

The Potential for Renewable Energy Sources in Aviation

Bob Saynor
Ausilio Bauen
Matthew Leach

Imperial College Centre for Energy Policy and Technology

www.iccept.ic.ac.uk

07 August 2003

Table of Contents

Glossary	4
Executive Summary	6
<i>Main Findings.....</i>	6
<i>Project Overview & Objectives.....</i>	6
<i>Renewable Aviation Fuels – Options Considered.....</i>	6
<i>Renewable Aviation Fuels – Rejected Options.....</i>	6
<i>Renewable Aviation Fuels – Favoured Options.....</i>	7
<i>Quantitative Analysis – Assumptions.....</i>	7
<i>Quantitative Analysis – Results.....</i>	8
<i>Conclusions.....</i>	11
Introduction.....	12
1. Renewable Transport Fuels - Key Trends Worldwide	14
<i>Ethanol.....</i>	14
<i>Biodiesel.....</i>	14
<i>Hydrogen.....</i>	15
<i>Methanol.....</i>	15
<i>Biogas.....</i>	15
2. Key Existing Aviation & Environment Studies	16
<i>Air Travel – Greener by Design, Society of British Airways Companies, 2002.....</i>	16
<i>Aviation and the Global Atmosphere, IPCC, 1999.....</i>	17
3. Renewable Aviation Fuels – Options Considered.....	19
<i>Biodiesel.....</i>	19
<i>Methanol.....</i>	20
<i>Ethanol.....</i>	20
<i>Fischer-Tropsch Kerosene.....</i>	21
<i>Nuclear.....</i>	22
<i>Hydrogen.....</i>	23
<i>Liquefied Bio-methane.....</i>	24
<i>Selection of Options for Detailed Study.....</i>	25
4. Renewable Fuel Chains – Selected Fuels.....	27

<i>Global Biodiesel Fuel Chains</i>	27
<i>Biodiesel Quantitative Analysis – Parameters & Assumptions</i>	31
<i>Biodiesel Quantitative Analysis - Results</i>	37
<i>Global Biomass Fischer-Tropsch Fuel Chains</i>	39
<i>Fischer Tropsch Quantitative Analysis – Parameters & Assumptions</i>	43
<i>Fischer-Tropsch Quantitative Analysis - Results</i>	47
<i>Hydrogen Fuel Chains</i>	50
<i>Hydrogen from Electrolysis Quantitative Analysis – Parameters & Assumptions</i> .	55
<i>Hydrogen from Electrolysis Quantitative Analysis – Results</i>	57
<i>Hydrogen from Biomass Quantitative Analysis – Parameters & Assumptions</i>	58
<i>Hydrogen from Biomass Quantitative Analysis – Results</i>	61
<i>Quantitative Analysis - Summary</i>	62
5. Discussion	63
Bibliography	66
<i>References</i>	66
<i>Websites Accessed</i>	67
<i>Experts Consulted</i>	68

APPENDICES

Glossary

Terms used in this report are defined as follows:

Term	Description
GBD	Air Traffic Greener By Design – SBAC report
°C	Degrees centigrade
CMG	Compressed methane gas
CNG	Compressed natural gas
CO	Carbon monoxide
CO ₂	Carbon dioxide
CO ₂ eq	CO ₂ equivalent
CP	Cloud point
EtOH	Ethanol
FT	Fischer-Tropsch
GHG	Greenhouse gas
GJ	1x10 ⁹ Joules
HC	Hydrocarbons
HCl	Hydrogen chloride
HGCA	Home Grown Cereals Association
H ₂ S	Hydrogen sulphide
ICAO	International Civil Aviation Organization
ICE	Internal Combustion Engine
IGT	Institute of Gas Technology gasifier
IPCC	Intergovernmental Panel on Climate Change
OECD	Organisation for Economic Co-operation and Development
OSW	Off-shore wind turbine electricity generation
kW	1x10 ³ Watts
LH ₂	Liquid hydrogen
LNG	Liquefied natural gas
MAFF	Ministry of Agriculture Fisheries and Food
MeOH	Methanol
MJ	1x10 ⁶ Joules
MSW	Municipal solid waste
MW	1 x 10 ⁶ Watts
MW _e	MW electricity (output)
MW _{th}	MW thermal (output)
NO _x	Oxides of nitrogen
N ₂ O	Nitrous oxide
ODT	Oven dry tonne

PJ	1×10^{15} Joules
PSA	Pressure swing adsorption
RME	Rape methyl ester
SBAC	Society of British Airways Companies
SME	Soya methyl ester
SO _x	Oxides of sulphur
SRC	Short rotation coppice
t	Metric tonne (1000 kg)
TPS	Termiska Processer gasifer
TJ	1×10^{12} Joules
USAF	United States Air Force
USDA	United States Department of Agriculture
VOC	Volatile Organic Compounds
\$	U.S. dollars
£	Pounds sterling

All financial figures used in this report are quoted in both US dollars and British pounds. An exchange rate of £1 = US\$1.60 is used throughout.

Renewable Aviation Fuels – Favoured Options

Three fuel options were considered to warrant more detailed analysis:

- Synthetic Fischer-Tropsch kerosene produced from biomass. FT kerosene could be blended with or used as a substitute for conventional kerosene.
- Biodiesel. Biodiesel has the potential to be used as a “kerosene extender” by blending it with conventional kerosene up to a maximum of approximately 10% - 20% by volume.
- Hydrogen. Hydrogen aircraft have been the subject of much research in Europe, the USA, Russia and elsewhere since the 1950s. In the long term, H₂ could be used in place of kerosene to fuel jet aircraft, although major changes in aircraft design would be required. Engines would have to be modified, in particular to keep NO_x emissions within acceptable levels. Moreover, airframes would have to be fundamentally redesigned to accommodate the larger volumes of fuel necessitated by H₂'s lower energy density. Designs include planes similar to current large passenger aircraft but with additional fuel tanks running above the length of the passenger compartment, or the more radical “blended wing body” or “flying wing”. Hydrogen aircraft emit more water vapour than kerosene aircraft, and more research is necessary to understand how the radiative forcing effect of such emissions varies at different altitudes. Hydrogen aircraft will clearly be required to meet the same stringent safety standards as conventional ones, although if public perception of H₂ safety is negative this may necessitate additional proving.

Quantitative Analysis – Assumptions

The project estimated carbon and energy balances, production potentials and costs of production for the fuel chains that appear most promising in the UK. The fuel chain parameters and assumptions were as follows:

Biodiesel (rape methyl ester, RME) is produced from rape grown on arable land in the UK. The energy balance and costs are calculated without any by-product credits. ‘Low’, ‘best estimate’ and ‘high’ values are provided for feedstock production, transport, conversion and RME distribution.

Fischer-Tropsch kerosene production calculations assume wood chips from short rotation coppice willow as the feedstock and are modelled for two different FT reactors. One has an indirectly heated, oxygen-blown, and pressurised gasifier, whilst the other uses an indirectly heated, air-blown gasifier and operates at atmospheric pressure. Both reactors use the ‘once-through’ configuration assuming 80% conversion with the remaining off-gas used for electricity generation, and both assume FT liquid production to be 50% kerosene, 25% diesel, and 25% naphtha.

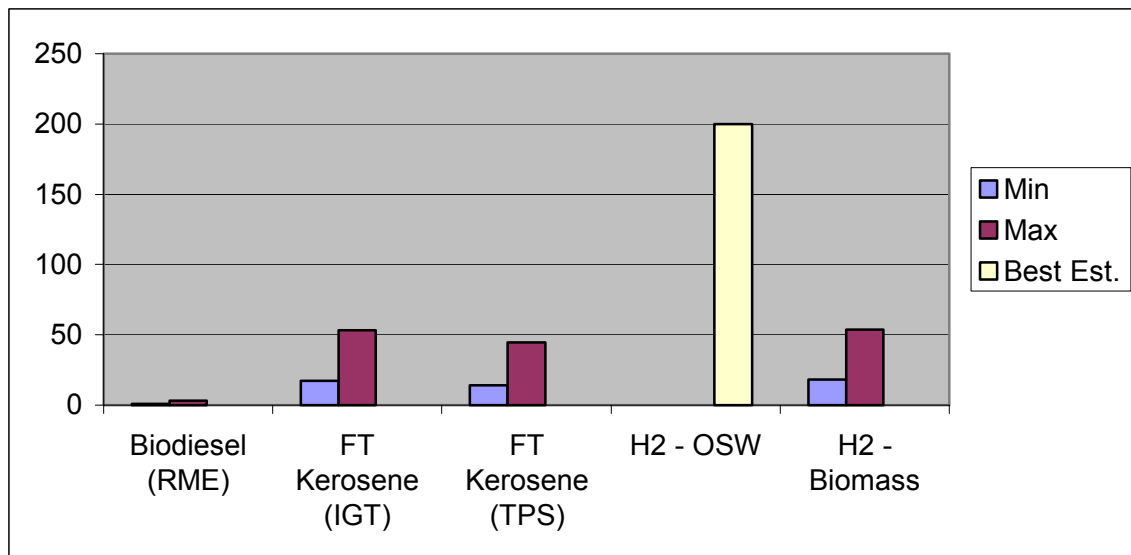
The electrolysis-based H₂ fuel chain consists of large-scale water electrolysis powered by offshore wind electricity. Electricity is transmitted through the

existing transmission and distribution network to a large-scale electrolyser (334MW) with a H₂ production capacity of 10 tonnes per hour. Hydrogen is transported as a liquid by road tanker or as a gas by pipeline.

Hydrogen from biomass calculations are based on large-scale short rotation coppice willow woodchip gasification using an air-blown atmospheric pressure indirectly heated gasifier followed by product gas reforming and upgrading. Hydrogen is transported to the airport as a liquid by road tanker or as a gas by pipeline.

Quantitative Analysis – Results

Energy Ratios – GJ Fuel Produced per GJ Non-Renewable Energy Input



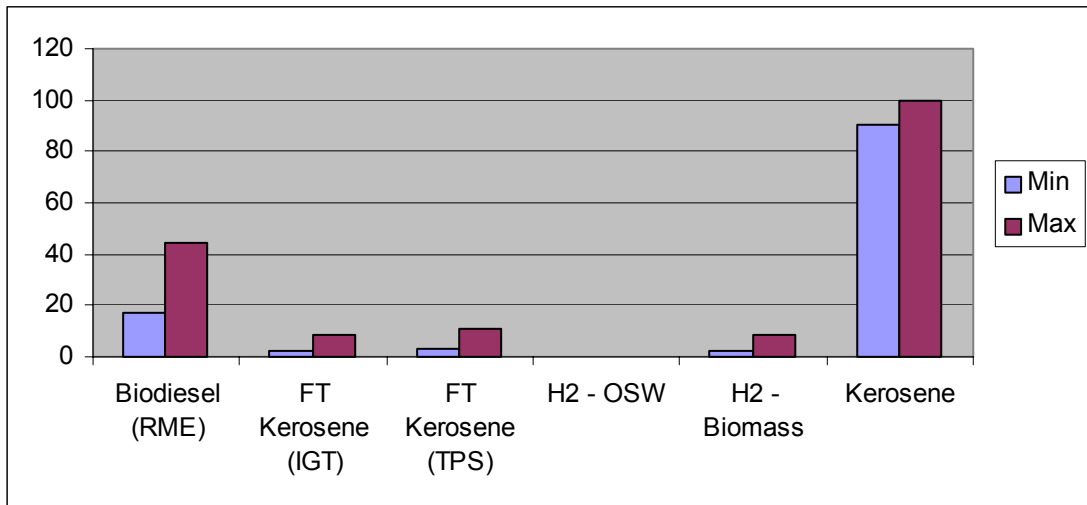
Notes:

OSW - Hydrogen produced from offshore wind electricity generation.

SRC – Hydrogen produced from short-rotation coppice

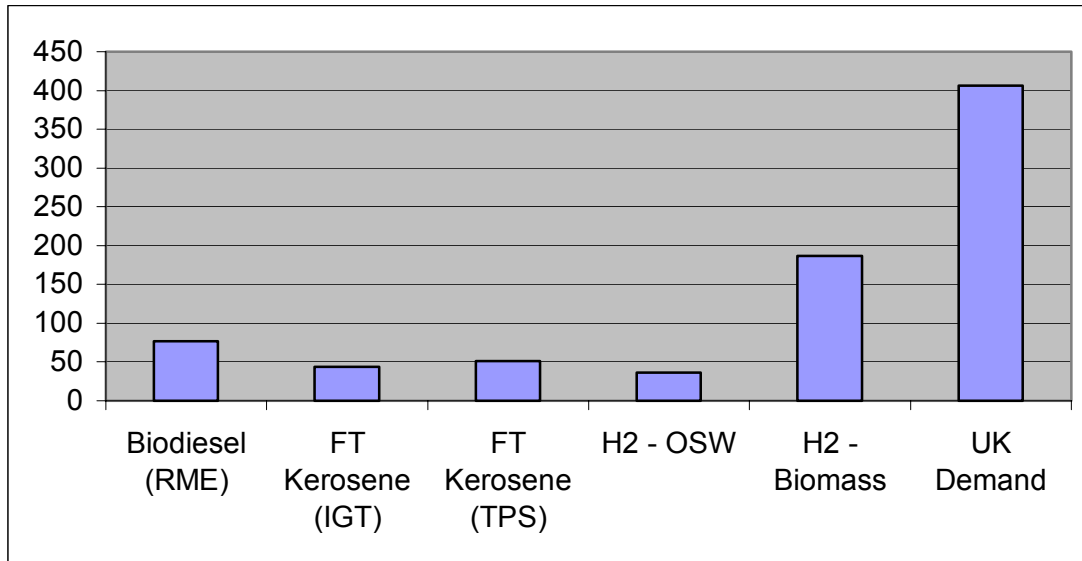
The energy ratios provide an indication of the possible non-renewable energy input to the fuel chain. Direct non-renewable energy inputs to most renewable transport chains could be very low. This is particularly the case for OSW and SRC H₂ if pipeline or cryogenic liquid transport is used FT kerosene ratios are broadly similar to those for pipeline or cryogenic SRC, but for RME the ratio is an order of magnitude lower.

Greenhouse Gas Emissions - kgCO₂eq/ GJ Fuel Produced



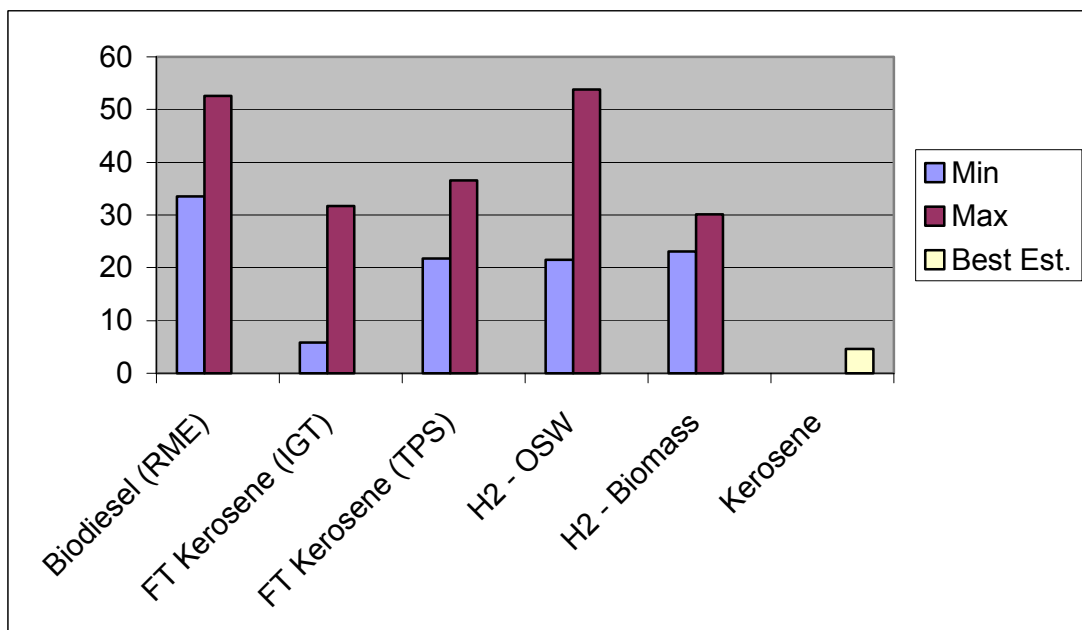
The relatively high figure for RME GHG emissions is explained partly by the N₂O emissions associated with the use of nitrate fertilisers. FT kerosene GHG emissions are lower due to the greater efficiency of the process and because little or no nitrogen fertiliser is applied to the SRC feedstock. Very low emissions can be achieved for OSW and SRC, depending mainly on the type of energy used for transporting the H₂ and the need for its transport. All the fuels considered would reduce greenhouse gas emissions compared to kerosene, which produces approximately 90-100 kgCO₂eq/GJ.

Illustrative UK Production Potentials & UK Demand



The RME, FT kerosene and H₂ from SRC figures are each based on 200,000ha of the UK's 600,000ha of arable land being available for feedstock production. The TPS gasifier system produces more liquid hydrocarbon fuel than the IGT gasifier system (though less co-produced electricity), which explains its higher kerosene production potential. Both FT systems are assumed to produce 50% kerosene and 50% other liquid hydrocarbon fuels. OSW figures refer to estimates of resources exploitable by 2010.

Cost of Production – US\$/GJ Fuel Produced



The costs shown above are estimates, though it is recognised that future costs are notoriously difficult to predict. The minimum cost for FT kerosene produced with the IGT system is low because of the subsidising effect of the large amount of co-produced electricity. OSW 'max' estimates are based on current OSW costs of 5-5.5p/kWh, and 'min' estimates are based on a price of 2-3p/kWh, (estimated for 2020.) Electrolyser costs assume a lifetime of 20 years and a 10% discount rate.

Conclusions

Hydrogen, FT kerosene and biodiesel all have the potential to bring savings in the aviation sector's use of non-renewable energy and emissions of greenhouse gases. These environmental benefits are greatest for H₂ (especially if transported to airport by pipeline or liquefied), FT kerosene then biodiesel, respectively.

All three renewable fuels would be significantly more expensive to produce than the current cost of conventional aviation kerosene. The large cost differences make it unlikely that a renewable alternative to aviation kerosene will be adopted in the foreseeable future, although in the long-term the costs of producing H₂ and FT kerosene may drop sufficiently for them to become viable options. A significant drop in the cost of producing biodiesel is less likely since the technologies involved with its production are already well established.

For H₂ a major research effort would be required to produce appropriate new engines and airframes, and it appears unlikely that commercial H₂ aircraft will be seen for at least several decades.

For safety reasons, the aviation industry is particularly resistant to new or unproven technologies and fuels, which provides a strong argument in favour of using finite supplies of renewable fuels for alternative purposes. For the foreseeable future road vehicles could consume the entire supply of biodiesel that will be available; renewable electricity could be used to displace non-renewable generation or to supply H₂ for road vehicles; and FT liquid hydrocarbon production could focus primarily on diesel for road vehicles. However, the FT process necessarily produces a minimum of 20-30% kerosene, so perhaps the most likely medium-term route for the introduction of a renewable fuel into aviation is FT kerosene produced in conjunction with FT diesel and blended with conventional kerosene.

Introduction

Over the past decades civil aviation has enjoyed strong growth. This growth is forecast to continue for the foreseeable future, and the environmental implications of this growth are proportional. Emissions from aircraft, both carbon dioxide (CO₂) and regulated pollutants such as oxides of nitrogen (NO_x), carbon monoxide (CO), hydrocarbons (HCs), etc. pose environmental problems affecting both local air quality and global climate change. Historically technology developments have reduced these environmental impacts, but the continued growth of the industry is outstripping the ability of current technology to compensate for the environmental problems. Renewable energy sources may be able to offset some of these environmental trends, particularly for carbon dioxide emissions, and allow civil aviation to respond appropriately to the UK's commitments under the Kyoto protocol. DTI was therefore pleased to support the PRESAV initiative to provide an initial UK overview of the extent to which renewable energy sources might facilitate aviation's environmental response.

