Department of Energy & Climate Change

RHI Evidence Report: Biopropane for Grid Injection

Assessment of the Market, Renewable Heat Potential, Cost, Performance and Characteristics of Biopropane for Gas Grid Injection.

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Glossary

AD	Anaerobic digestion
BCC	Biomass catalytic cracking
b/d	Barrels per day
CO_2	Carbon dioxide
CO_2eq	Carbon-dioxide equivalent
DECC	Department of Energy and Climate Change
DME	Dimethyl ether
EIA	Energy Information Administration
EPA	Environmental Protection Agency (United States)
FAME	Fatty acid methyl ester
FT	Fischer-Tropsch (process)
HVO	Hydrotreated vegetable oil
IEA	International Energy Agency
kWh	Kilowatt hour
LPG	Liquefied petroleum gas
MJ	Megajoules
Mt	Million tonnes
MTG	Methanol to gasoline
Ofgem	Office of Gas and Electricity Markets
PFAD	Palm fatty acid distillate
RED	Renewable Energy Directive (European Union)
RFS	Renewable Fuel Standards (United States)
RHI	Renewable Heat Incentive
RIN	Renewable identification number (United States)
SED	Sustainable Energy Production scheme (Netherlands)
TWh	Terawatt hour

Executive summary

Introduction

1. Biopropane is the term commonly used to describe liquid petroleum gas (LPG) derived from production processes that use biomass as the feedstock. Propane and butane (the other main gas that makes up LPG) are traditionally produced as a by-product of crude oil refining and natural gas processing, but new techniques being developed and commercialised can produce these gases from biomass feedstock, usually as a co-product.

2. The molecular structure of pure biopropane is identical to that of conventional pure propane produced from hydrocarbons, so can be blended into LPG or sold in a pure form. As a genuine "drop-in" fuel, it can be used in all current LPG market applications, including spiking of grid-distributed natural gas (bio or fossil methane) to adjust its heating value or density.

3. The main attraction of biopropane is that, as it is derived from renewable biomass, it can bring about significant reductions in greenhouse-gas emissions if it is substituted for fossil LPG. The UK government is, therefore, considering including biopropane – alongside five other new technologies – in the non-domestic Renewable Heating Incentive (RHI), as part of its efforts to meet its climate policy goals. The other technologies are 'heating only' bioliquids, heat networks, gas-driven heat pumps, reversible air-to-air heat pumps, and direct applications of renewable heat.

Characterising the technology and market outlook

4. Biopropane can, in principle, be produced in many different ways, using different types of thermal and chemical processes. Only one technology, hydrotreated vegetable oil (HVO), which involves the hydrogenation of vegetable oil or animal fat to produce diesel, is in full commercial use today, with seven plants in operation around the world. Total capacity of biopropane as of early 2014 amounts to around 130,000 tonnes/year, but the fuel is separated from other off-gases and purified for commercial sale at only one plant in the United States.

5. Neste Oil, the world leader in HVO diesel, is planning to build a biopropane separation unit at one of its plants in Rotterdam, which would make available around 40,000 tonnes/year of biopropane for commercial sale. In principle, similar separation facilities could be built at Neste's two other European HVO plants, and at two other European plants that are due to come onstream this year. If all the biopropane produced at these plants were commercialised, total availability worldwide would reach more than 200,000 tonnes (2.7 TWh) – equal to about 0.5% of European demand and just over 6% of UK demand. This amount also compares with the 16.4 TWh of renewable heat produced in the United Kingdom in 2012 (DECC, 2013a), i.e. 16%, and the central range estimate of the potential production of non-domestic biomass heat by 2020 of up to 50 TWh, i.e. 5.4% (DECC, 2011).

6. Additional HVO plants could be built in Europe or elsewhere, but a large-scale expansion in the next few years is considered unlikely given constraints on the availability of suitable vegetable oil and animal waste feedstock.

7. Extending the RHI to biopropane might make it more favourable to build new HVO capacity in the United Kingdom, as supplying both renewable diesel and biopropane to the UK market would avert the need to incur additional costs in importing those fuels from elsewhere in Europe. Part if not all of the feedstock, for example in the form of rapeseed oil or waste oils/fat, could be sourced domestically, further lowering the cost of HVO feedstock supply to the UK market compared with imports.

8. A number of other companies and organisations around the world are conducting research into other advanced biofuels production processes, some of which involve the production of biopropane co-product or as the principal output. Only one – a biomass catalytic cracking pyrolysis process developed by the US-based company, KiOR (BCC) – is as yet in commercial operation, producing small volumes of biopropane. The longer term prospects for alternative technologies that yield biopropane are very uncertain and depend on the success of efforts to minimise production costs, government incentives for biofuels production (including blending mandates, direct subsidies and favourable tax treatment), feedstock availability and cost, and oil prices.

Using biopropane to spike biomethane

9. DECC is collecting evidence regarding the possible extension of the RHI to biopropane to incentivise its use in spiking of biomethane for injection into the natural gas grid. Producing biomethane is a way to turn renewable waste, typically from food processing, agriculture or sewage treatment, into fungible energy.

10. At present, biogas is captured at a modest number of farms, landfills and sewage works in the United Kingdom. Traditionally this biogas has been used for electricity generation, with the electricity being fed back into the power grid. Research, particularly from Germany, suggests that this might be suboptimal, because: small-scale generators are relatively inefficient; the rural grid is unsuitable for significant power intake; impurities in the biogas can hamper or cripple generator operation; and co-generated heat is usually wasted. It might be more efficient to incentivise the feeding of this biogas into the natural gas grid.

11. Biogas cannot simply be injected into the grid, because it does not meet specifications for non-combustibles and impurities. Injecting it as-it-is could damage the grid and cause hazards. For injection, biogas must be treated to remove its non-combustibles and impurities (mainly carbon dioxide [CO_2], water and hydrogen sulphide). This creates biomethane. Although it consists mostly of methane, the gas usually is not energy-intensive enough to meet the UK grid standard[1].. To meet that standard, most biomethane is spiked with a more concentrated fuel and the fuel of choice for spiking is conventional LPG, typically at a volume ratio of 3-5% to the total spiked product.

12. Because the cost of LPG for spiking constitutes a material additional cost to biomethane sellers, the question has been asked whether minor quantities of injected biomethane always need to meet the energy-intensity requirements of the UK grid, in the short term, the answer is yes. Grid-injection standards require it. Even if the standards were changed, at least some customers might protest. Non-spiked biomethane, because of its lower energy intensity, could cheat customers by giving them fewer kWhs than they pay for.

13. While it is technically feasible to use biopropane for biomethane spiking, the UK market is currently very small, at around 150 tonnes/year. If the UK market were to match that of Germany, by far the largest biomethane producer, demand for spiking LPG (or

[1] A gross Wobbe index of 47.20-51.41 MJ/m3

biopropane) would still rise only to about 5,000 tonnes/year. For that reason, DECC could consider extending the RHI to other potential uses of biopropane for heating purposes. In 2012, the use of LPG amounted to 0.59 million tonnes (Mt) in industry and 0.93 Mt in the household sector and 0.11 in agriculture; an additional 0.09 Mt was used in transport (autogas) and 1.3 Mt as a petrochemical feedstock (DECC, 2013b).

Renewable and carbon saving credentials

14. Biopropane is of interest to the RHI primarily because it offers lower-carbon energy. How much the use of biopropane could reduce greenhouse gas emissions depends on the fuel's carbon footprint (or carbon intensity) and that of the fuel that biopropane displaces.

15. Biopropane is classified as a co-product of the HVO process under the Renewable Energy Directive (RED) (European Commission, 2009). Its carbon footprint can range substantially, typically from 10-50 g of CO_2 equivalent per MJ, with specific batches even beyond that range. This represents a 43-88% carbon savings to the benchmark fossil-fuel it displaces, the 'fossil fuel comparator', which according to the RED has a footprint of 87 g CO_2eq/MJ.[2] The key variable is the choice of feedstock. Lower-footprint feedstocks such as tallow and waste oils generate the lowest-footprint biopropane. Higher-footprint feedstocks such as rapeseed oil generate higher-footprint biopropane. If biopropane were however classified as a residue of the HVO process, we estimate its carbon footprint at around 10 g CO_2eq/MJ.

16. For all the other potential sources of biopropane except one, footprints are very low, because feedstock footprints are low. Woody biomass tends to have a low footprint, and (as noted above) crude glycerol is classified as a 'residue from processing' under RED. The exception among the sources is a process called Aqueous Phase Reforming: as its feedstocks are usually not wastes or residues, the carbon footprint of its biopropane is around 35 g CO_2eq/MJ.

17. HVO biopropane is not wholly renewable, which according to RED 'means energy from renewable, non-fossil sources', because its feedstock consists of 2.8 weight-% fossil-sourced hydrogen. This fossil content is far less than that of conventional FAME biodiesel, which is classified as renewable under the RED.

Market drivers and barriers to deployment

18. All three of the main potential barriers to the deployment of biopropane – technical, legal/regulatory and economic factors – can, in principle, be overcome. There is no technical impediment to the use of biopropane in the United Kingdom: Neste has already confirmed, through engineering studies, that biopropane can be made to the current specification of commercial LPG.

19. The principal potential economic barrier to the deployment of biopropane in the United Kingdom is the cost of production and supply. The indicative cost of producing HVO biopropane, based on a hypothetical 800,000 tonnes/year plant located in the United Kingdom, is estimated at 10.2 pence/kWh (around £1,400/tonne) including the cost of building a separation and purification unit, spreading the cost of the main plant over both the biodiesel and biopropane.

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[2] This comparator is published on page 17, paragraph 17 of Annex I of a report issued under the aegis of RED, Report from the Commission to the Council and the European Parliament on sustainability requirements for the use of solid and gaseous biomass sources in electricity, heating and cooling. COM(2010)11 final, 25 February 2010., ,

20. These costs are well above the current price of propane (3.6 p/kWh in 2013). But Neste and other HVO producers would be able to cover most of their overall cost of production through the price of HVO biodiesel, which is significantly higher. In other words, investment decisions on HVO plants are driven primarily by the price of diesel and not the price of biopropane/LPG.

21. To justify investment only in biopropane separation and purification facilities (at a biodiesel plant that is already built or a planned plant that is economically viable on its own), what matters is whether the marginal price at which the biopropane can be sold at the plant gate, over and above the price of off-gases, is high enough to cover the incremental capital and operating costs, which are estimated to be on the order of 3.5 pence/kWh (not including transportation costs).

22. Of particular importance is whether the fuel would command a significant premium over conventional propane. This might be case, if the United Kingdom or other countries were to introduce incentives to use biopropane or if LPG marketers proved willing to pay a premium for commercial reasons: there would most likely be some marketing value in being able to claim that the LPG is at least partially "green". If no such premiums were to emerge, our analysis suggests that the investment in a separation unit may not be financially attractive, based on the upper end of the range of cost estimates.

23. In any case, there is no reason why the price of biopropane in the market place should mirror the cost of production, as it is a co-product or residue of HVO biodiesel production. We calculate that the cost of actual supply of biopropane to an injection point on the UK gas grid – the price of biopropane in Rotterdam plus the cost of shipping and inland transportation by road in the United Kingdom – would amount to 4 pence/kWh in the absence of a price premium over fossil LPG. This assumes that the biopropane is blended in Rotterdam with conventional LPG to reduce shipping costs.

24. The only significant potential legal or regulatory barrier is the need to meet the sustainability criteria of the RHI (or the RED, if biopropane were to be used as a transport fuel). The RHI stipulates a maximum carbon footprint of 34.8 g CO_2eq/MJ, meaning that given the range discussed above, biopropane's footprint from some feedstocks could exceed the RHI and RED maxima, and might, therefore, be ineligible for incentives.

Conclusions

25. Our analysis supports the view that government intervention is necessary to encourage the use and, potentially, the production of biopropane in the United Kingdom. Without some form of policy support, there would be no particular incentive to ship biopropane to the United Kingdom from the plants that are currently in operation or due to come on stream in the near future; in all likelihood, the biopropane would be sold and consumed in the local market or exported to countries that decide to introduce a specific incentive. To the best of our knowledge, no other country is actively considering a subsidy to the use of biopropane, so the introduction of such as subsidy in the United Kingdom, if large enough, could ensure that available biopropane supplies are diverted to the UK market. The introduction of a financial incentive to use biopropane would also be expected to make it more likely that Neste and other emerging HVO producers decide to invest in separation and purification units.

26. The RHI is an appropriate mechanism for promoting biopropane. Other support mechanisms than the RHI would probably be infeasible or less effective. Mandates are inappropriate, because biopropane not an 'on-purpose' product. If HVO biodiesel production were to cease, so too would that of biopropane, making it impossible for

national mandates to be met. Tax incentives are feasible, but would probably be ineffective. In heating applications that are most attractive to biopropane, a reduction in the excise tax on biopropane (or VAT, if it were possible to implement) or a tax exemption would not be large enough to stimulate demand, and it would be far more complicated to administer than an RHI to suppliers.

27. The actual operation of a biopropane RHI could be similar to the existing RHI for biomethane. RHI payments would be made not to end users, but to central distributors of biopropane. In the event, these would be LPG distributors, to whom this would be an incentive for them to distribute biopropane alongside their primary product.

28. We recommend that a mass-balance approach be adopted as the basis for claiming the RHI, whereby biopropane could be blended with fossil LPG at the top of the supply chain, and the RHI applied to the delivered fuel on a proportional basis, rather than on the actual biopropane delivered to consumers. This would greatly reduce the unit cost of transportation and storage. Consumption of biopropane would not be physically traced, but its sales and purchases recorded in mass-balance accounts.

29. Biopropane for sale would need to be certified as ‘sustainable’, presumably according to criteria for carbon footprint and renewable content. A suitable certification system already is in operation within the European Union for transport biofuels, including HVO biodiesel, and could be extended to cover biopropane.

30. The RHI tariff would need to be large enough to cover the cost of shipping the fuel to the United Kingdom (around 0.2 p/kWh from Rotterdam in 2013) and any additional subsidies that may be applied to the use of biopropane in the country of production in the future (as this would raise the value of the biopropane and, therefore, its price in that market). Although there is a subsidy for the use of renewable energy in power generation in the Netherlands, we understand that it is currently not high enough to make it profitable to use biopropane given the higher price of LPG *vis-à-vis* natural gas.

31. The decision on whether to include biopropane in the RHI needs to take account of the related administration costs, including the certification of supplies under a mass-balance system. These are likely to be relatively small in absolute terms given that there are only a small number of potential sources of biopropane and LPG wholesalers in the United Kingdom, such that the benefits of including biopropane in the RHI would be expected to outweigh the administrative costs.

Introduction

Project scope and approach

1.1. The UK Government plans to review the Renewable Heat Incentive (RHI) in 2014. One of the three themes of the Review focusses on assessing the case for the inclusion of six new technologies in the non-domestic RHI:

- ‘Heating only’ Bioliquids (i.e. those bioliquids that cannot be used for transport).
- Biopropane injection into biomethane installations.
- Heat networks.
- Gas driven heat pumps.
- Reversible air to air heat pumps.
- Direct applications of renewable heat.

1.2. The Department of Energy and Climate Change has retained Menecon Consulting in association with Atlantic Consulting to develop new evidence on the potential for biopropane injection into the gas grid and other applications. Specifically, the work seeks to identify the market potential, carbon-emission savings potential, barriers to deployment and the suitability of the RHI to stimulate the supply of biopropane for injection into the natural gas grid, as well as to obtain detailed information on costs and performance in order to inform calculations of levelised costs and tariffs for biopropane production and injection.

1.3. The information and analysis presented in this report was obtained through market research and techno-economic modelling (including carbon footprinting). The research involved reviewing the relevant literature and public sources of information, as well making direct contact with market participants, observers and other stakeholders (a list of the stakeholders we contacted is included in Annex C). The techno-economic analysis was conducted primarily using spreadsheet software.

Purpose and structure of this report

1.4. This report summarises the overall findings of our work and examines the prospects for biopropane supply for biomethane grid injection in the United Kingdom, including the broader impacts of a decision to extend the RHI to biopropane spiking of biomethane, and discusses other potential uses of biopropane. The findings of this report are to be used to help policy makers decide whether there is a case for supporting biopropane through the RHI or an alternative mechanism and what size of incentive might be required.

1.5. This report is accompanied by a set of analytical outputs, including supply and production costs of different technologies, operational and environmental performance and other characteristics.

Characteristics of biopropane and liquid petroleum gas

1.6. Biopropane is the term commonly used to describe liquid petroleum gas (LPG) derived from production processes that use biomass as the feedstock. LPG is the generic name for mixtures of hydrocarbons that change from a gaseous to liquid state when compressed at moderate pressure or chilled. The chemical composition of LPG can vary, but is usually made up predominantly of propane (C_3H_8) and butane (C_4H_{10}). Propane and butane are traditionally produced as a by-product of crude oil refining and natural gas processing, but new techniques being developed and commercialised can produce these gases from biomass feedstock – either as the primary output or as a co-product. In practice, biopropane may contain some butane (normal butane or isobutene, an isomer of butane) and other light hydrocarbons, though most of the emerging production technologies yield primarily propane.

1.7. Biopropane is a type of biofuel or form of bioenergy, like bioethanol or biodiesel. Nonetheless, the molecular structure of pure biopropane is identical to that of conventional pure propane produced from hydrocarbons, so can be blended or sold in a pure form. As a genuine "drop-in" fuel, it can be used in all current LPG market applications, including spiking of grid-distributed natural gas (bio or fossil methane) to adjust its heating value or heating density.

1.8. Dimethyl ether (DME) – a similar product to propane – can be blended with or substituted for LPG within certain limits. Today, DME is produced largely from methanol (with natural gas or coal as the feedstock). If biomass is used as the feedstock, the resulting DME is referred to as bio-DME (or synthetic DME). Bio-DME may become more widely available than biopropane, depending on the development of new biofuel technologies. One possible use of bio-DME is to blend it with biopropane or conventional LPG. The prospects for dedicated biopropane production depend, at least partly, on the relative economics of producing bio-DME as well as other types of biofuels.

1.9. Propane and butane have a high-energy content on a per tonne basis (in a liquid state) compared with most other oil products, and they burn readily in the presence of air, giving off a hot flame. These characteristics have made LPG a popular fuel for household and commercial heating and cooking, for industrial processes and as an alternative automotive fuel. It is also used as a feedstock in the petrochemical industry. LPG is lighter than water as a liquid but heavier than air as a gas. In their liquid state, both propane and butane have the appearance of water with only about half the density of water. At atmospheric pressure, propane and butane boil at different temperatures: propane at around -42ºC and butane at close to 0ºC. The gas produced when both boil (or vaporise) is invisible and has no natural odour. An odorant is usually added to aid the detection of leaks. In liquid form, the volume of LPG changes significantly in response to changes in temperature. Consequently, storage containers are never filled to capacity to allow expansion to take place without causing an uncontrolled release of gas or damage to the container. LPG is easily stored as a liquid under moderate pressure. One unit of liquid expands to about 250 units of vaporised gas.

