Waste and Gaseous Fuels in Transport – Final Report

Report for DfT

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Executive summary

This study by Ricardo-AEA for the Department for Transport examines the potential use of gaseous and waste derived fuels in the UK transport sector, examining the costs energy use and greenhouse gas (GHG) emissions associated with both production and use of the fuels in road vehicles, aircraft and waterborne vessels. These are compared with the costs and emissions of using conventional fuels (e.g. petrol, diesel, jet fuel and marine oil) in each mode of transport so that the cost-effectiveness of the use of gaseous and waste-derived fuels in transport can be calculated.

The study is forward-looking and therefore considers a wide range of fuel pathways that could be commercially viable in 2025. In the case of waste-derived fuels, as well as processes such as anaerobic digestion to produce biomethane which are currently available, the production of gaseous and liquid fuels in advanced biofuels plants using gasification and pyrolysis techniques are examined. For gaseous fossil fuels, sources of supply which could be important in 2025, such as liquefied natural gas (LNG) imports and shale gas, are considered alongside current sources of supply from the North Sea.

This study evaluates a range of fuels, vehicles and infrastructure, providing a broad overview of a complex area. The results should therefore be taken as indicative rather than definitive. However, the study provides a useful guide as to the potential magnitude of the different carbon, energy and cost impacts of steps along the fuel supply chain. It also highlights the areas where further work is needed to fully understand the impact of innovative fuels and vehicles. The main conclusions from the analysis are summarised below.

Data Gaps and Research Needs

In collecting data on fuel production and upgrading processes, the infrastructure required to deliver the fuels and the cost and performance of vehicles using gaseous fuels, a number of data gaps and areas where there is considerable uncertainty over costs or emissions were identified. These include:

Advanced (second generation biofuels plants). The uncertainty surrounding the costs, energy requirements, and efficiencies of these plants is high (perhaps 40%), as most of the technologies are still at a pilot or demonstration stage.

Cost of waste feedstocks. The gate fee a plant receives for residual or source-separated food waste can significantly influence the economics of the plant. While data are available on current gate fees, these fees could change significantly by 2025 if the value of waste as a resource is recognised, and there is more competition for waste. Forecasts of future gate fees are thus uncertain.

Anaerobic digestion and injection of biomethane to the grid. While anaerobic digestion is a commercial technology, there can be significant variations in the design of plants, depending, for example, on the waste they are receiving, pre-processing requirements, and the scale of the plant. In addition, different technologies used for upgrading the biogas to biomethane have different emissions and costs, and the cost of injection into the grid, is dependent on the pressure of the grid at the point of injection. The Department of Energy and Climate Change (DECC) is currently carrying out a consultation on the costs of biomethane injection, as part of a review of the tariff for biomethane under the Renewable Heat Incentive. This work may help to improve the certainty of cost estimates in this area.

Fugitive emissions from boil-off of LNG in vehicle storage tanks. While the issue of boil-off of LNG from vehicle storage tanks is recognised and discussed in the literature, no data on the level of potential emissions during normal operation was given. An accurate assessment of emissions from this source requires information on how long vehicles are likely to be left idle with LNG in their tanks, and how much LNG is in the tanks during this idle period. Field trials of vehicles operating on LNG could be a potential source for this data.

Fuel efficiency of gas fuelled vehicles. The carbon benefits of gas compared to petrol and diesel are eroded if the fuel economy of the vehicle is lower when running on gas. An accurate assessment of the fuel economy of dual fuel HGVs compared to diesel fuelled HGVs, and of the substitution rate of gas is important to ensure an accurate assessment of emissions savings. Limited data are available on these factors at present, although more data may become available as more operating experience is gained under the current low carbon truck demonstration trials

Tailpipe emissions of methane. There is little data on the tailpipe emissions of methane from gas-fuelled vehicles, as methane emissions have not been subject to regulation in the transport sector. In particular more robust data from emissions measurements on dual fuel vehicles are required to ensure that tailpipe emissions of methane do not negate emissions savings from the use of LNG.

Infrastructure for delivery of alternative fuels to ships. No data were found in the literature review of any additional costs and emissions associated with infrastructure for delivery of LNG and bio-oils to ships, and in the case of bio-oils any changes required to ships or changes in their operating costs. There is considerable interest within the maritime sector in the use of alternative fuels in shipping due to the need to meet requirements to reduce sulphur emissions from shipping, and it is possible that work in this area may produce some of the data required.

Gaseous fuels

Using compressed biomethane in vehicles delivers greenhouse gas emissions savings of between 60% and 90% compared to conventional liquid fossil fuels, when the biomethane feedstock is fully renewable. Emissions savings are about 40 to 60% for biomethane produced from waste which is not a fully renewable fuel. Savings from anaerobic digestion routes could be reduced if upgrading technology which does not minimise fugitive methane emissions is used.

The cost effectiveness of the savings from biomethane use ranges from about -£90/t CO_2 to £240/t CO_2, for landfill gas and anaerobic digestion pathways depending on the vehicle type. However, cost-effectiveness could be much higher for anaerobic digestion routes (£340 to £550/t CO_2) if recently-published estimates of the current cost of biogas production and upgrading (DECC, 2014) are more representative than the costs used here for 2025. Use of biosynthetic gas produced from wood chips is less cost-effective (£240 to £455/tCO_2), and biosynthetic gas from solid recovered fuel even less so (£370 to £859/tCO_2) due to the lower GHG savings it delivers.

Using CNG produced from fossil fuel gas in vehicles delivers no or very small emissions savings for larger (diesel) vans, smaller HGVs and buses, as the advantage of using a fuel with a lower carbon content is lost due to the generally lower efficiencies of the vehicle when running on gas. For smaller vans and cars, when compared with petrol-fuelled vehicles, savings range from 9% to 27% depending on the source of the gas, with the lowest savings from imported LNG evaporated into the gas grid. Savings for ‘average’ gas in the grid would depend on the proportion of different sources of gas for grid-supplied gas, but would lie between these values. The cost-effectiveness of the savings is about £190 to £550/t CO_2 for shale and conventional gas, but is worse when the source of gas is LNG, (£530 to £900/t CO_2), due mainly to the lower level of savings achieved. The savings achieved from the use of CNG in cars are very similar to the savings which would be achieved from use of diesel rather than petrol.

In the case of liquefied biomethane (LBM) used in dual fuel vehicles, emission savings range from 32% to 52%[1] for LBM produced from anaerobic digestion, landfill waste and wood (the latter via biosynthetic natural gas). The cost of carbon savings is low for LBM produced from

[1] As gas is assumed to account for 60% of fuel use, savings cannot be greater than 60%.

anaerobic digestion and landfill waste (£10 to £50/tCO_2), but is much higher for the use of LBM from BioSNG produced from wood and solid recovered fuel (£230/t to £290/t CO_2).

For LNG, the well-to-tank emissions and higher tailpipe emissions of non-CO_2 GHGs offset much of the savings in tailpipe CO_2, so that overall savings at a substitution rate of 60% are only 6%. The cost-effectiveness of these savings is however good (-£145/tCO_2). Sensitivity analysis indicates however that the small savings offered by LNG could easily be negated if tailpipe emissions are higher than assumed. If more than 2% of the methane entering the engine is emitted in the tailpipe then there is no overall GHG saving. More robust data on these emissions is therefore required to allow conclusions to be drawn about the effectiveness of using LNG in dual fuel vehicles as a GHG mitigation option. Methane emissions from venting vehicle storage tanks when the pressure of LNG which has boiled off in the tank becomes too high could also reduce emissions savings. However sensitivity analysis indicates that this is likely to have a much smaller impact on emissions savings, perhaps reducing emissions savings by about 0.4% points (i.e. from (5.8% to 5.4%).

Savings from the use of LNG in shipping are higher than for vehicles (21%) and have a good level of cost-effectiveness (-£73/t), although more information on the cost and emissions associated with infrastructure for refuelling ships is required to improve confidence in these estimates.

Waste derived liquid fuels

The advanced biofuels routes producing biomass to liquid diesel, jet fuel, biopropane and bio-oil generally deliver good carbon savings (54% to 97% compared to the relevant comparator fuels). The cost-effectiveness is better for biomass to liquid diesel and jet (-£135/tCO_2 to £70/tCO_2) than for biopropane (£224/t CO_2). Use of bioethanol and bioalcohols produces only small savings (8 to 9%) due to the low blending levels assumed but is very cost-effective (-£154 to -62/t CO_2). The exception is biomass to liquid diesel and jet fuel produced from the gasification of residual waste, due to the lower efficiency of the process. The uncertainty in these values is high (perhaps 40%) but indicates that advanced biofuels could deliver GHG savings cost-effectively.

Advanced biofuels processes can produce both liquid and gaseous fuels. The results for different fuel pathways using solid recovered fuel as a feedstock show that, once the additional emissions and costs associated with delivery of fuels to vehicles, vehicle modifications and tailpipe emissions are taken into account, gaseous fuels derived from this source (with the exception of biopropane) offer slightly smaller emissions savings per km and have higher costs per tonne of carbon saved than liquid fuels.

Comparison with use in heat and power sector

Almost all biomethane currently produced is used in the heat and power sector. The cost-effectiveness of carbon savings achieved in the heat and power sector from the use of waste-derived fuels is generally better than the cost-effectiveness of using it in the transport sector, when the cost of modifying the fleet and infrastructure to allow the use of gaseous fuels is allowed for. The exception is residual waste, where using it to produce transport fuels (particularly liquid transport) fuels would deliver more cost-effective GHG savings than burning it in an EfW plant where only electricity is produced.

However if it is considered that the vehicle fleet and fuel delivery infrastructure have already been adapted to allow the use of natural gas, and only the costs of substituting biomethane for natural gas are considered, then the cost-effectiveness of using biomethane in the transport sector is very similar to that of using it in the heat and power sector. This is to be expected, as the cost-effectiveness is almost entirely determined by differences in the emissions and costs of producing and delivering the natural gas as compared to biomethane, as within each sector the efficiency of end use is the same for the two fuels.

The current use of biogas in the heat and power sector is mainly driven by the support available for electricity generation under the Renewables Obligation and more recently for grid injection under the Renewable Heat Incentive. The costs for an existing landfill gas operator currently producing electricity to change operations to produce liquefied biomethane for the transport sector were examined. It is currently proposed that under the Renewable Transport Fuels Obligation, biomethane produced from waste should be rewarded with Renewable Transport Fuel Certificates (RTFC) in line with its underlying energy content. The results suggest that at a higher level of RTFCs, production of liquefied biomethane could be slightly more favourable financially for landfill sites with a ROC banding of 1, and definitely more favourable financially for sites with a ROC banding of 0.2.

Policy implications

While the results of this study provide a useful indication of the cost-effectiveness of different fuel pathways, the uncertainty in some of the results means that care should be taken in interpreting the results and using them to inform policy on either GHG abatement options for the transport sector, or the 'best use' for the biogas resource. It should also be remembered that the options analysed here need to be considered alongside alternative mitigation options for the vehicle or in the heat and power sector.

For example, in the case of gaseous fossil fuels, the only bifuel vehicles[2] using CNG which deliver a saving for all potential sources of gas supply are cars and smaller vans, where the comparison has been made with a petrol-fuelled version of the vehicle. However, alternative mitigation options such as the use of diesel-powered vehicles or electric vehicles could deliver similar or greater GHG savings.

In the case of HGVs where fewer mitigation options are available, the use of LNG delivers savings of 6%. However as discussed above there is considerable uncertainty over a number of assumptions (substitution rate, efficiency when running in dual fuel mode, tail pipe methane emissions, and emissions from boil off) which could reduce, or in a worse case completely erode this saving. More data on these aspects, preferably from measurement and monitoring programmes, is needed to improve the accuracy and robustness of the results.

The use of compressed or liquefied biomethane delivers much higher greenhouse gas savings. Where the biomethane is sourced from landfill gas, the cost-effectiveness of these savings is likely to be good. However, the cost-effectiveness of savings from biomethane produced from anaerobic digestion is more uncertain, due to differing views on the cost of biomethane production from this source. More work is required to form a clearer view of the likely variation in future costs of biomethane from this source before decisions can be made on the suitability of this as a mitigation option.

[2] Bifuel vehicles have two independent fuel systems (one of them for natural gas) and can run on either fuel, but only on one at a time. Dual fuel vehicles also have two independent fuel systems (one of them for natural gas), but can run on both fuels simultaneously. Dual fuel vehicles may also run on one fuel alone.

Glossary

AD - anaerobic digestion

BioSNG – biosyngas

BioDME – bio dimethyl ether

BtL – biomass to liquid

C&I - commercial and industrial (waste)

CBM - compressed biomethane

CCGT – combined cycle gas turbine

CI – compression Ignition

CHP – combined heat and power

CNG - compressed natural gas

EfW – energy from waste

FT – FT diesel and FT jet

GHG – greenhouse gas

HDV – heavy duty vehicle

HGV – heavy goods vehicle

HFO – heavy fuel oil

LBM – liquefied biomethane

LDV – light duty vehicle

LNG - liquefied natural gas

LPG - liquefied petroleum gas

LTS – local transmission system

MBT – mechanical biological treatment

MP – medium pressure

MSW - municipal solid waste

RCV – refuse collection vehicle

RDF – refuse derived fuel

RED – Renewable Energy Directive

RTFC – Renewable Transport Fuels Certificate

RTFO – Renewable Transport Fuels Obligation

SI – spark ignition

SRF - solid recovered fuel

TRL – Technology Readiness Level

UCO – Used Cooking Oil

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1 Introduction

The UK has ambitious decarbonisation and renewable energy supply targets, and transport, which accounts for a large share of carbon emissions and energy use, must play its part in these targets. To date, low-carbon fuels and renewable energy in transport have tended to come from crop-based liquid fuels such as biodiesel and bioethanol. These fuels are broadly compatible with the existing fuel supply and vehicle infrastructure, which is based around other liquid fuels (primarily petrol and diesel). However, the risk of indirect land use change has led some to question the carbon savings that are achieved through some crop-based biofuels, and to turn attention to feedstocks such as wastes and residues. Using these feedstocks in advanced biofuels production processes could, in the future, allow production of a range of both gaseous and liquid biofuels. Indeed some of the feedstocks are already being used in anaerobic digestion (a more mature technology) to produce biomethane.

Other potential routes for decarbonising the transport sector which are of interest are the use of natural gas and other gaseous fossil fuels, such as liquefied petroleum gas (LPG) as a transport fuel. Use of these gaseous fuels also has other benefits such as diversifying fuels used in the transport sector, thereby improving security of supply, and potential air quality benefits. However their use also has considerable implications in terms of new delivery infrastructure which would be required for the more widespread use of gaseous fuels in transport, and costs for modifying the vehicle fleet to be able to run on gaseous fuels.

In order to evaluate options such as the use of gaseous or waste-derived fuels alongside other options for decarbonising the transport sector, a good understanding is required of the GHG savings, and costs of GHG savings that use of these fuels might deliver. Furthermore, it is important that this is on a 'well to wheel' basis, and includes emissions and costs from the fuel production process, the fuel delivery process as well as taking into account additional vehicle costs.

This study by Ricardo-AEA for the DfT therefore examines the costs, energy use and GHG emissions associated with the production of transport fuels by a number of routes, the infrastructure required to deliver the fuels and the cost of any modifications required for vehicles to use gaseous fuels. This information is then combined to calculate the cost-effectiveness of these fuels in delivering carbon savings across the transport sector. While the focus of the study is on use in road vehicles, shipping and aviation are also considered, albeit in less detail. The study is forward-looking, and as far as possible the analysis reflects costs and emissions in 2025, when advanced biofuel production processes may have reached commercial maturity. More details of the methodology used in the study are given in Section 2 of the report, and Sections 3 and 4 present results from the analysis of the fuel pathways and information on the use of fuels in a range of vehicles. As the focus of the study is on decarbonisation of the transport sector, it does not consider other potential benefits that the use of gaseous and waste-derived fuels might have.

In addition to considering the use of biomethane from wastes in the transport sector, the report also compares the savings which could be achieved in the transport sector with those which can be achieved through use of biomethane in the heat and power sectors (Section 5). Finally, the study considers the financial returns available to a landfill gas operator under current incentives and subsidies, when using biogas for power production, and how these would change if they were to switch to producing biomethane for use in the transport sector (Section 6).

2 Methodology

2.1 Overview

In order to meet the aims of the study it was necessary to identify a range of fuel 'pathways' for gaseous and liquid fuels for analysis. The term 'fuel pathway' is used to mean all of the processing and transport steps necessary to deliver a fuel to a vehicle from the original feedstock. This typically includes a fuel production or conversion step, fuel upgrading, transport of the fuel and dispensing of the fuel. An example of a fuel pathway for biomethane is shown in Figure 2.1. By then looking at the energy, emissions and costs associated with each step, it is possible to calculate the total cost, energy and emissions associated with delivery of a unit of fuel to a vehicle from that pathway (the 'well-to-tank' portion of the pathway). This is shown for the biomethane pathway in Figure 2.2.

By comparing the performance of different pathways, it is then possible to identify which of these give the greatest reductions in emissions for a given cost. As the study is forward-looking, the fuel supply pathways have been chosen to be representative of those which might be in place in 2025; similarly costs, emissions and energy use have also been chosen to be as representative of 2025 as possible.

Figure 2.1 Example of fuel pathway

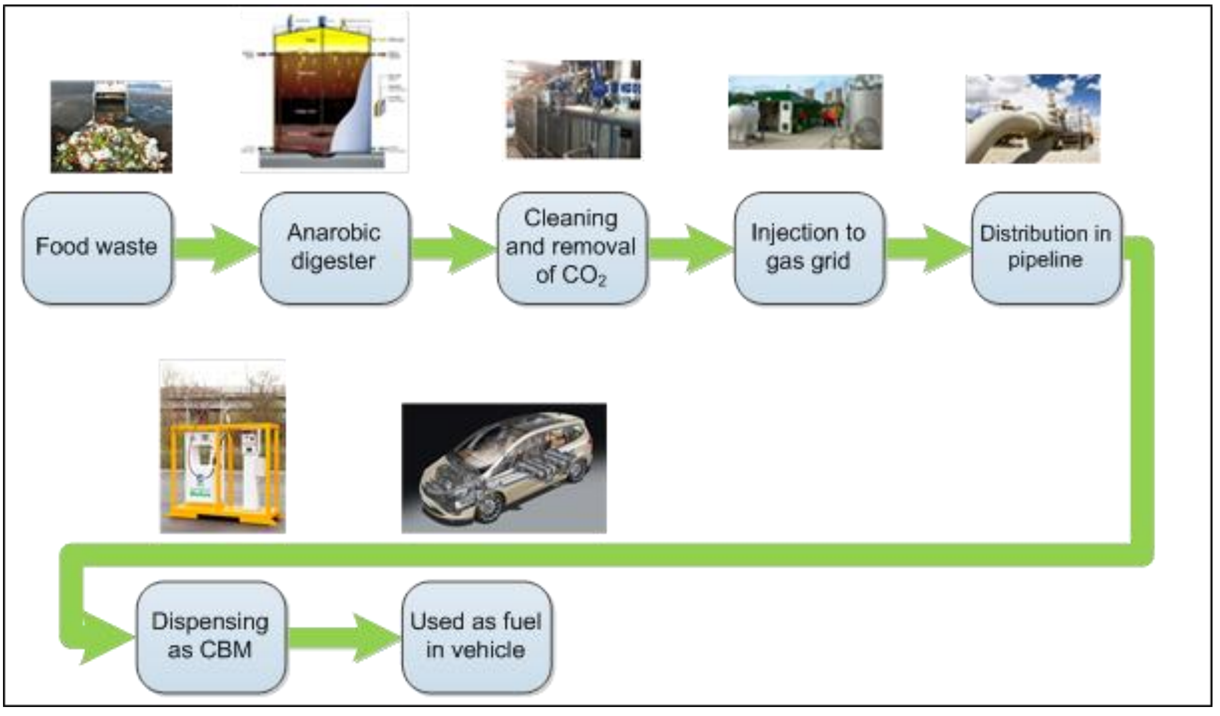
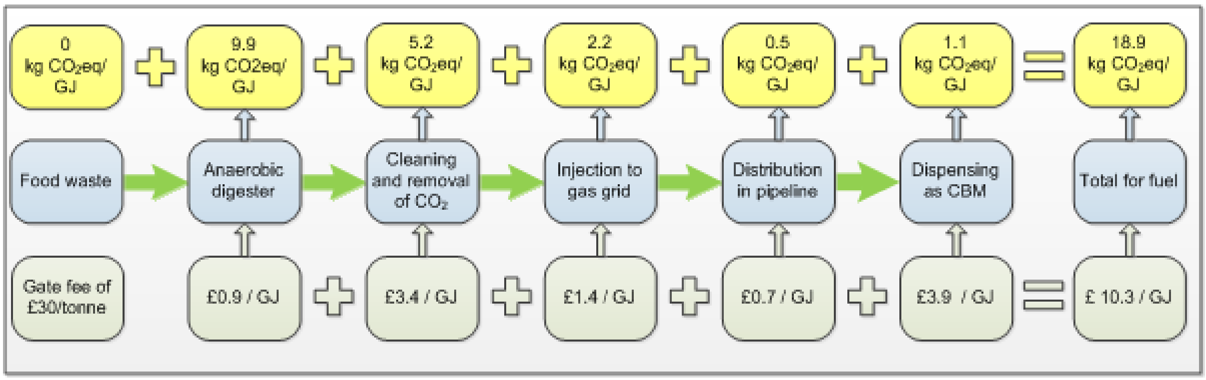


Figure 2.2 Calculation of emissions and costs for fuel pathway



The cost and GHG emissions of the well-to-tank footprint of the fuel can then be combined with information on how efficiently that particular fuel is used in a vehicle, and information on the corresponding tailpipe emissions in order to calculate total 'well to wheel' GHG emissions per km. Similarly, data on the cost of fuel produced can be combined with any additional costs (either operating or capital) for the vehicle to run on the fuel, in order to calculate the total operating costs per km. Finally these costs and GHG emissions can be compared with those from operating conventional vehicles on diesel and petrol to allow the cost-effectiveness of any CO_2 savings to be calculated. These savings can also be compared with those from the use of fuels such as biomethane for heat and power generation.

2.2 Choice of Fuel Pathways

A wide range of fuels can be produced from the waste feedstocks which are the focus of the study, using a variety of advanced biofuels processes giving a large number of fuel pathways which could potentially be studied. At the beginning of the study, a long-list of possible feedstocks, conversion processes and fuels was identified. A screening process (described in Appendix 1) was then used to narrow down the long-list of feedstocks, conversion processes and fuels to a number of pathways suitable for analysis within the time and budgetary constraints of the study. The choice of pathways (shown in Figure 2.3) is intended to give a balanced spread across conversion technologies, fuels, and vehicle use, and to allow comparisons between routes to relevant liquid and gaseous fuels. The analysis is intended to allow broad conclusions about the use of gaseous and waste-derived liquid fuels in transport to be made, rather than a detailed examination of the use of all fuel types in all vehicles.

Four sources of fossil gases were considered:

- natural gas from the UK continental shelf
- shale gas from hydraulic fracturing in the UK
- imports of liquefied natural gas (LNG) from the Middle East
- liquefied petroleum gas (LPG) from natural gas processing at remote gas fields[3]

LNG can be loaded onto road tankers for distribution to vehicle refuelling stations, or evaporated and injected into the gas grid. Once in the gas grid, it can (together with shale gas and natural gas from the UK continental shelf) be dispensed as compressed natural gas (CNG) at vehicle refuelling stations. In 2012 LNG accounted for 17% of natural gas supplied in the UK (DUKES, 2013). LPG is typically distributed by road tanker to vehicle refuelling stations.

[3] LPG is produced as a by-product in oil refineries, but almost all of this production is already accounted for and Europe currently imports a significant proportion of its LPG consumption. Therefore as in JEC, 2013 we have assumed that LPG originates from gas fields where it is produced in association with natural gas, and then shipped to the UK.

For biofuels, the conversion routes considered were:

- anaerobic digestion (AD) of wastes to produce biogas which is then upgraded to produce biomethane; biogas production from landfill sites was also examined. Feedstocks which were considered for anaerobic digestion were source-separated food wastes and animal manures
- advanced biofuels production processes based on gasification; treatment of the biosyngas (bioSNG) to produce both gaseous (biomethane and biopropane) and liquid fuels (diesel, jet fuels and bioalcohols)[4]. Feedstocks which were considered for the gasification processes were residual[5] municipal solid waste (MSW) and commercial and industrial (C&I) waste, solid recovered fuel (SRF - a fuel prepared from residual waste, which is more homogeneous and has a higher energy content), and wood chips (e.g. from forestry residues). The residual MSW and solid recovered fuel contain waste of both a biological origin (e.g. paper, card, food waste) and fossil origin (e.g. plastics), and this is allowed for when calculating GHG emissions from combustion of the fuel. It is assumed that 50% of the carbon in solid recovered fuel comes from a biogenic source, and 70% of the carbon in residual waste, based on the typical composition of residual waste.
- advanced biofuels production processes based on pyrolysis. The bio-oil produced from the pyrolysis process can either be cleaned and upgraded to produce a fuel suitable for use as a replacement for heavy fuel oil, e.g. in shipping, or undergo hydrotreatment and refining to produce a diesel fuel.
- advanced biofuels production using biochemical routes to produce bioethanol. The feedstock for this process is the organic fraction of waste (e.g. food waste and paper and card) which it is assumed is separated from residual waste during a pre-processing step.

More details of delivery routes for gaseous fuels to vehicles are shown in Figure 2.4. Biomethane from anaerobic digestion, landfill and gasification can be injected into the gas grid, for onward distribution by pipeline, and dispensing as compressed natural gas (CNG)/compressed biomethane (CBM). Two cases are considered for dispensing; from the higher pressure part of the gas grid (known as the local transmission system (LTS)); and from the medium pressure part of the system. Biomethane can also be liquefied and transported by road tanker to LNG/LBM refuelling stations. It is also possible to have a combined LNG/CNG dispensing station.

At present LNG is supplied to LNG filling stations from the natural gas liquefaction plant at Avonmouth, supplemented by supplies from the LNG terminal at Zeebrugge, brought in by road tanker and ferry, in case of problems with the Avonmouth supply. However Avonmouth has been operating since 1978 and is expected to close before 2018. It is not expected that it will be replaced, due to the existence of LNG import terminals. It is assumed in this study, that if a demand for LNG for road transport were to develop, then these import terminals would install road tanker loading facilities[6]. The facilities at import terminals could be supplemented by road tanker loading facilities at the small scale LNG facilities for ports around the country being planned by National Grid to service shipping. As the timescale for the analysis is 2025, it is assumed that all LNG will be supplied from import facilities. At present there are no fuel standards for LNG supplied as a transport fuel. In this analysis we have assumed that LNG from all sources has the same carbon content (and hence CO_2 emissions) and calorific value, and that this is the same as natural gas.

In the case of liquid fuels, the diesel and jet fuels produced from pyrolysis and gasification are 'drop in' replacements for conventional diesel which are not subject to restrictions on the amount that can be blended with conventional diesel or jet fuel. They would therefore be able to use the same delivery infrastructure as conventional diesel and jet fuel. It is assumed

[4] It was originally intended to also examine fermentation of syngas to produce bioethanol, but no data could be found in the literature to allow an estimation of the costs and emissions associated with this process.
[5] Residual waste is 'black bag' waste, the waste left after recyclables have been extracted.
[6] For example the new LNG terminal at the Isle of Grain is planning to install road tanker loading facilities.

that biopropane, which would be a replacement for LPG, would be delivered to filling stations using road tankers, as is the case for LPG. In the case of bioethanol and mixed bioalcohols, these would require separate storage and transport, and would typically be blended into petrol close to the retail point.

Figure 2.3 Fuel pathways analysed

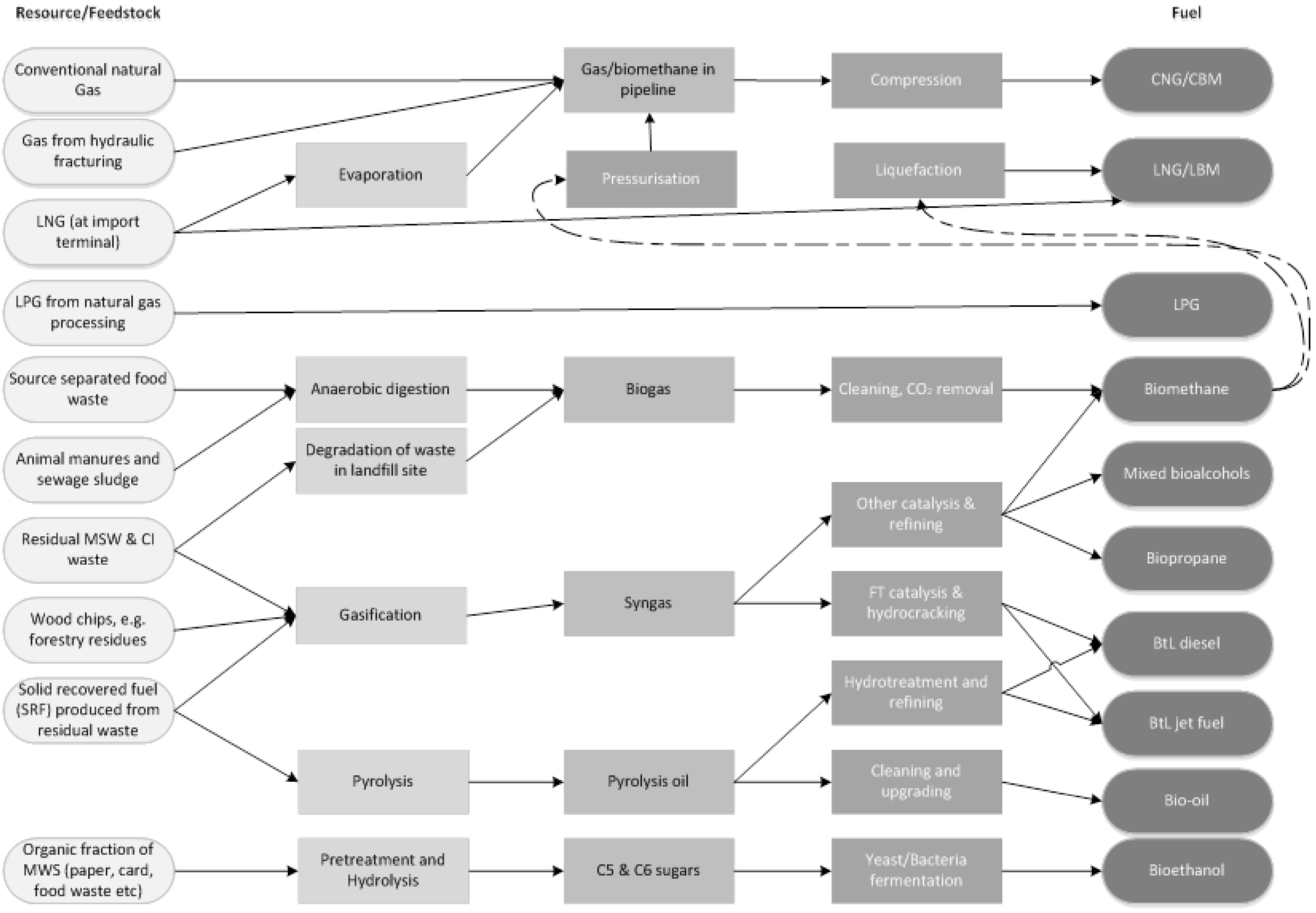
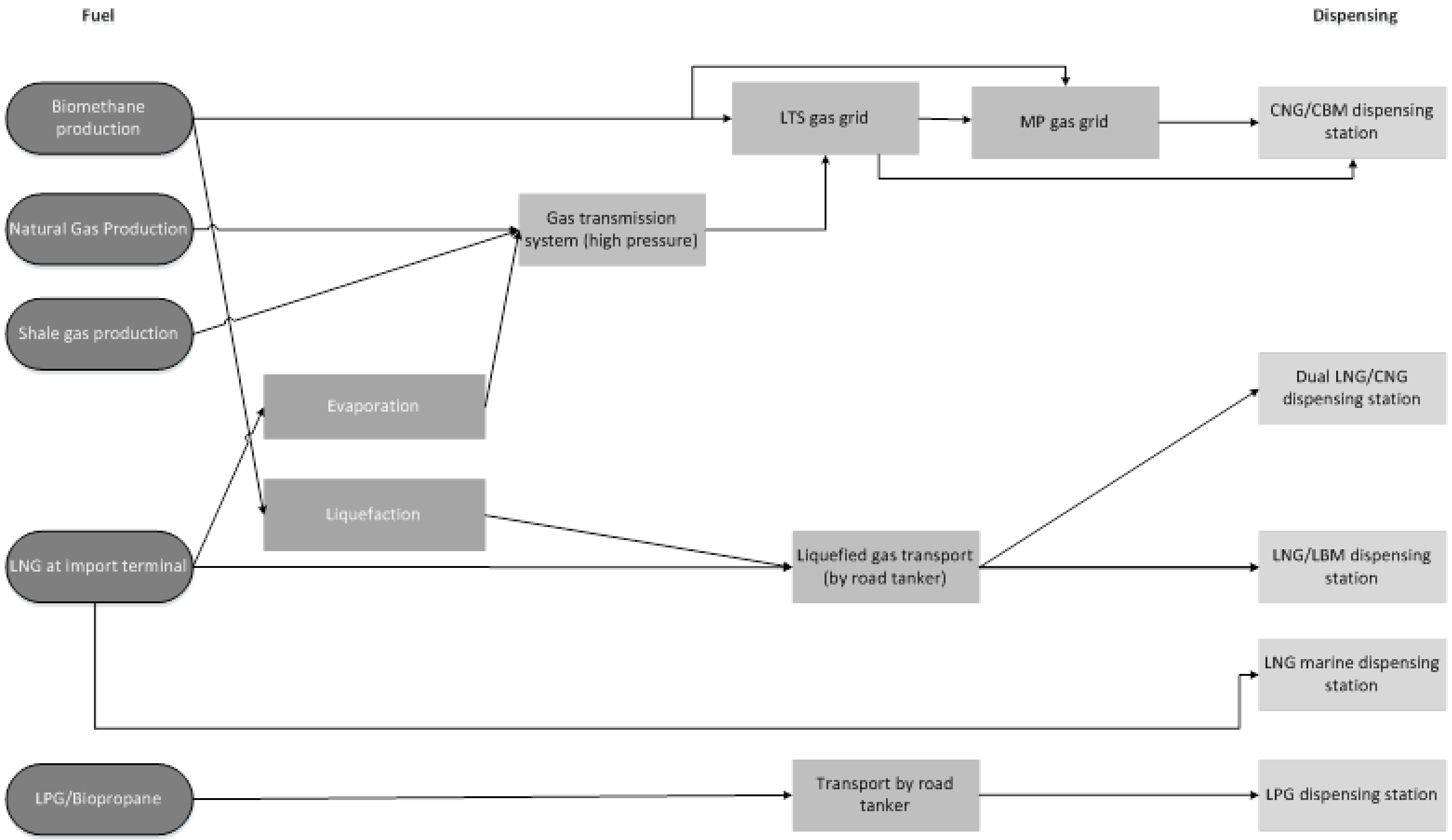


Figure 2.4 Delivery infrastructure for gaseous fuels



Notes:
1) Injection into the distribution grid and gas take off from the distribution grid for filling stations can occur at a variety of pressures depending where in the grid the connection is made
2) As well as dispensing equipment, CNG dispensing stations will include compressor and storage/buffer storage and LNG stations cryogenic storage tank and pumps

2.3 Data collected for each process step

For each process step in the fuel pathways, data was collected on the capital and operating cost of equipment required to process fuel in that step. The equipment required varies by step, so for example, for fuel production steps, this is the capital and operating costs of the fuel production facility, and for fuel dispensing steps, the capital and operating costs of the filling station and associated equipment. Data was also collected on the efficiency of the step, energy required for the step or produced by the step, and the GHG emissions associated with the step. GHG emissions were estimated based on fuels used in each process step, and where relevant, the embedded carbon in other materials used in the fuel production process. The capital and operating costs of the step were combined in a levelised cost model[7], to produce a levelised cost per GJ of fuel produced by the step. The cost model was based on a 10% cost of capital and a 10% discount rate. Costs for advanced biofuels production plant are representative of 'nth' of a kind plant, i.e. they assume that the production plant is at a commercial scale; details of the scales assumed for plant are given in Appendix 2. As no such plants have yet been built, estimates in the literature are engineering estimates, and have a relatively high level of uncertainty (perhaps as high as ±40%)[8]. Costs are all expressed in 2012 prices, and exclude all taxes, duty, and subsidies, as the analysis is examining the resource cost of the fuel pathways, rather than the cost as seen by the final consumer. Feedstock and fossil fuel prices assumed for 2025, together with sources are summarised in Table 2.1 below.

Data on the process steps was generally sourced from existing studies, supplemented with data from stakeholders (suppliers, producers and distributors of gaseous fuels, trade associations etc). Full details of the data and assumptions for each step in the fuel pathways are given in Appendix 2.

For wastes, no emissions were assumed to be associated with the waste feedstock and its delivery to the processing facility, as collection and delivery of the waste to a facility would be required however it was managed. The exception is solid recovered fuel where some processing of the waste to produce the fuel is required, often at a separate facility to the transport fuel production facility; emissions from this processing and transport are therefore included. No assumption is made about the 'alternative' fate of wastes used for fuel production and so there is no emissions 'credit' from emissions avoided by diverting waste away from e.g. disposal in a landfill. This approach is consistent with that set out in the Renewable Energy Directive (RED) for calculating GHG savings from biofuels.

Wood chips were assumed to come from forestry residues and emissions associated with harvesting, collection, chipping and transport of the wood chips. Any potential changes in carbon reserves that may occur in harvesting forest residues are not included. Again this approach is consistent with the approach currently set out in the RED.

[7] A levelised cost model calculates the price per GJ of fuel that must be received for the process step to 'break-even' given the assumed discount rate.

[8] Demonstration and first of a kind plant will be more expensive, and may require some form of support to allow technology development to proceed. However estimation of the additional costs associated with these plant and support which might be required to reach the nth plant is outside the scope of this study.

Table 2.1 Feedstock and fossil fuel prices assumed for 2025.

Feedstock	£/t	£/GJ	Assumption/source
Source separated collected food wastes	-30		Average gate fee under local authority contracts is currently £41/t (with a range of £24 to £66/t) (WRAP, 2013). Assumed that gate fees will fall in the future as more capacity developed and value of waste as a resource recognised.
Residual waste	-50		Average gate fee for large facilities under procurement is £68/t for MSW waste under local authority contracts (WRAP, 2013), but fees for C&I waste may vary. Assumed that gate fees will fall in the future as more capacity developed and value of waste as a resource recognised.
Solid recovered fuel	0		Pre-processing of residual waste required.
Wood chip	65 (per oven dried tonne)		Forecast of wood chip prices in report on global bioenergy supply for DECC (AEA, 2012).
Organic fraction of waste	30		Cost unknown, but assumed will require substantial pre-processing of residual waste.
Natural gas and shale gas		7.0	Wholesale price from DECC price forecasts; based on central forecast (DECC, 2013).
LNG		8.3	Based on wholesale gas price plus liquefaction and shipping costs.
LPG		23.4	Based on current retail price of LPG, minus duty and distribution costs, and increased by increase in oil price between now and 2025 as forecast by DECC.
Petrol		18.1	Unblended at pump pre-tax, as supplied by DfT; consistent with DECC central oil price forecasts.
Diesel		18.6	Unblended at pump pre-tax, as supplied by DfT; consistent with DECC central oil price forecasts.
Aviation fuel		18.6	Assumed to be same price as diesel.
HFO for shipping		14.1	Fuel price projection used in impact assessment of reducing GHG remissions from shipping (Ricardo-AEA, 2013).

3 Fuel Pathway Results

This section presents results for the 'well-to-tank' element of the fuel pathways, together with the CO_2 released on combustion of the fuel. This is divided into CO_2 which is of a 'fossil' origin, and CO_2 which is of a renewable, 'biogenic' origin. The CO_2 released on combustion of the fuels is shown alongside the well-to-tank emissions of the fuel, to allow a fuller comparison of the fuel pathways. For example some waste derived fuels may have higher well-to-tank emissions than fossil fuel pathways, but as they release lower amounts of fossil CO_2 when combusted have a lower overall GHG emission. While the main interest of the report is in the overall well to wheel emissions and costs of using the fuels in vehicles (for which results are given in Section 4), the costs and emissions from the well-to-tank part of the pathway have an important influence on the overall results, and it is thus useful to examine, and understand these. GHG emissions and production costs for diesel and petrol are shown in the figures in this chapter, to set emissions and costs for the other fuel pathways in context. They should not be used to make a direct comparison as specific vehicle models will have different fuel efficiencies when running on gaseous fuels, and different tail pipe emissions of non-CO_2 GHGs; these factors are taken into account in the analysis in Section 4. Full details of the assumptions for each step of each fuel pathway are given in Appendix 2. Tables of the emissions and costs and energy use for each pathway are given in Appendix 4.

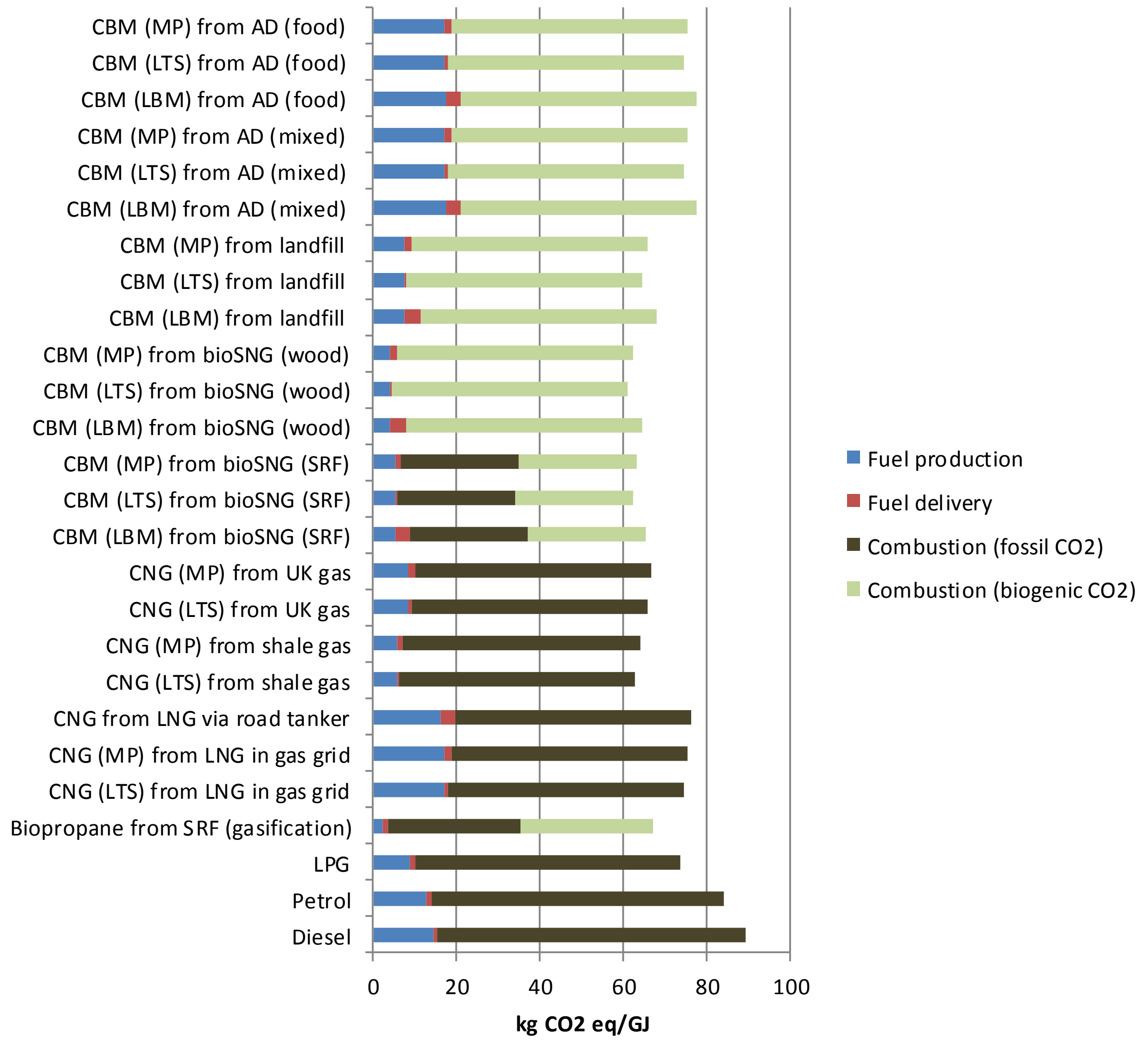
3.1 Results by fuel

3.1.1 Compressed biomethane and natural gas, biopropane and LPG

Figure 3.1 and Figure 3.2 show the GHG emissions and costs of delivering compressed biomethane (CBM) or compressed natural gas (CNG) to a vehicle. A variety of sources of compressed biomethane has been examined, including biogas from anaerobic digestion and landfill sites as well as production of biosynthetic natural gas (bioSNG) from the gasification of wood or solid recovered fuel (SRF) produced from waste. Biogas is upgraded into biomethane, and either injected into the gas grid, for dispensing at stations connected to the gas grid, or liquefied and transported by road tanker to stations dispensing both liquefied biomethane and compressed biomethane. Two types of anaerobic digestion plant are considered, one with only source separated food waste as a feedstock and one with mixed feedstocks of source separated food waste and animal manures.

GHG emissions for production of biomethane from the anaerobic digestion routes (after allowing for upgrading of the biogas) are in the range 18 to 21 kg CO_2eq/GJ, of which about half come from the production process itself. Emissions from landfill gas routes are lower (8 to 11 kg CO_2eq/GJ), as the landfill gas is essentially considered to be a waste resource, so only emissions from cleaning, upgrading and liquefaction are included. Emissions from gasification routes producing biosynthetic natural gas are low when using wood as a feedstock (4 to 9 kg CO_2 eq/GJ), as the process is self-sufficient in energy, with emissions arising only from the pre-processing of the feedstock, and distribution and dispensing of the fuel. Using solid recovered fuel as a feedstock increases emissions to 34 to 35 kg CO_2 eq/GJ due to the emissions associated with producing the SRF. Costs for production of biosynthetic natural gas are much higher (£18 to £22/GJ depending on feedstock) than biogas from anaerobic digestion (£1 to £3/GJ). However, this cost estimate is very sensitive to assumptions about the gate fees for waste received and costs for disposing of digestate. Clean up of the biogas adds about £3.5/GJ, injection into the grid £1.4/GJ and liquefaction about £5.9/GJ.

*Figure 3.1 Well-to-tank emissions for CBM and CNG pathways**



* CO_2 from combustion included to allow fuller comparison of fuel pathways

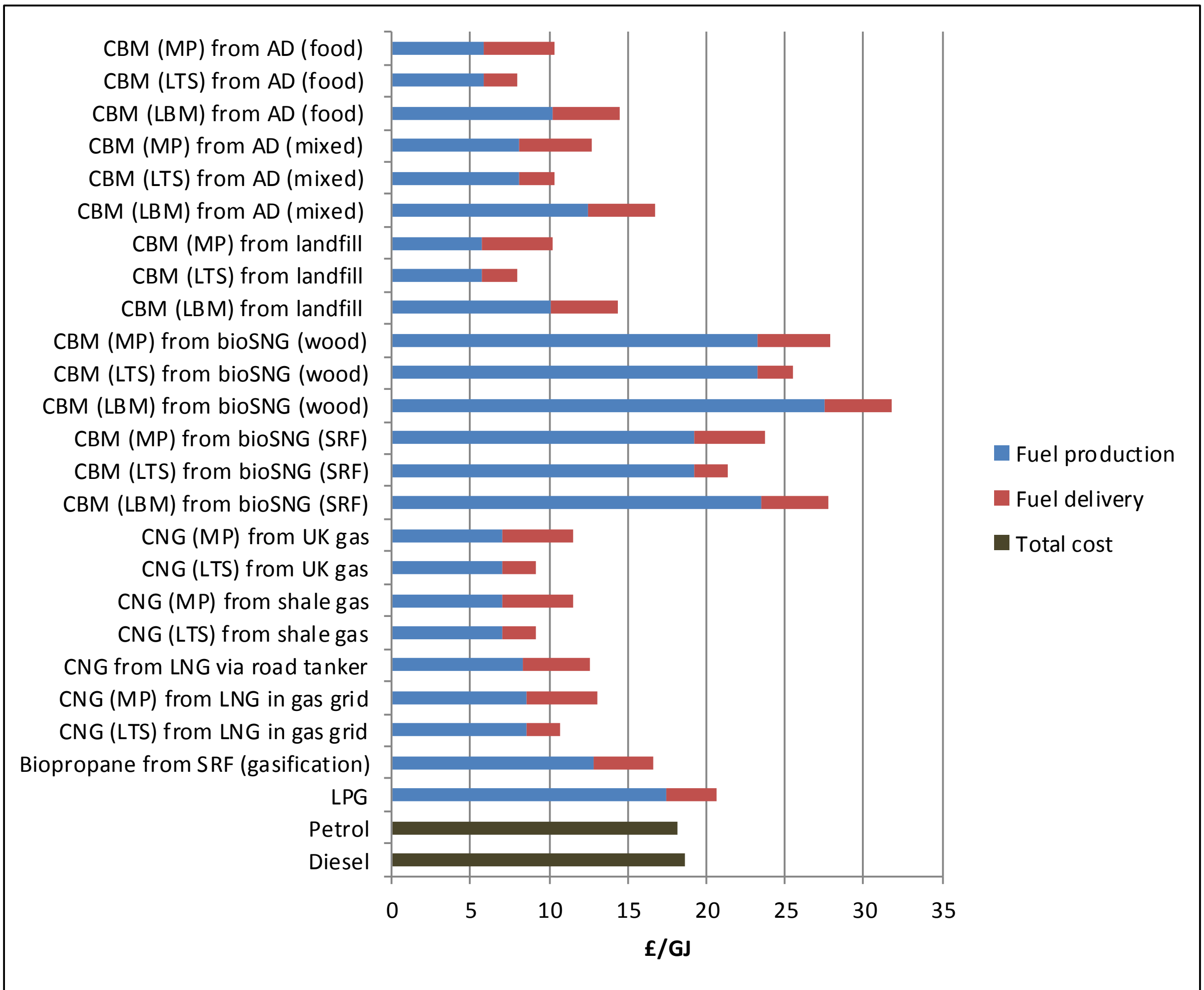
AD (food)	Anaerobic digestion of source separated food waste	**AD (mixed)**	Anaerobic digestion of food waste and animal manures
bioSNG	Bio-synthetic natural gas	**CBM**	Compressed biomethane
CNG	Compressed natural gas	**CBM (LBM)**	CBM dispensed from liquefied biomethane
LNG	Liquefied natural gas	**LPG**	Liquefied petroleum gas
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Two types of CNG/CBM dispensing station are considered, one connected to the higher pressure, local transmission system (LTS) which operates at 10 to 42 bar, and one connected to the medium pressure (MP) network which operates at 75 mbar to 2 bar. Dispensing stations connected to the local transmission system have a lower cost, as less compression of the gas is required to achieve the pressure required from dispensing, resulting in lower capital and operating costs. Total costs of dispensing from the local transmission system are about 40% of the cost of dispensing from the medium pressure system (£1.5/GJ compared to £3.8/GJ of gas dispensed). GHG emissions are also reduced as less electricity is needed to run the compressor; there is also a slight reduction in emissions from pipeline transport of the gas as leakage rates are higher in the medium pressure than in the local transmission system. Overall GHG emissions are 70% lower from distribution and dispensing for local transmission system routes than medium pressure routes (0.5 kg CO_2 eq/GJ compared to 1.6 kg CO_2 eq/GJ).

For the fossil gas routes, the GHG emissions from gas supplied from the UK continental shelf or from hydraulic fracturing[9] are about half of those from LNG shipped from the Middle East and evaporated into the grid (of about 17 kg CO_2 eq/GJ).

While overall, GHG emissions from fuel production and delivery are higher from the biomethane routes rather than fossil gas routes, these are more than offset on combustion, as the biogenic origin of the carbon in the fuel, means that it is not considered to contribute to climate change. Even for biosynthetic natural gas from solid recovered fuel, where the solid recovered fuel contains some fossil carbon and there are some 'fossil' CO_2 emissions on combustion, overall there is still a substantial emissions saving.

Figure 3.2 Cost of delivered fuel in CBM and CNG pathways



Key			
AD	Anaerobic digestion	**bioSNG**	Bio-synthetic natural gas
CBM	Compressed biomethane	**CNG**	Compressed natural gas
LNG	Liquefied natural gas	**LPG**	Liquefied petroleum gas
MP	Dispensed from medium pressure gas grid	**LTS**	Dispensed from local transmission system
SRF	Solid recovered fuel	**LBM**	From liquefied biomethane

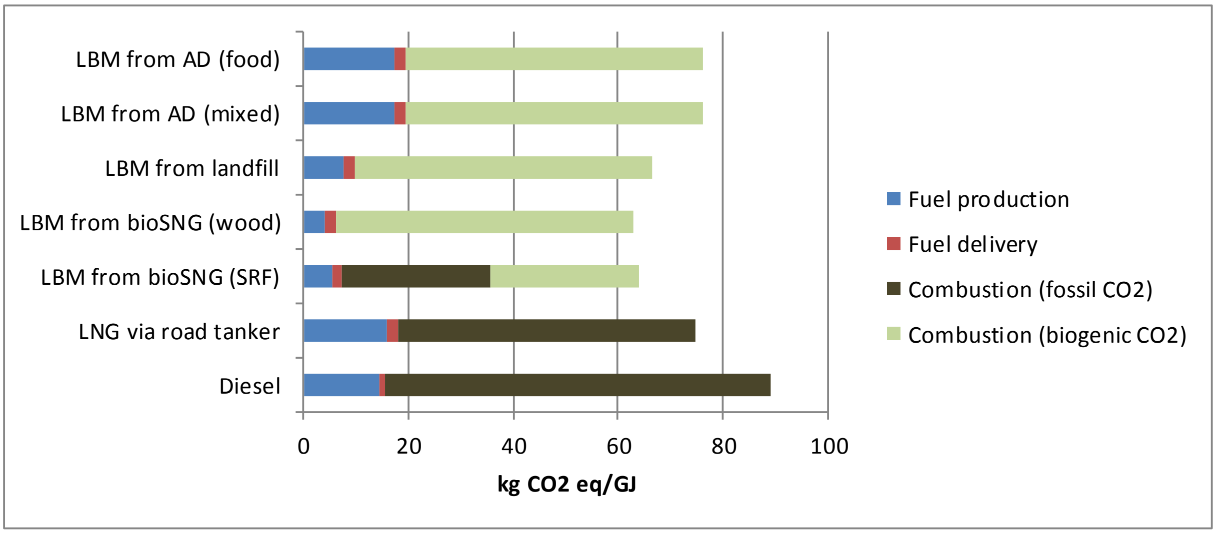
[9] For hydraulic fracturing it is assumed that by 2025, regulation would require 'green completion of wells, substantially reducing the potential emissions from shale gas production.