The environmental effects of emissions from civil aviation were reported in detail in the IPCC report "Aviation and the Global Atmosphere, 1999". This report commented that "alternative fuels may appear environmentally friendly but technical problems occur in adapting the fuel to current aircraft design and aviation infrastructures. Using current technology such changes would increase CO₂ released to the atmosphere". The PRESAV project aims to assess the veracity and validity of this statement, and to assess the other practical, technical and social implications of developing the options for renewable fuels for civil aviation. The information that this study will provide will be considered by DTI for the development of policies addressing the role of aviation in a sustainable society.

This report recognises that aviation is an industry that must be considered from a global perspective, but it places particular emphasis on the UK position, particularly with respect to fuel production and supply.

The first section of the report assesses current knowledge and experience of renewable transport fuels in general, and of key trends worldwide. The focus in this section is on road vehicle fuels as this is the sector in which most renewable transport fuels experience has been gained.

Section 2 reviews two key recent aviation and environment reports.

Section 3 is a qualitative assessment of the range of renewable fuel options for jet aircraft, and ends by identifying biodiesel, FT kerosene, and H₂ as the most promising options.

Section 4 assesses the options for the production of these three fuels from renewable sources.

Section 5 presents the study's assessment of the technical, environmental, and economic feasibility of the three fuels chosen for detailed study. For each of the three fuels, estimates are made for the cost, energy consumption, and CO₂ emissions per GJ of fuel delivered. Worldwide and UK production potentials are also estimated.

The final section of the report discusses the implications of the report's findings for the future investigation of alternative aviation fuels.

1. Renewable Transport Fuels - Key Trends Worldwide

Internal combustion (IC) engines and oil-derived fuels have dominated road transportation systems for many decades. The IC engine has been so successful that until recently prospects for radical alternatives were not taken seriously and thus little R&D has been directed to search for new alternatives.

However, in recent years, a combination of technological, environmental and socio-economic changes, are forcing the search for new alternatives that could challenge the dominance of the IC engine. These changes are steadily transforming worldwide markets for new fuels and propulsion systems. Local air quality problems and international concerns about climate change are creating markets for innovative transportation systems in urban areas (e.g. California's mandate that by 2003, 10% of the vehicles sold in that state must have zero emissions).

Thus, in the short to medium term the main challenge will be to find sound alternatives to fossil fuels that can be used in the IC engine. In the longer term the challenge will be to find large-scale alternatives to fossil fuels that can be used both in existing IC engines and new propulsion systems.

Ethanol

Of the many alternative transportation fuels under consideration, ethanol is perhaps the most promising in the short to medium term. Ethanol fuel is produced and used in a large commercial scale (approx. 25 billion l/yr), primarily in Brazil and the USA. Other alternative transport fuels that offer a significant potential include biodiesel, H₂, methanol, and to a lesser extent biogas.

Currently the two main sources of ethanol fuel are sugarcane in Brazil, and corn in the USA. These two sources will continue to dominate ethanol fuel production despite considerable efforts to diversify. This is particularly the case in the EU, which relies on less promising feedstocks such as cereals and sugar-beet, and the USA where corn still remains a high cost feedstock.

In the longer term, other feedstock such as cellulose containing material will play a much greater role, particularly in non-sugarcane growing countries. Sugarcane is one of the highest yielding crops and has been used commercially for the production of ethanol fuel for many years. Sugarcane is produced in approximately 100 countries covering a wide geographical area.

In the USA, corn will continue to be the principal ethanol feedstock in the short term, but considerable R&D is being devoted to the potential of alternative feedstocks, particularly cellulose material.

Biodiesel

Biodiesel use in road transport has grown in the past decade, particularly in the EU.

Studies generally show significantly reductions in emissions of CO, HC and particulates from road vehicles fuelled by biodiesel as compared to those fuelled by conventional diesel. However, NO_x emissions can be high, and in some cases have been found to exceed those from vehicles fuelled by conventional diesel.

Hydrogen

Hydrogen is believed by many experts to be a potential major fuel for transport in the future. However, its main potential for road transport lies in its future role for fuel cell vehicles and thus it may largely depend on the development of this technology. Important advances in storage, transport infrastructure, fuel cell technology, etc, require costly investment but could significantly improve performance. At the same time, H₂ will have to compete with existing alternatives, such as ethanol and natural gas.

Methanol

The use of methanol fuel is not new, as it has been used for many years blended in various proportions. Its main appeal is as a potential clean burning fuel, suitable for gas turbines, IC, and more specifically, for fuel cell applications for which it is a prime candidate.

Methanol is produced commercially - world production is over 47 billion l/yr - and is used in many industrial applications. Although in some countries (e.g. USA and Canada), methanol fuel could be used in large-scale, current economics favour natural gas, which is abundant, has greater advantages over methanol except that it is easier to transport. Thus on a worldwide basis, the methanol fuel market will probably remain relatively small, confined to specialised markets such as chemicals and fuel cells.

Biogas

Biogas production and use can be grouped into three main categories: a) small domestic production/applications, b) small cottage industries and, c) industrial production/uses, including transport. Biogas has been used as a transport fuel for decades, mostly on an experimental scale. Currently one of the widest uses of biogas is in the IC engine to generate electricity.

However, the main driving force in biogas production is not energy, but the necessity of addressing environmental and sanitary problems. Biogas, rather than an alternative energy source, should be considered even more as a potential solution to environmental problems posed by excess manure handling, water pollution, etc. Thus, it is highly unlikely that biogas will ever play any significant role as a transportation fuel. Instead its use would be limited to niche markets such as buses, and refuse vehicles, mostly in urban centres or areas of confined production and distribution.

2. Key Existing Aviation & Environment Studies

The following section provides a critical review of the two key studies identified.

Air Travel – Greener by Design, Society of British Airways Companies, 2002

Air Travel – Greener by Design (GBD) was published in February 2002 by the Society of British Aerospace Companies (SBAC). The report is the output of a collaborative research project undertaken by a wide variety of aviation experts drawn from Government, industry, and academia.

The report is divided into three sections, each of which conveys the main findings of GBD's separate working groups. The first section of the report – Improving Operations - is concerned with a wide variety of issues other than actual aircraft design and construction, including transport to and from airports, energy and fuel use at airports, and measurement and certification of emissions. Improving Operations also includes discussion and analysis of optimum flying altitudes and angles of descent, the benefits that longer runways can bring in facilitating de-powered take-offs and reducing use of reverse thrust, and of over provision of competition on some routes.

The second section of GBD is entitled The Technology Challenge and considers the various trade-offs that exist with aircraft, such as reduction of noise versus reduction of fuel consumption, increasing thermal efficiency versus reducing NO_x emissions, and even reducing CO₂ emissions versus reducing overall contribution to the greenhouse effect. It proposes a full study of the extent to which multi-sector journeys by aircraft with lower optimum design ranges could reduce fuel burn compared to the current arrangements.

The section of GBD also contains the results of modelling both kerosene and LH₂ aircraft. Eight kerosene aircraft were modelled, including unconventional designs such as the blended wing body and those incorporating hybrid laminar flow control on the upper surface of their wings. Five of these designs were also modelled for LH₂. The report's modelling of LH₂ fuelled aircraft shows a substantial reduction in greenhouse effect compared to their kerosene fuelled counterparts. For the blended wing body and laminar flying wing design – which are considered the natural candidates for LH₂ due to their inherently greater fuel storage capacity – the change of fuel reduces the projected greenhouse effect by factors of four and five respectively. These projections take no account of the potential increase in contrail and cirrus cloud formation from LH₂ aircraft, however, and GBD states that to achieve the full benefit LH₂ aircraft may have to be optimised to fly at altitudes where the risk of their formation is small i.e. at slightly lower altitudes than the current norm. It should be noted that GBD only considers aircraft emissions, not full fuel cycle emissions.

GBD concludes that kerosene or a synthetic equivalent to it will continue to be the principal jet fuel for the majority of the twenty-first century, and that

environment concerns alone will not force a shift to LH₂. The report does not recommend any expansion of research into LH₂ aircraft over and above the current EU supported international research programme.

The main conclusions of the third sections of GBD are that taxation is not recommended as the sole or even prime mechanism for managing CO₂ emissions, but that the favoured long-term approach is CO₂ trading within an agreed capped limit. This conclusion differs from those reached by some commentators.

Aviation and the Global Atmosphere, IPCC, 1999

Aviation and the Global Atmosphere was published by the Intergovernmental Panel on Climate Change (IPCC) in 1999. The report is in 10 chapters and includes assessment and modelling of the effects of emissions on the atmosphere and the climate, the potential for new aircraft technologies, the potential for operational improvements, and the potential for market based instruments and further regulation.

The report states that over the last 40 years efficiency increases have led to a 70% decrease in kerosene used per passenger km, and that 80% of these increases have been due to engine improvements, and 20% due to airframe improvements. It is estimated that operations improvements could reduce fuel burn and emissions by approximately 6-12%, and that higher load capacities could contribute 2-6 % improvements. It is stated that future efficiency increases will not be enough to offset predicted increases in demand, and that consequently emissions from the aviation sector are set to rise.

The report discusses the International Civil Aviation Organization's (ICAO) proposal for cruise emissions standards to be introduced (to compliment the Landing and Take-Off standards that already exist), as well as the relative advantages of an international kerosene tax, voluntary agreements, and emissions trading to limit emissions.

The report points out that whilst the introduction of lower sulphur limits has reduced production of oxides of sulphur (SO_x), there is some evidence that the sulphur levels in aviation fuels has increased again in recent years (though remaining within legal limits). This is thought to be because refineries with limited hydro-treating capacities have shifted blending stocks with higher sulphur content to jet fuel in order to use the lowest sulphur production for road fuels, where sulphur limits are becoming even more stringent. The IPCC calculates that mandating zero sulphur fuel limits would lead to 0.5% increase in CO₂ emissions over the fuel cycle, and also points out that the loss of the organic acids that are removed during the desulphurisation process would cause lubricity problems.

Gas to liquid production of synthetic kerosene is mentioned briefly, though with little analysis about its technical performance or cost of production. Ethanol and methanol are correctly discounted for having low energy densities, low flash points, and for producing formaldehyde and acetaldehyde at low power settings.

The report states that cryogenic fuels such as LH₂ would require bigger airframes. It also quotes a study that calculates that for large aircraft there would be 20% overall weight saving due to the higher energy content per unit mass of LH₂, but that for smaller aircraft there would be a 17-38% weight penalty.

The IPCC's main conclusion about future aviation fuels is that "there would not appear to be any practical alternatives to kerosene-based fuels for commercial jet aircraft for the next several decades", although it also says that "H₂ may be viable in the long-term, but would require new aircraft designs and new infrastructure for supply."

3. Renewable Aviation Fuels – Options Considered

This study identified and reviewed six potential renewable fuel options for jet aircraft and also assessed the viability of nuclear aircraft. The six renewable fuels considered were: biodiesel; methanol; ethanol; Fischer-Tropsch kerosene; H₂, bio-methane.

Biodiesel

Biodiesel, defined as mono-alkyl esters of fatty acids, can be obtained either from the esterification of oil-bearing crops such as canola/rape and soybeans, or from waste oil products. Biodiesel can be used as a “kerosene extender”, which means that it can be blended with kerosene for use by jet aircraft.

The Food & Industrial Oils Research at The US Department of Agriculture leads research into biodiesel as a kerosene extender, and is particularly interested in soybean methyl ester (SME), which it has been assessing at concentrations of 10 – 30% by weight.

Advantages

The use of biodiesel as a partial substitute for kerosene would reduce fuel-cycle carbon emissions. It is also hoped, though yet to be confirmed, that biodiesel blends in kerosene will bring air quality emissions advantages over neat kerosene in a similar way to that in which biodiesel internal combustion engines (ICEs) show air quality emissions benefits over mineral diesel ICEs.

Biodiesel produced from all major feedstocks is readily biodegradable. [Zhang et al].

Disadvantages

There are several disadvantages with the use of biodiesel as a kerosene extender. The single biggest problem is that biodiesel blends compromise kerosene’s ability to perform in the very cold temperatures that are encountered at high altitude. This occurs because biodiesel blends in kerosene raise the fuel’s cloud point (CP) – the temperature at which the fuel becomes hazy or cloudy due to the formation of micro crystals – which presents the danger of blocked fuel filters, plugs and fuel lines etc at the very cold temperatures that exist at high altitude. [Dunn 88]. Even just 10% by weight biodiesel blends raises the CP from –51 °C to –29 °C. [c.f. JP-8 military kerosene specification, for example, requires fuels to operate to –47 °C.] Furthermore, adding more than about 2% methyl esters would raise the fuel’s freezing point above currently legislated limits.

Most research into methyl ester kerosene extenders is, therefore, concerned with improving their cold flow properties to reduce their tendency for crystallisation. This involves chilling the fuel and filtering out the crystals, a process that must be carried out in several stages since biodiesel forms a viscous gel once it is more than a degree or two below its CP. Results from the USDA's research into "winterised" SME are promising, with 10% wt. biodiesel reducing CP by only 4°C, corresponding to a maximum safe operational altitude of 9500m.

Biodiesel comprises a high proportion of unsaturated and polyunsaturated fatty acids, which makes it susceptible to degradation through oxidation, which in turn introduces the possibility of storage problems. Research indicates, however, that 10% by volume does not significantly increase the tendency for oxidation, and therefore does not compromise storage stability.

Water reactivity and the ability of water to penetrate into jet fuel is an important and regulated property of jet fuel. This is because kerosene is frequently transported long distances by pipelines in which contact with moisture can occur, and because in military applications the fuel tanks of aircraft onboard aircraft carriers are often filled with seawater to provide ballast. Research with jet fuel JP-8 indicates that blends up to 50% biodiesel meet water penetration fuel specification requirements, [Dunn, 2001].

Methanol

Methanol is not suitable for use as a jet fuel for several reasons. Its energy density and specific energy density are too low, which means the fuel does not contain sufficient energy for a jet fuel, in either mass or volume terms. The practical implications of these two factors are that aircraft range would be too short, and even if air-frames were redesigned with significantly larger fuel capacity their take-off weight would be too high.

Methanol presents a health risk by contact with skin or by ingestion. There is also an emissions problem associated with methanol in that it produces formaldehyde (CH₂O) at idle or low power, producing localised health problems around airports, especially for ground support staff. Formaldehyde is associated with respiratory problems, irritation to eyes nose and throat, and is carcinogenic.

Finally, methanol's flash point of 18°C is well below the minimum requirement of 38°C for JP-8 and would present major safety dangers.

Ethanol

Ethanol, being an alcohol with similar properties to methanol, is also unsuitable as a jet fuel for similar reasons. Ethanol's energy density and

specific energy are too low, and would thus limit aircraft range and maximum payload.

At low power settings ethanol jet engines would emit acetaldehyde (C₂H₄O), again bringing localised health problems around airports, especially for ground support staff.

Ethanol's flash point of 12°C is even lower than methanol's, so it would not meet jet fuel specification requirements, and would present major safety dangers.

Fischer-Tropsch Kerosene

Kerosene can be produced synthetically by Fischer-Tropsch (FT) or other synthetic fuel production processes, from a wide variety of carboniferous feedstocks including biomass.

Fischer-Tropsch fuels are typically manufactured in a three-step procedure:

- Syngas generation: The feedstock is converted into synthesis gas (syngas) composed of carbon monoxide and H₂.
- Hydrocarbon synthesis: The syngas is catalytically converted into a mixture of liquid hydrocarbons and wax, producing a "synthetic crude". This step is the actual Fischer-Tropsch synthesis.
- Upgrading: The mixture of FT hydrocarbons is upgraded through hydrocracking and isomerization and fractionated into the desired fuels.

Fischer-Tropsch conversion was first used commercially by Germany in the 1930s to produce F-T vehicle fuels from coal.

To date most research into FT kerosene has been carried out by the South African oil company SASOL, whose interest is in developing synthetic fuels from South Africa's large coal reserves.

Advantages

Fischer-Tropsch kerosene derived from a biomass feedstock would bring fuel-cycle CO₂ benefits compared to mineral kerosene, and would also largely eliminate SO_x emissions since the fuel is virtually sulphur free.

Fischer-Tropsch kerosene is chemically and physically similar to mineral kerosene. As such it is broadly compatible with current fuel storage and handling facilities and, notwithstanding the comments below, with current jet engines.

Disadvantages

Fischer-Tropsch kerosene has low aromatic content and is virtually sulphur-free, which lead to poor lubricity. These disadvantages, however, may be solved through the introduction of additives and/or aromatic fractions. The non-aromatic proportion of current jet fuels, consisting of straight chain or

cyclic alkanes, is around 70 to 80 % of the total. The tendency at this point in time appears to be for more aromatics to appear in civilian aviation fuels due to the wish to remove such compounds from transportation fuels used for road vehicles. Therefore, there does not appear to be any shortage of aromatic fractions for blending. Small quantities of additives have proven to be potentially exceptionally effective in reducing maintenance cost for military aviation applications. Much of the related technology is, however, patent restricted and, while not directly related, active research programs are in place that could probably be moved in the direction of producing optimal FT based aviation fuels. Inevitably, the latter also requires a detailed analysis of the impact upon the gas turbine as a whole and the combustion chamber in particular. There would, however, appear to be significant scope for technical developments to deal with any issues arising

Fischer-Tropsch kerosene has a slightly lower energy density than mineral kerosene, as it is iso-paraffinic. The consequent reduction in aircrafts' maximum range would impact on long-haul flights. This range reduction is relatively small, however, and will be partially offset by the increases in aircraft efficiency that are predicted to continue in the short to medium term.

Nuclear

The concept of nuclear powered aircraft was first proposed in 1942 by Enrico Fermi and his associates at the Manhattan Project. The belief was that a nuclear plane would have almost unlimited range, and would be capable of much greater speeds than technologies of the day.

In 1946 the United States Air Force (USAF) initiated the Nuclear Energy for the Propulsion of Aircraft project to develop both a long-range nuclear bomber and a high performance aircraft. This was replaced in 1951 by the Aircraft Nuclear Propulsion (ANP) programme, which operated under the joint auspices of the Atomic Energy Commission and the USAF.

The ANP considered two designs, the 'direct' and the 'indirect' turbojet. With the direct design, air would enter through the compressor stage of one or more turbojets from where it would be directed through the reactor core. The air, acting as the reactor coolant, would be heated rapidly as it travels through the core, and would then be directed to the turbine section of the turbojets and from there out through the tailpipe.

The indirect design was similar, except that it would have used a coolant fluid in a sealed circuit to enter the reactor. Heat exchangers would then have transferred heat to the air which would have entered through the compressor stage, before subsequently entering the turbine sections of the turbojets as above.

The two main problems with designs for nuclear aircraft have always been weight and safety. In one early design, for example, the propulsion system would have reportedly weighed more than 80 tonnes, of which five tonnes was reactor and almost 50 tonnes was shielding. Safety concerns, either of radiation emissions during operation, or of greater emissions or explosions in the case of accidents have also, not surprisingly been major concerns.

President John F. Kennedy cancelled the ANP programme in 1961, after more than \$1 billion (£1.6 billion) and 15 years failed to produce a working test aircraft.

There has been very limited interest in nuclear aircraft in recent times. One of the main proponents is Ian Poll, Director of Cranfield College of Aeronautics, who believes nuclear aircraft should be considered as an option to meet the projected increase in demand for air travel, without vast increases in kerosene consumption and associated emissions. Poll proposes closed-cycle nuclear heated steam engine propeller driven aircraft.

Since the attack on the World Trade Centre on September 11 2001, heightened international concern about terrorism appears to have ruled out the possibility of nuclear powered aircraft for the foreseeable future.

Hydrogen

The use of liquefied H₂ (LH₂) as a jet fuel offers potential environmental benefits if the H₂ is derived either from the gasification of biomass, or by electrolysis of water using renewably generated electricity. Hydrogen also presents significant technical challenges, however, and would require fundamental changes to the airframe design as well as development and modification of jet engines.