1.10. LPG burns cleanly in the presence of air due to its simple chemical composition. The flammable range of LPG is a mixture of between 2% and 10% gas in air. This mixture needs for propane around 24 times and for butane 30 times the same volume of air for complete combustion, which means that LPG needs adequate ventilation to burn cleanly.

1.11. Fossil LPG is derived as a by-product, from crude oil refining or from natural gas or oil production. LPG must be separated out or removed from the oil product or natural gas streams. LPG is generally liquefied for bulk storage and transportation, because its density is much higher as a liquid. This requires pressurised vessels. The gas is normally refrigerated for shipment by sea and sometimes for storage of large volumes at receiving terminals.

1.12. Biopropane can, in principle, be produced in many different ways, using different types of thermal and chemical processes, either as a co-product in the production of other fuels or as the principal output. Only one technology – hydrogenation-derived renewable diesel, commonly referred to as hydrotreated vegetable oil (HVO), which yields significant volumes of biopropane as a co-product – is in full commercial use today. Only one biopropane producer, Dynamic Fuels, sells biopropane as a separate product (its one plant is not operating at present). Neste, the leading producer worldwide, sells the biopropane from its Rotterdam plant, as part of a mixture of other off-gases, to a nearby power plant. A number of companies and organisations around the world are conducting research into other advanced biofuels production processes, some of which involve the production of biopropane as a co-product or as the principal output using a variety of biomass feedstock.

The case for biopropane

1.13. The arguments for and against biopropane are similar to those related to other types of biofuel or bioenergy. There are three main arguments in favour of bioenergy in general, which explain why many governments are actively encouraging their production and use:

- *The energy-security gains from reduced reliance on imported oil or natural gas* (to the extent that the biofuels are produced indigenously). In reality, the degree to which domestic production of bioenergy displaces imported energy may be at least partly offset by the need to import energy to fuel the production process.
- *The economic benefits from indigenous bioenergy production*, through an improved balance of trade and the economic stimulus that it provides to the farm and/or forestry sector and related activities.
- *The potential for reduced emissions of greenhouse gases.* Bioenergy is by definition a renewable energy source, insofar as the carbon emissions (in the form of carbon-dioxide, or CO_2) that result from its combustion are fully offset by the carbon that it initially removed from the atmosphere by the biomass feedstock. CO_2 and other gases may, however, be emitted during the process of transforming the biomass into a useable form of bioenergy, as well as in producing any fertilizer used to grow the biomass and in irrigating the land and harvesting the biomass. The amount of production-related emissions depends on several factors, notably the type of crop; the amount and type of energy embedded in the fertilizer used to grow the crop and in the water used for irrigation; the resulting crop yield; the energy used in gathering and transporting the feedstock to the biorefinery; and the energy intensity of the conversion process. Biofuels production and use involves environmental effects other than greenhouse-gas emissions. Tailpipe emissions of nitrogen oxides, sulphur dioxide, carbon monoxide (CO) and particulates are generally low compared with conventional gasoline and diesel, but are higher in some cases (depending on the biofuel) and are offset to some degree by the emissions from fossil-fuel and fertilizer use in the production of biomass.

1.14. The degree to which any of these arguments in favour of bioenergy hold true depends largely on the type of bioenergy, the production technology involved, the type of feedstock, the need for fossil-energy inputs to the production process and whether the biofuel is produced domestically or imported. Where such benefits are real, they can be global as well as local; for instance, all oil-importing countries would enjoy the energy-security benefits associated with lower imports in a country that produces bioenergy, while the rest of the world would enjoy the climate benefit from lower greenhouse-gas emissions that may result).

1.15. There can, nonetheless, be disadvantages associated with increased use of bioenergy, foremost among which is the cost. In many cases, biofuels are significantly more expensive to produce than equivalent conventional forms of energy – especially in the northern hemisphere, where climatic conditions are less well-suited to producing first-generation biofuels (IEA, 2013a). Thus, it may require large subsidies or financial incentives to make some types of bioenergy commercially viable. There may also be significant local environmental costs associated with biofuels production, as a result of land-use changes. These costs may stem from the impact on eco-systems of intensive farming practices, the increased use of fertilizer and deforestation. Conventional feedstock currently used for biofuels production often requires large amounts of water, pesticides and fertiliser. There may also be social costs from the impact of using biomass for energy production rather than for food, particularly where arable land is devoted to energy-crop production. This has become a major political issue: several studies have shown that the recent surge in biofuels production worldwide has contributed to higher food prices to some degree (see below).

1.16. To date, most investment in biofuel production has gone to first-generation technologies to produce ethanol and fatty acide methyl ester (FAME) biodiesel[3], neither of which produce directly any biopropane. Some advanced, second-generation biofuel technologies, most of which are still at the development stage, have the potential to produce significant volumes of biopropane, but will ultimately need to be cost-competitive with existing biofuels technologies, other emerging biofuel technologies that yield no biopropane and conventional petroleum-based production, taking account of any fiscal or regulatory incentives.[4]

[3] FAME biodiesel is the predominant kind of biodiesel available commercially. It is produced with residue glycerine. HVO biodiesel, produced in much smaller quantities, is produced with the co-product biopropane.

[4] Details about these technologies can be found in Annex A.

Biopropane production technologies

Overview

1.17. Biopropane can, in principle, be produced in many different ways, using different types of thermal and chemical processes. There are a number of different technologies that are in use and under development that are designed to produce biopropane, either as a co-product in the production of other fuels or as the principal output. Only one of these technologies, involving the hydrogenation of vegetable oil or animal fat to produce diesel, is in full commercial use today. There are four patented hydrotreated vegetable oil (HVO) technologies[5] currently in use:

- The Finnish oil company, Neste Oil, has developed the NExBTL renewable diesel production process, which yields biopropane as a co-product. The company has four plants in operation (see below).
- The US company, Dynamic Fuels, has a small stand-alone plant (currently not in operation) that uses Syntroleum's Bio-Synfining process, which also produces mainly biodiesel as well as small volumes of biopropane.
- ConocoPhillips produces a small volume of biodiesel and biopropane at its Whitegate refinery in Ireland using its own proprietary technology.
- Diamond Green Diesel recently started operations at a plant in Louisiana, using the Ecofining technology developed by UOP and ENI.

1.18. To the best of our knowledge, these seven plants are the only sources of HVO biopropane production worldwide at present. Total output capacity of biopropane (unseparated) amounts to around 130,000 tonnes/year. Only the biopropane produced at the Dynamic Fuels plant, when operating, is sold commercially as a separate product as yet, though Neste sells off-gases containing biopropane from its Rotterdam plant to a local power plant. Petrobras also uses a process that hydrogenates mixtures of conventional petroleum and vegetable oil, but the resulting output is not pure biodiesel or biopropane. Two other HVO plants, under construction in Italy and Finland, are due to come onstream in 2014.

1.19. A number of other companies and organisations around the world are conducting research into other advanced biofuels production processes, some of which involve the production of biopropane or bio-DME as a co-product or as the principal output. These technologies can be categorised according to the type of feedstock – vegetable oil, wood and other starchy material and sugar (Figure 1). The maturity of these technologies varies considerably. Only one – a biomass catalytic cracking process developed by the US-based company, KiOR (BCC) – is as yet in commercial operation, producing small volumes of biopropane at a small-scale facility in Mississippi. Some emerging technologies can produce DME, either as an end-product or as an intermediate product that can be further processed to produce biopropane. The principal process technologies are described below.

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[5] Hydrotreated vegetable oil (HVO) is the common term used to describe this type of technology, though, strictly-speaking, the term is a misnomer, as animal fat can be and is used as feedstock too. For that reason, it is sometimes also called hydrogenation-derived renewable diesel.

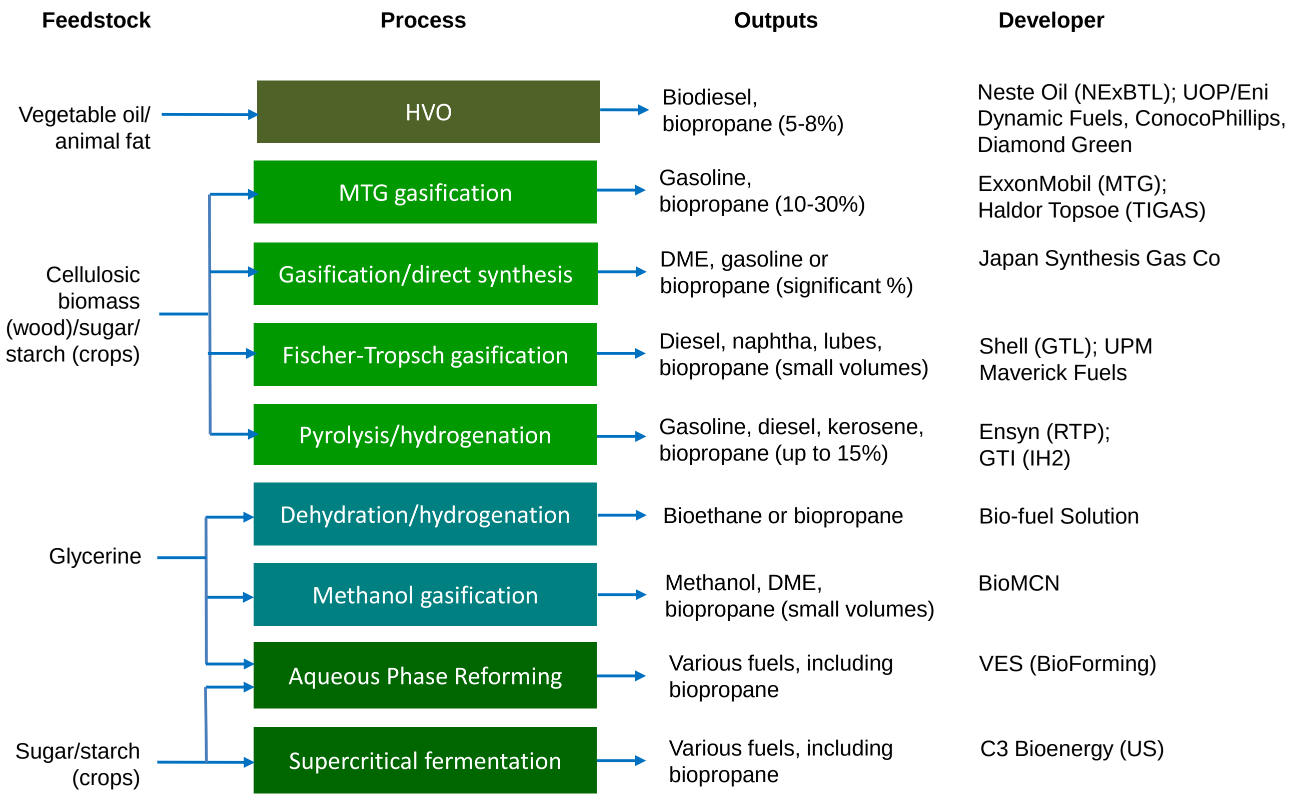

Figure 1: Principal process technologies that can produce biopropane

Source: Menecon Consulting/Atlantic Consulting analysis

Hydrotreated vegetable oil (HVO)

NExBTL technology

1.20. NExBTL (an acronym for Next Generation Biomass to Liquids) is a patented HVO process – an advanced biofuels technology – to produce biodiesel. Chemically, it entails direct catalytic hydrogenation of vegetable oil (a triglyceride) into paraffins. The glycerine chain of the triglyceride is hydrogenated to produce propane. The NExBTL process removes oxygen from the oil so that the diesel is not an oxygenate, as is traditional FAME biodiesel. The technology allows flexible use of any vegetable or waste oil, and the diesel produced is of very high quality (better even than conventional diesel), requiring no modifications to diesel engines and can be blended in any proportion with petroleum diesel. According to Neste, propane represents 4.5% by weight of the total output stream using a feedstock mixture of 70% crude palm oil and 30% palm fatty acid distillate (PFAD); the remaining output is 93.2% biodiesel, 0.6% bionaphtha a mixture of gases, mainly hydrogen, 1.7% (Figure 2). Since the process involves the application of hydrogen, it is well suited to integration at existing refineries where hydrogen is generated as part of the process. This also helps to keep costs low, as existing infrastructure is available.

1.21. Neste has brought four NExBTL plants into production:

- 2 units, each with a biodiesel capacity of 190,000 tonnes per year, at the Porvoo refinery in Finland, commissioned in 2007 and 2009.

- 1 unit at the company's Singapore refinery, with a capacity of 800,000 t/year, commissioned at the end of 2010.
- 1 unit in Rotterdam, also with a capacity of 800,000 t/year, commissioned in 2011. This is the largest biofuel plant in Europe and cost €670 million to build.

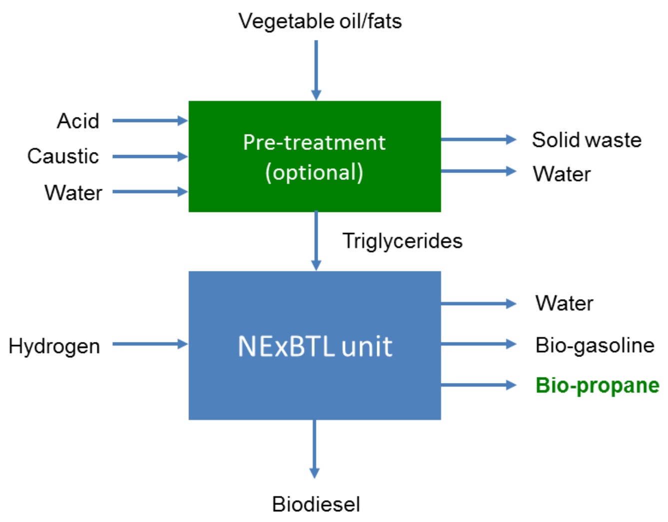

Figure 2: Neste Oil's NExBTL HVO process

Source: Neste Oil (http://www.nesteoil.com/default.asp?path=1,41,11991,12243,12335).

1.22. The company's HVO biodiesel capacity using totals almost 2 million tonnes/year. This implies a biopropane production capacity of around 90,000 tonnes, based on the current feedstock mix. While this is a significant volume, this is nonetheless equal to less than 0.05% of global LPG supply. In Europe, NExBTL's biopropane capacity from its plants in Finland and the Netherlands equals less than 0.3% of the region's LPG consumption. In 2012, Neste's Singapore and Rotterdam plants achieved normal operational status following their ramp-up, and recorded an average capacity utilization of 85%.[6]

1.23. Neste reports that the technology works well and that no major technical hitches have been encountered. Indeed, the Singapore and Rotterdam plants exceeded their nameplate capacities by 10% in the second half of 2013.[7] The company's plants use a range of oils and fats, though crude palm oil is the primary feedstock (Table 1). Others include waste animal fat and fish fat from the food processing industry, camelina oil, jatropha oil, soybean oil, rapeseed oil, technical corn oil, tall oil pitch, PFAD and stearin. They are purchased mainly under short- term contracts. Neste is researching the use of other types of feedstock, including woody biomass, microbial oil and algae (Europe's first microbial oil pilot plant using wastes and residues was commissioned in 2012).

1.24. At present, the biopropane produced is not separated from the other off-gases at any of the Neste plants. The off-gases at Rotterdam are sold to an adjacent power plant, connected by pipeline (the price paid for the gases reflects the fact that the power generated is low carbon and so qualifies for a subsidy under the Sustainable Energy Production (SDE) scheme. At the other plants, the gases are used as feedstock for hydrogen production and/or as energy input. This is considered an intermediate solution:

[6] http://2012.nesteoil.com/business/production--logistics/refineries

[7] Neste Financial Statement for 2013, available at: http://www.nesteoil.com/default.asp?path=1,41,538,2385

Neste told us that it has always been their intention to build purification units to separate out the biopropane and commercialise it as premium renewable LPG, rather than simply blending it into existing conventional LPG supplies. The company launched a study on the feasibility of building a propane purification unit at the plant to strip out the propane (a relatively simple distillation process) in 2012 and engineering work began in late 2013. Neste told Menecon Consulting that it expects to take a final investment decision in summer 2014, possibly before a decision on whether to extend the RHI to biopropane. In any event, Neste told us that it will in all likelihood go ahead at some point. It expects to build similar units at the other plants, though this will depend on how market conditions evolve.

Feedstock	2012		2013	
	Million tonnes	%	Million tonnes	%
Crude palm oil	1.36	64.5	1.1	47.4
Waste and residues (waste animal fat, waste fish fat, vegetable oil fatty acid distillates e.g. PFAD, technical corn oil, stearin, spent bleaching earth oil)	0.74	35.1	1.22	52.6
Other vegetable oil (rapeseed, soy bean, and camelina oil)	0.007	0.3	0.0002	Neg.
Total	**2.11**	**100.0**	**2.32**	**100.0**

Table 1: Biomass feedstock for Neste's NExBTL plants, million tonnes

Source: Neste Oil Annual Report 2013. Available at http://2013.nesteoil.com/business/renewable-fuels/Renewable-raw-material-procurement/.

Bio-Synfining technology

1.25. A US company, Dynamic Fuels – a joint-venture between Tyson Foods and Syntroleum – produces biodiesel, naphtha and biopropane using a similar HVO process to NExBTL. The company commissioned a 5,000 barrels per day (240,000 tonnes/year) plant in Geismar, Louisiana, in November 2010 – the first commercial advanced biofuels plant in the United States. The plant uses Syntroleum's patented Bio-Synfining technology to turn animal by-products such as beef tallow and pork and chicken fat from the local food-processing industry into renewable diesel. The plant cost more than $150 million to build. The plant was idled in November 2012 because of unfavourable market conditions. Agreement on restarting the plant has not been reached, despite the installation of a new catalyst, which is expected to boost yields, and claims by Syntroleum that the plant can now be run profitably.[8] Over the two month prior to its shut down, the company reported that it was running at 71% of capacity. In December 2013, it was announced that Renewable Energy Group would take over the assets of Syntroleum, including its stake in the Geismar plant, which is expected to restart as soon as the deal is completed in 2014.

