCS	Oil available
Oil/tar sands				
Current – mining	$10/bbl	$5-$7/bbl	$15-$22/bbl	
Current – in-situ	$15/bbl	$5-$7/bbl	$20-$22/bbl	
New Mining/Upgrading	$31-34/bbl	$5-$7/bbl	$36-$41/bbl	
New SAGD	$15-19/bbl*	$5-$7/bbl	$35-$42/bbl	
Heavy Oil - Current	<$20/bbl	n.a.	<$20/bbl	
Oil Shales	$25-$65/bbl	$5-7/bbl	$30-$70/bbl	
Summary of Costs and Potential Reserves				
Total Non-conventional				
IEA- Heavy oil and oil sands	$15-$35/bbl	$5-7/bbl	$20-$40/bbl	1000 billion barrels
IEA- Oil shales	$25-$65/bbl	$5-7/bbl	$30-$70/bbl	~800 billion barrels

* Per barrel of bitumen.

The amount of non-conventional oil available and at what price will depend on the rate of technology learning. Given that non-conventional oil production is in its infancy compared to the total resource, technology learning has the potential to significantly reduce the costs of production. Previous estimates have tended to underestimate the rate of reduction in production costs, notably Rogner.[43] However, based on today's estimates it would appear that around 1 000 Billion barrels of non-conventional oil resources could be produced for between $20/bbl and

[42] Current costs for mining and in-situ production of oil sands source: UTILIS (2004), *Oil Sands – Alberta 2004*, UTILIS Energy, New York. CCS costs from IEA (2005), *Resources to Reserves: Oil and Gas Technologies for the Energy Markets of the Future*, IEA, Paris and Cupic, F. (2002), *Extra heavy oil and bitumen. Impact of technologies on the recovery factor the challenges of enhanced recovery*, Presentation at ASPO Annual Meeting, Rueil, France, 26-27 May. New Oil and tar sands costs: National Energy Board (2006); *Canada's Oil Sands, Opportunites and Challenges to 2015: An Update*; National Energy Board, Calgary. Oil shale costs from IEA (2005).

[43] Rogner, H. –H (1997), An Assessment of World Hydrocarbon Resources. *Annual Review of Energy and the Environment*, 22, 217-262.

$40/bbl including CO_2 mitigation to ensure that non-conventional oil has the same emissions profile as conventional oil. Current production tends to be cheaper than this, as the rapid expansion of capacity in Canada is leading to project cost escalation for new capacity.

Given the relatively well defined nature of much of the non-conventional oil resource in Venezuela and Canada, there is likely to be much more upside potential than downside risk in these assessments. The key problems in exploiting these reserves will be price risk, environmental concerns, and capital constraints.

The price risk might necessitate a price that averages $10-$15/bbl above the economic level for these projects, depending on the volatility in oil markets. Environmental concerns can be addressed, however, these raise the cost of production. If CCS overcomes the technical challenges it faces and becomes commercially available, then it could go a long way to mitigating current environmental concerns. However, even taking these factors into account, there may be a limit to how rapidly production can be expanded in the short term, notably as early as around 2015 if gas supplies remain tight, and infrastructure and labour constraints remain. However, simply mobilizing the huge capital requirements for non-conventional oil projects could also be a constraint.[44]

[44] A 200 000 b/d project in Canada currently can require an investment of $5 billion.

4 Biofuels – Ethanol and Biodiesel

This section looks at the production of high quality ethanol and biodiesel for use as transport fuels. These fuels can be produced from sugar, grain, cellulosic and oil-seed crops. These fuels offer the potential for significant greenhouse gas reductions in the transport sector, however, they face a number of challenges in terms of technology, cost, production process' and feedstock production if these reductions are to be achieved.

4.1 Biodiesel

Biodiesel is the name for fatty acid methyl esters, often referred to as FAME. These are produced by transesterification, a chemical process that takes a fat or oil type feedstock and reacts it with methanol and a potassium hydroxide catalyst. The term biodiesel can also refer to a synthetic diesel made from biomass that is gasified and then turned into synthetic diesel.

FAME biodiesel can be produced from a number of different feedstocks, including vegetable oil (sunflower, soy, rapeseed, etc), animal fat (pork lard, beef tallow, poultry fat) and any used frying oil.

Although they are all similar, biodiesel from FAME can be produced from a variety of different processes. Generally, the oil is put through a pre-processing phase. Here the oil is filtered and if free fatty acids are present they maybe seperated and turned into biodiesel using pre-treatment processes. The pre-processing phase allows the removal of water and other contaminants. The pre-processed oils are then mixed with an alcohol (usually methanol) and a catalyst. The catalyst is usually sodium or potassium hydroxide. The oil molecules are broken up and then reformed into esthers and glycerol, these two then have to be split from each other and put through a purifying process. The end result is esters, which are the biodiesel, and the byproducts - glycerine and, if produced from oil seeds, the residual vegetable matter that can be made into a "cake".

The byproducts, the vegetable matter and glycerine, can be utilized, and are not a waste product. The vegetable matter can be turned into a crushed "bean cake" that can be used as an animal feed, while the glycerine is currently a relatively valuable chemical that is used in the manufacture of many types of cosmetics, foods and medicines. The co-production of glycerine, at present, improves the economics of biodiesel production. However, the large-scale production of biodiesel would probably saturate the market for glycerine, and its most valuable use might be as a fuel input to the biodiesel production process.

The final biodiesel from FAME is ready for use in most modern compression-ignition vehicles designed to use petroleum diesel. It can be used in its pure form, referred to as B100, or in virtually any blend ratio desired with petroleum diesel. If the level of blending is kept low, below around 20%, virtually any heavy-duty vehicle can use the blend without any adjustment to the engine or fuel system.[45] Some countries, notably Austria, Germany and Sweden have promoted the use of 100% biodiesel use in trucks, with only minor fuel system modifications.

[45] EC (1998), *Biodiesel in heavy-duty vehicles in Norway – Strategic plan and vehicle fleet experiments*, Final report from European Commission ALTENER project.

Biodiesel mixes well with petroleum diesel and will stay blended even if contaminated by water. Biodiesel offers a number of advantages over petroleum diesel. When mixed, even at as little as 1%, the blended diesels lubricity can be improved by up to 30%.[46] This reduces engine wear and tear, and engine components will last longer. Biodiesel's cetane number[47], at between 46 to 52 for that based on vegetable oils and 56 to 60 for animal fat, is generally higher than that used in the US and Europe. Thus despite the fact biodiesel has an energy content of around 90% of pertroleum diesel per litre, the higher cetane number and improved lubricity mean that the effective energy delivered is probably only a few percent less than petroleum diesel.[48]

Biodiesel, in its pure FAME form, is a mild solvent. It is therefore a problem for some types of natural rubber compounds and some elastomers. However, many manufacturers have shifted to engines with gaskets and seals that are biodiesel resistant due to the trend to low-sulphur diesel. However, the solvent property of biodiesel is also useful, in that petroleum diesel, in some cases, leaves deposits in fuel lines, tanks and delivery systems. Biodiesel can dissolve these deposits, although, they will then be flushed towards the fuel filter. This may require more frequent changing of the fuel filter until all of the deposits have been removed, but thereafter the vehicle will run more efficiently.[49] Biodiesel can also help clean out fuel systems and unblock injectors of gums and waxes left by petroleum diesel use.

FAME biodiesel degrades over time and can form deposits in the tank it is stored in. If the biodiesel is left in the car over a period of time, the deposits left from the degrading biodiesel can lead to damage to fuel injection systems. This implies that, depending on the blend level, special precautions or procedures would need to observed depending on the pattern of vehicle use.[50] The standardization of fuel standards for biodiesel would be an important step towards providing guidelines for its use when used in high blends.

Cold weather starting can be an issue for biodiesel, however, blends up to 20% FAME biodiesel do not require any additional precautions than used for petroleum based diesel. However, for higher blends, the fuel may "gel" sooner than petroleum diesel at temperatures below zero. The exact properties of the fuel depend on the type of vegetable oil used as a base for the FAME biodiesel (*e.g.* rapeseed yields biodiesel with better cold flow properties than palm oil). However, these issues can be managed by adding a winterizing agent, using a block heater, keeping the vehicle inside, and using a tank heater while driving in very cold conditions (these issues are more relevant to North America and Europe).