The first aircraft to fly with H₂ was a USAF B57, which flew with one of its engines running on LH₂ in 1956. In the 1970s and 80s further research was undertaken by organisations including NASA, Linde, Lockheed, and the Russian design bureau ADTK Tupolev, which modified one engine of a trijet TU154 to run on either LH₂ or liquefied natural gas. In the 1990s a joint Russian-German project by ADTK Tupolov and EADS Airbus studied many aspects of using LH₂ as jet aircraft fuel. Currently the main research in this field is being carried undertaken by the EC Fifth Framework funded Cryoplane project, which comprises a consortium of 35 partners from 11 EU countries.

The only primary product of combustion from the burning of H₂ is water, and the only secondary emissions of significance are oxides of nitrogen (NO_x). Burning H₂ does not produce CO₂, CO, unburned hydrocarbons, SO_x, or soot – all of which are emitted from kerosene burning jet engines.

Burning H₂ produces 2.6 times the amount of water vapour as burning a mass of kerosene with equal energy content, which is significant because at high altitude water vapour is a powerful greenhouse gas. The greenhouse effect of water varies greatly with altitude. Above approximately 6000m, where water vapour condenses and freezes to form thin ice clouds, the greenhouse effect per molecule is greater for water than for CO₂, [Conteras, Yigit et al; Pohl and Malychav]. Carbon dioxide has a much greater residence time, however: approximately 100 years, independent of altitude, compared to 3-4 days at ground level and 0.5-1 year in the stratosphere for H₂O. There is general consensus that the combined radiative forcing of emissions from LH₂ fuelled aircraft would be much lower than from kerosene. There is disagreement about critical altitudes, however: Some commentators, such as Heinz et al and Contreraz et al state that the effect of water vapour at current subsonic

altitudes will be ‘negligible’ or ‘not significant’, whereas Pohl et al believe that emissions from LH₂ aircraft flying above 10km would exceed those from kerosene aircraft. Consequently Pohl believes that flight altitudes will have to be reduced to below 10km where ‘the greenhouse effect is very close to zero.’

Oxides of nitrogen are emitted in direct proportion to flame temperature and dwell times. To reduce emissions of NO_x, new combustion concepts are required that take full advantage of H₂'s particular properties. These include the possibility for lean-burn low temperature combustion, short dwell times, and fuel/air homogeneity. [Pohl et al]. In the 1990s the European-Canadian “Euro-Quebec Hydro-Hydrogen Pilot Project” successfully proved that very low NO_x emissions are possible from practical LH₂ jet engines. [Klug et al]

For a given energy content LH₂ requires a volume 4 times larger than kerosene, but weights less than kerosene by a factor of approximately 2.6. This lower *volumetric* energy density means that LH₂ aircraft require different airframe designs from conventional aircraft in order to accommodate larger fuel tanks. In addition these tanks must insulate the cryogenic H₂ and must be able to withstand pressure differentials, which in practice means they must be spherical or cylindrical. For large passenger aircraft, tanks on top of the fuselage appear to be a pragmatic solution, and for smaller aircraft extra tanks under the wings may be feasible. In the future more radical designs such as the ‘blended wing body’ may prove the favoured solution for adequate fuel storage.

Liquid H₂'s higher energy density – its energy content per unit of mass – gives LH₂ aircraft a significant weight advantage over kerosene. Some of this weight advantage is lost to the weight of the larger tanks and additional fuel delivery equipment that LH₂ aircraft require - such as pressure relief valves and heat exchangers - but nevertheless LH₂ aircraft are expected to have higher maximum payloads than their kerosene equivalents.

Concerns are sometimes expressed about the safety of H₂, whether it is proposed for road transport, stationary applications or aircraft. Hydrogen-air mixtures detonate with a reactivity similar to that of lower alkanes and alkenes, and their flammability range is wide. Hydrogen fires will, however, burn out much more rapidly than kerosene fires. Successful detonations are easy to achieve compared to kerosene in enclosed areas, but are almost impossible in the open air. Aircraft designs, fuel handling equipment and procedures will clearly be developed with H₂'s specific characteristics in mind.

Liquefied Bio-methane

Some of the research into cryogenic aviation fuels has also considered the use of liquefied natural gas (LNG). The states of the Soviet Union, and subsequently of the former Soviet Union have shown a particular strategic interest in the development of LNG aircraft, as they have much larger reserves of natural gas than oil. In fact, the previously discussed ADTK's Tupolev 154 with one an engine modified to run on cryogenic fuel (see above) has flown most of its test flights on LNG rather than LH₂. As aircraft can be operated on LNG, there is also a possibility that they can be operated on bio-methane produced from a renewable source.

Most of the technical considerations and design requirements for LH₂ aircraft also apply to LNG, although LNG aircraft are less demanding in some areas. For example, unlike LH₂, methane does not cause materials embrittlement, and methane's boiling point of –161.3°C is considerably higher than LH₂'s boiling point of –252.7°C.

LNG aircraft's CO₂ emissions are approximately 25% lower than kerosene aircraft's, although with bio-methane the fuel cycle CO₂ benefits could potentially be much greater. It should also be remembered, however, that throughout the fuel cycle - production, distribution and combustion - there will inevitably be some emissions of methane, which is itself a powerful GHG.

It is unlikely that bio-methane could be supplied in sufficient quantities, at a low enough price, and with a sufficiently high and reliable degree of homogeneity to make it a practical option for aviation.

Selection of Options for Detailed Study

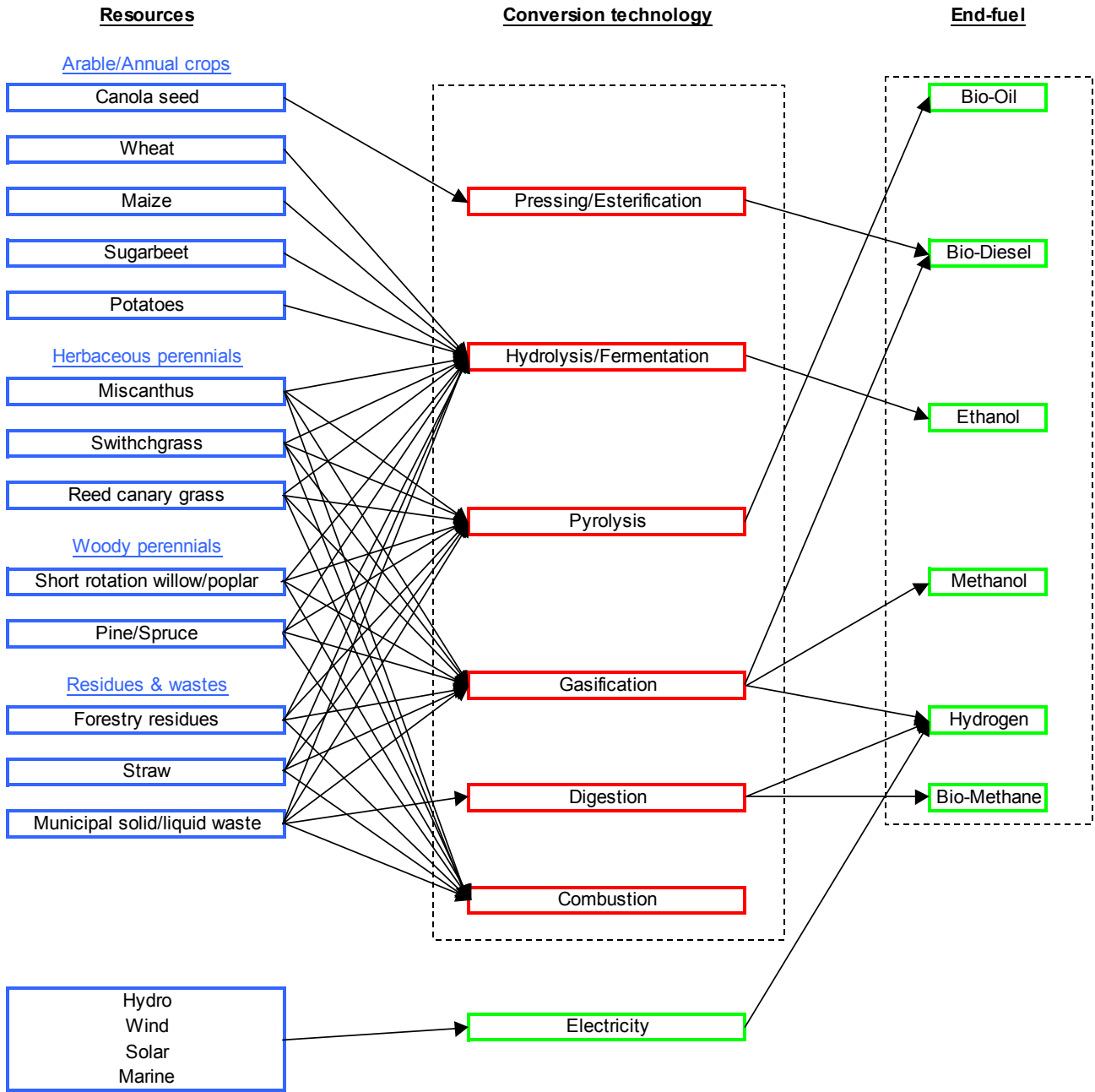
Of the seven fuel options reviewed above:

- Ethanol and methanol are not considered viable, principally because their energy densities are too low and also because of the likelihood of acetaldehyde or formaldehyde emissions at low power settings.
- Liquid bio-methane is ruled out on the grounds that it is unlikely to be available in sufficient quantities to be a major alternative to kerosene.
- Nuclear aircraft are considered to be too dangerous due to the possibility of accidents or terrorist attacks, even if the substantial technical and economic problems associated with the concepts could be overcome.

However, three renewable fuels were identified as warranting more detailed research:

- Biodiesel for use as a kerosene extender in the short to medium term.
- Fischer-Tropsch kerosene produced from a biomass feedstock.
- Liquid H₂ as an alternative to kerosene in the long term.

Potential Renewable Aviation Fuels and Sources



The fuel sources or 'Resources' shown in this diagram represent those available in the UK. 'Conversion Technologies' and 'End-Use' sections apply internationally.

4. Renewable Fuel Chains – Selected Fuels

This chapter presents the renewable fuel chains that could supply biodiesel, FT kerosene and H₂ globally, and identifies the fuel chains most appropriate in the UK. The parameters and assumptions used in the study's quantitative analysis are discussed for each fuel, and the results of the quantitative analysis are presented.

Global Biodiesel Fuel Chains

Feedstocks

Biodiesel, which has the potential to be used as a 'kerosene extender' once it has been treated to improve its cold temperature performance, can be derived from plant oils or waste frying oils, tallow, lard and butter. These cooking and waste oils will not be considered further in this report since the diverse nature of their origins makes them inappropriate as a source of jet fuel, for which there is a particularly strong emphasis on fuel uniformity and reliability.

Biodiesel can be produced from oilseed rape (known as 'canola' in north America), sunflowers, soybeans, coconut, maize, safflower, cottonseed, peanut, and palm. This section considers biodiesel produced from rape (80% of current global production, sunflower (13% of current global production), and soybean. Soybean currently accounts for only 1% of global production but is included in the scope of this report as it is believed by many experts to be a potentially important future source of the fuel, particularly in the USA.

The choice of which oilaginous crop to cultivate is dictated principally by local climatic and soil conditions, and by the availability of crop inputs (nutrients and water) since some species are more dependent than others on high input levels. **Oilseed rape**, latin name brassica napus, is grown as a winter or summer variety in temperate regions. Its main production areas are Canada, China, India, and North and West Europe. It grows best in humid conditions with a long growing season and deep soil, and is relatively cold tolerant, making it the most suitable oil producing crop for cultivation in the UK. Rape yields are more sensitive to nutrient and water inputs than either sunflower or soybean yields. This means that rape has poor drought tolerance and sees rapid reduction of yields with reduced nutrient inputs.

Over the last 15-20 years new high yielding hybrid varieties of rape have been developed. Many of these are known as 'double zero' varieties as they contain near-zero levels of erucic acid and glucocynolates, making their meal more suitable for animal feed (see below).

There are several advantages to growing rape, particularly –as is often the case - if it is grown in rotation with cereal crops: Rape cultivation provides an opportunity to break cereal pest and disease cycles; its deep roots aerate and improve soil structure, and it provides an opportunity to treat grass weeds as it is tolerant of many of the chemical control methods that cannot be applied during cereal cultivation.

Sunflower - *helianthus annuus* - originated in subtropical and temperate zones, but through selective breeding has been made highly adaptable, especially to warm temperate regions.

The crop was first developed as an important commercial oilseed crop in the Former Soviet Union and its oil has since found widespread acceptance as a high quality, edible oil throughout much of the world. Sunflower is now grown in many temperate, semi-dry regions of the world, often in rotation with small grain cereals such as wheat. Currently 84 percent of the world's production of both oilseed and non-oilseed sunflower comes from the FSU, Argentina, Eastern Europe, USA, China, France, and Spain.

The majority of sunflower cultivation is for oil, though it is also grown for confectionery seed and as an ornamental. Oil producing varieties tend to have 40-50% oil by seed mass, whereas in other varieties oil comprises <40% of total mass.

Sunflower is far more drought tolerant than rape, so is often grown in regions that are too arid for rape cultivation. Sunflower yield is also affected less by variations of other inputs, so the crop can be successful with less intensive management.

The first known record of **soybean** cultivation comes from China in 2838 B.C. Soybean cultivation spread from China to South East Asia, and then to Europe in 1712, and to the Americas in the early 19th century. In addition to providing oil, the crop provides a valuable source of protein for both human and livestock consumption. The USA is currently the world's largest producer of soybean, with the majority of yield producing protein rich meal for poultry, swine, beef and dairy cattle.

Soybeans produce a lower yield of oil per hectare and a lower energy gain than either rape or sunflower, but also produce more valuable by-products (see below).

Among the three species studied in this work, soybean is the least sensitive to crop inputs levels, allowing for the reduction of tillage, irrigation, and fertiliser applications, and weed control. This significantly decreases production costs, as well as energy consumption, and associated emissions.

Soybean has low cold tolerance, making it unsuitable for cultivation in the UK. Some experts believe, however, that the widespread future adoption of soybean cultivation in the UK is a realistic possibility. This could occur either as a result of global warming increasing mean temperatures, or if genetically modified cold tolerant varieties are developed. This is considered a short-to-

medium term possibility since cold tolerance is controlled by a single gene in most plants [ADAS].

Conversion Technologies

After harvest, oil is extracted by mechanically crushing the seeds/beans. These plant oils cannot be used unmodified in either reciprocating engines or jet engines since they would leave deposits of glycerine, which have the potential to block filters, injectors fuel lines etc. Instead they must be converted into methyl esters by treatment with methanol.

There are three main processes for converting oils to methyl esters:

- Base catalyst transesterification of the oil with methanol.
- Directed acid catalyzed esterification of the oil with methanol.
- Conversion of the oil to fatty acids, and then to methyl esters with acid catalysis.

Most methyl esters are produced with the base catalyst process, since this is the most economical of the three. During this process approximately ten parts plant oil are mixed with one part methanol (by mass), in the presence of a catalyst, which is usually sodium or potassium hydroxide. The ensuing reaction takes place at approximately 65°C and 1.4 bar and produces methyl esters and glycerine directly, with no intermediate steps.

The catalyst is usually caustic soda, and is dissolved in the methanol before the methanol and the oil are brought into contact with one another. The methanol/catalyst and the oil are then mixed for between one and 8 hours in the reactor, which is kept at a constant 65°C. The catalyst will preferentially react with any free fatty acids to form soap. If too many free fatty acids are present, or if any water is present, the soap forms emulsions with the methanol and oil, which can render the entire mixture useless. For this reason the incoming oil is first treated to remove fatty acids and care is taken with all inputs to ensure that no water enters the reactor.

The reaction produces a mixture of methyl esters and glycerine, and in most cases methanol since excess methanol is used to facilitate and speed up the reaction. Excess methanol is separated by distillation and re-used. The methyl esters and glycerine are then separated from each other relatively easily since their different densities mean they separate naturally if left to stand, allowing for the glycerine to be drawn off the bottom

Inputs

The source of the methanol used in the conversion of the plant oils to methyl esters is an important consideration. If, as is likely, this methanol is produced from natural gas, it will add considerably to biodiesel fuel cycle emissions, and have a negative effect on the fuel's overall energy balance.

The other main inputs are those added during crop cultivation. With respect to cost, energy consumption, and other environmental considerations, the most important crop inputs are nitrogen, phosphate, potash, and irrigation. The quantities of each that are required vary greatly, though indicative average figures are available. In general oilseed rape will require significantly higher levels of all three nutrients, particularly nitrogen, than either sunflower or soybean.

Additional energy inputs that must be considered are those that required for planting and harvesting of crops, transporting, drying and storing seeds, the methyl ester conversion process, and transporting the resulting biodiesel fuel.

By-products

Two important by-products result from the production of biodiesel: crop meals and glycerine.

Crop meal, also known as 'cake', is produced from the seeds/beans of all three crops after the plant oils have been extracted. The crop meals are important animal feeds and their values are important factors influencing biodiesel economics. This is particularly the case for soy meal, since soybean oil yields are lower than rape or sunflower, (due to the lower % of oil in soybeans), but the associated protein-rich soy meal is a particularly important and valuable animal feed. In fact, it is perhaps more accurate to consider soy meal as a co-product rather than a by-product of soybean biodiesel production.

Rape meal and sunflower meal, though not protein rich like soy meal, are also important constituents of livestock feeds.

Glycerine, which is produced during the conversion of plant oils to methyl esters, is generally sold for pharmaceutical purposes or as an animal feed.

An important consideration with respect to crop meal and glycerine by-products is their price elasticity of supply. This dictates how their values would be affected by the increased quantities of the by-products that would be available if biodiesel production were increased. It is possible that the market prices of these two products would greatly decrease in such a situation.

Other Key Factors

Research undertaken at the University of Idaho show that all the biodiesel fuels tested – including those produced from rape, soybeans and other feedstocks - are readily bio-degradable. [Zhang et al]. In addition, when mixed in equal quantities with Phillips 2-D reference diesel, the degradation rate of the mixed fuel increased by a factor of three relative to the 100% Phillips 2-D diesel, due to cometabolism [Zhang et al].

Biodiesel comprises a high proportion of unsaturated and polyunsaturated fatty acids, which makes it susceptible to degradation through oxidation, which in turn introduces the possibility of storage problems. Research indicates, however, that biodiesel added to kerosene up to a maximum of 10% by volume does not significantly increase the tendency for oxidation, and therefore does not compromise storage stability [Dunn].

Blends of up to 50% biodiesel: 50% kerosene have been found to meet water penetration fuel specification requirements [Dunn].

Biodiesel Quantitative Analysis – Parameters & Assumptions

This study has analysed the findings and conclusions of key references relating to biodiesel production in the UK. For most criteria ranges of values are given, showing low, high and best estimates. In some cases it has been possible to validate or re-assess previous studies' conclusions by reference to primary data.

This study assumes that biodiesel is produced from oilseed rape grown in the UK. After being harvested, rapeseeds are crushed and their oil is transported to a production plant for esterification. The resulting product, RME, is then distributed via road tanker. By-products and their value have been assessed and are discussed, though for reasons explained below they are not included in the overall cost, energy balance or GHG calculations.

Biodiesel produced from different feedstocks, under different climatic conditions, or under different management practices would be subject to different yields, agro-chemical input requirements, transport differences etc. Production costs, energy ratios and GHG ratios would, therefore, be different.

Feedstock Production

Oilseed rape cultivation is a well-proven commercial process, and as such most of the cost, energy and emissions estimates associated with RME feedstock production can be regarded with relatively high levels of confidence. The exception to this is estimations of N₂O emissions, which are discussed below.

In the future improvements may be seen to costs, GHG emissions, and energy ratios, as a result of new – possibly genetically modified – varieties of rape [ADAS]. However, any such improvements are likely to be moderate and incremental.