1.26. Biopropane output capacity is thought to be less than 20,000 tonnes per year (around 7-8% of total capacity). Dynamic Fuels told us that they sell the biopropane as a pure product to an energy company at a market-based price. The biopropane will be covered by the renewable identification number (RIN) scheme under the Renewable Fuel Standards (RFS) – a federal programme that requires transport fuel sold in the United

[8] http://www.thecitywire.com/node/30545#.Uwtu_jiYZaQ

States to contain a minimum volume of renewable fuels – once the company has obtained certification from the Environmental Protection Agency (EPA); the renewable diesel is already certified.[9]

ConcocPhillips HVO

1.27. In 2006, ConocoPhillips began commercial production of renewable diesel using an HVO process at its Whitegate refinery in Cork, Ireland. The process was developed in partnership with the Bartlesville Emerging Technology group. The unit has a capacity of 1,000 barrels per day (50,000 tonnes/year) of renewable diesel, which is blended into conventional biodiesel for sale on the Irish market; the biopropane and other gases produced are not separated or marketed. The main feedstock is soybean oil.

Ecofining

1.28. In 2013, Diamond Green Diesel, a joint venture between Valero subsidiary Diamond Alternative Energy LLC and Darling International, commissioned a renewable diesel plant in Norco, Louisiana with a throughput capacity of10,000 barrel per day (c.500,000 tonnes/year). It is designed to process recycled animal fat and used cooking oil as well as corn oil, using the patented Ecofining pretreatment and hydrotreating/isomerization process developed by the Honeywell subsidiary, UOP, and the Italian oil company, ENI (Figure 3). Diamond Green Diesel claims that the plant will meet almost 14% of the national mandate for production for biomass-based diesel. For now, the biopropane and other off-gases are used as process energy, but the company is considering separating out and commercialising the biopropane as a transport fuel. The EPA ruled in October 2013 that the biopropane and naphtha, as well as the diesel, produced at the plant qualify for classification as renewable fuels under the RFS.[10]

1.29. ENI is also in the process of converting its Porto Marghera refinery in Venice (Italy) into a biorefinery using the same Ecofining technology. The project involves an estimated investment of approximately €100 million (US$130 million), and is the first in the world to convert a conventional refinery into bio-refinery. An initial conversion of existing facilities was completed in 2013 and biofuel production was due to start at the beginning of 2014; output will grow progressively as other facilities enter into operation. Work is due to be completed in the first half of 2015, when throughput capacity will reach 400,000 tonnes/year (producing 310,000 tonnes of renewable diesel). Biopropane capacity is expected to be roughly 15,000 tonnes/year. We understand that ENI plans to separate out the biopropane and blend it with the LPG produced by the naphtha reformer at the refinery, which also supplies the hydrogen for the ecofining unit.

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[9] Under the Energy Independence and Security Act (EISA) of 2007, the RFS programme, now known as RFS2, was expanded to include diesel and the volume of renewable fuel required to be blended into transportation fuel was increased from 9 billion gallons in 2008 to 36 billion gallons by 2022; EISA also established new categories of renewable fuel, and set separate volume requirements for each one, and required EPA to apply lifecycle greenhouse gas performance threshold standards to ensure that each category of renewable fuel emits fewer greenhouse gases than the petroleum fuel it replaces.

[10] http://www.epa.gov/otaq/fuels/renewablefuels/documents/diamond-green-diesel-determination-ltr-10-13.pdf

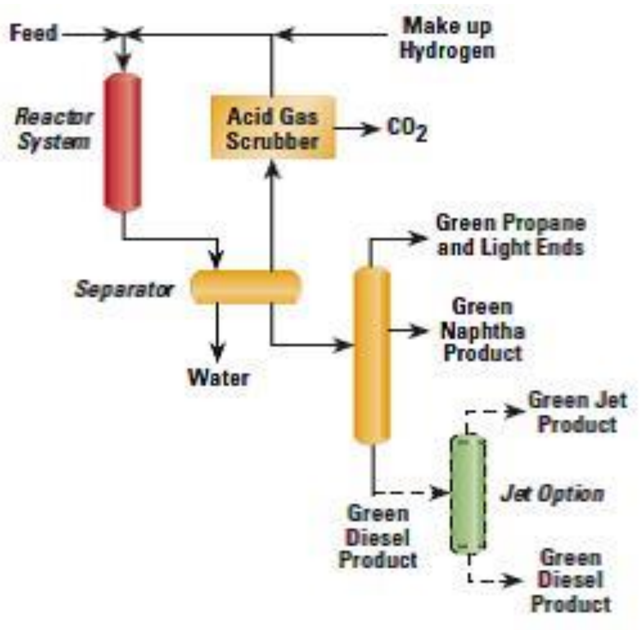

Figure 3: UOP/ENI Ecofining HVO process

Source: http://www.uop.com/hydroprocessing-ecofining/

1.30. UOP also signed an agreement in 2012 to license the same technology to Emerald Biofuels, an Illinois-based transport-fuel company, to produce renewable diesel from second-generation oils and animal fats at a planned 270,000 tonnes/year facility at a Dow Chemical site in Plaquemine in Louisiana. Portugal's largest refiner, Galp Energia, also licenced the technology in 2007 with a view to installing a 6,500 barrels per day (b/d) unit at its Sines refinery, Portugal. Neither company has yet taken a final investment decision.

UPM hydrotreatment

1.31. In 2014, UPM, a Finnish forestry-to-biofuels company, is due to complete the construction of the first biorefinery in the world producing wood-based renewable diesel using HVO technology. The plant will process crude tall oil – a residue of chemical pulp production. The plant, located in Lappeenranta, Finland, on the site of UPM's existing Kaukas paper mill, will have a throughput capacity of 100,000 tonnes.[11] Small quantities of biopropane are thought to be among the by-products, with output expected to be around 6,000 tonnes/year. UPM told us that the fuel is not separated out from other off-gases (which are presumably used as process energy). UPM's total investment amounts to approximately €150 million.

H-Bio Diesel

1.32. The Brazilian state company, Petrobras, has also developed an HVO process that hydrogenates mixtures of vegetable oil and petroleum, producing a fuel known as H-bio diesel that is blended into conventional diesel for marketing. Production started in 2007 at four refineries, but has fluctuated in line with vegetable oil prices, which have often rendered the process uneconomic. It is not known how much vegetable oil is added to the oil feedstock, nor how much LPG is produced (which is not strictly speaking biopropane, as it is only partially derived from renewable energy feedstock). Other

[11] http://www.upm.com/EN/PRODUCTS/Biofuels/Topical/Pages/default.aspx

refining companies, including Total, reportedly hydrotreat mixtures of petroleum diesel and vegetable oil resulting in a partially renewable diesel fuel and yielding small amounts of biopropane, that are typically blended into the refinery LPG streams.

Other technologies[12]

Gasification technologies

1.33. Biopropane can, in principle, be produced as a by-product of various gasification technologies, which involve the conversion of biomass into a synthetic gas (syngas) before being further processed into different products, including methanol, DME, gasoline and diesel. The product yields depend on the makeup of the syngas, the type of process, the process temperature and the catalyst used.

1.34. The main gasification technologies that are under development for used with biomass feedstock (which can be cellulosic or wood-based material or crops) are as follows:

- *Methanol-to-gasoline processes:* Methanol-to-gasoline (MTG) technology, an indirect liquefaction process, involves the gasification of any type of fossil fuel or biomass to produce syngas, which is then converted to crude methanol and low-sulphur, low-benzene biogasoline or biodiesel in separate stages. Various light ends are produced as by-products, including ethane, propane and butane. Methanol has traditionally been produced from coal or natural gas, but research is underway to adapt the process to use different types of biomass or biomass/coal mixtures. Up to 90% of the hydrocarbons in the methanol are converted to gasoline, with propane and butane making up most of the remaining 10%. Depending on the configuration of the plant and the composition of the syngas, LPG output can be as high as 30%. ExxonMobil was the first company to develop a commercial MTG technology in the 1970s, initially using gas and later coal as feedstock. Haldor Topsoe, a Danish company, is also developing a competing process – the TIGAS, or Topsoe Integrated Gasoline Synthesis – to utilise natural gas, coal or biomass for the production of gasoline with LPG as a by-product. A 20 b/d demonstration plant located near Chicago, built in partnership with Andritz/Carbona, Gas Technology Institute, Phillips and UPM-Kymmene, was completed in 2013.[13] Primus Green Energy is also developing a variant of the MTG process and recently built a demonstration plant in New Jersey.
- *Fischer-Tropsch gasification:* Biomass-based syngas can also be reformed to liquids using the well-established Fischer-Tropsch (FT) technology, which involves synthesising syngas into liquid hydrocarbons by passing the syngas through a reactor containing catalysts. However, the output of LPG from this process is relatively small, at a few per cent of the total hydrocarbons output. No commercial plants are yet in operation. The key challenges are securing enough biomass feedstock at low cost and reducing the cost of syngas production and clean-up. Maverick Synfuels, a California-based advanced biofuels company, has built demonstration plants in Florida and Colorado using a patented version of the FT technology which produces small amounts of biopropane. It plans to construct its first small-scale commercial plant once it has

[12] More detailed information about emerging technologies for producing biopropane can be found in Annex A.

[13] http://biomassmagazine.com/articles/9121/haldor-topsoe-and-partners-produce-biobased-gasoline

completed a pilot trial.[14] UPM is also developing an FT technology, in collaboration with the Austrian company, Andritz, for producing renewable diesel using wood.[15]

- *Direct conversion of biosyngas to propane:* The Japan Gas Synthesis Company (JGS) has developed a process, proven at bench-scale level, for the direct synthesis of LPG) from synthesis gas produced from natural gas, coal or biomass. Two catalysts that have been developed that yield a large share of LPG in the output (up to 85%). The company's technology has not yet been commercially deployed, though the company has reportedly sold licenses to investors and Chinese coal companies.

Pyrolysis

1.35. Pyrolysis involves the thermal decomposition of organic compounds, such as wood and agricultural waste products, to create pyrolysis oil (or biocrude), which can then be hydro-processed into gasoline, diesel and/or kerosene.[16] LPG (propane and butane) is produced as a by-product in both steps, amounting to about 10-15 % by weight. The Canadian company, Ensyn, has developed a technology – Rapid Thermal Processing – that uses a fast pyrolysis process that involves the thermal cracking of woody biomass feedstock to gases and vapours. The yields from processing dry biomass (with 8% moisture) are approximately 65 to 80% liquid by weight, with 12-16% each of char and combustible gas, including small amounts of biopropane. The precise liquid yield depends on the feedstock that is being processed.

1.36. Ensyn originally commercialised its RTP technology in the 1980s and currently operates seven small commercial biomass-processing plants in the US and Canada, producing numerous natural chemicals and energy products. Cumulative production to date is around 6 million barrels (an average of 800 b/d). How much of this is LPG is not known, but is unlikely to be much more than 2,000 tonnes/year. In 2008, Enysn and UOP Technology created a joint venture company, Envergent, to research and develop an integrated pyrolysis and hydro-processing technology to produce biofuels. A demonstration project was built in Hawaii. Another company, US-based KiOR, is currently developing the "biomass catalytic cracking" process (BCC), a pyrolysis process that is analogous to fluidised catalytic cracking to produce mainly gasoline and diesel.[17] How much LPG is produced, which is thought to be used as fuel for plant operations, is not known. The first commercial scale production facility with a capacity of approximately 35,,000 tonnes/year was built in 2012 in Columbus, Mississippi. Other larger plants are planned.

1.37. The US Gas Technology Institute (GTI) is developing an integrated hydropyrolysis and hydroconversion (IH2) technology, which converts cellulosic biomass (essentially wood and grass) into gasoline and diesel hydrocarbon blending components with biopropane as a by-product (about 10% by volume of the total liquid product output). GTI claims that IH2 is highly flexible and economical for both small- and large-scale applications. In January 2011, the company signed an exclusive worldwide licensing agreement with the US refining technology firm, CRI/Criterion (a subsidiary of Shell), to accelerate the commercialisation of the technology worldwide.

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[14] http://biomassmagazine.com/articles/9945/maverick-biofuels-changes-its-name-to-maverick-synfuels

[15] http://www.upm.com/EN/PRODUCTS/Biofuels/Biodiesel/Pages/default.aspx

[16] Other processing options are available, including using a reactor with a zeolite catalyst (although this results in lower yields), steam reforming into syngas and then other products, and can even be directly blended with diesel using surfactants to reduce the high-viscosity characteristics of pyrolysis oil.

[17] http://www.kior.com/

Processing of glycerine

1.38. Research and development is continuing on converting glycerine (sometimes called glycerol) – a residue of biodiesel production using conventional first-generation biodiesel production processes that produce FAME – into more valuable forms on energy. The boom in biodiesel production worldwide, particularly in Europe, has led to a huge increase in the supply of glycerine, which has depressed its price. As a result, efforts have been stepped to find alternatives uses for glycerine. In Europe, these efforts have been boosted by the EU Renewable Energy Directive, which allows biofuels produced from glycerine to count double in meeting transport-fuel targets and to be subsidised by member states. One technology, developed by Biofuel-Solution in Sweden but which has not yet been deployed commercially, involves dehydrating glycerine to produce acrolein and then hydrogenating it to produce propanol and then propane through further processing. The biopropane yield is claimed to be around 95 %. Biofuel-Solution is seeking funding to build a pilot plant to demonstrate the technology. Another path would be to produce biopropane as a by-product of biomethanol derived from glycerine, though no plant has yet been built to do so.

Emerging technologies and DME

1.39. There are a number of other technologies at various stages of development. Two prominent technologies are Aqueous Phase Reforming (part of the overall BioForming process), being developed by Virent, and supercritical fermentation, which is the subject of research at several institutions. Aqueous Phase Reforming involves catalytically transforming soluble plant sugars into gasoline and diesel, with biopropane produced as a by-product (the yield is not known). It is expected that much if not all of the LPG produced would be used for process heat, though it could in principle be separated out of the gaseous streams and marketed separately. Virent and Shell recently completed a five-year joint programme to develop and commercialise the technology and a small pilot plant was completed in 2010 in Madison, Wisconsin, with a capacity of around 240 barrels per year; Shell commissioned a small pilot plant in Houston in 2012.

1.40. Researchers at Massachusetts Institute of Technology have reportedly developed a chemical process for making propane from corn or sugarcane and have set up a company, C3 BioEnergy based in Cambridge, to commercialise the technology. The process uses supercritical water – water at a very high temperature and pressure – to facilitate chemical reactions that turn products from the fermentation of the sugars found in corn or sugarcane into propane. To our knowledge, the company has not yet been successful in finding the $25 million that it needs to build a demonstration plant. Other laboratories in the United States are looking at other ways of producing biofuels using super-critical fluids.

1.41. Bio-dimethyl ether (bio-DME) is both another pathway to biopropane as well as an alternative. It could be blended with biopropane or used as an intermediate feedstock for the production of biopropane. DME is chemically very close to propane and butane and displays similar characteristics in use. It is increasingly being used as a source of energy, mainly in China. DME (conventional or bio) can be used as an alternative to diesel (requiring some modifications to the diesel engine) or can be blended into LPG for use in all applications. However, there are limits on how much DME can be blended into LPG, as DME is a solvent so can cause corrosion.

1.42. Today, DME is primarily produced by converting natural gas or coal to syngas, which is then converted to DME in a two-step process via methanol. If the syngas is produced from biomass, the final output of this process would be bio-DME. One-step processes, such as those being developed by Haldor Topsoe and the Japan Synthesis Gas

Company (see above), permit both methanol synthesis and dehydration in the same process unit, eliminating the intermediate methanol synthesis stage and promising gains in efficiency and cost. Another potential pathway is to process glycerine into bio-DME via hydrogenation. It is also possible to convert DME to LPG using hydrogen and catalysts, though the technology has not yet been commercialised. In practice, the additional cost of converting DME to LPG would have to be weighed against the benefits of producing LPG rather than simply blending DME into LPG. To our knowledge, the only significant bio-DME production facility in operation today is a small demonstration plant in Piteå, Sweden, which was commissioned in September 2010 as part of the BioDME research and development project. The feedstock is black liquor, a by-product of the pulping process at the Smurfit Kappa pulp and paper mill.

Economics of biopropane production and supply to the UK market

1.43. The financial rate of return on investment in biofuel plants that yield biopropane depends on:

- the market prices of all of the fuel outputs;
- the cost of production (including the full cost of plant operation and procuring feedstock); and
- any financial incentives that might become available.

1.44. The cost of production of bio propane and other biofuels are heavily dependent on feedstock prices, which tend to fluctuate markedly and can vary considerably across countries and regions according to local market conditions. The market value of the fuel produced is determined both by blending mandates, other forms of subsidy – which push up demand for those fuels – and the price of competing conventional oil products.

1.45. For existing plants to run, the prices obtained for the products produced have to be at least high enough (allowing for any financial incentives) to cover the variable costs of plant operation, including the cost of the feedstock.

1.46. For investors to proceed with new plants, projected revenue streams have to be high enough to cover all costs, including the upfront capital cost of building the facilities, to ensure a return on investment. In practice, the hurdle rate of return on investment may be set relatively high to compensate for market, technical and policy risks, including uncertainties about the future price spread between feedstock and output prices, teething problems with new processes and possible changes in the policy/regulatory environment in the future.

1.47. There is, unsurprisingly, most certainty about the cost of production and the potential cost of supply of biopropane to the UK market for HVO biopropane, as none of the other potential sources of supply are as yet in commercial production (bar KiOR's small pyrolysis plant in Mississippi). No HVO biopropane has been imported into the United Kingdom to date, so the cost estimates for potential supply are indicative. Generic estimates are available of the possible cost of production for some emerging technologies.

HVO biopropane

Potential production costs for a new plant in the UK

1.48. It is important to bear in mind that biopropane from HVO plants is a co-product; the decision to build and to operate the plant once built is driven almost entirely by the value of the HVO diesel produced relative to the cost of feedstock and other fuel inputs. But the additional cost of separating and purifying biopropane, which is allocated solely to biopropane, represents a significant share of the total cost of biopropane production, whether the capital cost is included or not. This is because the HVO production cost without separation includes a credit for the value of the off-gases that are assumed to be used for energy within the plant itself (or sold), which is determined by the price of natural gas, that would otherwise be used; by separating out and commercialising the biopropane, this credit is lost as additional natural gas would be needed for the main HVO plant to replace the off-gases.

