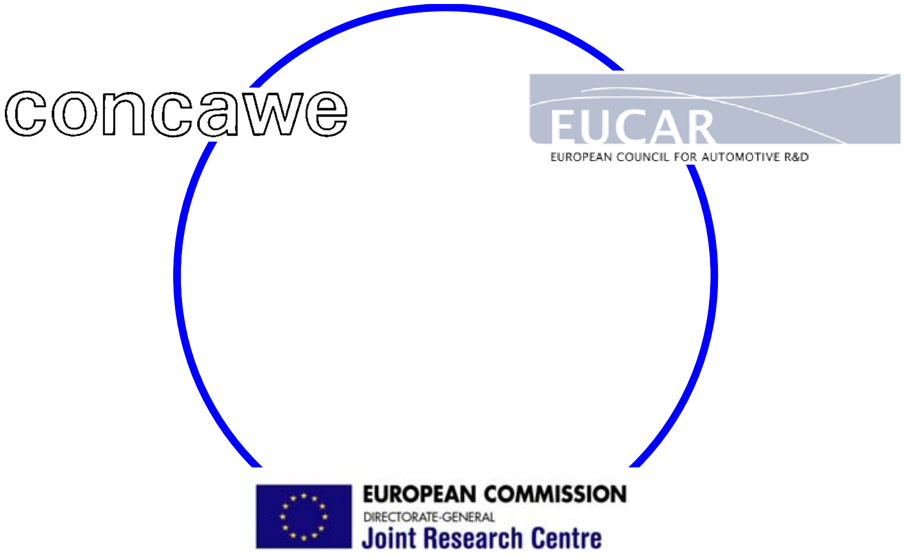
WELL-TO-WHEELS ANALYSIS OF FUTURE AUTOMOTIVE FUELS AND POWERTRAINS IN THE EUROPEAN CONTEXT



WELL-to-TANK Report

Version 2b, May 2006

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Notes on version number:

This is the second version of this report replacing version 1b published in December 2003.

There have been extensive modifications to the 2003 report including addition on new pathways, review of certain pathway basic data, review and update of cost and availability as well as correction of some errors pointed out by our readers.

Acknowledgments

This work was carried out jointly by representatives of EUCAR (the European Council for Automotive R&D), CONCAWE (the oil companies' European association for environment, health and safety in refining and distribution) and JRC/IES (the Institute for Environment and Sustainability of the EU Commission's Joint Research Centre), assisted by personnel from L-B-Systemtechnik GmbH (LBST) and the Institut Français de Pétrole (IFP).

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1 Introduction

This part of the study describes the process of producing, transporting, manufacturing and distributing a number of fuels suitable for road transport powertrains. It covers all steps from extracting, capturing or growing the primary energy carrier to refuelling the vehicles with the finished fuel.

As an energy carrier, a fuel must originate from a form of primary energy which can be either contained in a fossil feedstock (hydrocarbons of fissile material) or directly extracted from solar energy (biomass or wind power). Generally a fuel can be produced from a number of different primary energy sources. In this study, we have included all fuels and primary energy sources that appear relevant within the timeframe considered (next decade) and we have considered the issues and established comparisons from both points of view in order to assist the reader in answering the questions:

- What are the alternative uses for a given resource and how can it best be used?
- What are the alternative pathways to produce a certain fuel and which of these hold the best prospects?

Our primary focus has been to establish the **energy and greenhouse gas (GHG) balance** for the different routes. The methodology we used is based on the description of individual processes, which are discreet steps in a total pathway, and thereby easily allows the inclusion of additional combinations, should they be regarded as relevant in the future.

We have not considered the energy or GHG emissions associated with construction or decommissioning of plants and vehicles. There are two reasons for this. First the available data is often sketchy and uncertain. Second the impact of these additional energy requirements on the total pathway balance is generally small and within the range of uncertainty of the total estimates. This may, however, not always be the case and this should be checked when looking at a particular route in more details.

The scale at which a route might be developed is relevant to the selection of appropriate energy data but also to the attention that should be given to a particular option. We have therefore endeavoured to assess the **future “availability” of the different fuels** and associated resources.

The best options from an energy or GHG point of view are only likely to raise interest if they can be developed at a reasonable cost. Cost estimation is a difficult discipline and one must endeavour to define clearly what is intended. In this case we have attempted to consider the **macro-economic costs to Europe** of producing a certain fuel in a certain way at a certain scale. This implies for example that the cost of internationally traded commodities (such as oil products or natural gas) is equal to the expected international market price.

In any such study, many choices have to be made at every step. These cannot always be based purely on scientific and technical arguments and inevitably carry an element of judgement. While we do not pretend to have escaped this fact, we have endeavoured to make our choices and decisions as transparent as possible. In particular this report details all primary input data and underlying assumptions.

This study has been conducted in collaboration with LBST[1] through whom we have had access to the comprehensive information database compiled by the TES consortium[2] and in the course of the study carried out in 2001-2002 by General Motors [GM 2002]. With the agreement of these two organisations we have used the information extensively. Our contribution has been to extensively review and update the existing information and add a number of new processes and a number of new pathways not hitherto considered.

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[1] L-B-Systemtechnik, Germany

[2] Transport Energy Strategy Partnership.

2 Scope, Methodology, Definitions, Structure

2.1 Pathways

A number of existing and potential road transport **fuels** have been identified, in association with existing and/or future powertrains. Each fuel can be produced from a single or several **resources** as the source of primary energy. The combination of steps necessary to turn a resource into a fuel and bring that fuel to a vehicle is defined as a **Well-to-Tank pathway (WTT)**.

Each pathway is described in terms of the successive **processes** required to make the final fuel available to the vehicles. A complete pathway is a combination and succession of processes, many of which are common to several pathways. A process has a main input and a main output, secondary inputs, by-products as well as factors for energy consumption and greenhouse gas (GHG) emissions. Some pathways include closed loops that have to be solved by iteration.

The main calculations have been carried by a software program developed by LBST[3] and which combines a database for all input data and their references with an algorithm for the rigorous calculation of the total energy and GHG associated with a given pathway, including feedback loops.

Each pathway is described to a suitable level of detail including itemised contributions of the different processes. In order to facilitate comparison between sometimes very different pathways the results are also presented according to 5 generic stages:

Production and conditioning at source includes all operations required to extract, capture or cultivate the primary energy source. In most cases, the extracted or harvested energy carrier requires some form of treatment or conditioning before it can be conveniently, economically and safely transported.

Transformation at source is used for those cases where a major industrial process is carried out at or near the production site of the primary energy (e.g. gas-to-liquids plant).

Transportation to EU is relevant to energy carriers which are produced outside the EU and need to be transported over long distances.

Transformation in EU includes the processing and transformation that takes place near the market place in order to produce a final fuel according to an agreed specification (e.g. oil refineries or hydrogen reformers).

Conditioning and distribution relates to the final stages required to distribute the finished fuels from the point of import or production to the individual refuelling points (e.g. road transport) and available to the vehicle tank (e.g. compression in the case of natural gas).

The table below summarises the pathways considered in this study.

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[3] E^3 database by L-B-Systemtechnik, Germany

Table 2.1 Fuels and resources

Fuel Resource		Gasoline, Diesel, Naphtha (2010 quality)	CNG	LPG	Hydrogen (comp., liquid)	Synthetic diesel (Fischer-Tropsch)	DME	Ethanol	MT/ETBE	FAME/FAEE	Methanol	Electricity
Crude oil		X										
Coal					X$^{(1)}$	X$^{(1)}$	X				X	X
Natural gas	Piped		X		X$^{(1)}$	X	X				X	X
	Remote		X$^{(1)}$		X	X$^{(1)}$	X$^{(1)}$		X		X	X
LPG	Remote$^{(3)}$			X					X			
Biomass	Sugar beet							X	⇳			
	Wheat							X	X			
	Wheat straw							X				
	Sugar cane							X				
	Rapeseed									X		
	Sunflower									X		
	Woody waste				X	X	X	X			X	
	Farmed wood				X	X	X	X			X	X
	Organic waste		X$^{(2)}$									X
	Black liquor				X	X	X				X	X
Wind												X
Nuclear												X
Electricity					X							

(1) with/without CO_2 capture and sequestration
(2) Biogas
(3) Associated with natural gas production

Electricity is considered both as a fuel and as a resource. The hydrogen pathways involving electrolysis are therefore the combination of one electricity production route and of the electrolytic conversion. Although electric vehicles are not included in the current study, this paves the way for their introduction in later revisions.

2.2 Time horizon

The notional time horizon for the study is the next decade 2010-2020. The technologies considered are those that are expected to become commercially available in that time frame. The same applies to supply/demand, availability and potential for substitution of conventional fuels.

2.3 Incremental approach

The ultimate purpose of this study is to guide those who have to make a judgement on the potential benefits of substituting conventional fuels by alternatives. At the 2010-2020 horizon, this substitution is only plausible at a limited level, say between 5 and 15% at the maximum depending on the option considered. The true impact of the change can only be properly assessed by looking at the incremental sources of energy that will provide alternative fuels, and the incremental savings that can be achieved by reducing supply of conventional fuels.

In order to estimate the implications of replacing conventional fossil transport fuels with a certain alternative fuel (one at a time) in terms of energy use, GHG emissions and cost, we calculated the *difference* between two realistic future scenarios: one in which the alternative fuel was introduced or expanded and one "business as usual" reference scenario which assumed that demand was met by the forecast mix of conventional fossil fuels in 2010-2020. The transport demand (number of km driven) and all other factors remained the same in both scenarios. We then derived metrics such as the conventional replacement cost per km or per tonne conventional fuel, the GHG savings per km or per tonne and (by combining these) the GHG mitigation cost.

For conventional fuels, the question to consider is what savings can be realised by producing less of these fuels rather than how much energy, GHG emissions and costs are involved in absolute terms. The methodology for estimating these savings is also based on incremental changes and is further discussed in *section 3.1*.

2.4 Methodology for accounting for by-products

Many processes produce not only the desired product but also other streams or “by-products”. This is the case for biofuels from traditional crops such as bio-diesel from rapeseed. In line with the philosophy described above we endeavoured to represent the “incremental” impact of these by-products. This implies that the reference scenario must include either an existing process to generate the same quantity of by-product as the alternative-fuel scenario, or another product which the by-product would realistically replace.

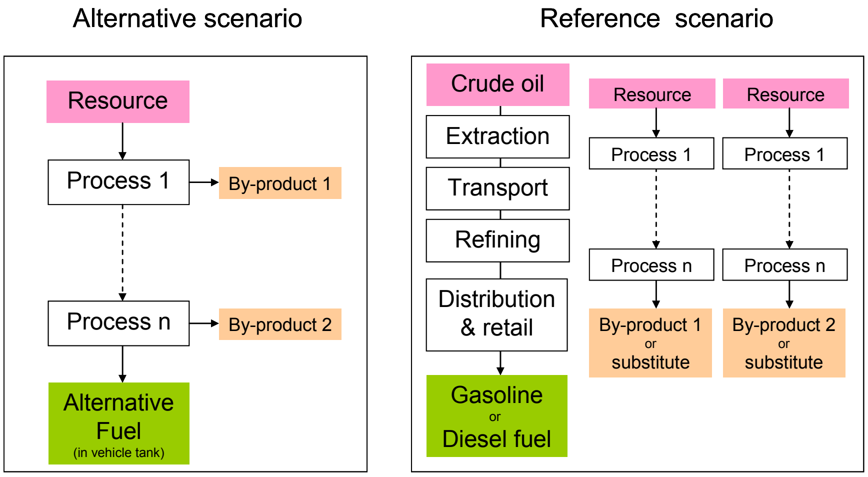
This logic is reflected in the following methodology (***Figure 2.1.4***):

- All energy and emissions generated by the process are allocated to the main or desired product of that process.
- The by-product generates an energy and emission credit equal to the energy and emissions saved by not producing the material that the co-product is most likely to displace.

For example, in the production of bio-diesel from oil seeds, protein-rich material from e.g. oil seeds pressing are likely to be used as animal fodder displacing soy meal.

We strongly favour this "substitution" method which attempts to model reality by tracking the likely fate of by-products. Many other studies have used "allocation" methods whereby energy and emissions from a process are arbitrarily allocated to the various products according to e.g. mass, energy content, “exergy” content or monetary value. Although such allocation methods have the attraction of being simpler to implement they have no logical or physical basis. It is clear that any benefit from a by-product must *depend on what the by-product substitutes:* all allocation methods take no account of this, and so are likely to give flawed results.

Figure 2.4 By-product credit methodology



In most cases, by-products can conceivably be used in a variety of ways and we have included the more plausible ones. Different routes can have very different implications in terms of energy, GHG or cost and it must be realised that economics rather than energy use or GHG balance, are likely to dictate which routes are the most popular in real life.

The following example shows how allocation methods can bear little relation to reality. The manufacture of FAME (biodiesel) makes glycerine as a by-product. Amongst other options, the glycerine could be used instead of synthetic (pharmaceutical) glycerine or as animal feed, instead of wheat grain. Making 1 MJ synthetic glycerine requires about 18 MJ of fossil energy. Making 1 MJ of wheat takes about 0.13 MJ. Clearly much more fossil carbon emissions will be saved in the first option than in the second. Yet the "allocation" approaches based on energy or mass predict that the savings will be exactly the same!

Many processes have more than one energy product: for example, many wood and straw processing pathways include a significant electricity export. The procedure above deals with how to find the greenhouse gas and fossil energy savings for the process, but it does not specify how much of the savings are due to making biofuels and how much is due to making bioelectricity. If one attributes all the GHG/energy credits to the biofuel, one comes to the conclusion that the smaller the fraction of biofuels produced compared to electricity, the better the GHG balance.

That quantity of bio-electricity could have been produced by a free-standing bioelectricity generator: its existence does not depend on the biofuels process. It is clear that to get a balance which pertains only to the biofuel output, we need in some way to subtract the bioelectricity part of the process. This is done by using a dedicated biomass-to-electricity process in the reference scenario; then the difference between the alternative and reference scenarios is only the production of biofuel. This is described in more detail in *section 3.4*.

2.5 Dealing with uncertainties

As already alluded upon in the introduction, the analysis of a certain process or pathway requires choices to be made and figures to be adopted on the basis of criteria that, even if they are logical and documented, always remain somewhat judgmental.

Whenever major contributions were at stake, we have endeavoured to create different pathways to directly show the effect of a particular option or view (e.g. the origin of natural gas has a strong influence on the total pathways through the transport contribution). This approach would, however, be impractical to deal with all sources of variability.

Industry generally uses a range of processes which, at least historically, have not been selected based solely on their energy efficiency but mainly on economic grounds. So established production paths display a range of variability. As we are dealing with the future, we mainly address new processes or improved existing ones, the future performance of which is necessarily somewhat speculative. As a result, each step in a pathway carries a certain variability range representing the combination of the range of performance of the future installations and the uncertainty attached to the expected technical developments. On the basis of the quality of the data available, the degree of development of the process and any other relevant parameter, a judgement has been made as to the level of uncertainty attached to each figure as well as the probability distribution within the range. We have used a Gaussian distribution as default but also a so-called "double-triangle" for asymmetrical ranges and an equal-probability or "square" distribution when there is reason to believe that all values in the range are equally probable.

In order to combine all uncertainties in a pathway and arrive at a plausible range of variation for the total pathway, we have used the traditional Monte Carlo approach. Subsequent calculations have been carried out with the median figure.

2.6 Availability and costs: the bigger picture

A detailed well-to-wheels analysis of each pathway is essential but by no means sufficient to capture the potential value and relevance of a particular route. Indeed issues of availability, feasibility of certain processes, costs, acceptability by the general public on a large scale, all play an important role to assess the practical potential of a certain route.

The choices and assumptions that have to be made when defining the various elements of a pathway are sensitive to the assumed scale at which that pathway might be developed. For example the size of the plants and of the ships, the distance between producer and customer are all affected to a degree. Where this is the case, we have given relevant indications and justified our choices.

In this connection, the availability of the primary resources is obviously critical. Within the timeframe of the study availability is not a major issue for fossil fuels, but the potential of primary renewable resources certainly needs to be carefully considered. The issues to consider here are either physical limitations, or those related to alternative use (e.g. use of arable land for food versus energy crops), or achievability (e.g. number of wind turbines that might conceivably be installed in a certain area). We have attempted to gather relevant information and to develop informed views on these aspects but we recognise that the conclusions remain partially judgmental.

In any study, the forecast of costs is always a particularly thorny problem. The first thing to define is what is included and what is not. In this study, we have elected to consider only the direct costs i.e. those related to investments in and operation of infrastructural equipments. We therefore have not considered other possible sources of costs (or benefits) related to e.g. employment opportunities, regional development and the like.

We have considered costs from the point of view of the EU as an economic entity ("macro-economic" costs). For those resources that are also internationally traded commodities (such as oil products, natural gas or wheat grain), the market price represents the minimum cost as it corresponds to the amount either required to purchase that commodity or not realised by using that resource elsewhere (for instance the cost of crude oil to the EU is not its production cost but its price on the international market). Production at a higher cost within the EU is only likely to occur if some form of subsidy is available. Since costs and not customer prices are presented, subsidies and taxes are not included in the calculation. The figures represent the full cost to the EU, regardless of how this is shared out. For other resources (e.g. wood) we have estimated the production cost from the various processes involved.

When it comes to investment in plants and infrastructure, costs are critically dependent on scale. This WTT report includes the cost figures for individual plants, refuelling stations and the like. In the integrated WTW analysis, we have estimated the cost of all pathways on the basis of a common scale scenario representing 5% substitution of conventional fuels (see *WTW report*).

2.7 Reference scenario for road fuels demand

In a number of cases, the estimation of energy requirement or cost of certain processes depends on the scale considered. An underlying scenario is therefore required to arrive at reasonable and consistent volume figures. A demand scenario for road transport is the starting point.

European road fuel demand is characterised by a slow decrease in gasoline more than compensated by an increase in diesel fuel. This is the combined result of the increasing shift to diesel passenger cars (encouraged by the drive to reduce CO_2 emissions) and of the increasing road haulage activities. In spite of the already achieved and expected further improvements in efficiency, road haulage should be responsible for a continued increase in diesel fuel consumption as it follows economic growth.

These trends are somewhat less marked when incorporating Eastern European countries where gasoline demand is still expected to grow for some time.

We have used figures from an oil industry study as summarised in the table below.

Table 2.7 ***EU-25 road fuels demand (Mt/a)***

Year	1995	2000	2005	2010	2015	2020
Gasoline	129	124	111	98	93	92
Total road diesel	110	138	169	197	204	199
Total road fuels	239	262	281	295	297	291
Diesel to personal cars						
%	*28%*	*27%*	*32%*	*35%*	*33%*	*29%*
Mt	31	37	54	69	68	57
Total road fuels to personal cars	160	161	165	167	161	149

Source: Wood McKenzie (unpublished Industry study)

These figures represent total demand for road transportation i.e. including what might be supplied by alternative fuels. They can be used as guidance when judging the potential of certain pathways for substitution of a portion of the road fuel market.

Compared to figures used in the previous version of this report, the new forecasts shows a much larger decline of gasoline demand, partly compensated by a larger increase of the diesel demand.

Other sources may somewhat deviate from these but this would not have a material effect on the conclusions. Indeed the figures are used to provide orders of magnitude and to ensure consistency between the various options.

2.8 Miscellaneous assumptions

A number of processes in the pathways make use of common assumptions listed below.

2.8.1 GHG coefficients

The CO_2 equivalence is applied to the non-CO_2 greenhouse gases according to the conversion coefficients recommended by the third assessment report of the Inter-governmental Panel for Climate Change [*IPCC*].

Table 2.8.1 ***IPCC factors***

Greenhouse gas	t CO_2eq / t
CO_2	1
Methane (CH_4)	23
Nitrous oxide (N_2O)	296

Other GHGs are not emitted in significant quantities in any of the processes considered.

2.8.2 Energy content

All energy contents referred to are on LHV basis i.e. excluding the heat generated after the combustion process by the condensation of water vapour.

2.8.3 Shipping

Many pathways include long-distance shipping of gases or liquids. In all such case we have used published data for a type of ship consistent with the length of the envisaged trip and the material being carried. Such ships normally return empty and the corresponding fuel consumption has been taken into account through the so-called “Admiralty formula” according to which the fuel consumption of a ship is proportional to the cubic root of the water displacement.

2.9 Presentation of results

2.9.1 Where to find what in this report?

The narrative part of this report is divided into three sections:

- In *section 3* **"From resource to fuel"** we seek to answer the question "what fuel can be made from a given resource?" We discuss the steps or processes necessary to transform a resource into a number of final fuels, indicating the relevant assumptions and choices. This section should be read together with *WTT Appendix 1* which gives process by process input data, and a stepwise description of all pathways.
- In *section 4* "Final fuels" we consider the question "how can a given fuel be made?" We compare the merits of the different routes from the points of view of energy and GHG balance, for which detailed figures are found in *WTT Appendix 2*.
- In *section 5* "**Potential availability and costs**" we consider the potential volumes that could be produced via the different routes and present the methodology, figures and assumptions used for cost estimates.

All references, including those relevant to the appendices are listed at the end of this document.

2.9.2 Units and conventions

All WTT figures are expressed relative to one MJ of finished fuel delivered into the vehicle fuel tank (MJ_f).

The energy figures are presented as total primary energy expended (MJ_{xt}), regardless of its origin, to produce one MJ_f of the finished fuel under study (LHV basis). The figures exclude the heat content of the fuel itself (i.e. 1 MJ_{xt}/MJ_f means that as much energy is required to produce the fuel as is available to the final user) but include both fossil and renewable energy. As such they describe the energy efficiency of the pathway. An exception to this was made for the electricity pathways because electricity is used as an intermediate energy source rather than a "road fuel" (*see section 4.8*). For fuels of renewable origin we have also evaluated the fossil energy expended in the pathway (MJ_{xf}), illustrating the fossil energy saving potential of that pathway compared to conventional alternatives.

The figures shown in the main body of this report and in *WTT Appendix 2* for the intermediate steps of a pathway all relate to a MJ of the finished fuel produced by that pathway, not to the output of the particular step. In *WTT Appendix 1*, which shows the detailed input data, the figures shown relate to a MJ of the output of each individual process.

GHG figures represent the total grams of CO_2 equivalent (see also *section 3.4*) emitted in the process of obtaining 1 MJ_f of the finished fuel. For fuels of biomass origin, an additional credit is allocated, equal to the amount of CO_2 generated by complete combustion of the fuel. In this way the TTW CO_2 emissions do not need to take account of the origin of the fuel but only of its composition.

2.9.3 References

A complete list of references used in the study is included at the end of this report. Those essential to the flow of the discussion are cited in the main text, however the majority refer to the text of *WTT Appendix 1*.

3 From Resource to Fuel: production routes

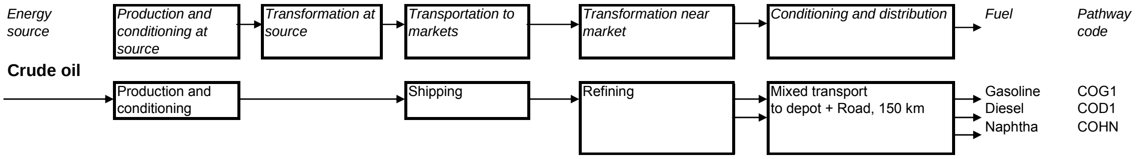
In this chapter we describe the pathways processes necessary to convert a certain primary resource into a final fuel. The stepwise description of the pathways together with the detailed input data and further detailed comments and remarks on individual processes are given in *WTT Appendix 1*.

3.1 Crude oil pathways

(See also WTT Appendix 1 section 1-3)

The pathways from crude oil to road fuels are straightforward, as illustrated in the following figure. Note that naphtha has been included here as it is a potential fuel for on-board reformers (see *TTW or WTW report*).

Figure 3-1 Conventional fuels pathways



3.1.1 Crude oil production and conditioning at source

Crude oil is generally extracted under the natural pressure of the underground reservoir. In some, mostly older fields, it may be necessary to boost the reservoir pressure by gas injection. In most cases oil is associated with gases and needs to be stabilised before shipment. Water separation is also sometimes required. The associated gases used to be commonly flared but are now generally either conditioned and shipped separately (e.g. LPG) or re-injected into the reservoirs.

Production conditions vary considerably between producing regions, fields and even between individual wells and it is only meaningful to give typical or average energy consumption and GHG emission figures for the range of crudes under consideration. We have used a value of 0.025 MJ/MJ (0.01-0.04) and 3.3 g CO_2eq/MJ (2.8-3.9), representing the combined estimates of a number of CONCAWE member companies.

The marginal crude available to Europe is likely to originate from the Middle East where production energy tends to be at the low end of the range. From this point of view the use of the above average figures can be considered as conservative.

3.1.2 Crude oil transportation to markets

Crude needs to be transported from the production areas to refineries in Europe. Crude oil is mostly transported by sea. The type of ship used depends on the distance to be covered. The bulk of the Arab Gulf crude is shipped in large ships (VLCC or even ULCC Very/Ultra Large Crude Carrier) that can carry between 200 and 500 kt and travel via the Cape of Good Hope to destinations in Western Europe and America or directly to the Far East. North Sea or African crudes travel shorter distances for which smaller ships (100 kt typically) are used.

Pipelines are also extensively used from the production fields to a shipping terminal. Some Middle Eastern crudes are piped to a Mediterranean port. The developing regions of the Caspian basin will rely on one or several new pipelines to be built to the Black Sea. Crude from central Russia is piped to the Black Sea as well as directly to eastern European refineries through an extensive pipeline network.

Although the majority of refineries tend to be at coastal locations, a number of them are inland. Within Western Europe, there are several inland pipelines from the Mediterranean to North Eastern France and Germany as well as from the Rotterdam area to Germany.

Here again, there is a wide diversity of practical situations. Considering mainly marginal crude originating from the Middle East an energy figure of 1% (10 MJ/MJ) has been used, corresponding to 0.8 g CO_2eq/MJ assuming a ship fuelled by heavy fuel oil.

3.1.3 Crude oil refining

Traditionally, crude oil is transported as such and refined near the markets. The advent, from the early 80's, of large "export" refineries in the Middle East provided another model of refining at source and long-haul product transportation. However, the number of such refineries remains limited and so does their impact, specifically on Europe where the overwhelming majority of finished products are produced by local refineries importing crude oil. Although Europe imports some blending components and finished products, the bulk of the fuels sold in Europe is manufactured in European refineries. This study therefore assumes that crude oil based fuels are manufactured from crude oil in European refineries.

An oil refinery is a complex combination of process plants, the objective of which is to turn crude oil into marketable products of the right quality and in the right quantities. This entails

- Physical separation of the crude components,
- Treating to remove such compounds as sulphur,
- Conversion of mainly heavy molecules into lighter ones to match the production slate to the market demand.

European refineries consume about 6% of their own intake as processing energy. Some energy is exchanged with the outside (e.g. electricity import/export, natural gas import). Although European refineries are global importers of energy/fuels other than crude oil, the bulk of the energy used by refineries comes from their crude oil intake. The refineries burn gas (mainly generated in the refinery processes) as well as liquid and solid fuels.

Oil refineries produce a number of different products simultaneously from a single feedstock. Whereas the total amount of energy (and other resources) used by refineries is well documented, there is no simple, non-controversial way to allocate energy, emissions or cost to a specific product. Distributing the resources used in refining amongst the various products invariably involves the use of arbitrary allocation keys that can have a major influence on the results. More to the point, such a simplistic allocation method ignores the complex interactions, constraints, synergies within a refinery and also between the different refineries in a certain region and is likely to lead to misleading conclusions. From an energy and GHG emissions point of view, this is also likely to give an incomplete picture as it ignores overall changes in energy/carbon content of feeds and products.

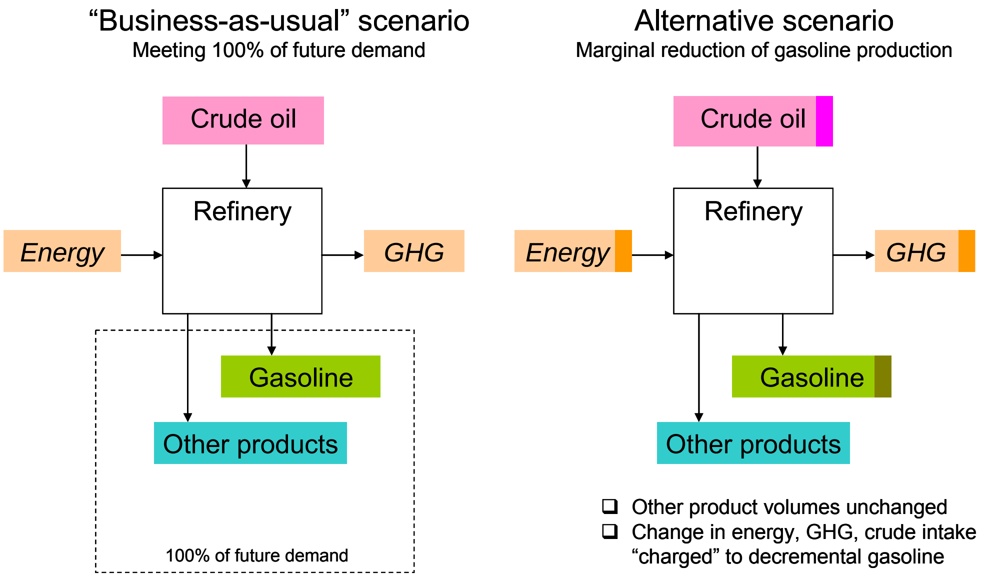
In order to estimate the savings from conventional fuels the question to consider was what could be saved by using less of these rather than how much they cost in absolute terms. We thus considered that, in the context of this study, the energy and GHG emissions associated with production and use of conventional fuels should be representative of how the EU refineries would have to adapt to a marginal reduction of demand. Such figures were obtained through modelling of the EU-wide refining system (see ***Figure 3.1.3*** and more details in *WTT Appendix 3*).

Within the scope of substitution mentioned above and the timeframe considered, production costs of alternative fuels could reasonably be taken as proportional to volumes. Infrastructure costs, which are significant for fuels that are not fungible with conventional ones (e.g. gaseous fuels), critically depend on the scale envisaged. In order to compare the various options on an equal footing we developed, for the most significant fuel options, a production and distribution cost scenario based on satisfying 5% of the future passenger car transport demand.

From this analysis it appears that, in Europe, marginal diesel fuel is more energy-intensive than marginal gasoline. In recent years Europe has seen an unprecedented growth in diesel fuel demand while gasoline has been stagnating or even dropping. According to all forecasts, this trend will continue in future years, driven by increased dieselisation of the personal car and the growth of freight transport in line with GDP. At the same time, jet fuel demand also steadily increases as air transport develops. The ratio of an ever increasing call for "middle distillates" and a call for gasoline that is at best constant goes beyond the "natural" capabilities of a refining system that was by and large designed with a focus on gasoline production. Reducing diesel fuel demand therefore "de-constrains" the system whereas decreasing gasoline demand makes the imbalance worse.

Similar calculations have been performed for marginal naphtha.

Figure 3.1.3: Impact of a marginal reduction of conventional gasoline demand



- ☐ Other product volumes unchanged
- ☐ Change in energy, GHG, crude intake "charged" to decremental gasoline

Based on our results, we have adopted the following figures:

		Gasoline	Diesel fuel	Naphtha
Energy	MJ/MJ	0.08	0.10	0.05
GHG	g CO_2eq/MJ	6.5	8.6	4.5

The calculations were carried out on the basis of a 2010 base case including all foreseen fuel specifications including sulphur-free road fuels. Although the additional quality requirements will result in a higher absolute level of energy consumption in the refineries in 2010 compared to the current situation, the effect on the marginal value are of a second order of magnitude. The above figures can therefore be considered as representative of the whole time period.

Note: In principle the same marginal analysis should apply to the other stages of the elaboration and distribution of conventional fuels. However, these figures are small compared to those for refining and it can reasonably be assumed that energy and GHG emissions associated with crude production and transportation as well as product distribution are proportional to the volumes concerned.

3.1.4 Gasoline and diesel fuel distribution

Finished products from the refinery are transported either by road tanker directly to a retail station or, for the larger part, to a depot by pipeline, train or barge. For the calculation a mix of the different transportation modes has been used according to the actual share of each mode in

Europe. Depots and service stations also account for a small energy consumption, essentially in the form of electricity.

The total average figure for Europe is estimated at 20 kJ and just over 1 g CO_2eq per MJ of delivered fuel. These figures can reasonably be assumed to be independent of the volumes concerned.
In monetary terms, however, most of the infrastructural costs attached to production and distribution of conventional fuels would not be significantly affected by a limited substitution, particularly as distribution of alternative fuels would rely on the existing network. Therefore only variable distribution costs were taken into account.

3.2 Natural gas pathways

(See also WTT Appendix 1 section 1-4)

Natural gas (NG) is the most plentiful fossil fuel after coal. It is available in most regions of the globe although there are a few very large producing regions such as Russia and, potentially, the Middle East. Only a relatively small part of the known reserves of natural gas is currently exploited. This is partly the result of the relative difficulty to bring natural gas to market when it originates from isolated areas. The exploitation of a natural gas field requires a heavy associated infrastructure in the form of either pipelines or liquefaction equipment and LNG ships. The real availability is therefore limited more by the realisation of projects to develop new fields and transportation systems than by the physical reserves. In recent years the option of turning natural gas into liquids (such as methanol, DME or FT fuels) has become a potentially viable option particularly for the most remote locations.

So far NG has been almost exclusively used in stationary applications, mainly in domestic heating, industrial fuel and electricity production. Use of NG as road fuel (in the form of compressed natural gas or CNG) has been limited to specific markets or niche applications. NG use for power generation has increased tremendously in the EU during the last decade as sulphur emission limits were introduced to combat acidification. The favourable C/H ratio of natural gas compared to coal or oil also makes it the fuel of choice to replace coal or heavy fuel oil when targeting CO_2 emissions.

3.2.1 Gas sourcing options for pathway calculation

It is clear that, by the second decade of this century, any extra supplies will most likely come from either the Middle East or the FSU. Bringing this gas to Europe will involve either new pipelines or LNG schemes. We have therefore considered two main options viz.

- “Piped” gas transported to Europe via long-distance pipeline. In practice this represents additional availability from the FSU or new sources from Central Asia.
- “Remote” gas from various world producing regions (particularly the Arabian Gulf) either shipped into Europe as LNG or transformed at source into liquids.

In addition we have calculated, for reference, a limited number of pathways based on a notional “EU-mix” representative of the current origin of the gas used in Europe. In line with the marginal approach, we do not consider this as a valid case for assessment of the future potential of natural gas pathways but it provides a reference representing current gas use.

3.2.2 Natural gas production, conditioning and transport via long-distance pipelines

Natural gas is produced from either dedicated fields or as associated gas in oil fields. Although it is primarily methane, the gas mixture coming out of the well can contain a range of light hydrocarbons as well as inert gases, mainly nitrogen and CO_2.

The bulk of the light hydrocarbons need to be separated as they would condense at various stages of the transportation system. These condensates may be used locally or transported to appropriate markets. C3 and C4 hydrocarbons can be used as LPG for various purposes or as chemical feedstocks which is also the case for heavier condensates. Some may be flared but this practice is gradually disappearing.

Inerts are not normally separated except for some fields where the CO_2 content is high. In a limited number of cases, the separated CO_2 is re-injected into the wells and this may become more common in the future. Unless this is the case, this CO_2 ends up in the atmosphere either at the processing plant or at the end consumer. The CO_2 content of the typical gas sources available to Europe is generally in the region of 1% v/v or less. In order to account for this CO_2 in a simple way in all pathways concerned, we have included a 1% v/v CO_2 venting at the production stage. The EU-mix used for the Tank-to-Wheels part of the study includes a small CO_2 content (see *WTT Appendix 1*, *section 1-1*). This has been included to reflect the correct gas parameters but no additional CO_2 emissions accrue from it.

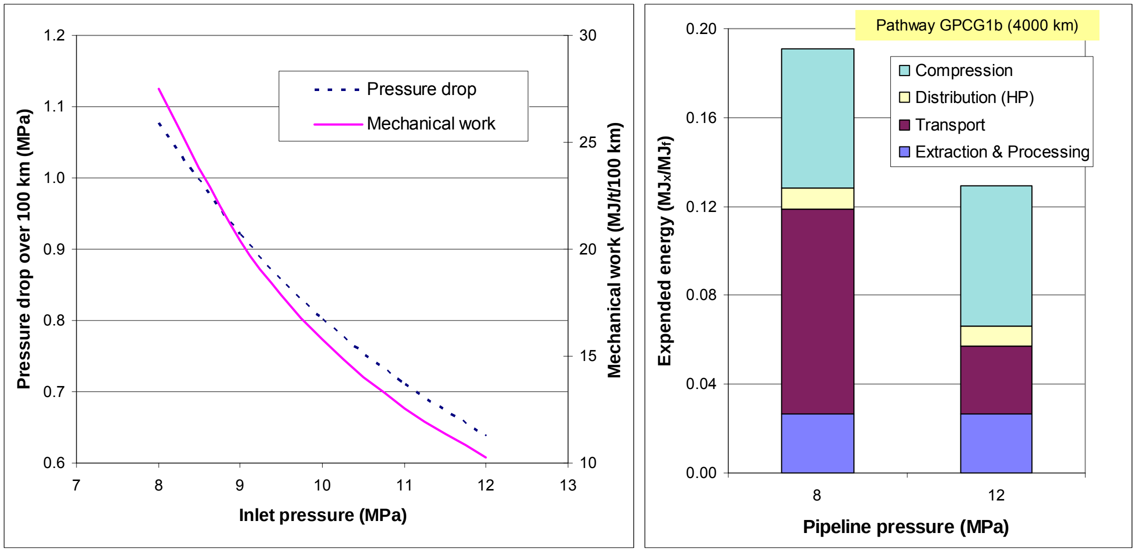
The energy associated with extraction and processing varies considerably with the producing region. This reflects different gas qualities, practices and climatic conditions. For extraction, most of the energy is supplied directly in the form of natural gas (typically through an on-site power plant). Processing can take place near the wellhead or, as is common in Russia, at a central location where light hydrocarbons can be readily used as chemical feedstocks. In such a case the energy supply may be mixed and include various hydrocarbon fuels as well as electricity from the local grid. Based on the various sources of information available we have used a median figure of 2% of the processed gas with a range of 1 to 4%. We have not included any term for associated condensates, postulating that their production and use would globally be energy/GHG neutral (compared to alternative sources). 0.4% of methane losses are also included.

Transportation accounts for the largest part of the energy requirement because of the large distances involved. Western Siberian fields are about 7000 km from Europe whereas typical future South West Asian locations may be 4000 km away. Pipelines require compression stations at regular intervals, typically powered by a portion of the transported gas. The specific energy requirement therefore increases with distance as the larger the distance the more gas has to be transported initially to obtain a unit of delivered gas. The actual energy consumption figures may vary considerably from one pipeline to another depending on the design and operation parameters (size v. throughput, compressors and drivers efficiency etc). The energy consumption is very sensitive to the pressure at which the pipeline is operated. Existing pipelines operate at pressures of 6 to 8 MPa. New pipelines may be designed to operate at significantly higher pressures which, at constant diameter and throughput, could cut energy requirements by a factor 2 to 3. This is illustrated in ***Figure 3.2.2***.

There is however a trade-off between energy consumption (i.e. operating costs) and pipeline diameter (i.e. capital cost). In order to represent the diversity of current of possible future situations we have used median and maximum values corresponding to today's operations with, as a potential future improvement, a minimum value corresponding to a 50% pressure increase. For the 4000 km case for instance we have used a median value of 8.8% of the delivered gas with a range of 2.9 to 9.9%.

Combined leakages in the transportation system result in some methane losses (directly emitted to the atmosphere). Although it has often been reported that such losses are very high in the Russian system, comprehensive studies such as conducted by Ruhrgas and Gazprom and more recently by the Wuppertal Institute [*Wuppertal 2004*], give a more sedate picture. According to the latter source we have accounted for a loss of 0.13% per 1000 km reduced from the 0.16% figure used in version 1 and based on the former study.

Figure 3.2.2 Impact of pipeline operating pressure on gas transport energy requirement



3.2.3 LNG

Liquefied Natural Gas (LNG) provides an alternative to pipelines where these are not practical or when distances are very large. LNG production and long distance shipping is a well-established route widely used throughout the world.

Gas is extracted and cleaned up before being liquefied in a cryogenic plant. For extraction and pre-processing we have assumed the same figure as for other gas sources.

Liquefaction entails essentially electricity consumption, commonly produced from the gas supply itself in a dedicated power plant. There are small associated methane losses (0.17%) while flaring of off-gas (0.25%) contributes to CO_2 emissions.

Transport takes place in dedicated ships. Heat exchange with the environment during transport is compensated by evaporation of a portion of the gas which is typically used as fuel by the ship, the balance being provided by standard residual bunker fuel. We have assumed a typical distance of 5000 to 6000 nautical miles (typical for trips from the Arab gulf to Western Europe via the Suez canal).

Note: LNG from Algeria or West Africa would have to travel significantly shorter distances to reach Europe. These sources are, however, not considered to be representative of bulk of the future marginal gas supply.

As mentioned in *section 3.2.1* LNG is likely to play a significant, if not major, role in the gas supply of Europe. LNG imported into Europe is most likely to be vaporised and mixed into the natural gas grid. As the number of terminals increases LNG will become more accessible as such and the possibility to deliver it by road directly to refuelling stations can also be envisaged. This option has a theoretical advantage from an energy point of view as compression and vaporisation can be combined. We have included this case in the analysis.

Liquefaction of natural gas requires a large amount of energy to be spent near the gas fields, essentially in the form of electricity. This provides an opportunity for CO_2 capture and storage (CC&S, see *section 3.6*)

3.2.4 NG distribution in Europe

Natural gas is widely available throughout Europe via an extensive network of pipelines covering virtually all densely populated areas. There is a limited network of high pressure pipelines (4-6 MPa) acting as trunk lines for the denser low pressure networks as well as serving large industrial consumers. The local distribution networks operate at different pressures depending on the countries. 0.4 MPa is becoming the norm but a number of countries/regions still operate a 0.1 MPa network while some such as a large part of the UK still have a very low pressure system (a few mbar) inherited from the town gas era. These networks serve small industrial and domestic consumers and are very dense. The transfers between the different pressure levels take place in reduction stations where the pressure energy is effectively lost. From a global point of view there is therefore an incentive to take the gas at the highest possible pressure level in the network although this is not always practical.

These systems do not appear to have serious capacity limitations for the foreseeable future and the additional quantities that can reasonably be foreseen for road fuel applications could in all likelihood be easily accommodated.

There are, however, a number of sparsely populated regions that do not have access to natural gas because the potential volumes cannot justify building a pipeline network. This is unlikely to change in the future even if some potential additional sales can be generated from road fuels. This concerns fairly large areas of e.g. France, Spain and Scandinavia and could be a problem when it comes to developing a dense refuelling station network, in particular along motorways. Direct LNG supply may be a suitable solution for these areas.

There is a small energy consumption attached to the high pressure distribution networks for which we have assumed an average distance of 500 km. Because they are fed directly from the long-distance high pressure pipelines, the local low pressure networks do not generate additional energy consumptions inasmuch as the upstream pressure is more than sufficient to cover the head losses.

Methane losses in the well-maintained European pipeline networks are reportedly very small. In the case of the local networks, they tend to be mostly related to maintenance and are therefore not relevant to marginal gas.

Natural gas from the network can be used to feed CNG refuelling stations. For more details on CNG see *section 4.3.1.*

3.2.5 NG transformation

NG to electricity

See section 3.5.1

NG to hydrogen

Hydrogen can be obtained from NG either directly via steam reforming or indirectly via power generation and electrolysis.

Hydrogen production by steam reforming of methane is an established process widely used e.g. in oil refineries. The catalysed combination of methane and water at high temperature produces a mixture of carbon monoxide and hydrogen (known as “syngas”). The “CO-shift” reaction then combines CO with water to form CO_2 and hydrogen. Many of today’s hydrogen plants, serving the needs of refineries and petrochemical industries, are relatively small compared to what would be required for large scale production of hydrogen as a fuel. Scaling up does not, however, present serious technical challenges and some larger plants already exist.

For plants located in Europe we have considered two configurations:
- A “central” plant with a capacity of 200 MW (as hydrogen), equivalent to 5.8 PJ/a of hydrogen (just under 50 kt/a). A minimum of 1.6 MPa feed gas pressure is required which is available from the industrial grid (4-6 MPa). The estimated efficiency is 75%.
- A small-scale “distributed” hydrogen plant serving a few or a single refuelling stations, typically fed from the natural gas domestic grid, with a capacity of up to 10 MW (as hydrogen). This smaller plant would have a lower estimated efficiency of 67%, the difference being mainly due to the fact that use of waste heat would not be practical at that scale.

Remote production and long-distance transport of liquid hydrogen as well as production of liquid hydrogen in the EU (with distribution by road) have also been considered. For this case a larger reformer capacity of 300 MW has been assumed. Indeed such capital-intensive projects are only likely to be justified at large scale. The hydrogen plant efficiency is expected to be similar to the smaller 200 MW plant.

Thermodynamically, the reforming reaction is favoured by lower pressures. The effect is relatively small and the actual pressure at which a plant will deliver the hydrogen has more to do with design considerations and the pressure of the gas supply. Large plants generally deliver the hydrogen at a fairly high pressure, between 3 and 4 MPa. For small "distributed" plants most of the actual or conceptual designs described in the literature indicate a pressure of about 1.5 MPa. To be consistent with the CNG pathways, we have assumed the gas to be available at the plant inlet at 0.5 MPa (abs). The chain then includes a gas compression step to 1.5 MPa.

Hydrogen production involves full decarbonisation of the fuel and production of CO_2, making it an attractive proposition for CC&S (see also *section 3.6*).

For a discussion of hydrogen transport and distribution refer to *section 3.7.1.*

NG to synthetic liquid fuels

Besides using natural gas as such as a motor fuel in the form of CNG, several technical options are available to synthesise liquid products that have the advantage of easier transportation and, for some, to be usable in mixture with conventional fuels. These processes rely on either steam reforming or partial oxidation of natural gas to produce to produce syngas which is then used a feedstock to a synthesis process. The most prominent options are:

- Synthetic hydrocarbons via the Fischer-Tropsch route,
- DME,
- Methanol.

The conversion plants can conceivably be located either near the gas production area or near the markets. For liquid fuels, the first option is far more likely to be implemented as it then becomes an alternative to LNG or very long-distance pipelines for remote gas sources. For hydrogen, plants near markets appear to be more logical as long-distance transport of natural gas would normally be preferred over that of hydrogen. Large scale electricity production needs of course to be near the consuming centres. The processes and installations involved are, however, conceptually the same.

The first step, common to all such processes, is the conversion of natural gas to "synthetic gas" (or syngas i.e. a mixture of mainly carbon monoxide and hydrogen) by partial oxidation or steam reforming.