Emissions from production of biopropane are low (2 kg CO_2 eq /GJ) and those from production of LPG (9 kg CO_2 eq /GJ) only slightly higher than those from production of UK gas. Distribution of biopropane and LPG from terminals to filling stations by road results in only small additional emissions (of about 1kg CO_2 eq /GJ).

3.1.2 Liquefied biomethane and liquefied natural gas

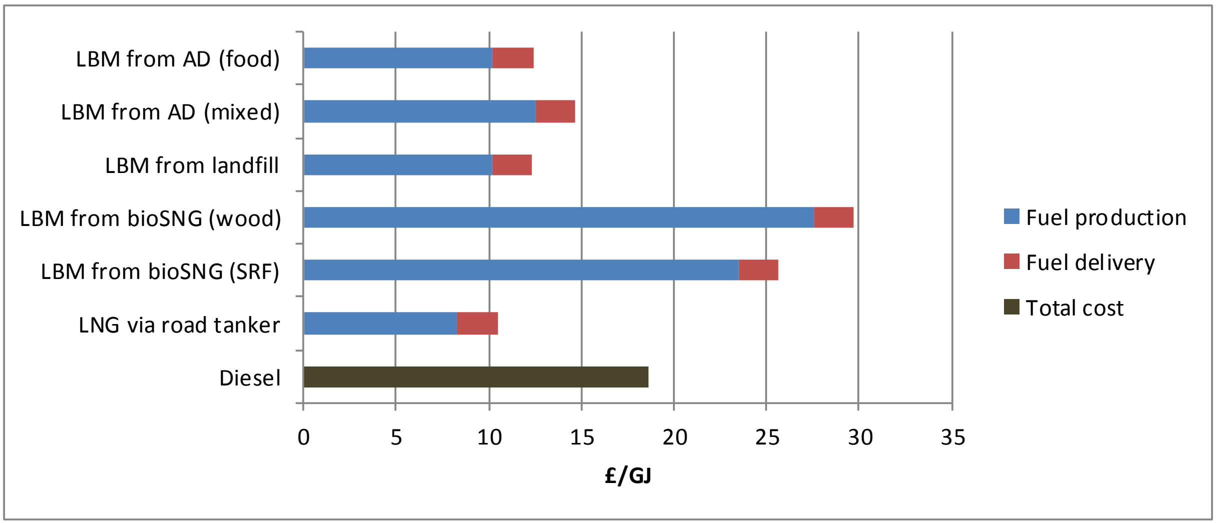
Well-to-tank emissions and costs for liquefied biomethane are shown in Figure 3.3 and Figure 3.4. Reasons for differences between the fuel pathways are as for compressed biomethane and CNG. Small scale liquefaction of biomethane has a cost of about £6/GJ and emissions of about £2 kg CO_2 eq/GJ. Dispensing of LNG has low GHG emissions (less than 0.1 kg CO_2 eq/GJ) and a cost of about £1.7/GJ. Again, all of the liquid biomethane routes offer substantial emissions savings.

Figure 3.3 Well-to-tank emissions for LBM and LNG pathways*



* CO_2 from combustion included to allow fuller comparison of fuel pathways

Figure 3.4 Cost of delivered fuel in LBM and LNG pathways



Key			
AD	Anaerobic digestion	**bioSNG**	Bio-synthetic natural gas
LBM	Liquefied biomethane	**LNG**	Liquefied natural gas
SRF	Solid recovered fuel		

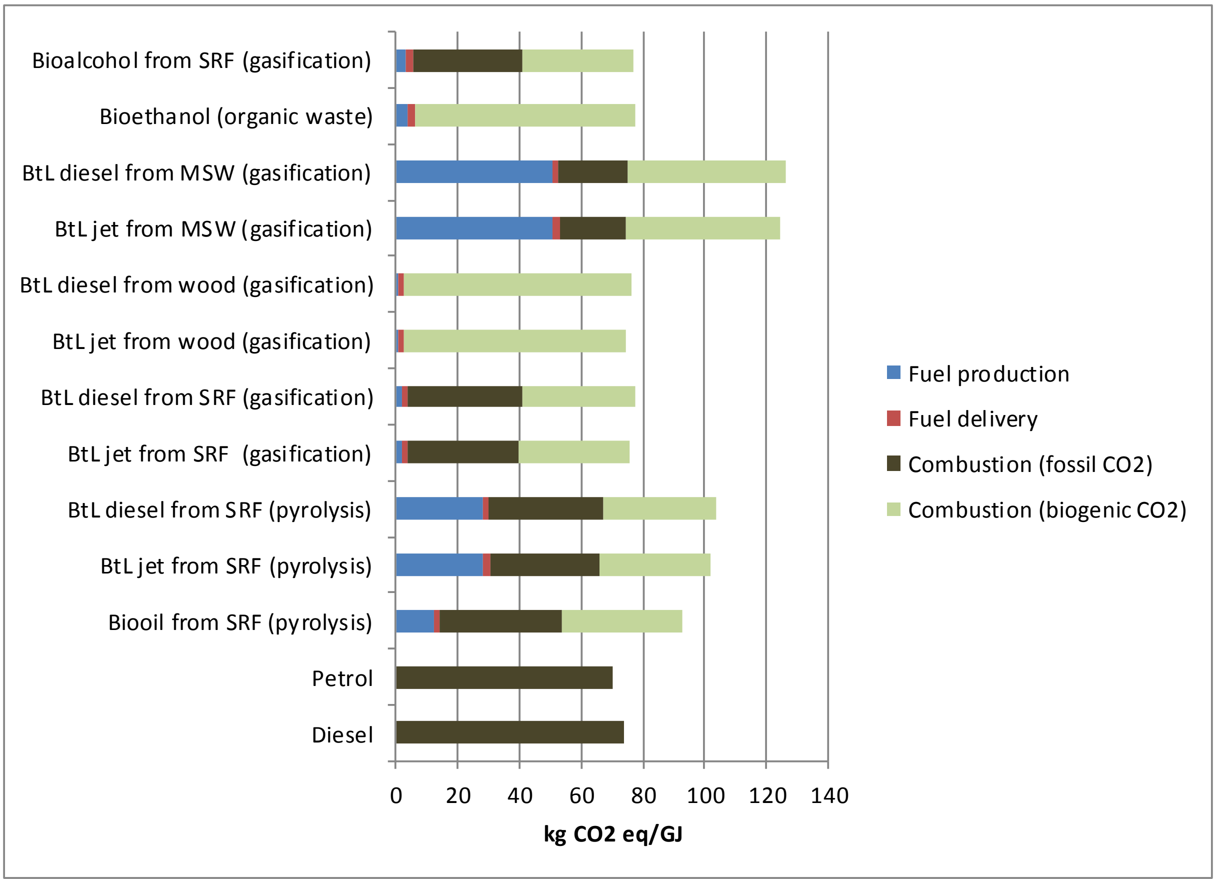
3.1.3 Liquid fuels (bioalcohols, bioethanol, BtL diesel, BtL jet and bio-oil)

GHG emissions and costs of liquid biofuels considered in the study are shown in Figure 3.5 and Figure 3.6. Emissions from the gasification processes using wood or solid recovered fuel to produce biomass to liquid (BtL) diesel and jet and bioethanol all have very low emissions from production, as they produce an excess of heat, which can be used to produce the electricity required for the process. The emissions (less than 4 kg CO_2 eq/GJ) arise from pre-processing of the waste to solid recovered fuel, or of wood into wood chips. In the case of MSW gasification, the much higher emissions arise from coal added to the gasification process for operational reasons. This combined with the relatively low efficiency of the process for fuel production (of 30%) as some of the syngas produced is required to operate the plasma gasifier, gives relatively high emissions (of about 50 kg CO_2eq/GJ). Emissions from the pyrolysis process are higher (13 to 28 CO_2 eq/GJ) due to electricity required in the process.

Emissions from the 'second generation' lignocellulosic process used to produce bioethanol from organic waste such as food waste and paper and card, are low (4kg CO_2eq/GJ).

The feedstock price has a strong influence on the cost of the fuels, so that those produced from solid recovered fuel (assumed to be available at £0/t) are competitive with conventional diesel fuels, whereas those produced from wood chip (at £65/t) are not. The gasification of residual MSW also has much higher costs due to the lower efficiency of the process and the higher capital cost of a gasifier able to treat residual waste.

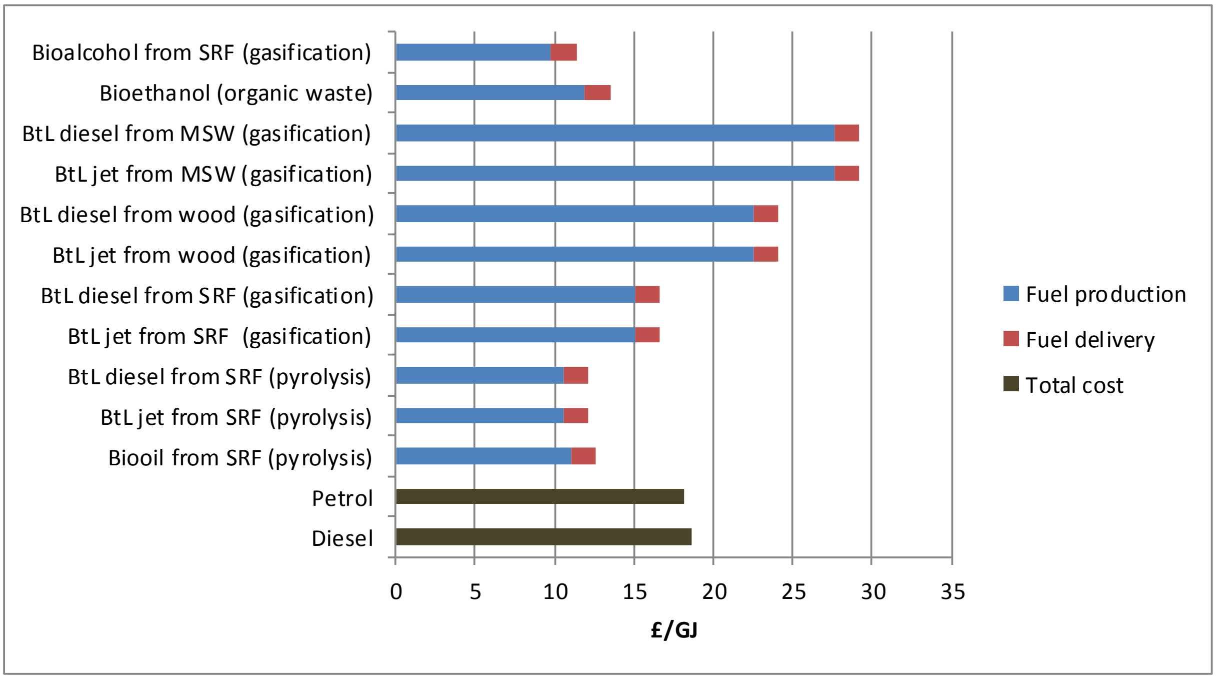
Figure 3.5 Well-to-tank emissions for liquid fuels*



* CO_2 from combustion included to allow fuller comparison of fuel pathways

Key			
BtL	Biomass to liquid	**MSW**	Municipal solid waste
SRF	Solid recovered fuel		

Figure 3.6 Cost of delivered liquid fuels



Key			
BtL	Biomass to liquid	**MSW**	Municipal solid waste
SRF	Solid recovered fuel		

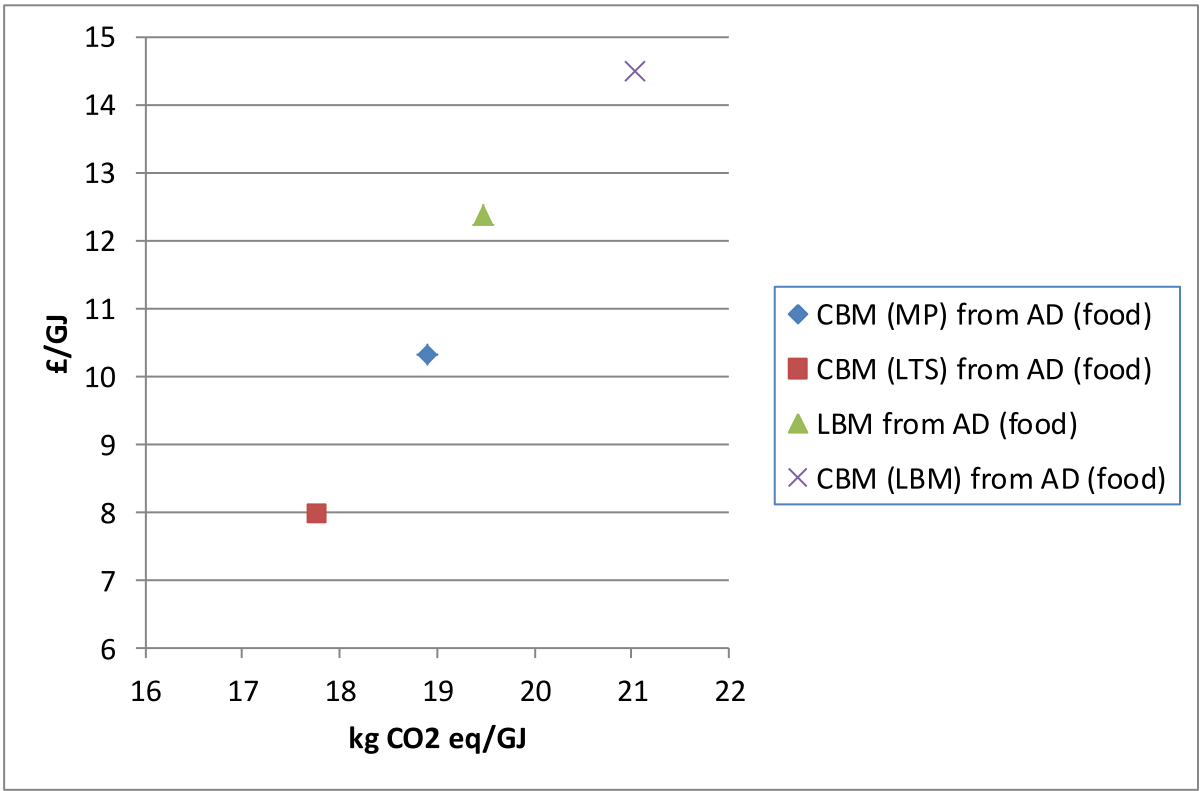
3.2 The influence of delivery routes for biogas

Figure 3.7 compares the cost and GHG emissions of various fuel pathways for a single biogas source (anaerobic digestion of food waste), in order to show the influence of the delivery pathway on overall values for the pathway. This clearly shows that delivery of compressed biomethane via a pipeline is cheaper and has lower emissions than liquefaction of biomethane. It also shows the advantages of dispensing from the local transmission system rather than the medium pressure network, where this is possible.

3.3 Differences between advanced biofuels routes

Thermochemical advanced biofuels processes can be used to produce a variety of liquid and gaseous fuels. Figure 3.8 compares the GHG emissions (including any fossil carbon- based combustion emissions) and costs of fuels produced from solid recovered fuel. It suggests that for solid recovered fuel, gaseous biosynthetic natural gas routes generally have higher costs but lower GHG emissions than liquid fuels routes. This is due partly to the additional costs associated with delivering and dispensing gaseous fuels, and partly to the higher costs and emissions estimated for biosynthetic natural gas production. The lower costs for the gasification to liquid fuels routes are due to an assumed income from the sale of excess electricity, whereas the biosynthetic natural gas plant, while self-sufficient in electricity, does not export electricity. The lower emissions for biosynthetic natural gas routes are mainly a result of lower combustion emissions – the biosynthetic natural gas has a better CO_2 to energy ratio than the liquid fuels so that on a per GJ basis the emissions from the fossil component of the solid recovered fuel are lower. If the biosynthetic natural gas is produced from a completely renewable resource such as wood (Figure 3.9), then then total emissions are much lower, but are higher than those from biomass to liquid diesel produced from wood. There is less difference in the cost of the fuels produced, as the cost of using wood as a feedstock dominates production costs.

Figure 3.7 Cost and GHG emissions for fuels produced via AD of food waste



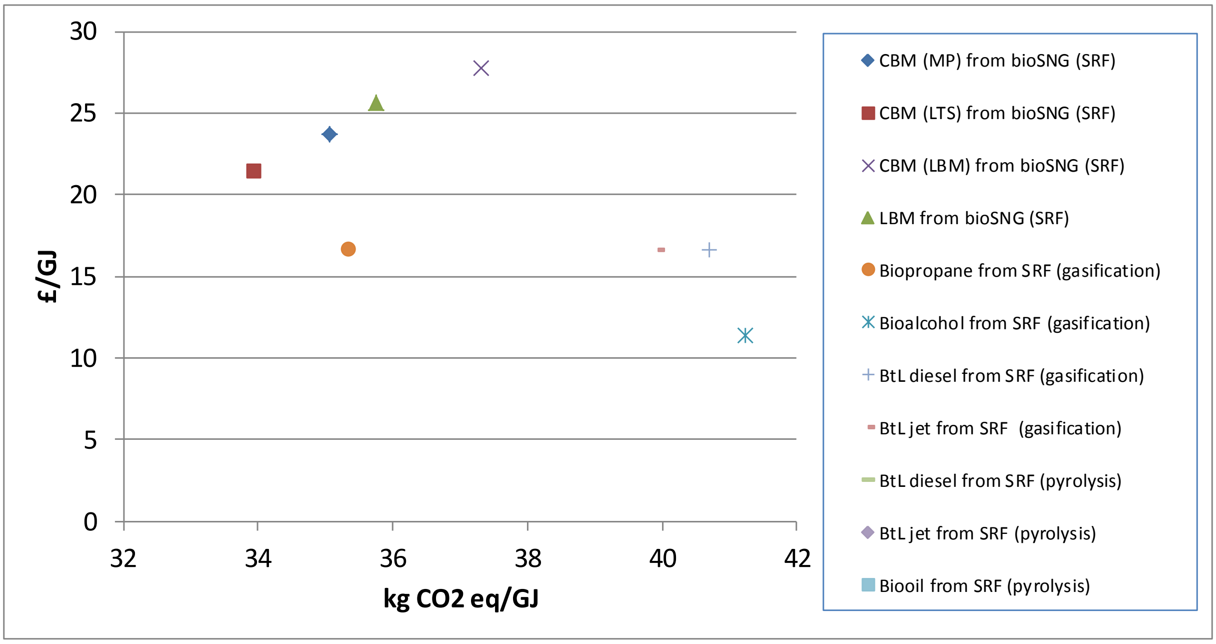
Key			
AD	Anaerobic digestion	**CBM**	Compressed biomethane
LBM	Liquefied biomethane transported by road tanker	**LTS**	Dispensed from local transmission system
MP	Dispensed from medium pressure gas grid		

3.4 Pathway efficiency and energy use

The ‘efficiency’ of the pathway i.e. how much of the energy in the original feedstock (for biological routes) or of the fuel resource (for fossil fuels) are shown in Table 3.1for gaseous fuels and Table 3.2 for liquid fuels. A negative value for energy use indicates that there is a net export of energy over the fuel cycle. This occurs in the advanced biofuels processes where the heat released during the process is sufficient to generate both enough energy for the fuel production process itself, but also excess electricity for export.

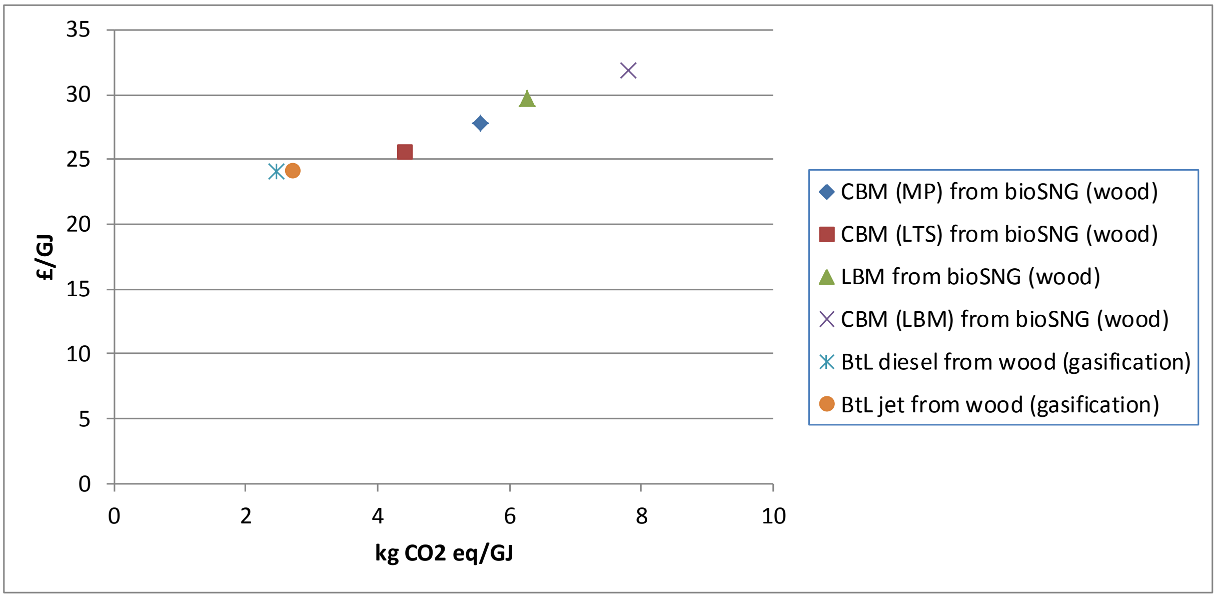
Biomethane production requires little energy input, as for anaerobic digestion routes, some of the biogas produced can be used to meet the heat and power requirements of the process. Most of the energy use occurs in the upgrading and injection steps. The influence of delivery routes for compressed biomethane can be clearly seen in the table, in terms of energy use, with dispensing from biomethane being the most energy efficient. For fossil methane the larger energy requirements for liquefying and transporting LNG can be clearly seen.

Figure 3.8 Cost and GHG emissions for advanced biofuels produced from SRF



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 3.9 Cost and GHG emissions for advanced biofuels produced from wood



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid

Table 3.1 Efficiency of gaseous fuel pathway and external energy inputs

	Dispensed as compressed gas from local transmission gas grid		Dispensed as compressed gas from medium pressure gas grid		Dispensed as compressed gas after road tanker transport of fuel in liquefied form		Dispensed as liquefied fuel via road tanker transport	
Fuel	**Energy use MJ/GJ**	**Pathway efficiency**	**Energy use MJ/GJ**	**Pathway efficiency**	**Energy use MJ/GJ**	**Pathway efficiency**	**Energy use MJ/GJ**	**Pathway efficiency**
Biomethane from landfill	54	25%	69	25%	120	25%	97	25%
Biomethane from AD of food waste	73	58%	88	58%	139	59%	116	59%
Biomethane from gasification of SRF	34	62%	49	62%	100	63%	77	63%
Biomethane from gasification of wood	34	62%	49	62%	100	63%	77	63%
Biopropane from gasification of SRF							-144	46%
Shale gas	25	99%	40	99%				
UK gas	92	99%	107	99%				
LNG	231	96%	246	96%	215	96%	192	96%
LPG							98	99%

Table 3.2 Efficiency of liquid fuel pathways and external energy inputs

Fuel pathway*	Energy use MJ/GJ	Pathway efficiency
Biomass to liquid diesel from MSW (gasification)	17	30%
Bioalcohol from SRF (gasification)	17	35%
Bioethanol (organic waste)	-63	44%
Biopropane from SRF (gasification)	-144	46%
Biomass to liquid diesel from SRF (pyrolysis)	1037	48%
Bio-oil from SRF (pyrolysis)	402	55%
Biomass to liquid diesel from SRF (gasification)	-73	56%
Biomass to liquid diesel from wood (gasification)	-73	56%

* Biomass to liquid jet routes have the same energy use and efficiency as biomass to liquid diesel routes

4 Use in Vehicles

4.1 Introduction

This section considers the difference in CO_2 and cost per km, between using the fuels considered in Section 3 and using conventional fuels such as petrol and diesel in a range of vehicles. Data on the 'well-to-tank' costs and emissions for these fuels are combined with information about the fuel economy and tail pipe emissions of vehicles when running on that fuel, and any additional capital or operating costs for the vehicle to use that fuel. For the fuel/vehicle combination this gives a 'well to wheel' cost and CO_2 emissions per km. This can then be compared with the cost and well to wheel emissions of running a similar vehicle on conventional fuels such as petrol and diesel. Where the alternative fuel gives emissions savings, then the cost of the carbon saving can be calculated. A negative cost per tonne of carbon indicates that overall there is a financial saving associated with the carbon saving, and a positive cost that overall there is a net cost incurred for the carbon saving.

All comparisons are made assuming that no biofuels have been blended into the petrol or diesel. This allows a fair comparison of the gaseous fuels options with the liquid biofuels options, as the liquid biofuels would be displacing only mineral petrol or diesel. CO_2 savings for gaseous fuels would be less if they were replacing a blend of fossil petrol and bioethanol, or a blend of fossil diesel and biodiesel; furthermore, the exact reduction in savings would depend on assumptions about the level at which biofuels had been blended in and the source of the biofuels.

The costs and well-to-tank emissions factors assumed for conventional fuels are shown in Table 4.1. The well-to-tank factors for petrol and diesel (taken from JEC, 2013) are based on current sources of crude oil, and the current oil refining environment in Europe. It is possible that in the future, there could be changes to the oil refining environment, related to quality changes for non-road fuels (mostly marine fuels) and changes in the relative demand for diesel and gasoline. In spite of anticipated improvements in energy efficiency of refining in the future, this is expected to lead to an increase in the specific CO_2 emissions per tonne of crude processed. The increase however is likely to be a small percentage change in the total well to wheel emissions for petrol and diesel.

Table 4.1 Conventional fuels

Fuel	Cost (£/GJ)	Source	WTT emissions kg CO_2 eq/GJ	Source
Petrol	18.1	Supplied by DfT	13.8	JEC, 2013; recalculated using GWPs used in this study
Diesel	18.59		15.4	
Aviation fuel	18.59	Assumed to be same as diesel	15.4	Assumed to be same as diesel
Marine fuel oil	14.1	Ricardo-AEA, 2013	15.4	Assumed to be same as diesel

4.2 Vehicles studied

The list of vehicle types included in the analysis is shown in Table 4.2. This is not an exhaustive list of all vehicle types that gaseous fuels and biofuels could be used in, but is intended to give a good representation across a range of different types of vehicles and is intended to provide evidence-based examples from new models of vehicles available on the market now[10]. While the focus is on road vehicles, examples from shipping and aviation are also considered to give a comparison across modes. As well as the broad category of vehicle to be studied, the Table shows specific examples of the type of vehicle. For each type of vehicle, an example of the vehicle running on conventional liquid fuels is included to allow estimation of the CO_2 savings offered by the gaseous fuels and biofuels relative to the fossil fuelled alternative.

For each vehicle data was collected on:

- any additional capital and operating costs compared to a similar vehicle running on conventional liquid fuels
- fuel economy of the vehicle
- estimated change in fuel economy and vehicle costs between now and 2025
- tailpipe emissions of non-CO_2 GHGs methane (CH_4) and nitrous oxide (N_2O)
- average lifetime and annual mileage

Full details of the data collected and assumptions made are given in Appendix 3. The highest degree of uncertainty is in the tailpipe emissions of CH_4 and N_2O, as these emissions have not been regulated in the past so there are relatively few emissions measurements.

As described in Section 2, this vehicle data was combined with data on well-to-tank emissions and costs for each fuel pathway to give total well-to-wheel emissions, and a cost per km, which reflects fuel costs, plus any additional costs for the vehicle to operate on the fuel. Results are summarised below. A full set of results is given in Appendix 4.

4.3 Cars

Two examples of cars were examined. One (Car A) is a VW Golf 1.4 Blue Motion which is available in both petrol and natural gas versions. The other (car B) is an Astra SRI 1.6 litre which is also available with the option of an LPG conversion. The percentage emissions savings and cost-effectiveness from the use of alternative fuels in the cars have been calculated in comparison to the use of petrol in the vehicle. However, it can be argued, that an alternative decarbonisation option for cars is to switch from petrol to diesel versions, and while a full evaluation of this option is not carried out, the emissions savings available from use of diesel are shown for comparison, and to help put the savings from alternative fuels into context. The use of bioethanol (at a 10% v/v blend) and bioalcohols (at a 15% v/v blend) is also examined. The percentage savings and cost-effectiveness of these two fuels are the same for Car A and Car B and are only shown in the table for Car B. Results for these fuels are only shown for Car B.

The use of compressed biomethane (CBM) in Car A (Table 4.3), gives substantial savings of 75% to 94% when the compressed biomethane is produced from a fully renewable source (biogas from anaerobic digestion or landfill and biosynthetic natural gas from woodchips and of about 60% when produced from biosynthetic natural gas from SRF. The cost-effectiveness of the carbon savings delivered is in the range of £90 to £240/t CO_2 for biogas options, and £300 to £550/t CO_2 for biosynthetic natural gas pathways. In the case of CNG from natural gas or shale gas, GHG savings are smaller (22% to 27%) with a cost-effectiveness of £350 to £550/tCO_2. However if the gas comes from imported CNG then savings are reduced to between 11 and 13% and cost-effectiveness worsens to £850 to

[10] . A refuse collection vehicle (RCV) was also considered, but as this is a small market segment results are not presented here. They are included in the full set of data in Appendix 4.

£1200/tCO_2. An alternative decarbonisation option, as discussed above, would be the use of diesel. This gives similar savings (of 23%) to options for using CNG from natural gas or shale gas.

Table 4.2 Vehicles considered in study

Vehicle type	Engine type	Fuels	Additional notes	Different engine to comparator vehicle?	Example vehicle
Car (A)	SI engine	Petrol	Comparator vehicle	N/A	VW Golf 1.4 TSI Blue Motion
	SI engine	CNG and CBM		Yes	VW Golf 1.4 TGI Blue Motion
Car (B)	SI engine	Petrol	Comparator vehicle	N/A	Astra SRI 1.6 litre petrol as from OEM
	SI engine	LPG and biopropane		Yes	Astra SRI 1.6 litre petrol conversion
	SI engine	Bioethanol	Blended at levels of up to 10% v/v	No	Astra SRI 1.6 litre petrol operating as sold
	SI engine	Mixed bioalcohols	Blended at suitable levels (assumed to be 15% v/v)	No	Astra SRI 1.6 litre petrol operating as sold
Van (A) (Class I)	SI engine	Petrol	Comparator vehicle	N/A	Fiat Doblo Cargo
	SI engine	CNG and CBM		Yes	Fiat Doblo Cargo Natural Power bi-fuel
Van (B) (Class III)	CI engine	Diesel	Comparator vehicle	N/A	Mercedes-Benz Sprinter 316
	SI engine	CNG and CBM	Used in bi-fuel engine with petrol	Yes	Mercedes-Benz Sprinter 316 NGT
	CI engine	BtL diesel		No	Mercedes-Benz Sprinter 316
HGV (urban) (Medium size rigid truck)	CI engine	Diesel	Comparator vehicle	N/A	Iveco Eurocargo (12 - 16 tonne) 120E20L 4815 150 kW
	SI engine	CNG and CBM		Yes	Iveco Eurocargo (12 - 16 tonne) 120E20L CNG 4815
HGV (long	CI engine	Diesel	Comparator vehicle	N/A	Volvo D13C D13C460 diesel 338 kW (13 litre) in Volvo

Vehicle type	Engine type	Fuels	Additional notes	Different engine to comparator vehicle?	Example vehicle
distance) (44 tonne articulated truck)					FM13 truck chassis
	CI engine	LNG and LBM	used in dual fuel engine with diesel	Yes	Volvo D13C Gas methane/diesel 338 kW (13 litre) in Volvo FM13 truck chassis
City bus	CI engine	Diesel	Comparator vehicle	N/A	MAN Lion City bus with D2066 LUH EEV 10.5 litre Euro VI diesel engine (265 kW)
	SI engine	CNG and CBM		Yes	MAN Ecocity bus with E2876 LUH 04 EEV 12.8 litre gas engine (204 kW)
Shipping	Low speed main engine	Marine fuel oil	Comparator vessel	N/A	General cargo ship <5,000 dwt
	Low speed main engine	LNG	carrying out short sea shipping	Yes	General cargo ship <5,000 dwt
Aviation		Jet fuel	Comparator aircraft	N/A	Airbus A320 t
		BtL jet fuel		No	Airbus A320 t

Note: SI engine = spark ignition engine; CI engine = compression ignition engine.
* e.g. mixture of ethanol, butanol and propanol

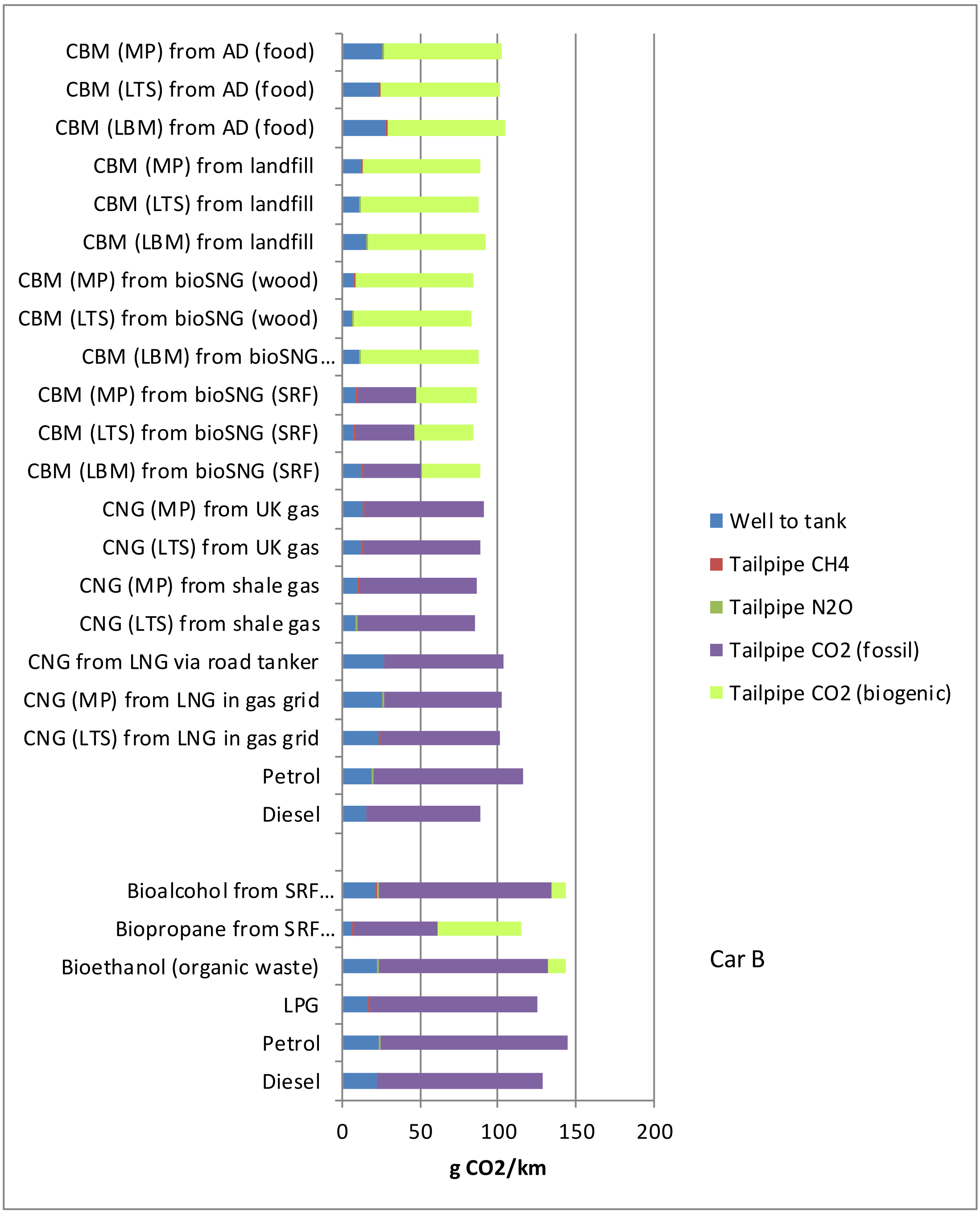
The use of biopropane in Car B results in substantial emissions savings per km, but costs per km are about 60% higher than for a petrol car, due to additional vehicle costs, giving a cost-effectiveness of £224/tCO_2 saved. The use of LPG gives much smaller savings (13%) and a high cost of carbon savings (£1233/tCO_2). The cost of the LPG/biopropane car is based on the cost of an after-market conversion in the UK (of £1,200), and it is possible that if an OEM version was available as it is in other parts of Europe, then the additional cost might be only half of this, which would improve the cost-effectiveness for LPG to £880/tCO_2 and for biopropane to £146/tCO_2.

Table 4.3 Cost-effectiveness of CO_2 savings for use of fuels in cars

Pathway	g CO_2 eq/km	p/km	GHG saving	Cost-effectiveness £/t CO_2
Car A				
CBM (LTS) from AD (food)	25	3.4	79%	102
CBM (LBM) from AD (food)	29	4.3	75%	207
CBM (MP) from landfill	13	3.7	89%	120
CBM (LTS) from landfill	12	3.4	90%	88
CBM (LBM) from landfill	16	4.3	86%	179
CBM (MP) from bioSNG (wood)	8	6.1	93%	334
CBM (LTS) from bioSNG (wood)	7	5.8	94%	300
CBM (LBM) from bioSNG (wood)	11	6.6	90%	395
CBM (MP) from bioSNG (SRF)	48	5.5	59%	447
CBM (LTS) from bioSNG (SRF)	46	5.2	60%	392
CBM (LBM) from bioSNG (SRF)	51	6.1	56%	551
CNG (MP) from UK gas	90	3.9	22%	552
CNG (LTS) from UK gas	89	3.6	23%	404
CNG (MP) from shale gas	87	3.9	25%	479
CNG (LTS) from shale gas	85	3.6	27%	353
CNG from LNG via road tanker	103	4.0	11%	1200
CNG (MP) from LNG in gas grid	102	4.1	12%	1170
CNG (LTS) from LNG in gas grid	101	3.8	13%	846
Petrol	116	2.5		
Car B				
Biopropane from SRF (gasification)	61	5.0	58%	224
LPG	126	545	13%	1233
Bioethanol (from organic waste)	132	3.0	9%	-62
Bioalcohol from SRF (gasification)	134	2.9	7%	-166
Petrol	144	3.1	N/A	N/A

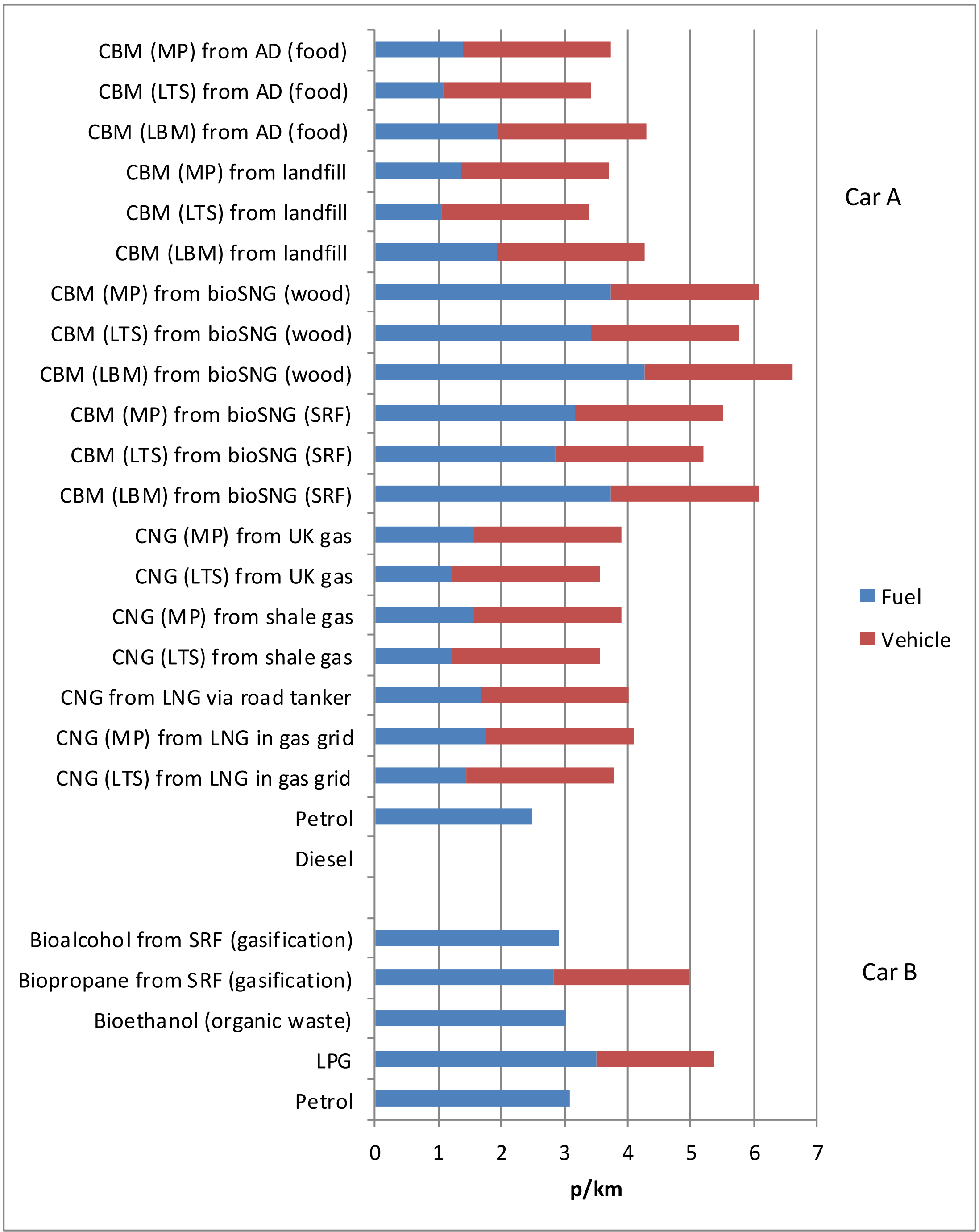
The use of bioethanol and bio-alcohols is both cost-effective in reducing greenhouse gas emissions, although actual savings achieved are relatively low due to the low blend levels assumed. Use at higher blend levels (e.g. E20) might be possible in the future, but could require additional modifications to vehicles, which might reduce the cost-effectiveness of savings. The use of very high strength blends (e.g. E85 in e.g. flex-fuel vehicles) has not been examined in this study due to resource constraints, but this is another possibility. A breakdown of GHG emissions and costs per km is shown in Figure 4.1 and Figure 4.2.

Figure 4.1 Breakdown of GHG emissions for cars)



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 4.2 Breakdown of costs for cars



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

4.4 Vans

Table 4.4 shows the cost-effectiveness of CO_2 savings for a small Class I van (Van A) running on CNG and compressed biomethane, compared to a similar petrol van, and of a larger Class III van (van B) where the comparison is with a similar van running on diesel, as for this larger size of van, this would be the most common type of van. The cost-effectiveness of using biomass to liquid diesel in this type of van is also evaluated. As with cars, all pathways using compressed biomethane from fully renewable sources (biogas from AD or landfill and biosynthetic natural gas from wood) deliver substantial savings (from 65% to 94% depending on the source and delivery pathway) for both types of van. Savings for compressed biomethane produced from biosynthetic natural gas from waste are lower (from 38% to 58%). Use of compressed biomethane from anaerobic digestion and landfill delivers the lowest cost reductions (£2 to £72/t CO_2), although this is increased where the biomethane is transported in liquefied form rather than through the pipeline (£120 to £170/t CO_2). The cost of carbon reductions when using biosynthetic natural gas is much higher (in the range of £280 to £860/t CO_2) due to the higher cost of the fuel. As discussed in Section 3, using the local transmission system part of the gas grid for dispensing increases emissions savings, compared to dispensing from the medium pressure grid, by about 2%

CNG from fossil fuel gas delivers emissions savings of 9 to 25%, for the smaller van, where the comparison is with a petrol powered van. As with cars, savings depend on the fuel pathway, with savings at the lower end of this range when the initial source of the gas is LNG. In the case of the larger (class III van) where the comparison is with a diesel fuelled van, use of CNG does not deliver any carbon savings. This is because the diesel van used as a comparator is more fuel efficient than the gas powered van, which has a spark ignition engine. The increased fuel use in the gas powered van more than offsets the savings achieved by using a less carbon intensive fuel (gas).

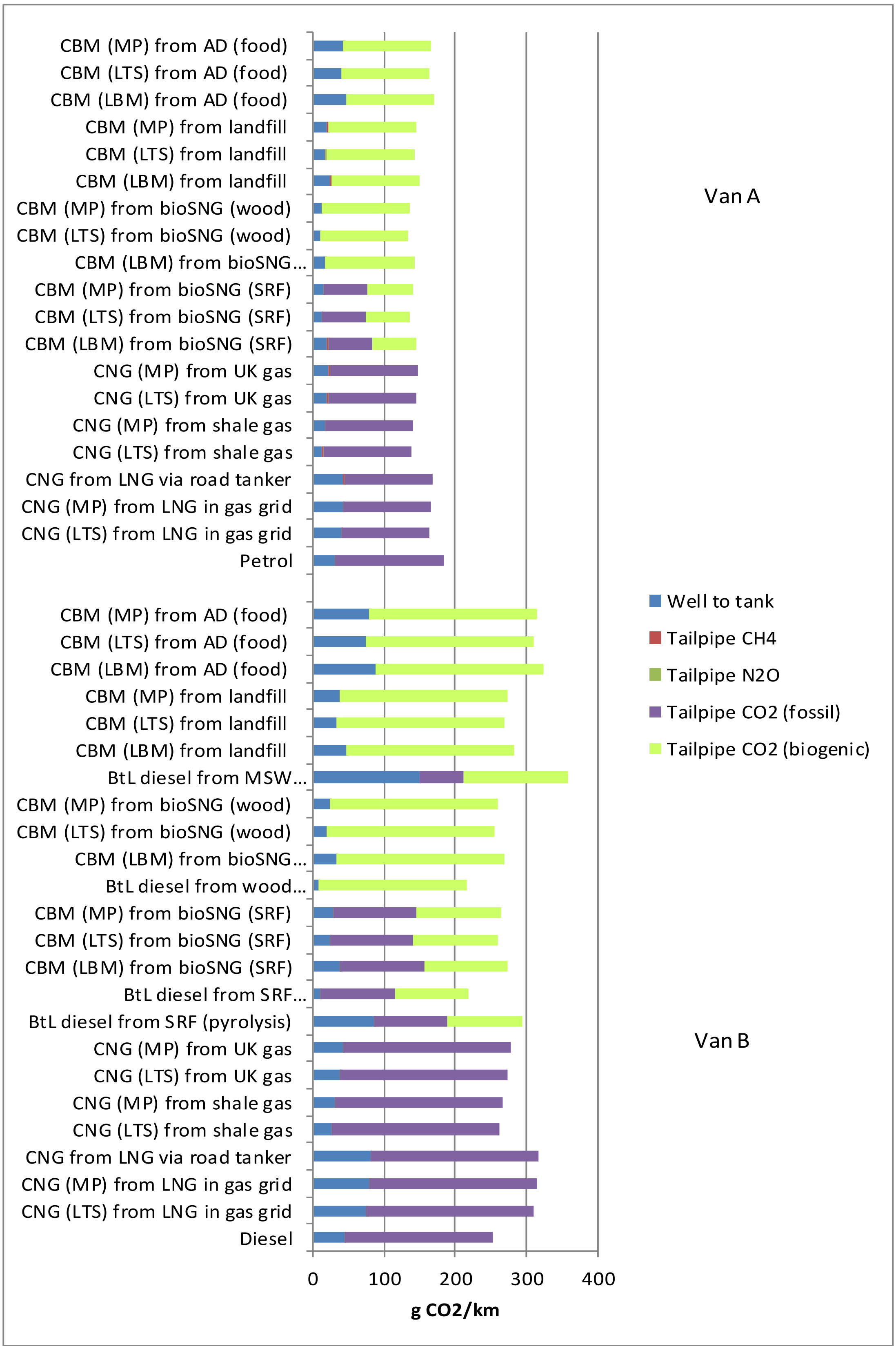
The use of biomass to liquid diesel in the larger diesel powered van, offers good emissions savings (54% to 97%) at a low or negative cost (-£119 to £68/t CO_2). The exception is biomass to liquid diesel produced through the gasification of MSW, which due to the high well-to-tank emissions for this fuel (as discussed in Section 3) gives much smaller savings (16%) at a much higher cost (£773/t $CO_{2)}$. The percentage savings and cost-effectiveness of carbon savings of using biomass to liquid diesel in other types of diesel vehicles will be very similar to those for vans, as there are no additional vehicle or infrastructure costs for using this ‘drop-in’ fuel.

Table 4.4 Cost-effectiveness of CO_2 savings for use of fuels in vans

Pathway	g CO_2 eq/km	p/km	GHG saving	Cost-effectiveness £/t CO_2
Van A (class I van)				
CBM (MP) from AD (food)	42	5.0	77%	72
CBM (LTS) from AD (food)	40	4.5	78%	35
CBM (LBM) from AD (food)	47	5.9	75%	140
CBM (MP) from landfill	21	5.0	89%	61
CBM (LTS) from landfill	18	4.4	90%	29
CBM (LBM) from landfill	26	5.9	86%	120
CBM (MP) from bioSNG (wood)	13	8.8	93%	283
CBM (LTS) from bioSNG (wood)	11	8.3	94%	249
CBM (LBM) from bioSNG (wood)	18	9.7	90%	344
CBM (MP) from bioSNG (SRF)	78	7.9	58%	370
CBM (LTS) from bioSNG (SRF)	75	7.4	59%	315
CBM (LBM) from bioSNG (SRF)	83	8.8	55%	475
CNG (MP) from UK gas	147	5.2	20%	344
CNG (LTS) from UK gas	145	4.7	22%	193
CNG (MP) from shale gas	141	5.2	24%	294

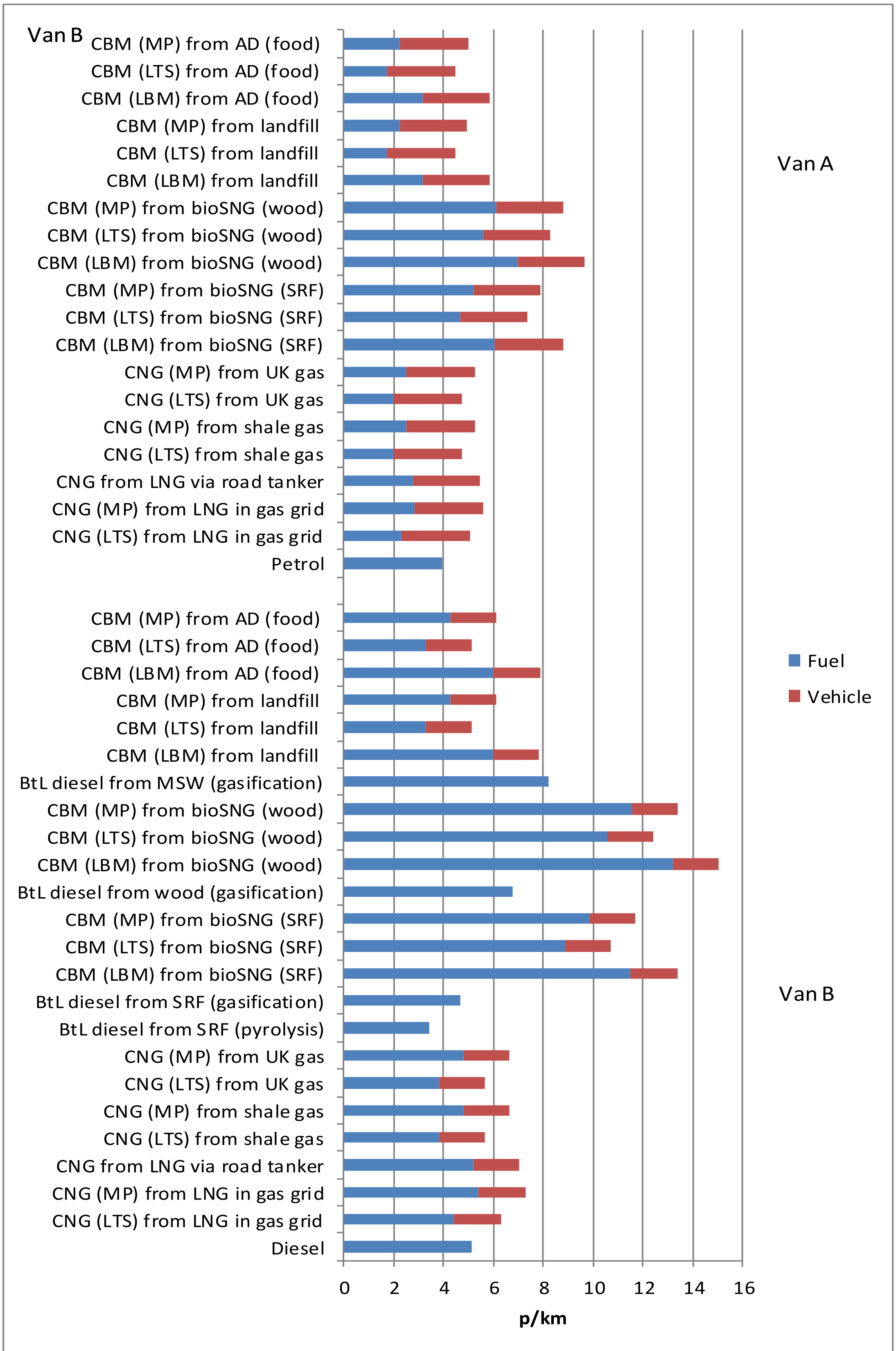
Pathway	g CO_2 eq/km	p/km	GHG saving	Cost-effectiveness £/t CO_2
CNG (LTS) from shale gas	138	4.7	25%	167
CNG from LNG via road tanker	168	5.5	9%	901
CNG (MP) from LNG in gas grid	166	5.6	10%	889
CNG (LTS) from LNG in gas grid	164	5.1	11%	532
Petrol	184	4.0	77%	
Van B (class III van)				
CBM (MP) from AD (food)	79	6.1	68%	60
CBM (LTS) from AD (food)	75	5.2	70%	3
CBM (LBM) from AD (food)	88	7.9	65%	169
CBM (MP) from landfill	38	6.1	85%	47
CBM (LTS) from landfill	34	5.1	87%	2
CBM (LBM) from landfill	48	7.8	81%	134
CBM (MP) from bioSNG (wood)	24	13.4	90%	364
CBM (LTS) from bioSNG (wood)	19	12.4	92%	315
CBM (LBM) from bioSNG (wood)	33	15.1	87%	455
CBM (MP) from bioSNG (SRF)	146	11.7	42%	625
CBM (LTS) from bioSNG (SRF)	142	10.7	44%	510
CBM (LBM) from bioSNG (SRF)	156	13.4	38%	859
CNG (MP) from UK gas	278	6.6	no saving	no saving
CNG (LTS) from UK gas	273	5.7	no saving	no saving
CNG (MP) from shale gas	266	6.6	no saving	no saving
CNG (LTS) from shale gas	261	5.7	no saving	no saving
CNG from LNG via road tanker	317	7.1	no saving	no saving
CNG (MP) from LNG in gas grid	314	7.3	no saving	no saving
CNG (LTS) from LNG in gas grid	309	6.3	no saving	no saving
BtL diesel from wood (gasification)	7	6.8	97%	68
BtL diesel from SRF (gasification)	115	4.7	54%	-31
BtL diesel from SRF (pyrolysis)	189	3.4	25%	-270
BtL diesel from MSW (gasification)	211	8.2	16%	773
Diesel	252	5.1		

Figure 4.3 Breakdown of GHG emissions for vans



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 4.4 Breakdown of costs for vans



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

4.5 Small HGVs

Emissions savings for small HGVs operating in an urban environment follow the same pattern as those for larger vans i.e. operation on compressed biomethane delivers carbon savings but operation on fossil-based CNG does not. Percentage savings from the use of compressed biomethane are all slightly lower for a small HGV than a van due to the bigger difference between the fuel economy of the gas fuelled HGV and a conventional diesel HGV, than between gas and diesel vans. The cost-effectiveness of savings for small HGVs running on compressed biomethane is very similar. As for Class III diesel vans the CNG from fossil fuel gas delivers no savings, as the advantage of a more decarbonised fuel is lost due to the poorer fuel economy of the HGV when running on methane[11].