	Total plant cost per year (£ million)	Unit cost of biopropane	
		£/tonne	Pence/kWh
HVO plant without biopropane separation & purification			
Fixed costs			
Direct fixed costs – labour	1.1	1.5	0.0
Direct fixed costs – overheads	0.9	1.3	0.0
Direct fixed costs – maintenance	11.4	17.8	0.1
Indirect fixed costs – other	11.4	17.8	0.1
Depreciation	28.5	37.9	0.3
Capital costs	77.5	103.1	0.8
Sub-total	*130.8*	*179.5*	*1.3*
Variable costs			
Feedstock (palm oil)	512.6	681.6	5.0
Hydrogen	35.9	47.8	0.3
Natural gas	2.1	2.7	0.0
Electricity	6.6	8.8	0.1
Non-fuel operating costs	18.2	24.3	0.2
Sub-total	*575.5*	*765.2*	*5.6*
Co-product credits			
Bionaphtha	1.7	2.3	0.0
Biopropane	14.3	19.0	0.1
Total cash cost (excluding depreciation & capital costs)	584.3	782.4	5.7
Total cost of production	690.3	923.4	6.7
Biopropane separation & purification			
Additional fixed costs	0.9	22.1	0.2
Additional variable costs	0.5	12.8	0.1
Loss of biopropane credit	14.3	369.8	2.7
Additional depreciation	0.9	22.1	0.2
Additional capital costs	2.0	53.0	0.4
Total additional cash cost (excluding depreciation & capital costs)	*15.6*	*404.6*	*3.0*
Total additional cost of production	*18.5*	*479.7*	*3.5*
Total cash cost (excluding depreciation & capital costs)	599.9	1187.0	8.7
Total cost of production	708.8	1403.0	10.2

Table 2: Indicative HVO biopropane production cost for plant located in United Kingdom

Note: Based on 2013 costs. The cost of production before biopropane separation and purification are allocated to each product stream (HVO diesel, bionaphtha and biopropane) on an energy basis; the additional costs of biopropane separation are allocated entirely to the biopropane stream. Capital costs include working capital. Capital spending is depreciated over 20 years. Capital costs assume an average weighted cost of capital of 12%.

Source: Menecon Consulting and Atlantic Consulting analysis; information provided by Neste Oil and other industry sources.

1.49. We have been able to obtain from Neste Oil some information on HVO production costs, which we have used, together with generic cost and-fuel price assumptions, to calculate he potential cost of production at a facility that might be built in the United Kingdom. We have also calculated the potential cost of supplying biopropane from Neste's existing plant in Rotterdam.

1.50. Our analysis assumes that a facility of the same size as Neste's Rotterdam plant, i.e. producing 800,000 tonnes/year of HVO diesel and around 40,000 tonnes/year of biopropane, is built in the United Kingdom. We also assume that the plant uses a mixture of imported crude palm oil (75%) and PFAD (25%) as feedstock, like the Rotterdam refinery, though it could also operate using domestically-sourced animal fat and/or waste oils (which might be cheaper).

1.51. The total cost of producing HVO biopropane is estimated at 10.2 pence/kWh (around £1,400/tonne) including the cost of building a separation and purification unit (all other costs are allocated equally on a per-kWh basis to diesel and biopropane) (Table 2). The cash cost, which excludes depreciation and capital costs, amounts to 8.7 p/kWh (£1,190/tonne). Thus, the cash cost makes up the bulk of the total cost of production.

1.52. To justify investment only in biopropane separation and purification facilities (meaning the biodiesel plant is already built or economically viable on its own), what matters is whether the marginal price at which the biopropane can be sold at the plant gate, over and above the price of off-gases, is high enough to cover the incremental capital and operating costs, which are estimated to be on the order of 3.5 pence/kWh (not including transportation costs).

Cost of imported biopropane

1.53. There are no plans reported to build an HVO plant in the United Kingdom. Even if a decision to do so were taken in the near future, it would probably take at least two years for the plant to be commissioned, assuming it were on the same scale as the most recent Neste plant.

1.54. For now, no biopropane is available for import into the United Kingdom: the only existing HVO plant that separates out the biopropane from other off-gases is the Dynamic Fuels plant (which is currently idle) in the United States, and the small volumes of biopropane produced are contracted to another firm. In any case, the plant is currently not operating and, even if it were to start up again in the near future (as the firm expects), it is unlikely that it would ever be economic to export the fuel to the United Kingdom, given the high cost of transportation and regulatory incentives to keep the fuel in the United States.

1.55. There are three possible sources of HVO biopropane that within the next year or so could be exported to the United Kingdom from continental Europe: Neste's three plants, UPM's new plant in Finland and ENI's Venice refinery. We understand that there are firm plans to build the required separation and purification facilities only at Neste's Rotterdam plant. If the company takes a final decision to proceed with the investment in the coming months, the biopropane could become available for export to the UK market before the end of 2015. The maximum amount of biopropane the plant could produce would be around 50,000 tonnes (with the current feedstock mix, output would be no more than about 40,000 tonnes).

1.56. The financial viability of the planned investment in Neste's Rotterdam plant and potential investment at other HVO plants in Europe hinges critically on the capital expenditures associated with the separation and purification unit and on the price of biopropane in the market. The determining factor is whether the price the biopropane can be sold at over and above that of the off-gases is high enough to cover both the capital and operating costs. Of particular importance is whether the fuel would command a significant premium over conventional propane. This might be case if the United Kingdom or other countries were to introduce incentives to use biopropane or if LPG marketers proved willing to pay a premium for commercial reasons: there would most likely be some marketing value in being able to claim that the LPG is at least partially "green". If no such premium was to emerge, our analysis suggests that the investment in a separation unit may not be financially attractive based on the upper end of the range of costs estimates we were able to obtain.

1.57. In any case, there is no reason why the price of biopropane in the market place should reflect the cost of production, as it is a co-product of HVO biodiesel production. We calculate that the cost of actual supply of biopropane to an injection point on the UK gas grid – the price of biopropane in Rotterdam plus the cost of shipping and inland transportation by road in the United Kingdom – would amount to 4.0 pence/kWh in the absence of a price premium (based on the average 2013 LPG price of 3.6 p/kWh[18] and estimated shipping and inland transport costs). At present, the cost of shipping LPG to the United Kingdom is estimated at around $42/tonne (around 0.2 pence/kWh) for a standard small cargo of 1,800 tonnes. This calculation assumes that the biopropane is blended in Rotterdam with conventional LPG (propane) to reduce costs (and that the RHI credit is accounted for on a mass-balance basis).

Emerging technologies

1.58. Some indicative information on production costs and profitability is available for some of the emerging biopropane technologies. However, costs in practice may turn out to be very different to those reported because of the uncertainty surrounding the cost of construction of new-technology plants. In general, the estimated cost of producing biopropane and other biofuels using these technologies is higher than for conventional fuels and existing first-generation biofuel technologies, though the costs could fall sharply through learning, especially if the technologies were commercialised on a large scale. The developers of some emerging technologies claim that they could be economic at oil prices close to today's levels.

Gasification technologies

1.59. There are two principal source of information on potential production costs from gasification-based processes: a study by the US Gas Technology Institute (GTI, 2010) and another by the US national Renewable Energy Laboratory (Phillips *et al.,* 2011). The GTI study calculates a breakeven crude oil price for the production of biopropane from biomass gasification (with carbon capture and storage) of $143/barrel, equating to a propane price of around $2.30/gallon (around £706/tonne, or 5.2 pence/kWh at the 2013 exchange rate).

1.60. The NREL study comes up with substantially lower production costs estimates, based on stand-alone gasification/synthesis process including sub-processes or unit operations for integrated tar reforming, acid gas scrubbing, and synthesis to methanol followed by conversion to gasoline. The calculations assume a mature plant with a capacity of 2,000 dry metric tonnes/day and 2012 technology targets as established in the Multi-Year Technical Plan of the US Department of Energy (DOE) Office of the Biomass Program. Gasoline output is assumed to be 42.5 million gallons and biopropane output 7.1 million gallons. The study concludes that to break even (assuming an internal rate of return of

[18] Spot price for bulk propane free on board at Rotterdam.

10%), the gasoline produced would need to sell at the plant gate at a price of $1.95/gallon and biopropane at $1.53/gallon (£470/tonne, or 3.4 pence/kWh).

Other technologies

1.61. A 2009 report prepared by the Pacific Northwest National Laboratory on behalf of the US Department of Energy on the economics of the pyrolysis of wood to biogasoline or biodiesel (with up to 15% propane/iso-butane as a by-product) came up with lower estimates of the cost of production compared with biomass-based LP Gas production in the GTI analysis. It estimates a production cost of $1.48/gallon of propane (£454/tonne, or 3.3 pence/kWh) based on a 5,000 b/d plant using hydrotreating, hydrogenation and hydrocracking technology.

1.62. Sweden's Biofuels-Solution has prepared estimates of the costs of biopropane production based on the processing of glycerine, assuming a plant with a capacity of 50,000 tonnes per year (Hulteberg *et al.*, 2010). It finds that the overall cost of biopropane production is highly sensitive to the cost of the glycerine feedstock, which tends to fluctuate widely, and the cost of hydrogen. Assuming a glycerine price of $150/tonne (the high end of the actual range of prices in Europe over the five years to 2010) and assuming a 10% internal rate of return, the cost of biopropane production is estimated at around €800/tonne (5.8 pence/kWh); the cost drops to €600/tonne (4.4 pence/kWh) with a glycerine price of €70/tonne.

1.63. Virent claimed in August 2010 that, based on the experience from their demonstration plant at Madison in the United States, production of biofuels (including biopropane as a by-product) using its Bioforming process would cost about the same as gasoline at current crude oil prices of around $70-80 per barrel (at that time).[19] That estimate does include any subsidy or carbon credit. The firm claims that the low energy requirements of the process help to keep operating costs down, while flexibility in the choice of feedstock and end-products produced will help to optimise the economics of plant operation.

[19] http://www.altenerg.com/back_issues/index.php-content_id=358.htm

Biogas production and conversion to biomethane

1.64. When organic wastes rot out in the open, in the presence of oxygen, they decompose mostly into CO_2. When they rot in closed or covered spaces, with oxygen generally absent, they still create some CO_2 but relatively more methane. The latter process, anaerobic digestion (AD), is increasingly being used to convert waste from agriculture, unused food and sewage to biogas, a mixture of CO_2 and methane (Figure 4).[20]

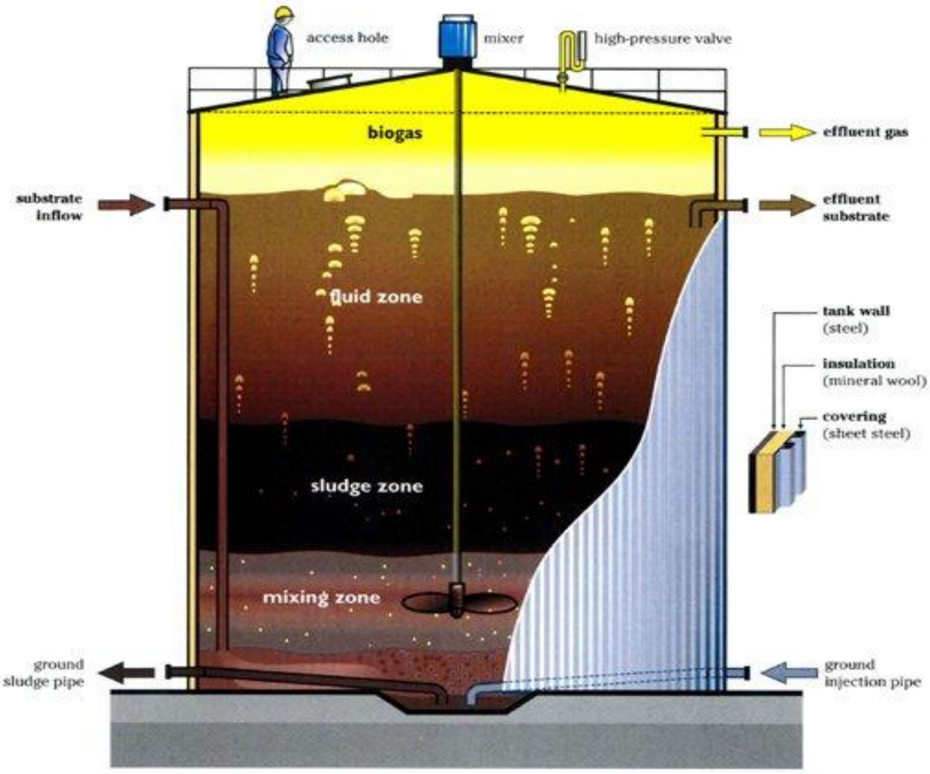

Figure 4: A commercial-scale anaerobic digester producing biogas

1.65. Biogas is in many ways an attractive form of energy. It is renewable, it is supplied domestically, and it makes use of waste that otherwise would need disposal. According to the Anaerobic Digestion and Biogas Association, the United Kingdom could potentially produce 40 TWh of biogas per year (ADBA, 2012). Recent modelling by DECC, as part of the 'The Future of Heating' programme, predicts that around 20 TWh of biogas (of a total gas demand of around 550 TWh) could be blended into the gas network in 2050 from the gasification of biomass, anaerobic digestion and landfill gas (DECC, 2013c).

[20] The process and its economics are well-described in numerous public sources, for instance Fraunhofer Institut and German Ministry for Education & Research (2008), and Teodorita Al Seadi, Dominik Rutz, Heinz Prassl, Michael Köttner and Silke Volk (2008).

Using biogas, however, can be a bit like putting a square peg into a round hole, because the existing network of gas supply and demand has been built around natural gas. Natural gas's main differences compared with biogas are: a much-higher methane content, 90+% compared to around 50%; and a few percent of higher hydrocarbons (mainly ethane plus a bit of propane), whereas biogas's only hydrocarbon is methane. These higher hydrocarbons are more energy rich; they contain more kWh for a given volume than does methane.

1.66. So to use biogas in the system set up for natural gas, its methane content must be boosted by removing most of its CO_2. Water and impurities must also be removed (as is the case with natural gas). This process for making cleaned-up biogas – known as biomethane – takes place in small industrial plants. Capital costs (not including the digester) run from several hundred thousand to several million pounds, depending mainly on their size.

1.67. Still, even this cleaned-up biomethane might not be as energy-rich as the natural gas in the grid. This depends on the grid. To meet the specification of Germany's 'L-grid', which has an average gross Wobbe Index[21] of 42.5 MJ/m^3, just cleaning up the biogas usually is enough to do the job. However, to meet Denmark's 'H-grid' average of 52.0 MJ/m^3 (which is higher than pure methane's gross Wobbe of 50.82), an energy-richer hydrocarbon must be added to the mix.[22]

1.68. Likewise, to meet the UK grid's gross Wobbe specification of 47.20-51.41 MJ/m^3 (UK Health and Safety Executive, 2010), most biomethane needs an energy boost. In principle, the specification could be met by super-intensive clean up to create nearly pure methane, but the extra outlay that would entail in most cases would exceed the cost of adding some LPG. So, most if not all biomethane grid-injection operations in the UK add LPG as part of the process. It is dosed in to the biomethane after the clean-up, directly before injection to the grid.

Must biomethane be spiked before grid injection?

1.69. There is no option but to meet the grid requirements, which are anchored in standards. Automated controls at injection points guarantee that off-spec gas will not enter the pipeline. If spiked gas fails to meet the Wobbe requirement, it is recycled for another dose of LPG.

1.70. Some UK biogas suppliers have questioned the necessity of this. They argue that if only minor amounts of the less energy-rich biomethane were injected, it would just be 'lost in the grid' with no adverse effects. Surely this would save them money, because they pay substantial sums for spiking equipment and LPG.

[21] A measure of a fuel gas's energy intensity, defined as the energy per volume divided by the square root of the gas's specific gravity with respect to air.

[22] See E.ON Ruhrgas & GDF Suez (2010), Table 2, page 11; Fraunhofer Institut & German Ministry for Education & Research (2008), page 25); Emerson Process Management (2007).

In effect, yes. Natural gas must be cleaned and its energy-density adjusted before it enters the gas grid. In part, this consists of removing or adding higher hydrocarbons to the mix at a gas-processing plant, located adjacent to the grid. This does not require the purchase of LPG (neither, too, does imported LNG require an LPG injection as its heating value is adjusted prior to shipment.) Moreover, the grid – and the entire network of gas appliances that use it – was designed with natural gas already in mind. So there has been a feedback loop of supply and demand shaping grid specifications for many years. Adjusting to accommodate biogas, not surprisingly, takes extra effort and negotiation.

Box 1: Must conventional gas be spiked too?

1.71. From a purely technical standpoint, meeting the Wobbe specification is not always necessary. As an Enviros Consulting report puts it, "'Off-spec' gas can be added to the grid if there is sufficient flow to ensure that concentration levels of the biogas do not become too high. If e.g. the Wobbe index of the natural gas is somewhat higher than the minimum limit, the Wobbe index of the upgraded gas can be lower than the specified index as long as the overall mixture meets the specification" (Enviros Consulting, 2008).

1.72. From a commercial standpoint, however, this would be difficult to do in practice. First, the standards would need to be changed. And the reasoning behind the standards would need to be overturned. Probably the most difficult argument to overcome would be that relaxing the specification for biomethane could be tantamount to cheating. Grid gas is sold and metered by volume, with an assumed unit energy content, i.e. volume x unit energy content = kWh. If the assumed unit energy content were to fall, then some customers would pay for more kWh then they actually receive.

1.73. Although cheating could happen, it is not inevitable. According to the same Enviros Consulting report, "the addition of off-spec gas can meet considerable resistance as end-users tend to question the quality of the delivered gas. The mixing of off-spec biogas also requires an adequate feedback measuring and control system to ensure that the overall gas quality remains adequate. It also requires close communication between the upgrading plant operator and the grid owner. Therefore, off-spec delivery is most suitable when the upgrading plant is owned and operated by the grid owner."

Biopropane can replace LPG in spiking

1.74. So, generally speaking, biomethane needs spiking to be allowed into the UK grid. LPG can feasibly be substituted with biopropane, subject to two technical conditions. In the event these conditions are met, biopropane may offer substantially higher value to biomethane suppliers than LPG.

Technical condition 1: Conformance to LPG specification BS 4250

1.75. LPG is fungible throughout Europe, as long as it meets British Standard 4250 (Specification for commercial butane and propane), which stipulates various physical and chemical properties.

1.76. Biopropane suppliers have a strong market incentive to make biopropane a 'drop-in' replacement to LPG – not just as a spiking substitute, but as a substitute to LPG anywhere. To do this, biopropane will need to meet BS 4250, If biopropane did not meet BS 4250, its use in biogas spiking and most other LPG applications, would not be allowed.

1.77. All evidence suggests that this is technically feasible. It is a matter of distillation and purification – processes that are well known and understood, and commonly used on a massive scale in petroleum refining and gas processing. Both of the potential suppliers of biopropane in Europe in the near term – ENI and Neste – operate refineries and processing plants as part of their core businesses.

1.78. As described above, Neste is considering extracting biopropane from the off-gases produced at its HVO plants in Finland, the Netherlands and Singapore. Detailed engineering has already been done for the extraction and purification process, Neste reports, all of it aimed at producing biopropane that will meet LPG specifications.