[46] NREL (2000), *Biodiesel: the Clean, Green Fuel for Diesel Engines*, Produced for the U.S. Department of Energy (DOE) by the National Renewable Energy Laboratory.
[47] The cetane number reflects the ignition quality of diesel. Generally speaking, the higher the cetane number, the the easier ignition occurs and the smoother the combustion. Higher cetane numbers imply good ignition, easy starting, good starts at low temperature, low ignition pressure and low knocking characteristics.
[48] IEA (2004), *Biofuels for Transport*, IEA, Paris.
[49] BAA (2003), *Fact Sheet: Biodiesel Usage*, Biodiesel Association of Australia.
[50] NREL (2001), *Biodiesel: Handling and Use Guidelines*, National Renewable Energy Laboratory.

There are a number of other production "pathways" to produce biodiesel. These include:

- Fischer-Tropsch synfuels, including biodiesel, from gasified biomass.
- Diesel production through hydrothermal upgrading.
- The fast pyrolysis of biomass into "bio-oil" and then refined to diesel.[51]

Gasifying biomass opens the way to produce a number of different fuels, including biodiesel. The most common means of achieving this is through digesters that create the right environment for the bacterial breakdown of the biomass into methane, typically using anaerobic digestion. However, a number of new technologies are being developed that are designed to yield a variety of different gases and end-products. Broadly speaking, they generally use chemicals and/or heat to breakdown the biomass into gases with little or no microbial action. The choice of which process is used depends on the feedstock, as lignin can't be easily transformed into gas and the lignin component of plants can range from 0% to 35%. For plants with a high lignin content, the heat dominated-process would be more effective and hence economic.[52]

Once the biomass has been gasified, the resulting gases can be turned into a number of different fuels, by a number of different processes. The fuels produced could be methanol, synthetic gasoline or diesel, dimethyl ether (DME), and gaseous fuels such as methane or hydrogen.

The Fischer-Tropsch process can convert the syngas into diesel fuel and naptha. Typically there are a variety of other products, mainly chemicals, produced by the process. If this fuel pathway is to be successful, markets for these other chemicals will need to be found.

A new, innovative process under development is the hydrothermal upgrading (HTU) of biomass to diesel. In this process, cellulosic materials are dissolved in water under high pressure, but at a low temperature. The process then uses various reactions to convert the cellulosic feedstock into a "biocrude". Various hydrocarbon liquids are then created, predominatly diesel, in a hydrothermal upgrading unit.[53]

Another innovative process under development uses "fast pyrolysis" where biomass is rapidly heated in an air-free environment, and then quickly cooled, thereby forming a liquid "bio-oil" and various solids and vapours/gases. The bio-oil can then be turned into diesel or other fuels. [54]

4.2 Ethanol

Ethanol can be used in its pure form or added to conventional petroleum fuels to make a blend. Ethanol can be made from any biological feedstock that contains significant levels of sugar or components that can be converted into sugar, such as starch or cellulose. Sugar beets and sugar cane are the two most common examples of crops that contain high levels of sugar, while corn,

[51] In fast pyrolysis, the biomass is quickly heated to high temperatures in the absence of air and then cooled down. This results in a liquid bio-oil, as well as various solids and gases.
[52] IEA (2004).
[53] Schindler, J. and W. Weindorf (2000), *Fuels for Transportation Derived from Renewable Energy Sources*, Hyforum 2000, Munich.
[54] This process can also be used to convert solid biomass residues, or by-prducts, into a fuel that is easier to burn for the process heat. This could be particularly important in improving the life-cycle emissions of some biofuels. For instance it can be used to convert bagasse, a sugar cane residue, into a process fuel for the production of ethanol.

wheat and other cereals contain starch in their kernels, which can be relatively easily converted into sugar and then into ethanol. Trees and grasses are composed largely of cellulose and hemicellulose, which can also be converted into sugar, albeit less easily than starch can.

Ethanol is currently, generally, produced by fermenting the sugar in a feedstock using an enzyme derived from yeast. The fermentation processes generally rely on converting glucose (six-carbon sugars) into ethanol. An important aspect of the economics of ethanol production at present is that starch is much more easily converted into glucose than cellulose. Nearly all ethanol produced outside countries with abundant sugar cane crops is therefore derived from grains, such as wheat, corn etc. The organisms and enzymes are readily available for commercial-scale starch conversion and glucose fermentation. While the conversion of cellulose to five and six carbon sugars is not only more difficult, but requires special organisms to complete the fermentation process.

The production of ethanol involves considerable process heat requirements. Currently in Europe and North America this is usually provided by thermal fuels. This has a negative impact on the well-to-wheels (WTW) CO_2 emissions balance. For example in the United States, the best "point estimate" for ethanol production from corn is that it reduces petroleum use by 95%, but GHG emissions by only 13%.[55] The ratio among primary energy inputs per unit energy output, for the best "point estimate", is very close to 0.8.

[55] Farrel, A. *et al* (2006), *Ethanol Can Contribute to Energy and Environmental Goals*, Science, Vol. 311, 27 January.

4.2.1 Grain-to-Ethanol

This is the most common process for producing ethanol in developed countries due to the availability and suitability of grain crops. In current processes, only the starchy part of the crop is used: the corn kernels or the wheat kernel. Unfortunately, these starchy components only represent a relatively small part of the plants total mass and considerable fibrous material is left over in the seed husks and stalks. This is where future research into the production of ethanol from cellulose might yield significant benefits, as it might be able to commercially convert the cellulose of these waste products into fermentable sugars that could greatly boost the yield, and hence lower the cost, of ethanol from these grain feedstocks.

Ethanol from grains is produced by first separating, cleaning and milling the starchy feedstock in preparation for the next step. Milling can be "wet" or "dry", depending on whether the grain is soaked in water and further broken down before the starch is converted to sugar – a wet process. Alternatively, the grain is not further broken down until the conversion process – a dry process. In general, the starch is converted into sugar using a high-temperature enzyme process. The sugar is then fermented into ethanol by using yeasts and other microbes. The final process is that of distilling the ethanol to purify and remove water so that it reaches the desired concentration. The ethanol is then ready to be blended into gasoline, or for use as a pure fuel. The grain-to-ethanol process also yields several byproducts such as protein rich animal feed and, depending on the feedstock and process used, a sweetener.

4.2.2 Sugar-to-Ethanol

The easiest way to produce ethanol, and currently the cheapest, is to use biomass that already contains six-carbon sugars that can be fermented directly and easily into ethanol. The two best candidates for this are sugar cane and sugar beets. In tropical countries, notably Brazil, sugar cane is the most common feedstock and the high yields make the production of ethanol from sugar cane in warm countries with abundant water supplies among the cheapest in the world.

The production process for producing ethanol from sugar entails, first, the processing of the crop to remove the sugar by crushing, soaking and chemical treatment. The sugar is then directly fermented into alcohol using yeasts and microbes. The final step is to distil the ethanol in order to purify it to the desired concentration, usually removing all the water. The resulting "anhydrous ethanol" can then be blended with gasoline. When made from sugar cane, the crushed stalk of the plant, the "bagasse", is left over. This product contains cellulose and lignin, and can be used for process energy in the manufacture of the ethanol, greatly reducing the greenhouse gas emissions of the process.

4.2.3 Cellulosic Biomass-to-Ethanol

One of the current handicaps to the widespread utilisation of biofuels is that most plant matter is not starch or sugars that can relatively easily be converted into ethanol, but cellulose, hemicellulose and lignin. Although, cellulose and hemicellulose can be converted into sugar and then into ethanol, this is much more complicated and expensive than converting starch into sugars and then into ethanol. In addition, the lignin cannot be converted into sugar.

Given these problems, there is very little production of ethanol from cellulosic material. However, there is a significant amount of research into this process being undertaken, because it has several potentially key advantages. First, if this process can be commercialised it will allow the production of ethanol from a much wider range of feedstocks, including waste cellulosic materials and dedicated grass and tree crops. This will be crucial if ethanol production is to be able to reach significant levels. Part of the reason for this is that it will help avoid competition between crops for biofuel production and for food. The use of cellulosic feedstocks will also greatly reduce well-to-wheel GHG emissions by allowing nearly complete biomass-powered systems to be used. This will potentially allow much greater GHG savings than the production of grain-to-ethanol, which uses substantial quantities of fossil fuels.