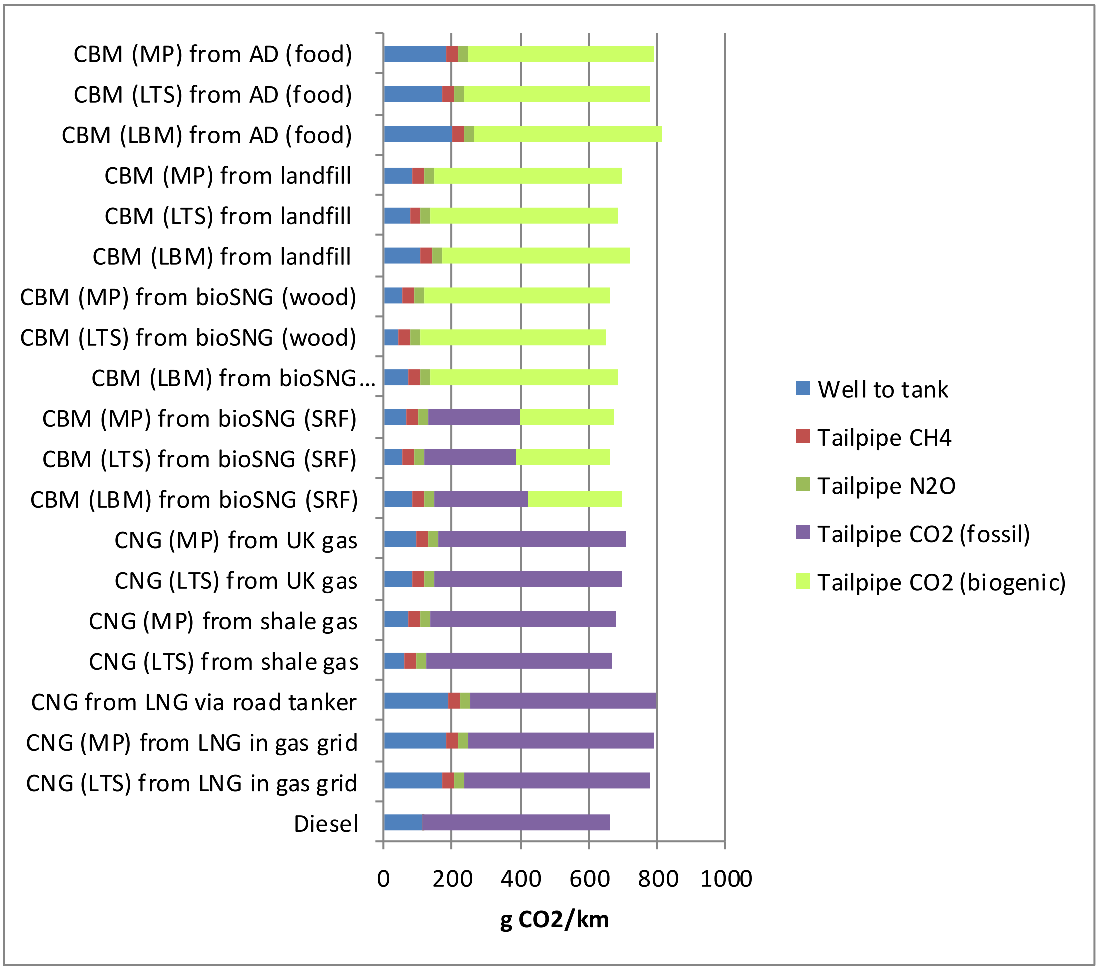
In the case of biomass to liquid diesel percentage emissions savings and cost-effectiveness of savings are the same as for vans using biomass to liquid diesel. This is because biomass to liquid diesel is a drop-in fuel replacement, and there are no additional vehicle or infrastructure costs and no change in fuel economy. The magnitude and cost of emissions savings for use of biomass to liquid diesel therefore only depend on the cost and emissions associated with the fuel, and do not vary between vehicle type.

Table 4.5 Cost-effectiveness of CO_2 savings for use of fuels in small HGVs

Pathway	g CO_2 eq/km	p/km	GHG saving	Cost-effectiveness £/t CO_2
CBM (MP) from AD (food)	245	16.1	63%	55
CBM (LTS) from AD (food)	235	13.8	65%	1
CBM (LBM) from AD (food)	266	20.1	60%	160
CBM (MP) from landfill	150	16.0	77%	44
CBM (LTS) from landfill	139	13.7	79%	-1
CBM (LBM) from landfill	172	20.0	74%	128
CBM (MP) from bioSNG (wood)	117	33.0	82%	352
CBM (LTS) from bioSNG (wood)	106	30.7	84%	305
CBM (LBM) from bioSNG (wood)	138	36.8	79%	441
CBM (MP) from bioSNG (SRF)	401	29.0	39%	586
CBM (LTS) from bioSNG (SRF)	390	26.7	41%	479
CBM (LBM) from bioSNG (SRF)	423	32.9	36%	802
CNG (MP) from UK gas	708	17.2	no saving	no saving
CNG (LTS) from UK gas	697	15.0	no saving	no saving
CNG (MP) from shale gas	680	17.2	no saving	no saving
CNG (LTS) from shale gas	669	15.0	no saving	no saving
CNG from LNG via road tanker	799	18.2	no saving	no saving
CNG (MP) from LNG in gas grid	792	18.7	no saving	no saving
CNG (LTS) from LNG in gas grid	781	16.4	no saving	no saving
Diesel	661	13.8		

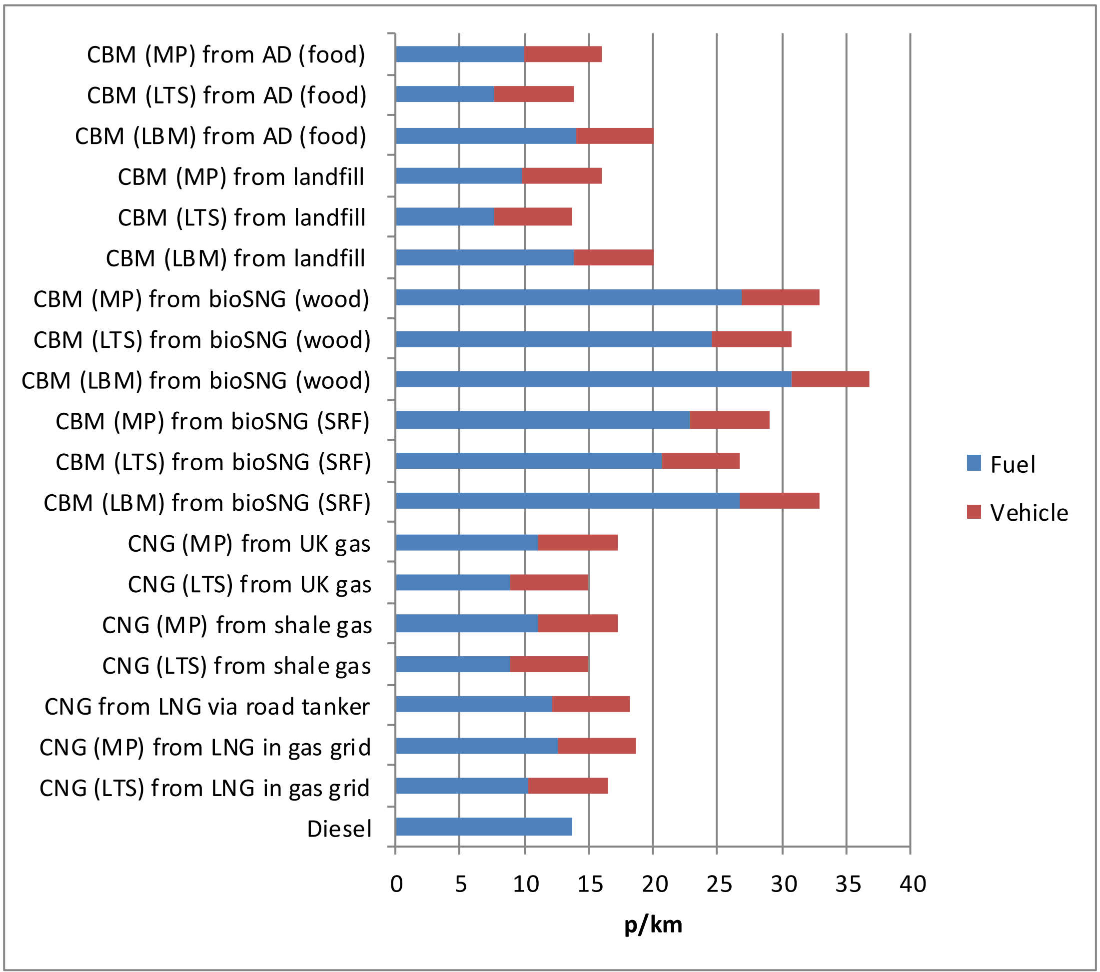
[11] Little data was available on the fuel economy of a small HGV running on gas. Available information on CO_2 emissions from a small HGV running on CNG are contradictory, with in use performance suggesting higher emissions and an engine bench test suggesting lower emissions. The analysis therefore assumes that CO_2 emissions when running on gas and diesel are similar. However as CO_2 emissions per GJ of fuel are lower for gas, the gas powered HGV has a fuel economy which is 30% worse than the diesel vehicle.

Figure 4.5 Breakdown of GHG emissions for small HGVs



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 4.6 Breakdown of costs for small HGVs



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

4.6 Dual fuel HGVs

For ‘long distance’ dual fuel HGVs, it was assumed that gas would substitute for 60% of diesel (on an energy basis). It was also assumed that a methane catalyst would be added to the vehicle to reduce tailpipe emissions of methane, and the cost of this catalyst is included in the additional costs of the vehicle. The additional capital cost of the vehicle could be reduced by not including a methane catalyst, but this would result in higher tailpipe emissions of methane.

Table 4.6 shows that the use of LBM from a fully ‘renewable’ biogas resource (landfill or anaerobic digestion) in these vehicles gives GHG savings of 43% to 49% compared to diesel. In the case of liquefied biomethane produced from biogas from anaerobic digestion and landfill sites, the lower fuel costs compared to diesel do not quite offset the additional costs of a dual fuel HGV, and total running costs are slightly higher than running on diesel alone. These fuel pathways thus show a good cost-effectiveness (of about £8 to £11/t CO_2). GHG savings from the use of LBM from BioSNG produced from wood are also good (-52%) but are achieved at a much higher cost for mitigation (£234/t CO_2). The higher fossil carbon content of biosynthetic natural gas produced from solid recovered fuel reduces savings (to 32%) and increases the cost of savings further (to £294/t CO_2). For LNG, well-to-tank emissions (equivalent to 145 g CO_2/km) are higher than those for diesel. These higher well-to-tank emissions, and higher tail pipe emissions of non-CO_2 GHGs (equivalent to 33 g CO_2/km compared to 1 g CO_2/km for a diesel vehicle) offset some of the savings in tailpipe CO_2 leading to overall savings of only 6%. However the cost-effectiveness of these savings is good (-£145/t CO_2).

Table 4.6 Cost-effectiveness of CO_2 savings for use of fuels in dual-fuel HGVs

Pathway	g CO_2 eq/km	p/km	GHG saving	Cost-effectiveness £/t CO_2
LBM from AD (food)	436	16.3	43%	11
LBM from landfill	386	16.2	49%	8
LBM from bioSNG (wood)	369	25.1	52%	234
LBM from bioSNG (SRF)	520	23.1	32%	294
LNG via road tanker	720	15.3	6%	-145
Diesel	764	15.9		

Figure 4.7 Breakdown of GHG emissions for dual fuel HGVs

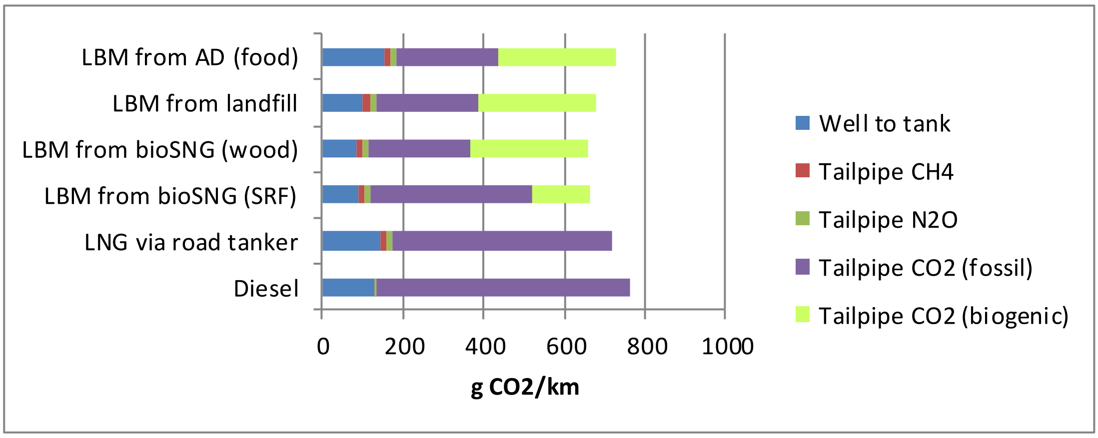
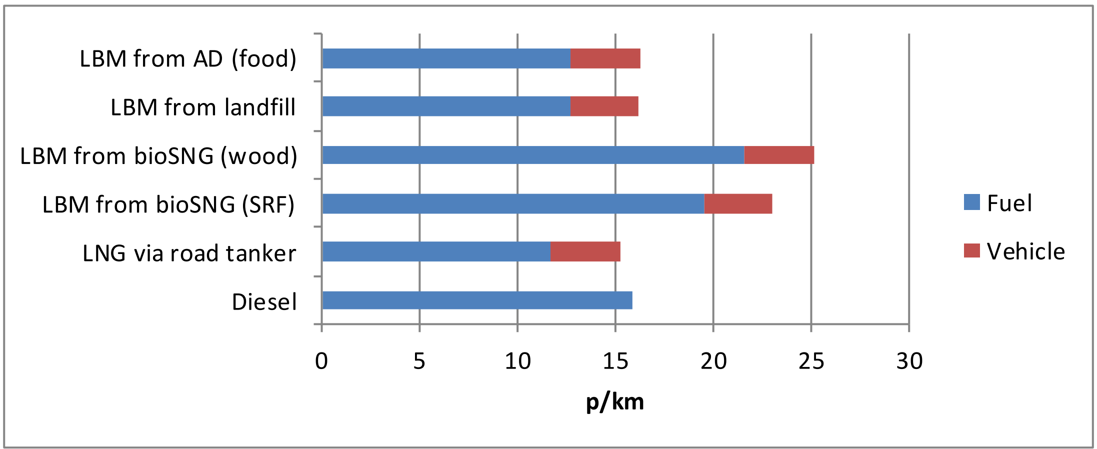


Figure 4.8 Breakdown of costs for dual fuel HGVs



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

In the case of dual fuel HGV vehicles, no data could be found in the literature for CH_4 emissions during operation in dual fuel mode, and so emissions were set at an average of values for operation on diesel and operation on CNG. The level of methane in tailpipe gases depends on the substitution rate, the drive cycle, the level of methane slip in the engine and the effectiveness of any methane catalyst that is present in oxidising the methane. Due to the high uncertainty in tailpipe methane emissions for dual fuel HGVs, some additional sensitivity analysis was carried out and is included in Section 4.10.2.2.

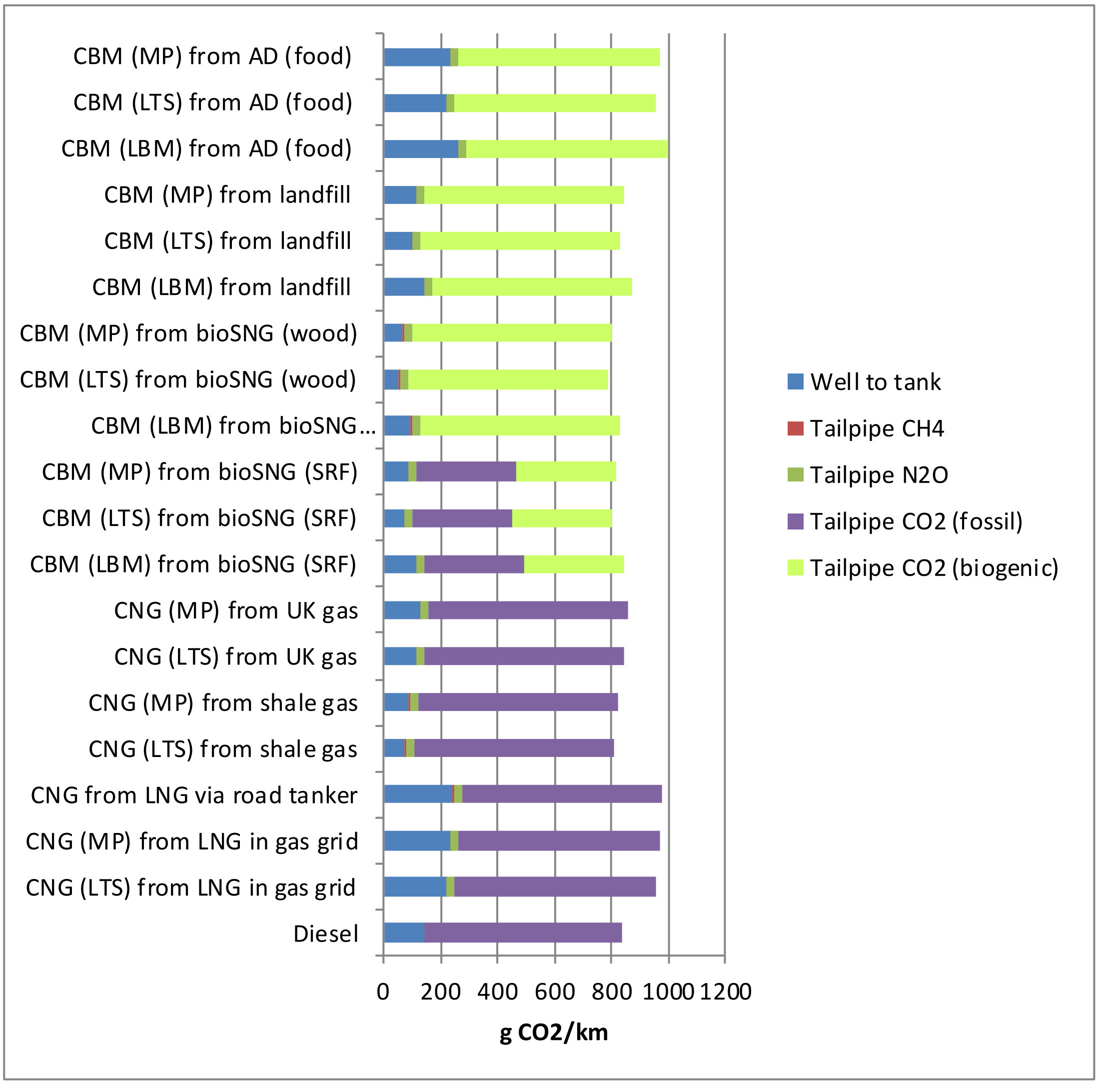
4.7 Buses

The savings and cost-effectiveness of using CBM/CNG in buses (Table 4.7) is similar to the use of those fuels in small HGVS. Compressed biomethane offers savings of 41% to 90% depending on the source and pathway, with cost-effectiveness being good for biogas routes (-£86/tCO_2 to £45/tCO_2) and much higher for biosynthetic natural gas routes (£224/tCO_2 to £575/tCO_2). As with other vehicle types, the poorer fuel economy of the bus when running on methane means that there are no, or very low (1 to 3%) GHG savings from running the vehicle on CNG. As in the rest of the study, no subsidies or incentives are included in the calculation of costs and cost-effectiveness, so the costs shown here do not take into account the Bus Service Operators Grant or Low Carbon Emissions Bus payments.

Table 4.7 Cost-effectiveness of CO_2 savings for use of fuels in buses

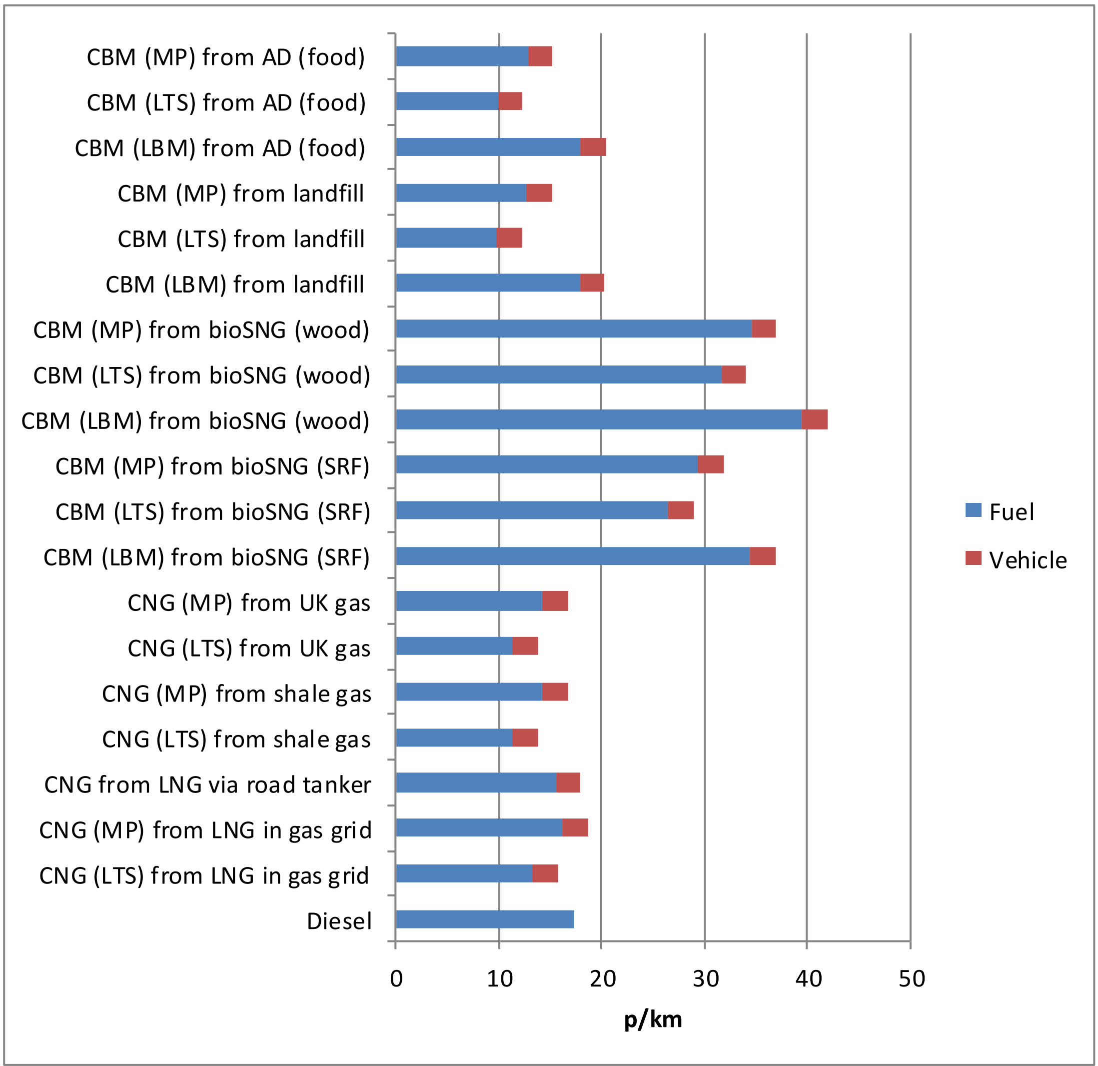
Pathway	g CO_2 eq/km	p/km	GHG saving	Cost-effectiveness £/tCO_2
CBM (MP) from AD (food)	265	15.3	68%	-37
CBM (LTS) from AD (food)	251	12.4	70%	-86
CBM (LBM) from AD (food)	292	20.4	65%	57
CBM (MP) from landfill	143	15.2	83%	-31
CBM (LTS) from landfill	129	12.3	85%	-72
CBM (LBM) from landfill	170	20.4	80%	45
CBM (MP) from bioSNG (wood)	100	37.0	88%	268
CBM (LTS) from bioSNG (wood)	86	34.1	90%	224
CBM (LBM) from bioSNG (wood)	128	42.0	85%	348
CBM (MP) from bioSNG (SRF)	466	31.9	44%	395
CBM (LTS) from bioSNG (SRF)	452	29.0	46%	305
CBM (LBM) from bioSNG (SRF)	494	36.9	41%	575
CNG (MP) from UK gas	859	16.8	no saving	no saving
CNG (LTS) from UK gas	845	13.9	no saving	no saving
CNG (MP) from shale gas	823	16.8	1%	-525
CNG (LTS) from shale gas	809	13.9	3%	-1411
CNG from LNG via road tanker	976	18.0	no saving	no saving
CNG (MP) from LNG in gas grid	968	18.7	no saving	no saving
CNG (LTS) from LNG in gas grid	954	15.8	no saving	no saving
Diesel	834	17.4		

Figure 4.9 Breakdown of GHG emissions for buses



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 4.10 Breakdown of costs for buses



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

4.8 Shipping and aviation

For comparison, the use of fuels in other transport modes (aviation and shipping) has also been considered (Table 4.8). For shipping, use of LNG reduces emissions (by -21%) cost-effectively (-£73/t CO_2). In the case of bio-oil, produced by cleaning up pyrolysis oils, which is a substitute for marine fuel oil, savings could be substantial (-57%).

The use of biomass to liquid jet fuel in aviation has very similar results to the use of biomass to liquid diesel in road vehicles. This is to be expected as the fuels are produced using the same process, so that fuel costs and production emissions are likely to be very similar (and were assumed to be equivalent for this study). Both fuels are ‘drop in’ replacements requiring no changes to delivery infrastructure or vehicles/aircraft, so the cost-effectiveness of carbon savings is determined only by the difference in emissions and the difference in costs between the biomass to liquid fuel and the conventional fuel it is replacing.

Table 4.8 Cost-effectiveness of CO_2 savings for use of fuels in shipping and aviation

Pathway	g CO_2 eq/km	p/km	GHG saving	Cost-effectiveness £/tCO_2
Shipping				
Bio-oil from SRF (pyrolysis)	41	1.0	-43%	(a)
LNG	57	1.0	-21%	-73
Marine fuel oil	73	1.1		
Aviation				
Biomass to liquid jet from MSW (gasification)	136	5.3	-13%	924
Biomass to liquid jet from wood (gasification)	5	4.4	-97%	65
Biomass to liquid jet from SRF (gasification)	73	3.0	-54%	-44
Biomass to liquid jet from SRF (pyrolysis)	70	2.2	-56%	-135
Jet fuel	157	3.4	N/A	N/A

Note: (a) no data could be found in the literature on potential additional costs of operating a ship on bio-oil or potential additional infrastructure costs, so no cost per km or cost-effectiveness can be calculated. On the basis of the difference in fuel costs only, the cost-effectiveness of the CO_2 saving achieved is about £30/t CO_2.

Figure 4.11 Breakdown of GHG emissions for shipping

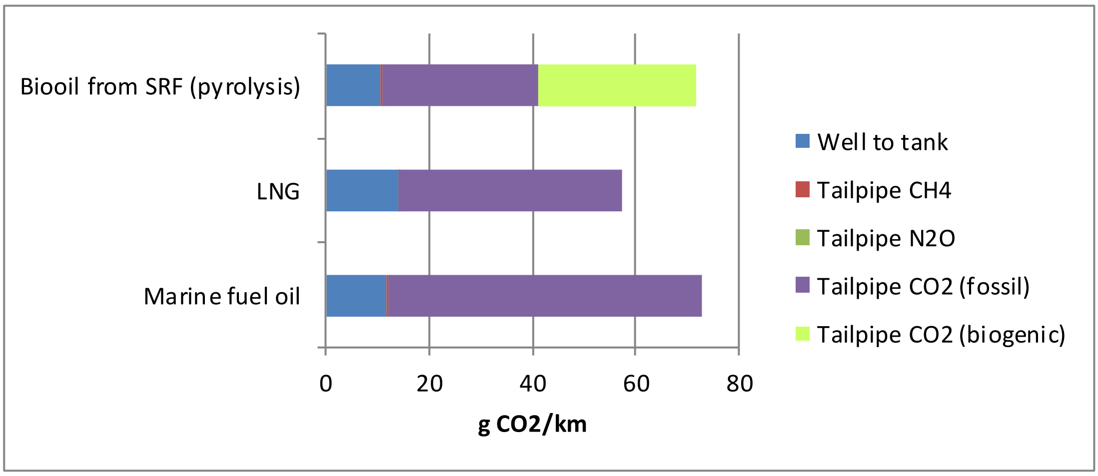
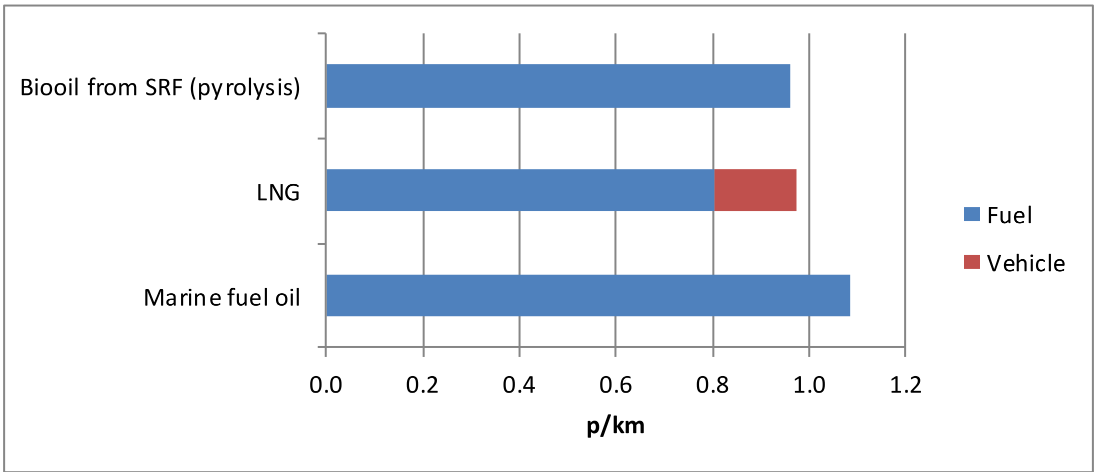


Figure 4.12 Breakdown of costs for shipping



Note: Fuel costs for use of biooil in shipping ate incomplete as no data could be found on additional operating or infrastructure costs

Figure 4.13 Breakdown of GHG emissions for aviation

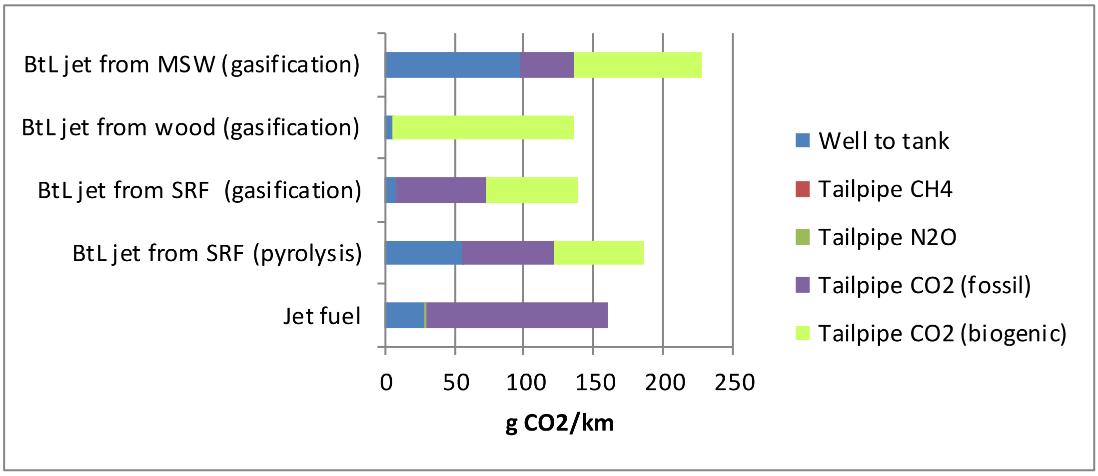
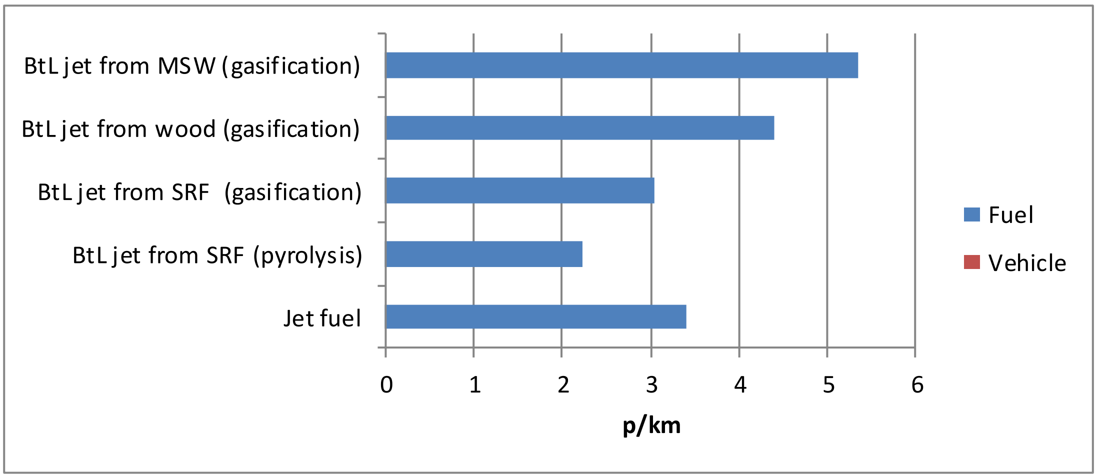


Figure 4.14 Breakdown of costs for aviation



4.9 Summary

In general, the results for CBM and CNG are similar across the different vehicles considered. Running vehicles on compressed biomethane produced from anaerobic digestion gives emissions savings of between 60% and 79%. The cost-effectiveness of the savings varies from about -£90/t CO_2 to £240/t CO_2, with use in buses, small HGVs and larger vans giving more cost-effective savings than in smaller vans and cars. Conversely, use of gas in cars and smaller vans and cars delivers greater percentage reductions than in larger vans, small HGVs and buses. This is because there is no (or very little difference in fuel efficiency between a gas or petrol powered van or car, whereas a gas powered large van, small HGV or bus which requires spark ignition engine will typically have a lower fuel efficiency than its diesel powered equivalent, which uses a higher efficiency compression ignition engine.

BioSNG produced from wood and biogas from the landfilling of waste give higher emissions savings (from about 74% to 94%) with the cost-effectiveness of using compressed biomethane from landfill gas ranging from about -£70 to £180/tCO_2 and from biosynthetic natural gas from wood from £249 to £455/tCO_2. The emissions savings from biosynthetic natural gas produced from solid recovered fuel are lower because the fuel is not fully renewable (about 50% comes from renewable sources), and this means that the cost of carbon savings is higher (£370 to £859/tCO_2) than for biosynthetic natural gas from wood, despite the lower cost of biosynthetic natural gas produced from solid recovered fuel.

Dispensing from the local transmission system slightly increases emissions savings compared to dispensing from the medium pressure network, and using compressed biomethane from biomethane delivered in liquid form slightly reduces emissions savings.

Using CNG from fossil fuel gas in vehicles delivers no or very small emission savings for larger (diesel) vans, smaller HGVs and buses, as the advantage of using a fuel with a lower carbon content is lost due to the generally lower efficiencies of the vehicle when running on gas. For smaller vans and cars, when compared with petrol-fuelled vehicles, savings range from 20 to 27% when conventional or shale gas is the source of CNG, but for CNG produced from imported LNG evaporated into the gas grid, savings are reduced to between 9 and 13%. Savings for 'average' gas in the grid would depend on the proportion of these three sources of gas for grid supplied gas, but would lie between these values. The cost-effectiveness of the savings is better for small vans than cars. It is about £193 to £552/t CO_2 for shale and conventional gas, but is higher when the source of gas is LNG, (£532 to £901/t CO_2, due mainly to the lower level of savings achieved. The savings achieved from the use of CNG in cars are very similar to the savings achieved from use of diesel.

In the case of liquefied biomethane used in dual fuel vehicles, emission savings compared to diesel vehicles range from 32% to 52%[12] for LBM produced from anaerobic digestion, landfill waste and wood (the latter via biosynthetic natural gas). The cost of carbon savings is low for LBM produced from anaerobic digestion and landfill waste (£10 to £50/tCO_2), but is much higher for the use of LBM from BioSNG produced from wood and solid recovered fuel (£234/t to £294/t CO_2). For LNG, the well-to-tank emissions, and higher tailpipe emissions of non-CO_2 GHGs offset much of the savings in tailpipe CO_2 leading to overall savings of only 6%. However, the cost-effectiveness of these savings is good (-£145/tCO_2). Savings from the use of LNG in shipping are higher (21%) and have a good level of cost-effectiveness (-£73/t).

With the exception of biomass to liquid diesel and biomass to liquid jet fuel produced from the gasification of residual waste, all of the advanced biofuels routes producing biomass to liquid diesel, jet fuel, biopropane and bio-oil deliver good carbon savings (54% to 97% compared to the relevant comparator fuels). The cost-effectiveness is better for biomass to liquid diesel and jet (-£135/tCO_2 to £68/tCO_2) than for biopropane (£224/t CO_2). Use of bioethanol and bioalcohols produces only small savings (8 to 9%) due to the low blending levels assumed but is very cost-effective (-£154 to -62/t CO_2).

Figure 4.15 shows the GHG savings achieved via different fuel and vehicle pathways based on a single feedstock (food waste). As discussed previously, good reductions in emissions per km are achieved in all vehicles and many routes offer cost-effective carbon savings too (Figure 4.16).

Advanced biofuels processes can produce both liquid and gaseous fuels. The results for solid recovered fuel shown in Figure 4.17 and Figure 4.18 indicate that, once the additional emissions and costs associated with delivery of fuels to vehicles, vehicle modifications and tailpipe emissions are taken into account, gaseous fuels derived from this source (with the exception of biopropane) offer slightly smaller emissions savings per km and have higher costs per tonne of carbon saved than liquid fuels.

[12] As gas is assumed to account for 60% of fuel use, savings cannot be greater than 60%.

Figure 4.15 GHG savings from use of fuels produced from food waste

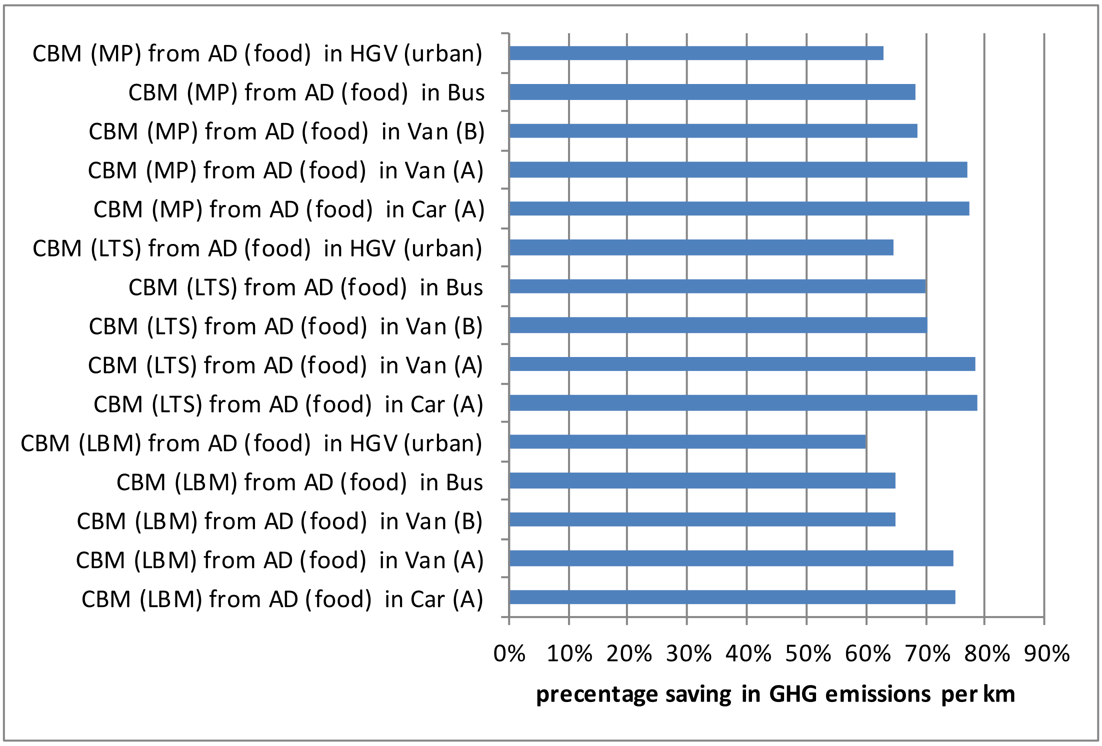


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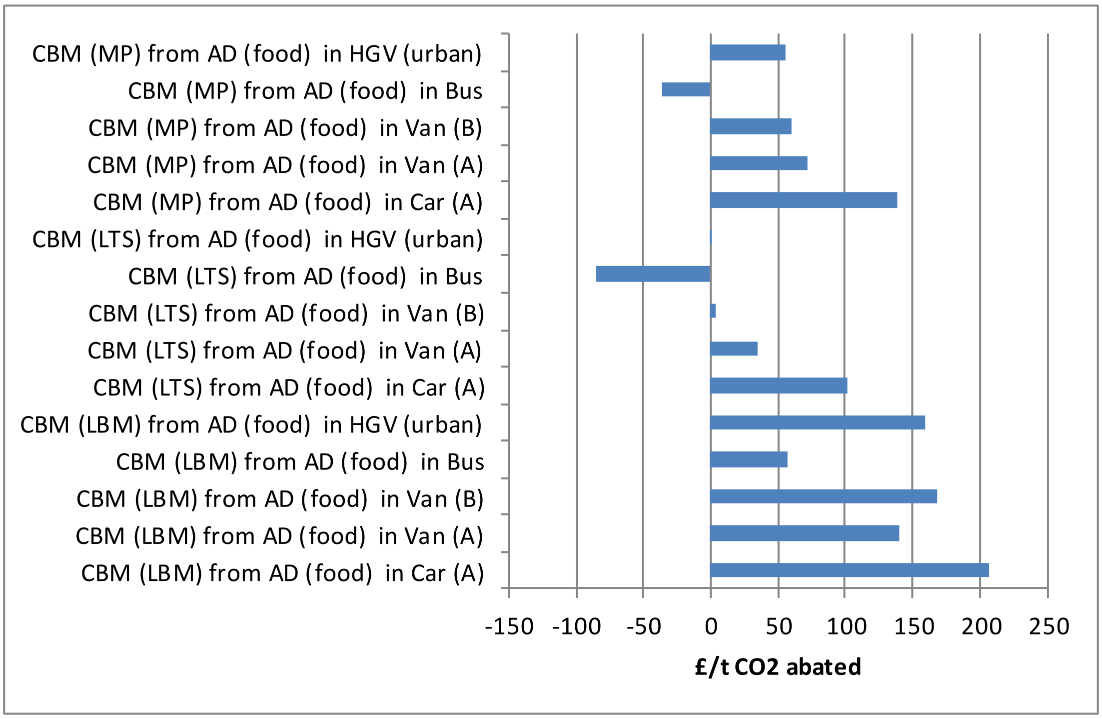
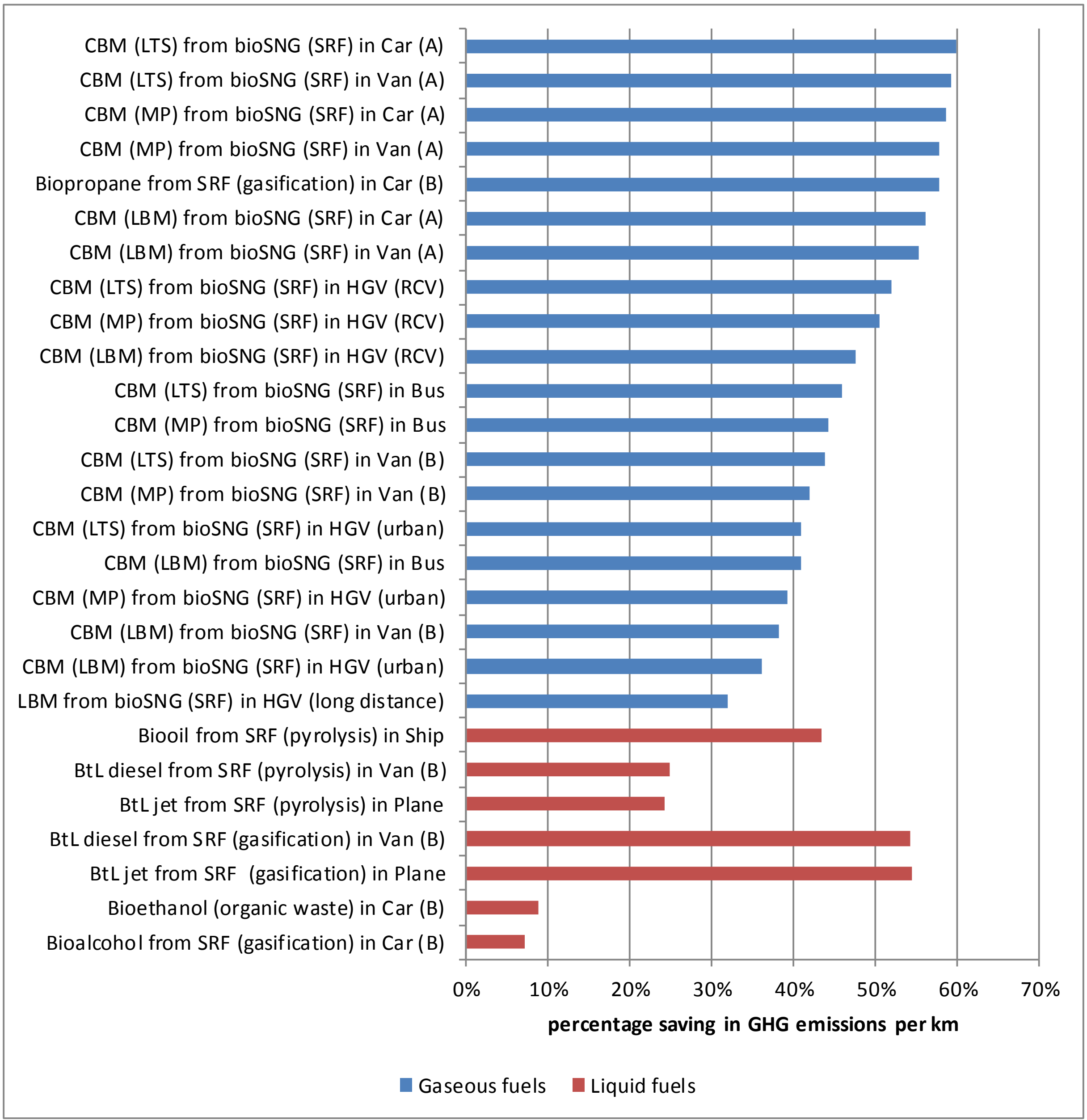
Figure 4.16 Cost of GHG savings from use of fuels produced from food waste



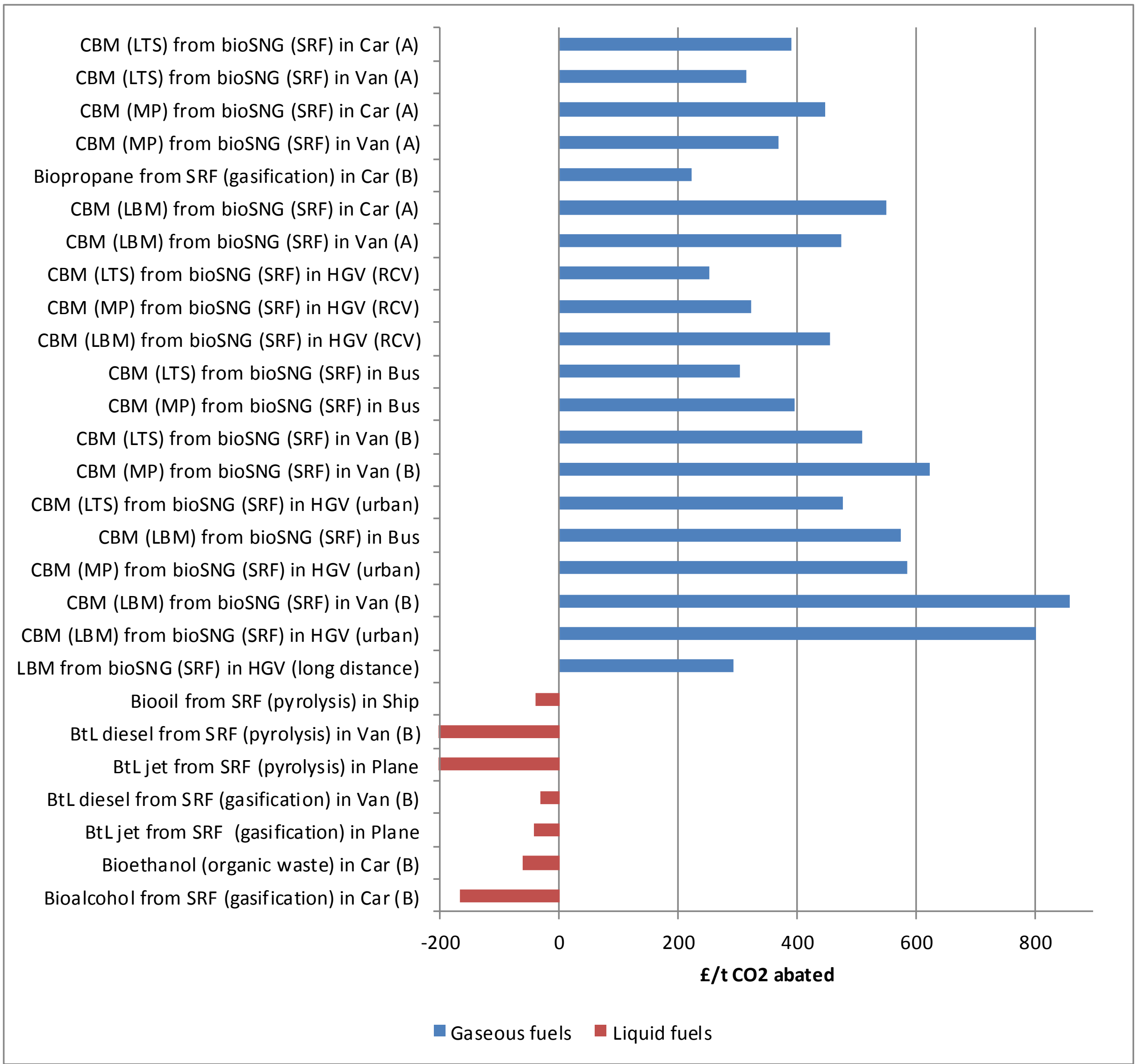
Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 4.17 GHG savings from using fuels produced from SRF



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 4.18 Cost of GHG savings from using fuels produced from SRF



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

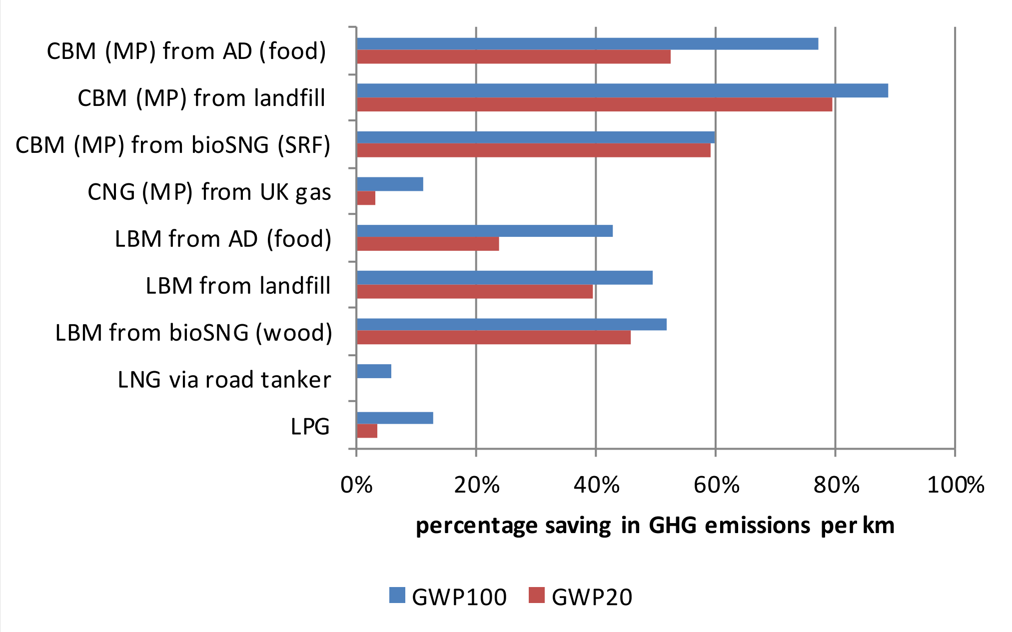
4.10 Sensitivity analysis

4.10.1 Timeframe for assessing global warming impacts

All of the results shown above are based on using 100 year Global Warming Potentials (GWP) for the greenhouse gases CH_4 and N_2O of 28 and 265 respectively. However CH_4 is a short-lived GHG which has a much higher 20-year GWP of 84, and so assessing options over a 20 year timeframe could, depending on the amount of methane emitted, substantially reduce savings. Figure 4.19 shows the change in GHG savings for some of the fuel and vehicle pathways with the highest methane emissions. The reduction in savings is potentially underestimated, as emissions data for some processes were only available as total kg CO_2 eq rather than split by GHG. The greatest reduction in emissions savings is for fuels produced via anaerobic digestion, but CNG, LNG and LPG fuel pathways are also affected. In combination with the higher weighting of the tailpipe methane emissions, some LNG and

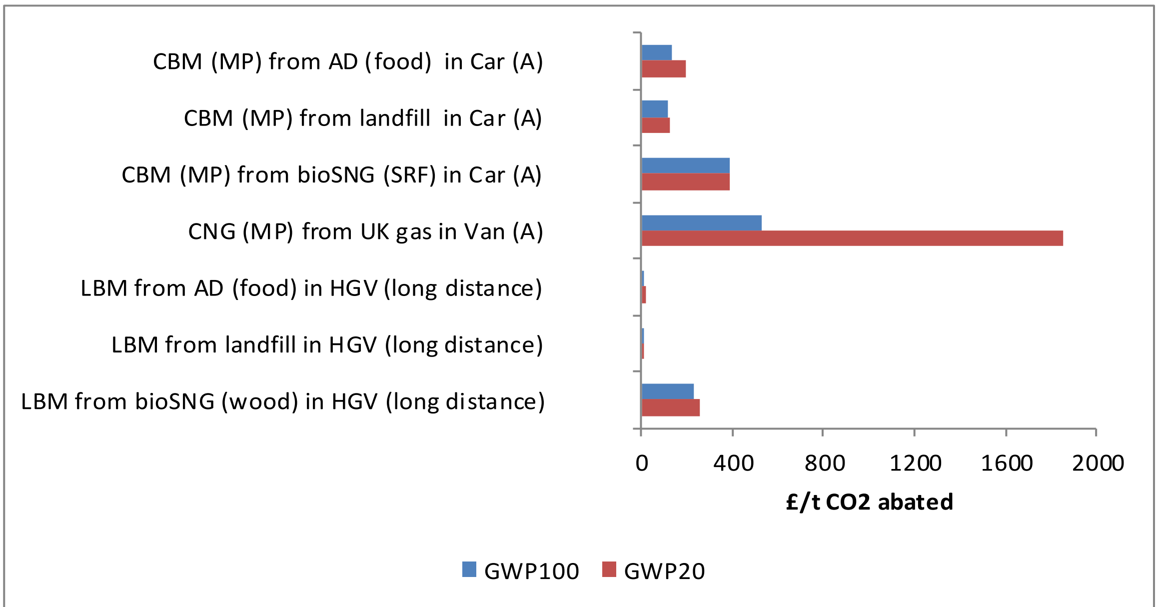
CNG fuel-vehicle pathways, routes which showed only small savings when evaluated with using 100 year GWPs, no longer show any savings when evaluated using 20 year GWPs. The savings achieved from the use of liquid fuels are typically reduced by only 1 percentage point. Figure 4.20 shows the impact of using a 20 year GWP in calculating the cost of carbon savings achieved. A full set of results for a 20 year GWP is given in Appendix 5.