Synthetic diesel fuel (Fischer-Tropsch)

Production of liquid hydrocarbons from syngas via the Fischer-Tropsch (FT) process has been known for many years and the subject of many variations and improvements. Many processes are or will be available although the only commercial plant in existence is the Shell Middle Distillate Synthesis (SMDS) plant in Malaysia. In this study we assume the synthetic fuels to be saturated i.e. the process scheme to include a hydrocracker to cut and hydrogenate the long chains to the desired fuel type. Accordingly the assumed FT plant is based on SMDS with an overall efficiency (including syngas generation from natural gas) in the range of 61 to 65%. This excludes any potential synergy with upstream or adjacent complexes which could add a few percent points. The theoretical efficiency is about 78% and, with the considerable R&D effort going into these processes at the moment, it is reasonable to believe that higher efficiencies will be achieved in the future. A lot can be achieved through improved heat integration, particularly in the syngas production step and, with rising energy cost, the extra capital investment required is likely to be easier to justify.

These plants can produce a complete range of products from LPG to base oils for lubricants and small amounts of specialty products such as waxes. Some plants, particularly early ones, may be designed to produce significant quantities of high value products such as base oils. However the market for such products is limited and naphtha kerosene and diesel fuel will eventually represent the bulk of the output. Yields can be adjusted over a fairly wide range. The maximum practically achievable diesel fuel yield (including the kerosene cut) is around 75% of the total product, the balance being mainly naphtha and some LPG.

The process scheme is essentially the same for all products that can be therefore considered as "co-products". There is no technical basis for arguing that more or less energy and emissions are associated to specific products so that, in this case, allocation on the basis of energy content is justified (i.e. that all products are produced with the same energy efficiency). We have taken this view which leads to consider that all products and their fate are independent of each other.

The alternative would be to consider diesel as the main product supporting all production energy and emissions and other streams as "by-products". In this case the fate of the by-products has to be considered in order to calculate a credit or debit to be applied to refinery diesel. This is the method that has been applied for biofuels in the present study. Note that this approach would make the implicit assumption that other products are produced as a result of diesel production which, in this instance, may or may not be the case.

If we accept these assumptions, the most likely disposal route for GTL naphtha and LPG would be to substitute for the equivalent petroleum products (in Europe or other world markets). This would result in an energy and GHG debit for the GTL diesel, since conventional production pathways are less energy intensive than the GTL process. The size of the debit would depend on the relative yields assumed for the various products, which may or may not be representative of future situations.

This study starts from the present situation with oil refineries supplying the virtual entirety of the road fuels market. In the reference case this continues for at least the next decade and the EU refining system is adapting accordingly. Within this time frame all identified alternatives to refinery production (e.g. the availability of GTL diesel) could only replace a limited amount of either gasoline or diesel fuel. The impact on the refineries is therefore considered in this context and this forms the basis of the marginal analysis described in *section 3.1.4* and through which the energy and CO_2 emissions associated with a marginal change in either gasoline or diesel fuel production are estimated.

Two studies by PriceWaterhouseCoopers (PWC) and one study by Nexant have taken a different approach to this question. They consider functionally equivalent hydrocarbon processing systems with and without GTL products, and calculate the energy and GHG balances for a portfolio of fuel products meeting the market demand. Their calculations confirm the debits for naphtha and LPG mentioned above. However, the calculations assume that availability of GTL can lead to less crude oil processing. In this situation, if lower availability of heavy fuel oil (HFO) were to result in a switch to natural gas in industrial heating and power generation, this would result in lower GHG emissions. The PWC and Nexant calculations show that, by accounting for the HFO in the refinery system, GHG emissions from the complete system become broadly equivalent for the scenarios with and without GTL fuels.

The key assumption made in the PWC and Nexant studies that availability of GTL would slow investment in crude oil capacity may well be applicable in rapidly developing markets (such as China) where a clear choice would need to be made between additional crude oil processing capacity and new capacity for making synthetic diesel via a Fischer Tropsch (or other) route. However the assumption is less obviously applicable for Europe which has an established refining industry with no foreseeable major expansion, although diesel is currently imported into the EU-25 because of a structural shortage of middle distillates in the European refining industry due to dieselisation of the light duty market. Substitution of HFO by natural gas is already happening to some extent and the trend may be expected to continue for reasons which are not linked to the road fuels market.

Our study does not consider that linking GTL diesel availability to HFO production and making the further assumption that a reduction of HFO production would be made up by natural gas, are appropriate in a European context. This is the key reason for the differences between the WTW results for GTL quoted in this study, as compared to the studies conducted by PWC and Nexant.

GTL plants produce a large amount of low temperature heat that could be of use in certain locations for e.g. seawater distillation or district heating. Such arrangements are highly location-specific and also require complex partnerships that cannot always be realised. As a result they are unlikely to apply to every project. We therefore considered the potential benefits should not be included in a generic pathway, although it is recognized that the Qatar location chosen by a number of parties (see below) would most likely be able to utilize the low grade heat (for sea water distillation).

In the GTL process CO_2 is produced and separated from the syngas upstream of the Fischer-Tropsch synthesis. This provides an opportunity for CC&S (see also *section 3.6*).

DME

Di-methyl ether or DME is a potentially attractive diesel fuel. There is, however, no commercial experience with its direct production from natural gas (via synthesis gas). Present commercial manufacture of DME is via methanol and not for fuel purposes. There are firm plans for a large scale plant to be built in Iran. We have used data available from Haldor Topsoe, scaled to a notional plant with the same gas intake as its methanol equivalent [*Haldor Topsoe 2001/2002*]. As mentioned for synthetic diesel development of such processes at a large scale would likely lead to process improvements and higher energy efficiency in the long run.

In the DME synthesis process CO_2 is produced and separated from the syngas upstream of the synthesis step. This provides an opportunity for CC&S (see also *section 3.6*).

Methanol

Methanol synthesis from methane is a well established process. We have assumed a state-of-the-art plant of 600 MW (in terms of methanol, equivalent to about 100 t/h), fully self-contained (i.e. with natural gas as only energy source and no energy export) and with an efficiency in the range of 67 to 69% [*Larsen 1998*].

NG to hydrogen via methanol

Methanol synthesised from remote natural gas could be used as energy vector instead of compressed or liquefied gas. Distributed into Europe it could be reformed locally to hydrogen.

MTBE

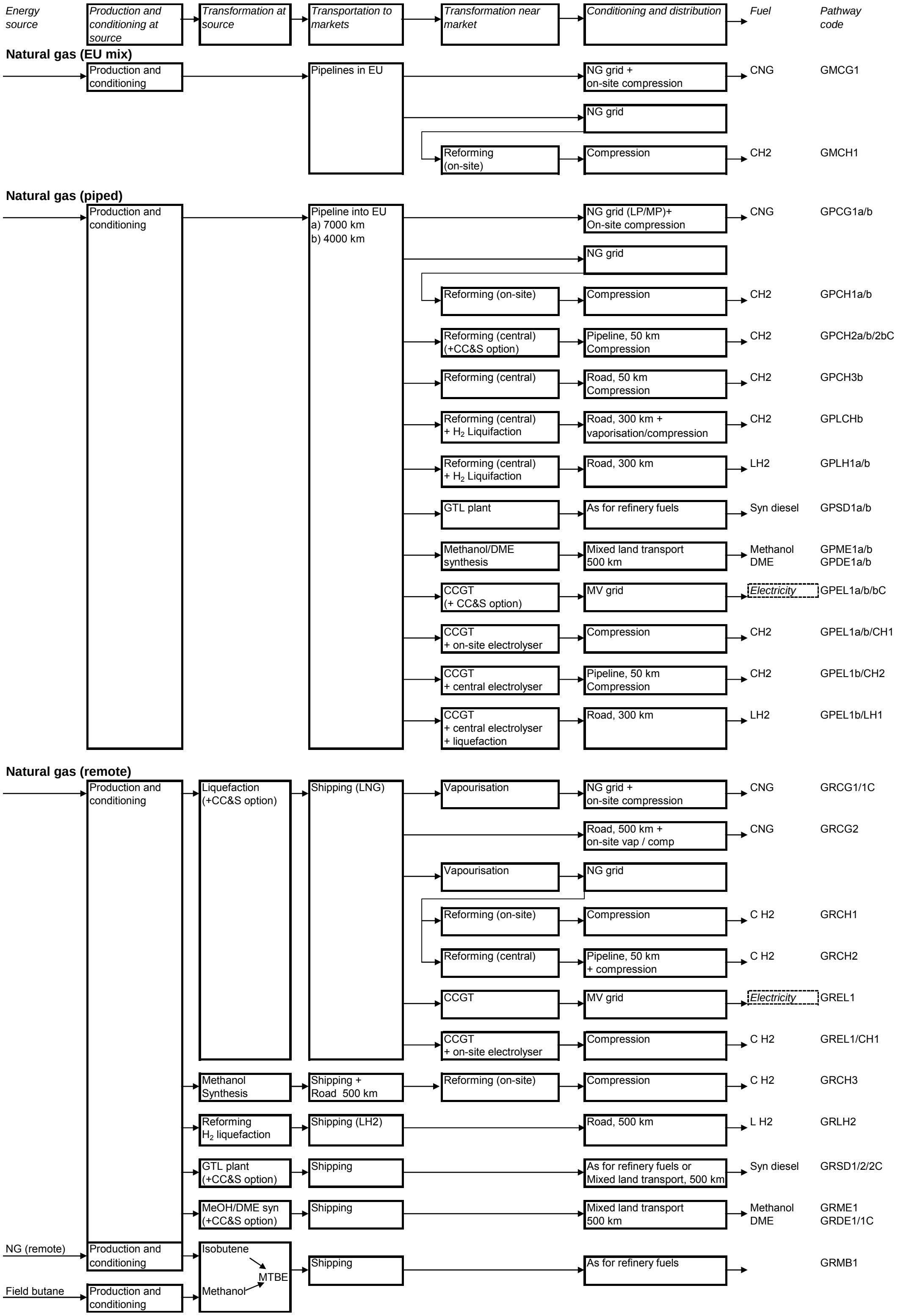
Methyl-Tertiary-Butyl Ether or MTBE is a high octane blending component for gasoline. Because of its ability to reduce emissions by bringing oxygen into the fuel, MTBE was widely used in US gasoline until water contamination issues led to a partial ban. In Europe MTBE was introduced as one of the measures to recover octane after phasing out of lead in gasoline.

MTBE is synthesised by reacting isobutene with methanol. Some isobutene is produced by refineries and petrochemical plants as by-product of cracking processes. Large MTBE plants include, however, isobutene manufacture via isomerisation and dehydrogenation of normal butane often from gas fields, near which the plants are often located. The entire process is fairly energy-intensive. In that sense MTBE is a fuel derived from natural gas. Marginal MTBE available to Europe is from that source and this is the pathway that we have investigated.

3.2.6 Natural gas pathways

There are a virtually infinite number of combinations of the various processes described above. We have endeavoured to select those pathways that appear the most relevant and plausible.

Figure 3.2.6 Natural gas pathways



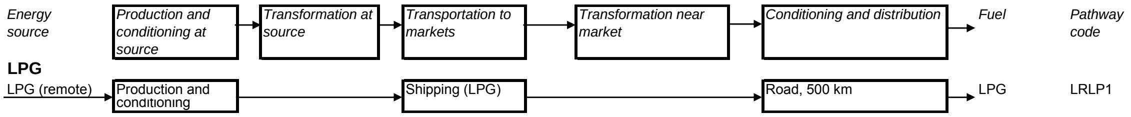
3.2.7 LPG

LPG (Liquefied Petroleum Gas) is the generic acronym for C3 and C4 hydrocarbons that are gaseous under ambient conditions but can be stored and transported in liquid form at relatively mild pressures (up to about 2.5 MPa for propane). LPG is widely used for heating and cooking as well as petrochemicals. It is also a suitable fuel for spark ignition engines with a good octane rating and favourable emissions performance. LPG is available as a road fuel in a number of European countries.

LPG is produced in oil refineries as by-products of virtually all treating and conversion processes. This resource is, however, limited and already completely accounted for. Indeed Europe imports a significant proportion of its LPG consumption. Accordingly the marginal LPG consumed in Europe originates from oil or gas fields where it is produced in association with either crude oil or natural gas. We have represented the case of natural gas fields.

Energy is required to produce the LPG and also for subsequent treatment and separation into C3 and C4 hydrocarbons (which tend to have different markets) and C5+ components. The pathway is represented below.

Figure 3.2.7 LPG from gas field



3.3 Coal pathways

(See also WTT Appendix 1 section 1-6)

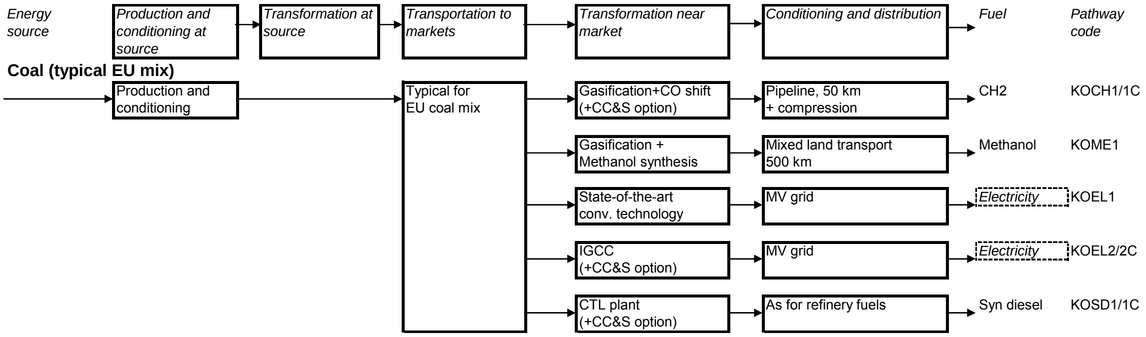
Although not fashionable in today's carbon-conscious world, coal still plays an important role in the world and even in Europe's energy supply, essentially for power generation. After a steady decline over many years, EU-25 consumption has stabilized around 300 Mtoe since the beginning of the decade. It is, however growing in most other parts of the world, particularly in China where consumption has doubled in the last five years. With abundant worldwide reserves, coal is expected to play a major role in world energy for many years to come. "Clean coal" technologies such as gasification followed by electricity generation through combined cycle (Integrated Gasification and Combined Cycle or IGCC) and advanced flue gas treatment schemes can resolve most of the air pollution issues while offering high thermal efficiencies. Gasification can also be followed by synthesis of methanol of by a Fischer-Tropsch plant to produce liquid hydrocarbons (Coal-To-Liquids or CTL). CO_2 capture and storage further offers the vision of virtually carbon-free electricity or hydrogen production from coal and could also reduce the carbon emissions footprint of synthetic fuels.

We have included a number of coal-based pathways representing processing of the current EU hard coal mix into hydrogen, methanol, synthetic diesel and electricity (both conventional boiler + steam turbine and IGCC). We have derived energy efficiency figures from the literature: 51% for hydrogen [*Foster Wheeler 1996*], 57% for methanol [*Katofsky 1993*] and 56% for syn-diesel [*Gray 2001*]. The coal to electricity pathways are further described in *section 3.5.1*.

We have also included the option of CC&S for the hydrogen, synthetic diesel and IGCC pathways to illustrate the potential of this technology (see *section 3.6*).

Note: There is not fundamental reason why DME could not be made from coal in the same way as methanol. This option has, however, not been seriously considered so far so we have not included it. By comparison methanol from coal is an established process.

Figure 3.3 Coal pathways



3.4 Biomass pathways

(See also WTT Appendix 1 section 1-7 to 1-11)

The availability of biomass and the production of fuels from it is a complex question intimately tied to the cost, because of the diversity of agricultural conditions in EU. Therefore availability and cost are combined in a single discussion in *section 5.2*.

We have included all sources of biomass which have the potential to substitute a significant amount of transport fuel in the EU i.e. farmed crops such as sugar beet, wheat and oil seeds and woody biomass either in the form of waste or purpose-grown. “Wood farming” incorporates also perennial grasses such as miscanthus or switch grass.

3.4.1 Common issues

Reference crop

Growing crops for energy involves using land in a different way. How the land would be used otherwise is a question that needs to be addressed in order to determine what possible energy and/or emissions debits or credits are attached to this.

In version 1 of this study there was no “reference crop”. We explained that this was a logical consequence of most of the crops for biofuels being produced in replacement of cereals exports. However, in this version, we have used as baseline agricultural scenario an updated version of the DG-AGRI’s “*Prospects for agricultural markets and income in the EU*” which now projects more set-aside and less cereals exports. Therefore the most common scenario for growing extra biofuels crops has changed to growing on set-aside land. Now there clearly *is* a reference crop: the alternative use of the land under set-aside. Apart from the area already used for energy crops, set-aside is either left fallow, or sown with a green cover crop (we could find no statistics on the most common uses). To estimate nitrous oxide emissions we used the DNDS soil chemistry model which offers a restricted set of options: another arable crop, fallow or grass.

Fallow is perhaps the most common land-use for set-aside, but unfortunately in the DNDS soils model selecting “fallow” as a crop suppresses all vegetative growth. In practice even a fallow field would not stay uncovered for long, especially on land good enough for arable crops. Even weeds are partially effective as a cover crop, reducing the loss of nitrogen from the soil by incorporating it until ploughed under for planting the next crop, so the assumption of *no* vegetation is worse than assuming that grass or another crop is present, even for “fallow” land.

Secondly, there is a question of manure use in the reference scenario. The amount of manure used in EU depends on how much is available rather than on which crop is grown. So the manure used in the “biofuels crop” scenario does not disappear if the field is in set-aside instead: even if used on another field, it would cause some N_2O emissions. Therefore, it is better to assume that the same amount of manure is used on the set-aside field, than to assume none is used. It is quite conceivable that manure would be applied on a field of unfertilized grass (for example, directly by grazing animals), but no-one would put manure on a fallow field. Furthermore, the absence of plant cover on a fallow field would change the amount of nitrous oxide released by manure decomposition.

Grass seems therefore to be the best choice of reference crop. Since grass has to represent all types of set-aside use including fallow, we did not attribute farming inputs to the maintenance of the field in set-aside.

For biofuels crops grown on voluntary set-aside land, [*Kaltschmitt 1997*] considered as reference crop a field under set-aside planted with unfertilized rye grass. This was effectively the same as no reference crop because the N_2O emissions were assumed proportional to the extra N applied. [*LBST 2002*] considered both this scenario and one in which clover (a nitrogen-fixing plant) was sown on the reference field. In this case, there was a reduction of between 1 and 2.5% in farming energy inputs (due to a small saving on N fertilizer for the next crop). This is well within the range of overall uncertainties in the farming emissions, and can be neglected.
LBST calculated a negligible effect of the choice reference crop on soil emissions because the saving on nitrous oxide emissions caused by the fertilizer was compensated by soils emissions from the clover.

Our study does not assume N_2O emissions tobe proportional to the N fertilizer rate, and we find significant emissions also from unfertilized land. Therefore we need to subtract the emissions in the reference scenario.

Yields and farming inputs

There are huge variations in yield for different land areas. For example the EU-15 national averages for soft wheat yields vary by a factor 6. The spread between individual farms would be even greater. The situation is similar for other crops, including wood. Therefore *extreme caution must be used in using "average" or "typical" yields:* they must correspond to the land being considered. In particular, EU land which is not already being used for arable farming is likely to give lower than average yields.

Different yields are needed for different purposes. Our availability calculations are based on the 2012 yields for EU-25 projected by DG-AGRI [*DG-AGRI 2005*]. We, however, increased the wheat yield per hectare because the low-protein feed wheat suitable for making ethanol has a higher yield than the EU-mix of 43% bread-making- and 57% feed-wheat. With the introduction of new varieties of feed-wheat with higher yields and lower protein content, experts expect the spread between bread-making and feed-wheat yield to increase to 30%. Thus we raised the wheat-for-ethanol yield by 13.5%.

For calculating energy balance, GHG balance and cost, we needed the yields which corresponded to the data we had on farming inputs. For all crops except wheat, we took data from [*FfE 1998*] which estimates all significant farming inputs (for fertilizers only EU- average data is available). The FfE study indicates higher Nitrogen rates than EU-25 average, but also higher yields. These effects cancel each other out, so the values of kg N/MJ crop are almost identical to the production-weighted averages for EU-25.

The potassium and phosphorous fertilizer rates vary greatly according to geography, but do not correlate with yield. However, they are only of minor importance in the calculation. We also took the FfE diesel use per tonne of crop as typical. This may lead to a slight underestimate because with a high yield one would expect fewer tractor-km per tonne of crop: on the other hand German farming may be more mechanized than average.

[*DG AGRI 2005*] expect EU yields to continue their slower rate of increase of recent years, (averaging 0.89% per year for EU-25 cereals between now and 2012. These increases are generally achieved by breeding and technical improvements which allow the crops to make use of more nitrogen. But this extra nitrogen must be provided (as fertilizer) to achieve the higher yield. Therefore the amount of nitrogen fertilizer applied per tonne of crop will not change much, and we considered our values from [*FfE 1998*] to remain valid. The average soil emissions per

MJ crop will also be little affected by yield increases, because, *for a given field*, N_2O emissions due to farming are very roughly proportional to nitrogen fertilizer rate.

An exception to the constant-farming-input-per-tonne rule must be made the new low-protein feed wheat varieties referred to above. They increase yields by decreasing the content of (nitrogen-rich) protein, *without* an increase in nitrogen fertilizer. Therefore, in this update, we kept our previous per-hectare wheat-farming inputs in spite of the yield increase, thereby reducing the specific inputs (per tonne of crop). The corresponding yield was increased by 13.5% to 7.9 dry t/ha (9 t/ha at 15% moisture). The reference farming inputs and yields were based on UK average figures [*ETSU 1996*] because [*FfE 1998*] does not include wheat farming. The farming inputs data were peer-reviewed by experts from the food industry and elsewhere for the UK Low Carbon Vehicle Partnership Report [*LowCVP 2004*].

Where straw is collected, fertilizers should be added to compensate for the lost minerals; we used figures from [*Kaltschmitt 2001*]. However, the effect of this on the calculations for straw pathways is hardly significant. We do not assume that more nitrogen must be added to compensate for the nitrogen removed in the straw, because the decomposition of the straw consumes nitrogen from the soil. One could indeed argue for a nitrogen *credit* for straw removal. However, in Southern Europe, where decomposition is fastest, the straw is often removed from the soil (even if it is just piled at the field perimeter) just to prevent this effect.

We also made no correction (in the other direction) for any long-term reduction in yields due to reducing the organic content of the soil (degradation of soil texture) by repeated straw removal. This would be the result of the soils losing some capacity for water retention, which would be important in times of water-stress. However, the effects depend extremely on local soil conditions, weather and hydrology: we assume farmers will not sell their straw if it could be damaging to their soil.

The diesel used for baling and collecting straw was taken from [*GEMIS 4.2*]

Our agricultural inputs per MJ are generally slightly lower than those in [*ADEME 2002*] although their reported diesel fuel use for rapeseed is, strangely, much higher than for wheat. The main reason that ADEME ends up with different results for energy balance is that they arbitrarily allocate energy inputs and emissions to by-products on a mass basis rather than calculating credits for the materials the by-products replace (see *section 2.4* on by-product methodology). Our inputs are also broadly in line with those of other studies.

Agro-chemicals production

The energy and GHG input associated with agro-chemicals (mainly fertilizers) is sizable and represents a small but significant share of the total pathway energy.

Our figures for agro-chemicals production are derived from [*Kaltschmitt 1997*]. They are not much different from those in other studies, such as [*ADEME 2002*]. Fertilizer transport is included, but is negligible.

Carbon release from changes in land-use

Use of grassland

The largest potential for expanding EU agricultural production for biofuels would be to increase the arable area at the expense of grazing land. However, there are very serious greenhouse-gas consequences to ploughing up grassland. The change in land-use results in a reduction in the organic carbon stored in the soil. Although this only happens once, the effect is very large and long-lasting. The soil reaches a new (lower) carbon content at a decaying-exponential rate, characterized by about a 20-year time-constant and an annual CO_2 emission (representative of EU-15) of the order of 3.7 t/ha, although the uncertainty range is more than 50% ([*Vleeshouwers 2002*], quoted by [*DG-ENV 2003*]). That makes a total of roughly 73 t/ha CO_2 (±>50%) emitted due to the change in land use. This figure is also congruent with the difference between grassland and arable soil-carbon stocks according to the default IPCC figures for temperate climates [*IPCC 1996/2*].

Note:
Table 5.10 of [*IPCC 1996/2*] indicates a soil C stock of 50 t/ha for grassland and improved pasture in cold temperate climate. The table 5.11 indicates the same figure for "native vegetation" in cold temperate conditions on "active" soils (the most likely soil type to be converted to arable cropping), rising to 110 t/ha for moist warm temperate climate. So let us take 50 t carbon /ha (in top 30cm) as a conservative figure for carbon stocks in EU grassland/pasture/native ground cover.
IPCC recommends calculating the change in carbon stocks by the change in the "base factor" for different types of land use. For improved pasture (and therefore we assume also grassland) the base factor is 1.1 (table 5.12). For continuous arable crops the base factor is 0.7. The difference, 0.4, represents the fraction of the nominal C lost due to the land use change from grassland to arable. Thus the expected carbon loss is 0.4x50 = 20 tonnes of C per hectare. This loss is equivalent to 20x44/12 **= 73 tonnes of CO2 emitted per hectare**.

Every year biofuels produced on the land give a GHG saving, gradually compensating the emissions due to the change in land-use. ***Table 3.4.1-1*** gives a very rough estimate of the GHG payback time, using GHG balances for the basic pathways for various crops from this study. These should only be taken as an order-of-magnitude guide, because no account is taken of the variation in soil carbon levels in different areas (for example, soil carbon is generally lower in the South, where sunflower is grown than in climates suitable for rapeseed). There is also a huge uncertainty in the soil carbon data.

Table 3.4.1-1 Rough estimate of GHG payback time for biofuels crops on grassland

Crop	FeedWheat	Sugar Beet	Rapeseed	Sunflower	Farmed wood
Example pathway	WTET1	SBET1	ROFA1	SOFA1	WFSD1
EU av. yield (t/ha)	8.0	61.2	3.0	1.8	11.1
Biofuel (GJ/ha/a)	73	124	42	27	76
GHG saved per GJ biofuel (kg CO_{2eq}/GJ)	9	36	36	58	64
GHG saved (kg CO_{2eq}/ha/a	660	4429	1505	1545	4806
Total C stock change (t CO_2/ha) +/-50%	-73	-73	-73	-73	0 to -73
Years for GHG to breakeven +/-50%	111	17	49	47	0 to 15

Note:
For simplicity, we have taken EU average yields for arable crops (incremented by 13.5% for feed-quality wheat): this is higher than the yield one would expect on the sort of land converted from grassland, so our break-even times are probably too short. To allow comparison between crops, we estimated the yield of farmed wood which one could expect on average wheat fields, from our yield ratios.

Planting biofuels crops on grazing land would probably not pay off in GHG terms for decades.

Reviews of carbon sequestration (e.g. [*Vleeshouwers 2002*]) generally assume soil carbon levels for Short Rotation Forestry (SRF) to be equivalent to forest and grassland. Until now, no-one has measured what happens to soil carbon stocks when SRF is planted on former grazing or forest. A newly published study on a 40-year-old poplar plantation [*Ferré 2005*] shows that total soil carbon had declined 25% compared to the original natural forest: a loss equivalent to 42 tonnes/ha of CO_2. It is well known that soil disturbance releases soil carbon, and the ground is usually ploughed before SRF is planted (although one could develop techniques to avoid this). Thus one expects some reduction in soil carbon, but less than from converting grassland to arable. That is why in the table we give a range the soil carbon change for grazing-land to SRF as between zero and that for changing to arable.

We conclude that **planting anything on grazing or forest land would be, in the short and medium term, counter-productive with regards to GHG reductions**.

Carbon release resulting from reduced cereal exports

Making biofuels from cereals which would otherwise be exported by EU would cause an expansion in cereals production outside Europe, compared to the reference scenario where more biofuels are not made. This would tend to increase pressure to bring grazing or forest land into cultivation, probably leading to GHG emissions from soil carbon and deforestation. However the effect is difficult to quantify. Like every other LCA or WTW study we know of, we do not take it into account.

Nitrous oxide emissions

Although not very significant in *energy* terms in the whole pathway, farming is the primary source of GHG emissions associated with biofuels because of emissions of nitrous oxide (N_2O), essentially from two sources: nitrogen fertilizer production and emissions of N_2O from the field. N_2O emissions are not very large in absolute terms but the very high greenhouse effect of this gas (about 300 times as much as CO_2 on a mass basis) makes them very significant. In particular, the huge **uncertainty** in estimates of GHG emissions from soils dominates the errors in the final GHG balances of biofuels pathways. There are enormous variations in N_2O emissions from one field to another, depending on soil type, climate, tillage, fertilizer rates and crop (in approximate descending order of importance). Therefore it is worthwhile putting a large effort into improving the accuracy of the soils-emissions estimates.

Where they have considered them at all, other biofuels studies have adopted two approaches to estimating nitrous oxide emissions from soils. One is to extrapolate from measurements on individual fields; the other is to use the IPCC guidelines. The revised 1996 IPCC guidelines [*IPCC 1996/2*] only give the possibility to consider nitrogen fertilizer and manure use, and whether or not the crop is nitrogen-fixing. To account for other variables, IPCC specifies a wide error range: the max/min ratio varies from 9 (for direct emissions) to 60 (for indirect emissions from leached nitrogen). But even this range is by far not sufficient to cover the range of values which have been measured on individual fields. For example, emissions ten times the *maximum* value from IPCC guidelines have been measured for fields with wet, peaty, soil.

This study uses a more sophisticated calculation exploiting the database-calculation-model of the soils-and-waste unit of the Institute for Environment and Sustainability at JRC-Ispra, developed to estimate agricultural GHG emissions for monitoring compliance with the Kyoto commitment. This is built on a recent version of a well-validated soils chemistry model, DNDC (version 82N) [*UNH 2003*], which calculates daily nitrous oxide emissions from fields, as well as the amount of nitrogen leached off into the groundwater. For this new version of the WTW study, JRC applied the model to points from the LUCAS land-cover survey [*Eurostat 2003*], which reports land use for clusters of ten measurement points on an 18-km grid covering EU-15, in the year 2000. The other main inputs were:

- The soil properties for each measurement point: from the soils database maintained by the European Soils Bureau at JRC-EIS, which attempts 1 km resolution by a disaggregating process based on GIS land-cover data.
- Daily weather for the year 2000, obtained from the 50 km meteo-grid of the MARS project at JRC-IHCP institute.
- Manure rates, per country and crop, derived from the CAPRI model at the University of Bonn.
- Fertilizer rates: we used the crop and soils characteristics at each grid point to derive the recommended N fertilizer rate, according to [*DEFRA 2000*]. Then we applied a separate correction factor to the N rates for each country and crop, in order to make the averages coincide with the actual usage published by the International Fertilizer Association [*IFA 2002*].

We calculated the indirect nitrous oxide emissions from the amount of nitrogen leached from the field, using the default IPCC N_2O-emission-factors for indirect emissions. The error range of these factors is the largest uncertainty in our estimate, even though the indirect emissions are smaller than the direct ones.

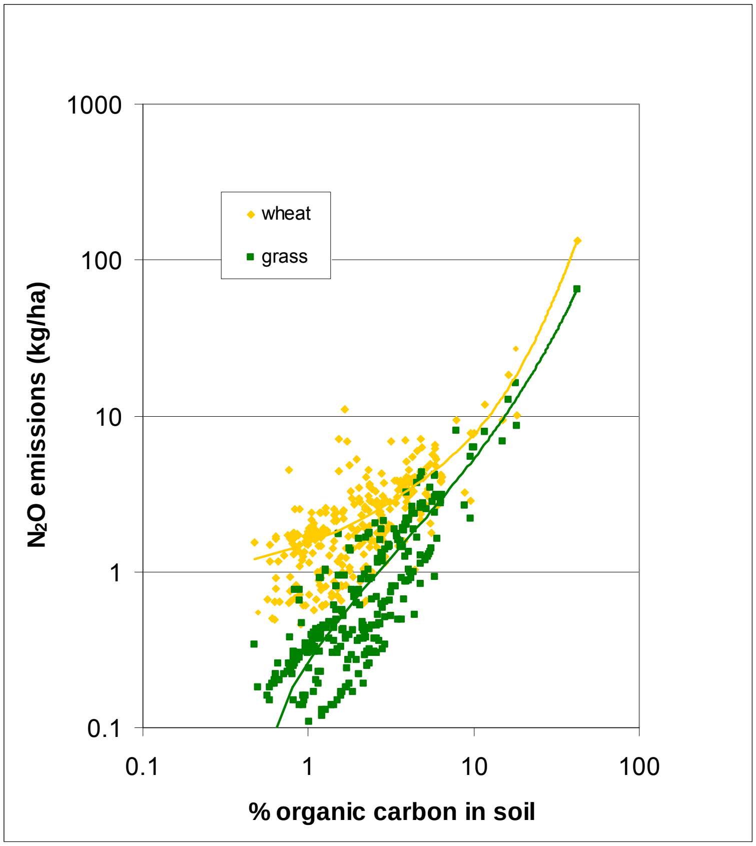
Per-hectare nitrous oxide emissions were averaged for all points sharing a common crop, and divided by the average year-2000 yields from EUROSTAT. In this way we averaged emissions for fields where the crop is actually grown. This removes much of the uncertainty from the calculation in version 1 of this study, where we worked on regions (NUTS-3) and had to average between the dominant soil types of each region.

Figure 3.4.1 shows, for points from the LUCAS survey, the calculated N_2O emissions per hectare when growing wheat or unfertilized grass. The difference between the two represents the incremental N_2O emissions from growing wheat on set-aside. The same calculation was carried out for the other crops: in each case the emissions from fields actually growing the crops were compared to what the emissions *would* have been if they grew grass (unfertilized except for a small amount of manure: see below).

The most sensitive parameter influencing agricultural N_2O emissions is the soil organic content (usually described by the soil organic carbon (SOC) concentration), as indicated in ***Figure 3.4.1***. Much of the emissions, especially from high-organic fields, would occur even if the field was not ploughed, and this effect is taken into account through the "grass" reference case. However, the *extra* N_2O emissions from arable farming also increase with SOC, and very rapidly when the SOC is over 10% (the scale is logarithmic). In fact this effect is so strong that the results from a few fields with over 10% SOC significantly affect the whole average.

These unlikely combinations of soil type and crop arise because of a difference in the nature of the soils-database and the LUCAS database. The soils database assesses the *typical* soil for the grid-square centred on a grid point, whereas the LUCAS dataset gives the “spot” ground cover observed on the ground at each measurement-point[4]. Therefore it sometimes happens that an arable field at a LUCAS measurement point falls in a square of the soils database which is predominantly peat-bog, for example. The soils properties for the peat-bog would then falsely be associated with an arable field.

Figure 3.4.1 ***Nitrous oxide emissions from 3459 EU fields growing either wheat or grass Year 2000***



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[4] The soils database starts with a list of principal soil types in each region (“soil polygon”), and then assigns one of these soil types to each grid point according to the *typical* land cover around that point (using pseudo-transfer rules). The typical land cover is taken as the most common land cover reported for the surrounding 100m “pixels” of the CORINE land-use database, based on satellite data.

In reality arable crops would not be grown on such high-organic soils likely to be too waterlogged and acid. Before averaging the N_2O emissions calculated for a particular crop, we therefore eliminated the points which showed an unlikely combination of soil and crop: we assumed arable crops would not be grown on soils with more than 10% organic-carbon (in the top 30 cm).

To obtain the emissions-per-tonne-of-crop, we divided the average per-ha emissions for each crop (calculated for the year 2000) by the average EU-15 yields for the same year (from EUROSTAT). The year 2000 was chosen for the emission calculations because yields in 2000 were typical for recent years.

The results are shown in the ***Table 3.4.1-2*** for the main crops considered in this study.

Rapeseed has the highest emissions because it is grown in the Northern half of Europe, where soils generally have a higher organic content. Conversely, sunflower, grown in the South, has the lowest emissions per ha, but also a low yield. The high yield of sugar beet brings its emissions-per-GJ-crop below that of the others.

Most of the uncertainty comes from the estimate of indirect emissions from leached nitrogen (because we have to use the full IPCC range of emission factors here). Uncertainty is lower for sugar beet because this crop cannot be grown in waterlogged soil, where run-off is worst and indirect emissions highest.

Table 3.4.1-2 Average N_2O emissions from biofuels crops grown in the EU

EU-15 average emissions (kg/ha)	*Wheat*		*Sugar Beet*	*Rapeseed*	*Sunflower*
N_2O soil emissions	1.65		2.52	2.70	1.01
N_2O from leached N	0.58		0.27	0.42	0.10
Total N_2O	**2.23**		**2.79**	**3.12**	**1.11**
range+/-	**1.49**		**0.88**	**1.23**	**0.33**
	Soft wheat	*Feed-wheat*			
EU-15 av. yield in 2000 (moist t/ha)	**7.07**	**8.02**	**61.2**	**3.03**	**1.78**
g N_2O/t moist crop					
N_2O soil emissions		0.206	0.041	0.892	0.568
N_2O from leached N		0.072	0.004	0.138	0.056
TOTAL N_2O		0.278	0.046	1.030	0.625
range+/-		0.185	0.014	0.407	0.186

Other environmental effects of biofuels

Soil quality/erosion

Sugar beet can cause soil erosion, especially if grown on the light soils typical of southern Europe. New techniques of inter-sowing between cover crops can help. However, we do not expect that sugar beet production would spread beyond areas of northern Europe with heavier soils. In wet areas, the heavy machinery used for harvesting sugar beet can cause soil compaction.

We already warned that increase of arable area would cause loss of soil organic carbon from grassland or forest: we assume it will not be allowed.

Continually removing straw instead of incorporating it in the soil will decrease the soil organic content, leading to poorer moisture retention. This should be a larger problem in light southern soils, but ironically this is where straw is most often removed, because its decomposition consumes nitrogen which has to be replaced. It is probably not a significant problem in the prime cereals-growing areas of Northern Europe where a high density of straw availability makes it most economic to site straw-to-biofuel conversion plant.

Eutrophication and acidification

Because intensive agriculture using fertilizers tends to cause eutrophication and acidification, increased crop production for biofuels would tend to exacerbate the problem. The driving force for intensification is crop price: hence meeting biofuels targets will probably cause more intensification of oilseed production than of cereals production. Sunflower, short rotation forest and other “advanced biofuels” crops generally use less fertilizer than the other crops, so have less impact.

Biodiversity

Growing biofuel crops instead of permanent crops, and on “nature” land now in voluntary set-aside, would decrease biodiversity. [*EEA 2004*] concluded that the negative biodiversity impacts are high for rape, medium for sugar beet and low to medium for short rotation forestry. The use of wood residues was considered to have no impact.

Pesticide use affects biodiversity. Break-years encouraged by compulsory set-aside rules tend to reduce pests and diseases, so doing away with it would tend to increase pesticide use. Large increases of pesticide applications are needed if frequency of sugar beet (and to a much lesser extent oilseed rape) crops in a rotation is increased beyond about one year in four. Sugar beet generally requires much more pesticide than other crops. Farmers might escape controls on pesticide levels if the crops are not for food.

Impact on water table

The increased growth of crops requiring extensive irrigation in arid areas will put pressure on water resources. For example sugar beet cultivation in Spain and Greece has a very high percentage of irrigated area (77 and 100% respectively). In Italy it is lower but still over a third of the area compared with 6% for Durum wheat and 7% for sunflower. Water use per tonne of dry matter is around 200 litres for sugar beet and 300 litres for wheat.

Increased cultivation of trees can also lead to a lowering of the water table. Lowering of the water table can have significant impact on the natural environment in the area concerned.

Introduction of non-native species and GMOs

There is some risk that non-native energy crops could spread in the wild, because they lack natural predators. Using sterile varieties (including GMOs) greatly reduce this risk. Some are concerned about GMOs in general, though.

Few of these environmental impacts are inevitable

Most of these potential impacts can be controlled by appropriate regulations and effective enforcement. The pressure to push the limits of regulations varies from crop to crop: in general sugar beet is the most environmentally suspect crop and short rotation forestry the least.

3.4.2 Biomass transportation

The energy and GHG emissions for biomass transportation to the processing plants are a very minor part of all pathways. However, the cost is very significant especially for materials such as forest residuals and straw (see *section 5*). For describing the emissions and cost-per-tonne, we have used data for Germany estimated by LBST. We made independent estimates of transport distances (see *WTT Appendix 1 section 1-9*). For farmed crops an average distance of 50 km is considered sufficient to feed a 200 MW plant (such a plant would e.g. consume some 350 kt/a of wood requiring 35,000 ha or about 4% of the area comprised within a 50 km circle). This distance would be reduced to 10 km for a 10 MW plant. Wood residuals are more scattered and would require sea transport over longer distances (400 km, typical of the Baltic Sea) when fed to a large plant. Transport distance for straw is only 25 km for 200 MW because processing plants would only be economic where there is a concentrated resource.

3.4.3 Sugar beet to ethanol

Sugar beet is a high yield crop. It produces carbohydrate already in the form of sugar and is easily crushed and mashed for fermentation which makes the processing into alcohol rather cheap. The economics of its cultivation are highly distorted by the CAP, as discussed in *section 5.2*.

Sugar beet continues to respire in storage causing a material loss. In order to limit the energy loss, the processing "campaigns" average 90 days. But since the syrup extracted from the sliced beets is pasteurised, one supposes that it could be stored to keep the fermentation and distillation parts of the plant running all year. By-products of the conversion process are sugar beet pulp and dried slop (everything insoluble produced by fermentation), which together are the beet equivalent of DDGS from wheat, but with a lower protein content; about the same as wheat grain. Thus we gave it a credit as a low-protein animal feed, based on the wheat-growing process and tables of digestible energy content. Because of the cost, no-one would consider drying these by-products just to burn them, but we did compare adding them to the process biogas digester (for cleaning the waste water), which gives almost the same energy balance and emissions as burning.

To improve the yield of ethanol, the pulp could, in principle, be treated by a SSCF-type process (Simultaneous Saccharification and Co-Fermentation) to break down the cellulose and hemicellulose. No such process actually exists and we have not further considered this route.

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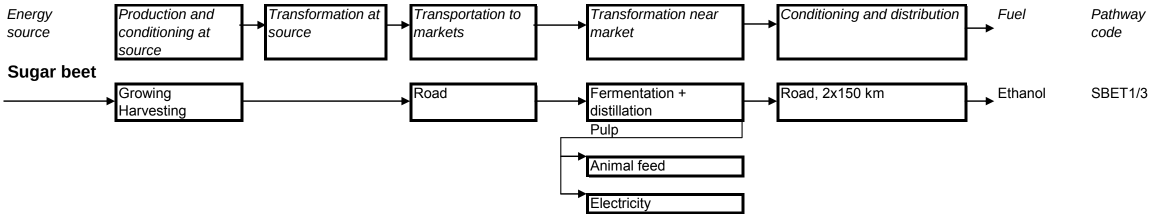
We have therefore considered 2 sugar-beet-to-ethanol pathways as shown below.

Figure 3.4.3 Sugar beet to ethanol pathways



3.4.4 Wheat to ethanol

Ethanol can be produced from wheat grain by hydrolysis and fermentation. The process is more complex and therefore more expensive than with sugar beet. Milling and distilling are the most energetically expensive parts of the wheat-to-ethanol pathway. These processes require some electricity but mostly heat albeit at a low temperature level. This makes the scheme well suited for CHP. The figures used in this study for the wheat grain to ethanol plants are essentially the same as in a study carried out in 2004 under the UK's Low Carbon Vehicle Partnership [*LowCVP 2004*].

Energy supply options

The energy can be provided by a variety of sources. We have considered 3 scenarios based on fossil fuels and representing plants actually on the ground or planned in Europe. A fourth scenario uses straw as energy source. Although this is in principle feasible there are no concrete examples of this either existing or considered.

WTET1: Conventional natural gas boiler

Heat is supplied by a conventional natural gas fired boiler and electricity is imported. This can be considered as representative of the vast majority of existing installations and is also by far the cheapest solution.

WTET2: Combined cycle gas turbine

A natural gas fired gas turbine with a heat recovery steam generator (HRSG) provides both heat and electricity. As more heat than electricity is required supplementary firing is applied in the

HRSG. As the heat is required only as low pressure steam, a back pressure turbo-generator is also installed behind the HRSG. The plant is assumed to be sized and operated to produce the heat required for ethanol manufacture. There is, however, a surplus of electricity which is exported into the grid, thereby generating an energy and GHG credit.

This solution is considerably more energy efficient but also significantly more complex and expensive to build and operate.

WTET3: Lignite boiler CHP

High pressure steam is produced in a lignite boiler. A back pressure turbo-generator produces electricity and low pressure steam for the process. Here again the plant is assumed to be sized and operated to produce the heat required for ethanol manufacture but it nevertheless generates an electricity surplus.

Lignite (or brown coal) is a cheap and abundant fuel in certain parts of Europe and actual plants are either operating or under construction in Eastern Germany.

WTET4: Straw boiler CHP

Wheat cultivation produces large amounts of straw. Some LCA studies have considered straw as a by-product but this is not necessarily the case. In most of the EU it should be ploughed back to maintain the water-retention properties of the soil (see straw availability, *section 5.2.3*). Where it may be removed from the field it is partly already used for litter and other applications. Therefore it is misleading to systematically assume that straw can be used to fuel the ethanol production process. In practice this should only be proposed where there is little water stress, a high density of cereals production and a low density of livestock. These conditions would apply to concentrated wheat-producing areas in Northern Europe excluding the Low Countries and Denmark. In any case removing straw will reduce soil nutrients, which needs to be compensated by an additional fertiliser input.

This scheme is similar to the previous case but straw in used instead of lignite. The main advantage of this scheme is to use a renewable source of energy to drive the process. It must be realised, however, that handling and burning of solids is considerably more complex and costly than with liquids or gases, particularly in the case of a low energy density material such as straw. This will therefore be the most expensive option.

Credit for surplus electricity

All CHP schemes produce a surplus of electricity which is assumed to be exported to the grid and must therefore generate a credit (energy and GHG). An ethanol plant with a CHP scheme in effect co-produces ethanol and electricity. If a straightforward credit is applied (e.g. based on substitution of EU-mix electricity) and the whole balance expressed relative only to the ethanol produced, ethanol is given a credit resulting from generation of electricity from straw. One would conclude that the higher the electricity generation compared to the ethanol yield, the better the fossil energy balance of ethanol! In the case of a natural gas CHP, this could be taken quite far as there is no physical limit to the size of the power plant that can be built.

The real contribution of ethanol to electricity generation is to provide and opportunity for CHP so that the credit should be based on the same fuel producing electricity only in a stand alone power plant. Although the energy and GHG saved by the bio-electricity itself is not credited to ethanol, the ethanol pathway does benefit from the extra energy efficiency resulting from the use of CHP.