The first step in converting cellulosic materials into ethanol is pre-treatment where the feedstock is cleaned and the materials broken down. A combination of chemical and physical processes are usually applied to speperate the biomass into its cellulose, hemicellulose and lignin parts. Some hemicellulose can be converted into sugars at this stage and the lignin is removed. The next step is the breaking down of the cellulose and hemicellulose in the feedstock material into sugars through a process called saccharification. This is most commonly achieved at the moment by using a diluted or concentrated acid hydrolysis process, however, these are expensive and appear to have reached their yield limit.[56]

Research is therefore focused on developing biological enzymes that can breakdown the cellulose and hemicellulose. The first efforts in this area replaced the acid hydrolysis step with an enzyme hydrolysis step, called "separate hydrolysis and fermentation" (SHF). An important process modification made for enzyme hydrolysis was the introduction of simultaneous saacharification and fermentation (SSF). This has been further refined to include the co-fermentation of multiple sugar substrates. In the SSF process, cellulose, enzymes and fermenting microbes are combined, reducing the size of the process equipment needed and improving efficiency. As the sugars are produced the fermentative organisms convert them to ethanol. However, the sugars that are produced are a complex set of five- and six-carbon sugars that are more difficult to completely ferment into ethanol.

The breakdown of cellulose and hemi-cellulose to sugar represents the biggest challenge for the commercialization of cellulose-to-ethanol production. There is currently a substantial amount of research into a variety of thermal, chemical and biological processes to achieve the saccharification process in an efficient and low-cost manner.

Another area of research is in trying to produce all the required enzymes in one reactor vessel. This would have the same microbial group producing the enzymes that help breakdown the cellulose into sugars and also ferment the sugars to ethanol. This is called "consolidated

[56] IEA (2004).

bioprocessing" (CBP) and could yield significant improvements in efficiency and in cost reductions.[57]

4.3 Biorefineries

Another area of research that is being pursued, particularly in the US, are "biorefineries" that will integrate the production of biofuels, electric power, chemicals and possibly even materials such as plastic. This type of integrated approach has the potential to reduce the overall cost of biofuels, by maximizing the production of other valuable products from the process. The US goal is to be able to produce cellulosic ethanol from biorefineries on a commercial scale by 2010. However, at this point the ethanol produced is not expected to be competitive with gasoline. By 2020, however, once the process has been refined and expanded to larger-scale plant, it is hoped that the net cost of the ethanol will be competitive with gasoline, depending on oil prices.

4.4 Biofuel Resource Availability and Distribution

Currently, ethanol and biodiesel production is very modest. In 2003 biofuels production amounted to around 28 billion litres.[58] Assuming an average energy content of 21.1 MJ/litre, this is equivalent to just 0.4 mb/d, or 0.5% of the global oil consumption. Production is mainly concentrated in Brazil, using sugar cane, and the United States, using corn.

Although there are many potential feedstock sources for biofuels, there exists significant uncertainty about the long-term potential availability of biomass to produce biofuels. The potential contribution of different food and energy crops, biomass wastes, and residues varies significantly by country; while the availability of suitable land that will not be needed for food production is unclear. Competing land-use options, demand for food crops, crop yields, biodiversity concerns, and conservation of soil, water and nature all contribute to the difficulty in assessing the potential contribution of biomass. This is before uncertainty surrounding the potential improvements in the efficiency with which this feedstock is converted into biofuels is considered.

To simplify a very complex problem, there are essentially two key issues: can technologies for the conversion of lingo-cellulosic crops be commercialized and what is likely to be the evolution of land-use over the next 50 to 100 years? The first issue is critical in not only improving the well-to-wheels emissions benefits of biofuels, but in making available a wider range of feedstocks, particularly those that need not be planted on potentially valuable arable land. The second issue is critical to identifying how much land will be available to produce crops for bioenergy after the global demand for food and the other uses of arable land are taken into account.

The study *World Agriculture: Towards 2015/2030* gives an overview of current agricultural trends and a scenario for the future global agriculture and food supply.[59] They project a slowing in the rate of increase in world food demand from 2.2% per year over the last 30 years, to 1.5% per year out to 2030. However, this scenario still raises concerns about the adequacy of food intake in

[57] Hamelinck, C. et al. (2003), *Prospects for Ethanol from Lignocellulosic Biomass: Techno-economic Performance as Development Progresses*, Utrecht University, Report NWS-E-2003-55.
[58] IEA statistics.
[59] FAO (2002), *World Agriculture: Towards 2015/2030,* Food and Agriculture Organisation, United Nations.

2030 in some developing countries. In 2030 three-quarters of the population in the developing world could be living in countries where 5% or less of people are under-nourished.

They estimate that of the total arable land that is rain fed and suitable for crop production of 4 153 million ha, only 1 608 ha is currently used. The estimated growth in food production in their scenario will come from 120 million ha of this land that is brought into production and from improved yields over the period. In some regions; notably South Asia, the Near East and North Africa; the use of arable land is approaching the limit of rain-fed land available. However, in Latin America, the Caribbean and sub-Saharan Africa only around one-fifth of the rain fed arable land is in use.

The report stresses that it is not clear whether the available arable land could actually be put into production. On the other hand, there appears to be a large potential to increase the yields in many regions. Actual crop yields for wheat in many countries are only around half of what is obtainable (including in the United States), although this is undoubtedly due at least in part to economic considerations rather than inefficiency.

The report tends to suggest that although some regions or countries may face limits to the rate at which they can expand food production, there is, at a global level at least, a large surplus in arable rain-fed land that could be used to grow energy crops. Key uncertainties remain regarding the exact suitability of some of this land for different crops, the availability of infrastructure in many regions, and the contribution that the growth in crop yields may make.

A more recent report published by the Dutch energy agency, NOVEM, projects global food and animal feed demand to 2050 and identifies possible scenarios for the availability of land for energy crops.[60] They project the demand for food by region by taking projections of average daily calorific food consumption, the percentage of this provided by meat and the projected population. They project that the daily food intake in developing countries will rise towards developed country levels, but with a much smaller proportion of that total intake will be provided by meat. Given these demand levels over time they develop scenarios for the amount of cropland required to meet this demand and that of other agricultural products.

They estimate that if crop management practices similar to those used in industrial countries are applied around the world, then the world's demand for food in 2050 can be met by using only a fraction of present agricultural land.

They estimate that between 729 million ha and 3 586 million ha of agricultural land could be made available for bioenergy production by 2050, depending on the demand for food, animal products, pastoral land, feed crops and the improvement in technology. This is between 14% and 70% of present agricultural land use. Their scenarios suggest that much of the land available would not be very suitable to bioenergy production, and therefore have relatively low yields. Despite this, the bioenergy production from this land could be between 215 EJ to 1 272 EJ per year in 2050.[61] In addition to this they estimate that 58 to 72 EJ per year in 2050 could be available from agricultural residues and between 0 and 37 EJ from surplus forest growth.

Even taking the lower estimate of 200 EJ per year, the potential yield of biofuels is very large if all of this could be used for biofuels production it could yield around 100 EJ of biofuels assuming

[60] Smeets, E. (2004), *A Quickscan of Global Bioenergy Potentials to 2050*, NOVEM, The Netherlands.
[61] 1 EJ is equal to 1 000 PJ.

biofuel yields rise to 50% of biomass input. This compares to projected transport demand in 2050 of 175 EJ per year.[62] However, it is highly unlikely, that even with improvements in the cost of producing biofuels, particularly from cellulosic feedstocks, that this quantity of energy crops would be economic at reasonable prices. More importantly, there will be other competing claims on this biomass for bioenergy use, including for home heating, biomass based cogeneration and electricity generation, co-firing of biomass in thermal plant etc.

Other estimates for the availability of bioenergy also range significantly. The IPCC Third Assessment Report: Mitigation (IPCC, 2001) estimated 440 EJ of bioenergy crops could be available in 2050. A study by IIASA[63] (Fischer and Schrattenholzer, 2001) estimated a range of between 370 and 450 EJ, with around 150 EJ being economic in 2050. Other studies have identified much lower figures for 2050, with the lowest being just 33 EJ in 2050[64], although this study had an upper figure of 1 130 EJ.

The contribution of biofuels is likely to be modest in the short term, given that ethanol from sugar cane will probably remain the most economic method. However, in the longer-term, ethanol and biodiesel from the lingo-cellulosic component of biomass will not only greatly increase the range of feedstocks available, but also result in better GHG emissions on a well-to-wheel basis.

Biofuels could play a large role by 2050, depending on the assumptions regarding the rate of improvement in crop yields and the cost reductions achieved by technologies to convert lingo-cellulosic feedstocks into ethanol and biodiesel.

By 2030, there is unlikely to have been sufficient progress in improving the economics of biofuels, particularly from cellulosic feedstocks, and in ramping up production of biofuels from traditional feedstocks to make a large contribution. At an oil price of around $55 to $65 per barrel, biofuels maybe able to contribute in the order of around 15 EJ per year, with over three-quarters of this likely to be from ethanol.[65]

By 2050, substantial quantities of ethanol could be available at the equivalent of around $45 to $50 per barrel of oil.[66] Substantial quantities of biodiesel are likely to be available at slightly more than this, perhaps around $55 to $60 per barrel of oil. In total, the contribution from ethanol and biodiesel might reach 50 EJ per year.[67] Given a conversion efficiency of 50% this would imply a primary biomass demand of around 100 EJ. This is around half of the lower estimate from the Smeets, et al study.