Figure 4.19 Impact of choice of GWP on GHG savings



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel		

Figure 4.20 Impact of choice of GWP on cost of GHG savings



Key			
bioSNG	Bio-synthetic natural gas	**BtL**	Biomass to liquid
CBM	Compressed biomethane	**LBM**	Liquefied biomethane
LTS	Dispensed from local transmission system	**MP**	Dispensed from medium pressure gas grid
SRF	Solid recovered fuel	**RCV**	Refuse Collection Vehicle

4.10.2 Uncertainties in methane emissions

There is still relatively little experience of using gas in vehicles in the UK, and there is a lack of data on some of the emissions associated with the use of gas in vehicles, particularly fugitive emissions of methane. This section examines the sensitivity of emissions savings to three sources of fugitive methane emissions.

- Methane losses from upgrading of biogas
- Tailpipe emissions of methane
- Boil-off of methane from LNG storage tanks in vehicles

4.10.2.1 Methane losses from upgrading of biogas

As discussed in Appendix 2, the fuel pathways for biomethane from anaerobic digestion and landfill gas assume the use of membrane separation for removal of CO_2 from biogas, as this is likely to be most commonly used technology in planned AD plants. However, alternative technologies such as pressure swing adsorption systems and water scrubbing have higher levels of methane slip. The impact of methane slip on emissions savings (for use off biomethane in a car) are shown in Table 4.9, emissions associated with the production and delivery of biogas could double if slippage levels were 2% (as e.g. if pressure swing adsorption technology were used) with overall emissions savings reduced by about 14 percentage points from 84% to 70%.

Table 4.9 Sensitivity of emissions savings to biogas upgrading technology

CO_2 removal technology	Methane slip %	Emissions from slip kg CO_2/GJ	Total emissions kg CO_2/GJ[a]	Total emissions g CO_2/km[b]	Emissions saving %
Membrane separation	0.5%	3	18	25	79%
Water scrubbers	1%	6	21	29	75%
Pressure swing adsorption	2%	12	30	41	65%

[a] For biogas produced from anaerobic digestion of food and delivered via the LTS
[b] For use in a car, savings calculated compared to petrol version of car

4.10.2.2 Tailpipe emissions of methane

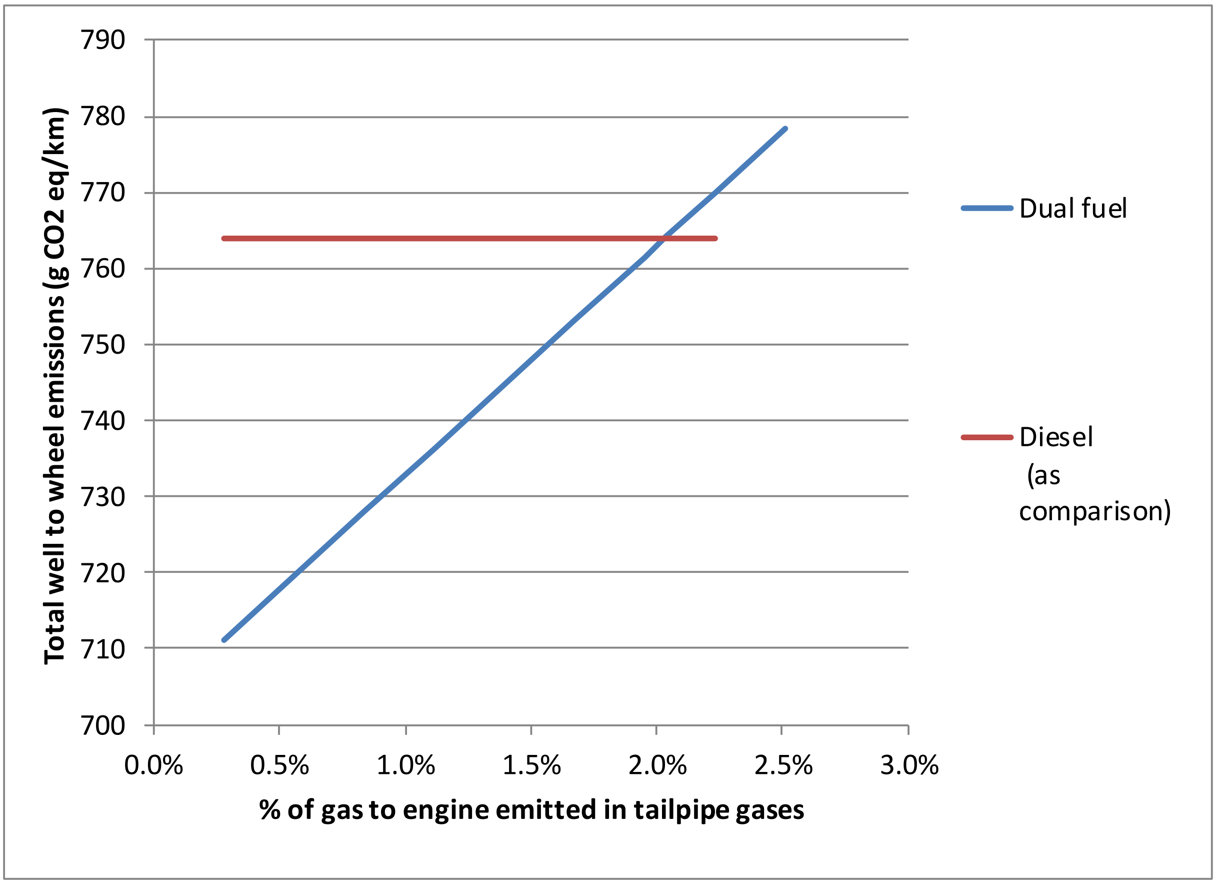
At present there are very few measurements of tailpipe emissions of methane from gas powered vehicles, and the uncertainty in the emissions factors used for vehicles is relatively high. In the case of dual fuel HGV vehicles, no data could be found in the literature for CH_4 emissions during operation in dual fuel mode, and so emissions were set at an average of values for operation on diesel and operation on CNG.

The level of methane in tailpipe gases depends on the substitution rate, the drive cycle, the level of methane slip in the engine and the effectiveness of any methane catalyst that is present in oxidising the methane. Such catalysts can also lead to the conversion of NO to N_2O, a GHG with an even higher GWP than methane, which offsets some of the benefits of reducing methane emissions. Again, there is no reported data in the literature to quantify this effect, so it is not included in the analysis below.

The estimated values used for tailpipe emissions of methane (based on the other assumptions made about fuel efficiency and gas substitution rate) equate to just over 0.5% of the methane injected into the engine being emitted as methane in the tailpipe gases. However, discussions with stakeholders have given a wide range of values, from around 1% to 5% methane slippage. Figure 4.21 shows the impact on the well to wheel GHG emissions (assuming a 100 year GWP) of higher and lower level of methane slip in a dual fuel vehicle using LNG. On the basis of the tailpipe emissions values used in this study (600 mg/km), GHG emissions savings are about 6% compared to operation on diesel. However if methane slip were to be about 2% or above, then there would be no emissions saving compared to operating on only diesel. As discussed earlier, if emissions are evaluated using a 20 year GWP, then the use of LNG offers no savings at the tailpipe emission level assumed. Methane slip would need to be less than 0.05% of gas use to deliver any GHG savings if the evaluation is carried out using a 20 year GWP for methane.

The savings estimated for use of LNG in dual fuel vehicles should therefore be treated with caution and more vehicle testing is required for such vehicles to obtain more robust data.

Figure 4.21 Impact of methane slip on well to wheel emissions for dual fuel HGV



4.10.3 Emissions from boil-off in vehicle tanks

LNG used in dual fuel HGVs is stored in tanks, which are typically a double walled, vacuum insulated pressure vessel with a safe working pressure of 15 atmospheres. The tank is typically made from Type 304 stainless steel because of its mechanical properties and cryogenic temperatures combined with a low thermal conductivity. Once the tank has been filled, ambient gains mean that the temperature in the tank slowly begins to rise, leading to some of the gas to vaporise (boil-off), increasing the pressure in the tank. If the pressure becomes too high, then some gas is vented. The time taken for boil-off to occur and amount vented depends on a number of factors, the temperature of the gas in the tank initially which is determined by the fuel delivery system and tank specifications, rate of ambient gain, and the amount of LNG in the tank.

For example, data from Taylor Wharton[13] specifies that a 400 litre tank is designed not to vent gas for a nominal period of three days after being filled to 100% net capacity. When the tank contains 75% of its capacity the nominal hold time is 5 days before venting begins. The

[13] http://www.taylorwharton.com/assets/base/doc/products/cylinders/tw-359_lng_vehicle_fuel_tanks.pdf

higher surface area to volume ratios of smaller tanks mean that small tanks would begin venting earlier. Other manufacturers e.g. Rolande[14] and Westport[15], suggest that venting will not occur before 10 days, although a study in the US and Canada (TIAX, 2012) found that hold times were about a week. There may be additional methane emissions from venting if the insulation of the LNG tank is damaged, and during repair and maintenance operations (Verbeek et al, 2013).

There are a number of possible engineering options that could be used to prevent venting of gas, including capture and compression of vented gases, and combustion of the vented gases. The holding time of tanks can also be improved by using a better insulated tank. All of these options will have additional costs.

In order to minimise costs, long distance HGVs are operated as many days of the year as possible, however there may be times in the year (e.g. holiday periods, repair or maintenance) when the vehicle may stand idle long enough for boil off to occur. While good practice would be to ensure that LNG tanks are empty or at least only partially full during this idle period in order to minimise boil-off, this may not be possible. Table 4.10 shows the impact on emissions savings for a dual fuel HGV as the number of days on which boil off occurs increases. The assessment assumes that that 1% of the tank boils off in a day if the tank is full (based on data from Taylor Wharton), and that a vehicle has four 300 litre tanks. For every day that boil off occurs, the emissions savings from the use of LNG compared to diesel are reduced by 0.24 percentage points. So, if boil-off occurs on 10 days of the year, the emissions saving from the use of LNG in a dual fuel vehicle compared to a diesel HGV is reduced from 5.8% to 3.4%. However this represents a worst case, and it could be expected that venting might only occur on 1 to 2 days a year. More information from field trials of LNG vehicles, including data on how long vehicles are left for with LNG in the tanks, and how much LNG is in the tanks during this period is required for a more accurate assessment of typical boil-off emissions.

Table 4.10 Sensitivity of emissions savings to venting of boil-off emissions

	Emissions savings (g CO_2 eq/km)				Emissions savings (%)			
Fuel	No venting	Venting for 1 day	Venting for 5 days	Venting for 10 days	No venting	Venting for 1 day	Venting for 5 days	Venting for 10 days
Liquefied biomethane	352	350	343	334	46.0%	45.8%	45.0%	43.7%
LNG	44	43	36	26	5.8%	5.6%	4.7%	3.5%

4.10.4 Uncertainties in biogas costs

The costs of producing biogas from anaerobic digestion plant are heavily influenced by a number of factors, some of which relate to how the process is operated and some of which relate to the market for the service it supplies (waste disposal) and markets for by-products such as digestate. For anaerobic digestion plant taking food waste, one of the most significant influences on costs is the gate fee that the plant can charge for taking the waste. Lower gate fees led to a higher cost for the biogas. The current median gate fee for organic waste in anaerobic digestion plant is £41/t (WRAP, 2013) with a range of £25 to £66/t), and this study assumed that gate fees might fall in the future as AD capacity increased, and used a value of £30/t. It is possible that this could fall even further in the future, leading to a higher cost for the biogas produced. Similarly the costs of disposing of digestate can alter operating costs.

[14] http://www.rolandelng.nl/en/the-trucks.htm

[15] http://www.westport.com/products/fuel-storage-and-delivery/ice-pack-lng-tank-system/benefits#maximum

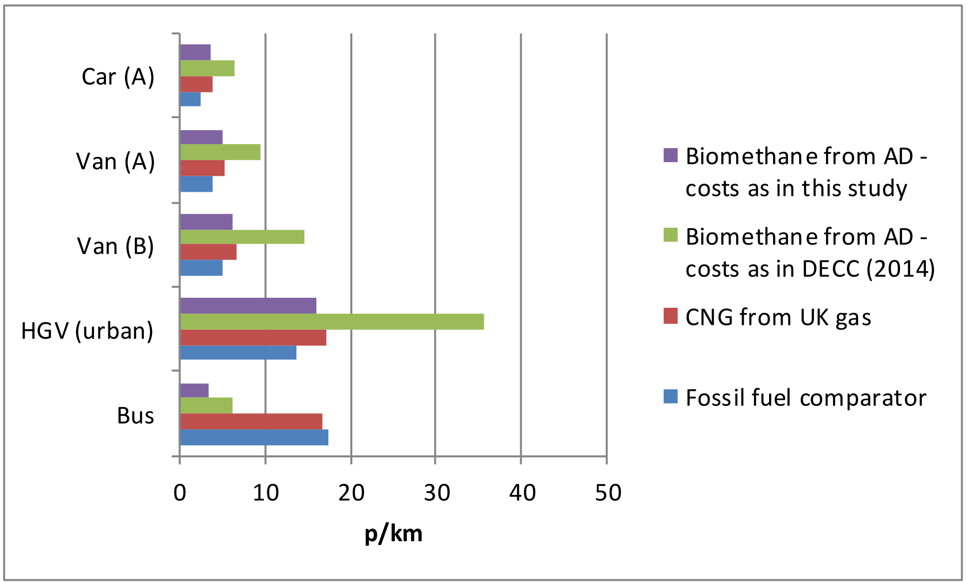
Plant taking in commercial food waste will require a depackaging plant, which can increase the capital costs of the plant. Material not suitable for anaerobic digestion e.g. packaging material will require disposal, and the quantity of these 'reject' materials and the route used to manage these rejects will also influence operating costs. For example, if they are disposed of to landfill, this can incur significant operational costs, whereas if they can be further processed and sold as refuse- derived fuel, or sent for recycling, the increase in operational costs can be minimised.

Subsequent to the main analysis for this study being completed, DECC issued a consultation reviewing the tariff paid under the Renewable Heat Incentive (RHI) to biomethane injected into the grid (DECC, 2014). Due to differing assumptions on a number of the factors discussed above, and also some differences in assumptions around the capital costs assumed, the cost estimates presented in the consultation document are considerably higher than the cost estimates made in this study. Using estimates from the consultation document for the costs of biogas production, upgrading and injection for a similar size plant to the one considered in this study (of about 3MW of biogas production) gives a cost of £26/GJ compared to £6/GJ calculated in this study[16].

The sensitivity of the cost of operating vehicles on biomethane as compared to CNG or conventional fossil fuels is shown in Figure 4.22, and the sensitivity of the cost-effectiveness of these options in reducing GHG emissions to a higher biomethane cost in Figure 4.23. The cost-effectiveness of using biomethane from AD as a GHG reduction option worsens significantly. On the basis of the costs used in this study, cost-effectiveness ranged from about £-40 to £140 over the vehicle types considered. On the basis of the costs contained in the DECC consultation document, cost-effectiveness is in the range of £350 to £550/t CO_2.

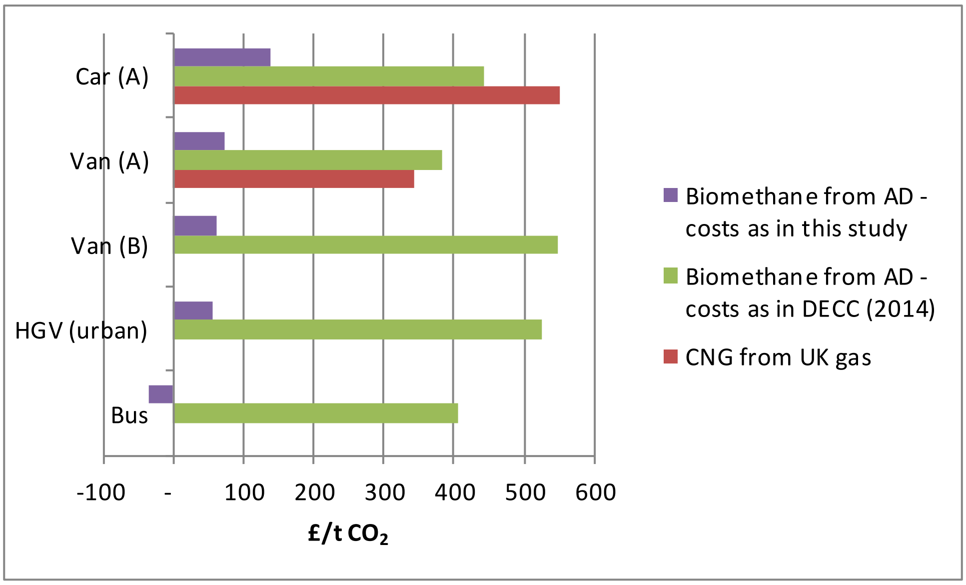
The large potential variation in the cost of biomethane from AD, and the sensitivity of the cost-effectiveness of options using biomethane to these costs suggests that a better understanding of the potential spread of costs for biomethane from AD is needed.

Figure 4.22 Sensitivity of vehicle operating costs to biomethane costs



[16] The cost was calculated using cost estimates from Table 7 in DECC (2014) and assuming a gate fee of £25/t. The cost per GJ of methane was calculated using the same levelised cost methodology as in the rest of this study, which uses a 10% discount rate as opposed to the 12% rate used in DECC 20124.

Figure 4.23 Sensitivity of cost-effectiveness of biomethane options to biomethane costs



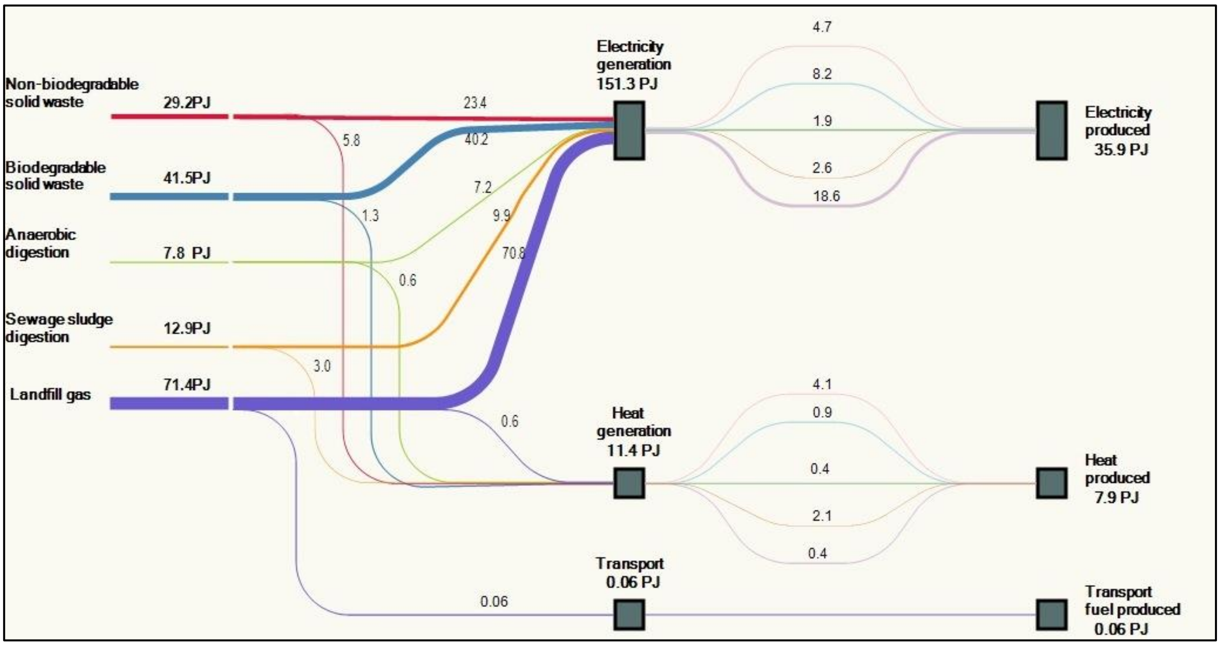
Note: the use of CNG in large vans, urban HGVs and buses does not deliver any GHG savings so the cost-effectiveness of these options is not shown in the Figure.

5 Comparison with Use in Heat and Power

5.1 Current Uses of Biomethane

At present almost all biogas and wastes are used to generate heat and power, with only a tiny fraction (<0.1%) of biogas produced being liquefied for use in transport. Historically, biogas from landfills, sewage sludge digestion and anaerobic digestion has been burnt in gas engines to produce electricity and sometimes heat as well. However the introduction of a payment under the Renewable Heat Incentive for biomethane injected into the grid (excluding that derived from landfill gas) is encouraging new anaerobic digestion plant to use this route, and volumes of gas injected to the grid are expected to increase substantially in the future.

Figure 5.1 Uses of biogas and solid waste in 2012



Source: DUKES 2013 and RTFO year 5 report

There is a limited resource of biogas available from landfill sites and anaerobic digestion of waste (estimated to be 128 PJ/year in 2025 in AEA, 2012) and so it is important that is utilised to achieve carbon savings in an effective way. This section of the report compares the cost-effectiveness of using biogas to reduce carbon emissions in the transport sector against its use for heat and power production.

5.2 Use of biogas and waste for heat and power production

The routes examined for heat and power production form biogas and waste are shown in Table 5.1.

Table 5.1 Heat and power routes

Fuel	Upgrading	Used in	Product
Biogas from landfill		Gas engine (1 MWe)	Electricity
Biogas from anaerobic digestion of food waste	Small amount of clean up	Gas engine (1MWe)	Electricity
		CHP unit (1MWe)	Electricity and heat
	Upgrading and injection to grid	CCGT plant (900 MWe)	Electricity
		CHP plant (86..5 MWe)	Electricity and heat
		Domestic Boiler (20 kW)	Heat
Residual waste		Energy from waste (power only) (25 MWe)	Electricity
Residual waste		Energy from waste (CHP) (25Mwe)	Electricity and heat

Operating characteristics and CAPEX and OPEX costs for these plant are given in Appendix 2. These were used together with the cost and upstream emissions for the feedstocks used in the analysis of transport options to calculate a cost per unit of electricity or heat produced. CHP plant were evaluated on their electricity output with a credit given for the heat produced and emissions allocated between electricity and heat using a weighting factor of 2 for electricity emissions.

The cost-effectiveness of savings was estimated by comparing the costs and emissions to those arising from the use of natural gas in a Combined Cycle Gas Turbine (CCGT) plant, a large Combined Heat and Power (CHP) plant and a domestic boiler. A CCGT plant is considered by DECC to be the marginal plant in 2025. Costs per GJ of heat or electricity produced were calculated using the same levelised cost model and discount rate (10%) as used for the transport sector. Emissions and costs per GJ are shown together with the cost-effectiveness of savings in Table 5.2. All uses of biogas gave cost-effective carbon savings; burning residual waste in an energy from waste (EfW) plant, only delivered carbon savings when burnt in an EfW plant operating in CHP mode.

Table 5.2 Cost-effectiveness of emissions savings in heat and power routes

Fuel	Used in	Emissions kg CO_2 eq/GJ[a]	Cost £/GJ	£/tCO_2 abated
Biogas from landfill	Gas engine	0.1	10	-53
Biogas from anaerobic digestion of food waste	Gas engine	27	10	-77
	Small CHP unit	8	3	-356
	CCGT plant	22	9	-84
	Large CHP plant	12	9	-258
	Domestic Boiler	14	13	-84
Residual waste	Energy from waste (power only)	127	21	n/a
	Energy from waste (CHP)	26	7	-415
Natural gas	CCGT plant	111	16	n/a
	CHP plant	50	19	n/a
	Domestic Boiler	69	18	n/a

[a] Emissions and costs are per GJ of electricity apart from the boiler which is per GJ of heat. For CHP plant emissions are allocated between the heat and power produced, with a weighting factor of two used in the allocation for electricity.

The cost-effectiveness of savings achieved in these heat and power routes is compared to the cost-effectiveness of using biogas and waste derived fuels in transport in Table 5.3

However if it is considered that the vehicle fleet and fuel delivery infrastructure have already been adapted to allow the use of natural gas, and only the costs of substituting biomethane for natural gas are considered, then the cost-effectiveness of using biomethane in the transport sector is very similar to that of using it in the heat and power sector. This is to be expected, as the cost-effectiveness is almost entirely determined by differences in the emissions and costs of producing and delivering the natural gas as compared to biomethane, as within each sector the efficiency of end use is the same for the two fuels.

Table 5.3 Cost-effectiveness of savings from different end uses of biogas and waste (£/tCO_2)

Fuel	Used in				
	Electricity generation	CHP	Boiler	Transport (replacing petrol or diesel)	Transport (replacing natural gas)
Landfill gas	-53			-72 to 179 (CBM) 8 (LBM)	-161 to -105 (CBM)) 29 (LBM)
Biogas from AD of food waste	-84 to -77	-258 to -356	-84	-86 to 207 (CBM) 11 (LBM)	-164 to -116 (CBM) 35 (LBM)
Residual waste	no reduction in emissions	-415		773 to 812	N/A
Solid recovered fuel				224 to 859 (gaseous fuels) -304 to -31 (liquid fuels)	264 to 423 (CBM) -72 (biopropane)

As biomethane is a finite resource, it is also useful to consider the magnitude of the carbon savings that use of a GJ of biomethane delivers in each sector i.e. CO_2 savings per GJ of biomethane utilised. Table 5.4 shows the carbon savings achieved from the use of 1 GJ of biomethane (produced from anaerobic digestion of food waste) to produce heat or power or fuel road vehicles. In the case of road vehicles, the savings are calculated assuming firstly that the biomethane displaces natural gas and secondly that it displaces petrol or diesel. When considering replacing natural gas in the transport sector, savings are very similar in the transport sector to those achieved in CCGT plant and boilers. This is to be expected as the difference in savings in both cases is determined by the difference in upstream emissions of the fuel pathway and CO_2 emissions on combustion of the gas, as all technology aspects (e.g. efficiency of the plant or vehicle) and emissions of non-CO_2 GHGs on combustion are the same with natural gas or biomethane are being combusted. In the case of the gas engine, the saving is lower because of its lower efficiency compared to the efficiency of the counterfactual CCGT plant. Carbon savings per GJ of biogas used, are between 2% and 42% higher in the transport sector compared to the heat and power sector, if it is assumed that biomethane powered vehicles are replacing petrol or diesel vehicles. The wide range for this latter comparison reflects the wide variations in savings for different vehicle types. The variation reflects both changes in the fuel efficiency of vehicles when running on natural gas compared to petrol or diesel and changes in tail pipe emissions of the non-CO_2 GHGs of CH_4 and N_2O.

Table 5.4 CO_2 savings per GJ of biomethane used

End use	Savings if displacing natural gas or CNG (kg CO_2/GJ of biogas)	Savings if displacing petrol or diesel (kg CO_2/GJ of biogas)
Gas engine	32	
CCGT, boilers and large CHP	52	
Road vehicles using CNG	53*	46 to 72
Road vehicles using LNG	55+	69

* Saving is for compressed biomethane from anaerobic digestion compared to CNG from natural gas sourced from UK continental shelf

\+ Saving is for liquefied biomethane from landfill compared to LNG delivered by road tanker

5.3 Optimising the use of biogas

As discussed above, biomethane is a limited resource, and it is therefore important that its use is optimised. This section explores the GHG savings and the cost of those savings from utilising biomethane in the heat and power sector and/or the transport sector. The potential supply of biogas and potential demand in the transport sector by 2025 are considered and then a number of scenarios are considered.

5.3.1 Future biomethane resource

Table 5.5 summarises estimates of the future biogas resource. Values from E4 Tech (2013) are for the total potential resource i.e. not allowing for competing uses. The study by AEA (2012) estimated both the total available resource and the accessible resource. The accessible resource estimates allow for competing uses of the resource, barriers to development of the resource, and the influence of price on developing the resource. The landfill gas resource is forecast to decline in future as more waste is diverted from landfill to comply with the legislative requirements of the landfill directive and meet recycling targets. The potential for biogas from food waste and animal wastes is large, up to 105 PJ in 2025 compared with current biogas production of 8 PJ in 2012. However when barriers to development are considered a more likely potential future biogas resource from these feedstocks is 46 to 86 PJ. For the purposes of the illustrative scenarios developed here, a value of 66 PJ is used, assuming that all but the hardest barriers to deployment are overcome by 2025. Together with the landfill gas resource, this gives a total biogas resource of 140 PJ, about 50% higher than the current quantity of biogas utilised.

It is noted that the value for biogas from anaerobic digestion of food wastes and animal manures, may be optimistic as the DECC/DEFRA Anaerobic Digestion Strategy and Action Plan (DEFRA, 2011) concluded that "based on current information available, and assuming that the real and perceived barriers are overcome through the actions undertaken, an estimated potential for AD deployment for heat and electricity could reach between 3 and 5 TWh by 2020." This is equivalent to about 31 to 51 PJ.

5.3.2 Potential demand for biogas in the transport sector

The potential fuel demand of different road transport vehicles in 2025 is shown in Table 5.6 based on previous modelling work done for DfT by AEA (AEA, 2012a). This has been combined with assumptions about the percentage of the fleet which could potentially be gas fuelled in 2025. This takes into account the turnover of vehicles in the fleet and the fact that in dual fuel HGVs only 60% of conventional fuel consumption would be displaced. In order to estimate the potential maximum demand for biogas, an ambitious scenario is developed, in which it is assumed that the penetration of gas fuelled vehicles rises over time until by 2025, 40 to 50% of vehicles purchased are gas fuelled. This gives a potential maximum consumption of CBM/LBM by different transport types in 2025, as shown in Table 5.6.

Table 5.5 Estimates of future biomethane resource (PJ)

		Potential resource		Accessible resource(2)	Accessible resource used in this study(2)	Resource which could be developed(3)
	DUKES (2013)	E4 Tech, (2013)	AEA, (2012)	AEA (2012)	AEA (2012	Defra, 2011
	2012	2020	2025	2025	2025	2020
Food waste	8	155(1)	80	37 to 63	48	
Animal manures		43	25	9 to 24	18	
Sewage sludge	13	10	15	11 to 14	13	
Total from AD	**21**	**208**	**121**	**57 to 100**	**79**	**31 to 51**
Landfill gas	71	n.e	241	56 to 93	61	n.e
Total biogas	**92**		**362**	**113 to 194**	**140**	

Notes:
(1) Estimate is for biogas which could be produced from the total biodegradable content of MSW and commercial and industrial waste, so includes fractions such as paper as well as food waste.

(2) Study estimated resource which would be available under different price scenarios and different levels of effort are made to overcome barriers. Low end of range is for a price of £4/GJ for biogas and assuming that only easy barriers to development are overcome. High end of range is for a price of £10/GJ and assuming that all barriers are overcome. Estimates used in the scenarios in this study are for a price of £10 GJ assuming easy and medium barriers are overcome.

Table 5.6 Potential demand for biogas

	Total fuel consumption in 2025 (PJ)(1)	Percentage of fleet which could be gas fuelled in 2025(2)	Potential consumption of CBM/LBM In 2025 (PJ)
Cars	812	15%	122
Vans	187	15%	28
Rigids	173	25%	26
Artics	187	40%	45
Buses	52	25%	13
Coaches	20	25%	3
Total	**1431**		**237**

Notes:
(1) Based on modelling of future fuel demand carried out for DfT in AEA, 2012a

(2) Assuming that 8% of car and van fleet is replaced each year, and 14% of HGV fleet (based on average lifetimes of 13 and 7 years respectively. Assumes that percentage of new vehicles purchased which are gas fuelled rises to 50% by 2025. More rapid rise is assumed for artic HGVs.

Potential scenarios for biogas use

A number of scenarios where biogas is used in the heat and power sector, the transport sector, or both sectors were constructed, and the GHG savings and cost of each scenario assessed. The cost of each scenario was evaluated as in previous sections by comparing the cost of using biogas to a 'counterfactual' cost of using natural gas for heat and power generation, or in the case of transport, conventional fossil fuels (petrol or diesel) or CNG/LNG. The scenarios were constructed to show the different outcomes which could be achieved from the same biogas resource. Some focus on maximising the amount of carbon savings which are achieved, by choosing utilisation options which have high carbon savings regardless of their cost-effectiveness. Others are focussed on implementing the most cost-effective utilisation options, and thus minimising the overall cost.

The results of the scenario modelling are shown in Figure 5.2 and Table 5.7. Scenarios where all of the biogas is used in the heat and power sector (coloured blue in Figure 5.2) have the lowest cost, (about £-320 to £-410million), with an average cost-effectiveness of about £-50 to £-70/t CO_2. However, where the gas is used for power generation on site, the GHG savings are the lowest of all the scenarios evaluated. GHG savings are improved if gas is injected into the grid and used for power generation in higher efficiency CCGT plant, delivering 7.3 Mt of CO_2 savings.

Scenarios where all of the biogas is used in the transport sector (coloured green in Figure 5.2) range significantly in cost and savings delivered. Where options which maximise GHG savings per unit of biogas available (use of biogas from AD in cars and vans, and use of landfill gas as LBM in HGVs), then savings pf 9.3 Mt CO_2 are achieved but at a high cost (£777 million) giving an average cost-effectiveness of £84/t CO_2. In contrast, utilising biogas in vehicles which deliver the most cost-effective savings first (buses, urban HGVs), with the remainder used in vans delivers a net saving (of £-162M). Emissions savings are however reduced by about 30% to 6.7Mt CO_2. These comparisons assume that biogas replaces the use of petrol and diesel; if the scenario is modelled assuming that the fuel used otherwise would be natural gas, then total savings are about 7Mt CO_2, with net savings of £114 million.

Scenarios where biogas from existing anaerobic digestion plant is assumed to still be used for heat and power, but biomethane from new anaerobic digestion plant is available for use in the transport sector are coloured orange in Figure 5.2. These scenarios give savings of 6 Mt CO_2 at a cost of £65million, if transport options are chosen which minimise costs are chosen and GHG savings of 7.8 Mt CO_2 at a cost of £400 million if transport options which maximise savings are chosen.

The scenario analysis demonstrates the range of GHG savings which could be achieved from the potential biogas resource, and the associated costs (to the economy) of those savings. They are theoretical and do not take into account all of the factors which would affect how biogas could be used (e.g. the proximity of biogas sources to a gas grid). They also look only at the use of biogas, whereas in reality development of a refuelling infrastructure for gas powered vehicles would also permit the use of natural gas, which does not always deliver GHG savings when used in vehicles. They do however indicate the envelope of savings and costs which might achieved from the use of biogas in both the transport and heat and power sector. In evaluating which may be the 'optimum' route of biogas use from a climate change mitigation perspective however, it will also be necessary to consider what other mitigation options are available in the sector and how the cost and savings delivered from these options compare with those of biogas use.

Figure 5.2 Cost and carbon savings in scenarios

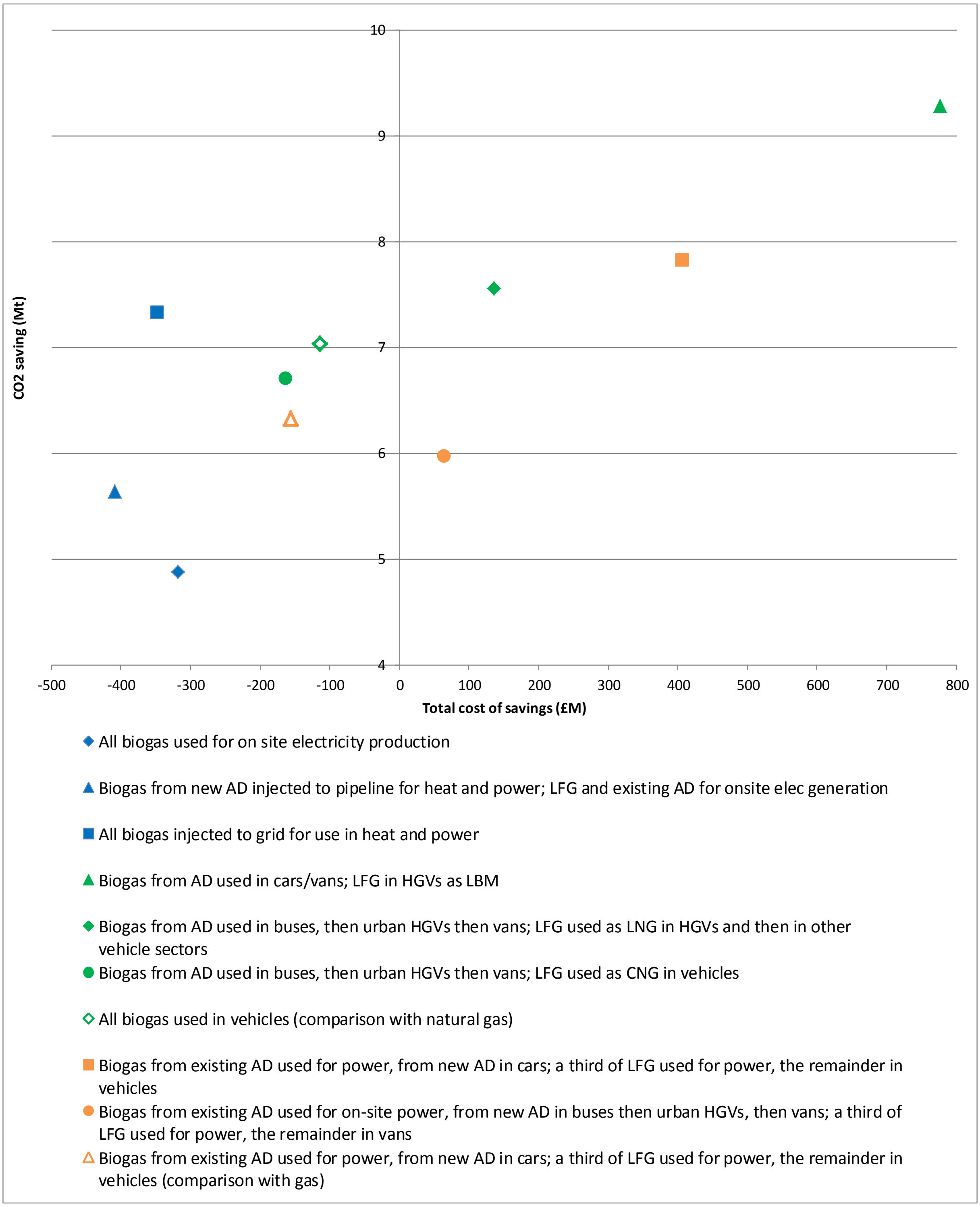


Table 5.7 Results of scenario modelling

		Use for heat and power	Use for transport	Total savings Mt CO_2	Total cost £M	Average cost-effectiveness £/t CO_2
1	All biogas used for on-site electricity production	100%	0%	4.9	-319	-65
2	Biogas from new AD injected to pipeline for heat and power; LFG and existing AD for onsite electricity generation	100%	0%	5.6	-409	-73
3	All biogas injected to grid for use in heat and power	100%	0%	7.3	-348	-48
4	Biogas from AD used in cars/vans; LFG in HGVs as LBM	0%	100%	9.3	777	84
5	Biogas from AD used in buses, then urban HGVs then vans; LFG used as LNG in HGVs and then in other vehicle sectors	0%	100%	7.6	135	18
6	Biogas from AD used in buses, then urban HGVs then vans; LFG used as CNG in vehicles	0%	100%	6.7	-162	-24
7	Scenarios 4 to 6 using all biogas in vehicles but where counterfactual is gas	0%	100%	7.0	-114	-16
8	Biogas from existing AD used for power, from new AD in cars; a third of LFG used for power, the remainder as LBM in HGVs	29%	71%	7.8	406	52
9	Biogas from existing AD and a third of LFG used for on-site power, all other biogas used in buses, urban HGVs and vans	29%	71%	6.0	65	11
10	Biogas from existing AD used for power, from new AD in cars; a third of LFG used for power, the remainder in vehicles (comparison with gas)	29%	71%	6.3	-156	-25

6 Case study

6.1 Introduction and objective

As already discussed, almost all biogas currently produced is used for heat and power. The following case study assesses the financial viability of an energy-from-waste supplier switching from electricity generation to producing alternative fuels which may be used for transport. The case study focuses on the production of biogas from landfill rather than other sources as landfill gas is currently the main source of production of biogas. The alternative output options investigated are as follows:

- upgrading the biogas and injecting into the grid for subsequent use as a transport fuel
- upgrading and liquefaction of the biogas to supply liquefied biomethane (LBM) by road tanker to the point of retail
- upgrading the biogas for supply as compressed biomethane (CBM) at the landfill site.

6.2 Case study methodology

6.2.1 Landfill gas use scenarios

To facilitate the comparison of financial viability between the different options for using landfill gas, we defined four detailed scenarios for assessment: the counterfactual plus three alternatives.

In the counterfactual, landfill gas is used for electricity generation and the plant is directly connected to the grid for export of electricity. The plant capacity is 1 MW and the useful lifetime of producing landfill gas from the site is taken as 15 years to represent a typical plant of this type. The availability of the landfill gas engine is assumed to be 81% with an efficiency of 35% (Arup, 2011). The plant operates for the full 15 years, generating around 7 GWh of electricity for export to the grid each year.

Across all scenarios (counterfactual and alternatives), the amount of landfill gas recovered and used for electricity generation or production of biomethane is assumed to remain constant[17]. The amount of landfill gas required by a 1 MW capacity generator is around 4.1 million m^3 per year with an energy content of around 73,000 GJ. This is equivalent to around 690,000 therms of gas injected into the grid or 3.4 million litres of LBM produced under the alternative scenarios.

All alternative scenarios assume that the landfill gas site currently exists to generate electricity and switches to produce alternative outputs after five years (of the total 15 year useful life of the site). Further, it is assumed that the switch occurs instantaneously such that no further cost is incurred through any interruption to production[18] and no change in site space is required across the different alternatives (hence no additional cost or benefit is included associated with any more or less land required)[19].

[17] The amount of landfill gas generated will decline over time, so this is a simplification. The decline in electricity generation or transport fuel production will depend on the characteristics of the landfill site, and also whether plant has been sized to match the peak flow expected from the site, or a more average flow.
[18] This assumption is again based on expert judgement of the project team given new technological processes may come pre-fabricated and could be built alongside the existing electricity generation plant.
[19] This assumption is based on the expertise of project team taking into account the fact that a typical landfill site is likely to be located outside urban areas and hence the owners are likely to also own some of the surrounding land.

6.2.2 Assessment of financial viability

In practice, firms have a number of financial tools at their disposal with which they can assess the financial viability of an investment opportunity, for example, Internal Rate of Return (IRR), payback period, Net Present Value (NPV), etc. IRR[20] is typically used by firms when comparing the payoffs of different investment opportunities against each other and against a required hurdle rate. Hence, for each scenario under the case study, the associated IRR was calculated. Given the case study compares a counterfactual with no switch against alternatives where a switch takes place, NPV[21] is also used as a second metric to inform the conclusions.

The assessment of financial viability is based on analysis of the key costs and benefits associated with each scenario. This includes: capital costs (CAPEX), operating costs (OPEX), shipping costs and revenue from energy sales and available subsidies. To minimise complexity, the assessment does not include some costs which would be faced by firms in practice, including tax, depreciation and interest. Hence the metrics presented are simplified estimates of the IRR and NPV but these are appropriate for this case study as the excluded costs are unlikely to have a significant bearing on the overall relative ranking of the scenarios.

6.2.3 Cost and price data

CAPEX and OPEX for the counterfactual of electricity generation were taken from DECC's 'Electricity Generation Costs' report (DECC, 2013b). DECC's estimates include construction and other infrastructure costs. When switching, it was considered unreasonable that all assets used for electricity generation would be stranded hence it was assumed that one-third of the costs on the turbine engines could be recovered through sale to off-set some of the additional capital costs under the alternative scenarios.

For grid injection, liquefaction and compression, estimates for CAPEX and OPEX are those used in the transport pathways (Appendix 2) unless otherwise stated.

Landfill gas has to be cleaned before it can be used for alternative outputs and thus gas cleaning is included in all three alternative scenarios; CAPEX and OPEX are included for the installation and operation of a CO_2 scrubbing plant.

Additional costs were added to the injection scenario to account for injection equipment (including flow and quality measurement, odour and compression) and ongoing costs of propane injection and piping costs. For LBM, CAPEX and OPEX were added to scrubbing costs to account for liquefaction and storage facilities and ongoing operation, vaporisation, overheads and shipping by tanker costs. Finally for compressed biomethane, costs were added for the compression asset and its ongoing operation from a study by SKM for DECC (2011).

The same costs associated with the ongoing operation of the landfill site are added across the alternative and counterfactual scenarios[22].

The key revenue streams associated with each investment opportunity are the value of the energy produced plus any applicable subsidy. Under the counterfactual, the electricity generated is valued at the price of electricity on the wholesale market taken from DECC's updated energy projections (DECC, 2013) plus Renewable Obligation Certificates (ROCs) for the electricity produced. The ROC banding for electricity generated from landfill gas has recently changed: in the central case it was assumed that the generator installed the plant when landfill gas was banded at 1 ROC[23]. The sensitivity of the results to the new eligibility of

[20] This is the rate of return (or discount rate) at which the sum of all discounted cash flows (both costs and benefits) over the lifetime of the project is zero.
[21] The sum of all discounted costs and benefits over the lifetime of the project.
[22] These are assumed to be 50% of the OPEX associated with electricity generation from Arup.
[23] Existing plant already accredited before the 2013 review of banding levels keep their old banding level under the scheme. Landfill sites accredited after the Aprl 2013 receive zero ROCs. This case is not examined as DfT wishes to look at the feasibility of existing landfill gas generators switching to supply transport fuel.

0.2 ROCs (DECC, 2012) was also tested[24]. The income from these ROCs is valued using the average auction price for ROCs over 2013 from the e-roc[25] auction.

Across the alternative scenarios, the gas produced is valued using different prices depending on the final state of the fuel. For injection into the grid, gas is valued using the wholesale price of gas from DECC's UEP fuel price assumptions. For compressed biomethane, a premium is added to the wholesale gas price based on the additional costs (calculated in the main part of the analysis in this study) for delivering and dispensing CNG from natural gas in the grid. For LBM, the retail price is taken as the price of imported LNG assumed in the study, plus the price of delivery by road tanker.

Where electricity is consumed (i.e. in scrubbing and injection activities), this was valued using DECC's retail price assumptions for an industrial consumer from the UEP fuel price dataset.

The injection of biomethane produced from landfill gas into the gas grid is currently not eligible for support under the UK Government's Renewable Heat Incentive (RHI) (Ofgem, 2013). Biomethane from landfill injected into the grid could be sold under the Green Gas Certificate scheme[26]. Although the landfill site owner may be able to charge a premium for any biomethane sold to participants, this is a voluntary scheme and not a formal subsidy hence we have not included any benefit in the analysis.

For both the LBM and compressed biomethane scenarios, it has been assumed that the fuel output is eligible for support under the Renewable Transport Fuels Obligation (RTFO). Under this scheme, Renewable Transport Fuel Certificates (RTFCs) are issued per kilogram of fuel produced (DfT, 2013a): The analysis assumes biogas is eligible for two certificates (DfT, 2013b) for every kilogram. In their recent response to the 'Advanced Fuels Call for Evidence', DfT noted that it intends to consult on the possibility of providing support for gaseous fuels on the basis of energy content rather than weight, given the energy content of gaseous fuels tends to be higher and have a broader range than liquid fuels. As such we have also included sensitivity analysis under which biomethane is eligible for 3.8 RTFCs per kilogram of fuel produced[27]. RTFCs are traded commodities and have no fixed price: this analysis assumes an average price based on observed RTFC auction prices from July 2012 to January 2014[28].

Emission factors and exchange rates, where used, were consistent with those used elsewhere in the project. A discount rate of 10% (consistent with a private rather than social perspective) was used to discount costs and benefits over time under the NPV calculation; this is consistent with discount rates used elsewhere in the project.

6.2.4 Uncertainty in the methodology used

When interpreting the results of this case study, it is important to note the uncertainty and assumptions on which these estimates have been made. Although the analysis below presents a reasonable approximation of the average costs and benefits involved, the assumptions made mean that these cash flows across different scenarios may be over or under-estimated.

This analysis was based on cost data from a number of sources. Although effort has been made to ensure consistency, some inconsistency may be inherent between the underlying methodologies used to compile the information. Furthermore, some data may be based on certain types of energy generation for which there are relatively few examples.

[24] This is the ROC banding for 'closed landfill' sites (i.e. where gas is captured from landfill sites that have ceased to accept waste for disposal). Generating stations added under the landfill gas band after 1 April 2013 (1st April 2015 for NIRO) using open landfill sites receive zero ROCs. Given the remit of this case study was to consider sites already operating LFG recovery systems, these sites are assumed to be closed for this sensitivity.
[25] http://www.e-roc.co.uk/trackrecord.htm (Accessed March 2014)
[26] http://www.greengas.org.uk/green-gas (Accessed March 2014)
[27] This is an illustrative estimate of the level of support biomethane could be eligible for, if RTFCs are awarded based on energy content
[28] http://www.nfpas-auctions.co.uk/etoc/trackrecord.html (Accessed March 2014)

The price for different gaseous fuels (and electricity) received by the firm will depend on a number of factors. Where output is sold to wholesale markets (i.e. under electricity generation or gas injection scenarios), prices will depend on the selling strategy of the firm: price typically varies between peak and off-peak and between long-term and short-term contracts, with differing trading costs implied by different strategies. Further, prices for LBM or compressed biomethane were not available from DECC's UEP prices hence proxy prices for both fuels were constructed based on the underlying additional costs of supply (i.e. for compressed biomethane) or on the supply of an equivalent fuel (i.e. for LBM). These values are used to illustrate the prices a landfill operator could achieve however the actual price received could be different depending on the prevailing conditions of the markets.

Across all scenarios it was assumed that there are mature markets for the outputs produced. Although this is appropriate for electricity generation and gas grid injection, it is unclear how substantial the markets for LBM and compressed biomethane for transport are and hence whether any additional production could be absorbed by the market. These markets are relatively immature and this could mean that the revenue streams under the LBM and compressed biomethane options could be over-estimated.

The assessment reflects the payoffs for a typical average installation. The exact payoff structure and hence incentives to invest in different technologies and switch will be case specific and could change between sites.

There may be additional factors which influence the financial viability of different options. Where options differ in terms of their maturity, this could impact on the rates of interest paid on loans to install technologies and the underlying leverage of the investment. Further, different technologies may imply different regulatory burdens, in particular where Health and Safety processes vary between technologies.

6.3 Case study results and discussion

6.3.1 Financial viability of landfill gas use scenarios

Under a ROC banding of 1, it is clear that using landfill gas for electricity generation is the most financially viable option. This option has the highest IRR and NPV over the lifetime of the investment scenario across all options. However, switching to producing LBM could still deliver a positive return for the investor. This has a 'good' IRR[29] and its NPV is positive over the lifetime of the scenario. The results of the analysis are presented in Table 6.1 below. The NPV and IRR shown are those for the remaining 10 years of operation.

All relative NPVs (i.e. compared to the counterfactual – relative NPV can also be interpreted as the costs of switching) of the alternative scenarios are negative. Hence under these assumptions, switching energy output after five years from electricity generation would not be financially viable. Hence landfill operators currently generating electricity have an incentive to continue with this. The key factor driving this result is the size of the additional CAPEX outlay in year 5 relative to the change in revenue structure following the switch to alternative options; this CAPEX implies the switching scenarios are not viable relative to the counterfactual.