Feedstock Production Costs

The 'low' estimate for the cost of feedstock production was calculated from rape production costs of £892/ha (\$1427/ha) [ECOTEC, 99] and a rape seed yield of 3.6 t/ha. The energy density of the rape seed taken to be 25.4 GJ/tonne seed, derived from Groves 2002. The 'best' and 'high' estimates for feedstock production costs use the same estimates of £892/ha (\$1427/ha) and 3.6 t/ha, but use a lower figure of 23.8 GJ/tonne seed [LBST_GM, 2002]. The figure of £892/ha (\$1427/ha) was assumed to include harvesting but not transport costs.

For comparison, the market value of rape seed quoted in ECOTEC 99 was £130/t (\$208/t) seed, which equates to £468/ha (\$749/ha). Rape for energy crops grown on set-aside land currently also qualifies for a subsidy of £256/ha (\$410/ha), therefore resulting in a net loss to farmers for rape seed production of £168/ha (\$269/ha). This set-aside payment has not been included in the study's cost calculations.

Feedstock Production Energy Inputs & GHG Emissions

The principle energy requirement of rape feedstock production comes from the manufacture of nitrogen fertiliser that is applied to the crop. Nitrogen fertiliser is also the principle source of GHG emissions, which arise from CO₂ associated with energy consumption, and also N₂O emissions after fertiliser applications. The N₂O emissions are significant, accounting for approximately 25% of the total feedstock production GHG emissions. Nitrogen fixing crops grown in rotation with rape can help reduce the crop's nitrogen fertiliser requirements.

Energy is also consumed and GHGs emitted during the preparation of ground for planting, the harvesting of crops, and the transport of feedstock.

Values for energy inputs to feedstock production were derived from the range found in the literature. Mortimer (2002), which provides the most detailed review of UK specific energy requirements rape cultivation, is used for both the 'low' and the 'best' estimates. In total this study reviewed 25 estimates for feedstock energy requirements, and used the maximum value quoted in the literature for its 'high' value.

This study's 'low' estimate for feedstock production GHG emissions is based on ECOTEC (2001), and the 'best' and 'high' estimates are derived from Mortimer (2002).

Feedstock Transport

Feedstock Transport Costs

Feedstock transport costs have been derived by combining literature values for feedstock transport distance with the HGCA's estimate of transport cost being £0.055/tonne-km (\$0.088/tonne-km). The 'best' estimate for roundtrip feedstock transport distance between field and mill uses Mortimer (2002)'s figure of 260km (160mile). The 'low' estimate is based on Groves (2002), which states 190km (120mile) round trip distance.

Feedstock Transport Energy Inputs & GHG Emissions

The 'low' estimate is derived from ECOTEC (2001) and the 'best' and 'high' estimates are derived from Mortimer (2002).

Conversion Process

The conversion of rape seed to RME involves oil extraction (crushing), oil transport, and esterification. These processes are discussed in detail in section 4 of this report.

Conversion Process Costs

Only a single 'best estimate' figure is provided for conversion process costs because there is insufficient data in the literature to generate a range of values. This estimate has been derived by this study from separate estimates for the cost of each of the three conversion stages.

Data for the costs of oil extraction was found in only one study [www.folkecenter.dk], which was based on the costs for relatively small scale crushing systems. Oil transport distance from crushing plant to esterification plant was assumed to be 120km, and as before HGCA data showing transportations costs of £0.055/tonne-km (\$0.088/tonne-km) was assumed. Esterification costs were obtained from OECD/IEA, and related to large-scale plants.

Of these three stages of conversion, extraction costs account for approximately 8% of total delivered RME costs, oil transport approximately 1%, and esterification approximately 10%. It is reasonable to assume that extraction costs may in practice be slightly lower than quoted as the data used was for a relatively small scale system. Oil transport costs are extremely variable - and would be zero if crushing and esterification plants were co-located – but in any case have only a small effect on RME price.

Conversion Process Energy Inputs & GHG Emissions

Both heat and electricity are required in significant quantities to power the oil extraction and the esterification processes. In keeping with most previous studies, this study assumes electricity to be derived from the grid and heat from natural gas. However, some references are made to natural gas combined heat and power systems providing both energy requirements, and others discuss the potential to supply the heat from either rape straw or wood [LBST-GM, 2002]. Such developments would significantly reduce non-renewable energy inputs and associated GHG emissions, but are not considered in this report due to the lack of published data for either of these scenarios.

Comprehensive, disaggregated calculations of the energy requirements for the conversion of rape seed into RME were only found in a few references. The 'best' estimate is derived from Groves (2002) and uses Shell data, so is likely to represent current business practice. The 'high' estimate is derived from IEA/OECD (1994) and represents the energy requirements for RME production at the start of the last decade. The 'Low' estimate is taken from Mortimer (2002) and represents the state-of-the-art in RME production technologies available now, showing the improvements that have occurred over the last decade in energy efficiency. A significant difference between the 'best' and the 'low' estimates is that Groves estimates an 80 km round trip for transporting oil from the crushing unit to the esterification plant, whereas Mortimer assumes the crushing and esterification units to be co-located.

The 'best' and 'high' estimates for GHG emissions during the conversion stages are both derived from Mortimer (2002). The 'low' estimate is based on ECOTEC (2001). CO₂ and total GHG emissions for the conversion stage are very similar since there are no nitrogen fertiliser-based N₂O emissions.

Distribution

It is assumed that RME for use in aviation is transported an average of 100 km from esterification plant to airport, thereby requiring a round trip distance of 200km. This figure was agreed with the steering group, and is derived from doubling the literature values for the transport distance of diesel road fuel to filling stations. The estimate recognises that the transport distance is likely to be significantly greater for aviation fuel than road fuel because the majority of kerosene is supplied to a few major airports, whereas diesel is supplied to c. 12,000 well-dispersed filling stations.

Distribution Costs

Distribution cost estimates are based on the £0.055/tonne-km (\$0.088/tonne-km) costs for road transport [HGCA, 2002] and contribute approximately \$0.39 (£0.24) /GJ RME.

Distribution Energy Inputs & GHG Emissions

The 'high' estimate for energy consumption and GHG emissions assumes that the 200km round-trip distance discussed above is undertaken by diesel road tanker. A value of 0.00082GJ/(km t) has been used for the fossil energy input to transport, which is derived from truck fuel consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre, Bauen 2000. However, it should be noted that the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO₂ emissions from the transport stage.

The 'low' values assume pipeline transport with no value input for the one-off energy requirements and GHG emissions associated with the construction of pipelines.

Co-Products

Three main co-products - by-products - are produced during the production of RME: straw, glycerine, and rape meal.

Co-Products - Costs

RME costs shown in this report do not take account of by-product value because of the uncertainty over their future market prices. In particular, large scale RME production would increase the supply of the three co-products, which would be expected to lead to reductions in their prices. By-product values have, however, been calculated according to the following current market prices and production rates.

Straw: A production rate of 0.98-1.6 t-straw/t-raw rape seed was assumed (low estimate, Mortimer 2002; high estimate, Groves 2002), and an economic value of £25/t (\$40/t) straw [Groves, 2002].

Glycerine: A production rates of 100 kg/t vegetable oil or 31 - 45 kg glycerine / t seed depending on the oil extraction efficiency are assumed, and a value £388/t (\$621/t) crude glycerine [Mortimer, 2002]

Rape meal: A production rate of 580 to 630 kg/t seed and a value of £95.5/t (\$153/t) was assumed [HGCA, 2002].

The summary sheet shows three estimates for the value of co-products. These estimated values are shown in the RME summary sheet for interest, but as stated above, their effect is not included in the calculated cost of RME. The 'low' estimate shown in the summary sheets is based on the value of glycerine only, the 'best estimate' on glycerine and meal, and the 'high' estimate on glycerine, meal and straw.

Co-Products - Energy allocation

The allocation of energy inputs to co-products is controversial and can be undertaken in three different ways: i) In proportion to the energy content of the co-products; ii) In proportion to the energy required to produce the co-products' substitutes e.g. rapemeal for soyameal and iii) In proportion to the co-products' market values. In this study the overall RME energy ratio is calculated without allocating any energy to co-products. This is because of the lack of consensus as to whether and how this should be done. As such this study's calculated energy ratio could be viewed as a conservative estimate or a 'worst case scenario'.

For interest, however, estimates are shown for co-product energy content. The 'low' estimate is the energy content of straw only; the 'best' estimate is the energy content of the straw and meal; and the 'high' estimate is the energy content of straw, meal, and glycerine. The energy content of the co-products was assumed to be: straw -14.2 MJ/kg, 0.98 t-straw/t-seed; glycerine - 17 MJ/kg, 0.0332 t-glycerine/t-seed; and rape meal -18 MJ/kg, 0.627 t-meal/t-seed.

It is worth noting that the energy content of the potentially harvestable rape straw could theoretically cover the entire energy requirements of the conversion processes many times over. In addition, Mortimer 2002 notes that CO₂ recovery during ammonium nitrate fertiliser manufacture occurs and is subsequently used as an industrial gas valued at £0.21/kgCO₂ (\$0.34/kgCO₂) and an economic credit is applied, although this does not lead to a significant reduction in carbon requirement for fertiliser manufacture allocated to rape production.

Other Environmental Effects

Emissions of particulates, carbon monoxide and water are not evaluated here, although their health and environmental impacts may be extremely important. A more complete analysis of emissions including oxides of sulphur (SO_x), oxides of nitrogen (NO_x), particulates, volatile organic compounds (VOC), and carbon monoxide (CO) is provided in ECOTEC 99.

Biodiesel Quantitative Analysis - Results

Cost

This study concludes that the cost of producing RME would be between \$33.5/GJ and \$52.6/GJ (£20.9/GJ - £32.8/GJ). As discussed, this cost does not include any cross-subsidy from the value of by-products, as their value is uncertain and would probably decrease if large-scale RME production increased their supply.

More than 75% of RME costs are attributed to feedstock production costs. Feedstock costs at the farm gate are well known and relatively consistent since oilseed rape is common agricultural crop in the UK. The main difference in RME cost estimates comes from different assumptions about production rate of RME (GJ RME/GJ seed).

This study has derived only one 'best estimate' value for conversion cost. This is US9.82 (£6.14), which represents approximately 20-25% of total RME costs.

Feedstock distribution costs are low – in the region of 1% of total costs.

This calculated cost range for RME production of \$33.5/GJ - \$52.6/GJ (£20.9/GJ - £32.9/GJ) compares with a current price (i.e. including profit) for conventional kerosene of approximately \$4.6/GJ (£2.9/GJ) - derived from stated kerosene price of 11p/litre [PRESAV Steering Group, 2002] and energy content of 1m³ kerosene = 38.68GJ [Canada Energy Outlook, 2002].

Energy Ratio

The ratio of RME output energy produced per unit of non-renewable energy input is 0.7 –3.2 GJ RME /GJ input.

Most of this variation comes stems from differences in estimated energy inputs to feedstock production. In practice the energy ratio range is likely to be considerably smaller than that quoted above, since the extremities of the range were derived by combining low feedstock energy inputs with high feedstock yields, and vice versa. The authors estimate that the energy ratio is likely to be approximately 2.0 GJ RME / GJ input.

GHG Balance

GHG emissions are generally calculated using IPCC (1996) guidelines and are based on emission factors from fertiliser use and 100 year global warming potentials.

The model shows that between 17.0-44.3 kgCO₂ eq/GJ FT RME are produced. The higher figure of 44.3 kgCO₂ eq/GJ FT RME is believed to be more accurate, and is also the study's best estimate for GHG emissions.

The low figure quoted above is greatly influenced by ECOTEC 99's anomalously low estimate for GHG emissions from energy input to the conversion process. This estimate (1.7 kgCO₂ eq/GJ FT RME) is an order of magnitude lower than most equivalent estimates.

With regard to feedstock production, CO₂ emissions can be stated with relatively high confidence, but the confidence level for estimates of total GHG emissions is reduced by uncertainties over nitrous oxide (N₂O). N₂O emissions arise primarily from complex reactions between synthetic nitrogen fertilisers, soils, and organic matter, and are also heavily influenced by climatic conditions. A high degree of uncertainty exists over actual emissions levels.

Production Potential

Annual UK RME production is estimated at 51 – 123 PJ, with a best estimate of 77 PJ. This figure is calculated assuming that 200,000ha of the UK's 600,000ha of arable land [DEFRA, 2002] are available for RME production, and that yields are between 25.6 GJ/ha – 61.6 GJ/ha, with a best estimate of 38.5 GJ/ha [Mortimer 2002].

Global Biomass Fischer-Tropsch Fuel Chains

Fischer-Tropsch conversion involves the synthesis of hydrocarbons from CO and H₂ over iron or cobalt catalysts. The CO and H₂ feed gas can be produced from a variety of biomass sources, or from other carbon containing feedstocks such as natural gas or coal.

The fuel chains being considered for the production of FT kerosene consist of biomass drying, biomass gasification, gas clean-up, gas compression, the actual FT synthesis, hydrocracking and gaseous hydrocarbon recovery.

Feedstocks

The principal biomass feedstocks for FT fuel production are woody perennials, forestry residues, and herbaceous species such as miscanthus, grass, reed canary grass and switchgrass

Woody perennial yields are heavily dependent upon the latitude in which they are grown, so calculations of energy balance and economics of production vary and must be case-specific.

After harvesting, biomass FT feedstock is first dried and sized if necessary. Indirect drying using heat from the FT reactor is usually used, and typically reduces the moisture content of the biomass from 50 wt% to 20 wt% moisture.

Gasifiers

Gasifiers convert biomass into 'syngas' by heating it to above 700°C in an oxygen poor environment. This principally comprises H₂ and CO, the feed gases required for FT synthesis.

The syngas is cooled and quenched with a water spray to remove particulates, and cleaned up to remove sulphur compounds. The methane and other light hydrocarbons that are present in the syngas are then converted to CO and H₂ by steam reforming, and the gas is compressed using an adiabatic compressor.

There are several different designs of gasifiers, with the principal differences being whether they are pressurised or atmospheric; fed with air or with oxygen; and direct or indirectly heated. There are advantages and disadvantages of each option:

Pressurised or Atmospheric

Pressurised gasifier systems are well suited to the co-generation of electricity. This is because the output gases from an FT reactor fed by a pressurised gasifier are also pressurised, and are therefore suitable to supply a gas

turbine. In contrast, the off-gases from an FT reactor fed by an atmospheric gasifier, must be compressed, which requires considerable energy. Pressurised gasifier systems also require smaller downstream equipment, which is less expensive.

Atmospheric gasifiers generate less co-produced electricity and require larger downstream equipment than pressurised gasifier systems, but benefit from more commercial experience.

Air Fed or Oxygen Fed

Air fed plants are cheaper and simpler than O₂ fed plants, since no air/oxygen separation plant is required. However, they suffer from nitrogen-diluted syngas, which reduces the proportion of C₅+ hydrocarbons produced as the final product, and they also require larger downstream equipment. Oxygen fed gasifiers are more complex and expensive, but avoid these problems of nitrogen dilution and larger downstream equipment.

Direct or Indirectly Heated

Directly heated gasifiers operate by partially oxidising their biomass. They produce less tar, therefore addressing one of the major problems associated with biomass gasification. Indirectly heated gasifiers require a heat exchanger and produce more tars, but have the advantage that they do not suffer from nitrogen dilution, even with air fed gasifiers. This study has not considered directly heated gasifiers in detail.

Syngas Cleaning

Although predominantly CO and H₂, syngas also contains many other products, notably particulates, condensable tars, alkali compounds, H₂S, HCl, and NH₃. These potential contaminants need to be removed to prevent poisoning of the iron or cobalt catalysts that are key to Fischer-Tropsch synthesis. At present this cleaning involves tar cracking, cyclone separation, filtering, hydrolisation and scrubbing.

Some uncertainty remains over this gas cleaning stage, because most FT operational experience has been gained using natural gas, which produces a less contaminated syngas than that produced from biomass. This is the principal reason that this report considers biomass derived FT kerosene to be at the demonstration rather than mature stage.

FT Reactor

The next stage is the actual FT reaction, in which CO and H₂ enter the FT synthesis reactor and combine exothermically in the presence of a catalyst under moderate pressure and temperature conditions (approximately 240°C). This produces a mixture of straight-chain gaseous and liquid hydrocarbons, namely paraffins (C_nH_{2n+2}) and olefins (C_nH_{2n}), ranging from methane to high

molecular weight waxes. The total single -pass H₂+CO conversion rate is approximately 80%.

FT reactors can be designed to maximise their production of hydrocarbon liquids, or to co-produce electricity. To maximise HC liquid production a feedback loop is included in the reactor. This returns the lighter gaseous hydrocarbons (some of which are always produced) back to the FT reactor input, from which they go through the FT reactor again. If electricity is to be co-produced these lighter hydrocarbon off-gases are instead used to power a turbine. These gases will often be mixed with natural gas in order to increase their overall higher heating value, and will usually feed a combined cycle gas turbine.

CO₂ Removal

After leaving the FT reactor CO₂ may be removed by chemical absorption. This prevents it from building up in recycle loops, reduces the required downstream equipment sizes, and avoids possible solidification problems during cryogenic hydrocarbon recovery. After CO₂ removal, unconverted gas is either fed back to the F-T reactor to increase overall conversion rate, or in the case of the 'once-through' reactor is used to feed a gas turbine (usually operating in combined cycle mode) to generate electricity. The Fischer-Tropsch liquid hydrocarbons produced generally comprise kerosene, naphta and diesel. The relative proportions of these three fuels can be varied within certain boundaries, with the proportion of kerosene comprising between 25 and 50%.

Inputs

In addition to biomass, there are three principle inputs required for the production of biomass FT fuels:

1. Cobalt and/or iron are used to catalyse the main FT reaction. Although neither of these metals are expensive commodities, and recent developments in liquid phase synthesis promise to halve the quantity of catalysts required, the effects of catalyst use on both the economics and the energy balance analyses of FT fuel production must be considered.
2. Electricity is required to heat the gasifier and the FT reactor, and to power compressors. The gasifier operates at a higher temperature than the FT reactor and accounts for the majority of the system's electrical demand. [Faaij et al]. However, most FT configurations co-produce electricity – see below – so have no net electrical demand.
3. Oxygen-blown gasification avoids nitrogen dilution, ensures high calorific value output gases, and thus reduces the downstream vessel and piping costs. These savings, however, have to be offset against the cost of oxygen.

By-products

FT reactors produce diesel and naphtha as well as kerosene. The proportions of these three liquid hydrocarbons can be varied to an extent, but producing more than approximately 50% kerosene reduces overall plant efficiency. The relative proportions of different hydrocarbons produced by the F-T process are determined primarily by feed gas composition, catalyst type and loading, reaction temperature, pressure, and residence time.

The highest proportion of kerosene that can be produced is approximately 50%, in which case the remaining output is diesel (25%) and naphtha (25%).

Other Key Factors

Gasification and gas cleaning equipment is still at the pre-commercial stage. Reforming, shift reaction and PSA equipment is commercially available at large scale and is widely used for industrial H₂ production, mainly from natural gas. Commercial developments are underway to scale down the equipment and develop its use for a variety of gaseous feedstocks.

Fischer-Tropsch kerosene is comprised principally of paraffins and olefins. It is sulphur free and has a very low aromatic content (aromatics in Jet A-1 are limited to maximum 25%wt) [Defence Procurement Agency, 2002].

The process for converting biomass into F-T liquids is similar to that used by SASOL to convert coal into kerosene. The main differences with biomass FT are that lower gasification temperatures can be used as biomass is more reactive; a reformer is required to maximise efficiency since biomass gasifiers almost always produce some light hydrocarbons in addition to H₂ and CO.

In recent years much of the drive for FT plant development has stemmed from the desire to convert into liquid fuels the relatively small supplies of natural gas that are often flared off during oil extraction. This has encouraged the development of small-scale FT plants, which are also well suited for biomass FT plants.

Biomass Fischer-Tropsch plants can be configured in many different ways depending principally upon gasifier type, method of syngas cleaning, whether electricity is to be co-generated, and what liquid hydrocarbon outputs are required as the final output.

Fisher Tropsch Quantitative Analysis – Parameters & Assumptions

General Description

This quantitative analysis undertaken by this study assumes that wood chips derived from willow grown under short-rotation coppice (SRC) in the UK are the feedstock for the production of Fischer-Tropsch fuels. This is the feedstock for which most research has been undertaken and experience gained in the UK. Recent research into the cultivation of herbaceous energy crops in the UK also shows promising results, however, so these crops are discussed at the end of this section.