[62] IEA (2006).
[63] Fischer, G. and Schrattenholzer, L., (2001), Global Bioenergy Potentials through 2050, *Biomass and Bioenergy*, 20(3):151-159. Reprinted as RR-01-009. International Institute for Applied Systems Analysis, Laxenburg, Austria.

[64] Hoogwijk, M *et al.* (2003), Exploration of the Ranges of the Global Potential of Biomass for Energy, *Biomass and Energy*, 25, pp 119-133.
[65] IEA (2006).
[66] Assuming $5 per barrel for refining and transport of petroleum products.
[67] IEA (2006).

4.5 Biofuel Costs

The cost of biofuels varies significantly depending on the type of feedstock and the conversion process used. Biofuel costs vary significantly by region depending on the yield of biomass per hectare, land costs, labour costs and finance costs. Global biofuels production is currently concentrated in Brazil, the Unites States and the European Union. In the short-term, over the next ten years, the supply curve will be dominated by ethanol from sugar cane and grains, and FAME biodiesel from oil seeds and waste oils.

The supply curves for ethanol and biodiesel are likely to evolve quite significantly over time. This reflects not only improvements in technology that allow the use of a wider range of feedstocks, but also the issues involved in scaling-up production from today's very low levels. The production of energy crops may not be able to be ramped up particularly rapidly, given that this implies quite dramatic changes in land-use over time.

Ethanol produced from sugar cane in Brazil is currently, by far, the cheapest ethanol produced and costs about $0.30 per litre of gasoline equivalent (that is to say it is economic when oil prices are around $35/bbl).[68] It is not clear at this stage if the production economics achieved in Brazil can be replicated elsewhere, but other tropical countries are likely to be able to approach the yields achieved in Brazil. In the short- to medium-term, the expansion of ethanol production from sugar cane in countries which can achieve high yields per hectare offers the best opportunity for low-cost ethanol production. However, production in these countries is likely to be somewhat higher at $0.40 to $0.50 per litre of gasoline equivalent ($50/bbl to $60/bbl) given Brazil's extensive experience in producing low-cost ethanol from sugar cane.

In the Unites States and the European Union, biofuels production is not economic without assistance. In the United States, ethanol produced from maize (corn) is sold for about $0.80 per litre of gasoline equivalent, with production costs estimated to be around $0.60 per litre of gasoline equivalent. In the European Union the cost of ethanol from wheat is estimated to cost in the region of $0.70 to $0.75 per litre of gasoline equivalent.[69]

The cost of ethanol from lignocellulosic feedstocks in Europe are currently estimated to be $28/GJ for a feedstock price of $3.6/GJ, or around $1.00 per litre of gasoline equivalent (Hamelinck, et al., 2005). However, it is possible that these costs may halve by 2030 due to better ethanol concentrations prior to distillation, lower costs for improved enzymes (due to biotechnology research advances), improved separation techniques and a quadrupling of the scale of plants. Lower feedstock costs, through the use of biomass residues and wastes such as corn stovers and bagasse, will also play an important role in lowering costs. Additional cost reductions would be possible if production occurred in developing countries with lower labour costs.

FAME biodiesel from rapeseed in the EU is estimated to cost around $0.60 to $0.70 per litre of diesel equivalent, although other sources suggest it could be as high as $1.20 per litre of diesel equivalent. [70] Biodisel from soy in the United States is estimated to be somewhat cheaper at around $0.60 per litre of diesel equivalent. Biodiesel produced using biomass feedstocks via the Fischer-Tropsch process is estimated to cost around $0.90 per litre of diesel equivalent at this time.[71]

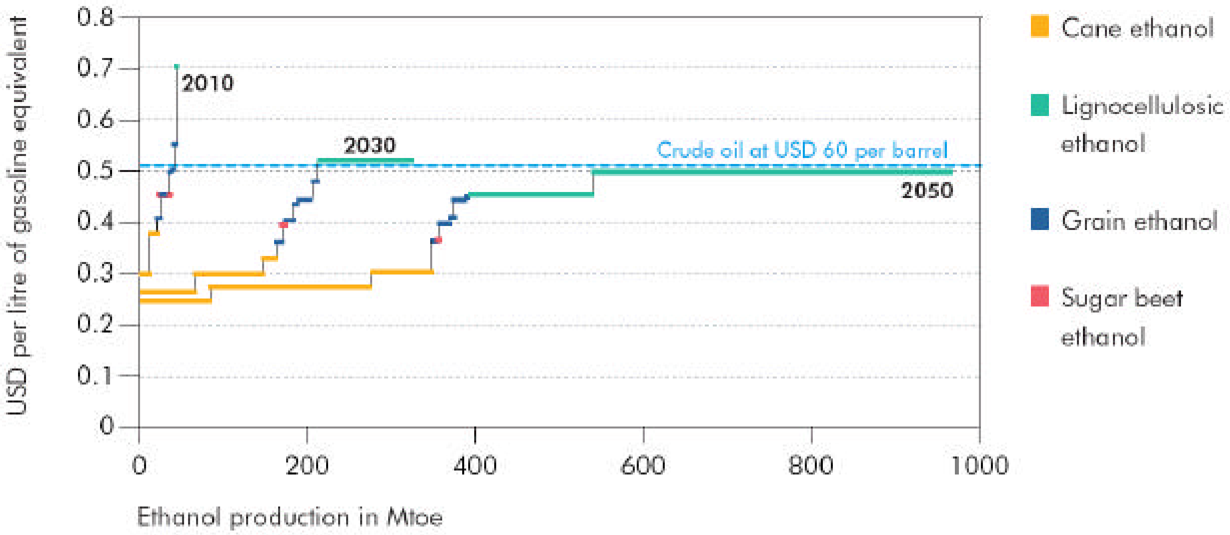
[68] IEA (2006).
[69] IEA (2006).
[70] IEA (2004).
[71] IEA (2006).

The prospects for cost reductions are not thought to be high for conventional FAME biodiesel, in the region of $0.10 per litre of diesel equivalent in the medium- to long-term. However, the long-term prospects for biodiesel from hydrothermal upgrading and from the conversion of biomass via the Fischer-Tropsch process could decline to around $0.70 per litre of diesel equivalent.[72] This would dramatically increase the production potential and reduce competition for arable land.

A scenario where technology learning, improved crop yields and increased plant economies of scale combine to lower the costs of cane and grain ethanol, and FAME biodiesel over time could dramatically increase the potential contribution of biofuels by 2030. However, it will be advances in the technology and economics of the production of ethanol from cellulosic feedstocks that make a big difference to the quantity of biofuels available. The same will be true for biodiesel, where at a global level the fundamental economics of FAME biodiesel are unlikely to improve dramatically given its inherent limitations. However, biomass-to-liquids biodiesel production using cellulosic feedstocks and Fischer-Tropsch (FT) conversion processes could significantly increase the quantity of biodiesel available.

Figures 4.1 and 4.2 present a scenario for what biodiesel and ethanol supply curves might look like assuming a significant ramp up in production and significant progress in improving the economics of biodiesel and ethanol production from cellulose.

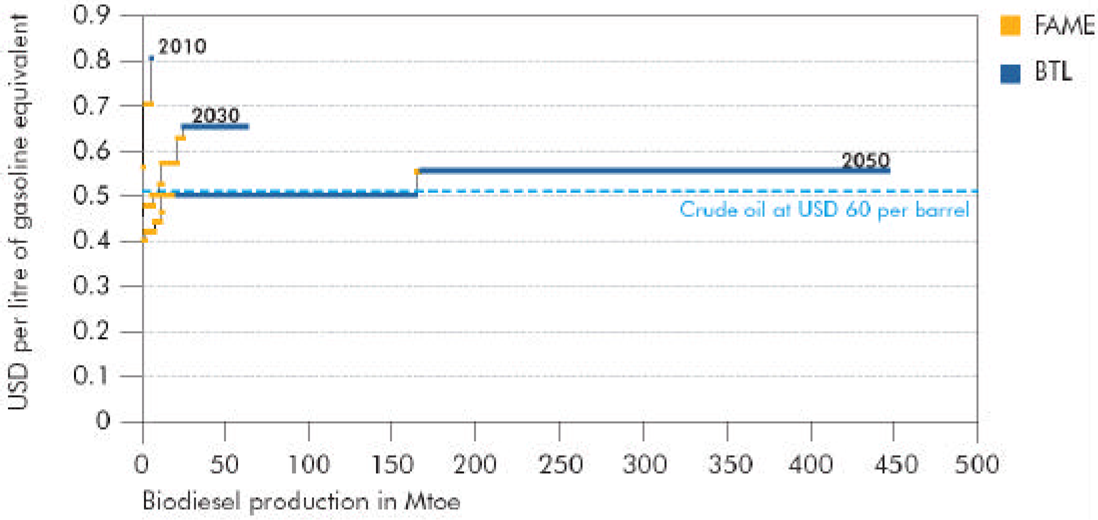
Figure 4.1: Supply Curves for Ethanol (2010, 2030, 2050)[73]



Energy Technology Perspectives, © OECD/IEA, 2006, Figure 5.6, p 283.