DDGS

Ethanol production produces a by-product known as DDGS (Distiller's Dried Grain with Solubles) which is the solid residue after digestion of the carbohydrates. DDGS is a protein-rich material and is therefore a useful animal feed component. Its nearest equivalent is corn gluten feed, a by-product of maize milling, the supply of which is fixed by the amount of maize. In the EU the balance of animal feed demand is met by soy meal (the *main* product of soybeans) which is, in the end, what DDGS substitutes. The equivalent quantity of soy bean meal is calculated on the basis of the protein content using data from [*NRC 1998*]. The energy and emissions for the soy meal is calculated according to a scenario of soy beans grown in the US, and crushed in EU, following [*UBA 1999*].

One should consider *how much* DDGS could be used as animal feed. Cattle and pigs can take an average of more than 25% corn DDGS in their diets [*Shurson 2005*]. For wheat DDGS, with its higher protein content, we should reduce this conservatively to 20%. EU animal feed consumption is around 300 Mt/a. 60 Mt per year of DDGS corresponds to 350 PJ ethanol, or about 6% of EU-2010 gasoline.

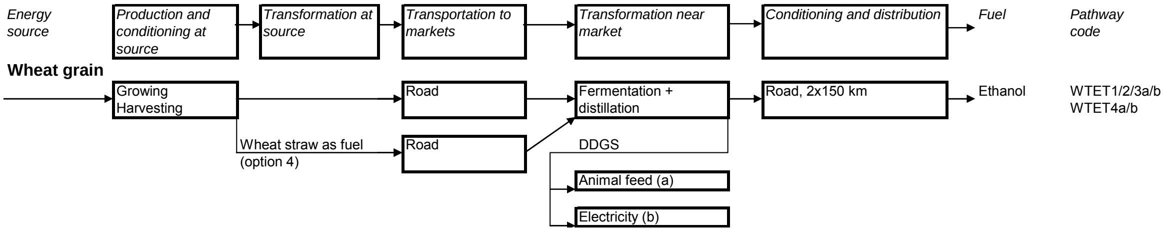
But at this level, not all DDGS would directly replace soy meal. EU soy meal consumption is about 25 Mt. That is equivalent to 30 Mt dry DDGS, and an ethanol supply of 160 PJ, or 2.8% of 2010 gasoline consumption. There would be some indirect replacement of soy meal by replacing other imported feeds (such as 4.4 Mt of maize gluten). Then one comes into conflict with rapeseed cake (see *section 5.2.1*).

Animal feed is by far the most lucrative usage and therefore the most likely; but we have seen that the animal feed market will saturate within EU if the 5.75% target of gasoline replacement is reached. At this point DDGS might be used as fuel, for instance in solid-burning (i.e. coal) power plants that need to meet their renewable energy obligations. The calorific energy content of DDGS is considerably greater than the energy required to produce the equivalent animal feed, so burning DDGS gives a higher energy credit. We have illustrated these two options in sub-pathways:

- WTET2/3/4a: DDGS as animal feed
- WTET2/3/4b: DDGS as fuel

The wheat grain to ethanol pathways are illustrated in the figure below.

Figure 3.4.4-1 Wheat grain to ethanol pathways

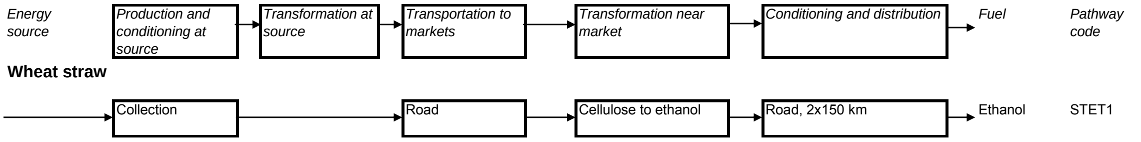


Straw to ethanol

In the above section we have described the conversion of wheat grain to ethanol, with optional use of straw as fuel for the process. The possibility also exists to use the straw as ethanol feedstock through an SSCF-type process (Simultaneous Saccharification and Co-Fermentation) that turns cellulose into sugars and can in principle be applied to all cellulosic biomass materials.

On the basis of experience with their pilot plant, Iogen corp. (Ontario, Canada) provided energy and emissions data for a projected 140 MW_{th} plant straw-to-ethanol plant [*Iogen 2003*]. Straw has a more suitable composition for SSCF than wood, and the Iogen plant claims a slightly higher energy efficiency than the projected SSCF wood-to-ethanol plant from NREL.

Figure 3.4.4-2 Wheat straw to ethanol pathways



Ethanol to ETBE

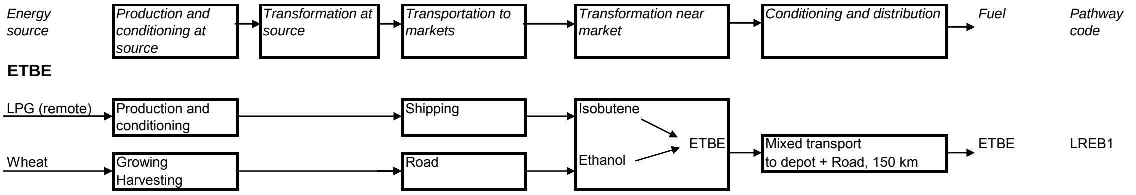
As an alternative to using ethanol as such as a gasoline blending component, it can be converted to ETBE (Ethyl-Tertiary-Butyl Ether). ETBE is a high octane component with very similar properties to MTBE but with a lower solubility in water. The main advantage of ETBE over ethanol as a gasoline component is its low vapour pressure.

Similarly to MTBE, ETBE is synthesised by reacting isobutene with ethanol. The process is very similar and MTBE plants only require minor changes to be able to produce ETBE.

ETBE is currently manufactured by some European oil refineries in plants that used to produce MTBE. The isobutene feed is not produced on purpose but is a by-product of the catalytic cracking process. It is only available in limited quantities. Whereas the energy required by the ETBE plant itself is known, the energy associated with the production of isobutene cannot be estimated in a rational way as isobutene is produced as one of many minor by-products of the cracking process. As a result this cannot be calculated as a discrete pathway. The way to approach the net impact of this route is to compare a base case where ethanol is used as such and MTBE is produced in refineries, to the alternative where ethanol is turned into ETBE in replacement of MTBE (*see section 4.7*).

Should more ETBE be required it would have to be made from isobutene produced by isomerisation and dehydrogenation of normal butane. We have represented this pathway with the assumption that the marginal butane required is imported from gas fields.

Figure 3.4.4-3 Wheat-ethanol to ETBE pathway



Ethanol from sugar cane (Brazil)

Sugar cane is an excellent biomass crop from almost every point of view, except that it will not grow in Europe. It resembles more a permanent biomass crop like miscanthus than it does an arable crop. There are usually 5 harvests, with very high annualized yields of about 68 t/ha/a (moist). Each tonne yields 86 litres (1.83 GJ) anhydrous ethanol at a conservative estimate.

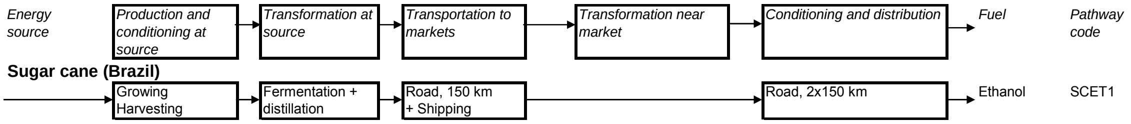
Brazil is the by far the world's largest producer, and has the greatest potential to expand production. The main growing area is in the South of the country, around Sao Paulo province. Expansion of sugar cane growth would occur in this and neighbouring regions, at the expense of rough grazing land. This is a very long way from any surviving rainforest. There is a small amount of sugar cane production in the coastal areas of the NE, nearer some patches of Atlantic rainforest, but this is not viable without subsidies, and is unlikely to expand.

Unlike arable crops in Europe, planting sugar cane on grazing land is believed to actually increase the soil carbon stocks. The risk of soil erosion (a major concern in Brazil) is only heightened in the first year of establishment. The plant has low fertilizer and water requirements and has low levels of minerals in the foliage.

A major benefit of the sugar cane to ethanol process is that the process heat is entirely provided by the bagasse; in fact there is even a small surplus of bagasse which can provides fuel for neighbouring food-processing plant (for example, orange juice production), generating a credit for saved fuel oil. The plant is self-sufficient for electricity. The vinasse from the fermentation vats is nowadays recycled to the fields. The emissions calculation takes into account the typical practice of burning the foliage to allow easier harvesting, although this is sometimes banned near populous areas.

We have taken our input data from a very thorough analysis by prof. Macedo et al. [*Macedo 2004*]. The balances include a credit for additional saving of fuel oil from the excess bagasse.

Figure 3.4.4-4 Sugar cane to ethanol pathway



3.4.5 Oil seeds

In Europe the two most used oil seed crops are rape (also known as colza) and sunflowers. Agricultural yields are much lower than for wheat or sugar beet. A certain proportion of oil seeds in crop rotation with cereals produces a synergistic improvement of cereal yields. Rape grows better in the North of EU and is more intensive. Sunflower is more suited to southern Europe. Processing of the oil seeds from either source is practically identical.

Before vegetable oil can be used as an internal combustion engine fuel, it needs to undergo esterification i.e. the reaction of the organic acid functions with an alcohol. This is an essential step to ensure the resulting fuel is stable. Vegetable oil can be thought of as three fatty acid “ribs” attached to glycerol (=propan1,2,3-triol) “backbone”. This large molecule is viscous and thermally unstable, forming the yellow deposit familiar on frying utensils. The "trans-esterification" process consists of replacing the glycerol with three methanol molecules, so that three separate fatty-acid methyl ester (FAME) molecules are formed from each molecule of plant oil. The processing is relatively straightforward, cheap and does not require a lot of energy.

Today methanol is used as it is abundantly available and cheap. Other alcohols, particularly (bio)-ethanol can be used, in principle. Although there are no such processes in actual operation, we have included this option in combination with rapeseed to show the impact of using bio-ethanol on the overall energy and GHG balance (to produce a fatty acid ETHYL ester (FAEE). We could not source actual process data and, in representing this option, we assumed the same energy input as for FAME for the esterification process, the benefit coming from the use of a partially renewable alcohol.

Rapeseed

In the oil mill, the rapeseed is crushed, and oil extracted by steam and hexane. The process we have described is very similar to others in the literature. The by-product is rapeseed cake, a high-protein animal feed, replacing soy bean cake as described for DDGS from wheat. It is interesting that the production of soy bean cake also makes a by-product: soy oil, which receives a credit based on the main pathway for rapeseed oil (this creates a calculation loop). Rapeseed cake could also in principle be used as a fuel, much in the same way as DDGS. This is at this stage an unlikely option because of its high value as animal feed and we have not developed a pathway to cover this.

The next step is purification, in which acidity is neutralized and the oil clarified. The trans-esterification reaction mentioned above often takes place in a separate plant inasmuch as it is the only step which is specific to bio-diesel compared to vegetable oil for food.

The raw glycerine stream contains only 80% pure glycerine but could be refined and sold as distilled pharmaceutical-quality synthetic glycerol. Several studies (including [*LBST 2002*]) have used this to calculate a by-product credit. This is very good for the energy ratio, because synthetic glycerol production uses about 18 times its heating value in fossil fuel. However, the scenario is not very realistic if we consider the size of the market. Total EU glycerol consumption is about 275 kt/a [*NRC 2004*] and the only remaining synthetic glycerol plant in EU has an output of 36 kt/a. By comparison 5% replacement of EU diesel fuel would pour an extra 1.15 *million* tonnes of glycerine onto the EU market (about 2.5kg per person per year), more than thirty times the EU production of synthetic glycerol. Therefore we did not consider this substitution option.

Most of the glycerine produced today is a by-product of soap-making from fats and oils and the supply will hardly change if more is produced from bio-diesel. Therefore a large increase in supply can only be accommodated by finding other uses, at a lower price. In fact in 2005 the effect of expanding bio-diesel production was already felt on the glycerol market: the crude 80% glycerine from bio-diesel fetched 130-200 €/t on the EU commodities markets. This price reflects the cost of purifying it to the standard vegetable-grade specification the EU price for which declined from 550 to as low as 300 €/t during 2005.

In a scenario of continuing rapid expansion of bio-diesel production in the EU, the glycerol price will be depressed further in the short term (indeed in the UK there are already reports of bio-diesel producers paying to dispose of glycerine as a waste). However, [*DOE 2004*] states that glycerine will be attractive as a chemical feedstock if the price remains between 80 and 200 €/t (0.2 to 0.5 $/lb). Therefore, in the long term we can expect industry to develop processes using glycerine which will stabilize the price at the bottom of its current range. On this basis our best-estimate medium term glycerine price is 130 €/tonne.

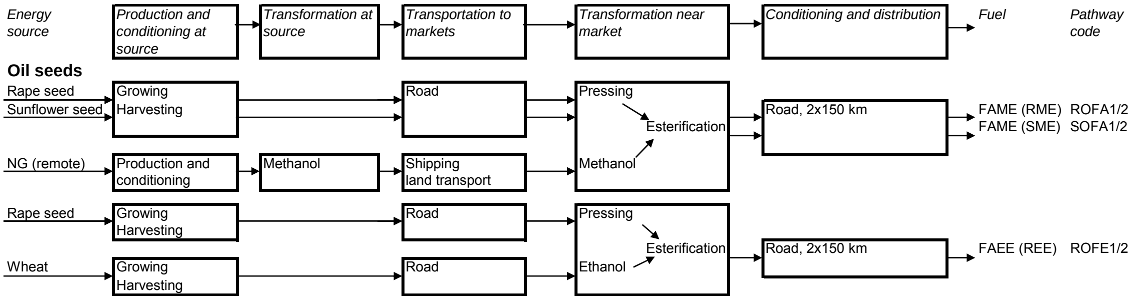
To get an idea of the potential size of this market we noted that synthetic propylene glycol and ethylene glycol are chemically similar to glycerol. They have a combined market about 14 times greater than synthetic glycerol [*DOE 2003*] and still fetch around 1100 €/tonne and 680 €/t in 2005. So even this market could still only absorb about half the potential glycerine glut.

Since we happen to have an estimate of the fossil energy content of propylene glycol [*GEMIS 4.1*], we have taken this as the upper limit of the energy and emissions credit. On the other hand, only a slight fall from the 2005 price would make glycerine attractive as animal feed. This gives a much lower energy and emissions credit. If glycerine is used as fuel (at a value of only 20€/t according to [*DOE 2003*]), the energy and emissions credit would lie between half-way these two extremes. So we can be fairly confident that the average credit for glycerine would be between these values.

Sunflower

Sunflower processing differs from rapeseed only inasmuch as the pressing yield is slightly higher, and the sunflower cake by-product has a lower protein content, replacing 0.61 kg pure soy-meal per kg, instead of 0.80 kg/kg for rapeseed cake.

Figure 3.4.5 Oil seeds to bio-diesel pathways



Oil seed imports

Europe is short of oil seeds. So far the trade pattern has been to import the raw materials (oil seeds) rather than finished bio-diesel. Perhaps this is because until now there has been a ready and profitable market for the animal-feed by-products in the EU.

The import of oilseeds or vegetable oils for bio-diesel production (or for replacing domestic oilseeds which are diverted to oilseed manufacture) raises major questions about sustainability. One source with a potential for expansion are soybeans in Brazil, but these are typically grown close to the rainforest and the existing high demand for soybeans is already suspected of accelerating the destruction of the rainforest. Another major source is palm oil from Malaysia and Indonesia: a rapid increase in demand could be met by unsustainable production on rainforest land. Sustainable certification could be considered as a solution, the EU importing only certified sustainable products. However, unless the scheme was adopted worldwide, sustainable exports to EU would simply be replaced by unsustainable production for other markets.

3.4.6 Wood

Wood waste is often presented as a vast untapped source of energy. Upon closer investigation, it appears that industrial wastes or used wood are already used as much as is possible (some problems with contamination) [*SBH 2000*] and agricultural prunings are mostly uneconomic to collect. The only type of wood waste which could make a significant impact on the energy sector with realistic economics is forest residuals from commercial forestry. The main producer countries already have plans to use more forest residuals for electricity and heat, but one could think to convert them to liquid fuels instead. Their use is essentially linked to pulp-mills.

The most efficient way to make biofuels from forest residuals is to use them inside a pulp mill, to substitute the burning of black liquor for process heat. This leads to a separate pathway for the “black liquor route”, which is essentially limited to the forest residuals associated with pulp-wood (see specific section below).

Although mature forests continue to sequester carbon by gradually increasing the thickness of their organic soil, harvested forests absorb carbon dioxide much faster when they re-grow, so harvesting them for energy definitely increases their CO_2 uptake. The commercial forests in EU grow more than is harvested each year, so there is potential to increase the sustainable supply of stem-wood in EU, for energy purposes. The pulp, paper and woodworking industry is understandably concerned about subsidized competition for their feedstock, both stem-wood and wood chips. This is not to be ignored, because life cycle analyses almost all agree that wood saves more greenhouse gas when made into durable products than when burnt for energy.

The other potential source of wood for energy is “wood farming” i.e. short rotation forestry (SRF) using fast-growing species to maximise biomass generation. This can be complemented by perennial grasses such as miscanthus and switchgrass. Miscanthus has yields in the same range as SRF without risking the expense of removing tree-roots if the land-use needs to go back to arable. Switchgrass has lower yields but also lower water requirements, an important consideration when we consider that agriculture is limited by water availability in a large part of the EU. As a fuel perennial grasses are similar to straw: although the lignin/cellulose ratio and dry-matter energy content are similar to wood, they have a higher salt content (which can cause ash agglomeration and corrosion in the burners) and lower bulk density. This makes them less attractive as a fuel, and perennial grasses command a similar market price to straw. Therefore SRF is usually the more profitable crop.

The drive to plant SRF on arable land in EU is motivated by three considerations: limiting food surpluses, providing renewable energy and sequestering carbon in the soil (see *section 3.4.1*).

Perennial crops and forests are thought to have a higher potential biomass yield than annual crops because the root system is already established at the start of the season. However, the very high yield expectations of the ‘80s have given way to more realism: in practice commercial SRF plantations give only slightly higher biomass yields than wheat on the same land, less if the straw is also harvested (see also *section 5.2.2*). On soils too poor to support arable crops, SRF is likely to fail altogether, rather than produce the “8-10 tonnes/ha/a” figure often quoted.

On the other hand, wood requires less fertilizer, labour and other inputs, and can therefore be grown more cheaply. SRF is also more eco-friendly and wood is generally a better fuel than straw and perennial grasses, having a lower salt content. Furthermore, perennial crops may keep more carbon in the soil than arable crops, so that one might be able to plant them on grassland without causing unacceptable reduction in soil carbon stock. However, in this case one should be prepared for very much lower yields, as explained above.

Wheat + straw as a bio-energy crop

Taking straw with the wheat would give a total (moist) biomass yield of at least 1.65 times the grain yield. If in addition the wheat variety is a high-yield low protein variety, the collectable (moist) biomass yield will be at least 1.78 times the average wheat yield. This corresponds to 1.56 dry biomass / conventional wheat yield. So feed-wheat + straw is actually a high-yielding biomass crop, but it requires more inputs (fertilizer, diesel, labour…) than SRF.

SRF wood can be burned directly to supply heat and possibly electricity via steam-raising. However, a more sophisticated route, which is now attracting a lot of attention, is gasification. The process is rather similar to coal gasification, producing syngas, which can be either used to fuel a gas turbine or further processed to hydrogen or to a synthetic liquid fuel such as methanol, DME or synthetic diesel fuel.

Gasification can be envisioned at either small or large scale. The former would only be suitable for electricity or possibly hydrogen production because of the high cost of investment and plant maintenance for more sophisticated processes.

Wood to hydrogen

Two process scales are considered: 10 MW_{th} and 200 MW_{th} (expressed in terms of biomass input). The larger scale we consider is the feasible limit for EU-produced wood to be available within economical transport distances. The smaller scale is for “local” production of hydrogen, the simplest fuel to make from wood. It applies to farmed wood within 12 km transport distance and forest residuals within 50 km.

For production of hydrogen and other fuels via gasification, it is important that the syngas is not diluted by nitrogen from air-blowing. Gasifiers carry out two reactions: partial oxidation, which is exothermic, and steam reforming (to make hydrogen) which is endothermic. Simple auto-thermal gasifiers carry out the two reactions simultaneously, and would need oxygen separation systems, which are expensive at these comparatively small scales and prohibitive at the 10 MW scale. Therefore allo-thermal (externally heated) gasifiers are preferred for small plant. The DM2 gasifier from Choren Industries is an example which works well at 10 MW. A different system is required at 200 MW, because it is difficult to get the heat in through the walls fast enough. For this case the BCL gasifier uses a pressurized circulating fluidized bed to transfer heat between the two processes.

Wood to synthetic liquid fuels

For biomass-to-liquid (Fischer-Tropsch) fuels, we also used a process analysis based on the BCL gasifier. The efficiency of this process depends strongly on the performance of the FT catalyst. For our “best estimate” we used the middle value of chain growth probability (0.85) quoted by [*Tijmensen 2002*].

The “best case” is the Choren process under development based on a DM2-type gasifier. They claim an efficiency of 51% combined with an output of pure diesel fuel (kerosene and gasoil), which others believe is not achievable, even assuming the best performing catalyst. Note that to produce only diesel fuel, the lighter FT products have to be recycled all the way back to the gasifier, an operation which is bound to require additional energy. The lowest efficiency limit is the BCL-based process again, but with the most pessimistic assumption for catalyst performance.

Apart from Choren, biomass-to-FT plants all produce 2 fuels simultaneously: naphtha and diesel fuel. We adopted the simple approach as considering the two equally valid products, and quoting the efficiency for the sum of both fuel products.

DME and methanol are produced by the same process: the only difference is the nature of the final catalyst. We found in the literature two analyses: one based on the BCL gasifier [*Katofsky 1993*], which becomes the "best case", and a "worst case" based on the simpler Värnamo auto-thermal pressurized fluidized-bed gasifier, used with oxygen blowing [*Atrax 1999*]. Note that we have no process for DME based on the Choren DM2 gasifier. To compare efficiency between production of FT and DME or methanol, we should compare the "best-case" FT process with the "best-estimate" process for methanol and DME.

Other processes for conversion of wood to liquids are described in the literature such as fast pyrolysis or the HTU process. We have not included these options. Fast-pyrolysis of wood produces products that cannot be used directly as road fuels, but can be fed to a gasifer in the same way as black liquor. Thus fast pyrolysis is a sort of pre-treatment step as far a road-fuel production is concerned. It may be a viable process for making other chemical products, but the capital cost of two processing plants in series is likely to present a major hurdle.

The HTU process has been under bench-scale development for some time. It converts the feedstock to a mix of solid and liquid products in superheated water. It is hoped that the liquid fraction can be upgraded to hydrocarbon fuel by hydrogenation. Clearly it is more attractive for wet feeds like organic waste or wet crops than wood. However, processing sewage is not likely to be economic because its low heat content means low throughput, which would not repay the high investment cost of the pressurized tank. So HTU is best thought of as an alternative to anaerobic digestion to produce biogas. The proposed process has changed greatly since it was included in [*LBST 2002*] and the new process configuration has not yet been costed in detail, so we could not include it.

Wood to ethanol

There are no commercial wood-to-ethanol plants operating at present. NREL have made detailed studies of an SSCF process for converting wood and other biomass to ethanol (see also wheat straw to ethanol in *section 3.4.4*). We have selected their "base case" as our "worst case": it is the design for a plant using the state-of the art technology available in 1999. For our "best cast" we selected their "best of industry" plant, which already anticipates advances which are still at the laboratory stage. We did not consider their projections further into the future to be appropriate for a 2010 timeframe.

Many of the processes described in the literature combine production of a certain fuel and of electricity. As a result the total process will consume more wood per MJ of fuel produced than would be the case without electricity production. This may make good economic sense in practice and, in some cases exploit genuine synergies. If this electricity is deemed to replace fossil electricity or even EU-mix electricity, this can generate a very large credit which considerably distorts the result while it is simply a reflection of the fact that two notionally independent processes are conducted side-by-side.

Accounting for co-production of electricity

Most of the wood processing schemes quoted in the literature produce some surplus electricity (and therefore consume some additional wood to that effect). To arrive at a meaningful comparison and in accordance with our philosophy that the reference scenario should differ from the biofuels scenario only in the production of biofuels, we made all the wood conversion processes electricity-neutral by adding or subtracting an appropriate proportion of a wood-to-electricity process. For each case we chose a power station which closely matched the one in the process: for example, processes making fuels using the BCL gasifier were made electricity-neutral using the efficiency of a wood power station based on BCL. To compare the efficiency of the processes, which now all had about zero emissions, we compare the "primary energy efficiency" defined as (all primary energy in)/(fuel out). Our efficiency values for pure fuel processes do not correspond to the overall process efficiencies quoted in some references such as [*Tijmensen 2002*]: which are for mixed electricity + fuel processes, with the electrical and fuel energies of the products simply added.

Waste wood in combination with black liquor gasification

Paper pulp manufacture involves separation of wood cellulose from the lignin which forms an important proportion of the wood matter and energy content. The residue from this process, known as black liquor, is a water-based slurry, 70 to 80% of which consists of lignin and spent pulping chemicals.

In conventional pulp mills the black liquor is burned in a so-called "recovery boiler". The non-combustible components leave the recovery boiler as the so-called "smelt" mainly consisting of molten sodium sulfide (Na_2S) and sodium carbonate (Na_2CO_3) which are recycled to the pulping process. The corrosive nature of the smelt limits the recovery boiler efficiency to about 65%.

The recovery boiler provides heat and electricity for the pulp mill. Including the combustion of the bark and the use of the sludge from the effluent treatment a modern pulp mill is self-sufficient in energy.

Replacement of the recovery boiler by a gasifier has been considered by the pulp and paper industry for some time. The original drive for such a scheme was increased energy efficiency which would allow combined production of process heat and surplus electricity for export. As the product of the gasifier is syngas, production of synthetic fuels can also be envisaged. However, the energy used for producing the synthetic fuels must be compensated for by another energy source, conveniently supplied in the form of additional (waste) wood intake into the "hog fuel" boiler already present to burn the bark and other residues. The net result is to turn waste wood into synthetic fuels.

Taking the original pulp mill as reference and for the same pulp production and electricity balance, one can calculate the net efficiency of synthetic fuels production, which turns out to be appreciably higher than that of the direct wood conversion processes. The reason is that the additional burning of forest residuals increases the thermal capacity of the plant, whilst the stack losses are reduced because the hog-fuel boiler has higher efficiency than the replaced recovery boiler. Almost all the heat from the syngas is recovered.

Of course this efficiency improvement can only come about through a substantial investment in a black liquor gasifier and fuel synthesis plant. The gasifier is expensive because of the need to resist corrosion by the very high sulphur and salt content of the syngas, and we are still awaiting the results of the first industrial trials.

In [*Ekbom 2003*] the generation of methanol and DME from black liquor has been investigated within the BLGMF (Black Liquor Gasification to Motor Fuels) project. We have included these pathways as well as pathways to synthetic diesel and hydrogen inferred from the methanol and DME data. We have also included the electricity pathway as it will be the reference against which mill operators will judge the attractiveness of fuel manufacture.

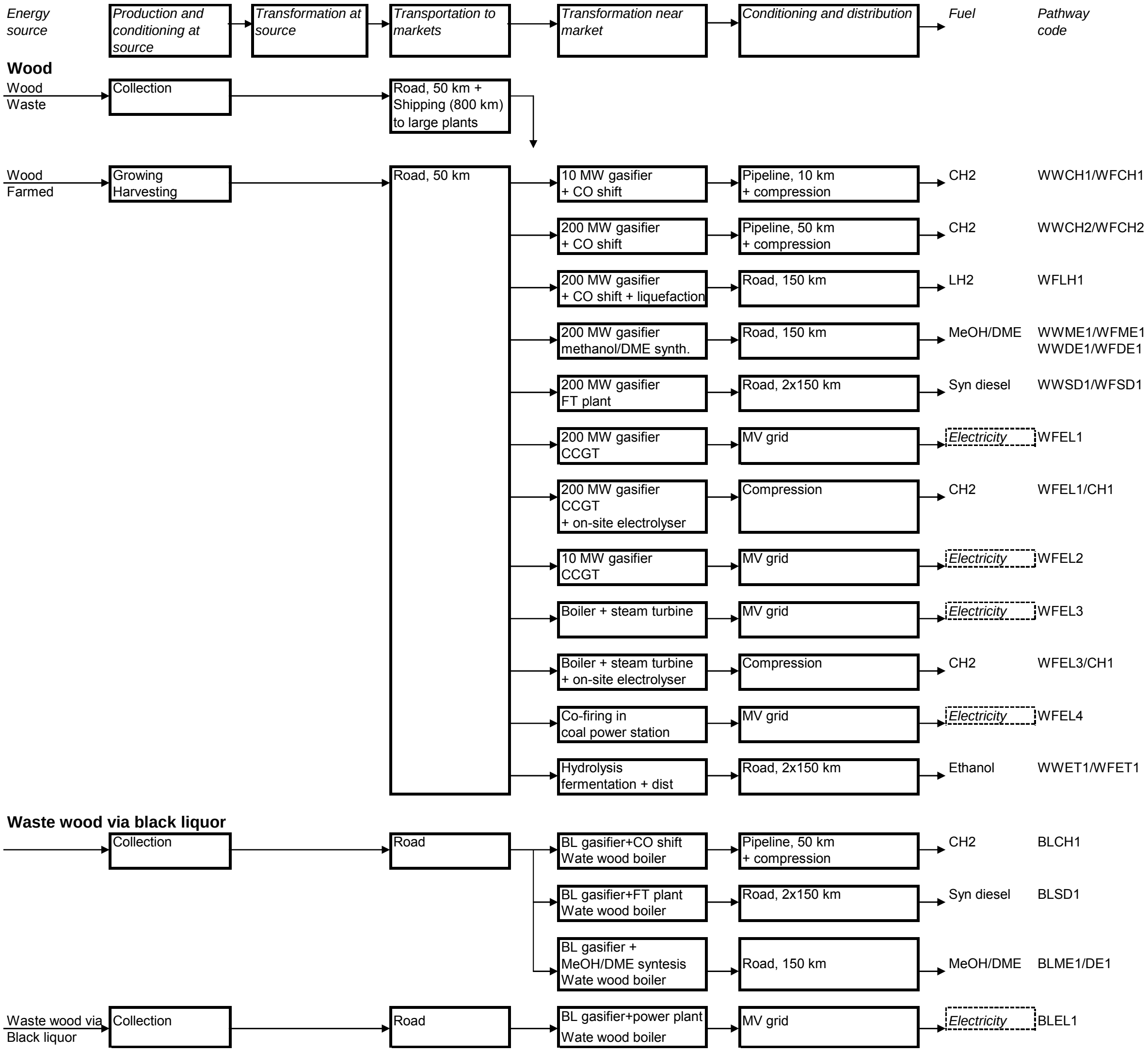
The following table summarises the “wood efficiency” of the various wood processes after correction for electricity production as discussed above.

Table 3.4.6 Wood efficiency of various wood conversion routes

MJ wood/ MJ final fuel	10 MW			200 MW			Black liquor route		
(corrected for electridity production)	Mean	min	Max	Mean	min	Max	Mean	min	Max
Electricity	2.8	2.7	3.0	2.1	2.0	2.2	1.1		
Synthetic diesel (200 MW)				2.1	2.0	2.2	1.8	1.7	1.9
Mehanol/DME (200 MW)				2.0	1.7	2.2	1.5	1.4	1.6
Hydrogen	1.9	1.8	2.0	1.5	1.4	1.5	1.2	1.2	1.3
Ethanol	2.9	2.8	3.1						

The various wood pathways considered are illustrated in the figure below.

Figure 3.4.6 Wood pathways



3.4.7 Organic waste to biogas

The anaerobic fermentation of organic matter produces a gaseous mixture, known as "biogas", consisting mainly of methane and CO_2 (typically 60/40 % v/v although the actual composition varies significantly depending on the type of organic matter). Biogas also contains small amounts of other substances, such as H_2 (0-1%), N_2 (0-7%), H_2S (0-1%) and traces of NH_3 as well as water vapour (in case of landfill gas also small amounts of halogenated compounds can occur).

The process consists of a hydrolysis step, formation of organic acids and of methane. In case of glucose (a saccharide) the methane formation reaction is:

$C_6H_{12}O_6 \Rightarrow 3\ CH_4 + 3\ CO_2$

A suitable feedstock is biomass which contains components such as carbohydrates (i.e. saccharides such as glucose), fatty acids and proteins. Cellulose and hemicellulose are converted to saccharides via hydrolysis. Lignin cannot be decomposed via anaerobic fermentation but only via aerobic processes which do not generate methane.

Anaerobic decomposition and formation of methane commonly occurs when manure, crop residues or municipal waste are stockpiled or used as landfill, or when organic matter is immersed in water as occurs naturally in swamps, or is applied as liquid manure. It is particularly suitable for wet feedstocks, since drying is not required.

Small, often farm-size installations designed to capture this gas have been used for many years. In this case the "raw" biogas is used directly to produce heat and occasionally power e.g. in a dedicated gas engine. Larger scale installations have started to appear in recent years, particularly in Scandinavia, driven both by environmental concerns and, in the case of municipal waste, increasing disposal constraints.

The gas can be used to produce power, possibly combined with a district heating scheme. Alternatively, such plants can produce enough biogas to justify an export infrastructure to a few local service stations for use as automotive fuels or to connect with the local natural gas grid as a substitute to natural gas. In these cases the biogas needs to be treated to remove contaminants, particularly H_2S, and upgraded to a higher heating value or Wobbe index by removing the bulk of the CO_2. Certain feedstocks (e.g. sewage) need to be "hygienised" by heat treatment prior to biogas production to avoid propagation of harmful bacteria or by operating the fermenter at 50 to 55°C (suitable for thermophilic bacteria).

In this study we are primarily concerned by pathways representing biogas use as a motor fuel, which include supply of the feedstock, biogas production, biogas treatment and upgrading, biogas distribution and finally compression to 25 MPa to refuel a vehicle.

For comparison purposes we have also included biogas-to-electricity pathways representing either local small-scale usage or export to the grid and use in a large scale power plant.

We have considered three possible feedstocks:

- Organic municipal waste
- Liquid manure
- Dry manure (mixed with straw)

Purpose-grown crops can of course also be used in principle although this has so far received limited attention. Perhaps as a result of the relatively high cost of biogas plants per unit of gas produced, the process appears to be more attractive for (cheap) wastes than for expensive crops. We have not included this option in this version but may consider it in future updates.

OWCG1: Municipal waste to automotive biogas

Feedstock supply

Municipal waste needs to be collected to a central point in any case so no energy/GHG debit applies to this stage.

Raw biogas production

The feedstock is processed in a “digester” in a batch process that can take several days. The gas produced is collected and sent to the treating section. The required heat and electricity are produced within the plant by a dedicated gas engine running on the raw biogas itself. The conversion level of the organic matter is typically 70%. The unconverted material is a good quality fertiliser for which a credit needs to be calculated (based on the traditional fertiliser substituted). In fact, the nitrogen in digested fertilizer is more quickly available to plants than that in manure, so that its use is more like that of synthetic nitrogen fertilizer. By applying digested fertilizer at the start of the growing season, a greater proportion of the nitrogen can be taken up than is the case with manure. Accordingly, we have given a credit to the biogas pathways corresponding to the equivalent quantity of synthetic nitrogen fertilizer.

Biogas treatment and upgrading

H_2S can be removed by several methods. A common method consists in adding small amounts of air into the fermenter (3 to 5% of the total amount of biogas). Bacteria (sulfobakter oxydans) convert the H_2S into solid sulphur which is collected on the surface of the fermented substrate (biological desulphurization). Reaction with metal oxides or adsorption on active carbon can also be used. Reaction with metal oxides generally is carried out downstream the biological desulphurization to achieve very low sulphur contents (<1 ppm).

In small to medium scale plants, CO_2 removal is normally carried out with a pressurised water wash for which the gas needs to be compressed to typically 1 MPa. The electricity required for compressing the gas and pumping the water is also supplied by the “in-house” power plant. Typical water consumption is 10-20 m^3 per 100 Nm^3 of gas. Waste water from the municipal treatment plant can be used for this purpose. If water availability is a problem it can be recycled after desorption at reduced pressure. In the process some methane emissions are inevitable (0.2 g CH_4/MJ treated biogas).

Heat and power plant

The concomitant requirement of power and low temperature heat is a favourable situation leading to a high efficiency of the gas engine (nearly 90%). We have assumed that the operation of the gas engine is adjusted to produce the heat requirement of the plant, leading to a surplus of electricity. Exported to the grid, this surplus commands a credit for substitution based on the EU-mix. Minor CH_4 losses are also taken into account.

Distribution and compression

The treated biogas is available at around 0.9 MPa at the plant outlet which is considered adequate for joining the grid without any further energy requirement. Compression energy is as assumed for natural gas i.e. 0.4 MPa suction and 25 MPa discharge.

OWCG2: Liquid manure to automotive biogas

This pathway is similar to the previous one with a few notable differences:

- Under the assumption of a medium size biogas plant, the manure has to be collected from individual farms and transported to the plant (we assumed a distance of 10 km).
- The biogas production step requires different amounts of heat and electricity due to the different nature of the feedstock.
- The residue left after biogas production still contains all the minerals and nitrogen of the original material and can be used as fertiliser. The credit for this is slightly different from the one considered in OWCG1.
- The largest difference though is due to the large GHG credit related to the avoidance of methane emissions from the manure when used in the traditional way. This is estimated to typically amount to some 15% of the biogas produced.

OWCG3: Dry manure + straw to automotive biogas

Again in this case the general setup is the same with a minor change in the transport energy due to the different nature of the feed. The main difference with OWCG2, however, is the much smaller credit for avoided methane emissions. Indeed with dry manure, these are only estimated to be about 1/10th of those with wet manure.

Liquid manure is mainly produced by intensive pig farms, while dry manure results from more environmentally-aware farming practices. It can therefore be argued that the large credit registered for liquid manure is mostly a compensating mechanism for inappropriate farming practices.

Biogas to electricity pathways

Two scenarios can be envisaged:

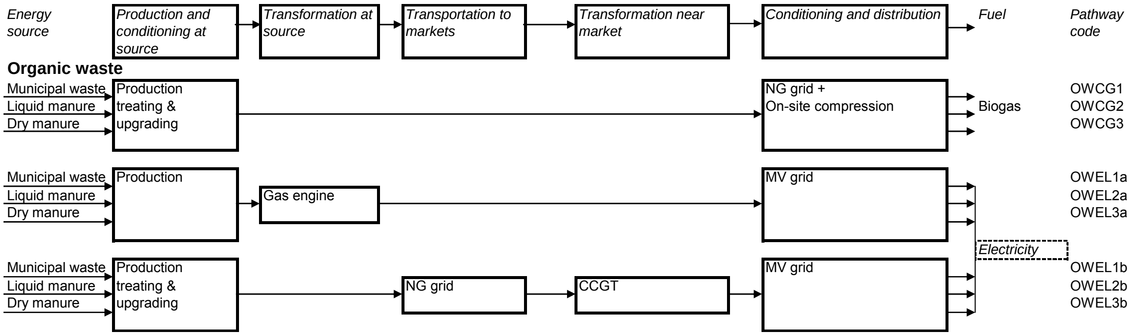
- Small scale plant where the raw biogas is used directly in a local power plant.
- Larger scale installation where upgraded gas is exported to the grid and subsequently used in a large power plant.

The main differences between these two cases are the requirement to upgrade the gas in the second case and the significantly higher generation efficiency in larger power plants.

Mixed Feedstock

Long residence time means that biogas plants are larger than thermal conversion plants for a given throughput, which tends to make them more capital-intensive. The economies of scale means that large biomass plants have lower capital costs per unit of output than small ones, and can thus provide biogas more cheaply. This is especially true if purification and compression is to be built into the same plant. Large biogas plants use all the feedstock available within an economic transport distance. Thus they typically use a mixture of animal slurry from local intensive animal farms, concentrated organic waste from the food processing industry, and sometimes municipal organic waste. There is also some synergy in mixing the feeds to optimise the C:N ratio. This point is important in the costs and availability calculation.

Figure 3.4.7 Organic waste to biogas pathways



3.5 Electricity production and electrolysis

(See also WTT Appendix 1 section 1-12, 1-13)

Electricity is an intermediate source of energy for e.g. the production of hydrogen via electrolysis. It is also the “fuel” for electric vehicles although at this stage we have not included these in the study. It is in any case of interest to establish the energy and GHG balance of the main generation pathways as electricity in effect competes with other fuels for primary energy sources.

3.5.1 Electricity generation pathways

Electricity can be produced from virtually any energy source. We have selected a range of pathways covering the most practical options namely natural gas, coal, biomass (in the form of wood), wind and nuclear. For comparison purposes we have also described the EU-mix generation as a discreet pathway.

Natural gas

Natural gas is already extensively used for power generation, representing about 12% of the primary energy in EU-15. This is due to increase strongly in the coming years where gas will replace some nuclear and coal generation as well as cover the bulk of the increasing demand.

Although gas is used in conventional thermal steam cycles, virtually all new capacity is and will be based on the CCGT concept (combined cycle gas turbine) which has a much better efficiency (55%). We have also included a CC&S option for this process (see *section 3.6*). Note, however, that such high efficiency can only be reached in a new state-of-the-art plant. A simple "switch to gas" in an existing installation will only marginally improve efficiency.

The above processes has been used in the calculations for specific pathways involving NG-based electricity (such as LNG, see *section 3.2.4*) with and without CC&S as appropriate. We have also included full NG-to-electricity pathways for three sources of natural gas namely piped gas (7000 and 4000 km) and LNG as well as a CC&S option for the 4000 km piped gas case.

Coal

Coal can nowadays be used "cleanly" to produce e.g. electrical power. While gasification associated with a combined cycle scheme (IGCC) can deliver the best overall efficiency, various technological advances have also boosted the performance of the conventional thermal cycle. We have included pathways representing both options. The conventional process represents a typical modern plant with an efficiency of 43.5% (range 40 to 50%, [*TAB 1999*]). For IGCC there is a large range of data from the literature [*TAB 1999*], leading to an average value of 48% ranging from 45 to 52%. A CC&S option has also been included in the latter case (see *section 3.6*).

Wood

Wood can be used in a simple boiler + steam turbine configuration or in a more sophisticated scheme involving gasification and CCGT. The expected efficiency is much higher in the latter case although costs will also be higher. Both large and small scale gasifiers and gas turbines can be envisaged. The black liquor route also offers an attractive alternative for efficiently producing electricity from waste wood (see also *section 3.4.6*).

Organic waste via biogas

See *section 3.4.7*.

Nuclear

The resource in this case is uranium and more precisely the U_{238} isotope of which there are large reserves. However, the future of nuclear fission as a major power source is a societal issue that goes far beyond the scope of this study and will not be further discussed.

Although nuclear electricity is not strictly renewable, it is virtually carbon-free, the only significant sources of CO_2 emissions being associated to fossil carbon energy used in mining processing and transport of the uranium as well as maintenance of the power plants.

Wind

In theory, there is a virtually unlimited potential for producing electricity from wind power. There are, however, a number of factors that constrain its development. The number of sites suitable for the development of major wind farms and acceptable to society is limited. The intermittent and largely unpredictable nature of wind makes it difficult to integrate large wind farms into existing electrical grids and opens the issue of back-up capacity.

Improvements in wind turbine technology have been very fast and are still expected to contribute a lot to the practical and economic viability of a number of projects, providing ever larger, cheaper, quieter, more efficient and flexible machines.

Nonetheless most forecasts agree that wind power, although growing very fast in the years to come, will not play more than a marginal role in the European energy scene of the next 20 to 30 years (see [*EU energy & transport 2003*]). Once installed, wind power is virtually free and is therefore likely to be used preferentially into national grids. Mismatch between demand and instantaneous production as well as the limited capabilities of grids to deal with sudden large load changes, may lead to surplus generating capacity being available e.g. to produce hydrogen.

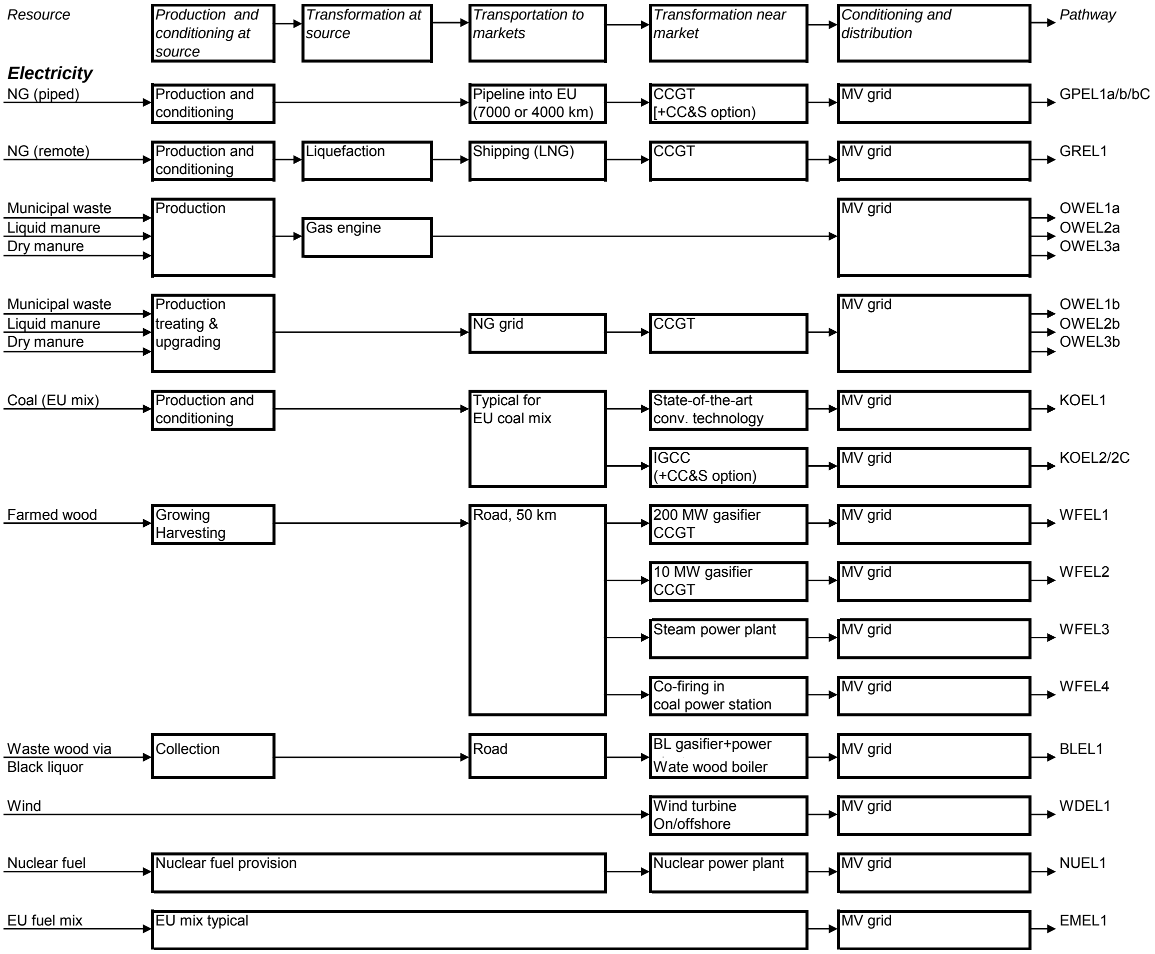
Drawing up the energy balance of wind power presents a specific problem inasmuch as the input wind energy cannot be precisely defined and is, for all practical purposes, unlimited. It is therefore generally considered that wind power is created from "nothing" except a minor amount of fossil energy required to cover maintenance activities of the installations.