The technologies considered could also be fed by most types of dried ligno-cellulosic biomass, and could therefore operate in most countries, but several parameters such as feedstock yields, agrochemical input requirements, and transport costs are specific to SRC grown in the UK.

This study models two different gasifiers: one, manufactured by TPS, is air blown, operates at atmospheric pressure, and is directly heated. This represents a relatively well tested and proven current technology, since similar TPS biomass gasifiers already operate at the ARBRE plant, in Sweden, and elsewhere. The other, manufactured by IGT, is oxygen blown, pressurised, and is also directly heated. This represents a potentially more economical future technology, but lacks operational experience.

The IGT system produces slightly less FT liquid hydrocarbon fuel than the TPS system, but produces considerably more electricity. This is because the atmospheric TPS system consumes more electricity for off-gas compression than the pressurised IGT system.

Both designs were modelled for a size of 367MW_{th}, which is a realistic medium-large scale, and is the size for which the most operational data is available. Both system configurations co-produce electricity, and use some of this electricity to provide all of the energy required at each stage of the conversion processes.

The value of FT kerosene, diesel and naphtha are assumed to be the same, so the relative proportion of these liquid fuels produced does not, therefore, affect the overall economics of production. 50% kerosene production was assumed for calculations of production potential.

Feedstock Production and Transport

Feedstock (SRC) costs vary depending on location, yield and management practices. A range of \$2/GJ to \$4/GJ (£1.25/GJ - £2.50/GJ) has been used, which equates to approximately \$25 to \$50 (£15.6 - £31.3) per tonne. This range reflects costs commonly cited in the literature for biomass production in

the UK. Biomass transport cost is based on transport by truck of 60m³ capacity at a cost of \$0.0059/km GJ (£0.0037/ km GJ). A 100km return transport distance is assumed, which contributes \$0.59/GJ (£0.37/GJ) to the above cost of feedstock.

Only direct non-renewable energy inputs to biomass feedstock production and transport are considered. These non-renewable energy inputs and associated GHG emissions arise principally from chemical fertiliser inputs, preparation of ground for planting, and the harvesting of crops, as well as from feedstock transport. Non-renewable energy inputs associated with the establishment of the conversion plant are not considered. These one-off energy requirements have been estimated to be of the same order of magnitude as the energy required annually for feedstock inputs [Bauen, 2000].

Distribution

It is assumed that FT kerosene is transported an average of 100 km from FT plant to airport, thereby requiring a round trip distance of 200km. This figure was agreed with the steering group, and is derived from doubling the literature values for the transport distance of diesel road fuel from FT plant to filling station. The estimate recognises that the transport distance is likely to be significantly greater for aviation kerosene than for road diesel because the majority of kerosene in the UK is supplied to a few major airports, whereas diesel is supplied to approximately 12,000 well-dispersed filling stations.

The 'high' estimate for energy consumption and GHG emissions assumes that the 200km round-trip distance discussed above is undertaken by diesel road tanker. A value of 0.00082 GJ/km t has been used for the fossil energy input to transport, which is derived from truck fuel consumption of 0.03litre/ km t and diesel energy content of 36.4MJ/litre [Bauen, 2000]. However, it should be noted that the use of a renewable transport fuel would result in zero non-renewable input to transport and zero GHG emissions from the transport stage

The 'low' values assume pipeline transport with no value input for the one-off energy requirements and GHG emissions associated with the construction of pipelines.

Both the high and the low cost estimates are based on the £0.055 per tonne-km costs for road transport, [HGCA, 2002]. It should be noted that the costs of distribution by road are small, accounting for only \$0.39/GJ (£0.24/GJ), so the effect of moving to pipeline cost estimates will not be great.

Other Environmental Effects

No particular environmental problems are envisaged with the production of biomass derived FT kerosene, unless ligno-cellulosic FT feedstock plantations replace ecologically important land use, for e.g. native forests.

Nitrogen fertiliser is only applied to SRC approximately once every four years, and for well-managed forests does not lead to significant N₂O emissions or nitrate leaching to water. Ligno cellulosic feedstocks grown elsewhere in the world would vary, but are also unlikely to lead to significant N₂O emissions or nitrate leaching.

Potential Alternative UK Feedstocks

Miscanthus, and reed canary grass are herbaceous perennials currently being evaluated as potential energy sources in the UK [ETST, 1999a & 1999b]. These crops are not included in this report's quantitative analysis, but are discussed here due to their potential future role in the UK.

Miscanthus (Miscanthus x giganteus and Miscanthus sacchariflorus)

Miscanthus has been one of the most extensively studied potential energy crops. In the UK, the former MAFF funded a large number of studies to determine its feasibility as an energy crop under UK conditions. Considerable knowledge has therefore been gained, which has taken this crop from an experimental concept to the verge of commercial exploitation [MAFF, 2000; MAFF/DEFRA, 2000; Christian & Riche, 2001].

Crop development depends on temperature being above 6°C, and the crop can easily attain a height of over 2.5m. As an energy crop, Miscanthus differs from SRC in that it is an annual crop. A further advantage is that all aspects of its propagation, maintenance and harvest can use existing agricultural machinery. Long-term annual yields average at the most productive sites have been over 18 t/ha with few agrochemical inputs.

Two main pests have been identified that could potentially cause serious economic damage to the plants: the larvae of the common rustic moth which is capable of killing newly emerged shoots, and the ghost moth's larvae which feed on rhizomes. However, so far no significant yield losses have been reported in any of the established sites, according to MAFF data.

Reed canary-grass (Phalaris arundinacea).

Reed canary grass (a C3 grass) has similar characteristics to switchgrass, and is widely distributed in the UK. It is well adapted to cool and wet conditions, but has no commercial use in this country yet. Yields are comparable to SRC, with energy characteristics similar to straw and thus it can be used as fuel in modern combustion plants. However, only limited research has been carried out so far, and it is possible fuel use should only be considered in the long term.

The main advantages of reed canary-grass is its high potential yields, similar caloric values per unit weight to wood, and its non-requirement of any specialised machinery [Bullard & Metcalfe, 2001].

Fischer-Tropsch Quantitative Analysis - Results

Cost

The model shows that the cost of producing Fisher Tropsch kerosene from SRC would be between \$21.8/GJ and \$36.5/GJ (£13.6 - £22.8/GJ) for the TPS gasifier system, and between \$5.8/GJ and \$31.7/GJ (£3.6 - £19.8/GJ) for the IGT gasifier system. The low cost estimate assumes low costs for feedstock production, conversion and distribution, and a high price received for by-produced electricity. Conversely the high cost estimate assumes high costs for feedstock production, conversion and distribution, and a low price received for by-produced electricity.

Literature values specific to each system configuration were taken for FT plant capital and operational costs, [Tijmensen et al]. Given that FT from biomass is currently only at the demonstration stage, it is likely that these costs could fall significantly if the technology was widely adopted.

The model takes account of co-produced electricity providing a revenue stream, and thereby reducing the cost of the FT liquid fuels. The low estimate for the revenue from this electricity assumes it is sold for \$0.03/kWh (£0.019/kWh), which was considered to be a likely near-future market price. The high estimate assumes \$0.09/kWh (£0.056/kWh), which was considered to be a likely near-future market price including a green subsidy.

This price of electricity is a major factor determining the cost of the FT liquid fuels: For the IGT system approximately two-thirds of the variation in calculated FT kerosene price is attributable to variations in the price paid for by-produced electricity. Electricity price - including whether subsidies are paid for electricity generated from biomass - will therefore be a key factor in determining the viability of FT fuels production.

As discussed, SRC feedstock costs have been assumed to range from \$2 - \$4/GJ (£1.25 - £2.5/GJ). This is a relatively large cost range and is indicative of the industry being in the early stages of commercialisation. This feedstock cost variation has a significant effect on the cost of FT kerosene, accounting for between \$7/GJ and \$9/GJ (£4.38 - £5.63/GJ) of the calculated cost range for FT kerosene.

Distribution costs are low – approximately \$0.40/GJ (£0.25/GJ) kerosene.

This calculated cost range for FT kerosene production of \$13.5 –\$37.0/GJ (£8.44 - £23.1/GJ) compares with a current price (i.e. including profit) for conventional kerosene of approximately \$4.6/GJ (£2.88/GJ, figures derived from stated kerosene price of 11p/litre [PRESAV Steering Group, 2002] and energy content of 1m³ kerosene = 38.68GJ [Canada Energy Outlook, 2002]

Energy Ratio

The ratio of biofuel energy produced per unit of non-renewable energy input is 13.9-44.6 GJ biofuel /GJ input for the TPS gasifier system, and 17.2–53.5 GJ biofuel /GJ input for the IGT gasifier system.

These figures are based on a proportion of the input energy being allocated to the co-produced electricity pro-rata according to the energy content of the electricity and of the liquid hydrocarbon fuels.

The range in the energy ratio comes from variations in energy input requirements for feedstock production and feedstock transport, which jointly account for more than 80% of input energy requirements.

The FT plant (including gasifier) has no net electrical demand since the values used in the model for electrical output are net of the plant's own electrical demand.

Kerosene distribution by road tanker is shown to account for approximately 10% of input energy requirement. However, this figure could vary for several reasons: The assumed round-trip distance of 200km could vary widely; road tankers could be fuelled with FT diesel produced by the plant itself, therefore reducing non-renewable energy required for distribution to zero; kerosene could be transported by pipeline.

GHG Balance

The model shows that for the TPS gasifier system between 3.2-11.3 kgCO₂ eq/GJ FT kerosene are produced, and for the IGT gasifier system 2.62-8.87 kgCO₂ eq/GJ FT kerosene are produced.

These figures do not include CO₂ emitted when the fuel itself is combusted, since this CO₂ would have been captured during the biomass growth phase.

These figures are based on a proportion of the GHG emissions being allocated to the co-produced electricity pro rata according to the energy content of the electricity and of the liquid hydrocarbon fuels.

As with the discussion of energy ratio above, most GHG emissions are attributable to feedstock production and transport; the conversion processes use electricity produced by the FT reactor and therefore produce no net GHGs; kerosene distribution GHG emissions can only be stated with low confidence, but only account for approximately 10% of GHGs.

Production Potential

The model shows that for the TPS gasifier system the UK's annual production potential for SRC derived FT kerosene is 51 PJ, and that world production potential is 22,800PJ. For the IGT gasifier system the figures are UK potential

of 44PJ and world potential of 19,400 PJ. As previously discussed, these figures are likely to increase if herbaceous crops such as miscanthus, reed canary grass and switchgrass prove viable and supplement SRC.

The calculations assume that 50% of the FT liquid hydrocarbon fuels produced will be kerosene, as this is approximately the highest proportion of kerosene that can be produced before the overall efficiency of the FT process is reduced. It should be noted, therefore, that an equal quantity of other liquid hydrocarbon fuels would also be produced.

The UK production potential calculation assumes that 200,000ha of the UK's 600,000ha of arable land [DEFRA, 2002] is available for FT liquid fuels production, and that SRC yields are 10 oven dried tonnes (ODT) /ha.

The worldwide FT kerosene production potential calculation is derived from existing estimates that global biomass energy potential is 160,000 PJ, and assumptions that would be used entirely to produce FT liquid fuels.

The UK kerosene production potential estimates of 44-51PJ compare with current UK kerosene consumption of 406PJ, and the worldwide production potential estimates 19,400PJ to 22,800 compare with worldwide kerosene consumption of 9,158PJ. Put in context the UK could potentially produce approximately 10% of its kerosene needs from renewable FT production, whilst globally bio-kerosene production could adequately accommodate double the current rate of consumption.

Hydrogen Fuel Chains

The potential for producing H₂ from renewable resources is very large and for this reason is considered by many to represent the most important long-term renewable aviation fuel. One of its main attractions is that it can be derived in many different ways, and from many different resources.

Three broad categories of H₂ fuel chains are considered here:

Hydrogen from Electrolysis using Renewably Generated Electricity

The renewable electricity generation technologies that are most important today or that are likely to become so in the short to medium term are onshore and offshore wind, wave, tidal energy, small scale hydro, and the conversion of biomass to electricity. (NB this use of biomass to generate electricity is not to be confused with the reforming of biomass gases covered in section 3).

Onshore and offshore wind generation are the technologies that are considered to have the greatest potential contribution to renewable electricity generation in the UK by 2020 [PIU, 2001h]. Both are technologically mature, their most significant constraint at present being obtaining planning consent. Onshore generation site output of 30 MW_e per farm is current practice, and offshore wind farms are expected to have capacities of up to 80MW_e.

In addition to wind power, wave, tidal, small-scale hydro, and biomass electricity production are also being considered. Large hydroelectric schemes have not been considered in this section as there is little potential for future development in most countries due to geographical and environmental constraints [ETSU, 1998].

Electricity generated is used either to produce H₂ directly at the generation site, or is exported to the grid to provide power for electrolysis elsewhere. Use of the electricity for electrolysis at the site of electricity production could reduce the need for grid extension and reinforcement for new renewable sites, although issues associated with the transport of the H₂ need to be considered. Electrolysis could also increase the financial viability of the renewable generator, as it offers a 'sink' for the electricity generated irrespective of electricity market conditions (ie power can be used for H₂ production at times of low price off-peak). Intermittency of generation is a less serious technical constraint for H₂ production than for grid export.

Onshore wind electricity

Onshore wind power is an established technology, with a world-wide capacity of over 20 GW [PIU, 2001h]. Total UK wind generating capacity is 473.6 MW, giving an annual electricity production of 1.24 TWh [BWEA, 2001].

As the market has grown, there has been a trend towards increased turbine size and decreased capital costs. There is volume production in the EU of turbines in the 600 kW range, but megawatt scale machines in several designs are also commercially available [EWEA, 1999]. Continued improvement in turbine power rating, reliability and lifetime is expected [ETSU, 1998].

Offshore wind electricity

Offshore wind generation has been in operation in Denmark since 1991, and there are currently 8 offshore projects world-wide, one sited at Blyth in the UK. The total installed capacity is 80.4 MW [OWF, 2002]. Offshore turbine technology is a development of onshore technology, and therefore benefits from experience in this area. 'Marinised' versions of onshore turbine technology are currently used, which have been modified to allow for the more corrosive marine environment and increased wind and wave loading. As many onshore turbines are designed for operation in a coastal atmosphere, the turbines themselves are generally able to withstand the saline nautical conditions associated with offshore operation with little or no modification. [EWEA, 1999]. However, the turbine tower must be strengthened to allow for greater wind and wave loading, and there are more stringent requirements for reliability since accessing the turbines for maintenance is a more costly process. Monopile foundation structures and undersea cabling for grid connection are mature technologies, although there is scope for continued improvement in foundation design with respect to interactions between loadings [PIU, 2001h].

In the future, improvements in offshore technology are likely as specific offshore designs are adopted. These are expected to be larger, designed for operation at greater tip speeds (and so greater efficiency) and designed for greater reliability and lower maintenance needs. There is also scope for weight and cost reductions as the turbines may be able to exceed onshore noise restrictions [EWEA, 1999]. However, there will also be greater technical challenges resulting from the move to deeper waters and less suitable sites after the most favourable sites are developed.

Wave, Tidal and Hydro

Wave and tidal stream energy technologies are still at the pilot stage [ETSU, 2001], and are expected to have little installed capacity by 2010 [Oxera, 2002], however they should be considered because of their large potential contribution to electricity generation [ETSU, 1998]. Prototype devices currently installed have capacities under 2 MW, but are expected to be used commercially in clusters of many devices.

Small hydro schemes are considered to have future potential applications in many countries, including the UK where the capacity exists for between 40MW and 110 MW, [ETSU, 1998]. However, many sites are not considered

to be economically feasible for electricity generation due to lack of grid connection. Direct H₂ generation would remove the grid connection problem, but would require H₂ collection and transportation from dispersed, relatively small scale sites.

Biomass (electrolytic hydrogen production using biomass electricity)

The final source of energy that is being considered in this study for electricity production is biomass. A wide range of biomass energy crops such as woody perennials, forestry residues, miscanthus grass landfill gases and municipal solid wastes (MSW) could all be used to power thermal power stations, and thus to provide a route to H₂ production via electrolysis. [PIU, 2002]. Many such biomass combustion systems are already in commercial use around the world, using a variety of technologies. In the case of biomass, direct H₂ production via gasification provides a more efficient route to H₂ production.

Hydrogen from Electrolysis using Nuclear Generated Electricity

Hydrogen could also be produced by electrolysis using nuclear generated electricity. The availability of nuclear generating capacity for this purpose will be heavily dependent upon political decisions taken by individual countries about the acceptability of nuclear power, as well as their operating characteristics.

Hydrogen from On-site Reforming of Biomass Gases from Gasification.

Hydrogen from biomass gasification.

The process described below is the same as the first stage of the biomass Fischer-Tropsch process.

The biomass feedstock is first dried and sized if necessary. The feedstock is then gasified to form syngas, by being heated to above 700°C in an oxygen poor environment. The syngas is composed of CO, H₂, CO₂ and H₂O, and in some cases methane and small quantities of other hydrocarbons. The syngas is then cooled and quenched with a water spray to remove particulates, and cleaned up to remove sulphur compounds. If significant quantities of hydrocarbons are present in the syngas, these must be converted to CO and H₂ by steam reforming. To produce H₂, the gases must then undergo several shift reactions. This usually involves two shift reactors in series, the first at 450°C and the second at 230°C to react the CO with H₂O to form H₂. Hydrogen is then recovered from the gas stream by pressure swing adsorption (PSA). PSA uses selectively adsorbing porous material, which adsorbs at high pressure and desorbs at low pressure, to first adsorb all CO₂ and H₂O, then to desorb all the gases except H₂. Ninety-seven percent of the H₂ passing through the PSA is recovered, and has greater than 99.999% purity. The H₂ can then be liquefied or compressed for transport.

Gasification and gas cleaning equipment is still at the early commercial stage. Reforming, shift reaction and PSA equipment is commercially available at large scale and is widely used for industrial H₂ production, mainly from natural gas. Commercial developments are underway to scale down the equipment and for its use with a variety of gaseous feedstocks.

Hydrogen from biomass pyrolysis.

Pyrolysis technology is at the research, development and demonstration stage. Like gasification, it is a high temperature reaction taking place in an oxygen poor environment. Biomass pyrolysis takes place in a lower oxygen environment compared to gasification and produces a mix of solid, liquid and gaseous products. The mix depends largely on the level of oxygen input to the process. The liquid fuel produced can be transported and stored and allows for de-coupling of the fuel production and energy conversion stages. Liquid fuels from pyrolysis could be reformed to H₂ at the forecourt. Small-scale reforming systems are in the advanced development stage and are not yet commercially available [Wolff, 2001].

Stationary Hydrogen Storage

It will be necessary to store H₂ at various stages of the fuel chains, including at the H₂ production sites and at airports in preparation for aircraft refuelling.

The principal storage options for H₂ are as a compressed gas, as cryogenic liquid H₂, or in large underground caverns. Underground storage is suitable for very large gas volumes, and is carried out commercially at several sites, including at Teesside in the UK [Ogden, 1999]. Compressed H₂ can be stored above ground in pressure vessels at a range of sizes and pressures. Equipment for compression is similar to that used for natural gas, and all equipment for compressed H₂ storage is in commercial use. Liquid H₂ technology is used for some long-distance transport, but there is little widespread experience with large scale storage [Amos, 1998; Ogden, 1999].

Hydrogen Transport and Distribution

Hydrogen can be transported as a compressed gas, either in dedicated pipelines or by container or as liquefied H₂, by tanker. Hydrogen pipelines are used successfully both in the US and EU, with lengths of 8-200 km [Ogden, 1999]. This may also be a viable option for transporting large volumes of H₂ for relatively short distances, or when a stable market is established [Mercuri, 2002; Ogden, 1999]. Transport of both compressed and liquid H₂ by road is currently used in industry, with liquid H₂ being favoured for long distances, due to a lower transport cost per unit of energy [Berry, 1996]. However, compressed gas road transport can be viable for short distances, or where the high capital cost of liquefaction plant is prohibitive.