[72] IEA (2004).
[73] Source: IEA (2006).

Figure 4.2: Supply Curves for Biodiesel (2010, 2030, 2050)[74]



Energy Technology Perspectives, © OECD/IEA, 2006, Figure 5.7, p 288.

4.6 Biofuels Environmental Impact

Replacing conventional petroleum products with biofuels does not lead to zero emissions. The well-to-wheels emissions of biofuels, that is to say including the emissions generated when producing the biofuels, depend on a wide range of factors. These include the productivity of the crop chosen, the emissions due to the energy embedded in the fertilizer used to grow the crop and in the water used, emissions from fertilizer production, the energy used in gathering and transporting the feedstock to the biorefinery, any emissions from the soil as a result of changes in farm management, the energy intensity of the conversion process, and energy feedstock used for the conversion process.

Calculating the energy and emissions balance of biofuel production requires estimates of, or assumptions about, all these variables, as well as the energy or emissions credit that should be attributed to the various by-products. Given the complexity of all these factors, well-to-wheels emissions estimates for different biofuels pathways tend to be highly assumption specific and estimates for one country may not be applicable in another.

Carbon-dioxide emissions at the point of use are assumed to be zero, assuming that the biomass feedstock is a renewable resource (the carbon emitted is exactly equal to the carbon absorbed by the biomass), however, this would not be the case if the biomass feedstock came from clear felling existing biomass with no re-planting.

[74] Source: IEA (2006).

Table 4.1: Well-to-Wheel CO_2 Emissions by Fuel Pathway[75]

	CO_2 emissions index (Gasoline-conventional =100)
Gasoline-Conventional (2002)	100
Gasoline-Hybrid	74
Diesel-Conventional (2002)	87
Diesel-Hybrid	67
Ethanol-wheat (process fuel natural gas)	68
Ethanol-wheat (lignite CHP)	97
Ethanol-sugar beet (pulp to heat)	35
Ethanol-sugar cane Brazil	13
Biodiesel	33

A recent CONCAWE study, although focused on European fuel pathways, shows that emission savings from ethanol production in Brazil are all most 90% compared to conventional gasoline.This is due to the high sugar-cane yield per hectare compared to corn-based ethanol, but also due to the lower fossil-fuel needs for processing, because the sugar is fermented directly and the crushed stalk of the plant (known as bagasse), rather than fossil energy, is used in the production process. The conversion of sugar beet into ethanol in Europe can yield reductions in well-to-wheels emissions of typically of around 65%, compared with gasoline. The results for ethanol from wheat are much more varied, depending on the assumed process fuel used, ranging from emissions savings of 3% to 32% in Europe. It should be noted that Biofuel well-to-wheels emissions estimates vary significantly by region, feedstock, source of process heat etc. The results for the European analysis may not necessarily reflect the well-to-wheels emissions benefits of biofuel production in other regions. In addition, these point estimates mask quite wide variations in well-to-wheels emissions benefits that exist within Europe for many biofuels, and even within individual countries in some cases.

Biofuels main attractions are its potential GHG emissions reductions, energy security benefits and, in some countries, their linkage with agricultural policy. However, production and use can have other important environmental effects in addition to these potential benefits. Today's intensive farming techniques in many countries can have negative impacts on the local environment as well, such as nitrogen run-off, over intensive use of pesticides etc. If the production of biofuels feedstocks displaces the otherwise unprofitable (subsidized) crops that were previously grown on the same land, then the overall impact might be modest, depending on differences in crop and farm management. However, if land that had not otherwise been farmed before is bought into production, then there maybe a significant impact on the environment. In addition to the impact of farming practices on the local environment, intensive cultivation of land that was otherwise in a natural state, will usually lead to a reduction in the soils organic carbon. The type of crop, crop management, the quantity of crop residues (and even their composition)

[75] CONCAWE (2006), *Well-to-Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context*, CONCAWE, EUCAR and JRC. Where a range of values were provided for a pathway, the mid-point was used.

can all have an impact on how much carbon is released and what the equilibrium level of organic soil carbon is once farming begins.

If biofuels are to meet a significant proportion of future liquid fuel demand, then major changes in the use of arable land, pasture and marginal land will be required. It will require careful analysis, planning, government oversight and perhaps regulation in order to manage this change to achieve the balance that maximizes the sustainable production of biofuels with the lowest GHG emissions profile.

The widespread use of land for biofuels feedstock production could have a profound impact on local and regional ecosystems. The effects are potentially positive or negative, depending, on the changes in crops, farming processes, and land-use that are implied. Another complication is that significant increases in the production of the so-called “first-generation” biofuels, which are derived from relatively high-value agricultural crops such as cereals, corn, oil seed crops and sugar cane could have significant impacts on food pricing and availability. There exists a risk that this could have negative impacts for the people of developing countries. Although it is beyond the scope of this paper, it is important to realize that the large-scale production of biofuels and the international trade in biofuels could have significant impacts on the poor of the world, in addition to any of the local environmental impacts. Ensuring that biofuels are produced in a truly sustainable manner, that reflects the three pillars of sustainable development, is a challenge that should not be underestimated.

In addition, first-generation biofuels, derived from conventional agricultural crops, such as rapeseed, corn and cereals generally require high-quality farm land and to achieve high yields substantial amounts of fertilizer and chemical pesticides are used. The production of crops for most first-generation biofuels would increase global competition for arable land, increase the pressure to turn more land over to crops, including possibly through deforestation, and could increase food and animal feed prices. The emissions from the production of fertiliser and its use also play a role in reducing the well-to-wheels GHG emissions reductions of first generation biofuels.

Palm oil is produced on plantations, typically on poor soils, but without the need for extensive use of fertilizers and pesticides. Palm oil production is significant in South East Asia and there is a growing interest in producing biodiesel from the oil, particularly in Malaysia and Thailand. However, increases in the size of plantations need to be done in a manner that avoids the loss of more natural forest area. Brazil is also considering producing Biodiesel from palm oil, given the very high yields of palm oil possible per hectare. Two processes are possible, traditional FAME production, as well as using the oil as a feedstock at a refinery.

The environmental impact of sugar-cane cultivation in Brazil is generally modest. Soil quality/productivity has been sustained over an extended period of time by recycling the nutrients in the waste from the sugar mill and distillery back into the land. The other advantage that Brazil and most other developing countries that grow sugar cane have, is that production depends on rainfall and does not require irrigation.

Given the often low GHG mitigation potential, high costs and issues surrounding competition for feedstocks with the food industry of most first-generation biofuels, so-called “second-generation” biofuels appear to represent the best option to supply serious quantities of biofuels. Research into second-generation biofuels production processes, if they succeed in reducing costs substantially, could open the way to biofuels that avoid many of the drawbacks first-generation biofuels face. For instance, ligno-cellulosic crops could be managed in a far less intensive way compared to annual crops. Ligno-cellulosic crops could also be grown on marginal, poor quality land reducing the competition with food. They would also require less fertilizer if sufficient nutrients were left either before or after harvesting. For instance, if the feedstock is a deciduous tree, the harvest could take place after the nutrient-rich leaves have dropped.

5 Synfuels from Coal and Gas

The production of synthetic fuels (so called “synfuels”) from coal and gas is an established, but expensive technology for producing liquid fuels. The production of liquid fuels from coal was pioneered in Germany. The Fischer-Tropsch (FT) process converts fossil fuels or biomass into synfuels. In the case of gas-to-liquids (GTL), there are two main steps:

- The conversion of natural gas into synthesis-gas ("syngas"). This is composed of CO and H_2 and is achieved through partial oxidation, steam reforming, catalytic autothermal reforming or a combination of these processes.
- The Fischer-Tropsch (FT) exothermic catalytic conversion process then converts the syngas into synthetic fuels.