Technical condition 2: Crediting by mass balance rather than physical consumption

1.79. A potential obstacle to biopropane substitution would be the requirement that it be consumed physically in the application for which it receives RHI credit. In principle, a parallel, dedicated supply system could be established to bring biopropane to biomethane-spiking operations. In practice, this would require additional investment and cash costs that would either dissuade action or increase the RHI credit necessary to make the investment viable.

1.80. Instead of this ‘physical segregation’ method of accounting for renewable-fuel consumption, the credit could be awarded virtually, by using the ‘mass balance’ method accounting. Under mass-balance accounting, production of fuel or energy is divided into batches (or consignments). Each batch is assigned certain ‘sustainability characteristics’, which in biopropane’s case would likely be: carbon footprint and % renewable-origin. These sustainability characteristics are then sold forward within the supply chain, independent of their original batch. The only condition is that, throughout the supply chain, sustainability characteristics must be conserved (hence the ‘mass-balance’ name[23]). When all batches are accounted for, carbon footprint in must equal carbon footprint out. (A detailed definition of mass balance can be found in International Sustainability & Carbon Certification, 2011.)

1.81. So, for instance, a fuel blender might combine two batches of equal size, one with carbon footprint 10 and the other with carbon footprint 20. If he then sells that pool in two equal batches, they can be accounted for as carbon footprints 10 and 20, even though in physical reality they have been mixed to 15 each.

1.82. UK LPG distributors could use this method to account for biopropane. They could receive shipments of biopropane, blend them into their stocks of conventional LPG, and sell on those blends. The sustainability characteristics would be sold independently of the physical biopropane, while their ‘mass balance’ would need to be conserved.

1.83. A mass-balance system would be much cheaper to implement than a physical segregation one, because the former would not require investment in a separate distribution system; the existing one could be used. Mass-balance also has strong precedents. Mass-balance is used already in allocating credits for transport biofuels, both under the EU’s Renewable Energy Directive and under the US Renewable Fuel Standards, for biomethane under the RHI and for green electricity.

[23] This is somewhat of a misnomer. A more accurate name might have been ‘sustainability characteristic’ balance, which probably explains why it was called mass balance.

Substituting bio- for fossil-propane could add substantial value

1.84. The variable cost (i.e. not including capital and fixed costs) to a biomethane supplier of buying LPG for spiking amounts to about 5% of his revenue for the grid-injected gas.[24] Discussions with industry players suggest that capital costs for spiking are £50,000-120,000 for a single injection point – a relatively small cost with respect to those of the digester and the gas-clean-up kit, which typically run into the single-digit millions of pounds.

1.85. As an illustrative example, substituting biopropane for LPG would bring a very significant benefit to biomethane suppliers, if the existing RHI credit for biomethane were extended to the biopropane and if biopropane were priced identically to LPG. Instead of receiving net revenue (minus LPG cost) of £0.90/m3 for LPG-spiked-biomethane, they would receive net revenue of £0.98/m3 for biopropane-spiked-biomethane, an increase of nearly 10%.[25] DECC launched a consultation on changes to the biomethane tariff in May 2014, and including biopropane was not being considered among the potential changes.

UK market potential for (bio- or fossil-propane) spiking

1.86. Grid-injected biomethane is a small industry in the United Kingdom. According to Green Gas Grids[26], some five injection plants are operating, with an estimated total biomethane capacity of 1,000 m^3/hour. This amounts to 0.3 PJ/year of biomethane[27], which is about 0.01% of current UK biogas production, estimated by (Ricardo-AEA, 2014) at 163 PJ/year.[28]

1.87. Demand for spiking LPG is accordingly low, approximately 150 tonnes per year.[29] This is insignificant compared with the overall UK LPG market of 3 million tonnes/year.[30]

1.88. If the UK biomethane-grid-injection industry were to grow to the same size as Germany's, which is by far the largest in Europe with 120 plants, then UK demand for spiking could reach around 5,000 tonnes of LPG (or biopropane) per year.

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[24] The net price of spiked-biomethane minus LPG is about £0.90/m^3. Assuming a 96%:4% blend of biomethane:LPG. The spiked-biomethane revenue is 96% x 37 MJ/m^3 x 1 kWh/3.6 MJ x £0.095/kWh = £ 0.94/m^3 plus a fraction of a penny for the LPG heating value. The cost of the LPG is 4% x 102.7 MJ/m^3 x 1 kWh/3.6 MJ x £0.045/kWh = £0.05/m^3. The biomethane revenue consists of £0.022/kWh wholesale gas price plus £0.073/kWh RHI payment. The LPG price of £0.045/kWh will fluctuate by season.

[25] The net price of spiked-biomethane minus LPG is about £0.98/m^3. Assuming the same 96%:4% blend but of biomethane:biopropane. The spiked-biomethane revenue is 96% x 37 MJ/m^3 x 1 kWh/3.6 MJ x £0.095/kWh = £ 0.94/m^3 plus a 4% x 102.7 MJ/m^3 x 1 kWh/3.6 MJ x £0.095/kWh = £0.083 /m^3. So the total spiked-biomethane revenue is £1.03/m^3. Cost of the biopropane is assumed to be identical to that of LPG, £0.05/m^3.

[26] http://www.greengasgrids.eu/market-platform/cross-country-overview/status-quo-of-biomethane-market.html

[27] Assuming 8,000 hours operation/year and 37 MJ/m^3 of biomethane.

[28] Most of this, some 150 PJ, is used to generate electricity.

[29] 8 million m^3/year of biomethane x 4% LPG = 320 km^3/yr LPG x 2.232 kg/m^3 = 143 t LPG.

[30] Estimated at 2.7 million tonnes/year consumed in petrochemicals, 1.1 million in heating and 0.2 in automotive transport.

Environmental performance of biopropane

Carbon footprint of biopropane

1.89. From a practical standpoint, there are two types of biopropane. Their first is the only type that could enter commercial production in the near future, HVO biopropane. The second is all the other types. Footprints of both types, respectively, are presented in the following sections.

Footprint of HVO biopropane

1.90. There is no current, official classification for biopropane, i.e. no official opinion that says that crude HVO biopropane is either a residue or a co-product. Neste, the only current producer of crude HVO biopropane in Europe, classifies it as a co-product in its sustainability declarations for the main output HVO biodiesel), which increases the declared greenhouse-gas emission savings from that fuel (Neste Oil, 2013, Section 7.1.1.4 and Annex B.1.2). This classification has been accepted by the European Union and the UK Department for Transport (DfT), and so implicitly they have accepted that biopropane is a co-product. However, informal queries to the Directorate-General for Energy, made as part of this study, suggest that the European Commission could accept either classification, and so we also include the footprint if it were treated as a residue. If the RHI is to be extended to biopropane and residue status is to be claimed, presumably the UK Government would need to make that claim explicitly.

1.91. If crude HVO biopropane were classified as a co-product of HVO biodiesel production, then HVO biopropane's footprint would range between 10-50 g CO_2eq /MJ, with specific batches even above that range. This represents a 43-88% carbon saving compared with the benchmark fossil fuel it displaces, the 'fossil fuel comparator', which according to the Renewable Energy Directive (RED)[31] has a footprint of 87 g CO_2eq/MJ (European Commission, 2009). More information on these emissions is presented below.

1.92. If crude HVO were instead classified as a residue, the carbon footprint of HVO biopropane would be much lower, because its direct predecessor – an intermediate known as crude HVO biopropane (i.e. the off-gases containing a mixture of biopropane and other gases) – could be assigned a footprint of nil under the RED. It assigns carbon footprints of zero to certain intermediates it calls 'residues'..

1.93. The precise footprint if treating HVO as a residue would include emissions from extracting crude HVO biopropane, purifying that to commercial-grade biopropane and transporting it to customers, and these have not been reported publicly. Based on discussions with technology providers and operators as well as our own calculations, its footprint is estimated at around 10 g CO_2eq /MJ, with a range of perhaps + 3 g CO_2eq /MJ. Most of this footprint would be generated in the extraction and purification, with the rest coming from transport of the feedstock.

[31] Report from the Commission to the Council and the European Parliament on sustainability requirements for the use of solid and gaseous biomass sources in electricity, heating and cooling. COM(2010)11 final, 25.2.2010. Annex I, Paragraph 17, p 17.

1.94. When wastes are used as raw materials, they are often assigned a carbon footprint of nil. For instance, in a recycling plant, the incoming waste tends to be assigned a footprint of zero (even though there obviously was a footprint incurred in making it in the first place). This zero rating is not the result of a scientific decision; indeed, it is a topic of scientific debate. The rating is political, made with the presumption that re-using wastes is generally desirable.

1.95. The RED, the primary precedent in measuring carbon footprints of bioenergy, adopts this 'waste = zero' approach. And it goes one step further, adding a similar category called 'residue'. As explained in Annex V, Section C, Para 17: *Wastes, agricultural crop residues, including straw, bagasse, husks, cobs and nut shells, and residues from processing, including crude glycerine (glycerine that is not refined), shall be considered to have zero life-cycle greenhouse gas emissions up to the process of collection of those materials*.

1.96. Defining crude glycerine as a residue would set a critical precedent for HVO biopropane. Just as crude glycerine is produced as an unavoidable residue of FAME[32] biodiesel, so too is crude biopropane produced as an unavoidable residue of HVO biodiesel. If crude biopropane therefore is a residue, with a carbon footprint of zero, this has a major impact on the overall footprint of HVO biopropane.

Process	Palm oil with methane capture	Palm oil without methane capture	Rapeseed	Sunflower	Tallow
Cultivation	15	15	30	18	1
Processing	7	30	10	10	8
Transport & distribution*	5	5	1	1	1
Total	**27**	**50**	**41**	**29**	**10**

Table 3: Typical footprints[33] of HVO biodiesel, by process and feedstock (g CO_2e/MJ), considered to be a proxy for HVO biopropane.

* Includes transport of feedstock to the manufacturing plant, and transport of the final product from the manufacturing plant to the customers.
Source: Annex V, RED (European Commission, 2009).

1.97. HVO biodiesel emissions from the RED are presented in Table 3 above, and make up the bulk of the emissions of biopropane when treated as a co-product. On top of these, some additional emissions from extraction and purification of the biopropane would need to be considered. There could also be a small increase to the footprint of the biodiesel if fuel displacement occurs. However these increases considered to be in the order of 1-2 g CO_2eq/MJ, and so are much smaller that the differences in footprint based on feedstock, and indeed less that the variability that is likely to exist between different batches of the same feedstock. It should also be noted that operators do not measure footprints for each co-product, they measure across the entire plant, and then allocate to the co-products.

[32] Fatty acid methyl ester, the predominant type of biodiesel commercially available.

[33] Typical, as defined in the RED. Process figures are derived from Annex V, Section D, with allocation by energy, Tallow is not in the RED but has been derived using the RED methodology.

1.98. The fossil fuel that a renewable fuel displaces is defined by the RED[34] as a 'fossil fuel comparator'. This comparator varies according to application type; different comparators are specified for transport, for heating and for electricity generation.

1.99. The footprint of the comparator for biopropane is not found in the Directive itself, but in a report[35] by the European Commission dated 25 February 2010. In Annex 1, paragraph 17 (page 18), it states: *For solid and gaseous biomass used for heating production, for the purposes of the calculation*[36] *referred to in point 4, the fossil fuel comparator* $EC_{F(h)}$ *shall be 87 g* CO_2*eq/MJ heat*.

1.100. The footprints of HVO biopropane differ considerably. This is due to several factors:

- *Yield of oil:* This can vary considerably. Palm oil output per agricultural input of land, fertiliser, tilling and cultivation is far higher than that of, say, rapeseed – not least, because the tropical growing season is so much longer than that in Europe.
- *Methane capture in palm oil processing:* After palm oil is pressed from fruit bunches (Figure 5), there is a left-over of stems, husks, peels and such that have no economic value. These, mixed with process water from the pressing operation, traditionally have been discharged to lagoons, where they rot naturally. Rotting, in this case, emits substantial amounts of methane, a greenhouse gas. If this methane is captured[37], the footprint of the palm oil is reduced dramatically.
- *Using waste or residue feedstock:* Of the feedstocks shown in Table 3, one of them, tallow, is classified by the RED as a waste. As noted above, waste or residue feedstocks or precursors carry a footprint of nil up to the process of collection of those materials. This tends to have a very large effect on the total footprint.

[34] Report from the Commission to the Council and the European Parliament on sustainability requirements for the use of solid and gaseous biomass sources in electricity, heating and cooling. COM(2010)11 final, 25.2.2010. Annex I, Paragraph 17, p 17.

[35] SEC (2010) 65 final, SEC (2010) 66 final. Report from the Commission to the Council and the European Parliament on sustainability requirements for the use of solid and gaseous biomass sources in electricity, heating and cooling.

[36] Of a fuel's carbon footprint.

[37] As palm oil producers are increasingly doing.

Figure 5: Palm oil fruit bunches, pre-harvest

1.101. Specific results can vary, but the rule-of-thumb is that feedstocks such as tallow and waste oils generate the lowest-footprint biopropane. Higher-footprint feedstocks such as rapeseed or soybean oil generate higher-footprint biopropane.

1.102. In comparing carbon footprints, it is important to be aware of the sensitivity of each estimate to the method of allocating emissions, because several allocation methods can be used. The main ones are: mass, energy content, market value and system expansion.[38]

1.103. The typical footprints presented in Table 3 are calculated according to allocation by energy. For HVO biopropane, this gives very similar results to allocation by energy content.[39] However, footprints calculated using market value or especially system expansion methods[40] can be very different. A US study of biodiesel footprints suggests that using system expansion, as opposed to energy or mass allocation, can change the reported footprint by a factor of two (Argonne National Laboratories, 2008, Figure 5-6).

1.104. The European Union has clearly selected one allocation method for use in carbon footprints of bioenergy: allocation by energy content. Use of this method seems to have been clearly and explicitly agreed, and it does not appear to be up for debate. Nonetheless, DECC should be aware that many footprint studies of bioenergy use market value or system expansion, and that these studies can come up with considerably different footprints than those done according to the accepted EU convention.

[38] Strictly speaking, system expansion is done to avoid choice of an allocation method. In practice, though, it another allocation option, and is used frequently in carbon footprinting.

[39] Which is nearly identical for HVO biodiesel (44 MJ LHV/kg) and biopropane (approx. 46 MJ LHV/MJ).

[40] The system expansion method for allocation, sometimes called the displacement method, is explicitly allowed for footprinting under the RFS currently applied in the United States. RFS also allows allocation by energy content.

Footprints of most other biopropane types

1.105. With one exception, all the other potential sources of biopropane (described earlier in the report and in Annex A) are made from cellulosic biomass or glycerine, feedstocks that are either wastes or residues. So, they leave the forest, field or factory with a footprint of zero.

1.106. Once again, this means that their overall footprints are almost certain to be low. Even allowing for a large processing footprint, it is hard to imagine that – including transport – they would top 15 g CO_2eq/MJ. This is estimated as follows: the refinery-only carbon footprint of gasoline is 6 g CO2eq /MJ according to ecoinvent (2010), which is a reasonably proxy for the processing of biopropane.[41] If, as a safety margin, we double this and add in another 3 g CO_2eq/MJ for transport, the total still comes to only 15.

1.107. The exception among the biopropane processes is the one that converts sugar/starch crops via Aqueous Phase Reforming. These feedstocks are usually not wastes or residues. A reasonable proxy here is bioethanol, produced from maize (starch) or sugar beets. The RED reports typical carbon footprints for these of 37 and 33 g CO_2eq/MJ, respectively.

HVO biopropane is not wholly renewable

1.108. In the hydrogenation of plant oil or animal fat to HVO biodiesel and biopropane, the hydrogen comes from a fossil source – either petroleum or natural gas. This hydrogen amounts to 2.8% by weight[42] of the feedstock to the process. This fossil hydrogen is accounted for in the carbon footprints presented above.

1.109. Biopropane is not the only renewable that is partly fossil-based. HVO biodiesel, which also consists of 2.8 weight-% fossil hydrogen, is classified as renewable. Moreover, the most widely-used biodiesel, so-called FAME biodiesel, consists of about 9 weight-% fossil feedstock, namely methanol. Rules for how this fossil content should be credited against renewables targets are currently under examination by the UK Department for Transport, under its review of the Renewable Transport Fuels Obligation.

Other impacts

1.110. Two other issues could affect the attractiveness of incentivising biopropane: land-use change and the impact of the use of land and crops for biofuels production on food prices.

Land use change – a possible negative

1.111. The conversion of forest to other uses is one of the potential downsides of mass-production of bioenergy. It can result in increased global warming, less biodiversity, water-quality problems and social disintegration. The land use changes induced by palm-oil cultivation (for many different uses) in Southeast Asia have become a particular focus of attention and political significance.

1.112. The carbon effects of direct land-use-change are not included in the footprints compiled in Table 3 in compliance with the RED (Annex V, Section C, Paragraph 7). Instead they are reported individually, for each consignment of biofuel produced. More recently, the

[41] Making biopropane is a chemical/refining process. It is reasonable to assume that it would have a footprint similar to a typical chemical/refining process. Probably the most typical process is that of making gasoline.

[42] Assuming 1.18 kg $C_{57}H_{102}O_6$ + 0.035 kg $H_2 \rightarrow$ 1 kg RD +0.05 kg CO_2 +0.1 kg H_2O +0.06 kg C_3H_8.

Commission and Member states have debated and subsequently rejected a proposal to include carbon effects caused by *indirect* land-use-change (iLUC), i.e. land-use changes around the world induced by the expansion of croplands for biofuels production. Had the proposal been adopted, it would have raised the typical footprints of non-waste-feedstock biodiesel sharply, such that they would no longer have qualified for government incentives under RED.

Impact on food supply and prices

1.113. The degree to which the production of biofuels affect the supply and prices of crops destined for human consumption remains unclear. Recent studies have suggested the impact tends to be less than originally thought and may actually be marginal.[43] In any case, the European Union has stepped up its efforts to incentivise non-food biofuels and reduce incentives to food-based ones.

1.114. Among biofuels in general, biopropane has an advantage in this respect, because it can be sourced to a large degree from non-food feedstocks, such as inedible[44] fractions of palm oil, animal fats and wastes (such as used cooking oil). Indeed, this is one of the economic selling-points of the HVO process: it can use such feedstocks, which tend to be cheaper than food-grade ones. HVO biodiesel also tends to hold an advantage over FAME biodiesel. The FAME process, as currently configured in most manufacturing plants, is limited in its ability to process inedible feedstocks. Most FAME sold in the European Union is produced from food-grade oils.

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[43] See, for example, World Bank, 2013, and Ecofys, 2013

[44] At least to humans.