Hydrogen from Electrolysis Quantitative Analysis – Parameters & Assumptions

General Description

The electrolysis-based H₂ fuel chain selected for more detailed analysis consists of large-scale water electrolysis powered by offshore wind electricity. The electricity generated by offshore wind installations is transmitted through the electricity transmission and distribution network to a large-scale electrolyser of a H₂ production capacity of 10 tonnes per hour. The H₂ is then assumed to be transported to the airport as a liquid by road tanker. An alternative option could be to transport the H₂ in gaseous form by pipeline to the airport and liquefy it on-site. Also, given the large quantities of fuel required by major airports, an interesting option would be to produce the H₂ on-site. All technologies considered in this fuel chain are commercial, but with potential for cost reduction.

Offshore Electricity Production

Current offshore wind electricity costs are estimated to be 8-8.8 \$cents/kWh (5-5.5 p/kWh), based on an installed wind turbine capital cost of about \$1600/kW, and these are estimated to decline with time to about 3.2-4.8 \$cents/kWh (2-3 p/kWh), based on an installed wind turbine capital cost of about \$640/kW. It is assumed that the figures include electricity transport and distribution costs.

No energy inputs are required for the operation of the offshore wind installations, apart from some energy used for periodic maintenance purposes. The direct energy inputs to the systems are very small over the lifetime of the installation, especially compared to the wind electricity output. Some emissions will be associated with the production of the materials and equipment used for the installation and with the building of the installation. However, the indirect emissions are also likely to be of little significance over the lifetime of the installation. Similarly, wind electricity generation does not result in any direct emissions of polluting agents, apart from emissions from occasional maintenance procedures. Some emissions will be associated with the production of the materials and equipment used for the installation and with the building of the installation. However, the indirect emissions are also not considered to be significant over the lifetime of the installation.

Electrolysis

The electricity requirement of the electrolysis plant is estimated to range between 3.8 and 4.5kWh/Nm³ (42 – 50kWh/kg), corresponding to a 67% to 79% efficiency. The power requirement of a 10t/h electrolyser is then between 423 and 498MW at full load. The current capital cost of an

electrolyser of the capacity considered is estimated to be \$600/kW(H₂) (£375/kW(H₂) or \$1800/Nm³/h (£1125/Nm³/h) and costs are estimated to decline in the future to about \$240/kW(H₂) (£150/kW(H₂) or \$720/Nm³/h (£450/Nm³/h). O&M costs are estimated at 2-3% of annualised capital cost. Based on a 20-year plant lifetime and 10% discount rate, the contribution of electrolysis equipment and operation and maintenance (O&M) costs (excluding electricity) to the production cost of H₂ is between \$0.96/GJ (£0.60/GJ) and \$2.40/GJ (£1.5/GJ). Based on the overall efficiency of the plant, the contribution of the electricity input to the electrolysis plant is between \$11.28/GJ (£7.05/GJ) and \$36.72/GJ (£22.95/GJ). The total H₂ production cost prior to liquefaction, on-site storage and delivery ranges then between \$12.24/GJ (£7.65/GJ) and \$40.74/GJ (£25.46/GJ).

Liquefying H₂ requires an 80MW power input for the plant considered, based on an electricity requirement for liquefaction estimated at about 0.73kWh/Nm³ (8.0kWh/kg). Following liquefaction, the overall efficiency of the electrolysis plant is between 57% and 71%, resulting in a power input requirement between 470 and 586MW at full load. On-site H₂ storage is set at 10t, and no losses are considered from storage. Liquefaction equipment capital cost at the scale considered is estimated at £295/kW(H₂) (\$472/kW(H₂)). On-site H₂ storage equipment capital cost is estimated at £57/kg (\$91.2/kg). Liquefying and storing the H₂ would contribute an additional \$1.41/GJ (£0.88/GJ) to \$1.76/GJ (£1.10/GJ) to the cost of H₂.

The only significant energy input to the operation of the electrolysis plant consists of wind electricity, hence it is assumed that no direct non-renewable energy input or emissions of pollutants result from the electrolysis plant.

Hydrogen Distribution

To avoid costs, energy inputs and emissions associated with H₂ distribution, the electrolyser plant should ideally be situated at the airport site. However, H₂ could also be transported to the airport as a liquid by road tanker. Liquid H₂ transport by road tanker over a distance of 200km (return) would contribute between \$6.50/GJ (£4.06/GJ) and \$7.0/GJ (£4.38/GJ). Compressed (10-30bar) H₂ transport by pipeline over a distance of 100km would contribute between \$1.17/GJ (£0.73/GJ) and \$1.44/GJ (£0.90/GJ).

If the H₂ production plant is sited at the airport, some local distribution may be envisaged by pipeline and it is assumed that there are no significant direct energy inputs or emissions of pollutants. The distribution of H₂ to the airport as liquid H₂ by road tanker would require an energy input of 0.13GJ/GJ(H₂). However, it must be noted that in the future the vehicles could be fuelled by renewable H₂ instead of mineral diesel. In the case of mineral diesel, liquid H₂ transport would result in 0.37kgCO₂eq. Pipeline transport would not require any significant additional energy input since the H₂ output pressure of the electrolyser should be suitable for transmitting the H₂ by pipeline. Also, pipeline transport would not result in any emissions.

Hydrogen from Electrolysis Quantitative Analysis – Results

Costs for liquid H₂ delivered by tanker are estimated to range between \$21.5/GJ (£13.44/GJ) and \$53.8GJ (£33.63/GJ).

At current estimated offshore electricity costs, the electricity input represents the major contributor to the cost of H₂. The contribution of the investment in the electrolysis plant is small compared to the electricity consumption and distribution costs.

For an electrolysis plant sited at an airport, long-term (2020) delivered H₂ costs could be about \$15/GJ (£9.38/GJ).

The offshore wind electricity potential for the UK is estimated at 986TWh/yr, with the exploitable potential by 2010 estimated at about 10TWh/yr. Exploiting 10% of the UK offshore potential for H₂ production would yield about 250PJ of H₂. [PIU,2002, OXERA, 2002].

Hydrogen from Biomass Quantitative Analysis – Parameters & Assumptions

General Description

The biomass-derived H₂ fuel chain selected for more detailed analysis consists of large-scale short rotation coppice (SRC) willow wood chip gasification followed by product gas reforming and upgrading. The wood chips are transported by truck from an average distance of 50km to a large-scale H₂ production plant of 6.2 tonnes per hour (206MW(H₂)) capacity. The H₂ could then be transported to the airport as a liquid by road tanker. An alternative option could be to transport the H₂ in gaseous form by pipeline to the airport and liquefy it on-site. Also, given the large quantities of fuel required by major airports, an interesting option would be to produce the H₂ on-site. The technologies considered in this fuel chain range from early demonstration to early commercial stage. SRC feedstock production is at the early commercial stage. Large-scale wood chip gasification is at the demonstration stage, while product gas reforming needs yet to be demonstrated. There is scope for technical and cost improvements along the entire fuel chain.

Biomass Feedstock Production

Wood chips from short rotation coppice willow are considered as feedstock. Wood chip costs can vary widely depending on yield and management practices. A range of \$3.2/GJ (£2.0/GJ) to \$6.4/GJ (£4.0/GJ) has been used, which reflects costs commonly cited in the literature. UK-specific cost calculations for SRC willow show that SRC willow wood chips could be produced for \$2.4/GJ (£1.50/GJ), assuming a yield of 10t(oven dry)/ha and efficient crop management practices. A 100km return transport distance adds about \$0.59/GJ (£0.37/GJ) to the cost of the feedstock, based on a specific transport cost of \$0.0059/(GJ km) (£0.0037/(GJ km)) for trucks of 60m³ capacity.

Only direct non-renewable energy inputs to biomass feedstock production and transport are considered. These consist of energy consumed by machinery used for feedstock production and transport activities. Indirect energy inputs, in the form of energy inputs for the production of machinery and agro-chemicals used, have not been considered. The energy input to feedstock production ranges between 0.0044 and 0.016GJ per GJ of biomass feedstock (wood chips) produced. The broad range is attributable to the range in the intensity of activities associated with crop establishment and management. A value of 0.82MJ/(t km) has been used for the mineral diesel energy input to transport (value derived from average truck consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre – [Bauen, 2000]). The energy input to feedstock transport ranges between 0.0027 and 0.010GJ per GJ of feedstock (wood chips) transported. Non-renewable energy inputs associated

with the establishment of the conversion plant are not considered, though these are estimated to be similar in magnitude to the direct energy input to feedstock production on an annual basis [Bauen 2000].

Feedstock production and transport activities result in direct greenhouse gas and other emissions associated with the consumption of mineral diesel in agricultural machinery and trucks. CO₂ emissions from transport are calculated based on a 73.5kgCO₂/GJ energy consumed by road transport. Greenhouse gas emissions from feedstock production range between 0.92 and 13 kgCO₂ equivalent per GJ of feedstock (wood chips) produced. Transport adds between 0.20 and 0.74 kgCO₂ equivalent per GJ of feedstock (wood chips) transported.

Gasification and Product Gas Reforming and Upgrading

The specific biomass-derived H₂ fuel chain is based on the BCL indirectly heated gasifier under demonstration in Burlington, Vermont. The biomass-to-H₂ conversion efficiency of the H₂ production plant is estimated at 66% (LHV). But, the plant requires an electrical power input of 22MW, reducing the overall efficiency of the H₂ conversion process to 52%. The 6.2 tonnes per hour H₂ production plant requires a 400MW_{th} biomass input. It is estimated that 70,000ha or 700km² of SRC plantation would be needed, based on a 10t(oven dry)/ha/yr yield, or the equivalent of 4% of the land within a 75km radius from the plant. The feedstock pre-treatment, gasifier and gas cleaning equipment investment cost is estimated at \$103.8 million. The steam reforming, CO shift reaction and pressure swing absorption equipment investment cost is estimated at \$134 million (£83.75 million). The investment in power generation equipment is estimated to contribute about \$15 million (£9.38 million). The contribution of gasification, reforming and upgrading equipment and O&M costs (excluding electricity) to the production cost of H₂ is estimated at \$5.65/GJ (£3.53/GJ). Based on the overall efficiency of the plant, the contribution of the biomass feedstock is between \$6.15/GJ (£3.84/GJ) and \$12.31/GJ (£7.69/GJ). The total H₂ production cost prior to liquefaction, on-site storage and delivery ranges then between \$11.80/GJ (£7.37/GJ) and \$17.96/GJ (£11.23/GJ).

Liquefying H₂ requires a 62MW power input for the plant considered, based on an electricity requirement for liquefaction estimated at about 0.73kWh/Nm³ (8.0kWh/kg). On-site H₂ storage is set at 10t, and no losses are considered from storage. Liquefaction equipment capital cost at the scale considered is estimated at £295/kW(H₂). On-site H₂ storage equipment capital cost is estimated at £57/kg (\$91.2/kg). Liquefying and storing the H₂ would contribute an additional \$1.41/GJ (£0.88/GJ) to \$1.76/GJ (£1.10/GJ) to the cost of H₂.

Direct energy requirements for the operation of the plant consist mainly of electricity, which is assumed to be produced on-site directly from the product

gas use or H₂ use in turbines or fuel cells. On-site electricity production would result in low or no emissions.

Hydrogen Distribution

To avoid costs, energy inputs and emissions associated with H₂ distribution, the H₂ production plant should ideally be situated at the airport site. However, H₂ could also be transported to the airport as a liquid by road tanker. Liquid H₂ transport by road tanker over a distance of 200km (return) would contribute between \$6.50/GJ (£4.06/GJ) and \$7.0/GJ (£4.38/GJ). Compressed (10-30bar) H₂ transport by pipeline over a distance of 100km would contribute between \$1.17/GJ (£0.73/GJ) and \$1.44/GJ (£0.90/GJ).

If the H₂ production plant is sited at the airport, some local distribution may be envisaged by pipeline, but it is assumed that there are no significant direct energy inputs or emissions of pollutants associated with its distribution. The distribution of H₂ to the airport as liquid H₂ by road tanker would require an energy input of 0.005GJ/GJ(H₂). However, it must be noted that in the future the vehicles could be fuelled by renewable H₂ instead of mineral diesel. In the case of mineral diesel, liquid H₂ transport would result in 0.37kgCO₂eq. Pipeline transport may require some energy input for compression of the H₂ to a pressure suitable for transmitting it by pipeline. However, pipeline transport would not result in any emissions.

Hydrogen from Biomass Quantitative Analysis – Results

Costs for liquid H₂ delivered by road tanker are estimated to range between \$23.1/GJ (£14.44/GJ) and \$30.1/GJ (£18.81/GJ).

For the low biomass feedstock cost, its contribution to the H₂ production cost is estimated to be similar to that of the annualised investment cost of the plant. However, for the range of feedstock costs considered, its contribution to the H₂ production cost could be as much as about two times that of the investment cost in the production plant.

For a H₂ production plant sited at an airport, long-term (2020) delivered H₂ costs could be about \$16/GJ (£10/GJ).

An indicative potential for H₂ production from SRC wood chips in the UK, based on a plantation area of 2 million ha of SRC with average yield of 10t(oven dry)/(ha yr) is 187PJ of H₂, equivalent to about 1.6 Mt. The UK has about 19Mha of agricultural land, of which about 5Mha are arable land.

Quantitative Analysis - Summary

Fuel	Cost /US\$ per GJ	Cost /£ per GJ	GJ out /GJ in	kgCO₂eq /GJ	UK Potential /PJ per yr
FT kerosene (IGT)	5.8–31.8	3.6- 19.9	17.2–53.5	2.6–8.9	44
FT kerosene (TPS)	21.8–36.5	13.6- 22.8	13.9-44.6	3.2-11.0	51
Biodiesel (RME)	33.5-52.6	20.9- 32.9	0.7-3.2	26.9-40.8	51 - 123
H₂ from SRC	23.1-30.1	14.4-18.8	18-54	2.5-8.3	187
H₂ from OSW	21.5-53.8	13.4-33.6	200	0.37	2307

Note:

- **SRC** - Hydrogen from regional gasification of biomass (liquid H₂ transport to forecourt via road tanker) – energy and CO₂eq values assume diesel use for transport
- **OSW** – Hydrogen from regional electrolysis of offshore wind electricity (compressed H₂ transport to forecourt by pipeline) – energy and CO₂eq values assume diesel use for transport

5. Discussion

The PRESAV project found an extensive and readily available supply of literature from many countries regarding research and experience of road transport renewable fuels. In contrast, however, there was found to be a surprising dearth of reports addressing the potential for renewable fuels in the aviation sector.

The two key references that were reviewed both considered renewable fuels as one aspect of the broader subject of aviation and environment. Both concluded that kerosene based fuels would continue to be the principal fuel for commercial aircraft for the “next several decades” [IPCC] or “the majority of the twenty-first century” [GBD]. These conclusions left open the possibility, however, of synthetic equivalents of conventional kerosene becoming widespread.

Chapter three of this report reviews six renewable aviation jet fuel options plus the potential for nuclear aircraft. The chapter concludes that ethanol and methanol are not viable options, principally because their energy densities are too low and also because of the likelihood of acetaldehyde or formaldehyde emissions at low power settings. Liquid bio-methane is ruled out on the grounds that it is unlikely to be available in sufficient quantities to be a major alternative to kerosene. Nuclear aircraft are considered to be too dangerous due to the possibility of accidents or terrorist attacks, even if the substantial technical and economic problems associated with the concepts could be overcome. However, three renewable fuels were identified as warranting further research: Biodiesel as a kerosene extender; biomass-derived Fischer-Tropsch kerosene; and H₂, which would be stored onboard in liquefied form.

Of the three fuels chosen for more detailed study:

- Biodiesel requires further research to improve and then build confidence about its cold weather performance. Research at the U.S. Dept. of Agriculture shows promising results, however, and it appears likely that the technical problems will be overcome in the near future to allow biodiesel to be added to kerosene jet fuel at blends of up to 10-20%.
- Fischer-Tropsch kerosene could be used in current jet aircraft with few if any modifications, although a fuel additive will probably be required due to the fuel’s low sulphur and aromatic content. In fact SASOL in South Africa already has a certified jet fuel blend of 50% coal-derived FT kerosene and 50% conventional kerosene. Although global production potential is large, the UK could only supply approximately 10% of its own aviation kerosene demand from renewable FT production.
- Hydrogen aircraft would require changes to jet engines, particularly to limit their production of NO_x, since the low NO_x combustion strategies adopted for lean burning kerosene jet engines would not be appropriate for those fuelled by H₂. These problems are relatively

minor, however, compared to the changes to airframe designs that will be required to carry sufficient volumes of liquid H₂ fuel.

This study has found that each of the three renewable fuels would be significantly more expensive to produce than the current cost of conventional aviation kerosene. Estimates of the delivered cost of biodiesel, FT kerosene and H₂ are \$33.5/GJ - \$52.6/GJ; \$5.8/GJ - \$31.7/GJ; and \$21.5- \$53.8/GJ (£20.94/GJ – £32.88/GJ; £3.63 – £19.81/GJ; and £14.4/GJ - £33.6/GJ). This compares to a current delivered price (including fuel company profit) of \$4.6/GJ (£2.88/GJ) for conventional aviation kerosene. Given the importance of fuel price to aircraft operator margins, this large cost difference makes it unlikely that a renewable alternative to aviation kerosene will be adopted in the foreseeable future.

Hydrogen aircraft show great potential for emissions reduction. However, the research and development work required to develop new aircraft designs and to install the capacity required to produce sufficient quantities of renewable H₂ mean that commercial H₂ aircraft are unlikely to be seen for at least several decades. Given the difficulty of predicting the future costs of new technologies it is also possible that the cost of producing FT kerosene may, in the long term, drop sufficiently for it to become a viable option. A large drop in the cost of producing biodiesel is less likely since the technologies involved with its production are already well established.

In order to safeguard its impressive safety record the aviation industry is particularly resistant to new or unproven technologies and fuels. This provides a strong argument in favour of using finite supplies of renewable fuels for purposes other than aviation. Considering each of the three most promising fuels:

- Biodiesel: For the foreseeable future the entire supply of biodiesel will be dwarfed by - and could be subsumed into - road vehicle diesel demand, particularly as many countries are witnessing increasing demand for diesel as opposed to petrol vehicles.
- Hydrogen: Most renewable electricity could be used to supply the national grid rather than to make H₂, thereby displacing non-renewable generation and associated emissions. Production of H₂ will still be preferable in some cases, notably where grid connection would be too expensive or during times of low electrical demand. It is likely, however, that road transport H₂ demand will develop before aircraft H₂ demand, and until sufficient renewable H₂ can be produced to supply both sectors it will probably be more pragmatic to use the fuel for road vehicles.
- FT kerosene. The proportion of kerosene within the mix of liquid hydrocarbons produced by an FT reactor can be reduced to approximately 25% [Tijmensen et al] with the major fraction being diesel. If commercial biomass-derived FT fuels production were to commence it is likely that the diesel fraction would be maximised and used to displace conventional road diesel. In this instance the kerosene is likely to be used for aviation. However, as previously

discussed, the cost of producing biomass-derived FT hydrocarbons is likely to rule out their commercial development for the foreseeable future.