The process for coal, coal-to-liquids (CTL) is very similar; syngas is produced from coal and water, after which the carbon monoxide/hydrogen ratio is adjusted in reactors and the sulphur removed. The cleaned syngas is then converted via the Fischer-Tropsch catalytic process into synthetic liquid fuel products.

Depending on the FT catalyst used and the temperature reached in the reactor, the process can lead to the production of different products. High-temperature FT synthesis leads to the production of synthetic gasoline and chemicals. Low-temperature FT synthesis leads to the production of waxy products that can be cracked to produce synthetic naphtha, kerosene or diesel fuel.[76]

5.1 Gas-to-Liquids

The gas-to-liquids plant built at Motunui, to utilize the then abundant Maui gas reserves, was one of the few gas-to-liquids plants in operation and its permanent switch to methanol production reduced global GTL capacity by about a third to 35 000 b/d. However, SASOL of South Africa operated a 150 000 b/d coal-to-liquids plant for about 25 years, which has recently switched to gas as a cheaper feedstock. However, in recent years there has been renewed interest in GTL and in 2002 around 0.9-1.1 Mb/d of projects were under consideration.[77] More recent reports suggest that up to 1 M/b per day could be operational by 2010.[78] However, the IEA projects much more modest increases, with GTL output reaching 0.3 Mb/d in 2010 and 2.3 Mb/d in 2030. Qatar has three major projects under construction totaling 100 000 b/d and output is projected to rise to 650 000 b/d in 2030.[79]

GTL plants produce a range of products that is very different to the average crude oil refinery (Figure 5.1). Depending on the technology process used, GTL plants can produce a range of premium products that will yield a higher price than the average value of output from a crude oil

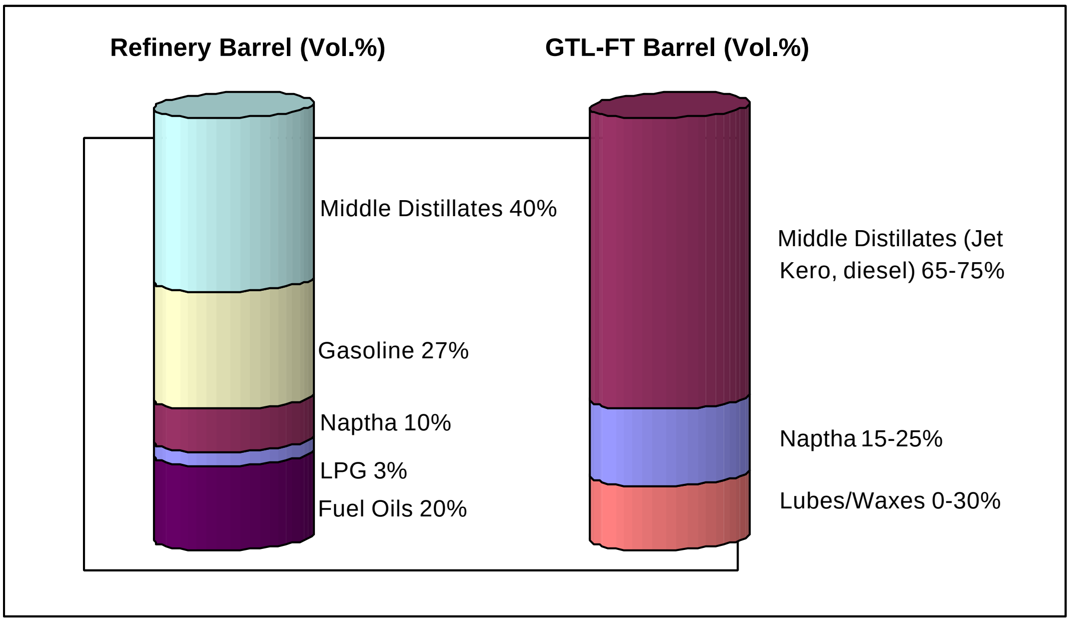
[76] IEA (2006).
[77] Fleisch, T. H. (2002), *Emergence of the Gas-to-Liquids Industry: a Review of Global GTL Developments*, Journal of Natural Gas Chemistry, Vol. 11, No. 1-2.
[78] Chemical Market Reporter (2004), GTL Could Become a Major Chemicals Feedstock, January 12.
[79] IEA (2005, *World Energy Outlook 2005: Middle East and North Africa Insights*, IEA, Paris.

refinery. A GTL plant may yield a product range that returns $30 per barrel for a crude oil price of $20 per barrel, some $5 more than the average refinery barrel.[80]

The diesel produced in GTL plants is a high-quality product with an energy density similar to conventional petroleum diesel, a high cetane number and low sulphur content. While the possibility of producing naptha and other middle distillates is also very attractive. Given the likely increasing trend towards heavier crude oils in the global production mix, the lighter products, with very attractive properties, produced by GTL plants are likely to be a particularly welcome addition to liquid fuel supply.

[80] Fleisch, T. H. (2002).

Figure 5.1: Petroleum Product Yields from Refineries and GTL Plant[81]



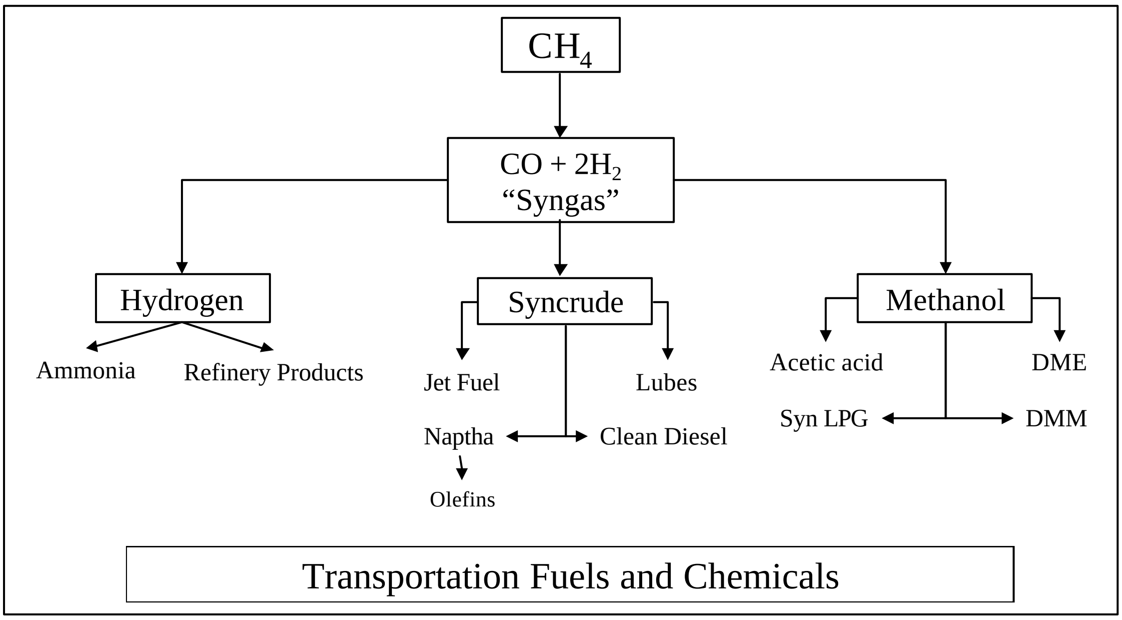
Currently, the conversion efficiency of the GTL process is about 55%, with a theoretical maximum of about 78%. The efficiency of the projects currently under construction or being proposed is around 60 to 65%.[82] There remains some technical risk in up-scaling plant-size to achieve significant economies of scale, but these are unlikely to significantly delay projects given today's oil prices.

However, GTL will have to compete with a growing LNG market to secure stranded gas resources. In addition, as in New Zealand, there are other competing products that gas can be converted into. Using other reactors and units other than the FT reactor, numerous products, including dimethyl ether (DME) and methanol, can be derived from the two fundamental building blocks (CO and H_2) that compose the syngas (Figure 5.2).

The conversion of gas into products other than hydrocarbons is a sizeable industry, consuming as much 4 Tcf of gas per year. Hydrogen is the main product and is used extensively at crude oil refineries. However, the conversion of gas into fertilizer (ammonia/urea) is also particularly important. GTL must therefore compete with other options for gas use, although at today's oil prices GTL is a very attractive proposition.

[81] Based on Fleisch, T. H. (2002).
[82] Fleisch, T. H. (2002).

Figure 5.2: GTL Production Options[83]



GTL technology is well-established, but continuing improvements are likely. The thermal efficiency of GTL plants could be increased by making better use of the heat generated in the exothermic processes of FT synthesis; with the co-production of steam or electricity one option to improve the economics of GTL production. The GTL process also allows the production of various chemicals, maximising the revenue stream from these co-products could further improve the economics of the GTL process.