Hydropower

Hydroelectricity currently represents by far the largest portion of Europe's renewable energy consumption. There are, however, very few sites still available and capacity is not expected to grow substantially.

Hydro electricity is very much a integral part of the European electricity scene, is fully integrated into the "EU-mix" and, being one of the cheapest source of power will always be used in preference to fossil fuels based power. From this point of view it has no direct relevance to marginal electricity and has not been further considered in this study.

Figure 3.5.1 Electricity generation pathways



The "EU-mix"

Electricity in the EU is produced via a large number of routes including coal, gas, nuclear, hydro etc. The combination, although not corresponding to a single actual pathway is used in this study to represent the typical electricity supply.

There are several sources of information for this amongst others the International Energy Agency, Eurelectric (the Union of the electricity industry) and the EU Commission's "Poles" model. All sources report slightly different figures for the past years and of course show different forecasts. There is, however, a general agreement to show a decrease of nuclear, solid fuels and heavy fuel oil compensated mainly by natural gas. Renewables, although progressing fast in absolute terms, do not achieve a significant increase in relative terms because of the sharp increase in electricity demand. As a result, although the primary energy composition of the 2010 "kWh" is different from that of 2000, the resulting CO_2 emissions are not very different.

We have opted to use the figures compiled in the German GEMIS database [GEMIS 2002] for the year 1999 resulting from a detailed country-by-country analysis of electricity production. The share of the different primary energy sources in the total electricity production is shown in the following table.

Table 3.5.1 EU-mix electricity sources

Source	Share
Nuclear	37.5%
Coal	22.4%
Oil	9.6%
Gas	15.5%
Hydro	12.4%
Wind	0.4%
Waste	1.8%
Other renewables	0.3%

Including the distribution losses to the medium voltage level the overall energy efficiency is around 35 % and the corresponding GHG emissions 430 g CO_2eq/kWh$_e$. A further correction is made for those cases where electricity is produced or used at low voltage. The detailed primary energy composition is given in *WTT Appendix 1, section 1-2.*

Note: the GHG figure quoted above is coincidently quite close to the global figure for generation of electricity with natural gas in a state-of-the-art combined cycle gas turbine, a route often viewed as the most likely marginal electricity source in Europe for the foreseeable future.

3.5.2 Hydrogen via electrolysis

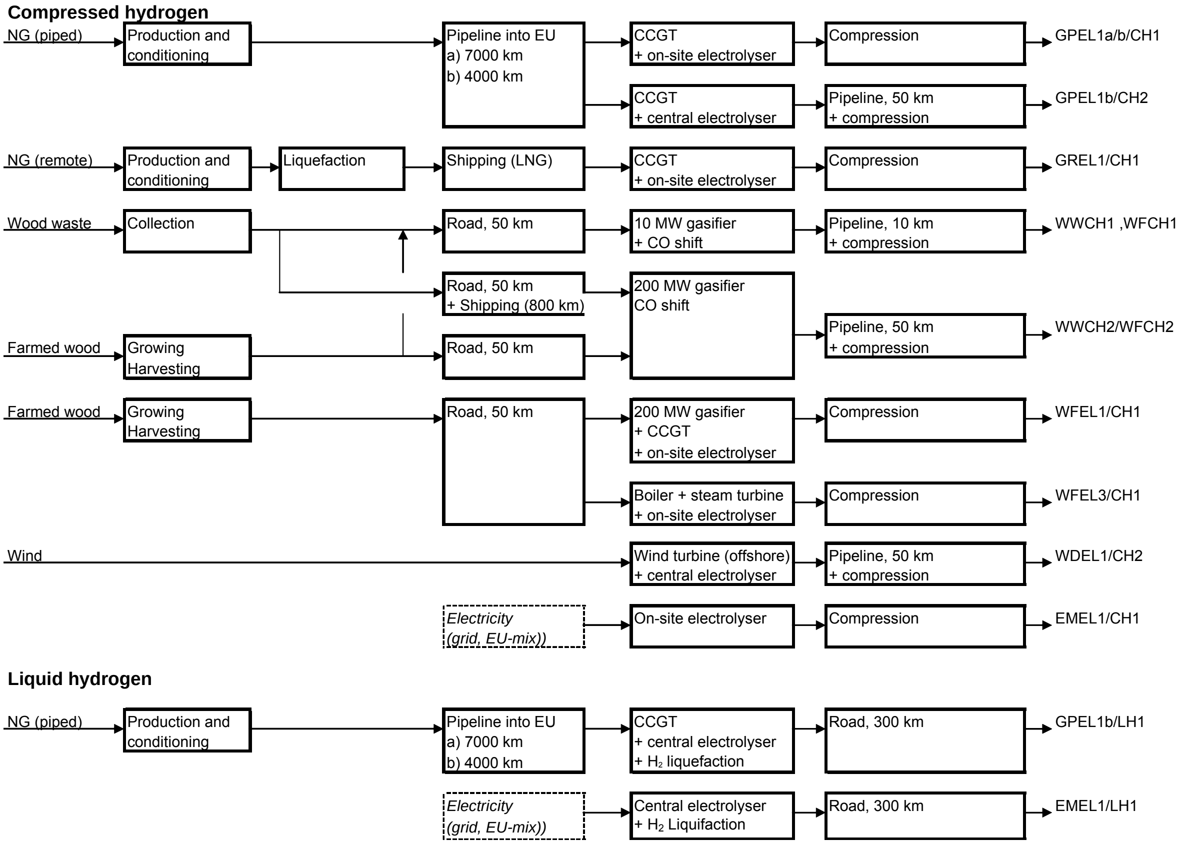
The electrolysis of water to hydrogen and oxygen is a long established process. It is possible to build electrolysis plants from very small to very large scale. The efficiency of the electrolysis process as such is largely unaffected by scale although the auxiliaries and the operating pressure can have a significant impact on the overall efficiency

Several sources of data are available, giving figures for both small and large (alkaline) electrolysers with and without auxiliaries. Including the latter most figures fall into the 62 to 70% bracket (related to hydrogen LHV, equivalent to 4.2 to 4.8 kWhe/Nm^3 of hydrogen produced), with no clear size effect ([*GHW 2001, 2004*], [*Hydrogen Systems 2000*], [*Stuart Energy 2005*], [*Vandenborre 2003*]). Some studies e.g. [*Dreier 1999*] have proposed far higher efficiency figures (up to 77% related to hydrogen LHV including all auxiliaries).

On balance we have considered that a figure of 65% with a range of 63 to 68%, irrespective of the size, is a reasonable representation of the available data.

We have considered a large scale plant, typically with the same hydrogen production capacity as a large reformer (200 MW as hydrogen) and a small on-site electrolyser serving a single filling station.

Figure 3.5.2 Hydrogen via electrolysis pathways



Many combinations are possible between electricity from various sources, electrolysis either central or on-site and hydrogen distributed in either liquid or gaseous form. We have selected a limited number to illustrate the main points.

One important issue is the pressure at which the hydrogen is available at the electrolyser outlet. Current and foreseeable technology at the 2010 horizon allows about 3 MPa. Higher pressures may be possible in the longer term but this is still somewhat speculative and we have not taken it into account. Hydrogen from a central electrolyser will need to be transported. If this is done through a pipeline network this pressure will be sufficient and a remaining pressure of 2 MPa has been assumed at the refuelling station compressor inlet. For the on-site electrolyser, no hydrogen transport is necessary and the whole 3 MPa outlet pressure is available.

3.6 CO_2 Capture and Storage (CC&S)

The concept of isolating the CO_2 produced in combustion or conversion processes and injecting it into suitable geological formations has been gaining credibility in the last few years. There are many such structures available in most areas of the globe from depleted gas and oil fields to salt domes and aquifers. CO_2 injection can also be used to enhanced and prolonged production from ageing oil and gas fields. Pilot projects are already in operation in the oil and gas industry.

The schemes includes separation of CO_2 from other gases, compression and liquefaction, transport (by pipeline or ships) to the point of injection and injection under pressure.

Separation of CO_2 from other gases is a well established process consisting in scrubbing the CO_2-containing gas mixture with a solvent or a physical absorbent. In combustion applications using air, scrubbing CO_2 out of the flue gases is feasible although very large equipment is required because of the large gas volumes. Oxy-combustion is more favourable from this point of view as it delivers virtually pure CO_2, although additional energy needs to be expended in the air separation unit. Reforming and gasification processes deliver CO/hydrogen/CO_2 mixtures or mostly hydrogen/CO_2 after the shift reaction. In these cases CO_2 scrubbing is more straightforward. In some cases, for example before syngas is fed to a Fischer-Tropsch reactor, CO_2 scrubbing is required irrespective of the CC&S option.

CO_2 separation and compression require some energy, the amount depending on the composition of the gas to be scrubbed and of the process used. Processes using a chemical solvent (such as MDEA, Methyl Di-Ethanol Amine) are more energy-intensive than absorption processes because of the heat needed to regenerate the solvent.

The concept can in principle be applied to many schemes. As illustration of its potential, we have included CC&S in the following cases:

- Electricity from natural gas and coal (IGCC)
- LNG: CO_2 from the power plant associated to the liquefaction plant.
- Hydrogen from NG and coal: Process CO_2 after shift reaction
- GTL and CTL diesel: Process CO_2 after reforming / partial oxidation
- DME from NG: Process CO_2 after reforming

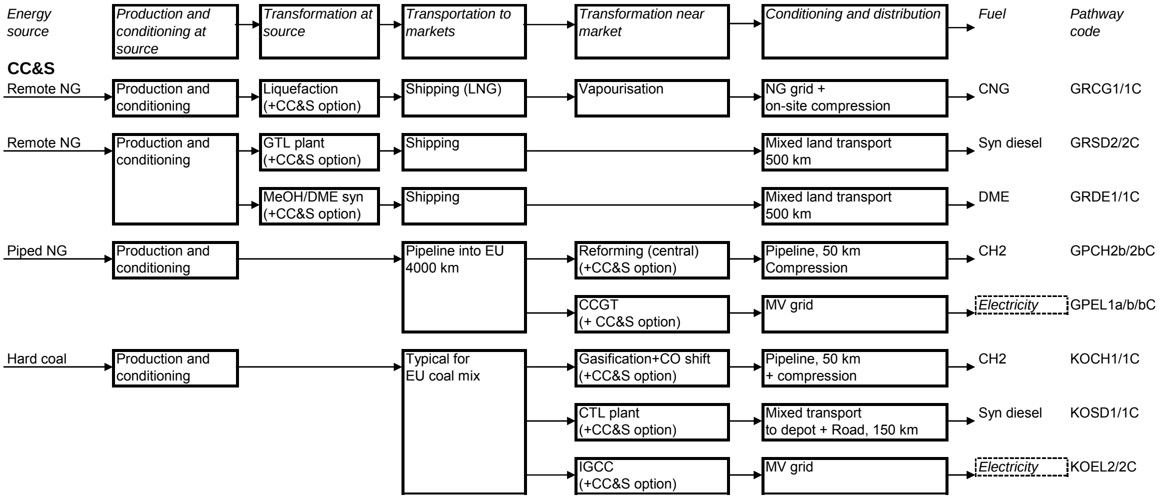
Note: the DME scheme could also be applied to methanol. We have not included it here because of the relatively minor importance of methanol as a potential automotive fuel.

In attempting to assess the CO_2 benefit and energy requirement of CC&S in these different cases we found many literature references. In particular we were guided by a recent study by the IEA's Greenhouse gas R&D programme [*IEA 2005*]. As CC&S has so far only been applied on a limited scale in very few locations worldwide, all references refer to theoretical studies. These do not always include details of the envisaged flow schemes and/or full comparative data between the case without CC&S and the case with CC&S. Many of the process schemes are complex, involving multiple sources of CO_2. In a GTL plant, for instance, CO_2 is emitted by the syngas production process, the Fischer-Tropsch process and the power plant. Each of these sources produces a different gas mixture which would require different systems to separate the CO_2. Generally therefore the degree of CO_2 recovery, the energy involved and the cost of the installations required will depend on which gas streams are being tackled.

Following capture at the point of emission, CO_2 must be compressed and liquefied, transported to the point of storage and injected. We have accounted for the energy required for compression to 15 MPa. No additional energy has been included under the assumption that this pressure level would be sufficient to transport CO_2 by pipeline over a reasonable distance (typically 100-150 km) and inject it into the geological storage.

Because of all these uncertainties and possible lack of consistency between the sources, we consider that the figures shown in this report for the CC&S schemes should be regarded as preliminary and indicative of the potential of the technology. As more real-life applications develop, better estimates are expected to become available.

Figure 3.6 Pathways with CC&S option



Electricity

For natural gas two different routes can be envisaged. The so-called "post-combustion" route involves scrubbing flue-gases of a standard power plant using an amine absorption process. Such systems have been proposed in studies carried out in the USA such as [*Rubin 2004*]. Alternatively the "pre-combustion" route includes reforming NG into hydrogen and separating CO_2 before burning the hydrogen in an adapted CCGT. This is the scheme envisaged for a recently announced plant to be built in Scotland by a consortium of BP, Shell and Scottish Power.

In this study we have considered the post-combustion option. Based on [*Rubin 2004*] the overall efficiency would decrease from 55% in the reference case to 47% with CC&S, for a CO_2 recovery of 90% and including the energy required to compress and inject CO_2 in the storage structure. Indications are that the efficiency loss will be higher for pre-combustion schemes, with overall efficiencies in the order of 42%. Such schemes would, however, offer greater flexibility, not least being able to produce hydrogen in addition to power.

For coal we have considered an IGCC scheme with and without CC&S based on [*TAB 1999*] and [*ENEA 2004*].

The table below shows the impact of CC&S on energy and CO_2 emissions.

Table 3.6-1 Electricity production with/without CC&S

Feedstock		Natural gas		Coal	
Case		Base	with CC&S	Base	with CC&S
Natural gas	MJ/MJe	1.818	2.123		
Coal	MJ/MJe			2.0833	2.439
Energy efficiency		55.0%	47.1%	48.0%	41.0%
Net GHG emissions	g CO_{2eq}/MJe	360.4	43.0	722.1	84.4
CO_2 removal efficiency			88.1%		88.3%

Hydrogen

Hydrogen is produced from natural gas via steam reforming followed by CO-shift. The hydrogen-rich gas, including CO_2 is then commonly routed to a pressure swing adsorption (PSA) plant to separate the bulk of the hydrogen. The same scheme applies to coal, replacing steam reforming by partial oxidation (gasification). The tail gas of the PSA is fed to a boiler to provide heat for the endothermic steam reforming reaction or electricity for the air separation plant that provides pure oxygen for coal gasification.

CO_2 capture involves an additional scrubbing process between CO-shift and PSA followed by compression / liquefaction of CO_2 to 15 MPa. We have based our figures on a conceptual plant design described in [*Foster Wheeler 1996*]. The study includes base case (no CC&S) and CC&S case for both natural gas and coal. In the CC&S cases, CO_2 is extracted chemically with activated MDEA as solvent. Heat and electricity are required for the regeneration of the solvent and CO_2 compression.

Note: in the first version of this report we based the NG-to-hydrogen pathway on a reference from Linde [*Linde 1992*]. The latter involved a larger NG input but also surplus electricity production. Taking the appropriate credit into account the net energy balance falls within 1% of the Foster Wheeler case.

The table below shows the impact of CC&S on energy and CO_2 emissions.

Table 3.6-2 Hydrogen production with/without CC&S

Feedstock		Natural gas		Coal	
Case		Base	with CC&S	Base	with CC&S
Natural gas	MJ/MJ H_2	1.315	1.365		
Coal	MJ/MJ H_2			1.967	2.303
Energy efficiency		76.0%	73.3%	50.8%	43.4%
Net GHG emissions	g CO_{2eq}/H_2	72.4	11.9	189.4	5.6
CO_2 removal efficiency			83.6%		97.0%

The energy efficiency penalty for CC&S is much larger for coal but so is the absolute amount of CO_2 removed. In the coal case, virtually all CO_2 is produced in the gasifier and/or CO-shift reactor so that removal can be close to complete. In the natural gas case, the CO_2 produced by the fuel burned in the reformer (recycled PSA off-gas supplemented by additional natural gas) cannot practically be recovered.

Synthetic fuels

Steam reforming and/or partial oxidation is also the first step towards production of DME or synthetic diesel from natural gas or coal. However, CO_2 has to be removed upstream of the synthesis step because CO_2 is not desired in the gas stream entering the synthesis reactor. Usually CO_2 is separated via a selective physical absorption process such as SELEXOL™ which uses an aqueous solution of a di-methyl ether of polyethylene glycol in water. Such processes are generally less energy-intensive than chemical scrubbing processes.

For the DME base case we used data from Haldor Topsoe ([*Haldor Topsoe 2001*] and [*Haldor Topsoe 2002*]). The CC&S case was produced by the IEA Greenhouse group [*IEA 2005*] on the basis of the same data.

Table 3.6-3 DME production with/without CC&S

Feedstock		Natural gas	
Case		Base	with CC&S
Natural gas	MJ/MJ DME	1.412	1.425
Coal	MJ/MJ DME		
Energy efficiency		70.8%	70.2%
Net GHG emissions	g CO_{2eq}/DME	10.6	0.7
CO_2 removal efficiency			93.7%

For FT liquids from NG there is not literature source where a NG FT plant with and without CC&S is compared. FT plants are very complex. The layout differs from licensor to licensor and this can have a large impact on the energy penalty for CC&S. [*IEA 2005*] suggests an energy efficiency penalty of 3%. We have used this figure as a basis for our calculation, starting from an overall plant efficiency of 63% in the base case. The CO_2 generated in the auxiliary power plant is not recovered in this scheme, so that the CO_2 recovery is relatively low at around 75%.

For coal-to-liquid [*Gray 2001*] gives a direct comparison of base and CC&S cases.

Table 3.6-4 Syn-diesel production with/without CC&S

Feedstock		Natural gas		Coal	
Case		Base	with CC&S	Base	with CC&S
Natural gas	MJ/MJ SD	1.587	1.667		
Coal	MJ/MJ SD			1.784	1.861
Energy efficiency		63.0%	60.0%	56.1%	53.7%
Net GHG emissions	g CO_{2eq}/MJ SD	16.5	4.2	363.2	33.5
CO_2 removal efficiency			74.7%		90.8%

The process as described produces surplus electricity in both cases. We treated this as a credit based on alternative generation with a coal-fired IGCC with and without CC&S (as described above).

3.7 Synthetic fuels transport and distribution

3.7.1 Hydrogen transport and distribution

(see also WTT Appendix 1 section 1-14)

Hydrogen can be transported and/or used in either compressed or liquid form. Liquefaction is an energy-intensive process but liquid hydrogen has the advantage of having a much higher density, becoming more efficient to transport and store on-board a vehicle.

Compressed hydrogen from a central plant can be transported either in pipelines at moderate pressures (2-4 MPa) or at high pressure (20-30 MPa) in cylinders loaded on a road truck. In the case of a large central plant, the average distribution distance has been taken as 50 km. Generally the pressure available at the plant outlet is considered sufficient to carry the hydrogen through a 50 km pipeline without the need for additional energy input. A residual pressure of 2 to 3 MPa has been assumed at the refuelling site, depending on the type of plant. Hydrogen from small on-site plants will generally be available at a somewhat lower pressure of typically 1.5 MPa.

Gaseous hydrogen reaching the refuelling station needs to be compressed to the high pressure required to store sufficient fuel on-board. The current “state-of-the-art” is 35 MPa although tests are already underway for 70 MPa storage tanks. In practice, this requires a compressor discharge pressure of 45 MPa or 88 MPa to ensure an adequate filling time. The 70 MPa level is required to allow an acceptable vehicle range. For this reason it is expected to become the standard and we have calculated the pathways for that case (this is also consistent with the assumptions made for the on-board storage in the *Tank-to-Wheels report*).

Liquid hydrogen has a big advantage in terms of energy density but involves additional energy for liquefaction. Current liquefaction plants require up to 40% of the liquefied hydrogen energy content but figures vary a great deal from plant to plant. Manufacturers argue that existing plants have not always been designed for minimum energy consumption (but often for minimum investment cost). Technology is believed to be able to eventually deliver large scale plants that would reduce the consumption to around 20%. We have used a median value of 30% with a range of 21 to 39%.

Long-distance transport of liquid hydrogen from a remote plant would require special ships for which only design concepts exist today. Liquid hydrogen would be further transported by road from the EU entry port directly to the service stations (assumed distance 500 km). Liquid hydrogen from an EU plant would also be transported by road albeit along a somewhat lower average distance (assumed 300 km) as it can be surmised that the plant would be better located to serve the market.

Hydrogen can be stored in the vehicle in either compressed or liquid form. The advantage of liquid hydrogen from a transport point of view may lead to its use for transportation even if the end-user vehicle requires the compressed form. In this case the refuelling station must include vaporisation/compression equipment.

3.7.2 Biofuels and Synthetic fuels transport and distribution

(See also WTT Appendix 1 section 1-15)

Liquid fuels

Long-distance transportation

Synthetic fuels from a remote plant will be transported by ships appropriate to the type of product. Synthetic hydrocarbons can be transported in conventional oil product carriers. Large methanol ships already exist today.

Distribution within Europe

Distribution within Europe does not generally involve large distances and therefore only accounts for a minor energy consumption.

For biofuels (ethanol, bio-diesel and syn-diesel from wood) manufactured in Europe we have assumed blending with conventional fuels is more likely to occur down the distribution chain, Accordingly, we have used two standard road transport vectors of 150 km each representing trips from the plant to a blending depot (or a refinery) and from the depot to the filling station. We have assumed that synthetic diesel manufactured in Europe in large plants (GTL or CTL) would necessarily go through blending in a refinery and we have used the standard transport vector for conventional fuels followed by the 150 km road transport for final distribution (pipeline/rail/water, see *section 3.1.4*). Imported synthetic diesel from a remote location would be available at an EU entry port. In case of blending with refinery products (variant 1), the conventional fuels transport vector would apply. For the case where the fuel is used neat (variant 2) a 500 km rail/road transport vector was applied. The same vector was also used for bulk ethanol imports (e.g. Brazil).

Methanol cannot be mixed with conventional fuels. Its introduction in the existing multi-product pipeline infrastructure is not technically feasible. It would therefore require a specific distribution system. A dedicated methanol pipeline network is unlikely to be built at least as long as the market remains limited. For bulk imports, distribution from a coastal import terminal was therefore assumed with the same parameters as for imported ethanol. Intermediate depots may be involved but the associated extra energy consumption would be insignificant. For methanol from biomass we assumed a single road transportation leg of 150 km, recognising the fact that the plants would be of limited size and serving the local market.

DME

DME is gaseous under ambient conditions but can be liquefied at moderate pressure. Its logistic is therefore very similar to that of LPG, an already common road fuel in some countries. In case of DME from remote NG long-distance transport would require ships similar to the existing LPG carriers. The transport distance between the port in the EU and the filling stations was assumed to be 500 km (50/50 train/truck). In case of biomass derived DME the transport distance between the DME plant and the filling stations was assumed to be 150 km.

The infrastructure required for storage, road or rail transport and refuelling points would of course have to be built from scratch.

The following table gives an overview of the transport vectors.

Table 3.7.2 Fuel transport vectors

	Transport to EU	Transport within EU	
		Transport to depot	Transport to filling stations
Crude oil based gasoline and diesel, Syn-diesel from piped NG or coal	NA	Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
Ethanol & FAME produced within EU	NA	Road, 150 km	Road, 150 km
Ethanol bulk imports (Brazil)	Ship, 5,500 nautical miles	Road, 150 km	Road, 150 km
MTBE (remote)	Ship, 5,500 nautical miles	Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
ETBE		Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%)	Road, 150 km
Syn-diesel from biomass (BtL)	NA	Road, 150 km	Road, 150 km
Syn-diesel from remote NG			
Variant 1	Ship, 5,500 nautical miles	Ship, 500 km (20%) Pipeline, (60%) Train, 250 km (20%	Road, 150 km
Variant 2		NA	Train/Road, 500 km
Methanol or DME from remote NG	Ship, 5,500 nautical miles	NA	Train/Road, 500 km
Methanol or DME from biomass	NA	NA	Road, 150 km
LPG (remote)	Ship, 5,500 nautical miles		Road, 500 km

4 Final fuels: Energy and GHG balance

4.1 Reporting formats

In this section we report the detailed energy and GHG balance of each pathway. In order to illustrate the relative importance of the different stages of the pathway, we give detailed results according to the 5 standard steps defined in *section 2.1*. The actual figures with additional details for each pathway are listed in *WTT Appendix 2*.

In the generic presentation, we focus on total energy expended, i.e. all the energy, regardless of its origin, that needs to be used to produce the desired fuel, *after discounting the energy content of the fuel itself*. The unit used is

MJ_{xt}/MJ_f = MJ expended total energy per MJ finished fuel (LHV basis)

For example a figure of 0.5 means that making the fuel requires 50% of the energy that it can produce when burned.

This total energy figure gives a truly comparable picture of the various pathways in terms of their ability to use energy efficiently.

For fuels derived from renewable resources it is also of interest to report the fossil energy used in the pathway, particularly by comparison with the energy content of the final fuel. This is reported and discussed separately as

MJ_{xfo}/MJ_f = MJ expended fossil energy per MJ finished fuel

The reported WTT GHG figures exclude CO_2 emissions associated with the combustion of the final fuel.

For the WTW analysis, carbon-containing fuels of renewable origin are, however, given a credit for an amount of CO_2 equivalent to that released during combustion. In the TTW part of the study, all fuels can then be treated in the same way and allocated CO_2 emissions corresponding to their carbon content regardless of its origin.

In many graphs presented in this section, the gasoline or diesel balance is also included. For total energy, this provides a valid reference as long as vehicle efficiency is expected to be essentially the same for fossil and biofuel. To make the same comparison for fossil energy or total GHG emissions, we have added the combustion energy and CO_2 emissions for the fossil fuels.

4.2 Crude oil based fuels (gasoline, diesel fuel, naphtha)

(see also WTT Appendix 2 section 2-1)

The pathways to conventional fuels are straightforward and have been discussed in *section 3.1*.

Conventional gasoline and diesel fuel supply almost the totality of road transport needs today. Within the time frame of this study the market share of alternative fuels is not expected to go beyond 10 to 20% of the market.

The energy and GHG “cost” of introducing alternative fuels needs to be measured against the savings related to “not-providing” the conventional equivalents. The energy and GHG balance that we need to be concerned with here pertain, therefore, to the effect of marginally reducing the production of conventional fuels compared to a “business-as-usual” case. The following figures reflect this approach (see also *section 3.1.4* and *WTT Appendix 3*).

Figure 4.2-1 WTT total energy balance for crude oil based fuels

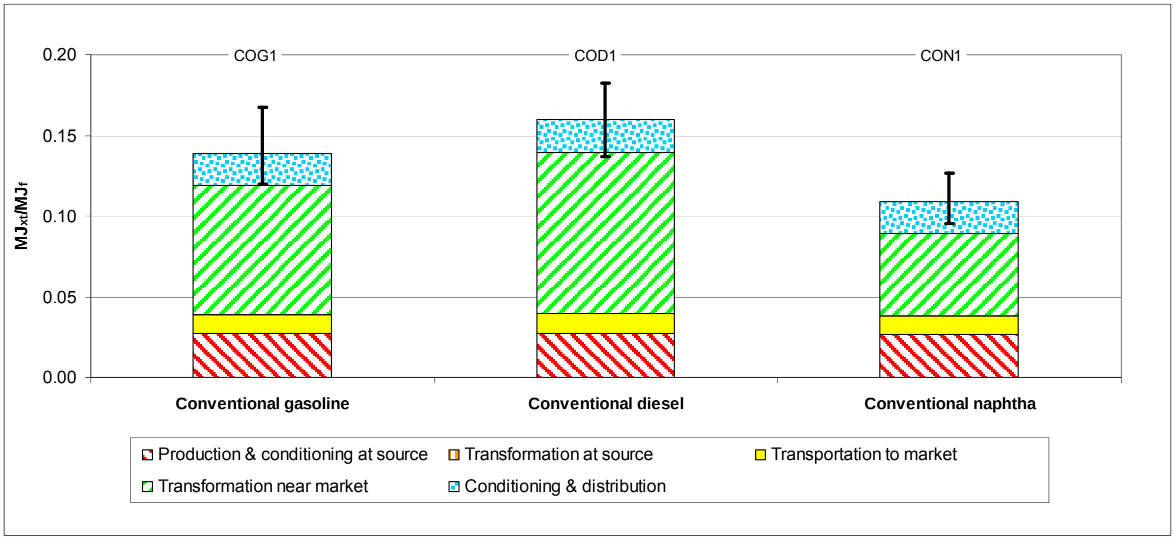
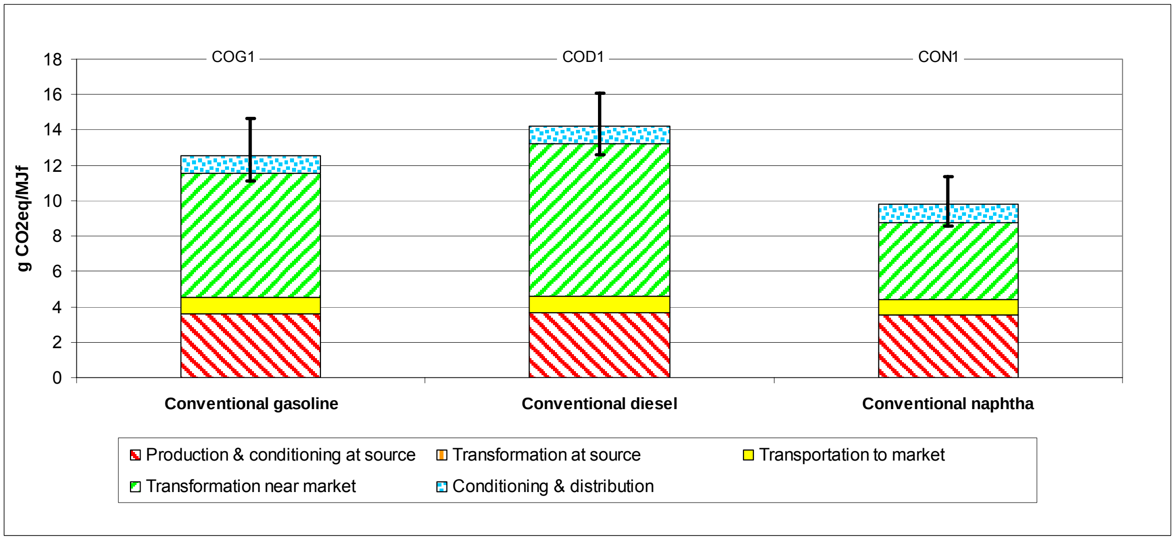


Figure 4.2-2 WTT GHG balance for crude oil based fuels



Refining is the most energy-consuming step followed by crude production. For the reasons developed in *section 3.1.3*, the marginal production of diesel fuel is more energy intensive than that of gasoline.

Note that these figures apply to Europe as a result of the specific situation prevailing in the region. The situation will be different in other parts of the world and a similar assessment would have to be made taking into account the local parameters and leading to different figures and conclusions.

Naphtha is not currently used as automotive fuel. It is included here as a potential fuel for on-board reformers.

4.3 CNG, CBG (Compressed Biogas), LPG

(See also WTT Appendix 2 section 2-2)

4.3.1 Pathways to CNG

In order to be used in a vehicle natural gas needs to be brought to a refuelling station and pressurised into the vehicle tank. Gas from the distribution networks is the first choice but the use of LNG can also be envisaged.

Gas sent down the pipelines from various sources still contains some light hydrocarbons and some inerts so that its composition varies between producing regions. In the case of LNG, practically all heavier hydrocarbons have been removed in the liquefaction process and the gas is virtually pure methane. These differences in composition result in a range of volumetric heating values as well as significant differences in combustion characteristics as measured by the methane or octane number. In spite of these variations, the current European gas grid is estimated to deliver a minimum MON of 115, which is sufficient to allow the use of dedicated CNG vehicles with higher compression ratio.

Based on the current EU supply information we have calculated a notional "EU-mix" used in the study as the standard gas available in the EU distribution network e.g. for use as a road fuel. This composition and quality is used as input to the Tank-to-Wheels part of the study for CNG vehicles.

Table 4.3.1 Notional EU-mix natural gas

Origin	CIS	NL	UK	Norway	Algeria	Notional EU-mix
Notional EU-mix share	21.4%	22.0%	30.4%	11.8%	14.4%	100.0%
Composition (% v/v)						
Methane	98.4	81.5	86.0	86.0	92.1	88.5
Ethane	0.4	2.8	8.8	8.8	1.0	4.6
Propane	0.2	0.4	2.3	2.3	0.0	1.1
Butane and heavier	0.1	0.1	0.1	0.1	0.0	0.1
CO_2	0.1	1.0	1.5	1.5	0.0	0.9
Nitrogen	0.8	14.2	0.8	0.8	6.1	4.5
LHV (GJ/Nm^3)	35.7	31.4	38.6	38.6	33.7	35.7
(GJ/t)	49.2	38.0	47.1	47.1	44.9	45.1
Methane number	105	97	80	80	105	91
MON	138	133	122	122	138	129

We have made the assumption that the changes to European supply at the 2010-2020 horizon will not materially affect the quality of the gas available as automotive CNG.

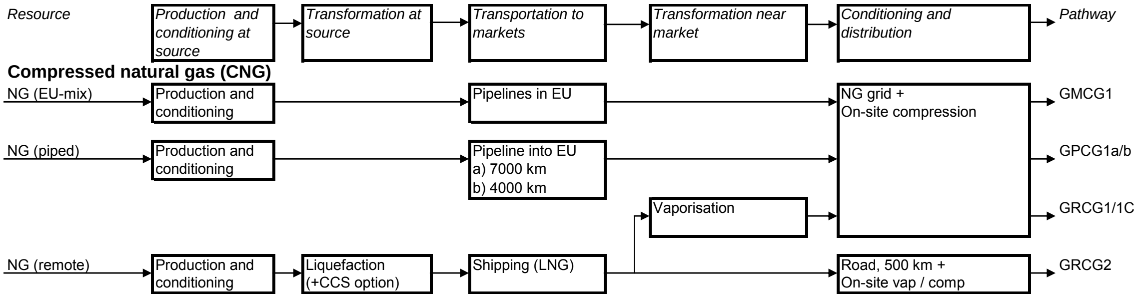
After reaching the refuelling station the gas needs to be compressed to a sufficient pressure to ensure fast refuelling. For on-board tanks at 20 MPa maximum a pressure of 25 MPa is required. Compression is an energy-intensive process, the energy consumption being strongly dependent on the outlet to inlet pressure ratio. For a given outlet pressure, the higher the inlet pressure, the lower the energy required. A relatively small increase of the inlet pressure can significantly reduce the compression ratio.

Direct connection to the high pressure network would be preferred from this point of view. However, the high pressure pipelines are only few and far between and even if available in the vicinity of a refuelling point may not be accessible for practical or regulatory reasons. In the majority of cases, the standard pressure of the local distribution network is more likely to be used. We have opted for a typical inlet pressure of 0.4 MPa.

In the case of direct LNG distribution the liquid is pumped to the appropriate pressure while the heat of vaporisation has to be supplied by an external source (atmospheric evaporation, although feasible, is unlikely to be fast enough to allow acceptable refuelling times). The total energy requirement is still less than in the compression case.

The pathways selected to represent CNG provision reflect the various supply routes available. In the case of LNG we have included a CC&S option.

Figure 4.3.1 CNG pathways



4.3.2 WTT CNG Energy and GHG balance

Figures 4.3.2-1/2 illustrate the contribution of the various steps to the total energy and GHG balance. Transport and compression are the two most important components of the balance.

For piped gas, the transport distance plays a crucial role: changing the length of the pipeline from 7000 to 4000 km reduces both energy requirement and GHG emissions by roughly 1/3rd. The potential impact of higher pressure pipelines is illustrated by the large downwards error bars for pathways GPCG1a/b. For LNG the liquefaction energy is compensated by the relatively low energy required for shipping over the typical distance of around 10,000 km, so that the total balance is close to that of a 7000 km long-distance pipeline.

The impact of CC&S is clearly visible when comparing GRCG1 and 1C: the energy required for liquefaction is somewhat higher but the GHG reduction is significant. Overall LNG with CC&S comes close to the 4000 km pipeline option in terms of GHG. The potential of CC&S is further discussed in *section 5.4*.

This effect of transport distance will be visible in all other pathways based on piped gas although it will generally have a lower relative share of the total as all those pathways include some form of conversion and are therefore much more energy-intensive. Unless otherwise stated, we have taken the 4000 km case as the reference.

There is little difference between the case where LNG is vaporised into the gas distribution network (GRCG1) and the alternative where LNG as such is trucked to a refuelling station and vaporised/compressed locally (GRCG2). The latter is marginally more energy-efficient because compression is more efficient when starting from the liquid state. The trade-off between the different energy sources used results in the figures being reversed in terms of GHG. We consider that these differences are not significant and therefore view both options as equivalent.

Although not illustrated in the figures, it must be noted that the compression energy is strongly dependent on the suction pressure of the compressor. The figures shown here pertain to a pressure of 0.4 MPa which we believe to be the most typical in Europe. With a suction pressure of 4 MPa, the energy required would be cut by a factor two.

Figure 4.3.2-1 WTT total energy balance build-up for CNG pathways

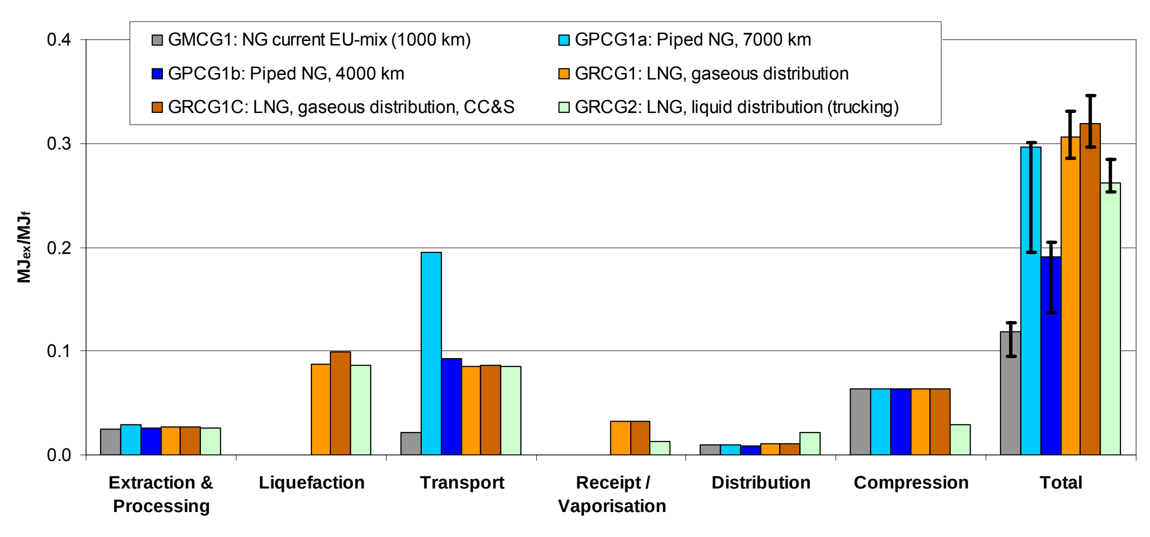
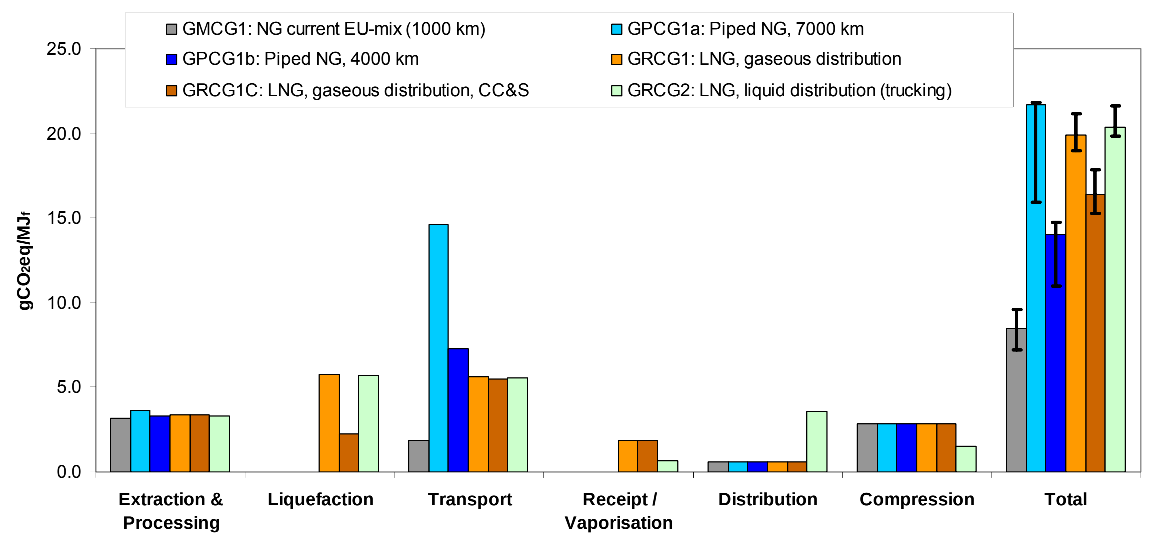


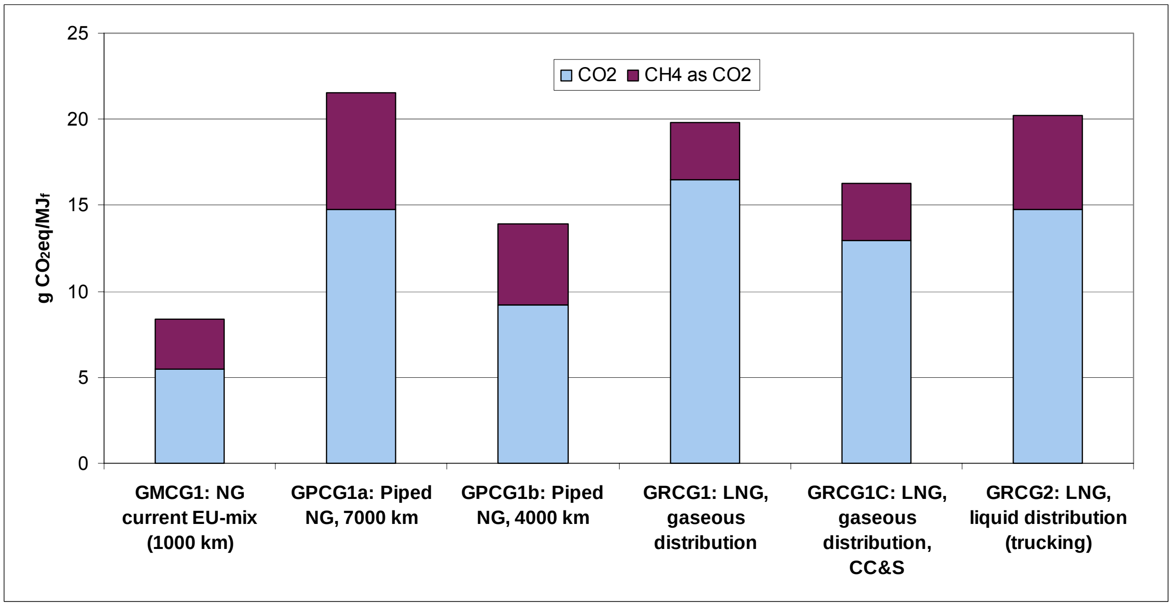
Figure 4.3.2-2 WTT GHG balance build-up for CNG pathways



It is also worth noting that direct methane emissions account for a significant share of the total GHG emissions in the CNG chains (***Figure 4.3.2-3***). For the pipeline cases, they stem mainly from extraction and transport and are responsible for up to a third of the total GHG emissions. For LNG the proportion is smaller mainly because methane evaporation during shipping is fully recovered.

Of course the evaluation of such emissions is partly speculative inasmuch as they correspond to losses occurring in different parts of a very large and complex supply system and that are not always well documented. This, however, illustrates the fact that failure to tightly control methane losses could lead to a serious degradation of the GHG balance of natural gas chains.

Figure 4.3.2-3 Share of methane in CNG GHG balance



On an energy content basis, CNG from marginal gas supplies is more energy-intensive than conventional fuels. Only the current “EU-mix”, partly based on domestic and Algerian gas, comes out better than the conventional fuels but we stress again that this is not a truly “marginal” case. This simply indicates that, because the gas supply to Europe will come from increasingly remote sources, the total energy attached to it will increase in the future.

Figure 4.3.2-4/5 show the energy and GHG balance split into the 5 standard stages used for all other pathways. Direct comparison with conventional gasoline or diesel is only possible on a WTW basis because of the different carbon contents of these fuels and also because of the difference in efficiency e.g. between CNG, gasoline and diesel vehicles (See *TTW* and *WTW report*).