Bibliography

References

- André P.C, Faaij, A, Michiel J.A, Tijmensen, M.J.A, Martijn R.M. van Hardeveld, D, Hamelincka, C.N., “The production of Fischer Tropsch liquids and power through biomass gasification”, Department of Science, Technology and Society, Utrecht University
- Contreras, A, Yigit, S, Ozay, K, Veziroglu, T.N, “Hydrogen as Aviation Fuel: A Comparison with Hydrocarbon Fuels”, International Journal of Hydrogen Energy, Vol, 22, No 10/11, 1997.
- Dahl, G and Suttrop, F, “Engine Control and Low NOx Combustion for Hydrogen Fuelled Aircraft Gas Turbines, International Journal of Hydrogen Energy Vol. 23, No. 8
- Defence Standard 91-91/4: Turbine Fuel, Aviation Kerosine Type, A-1 NATO code: F-35 Joint Service Designation: AVTUR; Defence Procurement Agency, Glasgow, Issue 4, 2002.
- Dept. of Environment, Transport and the Regions, UK Government, “The Future of Aviation, The Government’s Consultation Document on Air Transport Policy”
- Dieselnets Technical Summary, Synthetic Diesel Fuel
- Dunn, R.O, “Alternative Jet Fuels from Vegetable Oils”, American Society of Agricultural Engineers, 2001.
- Dunn, R.O, “Alternative Jet Fuels from Soybean Oil Biodiesel”, Lipid Technology Newsletter Vol. 7 No. 4, 2001
- ECOTEC. “Financial and Environmental Impact of Biodiesel as and Alternative to Fossil Diesel in the UK”.. Priestley House, 28-34 Albert Street, Birmingham, B4 7UD, UK:ECOTEC. 1-22, 1999. Green A4 booklet. JW RTF refs. JW. 2.
- Ebbinghaus, A and Wiessen, P, “Aircraft Fuels and their Effect upon Engine Emissions”, Air and Space Europe, Vol 3, No. 1, 2001
- European Energy Crops Network, Oil Crop for Biodiesel Production in Italy, 2002
- “Europe’s Aeroengine Community Targets Major Environmental Improvements”, Air and Space Europe, Vol 2, No. 3, 2000.
- Groves, A. P. “Well to Wheels Assessment of Rapeseed Methyl Ester Biodiesel in the UK”. Second World Biofuels Conference. F.O.Lights. London, UK:Shell Global Solutions. 1-32, 2002. IC DTI RTF reference material folders. JW. 1.
- Heinz, G, and Faass, R, “Cryoplane: Hydrogen Fuelled Aircraft – Status and Challenges, Air and Space Europe, Vol. 3, No. ¾, 2001
- Intergovernmental Panel on Climate Change, “Aviation and the Global Atmosphere”, IPCC, 1999
- Larson, E.D, and Haiming, J, “A Preliminary Assessment of Biomass Conversion to Fischer-Tropsch Cooking Fuels for Rural China”, proceedings of the 4th Biomass Conference of the Americas, Elsevier Science Ltd 1999
- Larson, E.D, and Haiming, J, “Biomass Conversion to Fischer-Tropsch Liquids: Preliminary Energy Balances”, proceedings of the 4th Biomass Conference of the Americas, Elsevier Science Ltd 1999
- LBST-GM. Annex: “GM Well-to-Wheel Analysis of Energy Use and Greenhouse Gas Emissions of Advanced Fuel / Vehicle Systems- A European Study.”. 1-425, 2002. Bacchus. JW. 2.
- Maurice, L.Q, Lander, H, Edwards, T, and Harrison, W.E, “Advanced Aviation Fuels: a Look Ahead via a Historical Perspective”, Fuel 80, 2001.

- Mortimer, N.D, Cormack, P, Elsayed, M. A, and Horne R. E, “Evaluation of the Comparative Energy, Environmental and Socio-economic Costs and Benefits of Biodiesel, Department for Environment, Food and Rural Affairs, 2002
- OECD/IEA. Biofuels: Energy & Environment, Policy Analysis Series. 2 rue Andre Pascal, 75775, Paris, CEDEX 16, France:OECD Publications. ISBN 9264-14233-9:1-117, 1994.
- Olsthoorn, X, “Carbon Dioxide emissions from international aviation 1950 – 2050”, Journal of Air Transport Management 87-93, 2001
- OXERA Environmental. Regional Renewable Energy Assessments. Blue Boar Court, Alfred Street, Oxford, OX1 4EH, UK:OXERA, ARUP Economics & Planning. 1-44 2002.
- PIU. Technical and Operating Potential of Renewable Energy Generating Technologies: potentials and cost reductions to 2020. R. Gross and J. Chapman. London, UK: Cabinet Office. 1-43 <http://www.cabinet-office.gov.uk/innovation/reports/reports.shtml>. 2002.
- Pohl, H.W, Malychev, V.V, “Hydrogen in Future Civil Aviation”, International Journal of Hydrogen Energy Vol 22, 1997
- Ptasinski, K.J, Loonen, M.J, Prins, F.J, Janssen, J.G. “Exergy analysis of a production process of Fischer-Tropsch fuels from biomass”; Department of Chemical Engineering, Technical University of Eindhoven.
- Quick, M, “Aviation, Renewables and the Climate, Energy World No. 298, 2002.
- Schmidtchen, U. Behrend, E. Pohl, H-W, and Rostek, N, “Hydrogen Aircraft and Airport Safety”, Renewable and Sustainable Energy Review, Vol. 1, No. 4, 1997
- Schnelldienst, I, “Macroeconomic evaluation of rape cultivation for biodiesel production in Germany”, 2002
- Society of British Aerospace Companies, “Air Travel – Greener by Design”, 2002
- Tijmensen, M.J.A, Faaija, A.P.C., Hamelincka, C.N, Martijn R.M. van Hardeveld, D. “Exploration of the possibilities for production of Fischer Tropsch liquids and power via biomass gasification”, Biomass and Bioenergy 23 (2002) 129 – 152
- Weber, J.A, and Van Dyne, D.L, “Cost Implications of Feedstock Combinations for Community Sized Biodiesel Production” University of Missouri-Columbia, USA
- United States Dept of Agriculture, Biofuels Research Program
- Hosein Shapouri & James Duffield, “The Economics of Producing Energy Crops”, U.S. Department of Agriculture, Office of Energy Washington, D.C. 20250
- Zagonel, G. F, Peralta-Zamora, P.G, and Ramos, L P, “Production of ethyl esters from crude soybean oil: Optimization of reaction yields”, Department of Chemistry, Federal University of Paraná,
- Zhang, X, Peterson, C.L, Reece, D, Moller, G, Haws, R, “Biodegradability of Biodiesel in the Aquatic Environment”; University of Idaho, USA. ASAE paper no. 956742

Websites Accessed

- www.transportation.anl.gov/ttrdc/pdfs/FC/225.pdf
- <http://www.sae.org/aeromag/techupdate/05-2001/>
- <http://www.swri.org/9what/releases/qualify.htm> SwRI to qualify synthetic jet fuel for use in commercial aircraft 1996
- http://www.csd.uwo.ca/~pettypi/elevon/baughner_other/x-6.html The Decay of the Atomic Powered Aircraft Program
- <http://www.eerc.und.nodak.edu/features/EBAF.html>
- <http://www.piperowner.org/Ethanol.htm>

- <http://www.sciam.com/1097issue/1097rennie.html>
- Home Grown Cereals Association: Haulage Survey 2001.
<http://www.hgca.com/Articles/DisplayArticle.asp?ArticleID=3170>
- www.mpizeln.mpg.de/pr/garten/schau/BrassicinapusLvarnapus/Rape.html
- [www.fas.usda.gov/WAP/circular/1998/98 \]](http://www.fas.usda.gov/WAP/circular/1998/98)
- www.btgs1.ct.utwente.nl/eeci/archive/biobase/B10372.html
- www.csl.gov.uk/ienica/data/sunflowe.htm
- <http://www.ag.ndsu.nodak.edu/fargo/00data/sunflower.htm>
- <http://www.agric.nsw.gov.au/reader/14897>
- <http://www.botanical.com/botanical/mgmh/s/sunfl100.html#see>
- www.ars.usda.gov/is/pr/2001/010807.htm
- FAOSTAT (2002) www.fao.org

Experts Consulted

In addition to PRESAV Steering Group Members, the following experts were consulted:

- Lindstedt, Prof P, Imperial College London, Dept of Mechanical Engineering, March 2002 – February 2003.
- Dunn, Dr R.O, United States Department of Agriculture, pers comm. April 2002.
Subject: The potential for biodiesel as a kerosene extender.
- Moses, Dr Clifford, South West Research Institute pers comm. May 2002.
Subject: The potential for renewably sourced Fischer Tropsch synthetic kerosene. (Work undertaken for SASOL).
- Maurice, L.Q, formerly United States Air Force
Subject: General potential for renewable aviation fuel.
- European Commission Working Group 5
Subject: General potential for renewable aviation fuel.

APPENDIX 1: Rape (*Brassica napus*) Methyl Ester (RME)

Life Cycle evaluation of Rape Methyl Ester (RME) production in the UK based on mature, or near market, technologies. The energy balance is calculated without any co- or by-product benefits i.e. all energy inputs to rape seed production and conversion are assigned to RME production. Low, Best Estimate and High values are provided for feedstock production, transport, conversion and RME distribution and key 'fuel chain summary' factors provided as derived from the literature and explained in the footnotes.

Fuel chain summary

	Low	Best Est	High	Unit
<i>Cost (no co-product credits):</i>	33.468	52.59	52.59	\$/GJ RME
<i>Energy ratio (biofuel energy produced per unit non-renewable energy input)</i>	0.7	2.0	3.2	GJout:GJin
<i>CO2 emissions</i>	26.9	28.0	40.8	kgCO2/GJ RME
<i>GHG emissions</i>	17.0	44.3	44.3	kgCO2equiv./GJ RME
<i>UK Specific?</i>			Yes	
<i>Technology status (feedstock, conversion and distribution)</i>	Both feedstock production and conversion technologies are mature. However, improvements are expected to continue in feedstock yields and conversion efficiencies.			

Intermediary fuel chain stage parameters

Production and transport	Low	Best Est	High	Unit	Conversion and distribution				Unit
<i>Feedstock cost (farm gate)</i>	15.60	16.66	16.66	\$/GJseed	Costs from conversion		9.82		\$/GJ RME
	23.16	37.12	55.82	\$/GJ RME					
<i>Feedstock transport cost</i>		0.44		\$/GJseed	RME production	0.69	1.03	1.6524	t RME/ha
		0.98		\$/GJ RME	RME production	25.6	38.5	61.6	GJ RME/ha
<i>Feedstock yield (seed)</i>	2.2	3.1	4.1	t/ha	By-product value	2.40	9.42	10.31	\$/GJ RME
					Distribution cost		0.40		\$/GJ RME
<i>Energy input to feedstock production:</i>	8.93	8.93	21.17	GJ/ha	Energy input to conversion process	0.21	0.22	0.27	GJ/GJ RME
	0.232		0.550	GJ/GJ RME	Energy input to distribution	0.004	0.004	0.004	GJ/GJ RME
<i>Energy input to feedstock transport:</i>	0.24	0.51	0.6657	GJ/ha	Energy content of by-products	1.12	2.04	2.08	GJ/GJ RME
	0.006		0.017	GJ/GJ RME					
<i>GHG from feedstock production:</i>	14.8	28.6	28.6	kgCO2equiv./GJ RME	GHG from energy input to conversion process	1.7	14.3	14.3	kg CO2equiv. /GJ RME
<i>CO2 from feedstock production:</i>	13.6	13.6	21.8	kgCO2/GJ RME	CO2 from energy input to conversion process	12.3	13.1	17.7	kg CO2/GJ RME
<i>GHG from feedstock transport:</i>	0.2	1.1	1.1	kgCO2equiv./GJ RME	CO2 from distribution	0.28	0.28	0.28	kg CO2/GJ RME
<i>CO2 from feedstock transport:</i>	0.8	1.0	1.0	kgCO2/GJ RME	Allocation of CO2 to by-products				

NOTES: [ECOPORT plant id: 549 (www.ecoport.org)]

COSTS

Overall costs:

Cost (no co-product credits): **'Low'** cost (\$/GJ) is based on the median market value of rape seed in the UK for 2002 (£150.00 per t; HGCA, 2002). The conversion and distribution costs are estimated at £6.14/t RME produced (as shown). **'High'** cost is based on actual production costs (ECOTEC 1999) without any set-aside subsidies- conversion costs are assumed to the £6.14/t RME.

Feedstock costs:

General Notes: Feedstock production costs of £892/ha as calculated in ECOTEC 99 (p11) are used for both the 'low' and 'Best Est' calculations above - assumed to include harvesting but not transport costs. 70% of these feedstock costs are 'fixed' and 30% 'variable'. For comparison, the market value of rape seed was £130/t seed (£468/ha) in ECOTEC 99 which combined with the set-aside subsidy of £256/ha resulting in a net loss to farmers for rape seed production of £168/ha. Mortimer (2002) provides an average price for Rape Seed of £152/t seed (p27) and a gross margin per ha for winter rape of £261/ha or £586 with subsidies. Set-aside land used for RME production benefits from a subsidy of £256/ha (£7.5/GJ RME) and using ECOTEC 99 data this equates to a benefit of £0.169/l RME. In addition, a tax break of 20p/l RME is available in the UK equivalent to £6.8/GJ RME.

Feedstock production Low estimate: calculated from production costs of £892/ha (ECOTEC 99) and a rape seed yield of 3.6 t/ha (as quoted). The energy density of the rape seed taken to be 25.424 GJ/tseed, based on Groves 2002. £/GJ RME is calculated from the 'low' rate of RME production shown above in the conversion and distribution section.

Feedstock production Best and High estimates: Production costs of £892/ha (ECOTEC 99) and rape yields of 3.6 t/ha (as quoted). Energy density (LHV, 10% moisture) for Rape Seed of 23.8 MJ/kg quoted in the LBST_GM (2002) study (page 258 annex) compared to seed energy density used in 'Low Est' of 25.424 GJ/t seed (Groves 2002). £/GJ RME is calculated from the 'best est' and 'high' rates respectively, of RME production shown above in the conversion and distribution section.

Feedstock transport costs are based on HGCA (2002) haulage costs for a 120 km journey (75 miles) of £6.60 per tonne- £0.055 per t.km. Groves (2002) states a distance of 100km from field to crusher and Mortimer 2002 (p27) quotes an average round trip distance of 260 km for raw rapeseed transportation.

Conversion & Distribution costs:

Conversion costs include oil extraction (crushing) + transport (120 km) + esterification. Only a single **Best Est'** figure is provided because there is insufficient data in the literature to generate a low and high value. The value provided above is based on the average costs for small scale crushing systems and large scale esterification plants- detailed costs for conversion (oil extraction) could only be found for relatively small scale systems e.g. 15, 130 and 750 kg seed/h, 0.1 to 6 t RME per day (www.folkecenter.dk). Costs for esterification are based on Michaelis (IEA/OECD, 94) who quotes a cost for esterification only (i.e. not including oil extraction) of US\$ 16/l RME (1991 US\$) equivalent to £0.10/l (1991 GBP exchange equiv) for a 60 t RME per day plant. ECOTEC 1999, provide 'pump prices' for RME in the range of 25 to 37p/l (£7.62 to £11.28/GJ RME). Groves (2002) estimates an 80 km round trip for transporting the oil from the crushing unit to the esterification plant. In Mortimer 2002, the crushing and esterification units are assumed to be co-located. We have used data from the HGCA (www.hgca.com) 'Haulage Survey 2001' for haulage economics in the UK of £6.60/tonne hauled for an average distance of 75 miles (120 km) Transport to airport is assumed to be by tanker at a cost of £0.053/(t km). For comparison with hydrogen fuel chain, transport distance is estimated to be 100 km (200km return). (The energy density of biodiesel is assumed to be the same as that of fossil diesel 42.8 MJ/kg).

By-product value(s): Three main by-products are produced during the production of RME which have a potential value: i) straw: Mortimer 2002 quote a straw production rate of 0.98 tstraw/t raw rape seed and an economic value of £25/t straw and Groves (2002) 1.6 tstraw/tseed. ii) Glycerine: £388/t crude glycerine (Mortimer 2002) which is produced at the rate of 100 kg/t vegetable oil or 31 to 45 kg glycerine / t seed depending on the oil extraction efficiency. ECOTEC 99 provide a by-product value for Glycerine of £0.22 per l RME. iii) Rape Meal: £95.5/t (HGCA 2002) and 580 to 630 kg/tseed depending on the oil extraction efficiency.

'Low': glycerine only (high oil extraction efficiency- therefore high glycerine yield). **Best Est'** is based on the sale of both glycerine and meal, but not straw, at the low production rates and values stated above.

'High' is calculated from the value of the glycerine+meal+straw (based on the values quoted above) and the high seed production rate and therefore represents the maximum possible practical financial return from by-products.

ENERGY

In total, Nitrogen inputs to RME production represent between 40 and 50% of energy inputs to feedstock production. Energy inputs into conversion are based on heat requirements being met from natural gas and electrical requirements being met by grid-based electricity.

Energy ratio (balance): calculated from the feedstock production, transport, conversion and distribution values provided above. The **high'** estimate is calculated from the lowest seed yield and highest production, transport conversion and distribution energy inputs. The **low'** estimate is based on the highest seed yields and the lowest production, transport conversion and distribution energy inputs. Therefore, it is important to note that this is a theoretical calculation and is extremely unlikely to represent a practical implementation e.g. the highest yields will not result from the lowest agricultural energy inputs, but the data does provide an indication of the range in energy balances that could occur between good and bad implementation. The **Best Est'** of 1.9 GJout/GJin is in line with a number of the more detailed studies evaluated, however, it does not include any co-product credits and so in practice represents the low end of likely future energy balances.

Feedstock production energy requirements:

Energy inputs for feedstock production are derived from the range found in the literature. The **Best Est'** is derived from Mortimer (2002) as this is the most detailed review of UK specific energy requirements for RME production to date. The Mortimer 2002 figure is also used for the **Low'** estimate and the **High'** is the maximum energy requirement found quoted in the literature. In total 25 estimates for feedstock energy production have been evaluated with a mean energy requirement of 13 254± 3132 MJ/ha.

Feedstock transport energy requirements:

Feedstock Transport- although not a major component in total energy input requirements, considerable differences in assumptions exist in the literature. The **Best Est'** is based on Mortimer et al. (2002) which quotes a round trip distance 260km (160 miles) between field and mill. The **Low'** estimate is based on Groves (2002) which quotes a 190 km round trip (120 miles). The **High'** estimate calculation is based on the energy requirement per tonne of rape seed for the 'Best Est' multiplied by the 'High' seed yield value above.

Conversion & Distribution energy requirements:

Conversion: Detailed, disaggregated calculations of the energy requirements for conversion of rape seed into RME were only found in a few references. As a result, the **Best Est** is derived from Groves (2002) and being based on Shell data probably represents current business practice. The **High** estimate is derived from IEA/OECD (1994) and represents the energy requirements for RME production at the start of the last decade. The **Low** estimate is taken from Mortimer (2002) and represents the state-of-the-art in RME production technologies available now, showing the improvements that have occurred over the last decade in energy efficiency. Both heat and electricity are required in significant quantities to power the oil extraction and the esterification processes. The electricity is generally assumed to be derived from the grid and the heat from natural gas, however, some references are made to natural gas CHP systems being operated and the potential to supply the heat from either rape straw or wood (LBST-GM 2002). It is assumed that all machinery and transport vehicles are fuelled with diesel. A value of 0.00082GJ/(km t) has been used for the fossil energy input to transport (value derived from avg truck consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre - Bauen 2000). However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO2 emissions from the transport stage.

Co-product energy credits:

Co-product allocation: Three potential by-products result from the production of RME. These are: i) straw (14.2 MJ/kg, 0.98 tstraw/tseed), ii) glycerine (17 MJ/kg, 0.0332 tglycerine/tseed) and iii) rape meal (18 MJ/kg, 0.627 tmeal/tseed). No co-product credits are calculated here, however, the energy content of the co-products is provided. The allocation of energy inputs to co-product outputs is controversial and can be done by i) the energy content of the co-product, ii) the energy required to produce the co-products substitute e.g. rapemeal for soyameal and iii) the co-products market value.

Low is the energy content of straw only given 'best' estimate seed yields and RME production efficiency. **Best** estimate is the energy content of the straw plus meal and **High** is the energy content of the straw+meal+glycerine calculated from 'best' estimate seed yields and RME production efficiency (tRME/tseed).

GHG & CO2 EMISSIONS

GHG emissions are generally calculated using IPCC (1996) guidelines and are based on emission factors from fertiliser use and 100 year global warming potentials.