Barriers/incentives to biopropane deployment

1.115. Potential barriers (or incentives) to deployment of biopropane are of three types: technical, legal/regulatory and economic factors.

Technical

1.116. As noted above (see Technical condition 1: Conformance to LPG specification BS 4250), Neste has already confirmed through engineering studies that biopropane can be made to the current specification of commercial LPG.[45]

Economic

1.117. The principal potential economic barrier to the deployment of biopropane in the United Kingdom is the cost of production. This is discussed in detail in the above section, Economics of biopropane production and supply. We have identified three other potential economic barriers, all of which can be overcome.

Physical consumption accounting, rather than mass balance

1.118. As noted above (see *Technical condition 2: Crediting by mass balance rather than physical consumption*), accounting for biopropane consumption with a 'physical consumption' method rather than the 'mass balance' method would create additional costs. Given that the mass balance method is widely used already, there would seem to be no reason to apply the physical consumption method.

Economy of scale

1.119. If the RHI for biopropane is applied only to biomethane spiking, the market potential over the next five years or so is at best only 5,000 tonnes (see *UK market potential for (bio- or fossil-propane) spiking)*. If a larger market is made available, presumably by extending the scope of biopropane's RHI to other applications, this will reduce the overall cost, by spreading fixed costs over a larger volume of supply.

Inclusion in the existing RHI

1.120. If the RHI is not extended to biopropane, there would be no particular incentive to ship biopropane to the United Kingdom from the plants that are currently in operation or due to come on stream in the near future; in all likelihood, the biopropane would be sold and consumed in the local market or exported to countries that decide to introduce a specific incentive.

[45] Neste reports the design of its proposed separation/purification unit at the Rotterdam plant will produce biopropane to meet the following limits: C_2 max. 5 mol-%, C_4+ max. 5 mol-%,total S max. 50 wt-ppm. In other words, it would meet commercial specifications for LPG.

Legal and regulatory

1.121. If the use of biopropane as a transport fuel were to be encouraged by the UK government through the RHI or some other form of financial incentive, it would need to meet the sustainability criteria of the RED. These stipulate that transport biofuels eligible for incentives must achieve greenhouse-gas savings of 35% or more. In 2017 and 2018, the savings hurdle rises to 50% and then to 60%. For biopropane used in transport, this means the maximum carbon footprint[46] eligible for incentives would be: 54.4 g CO_2eq/MJ today, 41.9 g in 2017 and 33.5 g in 2018. For biopropane used in heating, the maximum carbon footprint[47] eligible for incentives would be that stipulated by the RHI, i.e. 34.8 g. When considered as a co-product, not a residue, 'typical' biopropane from some feedstocks, as defined in RED's Annex V (Table 3), would exceed the 2017-18 transport maximum as well as the maximum already in place for heating, therefore making it ineligible for incentives. If crude biopropane were considered a residue, biopropane would easily exceed the carbon savings criterion.

1.122. However, RED's greenhouse-gas hurdles are binding only for transport fuels. For non-transport applications, the hurdles serve not as requirements but guidance. EU member states are free to set their own footprint criteria.

1.123. Biopropane could be used in the transport sector, to substitute some of the few hundred thousand tonnes of LPG consumed annually as an automotive fuel. But this is not at all necessary. A UK heating market of over 1 million tonnes/year for LPG is potentially available, which dwarfs the possible supply of biopropane in the foreseeable future.

[46] Relative to a fossil fuel comparator of 83.8 g CO_2e/MJ.

[47] Relative to a fossil fuel comparator of 87 g CO_2e/MJ.

Outlook for biopropane supply

1.124. The prospects for expanding production from HVO plants and how quickly, if ever, emerging second-generation biofuels technologies now under development that yield biopropane could be commercialised are clearly very uncertain. The prospects for both depend on the success of efforts to minimise production costs, government incentives for biofuels production (including blending mandates, direct subsidies and favourable tax treatment), feedstock availability and cost, and oil prices. Clearly, the higher the prices of conventional refined oil products, the greater the financial viability of technologies generally to convert biomass to liquid or gaseous fuels for a given set of prices of biomass feedstock (though, in practice, production cost and feedstock prices are correlated with oil prices to some degree). Yet, even if relative costs fall or oil prices rise to a level that makes those technologies commercially attractive, taking government incentives into account, biofuels that do not yield much or any biopropane may be preferred to those that do. In particular, technologies that produce bio-DME rather than biopropane may prove more successful.

1.125. In any event, because biopropane is a co-product of most of the technologies in use and under development, the supply of biopropane will be driven largely by the economics of producing renewable gasoline or diesel. It follows that incentives to biopropane are likely to have only a limited impact on investment in plants that produce biopropane as a co-product.

HVO plants

1.126. Output of biopropane from the seven existing HVO plants worldwide and the new ENI plant that is due to start up this year is expected to total around 135,000 tonnes in 2014, assuming the Dynamic Fuels plant resumes production and the other plants operate at close to full capacity. Of this output, less than 10,000 tonnes from the Dynamic Fuels plant is expected to be available commercially as pure biopropane, as no separation and purification facilities are in place as yet at any of the other plants in operation.[48] The biopropane from Dynamic Fuels is understood to be contracted to a local buyer so will not be available for export.

1.127. The first commercial supplies of biopropane available in Europe could come onto the market in 2015 or 2016, if Neste and/or ENI decide to build the necessary facilities. If Neste Oil invests in a purification unit at its Rotterdam plant as expected, then up to 40,000 tonnes/year (0.55 TWh/year) of biopropane will become commercially available (based on the current feedstock mix). This would grow to around 65,000 tonnes/year (0.88 TWh/year) if ENI decides to purify and markets its biopropane output. If all the biopropane produced at plants currently in operation or about to start up were commercialised, total availability worldwide would reach around 200,000 tonnes/year (2.72 TWh/year) – equal to about 0.5% of current European demand and 6% of UK demand (Table 4). This amount also compares with the 16.4 TWh of renewable heat produced in the United Kingdom in 2012 (DECC, 2013a), i.e. 16%, and the central range

[48] ENI plans to purify the biopropane from the HVO unit at its Venice refinery, which is starting up in 2014, but we understand that the biopropane will then be blended with conventional LPG.

estimate of the potential production of non-domestic biomass heat by 2020 of up to 50 TWh, i.e. 5.4% (DECC, 2011).

1.128. The prospects for investment in new HVO capacity hinge to a significant degree on the availability and cost of suitable feedstock. Any significant growth in production capacity would push up global demand for vegetable oil, driving up its price and reducing the margin and prospective rate of return on investment in new plants. The fact that vegetable oil is a food crop and that there are concerns about the sustainability of some vegetable oils, notably palm oil, may also constrain the long-term production growth potential of HVO (though some of the palm oil feedstock currently used is made of grades that are not useable as food – see Environmental performance of biopropane, above). The local availability of waste animal fat in amounts that are large enough to supply a commercial-scale plant may also be a constraining factor. Several people in the biofuels industry we spoke to, including Neste, were of the view that a large-scale expansion of HVO production worldwide is unlikely in view of the constraints on feedstock supply.

	2013	2014	2015	2020	Assumptions
HVO					
Current capacity					
Neste - Porvoo 1 &2	10	10	10	10	Plant runs at full capacity
Neste - Singapore	40	40	40	40	Plant runs at full capacity
Neste - Rotterdam	40	40	40	40	Plant runs at full capacity
Dynamic Fuels	0	9	18	18	Plant restarts in 2H 2014 and runs at full capacity thereafter
ConocoPhillips	3	3	3	3	Plant runs at full capacity
UPM - Finland	0	0	6	6	Plant not fully commissioned until end-2014
ENI - Venice	0	3	16	25	Full production reached in mid-2015
Diamond Green Diesel	1	31	31	31	Plant runs at full capacity from 2014 and averaged a third in 2013
Possible new capacity					
Emerald Biofuels	0	0	0	17	Planned 270kt plant proceeds after 2015
Sub-total	***94***	***136***	***164***	***190***	
Other production paths					
Gasification	0	0	0	0	
Pyrolysis	4	4	4	11	10% yield at KiOR plant & 2 similar plants commissioned by 2020
Other	0	0	0	0	
Sub-total	***4***	***4***	***4***	***11***	
Total	**98**	**140**	**167**	**201**	

Table 4: Medium-term outlook for biopropane supply to 2020 (thousand tonnes)

Source: Menecon Consulting and Atlantic Consulting analysis.

1.129. The uncertainty over biofuels policy may also undermine investment in new HVO plants, particularly in Europe and the United States. There are no formal plans as yet for an extension of the renewable energy mandates beyond 2020, while there are discussions in the United States over a possible scaling back of the overall biofuels mandates under RFS2.[49] It is also uncertain whether the US biodiesel tax credit, which expired at the end of last year, will be reinstated and applied retroactively.

1.130. Extending the RHI to biopropane might make it more favourable to build new HVO capacity in the United Kingdom, as supplying both renewable diesel and biopropane to the UK market would avert the need to incur additional costs in importing those fuels from elsewhere in Europe. Part if not all of the feedstock, for example in the form of rapeseed oil or waste oils/fat, could be sourced domestically, further lowering costs of supply of that feedstock to the UK market compared with imported feedstock.

Other sources

1.131. Emerging biofuel technologies other than HVO processes that yield at least some biopropane are at varying stage of development. The technologies that may be closest to commercialisation are biomass-gasification, pyrolysis and the biomass-reforming process currently being developed by Virent. KiOR's commercial-scale pyrolysis production technology is the most advanced; one facility has already been brought onstream, though the small volume of biopropane produced – around 4 tonnes/year – is currently used as fuel for plant operations, and others are planned.

1.132. The global output of biopropane from these emerging technologies is unlikely to reach a significant level before 2020. Even if total production capacity from bio-MTG, pyrolysis and reforming plants combined reached 500,000 tonnes per year – a highly optimistic projection in view of the current difficulties in financing new biofuel projects and the lead times involved in commissioning complex new production facilities – biopropane output would probably not exceed 50,000 tonnes per year. Not all of this output would be marketed.

1.133. Beyond 2020, there is potential for growth in production from these and other technologies that yield biopropane. Initially, these technologies may require significant government support for them to be financially viable. In the longer term, their commercial viability will hinge critically on the results of on-going biofuel research and development efforts, particularly those focused on production technologies based on using non-food biomass feedstock. Public and private research and development (R&D) spending on biofuels is thought to have increased substantially in recent years, particularly in the United States and Europe, where the increased use of biofuels has been mandated.[50]

Scenario-based long-term projections

1.134. In spite of these R&D efforts, biopropane production is likely to remain modest in relation to total world LPG supply in the longer term. We have calculated the possible supply of biopropane to 2035 based on the central scenarios of the world's two leading sources of long-term energy projections to illustrate the long-term biopropane supply potential: the US Energy Information Administration's *International Energy Outlook 2013* and the International Energy Agency's *World Energy Outlook 2013* (EIA, 2013; IEA, 2013b). We assumed that 10% of the world's biofuels supply in that year would come from advanced

[49] The mandated volumes for cellulosic ethanol have already been lowered, though the volumes for biomass-based diesel were raised in 2013 to compensate. The EPA has proposed a mandated volume of 1.28 billion gallons for 2014 – unchanged from 2013 (http://www.epa.gov/otaq/fuels/renewablefuels/documents/420f13048.pdf).

[50] IEA data on public spending on research, development and demonstration is available at http://wds.iea.org/WDS/Common/Login/login.aspx.

biofuel technologies that yield biopropane either as the primary product or as a co-product; and that the average biopropane yield would be 15%.[51]

1.135. This analysis results in projected world biopropane production in 2035 of 36,000 b/d (1.1 million tonnes) based on the EIA projection reference scenario and 62,000 b/d (just under 2 million tonnes) based on the IEA New Policies Scenario (Table 5).

1.136. These calculations are intended purely to illustrate the technical potential and should not be treated as a forecast; biofuels production could grow considerably faster than projected by either the EIA or the IEA, and the share of biopropane in biofuels production could turn out to be considerably higher. Nonetheless, this analysis demonstrates that the volume of biopropane that could be produced is likely to remain marginal in relation to total LPG supply for at least the next two decades or so.

Source	Biofuels (mb/d)	Biopropane		Biopropane as % of world LPG production
		Mb/d	Million tonnes	
International Energy Outlook 2013 (EIA)	2.400	0.036	1.133	0.28%
World Energy Outlook 2013 (IEA)	4.100	0.062	1.951	0.58%

Table 5: Projected world biopropane supply in 2035

Note: Assumes 10% of biofuels production comes from gasification-based processes yielding 15% biopropane. For the EIA, LPG production is assumed to grow at the same rate as natural gas production between 2012 and 2035, since it does explicitly project LPG production.

Source: Menecon Consulting and Atlantic Consulting analysis; EIA (2013, 2014); IEA (2013b).

[51] Neither the IEA nor the EIA explicitly project biofuels by type of technology at the global level. The EIA projects US biofuels supply by type: by 2035, advanced biofuels (excluding cellulosic ethanol) are projected to reach 17% of US biofuels supply in the reference scenario (EIA, 2014). Taking this as a proxy for the world as a whole, and given that not all emerging advanced biofuel technologies produce any biopropane as a co-product, we assumed that 10% of world biofuels output in 2035 would come from those technologies that do. We also assumed a yield of 15% based on the approximate typical yield of biopropane from emerging gasification and pyrolysis technologies.

Feasibility of applying the RHI to biopropane spiking of biomethane

1.137. Applying the RHI – to biopropane used to spike biomethane – is clearly feasible, both technically and legally. Depending on the RHI tariff, it is potentially feasible economically too: if a tariff similar to that already granted to biomethane were to be applied, there would a strong incentive to use biopropane. In other words, the barriers to its deployment (see ‘Barriers’ chapter above) are surmountable.

1.138. This chapter addresses how the RHI for biopropane could work, its benefits, how those benefits could be increased, and how RHI compares to other support mechanisms.

How a RHI for biopropane would work

1.139. The actual operation of a biopropane RHI could be similar to the existing RHI for biomethane. RHI payments would be made not to end users, but to central distributors of biopropane. In the event, these would be LPG distributors, to whom this would be an incentive to distribute biopropane also.

1.140. Biopropane distributors would account for their biopropane intake and outgo using the mass-balance’ method. That is, biopropane would be accounted for – and this would be on the basis of periodic RHI claims. Biopropane distributors could sell to their customers the ‘sustainability characteristics’ of biopropane, i.e. its carbon content or renewability, without physically delivering biopropane to those same customers.

1.141. Consumption of biopropane would be not be physically traced (any more than the consumption of green electricity, biomethane or transport biofuels are traced). In physical reality, it would be blended into the LPG distribution network[52], ending up as a small portion of all LPG applications. In the records of mass-balance accounting, however, biopropane would be sold and bought by specific entities.

1.142. Biopropane for sale would need to be certified as ‘sustainable’, presumably according to ceilings for carbon footprint and fossil content. A suitable certification system already is in operation for transport biofuels, including HVO biodiesel, and could in theory be extended to cover biopropane.

[52] A virtual grid, as it is sometimes called, consisting of terminals, tankers, depots and other transport infrastructure that moves over 1 million tonnes of LPG throughout the UK every year. It is called virtual, because its connections are a bit less obvious than those of the electricity or the natural gas grids, where linkages of pipe or wire are plain to see.

The RHI for biomethane (and, presumably, biopropane) functions somewhat differently to the RHI for other renewables. For the others, the RHI is based on actual heat generated. For biomethane, the RHI is based on the lower-heating-value of the fuel injected into the distribution network. Where and when that fuel is converted to heat, is not known precisely.

For a biopropane RHI, the system mechanics would likely be similar to those for biomethane. Suppliers would need to register their activity with the government through OFGEM, providing a list of injection equipment; details of measurement and heating-value calculations; a schematic of the flows; evidence that the biopropane will be suitable for consumption as LPG; and evidence of metering accuracy. Periodically they would need to provide date and quantity of injections; feedstock origin and supplier; and sustainability information for the feedstocks and product.

Presumably the periodic information would be reported by suppliers quarterly. Payment of the resulting RHI would follow within six weeks.

Box 2: Registration, reporting and payment for a biopropane RHI

Benefits: unit-carbon savings, consumer acceptance, economic development

1.143. Substituting biopropane for LPG would create, on a unit basis, a considerable reduction in greenhouse-gas emissions. The carbon-footprint reduction per MJ is similar to that of substituting other advanced biofuels for fossil fuels. Given that the fossil-fuel comparator has a carbon footprint of 87 g CO2eq/MJ and biopropane's ranges from 10 to 50 g CO_2eq, this/ implies a saving of 37 to 77 g CO_2eq/MJ, or 43% to 89%.This equates to between 1.70 and 3.54 tonnes CO_2eq saved per tonne of biopropane[53] substituted, which is much higher than the savings for most transport fuels. The most common substitution in the European Union, rapeseed FAME biodiesel for fossil diesel, achieves a saving of only 1.4 t CO_2eq per tonne of biodiesel.[54]

1.144. Some renewables require consumers or distributors to make changes in their operations or equipment that can be difficult and/or expensive. Heat pumps, for instance, typically require the installation of underfloor radiators. Wind power's volatile availability has pushed greater adoption of fast-cycling gas generators. Biopropane, by contrast, as a genuine 'drop-in' fuel, requires no adjustment by consumers and a minimum by distributors.

1.145. Incentivising a business for biopropane – which does not yet exist – is an opportunity for the United Kingdom to become a market leader. No other countries are known to be offering incentives to use it.

1.146. It also offers a potential boost to UK refining and chemical processing. Having a local market will offer an incentive for the next HVO plant to be located in the United Kingdom. UK refiners, like their counterparts throughout Europe, are generally struggling with declining demand, overcapacity and aging equipment. One rescue strategy could be to convert uncompetitive, existing refineries into competitive bio-refineries. ENI, the Italian

[53] Assuming a biopropane lower heating value of 46 MJ/kg, identical to that of LPG.

[54] From RED Annex 5. The typical greenhouse-gas saving for rapeseed biodiesel is 45% from fossil fuel comparator of 83.8 g CO_2eq, i.e. a saving of 37.7 g CO_2eq. FAME biodiesel's LHV is 37.2 MJ/kg.

oil company, is in the process of doing this at its Porto Marghera refinery in Venice. The attractiveness of this strategy would be enhanced by the emergence of a viable market for biopropane.

A way to boost the benefit

1.147. The absolute impact of the development of the use of biopropane for spiking biomethane in the United Kingdom would, however, remain small. Even in the medium term, the total UK market for biomethane-spiking might at best amount to 5,000 tonnes/year, saving 17,700 tonnes CO_2eq. For that reason, one could consider extending the RHI to include other, larger-scale applications such as space and water heating. In 2012, the use of LPG amounted to 0.59 million tonnes (Mt) in industry and 0.93 Mt in the household sector and 0.11 in agriculture; an additional 0.09 Mt was used in transport (autogas) and 1.3 Mt as a petrochemical feedstock (DECC, 2013b).