Figure 4.3.2-4 WTT total energy balance of CNG pathways

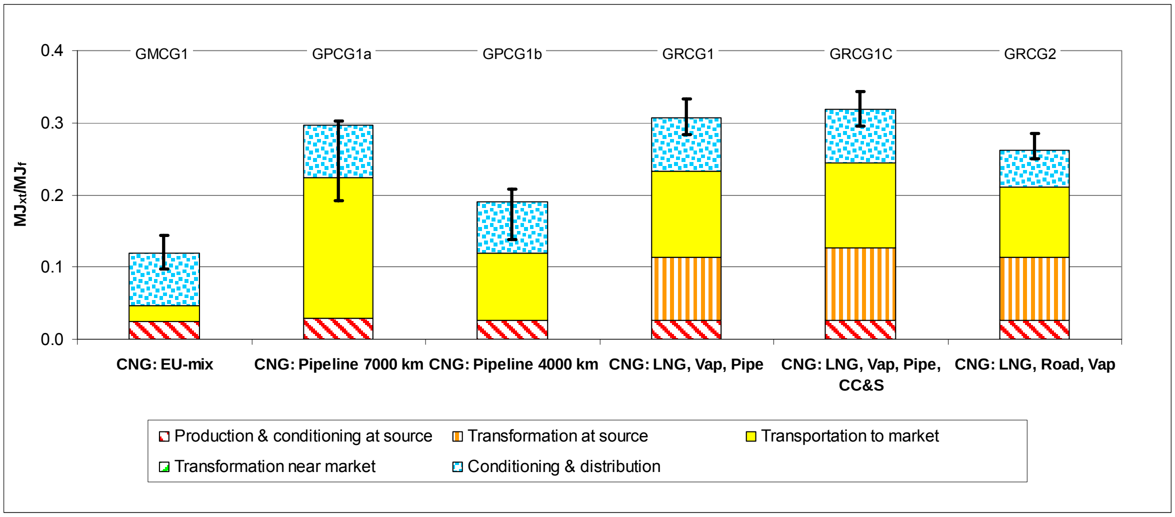
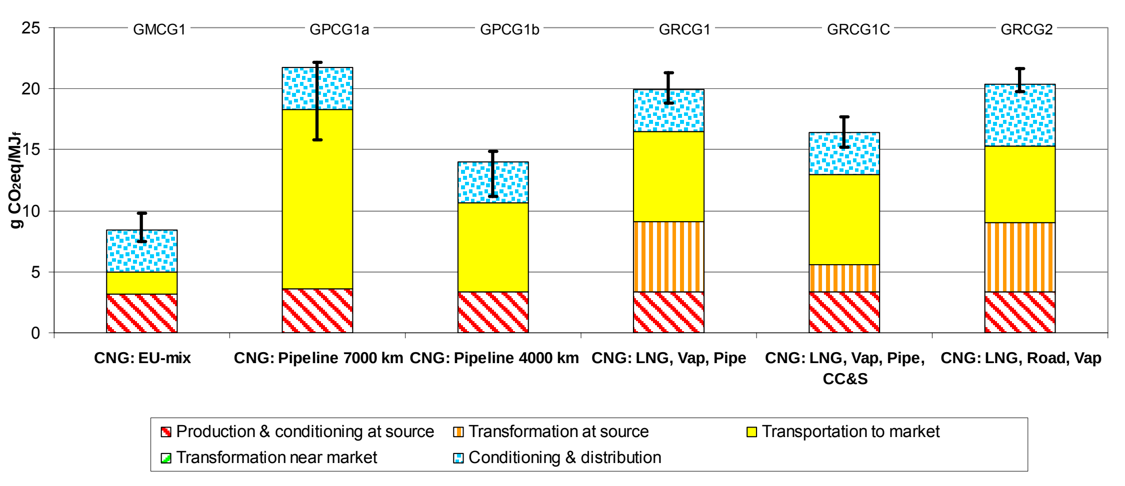


Figure 4.3.2-5 WTT GHG balance of CNG pathways



4.3.3 Compressed Biogas (CBG)

In the pathways considered here, biogas is obtained from a waste organic material. As a result there is little fossil energy involved.

Figure 4.3.3-1 CBG pathways

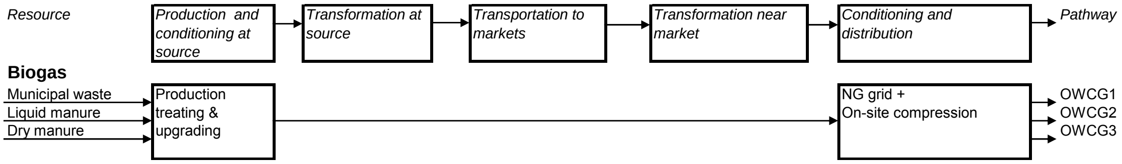


Figure 4.3.3-2 shows a relatively high total energy, mostly related to the limited conversion rate of the biomass used (assumed 70%). Inasmuch as this represents the only practical way of using such wastes for energy purposes, this is not important here. The fossil energy share of this is very small indeed ranging from 0.17 MJ_{xf}/MJ_f for municipal waste to 0.01 for dry manure.

Note: the higher fossil energy for municipal waste results from our decision to limit the on-site energy generation to the process heat requirement, which in this case demands some electricity import (compared to export in the manure cases).

The GHG emissions balance is very favourable, the more so in the case of liquid manure because large emissions of methane from the raw manure are avoided in the process (the credit has been given at the collection stage). Collecting liquid manure and using it for biogas production in itself prevents some GHG emissions to the atmosphere. Note that this is essentially the result of bad farming practices which should be avoided in any case.

All in all, using organic waste to produce biogas is a good option from an energy and GHG viewpoint. Whether and under which circumstances it can make practical and economic sense to produce biogas and use it as automotive fuel is another matter that is discussed in *section 5* together with the related issue of potential.

Figure 4.3.3-2 WTT total energy balance of CBG pathways

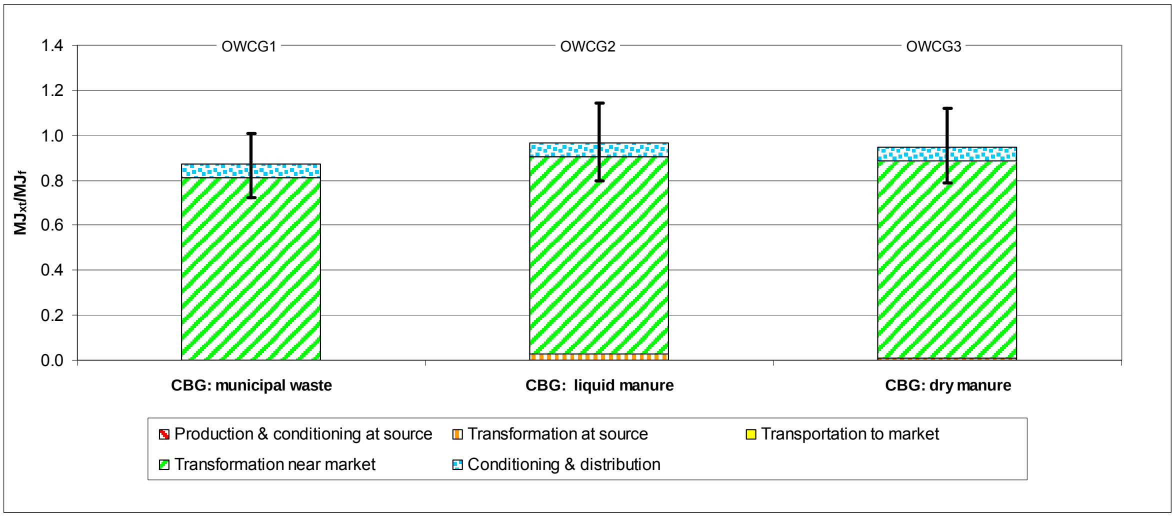
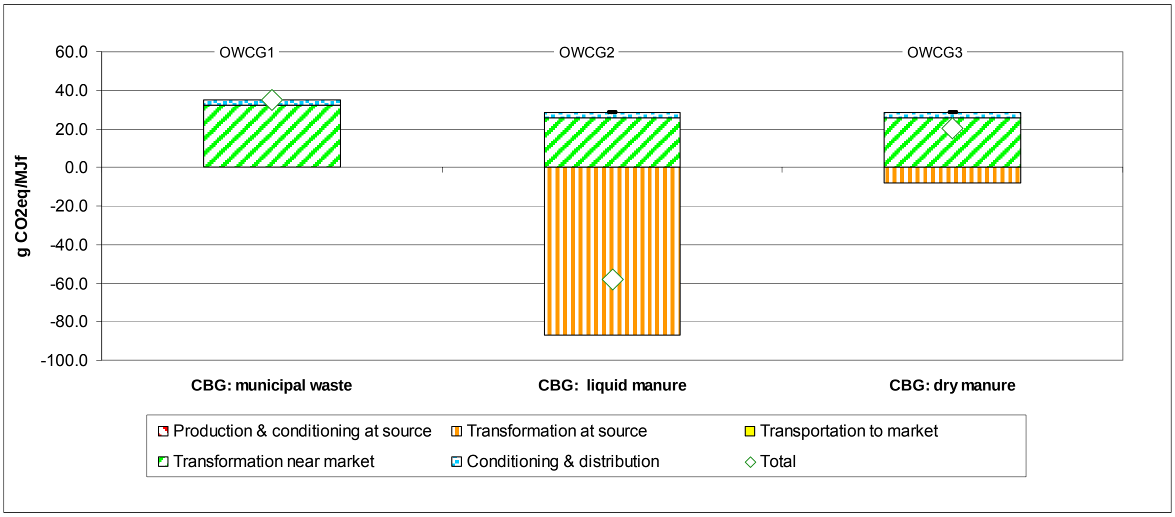


Figure 4.3.3-3 WTT GHG balance of CBG pathways

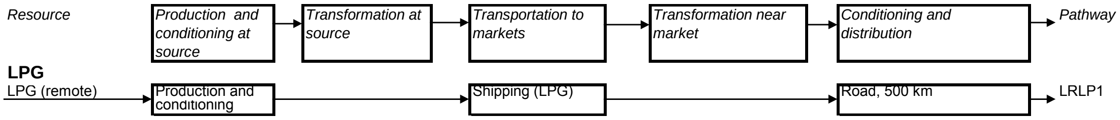


4.3.4 Liquefied Petroleum Gas (LPG)

(See also WTT Appendix 2 section 2-2)

As explained in *section 3.2.7*, we have considered only the marginal LPG imported to Europe from natural gas field condensate.

Figure 4.3.4-1 LPG pathway



A large proportion of the total energy required relates to separation, treatment and liquefaction near the gas field. Long-distance transport is also more onerous than crude oil because of the smaller dedicated ships used. The same applies to distribution.

The energy required at source in the form of natural gas or other light hydrocarbons and is therefore less carbon-intensive than is the case for crude oil, thereby reducing the total GHG emissions.

In the following figures, the energy and GHG emissions balances are compared to those for gasoline (a valid comparison as the energy efficiencies of gasoline and LPG vehicles are essentially the same, see *TTW report*).

Figure 4.3.4-2 WTT total energy balance of LPG pathway

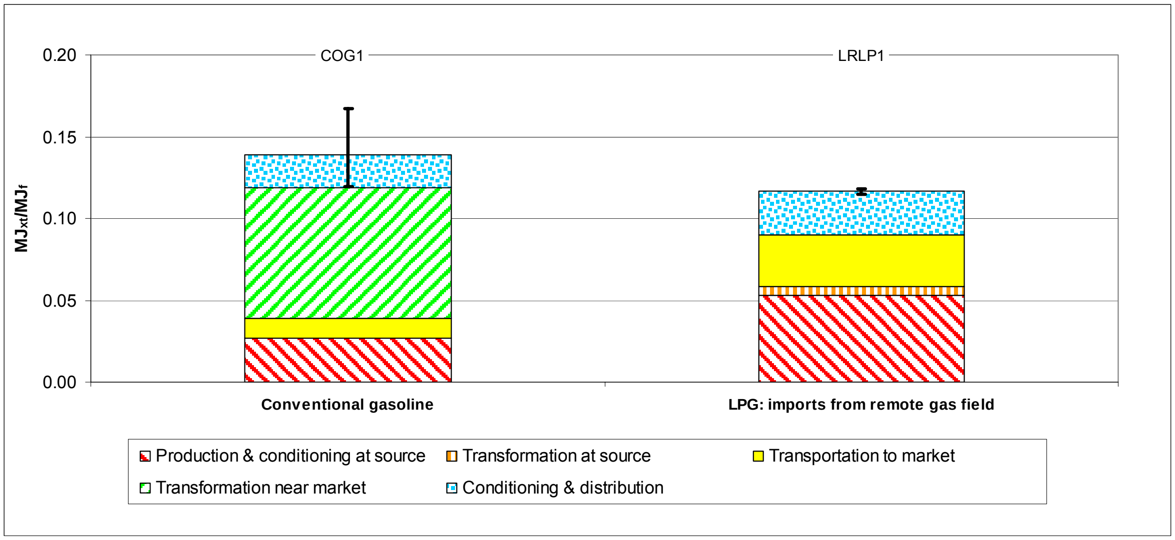
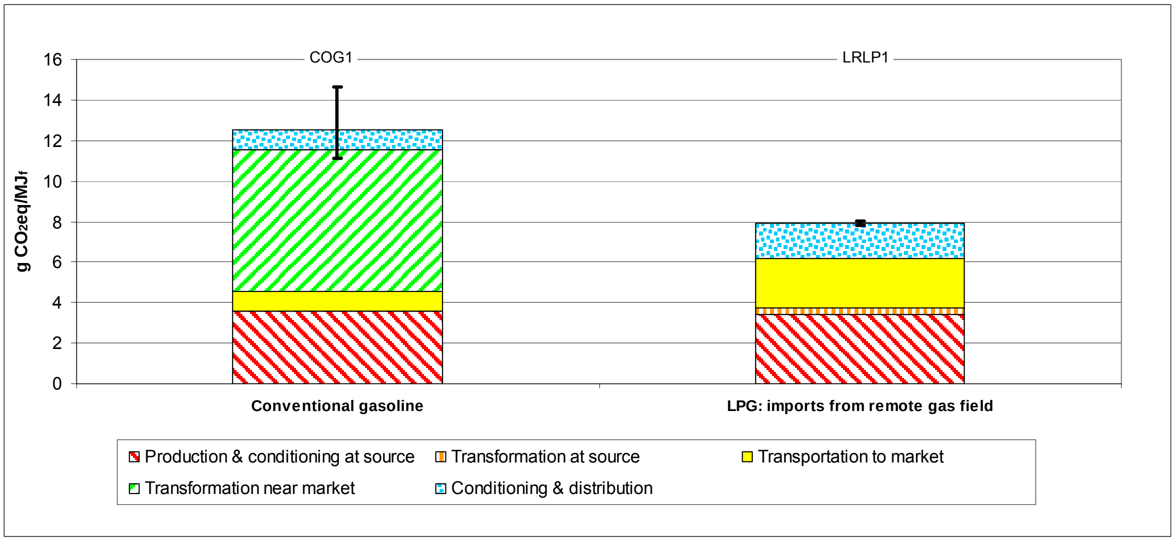


Figure 4.3.4-3 WTT GHG balance of LPG pathway



4.4 Ethanol

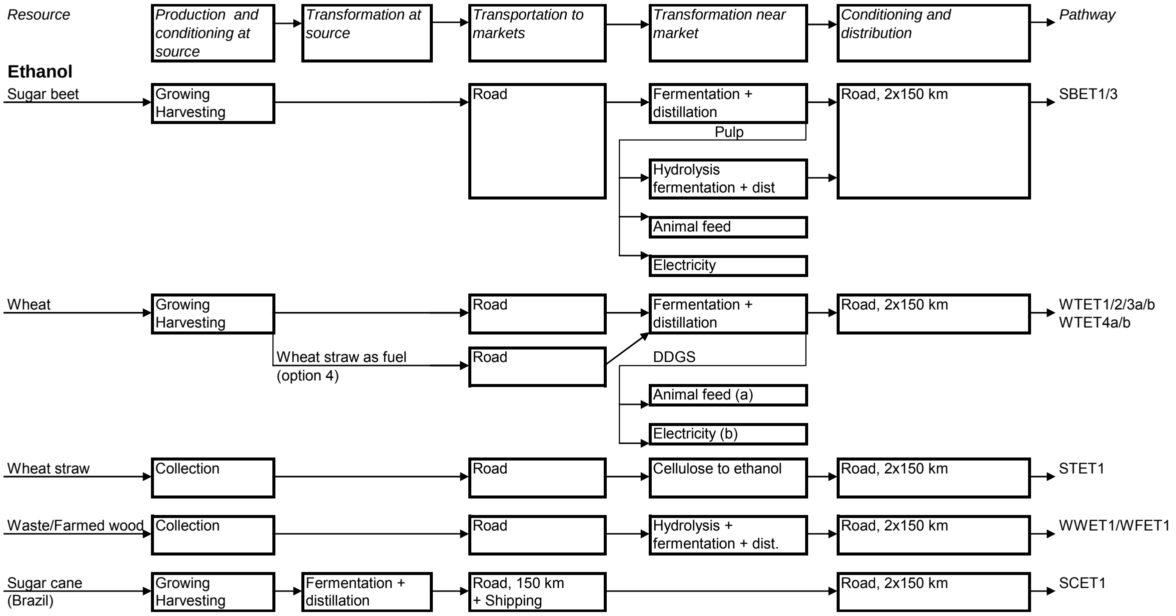
(See also WTT Appendix 2 section 2-3)

4.4.1 Ethanol pathways

Ethanol can be produced from a variety of crops. We have represented the most common in Europe i.e. sugar beet and wheat. For each of these crops a number of options are available depending on the use of by-products and the way the energy for the manufacturing process is generated (see *section 3.4.3/3.4.4*).

Also included are two more advanced pathways for the hydrolysis and fermentation of cellulose, one with wheat straw (Iogen process), the second with wood representing the more general group of cellulose feeds. For comparison purposes we have also included ethanol produced in Brazil from sugar cane and imported to Europe.

Figure 4.4.1 ***Ethanol pathways***



4.4.2 Ethanol WTT energy balance

Total energy

Figure 4.4.2-1a shows the total energy build-up along the different stages of the more conventional pathways to bio-ethanol. The gasoline balance is also included as reference (gasoline and ethanol are used in the same vehicles delivering the same energy efficiency). In this case "total" energy includes the energy content of the bio-feedstock used (e.g. wheat grain) as well as the energy content of any biomass used as a fuel at any stage of the pathway. As explained in *section 4.1*, this is the energy "expended" i.e. it excludes the energy content of the ethanol produced.

All pathways require several times more energy than is the case for gasoline although there are large differences between the various options. Most of this energy is expended during ethanol manufacturing and to a lesser extent for growing the crop (a large portion of the latter energy stemming from fertilisers).

The energy balance is critically dependent on the specific pathway, particularly with regards to the fate of by-products. As a result of the energy credits generated, the more by-products are used for energy purposes, the better the energy balance (compare e.g. SBET1 to SBET3 and WTET2a to WTET2b).

The way energy for the manufacturing process is produced has also an impact on the energy balance: in WTET2a the use of a CHP scheme reduces the energy requirement by about 15% compared to the more conventional scheme used in WTET1a. For WTET3/4, although CHP is also used the relatively low efficiency of solids burning compared to gas reduces the energy gain to insignificance.

Figure 4.4.2-1a WTT total energy balance of ethanol pathways (sugar beet and wheat)

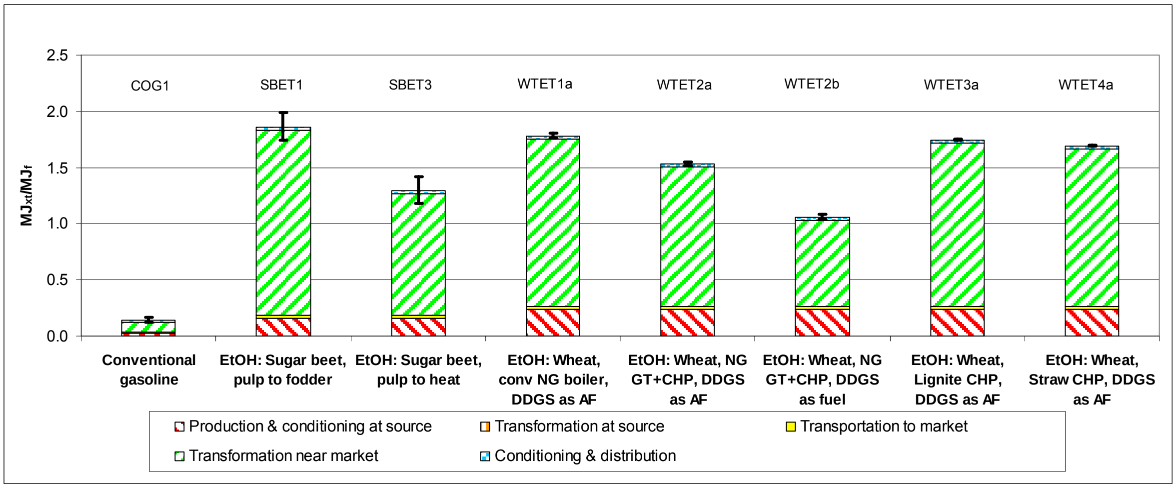
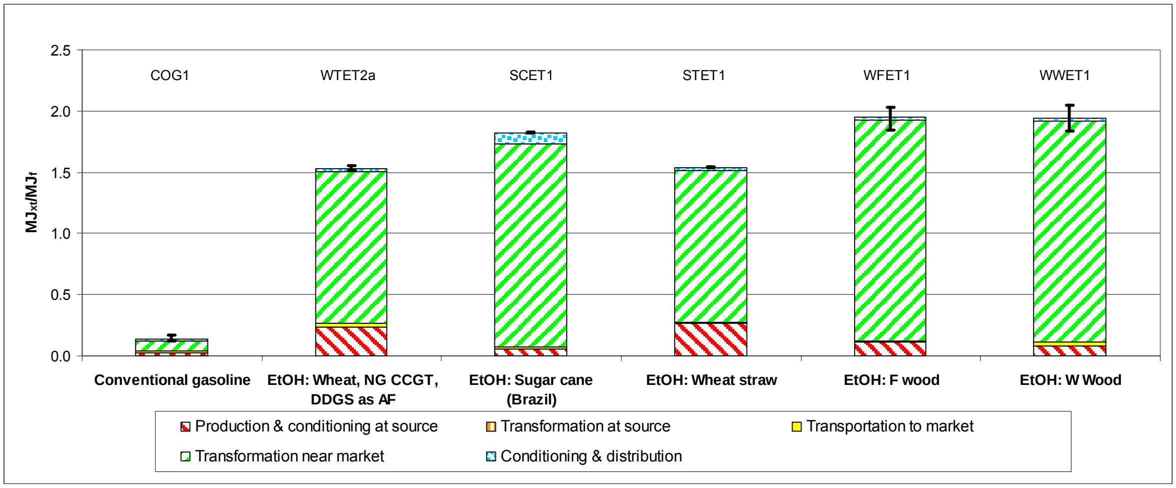


Figure 4.4.2-1b shows the total energy balance for more advanced biomass-to-ethanol pathways (WTET2a is repeated for comparison).

Figure 4.4.2-1b WTT total energy balance of ethanol pathways (various feedstocks)



Clearly these pathways do not offer much from a total energy point of view. Their interest resides in their potential to save fossil energy and therefore to reduce GHG emissions (see below).

Fossil energy

Figures 4.4.2-2a/b compares total and fossil energy as a measure of the "renewability" of the pathways. For ethanol, this is in effect the WTW fossil energy (as no additional fossil energy is expended in the vehicle). To compare to gasoline we would have to add the combustion energy. This is in effect a WTW comparison and reference is made to the WTW report.

Figure 4.4.2-2a WTT fossil energy balance of ethanol pathways (sugar beet and wheat)

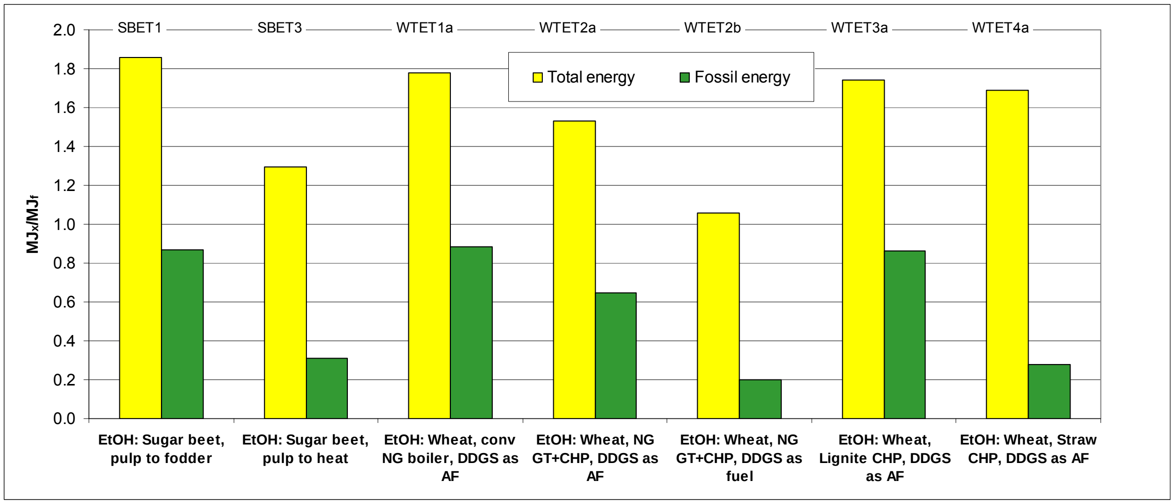
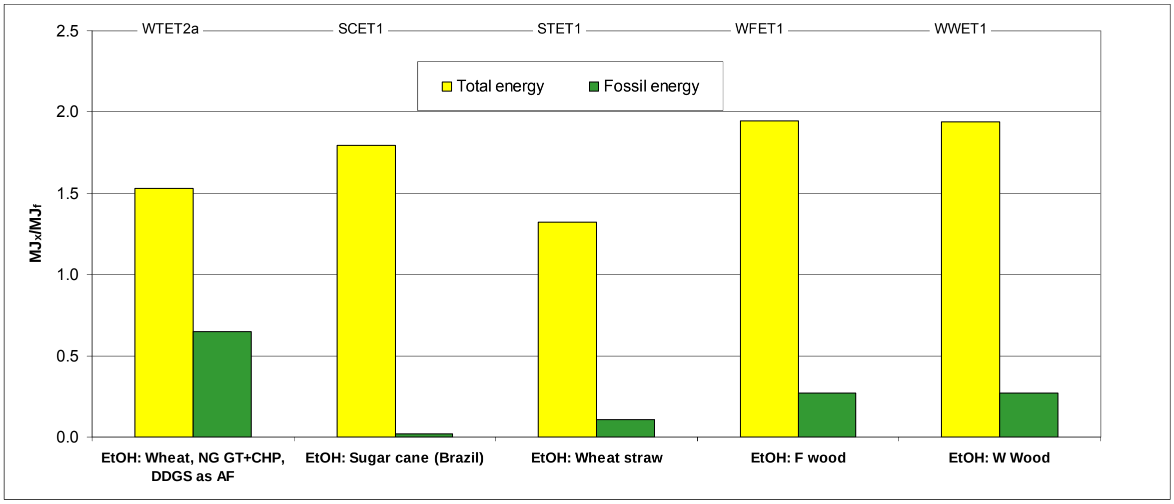


Figure 4.4.2-2b WTT fossil energy balance of ethanol pathways (various feedstocks)



The impact of using by-products for energy purposes and/or using bio-energy for fuelling the production process appears very clearly in this case. For the more conventional pathways, this does not, however, generally correspond to either common practice or economic optimum (see also *section 3.4*). The advanced pathways use a lot less fossil energy because the processes used allow usage of biomass for the major energy requirements. Using bagasse to fuel the sugar cane ethanol manufacturing plant is a well established practice (a credit for additional fuel oil saving further reduce the net fossil energy used in SCET1). In pathways using wood or straw a significant proportion of the energy used is also of renewable origin. Note that using wheat straw induces a small penalty as additional fertilisers have to be used in order to replace the nutrient contained in the straw.

4.4.3 Ethanol WTT GHG balance

Figure 4.4.3-1a/b show the total GHG build-up along the different stages of the pathways. The gasoline balance is also included as reference (as for the fossil energy figures above, the gasoline combustion CO_2 has been added to make the GHG figures comparable).

Figure 4.4.3-1a GHG balance of ethanol pathways (sugar beet and wheat)

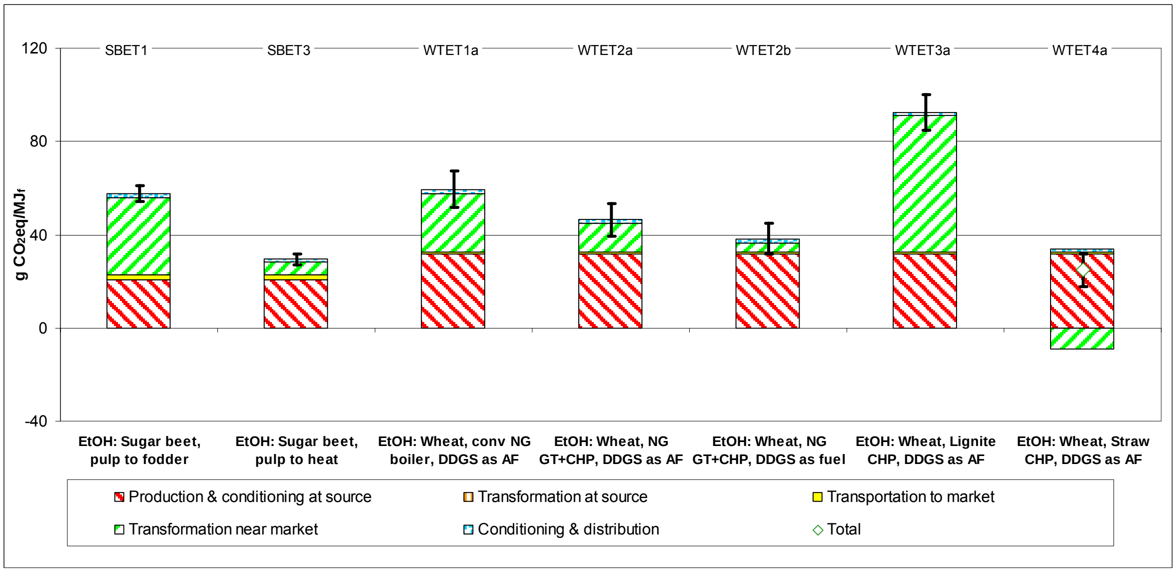
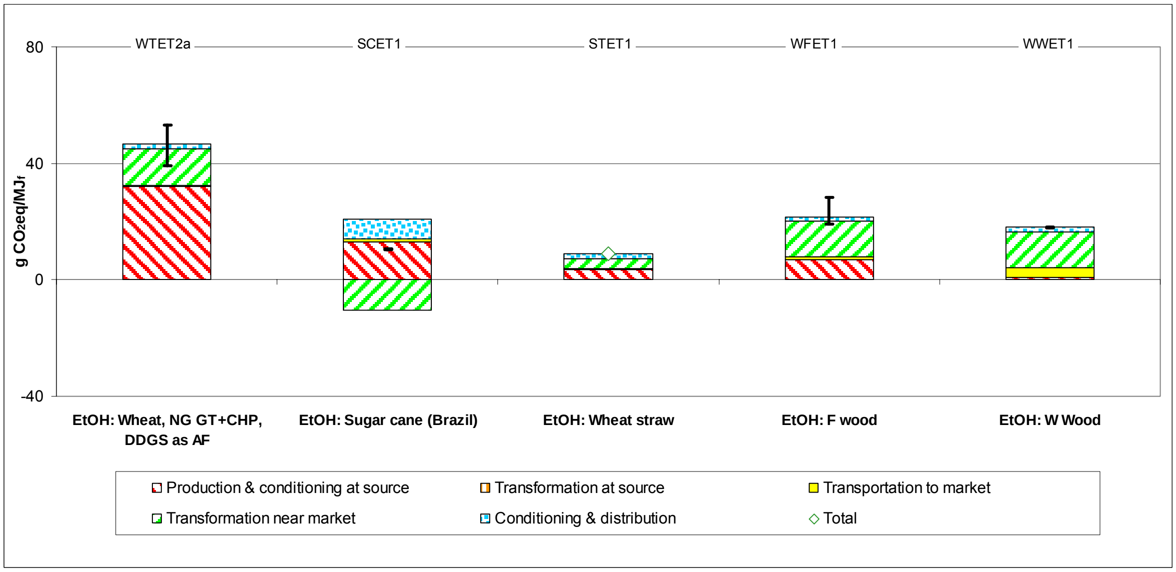


Figure 4.4.3-1b GHG balance of ethanol pathways (various feedstocks)



The impact of by-product use and production energy generation scheme is again apparent here. The picture is similar to that of fossil energy above although there are additional impacts related to field N_2O emissions and to the type of fossil fuel used.

Wheat production requires more nitrogen than sugar beet resulting in higher field emissions. Sugar cane and farmed wood require much less still. Uncertainties attached to N_2O emissions are also responsible for the relatively large error bars, particularly for wheat.

Switching from natural gas to lignite for fuelling the ethanol plant has a dramatic effect, resulting in an increase of GHG emissions for ethanol compared to gasoline.

For sugar cane, the CO_2 credit attached to additional fuel oil saving from surplus bagasse results in a negative figure for the "transformation" step.

The wood-based pathways yield a very favourable GHG balance as very little fossil energy is involved in the process. The straw option is less favourable because of the increased farming inputs required to compensate for removing the straw from the land (additional energy for fertiliser production and additional N_2O emissions from the fields).

Comparison with gasoline is discussed in the *WTW report*.

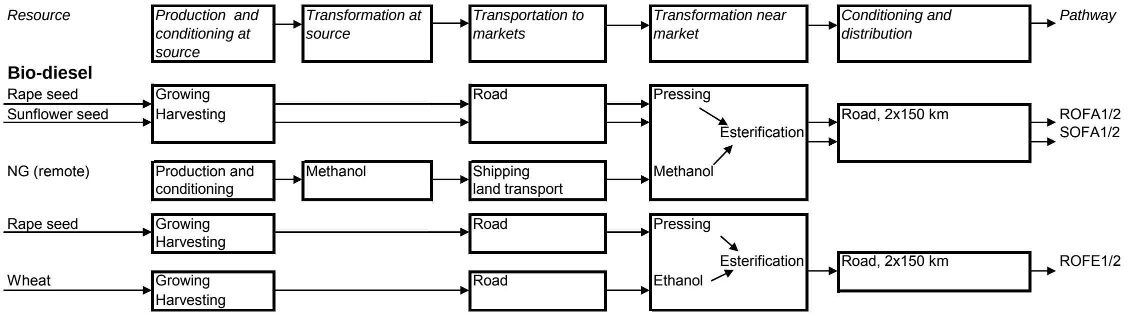
4.5 Bio-diesel (FAME and FAEE)

(See also WTT Appendix 2 section 2-4)

4.5.1 Bio-diesel pathways

Bio-diesel is mostly produced from rapeseed as RME. Sunflower is also used in Southern Europe. Methanol is commonly used for the trans-esterification step hence the generic name of FAME (Fatty Acid Methyl Ester). We have included both rape and sunflower seeds with two options for the disposal of glycerine. Ethanol can also replace methanol for esterification (FAEE) and we have included this in combination with rapeseeds.

Figure 4.5.1 Bio-diesel pathways



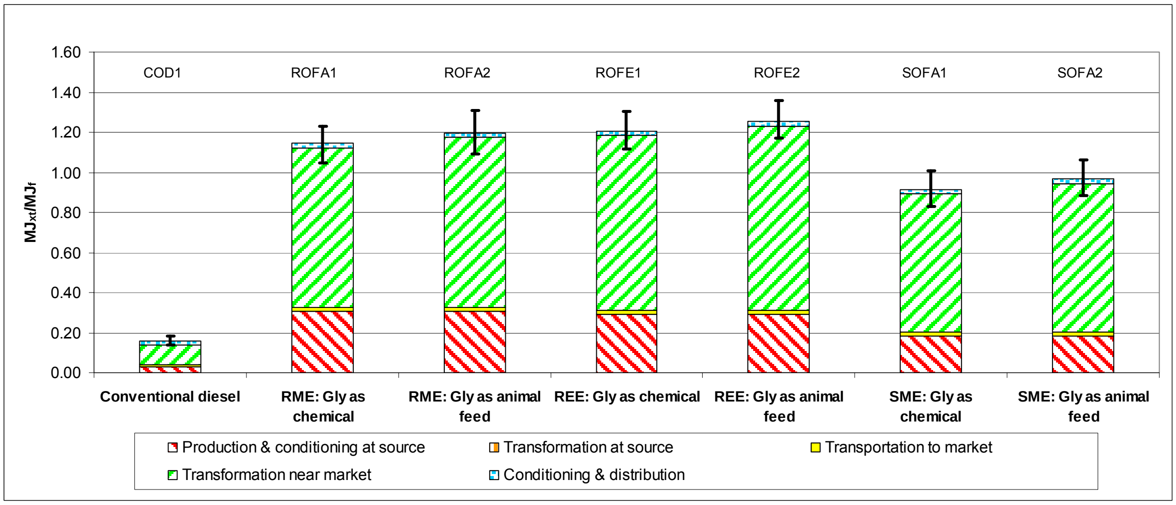
4.5.2 Bio-diesel WTT energy balance

Total energy

Figure 4.5.2-1 shows the total energy build-up along the different stages of the pathways. The fossil diesel balance is also included as reference (conventional and bio-diesel are used in the same vehicles delivering the same energy efficiency). In this case "total" energy includes the energy content of the oil seeds as well as the energy content of any biomass used as a fuel at any stage of the pathway. As explained in *section 4.1*, this is the energy "expended" i.e. it excludes the energy content of the bio-diesel produced.

Bio-diesel requires up to 5 times more total energy than fossil diesel. Sunflower is somewhat more favourable than rape in this respect. Using ethanol instead of methanol for esterification further increases the required energy. Use of glycerine as a chemical or animal feed has only a marginal impact.

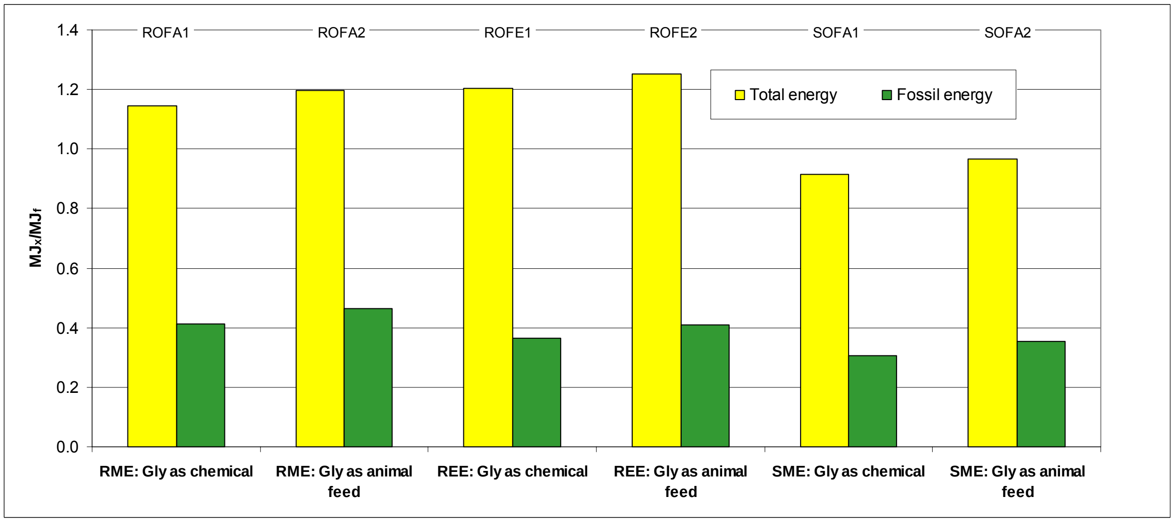
Figure 4.5.2-1 WTT total energy balance of bio-diesel pathways



Fossil energy

Figure 4.5.2-2 compares total and fossil energy as a measure of the "renewability" of the pathways. For bio-diesel, this is in effect the WTW fossil energy (as no additional fossil energy is expended in the vehicle). To compare to conventional diesel we would have to add the combustion energy. This is in effect a WTW comparison and reference is made to the WTW report.

Figure 4.5.2-2 WTT fossil energy balance of bio-diesel pathways

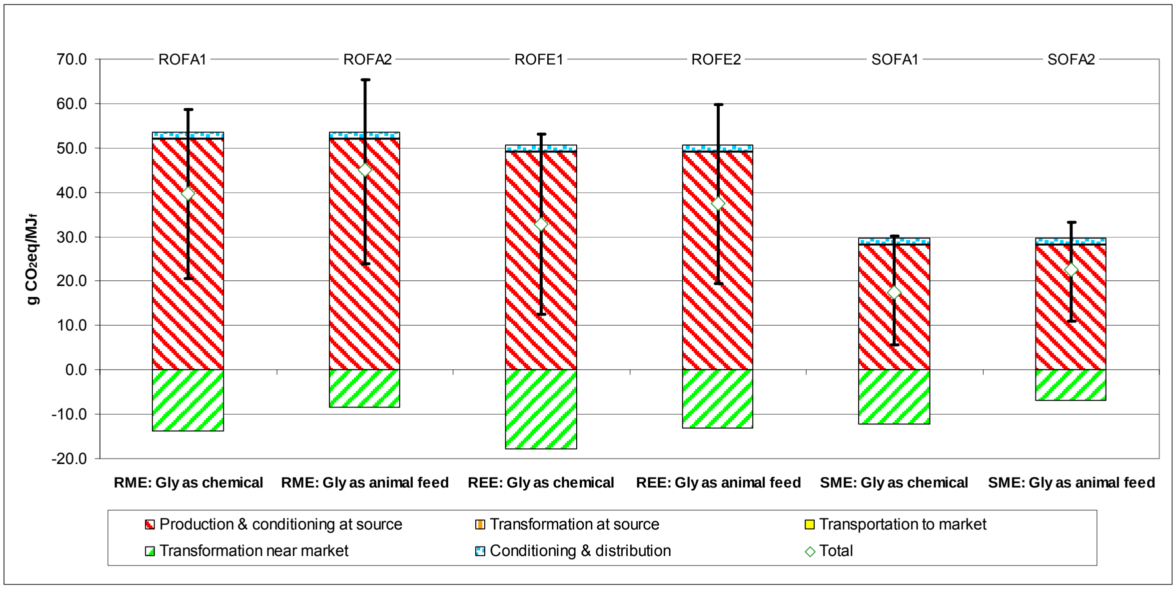


When focussing on fossil energy, the ratio to fossil diesel is in the region of 0.4 for rape, i.e. a net fossil energy saving of about 60% compared to fossil diesel. Again sunflower is slightly more favourable than rape. Obviously the use of bio-ethanol instead of fossil-based methanol results in a small decrease of the total fossil energy requirement.

4.5.3 Bio-diesel WTT GHG balance

Figure 4.5.3-1 shows the total GHG build-up along the different stages of the pathways. The fossil diesel balance is also included as reference (as for the fossil energy figures above, the fossil diesel combustion CO_2 has been added to make the GHG figures comparable).

Figure 4.5.3-1 WTT GHG balance of bio-diesel pathways



The GHG emissions are dominated by the seed production step, mostly through N_2O emissions. This is largely due to the fact that oil seed crops, and particularly rape, require a lot of nitrogen fertiliser. The uncertainty attached to these emissions is also responsible for the large error bars.

The negative numbers shown for the "transformation" stage are the result of fossil energy credits for by-products including the residue from pressing the oil seeds and the glycerine produced by the esterification process.

Comparison with conventional diesel is discussed in the *WTW report*.

4.6 Synthetic fuels

(See also WTT Appendix 2 section 2-5)

4.6.1 Synthetic fuels pathways

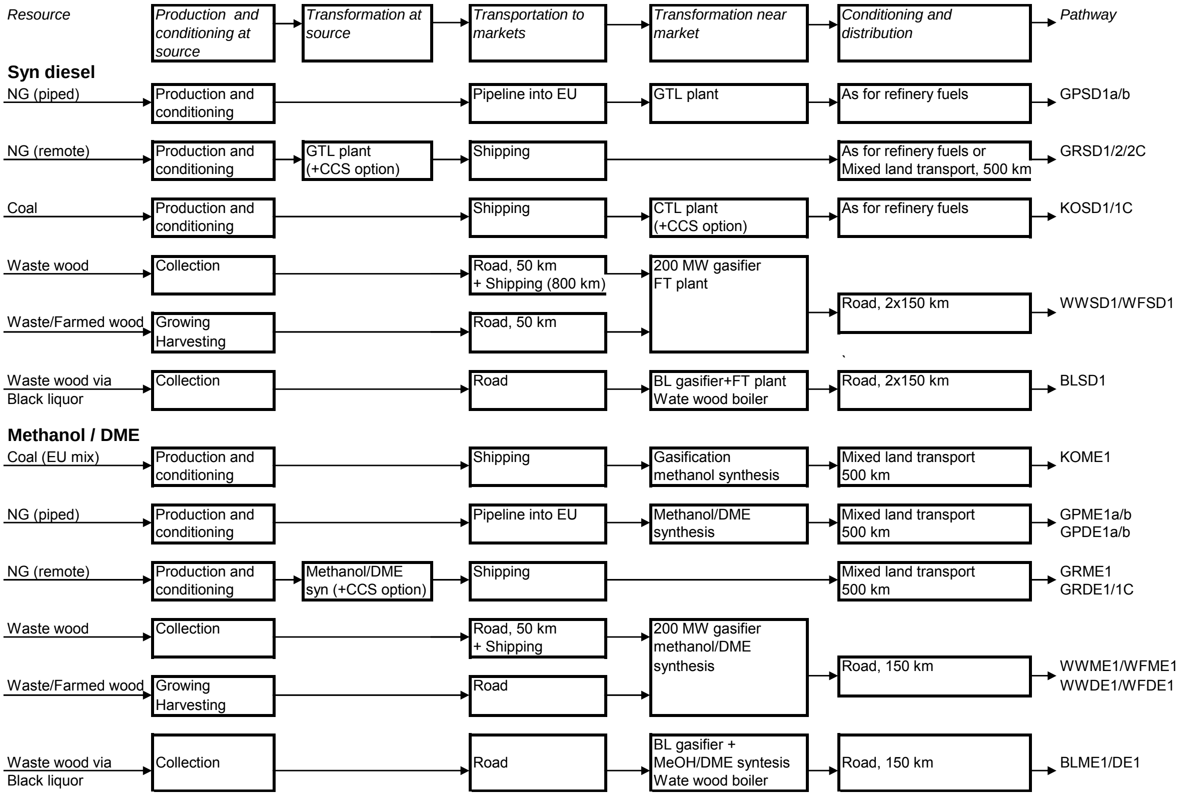
We have considered three synthetic fuels namely Fischer-Tropsch or syn-diesel, DME and methanol. DME has attractive characteristics as a fuel for diesel engines although the fact that it is gaseous at ambient conditions reduces its appeal. Methanol is only envisaged here as a potential fuel for on-board reformers.

The manufacturing of such fuels relies on steam reforming or partial oxidation of a fossil hydrocarbon or organic feedstock to produce syngas which is, in turn, converted into the desired fuel using the appropriate process.

Natural gas is the most likely feedstock for these processes because of its widespread availability, particularly as stranded (and therefore cheap) gas in remote locations and also because of the relative simplicity of the steam reforming and/or partial oxidation process compared to heavier feedstocks. Coal can also be used although the complexity and cost of the required plant are much higher.