Feedstock production emissions:

or both feedstock production and feedstock transport, **Low** estimate is based on ECOTEC (2001) and **Best Est** and **High** emissions are derived from Mortimer (2002). Nitrogen fertiliser use represents the most significant source of emissions resulting from both the energy requirements from its production and the in-field emissions after application to the soil.

Conversion & Distribution emissions:

CO2 and GHG emission are provided for comparison above but this note refers only to GHG emissions. For both conversion and distribution, **Low** estimate is based on ECOTEC (2001) and **Best Est** and **High** emissions are derived from Mortimer (2002). The similarity between the CO2 and GHG emissions data provided for conversion arises because there are no nitrogen fertiliser-based N2O emissions during the conversion and distribution phases of RME production.

OTHER EMISSIONS

Emissions of particulates, carbon monoxide and water are not evaluated here although the health and environmental impacts may be extremely important. A more complete analysis of emissions including Sulphur Oxides (SOx), Nitrogen Oxides (NOx), Particulates and Volatile Organic Carbon (VOC) and Carbon Monoxide (CO) is provided in ECOTEC 99.

RESOURCE POTENTIAL

UK production potential is estimated to be 51.2 PJ to 123 PJ. Base on: Rape seed yields are derived from the range found in the literature and cross-checked with the UK average for 2001 (FAOSTAT 2002). The **Best Est** is the mean of the literature derived range and the **Low** and **High** are the minimum and maximum yields found quoted in the literature. The energy content of raw rape seed is taken from RME Production: **Low** is low conversion efficiency (high temperature pressing) and low seed yield. **Best Est** is based on Mortimer (2002) average extraction efficiency and 'Best Est' seed yield. **High** is solvent extraction and high seed yield.

TECHNOLOGY STATUS

The evaluation provided here is based on the range of data found in the literature. It represents the range of technologies available for both production and conversion of rape to produce methyl ester and all the technologies are technologically mature.

APPENDIX 2: Biomass Derived Fischer-Tropsch Kerosene - IGT (Oxygen Blown, Pressurised) Gassifier

Fuel chain summary

Wood chips from short rotation coppice (SRC) willow. Biomass gasified in an indirectly heated, oxygen-blown, pressurised (IGT) gasifier. Syngas reforming prior to FT reactor using once-through concept, assuming 80% conversion and generation of electricity using off-gas. FT liquids production assumed to be 50% kerosene, 25% diesel, 25% naphtha.

	<u>Low</u>	<u>Best Est.</u>	<u>High</u>	<u>Unit</u>
Biofuel cost	5.82		31.70	\$/GJ(FTliq)
Energy ratio (biofuel energy produced per unit non-renewable energy input)	17.17		53.52	GJ(FTliq) out/GJ in
GHG emissions:	2.62		8.87	KgCO2 eq / GJ(FTliq) out
UK Specific?	Yes for SRC			
Technology status (feedstock, conversion and distribution)	Feedstock production is early commercial. Biomass gasification technology is at the demonstration stage. FT process technology is mature (proven since 1950s using fossil fuel derived feedstock). Integrated biomass gasification FT process is at demonstrat			

Intermediary fuel chain stage parameters

	<u>Low</u>	<u>Best Est.</u>	<u>High</u>	<u>Unit</u>		<u>Low</u>	<u>Best Est.</u>	<u>High</u>	<u>Unit</u>
Production and transport					Conversion and distribution				
<i>Feedstock cost (delivered):</i>	2.00		4.00	\$/GJ (biomass)	Costs from conversion	21.4000		22.9000	\$/GJ(FTliq)
<i>Feedstock cost (delivered):</i>	8.24		16.48	\$/GJ (FTliq)					
<i>Feedstock transport cost:</i>	Above costs include feedstock transport								
					By-product electricity	1.0324		1.0324	GJ (el)/GJ (FTliq)
					By-product value	0.0300		0.0900	\$/kWh
					By-product value	8.0715		24.2144	\$/GJ(FTliq)
					Distribution cost	0.3963		0.3963	\$/GJ(FTliq)
NB: All energy data below refers to non-renewable energy									
<i>Energy input to feedstock production:</i>	0.0044		0.0160	GJ / GJ(Biomass)	Energy input to conversion process	None - Uses electricity generated on site			
	0.0092	0.0000	0.0335	GJ/GJ(FTliq)					
<i>Energy input to feedstock transport:</i>	0.0027		0.0100	GJ / GJ(Biomass)	Energy input to distribution	0.0038		0.0038	GJ/GJ(FTliq)
	0.0056	0.0000	0.0209	GJ/GJ(FTliq)					
<i>GHG from feedstock production:</i>	0.9200		3.3700	kgCO2 eq./ GJ(biomass)	GHG from energy input to conversion process	None			GJ/GJ(FTliq)
	1.9247	0.0000	7.0502	kgCO2 eq./ GJ (FTliq)	GHG from distribution	0.2816355	0	0.2816355	kgCO2 eq./ GJ (FTliq)
<i>GHG from feedstock transport:</i>	0.1985		0.7350	kgCO2 eq./ GJ(biomass)					
	0.4152	0.0000	1.5377	kgCO2 eq./ GJ (FTliq)					

Notes:

IGT - Institute of Gas Technology

Costs

Feedstock costs

Wood chips from short rotation coppice willow are assumed as feedstock. Feedstock costs can vary widely depending on yield and management practices. A range of £2/GJ to £4/GJ has been used (equivalent to about £25 to £50 per tonne), which reflects costs commonly cited in the literature. UK-specific cost calculations for SRC willow have shown that the feedstock could be produced for £1.5/GJ for a yield of 10t(oven dry)/ha and efficient crop management practices. Transport cost is based on transport by truck of 60m3 capacity at a cost of £0.0037/(km GJ). A 100km return transport distance contributes about £0.37/GJ to the cost of feedstock

Conversion cost

367MWth feedstock input gasifier is considered based on considerations of economies of scale and feedstock supply (would require 70,000ha or 700km² of SRC plantation - i.e. planting of 1% of land within a 150km radius). FT liquid production is 89.1MW(FTliq). In FT kerosene mode, the following FT liquid split is assumed: 50% kerosene, 25% diesel and 15% naphtha. FT kerosene production is 44.6MW. The conversion plant also produces about 86.3 MW electricity. The overall conversion efficiency is 48% net of electricity production. Calculations based on IGT indirectly heated gasifier. On-site FT diesel storage costs are not considered.

By-product value

The range of by-product (electricity) prices is typical for present day. High price assumes 'green' premium, low price assumes no premium

The value of FT kerosene, diesel and naphtha are assumed to be the same. The relative proportion of these liquid fuels produced does not, therefore, affect the overall economics

Distribution cost

Transport to airport is assumed to be 100km (200km round trip) by tanker at a cost of £0.053/(t km) (The energy density of FT diesel is assumed to be the same as that of fossil diesel 42.8 MJ/kg).

Energy

All references to input energy refer to non-renewable energy inputs

Only direct non-renewable energy inputs to biomass feedstock production and transport are considered - Bauen 2000. Non-renewable energy inputs associated with the establishment of the conversion plant are not considered - these have been estimated to be of the same order of the energy input to feedstock production on an annual basis (Bauen 2000).

Energy inputs are allocated between FT liquid fuels and by-product (electricity) in proportion to the energy content of the two outputs

The heat and electricity requirements of the conversion plant are met by biomass energy produced on-site so net elec demand and non-renewable energy input to the plant is zero

It is assumed that all machinery and transport vehicles are fuelled with diesel. A value of 0.00082GJ/(km t) has been used for the fossil energy input to transport (value derived from avg truck consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre - Bauen 2000). However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO₂ emissions from the transport stage.

CO₂

Direct CO₂ emissions from biomass production and transport activities are considered.

No CO₂ emissions are associated with the conversion plant.

CO₂ emissions from transport are based on a 73.5kgCO₂/GJ energy consumed by road transport

CO₂ emissions are allocated between FT liquid fuels and by-product (electricity) in proportion to the energy content of the two outputs

Other emissions

No significant greenhouse gas emissions other than CO₂

Resource potential

UK's production potential for kerosene from biomass derived FT = **44PJ**, based on the assumptions below.

Assumptions: 4,000,000ha arable land in the UK, of which 50% available for SRC for FT liquid production; Yield =10 ODT/ha; Energy content of SRC =18GJ/ODT; FT liquid output =50% kerosene

This compares to UK aviation kerosene consumption of **406PJ** (1999 data)

World production potential for kerosene from biomass derived FT = **19,422PJ**, based on the assumptions below.

Assumptions: Worldwide biomass potentially available for FT liquid fuels production (ie all that is estimated to be available for energy crops) = 160,000PJ; FT liquid output =50% kerosene

This compares to worldwide aviation kerosene consumption of **9,158PJ** (1999 data)

Technology Status

Large-scale IGT gasifiers are yet to be proven.

Systems using IGT gasifiers produce slightly less FT liquids than those using the TPS, but considerably more electricity. The model shows that this gives IGT systems an advantage over TPS on both economic and ~~anta~~

APPENDIX 3

Hydrogen from regional electrolysis of offshore wind electricity (liquid hydrogen transport to airport via road tanker)											
Offshore wind electricity generation; transmission to regional electrolysis plant of capacity up to about 500MWe; liquid hydrogen transport to airport 100km distant											
Fuel chain summary											
Hydrogen cost (delivered to airport)						Low	Best Est.	High	Unit		
Energy ratio (Hydrogen energy produced per unit non-renewable energy input)						22.3	200.0	53.8	\$/GJ(H2)		
GHG emissions						0.37		0.37	kgCO2eq/GJ(H2)		
UK Specific?								Yes			
Technology status (feedstock, conversion and distribution)						Electrolysis, liquefaction and offshore wind technologies are commercial, but with potential for cost reductions.					
Intermediary fuel chain stage parameters											
Production and transport	Low	Best Est.	High	Unit	Conversion and distribution	Low	Best Est.	High	Unit		
<i>Electricity cost (delivered):</i>	3.20		8.80	\$cents/kWh	<i>Electrolysis cost</i>	0.96		2.40	\$/GJ(H2)		
<i>Electricity cost (delivered):</i>	11.28		36.72	\$/GJ H2	<i>Compression / liquefaction and storage cost</i>	3.55		7.66	\$/GJ(H2)		
					<i>Distribution cost</i>	6.50		7.00	\$/GJ(H2)		
					<i>Electricity consumption</i>	1.27		1.50	MJe/MJ(H2)		
NB: All energy data below refers to non-renewable energy											
<i>Energy input to electricity production:</i>	None			GJ / GJ(elec.)	<i>Energy input to electrolysis process</i>	None (renewable electricity)			GJ /GJ(H2)		
<i>Energy input to electricity production:</i>	None			GJ /GJ(H2)	<i>Energy input to compression / liquefaction and storage</i>	None (renewable electricity)			GJ /GJ(H2)		
<i>Energy input to electricity transport:</i>	None				<i>Energy input to distribution</i>	0.005		0.005	GJ /GJ(H2)		
<i>GHG from electricity production:</i>	None			kgCO2 eq./ GJ(elec)	<i>GHG from energy input to electrolysis process</i>	None			kgCO2 eq./ GJ (H2)		
<i>GHG from electricity production:</i>	None			kgCO2 eq./ GJ (H2)	<i>GHG from energy input for distribution</i>	0.37		0.37	kgCO2 eq./ GJ (H2)		

Notes:

Costs

Electricity cost

Current offshore wind electricity costs are estimated to be 5-5.5 p/kWh (based on capital cost of about £1000/kW). Future (2020) offshore wind electricity costs are estimated to be 2-3 p/kWh (based on capital cost of about £400/kW). It has been assumed that the figures include electricity transport and distribution costs.

The electricity cost per unit of hydrogen generated accounts for the electrolysis (3.8-4.5kWh/Nm3h) and compression (2.2kWh/kg) energy requirement per unit of hydrogen produced.

Electrolysis cost

Electrolysis plant hydrogen production capacity is 334MW (10t/h. High value is based on current electrolyser capital cost estimated at \$600/kW(H2) (this corresponds to about \$1800/Nm3/h). Low value is based on estimated future electrolyser cost of \$240/kW(H2) (this corresponds to about \$720/Nm3/h). Calculations based on 20 year lifetime and 10% discount rate. O&M costs estimated at 2-3% of annualised capital cost.

Compression / liquefaction and storage cost

Liquefied storage is assumed. The hydrogen production plant requires 80MW liquefaction power. Liquefaction cost at this scale is estimated at £295/kW(H2). On-site hydrogen storage is set at 10t. Storage cost at this scale is estimated at £57/kg.

Transport cost

Transport to the airport is assumed to be by tanker of capacity between 360 and 4300kg liquid H₂. Transport distance is estimated to be 100km (200km return).

Energy

All references to input energy refer to non-renewable energy inputs.

No direct non-renewable energy inputs are associated with offshore wind energy production. Indirect energy has not been considered, but are assumed to be very low over the lifetime of the installation.

No direct non-renewable energy inputs to electrolysis plant. Indirect energy has not been considered.

Energy input to transport consists of diesel use (based on 6 mile per gallon consumption). However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO₂ emissions from the transport stage.

CO₂

No direct CO₂ emissions from offshore wind electricity production. Indirect emissions have not been considered, but are assumed to be very low over the lifetime of the installation.

No direct CO₂ emissions from electrolysis plant. Indirect emissions have not been considered.

CO₂ emissions from transport are based on a 73.5kgCO₂/GJ energy consumed by road transport

Resource potential

The offshore wind electricity potential for the UK is estimated at 3550PJ/yr. Exploitable potential by 2010 is estimated at about 36PJ/yr.

Sources:

Various cited in Howes (2002)

Hydrogen from biomass gasification (liquid hydrogen transport to airport via road tanker)

Wood chips from short rotation coppice; atmospheric indirectly heated gasification (BCL gasifier); syngas reforming and shift reaction; hydrogen purification; compressed hydrogen; liquid hydrogen transport to airport 100km distant

Fuel chain summary

	Low	Best Est.	High	Unit
Hydrogen cost (delivered to airport)	23.06		30.07	\$/GJ(H2)
Energy ratio (biofuel energy produced per unit non-renewable energy input)	18.18		53.61	GJ(H2)/GJ in
GHG emissions	2.5		8.3	kgCO2eq/GJ(H2)
UK Specific?			Yes	
Technology status (feedstock, conversion and distribution)	SRC feedstock production is early commercial. Biomass gasification technology is at the demonstration stage. Syngas reforming to hydrogen needs to be demonstrated.			

Intermediary fuel chain stage parameters

	Low	Best Est.	High	Unit		Low	Best Est.	High	Unit
Production and transport					Conversion and distribution				
<i>Biomass feedstock cost (delivered)</i>	3.20		6.40	\$/GJ (biomass)	<i>Conversion cost</i>	5.65		5.65	\$/GJ(H2)
<i>Biomass feedstock cost (delivered)</i>	6.15		12.31	\$/GJ H2	<i>Compression / liquefaction and storage cost</i>	4.76		5.11	\$/GJ(H2)
					<i>Electricity consumption</i>	0.24		0.24	MJe/MJ(H2)
					<i>Distribution cost</i>	6.5		7.0	£/GJ(H2)

NB: All energy data below refers to non-renewable energy

<i>Energy input to feedstock production:</i>	0.0044		0.016	GJ / GJ(biomass)	<i>Energy input to conversion process</i>				GJ /GJ(H2)
<i>Energy input to feedstock production:</i>	0.008		0.031	GJ /GJ(H2)	<i>Energy input to compression / liquefaction and storage cost</i>	None (on-site bioelectricity)			GJ /GJ(H2)
<i>Energy input to feedstock transport:</i>	0.0027		0.010	GJ / GJ(biomass)	<i>Energy input to distribution</i>	0.005		0.005	GJ /GJ(H2)
<i>Energy input to feedstock transport:</i>	0.005		0.019	GJ /GJ(H2)					
<i>GHG from feedstock production:</i>	0.92		3.37	kgCO2 eq./ GJ(biomass)	<i>GHG from energy input to conversion process</i>	None			kgCO2 eq./ GJ (H2)
<i>GHG from feedstock production:</i>	1.8		6.5	kgCO2 eq./ GJ (H2)	<i>GHG from energy input for distribution</i>	0.37		0.37	kgCO2 eq./ GJ (H2)
<i>GHG from feedstock transport:</i>	0.20		0.74	kgCO2 eq./ GJ(biomass)					
<i>GHG from feedstock transport:</i>	0.38		1.41	kgCO2 eq./ GJ (H2)					

Notes: For calculations regarding different hydrogen transport modes refer to electrolytic hydrogen sheets

Costs

Feedstock cost

Wood chips from short rotation coppice willow are assumed as feedstock. Feedstock costs can vary widely depending on yield and management practices. A range of £2.0/GJ to £4/GJ has been used, which reflects costs commonly cited in the literature. UK-specific cost calculations for SRC willow have shown that the feedstock could be produced for £1.5/GJ for a yield of 10t(oven dry)/ha and efficient crop management practices. Transport cost is based on transport by truck of 60m3 capacity at a cost of £0.0037/(km GJ). A 100km return transport distance contributes about £0.37/GJ to the cost of feedstock.

Conversion to hydrogen

400MWh feedstock input gasifier is considered based on considerations of economies of scale and feedstock supply (would require 70,000ha or 700km2 of SRC plantation - i.e. planting of 1% of land within a 150km radius). Hydrogen production is 7.7t/h (256MW(H2)). The overall conversion efficiency is 66% (LHV) or 70% (HHV) - 52% (LHV) net of electricity used in the process. Calculations based on BCL indirectly heated gasifier under demonstration in Burlington, Vermont. Feedstock pre-treatment, gasifier and gas cleaning investment cost is estimated at 103.8 mill \$. Steam reforming, CO shift reaction and pressure swing absorption investment cost is estimated at 134 mill \$. The plant requires an electrical power input of 22MW and investment in power generation is estimated to contribute about 15 mill \$. The hydrogen production plant requires 62MW liquefaction power. Liquefaction cost at this scale is estimated at £295/kW(H2). On-site hydrogen storage is set at 10t. Storage cost at this scale is estimated at £57/kg. Electricity for liquefaction is assumed to cost \$0.05/kWh.

Distribution

Transport to the airport is assumed to be by tube trailer of capacity up to 460kg. Transport distance is estimated to be 100km (200km return).

Energy

All references to input energy refer to non-renewable energy inputs.

Only direct non-renewable energy inputs to biomass feedstock production and transport are considered - Bauen 2000. Non-renewable energy inputs associated with the establishment of the conversion plant are not considered - these have been estimated to be of the same order of the energy input to feedstock production on an annual basis (Bauen 2000).

No direct non-renewable energy inputs are associated with biomass conversion. Electricity needed for the plant is assumed to be produced from biomass on-site.

It is assumed that all machinery and transport vehicles are fuelled with diesel. A value of 0.00082GJ/(km t) has been used for the fossil energy input to transport (value derived from avg truck consumption of 0.03litre/(km t) and diesel energy content of 36.4MJ/litre - Bauen 2000). However, the use of a renewable transport fuel would result in zero non-renewable input to transport and zero CO2 emissions from the transport stage.

CO2

Direct CO2 emissions from biomass production and transport activities are considered.

No CO2 emissions are associated with the conversion plant.

CO2 emissions from transport are based on a 73.5kgCO2/GJ energy consumed by road transport

Resource potential

Indicative potential for the UK based on 2 mill ha of SRC with avg yield of 10t(oven dry)/(ha yr): 187PJ/yr of H2 , equivalent to about 1.6 mill t/yr.

Note:

For comparison with liquid hydrogen and compressed hydrogen by pipeline storage and transport options see "Offshore wind" sheets.

Sources:

Hamelinck (2001)

Bauen (2000)

Howes (2002)

Appendix 4

PRESAV Steering Group

Mr Andy Kershaw	British Airways.
Mr Colin Beesley	Rolls Royce Plc.
Ms Paula Carberry	QinetiQ.
Mr Robert Falk	Department of Trade and Industry.
Prof. Tony Marmont	Beacon Energy.
Mr Peter Newton	Department of Trade and Industry.