When the (lower) revised ROC banding of 0.2 is considered, switching to produce an alternative fuel becomes more attractive. The difference in the IRRs (and NPVs) between the counterfactual and alternative scenarios become smaller which also implies the relative NPVs (or costs of switching) are also lower. Under these specific assumptions, the payoffs for a landfill operator of continuing to generate electricity or switch to producing LBM are very similar (both scenarios have an IRR of 11%). In fact, these results suggest that an average landfill operator may have a small incentive to switch to producing LBM which has a slightly higher NPV (and hence a positive relative NPV) in comparison to the counterfactual.

[29] Relative to a typical private hurdle rate of 10% as assumed here for discounting costs and benefits – hurdle rates will vary between firms.

***Table 6.1**: Payoffs of different landfill gas options*

Scenario	Financial Metric	Electricity generation	Gas grid injection	LBM	Compressed biomethane
Generation receives ROC banding of 1; 2 RTFCs per kg	IRR	23%	8%	18%	-5%
	NPV (£000's, 2012 prices) (NPV relative to counterfactual)	1940	-180 (-2120)	1150 (-790)	-1480 (-3420)
Generation receives ROC banding of 0.2; 2 RTFCs per kg	IRR	11%	0%	11%	-9%
	NPV (£000's, 2012 prices) (NPV relative to counterfactual)	110	-1090 (-1200)	240 (130)	-2390 (-2500)
Generation receives ROC banding of 1; 3.8 RTFCs per kg	IRR	23%	8%	23%	7%
	NPV (£000's, 2012 prices) (NPV relative to counterfactual)	1940	-180 (--2120)	2220 (280)	-400 (-2340)
Generation receives ROC banding of 0.2; 3.8 RTFCs per kg	IRR	11%	0%	17%	2%
	NPV (£000's, 2012 prices) (NPV relative to counterfactual)	110	-1090 (-1200)	1310 (1200)	-1320 (-1430)

Note: NPV values rounded to the nearest £10m

Under these assumptions, where a landfill operator has already incurred the upfront CAPEX to generate electricity, there is still an incentive (although now a smaller one) to continue to generate relative to switching to either gas grid injection or producing CBM[30]. An additional subsidy of around 46p and 95p per therm of biomethane output would be required under injection and CBM scenarios respectively for each alternative to become comparable in terms of payoffs to the counterfactual scenario (the equivalent figures under a ROC banding of 1 are 80p and 130p for injection and CBM respectively, and 30p for LBM). This is equivalent to offering around 6.2 RTFCs per kg of biomethane in total under the CBM scenario (equivalent figures under a ROC banding of 1 are 3.3 and 7.7 RTFCs per kg for LBM and CBM respectively). In this case, no further subsidy would be required to incentivise the typical landfill operator characterised here to switch under a ROC banding of 0.2.

The impact of changes in levels of subsidy is tested further in the sensitivity analysis where it is assumed that biomethane is eligible for 3.8 RTFCs per kg[31]. It can be seen from the results that under this assumption the LBM and CBM options become relatively more favourable, with the NPV of LBM in particular becoming slightly greater than that of the counterfactual. Hence under this more generous level of subsidy, the financial payoffs for an average landfill site receiving a ROC banding of 1 (i.e. commissioned before the recent banding changes) would be similar between continuing to generate electricity for export to the grid and switching to produce LBM for transport (if not slightly higher under the latter). In certain circumstances, depending on the installation specifics and other barriers withstanding, this higher level of subsidy could incentivise some operators to switch. Under the revised ROC banding of 0.2, these shifts are even more pronounced: switching to produce LBM becomes an even more attractive proposition as both the IRR and NPV increase relative to the counterfactual. Although the case for switching to produce CBM also improves, the IRR and NPV are still below that of the counterfactual.

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[30] IRRs of all projects drop as all scenarios are same for first five years before switch (all assume electricity generation).
[31] This scenario assumes there will be no consequent change in the value of RTFCs on average associated with a change in eligibility.

The comparison between alternative technologies would provide different results if new investment opportunities are considered rather than switching from electricity generation after a certain number of years. If the firm does not incur the initial upfront cost of electricity generation before pursuing LBM, it is likely that the IRR and NPV are higher for LBM relative to electricity generation over the course of the site lifetime even under the existing RTFC arrangements. Hence where new investors are considering alternatives under the new ROC banding, there is likely to be a greater incentive on average to choose to produce LBM for transport relative to the other investment opportunities.

6.3.2 Discussion and interpretation of results

This case study illustrates the key costs and benefits associated with different opportunities facing an average landfill operator regarding the use of landfill gas. The scenario used is highly stylised in that it was assumed that the landfill site was set up to generate electricity but had the opportunity to switch its output after five years.

The results of this case study suggest that under the subsidy structure for different renewable fuels offered by UK Government (and before the recent RO banding change), continuing to generate electricity is more financially viable than switching to any of the alternatives considered. The key factors driving this result were the additional CAPEX required (which represents a significant cost when CAPEX has already been invested to set up the generating plant) and lower OPEX associated with generation. The relatively short lifetime of landfill sites also limits the potential to switch as this curtails the lifetime over which any additional CAPEX can be offset. Hence where existing landfill operators generate electricity, there is little incentive to switch to other uses of biomethane. However, for existing landfill operators or new investors receiving support under the revised ROC bands, LBM appears to be a potential viable alternative.

7 Conclusions

This study has evaluated the costs and greenhouse gas emissions associated with the production, delivery and use of a range of liquid and gaseous fuels derived from waste, and conventional gaseous fuels in a variety of road vehicles and in aviation and shipping. The costs and emissions reflect, as far as possible, those which might be expected once technologies to produce these fuels have become established, which is nominally assumed to be 2025. The use of biogas in the heat and power sector, which is the most common use of biogas currently in the UK, was also evaluated to allow a comparison,

The results of the analysis are summarised below, but should be interpreted with caution. In collecting data for the study it became clear that there was considerable uncertainty in either the costs or emissions associated with a number of aspects of fuel production, and with the use of gaseous fuels in the vehicles. These data gaps are discussed below. For some key uncertainties, sensitivity analysis has been carried out, but due to the number of fuel pathways examined, a full sensitivity analysis on all parameters was not possible within the resources of the study.

7.1 Data gaps and research needs

Data gaps and research needs which were identified during the project were:

Advanced (second generation biofuels plants): The uncertainty surrounding the costs, energy requirements, and efficiencies of these plant is high (perhaps 40%) as most of the technologies are still at a pilot or demonstration stage. The study has therefore had to rely on data from engineering estimates for the cost and efficiency of commercial scale plant. Further uncertainty was introduced due to the need to estimate the additional cost and impact on yields of using a waste feedstock (which is more contaminated and inhomogeneous) rather than the clean biomass feedstocks (e.g. wood chip or crop residues) assumed in the engineering estimates. The robustness of cost-estimates is likely to improve as more demonstration and first-of-a-kind plant are built; and some experience is gained of operating such plant. An alternative, as it may be some years until this data becomes available, is to carry out some further sensitivity analysis for these fuel pathways.

Cost of waste feedstocks: The gate fee a plant receives for residual or source separated food waste, can significantly influence the economics of the plant. Data is available on current gate fees paid by local authorities for waste disposal and it was assumed that these would fall by 2025 as the value of waste as a resource is recognised and the number of plant producing energy or fuel from waste increases, and increases demand for waste. As the cost of fuel produced is relatively sensitive to the gate fee, more analysis of future trends in gate fees, and subsequent sensitivity analysis for the relevant fuel pathways would be useful.

Anaerobic digestion and injection of biomethane to the grid: While anaerobic digestion is a commercial technology, there can be significant variations in the design of plants, depending for example, on the waste they are receiving and pre-processing requirements, and the scale of the plant. In addition, different technologies used for upgrading the biogas to biomethane have different emissions and costs, and the cost of injection into the grid, is dependent on the pressure of the grid at the point of injection. The costs used in this study give a cost for biogas which is about the wholesale price of natural gas. However, the costs of the biomethane injected to the grid, are heavily influenced by assumptions on the gate fee for waste, and operating costs and characteristics, and some other studies have estimated a much higher cost. This has a significant impact on the cost-effectiveness of options using biogas (see below). DECC are currently carrying out a consultation on the costs of biomethane injection, as part of a review of the tariff for biomethane under the Renewable Heat Incentive, which may help to improve the certainty of cost estimates in this area.

Fugitive emissions from boil-off of LNG in vehicle storage tanks: While the issue of boil-off of LNG from vehicle storage tanks is recognised and discussed in the literature no data on the level of potential emissions during normal operation was given. An estimate was therefore made in the study to allow an assessment of the potential significance of this source (see below). This showed that an accurate assessment of emissions from this source requires information on how long vehicles are likely to be left idle with LNG in their tanks, and how much LNG is in the tanks during this idle period. Field trials of vehicles operating on LNG could be a potential source for this data.

Fuel efficiency of gas-fuelled vehicles: The lower carbon benefits of gas compared to petrol and diesel are eroded if the fuel economy of the vehicle is lower when running on gas. For vehicles typically having a compression ignition diesel engine, (such as larger vans, smaller HGVs and buses), changing to a spark ignition engine to run on gas will cause a drop in fuel efficiency. An accurate assessment of this change in fuel efficiency is important to allow emissions savings to be calculated accurately. Similarly, an accurate assessment of the fuel economy of dual fuel HGVs compared to diesel fuelled HGVs, and of the substitution rate of gas is important. Limited data is available on these factors at present, although more data may become available as more operating experience is gained under the current low carbon truck demonstration trials.

Tailpipe emissions of methane: There is little data on the tailpipe emissions of CH_4 from gas fuelled vehicles, as these pollutants have not been subject to regulation in the transport sector. In the case of dual-fuelled HGVs no data could be found in the literature at all, and it was therefore assumed that tailpipe methane emissions would be midway between those of a diesel-powered and gas-fuelled vehicle. In practice, tail pipe emissions in such HGVs depends on the substitution rate, the drive cycle, the level of methane slip in the engine and the effectiveness of any methane catalyst that is present in oxidising the methane. More robust data from emissions measurements on dual fuel vehicles is required to verify that the assumption made is reasonable, as higher tailpipe emissions can quickly negate emissions savings from the use of LNG.

Infrastructure for delivery of alternative fuels to ships: No data was found in the literature review of any additional costs and emissions associated with infrastructure for delivery of LNG and bio-oils to ships, and in the case of bio-oils any changes required to ships or changes in their operating costs. The results for those parts of the pathway for which data was available suggest that use of both these fuels would deliver savings relatively cost-effectively, and completing estimates for these additional elements, would be useful to allow a final assessment of these options. There is considerable interest within the maritime sector in the use of alternative fuels in shipping due to the need to meet requirements to reduce sulphur emissions from shipping. It is possible that work in this area may produce some of the data required.

7.2 Summary of Main Results

7.2.1 Gaseous fuels

In general, the results for compressed biomethane and CNG are similar across the different vehicles considered. Running vehicles on compressed biomethane produced from anaerobic digestion gives emissions savings of between 60% and 79%. The cost-effectiveness of the savings varies from about -£90/t CO_2 to £240/t CO_2, with use in buses, small HGVs and larger vans giving more cost-effective savings than in smaller vans and cars. Conversely, use of gas in cars and smaller vans and cars delivers greater percentage reductions than in larger vans, small HGVs and buses. This is because there is no (or very little) difference in fuel efficiency between a gas or petrol powered van or car, whereas a gas-powered large van, small HGV or bus with a spark ignition engine will typically have a lower fuel efficiency than its diesel-powered equivalent, which uses a higher efficiency compression ignition engine. Cost effectiveness is better because the additional capital and operating costs of gas fuelled buses, HGVs and vans are on a per km basis, lower than for cars and smaller vans.

Several technologies are available to remove CO_2 from the biogas and upgrade it to biomethane. Emissions savings reported above are for the use of membrane separation which has relatively low fugitive emissions of methane (0.5%). Using other technologies which have higher losses (e.g. pressure swing adsorption) could reduce savings (from 79% to 65%) highlighting the need to ensure that fugitive emissions of methane are minimised as much as possible.

As discussed above, estimates of the costs of biomethane production and injection vary significantly, due partly to differing assumptions about the operation of the technology and partly to differences in cost-estimates for elements of the plant. Some estimates are substantially higher (£26/GJ) than those calculated in this study (£6/GJ). At this higher cost the cost-effectiveness of GHG savings achieved from using biomethane rises to £340 to £550/t CO_2.

Savings and the cost-effectiveness of using biomethane from landfill are slightly better than those for biomethane from anaerobic digestion. Biosynthetic gas produce from woodchips also delivers high savings, although is less cost-effective £240 to £455/tCO_2. The emissions savings from biosynthetic natural gas produced from solid recovered fuel are lower because the fuel is not fully renewable (about 50% comes from renewable sources), and this means that the cost of carbon savings is higher (£370 to £859/tCO_2) than for biosynthetic natural gas from wood, despite the lower cost of biosynthetic natural gas produced from solid recovered fuel.

Dispensing from the local transmission system slightly increases emissions savings compared to dispensing from the medium pressure network, and using compressed biomethane from biomethane delivered in liquid form slightly reduces emissions savings.

Using CNG from fossil fuel gas in vehicles delivers no or very small emission savings for larger (diesel) vans, smaller HGVs and buses, as the advantage of using a fuel with a lower carbon content is lost due to the generally lower efficiencies of the vehicle when running on gas. For smaller vans and cars, when compared with petrol-fuelled vehicles, savings range from 9% to 27% depending on the source of the gas, with the lowest savings from imported LNG evaporated into the gas grid. Savings for 'average' gas in the grid would depend on the proportion of different sources of gas for grid supplied gas, but would lie between these values. The cost-effectiveness of the savings is better for small vans than cars. It is about £190 to £550/t CO_2 for shale and conventional gas, but is higher when the source of gas is LNG, (£530 to £900/t CO_2), due mainly to the lower level of savings achieved. The savings achieved from the use of CNG in cars are very similar to the savings achieved from use of diesel.

In the case of liquefied biomethane used in dual fuel vehicles, emission savings compared to diesel vehicles range from 32% to 52%[32] for LBM produced from anaerobic digestion, landfill waste and wood (the latter via biosynthetic natural gas). The cost of carbon savings is low for LBM produced from anaerobic digestion and landfill waste (£10 to £50/tCO_2), but is much higher for the use of LBM from BioSNG produced from wood and solid recovered fuel (£230/t to £290/t CO_2). For LNG, the well-to-tank emissions and higher tailpipe emissions of non-CO_2 GHGs offset much of the savings in tailpipe CO_2, so that overall savings are only 6%, The cost-effectiveness of these savings is however good (-£145/tCO_2). Sensitivity analysis indicates however that the small savings offered by LNG could easily be negated if tailpipe emissions are higher than assumed. As no data was available on tailpipe methane emissions for dual fuelled vehicles they were set at midway between emissions from a diesel

[32] As gas is assumed to account for 60% of fuel use, savings cannot be greater than 60%.

and gas-fuelled vehicle, which equates to about 0.6% of methane entering the engine being emitted in the tailpipe. If emissions were to be double this, then GHG savings are reduced to 4%, and if more than 2% of the methane entering the engine is emitted in the tailpipe then there is no overall GHG saving. More robust data on these emissions is therefore required to allow conclusions to be drawn about the effectiveness of using LNG in dual fuel vehicles as a GHG mitigation option. Methane emissions from venting vehicle storage tanks when the pressure of LNG which has boiled off in the tank becomes too high could also reduce emissions savings. However, sensitivity analysis indicates that this is likely to have a much smaller impact on emissions savings. Under normal patterns of operation, where the vehicle is in fairly constant, use, venting might be expected to occur on only 1 or 2 days a year, which would reduce emissions savings by about 0.4% points (i.e. from (5.8% to 5.4%).

Savings from the use of LNG in shipping are higher than for vehicles (21%) and have a good level of cost-effectiveness (-£73/t).

7.2.2 Waste derived liquid fuels

With the exception of biomass to liquid diesel jet fuel produced from the gasification of residual waste, all of the advanced biofuels routes producing biomass to liquid diesel, jet fuel, biopropane and bio-oil deliver good carbon savings (54% to 97% compared to the relevant comparator fuels). The cost-effectiveness is better for biomass to liquid diesel and jet (-£135/tCO_2 to £70/tCO_2) than for biopropane (£224/t CO_2). Use of bioethanol and bioalcohols produces only small savings (8 to 9%) due to the low blending levels assumed but is very cost-effective (-£154 to -62/t CO_2).

Advanced biofuels processes can produce both liquid and gaseous fuels. The results for different fuel pathways using solid recovered fuel as a feedstock show that, once the additional emissions and costs associated with delivery of fuels to vehicles, vehicle modifications and tailpipe emissions are taken into account, gaseous fuels derived from this source (with the exception of biopropane) offer slightly smaller emissions savings per km and have higher costs per tonne of carbon saved than liquid fuels.

7.2.3 Comparison with use in heat and power sector

Almost all biomethane currently produced is used in the heat and power sector. The cost-effectiveness of carbon savings achieved in the heat and power sector from the use of waste derived fuels is generally better than the cost-effectiveness of using it in the transport sector, when the cost of modifying the fleet and infrastructure to allow the use of gaseous fuels is allowed for. The exception is residual waste, where using it to produce transport fuels (particularly liquid transport) fuels would deliver more cost-effective GHG savings than burning it in an EfW plant where only electricity is produced.

However if it is considered that the vehicle fleet and fuel delivery infrastructure have already been adapted to allow the use of natural gas, and only the costs of substituting biomethane for natural gas are considered, then the cost-effectiveness of using biomethane in the transport sector is very similar to that of using it in the heat and power sector. This is to be expected, as the cost-effectiveness is almost entirely determined by differences in the emissions and costs of producing and delivering the natural gas as compared to biomethane, as within each sector the efficiency of end use is the same for the two fuels.

The current use of biogas in the heat and power sector is mainly driven by the support available for electricity generation under the Renewables Obligation and more recently for grid injection under the Renewable Heat Incentive. The study evaluated whether the support that Renewable Transport Fuel Certificates (RTFCs) provide was enough to make the move from generating electricity to producing biomethane for use as a transport generation financially viable. It examined the case of an landfill gas operator, and found that at the current level of RTFCs for biomethane there was no financial incentive to swap to production of biomethane for transport if the site had a ROC banding of 1, which is the case for closed sites which were 'grand-fathered'. For closed sites receiving 0.2 ROCs then switching to produce liquefied biomethane (which would receive 2 RTFCs) has about the same financial viability as continuing to generate electricity. However if the RTFCs for biomethane were to increase to reward biomethane in line with its underlying energy content as is proposed, then production of liquefied biomethane becomes slightly more favourable for sites with a ROC banding of 1, and definitely more favourable financially for sites with a ROC banding of 0.2.

7.3 Use of results from this study

While the results of this study provide a useful indication of the cost-effectiveness of different fuel pathways, the uncertainty in some of the results means that care should be taken in interpreting the results and using them to inform policy on either GHG abatement options for the transport sector, or the 'best use' for the biogas resource. It should also be remembered that the options analysed here need to be considered alongside alternative mitigation options for the vehicle or in the heat and power sector.

For example, in the case of gaseous fossil fuels, the only bifuel vehicles[33] using CNG which deliver a saving for all potential sources of gas supply are cars and smaller vans, where the comparison has been made with a petrol-fuelled version of the vehicle. However alternative mitigation options such as the use of diesel-powered vehicles or electric vehicles could deliver similar or greater GHG savings.

In the case of HGVs where fewer mitigation options are available, the use of LNG delivers savings of 6%. However, as discussed above, there is considerable uncertainty over a number of assumptions (substitution rate, efficiency when running in dual fuel mode, tail pipe methane emissions, and emissions from boil-off) which could reduce, or in a worse case completely erode this saving. More data on these aspects, preferably from measurement and monitoring programmes is needed to improve the accuracy and robustness of the results.

One strategy to ensure that GHG savings are achieved from the use of gaseous fuel is to ensure that CNG and LNG supplied to vehicles contains some biomethane, as this delivers much higher GHG savings in all vehicle types.

[33] Bifuel vehicles have two independent fuel systems (one of them for natural gas) and can run on either fuel, but only on one at a time. Dual fuel vehicles also have two independent fuel systems (one of them for natural gas), but can run on both fuels simultaneously. Dual fuel vehicles may also run on one fuel alone.

8 References

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Appendices

Appendix 1 – Scoping

Introduction

The range of potential feedstocks, conversion technologies, fuels and infrastructure steps which could potentially have been considered in the study is large, leading to a large number of potential fuel pathways for analysis. As it was only possible to study a limited number of pathways with the time and budgetary constraints of the study, it was necessary to reduce these to a more limited set[34]. This Appendix sets out the process used to identify those routes which could potentially form important pathways for a low carbon transport sector in the period 2020 to 2030. The process used a number of screening criteria, and was carried out in consultation with DfT and the wider steering group for the project.

The final choice of pathways needed to give a balanced spread across conversion technologies, fuels, and vehicle use, and in particular to allow comparisons between routes to liquid and gaseous biofuels. Screening of feedstocks and conversion technology is described below. The short lists from each of these screening processes were then considered together with considerations about fuels produced to create a recommended list of fuel production pathways.

Feedstocks

For waste feedstocks, the starting point for the screening was the list of feedstocks identified in the recent E4Tech report for DfT on the sustainability of advanced biofuel feedstocks (E4Tech, 2013). These are listed in Table A8.2 in order of potential biofuels production in 2020, as estimated in the E4Tech study. Only the UK resource was considered as this is the focus of the current study, (it should be noted that the biofuel production estimate provided byE4Tech is for the complete UK resource, i.e. no allowance is made for existing competing uses).

For each feedstock the table notes whether the feedstock is excluded in the Terms of Reference for the study, and assigns a high, medium, low rating to the potential biofuels contribution from the feedstock. Previous work by Ricardo-AEA for the DfT estimated that liquid fuel demand for the road and rail sector in 2020 would be 1,568 PJ, and this is used to derive a rating for the potential biofuels contribution as shown in Table A8..

Table A8.1 Ratings for assessing potential biofuels contribution

% of 2020 fuel demand	Expressed as PJ	Rating
0 to 0.1%	<1.6 PJ	Low
0.1 to 1%	1.6 to 16 PJ	Medium
>1%	>16 PJ	High

In assessing which feedstocks were to be shortlisted, consideration was also given to the characteristics of the feedstock and typical potential conversion routes, to assess whether it could be represented by another feedstock with similar properties for the purposes of the feedstock analysis.

The analysis in the table led to the following short list of feedstocks:

- **Bio-fraction of MSW and C&I waste-** considered in three separate forms:
  - **Source separated food waste**
  - **Residual MSW and C&I waste** (no pre-processing)
  - **SRF/RDF** produced from biogenic fraction of waste in MBT plant
- **Animal manure and sewage sludge**: considered together as have similar characteristics and used in same conversion technology (anaerobic digestion)

[34] The study allowed for analysis of 15 key fuel pathways

- **Barks, branches and leaves:** although excluded in the terms of reference**,** useful to include as more detail is available for gasification of this type of feedstock
- **Waste carbon gases**

In addition to these waste feedstocks, the following sources of fossil fuels were also included:

- **Conventional natural gas**: the main source of pipeline gas currently is UK fields, followed by imports from Norway and the Netherlands. OFGEM in a recent report for the Government on security of supply issues for gas, considered that, as production from the UK continental shelf continues to decline, the most likely source of additional gas supply is imported LNG (OFGEM, 2012). Imports of gas from Europe via the existing interconnectors are unlikely to increase significantly.
- **Gas from hydraulic fracturing:** from UK fields
- **LNG**: from Middle East (Qatar is currently the main source of imported LNG)[35]
- **LPG**: from natural gas processing

Conversion technologies

A wide range of conversion technologies is being considered for waste fuels, producing a range of fuels. The main technologies of relevance to the feedstocks identified above are shown in Table A8.3. The key consideration in screening conversion technologies was the feasibility of plant reaching commercialisation stage in the period of interest in the study (2020 to 2030). Given typical rates of development, it is considered that technologies at TRL level 7 could potentially reach commercialisation by the beginning of this period, and those at levels 5 to 6 by 2030. TRL levels are taken from the E4Tech report on feedstock sustainability[36]. On this basis, all of the conversion processes could become commercial by 2030. The only processes excluded were those which result in the production of hydrogen, as this was defined as out of scope for the study in the study terms of reference.

Feedstock to Fuel Pathways

Combining the shortlisted feedstocks with relevant conversion processes gave more than 15 fuel pathways (i.e. routes from feedstock to fuel), so some further screening was required.

Potential routes considered for exclusion were:

1) Degradation of waste in landfill site: this is essentially uncontrolled anaerobic digestion and production of biogas from landfill sites use is likely to decrease in the future due to drives to exclude organic materials from landfill. Biofuel yields from waste will be higher via other controlled routes. However, at present landfill gas is the only source of liquefied biomethane in the UK, so is important to include if analysis of the current situation is desired.
2) Methanol is currently little used in road transport in the UK, partly because of its challenging physical properties. The current EU petrol (gasoline standard) permits it to be blended with petrol in low concentrations (up to 3%) in addition to ethanol at 10%. Higher alcohols such as butanol can be blended at higher concentrations suggesting that in the longer term this route may offer more potential. A mixed/higher alcohol route from gasification would therefore seem preferable to a methanol route.
3) The production process for bioDME and biopropane are similar, with an additional processing step required for bioDME. Biopropane could potentially use LPG distribution and retail infrastructure, as well as being used directly as a substitute for LPG in vehicles, it could also be used at biomethane installations, being injected into the gas grid (instead of fossil derived propane) to meet gas specifications. Use of bioDME would require new distribution and retail infrastructure to be developed, as well as the development of appropriately modified vehicles.

[35] At present some LNG is being imported from European LNG stations by road tanker (and ferry) to supply LNG refuelling stations. However it does not seem likely that this will be a major supply route in the future.
[36] Apart from gasification to DME/biopropane, where we believe the TRL level to be higher as shown in the Table A8.3.

4) Use of waste carbon gases via yeast/bacteria fermentation or catalysis with hydrogen. As already discussed, the E4Tech study on sustainability of feedstocks suggests there may be some uncertainty over whether these would be included in the RED, although it appears likely that they could be included. Of all the feedstocks shortlisted, this had the lowest resource potential (as estimated in the E4Tech feedstock study), although this is based on utilising waste industrial gases (e.g. from iron and steel production). In the future, if other sources of CO_2 could be utilised, the feedstock resource potential could be much larger.

In discussion with the DfT it was agreed to include biomethane from landfill. Use of waste gases was excluded, to allow the study to focus on more conventional biomass and waste feedstocks, although it was noted that this route may have significant potential in the future, particularly if green hydrogen is available from renewable energy generation. It was agreed to look at mixed/higher alcohol routes rather than methanol, and biopropane rather than bioDME.

The final routes selected for study are shown in Figure A8.1.

For the gasification routes which have several potential upgrading routes, and final fuel production, within the limits of the study it was not possible to examine all combinations of feedstocks and routes, but at least one example, for each feedstock, and at least one example for each gasification technology was included.

Fuel to vehicle

Routes for the delivery of fuels to vehicles are shown in Figure A8.2, with a more detailed map for the delivery of CNG/CBM and LNG/LBM in Figure A8.3. The representation of vehicle types which were considered has been simplified in the diagram to aid clarity. In general, 'drop-in' liquid fuels, i.e. biomass to liquid diesel and jet, and upgraded hydrocarbons from pyrolysis will be able to use the existing infrastructure. Bioalcohols (e.g. bioethanol, biobutanol) are likely to require separate storage and blending close to point of distribution. The study considered blending of these fuels to limits which allow their use in unmodified vehicles. In the case of routes for gaseous fuels, compression, storage and dispensing of biogas at the landfill or anaerobic digestion site is not included, as it is unlikely that this would be a widely used route. The variations in biogas production, and 'lumpiness' of demand for fuel (e.g. there may be no demand for fuel overnight or at weekends) mean that considerable storage can be needed.

At present, LNG for LNG refuelling stations is sometimes imported by road tanker (and ferry) from European LNG terminals such as the one at Zeebrugge. This was not included on the list of routes to be studied, as in the longer term it is expected that that LNG will be supplied from UK LNG import terminals.

Table A8.2 Screening of Waste Feedstocks

Feedstock	2020 biofuel production potential (PJ/yr)	Expansion post 2020?	Excluded in ToR for study	Theoretical contribution in 2020	Main existing competing uses	Other considerations	Short-list
Bio-fraction of C&I waste	87	↔	No	High	EfW for heat and power, anaerobic digestion for heat and power, composting.	Form of this waste is important for conversion technologies. Suggest consider as source separated food waste, residual MSW/C&I waste (i.e. after recycling but with no reprocessing) and SRF/RDF fuel where there is some sorting to screen our non-biogenic component e.g. at MBT plant.	Yes
Bio-fraction of MSW	68	↓	No	High	EfW for heat and power, anaerobic digestion for heat and power, composting.		Yes
Straw	52	↔	Yes (A)	High			No
Animal manure	43	↔	No	High	None for resource - some feedstock goes to anaerobic digestion for heat and power.	Feedstock characteristics and conversion routes similar enough to consider animal manure/sewage sludge as a combined category.	Yes
Barks, branches and leaves	15	↔	Yes (A)	Medium		Although excluded in terms of reference, in order to reduce complexity of project, consider that would be useful to include one 'wood chip' feedstock for gasification, as more data available for plants operating on this type of feedstock.	Yes
Small round-wood	14	↔	Yes (A)	Medium			No
Sewage sludge	9.5	↑↑	No	Medium	None for resource - some feedstock goes to anaerobic digestion for heat and power.	Feedstock characteristics and conversion routes similar enough to consider animal manure/sewage sludge as a combined category	Yes
Saw dust and cutter shavings	8.5	↔	Not clear	Medium	Animal bedding. Panel board, onsite heat and power, pellet production.	Feedstock characteristics similar to forestry residues. Strong competing uses could reduce available resource.	No
UCO	6.6	↔	No	Medium	Small amount to chemicals.	Cost, energy use and GHG of using UCO and tallow for FAME (or potentially in future HVO) relatively well studied already. Already strong interest in maximising collection and use of these resources. Unlikely to be	No
Animal fats	3.7	↔	No	Medium	Some to heat and		No

Feedstock	2020 biofuel production potential (PJ/yr)	Expansion post 2020?	Excluded in ToR for study	Theoretical contribution in 2020	Main existing competing uses	Other considerations	Short-list
Cat 1&II					power.	used in other conversion processes.	
Waste carbon gases	3.3	↔	No	Medium	May be used for heat and power (~50% in EU); remainder flared.	Some uncertainty over whether fuels from this resource will be able to count as biofuels and will be retained in the RED	Yes
Black and brown liquor	1.9	-	No	Medium	Typically used for heat and power onsite.	Strong competing use for heat and power already established. Actual available resource will be considerably less than the potential resource/	No
Miscanthus	1.8	↑↑↑	Yes (B)	Medium		Characteristics for conversion would be similar to bark, branches and leaves.	No
Short rotation coppice	0.46	↑↑↑	Yes (B)	Low		Characteristics for conversion would be similar to bark, branches and leaves.	No
Crude glycerine	0.36	↔	No	Low	Upgrading for industrial uses, low value sales into animal feed, waste water treatment.	Potential contribution small; current surplus is linked to FAME production, so unlikely to increase significantly given current concerns over FAME production from land based crops. Relatively versatile feedstock that can be used to produce number of fuels.	No
Grape marcs	0.05	↔	No	Low	Mulch/composting	Potential contribution in 2020 very small, unlikely to increase.	No
Cobs	0.04	↔	Yes (A)	Low			No
Tall oil pitch	0.02	-	No	Low	Onsite heat and power	Potential contribution in 2020 very small, unlikely to increase	No
Wine lees	0.01	↔	No	Low	Mulch/composting	Potential contribution very small.	No
Macro-algae	0.01	↑↑↑	No	Low		Potential contribution very small.	No
Palm oil mill effluent	0	-	No	Zero		No UK resource.	No
Empty palm fruit branches	0	-	Yes (A)	Zero		No UK resource.	No
Bagasse	0	-	Yes (A)	Zero		No UK resource.	No
Nut shells	0	-	Yes (A)	Zero		No UK resource.	No
Husks	0	-	Yes (A)	Zero		No UK resource (considered with straw in original	No

Feedstock	2020 biofuel production potential (PJ/yr)	Expansion post 2020?	Excluded in ToR for study	Theoretical contribution in 2020	Main existing competing uses	Other considerations	Short-list
						study).	
Short rotation forestry	0	↑↑↑	Yes (B)	Zero		No current resource; could expand significantly post 2020; would have same characteristics as bark, branches and leaves.	No
Micro-algae	0	-	No	Zero			No
Renewable electricity (Mtoe)	235	↑↑↑	Yes			Renewable electricity could be used for electrolysis to produce 'green' hydrogen. Direct use of hydrogen (e.g. in fuel cell vehicles is out of scope in this study but hydrogen could also be used in a catalysis process with CO_2 from waste gases to produce bioSNG, or liquid fuels.	Yes

Notes:

A: Excluded in terms of reference to limit scope and complexity of study and on basis that conversion processes of interest using agricultural or forestry residues such as gasification will be covered by process applicable to the biofraction of waste.
B: Excluded as terms of reference state that fuels derived from food or energy crops should not be considered.

Table A8.3 Screening of Conversion Processes

Conversion technology	Intermediate product	Upgrading step	Final fuel	TRL level	Shortlist
Anaerobic digestion	Biogas	Cleaning - CO_2 removal	Biomethane	8 to 9	Yes
Pyrolysis	Pyrolysis oil	Hydrotreating and refining	Diesel/jet	4 to 6	Yes
		Cleaning and upgrading	Marine fuel	6 to 7	Yes
Gasification	Syngas	FT catalysis and hydrocracking	Diesel/jet	6	Yes
Gasification	Syngas	Other catalysis and refining	Mixed alcohols (bioethanol, biobutanol, biopropanol)	4 to 6	Yes
Gasification	Syngas	Other catalysis and refining	DME/biopropane	5 to 7	Yes
Gasification	Syngas	Other catalysis and refining	Methanol	6 to 7*	Yes
Gasification	Syngas	Other catalysis and refining	BioSNG	6 to 7	Yes
Gasification	Syngas	Syngas fermentation	Bioethanol	5 to 7	Yes
Gasification	Syngas	Other catalysis and refining	Hydrogen	4 to 5	No - H2 out of scope
	Waste carbon gases	CO_2 catalysis with hydrogen	Biomethane, methanol, diesel. Jet, gasoline	4 to 6	Yes
	Waste carbon gases	Yeast/bacteria fermentation	Bioethanol, biobutanol	5 to 6	Yes
Hydrolysis	C5 and 6 sugars	Yeast/bacteria fermentation	Bioethanol	5 to 6	Yes

Figure A8.1 Feedstock to fuel pathways to be analysed

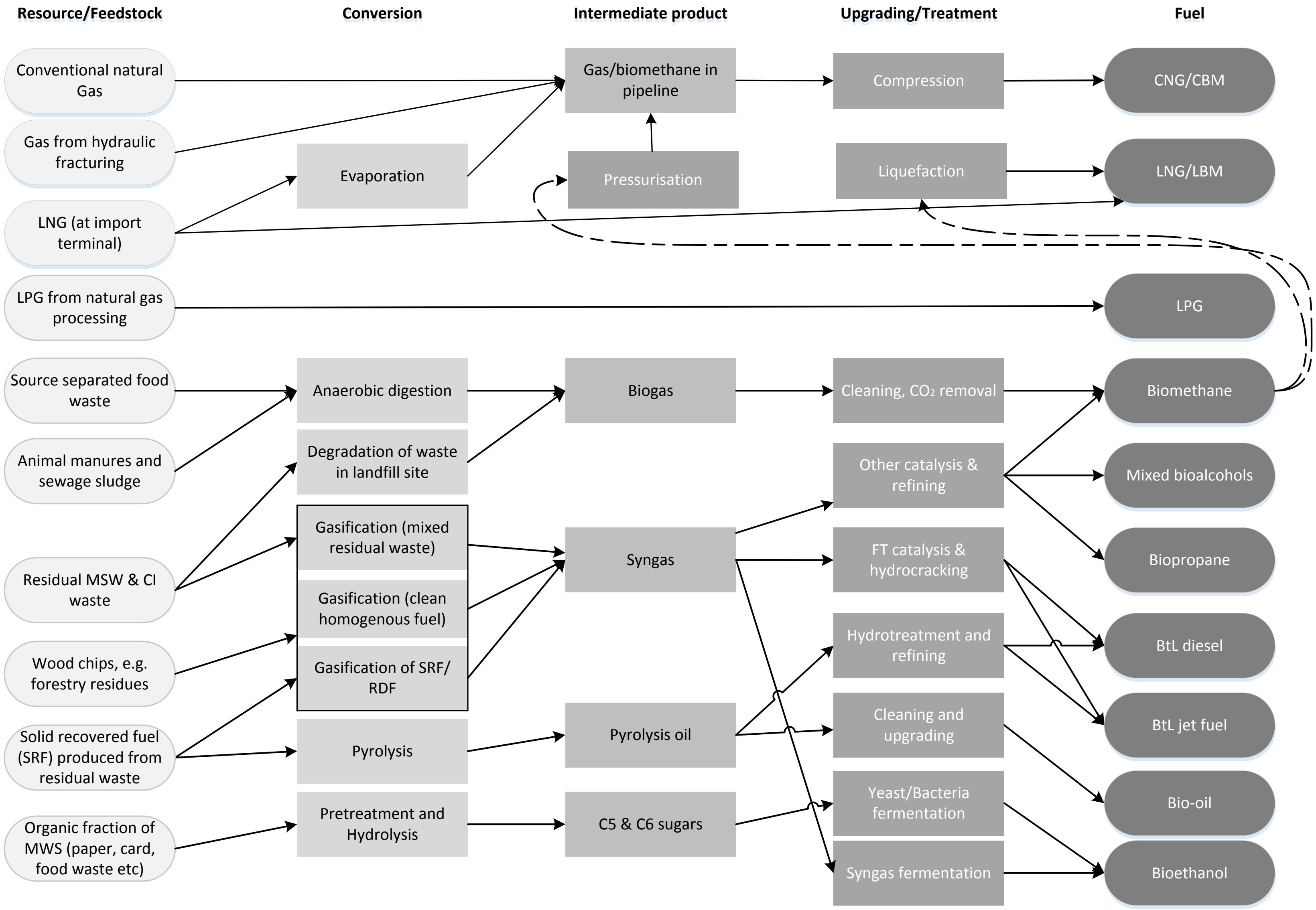


Figure A8.2 Liquid fuel to vehicle routes to be analysed

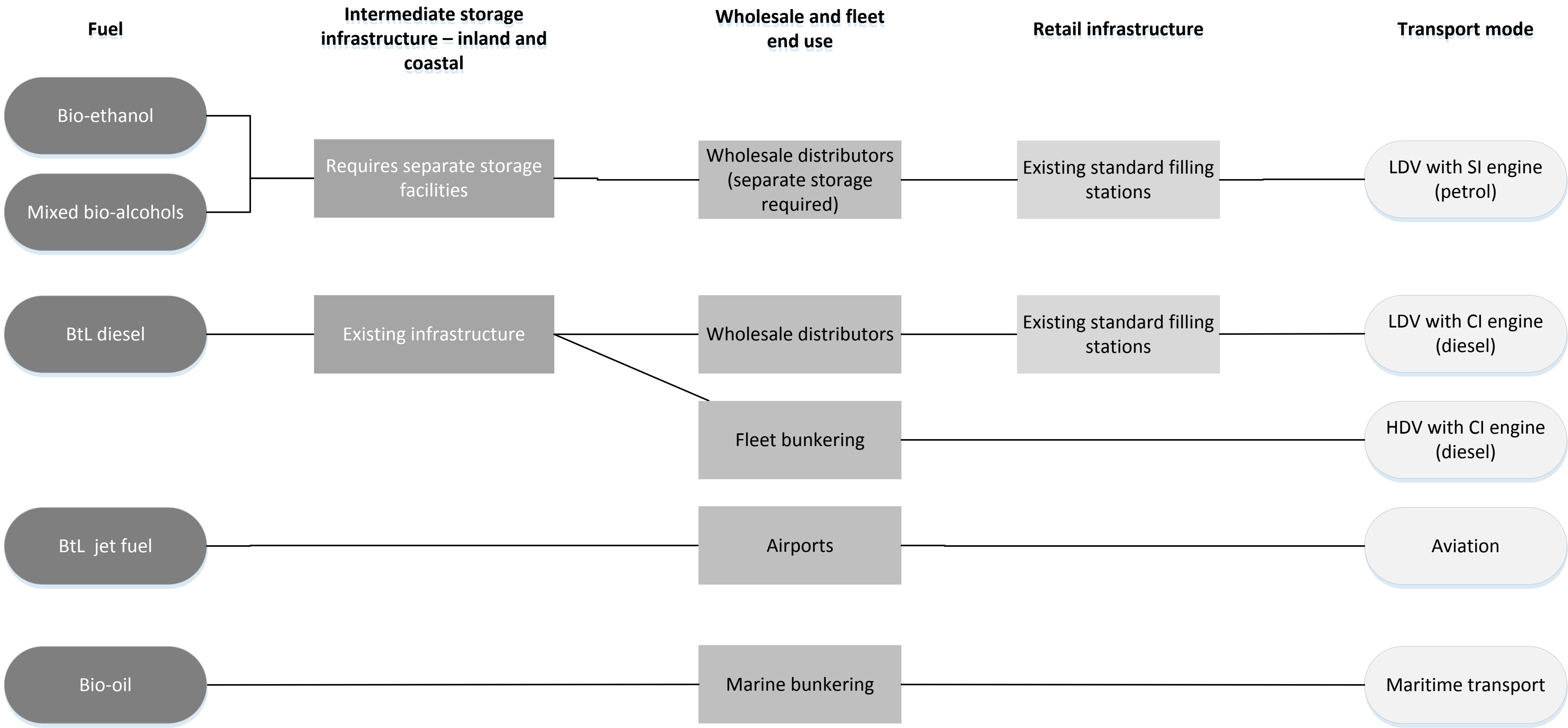
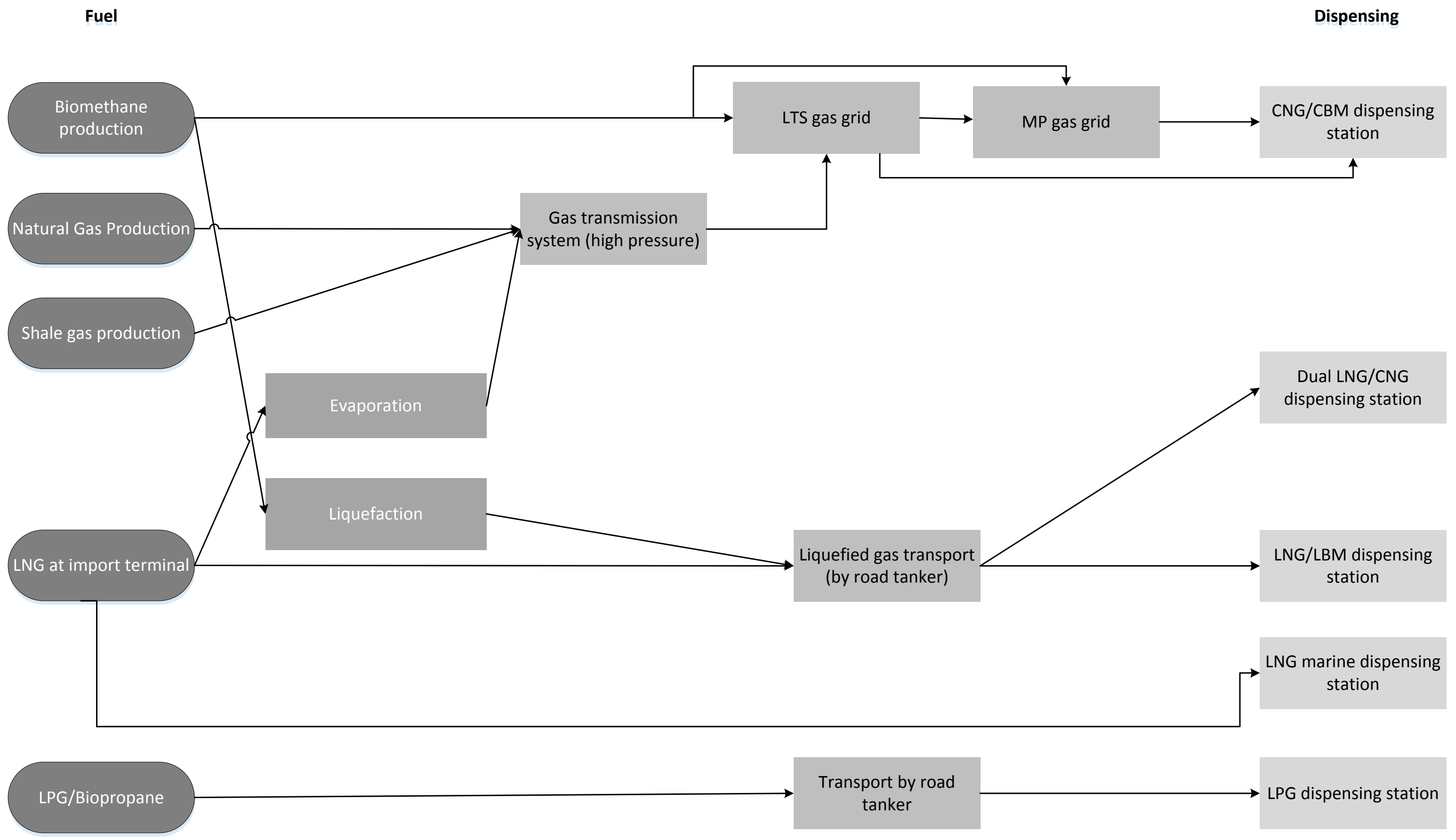


Figure A8.3 Gaseous fuels to vehicle routes to be analysed



Notes:
1) Injection into the distribution grid and gas take off from the distribution grid for filling stations can occur at a variety of pressures depending where in the grid the connection is made
2) As well as dispensing equipment, CNG dispensing stations will include compressor and storage/buffer storage and LNG stations cryogenic storage tank and pumps

Appendix 2 – Description of Process Steps

Table of contents

1 Introduction

As described in the main report, the study examines the use of gaseous and waste derived fuels in a range of vehicles, looking at the costs, greenhouse gas emissions and energy for each fuel pathway. This technical appendix, describes each of the steps in these fuel pathways, from production of fuels, to the infrastructure and processes required to deliver and dispense the fuels to vehicles. It also details the approach taken to estimate costs, GHG emissions and energy used in each of the steps, and details the values for these three parameters for each step in the fuel pathway.

Section 1.1 outlines the fuel pathways analysed in the study and where information on each step can be found in this Appendix. Section 1.2 describes the methodology used to estimate costs, GHG emissions and energy use for each step and key common assumptions in the analysis. Section 2 describes the process steps involved in the production and upgrading of fuels, and Section 3, processes for distributing and dispensing of the produced fuel to vehicles. Finally, in Section 4, the use of biomethane for heat and power applications is described.

1.1 Fuel pathways considered in study

The fuel pathways analysed in the study are shown in Figure 1.1 below. The process used to identify which pathways were to be studied is given in Appendix 1 and Section 2 of the main report.

1.1.1 Fuel production

For fossil gaseous fuels, four sources were considered:

- Natural gas from the UK continental shelf.
- Shale gas from hydraulic fracturing in the UK.
- Imports of liquefied natural gas (LNG) from the Middle East.
- Liquefied petroleum gas (LPG) from natural gas processing.

LNG can either be loaded onto road tankers for distribution to vehicle refuelling stations as LNG, or evaporated and injected into the gas grid.

For biofuels, the conversion routes considered were:

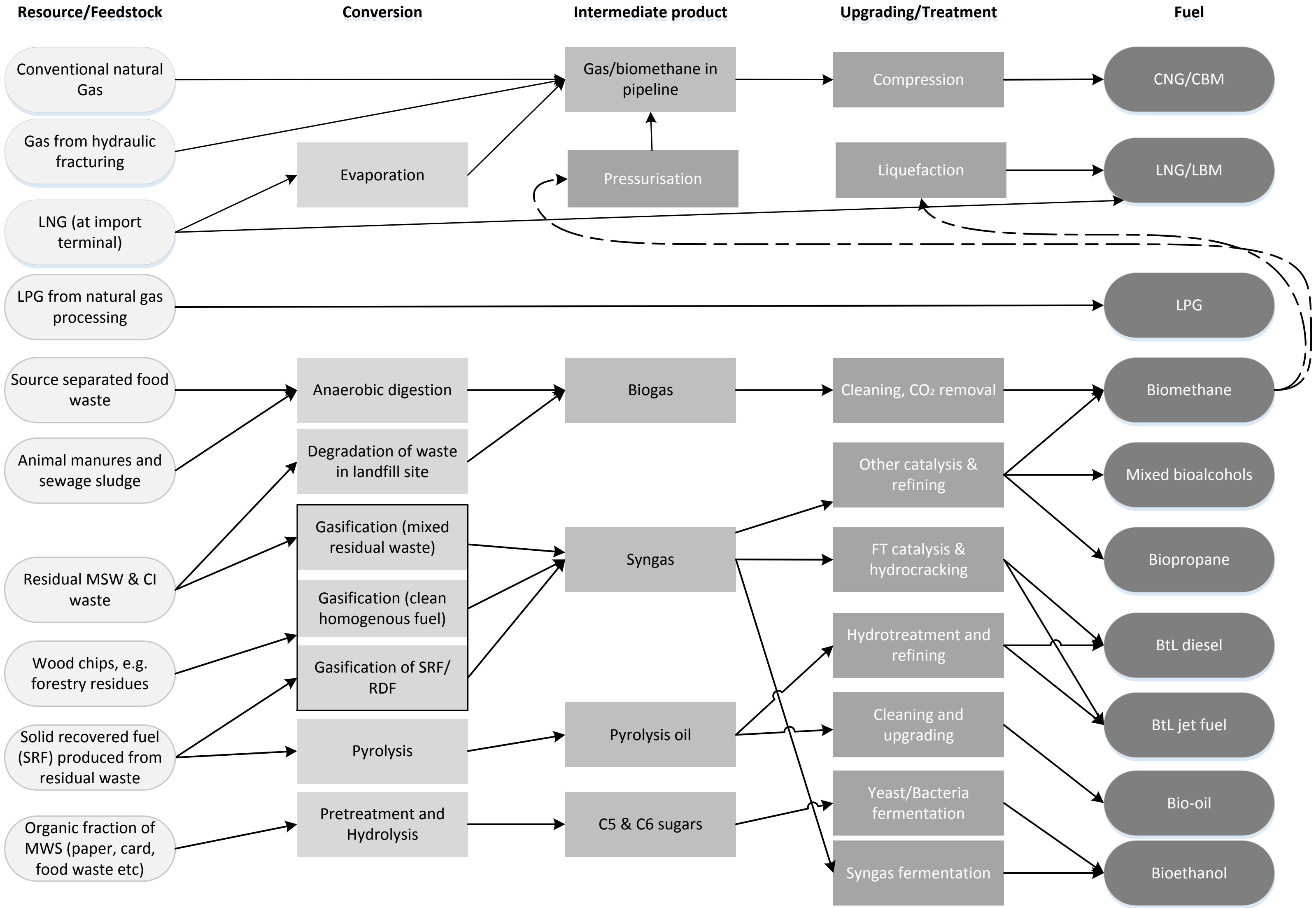
- Anaerobic digestion (AD) of wastes to produce biogas which is then upgraded to produce biomethane; biogas production from landfill sites was also examined. Feedstocks which were considered for AD were source separated food wastes and animal manures
- Advanced biofuels production processes based on gasification; treatment of the bio-syngas (bio-SNG) to produce both gaseous (biomethane and biopropane) and liquid fuels (diesel, jet fuels and bio-alcohols)[37]. Feedstocks which were considered for the gasification processes were residual[38] municipal solid waste (MSW) and commercial and industrial (C&I) waste, solid recovered fuel (SRF), a fuel prepared from residual waste, which is more homogeneous and has a higher energy content, and wood chips from e.g. forestry residues.
- Advanced biofuels production processes based on pyrolysis. The bio-oil produced from the pyrolysis process can either be cleaned and upgraded to produce a fuel

[37] It was originally intended to also examine fermentation of syngas to produce bioethanol, but no data could be found in the literature to allow an estimation of the costs and emissions associated with this process.
[38] Residual waste is 'black bag' waste, the waste left after recyclables have been extracted.

suitable for use as a replacement for heavy fuel oil, e.g. in shipping, or undergo hydrotreatment and refining to produce a diesel fuel.

- Advanced biofuels production using biochemical routes to produce bioethanol. The feedstock for this process is the organic fraction of waste (e.g. food waste and paper and card) which it is assumed is separated from residual waste during a pre-treatment stage.

Figure 1.1 Fuel pathways analysed



1.1.2 Fuel delivery

Natural gas (whether from the UK continental shelf, hydraulic fracking or evaporated LNG) is assumed to be injected into the natural gas grid for distribution to filling stations, where it is dispensed as compressed natural gas (CNG). LNG can also be distributed straight from import terminals by road tanker to filling stations for use as either LNG or CNG. LPG is distributed by road tanker to filling stations.

Biomethane (produced by upgrading biomethane or from bio-syngas), can either be injected in to the gas grid for distribution and dispensing as compressed biomethane (CBM) in the same way as natural gas, or can be liquefied and distributed by road tanker like LNG. Biopropane would be distributed by road tanker like LPG.

Liquid biofuels which are drop in replacements for conventional fuels (BtL diesel, jet fuel and bio-oil) can be distributed and dispensed using the same infrastructure as for conventional fuels. Bioalcohols and bioethanol require separate storage and transportation, and are typically blended with petrol close to the point of sale.

1.1.3 Process steps in each pathway

Table 1-1 and Table 1-2 show the process steps considered in each fuel pathway (41 in total), from feedstock to delivery of the fuel. The number in brackets after description of the step shows the Section of this Appendix where a description of the step, and values used in the analysis of the step can be found.