How that compares to other support mechanisms for biopropane

1.148. Other support mechanisms than the RHI would probably be infeasible or less effective:

- Mandates are inappropriate, because biopropane is derived from a residue; it is not an ‘on-purpose’ product. If HVO biodiesel production were to cease, so too would that of biopropane, making it impossible for national mandates to be met.
- Tax incentives are feasible, but would probably be ineffective. In heating applications that are most attractive to biopropane, a reduction in the excise tax on biopropane (or VAT, if it were possible to implement) or a tax exemption would not be large enough to stimulate demand, and it would be far more complicated to administer than an RHI to suppliers.
- Tax credits would need to be awarded to end-consumers, rather than to suppliers, who are tax-neutral.

Conclusions

1.149. Our analysis supports the view that government intervention is necessary to encourage the use and, potentially, the production of biopropane in the United Kingdom. At present, the only biopropane likely to become available in Europe within the next year or two is from Neste' existing Rotterdam HVO biorefinery and, perhaps later, from ENI's Venice HVO refinery and/or UPM's small HVO facility in Finland. Supplies from any of these sources would require decisions to invest in facilities to separate and purify biopropane from other off-gases. The introduction of a financial incentive to use biopropane would also be expected to make it more likely that Neste and other emerging HVO producers decide to invest in separation and purification units, increasing the potential supply of biopropane to the UK market. Without government support, there would be no particular reason why biopropane available in Europe or the world would be exported to the United Kingdom. To the best of our knowledge, no other country is actively considering a subsidy to the use of biopropane, so a subsidy in the United Kingdom, if large enough, could divert supply to the United Kingdom.

1.150. The greenhouse-gas savings from substituting HVO biopropane for fossil fuels can be as much as 3.5 t CO_2 per t biopropane, considerably higher than the 1.4 t/t saved by substituting the most common biofuel, FAME biodiesel. The actual savings, to some degree, depend on the feedstock used and whether the biopropane produced is classified as a co-product or a residue, but at the lower end would likely still be around 1.7 t/t

1.151. The RHI is, in our view, an appropriate mechanism for encouraging the use of biopropane in the United Kingdom. There is no reason why the mechanism could not be applied in a way similar to the RHI for biomethane. We recommend than a mass-balance accounting approach be adopted, whereby biopropane can be blended with fossil LPG at the top of the supply chain and the RHI applied to the delivered fuel on a proportionate basis rather than on the actual biopropane physically delivered to consumers. This would greatly reduce the unit cost of transportation and storage.

1.152. The RHI tariff would need to be large enough to cover the cost of shipping the fuel to the United Kingdom and any additional subsidies that may be applied to the use of biopropane in the country of production in the future (as this would raise the value of the biopropane and, therefore, its price in that market). Although there is a subsidy for the use of renewable energy in power generation in the Netherlands, we understand that it is currently not high enough to make it profitable to use biopropane for that purpose given the higher price of LPG *vis-à-vis* natural gas. At present, the cost of shipping LPG to the United Kingdom is estimated at around 0.2 p/kWh. The cost of inland transport, from the import terminal to the point of use, varies of course according to the volumes transported and distance travelled. In the case of biomethane spiking, we estimate that cost for a 10-tonne load transported to an injection point on the natural gas grid would be of the order of 0.1-0.2 p/kWh.

1.153. The decision on whether to include biopropane in the RHI needs to take account of the related administration costs, including the certification of supplies under a mass-balance system. These are likely to be relatively small in absolute terms given that there are only a small number of potential sources of biopropane and LPG wholesalers in the United Kingdom, such that the benefits of including biopropane in the RHI would be expected to outweigh the administrative costs.

Annex A: Emerging technologies for producing biopropane

Gasification technologies

1.154. Biopropane can be produced as a by-product of various gasification technologies, which involve the conversion of biomass into a synthetic gas (syngas) before being further processed into different products, including methanol, DME, gasoline and diesel. The product yields depend on the makeup of the syngas (Box 1), the type of process, the process temperature and the catalyst used. The main gasification technologies that are under development for used with biomass feedstock (which can be cellulosic or wood-based material or crops) are described below.

Syngas (synthetic gas or synthesis gas) is the name given to a gas mixture that contains carbon monoxide (CO) and hydrogen (H_2). Syngas is usually produced by steam reforming natural gas or coal, but can be produced from biomass. The relative ratios of CO and H_2 and the composition of the impurities in the syngas, depend on several factors, including the type of feedstock, the rate in which the feedstock is fed into the gasification chamber and the temperature and pressure at which the chamber is operated. In general, a ratio of H_2 to CO of 1.5 or greater is needed to produce a high percentage of hydrogenated products relative to oxygenated products. As with gasification technology, there are several technologies available to purify the syngas and to adjust the ratio of H_2 and CO. The purity of the syngas is an important factor in the rate of degradation of the catalysts used in subsequent processing of the syngas.

Conversion of biomass to syngas is typically low-yield compared with natural or coal feedstock. Research is underway to improve yields, raise thermal efficiency and limit problems with waste. Biomass can be combined with coal to produce syngas. This can reduce problems with tar, as the presence of coal means that higher temperatures can be used in the production process. In addition, the addition of coal may allow the production facility to be scaled up, reducing unit costs, where the local availability of biomass is limited. When a mixture of coal and biomass is used as feedstock, the resulting LPG output would be only partially biopropane, though it may be officially categorised as such (thereby benefiting from any policy incentives for renewable bioenergy) depending on the overall emissions savings and local regulations.

Box 3: Syngas derived from biomass

Methanol-to-gasoline processes

1.155. Methanol-to-gasoline (MTG) technology, an indirect liquefaction process, involves the gasification of any type of fossil fuel or biomass to produce syngas, which is then converted to crude methanol and low-sulphur, low-benzene biogasoline or biodiesel in separate stages. Various light ends are produced as by-products, including ethane, propane and butane. The outputs can be sold directly or blended with conventional refinery gasoline. Methanol has traditionally been produced from coal or natural gas, but research is underway to adapt the process to use different types of biomass or biomass/coal mixtures (a process to produce methanol from glycerine has recently been brought into commercial production – see below). Up to 90% of the hydrocarbons in the methanol is converted to gasoline, with LPG (propane and butane) making up most of the remaining 10%. Depending on the configuration of the plant and the composition of the syngas, LPG output can be as high as 30%. To be economic, MTG plants normally need to be very large.

1.156. ExxonMobil was the first company to develop a commercial MTG technology in the 1970s. In that process, part of the methanol feed is dehydrated to DME over an alumina catalyst. A mixture of methanol, DME and water is then converted in the MTG reactors containing a ZSM-5 zeolite catalyst into light olefins. Heavy gasoline is then passed through a reactor to remove impurities. A final distillation step leads to the synthesis of higher olefins, normal and iso-paraffins (including propane and butane), aromatics and naphthenes (Figure 6). The catalyst limits the hydrocarbon synthesis to light products. Methane, ethane, propane and butane are removed in a de-ethanizer. The liquid product from the de-ethanizer is then sent to a stabilizer where propane and part of the butane components are removed. These products are typically used as fuel gas, but can be marketed.

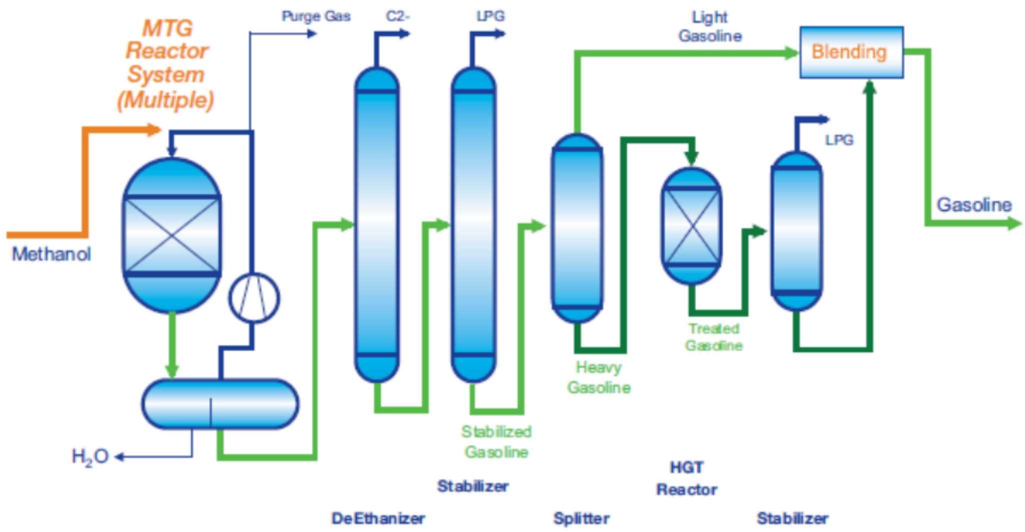

Figure 6: ExxonMobil's methanol-to-gasoline process

Source: ExxonMobil Research and Engineering, Methanol to Gasoline (MTG): Production of Clean Gasoline from Coal (company brochure); available at: http://www.exxonmobil.com/Apps/RefiningTechnologies/files/sellsheet_09_mtg_brochure.pdf.

1.157. ExxonMobil started up a MTG plant in New Zealand in 1985, processing natural gas, and operated it for more than 10 years before converted into a chemical-grade methanol production. In the 1990s and 2000s, ExxonMobil adapted the technology to improve the efficiency of the process, lower capital costs and allow the use coal as the feedstock to profit from the widening gap between coal and oil prices. In 2009, a 100,000 tonnes of gasoline per year (2,300 barrels per day, b/d) plant using the MTG process was commissioned in China by Jincheng Anthracite Mining Group (JAMG). The plant is part of a demonstration-scale complex, which also includes a coal gasification plant and a methanol plant. The second stage of the project is expected to see an expansion of capacity to about 1 million tonnes/year.

1.158. DKRW Advanced Fuels has agreed to use the MTG technology to convert methanol produced from the coal-based Medicine Bow Methanol project in Wyoming in the United States. The project involves the capture of 3.6 million tonnes of CO_2 per year, which will be delivered by pipeline to Denbury Resources for enhanced oil recovery at its oilfields in the Rocky Mountains. The plant, which will produce more than 20,000 b/d of gasoline, is due to come on stream in 2015. Although not technically biopropane the LPG output will be low-carbon.

1.159. In 2008, ExxonMobil and Synthesis Energy Systems agreed on an option to build up to 15 MTG units at SES coal gasification plants globally in 2008, but because of financing difficulties following the financial crisis, none has yet been given the green light.

1.160. Haldor Topsoe, a Danish company, is also developing a competing process – the TIGAS, or Topsoe Integrated Gasoline Synthesis – to utilise natural gas, coal or biomass for the production of gasoline with LPG as a by-product. Like ExxonMobil's process, TIGAS converts the syngas derived from the feedstock to methanol to gasoline via DME, but the TIGAS process converts the methanol to DME in one step using integrated reactors and methanol is not separated as an initial product (Figure 7). Consequently, Haldor Topsoe claims the process is more efficient and less costly. According to a recent study by the US Gas Technology Institute, total LPG yields in the TIGAS process are around 19% by weight but could in principle be increased to about 25-30% (GTI, 2010). Two TIGAS demonstration plants have been built to date: a 1 tonne/day plant in Houston and 3 tonnes/day plant near Chicago, built in partnership with Andritz Carbona, Gas Technology Institute, Phillips and UPM-Kymmene, completed in 2013. Testing is underway with a view to building a commercial-scale plant.

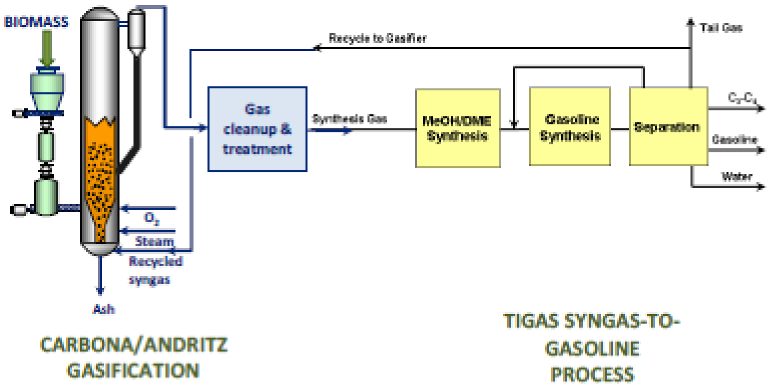

Figure 7: Haldor Topsoe's TIGAS process

Source: http://www.iea-bioenergy.task42-biorefineries.com/upload_mm/0/7/2/7c696ad5-6737-4b7a-b5cf-c3f27f8d3aab_(5)%20Wood%20to%20green%20gasoline%20using%20Carbona%20gasification%20and%20Topsoe%20TIGAS%20processes%20-%20Niels%20Udengaard.pdf

1.161. Primus Green Energy – a US subsidiary of Israel Corporation's renewable energy unit, IC Green Energy – is also developing a MTG process , having recently expanded its development facility in New Jersey. Its technology is a proprietary variant of the ExxonMobil process, simplified to produce standard gasoline without need for separation or further treatment. The company claims that its gasoline is cost-competitive with fossil fuels without subsidy. In 2013, it completed construction of its first full-scale demonstration plant in Hillsborough, New Jersey, which will produce up to 100,000 gallons of drop-in gasoline annually.[55] Although the feedstock is natural gas, the company is looking at adapting the technology to use biomass feedstock.

Fischer-Tropsch gasification

1.162. Biomass-based syngas can also be reformed to liquids using the well-established Fischer-Tropsch (FT) technology, which involves synthesising syngas into liquid hydrocarbons by passing the syngas through a reactor containing catalysts. However, the output of LPG from this process is relatively small, at a few per cent of the total hydrocarbons output. Recent advances in catalyst technology and high oil prices have spurred large investments in new natural gas-to-liquids plants using this technology, notably the 30,000 b/d Oryx plant in Qatar, which was commissioned in 2007. A second Qatari GTL plant, the 140,000 b/d Pearl projects is being built by Shell and is due to begin operation in 2011. In principle, the syngas required for the FT process (as with MTG technologies) can be derived from biomass, though no commercial plants are yet in operation. The key challenges are securing enough biomass feedstock at low cost and reducing the cost of syngas production and clean-up.

1.163. UPM is also developing an FT technology, in collaboration with the Austrian company, Andritz, for producing renewable diesel using wood-based biomass. The company is studying the feasibility of building a plant either in Rauma, Finland, or Strasbourg, France. The environmental impact assessment has been completed in Rauma and started in Strasbourg.[56]

1.164. Maverick Synfuels, a California-based advanced biofuels company, has built demonstration plants in Florida and Colorado using a patented version of the FT technology known as Olefinity, which is designed to run on biomass and waste. The feedstock is first converted into syngas, which is then converted to olefins using a Fisher-Tropsch synthesis, or, alternatively, to methanol, which is then converted to olefins using a methanol-to-olefins process. In the final step, the olefins are converted into high-value products, including small amounts of biopropane. The company claims that the synthesis is conducted at lower pressures than in conventional gas-to-liquids plants, making the production facility less expensive to build, maintain, and operate. It also claims that product yields per pass are higher: because the reaction is carried out at a relatively low pressure, it is economically feasible to recompress any unreacted syngas and to recycle it through the reactor to increase the overall syngas conversion. The company uses existing technologies to convert biomass to syngas. It plans to construct its first small-scale commercial plant once it has completed a pilot trial.[57]

Direct conversion of biosyngas to propane

1.165. The Japan Gas Synthesis Company (JGS) has developed a process, proven at bench-scale level, for the direct synthesis of LPG (with very high selectivity) from synthesis gas produced from natural gas, coal or biomass. The process involves the use of methanol synthesis catalyst and zeolite in a fixed bed reactor to produce in separate stages, methanol, DME, olefins (a class of unsaturated open-chain hydrocarbons such as ethylene) and LPG (via hydrogenation) – all in a single reactor (Zhang *et al.*, 2004). Two catalysts that have been developed yield a large share of LPG in the output (between

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[55] http://www.biofuelsdigest.com/bdigest/2013/10/02/primus-green-energy-commissions-100000-gallon-per-year-gtl-plant/

[56] http://www.upm.com/EN/PRODUCTS/Biofuels/Biodiesel/Pages/default.aspx

[57] http://biomassmagazine.com/articles/9945/maverick-biofuels-changes-its-name-to-maverick-synfuels

78% and 85%). While there are various existing technologies for synthesis of methanol and DME from syngas, DME from methanol, olefins from methanol and/or DME and LPG via hydrogenation of olefins, the JGS catalysts allow all of these steps to be combined into a single reactor. This may lead to a cost-effective technology for the production of biopropane from biomass.

1.166. JGS has Japanese LPG companies as shareholders and uses four patents held by Professor Kaoru Fujimoto of the University of Kitakyushu (who is also a board member of the company): two on the production process from ethanol or DME to propane and butane; one on catalysts for LPG production (combination of more than two zeolite catalysts); and one on the production of LPG/gasoline out of synthetic gas. JGS receives research and development grants from the government through the New Energy and Industrial Technology Development Organisation and runs the bench plant in Kitakyushu together with the University of Kitakyushu and Japan's National Institute of Advanced Industrial Science and Technology. The company's technology has not yet been commercially deployed yet, though the company has reportedly sold licenses to investors and Chinese coal companies.

Pyrolysis

1.167. Pyrolysis involves the thermal decomposition of organic compounds, such as wood and agricultural waste products, to create pyrolysis oil (or biocrude), which can then be hydro-processed into gasoline, diesel and/or kerosene.[58] LPG (propane and butane) is produced as a by-product in both steps, amounting to about 10-15 % by weight.

1.168. The Canadian company, Ensyn, has developed a technology – Rapid Thermal Processing – that uses a fast pyrolysis process, in which wood feedstock is heated to more than 450º at ambient pressure to generate high yields of a light, non-viscous oil. Dried wood is typically converted to approximately 75% (by weight) liquid with the balance converted to combustible gases and char. The pyrolysis process does not directly heat the biomass, but is based on the application of a hot "transported" bed (typically sand) that is circulating between two key vessels. The wood is subjected to fast, intimate contact with the hot sand, resulting in the thermal cracking of the feedstock to gases and vapours. Product vapours are rapidly quenched, or cooled, and recovered as a light liquid product. Conversion typically takes place in less than two seconds, which allows for high yields with low capital costs. The yields from processing dry biomass (with 8% moisture) are approximately 65 to 80% liquid by weight, with 12-16% each of char and combustible gas, including small amounts of biopropane. The precise liquid yield depends on the feedstock that is being processed. The char is separated from the sand in a cyclone and this, as well as the off-gas, is typically used as fuel for plant operations. The biopropane could, in principle, be stripped out of the gas and marketed separately.