Costs

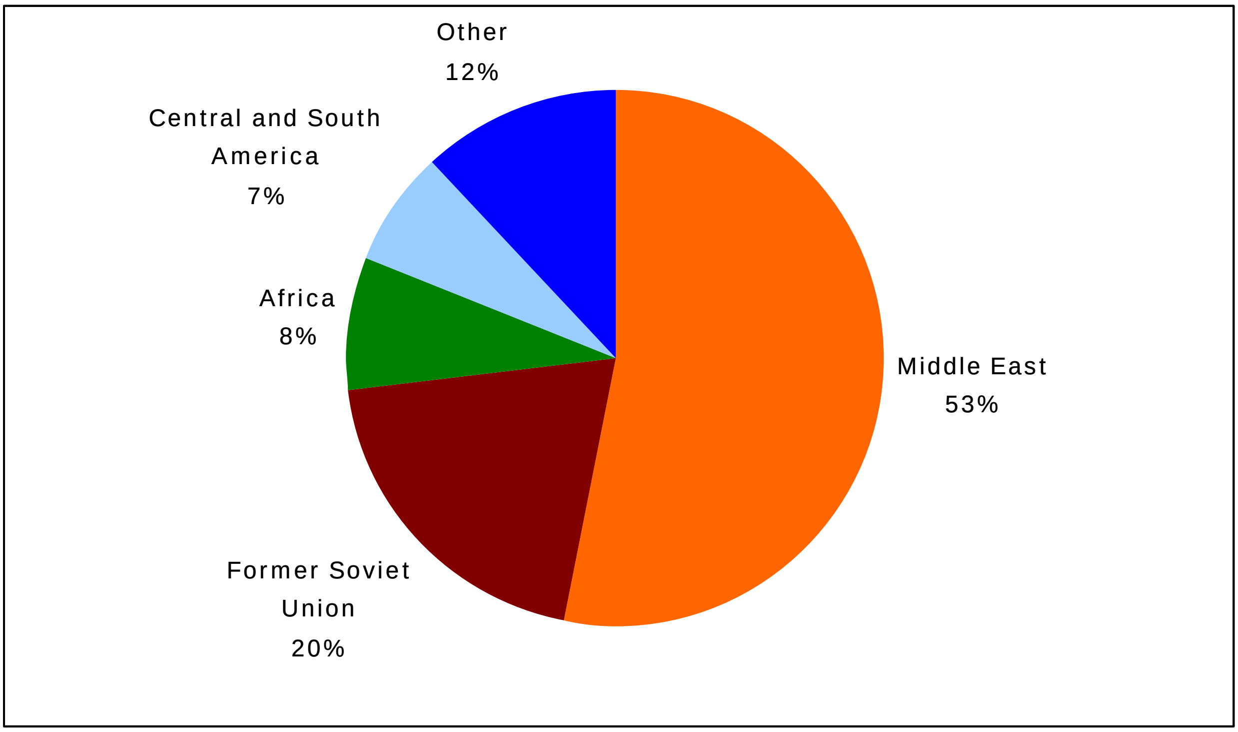
Costs for gas -based FT production are about USD 30/bbl (USD 5-6 per GJ), assuming a gas price of USD 0.50/GJ.[84] However, gas prices today are substantially above these levels in mature natural gas markets. GTL projects are therefore only likely to be pursued in situations where gas reserves do not have access to a market (so called "stranded gas") and the economics for GTL look better than the investment required in an LNG terminal to export the gas. To be viable, a GTL project needs at least 1.5 EJ (about 35 Mtoe) of gas nearby.[85] GTL plant with smaller reserves in place could be considered, but the final product cost would be higher, as GTL plants depend on economies of scale to reduce costs. Capital costs could decline to $15 000 b/d of production capacity by 2015, from $20 000 to $25 000 for recent projects.[86]

The total amount of stranded gas reserves is 6000 EJ (about 140 thousand Mtoe, *i.e.* half of global gas reserves), equal to 60 years of current gas use. A large fraction of these reserves is situated in the Middle East (Figure 5.3). The potential production of GTL is therefore quite

[83] Based on Fleisch, T. H. (2002).
[84] Marsh, *et al.* (2003), Application of CO_2 Removal to the Fischer-Tropsch Process to Produce Transport Fuel, Proceedings of the 6th International Conference on Greenhouse Gas Control Technologies, 1-4 October 2002, Kyoto, Japan. See also IEA (2006).
[85] IEA (2006).
[86] Fleisch, T. H. (2002).

significant, although GTL projects still have to compete for this gas with other uses, such as LNG, supplying the rapidly growing economies of some of these countries etc.

Figure 5.3: Stranded Natural Gas Resources by Region[87]



[87] IEA (2005).

5.2 Coal-to-Liquids

The production of synfuels from coal (CTL) via the Fischer-Tropsch synthesis process was first developed in coal-rich Germany in the early decades of the twentieth century, primarily for strategic reasons. South Africa, which, like Germany, has no oil reserves, developed and improved the process during the apartheid boycotts. Sasol, the South African oil company, operates coal-to-liquid plants with a capacity of around 150 000 barrels of crude oil equivalent per day.

Process technologies for the production of synthesis gas from coal are well established, as well as the FT synthesis of syngas to liquid fuels. Currently, the efficiency of the conversion process for a High-Temperature FT process is about 42%.[88] However, similarly to the GTL process, the thermal efficiency of CTL plants can be increased by making better use of the heat generated during FT synthesis.

In order to improve the economics of CTL production, Sasol is investigating the co-production of electricity and heat from coal. The co-production of FT transportation fuels and electricity from coal could raise the energy conversion efficiency of the process from 40% to 50%. Other improvements can make the CTL process more economical, such as the combined production of methanol and DME, but this opportunity is only available if there is a ready market for these products. Co-production of electricity, heat and other chemicals would allow a high average load factor and therefore reduce the capital cost per unit of liquid fuel product. A study by Sasol suggests that CTL plants with cogeneration could produce fuel and electricity in a ratio of eight-to-one; perhaps reducing synfuel production costs by 10%.[89]

Costs

A CTL plant at the mine-mouth with a coal price of $1/GJ (*i.e.* $20/tonne) could produce synfuels from coal for between $8-10/GJ[90] (roughly equivalent a crude oil price of $35 to 40/bbl, and a liquid fuels price of $40-45/bbl), but would need reserves of 2 to 4 Gt of coal reserves nearby. The CTL process is less sensitive to feedstock prices than the GTL process, given the higher capital costs for the coal-based process. The construction of a CTL plant producing 80 000 barrels per day of liquid fuels would cost about $5 billion, versus $1.6 to1.9 billion for a GTL installation.[91]

The high capital costs of CTL plant are a major barrier to the development of FT synthesis from coal, as CTL plants can only be competitive if they are extremely large facilities. CTL processes are also very energy intensive and lead to 10 times higher CO_2 emissions per unit of energy delivered than in a conventional refining process. In coal-to-liquid conversion, two-thirds of the carbon in the coal is released as CO_2 in the fuel production process. Well-to-wheel emissions are more than doubled by CTL processes.[92]

[88] Steynberg, A.P. and Nel, H.G. (2004), *Clean Coal Conversion Options Using Fischer-Tropsch Technology*, Fuel 83, pp. 765-770.
[89] Espinoza, R.L. *et al.* (1999), *Low Temperature Fischer-Tropsch Synthesis from a Sasol Perspective*, Applied Catalysis A: general 186, pp. 13-26.
[90] Williams, R.H., Larson, E.D. (2003), *A Comparison of Direct and Indirect Liquefaction Technologies for Making Fluid Fuels from Coal*, Energy for Sustainable Development, vol. VII, no. 4, pp. 103-129.
[91] IEA (2006) and Fleisch, T. (2004).
[92] IEA (2006).

Climate change concerns and CO_2 mitigation policies may put CTL at a disadvantge, but the use of CO_2 capture and storage (CCS) could reduce the additional CO_2 emissions on top of conventional petroleum products by 90-95%. However, CCS would add additional investment costs to an already capital-intensive operation.

CTL projects are attracting increasing attention from coal-rich oil importing countries given today's oil prices. CTL projects could be attractive to countries like South Africa, China, India, Australia, the United States and Poland. China is interested in an advanced version of the Sasol CTL process and has plans for two plants,[93] while Poland is considering the construction of a 4 to 5 Mt/yr CTL facility with CO_2 capture and storage.[94]

Unlike stranded gas reserves, coal reserves are abundant in various regions, and hence CTL will benefit from this resource availability. However, environmental impacts are a concern, given the significant GHG emissions resulting from these processes. The growth in CTL production in countries with strong GHG reduction goals will therefore depend not only on the oil price, but whether CCS can be applied successfully at a reasonable additional cost.