Table 1-1 Steps in biofuel pathways

Feedstock	Fuel Production and Upgrading		Fuel distribution and delivery			Fuel in Vehicle
Source separated food waste	Anaerobic digestion to produce biogas (2.5.1)	Upgrading to biomethane (2.6.1)	Grid injection (2.6.2)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CBM
				Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CBM
			Liquefaction (2.6.3)	Distribution by road tanker (3.1.2)	Dispensing as LNG (3.1.4)	LNG
					Dispensing as CBM (0)	CBM
Animal manure	Anaerobic digestion to produce biogas (0)		Grid injection (2.6.2)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CBM
				Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CBM
			Liquefaction (2.6.3)	Distribution by road tanker (3.1.2)	Dispensing as LNG (3.1.4)	LNG
					Dispensing as CBM (0)	CBM
Residual MSW and C&I waste	Degradation of waste in landfill to produce biogas (2.3.5)		Grid injection (2.6.2)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CBM
				Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CBM
			Liquefaction (2.6.3)	Distribution by road tanker (3.1.2)	Dispensing as LNG (3.1.4)	LNG
					Dispensing as CBM (0)	CBM
SRF	Gasification to produce bioSNG (0)		Grid injection (2.6.2)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CBM
				Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CBM
			Liquefaction (2.6.3)	Distribution by road tanker (3.1.2)	Dispensing as LNG (3.1.4)	LNG
					Dispensing as CBM (0)	CBM
Wood chips	Gasification to produce bioSNG (2.3.1)		Grid injection (2.6.2)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CBM
				Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CBM
			Liquefaction (2.6.3)	Distribution by road tanker (3.1.2)	Dispensing as LNG (3.1.4)	LNG
					Dispensing as CBM (0)	CBM
Residual MSW and C&I waste	Gasification to produce BtL diesel (2.3.5)		Storage and distribution of BtL diesel (3.2.1)		Dispensing at filling station (3.2.5)	BtL diesel
	Gasification to produce BtL jet (2.3.5)		Storage and distribution of BtL jet (3.2.2)		Dispensing at airport (3.2.6)	BtL jet

Feedstock	Fuel Production and Upgrading	Fuel distribution and delivery		Fuel in Vehicle
Wood chip	Gasification to produce BtL diesel (2.3.6)	Storage and distribution of BtL diesel (3.2.1)	Dispensing at filling station (3.2.5)	BtL diesel
		Storage and distribution of BtL jet (3.2.2)	Dispensing at airport (3.2.6)	BtL jet
SRF	Gasification to produce BtL diesel (2.3.7)	Storage and distribution of BtL diesel (3.2.1)	Dispensing at filling station (3.2.5)	BtL diesel
		Storage and distribution of BtL jet (3.2.2)	Dispensing at airport (3.2.6)	BtL jet
	Pyrolysis and hydrotreatment (2.3.8)	Storage and distribution of BtL diesel (3.2.1)	Dispensing at filling station (3.2.5)	BtL diesel
		Storage and distribution of BtL jet (3.2.2)	Dispensing at airport (3.2.6)	BtL jet
	Pyrolysis and cleaning/ upgrading (2.3.9)	Bunkering of bio-oil (3.2.3)	Dispensing of bio-oil (3.2.7)	Bio-oil
	Gasification to produce biopropane (0)	Storage and distribution of biopropane (**Error! Reference source not found.**)	Dispensing of biopropane (0)	Bio-propane
	Gasification to produce bioalcohols (2.3.3)	Storage and distribution of bioalcohols (3.2.1)	Dispensing of bioalcohols (3.2.4)	Bio-alcohols
Organic waste (food, paper and card)	Pre-treatment, hydrolysis and fermentation (2.4)	Storage and distribution of bioethanol (3.2.1)	Dispensing of bioethanol (3.2.4)	Bio-ethanol

Table 1-2 Steps in fossil fuel pathways

Source	Production Step	Fuel distribution and delivery		Fuel in Vehicle
Natural gas from UK continental shelf	Production and transport to gas transmission grid (2.7.1)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CNG
		Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CNG
Shale gas from hydraulic fracturing	Production and injection to gas transmission grid (2.7.2)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CNG
		Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CNG
LNG imported from Middle East	Evaporation and injection into gas transmission grid (2.7.5)	Distribution in LTS grid (3.1.1)	Dispensing from LTS grid (3.1.6)	CNG
		Distribution in LTS grid and MP grid (3.1.1)	Dispensing from MP grid (3.1.7)	CNG
	Storage at port and loading onto road tanker (2.7.4)	Distribution by road tanker (3.1.1)	Dispensing as LNG (3.1.4)	LNG
			Dispensing as CNG (0)	CNG
LPG from gas processing	Production of LPG (2.7.3)	Distribution by road tanker (3.1.1)	Dispensing as LPG (0)	LPG

1.2 Data collected for each step and common assumptions

1.2.1 Cost data

For each step data was collected on capital and operating costs for a typical plant. This was sourced mainly from existing studies, but was supplemented in several cases, with data from industry or trade associations. Where significant variations are possible high and low values are also given.

The cost data for a typical plant were then combined with data on the throughput of the plant, in a levelised cost model to enable the calculation of a cost per GJ of fuel produced or fuel processed. The CAPEX and OPEX costs shown in the Tables in this Appendix are the levelised CAPEX and OPEX costs per GJ produced The levelised cost model is based on a discount rate of 10% to reflect the type of returns required in the private sector, and a cost of capital of 10%. All costs are in real terms in 2012 £. As the study is focused on overall costs to the economy of the each of options, no taxes, duties or subsidies are included in the analysis.

As the analysis in the study is intended to be as representative as possible of 2025, all fossil fuel and feedstock prices represent projected costs for 2025 (full details are given in the relevant sections). Where electricity is consumed in the process step (and can be identified separately) costs are calculated based on the projected price of electricity to an industrial consumer in 2025 of 13.6 p/kWh. Any sales of excess electricity produced and exported during fuel production are credited with a value equivalent to the wholesale price of electricity of 7.1 p/kWh. Both of these values are taken from projections (DECC, 2013).

1.2.2 GHG emissions

GHG emissions are either calculated based on the fuel and electricity requirements for the step or taken from existing studies (principally JEC, 2013). Only fossil based GHG emissions are calculated. Wherever possible data was collected for each of the three GHGs, CO2, CH4 and N2O separately, and converted to CO_2 equivalent (CO_2e) using the latest 100 year global warming potentials for CH4 and N2O from the IPCC 5th Assessment Report, of 28 for CH4 and 265 for N2O. A sensitivity study is carried out using 20 year GWPs, as these are much higher for CH4 (84) (see Section 5 of the main report).

An emissions factor of 49 kg CO_2e/GJ is used for electricity consumed in 2025 (as forecast in DECC, 2013); emissions factors for other fuels are taken from the DECC/Defra GHG conversion factors for company reporting[39]. Exported electricity (from some of the advanced biofuels fuel production processes) is not given a GHG emissions credit. In line with the methodology used in the JEC well to wheel study, it is assumed that if the biomass feedstock was not used for fuel production, it could be used directly for electricity production, therefore the correct 'credit' for the electricity produced is not the grid based average for electricity production, but electricity production from the same biomass source.

1.2.3 Energy use

For each step, the efficiency of the step in converting fuel or feedstock to the process to the final fuel is recorded. Any additional fuel or electricity inputs are also recorded.

[39] http://www.ukconversionfactorscarbonsmart.co.uk/

2 Fuel production

2.1 Introduction

This chapter contains characteristics of the waste feedstocks considered (Section 2.2) and descriptions of:

- Production of biofuels using thermochemical routes (gasification and pyrolysis) (Section 2.3)
- Production of biofuels through biochemical routes
- Anaerobic digestion to produce biogas
- Biogas upgrading
- Fossil gas supply including natural gas, shale Gas, LNG and LPG

2.2 Waste and biomass feedstocks

Waste and biomass feedstocks which are considered in the study are:

- Residual[40] municipal solid waste (MSW) and commercial and industrial (C&I) waste,
- Solid recovered fuel (SRF), a fuel prepared from residual waste, which is more homogeneous and has a higher energy content
- Wood chips (e.g. from forestry residues)
- Source separated food waste
- An organic fraction of waste organic fraction of waste (food waste and paper and card) which it is assumed is separated from residual waste during a pre-processing step.

The residual MSW and SRF contain waste of both a biological origin (e.g. paper, card, food waste) and fossil origin (e.g. plastics), and this is allowed for when calculating GHG emissions from combustion of the fuel. It is assumed that 50% of the carbon in SRF comes from a biogenic source, and 70% of the carbon in residual waste, based on the typical composition of residual waste.

The cost, energy content (for those wastes used in thermo-chemical processes) and emissions associated with pre-processing or preparation of the waste is shown in Table 2-1. A negative cost indicates that a gate fee would be received for the waste. Gate fees for waste are based on data from WRAP on gate fees received by current facilities and those in planning, but are reduced slightly from the values in the report to allow for the fact that gate fees may reduce by 2025 as processing capacity increases, and the value of waste as a resource is recognised. Values of SRF are based on data from NNFCC. In the case of the organic fraction of waste produced by processing of residual waste in an MBT, no data could be found in the literature on the likely costs of such pre-treatment, and how they might be spread across the products produced from the MBT plant (which would also include recyclables). A conservative assumption of £20/t is therefore made.

Emissions associated with the collection and transport of waste to the facility are not included, as these are considered to be emissions associated with waste disposal and management. However where an additional processing step is undertaken, as is the case of SRF, emissions from this process and the transport of the SRF from the production facility to the biofuels production plant are included. In the case of the organic fraction of waste, it is

[40] Residual waste is 'black bag' waste, the waste left after recyclables have been extracted.

assumed that processing of residual waste to produce this fraction takes place at the biofuels production site.

Table 2-1 Characteristics of waste and biomass feedstocks

Feedstock	NCV (GJ/tonne)	Cost (£/t)	Emissions from feedstock preparation and transport $kgCO_2/t$
Residual MSW and C&I waste	12	-50	4
SRF	19	0	20
Wood chip	19	65	6
Source separate collected food waste		-30	0
Organic fraction of waste		20	Assumed 0

2.3 Biofuels – thermochemical routes

The production of biofuels can be undertaken through a number of gasification routes. These are detailed in turn below and include:

- Gasification of wood chips
- Gasification of SRF
- Gasification of residual MSW and CI waste
- Pyrolysis of SRF

2.3.1 Gasification of wood chips to syngas and further conversion to biomethane

2.3.1.1 Description

Here, synthesis gas is produced from the indirect gasification of forestry wood chips, (the gasification process proposed for the Gobigas Project is assumed (Göteborg Energi, 2014)). This is cleaned and the proportions of H_2 and CO are adjusted using a CO_2 shift reaction. The resultant gas is reacted over a catalyst to form a methane rich gas which is upgraded to pipeline quality.

The methanation process is exothermic and the overall efficiencies are improved if the high grade heat produced in the methanation reaction is exported for use in district heating or industrial processing. This is not assumed in this step beyond the usage necessary for the installation to be self-sufficient in electricity.

The plant is assumed to produce 75 million m3 per year.

2.3.1.2 Process parameters

The main source of cost and performance data is the review carried out by, DEA 2013. This is in turn based on data from the GobiGas project in Sweden (Göteborg Energi, 2014). Biodiesel is used as a scrubber liquid. The consumption of biodiesel is assumed to be converted to product gas. The installation is assumed to be self-sufficient in electricity generation as there is a surplus of energy from the methanation reaction which is a slight deviation from the GobiGas case. Efficiency defined as energy in BioSNG /energy in wood chip fuel and does not take account of heat, which could be exported to district heating or process heat. GHG emissions are those associated with feedstock production and preparation and with production of the biodiesel used in the process.

Table 2-2 Gasification of wood chips to syngas and further conversion to biomethane

Parameter	Unit	Typical Value	Key sources
GHG emissions	Total GHG as kgCO2eq/GJ	1.8	Defra 2009
Total energy use	MJ used /GJ	25	
Total costs	£/GJ	21.7	
Efficiency of step	%	63%	

2.3.2 Gasification of SRF to syngas and further conversion to biomethane

2.3.2.1 Description

The description for the gasification of SRF to syngas is as detailed above.

2.3.2.2 Process parameters

The main source of cost and performance data is the review carried out by DEA, 2013. This is in turn based on data from the GobiGas project in Sweden (Göteborg Energi, 2014). The use of SRF is a substantial technical advance on what is currently proposed in planned demonstration projects. To allow for the additional capital costs of processing a prepared waste fuel the cost of the gasification sections of the installation have been increased by 30% (estimate by Ricardo-AEA). Biodiesel is used as a scrubber liquid. The consumption of biodiesel is assumed to be converted to product gas. GHG emissions are those associated with feedstock production and preparation and with production of the biodiesel used in the process

The installation is assumed to be self-sufficient in electricity generation as there is a surplus of energy from the methanation reaction which is a slight deviation from the GobiGas case. GHG emissions are those associated with feedstock production and preparation and with production of the biodiesel used in the process

Efficiency defined as energy in bioSNG /energy in SRF fuel and does not take account of heat.

Table 2-3 Gasification of SRF to syngas and further conversion to biomethane

Parameter	Unit	Typical Value	Key sources
GHG emissions	Total GHG as kgCO2eq/GJ	3.0	Defra 2009
Total energy use	MJ used /GJ	25	
Total costs	£/GJ	17.6	
Efficiency of step	%	63%	

2.3.3 Gasification of SRF to syngas and further conversion to mixed bio-alcohols

2.3.3.1 Description

In this step synthesis gas from indirect gasification of SRF is cleaned and the proportions of H_2 and CO are adjusted. The resultant gas is reacted over a catalyst to form a product containing a range of alcohols, including ethanol. The resulting product is then fractionated to ethanol and other grades of alcohols that can be either used as fuel or chemicals.

2.3.3.2 Process parameters

The below analysis and data is based on NREL, 2011, and is for a plant producing 2,205 tons (US) of product per day. There is no external fuel or other energy usage. Emissions associated with catalysts and other consumables are negligible and have therefore not been factored into the analysis. The process plant is considered to be self-sufficient in energy.

Table 2-4 Gasification of SRF to syngas and further conversion to mixed bio-alcohols

Parameter	Unit	Typical Value	Key sources
GHG emission	Total GHG as kgCO2eq/GJ	3.3	
Total energy use	MJ used /GJ	0.0	
Total costs	£/GJ	9.7	NREL, 2011
Efficiency of step	%	35%	

2.3.4 Gasification of SRF to syngas and further conversion to biopropane

2.3.4.1 Description

The production of syngas (from biomass gasification) uses a one stage catalytic synthesis using a process under development by Japan Synthesis Ltd. The costs include an allowance for CO_2 collection but not sequestration.

The installation is self-sufficient in energy and exports 31.3MW of electricity from an integrated CHP that uses surplus heat from the reaction.

2.3.4.2 Process parameters

This process is based on case B of the economic analysis in GTI, 2010, and is for a plant producing 130 kt of biopropane per year. . Feedstock usage is 3k tonnes dry wood per day. Data is only available for wood based processes. SRF would be a significant departure but entirely possible. To compensate for this the gasification element has been increased by 30% which represents an additional cost of $53 M over the GTI estimate.

As there are no significant inputs to the process emissions are limited those associated with feedstock preparation. Excess electricity is exported from the process.

Table 2-5 Gasification of SRF to syngas and further conversion to biopropane

Parameter	Unit	Typical Values	Key sources
GHG emissions	Total GHG as kgCO2eq/GJ	2.3	
Total energy use	MJ used /GJ	-146.0	GTI, 2010
Total costs	£/GJ	12.9	GTI, 2010
Efficiency of step	%	46%	GTI, 2010

2.3.5 Gasification of residual MSW and CI waste to syngas and further conversion by Fischer Tropsch synthesis to synthetic diesel and jet fuel

2.3.5.1 Description

In this step unsorted waste is gasified in a plasma gasifier to produce a mixture of H2 and CO. There is a heavy consumption of power for the plasma generators and air separation unit. This is assumed to come from a dedicated power plant on site fuelled by 33% of the syngas. The technology uses 5% coking coal for operational reasons to maintain a porous bed in the gasification reactor. The emissions from this are included in the Table below.

The syngas, which results, is then used to produce diesel grade and other alkanes using the Fischer Tropsch reaction.

2.3.5.2 Process parameters

Cost and performance data is estimated from published data from the Tees valley Plasma gasification installation (AlterNG, 2013), which takes 350,000 tonnes of waste per year. The data is adjusted to allow for the addition of a FT synthesis plant and a smaller power plant. The cost of the FT synthesis is based on the DEA data used in the gasification of wood chip for FT diesel scaled for the reduced capacity with an exponent of 0.7.

Self-supply of all electricity is assumed and emissions from coal use are included.

Table 2-6 Gasification of residual waste to syngas and further conversion by Fischer Tropsch synthesis to synthetic diesel and jet fuel

Parameter	Unit	Typical Value	Key sources
GHG emissions	Total GHG as kgCO2eq/GJ	50.8	
Total energy use	MJ used /GJ	0.0	
Total costs	£/GJ	27.7	DEA, 2013. AlterNG, 2013
Efficiency of step	%	30%	

2.3.6 Gasification of wood chips to syngas and further conversion by FT synthesis to synthetic diesel and jet fuel

2.3.6.1 Description

Here, clean wood chip is gasified in oxygen blown gasifier to produce a mixture of H2 and CO. This mixture is cleaned and the proportion of H2 to CO is adjusted by the water gas shift reaction. The resulting gas is reacted over a catalyst to form a mixture of alkanes. The alkane mixture is distilled into gasoline, diesel and jet fuel products plus minor quantities of propane and lighter compounds. The process is exothermal overall with the surplus heat from the FT reaction being used to raise steam which is used for power generation.

2.3.6.2 Process parameters

The energy conversion efficiency of 56% shown below is based solely on liquid fuel products (gasoline and diesel/jet oil). If electricity export is accounted for this increases to 59%. If waste heat can be used then the overall energy efficiency increases to 80%. The plant is assumed to produce 105 kt of FT diesel per year.

Table 2-7 Gasification of wood chips to syngas and further conversion by FT synthesis to synthetic diesel and jet fuel

Parameter	Unit	Typical Value	Key sources
GHG emissions	Total GHG as kgCO2eq/GJ	0.5	
Total energy use	MJ used /GJ	-90.0	
Total costs	£/GJ	22.5	
Efficiency of step	%	56%	

2.3.7 Gasification of SRF to syngas and further conversion by Fischer Tropsch synthesis to synthetic diesel and jet fuel

2.3.7.1 Description

Here dry solid refuse derived fuel is gasified in an oxygen blown gasifier to produce a mixture of H2 and CO. This mixture is cleaned, and the proportion of hydrogen to carbon monoxide is adjusted by the water gas shift reaction. The resulting gas is reacted over a catalyst to form a mixture of alkanes. The alkane mixture is distilled into gasoline, diesel and jet fuel products plus minor quantities of propane and lighter compounds. The process is exothermal overall with the surplus heat from the FT reaction being used to raise steam which is used for power generation.

2.3.7.2 Process parameters

The Cost and performance data are based DEA, 2013. The only data available is for straw so this study therefore assumes that the broad process parameters for SRF will be sufficiently similar for the purposes of this study. The use of SRF is a substantial technical advance on what is currently proposed in planned demonstration projects. To allow for the additional capital costs of processing a prepared waste fuel the cost of the gasification sections of the installation have been increased by 30%. As for the wood chip plant, the plant is assumed to produce 105 kt of FT diesel per year.

In the DEA (2013) analysis 100 GJ of feedstock gives 39GJ Diesel/ jet oil, 17GJ Gasoline, 3GJ electricity and 41GJ waste heat and the same proportions have been used below.

CAPEX and OPEX are proportional to the share of saleable product represented by the diesel fraction as calculated in DEA, 2013.

The Gasoline value is not accounted for in this study. This will not significantly affect the levelised cost of the products as it has a similar calorific value and commercial value to diesel.

The energy conversion efficiency of 56% shown below is based solely on liquid fuel products (gasoline and diesel/jet oil). This becomes 59% if electricity export is accounted for. If waste heat can be used then the overall energy efficiency of the process increases to 80%.

Table 2-8 Gasification of SRF to syngas and further conversion by Fischer Tropsch synthesis to synthetic diesel and jet fuel

Parameter	Unit	Typical Value	Key sources
GHG emissions	Total GHG as kgCO2eq/GJ of resulting product	1.9	
Total energy use	MJ used /GJ of resulting product	-90.0	
Total costs	£/GJ of resulting product	15.1	
Efficiency of step	%	56%	

2.3.8 Pyrolysis of SRF to bio-oil and further conversion by hydro treatment to synthetic diesel and jet fuel

2.3.8.1 Description

The pyrolysis plant is designed to use 2000 dry metric tons/day of feedstock. The processing steps include:

- Feed drying and size reduction
- Fast pyrolysis[41] to a highly oxygenated liquid product. In the fast pyrolysis process finely ground feedstock is heated rapidly to 400-600°C causing it to decompose into a wide range of organic molecules plus char. The resulting vapour is cooled giving liquid condensate, or fast pyrolysis oil, and gaseous fractions. The char can be used to supply internal process heat but can also be sold as a product in its own right. The gaseous fraction similarly can be used for process heat or as a source of hydrogen in following processing.
- Hydrotreating of the fast pyrolysis oil to a stable hydrocarbon oil with less than 2% oxygen
- Hydrocracking of the heavy portion of the stable hydrocarbon oil
- Distillation of the hydrotreated and hydrocracked oil into gasoline and diesel fuel blendstocks. These are typically 30-40% diesel and jet oil grades, 50-60% gasoline fractions.
- Hydrogen production from natural gas purchased from the gas grid to support the hydrotreater reactors. (SGC, 2013 & APEC 2011)

2.3.8.2 Process parameters

The emissions for natural gas usage for hydrogen generation are not accounted for in this step. The emissions are for electricity only.

No credit is given for the value of the char or gas product from the pyrolysis step as their value is uncertain, but likely to be low.

[41] Thermal pyrolysis in circulating fluidised bed.

Natural gas usage is 42 scf[42] /US gall product. Power usage is 2.5kWh/ gall.

CAPEX and OPEX are pro-rated to the proportion of diesel in the product mix.

Performance and cost data are largely taken from PRNL (2009).

The use of SRF is a substantial technical advance on what is currently proposed in planned demonstration projects. To allow for the additional capital costs of processing a prepared waste fuel the cost of the pyrolysis sections of the installation have been increased by 30%. The impacts of the composition of SRF on the other processes in the installation are unknown, but for the purposes of this study are assumed to be negligible as it is unlikely to impact on the size or throughput.

48% of the energy in both the dry biomass and the natural gas is converted to liquid product. Of this 40% is diesel fraction.

Parameter	Unit [(1)]	Typical Value	Key sources
	Total GHG as kgCO2eq/GJ	28.2	
Total energy use	MJ used /GJ	1021	
Total costs	£/GJ	10.6	
Efficiency of step	%	48%	

2.3.9 Pyrolysis of SRF to bio-oil and further conversion by minimal hydro treatment to a stable marine oil

2.3.9.1 Description

This is the same process as in Section 2.3.8 but the second hydrogenation step and the fractionation of the products have been removed. The resulting fuel is suitable for use in heavy duty 2 stroke diesel engines typical of those used for ship propulsion.

2.3.9.2 Process parameters

According to the mass balances supplied in PRNL (2009) the hydrogen usage for hydrotreatment alone is 85.5% of the total used for diesel production. Capex for hydrogen has been reduced pro rata.

Table 2-9 Pyrolysis of SRF to bio-oil and further conversion by minimal hydro treatment to a stable marine oil

Parameter	Unit [(1)]	Typical Value	Key sources
	Total GHG as kgCO2eq/GJ	12.5	
Total energy use	MJ used /GJ	400	
Total costs	£/GJ	11.0	
Efficiency of step	%	55%	

2.4 Biofuels - biochemical routes

2.4.1 Process description

The process is based on a, state of the art, commercial straw to ethanol plant. No pre-processing of feedstock is included. The process includes:

- Feedstock reception and storage,
- Dilute acid pre-treatment,
- Batch enzymatic hydrolysis
- Fermentation of C5 and C6 sugars

[42] Standard Cubic Feet

- On site enzyme production,
- Ethanol distillation/ purification,
- On site CHP using by-products and wastewater treatment.

The hydrolysis of the feedstock and subsequent fermentation of the hydrolysate are conducted as an integrated operation, so it is most useful to consider both modules together.

2.4.2 Process parameters

Key assumptions for the typical case are:

- The cost data are based on a detailed study of available information on corn stover to ethanol plant by NREL (2011). The information is adjusted to represent a commercial plant, producing 183 kt bioethanol per year. Subsequent studies (DEA, 2013 and NNFCC, 2013) are based on the NREL (2011) study, making assumptions about how the data can be adapted for use of straw as feedstock in the European context.
- No data was available in the literature on the use of waste feedstocks for bioethanol production by this route- these are still at the early demonstration stage. It was therefore assumed that the waste feedstock will be the paper and card and organic fractions of residual MSW. These fractions will be separated by an on-site MBT plant, and will represent about 40% of the residual MSW. The pre-processed feedstock will be delivered to the ethanol plant ready for use at a nominal cost of £20/t. Processing at the plant will be the same as for straw.
- On site CHP utilising the lignin fraction of the feedstock is assumed to provide sufficient heat and power for the process and to produce a surplus of electricity for export.
- On site waste water treatment is assumed.
- On site production of enzymes is assumed. This increases the capital cost of the plant, but reduces the operating cost.
- GHG emissions and process efficiency are based on conversion of straw to ethanol (JEC, 2013).

Key areas of uncertainty are:

Utilisation of waste feedstocks:

- It is assumed that the waste feedstock is supplied ready for hydrolysis and that it can be processed in a similar way and at similar cost to straw. However, the composition and form of the waste feedstock is currently untested. Any additional pre-processing required at the ethanol plant will impact both the cost and energy requirement of the process.
- The cost of the feedstock is currently unknown. A nominal cost of £20/t to cover the cost of separating and preparing the paper and card and organic fraction for hydrolysis has been assumed. The low cost scenario assumes the feedstock is available at no cost, as an output from the MBT plant requiring further treatment prior to disposal. The high cost scenario assumes a higher cost of feedstock pre-processing and/ or lower ethanol potential, giving a cost per tonne of £50/t. This is similar to the cost of using straw as a feedstock in the UK.

GHG emissions for use of waste feedstocks.

- Here, conversion efficiency for wastes may be significantly lower than for straw, depending on the waste composition, how well the hydrolysing enzymes can be tailored to the feedstock, and levels of contaminants and inhibitors in the feedstock. As an example, the high case shows the higher GHG emissions and lower efficiencies expected for waste wood.

Table 2-10 Biofuels production biochemical routes

Parameter	Unit	Value			Key sources
		Typical	Low	High	
GHG emissions	CO2 as kgCO2eq/GJ	3.3		13.6	JEC 2013
	CH4 as kgCO2eq/GJ	0.2		0.5	
	N2O as kgCO2eq/GJ	0.2		-0.1	
	Total GHG as kgCO2eq/GJ	3.7		14	
Fuel use	MJ used/GJ	0		1240	
Electricity use	MJ used /GJ	-80.0		-52	
Total energy use	MJ used /GJ	-80.0		1240	
CAPEX costs	£/GJ	5.1		6.5	NREL 2011, DEA 2013
OPEX costs	£/GJ	6.7		13.0	
Total costs	£/GJ	11.8		19.5	
Efficiency of step	%	44%		41%	

2.5 Anaerobic Digestion

2.5.1 Source separated food waste to produce biogas

The input to this module is source separated food waste and the output is the intermediate product biogas.

2.5.1.1 Process description

This module includes:

- reception and storage of source separated food waste,
- pre-processing including heat treatment,
- digestion to produce biogas,
- On site biogas storage.

It is assumed that the biogas will be cleaned sufficiently for use in a CHP engine, and on site CHP using biogas will be used to provide heat and power.

2.5.1.2 Process parameters

The key assumptions for the typical plant are:

- Plant capacity is 2.7 million m^3 biomethane per year (equivalent to 1MWe), and feedstock is 40,000tpa source separated food waste (Ricardo-AEA, 2013 and NNFCC 2013).
- On site CHP uses a proportion of the biogas to meet site heat demand and a proportion of the electricity demand. Remaining electricity is imported (BIOGRACE, 2013).
- Capital costs are a mid-range estimate based on a review of recent published information and case studies (Ricardo-AEA 2013, Parsons Brinckerhoff, 2013 and SKM, 2011).

- Operating costs are estimated to be 7% of capital costs (Ricardo-AEA, 2013).
- Feedstock is assumed to attract a gate fee of £30 per wet tonne. I.e. the plant operator is paid to take the food waste (WRAP, 2013).
- Digestate is assumed to comply with PAS 110[43], and so be spread to land. Digestate is assumed to be cost neutral at the point of application, and costs are associated with storage and transport[44].
- The total energy use is the ratio of feedstock energy to product energy. It includes loss of methane and biogas used for CHP.

Key uncertainties are:

- Capital and operating costs. Capital costs ranged from £1.7million to £7.2 million in the literature.
- Operating costs. These are very sensitive to the gate fee achieved for the food waste (range -£25/tonne to -£42/tonne[45]) and the disposal cost of the digestate (£0/tonne to £40/tonne[46]). There is considerable uncertainty in the value of both these parameters.
- GHG emissions associated with processing. These depend on the source of heat and electricity used for the processing. If biogas is used only for heat production, GHG emissions associated with grid electricity use increase. If a larger CHP unit is built, which produces surplus electricity, then electricity could be exported or utilised on site for further biogas upgrading.
- GHG emissions from methane leakage. Leakage in the typical case is assumed to be 1%. Higher leakage rates associated with incomplete processing or poor storage would substantially increase GHG emissions
-

Table 2-11 Anaerobic digestion – source separated food waste to produce biogas

Parameter	Unit	Value			Key sources
		Typical	Low	High	
GHG emissions	CO2 as kgCO2eq/GJ	2.7		11.8	BIOGRACE 2013, JEC 2013
	CH4 as kgCO2eq/GJ	7.0		0.8	
	N2O as kgCO2eq/GJ	0.0		-0.9	
	Total GHG as kgCO2eq/GJ	9.7		11.7	
Fuel use	MJ used/GJ	0			
Electricity use	MJ used /GJ	19			
Total energy use	MJ used /GJ	19			
CAPEX costs	£/GJ	8.2			Ricardo-AEA 2013, Parsons Brinckerhoff 2013,NNFCC 2013
OPEX costs	£/GJ	-7.3		-9.4	WRAP 2013
Total costs	£/GJ	0.9			
Efficiency of step	%	59%			BIOGRACE 2013

[43] http://www.wrap.org.uk/content/bsi-pas-110-specification-digestate
[44] Personal communication with R-AEA waste experts.
[45] Based on responses from AD plant operators
[46] Based on range from cost neutral to landfill cost.

2.5.2 Anaerobic digestion of a mixture of animal slurry and food waste

The input to this module is a mixture of animal slurry and food waste. The output is the intermediate product biogas.

2.5.2.1 Process description

The modelled plant capacity is 2.7 million m3/y biomethane (equivalent to1MWe). This scale is required for on-site biogas upgrading to biomethane. It is assumed that a plant utilising solely animal slurry is not feasible at this scale, due to the low biogas production potential of slurry and issues with transport of large volumes of slurry. Feedstock is assumed to be mixture of slurry (12,000tpa) and food waste (30,000tpa)[47]. The process includes feedstock reception; storage, pre-treatment (including heat treatment), wet AD and biogas clean up to allow use in CHP engine. Heat and power for process is provided by on-site CHP sized to heat load. Excess electricity is exported.

2.5.2.2 Process parameters

The key assumptions for the typical plant are:

- Plant capacity is 2.7 million m^3 biomethane per year (equivalent to 1MWe), and feedstock is 12,000tpa animal slurry and 30,000tpa source separated food waste (Ricardo-AEA 2013, NNFCC 2013).
- On site CHP uses a proportion of the biogas to meet site heat demand and a proportion of the electricity demand. Remaining electricity is imported (BIOGRACE 2013).
- Capital costs are a mid-range estimate based on a review of recent published information and case studies (Ricardo-AEA 2013, Parsons Brinckerhoff 2013, and SKM 2011). Capital costs are assumed to be the same as for food waste plant, as food waste pre-processing will be required.
- Operating costs are estimated to be 7% of capital costs (Ricardo-AEA 2013).
- Waste food feedstock is assumed to attract a gate fee of £30 per wet tonne. I.e. the plant operator is paid to take the food waste (WRAP 2013). Slurry is assumed to be cost neutral.
- Digestate is assumed to comply with PAS 110[48], and so be spread to land. Digestate is assumed to be cost neutral at the point of application.
- The total energy use is the ratio of feedstock energy to product energy. It includes loss of methane and biogas used for CHP.

Key uncertainties are:

- Capital costs. Capital costs assumed to be the same as for food waste, as pre-processing of food waste will be required and proportion of slurry will not require significant increase in digester capacity. Capital costs ranged from £1.7million to £7.2 million in the literature.
- Operating costs. These were sensitive to the gate fee achieved for the food waste (range -£25/tonne to -£42/tonne[49]). Sensitivity analysis was conducted on this parameter. Digestate disposal was assumed to be to land through arrangement with slurry suppliers and to be cost neutral. No GHG credit was assumed for the fertiliser replacement value of the digestate.

[47] Modelled on recent plant in the UK.
[48] http://www.wrap.org.uk/content/bsi-pas-110-specification-digestate
[49] Based on responses from AD plant operators

- GHG emissions associated with processing. These depend on the source of heat and electricity used for the processing. In the typical case it was assumed that heat requirements and some electricity requirements were met from on-site CHP using a proportion of the biogas produced, as in the food waste case. In the low emissions case a larger CHP unit is built to meet the larger heating demand associated with a higher volume slurry-based system. This produces surplus electricity which can then be exported or utilised on site for further biogas upgrading. No credit is given in the calculation for this surplus electricity. In the high case it is assumed that only heat requirements are met by a biogas boiler, and electricity is imported from the grid.
- GHG emissions from methane leakage. Leakage in all cases is assumed to be 1%. Higher leakage rates associated with incomplete processing or poor storage would substantially increase GHG emissions.

Table 2-12 Anaerobic digestion of a mixture of animal slurry and food waste

Parameter	Unit	Value			Key sources
		Typical	Low	High	
GHG emissions	CO2 as kgCO2eq/GJ	2.7	0.00	7.27	BIOGRACE 2013, JEC 2013
	CH4 as kgCO2eq/GJ	7.0	7.92	7.52	
	N2O as kgCO2eq/GJ	0.0	0.00	0.13	
	Total GHG as kgCO2eq/GJ	9.7	7.92	14.93	
Fuel use	MJ used/GJ	0		150	
Electricity use	MJ used /GJ	19		43	
Total energy use	MJ used /GJ	19		1946	
CAPEX costs	£/GJ	8.2			R-AEA 2013, Parsons Brinckerhoff 2013, NNFCC 2013
OPEX costs	£/GJ	-5.0			WRAP 2013
Total costs	£/GJ	3.2			
Efficiency of step	%	59%		51%	

2.6 Biogas upgrading

2.6.1 Biogas cleaning and CO2 removal to produce biomethane

2.6.1.1 Description

In this step CO_2 is removed from biogas produced in the anaerobic digester. Various technologies can be used, membrane separation, chemical scrubbing, water scrubbing and pressure swing adsorption. Of 34 projects in the UK that are planned and have identified their choice of technology the majority (21) are using membrane separation, 12 water scrubbing and one, chemical scrubbing. The process modelled here is the most common, membrane separation. The process uses semipermeable membranes to separate the biogas into a methane rich stream and a stream rich in CO_2.

The data provided assumes a system cleaning 1500m^3/hr. raw biogas with a methane content of 60%. The only external input is electricity for compression. This is typical of larger installations (for example in Germany) and is towards the upper end of the capacity range offered by suppliers.

A significant source of GHG emissions is through methane leakage, or slip equivalent to 0.5% of the product methane into the CO_2 rich stream that is normally vented to atmosphere.

2.6.1.2 Process parameters

The data for the costs, energy and emissions has been taken largely from the review of the technology by the Swedish Gas Centre (SGC, 2013) complemented by data supplied by UK industry (Confidential source, 2014[50]).

While costs and energy consumption are not expected to vary widely between technologies, methane slip does vary. For membrane separation as modelled here, methane slip is typically 0.5% but can be reduced to 0% by liquefaction of the carbon dioxide in the waste gas to recover 100% of the methane in the waste gas by cryogenic separation. Reported methane slip in pressure swing adsorption systems is reported as 1.8-2%, and modern, well operated water scrubber plants have a slip of about 1% (SGC, 2013). Methane slippage of 1% would increase emissions from this step to 8.2 kg CO_2/GJ and methane slippage of 2% would increase emissions to 14.2 CO_2/GJ.

Table 2-13Biogas cleaning and CO_2 removal to produce biomethane

Parameter	Unit	Typical Value	Key sources
GHG emissions	CO2 as kgCO2eq/GJ	2.2	
	CH4 as kgCO2eq/GJ	3.0	
	N2O as kgCO2eq/GJ		
	Total GHG as kgCO2eq/GJ	5.2	SGC, 2013
Total energy use	MJ used /GJ	45	
Total costs	£/GJ	3.4	
Efficiency of step	%	99.5%	

2.6.2 Conditioning and injection of Biomethane to the grid

2.6.2.1 Description

In this step biomethane, having had CO_2 and other impurities removed, is compressed, metered, and odourised. Its calorific value is adjusted by propane addition typically 3%, by volume. The gas is then compressed from 5 bar to 30 bar for injection into the local transmissions system (LTS).

It is also possible for biomethane to be injected into the medium pressure network. This has the advantage of not requiring the gas to be compressed, but potentially requires the addition of greater amounts of propane in order to meet the quality standards for this part of the network.

2.6.2.2 Process parameters

The emissions from the combustion of enrichment propane are added to the system emissions. Zero methane leakage is assumed as the system is fully sealed and has no vents. Cost and performance data is from SGC (2013), complemented by Baksteen (2013).

Compressor power usage was taken from manufacturer's data (RIX Industries, 2014).

Table 2-14 Conditioning and injection of Biomethane to the grid

Parameter	Unit	Typical Value	Key sources
GHG emissions	Total GHG as kgCO2eq/GJ	2.1	
Total energy use	MJ used /GJ	0.8	
Total costs	£/GJ	1.4	
Efficiency of step	%	100%	

[50] Here, the industry respondent did not wish to be identified.

2.6.3 Biomethane Liquefaction

2.6.3.1 Description

Here the gaseous form of methane produced from anaerobic digestion is reduced to a liquid via a cooling process. In liquid form the biomethane occupies only 1/600th of its gaseous volume, while for it to be in liquid form a temperature of around -162°C is required. This liquefied biomethane is then stored in large insulated tanks, prior to transportation to the dispensing point.

2.6.3.2 Process Parameters

Energy use of liquefaction is assumed to be 5% of its energy content[51]. While large-scale liquefaction of natural gas is an established technology, small-scale liquefaction of biomethane is a very new concept and as such cost reduction and efficiency improvements will occur over time. The below analysis has incorporated these accordingly. For example current LBM producers suggested 10% energy use for current processing but 5% in the longer term[51].

Table 2-15 Biomethane Liquefaction

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ		
	CH4 as kgCO2eq/GJ		
	N2O as kgCO2eq/GJ		
	Total GHG as kgCO2eq/GJ	2.5	DECC, 2014 & Gasrec[52]
Fuel use	MJ used/GJ		
Electricity use	MJ used /GJ	50.0	
Total energy use	MJ used /GJ	50.0	Personal Communications[51]
CAPEX costs	£/GJ	4.4	Lantau Group, 2012
OPEX costs	£/GJ	1.5	Lantau Group, 2012
Total costs	£/GJ	5.9	Lantau Group, 2012
Efficiency of step	%	100%	

2.7 Fossil gas supply

2.7.1 Natural Gas

2.7.1.1 Description

This step refers to production of gas up to its injection to the grid. Natural gas considered here is "conventional" gas, i.e. that which is trapped in porous rocks below an impermeable layer. It is often found alongside oil and usually under pressure. The extraction is performed via a "well" which taps into the gas source.UK gas currently comes mainly from the North Sea fields.

Looking forwards, OFGEM in a recent report for the Government on security of supply issues for gas, considered that, as production from the UK continental shelf continues to decline, the most likely source of additional gas supply is imported LNG (OFGEM, 2012). Imports of gas from Europe via the existing interconnectors are unlikely to increase significantly. Imports of LNG are considered separately in this study.

Energy required for step was sourced accordingly, based on the JEC WTT study (JEC, 2013). However the value is scaled down to take into account the shorter distance to the UK from the gas fields in the North Sea than is assumed in the JEC study for gas supplied to Europe.

[51] Based on personal communications with Lidkoping and Gasrec, February 2014.
[52] Based on personal communications with Gasrec, February 2014.

2.7.1.2 Process parameters

Data for energy and emissions (typical values) are based on JEC, 2013, but are adjusted (as in Ricardo, 2013), to account for the shorter pipeline distance to bring gas from the North Sea to the UK compared to the pipeline distances assumed for European supply in JEC, 2013. Additional data for low and high values are based on McKay, 2013, which reviewed a number of studies of upstream gas emissions.

Costs in this step are based on the wholesale, 'beach price' forecast by DECC (2013) for natural gas in 2025.

Table 2-16: Data for Natural gas supply

Parameter	Unit	Value			Key sources
		Typical	Low	High	
GHG emissions	CO_2 as $kgCO_2eq/GJ$	4.2			JEC, 2013
	CH_4 as $kgCO_2eq/GJ$	4.2			JEC, 2013
	N_2O as $kgCO_2eq/GJ$	0.03			JEC, 2013
	Total GHG as $kgCO_2eq/GJ$	8.4	2.5	16.7	JEC, 2013, Ricardo, McKay, 2013
Total energy use	MJ used /GJ	84			JEC, 2013
Total costs	£/GJ	7.0			DECC, 2013 & LowCVP 2011
Efficiency of step	%	99%			JEC, 2013

2.7.2 Shale Gas

2.7.2.1 Description

This step refers to production of shale gas up to its injection to the grid. Shale gas is similar in composition to natural gas, but is considered an "unconventional" gas due to the processes required to extract it. Shale gas occurs in low-permeability sediments such as shale, mudstones, etc., and to extract it the rock is fractured with high pressure fluid.

Sources of emissions in the process of shale gas extraction are: venting of methane and CO_2, emissions from combustion of fossil fuels onsite, and fugitive emissions. The level of emissions per unit of energy will depend on the processes of extraction, as well as the well size. One of the main factors affecting emissions from this process is the level of venting, which can vary from 100% vented (worst case), to 100% capture.

2.7.2.2 Process parameters

Emissions data was taken from McKay, 2013. For all scenarios in this study, the scenario where 90% of gas is captured and flared was used, as it is considered that by 2025, regulation would be in place to minimise GHG emissions from shale gas extraction. The high and low figures indicate the range within this scenario (e.g. due to variations in well size). Energy values are taken JEC, 2013.

It is assumed that to be commercial, shale gas production would need to be competitive with natural gas from conventional sources. The cost of shale gas production is therefore set to that of natural gas.

Table 2-17: Data for shale gas

Parameter	Unit	Value			Key sources
		Typical	Low	High	
	Total GHG as kgCO2eq/GJ	5.6	2.8	17.5	McKay, 2013
Fuel use	MJ used/GJ	0.02			JEC 2013
Electricity use	MJ used /GJ	0.1			JEC 2013
Total energy use	MJ used /GJ	17.7			JEC 2013
Total costs	£/GJ	7.0			Low CVP study, 2011
Efficiency of step	%	99%			McKay, 2013

2.7.3 LPG

2.7.3.1 Description

Here, LPG is assumed to be produced from natural gas[53] (in line with JEC, 2013), and in line with data on sources of LPG for the UK. Natural gas sourced from the ground contains around 1-10% ethane, butane and propane, with the remaining molecules being methane and condensates (such as hydrogen sulphide and carbon dioxide). These gases must be separated out prior to the sale of methane, and this occurs via a fractionalisation process. Butane and propane are separated out and compressed until the gases change into a liquid. This liquid is sold as LPG. In the UK, the main source of LPG from gas is gas from the UK Continental Shelf in the North Sea.

2.7.3.2 Process Parameters

For the analysis, GHG emission and fuel use data for the natural gas extraction stage (including transport to the UK) are as for UK gas production. Data on the production of LPG from the gas are taken from JEC, 2013. There was limited data available on the costs of producing LPG[54]. The total costs provided below are therefore calculated from a retail price of LPG (based on HMRC guidance on advisory fuel rates for company cars[55]) minus, duty, VAT and an estimated retailer margin of £3.5/GJ. To obtain a cost in 2025, the resulting value is increased by the percentage increase in natural gas prices to 2025 forecast by DECC.

Table 2-18 LPG

Parameter	Unit	Typical Value	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	4.52	JEC, 2013
	CH4 as kgCO2eq/GJ	4.17	JEC, 2013
	N2O as kgCO2eq/GJ	0.03	JEC, 2013
	Total GHG as kgCO2eq/GJ	8.72	JEC, 2013
Fuel use	MJ used/GJ	89.2	JEC, 2013
Electricity use	MJ used /GJ		JEC, 2013
Total energy use	MJ used /GJ	89.2	JEC, 2013
CAPEX costs	£/GJ		
OPEX costs	£/GJ		
Total costs	£/GJ	17.5	HMRC[55]
Efficiency of step	%	99%	

[53] LPG can be produced from either the refining of crude oil or the processing of natural gas. 60% of global LPG is produced from the processing of natural gas, and in Europe this figure is approximately 47%.

[54] Data was available for the price of LPG at Rotterdam, but this does not factor in the breaking of bulk delivery, further transport to the UK, and markup.

[55] http://www.hmrc.gov.uk/cars/advisory_fuel_current.htm

2.7.4 LNG Production

2.7.4.1 Description

This step includes LNG production and import by sea, storage at the import terminal and loading on to a road tanker. Gas extraction and processing is assumed to occur near the wellhead. Liquefaction is performed at the remote location

The LNG is then transported by an LNG carrier over sea and stored at port for collection and delivery in its liquefied form by road tankers.

2.7.4.2 Process parameters

For this analysis energy and emissions values are obtained from JEC, 2013. Cost projections are based on the gas price in 2025 and an additional liquefaction and transport component. The latter are based on data from the US EIA[56], as used in Ricardo-AEA, 2013a.

Table 2-19: Data for LNG production and storage

Parameter	Unit	Typical value	Key sources
GHG emissions	CO_2 as $kgCO_2eq/GJ$	12.2	JEC, 2013
	CH_4 as $kgCO_2eq/GJ$	3.7	JEC, 2013
	N_2O as $kgCO_2eq/GJ$	0.1	JEC, 2013
	Total GHG as $kgCO_2eq/GJ$	16.0	JEC, 2013
Total energy use	MJ used /GJ	190	JEC, 2013
Total costs	£/GJ	8.3	DECC 2013; EIA, 2003
Efficiency of step	%	96%	JEC, 2013

2.7.5 LNG production and injection to grid

2.7.5.1 Description

This step includes LNG production, import by sea, and evaporation for injection to grid. Gas extraction and processing is assumed to occur near the wellhead. Liquefaction is performed at the remote location. The LNG is then transported by an LNG carrier by sea and evaporated into gaseous form for injection to grid at the import terminal.

2.7.5.2 Process parameters

In terms of the below analysis energy and emissions values are from JEC, 2013. As in 2.7.4, cost projections are based on the gas price in 2025, and an additional liquefaction, transport component to which is added the cost of vaporisation.

Table 2-20: Data for LNG production and injection to grid

Parameter	Unit	Typical value	Key sources
GHG emissions	CO_2 as $kgCO_2eq/GJ$	13.4	JEC, 2013
	CH_4 as $kgCO_2eq/GJ$	3.7	JEC, 2013
	N_2O as $kgCO_2eq/GJ$	0.1	JEC, 2013
	Total GHG as $kgCO_2eq/GJ$	17.2	JEC, 2013
Total energy use	MJ used /GJ	223	JEC, 2013
Total costs	£/GJ	8.5	DECC 2013; EIA, 2003
Efficiency of step	%	96%	JEC, 2013

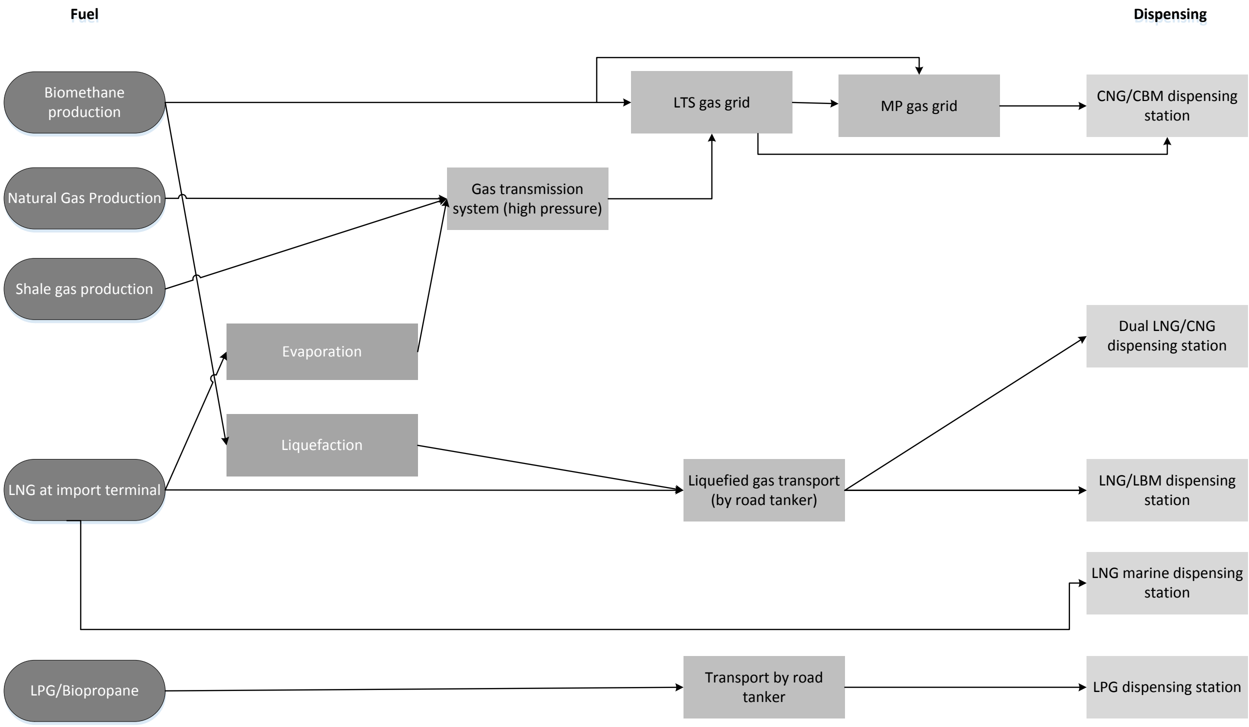
56 http://www.eia.gov/oiaf/analysispaper/global/lngindustry.html

3 Fuel Delivery and Dispensing

3.1 Gaseous fuels

Fuel delivery and dispensing routes for gaseous fuels are shown in Figure 3.1. Each step is described in the following sections.

Figure 3.1 Routes for delivery and dispensing of gaseous fuels



Notes:
1) Injection into the distribution grid and gas take off from the distribution grid for filling stations can occur at a variety of pressures depending where in the grid the connection is made
2) As well as dispensing equipment, CNG dispensing stations will include compressor and storage/buffer storage and LNG stations cryogenic storage tank and pumps

3.1.1 Pipeline distribution

This step covers the transmission and distribution of gas (high and low pressure) from import terminal to retail terminal. Four cases are considered:

- Natural gas – transmission in the high pressure transmission network followed by distribution in the LTS to a retail point off taking gas from the LTS
- Natural gas - transmission in the high pressure transmission network and followed by distribution in the LTS and MP to a retail point off taking gas from the MP network
- Biomethane – distribution in the LTS to a retail point off taking gas from the LTS
- Biomethane – distribution in the LTS and MP to a retail point off taking gas from the MP network

3.1.1.1 Process parameters

The UK GHG Inventory (Webb et al, 2013, GBR, 2011) provides estimates of emissions of GHGs from both the transmission and distribution of gas. In the case of distribution, emissions were further allocated between the LTS, IP>MP and low pressure parts of the network based on information from National Grid[57].

Distribution costs are taken as £0.7/GJ based on data from LowCVP, 2011, adjusted to account for forecast increases in the cost of gas.

Table 3-1: Data for gas pipeline

Parameter	Unit	Natural gas LTS	Natural gas MP	Bio-methane LTS	Bio-methane MP
GHG emissions	CO_2 as $kgCO_2eq/GJ$	0.0003	0.0007	0.0001	0.0006
	CH_4 as $kgCO_2eq/GJ$	0.2178	0.6043	0.1104	0.4969
	N_2O as $kgCO_2eq/GJ$	0.0000	0.0000	0.0000	0.0000
	Total GHG as $kgCO_2eq/GJ$	0.2181	0.6050	0.1105	0.4975
Efficiency of step	%	99%	99%	99%	99%

3.1.2 Road tanker transport – LNG and Biomethane

3.1.2.1 Description

The transportation of liquefied natural gas (fossil) is from an LNG import terminal, such as the Isle of Grain, to a retail refuelling station. This is undertaken via a diesel fuelled heavy goods vehicle, with a 50m^3 insulated tank capable of carrying approximately 20 tonnes of LNG. This is a highly insulated and pressurised storage vessel, which minimises the LNG ‘boil off’ into gaseous form.

The transportation of liquefied biomethane is similar, from the production site to retail point in a specially designed road tanker.

3.1.2.2 Process Parameters

GHG emissions and energy use are based on emissions from transport of LNG in JEC, 2013, but assuming a 250km journey rather than the 500 km journey assumed in JEC, 2013. This reflects the shorter transport distances likely in the UK compared to mainland Europe. The original study makes an allowance for a return journey with an empty tanker. Cost estimates were obtained from APEC, 2011, but confidence in this data for the European situation is not high as the original data is relevant for Asian Pacific economies and caution is therefore required as this report does not refer to a European transportation situation.

Table 3-2 Road Tanker Transport – LNG and Biomethane

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.6	JEC, 2013
	CH4 as kgCO2eq/GJ	1.4	JEC, 2013
	N2O as kgCO2eq/GJ	0.0	JEC, 2013
	Total GHG as kgCO2eq/GJ	2.0	JEC, 2013
Fuel use	MJ used/GJ	1.7	
Electricity use	MJ used /GJ	0	
Total energy use	MJ used /GJ	1.7	
Total costs	£/GJ	0.46	APEC, 2011
Efficiency of step	%	100%	

[57] Personal communication with R Malin from National Grid in February 2014.

3.1.3 Road tanker transport – LPG and biopropane

3.1.3.1 Description

The transport of LPG from an LPG import terminal, or for biopropane from a UK based production plant to a retail refuelling station, by road in a pressurised tanker.

3.1.3.2 Process Parameters

As for the road transport of LNG, GHG estimates are taken from JEC, 2013, but assuming a 250 km rather than 500 km journey. Due to a lack of data on transport costs for LPG, these are included in refuelling costs.

Table 3-3 Road tanker transport of LPG to retail point

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.65	
	CH4 as kgCO2eq/GJ	0.01	
	N2O as kgCO2eq/GJ	0.01	
	Total GHG as kgCO2eq/GJ	0.66	JEC, 2013
Fuel use	MJ used/GJ	8.9	JEC, 2013 Ricardo-AEA calculations
Electricity use	MJ used /GJ	0	
Total energy use	MJ used /GJ	8.9	Ricardo-AEA calculations
Total costs	£/GJ		
Efficiency of step	%	100%	

3.1.4 Dispensing of LNG from retail station

3.1.4.1 Description

In this step the LNG (from the road tanker) is transferred to a large, above-ground, insulated storage vessel at the refuelling station. LNG is then pumped from the storage vessel, through a dispenser, into the vehicle.