Biomass, most likely in the form of wood or perennial grasses, is also being actively considered as a source of such fuels. Our generic wood pathways represent this group of feedstocks. This includes farmed wood (based on poplar) and waste wood. One particularly attractive option for using waste wood would be the so-called Black Liquor route (see *section 3.4.6*).

Figure 4.6.1 Synthetic fuels pathways

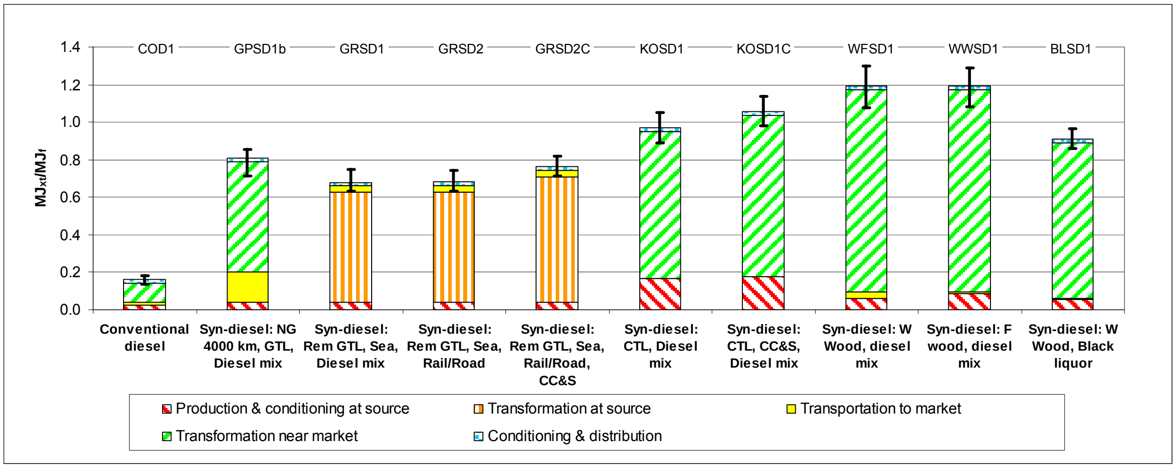


Resource	*Production and conditioning at source*	*Transformation at source*	*Transportation to markets*	*Transformation near market*	*Conditioning and distribution*	*Pathway*
Syn diesel						
NG (piped)	Production and conditioning		Pipeline into EU	GTL plant	As for refinery fuels	GPSD1a/b
NG (remote)	Production and conditioning	GTL plant (+CCS option)	Shipping		As for refinery fuels or Mixed land transport, 500 km	GRSD1/2/2C
Coal	Production and conditioning		Shipping	CTL plant (+CCS option)	As for refinery fuels	KOSD1/1C
Waste wood	Collection		Road, 50 km + Shipping (800 km)	200 MW gasifier FT plant	Road, 2x150 km	WWSD1/WFSD1
Waste/Farmed wood	Growing Harvesting		Road, 50 km			
Waste wood via Black liquor	Collection		Road	BL gasifier+FT plant Wate wood boiler	Road, 2x150 km	BLSD1
Methanol / DME						
Coal (EU mix)	Production and conditioning		Shipping	Gasification methanol synthesis	Mixed land transport 500 km	KOME1
NG (piped)	Production and conditioning		Pipeline into EU	Methanol/DME synthesis	Mixed land transport 500 km	GPME1a/b GPDE1a/b
NG (remote)	Production and conditioning	Methanol/DME syn (+CCS option)	Shipping		Mixed land transport 500 km	GRME1 GRDE1/1C
Waste wood	Collection		Road, 50 km + Shipping	200 MW gasifier methanol/DME synthesis	Road, 150 km	WWME1/WFME1 WWDE1/WFDE1
Waste/Farmed wood	Growing Harvesting		Road			
Waste wood via Black liquor	Collection		Road	BL gasifier + MeOH/DME syntesis Wate wood boiler	Road, 150 km	BLME1/DE1

4.6.2 Syn-diesel

Total energy

Figure 4.6.2-1 WTT total energy balance of syn-diesel pathways



Making synthetic diesel is an energy-intensive endeavour. The combination of steam reforming, partial oxidation and Fischer-Tropsch synthesis result in overall efficiencies within a broad range of 45 to 65% depending mostly of the feedstock and to a lesser extent the process scheme.

The GTL (natural gas to liquids) processes are the most efficient with figures in the 60-65% bracket. Coal-based processes (CTL) can achieve in the region of 55%. The wood-based processes are expected to be less efficient (up to 50%) because of the inherent complexity of wood processing compared to gas and also because the plants are likely to be much smaller and less optimised in energy terms. This is also the main reason why wood processes are less favourable than CTL from this point of view. Future developments may improve the performance of these processes. In the black liquor case there is a potential for up to 55% efficiency. Wood waste is, as expected, slightly less energy-intensive than farmed wood, the difference being larger for GHG emissions mainly as a result of N_2O emissions related to wood farming.

GTL production makes the most sense at a remote location when the large gas transport energy can be avoided and replaced by the much more efficient transport of a liquid (compare e.g. GRSD1 to GPSD1a/b).

In the best case syn-diesel fuel production still requires about 4 times as much energy as conventional diesel fuel (GRSD1/COD1).

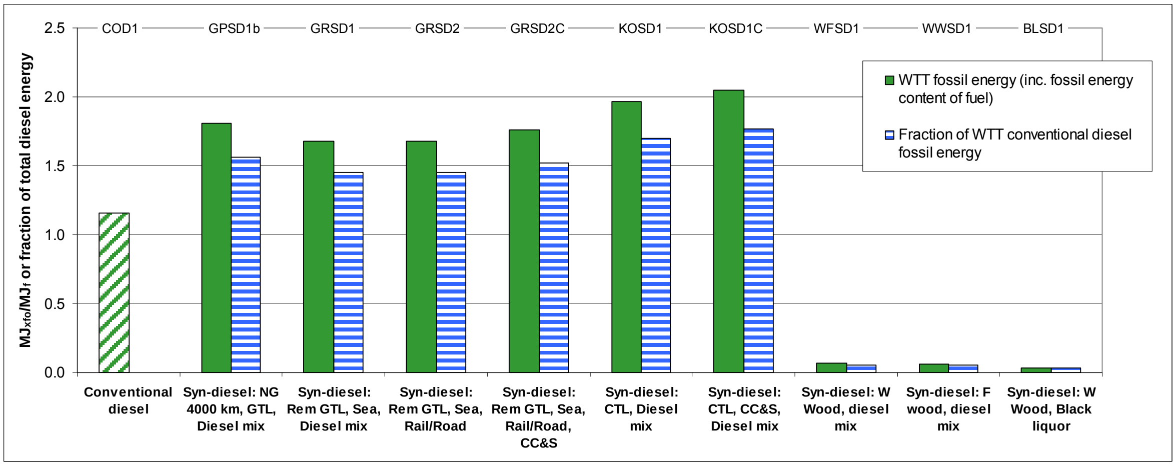
Fossil energy

The total energy graph (Figure 4.5.2-1) represents the *expended* energy i.e. excluding the energy content of the fuel itself (which is of course 1 MJ/MJ in all cases). In order to compare the *fossil* energy or GHG balances of renewable and non-renewable pathways one has to take into account the fossil energy and non-renewable carbon content of the fuels produced through the different routes (i.e. for energy, 1 MJ/MJ for fossil fuels and 0 MJ/MJ for renewable fuels). The fossil energy balance calculated in this way for the different routes to synthetic diesel is shown in ***Figure 4.6.2-2***.

In this case all options produce a diesel fuel that will result in the same efficiency when burned in a given vehicle (see *TTW report*) and the figures calculated in that way are in fact the same as the WTW figures expressed per MJ_f rather than per km.

Figure 4.6.2-2 reveals ratios of 1.5 to 2 between conventional diesel and the different fossil-based syn-diesel options. Wood-based options hardly use any fossil energy as these processes are mostly fuelled by their own feedstock (note, however, that this increases the specific rate of biomass usage and therefore the potential of such fuels for a given biomass availability, see also *section 5*).

Figure 4.6.2-2 WTT fossil energy balance of syn-diesel pathways (including fossil energy content of the final fuel)



GHG emissions

The GHG picture (***Figures 4.6.2-3/4***) is more favourable for natural gas as the energy involved is less carbon-intensive (the GTL process is in effect a carbon concentration process and a large fraction of the expended energy is in the form of hydrogen). Using coal, however, results in very large GHG emissions. For wood, GHG emissions are mainly incurred for wood growing and collection/transport.

CC&S offers an opportunity for substantial reductions of CO_2 emissions. For GTL the reduction potential is in the order of 10% turning the product from slightly more GHG-intensive than conventional diesel to slightly less so. For CTL the reduction is much more dramatic (about 50%) because of the much larger amount of CO_2 emitted during the CTL process. With CC&S, CTL becomes only marginally more GHG-intensive than conventional diesel. One has also to remember that the CC&S data are only based on technical studies and are only indicative at this stage. As these processes develop, higher CO_2 recovery may be possible. The potential of CC&S is further discussed in *section 5.4*

Figure 4.6.2-3 WTT GHG balance of syn-diesel pathways (including fossil CO_2 content of final fuels)

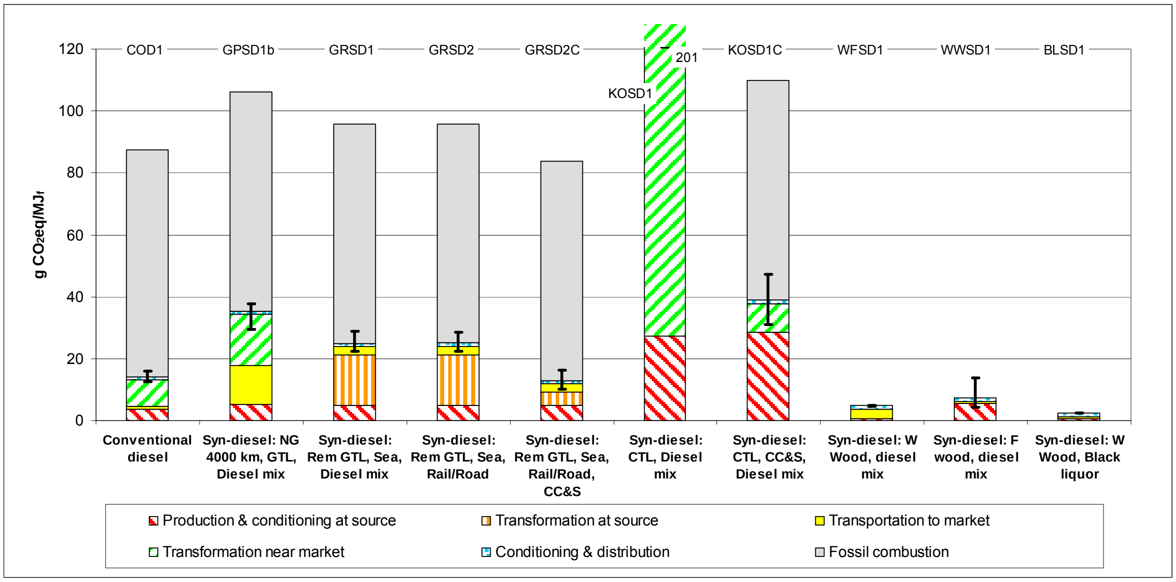
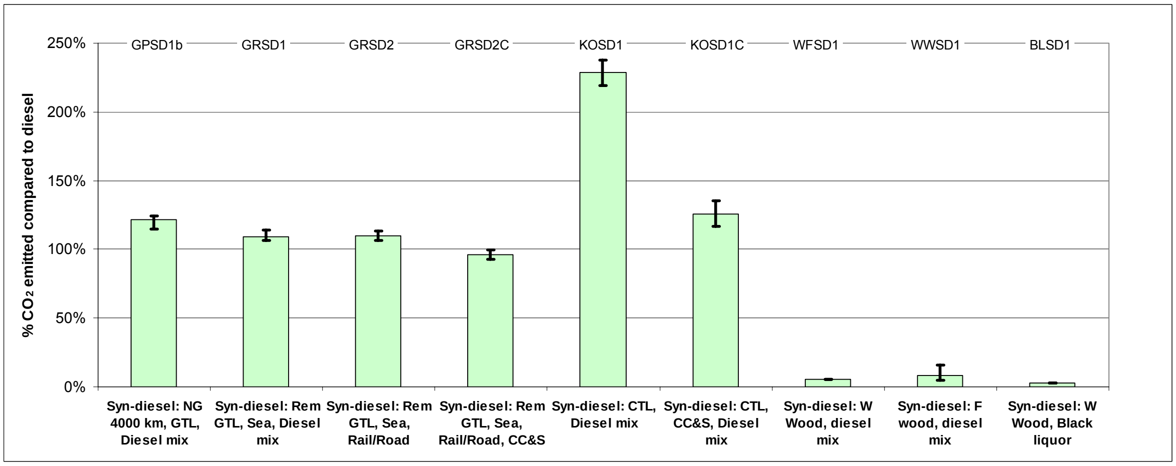


Figure 4.6.2-4 WTT GHG balance of syn-diesel pathways compared to conventional fossil diesel (including fossil CO_2 content of final fuels)



4.6.3 DME

The synthesis of DME is a more efficient than that of FT diesel, resulting is a more favourable energy balance (compare GRSD2 and GRDE1 in ***Figure 4.6.3-1***).
DME from wood is much less energy-efficient but virtually all the energy used comes from the wood itself, resulting in a very favourable fossil energy balance (***Figure 4.6.3-2***). The black liquor route offers a substantial energy efficiency improvement when using wood. In terms of fossil energy or GHG balance the difference is of course small in absolute terms (because all figures are small). The main benefit resides in the better utilisation of a limited resource allowing substitution of more fossil energy with the same quantity of wood.

Manufacturing of DME near a remote natural gas source is one of the most credible scenarios as DME can be transported in liquid form by simple compression, much like LPG, avoiding the need for expensive LNG installations. For this route DME is on a par with conventional diesel in terms of GHG emissions (***Figure 4.6.3-3/4***). In such a case CC&S could be envisaged to capture the CO_2 emitted during the synthesis process. WTT GHG emissions could potentially be cut by a factor 2 for a relatively small energy penalty, making DME somewhat more GHG-efficient than conventional diesel.

Note that, when comparing DME with liquid diesel fuels, the WTT fossil energy figures including the fuel fossil energy content are not quite equivalent to the WTW figures because DME burns with a somewhat higher efficiency in the vehicle (see *TTW report*).

Figure 4.6.3-1 WTT total energy balance of DME pathways

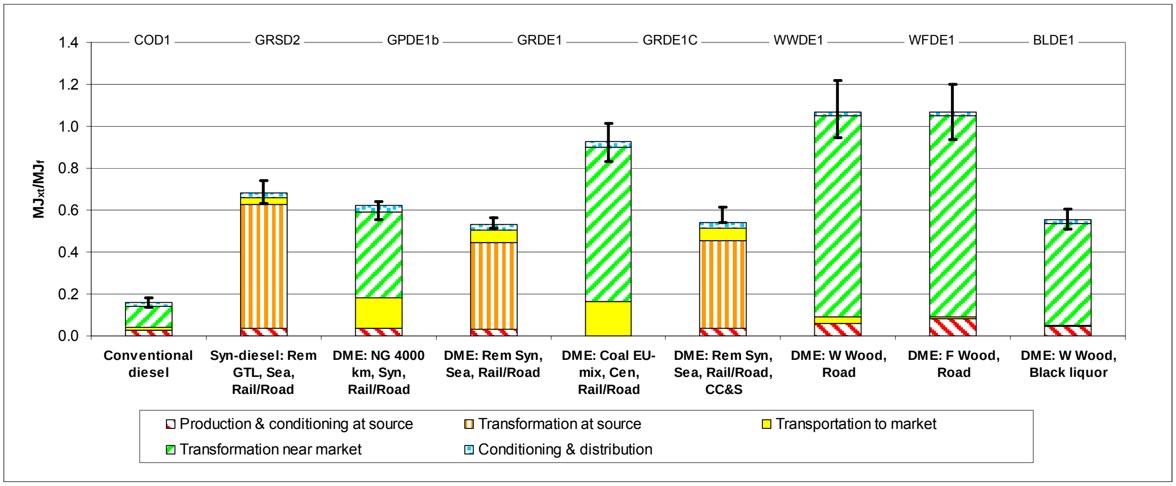


Figure 4.6.3-2 WTT fossil energy balance of DME pathways (including fossil energy content of the final fuel)

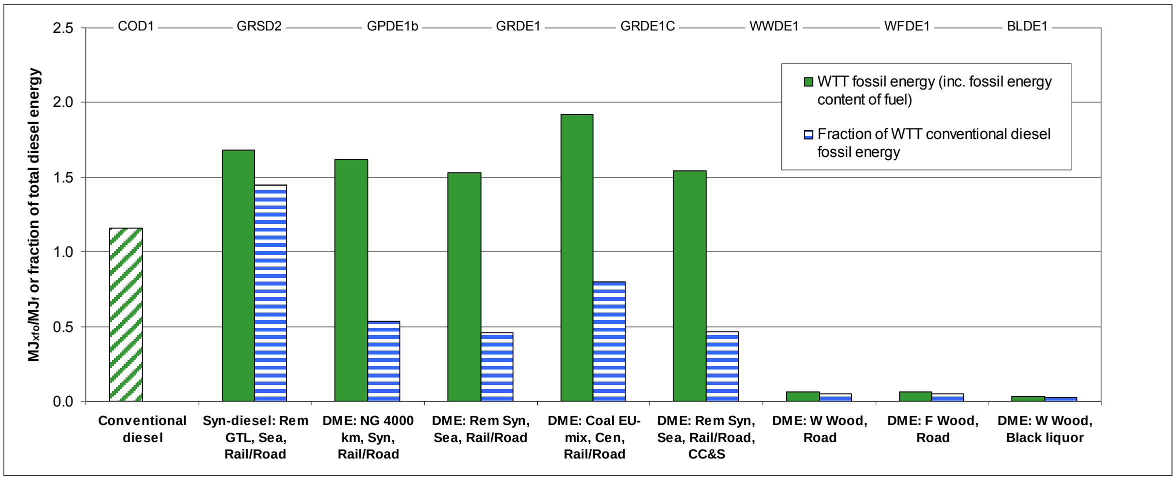


Figure 4.6.3-3 WTT GHG balance of DME pathways (including fossil CO_2 content of final fuels)

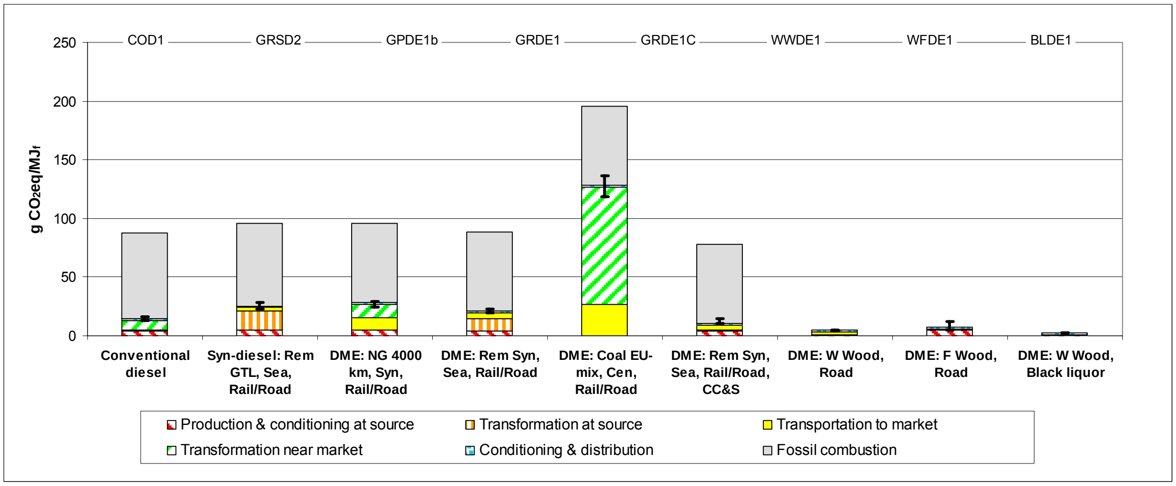
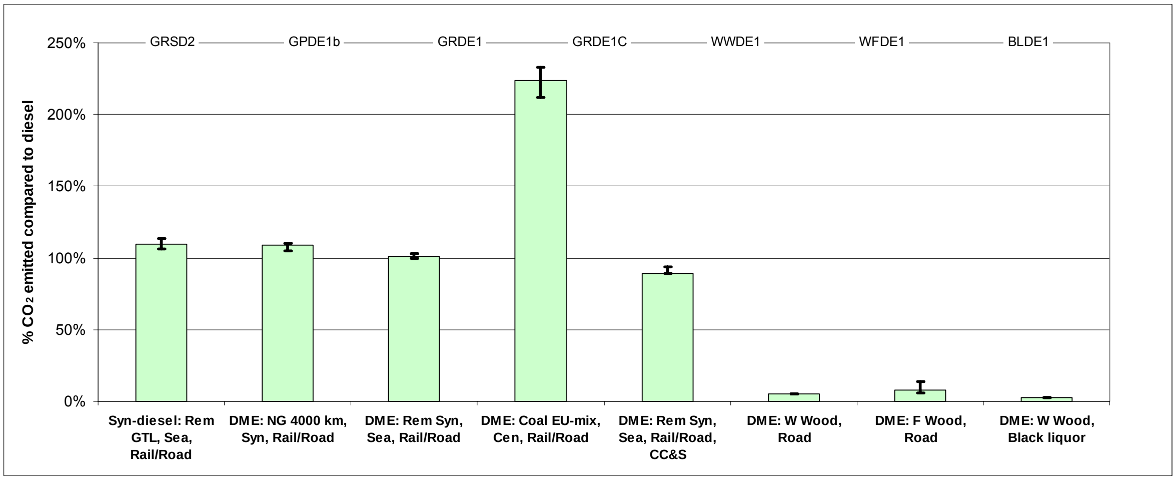


Figure 4.6.3-4 WTT GHG balance of DME pathways compared to conventional fossil diesel (including fossil CO_2 content of final fuels)



4.6.4 Methanol

WTT figures for methanol are very similar to those of DME and show the same trends. Because of the relatively minor importance of methanol as a future automotive fuel, a CC&S option has not been included here. It would of course be perfectly feasible and again bring benefits similar to those seen for DME.

Figure 4.6.4-1 WTT total energy balance of methanol pathways

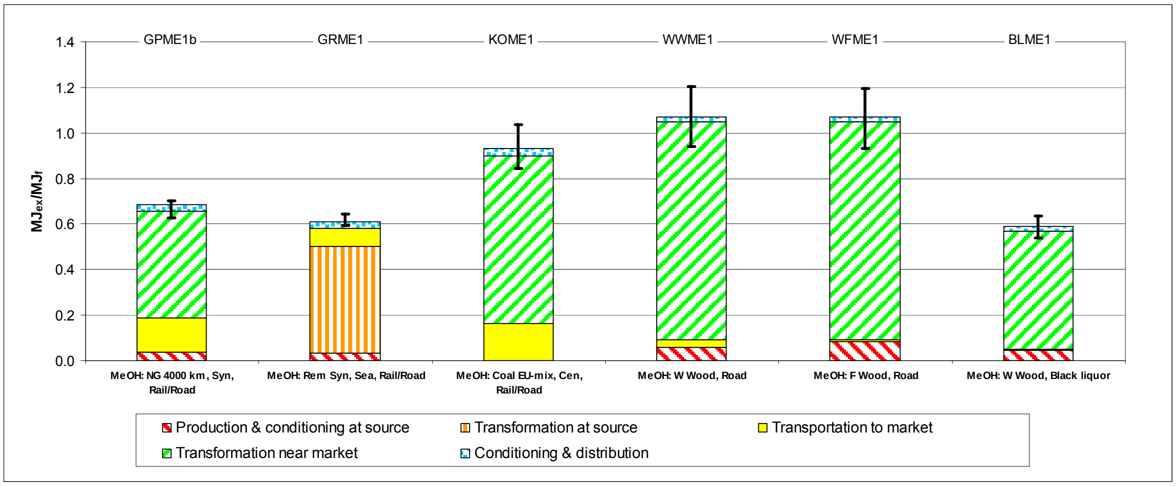
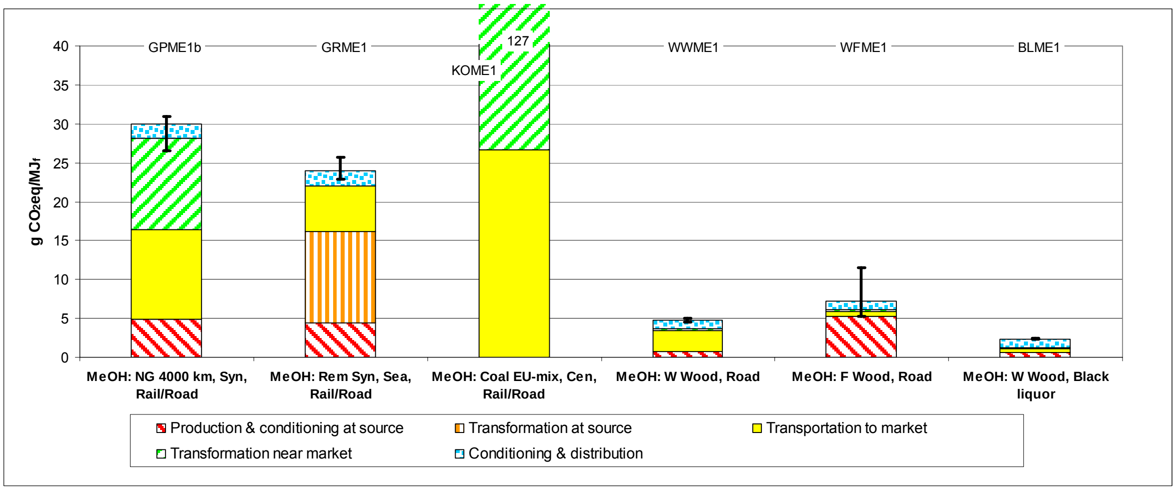


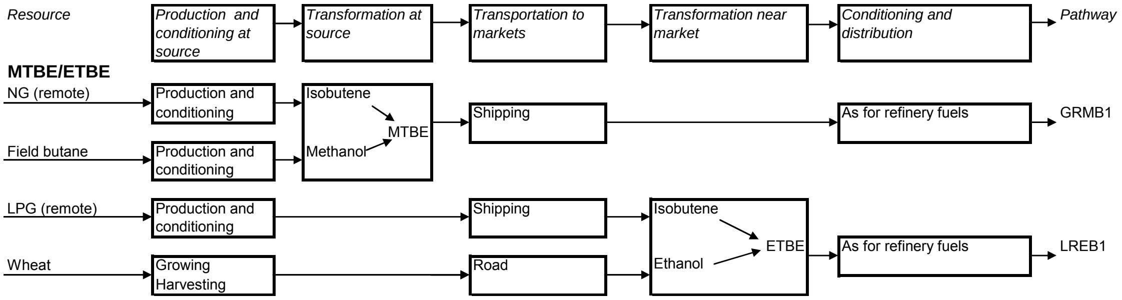
Figure 4.6.4-2 WTT GHG balance of methanol pathways



4.7 Ethers (MTBE/ETBE)

(See also WTT Appendix 2 section 2-6)

Figure 4.7-1 MTBE and ETBE pathways



Pathway GRMB1 represents marginal MTBE produced from natural gas and associated butane in a remote plant located near a gas field (see *section 3.2.5*). Pathway LREB1 represents a case where ETBE would be produced in Europe from imported butane and bio-ethanol (from wheat according to pathway WTET2a, see *section 3.4.4*).

MTBE is more energy-intensive than gasoline as it involves several energy-consuming chemical steps. GHG emissions are very close, however, because the bulk of the energy for MTBE manufacture is natural gas rather than heavier hydrocarbons in the case of gasoline.

ETBE's energy footprint is much higher, partly because of the high energy demand for bio-ethanol. Part of that energy is renewable though and this is taken into account when calculating GHG emissions. ETBE is itself partly renewable so that, to compare GHG emissions with purely fossil pathways, only the non-renewable part of the CO_2 combustion emissions (2/3) has to be factored in.

Figure 4.7-2 WTT total energy balance of MTBE and ETBE pathways

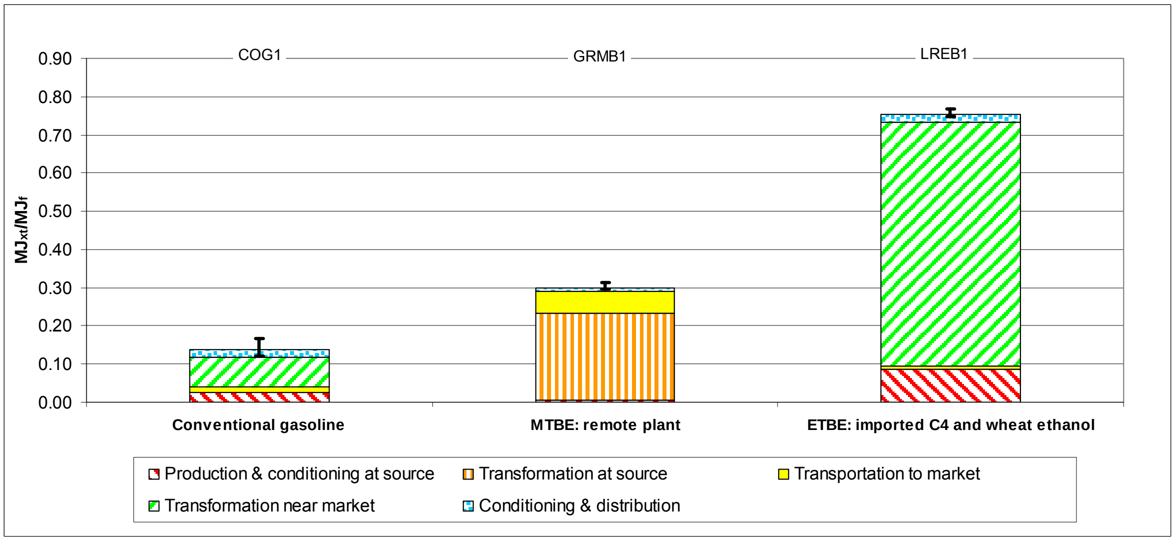
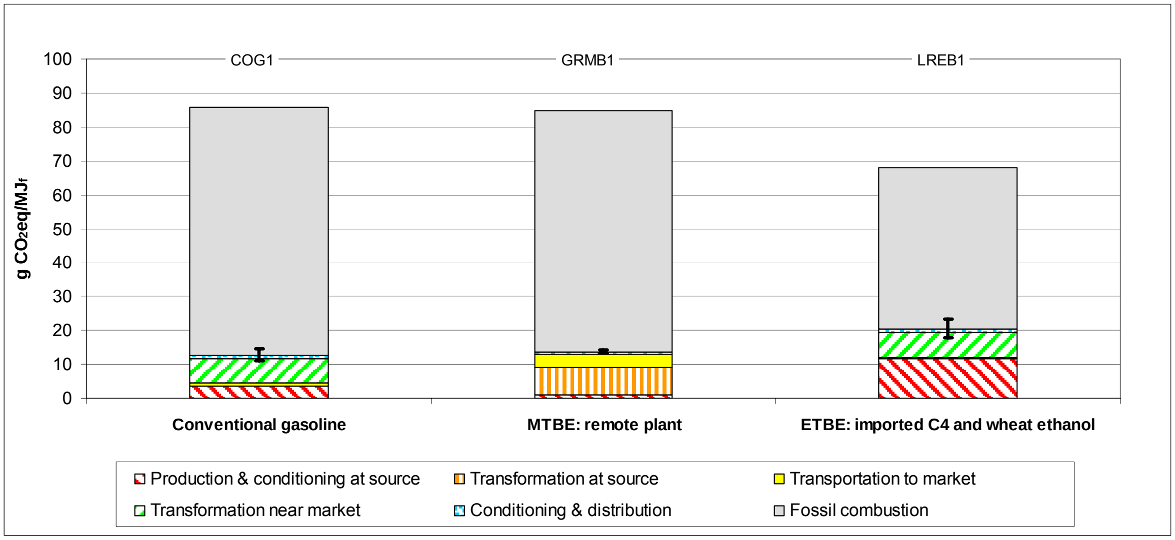


Figure 4.7-3 WTT GHG balance of MTBE and ETBE pathways



MTBE is more energy-intensive than gasoline as it involves several energy-consuming chemical steps. GHG emissions are very close, however, because the bulk of the energy for MTBE manufacture is natural gas rather than heavier hydrocarbons in the case of gasoline.

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Pathway LREB1 is thus far a hypothetical case inasmuch as ETBE is currently made by substituting methanol by ethanol in existing refinery MTBE plants. In order to assess the impact of this route we have looked at the differential between a base case where MTBE is made in the refinery and an alternative where ETBE is made instead. The calculations are summarised in the table below:

Table 4.7 Substitution of methanol by bio-ethanol for ETBE manufacture in refineries

		Gasoline components available				Additional gasoline	Feedstocks used			Balance		**Balance**	
		MTBE	ETBE	Ethanol	Total		Isobutene	Methanol	Ethanol	/MJ MTBE	/MJ ETBE	/MJ EtOH	
Use of ethanol as such													
Used or produced	MJ$_f$	1.00		0.40	1.40		0.82	0.21					
Total energy	MJ$_{xt}$			1.01						1.01		**2.53**	
Fossil energy	MJ$_{xf}$			0.26						0.26		**0.65**	
GHG	g CO_2eq			18.58						18.58		**46.6**	
ETBE instead of MTBE													Net
Used or produced	MJ$_f$		1.20		1.20	0.20	0.82	-0.21	0.40				
Total energy	MJ$_{xt}$					0.230		-0.33	1.01	0.91	0.76	**2.28**	**-0.26**
Fossil energy	MJ$_{xf}$					0.23		-0.33	0.26	0.16	0.13	**0.39**	**-0.26**
GHG	g CO_2eq					17.3		-19.2	18.6	16.75	13.99	**42.0**	**-4.6**

1 MJ of MTBE requires 0.82 MJ of isobutene. That same amount can produce 1.2 MJ of ETBE by replacing 0.21 MJ of methanol by 0.40 MJ of ethanol (this is simply the result of the chemical balance). Thus in the base case 1 MJ of MTBE is available along with 0.40 MJ of ethanol that can both be used as gasoline. When making ETBE a total of only 1.2 MJ is available to the gasoline pool while 0.21 MJ of methanol have been "saved". In order to bring both cases to the same basis one has to add to the ETBE case the amounts related to production of additional gasoline (1.40-1.20 = 0.20 MJ).

The ETBE route is slightly more favourable from a GHG point of view, i.e. using ethanol to make ETBE as a substitute to refinery MTBE saves more GHG than using that ethanol as such. The reason for this is that making ETBE saves in part methanol instead of gasoline, the former having a larger GHG footprint.

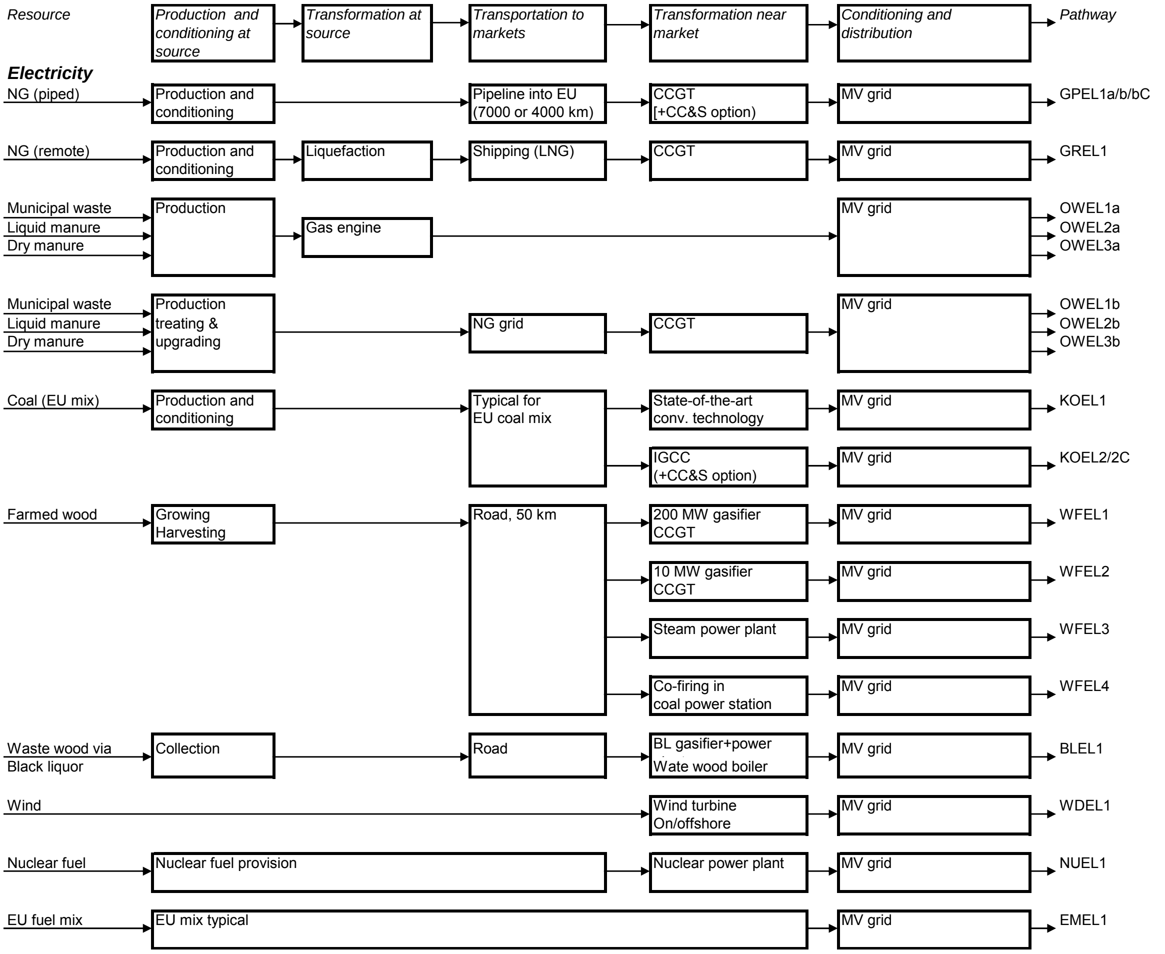
4.8 Electricity

(See also WTT Appendix 2 section 2-7)

4.8.1 Electricity generation pathways

The pathways to electricity are included here as a reference against other fuels with which electricity competes for primary resources. Electricity is also used as intermediate stage for electrolysis pathways to hydrogen (see *section 4.9*).

Figure 4.8.1 Electricity generation pathways



4.8.2 Energy and GHG balance for electricity pathways

In the section the energy figures include the energy content of the electricity produced. This is because electricity is used as an intermediate energy source (e.g. for electrolysis) rather than a "road fuel".

Total energy

In terms of total energy (***Figures 4.8.2-1a/b***), the very efficient gas-fired CCGT (combined cycle gas turbine) fares best amongst fossil fuels. Coal is significantly more energy-intensive.

Figure 4.8.2-1a Total energy balance for various electricity pathways (including final electrical energy)

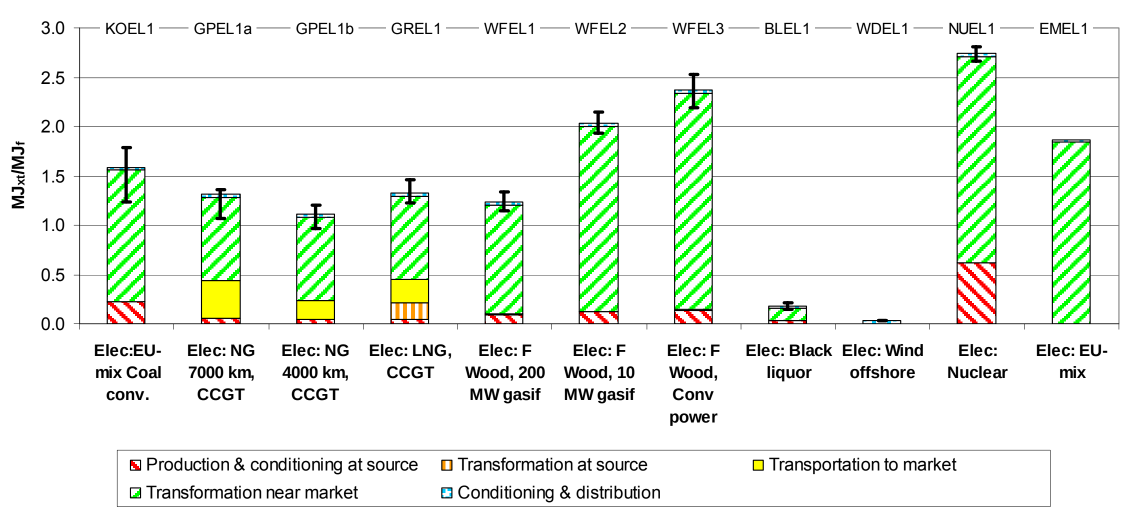
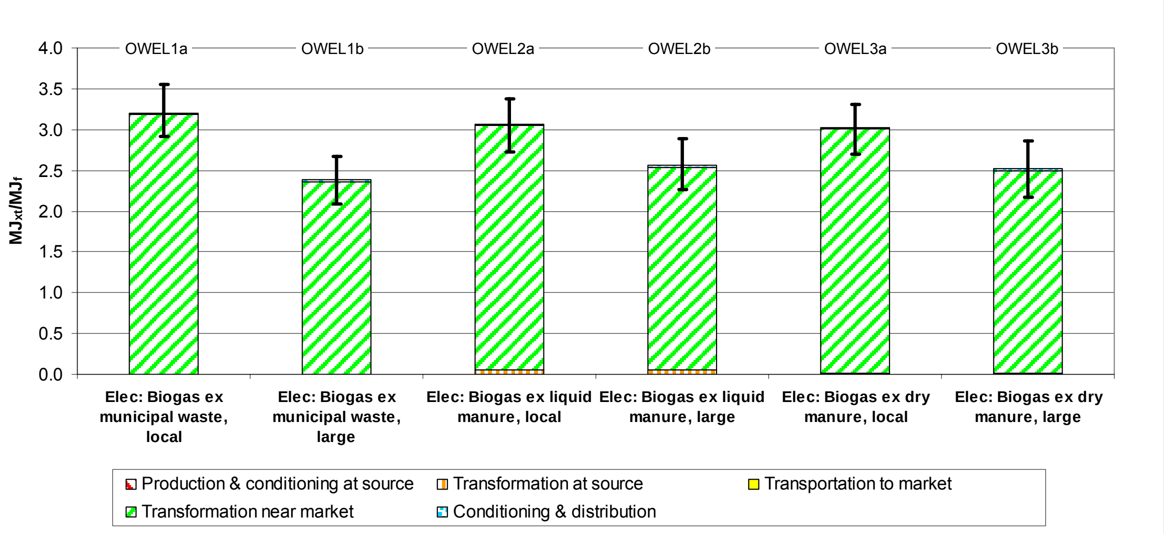


Figure 4.8.2-1b Total energy balance for biogas to electricity pathways (including final electrical energy)



The average generation efficiency of the EU-mix electricity is not as good as the gas-fired CCGT scheme. However, the shares of renewables and nuclear compensate for this, resulting in very similar GHG figures.

Wood comes close to gas in the case of a large gasifier associated to a CCGT but other schemes such as small gasifiers or conventional steam plants are much less efficient. The wood GHG balance is of course much more favourable that that of fossil fuels. The black liquor scheme achieves a remarkably high energy efficiency due to the synergy with the requirements of the paper mill.

Wind is a course a special case inasmuch as the input energy cannot be measured and, being in effect unlimited, can be considered as totally “free”.

It is common practice to calculate the efficiency of a nuclear power plant as the fraction of the energy transferred to the steam that is turned into electricity which explains the fairly high energy use figures. Provision of nuclear fuel also requires a significant amount of energy.

Fossil energy

When it comes to fossil energy only (***Figures 4.2.8-2a/b***), wood and wind fare very well of course.

If nuclear energy is considered to be fossil the EU-mix figure is poor relative to fossil hydrocarbon options. When considering only the fossil hydrocarbons part, EU-mix has a fossil energy footprint similar to natural gas.

Most of the biogas figures are negative (i.e. biogas saves more fossil energy than it uses, please also note the difference in scale between ***Figures 48.2.-2a/b***). The seemingly inconsistent figure for OWEL1b stems from the fossil electricity requirement of the biogas plant. This requirement is different in OWEL2b and 3b because of a different heat to electricity ratio.