[93] IEA (2006) and Corinthus, T. (2006), *The Impact of Synfuels on World Petroleum Supply*, Presentation to the 2006 EIA Energy Outlook and Modeling Conference, March, 2006.
[94] IEA (2006).

6 Summary of Costs, Availability and Environmental Impacts

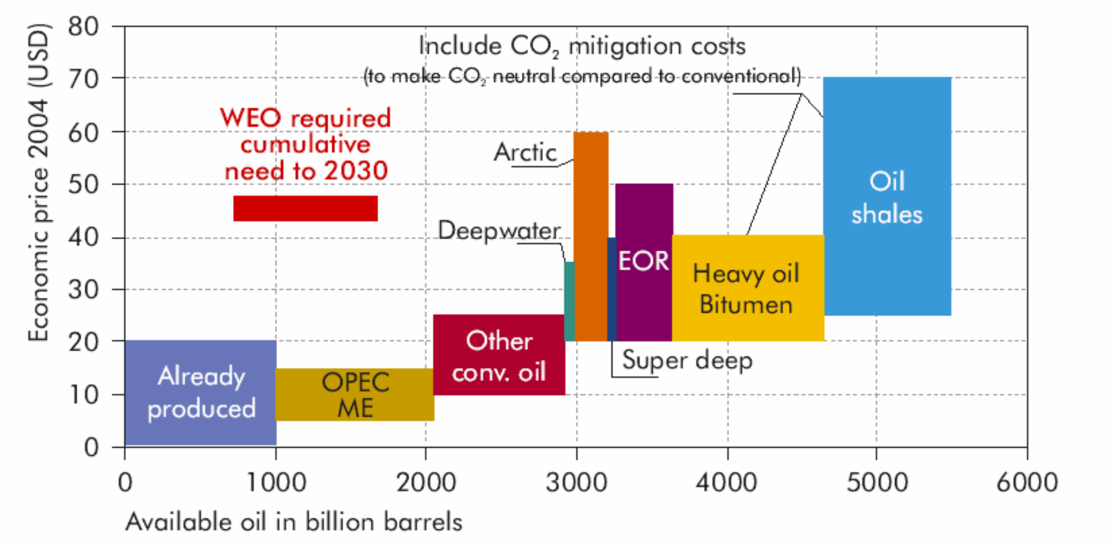
Alternative liquid fuels are generally more expensive to produce than conventional oil and so their production to date has only been restricted to relatively minor quantities. OPECs efforts to restrict supply in the 1970s and early 1980s resulted in more expensive conventional oil sources being exploited, such as the North Sea. However, in the coming years oil companies will have increasing difficulty in accessing prospective areas which are thought to have high potential, because many of these areas in the Middle East, Africa, South America and Asia are restricted to national oil companies and the opportunities for foreign investment are limited or non-existent.[95]

High oil prices are therefore increasingly likely to result in alternative sources being considered. This paper has looked briefly at oil sands, heavy oil, oil shales, biofuels and synthetic fuels from coal and gas. Their availability and costs need to be considered in terms of the overall supply curve for liquid fuels, something that is not easily done given the uncertainties involved and the renewable nature of biofuels vs. the finite resources of coal, oil and gas.

The IEA has attempted to put together a supply curve that covers conventional and non-conventional oil sources. This is presented in Figure 6.1. This conveys a number of interesting points. Firstly, oil demand over the next 25 years will be about the same as the total historical production *to date*. The second important point is that OPEC Middle East producers still have significant reserves, which can significantly undercut most other sources. This will mean that projects face significant price risk if supply growth exceeds demand growth. The final point is that at present oil prices, there is very little in the way of conventional or non-conventional oil production that is not economic. However, price volatility will ensure that for these more expensive non-conventional oil options to be built will require a significant premium over their economic threshold.

[95] IEA (2003), *World Energy Investment Outlook* , IEA, Paris.

Figure 6.1: Supply Curve for Conventional and Non-conventional Oil



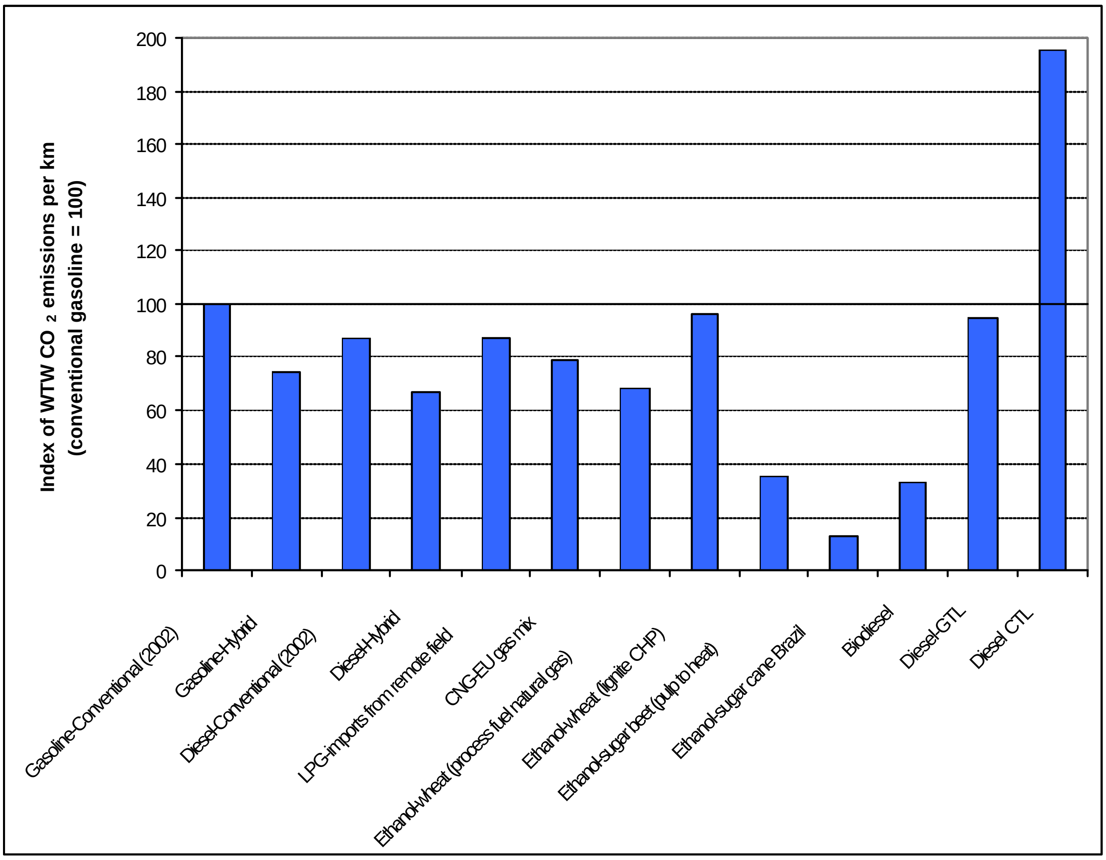
Resources to Reserves, © OECD/IEA, 2005, Figure 7.1, p 112.

To this picture needs to be added GTL, CTL and biofuels. GTL could be available in significant quantities at prices of around \$30/bbl and above, while very large quantities of CTL could be produced for between \$35-\$40/bbl. Synthetic fuels therefore compete in the price range of heavy oil and oil sands.

Biofuels are more difficult to factor into this picture, given that they are renewable, but the IEA projections is that these could contribute as much as 25 mb/d in 2050 if the oil price was \$60/bbl. However, as discussed, a premium over this is likely if all the economic capacity is to come through.

The GHG implications of some of these fuels are significantly different from conventional gasoline or diesel. Figure 6.2 presents the Well-to-Wheels CO_2 emissions as an index relative to a standard gasoline powered vehicle. Ethanol and biodiesel provide relatively modest GHG reduction potentials based on existing technologies if produced from corn, wheat or sugar beets. However, the outlook changes for ethanol from sugar cane in Brazil. Diesel derived from CTL is by far the most polluting, but CCS at synfuels plant could reduce this down to about conventional diesel levels.

Figure 6.2: Well-to-Wheel CO_2 Emissions by Fuel Pathway[96]



[96] CONCAWE (2006), *Well-to-Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context*, CONCAWE, EUCAR and JRC. Where a range of values were provided for a pathway, the mid-point was used.