1.169. Ensyn originally commercialised its RTP technology in the 1980s and currently operates seven small commercial biomass-processing plants in the US and Canada, producing numerous natural chemicals and energy products. Cumulative production to date is around 6 million barrels (an average of 800 b/d). How much of this is LPG is not known, but is unlikely to be much more than 2,000 tonnes/year. In 2008, Enysn and UOP Technology created a joint venture company, Envergent, to research and develop an

[58] Other processing options are available, including using a reactor with a zeolite catalyst (although this results in lower yields), steam reforming into syngas and then other products, and can even be directly blended with diesel using surfactants to reduce the high-viscosity characteristics of pyrolysis oil.

integrated pyrolysis and hydro-processing technology to produce biofuels. The US Department of Energy awarded the company a grant of US$25 million to build a demonstration project in Hawaii, which is expected to be commissioned in 2012.

1.170. Another company, US-based KiOR, is currently developing the “biomass catalytic cracking” process (BCC), a pyrolysis process that is analogous to fluidised catalytic cracking used in petroleum refineries to convert large hydrocarbons into smaller ones.[59] Marketed output is mainly gasoline and diesel. How much LPG is produced is not known. It has already built a small demonstration plant in Houston and completed construction of its first commercial scale production facility in Columbus, Mississippi, in 2012. Any LPG produced is thought to be used as fuel for plant operations. Total capacity will be around 700 b/d (approximately 35,000 tonnes/year). The company plans to build other plants, potentially scaling up the Columbus facility by a factor of three.

Integrated hydropyrolysis and hydroconversion

1.171. The US Gas Technology Institute (GTI) is developing an integrated hydropyrolysis and hydroconversion (IH2) technology, which converts cellulosic biomass (essentially wood and grass) into gasoline and diesel hydrocarbon blending components. This process is carried out in two integrated stages (Figure 8). The first stage is a medium-pressure, catalytically-assisted, fast hydropyrolysis step completed in a fluid bed under moderate pressure. Vapour from this stage passes directly to a second stage hydroconversion unit, where a proprietary hydro-deoxygenation catalyst removes all remaining oxygen and produces gasoline and diesel range liquids along with biopropane a by-product (about 10% by volume of the total liquid product output). A unique feature of this process is that all the hydrogen required in the process is produced by reforming the light hydrocarbons (mostly methane and ethane) produced in the process. GTI claims that IH2 is highly flexible and economical for both small- and large-scale applications.

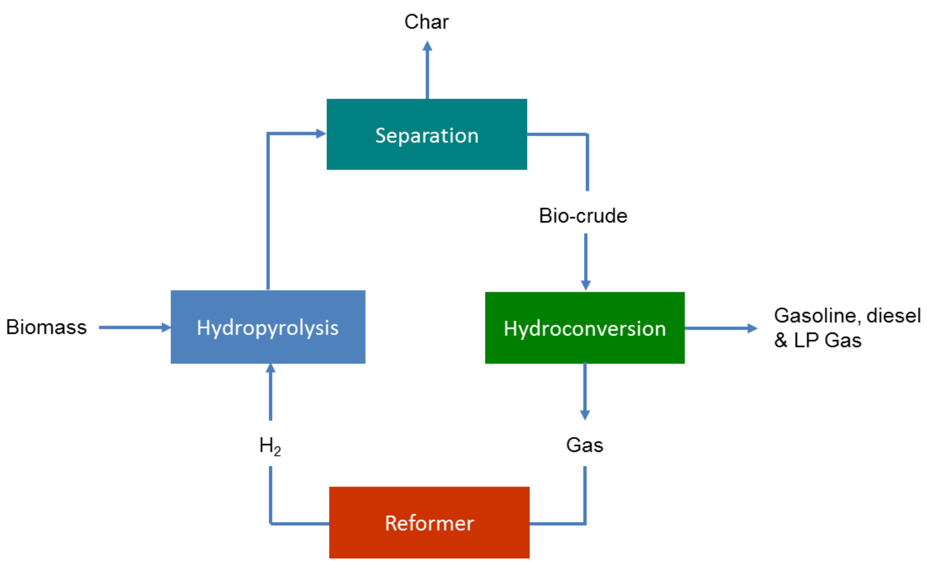

Figure 8: GTI’s IH2 process

Source: GTI (2012).

1.172. GTI has received funding to develop the technology from the US Department of Energy (EERE Office of Biomass Program) under the integrated biorefinery initiative.

[59] http://www.kior.com/

Participants in the IH2 development project include Cargill, Johnston Timber, Aquaflow, Blue Marble Energy, the National Renewable Energy Laboratory and Michigan Technological University. In January 2011, the company signed an exclusive worldwide licensing agreement with the US refining technology firm, CRI/Criterion (a subsidiary of Shell), to accelerate the commercialisation of the technology worldwide. According to GTI, Criterion is pressing ahead with plans to build commercial and has commissioned engineering and design work on a 120,00 tonnes/year plant.[60]

Processing of glycerine

1.173. Research and development is continuing on converting glycerine (sometimes called glycerol) – a residue of biodiesel production using conventional first-generation biodiesel production processes that produce fatty acid methyl esters (FAME) – into more valuable forms on energy. The boom in biodiesel production worldwide, particularly in Europe, has led to a massive increase in the supply of glycerine, which is used primarily in the food, pharmaceuticals and chemicals industries, and a collapse in its price. As a result, efforts have been stepped to find alternatives uses for glycerine. In Europe, these efforts have been boosted by the EU Renewable Energy Directive, which allows glycerine to count double in meeting transport-fuel targets and to be subsidised by member states.

1.174. One technology, developed by Biofuel-Solution in Sweden but which has not yet been deployed commercially, involves dehydrating glycerine to produce acrolein and then hydrogenating it to produce propanol and then propane through further processing (Figure 9). Thus, most of the glycerine would be converted be to biopropane. Recent experimental work has demonstrated that a dual-function catalyst increases the biopropane yield to around 95 %, while the by-products are mainly methane, ethane and CO. Alternatively, the acrolein can be converted to ethylene or ethane via decarbonylation. Biofuel-Solution is seeking funding to build a pilot plant to demonstrate the technology.

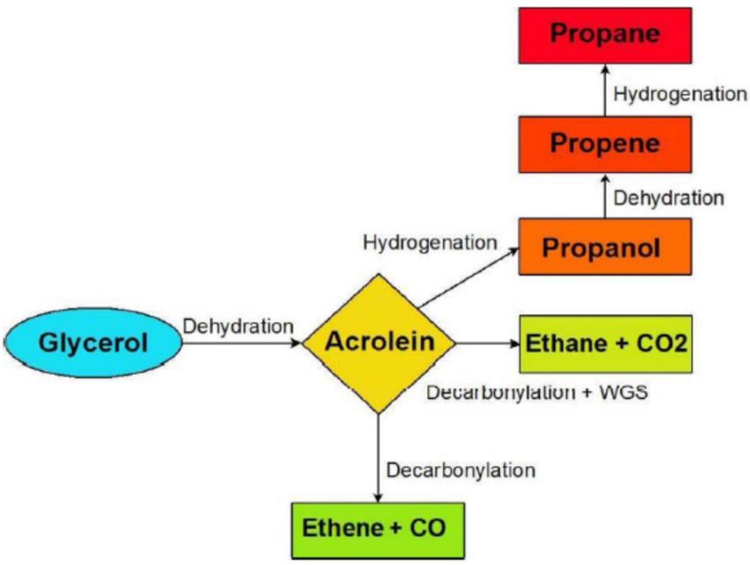

Figure 9: Biopropane from glycerine Biofuels-Solution production process

Source: Brandin et al., (2008).

[60] http://www.cricatalyst.com/catalysts/renewables/presentations/ih2-technology-economics-update-.html

1.175. Another path would be to produce biopropane as a by-product of biomethanol derived from glycerine. BioMCN, a Dutch biofuels company, started up a pilot plant – the first plant of its kind – in Delfzijl in the Netherlands in 2008, producing 20,000 tonnes of biomethanol per year, and a full production unit of 200,000 tonnes per year in 2009 – the largest advanced biofuels plant in the world at that time (it has now been overtaken by Neste Oil's NExBTL plant in Rotterdam). The new plant purifies and evaporates crude glycerine, which is then used to produce biosyngas for making biomethanol. The company plans to build another large-scale plant at the same site to produce biomethanol from woody biomass. Although the biomethanol is currently sold as a chemical and for blending with gasoline, it could in principle be used as feedstock for making biopropane or bio-DME (potentially for blending with LPG).

Other technologies

1.176. There are a number of other technologies at various stages of development. Two prominent technologies are Aqueous Phase Reforming (part of the overall BioForming process), being developed by Virent, and supercritical fermentation, which is the subject of research at several institutions.

1.177. The Virent BioForming technology involves catalytically transforming soluble plant sugars into gasoline and diesel, with biopropane produced as a by-product. The biogasoline has a higher energy content than ethanol that is normally produced from sugar in biorefineries. Sugar mixtures, including five- and six-carbon sugars, disaccharides, and other water soluble polysaccharides can potentially be derived from sugar and energy crops, as well as agricultural and forestry residues. This flexibility translates into more biomass options and potentially lower input costs. The BioForming process is based on the combination of Virent's core Aqueous Phase Reforming technology with conventional catalytic processing technologies, including catalytic hydrotreating and catalytic condensation processes (Figure 10). Like a conventional petroleum refinery, each of these process steps in the BioForming platform can be optimized and modified to produce a particular slate of desired hydrocarbon products. For example, a gasoline product can be produced using a zeolite (ZSM-5) catalyst-based process, jet fuel and diesel can be produced using a base catalysed condensation route, and a high octane fuel can be produced using a dehydration/oligomerisation route.

1.178. The Aqueous Phase Reforming process was initially developed (at the University of Wisconsin-Madison) to produce primarily biopropane The company's research and development programme was modified under the guidance of the US Department of Energy (DOE) to primarily produce gasoline and diesel, as these products are expected to be more in demand, improving the economics of the technology. In gasoline/diesel mode, it is not known how much biopropane is produced. It is expected that much if not all of the LPG produced would be used for process heat, though it could in principle be separated out of the gaseous streams and marketed separately.

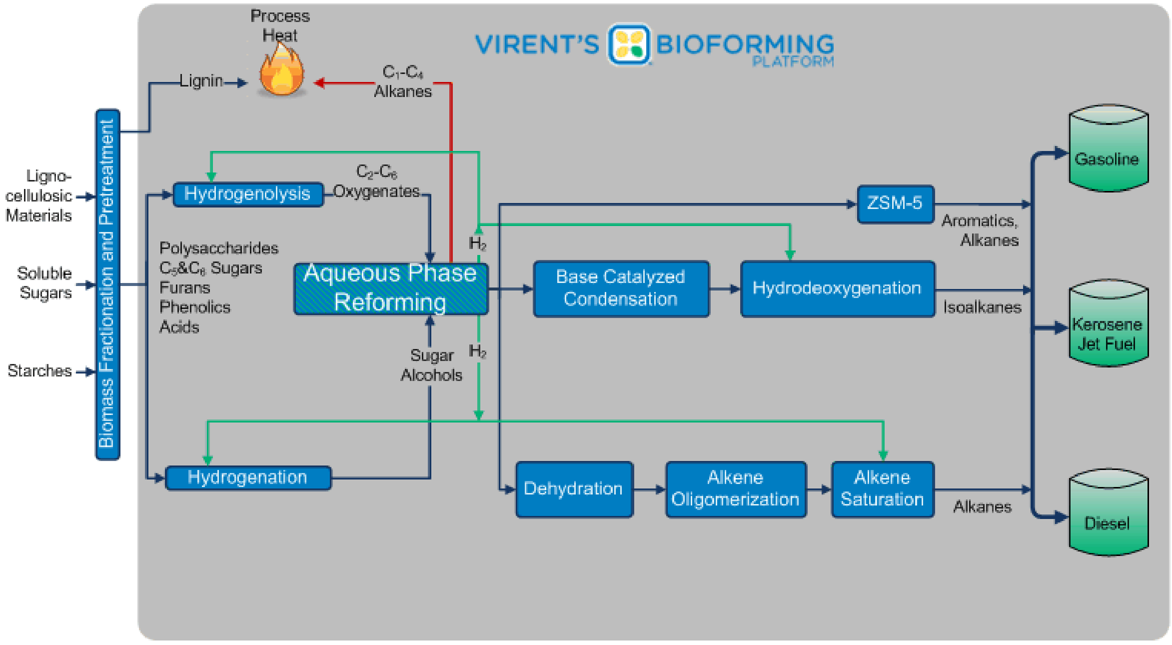

Figure 10: Virent BioForming technology

Source: Virent Energy Systems, Inc (http://www.virent.com/BioForming/technology.html

1.179. In 2007, Virent and Shell agreed on a five-year joint programme to develop further and commercialise the technology. In March 2010, they started up a small pilot plant in Madison, Wisconsin, with a capacity of around 240 barrels per year, which they claim is the world's first biogasoline production plant. In February 2010, Virent was awarded $2.4 million from the U.S. Department of Energy as part of a $33.8 million grant to the National Advanced Biofuels Consortium. In 2012, Shell commissioned a small pilot plant in Houston.[61]

1.180. It is reported that researchers at Massachusetts Institute of Technology have developed a chemical process for making propane from corn or sugarcane and have set up a company, C3 BioEnergy based in Cambridge, to commercialise the technology. The process uses supercritical water – water at a very high temperature and pressure – to facilitate chemical reactions that turn products from the fermentation of the sugars found in corn or sugarcane into propane. To our knowledge, the company has not yet been successful in finding the $25 million that it needs to build a demonstration plant. Other laboratories in the United States are looking at other ways of producing biofuels using super-critical fluids.

Bio-dimethyl ether (DME)

1.181. Bio-dimethyl ether (bio-DME) could be blended with biopropane or used as an intermediate feedstock for the production of biopropane. DME is chemically very close to propane and butane and displays similar characteristics in use (Figure 11). Today, it is used primarily as a propellant in aerosol canisters, as a precursor to producing dimethyl sulphate and as a refrigerant. However, it is increasingly being used as a source of energy, mainly in China. DME (conventional or bio) can be used as an alternative to diesel (requiring some modifications to the diesel engine) or can be blended into LPG for use in all applications. However, there are limits on how much DME can be blended into LPG, as DME is a solvent so can cause corrosion (see Marketing section). DME is a

[61] http://www.virent.com/news/shell-using-technology-licensed-from-virent/

relatively clean fuel: when burned, it emits minimal amounts of NOx and CO, though HC and particulate emissions can be significant. It also has lower lifecycle emissions of greenhouse gases than most other biofuels (IEA, 2008).

1.182. Today, DME is primarily produced by converting natural gas or coal to syngas, which is then converted to DME in a two-step process; firstly into methanol in the presence of catalyst (usually copper-based) and then into DME by dehydrating the methanol in the presence of another type of catalyst (such as silica-alumina). One-step processes, such as those being developed by Haldor Topsoe and the Japan Synthesis Gas Company (see above), permit both methanol synthesis and dehydration in the same process unit, eliminating the intermediate methanol synthesis stage and promising gains in efficiency and cost. If the syngas is produced from biomass, the final output of this process would be bio-DME.

DME (C_2H_6O) Propane (C_3H_8) Butane (C_4H_{10})

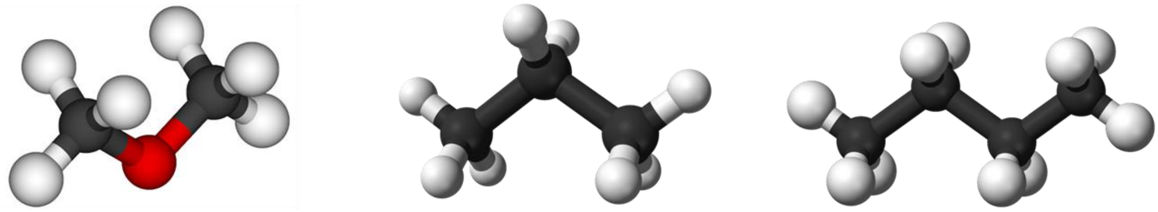

Figure 11: Molecular structure of DME, propane and butane

Note: Carbon atoms are black, hydrogen white and oxygen red.

1.183. The MTG production processes described above involve the intermediate production of DME from methanol, which is then converted to gasoline, with significant amounts of LPG produced as a by-product. In principle, it is possible to produce a much larger share of LPG from DME. The University of Kitakyushu, for example, has developed a process for the conversion of DME to LPG using hydrogen. This provides a pathway for LPG production if low-cost DME is available in specific locations, and the demand for LPG is relatively high. The technology uses hybrid catalysts consisting of zeolite and hydrogenation catalysts to convert DME (plus hydrogen) to LPG. The conversion of DME reaches nearly 100% with near-zero CO and CO2 yields. The technology has not yet been commercialised. In practice, the additional cost of converting DME to LPG would have to be weighed against the benefits of producing LPG rather than simply blending DME into LPG. Another potential pathway is to process glycerine into bio-DME via hydrogenation (GTI, 2010).

1.184. To our knowledge, the only significant bio-DME production facility in operation today is a small demonstration plant in Piteå, Sweden, which was commissioned in September 2010 as part of the BioDME research and development project. The plant is located at the Smurfit Kappa pulp and paper container board mill. The plant utilises black liquor, a by-product of the pulping process, to produce the bio-DME. The gasification technology comes from Chemrec AB, while Haldor Topsøe A/S provides the fuel synthesis technology. Volvo Trucks is coordinating the project, with participation from Swedish fuels company Preem, France-based oil and gas giant Total, Delphi and local research institute ETC. The project is co-financed by the partners of the consortium, EU's Seventh Framework Programme and the Swedish Energy Agency with a total estimated cost of €28 million.[62]

[62] http://www.dieselnet.com/news/2008/09biodme.php

Annex B: Stakeholders contacted

AEGPL (European LPG Association)
Avanti Gas
Benegas
Biofuel-Solution AB
Calor Gas
Diamond Green Diesel
Dynamic Fuels
ENI
European Commission, DG-Energy
Flaga Group
Flogas Sverige
Flogas UK
Gas Technology Institute
International Energy Agency
Kentz Engineering & Constructors
Mustang Engineering
Neste Oil
Primagas Deutschland
Roundtable on Sustainable Palm Oil
SHV Energy
Total
UK LPG Association
UPM
World LP Gas Association (WLPGA)

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