3.1.4.2 Process Parameters

GHG emissions are based on JEC, 2013, and capture the emissions associated with electricity consumption and a small amount of methane leakage. CAPEX and OPEX costs are based on those in LowCVP, 2011. This assumes 2000kg/ day of product is dispenses from the fuelling station (the middle scenario in the LowCVP analysis).

Table 3-4 Dispensing of LNG from retail station

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.0	JEC 2013
	CH4 as kgCO2eq/GJ	0.01	JEC 2013
	N2O as kgCO2eq/GJ	0.0	JEC 2013
	Total GHG as kgCO2eq/GJ	0.01	JEC 2013
Fuel use	MJ used/GJ		
Electricity use	MJ used /GJ		
Total energy use	MJ used /GJ	0.1	LowCVP, 2011
CAPEX costs	£/GJ	0.7	LowCVP, 2011
OPEX costs	£/GJ	1.0	LowCVP, 2011
Total costs	£/GJ	1.7	LowCVP, 2011
Efficiency of step	%	100	JEC 2013

3.1.5 Dispensing LPG and biopropane from retail station

3.1.5.1 Description

In this step, the LPG is stored on site in a liquid form in underground tanks, which can be on the site of an existing refuelling station. The LPG is then dispensed to the vehicle. The same approach is applied to biopropane.

3.1.5.2 Process Parameters

The energy use and GHG emission data are obtained from JEC, 2013 and reflect the energy (electricity) use and methane loss. The data on total costs for LPG refuelling were based on the breakdown of LPG sale costs in Australia (ACCC, 2012), as no data could be found I the literature on the costs of refuelling. The costs used here is the retailer margin, and is assumed to include the costs of transporting LPG as well as the cost of refuelling infrastructure.

Table 3-5 LPG from retail station

Parameter	Unit	Typical Value	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.5	JEC, 2013
	CH4 as kgCO2eq/GJ	0.0	JEC, 2013
	N2O as kgCO2eq/GJ	0.0	JEC 2013
	Total GHG as kgCO2eq/GJ	0.5	JEC, 2013
Total energy use	MJ used /GJ	0.01	JEC, 2013
CAPEX costs	£/GJ		
OPEX costs	£/GJ		
Total costs	£/GJ	3.15	ACCC, 2012
Efficiency of step	%	100%	

3.1.6 Dispensing as CNG / compressed biomethane from LTS Grid

3.1.6.1 Description

The dispensing of compressed natural gas/biomethane at a dedicated compressed natural gas/biomethane refuelling station. This station constructed close to the LTS part of the network, which has a pressure of 7 to 50 bar. Some additional compression on site is required to ensure the gas is compressed to the required levels for dispensing. Electrical pumps are used to compress the gas, and no natural gas is consumed in the process.

3.1.6.2 Process Parameters

CAPEX, and OPEX costs, and energy use is based on estimates provided by the Renewable Energy Association[58], for a station taking gas from the LTS at 30 bar pressure. Note at present, there are no CNG refuelling facilities using gas from the LTS grid, so the data is an engineering estimate.

GHG emissions are estimated on electricity consumption for compression estimated by the REA, and an emissions factor for electricity supply in 2025.

[58] Personal communication provided to Ricardo-AEA from Renewable Energy Association, March 2014.

Table 3-6 Dispensed CNG from LTS grid

Parameter	Unit	Typical Values	Key Sources
GHG emissions	Total GHG as kgCO2eq/GJ	0.4	REA, 2014[58] DECC, 2014
Fuel use	MJ used/GJ	0.0	REA, 2014[58]
Electricity use	MJ used /GJ	7.5	REA, 2014[58]
Total energy use	MJ used /GJ	7.5	REA, 2014[58]
CAPEX costs	£/GJ	0.6	REA, 2014[58]
OPEX costs	£/GJ	0.9	REA, 2014[58]
Total costs	£/GJ	1.5	REA, 2014[58]
Efficiency of step	%	100	

3.1.7 Dispensing as CNG/ compressed biomethane from MP Grid

3.1.7.1 Description

The dispensing of compressed natural gas/biomethane is at a dedicated compressed natural gas/biomethane refuelling station. This station is constructed close to the medium pressure grid. Significant additional compression on site is required to ensure the gas is compressed to the required levels for dispensing. Electrical pumps are used to compress the gas, and no natural gas is consumed in the process.

CAPEX, and OPEX costs, and energy use is based on estimates provided by the Renewable Energy Association[59], for a station taking gas from the medium pressure network at 0.25 bar pressure GHG emissions are estimated on electricity consumption for compression estimated by the REA, and an emissions factor for electricity supply in 2025. The level of accuracy for the estimates is higher than LTS based reflecting the greater, real life, experience in Compressing Natural Gas from the Medium Pressure Grid.

3.1.7.2 Process Parameters

Table 3-7 Dispensing CNG from MP Grid

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ		
	CH4 as kgCO2eq/GJ		
	N2O as kgCO2eq/GJ		
	Total GHG as kgCO2eq/GJ	1.1	REA[58] DECC, 2014
Fuel use	MJ used/GJ	0.0	REA[58]
Electricity use	MJ used /GJ	22.6	REA[58]
Total energy use	MJ used /GJ	22.6	REA[58]
CAPEX costs	£/GJ	1.4	REA[58]
OPEX costs	£/GJ	2.5	REA[58]
Total costs	£/GJ	3.9	REA[58]
Efficiency of step	%	100	

3.2 Liquid fuels

The delivery and dispensing of liquid fuels are considered below. These are:

- Bioethanol
- Mixed bio-alcohols
- Biomass to liquid (BtL) diesel
- Biomass to liquid (BtL) jet Fuel

[59] Personal communication provided to Ricardo-AEA from Renewable Energy Association, March 2014.

- Bio-oil

Storage and distribution is considered first, followed by dispensing. For bioethanol and bioalcohol only blending at relatively low levels is considered. Biomass to liquid diesel and jet fuel are 'drop-in' replacements for diesel and jet so can use the same distribution and dispensing infrastructure as conventional diesel and jet fuel.

3.2.1 Storage and Distribution of Bioethanol, Mixed Bio-alcohols BtL diesel

3.2.1.1 Description

These liquid fuels are stored at the production site, then distributed to a blending facility, where a low percentage fuel blend is produced and then delivered to a retail outlet. In both cases the fuel is transported by road tanker.

3.2.1.2 Process Parameters

In the below analysis the GHG emission and energy use data is from JEC (2013). Note only the total of GHG emission was available. An estimate of 150km has been used for the travel distance between the production facility and the retail point, in line with JEC (2013).

Limited data availability resulted in Ricardo-AEA calculations of infrastructure costs, these were based on Ricardo-AEA (2013).

Table 3-8 Storage and distribution of bioethanol, and mixed bio-alcohols

Parameter	Unit	Typical Value	Key Sources
GHG emissions	Total GHG as kgCO2eq/GJ	1.7	JEC, 2013
Fuel use	MJ used/GJ	1.3	JEC, 2013
Electricity use	MJ used /GJ	0.8	JEC, 2013
Total energy use	MJ used /GJ	2.1	JEC, 2013
Total costs	£/GJ	0.2	Ricardo-AEA calculations
Efficiency of step	%	100%	

Table 3-9 Storage and distribution of BtL diesel

Parameter	Unit	Typical Value	Key Sources
GHG emissions	Total GHG as kgCO2eq/GJ	1.4	JEC, 2013
Fuel use	MJ used/GJ	1.3	JEC, 2013
Electricity use	MJ used /GJ	0.8	JEC, 2013
Total energy use	MJ used /GJ	2.1	JEC, 2013
OPEX costs	£/GJ		
Total costs	£/GJ	0.2	Ricardo-AEA calculations
Efficiency of step	%	100%	

3.2.2 Storage and distribution of BtL jet fuel

3.2.2.1 Description

The storage of BtL jet fuel on the production site, followed by the transportation to a central blending plant where the BtL jet fuel is blended with kerosene, and then distributed to the airport bunker. Tanker trucks are the mode of transport that delivers the fuel from the production facility to the airport.

3.2.2.2 Process Parameters

Data is not readily available for this step, and so estimates have been made based on the emissions, energy use and costs for the storage and distribution of BtL Diesel (see Table 3-9).

3.2.3 Storage and distribution of bio-oil

3.2.3.1 Description

The storage of bio-oil is on the fuel production site, followed by the transportation to a blending facility. Here it is assumed that bio-oil is blended with marine fuel oil. While this is not currently permissible reflecting the purposive limited consideration of marine fuels in this study, the informed simplifying assumption that it would be permitted by 2025 was applied. The oil is then transported to the location of marine bunker through the use of tanker trucks.

3.2.3.2 Process Parameters

Data is not readily available for this step, and so estimates have been made based on the emissions, energy use and costs for the storage and distribution of BtL Diesel (Table 3-9).

3.2.4 Dispensing of bioethanol and mixed bio-alcohols at filling station

3.2.4.1 Description

The dispensing of bioethanol-and mixed bio-alcohols petrol blend from a forecourt refuelling station is directly into the vehicle (motorcycle, car, or van). As discussed previously it is assumed the blend will be of low percentage and so no changes are required to the fuelling infrastructure.

3.2.4.2 Process Parameters

The analysis was based on Emission, Energy Use and Fuel use data from JEC (2013) while cost data were from the UK Petroleum Industry Association (UKPIA, 2012).

It is assumed that a low percentage bioethanol blend will not require any changes to the current retail refuelling infrastructure.

Table 3-10 Dispensing of bioethanol at filling station

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.5	JEC, 2013
	CH4 as kgCO2eq/GJ	0.03	JEC 2013
	N2O as kgCO2eq/GJ	0.0	JEC, 2013
	Total GHG as kgCO2eq/GJ	0.6	JEC, 2013
Fuel use	MJ used/GJ	11.8	JEC, 2013
Electricity use	MJ used /GJ	3.4	JEC, 2013
Total energy use	MJ used /GJ	15.2	JEC, 2013
Total costs	£/GJ	1.5	UK PIA, 2012
Efficiency of step	%	100%	

3.2.5 Dispensing of BtL diesel at filling station

3.2.5.1 Description

The dispensing of BtL diesel, in a low percentage fossil diesel blend from a retail refuelling station, to a road vehicle such as a car, van or heavy goods vehicle. Here it is assumed that the low percentage blend will mean no changes are required to the refuelling infrastructure.

3.2.5.2 Process Parameters

The emission and energy use data is gathered from JEC (2013) and the costs are taken from the UK Petroleum Industry Association. Here, values are taken to be the same as for diesel refuelling reflecting that a low percentage BtL diesel blend will not require any changes to the current retail refuelling infrastructure.

Table 3-11 Dispensing of BtL diesel at filling station

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.5	JEC, 2013
	CH4 as kgCO2eq/GJ	0.0	JEC, 2013
	N2O as kgCO2eq/GJ	0.0	JEC, 2013
	Total GHG as kgCO2eq/GJ	0.5	JEC, 2013
Fuel use	MJ used /GJ	11.0	JEC, 2013
Electricity use	MJ used /GJ	3.4	JEC, 2013
Total energy use	MJ used /GJ	14.4	JEC, 2013
Total costs	£/GJ	1.4	UK PIA, 2012
Efficiency of step	%	100%	

3.2.6 Dispensing of BtL Jet fuel at airport

3.2.6.1 Description

For this step fuel is dispensed from a fuel bunker storage to a tanker truck. This truck drives to the parked aircraft where it delivers the jet fuel directly onto the aircraft via hoses.

3.2.6.2 Process Parameters

It is assumed that there are no changes required to existing fuelling infrastructure. Reflecting the limited data availability on this step and the focus of this study on road transport modes rather than aviation a simplified approach to estimates was taken based on the fuelling cost for road vehicles (Table 3-11).

3.2.7 Dispensing of marine bio-oil at port

3.2.7.1 Description

Marine bio-oil is blended with fossil oil and dispensed from a bunker storage tank to a ship via a small bunker ship. Here the bunker vessel is fuelled at the portside with fuel oil, where it moors alongside the ship and delivers the fuel to the vessel.

3.2.7.2 Process Parameters

No data was readily available on the cost of dispensing marine fuel oils. As shipping is not the focus of the study, a simplifying assumption was made that dispensing costs would be similar to those of dispensing diesel to vehicles. Data on fuel use of bunkering vessels is based on IVL (2013). While GHG emissions are derived from the fuel use in ship operation caution is therefore required with regard to the energy use figures.

Table 3-12 Dispensing of marine bio-oil at port

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.01	Chalmers, 2011
	CH4 as kgCO2eq/GJ	0.0	Chalmers, 2011
	N2O as kgCO2eq/GJ	0.0	Chalmers, 2011
	Total GHG as kgCO2eq/GJ	0.01	Chalmers, 2011
Fuel use	MJ used/GJ	0.00007	IVL, 2013
Electricity use	MJ used /GJ		
Total energy use	MJ used /GJ	0.00007	
Total costs	£/GJ	1.4	Diesel dispensing costs this study
Efficiency of step	%	100%	

3.2.8 Dispensing CNG / Compressed Biomethane, delivered in liquid form

3.2.8.1 Description

In this step, processes for a liquefied-compressed natural gas (LCNG) station are considered. A LCNG station combines LNG and CNG in one station. LNG vehicles are fuelled in the same way as at an LNG station. To produce CNG, the LNG is pumped into a vaporizer that converts it from liquid to gas in a controlled way so that it can be dispensed at the right pressure as CNG.

3.2.8.2 Process Parameters

The GHG emissions and energy use data are obtained from JEC (2013).

CAPEX and OPEX costs are provided from LowCVP (2011), which assumes 2000kg/day of product dispensed (the mid-point in range explored)

Table 3-13 Dispensing of CNG/Biomethane at retail point from delivered LNG/LBM.

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	1.5	JEC, 2013
	CH4 as kgCO2eq/GJ	0.0	JEC 2013
	N2O as kgCO2eq/GJ	0.0	JEC 2013
	Total GHG as kgCO2eq/GJ	1.6	JEC 2013
Fuel use	MJ used/GJ	19.4	JEC 2013
Electricity use	MJ used /GJ	3.4	JEC, 2013
Total energy use	MJ used /GJ	22.8	JEC, 2013
CAPEX costs	£/GJ	1.3	LowCVP, 2011
OPEX costs	£/GJ	2.5	LowCVP, 2011
Total costs	£/GJ	3.8	LowCVP, 2011
Efficiency of step	%	100	

3.2.9 Dispensing liquefied biomethane at retail point

3.2.9.1 Description

The dispensing of liquefied biomethane at a designated LNG/LBM fuelling station involves receiving the biomethane in liquid form, storing it on site in liquid form and dispensing the liquid to heavy goods vehicles.

3.2.9.2 Process Parameters

The GHG emissions and energy consumption data are taken directly from JEC (2013) with the emissions based electricity consumption and methane leakage.

The cost of dispensing the LNG is based on the LowCVP (2011), the data assumes an LNG/LBM station that dispenses 2000kg/day of product, the LowCVP (2011) mid-point scenario.

Table 3-14 Dispensing liquefied biomethane at retail point

Parameter	Unit	Typical Values	Key Sources
GHG emissions	CO2 as kgCO2eq/GJ	0.004	JEC, 2013
	CH4 as kgCO2eq/GJ	0.006	JEC, 2013
	N2O as kgCO2eq/GJ	0.00	JEC, 2013
	Total GHG as kgCO2eq/GJ	0.01	JEC, 2013
Fuel use	MJ used/GJ		JEC, 2013
Electricity use	MJ used /GJ		JEC, 2013
Total energy use	MJ used /GJ	0.1	JEC, 2013
CAPEX costs	£/GJ	0.7	LowCVP, 2011
OPEX costs	£/GJ	1.0	LowCVP, 2011
Total costs	£/GJ	1.7	LowCVP, 2011
Efficiency of step	%	100	JEC, 2013

4 Use for Heat and Power

In order to allow comparison of use Biogas and residual waste for transport fuels with their use to produce heat and power the following fuel pathways were also examined in the study. As well as biogas and waste, pathways using natural gas are also analysed, as these provide the comparator, against which savings can be calculated (Table 4-1).

Table 4-1 Heat and power routes to be analysed

Feedstock	Initial conversion	Intermediate product	Upgrading	End use conversion	Product
Food waste	AD plant	Biogas		Gas engine	Electricity
Food waste	AD plant	Biogas		Small CHP unit	Electricity and heat
Food waste	AD plant	Biogas	Injection to grid	CCGT plant	Electricity
Food waste	AD plant	Biogas	Injection to grid	Large CHP plant	Electricity and heat
Food waste	AD plant	Biogas	Injection to grid	Domestic Boiler	Heat
Residual waste	Landfill	Biogas		Gas engine	Electricity
Residual waste				Energy from waste (power only)	Electricity
Residual waste				Energy from waste (CHP)	Electricity and heat
Natural gas				CCGT plant	Electricity
Natural gas				CHP plant	Electricity and heat
Natural gas				Domestic Boiler	Heat

The key characteristics and CAPEX and OPEX costs for each of heat and power conversion routes are shown in Table 4-2. OPEX costs include fixed and variable costs; variable costs have been converted to a per kW per year basis based on size and load factor shown. Costs associated with biogas and residual waste are as for the transport pathways analysis detailed in Sections 2 and 3 of this Appendix.

Table 4-2 Cost and operating characteristics of heat and power plant

Technology	Typical size (MWe)	Net LHV efficiency		Availability / load factor	CAPEX (£/kW)	OPEX (£/kW/ year)	Source	Notes
		Electrical	Heat					
Landfill gas in gas engine	1	35%		58%	2130	127	Costs: DECC, 2013 Load Factor, National Grid, 2012	
Biogas from AD plant in gas engine	1	38%		84%	967	101	Costs: SKM Enviros, 2011;	CAPEX costs for gas engine and other (not including digester) OPEX costs for gas engine, plus insurance at 1% of CAPEX)
Biogas from AD plant in small CHP unit	1	38%	43%	84%	1,396	101	Costs: SKM Enviros, 2011; Load Factor, National Grid, 2012	CAPEX costs for gas engine and other (not including diegester) OPEX costs for gas engine, plus insurance at 1% of CAPEX)
Energy from waste - power only	25	24%		85%	4,800	408	DECC, 2013	Size and availability not specified in original report; AEA estimated based on new plant
Energy from waste - CHP	25	20%	40%	85%	6,100	492	DECC, 2013,	Size and availability not specified in original report; AEA estimated based on new plant
Generation from natural gas in CCGT	900	58.8%		93%	610	32	DECC, 2013	
Natural gas in CHP plant	86.5	45%	27%	64%	650	56	DECC, 2013	
Technology	**Typical size (kW th)**	**Electrical**	**Heat**	**Availability / load factor**	**CAPEX (£/kW)**	**OPEX (£/kW/ year)**	**Source**	**Notes**
Domestic gas boiler	20		94%	9%	137.5	9	AEA, 2012	

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Appendix 3 – Use of waste and gaseous fuels in vehicles

This appendix describes the steps taken to examine the use of biofuels and gaseous fuels in vehicles. Chapter 2 identifies the vehicle types included in the study; Chapter 3 summarises the ways these fuels could be used in these vehicles: Chapter 4 describes the additional costs of using these fuels; Chapter 5 describes the fuel economy / efficiency and Chapter 6 provides the tail-pipe emissions of CH_4 and N_2O.

Vehicles chosen for study

The principal objective of this study is to consider the “well-to-wheel” options for gaseous and waste-derived fuels. This involves the three key areas of fuel production, the associated infra-structure and the end use of the fuels. Such an analysis requires the identification of “end users”, i.e. vehicles that can use these gaseous and waste derived fuels. These were chosen to:

- Encompass the way methane can be used in vehicles, using both dedicated spark ignition (SI) engines, and dual fuel compression ignition (CI) engines;
- Reflect the range of vehicle sizes that might use these fuels, from passenger cars through to buses and large trucks;
- Include more contemporary, recently developed models. Since the study is considering the effectiveness of options for decarbonising the transport sector in 2025, it be inappropriate to use automotive technology that is already becoming superseded;
- Cover a range of different manufacturers;
- Include vehicles which have a direct comparator (conventionally fuelled) vehicle to provide a baseline against which changes in price or emissions can be assessed.

The list of vehicle types included in the analysis is shown in Table 1. This is not an exhaustive list of all vehicle types that could use gaseous fuels and biofuels, but is intended to give a good representation across different types of vehicles and provide evidence based examples from new models available on the market now. As well as the broad category of vehicle studied, the table shows specific examples of the type of vehicle modelled. For each type of vehicle, an example of the same model of vehicle running on conventional liquid fuels is included to allow estimation of the CO_2 savings offered by the gaseous fuels and biofuels relative to the fossil fuelled alternative. The range of the vehicle when running on alternative fuels and on conventional fuels, is shown. In most cases for bifuel vehicles[60], although the range on gas may be lower, manufacturers have sought to ensure that the petrol tank included in the vehicle is large enough to maintain range.

[60] Bifuel vehicles have two independent fuel systems (one of them for natural gas) and can run on either fuel, but only on one at a time. Dual fuel vehicles also have two independent fuel systems (one of them for natural gas), but can run on both fuels simultaneously. Dual fuel vehicles may also run on one fuel alone.

Table 1 Vehicle types included in the analysis

Vehicle type	Engine type	Fuel(s)	Additional notes	Different engine from comparator vehicle?	Vehicle selected	Comparator vehicle	Range	Range comparator vehicle
Passenger car	SI	CNG, CBM		Yes	VW Golf 1.4 TGI Blue Motion	VW Golf 1.4 TSI Blue Motion petrol	420 (gas) 940 (petrol) 1360 (total)	940
Passenger car	SI	LPG, bio-propane Bio-ethanol, mixed bio-alcohols	Blended at levels up to 10% for ethanol (and up to 15% for others)	Yes No	Vauxhall Astra SRI 1.6 litre petrol conversion Comparator vehicle	Vauxhall Astra SRI 1.6 litre petrol	715	725
Small van (LDV)	SI	CNG, CBM	OEM vehicle selected aftermarket conversions also used	Yes	Fiat Doblo Cargo	Fiat Doblo Cargo	370 (gas) 255 (petrol) 625 (total)	700
Large van (LDV)	SI	CNG, CBM	OEM vehicle selected		Mercedes-Benz Sprinter 316 NGT	Mercedes-Benz Sprinter 316	920 (gas) 150 (petrol) 1070 (total)	860
	CI	BtL diesel	Direct replacement fuel, used instead of, or with, pump diesel	No	Comparator vehicle		860	860
Medium size rigid truck (HDV)	SI	CNG, CBM	Vehicle typically used for urban delivery	Yes	Iveco Eurocargo (12-16 tonne) 120E20L CNG 4815	Iveco Eurocargo (12-16 tonne) 120E20L 4815 150 kW	480 (gas) 90 (petrol) 570 (total)	505
Refuse collection vehicle (HDV)	SI	CNG, CBM	This dedicated methane fuelled SI engine is rated at 205 kW, also available as a 4x2 tractor unit	Yes	Mercedes Benz Econic, 2628 LLG Rigid 205 kW	Mercedes Benz Econic, 1830 LL Rigid 220 kW	63 (gas)	172

Vehicle type	Engine type	Fuel(s)	Additional notes	Different engine from comparator vehicle?	Vehicle selected	Comparator vehicle	Range	Range comparator vehicle
44 tonne articulated truck (HDV)	CI	LNG, LBM	This is a dual fuel (methane/diesel) truck engine (Aftermarket conversions also available)	Yes	Volvo D13C as methane /diesel 338 kW (13 litre) in FM13 chassis	Volvo D13C460 diesel 338 kW (13 litre) in FM13 chassis	Depends on model (various diesel fuel tank sizes available)	
City bus (HDV)	SI	CNG, CBM	MAN 18 tonne GVW, 40 seater city bus	Yes	MAN Ecocity bus with E2876 LUH 04 EEV 12.8 litre gas engine (204 kW)	MAN Lion City bus with D2066 LUH EEV 10.5 litre Euro VI diesel engine (265 kW)		

Ways in which gaseous fuels and biofuels can be used in vehicles

This section summarises the different modifications to standard engines that are required for vehicles to use gaseous and biomass fuels.

Methane

Methane in the form of compressed natural gas, compressed bio-methane, liquefied natural gas and liquefied bio-methane, can be used in vehicle internal combustion engines in a number of different ways.

Dedicated methane-fuelled vehicle (including bi-fuel vehicles)

These are a development of petrol-fuelled SI engines. They are made by a relatively small number of vehicle manufacturers. Examples chosen for this study are the VW Caddy (CNG), Iveco Eurocargo urban truck, Mercedes Benz Econic refuse collection vehicle and MAN Gas engine.

Converted petrol vehicles

These vehicles are converted from standard petrol fuelled, SI engined light duty vehicles. They are often bi-fuelled, having both petrol and methane fuel tanks. Some start on petrol before switching to run on methane. There are some vehicle types, e.g. those with direct petrol injection, where some petrol consumption is required to keep the injectors cool. The performance of these vehicles in terms of fuel efficiency and emissions performance are at best comparable to the OEM equivalents and sometimes considerably inferior (with the after-market conversions being less fuel efficient, or having higher GHG tailpipe emissions).

Dual fuel vehicles

This type of internal combustion engine (ICE) uses a mixture of diesel and methane (together) in a CI engine. Fundamental thermodynamic principles mean that these engines are intrinsically more efficient (have a better fuel economy) than their SI equivalents. The rate of substitution of diesel by methane varies from being low (for low engine power portions of the duty cycle) to 50% - 80% for high power operation. The benefits of dual fuel vehicles are most apparent for long distance haulage operations, where the quantities of methane consumed make liquefied methane (LNG or LBM) the favoured fuelling option.

One OEM (Volvo) produces a dual-fuel tractor unit, with other manufacturers' vehicles available as aftermarket conversions of standard trucks.

LPG and bio-propane

Currently there are virtually no vehicles on sale in the UK that are manufactured to run on LPG[61]. This has not always been the case: in the past, for example, Vauxhall and Volvo manufactured vehicles that used LPG and vehicles that can run on LPG continue to be available in mainland Europe. Consequently, this study has assumed an after-market conversion of a standard SI engine vehicle, that was manufactured to run using petrol, is required. It is also assumed that this is a high quality conversion and it produces very similar fuel economy benefits to those found in a European based assessment (around an 11% tailpipe CO2 reduction when using LPG relative to using petrol).

Bioethanol and mixed bio-alcohols

Bio-alcohols are already used in petrol fuelled vehicles, with the current petrol fuel standard (EN 228) permitting up to 10% substitution (by volume) of petroleum gasoline by ethanol. For this study it is assumed that blend strengths are constrained such that the bio-alcohols

[61] Conversations with UKLPG representative and independent web-based research

can be used in existing vehicles with spark ignition engines without any modifications being required.

Biomass to Liquid (BtL) diesel

Biomass to liquid diesel is refined and distilled to give it physical properties that are virtually indistinguishable from pump diesel. Consequently, it is a drop-in replacement fuel and can be used in all diesel engines without any modifications being required.

Additional costs

The additional costs of using biofuels or gaseous fuels may arise from capital costs of manufacturing or converting a vehicle to run on these fuels as well as the ongoing running costs or savings compared to vehicles using standard pump fuels. These are considered below and summarised in Table 2.

Capital costs

Additional capital costs can arise from:

- The additional costs of purchasing an appropriate engine and exhaust system: for example, buying a dedicated methane engine rather than its equivalent diesel counterpart. Although SI engines are generally cheaper than CI engines, this is not the case for methane vehicles, possibly because some of the economies of scale do not apply. Other costs arise because of expensive fuel tanks, both for compressed methane and liquefied methane fuels relative to a cheap steel diesel fuel tank. Also the exhaust after-treatment systems differ, with a stoichiometric methane engine requiring a three way catalyst system, and a methane slippage catalyst, but not requiring either a diesel particulate filter or a SCR NOx reduction system.
- The cost of conversion of an existing engine to use biofuels or gaseous fuels. Examples are:
    - converting a standard petrol engine either to run on LPG (liquid bio-propane) or methane fuels, or
    - converting a large diesel engine vehicle to a dual fuel (diesel/methane) engine.

  As above, additional costs may also arise for the purchase of specific fuel tanks, and for adding a methane slippage catalyst to vehicles converted to use methane gas.

These capital costs are annualised over the lifetime of the vehicle (at a discount rate of 10% as used for economic evaluations in the rest of the study) and then divided by annual mileage to give a cost per km. The costs provided are for a like-for-like replacement of a fossil fuelled vehicle with its counterpart that can use biofuels or gaseous fuels. Where possible, data from OEMs are used. (For vehicles designed, or adapted, to use methane fuels these costs include methane catalysts. However, cheaper conversions are available, but their environmental performance is often significantly inferior to those priced in this study.)

Ongoing running costs

For vehicles designed to use biofuels or gaseous fuels there are often differences in their operating costs beyond differences in fuel costs. For example, for an SI methane engine, servicing costs may be greater compared to the diesel CI counterpart, since spark plugs and often an additional air filter need to be serviced. Gaseous fuelled vehicles are likely to be cheaper than their diesel counterparts since they do not require the AdBlue reagent required by the SCR system to control NOx emissions. Annual operating costs are converted to a per km value, so that a total additional cost per km can be calculated.

Future trends

In assessing the effectiveness of options for decarbonising the transport sector in 2025, it is necessary to consider how these costs might change by 2025. For new automotive powertrain developments, experience shows that capital costs reduce with time as manufacturing costs are reduced, production volumes are increased and the presence of more manufacturers increases competition.

The potential reduction in costs has been estimated using data from work previously completed by Ricardo-AEA for the Committee on Climate Change (CCC) which reviewed the efficiency and cost of road transport vehicle to 2050 (AEA,2012). As the costs required for this analysis are the additional costs relative to the comparator vehicle rather than absolute costs, changes in capital costs were calculated using the following methodology:

- Finding the difference between cost of vehicles using biofuels or gaseous fuels compared to their “conventionally fuelled” counterparts for the years 2010, 2020 and 2030 (directly from the tabulated results in the CCC report).
- Taking the average of the difference for 2020 and 2030 to interpolate a cost difference for 2025.
- Taking the ratio of the interpolated 2025 data and the 2010 value.

The percentage reduction on costs assumed for each vehicle type is shown in Table 3, together with the overall additional costs per vehicle in 2025.

Table 2 Additional costs of purchasing and operating vehicles (2012 costs)

Vehicle type	Fuel	Vehicle selected	Comparator vehicle	Capital costs in 2012	Operational cost in 2012 £/km	Comments & reference for values
Passenger car	CNG, CBM	VW Golf 1.4 TGI Blue Motion	VW Golf 1.4 TSI Blue Motion petrol	£2,000	£0.01	
Passenger car	LPG, bio-propane	Vauxhall Astra SRI 1.6 litre petrol conversion	Vauxhall Astra SRI 1.6 litre petrol	£1,200 £1,450	£0.006 (1)	UK LPG As for LPG + for recalibration
	Bio-ethanol mixed bio-alcohols	Vauxhall Astra SRI 1.6 litre petrol	Vauxhall Astra SRI 1.6 litre petrol	£0	£0.00 (2)	No modification required for alcohols within limits (assumed to be 10% and 15% v/v)
Small van (light duty vehicle)	CNG, CBM	Fiat Doblo Cargo	Fiat Doblo Cargo	£2,500	£0.01	Typical difference in new vehicle costs for CNG van
Large van (light duty vehicle)	CNG, CBM	Mercedes- Benz Sprinter 316 NGT	Mercedes- Benz Sprinter 316	£2,500	£0.01	Typical difference in new vehicle costs for CNG van
	BtL diesel	Mercedes- Benz Sprinter 316	Mercedes- Benz Sprinter 316	£0	£0.00 (2)	No modification required for this drop-in fuel
Medium size rigid truck (HDV)	CNG, CBM	Iveco Eurocargo (12-16 tonne) 120E20L CNG 4815	Iveco Eurocargo (12-16 tonne) 120E20L 4815 150 kW	£20,000	£0.015 (3)	Iveco
Refuse collection vehicle (HDV)	CNG, CBM	Mercedes Benz Econic, 2628 LLG Rigid 205 kW	Mercedes Benz Econic, 1830 LL Rigid 220 kW	£22,500	£0.01 (3)	CENEX study & Mercedes Benz
44 tonne Articulated truck (HDV)	LNG, LBM	Volvo D13C Gas methane /diesel 338 kW (13 litre) in FM13 chassis	Volvo D13C460 diesel 338 kW (13 litre) in FM13 chassis	£22,500	£0.01	Clean Air Power, Volvo
City bus (HDV)	CNG, CBM	MAN Ecocity bus :E2876 LUH 04 EEV 12.8 litre gas engine (204 kW)	MAN Lion City bus: D2066 LUH EEV 10.5 litre Euro VI diesel engine (265 kW)	£15,500	£0.005 (3)	AEA, 2011(4)

Notes:

1 For LPG vehicle there are some additional fuel injection systems, hence assume some additional operational cost. However the relatively low annual mileage of passenger cars, 13,000 km p.a., makes these additional costs (£75 p.a.) around 0.6p per km.

2 When fuel can be used in the same vehicle as pump petrol/diesel, it is assumed there are no additional operational costs.

3 For these methane SI engines, which displace a conventional diesel engine, there are some additional costs: spark plugs and an additional air filter need to be changed. However, relative to the diesel counterpart there is a saving because it is assumed the SI engine is uses a three way catalyst for exhaust after-treatment, whereas the diesel counterpart uses SCR which consumes AdBlue. An estimation gives a saving of around £0.01 for every 700 g CO2 generated. So for the Refuse Collection Vehicle, its high fuel consumption for its stop/start/compact duty cycle consumes around £0.03 AdBlue /km savings. This is included when estimating the operational costs.

4 Estimated capital cost of methane -fuelled city buses was taken from data used in 'Scenarios for the cost effective deployment of biofuel in the UK road transport sector in 2020, Biofuels Modes 3 Project' prepared for DfT by AEA in 2012.

Table 3 The additional costs of purchasing and operating vehicles using gaseous and waste derived fuel (2025 costs) and anticipated changes in energy efficiency from 2010 to 2025

Vehicle type	Fuel	Vehicle selected	2025 costs scaling	Capital costs in 2025	Operating costs in 2025 £/km	Reference
Passenger car	CNG, CBM	VW Golf 1.4 TGI Blue Motion	62%	£1,240		From AEA, 2012
Passenger car	LPG, bio-propane	Vauxhall Astra SRI 1.6 litre petrol conversion	100%	£1,200 £1,450	0.006 0.006	Taken as quite mature now, not in AEA, 2012
Small van (light duty vehicle)	CNG, CBM	Fiat Doblo Cargo	76%	£1,950	0.01	From AEA, 2012
Large van (light duty vehicle)	CNG, CBM	Mercedes- Benz Sprinter 316 NGT	39%	£975	0.00	From AEA, 2012
Medium size rigid truck (HDV)	CNG, CBM	Iveco Eurocargo as in Table 2	49%	£9,800	0.015	From AEA, 2012
Refuse collection vehicle (HDV)	CNG, CBM, LNG, LBM	Mercedes Benz Econic, as in Table 2	38%	£8,550	0.01	From AEA, 2012
44 tonne Articulated truck (HDV)	LNG, LBM	Volvo D13C Gas methane /diesel as in Table 2	51%	£11,475	0.01	From AEA, 2012
City bus (HDV)	CNG, CBM	MAN Ecocity bus as in Table 2	54%	£8,370	0.005	From AEA, 2012

Fuel economy/efficiency

Current situation

The fuel economy of each type of vehicle when running on different fuels was estimated and the results are shown in Table 4, which also shows the sources of the data and the fuel economy for the comparator vehicles.

For many vehicles this is expressed in terms of the tailpipe CO_2 emissions, rather than directly as fuel consumption. It is emphasised that the values chosen were taken to be representative of “real world” performance. For example, for some of the light duty vehicles where data on the CO_2 emissions from currently available models are provided in the VCA CO_2 passenger car and van databases, this involved a 20% uplift from test cycle data for passenger cars, and a 15% uplift for vans, to convert to ‘real world’ performance.

It is necessary to consider how these costs might change by 2025. For new automotive powertrain developments experience generally shows that capital costs reduce with time as experience enables manufacturing costs to be reduced, production volumes increase and the presence of more manufacturers introduces competition into the market place.

Future trends

As discussed in the previous chapter for costs, the current fuel economies have then been adjusted to allow for improvement in fuel economy by 2025. The methodology used was:

- Current 2012 fuel economies were established, as shown in Table 4.
- The average fuel efficiency for each type of fuel-engine was found for the years 2010, 2020 and 2030 (directly from the tabulated results in the CCC report).
- The average for 2020 and 2030 was found to interpolate an average value for 2025.
- Taking the ratio of the CCC fuel economy data for 2025 relative to 2010 was found. (These values are included in Table 4).
- This ratio was applied to the current 2012 fuel economy data.

For dual fuel vehicles, it is assumed that 60% of energy is supplied by natural gas and 40% by diesel.

During the modelling these data are combined with data on CO_2 from combustion from the fuel used in the vehicles to calculate tailpipe CO_2 emissions.

The tailpipe CO_2 values are then converted into vehicle energy usage (MJ/km) in 2025 using UK conversion factors for Company Reporting (quote source). This provides consistent conversion coefficients between CO_2 emissions (kg CO_2) and energy (GJ) for all the fuels used.

Table 4 Fuel economy for different vehicles (and their comparators) and changes forecast for 2025 relative to 2012

Vehicle type	Fuel	Vehicle selected	CO2 (g/km)	Reference	Fuel economy 2012 (MJ/km)	Energy eff in 2025 relative to 2012	Fuel economy 2025 (MJ/km)
Passenger car	Petrol	VW Golf 1.4 TSI Blue Motion petrol	142	VCA database uplifted by 20%	2.02	68%	1.37
Passenger car	CNG, CBM	VW Golf 1.4 TGI Blue Motion	112	NGVA website uplifted by 20%	1.97	68%	1.34
Passenger car	Petrol, bioethanol mixed bio-alcohols	Vauxhall Astra SRI 1.6 litre petrol	176	VCA database uplifted by 20%	2.52	68%	1.71
Passenger car	LPG, bio-propane	Vauxhall Astra SRI 1.6 litre petrol conversion	159	Value for petrol version reduced by 11% (1)	2.49	68%	1.69
Small van	Petrol	Fiat Doblo	199	VCA database uplifted by 20%	2.84	77%	2.19
Small van	CNG, CBM	Fiat Doblo	161	NGVA website uplifted by 20%	2.84	77%	2.19
Large van	Diesel, BTL diesel	Mercedes- Benz Sprinter 316	230	VCA website database uplifted by 20%	3.48	81%	2.82
Large van	CNG, CBM	Mercedes- Benz Sprinter 316	230	NGVA website uplifted by 20%	5.38	81%	4.15
Medium size rigid truck	Diesel	Iveco Eurocargo (12-16 t) 120E20L 4815 150 kW	600	From GHGI SREF for 12 to 16 tonne diesel vehicle(2)	8.13	91%	7.40
Medium size rigid truck	CNG, CBM	Iveco Eurocargo as in Table 2	600	Combination of data (3)	10.60	91%	9.65
Refuse collection vehicle (RCV)	Diesel	Mercedes Benz Econic, 1830 LL Rigid 220 kW	2,320	Based on counter factual for CENEX Leeds RCV study	31.45	81%	25.79
Refuse collection vehicle (RCV)	CNG, CBM,	Mercedes Benz Econic, as in Table 2	2,115	Based on 0.79 kg fuel used per km as per CENEX report	37.36	81%	30.64

Vehicle type	Fuel	Vehicle selected	CO2 (g/km)	Reference	Fuel economy 2012 (MJ/km)	Energy eff in 2025 relative to 2012	Fuel economy 2025 (MJ/km)
	LNG, LBM						
44 tonne articulated truck	Diesel	Volvo D13C460 diesel 338 kW (13 litre) in FM13 chassis	830	From GHGI SREF for 44 tonne articulated diesel truck (4)	11.25	76%	8.55
44 tonne articulated truck	LNG, LBM	Volvo D13C Gas methane /diesel as in Table 2	760	Private communication with CENEX (5)	11.25	76%	8.55
City bus	Diesel	MAN Lion City bus with D2066 LUH EEV 10.5 litre Euro VI diesel engine (265 kW)	820	Report to LowCVP: Preparing a low CO2 technology roadmap for buses (6)	11.12	84%	9.34
City bus (HDV)	CNG, CBM	MAN Ecocity bus as in Table 2	836	From Ricardo study for LowCVP (7)	14.78	84%	12.41

Notes:

1 Uses 176 g/km VCA starting point. UKLPG cites study showing on average 11% tailpipe CO_2 reduction on conversion from petrol to LPG: http://brcgb.co.uk/uklpg-announces-support-for-healthy-air-campaign . Here we use a 10% reduction because the UK LPG vehicles are not OEM but aftermarket conversions, which tend to be a little less efficient that their OEM counterparts.

2 Uses generic CO_2 emissions value as is used in the UK Greenhouse Gas Inventory from road transport, see http://naei.defra.gov.uk/reports/reports?section_id=3 . The emission factors used are the emissions for a 14 – 20 tonne rigid truck at around 40 - 45 kph average speed. (Values appropriate for the urban delivery cycle).

3 In a direct comparison of the performance of an Iveco Stralis (a larger rigid truck) the report by CENEX, the in-use performance had the CO_2 emissions from the CNG vehicle around 8.8% **higher** than for its petrol equivalent. When a CNG Eurocargo engine was tested on an engine test bench it was found it produce around 20% **lower** than for the diesel equivalent (as reported in the Eurocargo sales brochure). We are presuming in this comparison that the CO_2 emissions of both the CNG (and CBM) vehicle and its diesel counterpart are **comparable**.

4 Uses generic CO_2 emissions value as is used in the UK Greenhouse Gas Inventory from road transport, see http://naei.defra.gov.uk/reports/reports?section_id=3 . The emission factors used are the emissions for a 34 – 40 tonne articulated truck at around 70 - 75 kph average speed. (Values appropriate for long haul delivery).

5 Data are being collected for dual fuel vehicles at the time of writing as part of the TSB managed “Low carbon truck demonstration programme”. The 9% reduction in tail-pipe CO_2 was a figure given in a presentation by CENEX, at the Low Carbon Truck Trial review and workshop in January 2014.

6 Values taken from report to LowCVP entitled: “Preparing a low CO_2 technology roadmap for buses”, Ricardo, 2013. Slide 5/188 gives the figure of 8 miles per gallon of diesel, from which the quoted CO_2 was derived. This value is also consistent with other values found in the literature.

7 Values taken from report to LowCVP entitled: “Preparing a low CO_2 technology roadmap for buses”, Ricardo, 2013. There is some inconsistency in the material, in one place in the text it indicates a 1% penalty when running on methane (relative to diesel) whereas the CO_2 penalty reported in the table is 4%. The figure used in this study was a 2% penalty.

Tail pipe emissions of CH_4 and N_2O

Tailpipe emissions of CH_4 and N_2O are shown in Table 5 for each vehicle type, together with the sources of the data.

There are some significant challenges to providing this data:

- Since there are no specific emissions standards for N_2O vehicle manufacturers are not required to measure these emissions, or to report them: generally they are not measured.
- For light duty vehicles there is no standard for methane, rather there are standards for total hydrocarbons and non-methane hydrocarbons. In contrast, for heavy duty vehicles fuelled with methane there have been methane emissions limits for over a decade.
- For light duty vehicles emissions are expressed in units of mass/km travelled, ideal for use in this study. However, for heavy duty vehicles it is their engines that are certified, and these emissions are expressed in units of mass/kWh. There is no simple relationship to mass per km.
- The IPCC GHG Emissions Inventory Handbook[62] does give values for alternatively fuelled vehicles in units of mg/km. Although this looks promising, there is a single value given for CNG and LPG heavy duty trucks (designed to cover all rigid and articulated trucks). These values are 185 mg/km N_2O and 5,983 mg/km CH_4. It is also noted that the source for this data is the US EPA 2004. In contrast for a diesel-fuelled analogous vehicle the emission factors given are: 3 mg/km N_2O and 4 mg/km CH_4.
- The more recent EPA data (citing 2007 research) indicates emission factors are 109 mg/km N_2O and 1,222 mg/km CH_4 for all heavy duty vehicles when fuelled by either compressed or liquefied methane fuels.
- For dual-fuel vehicles there are virtually no data available. However, conversations with stakeholders have given a wide range of values, from around 1% to 5% methane slippage occurring. Part of the challenge is that for these dual fuel vehicles the answer obtained depends both on the technology employed, e.g. whether a methane slippage catalyst is included, and on the test cycle and the degree of diesel substitution. For some drive cycles, typically those for urban usage, which includes the engine World Harmonised transient cycle (the heavy duty engine test cycle) substitution rates may only be around 20%. This is not the typical drive cycle for dual fuel vehicles, and if these are used to obtain methane emissions (slippage) they produce an unrepresentatively high figure.

Therefore, while values are given in Table 5 these should be treated with caution, and more vehicle testing is required for alternatively fuelled vehicles (particularly for dual fuel, diesel/methane vehicles) to obtain more robust data.

[62] See http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_3_Ch3_Mobile_Combustion.pdf

Table 5 Emission factors for N2O and CH4

Vehicle type	Fuel	Vehicle selected	N_2O (mg/km)	CH_4 (mg/km)	Ref
Passenger car	Petrol	VW Golf 1.4 TSI Blue Motion petrol	1.7	7.5	Euro 4 vehicle, IPCC guidebook, See note 1
Passenger car	CNG, CBM	VW Golf 1.4 TGI Blue Motion	0.64	27.6	Inferred from Tier 1 EFs, Table 3.2.2 of IPCC guidebook, See note 1
Passenger car	Petrol	Vauxhall Astra SRI 1.6 litre petrol	1.7	7.5	Euro 4 vehicle, IPCC guidebook, See note 1. Blends with biofuels assumed same as petrol
Passenger car	LPG, bio-propane	Vauxhall Astra SRI 1.6 litre petrol conversion	0.085	38.4	Inferred from Tier 1 EFs, Table 3.2.2 of IPCC guidebook, See note 1
Passenger car	Bio-ethanol (to E10%), mixed bio-alcohols (up to 20%)	Vauxhall Astra SRI 1.6 litre petrol	1.7	7.5	Assumed same as baseline vehicle on petrol
Small van (light duty vehicle)	Petrol	Fiat Doblo	1.7	7.5	Euro 4 vehicle, IPCC guidebook, See note 1
Small van (light duty vehicle)	CNG, CBM	Fiat Doblo	0.64	27.6	Inferred from Tier 1 EFs, Table 3.2.2 of IPCC guidebook, See note 1
Large van (light duty vehicle)	Diesel BtL diesel	Mercedes- Benz Sprinter 316	1	1	Euro 4 diesel van, IPCC guidebook, See note 1
Large van (light duty vehicle)	CNG, CBM	Mercedes- Benz Sprinter 316	1	1	Identical figure to above for this drop-in fuel
Medium size rigid truck (HDV)	Diesel	Iveco Eurocargo (12-16 t) 120E20L 4815 150 kW	30	30	<16 t diesel truck, Table 3.2.5 IPCC guidebook, See note 1
Medium size rigid truck (HDV)	CNG, CBM	Iveco Eurocargo as in Table 2	109	1,220	Table A-7 of EPA guidebook, see note 2

Vehicle type	Fuel	Vehicle selected	N_2O (mg/km)	CH_4 (mg/km)	Ref
Refuse collection vehicle (HDV)	Diesel	Mercedes Benz Econic, 1830 LL Rigid 220 kW	30	90	>16 t diesel truck, Table 3.2.5 IPCC guidebook, See note 1
Refuse collection vehicle (HDV)	CNG, CBM, LNG, LBM	Mercedes Benz Econic, as in Table 2	109	1,220	Table A-7 of EPA guidebook, see note 2
44 tonne Articulated truck (HDV)	Diesel	Volvo D13C460 diesel 338 kW (13 litre) in FM13 chassis	30	90	>16 t diesel truck, Table 3.2.5 IPCC guidebook, See note 1
44 tonne Articulated truck (HDV)	LNG, LBM	Volvo D13C Gas methane /diesel as in Table 2	70	650	Estimate, 50% diesel vehicle, 50% CNG vehicle
City bus (HDV)	Diesel	MAN Lion City bus with D2066 LUH EEV 10.5 litre Euro VI diesel engine (265 kW)	30	30	<16 t diesel truck, Table 3.2.5 IPCC guidebook, See note 1
City bus (HDV)	CNG, CBM	MAN Ecocity bus as in Table 2	109	60	From MAN data

Notes to table 5

Note 1 For conventional vehicles data source is IPCC Inventory handbook, Table 3.2.5 for European vehicles (EPA data will be for vehicles meeting different (US) emission standards) from http://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/2_Volume2/V2_3_Ch3_Mobile_Combustion.pdf

Note 2 For alternatively fuelled vehicles data source is EPA Inventory handbook, as discussed in the text. Available from: http://www.epa.gov/climateleadership/documents/resources/mobilesource_guidance.pdf

Appendix 4 – Detailed Results (using 100 year GWPs)

Table A4.1 Results for fuel pathways (using 100 year GWPs)

Pathway	GHG Emissions: Total GHG emissions WTT (fossil only)	GHG Emissions, of which: Fuel production	GHG Emissions, of which: Fuel delivery and dispensing	CO2 emissions from Combustion: Combustion CO2 (fossil)	CO2 emissions from Combustion: Combustion CO2 (biogenic)	Energy use	WTT efficiency	Costs: Total	Costs, of which: Fuel production	Costs, of which: Fuel delivery and dispensing
	kgCO2eq/GJ	kgCO2eq/GJ	kgCO2eq/GJ	kgCO2eq/GJ	kgCO2eq/GJ	MJ/GJ	%	£/GJ	£/GJ	£/GJ
CBM (MP) from AD (food)	18.9	17.3	1.6	0.0	56.6	88	58%	10.3	5.8	4.5
CBM (LTS) from AD (food)	17.8	17.3	0.5	0.0	56.6	73	58%	8.0	5.8	2.2
LBM from AD (food)	19.5	17.5	2.0	0.0	56.6	116	59%	12.4	10.2	2.2
CBM (LBM) from AD (food)	21.0	17.5	3.6	0.0	56.6	139	59%	14.5	10.2	4.3
CBM (MP) from AD (mixed)	18.9	17.3	1.6	0.0	56.6	88	58%	12.7	8.1	4.5
CBM (LTS) from AD (mixed)	17.8	17.3	0.5	0.0	56.6	73	58%	10.3	8.1	2.2
LBM from AD (mixed)	19.5	17.5	2.0	0.0	56.6	116	59%	14.7	12.5	2.2
CBM (LBM) from AD (mixed)	21.0	17.5	3.6	0.0	56.6	139	59%	16.8	12.5	4.3
CBM (MP) from landfill	9.0	7.4	1.6	0.0	56.6	69	25%	10.3	5.7	4.5
CBM (LTS) from landfill	7.9	7.4	0.5	0.0	56.6	54	25%	7.9	5.7	2.2
LBM from landfill	9.7	7.7	2.0	0.0	56.6	97	25%	12.3	10.1	2.2
CBM (LNG) from landfill	11.3	7.7	3.6	0.0	56.6	120	25%	14.4	10.1	4.3
BtL diesel from MSW (gasification)	52.7	50.8	1.9	22.1	51.6	17	30%	29.2	27.7	1.5
BtL jet from MSW (gasification)	53.0	50.8	2.2	21.5	50.2	17	30%	29.2	27.7	1.5
CBM (MP) from bioSNG (wood)	5.6	3.9	1.6	0.0	56.6	49	62%	27.8	23.3	4.5
CBM (LTS) from bioSNG (wood)	4.4	3.9	0.5	0.0	56.6	34	62%	25.5	23.3	2.2
LBM from bioSNG (wood)	6.3	4.2	2.0	0.0	56.6	77	63%	29.7	27.6	2.2
CBM (LBM) from bioSNG (wood)	7.8	4.2	3.6	0.0	56.6	100	63%	31.8	27.6	4.3
BtL diesel from wood (gasification)	2.5	0.5	1.9	0.0	73.8	-73	56%	24.0	22.5	1.5
BtL jet from wood (gasification)	2.7	0.5	2.2	0.0	71.7	-73	56%	24.0	22.5	1.5
CBM (MP) from bioSNG (SRF)	6.8	5.2	1.6	28.3	28.3	49	62%	23.7	19.2	4.5
CBM (LTS) from bioSNG (SRF)	5.6	5.2	0.5	28.3	28.3	34	62%	21.4	19.2	2.2
LBM from bioSNG (SRF)	7.5	5.4	2.0	28.3	28.3	77	63%	25.7	23.5	2.2
CBM (LBM) from bioSNG (SRF)	9.0	5.4	3.6	28.3	28.3	100	63%	27.8	23.5	4.3
Bioalcohol from SRF (gasification)	5.5	3.3	2.2	35.7	35.7	17	35%	11.4	9.7	1.7
Biopropane from SRF (gasification)	3.5	2.3	1.2	31.9	31.9	-144	46%	16.6	12.9	3.8
BtL diesel from SRF (gasification)	3.8	1.9	1.9	36.9	36.9	-73	56%	16.6	15.1	1.5
BtL jet from SRF (gasification)	4.1	1.9	2.2	35.9	35.9	-73	56%	16.6	15.1	1.5
BtL diesel from SRF (pyrolysis)	30.1	28.2	1.9	36.9	36.9	1037	48%	12.1	10.6	1.5
BtL jet from SRF (pyrolysis)	30.4	28.2	2.2	35.9	35.9	1037	48%	12.1	10.6	1.5
Biooil from SRF (pyrolysis)	13.9	12.5	1.4	39.6	39.6	402	55%	12.5	11.0	1.5
Bioethanol (organic waste)	6.0	3.7	2.2	0.0	71.4	-63	44%	13.5	11.8	1.7
CNG (MP) from UK gas	10.2	8.4	1.7	56.6	0.0	107	99%	11.6	7.0	4.5
CNG (LTS) from UK gas	9.0	8.4	0.6	56.6	0.0	92	99%	9.2	7.0	2.2
CNG (MP) from shale gas	7.3	5.6	1.7	56.6	0.0	40	99%	11.6	7.0	4.5
CNG (LTS) from shale gas	6.1	5.6	0.6	56.6	0.0	25	99%	9.2	7.0	2.2
LNG via road tanker	18.0	16.0	2.0	56.6	0.0	192	96%	10.5	8.3	2.2
CNG from LNG via road tanker	19.6	16.0	3.6	56.6	0.0	215	96%	12.6	8.3	4.3
CNG (MP) from LNG in gas grid	18.9	17.2	1.7	56.6	0.0	246	96%	13.1	8.5	4.5
CNG (LTS) from LNG in gas grid	17.8	17.2	0.6	56.6	0.0	231	96%	10.7	8.5	2.2
LPG	9.9	8.7	1.2	63.8	0.0	98	99%	20.7	17.5	3.2