Figure 4.8.2-2a Fossil energy balance for various electricity pathways

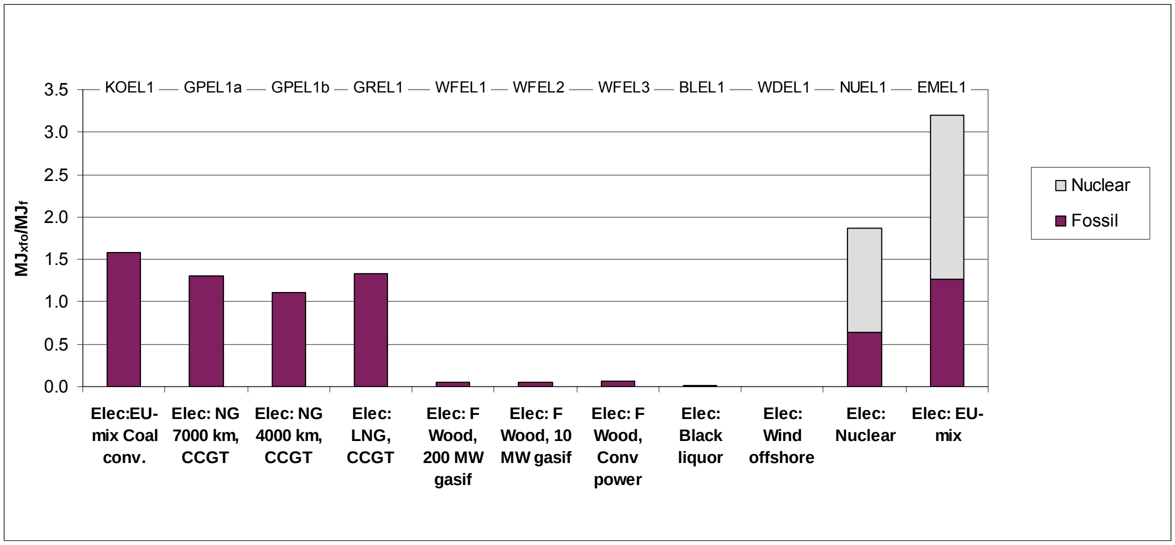
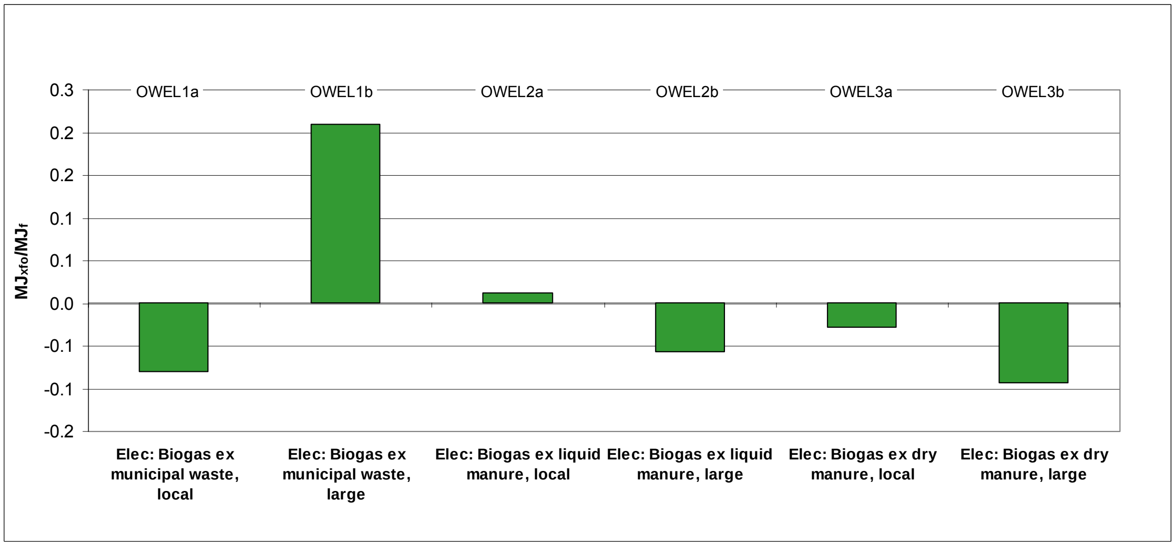


Figure 4.8.2-2b Fossil energy balance for biogas to electricity pathways



GHG emissions

The picture for GHG emissions is very similar to fossil energy. The notable exception is biogas from liquid manure for which a large GHG credit is accrued from avoided methane emissions from untreated manure.

Figure 4.8.2-3a GHG balance for various electricity pathways

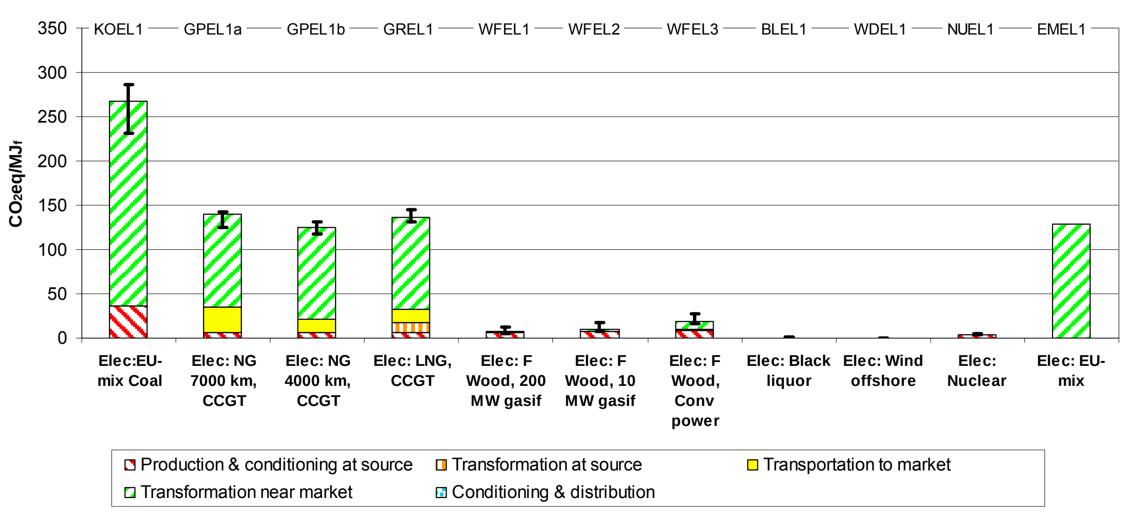
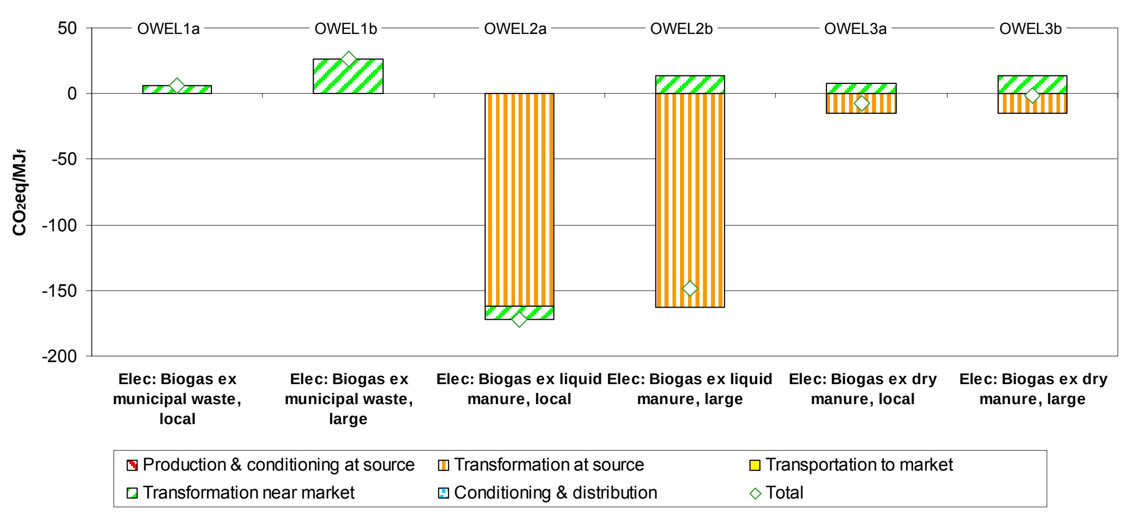


Figure 4.8.2-3b GHG balance for biogas to electricity pathways



4.9 Hydrogen

(See also WTT Appendix 2 section 2-8)

4.9.1 Pathways to hydrogen

One of the perceived merits of hydrogen is that it can in principle be produced from virtually any primary energy source. This can be done either via a chemical transformation process generally involving decarbonisation of a hydrocarbon or organic feedstock and splitting of water or through electricity via electrolysis. Most of these processes can be put to work in large "central" facilities or in small "distributed" plants near or at a refuelling station.

The different hydrogen production routes are described in *section 3.2.5 for natural gas, 3.3 for coal and 3.4 for biomass*.

The pathways selected to represent hydrogen provision reflect the various supply routes available.

Figure 4.9.1a Compressed hydrogen pathways

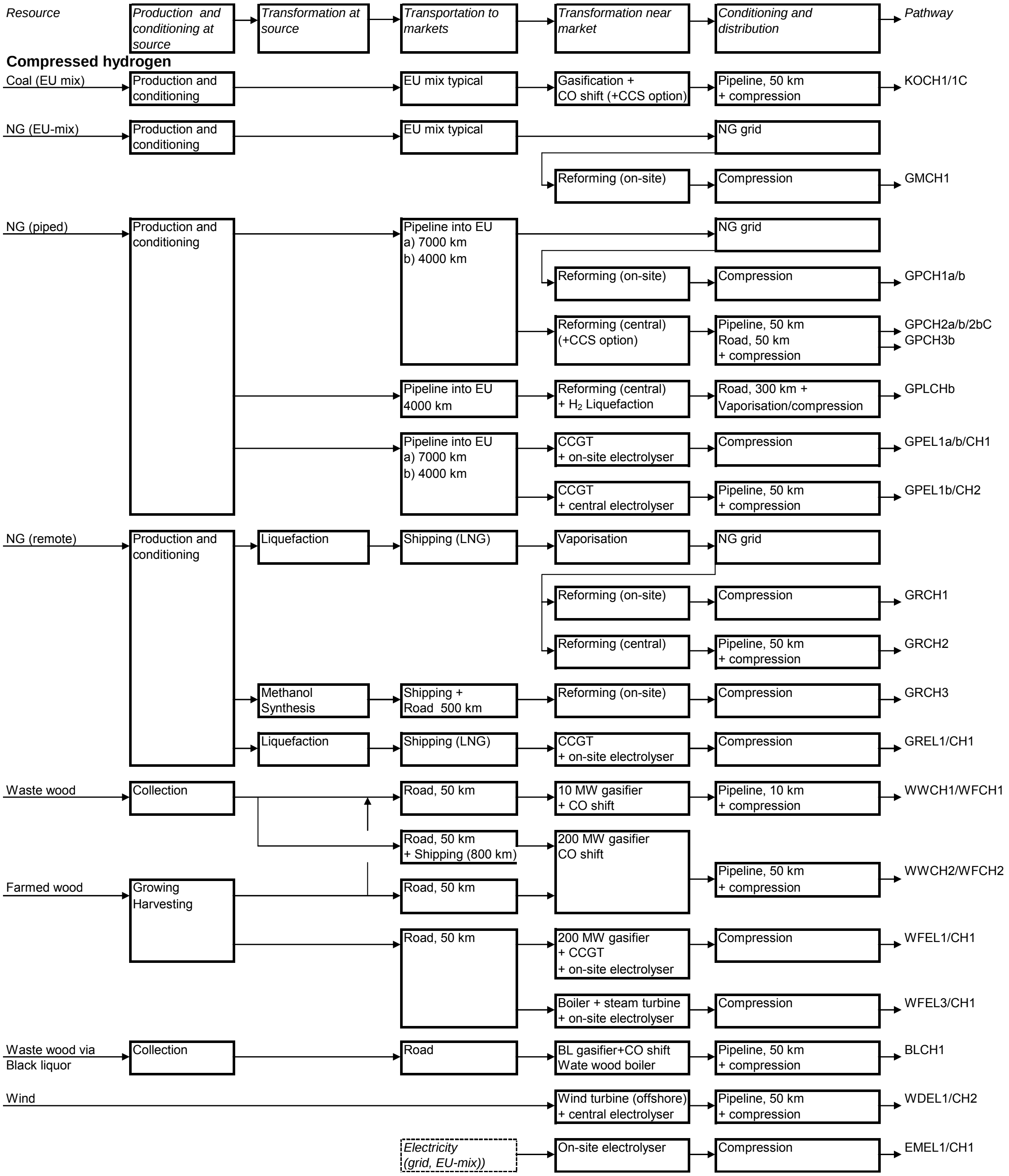
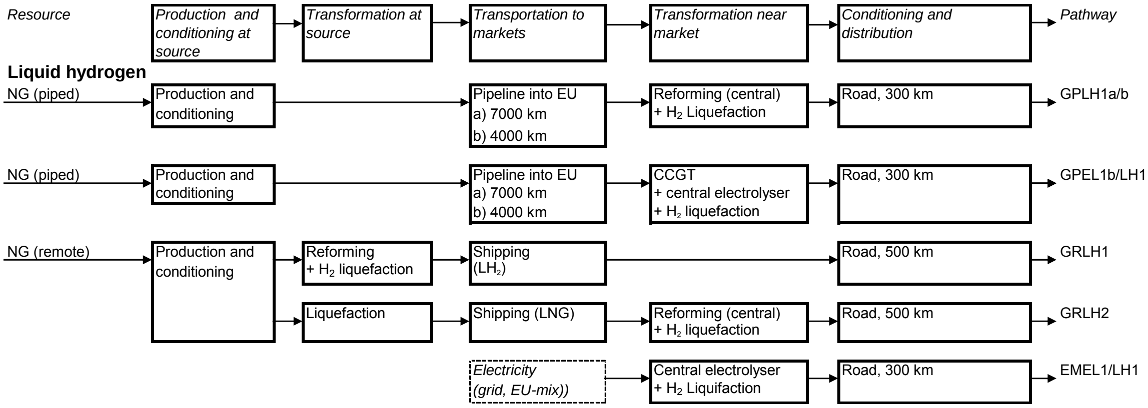


Figure 4.9.1b **Liquid hydrogen pathways**



4.9.2 Hydrogen from NG energy and GHG balance

Compressed hydrogen

Not surprisingly the main contribution comes from the hydrogen production step which requires energy and where all carbon is effectively "shed". The transport distance of the gas still has a significant impact although less in relative terms than for CNG pathways (GPCH1a/b).

For a given transport distance, central reforming is more efficient (because of the better waste heat recovery potential of a large plant), irrespective of mode of transport to the delivery point (GPCH1/2/3b). Although it could be quite attractive from an economic point of view especially in the early stages of development, the option of transporting hydrogen in liquid form is not energy-efficient (GPCLHb).

CC&S is obviously a very attractive option for hydrogen because all carbon is turned into CO_2 during the process. There is a small energy cost which in practice will depend on the process scheme used in the base case. More efficient CO_2 recovery than has been assumed here could be possible in the future making the scheme even more beneficial. The potential of CC&S is further discussed in *section 5.4*.

Figure 4.9.2-1 **WTT total energy balance of selected NG to compressed hydrogen pathways**

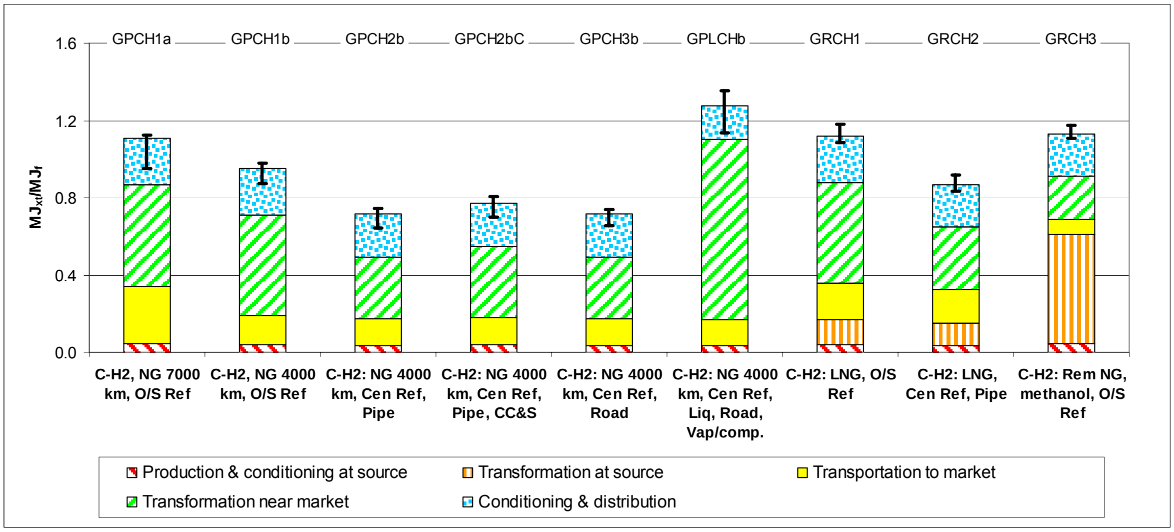
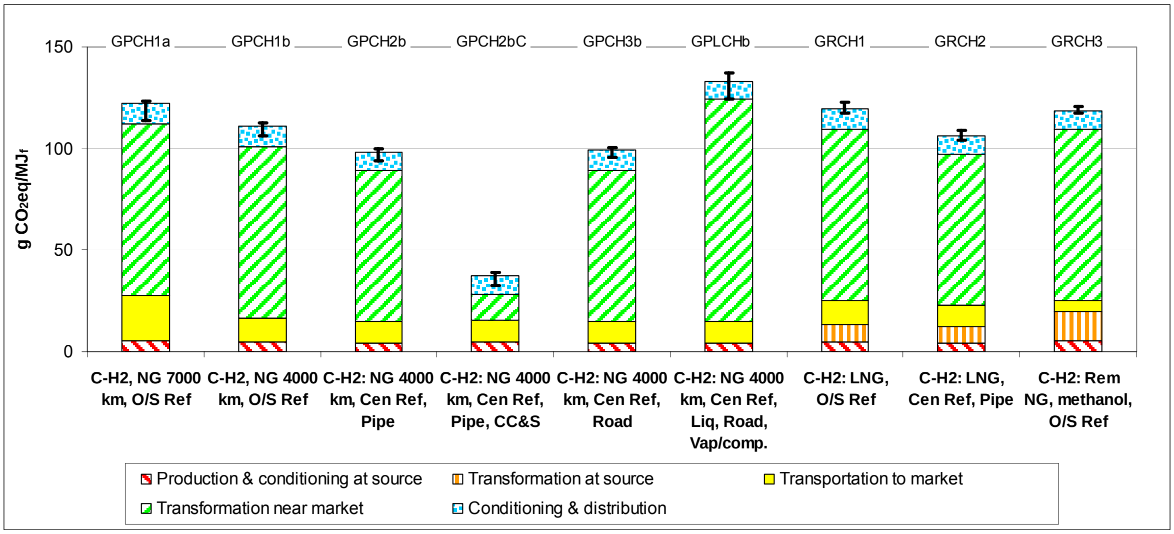


Figure 4.9.2-2 WTT GHG balance of selected NG to compressed hydrogen pathways



The option of using methanol as an energy carrier (rather than gas) does not appear to offer any advantage from an energy/GHG point of view, in particular because the scheme can only be justified with relatively inefficient small scale reformers (GRCH3).

As we have seen for CNG, the LNG route fares similarly to the longer pipeline distances.

Liquid hydrogen

The energy required for liquefaction penalises the liquid hydrogen option (the attractiveness of liquid hydrogen rather stems from practicality and economics considerations). The fairly large error bar for the liquid hydrogen pathways is mainly due to the large range of liquefaction energy. The somewhat far-fetched option of remote hydrogen production and long-distance hydrogen (GRLH1) transport does not appear to match the local production options.

Figure 4.9.2-3 Energy balance of selected NG to liquid hydrogen pathways

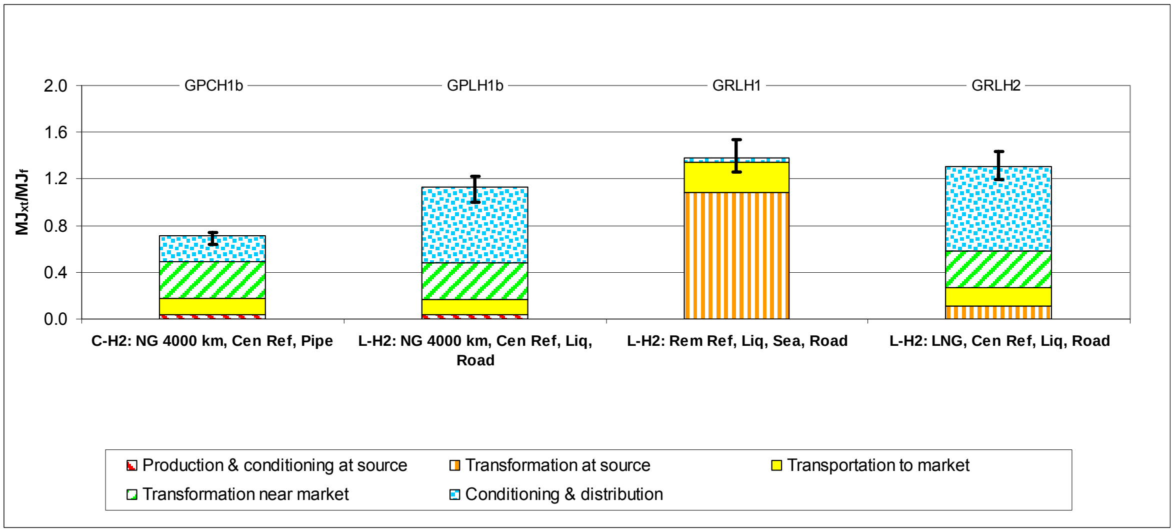
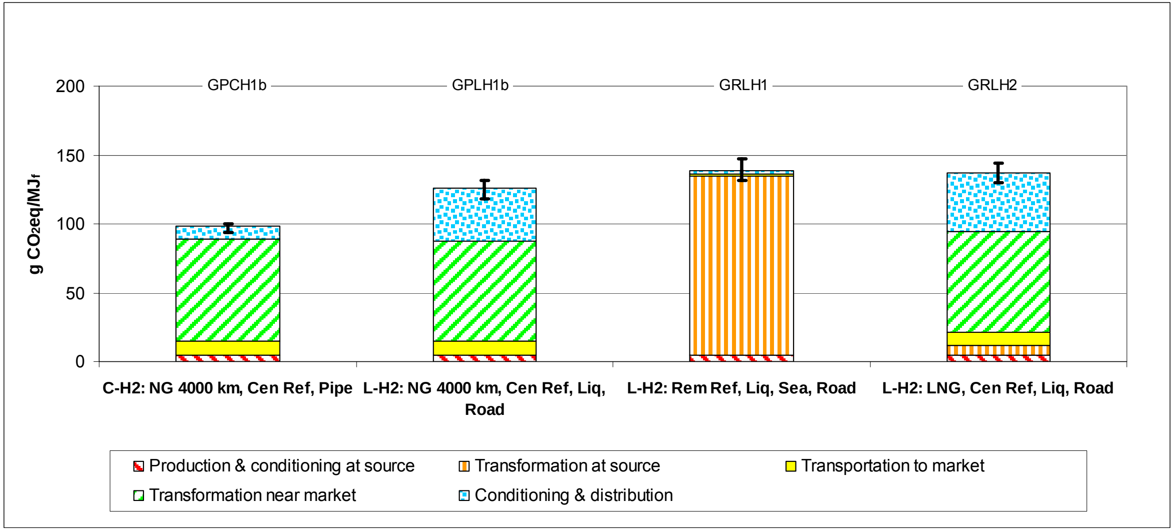


Figure 4.9.2-4 GHG balance of selected NG to liquid hydrogen pathways



4.9.3 Hydrogen from coal and wood, energy and GHG balance

The coal route is more energy-intensive than the gas route (because the gasification process is less efficient). The difference is even greater when it comes to GHG because of the higher carbon content of coal. As a corollary, however, a large amount of CO_2 can be captured, albeit with an energy penalty. When applying CC&S to both the gas and the coal schemes, the residual GHG emissions are still somewhat higher for coal but the difference is much smaller than without CC&S. The potential of CC&S is further discussed in *section 5.4*.

The gasification is also less efficient with wood than gas. For wood the ranking between the large and small scale gasifier is very much a result of the extent to which waste heat can be recovered to produce surplus electricity. The GHG emission figures are of course very small as the main conversion process uses nothing but wood as energy source. The differences between the wood options are not very significant and are all much smaller than those observed in equivalent pathways based on fossil fuels.

Figure 4.9.3-1 Energy balance of coal and wood to compressed hydrogen pathways

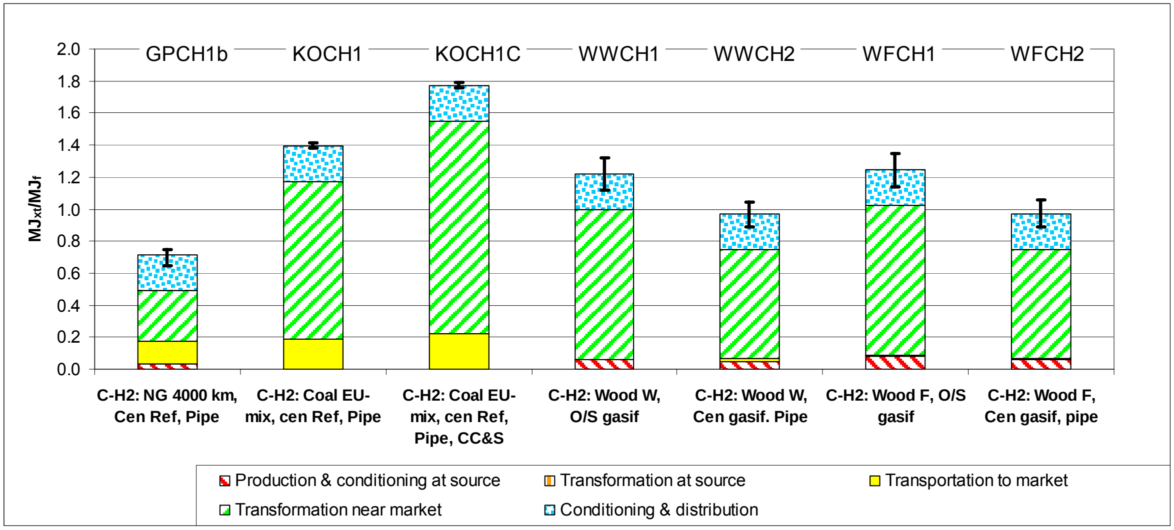
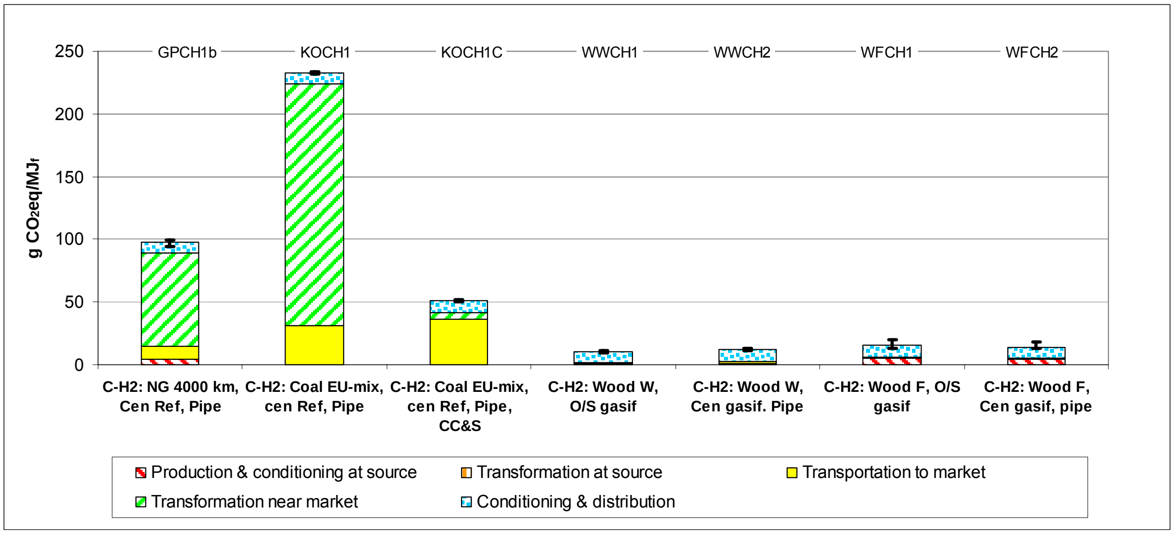


Figure 4.9.3-2 GHG balance of coal and wood to compressed hydrogen pathways



4.9.4 Hydrogen via electrolysis, energy and GHG balance

For a given source of electricity, central and on-site electrolysis give nearly equal results with compressed hydrogen, the only small difference coming from the somewhat lower final compressor suction pressure in the central case (e.g. GPEL1b/CH1/CH2). The relative merits of the different energy sources are of course the same as discussed for electricity generation in *section 4.8*.

The low energy consumption of the wind pathway (WDEL1/CH2) reflects the somewhat arbitrary assumption that the wind energy harnessing is 100% efficient. As this energy is renewable and, for all practical purposes, unlimited this is a somewhat academic debate anyway. It is reasonable to consider that the hydrogen compression energy is electricity from the EU-mix rather than wind electricity. The pathway therefore shows some GHG emissions.

Here again the wood pathways GHG figures (WFEL1-3/CH1) are very low as most of the energy used is renewable.

Figure 4.9.4-1 Energy balance of selected electrolysis pathways

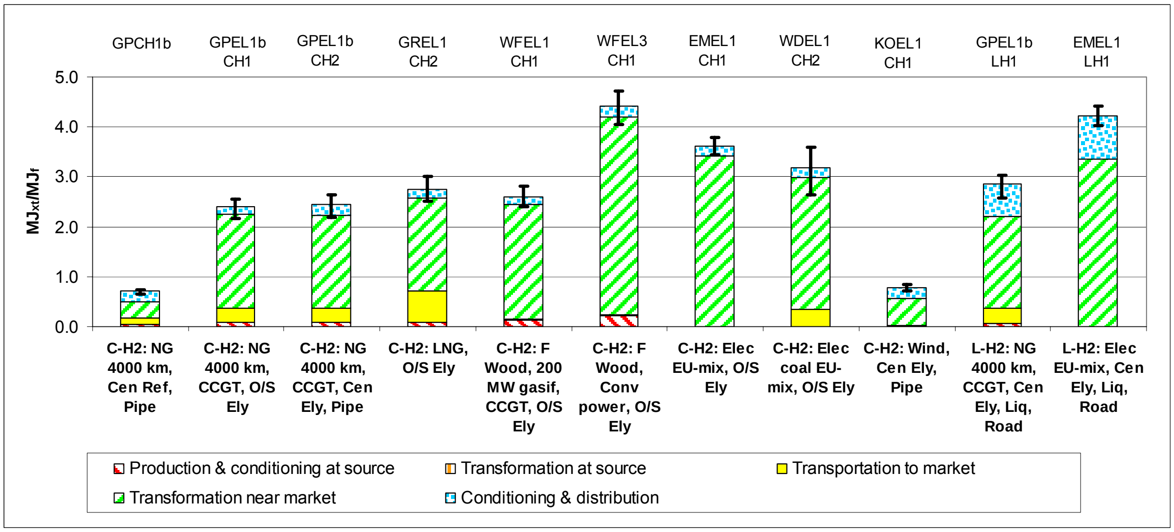
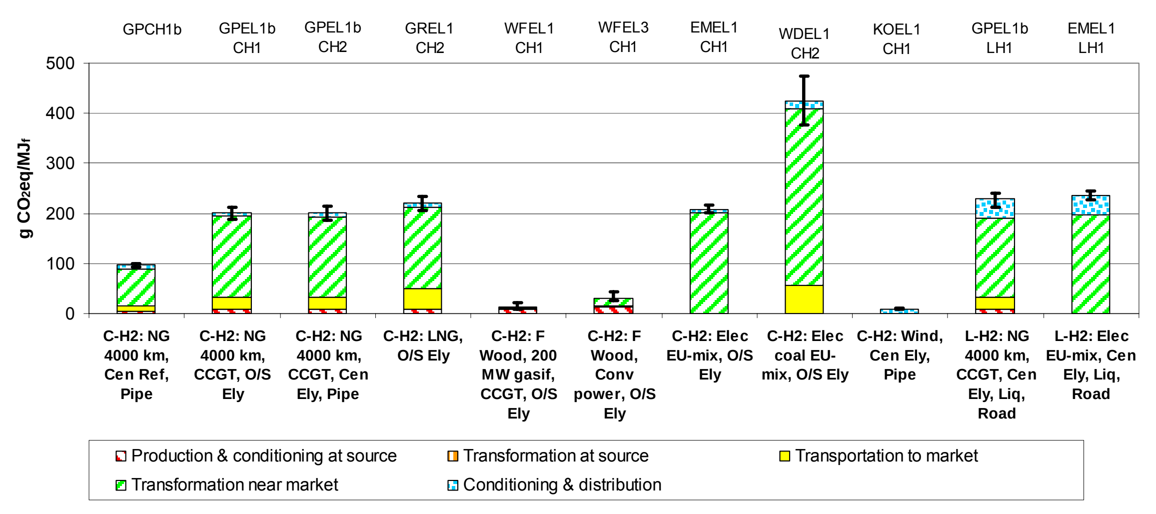


Figure 4.9.4-2 GHG balance of selected electrolysis pathways



Comparison with the straightforward NG to hydrogen pathway (GPCH1b vs. GPEL1b/CH1) highlights the poor energy-efficiency of the electrolysis route. Turning usable electricity into hydrogen is unlikely to make sense from a global energy or GHG point of view.

Renewable electricity, in particular, is a case in point. The real issue is not whether these pathways have a favourable GHG profile, which is obvious, but rather under what circumstances it would make sense to use them. This issue can only be addressed on a global well-to-wheels basis and the reader is referred to *section 9 of the WTW report*.

Of course the total energy required to produce hydrogen and the total GHG emitted are in all cases much higher than is the case for CNG (or conventional gasoline of diesel fuel). The latter is only shown here to put the hydrogen figures in perspective. Indeed, the simple “well-to-tank” assessment finds its limits here as there is no point comparing “carbon-containing” fuels that are to be used in a conventional engine to a carbon-free fuel that may be used in an inherently more efficient fuel cell.

5 Potential availability and costs

The question of how much of a certain fuel could conceivably be made from a given feedstock and at what cost is, of course, central to an analysis of competing fuel pathways. It is, however, arguably the most difficult part.

The potential availability of a feedstock or resource to produce a certain fuel depends on many factors. There may be physical limitations (e.g. land) and practical ones (e.g. number of sites for wind turbines). There may also be issues of competing uses of resources, social and political choices etc.

Cost evaluations and forecasts are always fraught with difficulties, particularly so when it comes to processes or systems that do not yet exist at any notable scale. The future cost of feedstocks or of access to resources will depend on more or less the same factors as availability.

Although a definitive analysis is clearly not possible we believe the available data can provide a valuable insight into the various options.

Costs have been evaluated on a macro-economics basis for Europe (EU-25) as a whole. This implies that the minimum cost of an international commodity is its market price (delivered to Europe). This holds true when the commodity is imported but also when is it produced within Europe as any amount used internally denies Europe a revenue based on the market price (in this last case, it is the minimum cost assuming the production cost is not higher). We did not attempt to forecast fuel prices: the oil price is a variable, and other prices are related to it. For crop prices in 2012 we used a respected forecast, upon which we added our own estimates of the market effects of increasing biofuels use.

All costs are expressed in EUROS. Whenever the literature source indicated cost in US Dollars we have assume €/$ parity. However, forecasts of agricultural commodity prices follow [*DG-AGRI 2005*] in converting 2012 prices from dollars at a rate of 1.15 $/€.

When it comes to cost of new facilities (production, distribution etc) one has to rely mainly on literature sources which, even when carefully selected, often cannot be independently checked. Because they mostly refer to facilities which exist either at a limited scale or not at all, cost figures are often only rough estimates with both upwards (unforeseen items) and downwards (experience, scale) potential.

Our analysis is limited to the more tangible costs such as feedstock costs, processing costs and the like. It does not include any possible credit or debit for e.g. employment, regional development, environmental impact etc.

In the following sections we discuss the cost data and calculations for each set of pathways. *WTW Appendix 2* gives a convenient summary of the calculations and results.

5.1 Fossil fuels supply and cost to Europe

5.1.1 Crude oil

Crude oil is a worldwide commodity. Although most grades are traded on a wide geographical basis, consuming regions tend, for logistic and geopolitical reasons, to have preferred supply sources. In Europe the main sources are:

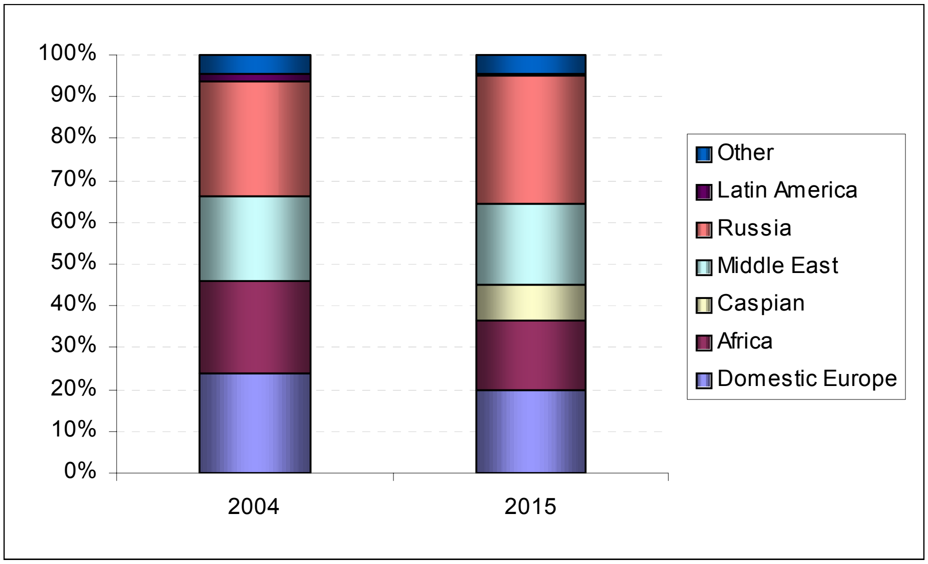
- North Sea: this is indigenous production for which Western Europe has a clear logistic advantage. Although some North Sea crude finds its way to the US, the bulk is consumed in Europe.

- Africa: North African crudes (Algeria, Lybia, Egypt) are naturally part of Southern Europe's "captive" production. West African crudes can profitably go either to North America or to Europe and the market is divided between these two destinations.
- Middle East: The region is an important supplier, mainly of heavy, high-sulphur grades, typically used for the manufacture of bitumen or base oils for lubricant production and by refineries with appropriate desulphurisation and residue conversion facilities.
- FSU: Russia is a steady supplier to Europe, partly through an extensive inland pipeline system extending to most former East European block countries. The Caspian basin is poised to become a major producer with Europe as a preferred customer because of favourable logistics.

EU-25 will consume about 650 Mt of crude oil in 2005 (plus some 85 Mt of various feedstocks). This is set to grow slightly up to around 665 Mt in 2015 with a subsequent slight decrease at the 2020 horizon. Although it is considered that supply should be adequate within this timeframe, the sources of supply for Europe will change. North Sea production will decline but other regions such as West Africa and the Caspian basin will take over. These changes in the origin of the crude oil will not significantly affect the average quality and the current proportion of around 48% of sweet (i.e. low sulphur) crudes should remain essentially constant over the next decade.

The current and forecast European supply is shown in the following figure.

Figure 5.1.1 Current and future EU crude oil supply



(Source Wood MacKenzie)

Reference oil price and Oil Cost Factor (OCF)

In order to represent the fluctuations of the oil price we made the calculations for 25 and 50 €/bbl (i.e. around 30 and 60 €/bbl respectively at current exchange rate). A major change in oil price, if sustained over a long period, would undoubtedly have an effect on prices of other commodities, resources and services. We have taken this into account by applying an "oil cost factor" (OCF) to all major cost items, expressed as a fraction of the change in crude price (with an OCF of 1 the price would track that of crude oil; with an OCF of 0.5 a doubling of crude price would result in a 50% increase). For energy commodities the OCF reflects the linkage of the particular form of energy to crude oil. For goods and services, it reflects the fraction of the cost that originates from energy and the energy mix used.

5.1.2 Natural gas

EU-15 consumed 417 Mtoe of NG in 2004, up from 375 in 2000 [*BP 2005*], about a quarter of which was for power generation. Demand has increased at a steady 4% per annum over the past 10 years and is expected to increase strongly over the coming years as more power stations as well as industrial users switch to gas under the pressure of environmental legislation. A gas industry projection foresees a sustained EU demand increase with forecast of 500-530 Mtoe in 2010 and nearly 575-600 Mtoe in 2020 [*Source OGP*[5]*, unpublished*]. In comparison, a 10% share of the 2020 European road fuel market would represent 25-30 Mtoe/a, i.e. only some 5% extra demand.

Whereas a number of EU countries have some NG production, the UK, and the Netherlands are by far the largest EU producers. Norway is also a large producer, with the EU as its captive market through a largely integrated pipeline system in the North Sea area. Europe is, however, not self-sufficient and imports large quantities mainly from Algeria and the FSU, with both of which it has large capacity pipeline links. The current origin of the gas used in Europe is shown in the following table.

Table 5.1.2-1 Origin of the gas consumed in Europe

Netherlands	18.6%
UK	25.6%
Other EU	12.3%
Norway	10.0%
FSU	18.10%
Algeria	13.10%
Others	2.30%

Source: International Energy Agency 1999

Worldwide NG reserves are vast and in many parts of the world, untapped. A number of existing and potential producing regions are located such that Europe would be one of their most natural markets from a logistic and therefore cost point of view.

- Algeria is an established supplier of Europe and still has sufficient reserves to play a role in the medium term. The European market, with already existing pipeline connections and additional ones under development, is obviously the most attractive. Algeria is also developing its LNG exporting capacity which could favour some exports to e.g. North America.
- Nigeria has a large potential of associated gas, the development of which has just started. From a logistic point of view, Europe is in direct competition with North America. Transport will be in the form of LNG.
- The Middle East, both in the Arabian Gulf area and in Iran, holds vast, virtually untapped reserves. LNG is a likely transport route although pipelines to Europe are a very real possibility.
- The FSU, both Russia and a number of States in the Caspian areas have the largest reserves. Whereas Eastern Siberian gas would be most likely to find its way into the Far East, the rest of Russian and the Caspian outputs will naturally flow to Europe through expanded existing and new pipelines.

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[5] Oil and Gas Producers association

Table 5.1.2-2 Natural gas reserves economically available to Europe
(Source OGP)

	Billion m^3 (BCM)				Mt Oil Equivalent (Mtoe)			
	Reserves (1)	Discovered potential (2)	Undiscovered potential (3)	Total	Reserves (1)	Discovered potential (2)	Undiscovered potential (3)	Total
EU/EEA	5512	2645	3940	12097	4683	2247	3348	10279
Accession countries	358	264	350	972	304	224	297	826
Africa	6544	4942	7240	18726	5560	4199	6152	15911
ME	15410	33760	23950	73120	13094	28685	20350	62129
FSU	32960	14906	29830	77696	28006	12665	25346	66017
Carribean	850	142	1100	2092	722	121	935	1778
Total	61634	56659	66410	184703	52369	48142	56427	156939

(1) Reserves that are confirmed and will be exploited with current technology and economic conditions

(2) Reserves that are known to exist and would be economically recoverable with either an improvement in technology or better economic conditions

(3) Potential for additional reserves based on detailed field-by-field analysis

Reserves are sufficient to cover any realistic demand scenario for a number of decades to come. Bringing the gas to market may, however, be an issue. Natural gas projects are large, costly and involve a complex network of interest that has to include the investors, the producing country but also the consuming countries and, in case of pipelines, the countries through which the pipelines travels. Because of the weight of the infrastructure these are long-term projects. The large investments required are only likely to be realised if the economic and political conditions are right. Data in the ***Table 5.1.2-3*** has been compiled assuming a fairly conservative investment scenario, essentially based on the exploitation of the first category of reserves shown in ***Table 5.1.2-2***.

As European production decreases, it is replaced by new sources in the Middle East and in the FSU. In this scenario the total production decreases from around 2010 pointing out to a relative lack of investments and possible tightening of the world supply.

Table 5.1.2-3 Europe natural gas balance sheet (EU-25+Norway)
(Source OGP)

	BCM			Mtoe		
	2002	2010	2020	2002	2010	2020
Production potentially available to Europe						
Europe	310	300	190	292	282	179
Africa	110	130	110	104	122	104
ME	60	300	160	56	282	151
FSU	220	240	320	207	226	301
Carribean	10	20	0	9	19	0
Total	710	990	780	668	932	734
European demand	460	570	630	433	536	593
Potential coverage	154%	174%	124%			
EU Shortfall	150	270	440			
EU internal demand coverage	67%	53%	30%			

Similarly to oil, gas is an internationally traded commodity. As the gas business develops and grows, the infrastructure becomes more flexible, markets become deregulated leading to less long term contracts and more spot sales and therefore a more liquid market. The cost of natural gas to Europe is therefore directly linked to gas price on the international markets. Prices are normally quoted at the customer end of pipelines and terminals i.e. the producer supports the energy cost of production and transport. For this reason we have not considered the actual costs related to extraction, production and transport of natural gas.

Historically the price of natural gas has been loosely linked to that of crude oil, trading in Europe at around 60 to 80% of North Sea crude oil on an energy content basis. Although there are very large short-term fluctuations in the gas to crude ratio, this long-term range appears to hold (during 2004 for instance EU gas prices have both risen by about 50%). We have used a ratio of 0.8 irrespective of the price of crude oil. This corresponds to 3.7 and 7.3 €/GJ or approximately 0.13 to 0.26 €/Nm^3 in the 25 and 50 €/bbl oil scenario respectively.

This cost is relevant to all pathways where gas is imported into Europe before being transformed into a final fuel. The operating and investment costs within Europe have to be added. For those pathways where gas is transformed at source, the cost of gas is irrelevant to this analysis. The fuel produced has to be traded on the appropriate commodity market and the same reasoning applies with regard to the cost to Europe.

5.1.3 Conventional gasoline and diesel

In this study we are considering the marginal substitution of conventional fuels. The relevant cost figure is therefore not the cost of providing these marginal fuels but rather the savings that would be realised by not producing them.

When faced with a decrease in demand refiners can either reduce production or trade i.e. seek to export more if the product is globally in surplus in the region or reduce imports if the product is in deficit. The most economically attractive route will depend on the interplay between the international markets of crude and products. In a “short” market, typical of diesel fuel in Europe, the price will be driven towards that of imports, most likely to be above the domestic costs of production. The most likely outcome of a reduction of demand will be a sustained domestic production and a reduction of imports. In a “long” market, typical of gasoline in Europe, the price will be dragged down towards that of the marginal available export market. Export will only make sense if a net profit can be made on the marginal volumes which may or may not be the case. So far in Europe export markets have been available for gasoline while diesel fuel prices have encouraged maximum domestic production. For the purpose of this study we have assumed this situation to remain.

The “saving” to Europe of not consuming a fuel is therefore equal to its international market price in a European port. Refined product and crude prices are loosely linked but the ratios fluctuate considerably. Gasoline and diesel fuels typically trade at 1.2 to 1.4 times crude price on a mass basis. At the 25 €/bbl crude price level the typical road fuel price would then be in the 225-260 €/t bracket. We have used a ratio of 1.3 for both fuels, irrespective of crude price.

5.1.4 Synthetic fuels from natural gas

There has been a lot of interest in GTL in recent years and a number of projects have been considered. Such plants are extremely complex and capital-intensive. When the original version of the report was produced, only the existing 12,000 bbl/d SMDS plant in Malaysia was considered. Four large GTL plants have now been announced for Qatar, bringing the total announced global GTL production to 700,000 bbl/d by 2015.

Synthetic diesel fuel will be offered on world markets and mostly used as a high quality blending component to help meet diesel fuel specifications. It is therefore likely to trade at diesel fuel price plus a certain quality premium. Attempting to estimate how much this premium might be would be pure guess work. For argument’s sake we have used a 20% premium corresponding to about 100 €/t in the 50 €/bbl crude scenario. This will be valid for synthetic diesel fuel imported into Europe from remote GTL plants but will also provide a backstop (outside any subsidy) for any material produced internally from biomass.