Table A4.2 Results for fuel use in vehicles (using 100 year GWPs)

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
			Tailpipe emissions				Total		*of which*			
		WTT	CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)	WTW (fossil only)	Total	Fuel	Vehicle	% saving per km	Cost
		kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (MP) from AD (food)	Car (A)	25.3	0.8	0.2	0.0	75.9	26.3	3.7	1.4	2.3	77%	139
CBM (MP) from AD (food)	Van (A)	41.4	0.8	0.2	0.0	123.8	42.3	5.0	2.3	2.7	77%	72
CBM (MP) from AD (food)	Van (B)	78.4	0.8	0.2	0.0	234.7	79.3	6.1	4.3	1.9	68%	60
CBM (MP) from AD (food)	HGV (urban)	182.4	34.2	28.9	0.0	546.0	245.5	16.1	10.0	6.1	63%	55
CBM (MP) from AD (food)	HGV (RCV)	579.3	35.0	28.9	0.0	1734.3	643.1	44.3	31.6	12.7	72%	-22
CBM (MP) from AD (food)	Bus	234.7	1.7	28.9	0.0	702.6	265.2	15.3	12.8	2.5	68%	-37
CBM (LTS) from AD (food)	Car (A)	23.8	0.8	0.2	0.0	75.9	24.8	3.4	1.1	2.3	79%	102
CBM (LTS) from AD (food)	Van (A)	38.9	0.8	0.2	0.0	123.8	39.8	4.5	1.7	2.7	78%	35
CBM (LTS) from AD (food)	Van (B)	73.7	0.8	0.2	0.0	234.7	74.7	5.2	3.3	1.9	70%	3
CBM (LTS) from AD (food)	HGV (urban)	171.5	34.2	28.9	0.0	546.0	234.6	13.8	7.7	6.1	65%	1
CBM (LTS) from AD (food)	HGV (RCV)	544.7	35.0	28.9	0.0	1734.3	608.6	37.2	24.4	12.7	74%	-64
CBM (LTS) from AD (food)	Bus	220.7	1.7	28.9	0.0	702.6	251.2	12.4	9.9	2.5	70%	-86
LBM from AD (food)	HGV (long distance)	152.7	16.8	14.6	252.3	290.5	436.4	16.3	12.7	3.5	43%	11
CBM (LBM) from AD (food)	Car (A)	28.2	0.8	0.2	0.0	75.9	29.1	4.3	1.9	2.3	75%	207
CBM (LBM) from AD (food)	Van (A)	46.0	0.8	0.2	0.0	123.8	47.0	5.9	3.2	2.7	75%	140
CBM (LBM) from AD (food)	Van (B)	87.2	0.8	0.2	0.0	234.7	88.2	7.9	6.0	1.9	65%	169
CBM (LBM) from AD (food)	HGV (urban)	202.9	34.2	28.9	0.0	546.0	266.0	20.1	14.0	6.1	60%	160
CBM (LBM) from AD (food)	HGV (RCV)	644.4	35.0	28.9	0.0	1734.3	708.3	57.1	44.4	12.7	69%	57
CBM (LBM) from AD (food)	Bus	261.1	1.7	28.9	0.0	702.6	291.6	20.4	18.0	2.5	65%	57
CBM (MP) from AD (mixed)	Car (A)	25.3	0.8	0.2	0.0	75.9	26.3	4.0	1.7	2.3	77%	173
CBM (MP) from AD (mixed)	Van (A)	41.4	0.8	0.2	0.0	123.8	42.3	5.5	2.8	2.7	77%	107
CBM (MP) from AD (mixed)	Van (B)	78.4	0.8	0.2	0.0	234.7	79.3	7.1	5.2	1.9	68%	116
CBM (MP) from AD (mixed)	HGV (urban)	182.4	34.2	28.9	0.0	546.0	245.5	18.3	12.2	6.1	63%	109
CBM (MP) from AD (mixed)	HGV (RCV)	579.3	35.0	28.9	0.0	1734.3	643.1	51.5	38.8	12.7	72%	21
CBM (MP) from AD (mixed)	Bus	234.7	1.7	28.9	0.0	702.6	265.2	18.2	15.7	2.5	68%	14
CBM (LTS) from AD (mixed)	Car (A)	23.8	0.8	0.2	0.0	75.9	24.8	3.7	1.4	2.3	79%	136
CBM (LTS) from AD (mixed)	Van (A)	38.9	0.8	0.2	0.0	123.8	39.8	5.0	2.3	2.7	78%	70
CBM (LTS) from AD (mixed)	Van (B)	73.7	0.8	0.2	0.0	234.7	74.7	6.1	4.3	1.9	70%	58
CBM (LTS) from AD (mixed)	HGV (urban)	171.5	34.2	28.9	0.0	546.0	234.6	16.0	9.9	6.1	65%	53

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
		WTT	Tailpipe emissions				Total WTW (fossil only)	Total	of which		% saving per km	Cost
			CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)			Fuel	Vehicle		
		kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (LTS) from AD (mixed)	HGV (RCV)	544.7	35.0	28.9	0.0	1734.3	608.6	44.3	31.6	12.7	74%	-22
CBM (LTS) from AD (mixed)	Bus	220.7	1.7	28.9	0.0	702.6	251.2	15.3	12.8	2.5	70%	-36
LBM from AD (mixed)	HGV (long distance)	152.7	16.8	14.6	252.3	290.5	436.4	17.4	13.9	3.5	43%	47
CBM (LBM) from AD (mixed)	Car (A)	28.2	0.8	0.2	0.0	75.9	29.1	4.6	2.3	2.3	75%	243
CBM (LBM) from AD (mixed)	Van (A)	46.0	0.8	0.2	0.0	123.8	47.0	6.4	3.7	2.7	75%	177
CBM (LBM) from AD (mixed)	Van (B)	87.2	0.8	0.2	0.0	234.7	88.2	8.8	7.0	1.9	65%	227
CBM (LBM) from AD (mixed)	HGV (urban)	202.9	34.2	28.9	0.0	546.0	266.0	22.3	16.2	6.1	60%	216
CBM (LBM) from AD (mixed)	HGV (RCV)	644.4	35.0	28.9	0.0	1734.3	708.3	64.1	51.4	12.7	69%	102
CBM (LBM) from AD (mixed)	Bus	261.1	1.7	28.9	0.0	702.6	291.6	23.3	20.8	2.5	65%	110
CBM (MP) from landfill	Car (A)	12.1	0.8	0.2	0.0	75.9	13.1	3.7	1.4	2.3	89%	120
CBM (MP) from landfill	Van (A)	19.8	0.8	0.2	0.0	123.8	20.7	5.0	2.2	2.7	89%	61
CBM (MP) from landfill	Van (B)	37.5	0.8	0.2	0.0	234.7	38.4	6.1	4.3	1.9	85%	47
CBM (MP) from landfill	HGV (urban)	87.2	34.2	28.9	0.0	546.0	150.3	16.0	9.9	6.1	77%	44
CBM (MP) from landfill	HGV (RCV)	277.0	35.0	28.9	0.0	1734.3	340.8	44.1	31.4	12.7	85%	-19
CBM (MP) from landfill	Bus	112.2	1.7	28.9	0.0	702.6	142.8	15.2	12.7	2.5	83%	-31
CBM (LTS) from landfill	Car (A)	10.6	0.8	0.2	0.0	75.9	11.5	3.4	1.1	2.3	90%	88
CBM (LTS) from landfill	Van (A)	17.3	0.8	0.2	0.0	123.8	18.2	4.4	1.7	2.7	90%	29
CBM (LTS) from landfill	Van (B)	32.8	0.8	0.2	0.0	234.7	33.7	5.1	3.3	1.9	87%	2
CBM (LTS) from landfill	HGV (urban)	76.3	34.2	28.9	0.0	546.0	139.4	13.7	7.6	6.1	79%	-1
CBM (LTS) from landfill	HGV (RCV)	242.4	35.0	28.9	0.0	1734.3	306.3	36.9	24.2	12.7	87%	-55
CBM (LTS) from landfill	Bus	98.2	1.7	28.9	0.0	702.6	128.8	12.3	9.8	2.5	85%	-72
LBM from landfill	HGV (long distance)	102.6	16.8	14.6	252.3	290.5	386.3	16.2	12.7	3.5	49%	8
CBM (LBM) from landfill	Car (A)	15.1	0.8	0.2	0.0	75.9	16.0	4.3	1.9	2.3	86%	179
CBM (LBM) from landfill	Van (A)	24.6	0.8	0.2	0.0	123.8	25.6	5.9	3.2	2.7	86%	120
CBM (LBM) from landfill	Van (B)	46.7	0.8	0.2	0.0	234.7	47.7	7.8	6.0	1.9	81%	134
CBM (LBM) from landfill	HGV (urban)	108.7	34.2	28.9	0.0	546.0	171.8	20.0	13.9	6.1	74%	128
CBM (LBM) from landfill	HGV (RCV)	345.2	35.0	28.9	0.0	1734.3	409.0	56.9	44.2	12.7	82%	47
CBM (LBM) from landfill	Bus	139.8	1.7	28.9	0.0	702.6	170.4	20.4	17.9	2.5	80%	45
BtL diesel from MSW (gasification)	Van (B)	148.7	0.0	0.3	62.4	145.6	211.4	8.2	8.2	0.0	16%	773
BtL jet from MSW (gasification)	Plane	96.9	0.0	0.0	39.4	91.9	136.3	5.3	5.3	0.0	15%	812
CBM (MP) from bioSNG (wood)	Car (A)	7.4	0.8	0.2	0.0	75.9	8.4	6.1	3.7	2.3	93%	334
CBM (MP) from bioSNG (wood)	Van (A)	12.2	0.8	0.2	0.0	123.8	13.1	8.8	6.1	2.7	93%	283
CBM (MP) from bioSNG (wood)	Van (B)	23.0	0.8	0.2	0.0	234.7	24.0	13.4	11.5	1.9	90%	364

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
		WTT	*Tailpipe emissions*				Total WTW (fossil only)	Total	*of which*		% saving per km	Cost
			CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)			Fuel	Vehicle		
		kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (MP) from bioSNG (wood)	HGV (urban)	53.6	34.2	28.9	0.0	546.0	116.7	33.0	26.9	6.1	82%	352
CBM (MP) from bioSNG (wood)	HGV (RCV)	170.2	35.0	28.9	0.0	1734.3	234.1	98.0	85.3	12.7	90%	242
CBM (MP) from bioSNG (wood)	Bus	69.0	1.7	28.9	0.0	702.6	99.5	37.0	34.6	2.5	88%	268
CBM (LTS) from bioSNG (wood)	Car (A)	5.9	0.8	0.2	0.0	75.9	6.9	5.8	3.4	2.3	94%	300
CBM (LTS) from bioSNG (wood)	Van (A)	9.7	0.8	0.2	0.0	123.8	10.6	8.3	5.6	2.7	94%	249
CBM (LTS) from bioSNG (wood)	Van (B)	18.4	0.8	0.2	0.0	234.7	19.3	12.4	10.6	1.9	92%	315
CBM (LTS) from bioSNG (wood)	HGV (urban)	42.7	34.2	28.9	0.0	546.0	105.8	30.7	24.6	6.1	84%	305
CBM (LTS) from bioSNG (wood)	HGV (RCV)	135.6	35.0	28.9	0.0	1734.3	199.5	90.8	78.1	12.7	91%	204
CBM (LTS) from bioSNG (wood)	Bus	54.9	1.7	28.9	0.0	702.6	85.5	34.1	31.6	2.5	90%	224
LBM from bioSNG (wood)	HGV (long distance)	84.9	16.8	14.6	252.3	290.5	368.6	25.1	21.6	3.5	52%	234
CBM (LBM) from bioSNG (wood)	Car (A)	10.5	0.8	0.2	0.0	75.9	11.4	6.6	4.3	2.3	90%	395
CBM (LBM) from bioSNG (wood)	Van (A)	17.1	0.8	0.2	0.0	123.8	18.0	9.7	7.0	2.7	90%	344
CBM (LBM) from bioSNG (wood)	Van (B)	32.4	0.8	0.2	0.0	234.7	33.4	15.1	13.2	1.9	87%	455
CBM (LBM) from bioSNG (wood)	HGV (urban)	75.4	34.2	28.9	0.0	546.0	138.5	36.8	30.7	6.1	79%	441
CBM (LBM) from bioSNG (wood)	HGV (RCV)	239.5	35.0	28.9	0.0	1734.3	303.4	110.2	97.5	12.7	87%	312
CBM (LBM) from bioSNG (wood)	Bus	97.0	1.7	28.9	0.0	702.6	127.6	42.0	39.5	2.5	85%	348
BtL diesel from wood (gasification)	Van (B)	7.0	0.0	0.3	0.0	208.0	7.3	6.8	6.8	0.0	97%	68
BtL jet from wood (gasification)	Plane	5.0	0.0	0.0	0.0	131.3	5.0	4.4	4.4	0.0	97%	64
CBM (MP) from bioSNG (SRF)	Car (A)	9.1	0.8	0.2	37.9	37.9	48.0	5.5	3.2	2.3	59%	447
CBM (MP) from bioSNG (SRF)	Van (A)	14.8	0.8	0.2	61.9	61.9	77.6	7.9	5.2	2.7	58%	370
CBM (MP) from bioSNG (SRF)	Van (B)	28.0	0.8	0.2	117.3	117.3	146.3	11.7	9.8	1.9	42%	625
CBM (MP) from bioSNG (SRF)	HGV (urban)	65.2	34.2	28.9	273.0	273.0	401.3	29.0	22.9	6.1	39%	586
CBM (MP) from bioSNG (SRF)	HGV (RCV)	207.3	35.0	28.9	867.2	867.2	1138.3	85.4	72.7	12.7	51%	322
CBM (MP) from bioSNG (SRF)	Bus	84.0	1.7	28.9	351.3	351.3	465.8	31.9	29.5	2.5	44%	395
CBM (LTS) from bioSNG (SRF)	Car (A)	7.6	0.8	0.2	37.9	37.9	46.4	5.2	2.9	2.3	60%	392
CBM (LTS) from bioSNG (SRF)	Van (A)	12.3	0.8	0.2	61.9	61.9	75.2	7.4	4.7	2.7	59%	315
CBM (LTS) from bioSNG (SRF)	Van (B)	23.4	0.8	0.2	117.3	117.3	141.7	10.7	8.9	1.9	44%	510
CBM (LTS) from bioSNG (SRF)	HGV (urban)	54.4	34.2	28.9	273.0	273.0	390.5	26.7	20.6	6.1	41%	479
CBM (LTS) from bioSNG (SRF)	HGV (RCV)	172.7	35.0	28.9	867.2	867.2	1103.7	78.2	65.5	12.7	52%	253
CBM (LTS) from bioSNG (SRF)	Bus	70.0	1.7	28.9	351.3	351.3	451.8	29.0	26.5	2.5	46%	305
LBM from bioSNG (SRF)	HGV (long distance)	91.1	16.8	14.6	397.6	145.2	520.0	23.1	19.5	3.5	32%	294
CBM (LBM) from bioSNG (SRF)	Car (A)	12.1	0.8	0.2	37.9	37.9	51.0	6.1	3.7	2.3	56%	551
CBM (LBM) from bioSNG (SRF)	Van (A)	19.7	0.8	0.2	61.9	61.9	82.6	8.8	6.1	2.7	55%	475

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
			Tailpipe emissions						*of which*			
		WTT	CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)	Total WTW (fossil only)	Total	Fuel	Vehicle	% saving per km	Cost
		kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (LBM) from bioSNG (SRF)	Van (B)	37.4	0.8	0.2	117.3	117.3	155.7	13.4	11.5	1.9	38%	859
CBM (LBM) from bioSNG (SRF)	HGV (urban)	86.9	34.2	28.9	273.0	273.0	423.0	32.9	26.8	6.1	36%	802
CBM (LBM) from bioSNG (SRF)	HGV (RCV)	276.2	35.0	28.9	867.2	867.2	1207.2	97.8	85.1	12.7	48%	455
CBM (LBM) from bioSNG (SRF)	Bus	111.9	1.7	28.9	351.3	351.3	493.7	36.9	34.5	2.5	41%	575
Bioalcohol from SRF (gasification)	Car (B)	21.5	0.4	0.9	111.1	9.2	134.0	2.9	2.9	0.0	7%	-166
Biopropane from SRF (gasification)	Car (B)	5.9	1.1	0.0	54.0	54.0	60.9	5.0	2.8	2.1	58%	224
BtL diesel from SRF (gasification)	Van (B)	10.8	0.0	0.3	104.0	104.0	115.1	4.7	4.7	0.0	54%	-31
BtL jet from SRF (gasification)	Plane	7.4	0.0	0.0	65.7	65.7	73.1	3.0	3.0	0.0	54%	-42
BtL diesel from SRF (pyrolysis)	Van (B)	85.0	0.0	0.3	104.0	104.0	189.3	3.4	3.4	0.0	25%	-270
BtL jet from SRF (pyrolysis)	Plane	55.6	0.0	0.0	65.7	65.7	121.3	2.2	2.2	0.0	24%	-304
Biooil from SRF (pyrolysis)	Ship	10.7	0.0	0.1	30.4	30.4	41.2	1.0	1.0	0.0	43%	-39
Bioethanol (organic waste)	Car (B)	22.3	0.4	0.9	108.0	12.2	131.6	3.0	3.0	0.0	9%	-62
CNG (MP) from UK gas	Van (B)	42.1	0.8	0.2	234.7	0.0	277.8	6.6	4.8	1.9	no saving	no saving
CNG (MP) from UK gas	HGV (urban)	98.0	35.0	28.9	546.0	0.0	707.9	17.2	11.1	6.1	no saving	no saving
CNG (MP) from UK gas	HGV (RCV)	311.3	35.0	28.9	1734.3	0.0	2109.5	48.1	35.4	12.7	8%	8
CNG (MP) from UK gas	Bus	126.1	1.7	28.9	702.6	0.0	859.3	16.8	14.3	2.5	no saving	no saving
CNG (MP) from UK gas	Car (A)	23.8	0.8	0.2	75.9	0.0	100.7	3.8	1.4	2.3	13%	846
CNG (MP) from UK gas	Van (A)	38.9	0.8	0.2	123.8	0.0	163.6	5.1	2.3	2.7	11%	532
CNG (LTS) from UK gas	Van (B)	37.4	0.8	0.2	234.7	0.0	273.1	5.7	3.8	1.9	no saving	no saving
CNG (LTS) from UK gas	HGV (urban)	87.1	35.0	28.9	546.0	0.0	696.9	15.0	8.9	6.1	no saving	no saving
CNG (LTS) from UK gas	HGV (RCV)	276.5	35.0	28.9	1734.3	0.0	2074.7	40.9	28.2	12.7	10%	-311
CNG (LTS) from UK gas	Bus	112.0	1.7	28.9	702.6	0.0	845.2	13.9	11.4	2.5	no saving	no saving
CNG (LTS) from UK gas	Van (A)	42.9	0.8	0.2	123.8	0.0	167.6	5.5	2.7	2.7	9%	901
CNG (LTS) from UK gas	Van (A)	41.4	0.8	0.2	123.8	0.0	166.1	5.6	2.9	2.7	10%	889
CNG (MP) from shale gas	Van (B)	30.2	0.8	0.2	234.7	0.0	265.8	6.6	4.8	1.9	no saving	no saving
CNG (MP) from shale gas	HGV (urban)	70.2	35.0	28.9	546.0	0.0	680.1	17.2	11.1	6.1	no saving	no saving
CNG (MP) from shale gas	HGV (RCV)	223.0	35.0	28.9	1734.3	0.0	2021.2	48.1	35.4	12.7	12%	6
CNG (MP) from shale gas	Bus	90.3	1.7	28.9	702.6	0.0	823.5	16.8	14.3	2.5	1%	-525
CNG (MP) from shale gas	Car (A)	26.3	0.8	0.2	75.9	0.0	103.1	4.0	1.7	2.3	11%	1200
CNG (MP) from shale gas	Car (A)	25.4	0.8	0.2	75.9	0.0	102.2	4.1	1.8	2.3	12%	1170
CNG (LTS) from shale gas	Van (A)	22.2	0.8	0.2	123.8	0.0	147.0	5.2	2.5	2.7	20%	344
CNG (LTS) from shale gas	Van (A)	19.7	0.8	0.2	123.8	0.0	144.5	4.7	2.0	2.7	22%	193
CNG (LTS) from shale gas	Van (B)	25.5	0.8	0.2	234.7	0.0	261.1	5.7	3.8	1.9	no saving	no saving

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
		WTT	*Tailpipe emissions*				Total WTW (fossil only)	Total	*of which*		% saving per km	Cost
			CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)			Fuel	Vehicle		
		kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq/km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CNG (LTS) from shale gas	HGV (urban)	59.3	35.0	28.9	546.0	0.0	669.2	15.0	8.9	6.1	no saving	no saving
CNG (LTS) from shale gas	HGV (RCV)	188.3	35.0	28.9	1734.3	0.0	1986.5	40.9	28.2	12.7	14%	-224
CNG (LTS) from shale gas	Bus	76.3	1.7	28.9	702.6	0.0	809.4	13.9	11.4	2.5	3%	-1411
LNG via road tanker	HGV (long distance)	145.4	16.8	14.6	542.8	0.0	719.6	15.3	11.7	3.5	6%	-145
LNG via road tanker	Ship	13.9	0.0	0.1	43.5	0.0	57.4	1.0	0.8	0.2	21%	-73
CNG from LNG via road tanker	Car (A)	13.6	0.8	0.2	75.9	0.0	90.5	3.9	1.5	2.3	22%	552
CNG from LNG via road tanker	Car (A)	12.1	0.8	0.2	75.9	0.0	88.9	3.6	1.2	2.3	23%	404
CNG from LNG via road tanker	Van (B)	81.3	0.8	0.2	234.7	0.0	316.9	7.1	5.2	1.9	no saving	no saving
CNG from LNG via road tanker	HGV (urban)	189.1	35.0	28.9	546.0	0.0	799.0	18.2	12.1	6.1	no saving	no saving
CNG from LNG via road tanker	HGV (RCV)	600.6	35.0	28.9	1734.3	0.0	2398.8	51.2	38.5	12.7	no saving	no saving
CNG from LNG via road tanker	Bus	243.3	1.7	28.9	702.6	0.0	976.5	18.0	15.6	2.5	no saving	no saving
CNG (MP) from LNG in gas grid	Van (A)	15.9	0.8	0.2	123.8	0.0	140.7	5.2	2.5	2.7	24%	294
CNG (MP) from LNG in gas grid	Van (A)	13.4	0.8	0.2	123.8	0.0	138.2	4.7	2.0	2.7	25%	167
CNG (MP) from LNG in gas grid	Van (B)	78.4	0.8	0.2	234.7	0.0	314.1	7.3	5.4	1.9	no saving	no saving
CNG (MP) from LNG in gas grid	HGV (urban)	182.5	35.0	28.9	546.0	0.0	792.4	18.7	12.6	6.1	no saving	no saving
CNG (MP) from LNG in gas grid	HGV (RCV)	579.6	35.0	28.9	1734.3	0.0	2377.8	52.7	40.0	12.7	no saving	no saving
CNG (MP) from LNG in gas grid	Bus	234.8	1.7	28.9	702.6	0.0	967.9	18.7	16.2	2.5	no saving	no saving
CNG (LTS) from LNG in gas grid	Car (A)	9.8	0.8	0.2	75.9	0.0	86.6	3.9	1.5	2.3	25%	479
CNG (LTS) from LNG in gas grid	Car (A)	8.2	0.8	0.2	75.9	0.0	85.1	3.6	1.2	2.3	27%	353
CNG (LTS) from LNG in gas grid	Van (B)	73.7	0.8	0.2	234.7	0.0	309.3	6.3	4.4	1.9	no saving	no saving
CNG (LTS) from LNG in gas grid	HGV (urban)	171.5	35.0	28.9	546.0	0.0	781.4	16.4	10.3	6.1	no saving	no saving
CNG (LTS) from LNG in gas grid	HGV (RCV)	544.7	35.0	28.9	1734.3	0.0	2342.9	45.5	32.8	12.7	no saving	no saving
CNG (LTS) from LNG in gas grid	Bus	220.6	1.7	28.9	702.6	0.0	953.8	15.8	13.3	2.5	no saving	no saving
LPG	Car (B)	16.8	1.1	0.0	108.0	0.0	125.8	5.4	3.5	1.9	13%	1233

Appendix 5 – Detailed Results (using 20 year GWPs)

Table A5.1 Results for fuel pathways (using 20 year GWPs)

	GHG Emissions							Costs		
	Total GHG emissions WTT (fossil only)	*of which*		CO2 emissions from Combustion		Energy use	WTT efficiency	Total	*of which*	
		Fuel production	Fuel delivery and dispensing	Combustion CO2 (fossil)	Combustion CO2 (biogenic)				Fuel production	Fuel delivery and dispensing
Pathway	kgCO2eq/GJ	kgCO2eq/GJ	kgCO2eq/GJ	kgCO2eq/GJ	kgCO2eq/GJ	MJ/GJ	%	£/GJ	£/GJ	£/GJ
CBM (MP) from AD (food)	40.2	37.6	2.6	0.0	56.6	88	58%	10.3	5.8	4.5
CBM (LTS) from AD (food)	38.3	37.6	0.7	0.0	56.6	73	58%	8.0	5.8	2.2
LBM from AD (food)	42.4	37.5	4.8	0.0	56.6	116	59%	12.4	10.2	2.2
CBM (LBM) from AD (food)	43.9	37.5	6.4	0.0	56.6	139	59%	14.5	10.2	4.3
CBM (MP) from AD (mixed)	40.2	37.6	2.6	0.0	56.6	88	58%	12.7	8.1	4.5
CBM (LTS) from AD (mixed)	38.3	37.6	0.7	0.0	56.6	73	58%	10.3	8.1	2.2
LBM from AD (mixed)	42.4	37.5	4.8	0.0	56.6	116	59%	14.7	12.5	2.2
CBM (LBM) from AD (mixed)	43.9	37.5	6.4	0.0	56.6	139	59%	16.8	12.5	4.3
CBM (MP) from landfill	16.1	13.5	2.6	0.0	56.6	69	25%	10.3	5.7	4.5
CBM (LTS) from landfill	14.2	13.5	0.7	0.0	56.6	54	25%	7.9	5.7	2.2
LBM from landfill	18.5	13.7	4.8	0.0	56.6	97	25%	12.3	10.1	2.2
CBM (LNG) from landfill	20.1	13.7	6.4	0.0	56.6	120	25%	14.4	10.1	4.3
BtL diesel from MSW (gasification)	54.0	52.0	2.0	22.1	51.6	17	30%	29.2	27.7	1.5
BtL jet from MSW (gasification)	54.1	52.0	2.2	21.5	50.2	17	30%	29.2	27.7	1.5
CBM (MP) from bioSNG (wood)	6.6	3.9	2.6	0.0	56.6	49	62%	27.8	23.3	4.5
CBM (LTS) from bioSNG (wood)	4.7	3.9	0.7	0.0	56.6	34	62%	25.5	23.3	2.2
LBM from bioSNG (wood)	9.1	4.2	4.8	0.0	56.6	77	63%	29.7	27.6	2.2
CBM (LBM) from bioSNG (wood)	10.6	4.2	6.4	0.0	56.6	100	63%	31.8	27.6	4.3
BtL diesel from wood (gasification)	2.5	0.5	2.0	0.0	73.8	-73	56%	24.0	22.5	1.5
BtL jet from wood (gasification)	2.7	0.5	2.2	0.0	71.7	-73	56%	24.0	22.5	1.5
CBM (MP) from bioSNG (SRF)	7.8	5.2	2.6	28.3	28.3	49	62%	23.7	19.2	4.5
CBM (LTS) from bioSNG (SRF)	5.9	5.2	0.7	28.3	28.3	34	62%	21.4	19.2	2.2
LBM from bioSNG (SRF)	10.3	5.4	4.8	28.3	28.3	77	63%	25.7	23.5	2.2
CBM (LBM) from bioSNG (SRF)	11.8	5.4	6.4	28.3	28.3	100	63%	27.8	23.5	4.3
Bioalcohol from SRF (gasification)	5.5	3.3	2.2	35.7	35.7	17	35%	11.4	9.7	1.7
Biopropane from SRF (gasification)	3.5	2.3	1.2	31.9	31.9	-144	46%	16.6	12.9	3.8
BtL diesel from SRF (gasification)	3.9	1.9	2.0	36.9	36.9	-73	56%	16.6	15.1	1.5
BtL jet from SRF (gasification)	4.1	1.9	2.2	35.9	35.9	-73	56%	16.6	15.1	1.5
BtL diesel from SRF (pyrolysis)	30.2	28.2	2.0	36.9	36.9	1037	48%	12.1	10.6	1.5
BtL jet from SRF (pyrolysis)	30.4	28.2	2.2	35.9	35.9	1037	48%	12.1	10.6	1.5
Biooil from SRF (pyrolysis)	13.9	12.5	1.4	39.6	39.6	402	55%	12.5	11.0	1.5
Bioethanol (organic waste)	6.4	4.1	2.3	0.0	71.4	-63	44%	13.5	11.8	1.7
CNG (MP) from UK gas	19.7	16.8	2.9	56.6	0.0	107	99%	11.6	7.0	4.5
CNG (LTS) from UK gas	17.8	16.8	1.0	56.6	0.0	92	99%	9.2	7.0	2.2
CNG (MP) from shale gas	8.5	5.6	2.9	56.6	0.0	40	99%	11.6	7.0	4.5
CNG (LTS) from shale gas	6.6	5.6	1.0	56.6	0.0	25	99%	9.2	7.0	2.2
LNG via road tanker	28.2	23.4	4.8	56.6	0.0	192	96%	10.5	8.3	2.2
CNG from LNG via road tanker	29.8	23.4	6.4	56.6	0.0	215	96%	12.6	8.3	4.3
CNG (MP) from LNG in gas grid	27.5	24.6	2.9	56.6	0.0	246	96%	13.1	8.5	4.5
CNG (LTS) from LNG in gas grid	25.6	24.6	1.0	56.6	0.0	231	96%	10.7	8.5	2.2
LPG	18.3	17.1	1.2	63.8	0.0	98	99%	20.7	17.5	3.2

Table A4.2 Results for fuel use in vehicles (using 20 year GWPs)

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
			Tailpipe emissions				Total WTW (fossil only)	Total	*of which*		% saving per km	Cost
		WTT	CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)			Fuel	Vehicle		
		kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (MP) from AD (food)	Car (A)	53.9	2.3	0.2	0.0	75.9	56.4	3.7	1.4	2.3	52%	200
CBM (MP) from AD (food)	Van (A)	87.9	2.3	0.2	0.0	123.8	90.4	5.0	2.3	2.7	52%	104
CBM (MP) from AD (food)	Van (B)	166.6	2.3	0.2	0.0	234.7	169.1	6.1	4.3	1.9	34%	119
CBM (MP) from AD (food)	HGV (urban)	387.7	102.6	28.8	0.0	546.0	519.1	16.1	10.0	6.1	23%	149
CBM (MP) from AD (food)	HGV (RCV)	1231.4	105.0	28.8	0.0	1734.3	1365.1	44.3	31.6	12.7	42%	-37
CBM (MP) from AD (food)	Bus	498.8	5.0	28.8	0.0	702.6	532.7	15.3	12.8	2.5	37%	-66
CBM (LTS) from AD (food)	Car (A)	51.3	2.3	0.2	0.0	75.9	53.8	3.4	1.1	2.3	55%	143
CBM (LTS) from AD (food)	Van (A)	83.8	2.3	0.2	0.0	123.8	86.2	4.5	1.7	2.7	54%	49
CBM (LTS) from AD (food)	Van (B)	158.8	2.3	0.2	0.0	234.7	161.2	5.2	3.3	1.9	37%	6
CBM (LTS) from AD (food)	HGV (urban)	369.3	102.6	28.8	0.0	546.0	500.7	13.8	7.7	6.1	26%	2
CBM (LTS) from AD (food)	HGV (RCV)	1173.1	105.0	28.8	0.0	1734.3	1306.9	37.2	24.4	12.7	44%	-104
CBM (LTS) from AD (food)	Bus	475.2	5.0	28.8	0.0	702.6	509.1	12.4	9.9	2.5	40%	-147
LBM from AD (food)	HGV (long distance)	275.9	50.4	14.5	252.3	290.5	593.1	16.3	12.7	3.5	24%	19
CBM (LBM) from AD (food)	Car (A)	58.9	2.3	0.2	0.0	75.9	61.4	4.3	1.9	2.3	48%	315
CBM (LBM) from AD (food)	Van (A)	96.1	2.3	0.2	0.0	123.8	98.6	5.9	3.2	2.7	48%	215
CBM (LBM) from AD (food)	Van (B)	182.1	2.3	0.2	0.0	234.7	184.6	7.9	6.0	1.9	28%	384
CBM (LBM) from AD (food)	HGV (urban)	423.7	102.6	28.8	0.0	546.0	555.2	20.1	14.0	6.1	18%	533
CBM (LBM) from AD (food)	HGV (RCV)	1345.9	105.0	28.8	0.0	1734.3	1479.7	57.1	44.4	12.7	37%	106
CBM (LBM) from AD (food)	Bus	545.2	5.0	28.8	0.0	702.6	579.1	20.4	18.0	2.5	32%	114
CBM (MP) from AD (mixed)	Car (A)	53.9	2.3	0.2	0.0	75.9	56.4	4.0	1.7	2.3	52%	250
CBM (MP) from AD (mixed)	Van (A)	87.9	2.3	0.2	0.0	123.8	90.4	5.5	2.8	2.7	52%	156
CBM (MP) from AD (mixed)	Van (B)	166.6	2.3	0.2	0.0	234.7	169.1	7.1	5.2	1.9	34%	229
CBM (MP) from AD (mixed)	HGV (urban)	387.7	102.6	28.8	0.0	546.0	519.1	18.3	12.2	6.1	23%	294
CBM (MP) from AD (mixed)	HGV (RCV)	1231.4	105.0	28.8	0.0	1734.3	1365.1	51.5	38.8	12.7	42%	36
CBM (MP) from AD (mixed)	Bus	498.8	5.0	28.8	0.0	702.6	532.7	18.2	15.7	2.5	37%	25
CBM (LTS) from AD (mixed)	Car (A)	51.3	2.3	0.2	0.0	75.9	53.8	3.7	1.4	2.3	55%	191
CBM (LTS) from AD (mixed)	Van (A)	83.8	2.3	0.2	0.0	123.8	86.2	5.0	2.3	2.7	54%	99
CBM (LTS) from AD (mixed)	Van (B)	158.8	2.3	0.2	0.0	234.7	161.2	6.1	4.3	1.9	37%	108
CBM (LTS) from AD (mixed)	HGV (urban)	369.3	102.6	28.8	0.0	546.0	500.7	16.0	9.9	6.1	26%	132

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
		WTT	*Tailpipe emissions*				Total WTW (fossil only)	Total	*of which*		% saving per km	Cost
			CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)			Fuel	Vehicle		
		kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (LTS) from AD (mixed)	HGV (RCV)	1173.1	105.0	28.8	0.0	1734.3	1306.9	44.3	31.6	12.7	44%	-35
CBM (LTS) from AD (mixed)	Bus	475.2	5.0	28.8	0.0	702.6	509.1	15.3	12.8	2.5	40%	-62
LBM from AD (mixed)	HGV (long distance)	275.9	50.4	14.5	252.3	290.5	593.1	17.4	13.9	3.5	24%	83
CBM (LBM) from AD (mixed)	Car (A)	58.9	2.3	0.2	0.0	75.9	61.4	4.6	2.3	2.3	48%	369
CBM (LBM) from AD (mixed)	Van (A)	96.1	2.3	0.2	0.0	123.8	98.6	6.4	3.7	2.7	48%	271
CBM (LBM) from AD (mixed)	Van (B)	182.1	2.3	0.2	0.0	234.7	184.6	8.8	7.0	1.9	28%	517
CBM (LBM) from AD (mixed)	HGV (urban)	423.7	102.6	28.8	0.0	546.0	555.2	22.3	16.2	6.1	18%	720
CBM (LBM) from AD (mixed)	HGV (RCV)	1345.9	105.0	28.8	0.0	1734.3	1479.7	64.1	51.4	12.7	37%	187
CBM (LBM) from AD (mixed)	Bus	545.2	5.0	28.8	0.0	702.6	579.1	23.3	20.8	2.5	32%	220
CBM (MP) from landfill	Car (A)	21.6	2.3	0.2	0.0	75.9	24.1	3.7	1.4	2.3	80%	131
CBM (MP) from landfill	Van (A)	35.2	2.3	0.2	0.0	123.8	37.7	5.0	2.2	2.7	80%	67
CBM (MP) from landfill	Van (B)	66.8	2.3	0.2	0.0	234.7	69.3	6.1	4.3	1.9	73%	54
CBM (MP) from landfill	HGV (urban)	155.4	102.6	28.8	0.0	546.0	286.8	16.0	9.9	6.1	57%	58
CBM (MP) from landfill	HGV (RCV)	493.6	105.0	28.8	0.0	1734.3	627.4	44.1	31.4	12.7	73%	-22
CBM (MP) from landfill	Bus	200.0	5.0	28.8	0.0	702.6	233.8	15.2	12.7	2.5	72%	-35
CBM (LTS) from landfill	Car (A)	19.1	2.3	0.2	0.0	75.9	21.5	3.4	1.1	2.3	82%	95
CBM (LTS) from landfill	Van (A)	31.1	2.3	0.2	0.0	123.8	33.6	4.4	1.7	2.7	82%	32
CBM (LTS) from landfill	Van (B)	58.9	2.3	0.2	0.0	234.7	61.4	5.1	3.3	1.9	76%	2
CBM (LTS) from landfill	HGV (urban)	137.1	102.6	28.8	0.0	546.0	268.5	13.7	7.6	6.1	60%	-1
CBM (LTS) from landfill	HGV (RCV)	435.4	105.0	28.8	0.0	1734.3	569.2	36.9	24.2	12.7	76%	-62
CBM (LTS) from landfill	Bus	176.4	5.0	28.8	0.0	702.6	210.2	12.3	9.8	2.5	75%	-79
LBM from landfill	HGV (long distance)	153.5	50.4	14.5	252.3	290.5	470.8	16.2	12.7	3.5	39%	10
CBM (LBM) from landfill	Car (A)	26.9	2.3	0.2	0.0	75.9	29.4	4.3	1.9	2.3	75%	201
CBM (LBM) from landfill	Van (A)	43.9	2.3	0.2	0.0	123.8	46.4	5.9	3.2	2.7	75%	135
CBM (LBM) from landfill	Van (B)	83.3	2.3	0.2	0.0	234.7	85.8	7.8	6.0	1.9	67%	160
CBM (LBM) from landfill	HGV (urban)	193.8	102.6	28.8	0.0	546.0	325.2	20.0	13.9	6.1	52%	179
CBM (LBM) from landfill	HGV (RCV)	615.6	105.0	28.8	0.0	1734.3	749.4	56.9	44.2	12.7	68%	56
CBM (LBM) from landfill	Bus	249.4	5.0	28.8	0.0	702.6	283.2	20.4	17.9	2.5	67%	53
BtL diesel from MSW (gasification)	Van (B)	152.2	0.1	0.3	62.4	145.6	214.9	8.2	8.2	0.0	16%	752
BtL jet from MSW (gasification)	Plane	99.1	0.0	0.0	39.4	91.9	138.5	5.3	5.3	0.0	15%	784
CBM (MP) from bioSNG (wood)	Car (A)	8.8	2.3	0.2	0.0	75.9	11.3	6.1	3.7	2.3	90%	335
CBM (MP) from bioSNG (wood)	Van (A)	14.3	2.3	0.2	0.0	123.8	16.8	8.8	6.1	2.7	91%	283
CBM (MP) from bioSNG (wood)	Van (B)	27.2	2.3	0.2	0.0	234.7	29.7	13.4	11.5	1.9	88%	366

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
			Tailpipe emissions						*of which*			
		WTT	CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)	Total WTW (fossil only)	Total	Fuel	Vehicle	% saving per km	Cost
		kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (MP) from bioSNG (wood)	HGV (urban)	63.2	102.6	28.8	0.0	546.0	194.6	33.0	26.9	6.1	71%	401
CBM (MP) from bioSNG (wood)	HGV (RCV)	200.7	105.0	28.8	0.0	1734.3	334.5	98.0	85.3	12.7	86%	249
CBM (MP) from bioSNG (wood)	Bus	81.3	5.0	28.8	0.0	702.6	115.1	37.0	34.6	2.5	86%	268
CBM (LTS) from bioSNG (wood)	Car (A)	6.2	2.3	0.2	0.0	75.9	8.7	5.8	3.4	2.3	93%	298
CBM (LTS) from bioSNG (wood)	Van (A)	10.2	2.3	0.2	0.0	123.8	12.7	8.3	5.6	2.7	93%	247
CBM (LTS) from bioSNG (wood)	Van (B)	19.3	2.3	0.2	0.0	234.7	21.8	12.4	10.6	1.9	92%	312
CBM (LTS) from bioSNG (wood)	HGV (urban)	44.9	102.6	28.8	0.0	546.0	176.3	30.7	24.6	6.1	74%	340
CBM (LTS) from bioSNG (wood)	HGV (RCV)	142.5	105.0	28.8	0.0	1734.3	276.3	90.8	78.1	12.7	88%	207
CBM (LTS) from bioSNG (wood)	Bus	57.7	5.0	28.8	0.0	702.6	91.5	34.1	31.6	2.5	89%	221
LBM from bioSNG (wood)	HGV (long distance)	105.0	50.4	14.5	252.3	290.5	422.2	25.1	21.6	3.5	46%	260
CBM (LBM) from bioSNG (wood)	Car (A)	14.2	2.3	0.2	0.0	75.9	16.7	6.6	4.3	2.3	86%	405
CBM (LBM) from bioSNG (wood)	Van (A)	23.2	2.3	0.2	0.0	123.8	25.7	9.7	7.0	2.7	86%	352
CBM (LBM) from bioSNG (wood)	Van (B)	44.1	2.3	0.2	0.0	234.7	46.6	15.1	13.2	1.9	82%	474
CBM (LBM) from bioSNG (wood)	HGV (urban)	102.5	102.6	28.8	0.0	546.0	233.9	36.8	30.7	6.1	65%	524
CBM (LBM) from bioSNG (wood)	HGV (RCV)	325.6	105.0	28.8	0.0	1734.3	459.4	110.2	97.5	12.7	80%	330
CBM (LBM) from bioSNG (wood)	Bus	131.9	5.0	28.8	0.0	702.6	165.7	42.0	39.5	2.5	80%	360
BtL diesel from wood (gasification)	Van (B)	7.1	0.1	0.3	0.0	208.0	7.5	6.8	6.8	0.0	97%	67
BtL jet from wood (gasification)	Plane	5.0	0.0	0.0	0.0	131.3	5.0	4.4	4.4	0.0	97%	63
CBM (MP) from bioSNG (SRF)	Car (A)	10.4	2.3	0.2	37.9	37.9	50.8	5.5	3.2	2.3	57%	449
CBM (MP) from bioSNG (SRF)	Van (A)	17.0	2.3	0.2	61.9	61.9	81.4	7.9	5.2	2.7	57%	369
CBM (MP) from bioSNG (SRF)	Van (B)	32.2	2.3	0.2	117.3	117.3	152.0	11.7	9.8	1.9	41%	631
CBM (MP) from bioSNG (SRF)	HGV (urban)	74.9	102.6	28.8	273.0	273.0	479.3	29.0	22.9	6.1	29%	784
CBM (MP) from bioSNG (SRF)	HGV (RCV)	237.8	105.0	28.8	867.2	867.2	1238.7	85.4	72.7	12.7	47%	339
CBM (MP) from bioSNG (SRF)	Bus	96.3	5.0	28.8	351.3	351.3	481.4	31.9	29.5	2.5	43%	396
CBM (LTS) from bioSNG (SRF)	Car (A)	7.9	2.3	0.2	37.9	37.9	48.3	5.2	2.9	2.3	59%	388
CBM (LTS) from bioSNG (SRF)	Van (A)	12.8	2.3	0.2	61.9	61.9	77.2	7.4	4.7	2.7	59%	309
CBM (LTS) from bioSNG (SRF)	Van (B)	24.3	2.3	0.2	117.3	117.3	144.1	10.7	8.9	1.9	44%	500
CBM (LTS) from bioSNG (SRF)	HGV (urban)	56.5	102.6	28.8	273.0	273.0	460.9	26.7	20.6	6.1	32%	610
CBM (LTS) from bioSNG (SRF)	HGV (RCV)	179.5	105.0	28.8	867.2	867.2	1180.4	78.2	65.5	12.7	50%	260
CBM (LTS) from bioSNG (SRF)	Bus	72.7	5.0	28.8	351.3	351.3	457.8	29.0	26.5	2.5	46%	297
LBM from bioSNG (SRF)	HGV (long distance)	111.1	50.4	14.5	397.6	145.2	573.6	23.1	19.5	3.5	26%	350
CBM (LBM) from bioSNG (SRF)	Car (A)	15.9	2.3	0.2	37.9	37.9	56.3	6.1	3.7	2.3	53%	575
CBM (LBM) from bioSNG (SRF)	Van (A)	25.9	2.3	0.2	61.9	61.9	90.3	8.8	6.1	2.7	52%	493

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
		WTT	*Tailpipe emissions*				Total WTW (fossil only)	Total	*of which*		% saving per km	Cost
			CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)			Fuel	Vehicle		
		kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CBM (LBM) from bioSNG (SRF)	Van (B)	49.0	2.3	0.2	117.3	117.3	168.9	13.4	11.5	1.9	34%	943
CBM (LBM) from bioSNG (SRF)	HGV (urban)	114.1	102.6	28.8	273.0	273.0	518.5	32.9	26.8	6.1	23%	1232
CBM (LBM) from bioSNG (SRF)	HGV (RCV)	362.3	105.0	28.8	867.2	867.2	1363.2	97.8	85.1	12.7	42%	508
CBM (LBM) from bioSNG (SRF)	Bus	146.8	5.0	28.8	351.3	351.3	531.9	36.9	34.5	2.5	37%	616
Bioalcohol from SRF (gasification)	Car (B)	23.9	1.3	0.9	111.1	9.2	137.2	2.9	2.9	0.0	7%	-167
Biopropane from SRF (gasification)	Car (B)	5.9	3.2	0.0	54.0	54.0	63.1	5.0	2.8	2.1	57%	222
BtL diesel from SRF (gasification)	Van (B)	11.0	0.1	0.3	104.0	104.0	115.3	4.7	4.7	0.0	55%	-30
BtL jet from SRF (gasification)	Plane	7.4	0.0	0.0	65.7	65.7	73.1	3.0	3.0	0.0	55%	-41
BtL diesel from SRF (pyrolysis)	Van (B)	85.3	0.1	0.3	104.0	104.0	189.6	3.4	3.4	0.0	26%	-252
BtL jet from SRF (pyrolysis)	Plane	55.7	0.0	0.0	65.7	65.7	121.4	2.2	2.2	0.0	26%	-283
Biooil from SRF (pyrolysis)	Ship	10.7	0.0	0.1	30.4	30.4	41.2	1.0	1.0	0.0	44%	-38
Bioethanol (organic waste)	Car (B)	24.9	1.3	0.9	108.0	12.2	135.0	3.0	3.0	0.0	8%	-63
CNG (MP) from UK gas	Van (B)	81.7	2.3	0.2	234.7	0.0	318.8	6.6	4.8	1.9	no saving	no saving
CNG (MP) from UK gas	HGV (urban)	190.0	105.0	28.8	546.0	0.0	869.7	17.2	11.1	6.1	no saving	no saving
CNG (MP) from UK gas	HGV (RCV)	603.4	105.0	28.8	1734.3	0.0	2471.4	48.1	35.4	12.7	no saving	no saving
CNG (MP) from UK gas	Bus	244.4	5.0	28.8	702.6	0.0	980.8	16.8	14.3	2.5	no saving	no saving
CNG (MP) from UK gas	Car (A)	34.3	2.3	0.2	75.9	0.0	112.7	3.8	1.4	2.3	5%	2201
CNG (MP) from UK gas	Van (A)	56.0	2.3	0.2	123.8	0.0	182.3	5.1	2.3	2.7	3%	1851
CNG (LTS) from UK gas	Van (B)	73.7	2.3	0.2	234.7	0.0	310.9	5.7	3.8	1.9	no saving	no saving
CNG (LTS) from UK gas	HGV (urban)	171.5	105.0	28.8	546.0	0.0	851.3	15.0	8.9	6.1	no saving	no saving
CNG (LTS) from UK gas	HGV (RCV)	544.8	105.0	28.8	1734.3	0.0	2412.8	40.9	28.2	12.7	no saving	no saving
CNG (LTS) from UK gas	Bus	220.7	5.0	28.8	702.6	0.0	957.1	13.9	11.4	2.5	no saving	no saving
CNG (LTS) from UK gas	Van (A)	65.2	2.3	0.2	123.8	0.0	191.5	5.5	2.7	2.7	no saving	no saving
CNG (LTS) from UK gas	Van (A)	60.2	2.3	0.2	123.8	0.0	186.5	5.6	2.9	2.7	1%	9231
CNG (MP) from shale gas	Van (B)	35.2	2.3	0.2	234.7	0.0	272.4	6.6	4.8	1.9	no saving	no saving
CNG (MP) from shale gas	HGV (urban)	81.9	105.0	28.8	546.0	0.0	761.6	17.2	11.1	6.1	no saving	no saving
CNG (MP) from shale gas	HGV (RCV)	260.0	105.0	28.8	1734.3	0.0	2128.1	48.1	35.4	12.7	9%	8
CNG (MP) from shale gas	Bus	105.3	5.0	28.8	702.6	0.0	841.7	16.8	14.3	2.5	1%	-719
CNG (MP) from shale gas	Car (A)	39.9	2.3	0.2	75.9	0.0	118.3	4.0	1.7	2.3	0%	61766
CNG (MP) from shale gas	Car (A)	36.9	2.3	0.2	75.9	0.0	115.3	4.1	1.8	2.3	3%	4868
CNG (LTS) from shale gas	Van (A)	43.1	2.3	0.2	123.8	0.0	169.4	5.2	2.5	2.7	10%	681
CNG (LTS) from shale gas	Van (A)	38.9	2.3	0.2	123.8	0.0	165.2	4.7	2.0	2.7	12%	334
CNG (LTS) from shale gas	Van (B)	27.3	2.3	0.2	234.7	0.0	264.5	5.7	3.8	1.9	no saving	no saving

Pathway	Vehicle	GHG Emissions						Costs			GHG savings	
		WTT	*Tailpipe emissions*				Total WTW (fossil only)	Total	*of which*		% saving per km	Cost
			CH_4	N_2O	CO_2 (fossil)	CO_2 (biogenic)			Fuel	Vehicle		
		kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq/ km	kg CO_2eq /km	kg CO_2eq /km	kg CO_2eq/km	p/km	p/km	p/km	%	£/t CO2
CNG (LTS) from shale gas	HGV (urban)	63.5	105.0	28.8	546.0	0.0	743.3	15.0	8.9	6.1	no saving	no saving
CNG (LTS) from shale gas	HGV (RCV)	201.7	105.0	28.8	1734.3	0.0	2069.7	40.9	28.2	12.7	12%	-257
CNG (LTS) from shale gas	Bus	81.7	5.0	28.8	702.6	0.0	818.1	13.9	11.4	2.5	4%	-1108
LNG via road tanker	HGV (long distance)	203.3	50.4	14.5	542.8	0.0	811.0	15.3	11.7	3.5	no saving	no saving
LNG via road tanker	Ship	21.7	0.0	0.1	43.5	0.0	65.3	1.0	0.8	0.2	12%	-129
CNG from LNG via road tanker	Car (A)	26.4	2.3	0.2	75.9	0.0	104.8	3.9	1.5	2.3	12%	1020
CNG from LNG via road tanker	Car (A)	23.8	2.3	0.2	75.9	0.0	102.2	3.6	1.2	2.3	14%	667
CNG from LNG via road tanker	Van (B)	123.6	2.3	0.2	234.7	0.0	360.7	7.1	5.2	1.9	no saving	no saving
CNG from LNG via road tanker	HGV (urban)	287.4	105.0	28.8	546.0	0.0	967.2	18.2	12.1	6.1	no saving	no saving
CNG from LNG via road tanker	HGV (RCV)	913.0	105.0	28.8	1734.3	0.0	2781.1	51.2	38.5	12.7	no saving	no saving
CNG from LNG via road tanker	Bus	369.9	5.0	28.8	702.6	0.0	1106.2	18.0	15.6	2.5	no saving	no saving
CNG (MP) from LNG in gas grid	Van (A)	18.6	2.3	0.2	123.8	0.0	144.9	5.2	2.5	2.7	23%	296
CNG (MP) from LNG in gas grid	Van (A)	14.4	2.3	0.2	123.8	0.0	140.7	4.7	2.0	2.7	25%	162
CNG (MP) from LNG in gas grid	Van (B)	114.1	2.3	0.2	234.7	0.0	351.3	7.3	5.4	1.9	no saving	no saving
CNG (MP) from LNG in gas grid	HGV (urban)	265.4	105.0	28.8	546.0	0.0	945.2	18.7	12.6	6.1	no saving	no saving
CNG (MP) from LNG in gas grid	HGV (RCV)	843.1	105.0	28.8	1734.3	0.0	2711.2	52.7	40.0	12.7	no saving	no saving
CNG (MP) from LNG in gas grid	Bus	341.6	5.0	28.8	702.6	0.0	1077.9	18.7	16.2	2.5	no saving	no saving
CNG (LTS) from LNG in gas grid	Car (A)	11.4	2.3	0.2	75.9	0.0	89.8	3.9	1.5	2.3	24%	488
CNG (LTS) from LNG in gas grid	Car (A)	8.8	2.3	0.2	75.9	0.0	87.2	3.6	1.2	2.3	26%	348
CNG (LTS) from LNG in gas grid	Van (B)	106.1	2.3	0.2	234.7	0.0	343.3	6.3	4.4	1.9	no saving	no saving
CNG (LTS) from LNG in gas grid	HGV (urban)	246.9	105.0	28.8	546.0	0.0	926.7	16.4	10.3	6.1	no saving	no saving
CNG (LTS) from LNG in gas grid	HGV (RCV)	784.4	105.0	28.8	1734.3	0.0	2652.4	45.5	32.8	12.7	no saving	no saving
CNG (LTS) from LNG in gas grid	Bus	317.7	5.0	28.8	702.6	0.0	1054.1	15.8	13.3	2.5	no saving	no saving
LPG	Car (B)	31.0	3.2	0.0	108.0	0.0	142.2	5.4	3.5	1.9	4%	4329

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