Methanol is already widely traded today as a chemical. It is overwhelmingly made from natural gas. Over the last 3 years, the international market price has broadly followed the increase of oil and gas, the mass ratio fluctuating between 0.9 and 1.15. We have used a factor of 1 irrespective of the crude price, translating into 9.6 €/GJ for 25 €/bbl crude. In the context of this study, methanol would be used as an energy vector to produce hydrogen either at or near a refuelling station or directly on-board a vehicle. A dedicated distribution infrastructure would be required generating additional distribution cost in the form of fixed operating costs and capital charge. Also methanol having a low LHV, its transport is more energy-intensive when expressed in energy terms.

Because methanol is an international commodity, its market price can be used as opportunity cost i.e. either the cost of buying it or the minimum cost of using any amount that is internally produced. This is not the case for DME for which we have estimated the actual production cost.

DME is thus far not a commodity. Its production route is, however, very similar to that of methanol both in terms of feedstock and in terms of hardware to the extent that plants producing DME could feasibly also produce methanol. It is plausible that DME would trade at a price corresponding to the methanol equivalent. We have nevertheless ignored this potential link and have reported DME production costs.

5.2 Availability and cost of biomass for production of road fuels

Availability depends on cost

It is very important to bear in mind that for all crops (and other biomass resources) the potential supply is a strong function of the price one is prepared to pay. There is a tendency in the literature to report the costs from the cheapest supply scenario while choosing the maximum availability limit regardless of cost. To remain in touch with reality it is essential that availability and cost are assessed *together*: we need to know how much biofuel can be produced for the cost we are considering. Ideally, one would like to generate a cost-supply curve for each resource, but this is beyond the resources of this study.

5.2.1 Methodology for agricultural availability calculations

Learning curves for future yields and costs

For conventional crops (including oilseeds and cereals) our method automatically includes DG-AGRI's moderate estimate of future agricultural yield improvements, (0.8% per year in EU15; higher in the new Member States) but we added new data on newly-developed high-yield varieties of feed wheat.

Some studies have proposed strong learning curves, which reduce the cost estimates for future biomass supplies. This makes sense for long-term estimates of relatively undeveloped processes (e.g. energy crops such as short rotation forestry). However, for our relatively short time horizon, we assumed only that the best current commercial practice of short-rotation forestry will be typical by 2012. . For wastes, where the costs are dominated by collection and especially transport, we saw little opportunity for future cost reductions, so we used present-day costs.

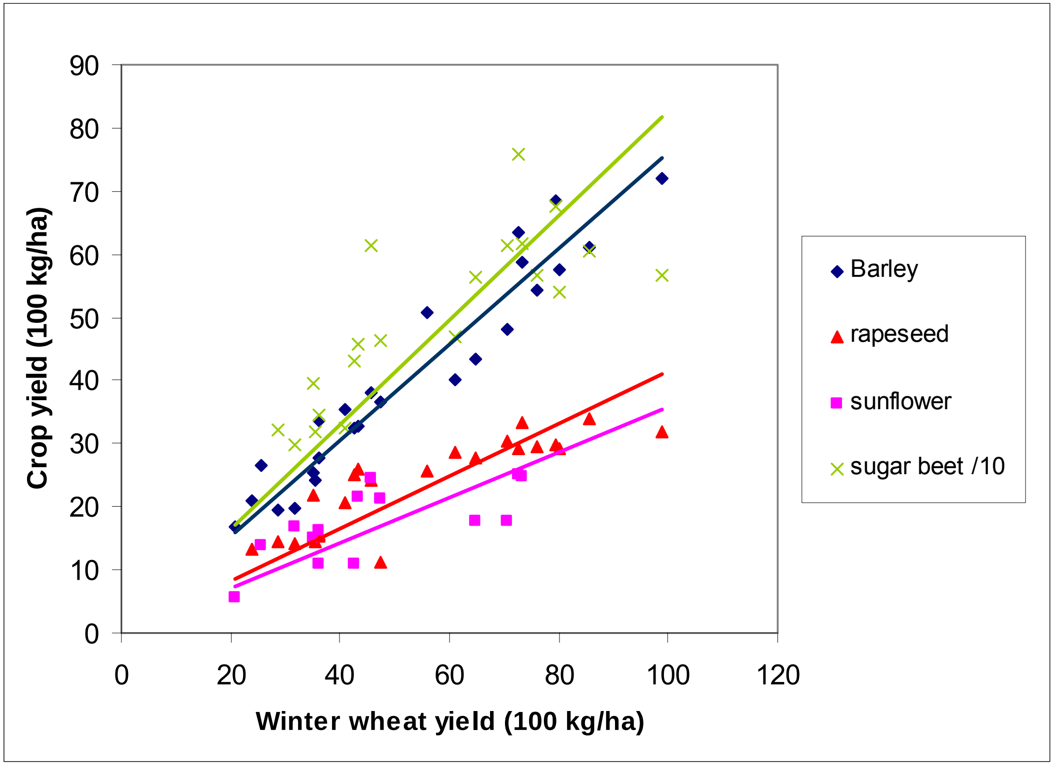
Using yield ratios is much more accurate than "average yield" calculations

As much as possible, we have tried to avoid estimating the potential supply of crops for biofuels by multiplying an estimate of the available area by an estimate of a "typical yield". This is because of the extreme variation of yield between different types of land. Even within the area presently planted with wheat, some EU-15 land yields seven times less than the best. If more marginal land was planted in order to increase total production even worse yields could be encountered.

However, there is a relatively good correlation between the yield of different crops on the same land (see ***Figure 5.2.1***). Cereals are grown on 86% of EU arable land. Since it grows on most areas, we prefer to express the agricultural resources of EU in terms of how much cereals could be grown on the available land, rather than on the number of hectares available. We measure the agricultural capacity in "Mt **A**verage **C**ereals **E**quivalent". 1 Mt feed wheat has an average cereals equivalent (ACE) of 1.135 Mt, because the new varieties of feed wheat now coming into use show 30% better yield than soft bread-wheat, and 13.5% better yield than the weighted average of the present mix of wheat types.

Our approach automatically takes into account the limitations on agricultural potential imposed by water resources, which is the dominating constraint in many of the drier parts of Europe.

Figure 5.2.1 Correlation between yields of different crops in EU-25 (National averages, excluding irrigated crops)



Impact of geographical distribution and break-crop effect on yield ratios

According to [*Christen 1999*], the yield of wheat after a crop of rapeseed is 10% higher than after another wheat crop. An increase in EU oilseed production would be met principally by increasing the frequency of oilseeds in a cereals rotation. If we take a typical rotation of wheat-wheat-barley-rapeseed, it would shorten to wheat-rapeseed-wheat-rapeseed. Then for each extra rapeseed crop, one barley crop is lost and one wheat crop grown after wheat is replaced by one wheat crop grown after rapeseed. The net loss of cereals is about 85% of the average yield on that land.

Using EUROSTAT crop distribution and yield data, we calculated the average cereals yield in the area where rapeseed is grown: 5.76 t/ha. On the basis of an average rapeseed yield of 3 t/ha (= EU15 average yield), growing an extra 1 Mt rapeseed by increasing the frequency of rapeseed-years in a cereal rotation leads to the loss of (only) 1.58 Mt average cereals, much less than the simple yield difference would indicate. So 1 Mt rapeseed has an Average Cereals Equivalent (ACE) of 1.58. The same calculation for sunflower indicates 1.47 Mt cereals lost per Mt sunflower seed. So 1 Mt sunflower seed is 1.47 Mt ACE.

5.2.2 Defining the baseline scenario

Our "business as usual" baseline adds sugar-reform to an existing DG-AGRI agricultural market projection, which assumes no expansion of biofuels.

In July 2005 DG-AGRI released a projection for EU agricultural markets up to 2012 in EU-25 [*DG-AGRI 2005*]. This assumes the implementation of planned CAP reforms and the transitional measures for the new Member States. Also taken into account are the Uruguay Round Agreement on Agriculture (URAA) commitments on subsidized exports and import barriers. This projection is significantly amended from the first results of the 2002 version of the DG-AGRI agro-economic model, used in version 1 of this study.

It includes a qualitative discussion of a scenario where the Biofuels Directive is implemented by subsidizing biofuels consumption, under the current CAP and trade regimes (see box in *section 5.2.4*). However, the quantitative projections are for biofuels production at expected 2005 levels. This constitutes a baseline onto which we can build the foreseeable effects of expanded biofuels production.

Table 5.2.2-1 2012 total cereals and oilseeds production and prices according to [DG-AGRI 2005]

		Cereals	Oilseeds
World production (FAPRI)	Mt/a	1602.4	334.4
EU-25			
Production	Mt/a	270.9	19.9
Consumption	Mt/a	256.0	37.8
Exports-imports	Mt/a	14.9	-17.9
Consumption for biofuels	Mt/a	1.5	5.6
Commodity price (FAPRI)(1)	€/t	150 (2)	215 (2) (3)

(1)Converted at 1.15 $/€ (DG-AGRI's assumed exchange rate)

(2)For US hard red wheat. Equivalent price for feed wheat 85 €/t

(3)FAPRI rapeseed price (FOB Hamburg)

In 2012 [*DG-AGRI 2005*] projects that the arable area would remain practically unchanged from the 2005 level: 58 Mha of which 50 Mha are devoted to cereals. Out of a total EU-25 cereals production of 271 Mt in 2012, there would be a surplus of 14.9 Mt (equal to exports–imports if stocks are constant). Other crops would be roughly in balance except for oilseeds: if bio-diesel remained at the present level of production the EU would continue to import almost half its total oilseed requirements: 17.9 out of 37.8 Mt in 2012.

The area of set-aside is expected to increase to 8.3 Mha, because of the extension of compulsory set-aside in the new Member States and the extension of voluntary set-aside due to declining profitability there. This accounts for a large proportion of the present "land reserve" of abandoned or under-utilized agricultural land in Eastern and Central Europe.

However the DG-AGRI projection does not include the effects of the proposed reform of the sugar regime, which would have a significant effect on EU arable potential. Since these reforms do not depend on biofuels production, we should add them in to our baseline projection.

Reform of the EU sugar policy will probably release about 9 Mt cereals capacity

In [*EC 2005*] the EC describes its proposals to reduce EU sugar production by reducing the support price. Some type of reform is forced by international trade agreements, but it was not yet considered in [*DG-AGRI 2005*].

The present support regime for sugar beet leads to its cultivation in many regions of the EU that are not agronomically very suitable. However, the proposed reduction in price will, by 2012, confine its growth to the lowest cost regions: France, Belgium, Denmark, and a few parts of the Netherlands, Germany and UK. A price reduction from the present 41 €/tonne to 25 €/tonne is expected to reduce sugar beet production by 76 Mt, from the present total of 182 to 106 Mt (22.7 Mt to 13.2 Mt sugar equivalent), assuming the option of buying an extra 1 Mt "C sugar" quota under the reform is taken up [*EC 2005*].

Our calculations confirm that the total anticipated sugar beet production in [*EC 2005*] corresponds to growing one crop of sugar beet for every four crops of wheat in the most suitable areas: this is the maximum frequency recommended to avoid the survival of pests in the soil from one sugar beet crop to the next (sugar beet can be grown more frequently only by intensive use of pesticides to disinfest the soil).

For simplicity, we assume all the land released goes to making cereals in the baseline scenario. To estimate how much extra cereals would be produced, we need to find a suitable ratio of sugar beet to cereals yield. Sugar beet requires good soil and plenty of water, so one expects winter wheat to be the preferred replacement crop, and to show a better-than-average wheat yield. On the other hand, the locations where sugar beet production will be abandoned will be where yields are poorest. Assuming these effects roughly cancel each other out, we used the simple ratio of EU-average sugar beet to winter-wheat yield. According to EUROSTAT data for the year 2000 (an average year) the average EU-25 yield for sugar beet at 76% moisture was 56.24 t/ha and for winter wheat at 13% moisture 6.49 t/ha: a ratio of 8.66 to 1 (not quite the same value as the slope of ***Figure 5.2.1***, because that is a line through un-weighted national yields). The ratio for EU-15 is the same because both yields are 9% higher.

Thus, at 2005 yields, an extra 8.8 Mt/a cereals could be produced on the land released from the sugar reform. [*DG AGRI 2005*] assume 0.8% per year improvement in cereals yields, which would raise the **cereals production on ex-sugar-beet land to 9.3 Mt/a (ACE) in 2012. This raises the cereals surplus from 14.9 Mt/a in [*DG-AGRI 2005*] to 24.2 Mt/a in our baseline scenario.**

Table 5.2.2-2 Calculation of baseline total cereals and oilseeds production

		Cereals	Oilseeds
Production	Mt/a	270.9	19.9
+ from land released by sugar reform	Mt/a	9.3	0.0
= total production in baseline	Mt/a	**280.2**	**19.9**
EU consumption	Mt/a	256.0	37.8
Baseline exports-imports	Mt/a	24.2	-17.9
Baseline biofuel feedstock price (1)	€/t	85 (2)	215 (3)

(1) Converted at 1.15 $/€ (DG-AGRI's assumed exchange rate)

(2) For low-protein wheat. Corresponding FAPRI price for US hard bread-wheat is commodity price is 140 €/t

(3) FAPRI rapeseed price (FOB Hamburg)

We note that EU imports almost half its oilseed requirements, both now and in the 2012 projection. When we come to estimate the maximum bio-diesel which can be made in the EU, we assume the absolute level of imports to be the same as in the baseline.

Table 5.2.2.3 shows the amount of biofuels which would be produced from EU sources in our baseline scenario for 2012. The amounts of cereals and rapeseed for biofuels are those in the [*DG-AGRI 2005*] 2012 projection, based on conservative estimates of the EU biofuels production figures for 2005.

Table 5.2.2-3 Biofuels in the 2012 baseline scenario: fixed at 2004/5 levels

	Crop		Ethanol	Bio-diesel
	Mt/a	PJ/a	PJ/a	PJ/a
Rapeseed	5.6	133		78
Cereals	1.7	25	13	
Gasoline/diesel market coverage			**0.3%**	**0.9%**
Total road fuel market coverage			**0.7%**	

Organization of section 5.2

In *section 5.2.3* we looked at conventional biofuels: first we considered how much could be grown in EU regardless of cost and concluded that it is not possible to reach the targets in the biofuels Directive from EU production only. To allow the fulfilment of the Directive's targets, we then considered scenarios allowing imports. In these cases we assumed the targets are exactly achieved and looked at the effect on agricultural prices and on how much of the crops required would be produced in the EU. The first scenario is the simplest: set-aside rules would be kept unchanged. The second scenario looks at what would happen if set-aside was abolished: we used agricultural prices in the scenario for our calculations of total biofuels costs. Both import scenarios assume that the present agreements on agricultural trade are respected.

Using alternative biofuels one can think to exceed the biofuels Directive targets for 2010 using domestic production. *Section 5.2.3* looks at the cost and supply of crop residuals, wood waste and farmed wood, transported to biofuels conversion plants. Finally, *section 5.2.4* examines how much compressed biogas could be produced in EU at the present cost.

5.2.3 Conventional biofuels production in the EU

In this first section we estimate in a transparent way how much bio-ethanol (from cereals and sugar beet) and bio-diesel could possibly be produced from EU domestic sources in 2012, regardless of how this would affect prices.

Starting assumptions

- We excluded the expansion of arable area by ploughing up pasture or forest land, to avoid loss of historical soil carbon stocks (see *section 3.4.1*).
- We assumed the same food consumption and food imports as in the reference "business-as-usual" scenario. This includes continuing to import about half the EU's food-oilseed requirements.
- EU-grown animal feed crops could be diverted to increase biofuel production, but these would have to be replaced by imported animal feed. In other words biofuels from this source would be made from indirectly-imported crops, so we didi not take it into consideration.
- On the other hand, we allowed the diversion of EU exports to biofuel production.
- The biofuels Directive target of 5.75% replacement of road fuels by 2010 does not specify how this should be split between gasoline and diesel. We assume that 5.75% of diesel should be replaced by bio-diesel and 5.75% of gasoline by bio-ethanol.

There are three sources for increased EU production of biofuels crops in 2012

I Diversion of the baseline cereals exports (including land from sugar reform) Although the present EU cereals production is roughly balanced with consumption, table 5.2.2-2 shows that our 2012 baseline scenario projects 23.7 Mt ACE surplus cereals for export. This comprises 14.9 Mt ACE in [*DG AGRI 2005*] (due to improved yields) and an additional 8.8 Mt ACE on land released by the sugar reform. To maximize EU-produced biofuels we assumed all this arable capacity would be devoted to making biofuels.

II Additional production on ex-set-aside land

The extra production from set-aside cannot be calculated simply from the average EU wheat yield

Production of oilseed and cereals for biofuels is already permitted on set-aside land, but only if the farmer has a contract with a biofuel producer. The effect is to confine production on set-aside to farms in the region of biofuels factories. However, if set-aside rules were abolished there would be a general increase in cereals output, which could translate directly and indirectly into increased EU production for biofuels. First we estimate the general increase in cereals output.

Rotational set-aside is already part of cereal rotations and the effect of removing these compulsory break-years is offset by the need for break-years anyway and by the benefit of break-crops to subsequent cereals yields. Voluntary set-aside land would also give lower-than average yields because it is relatively poor land where cereal farming is hardly profitable. Much of the land would not be good enough for wheat production: a mix of cereal types would be produced. Statistical analysis of data from the 1990s, when set-aside rates were changed several times, indicated that set-aside at 14% reduced cereals production by 10% [*DEFRA 2000*].

Looking at the variation in cereals area as compulsory set-aside was reduced from 10% to 5% in 2004 and then increased again to 10% in 2005 suggests that the effect on cereals production is now significantly lower than this, implying that farmers have learnt how better to integrate set-aside years in their crop rotations (but the set-aside increase for 2004 was announced too late to allow planting of winter wheat, so one should not take these data alone).

Another reason why the DEFRA ratio will give an overestimate of set-aside production is that, in 2012, there would be a substantial increase in voluntary set-aside on poorly-yielding marginal land in the new Member States. Nevertheless, we shall use the DEFRA ratio for giving the **upper limit** of EU production.

The overall rate of set-aside projected for 2012 in our baseline [*DG-AGRI 2005*] is 13.6%, so we could expect this to reduce the potential cereals output by a maximum of 10%. The projected 2012 cereals production is 270.9 Mt, so the maximum on set-aside would be about 27 Mt. About 19 Mt of this would be from compulsory set-aside. To find how much *extra* biofuels could be grown on set-aside, we have to subtract baseline production of biofuels crops on set-aside, which amounted to 2.4 Mt rapeseed [*DG-AGRI 2005*] (equivalent to 3.8 Mt average-cereals), plus roughly 0.3 Mt cereals-for-ethanol. So the *extra* production on set-aside would be equivalent to 23 Mt average-cereals at maximum. The extra production on only *compulsary* set-aside would be 15 Mt ACE.

What is a set-aside?

There are two types of set-aside at present in EU-15: compulsory (or “rotational”) and voluntary (or “permanent”) set-aside. Compulsory set-aside forbids cereals farmers growing food on part of their land. The “default” area of obligatory set-aside is 10% of the area of all farms growing a significant amount of cereals, but the reference rate is adjusted according to the level of EU cereals stocks.

However, farmers are allowed to grow non-food crops on set-side land without further subsidy: these are generally part of a crop rotation with cereals. At present about 20-30% of set-aside in EU-15 is planted with “industrial” oilseeds (mostly rape for bio-diesel production) as part of cereals rotations, producing about 2.2-2.4 Mt/a of seeds designated as “industrial” [*FEDIOL 2002*][*DG-AGRI 2005*]. Set-aside rules will come into force in the new Member States in 2009: they will set-aside about 1.25 Mha arable land.

If planted year-after-year, cereals decline in yield because of disease build-up and soil degradation. This applies especially to soft wheat, which has the highest yield. As a result, most wheat in Europe is grown in rotation with a lower-yielding “break” crop. The farmer can declare a field to be in rotational set-aside and still use it for a break-crop, such as grass, clover or rapeseed. So the effect of set-aside is to encourage more frequent break-crops, and the reduction in EU cereals output is less than would be predicted by the % area in set-aside (a phenomenon known as “slippage”).

Although small farms are exempted from set-aside obligation, the overall set-aside rate in EU-15 is well above 10% (14% in 1999/2000 [*DEFRA 2000*]) of the eligible area, because of the operation of permanent set-aside: farmers are rewarded for turning up to 50% of their land over to “nature” for at least five years. According to current CAP rules, permanent set-aside cannot be used to grow arable biofuels crops, but can be used for wood farming.

Not much sugar beet would be grown on set-aside

Sugar beet is grown in rotation with other crops, especially wheat. In areas where sugar beet production at 25 €/t is more profitable than wheat, sugar beet will already be planted as frequently as possible in the rotation. That means roughly once in 4 years if large pesticide applications are to be avoided. Where sugar beet is the most profitable crop, farmers time set-aside years to be in the part of the rotation where sugar beet is not grown. So eliminating set-aside would not increase sugar beet production significantly: it would mostly increase the other crops in the rotation, most likely wheat. The land in voluntary set-aside is not good enough to produce sugar beet at all.

A significant amount of extra sugar beet might be produced at a competitive price if the wheat price increased significantly, for example if total ethanol production was pushed beyond 5.75% gasoline replacement.

III Use of "C" sugar beet

"C sugar" is sugar produced in excess of the food-quota. It cannot be sold for food in the EU but can be exported (assumed in the baseline) or sold for ethanol production. The sugar reform proposal allows up to 1 Mt of "C sugar" production (equivalent to 8 Mt sugar beet).

[*EC 2005*] estimates that the price of sugar beet should be 25 €/t to reach the planned levels of production. By a happy coincidence, our processing-cost calculations show that ethanol production from sugar beet at 25 €/t is just competitive with ethanol from wheat. So the production cannot anyway be increased much above this level without making ethanol from sugar beet uncompetitive.

The EU cannot produce enough crops to meet the 2010 biofuels Directive target using conventional biofuels, even if set-aside is abolished

Table 5.2.3-1 sums the maximum extra production of arable crops from sources I and II above, expressed in terms of Average-Cereals-Equivalent. We assigned sufficient cereals to provide exactly 5.75% gasoline replacement with bio-ethanol (see also forecast road fuels demand in ***Table 2.7***) taking into account:

- The existing (2005) production for biofuels, and the higher yield of cereals varieties suitable for bio-ethanol production expected in 2012,
- The 13.5% better yield produced by distillation-quality wheat varieties compared to average cereals,
- The additional ethanol available from 8 Mt "C" sugar beet as a result of the sugar reform.

The **rest** of the arable capacity was assigned to oilseed production, assuming 80% of it would go to rapeseed and 20% to sunflower seed production.

Table 5.2.3-1 Upper limit of conventional biofuels production from EU crops in 2012, with set-aside abolished.

	ACE(1)	Crop		Ethanol	Biodiesel
	Mt/a	Mt/a	PJ/a	PJ/a	PJ/a
I Diverted baseline cereal exports:					
From land released by sugar reform	9.3				
Fom improved yields	14.9				
II Maximum extra cereal from set-asides(2)	22.9				
Total spare cereals	47.1				
To feed-wheat for ethanol	22.4	25.4	376	202	
To oil seeds	24.7				
Equivalent oil seeds(3)	⇩				
Rapeseed	19.8	12.5	298		174
Sunflower	4.9	3.4	80		50
III Ethanol from"C" sugar beet		8.0	31	16	
Existing crops for energy in baseline(4)					
Rapeseed		5.6	133		78
Cereals		1.5	22	12	
Total				**230**	**302**
Gasoline/diesel market coverage				**5.75%**	**3.4%**
Total road fuel market coverage				**4.2%**	

(1) Average Cereals Equivalent (our measure of arable capacity)
(2) Excluding biofuels already grown on set-asides
(3) Assumes 80/20 rape/sunflower
(4) i.e. in the baseline scenario, including those grown on set-aside

The existing arable area, even including set-asides**, is not sufficient to attain the biofuels targets through domestic production in 2012. An upper limit of 4.2% of conventional road-fuels can be substituted, which is 72% of the biofuels Directive target**. Some fossil energy is used in making biofuels. Taking a mix of the most likely biofuels processes, we estimate that the net fossil energy avoided is about 3.2% of the total used for making road-fuels in 2012.

Without more biofuels from set-aside only 2.5% road-fuels can be replaced by domestic production

We can perform the same procedure without assuming an increase in arable production on set-aside compared to the baseline (i.e. no source II). After satisfying the cereals-for ethanol demand, there is not much capacity left over for bio-diesel. In reality, the proportion of resources going to oilseeds would be somewhat higher than indicated, but this hardly affects the overall replacement of road-fuel: about 2.5% from EU crops.

Table 5.2.3-2 Limit of conventional biofuels production from EU crops in 2012 with no increase in production on set-aside

	ACE(1)	Crop		Ethanol	Biodiesel
	Mt/a	Mt/a	PJ/a	PJ/a	PJ/a
I Diverted baseline cereal exports:					
From land released by sugar reform	9.3				
Fom improved yields	14.9				
II Maximum extra cereal from set-asides(2)	0.0				
Total spare cereals	24.2				
To feed-wheat for ethanol	22.4	25.4	376	202	
To oil seeds	1.8				
Equivalent oil seeds(3)	⇩				
Rapeseed	1.4	0.9	22		13
Sunflower	0.4	0.2	6		4
III Ethanol from"C" sugar beet		8.0	31	16	
Existing crops for energy in baseline(4)					
Rapeseed		5.6	133		78
Cereals		1.5	22	12	
Total				**230**	**94**
Gasoline/diesel market coverage				**5.75%**	**1.1%**
Total road fuel market coverage				**2.5%**	

for notes see table 5.2.3-1

Maximizing production of biofuel from EU crops would cause a large rise in oilseed price

Still assuming oilseeds are not diverted from food-use, the maximum EU production scenario above requires an extra 15.7 Mt oilseeds from EU production, raising it to 178% of the 2012 baseline production of 19.9 Mt (see ***Table 5.2.2-1***). However, the release of set-aside land would increase the EU arable capacity by up to about 10% compared to baseline 2012. Therefore the *fraction* of arable capacity used for oilseeds would rise to about 163% of the fraction in the baseline scenario.

The long-term EU oilseed-sector area response flexibility on price was estimated to be 0.84 in [*Meilke 1998*] (that means that a price increase of 1% causes a supply increase of 0.84% at constant yield). This implies that the price increase associated with a 63% increase in production would be about 63/0.84 = 75%! Other estimates for the flexibility are lower, implying even higher price rises. More details of our method of price-change calculation are given in *section 5.2.4*.

Crop rotations limit maximum rapeseed production

Flexibility calculations are not really valid for such large changes. The large oilseed price increases found to accompany this maximum EU production scenario indicate that it is probably beyond what is agronomically reasonable. To quote [*DG-AGRI 2005*]: “under an extreme scenario with substantial price increases, the rise in domestic production of cereal and oilseed could meet 50% of the additional demand from the biofuels Directive” (although the assumptions behind this calculation are not clear). Our maximum EU production amounts to 68% of the additional demand from the biofuels Directive.

At the moment almost all bio-diesel grown in EU is from rapeseed, because it is the cheapest and most suitable vegetable oil grown in EU. Soil and climate limitations mean that rapeseed is usually rotated with common wheat. Common wheat production would be about 140 Mt in 2012 [*DG-AGRI-2005*], whereas our upper limit of oilseed (rapeseed + sunflower in table 5.2.3.1) cultivation is 24.7 Mt. The unadjusted yield ratio of wheat/rapeseed is about 2.3, so, if all extra production is rapeseed, there would be only about 2.5 wheat crops to each rapeseed crop. Bearing in mind that less land is suitable for rapeseed than common wheat, this is an extreme scenario. It means that rapeseed would have to be grown in 3 or even 2-year rotations (which reduces the benefit of the break-crop and may allow survival of pests between crops), and/or on land for which it is not very suited, probably rotating with coarse cereals.

One expects that the lower yields and dilution of the break-crop benefit would increase the marginal cost of rapeseed production substantially. The increasing price of rapeseed oil would drive biofuels producers to mix in other oils such as sunflower oil, which can be grown in EU areas unsuitable for rapeseed. We assumed 20% of the oil demand would come from sunflower oil, but the proportion is not critical to the calculation of the overall biofuels production potential.

The contribution of animal fats and used cooking oil is small and uncertain

EU-15 used to use about 1 Mt animal fats per year in animal feed. That is no longer permitted because of the BSE problem, so turning it into useful bio-diesel is a very attractive idea. One could also possibly divert some of the 2 Mt animal fat used for other purposes in the EU. Argent energy are building a plant to convert most of the material available in the UK to a form of bio-diesel. Animal fats give a more viscous quality of FAME with a high cloud point, so there may be problems to reach road fuel specification.

About 6 Mt/a vegetable oils are consumed in EU-15, but the proportion that can be recovered separately and economically is highly speculative.

We have not included these sources in our availability scenarios for conventional biofuels.

5.2.4 Estimate of bio-fuel crop prices

Market prices rather than bottom-up costs

Many LCA studies attempt to calculate costs of agricultural products by bottom-up estimates of farming cost. We think this is a very difficult way to approach the subject: it is almost impossible to represent an average "cost to EU" and it is very easy to lose touch with farming reality. The reforms of the CAP have largely brought internal EU prices in line with world prices (with the exception, until now, of sugar beet). In any case, since biofuels crops are internationally traded commodities, the cost to EU is the price which EU gets for exporting them or pays for importing them. Not only are these world prices known, but there are sophisticated projections available about how they may develop in the future.

In this section we confine ourselves to estimating the implications of meeting the targets for road-fuels replacement in the biofuels Directive, in the year 2012. The effects on domestic production, imports, exports and cost are considered.

Ligno-cellulosic resources (wood waste, short rotation forestry and crop residuals) are treated separately, since their production is not confined to arable land.

Key assumptions are:

- *5.75% (energy content) of the 2012 gasoline and diesel fuel demand* is replaced by bio-ethanol and bio-diesel respectively,
- *There is no expansion of arable area onto forest or grazing land*, to avoid loss of historical soil carbon stocks (see *section 3.4.1*),
- *Existing trade agreements are maintained.*
  The EU is committed to various trade treaties, and probably cannot erect new tariff barriers even if it was desirable to restrict imports of feedstock for biofuels.
- *Cereals are treated as a single market*
  Even though not all types of cereals are equally suited for making ethanol, there is plenty of flexibility in competing uses, especially animal feed. Furthermore some farmers will change the cereals crop they grow, if one or other becomes relatively more expensive. Therefore we think it appropriate, when estimating the effect on prices of demand changes, to consider cereals as a single market, and not to consider wheat only. There is an argument for including also alternative carbohydrate animal feeds, such as manioc, but the effect on the results would be marginal.
- *Oilseeds are treated as a single world market*
  At present, quality standards restrict EU bio-diesel production effectively to rapeseed. In the future we may expect technology and legislation to evolve to permit use of a wider range of oilseeds. But even if this does not happen, rapeseed oil is easily substituted by other oils in the food market. Thus at the moment most EU bio-diesel is made from domestically grown rapeseed, but this is partly substituted by importing other oilseeds to satisfy the food demand.
- *The single farm payment is not included in the costs*
  In line with other costs, the cost considered is the direct cost-to-EU. However, the cost does not include the single farm payment. This incorporates the former “direct area payment” of 63 €/t nominal historic cereal production on the land, including rotational set-asides, no matter what crop the farmer produces. This payment would remain the same whatever use is made of the crops so that it does not have to be taken into account in the biofuels cost assessment.
- *Food and feed demand are the same as in the baseline 2012 scenario*
  This means we only consider the supply elasticity. Although in theory we should also consider the demand elasticity, the demand elasticities in the literature are caused by people switching from one type of cereal or oilseed for another. If we are considering the whole cereal or oilseed market, the demand elasticities will be very low: people and cows will not eat much less in total even if the price rises.

We started from DG-AGRI's prices projection for 2012 without extra biofuels

[*DG-AGRI 2005*] forecasts EU prices on the basis of the interaction of the CAP and other EU agronomic and trade rules. The introduction of the single farm payment, combined with the progressive lowering of trade barriers in agriculture according to obligations under trade treaties, means that the price of agricultural products in the EU is tied to the world market price. Thus [*DG-AGRI 2005*] bases its agricultural prices for 2012 on two independent forecasts of the world market, from FAPRI and OECD, which predict the price of agricultural commodities at EU ports. For the products which interest us, the two forecasts are very similar: they differ by much less than the uncertainty from fluctuations in the $/€ exchange rate (which is assumed to stabilize at 1.15 $/€ in [*DG-AGRI 2005*]). We used the price forecast from [*FAPRI 2005*] because it differentiates between different oilseeds.

The prices in [*FAPRI 2005*] and [*DG-AGRI 2005*] assume that biofuel production stays at 2005 levels (0.6% road fuel replacement, mostly by bio-diesel). Thus they could serve for calculating the cost of biofuels *where there is only a marginal increase in biofuels production*. But as we show below, attaining 5.75% road fuels substitution will have a large effect not only on EU agricultural markets, but even on the world market.

Distillation-quality wheat costs 95 €/t in the baseline scenario

[*DG-AGRI 2005*] quote the [*FAPRI 2005*] price projection of 159 $/t for the standard commodity "hard red US wheat FOB Gulf". EU soft wheat trades at about 40$/t less than this, and experts expect further improvements in yields of distillation-quality very-low-protein feed wheat to reduce the production cost by a further 10$/t by 2012, bringing the price to 109$/t, or **95€/t**. At this price it could be competitive with imported feed-barley, even without an import tariff barrier. This type of wheat requires adequate water, so is especially suitable for growing in the highly-intensive wheat-growing regions of Northern Europe.

In our baseline scenario, the extra cereals production on land released by the sugar reform would decrease world cereals prices by a negligible 1% or so.

Effect of meeting the biofuels Directive targets on trade, food and feedstocks prices: DG-AGRI's analysis

[*DG-AGRI 2005*] warns that achieving the biofuels directive's target of 5.75% road-fuels substitution by biofuels in 2010 would have a "major impact" on cereal and oilseed prices.

The effect on ethanol production cost would be partially offset by an increase in the value of by-products as animal feed, due to ethanol production competing for the supply of feed-wheat. On the other hand, the EU would end up paying substantially more not only for the crops used for biofuels, **but also for the crops used for food and animal feed.** This would be reflected in sharply improved farm incomes and higher food prices for consumers.

Effect of biofuels targets on imports
On the assumption that the trade regime follows current obligations (import tariffs and quotas), [*DG-AGRI 2005*] discusses the effect on the market and on production of achieving 5.75% replacement of gasoline and diesel by bioethanol and FAME respectively.

The report states that "under an extreme scenario with substantial price increases, the rise in domestic production of cereal and oilseed could meet 50% of the additional demand from the biofuels directive".

Of the remaining demand, 25% would be met through direct imports and 25% by diverting wheat, maize and rapeseed from animal feed and food use. The supplies of animal feed and food would then be made up by imports, so in the end at least 50% of the extra biofuel supplies would come directly or indirectly from imported crops.

Thus DG-AGRI contends that the EU would become a net importer of cereals, despite the substitution of feed-wheat by other (partly imported) animal feeds, and the existence of import barriers. The EU already imports half its oilseed requirements and the production of oilseeds is constrained by crop rotations, climate, and the Blair House agreement. Therefore, under the current trading regime, **more than half of the extra vegetable oils needed to reach 5.75% diesel substitution by FAME would come from imported oilseeds or vegetable oil.**

5.2.5 Meeting the Biofuels Directive with imported crops: impact on prices and EU production

No change in trade barriers

We have seen that attempting to maximize EU-produced biofuels can give large price increases and lead to a shortage of oilseeds. EU imports about half its present oilseed requirements, and they attract no import tariff. Furthermore, it would be legally difficult to erect new trade barriers against imports of oilseeds. Therefore, we consider trade to be an essential part of a realistic scenario for biofuels pricing. EU has a 90€/t tariff on imports of cereals, but this has limited impact because the EU is expected to have a net cereals surplus.

5.75% EU ethanol in gasoline would increase world cereals prices slightly

The rate at which cereals supply varies with price is called the supply flexibility. Estimates vary widely, partly because of geographical variations and (often unspecified) statistical uncertainty, but also because different effects may be included. Values for individual cereals types reflect the flexibility of farmers to switch between different cereals crops, but we need the flexibility for the cereals sector as a whole. Furthermore, we should not include the inertia for change from one growing season to the next, because in our case the change happens over a number of years. An analysis which produced a sensitivity measure suitable for our purposes is described in [*DEFRA 2000*], p.132. Separating out the inertia for change in a separate coefficient, they find the EU-15 cereals sectorial supply flexibility to be 0.62 +/- 0.26.

Although there would be no increase in EU *production cost* due to the extra demand from biofuels, there will be a small increase in cereals *market price* compared to baseline, because expanding biofuels production would deprive the world market of the baseline EU exports. These total 24.2 Mt ACE (see ***Table 5.2.3-1***) or 1.5% of the projected world 2012 cereals production of 1600 Mt. If production on set-aside was unchanged, this would cause a 2.3% increase in world price (± 1.2 %). But we remember that the baseline price should anyway be 1% below the DG-AGRI/FAPRI projection due to the effects of the sugar reform: the net price change is insignificant.

This is a simplified analysis: the effects of making biofuels on local prices may be more significant due to the isolating effects of transport and shipping costs. Here we are talking of differences in the region of 10-20 €/t: still less than the annual variation due to weather.

5.75% EU bio-diesel would increase world oilseed prices significantly

Replacing 5.75% of EU 2012 diesel with bio-diesel from rapeseed would require 36 Mt of oilseed. Subtracting the oilseeds already used for EU bio-diesel in the baseline scenario, the demand *increase* would be 30.8 Mt, 9% of the projected world oilseed supply in 2012 (or 160% of projected 2012 EU production in the baseline scenario).

We need the world supply flexibility of the oilseed sector as a block. The nearest we could get to this was long-term area response flexibilities for the oilseed block in different countries. These may be used as a proxy for supply flexibility, because yields hardly change with price [*DEFRA 2000*]. According to [*Meilke 1998*], the flexibilities range from 0.2 to 1.03 for different countries. If we take an average figure of 0.8 ± 0.3, we conclude that a 9% increase in oilseed supply would require a **rise in world price between 8% and 18%.** If set-aside is liberated, the price rise should be lower because of the increase in arable area. However, the effect on the price estimate is insignificant. We set the oilseeds prices for our biofuels cost calculations **10% above the 2012 FAPRI-projection prices** quoted in [*DG-AGRI 2005*]. That brings them to **237 €/t for rapeseed and 265 €/t for sunflower.**

EU cereals production for biofuels should increase more than oilseed production

Our cost analyses show that bio-ethanol from cereals and bio-diesel are approximately cost-competitive. At the time of writing, bio-diesel production is expanding more rapidly than ethanol, but that is probably because of the shorter lead-time and lower capital cost for bio-diesel production plants; furthermore EU oilseed production is not keeping pace with the increase in bio-diesel processing capacity. In the longer term, the EU oilseed price can be expected to increase much faster than that of cereals (for comparable increases in FAME and ethanol production) because the EU oilseed supply potential is much smaller (being limited by rotations, climate and soils). If bio-diesel and bio-ethanol are given equal incentives, we should expect that bio-diesel would use more imported feedstock than bio-ethanol processed in EU.

Since the EU is projected to produce more cereals than it consumes for food and feed, its use for ethanol production inside the EU also avoids the costs associated with exporting it. This does not apply to oilseeds which would not be exported anyway, because the EU has a deficit in supply.

So one may expect most of the spare EU arable capacity to go towards satisfying the cereals-for-ethanol demand until that market is saturated (in ***Table 5.3.2-1*** we assumed that it happened at 5.75% gasoline replacement). After that, using EU arable capacity for oilseeds becomes more interesting because any *more* cereals produced would then have to be exported, with associated costs.

The effect of liberating or freezing production on set-aside

There is presumably no legal barrier to EU relaxing its set-aside rules in order to reduce imports. Even if the present set-aside rules are not changed, we can expect some expansion of production on set-aside. But the extra production will be limited by logistics, because according to the present CAP rules, crops from set-aside must be contracted to go directly to a processor, rather than joining the larger food/feed market. Furthermore, production of oilseeds on set-aside is partially constrained by the Blair House agreement (see box).

The Blair House agreement

The Blair House agreement, extended in 2002, limits the effect on US soy bean exports of the oilseed-meal by-products from subsidized “industrial” oilseeds grown on EU set-aside land. In practice it limits oilseed production on EU-15 set-aside land to about 2.4 Mt, grown on approx. 0.95 Mha. [*DG-AGRI 1997*]. Current production of rapeseed on set-aside runs at close to this level.

But biofuels manufacturers are already using almost three times this amount of oilseeds: they have to buy unsubsidized "food" rapeseed at the world market price.

Blair House would not seem to prevent set-aside areas being used to grow food crops in replacement of crops grown for biofuels on non-set-aside, or simply doing away with set-aside altogether. Anyway, Blair House only applies to *subsidized* oilseed farming: it is not applicable if bio-diesel production is encouraged by fuel tax exemptions rather than by direct farming subsidies. So in practice Blair House need not limit bio-diesel production, even if set-aside land is used.

If the EU wishes to increase oilseed production for biofuel, it appears that Blair House disallows the use of more subsidized oilseeds but allows subsidies on biofuels production.

To cover the range of outcomes for different set-aside policies, we considered two extremes. In one case we froze production on set-aside at the 2004/5 levels assumed for 2012 in [*DG-AGRI 2005*]. In the second case we assumed that set-asides were liberalized, so farmers could choose which crops to grow on that land, and that the produce could be sold freely on the market. The maximum possible production on set-asides was already estimated in *section 5.2.3*. The problem now is to analyse how much oilseeds and how much cereals would actually be produced in the EU.

Only production on voluntary set-aside would cost more than baseline

The supply calculated for a given market price would not be valid if that price was exceeded by the production cost. The extra sources of arable potential for expanded biofuels, compared to baseline scenario, are production on set-asides and diverted exports. The cost of crop production on compulsory (rotational) set-aside is about the same as on the same land not in set-aside [*DEFRA 2000*]. Exported cereals (from increased yields and the good farmland liberated by the sugar reform) could be diverted to biofuel production even with a cost saving, because no shipping is needed. Only the marginal land typically volunteered for voluntary set-aside would have higher crop production costs. Arable farming on most of this land would probably not be profitable even with the price rises due to biofuels. Furthermore, although there may be little historical accumulation of soil carbon to lose on voluntary set-aside land, ploughing it up would prevent any *increase* of soil carbon uptake.

If we do not account for the potential production from voluntary set-aside, we get the EU cereals potential at the baseline production cost. Voluntary set-aside contributed about 30% to our total EU 2012 set-aside production potential, leaving a contribution of about 16 Mt average-cereals from rotational set-aside. This is included in ***Table 5.2.5-1***.

Table 5.2.5-1 ***Achieving the biofuels Directive targets with trade***
Set-aside frozen at baseline production (2004/5)

	ACE(1)	Crop		Ethanol	Biodiesel
	Mt/a	Mt/a	PJ/a	PJ/a	PJ/a
I Diverted baseline cereal exports:					
From land released by sugar reform	9.3				
Fom improved yields	14.9				
II Maximum extra cereal from set-asides(2	0.0				
Total spare cereals	24.2				
To feed-wheat for ethanol	22.4	25.4	376	202	
To rape seeds(3)	1.8	1.1	27		16
Oil seeds imports		**29.6**	704		**412**
III Ethanol from"C" sugar beet		8.0	31	16	
Existing crops for energy in baseline(4)					
Rapeseed		5.6	133		78
Cereals		1.5	22	12	
Total				**230**	**505**
Gasoline/diesel market coverage				**5.75%**	**5.75%**
Total road fuel market coverage				**5.75%**	

(1)Average Cereals Equivalent (our measure of arable capacity)

(2)Excluding biofuels already grown on set-asides

(3)Small extra production, most cheaply from rapeseed

(4)i.e. in the baseline scenario, including those grown on set-aside

The market would favour exporting cereals and importing most oilseeds

Having estimated the effect of the biofuels Directive on the world price, we will now see how this would affect EU oilseed output. We recall from the previous section (*5.2.5*) that for our cost calculations in the "biofuels" scenario, we chose an oilseed price of 10% above the business-as-usual price, although the calculation showed the increase could be in the range 8 to 18%.

[*Meilke 1998*] states that the long-term area response flexibility for oilseeds sector in EU is 0.87. Therefore a price increase of 10% results in a production increase of about 8.7% (assuming constant yield). Our baseline EU oilseed production is 19.9 Mt/a. So, on the same arable area one would expect to get an additional 1.7 Mt oilseeds. However the sugar reform increases arable capacity by 4% and the possible liberation of compulsory set-aside by a further 7%, so the total **increase in EU oilseeds supply would be about 2 Mt/a** according to our reference price increase, with a range is between 1.5 and 3.4 Mt/a. This is only a small part of the extra 31 Mt/a oilseeds needed to reach the 5.75% bio-diesel target.

Note:

Shipping costs tend to favour local production. However, the calculation is based on changes from the baseline scenario, where oilseeds already compete with EU production in spite of shipping costs, so this effect should cancel out. Furthermore the cereals are exported also in the baseline scenario, so shipping costs should make no difference there either. Anyway, adding 10% costs for shipping would not change the main conclusion.

The main point is that it would be more profitable for EU farmers to use most their increased arable capacity in 2012 for cereals exports rather than growing oilseeds, and it would be cheaper for biofuels producers to import (directly or indirectly) most of their feedstock. This reflects the reality that, compared to the rest of the world, EU is more suited to growing cereals than oilseeds. In practice, rapeseed is preferred for bio-diesel production, whereas soy, sunflower and maize oils (mostly imported) are preferred for food. Therefore EU rapeseed oil would be diverted from food-use to bio-diesel, to be replaced by imported food oils. Thus the feedstock for bio-diesel would largely come *indirectly* from imports.

Table 5.2.5-2 Achieving the biofuels Directive targets with trade
Set-aside abolished

	ACE(1)	Crop		Ethanol	Biodiesel
	Mt/a	Mt/a	PJ/a	PJ/a	PJ/a
I Diverted baseline cereal exports:					
From land released by sugar reform	9.3				
Fom improved yields	14.9				
II Maximum extra cereal from set-asides(2	16.0				
Total spare cereals	40.2				
To feed-wheat for ethanol	22.4	25.4	376	202	
To rape seeds(3)	3.0	1.9	46		27
To cereal exports	14.8				
Oil seeds imports		**28.8**	687		**401**
III Ethanol from"C" sugar beet		8.0	31	16	
Existing crops for energy in baseline(4)					
Rapeseed		5.6	133		78
Cereals		1.5	22	12	
Total				**230**	**506**
Gasoline/diesel market coverage				**5.75%**	**5.75%**
Total road fuel market coverage				**5.75%**	

for notes see table 5.2.5-1

We see that without increasing production on rotational set-aside, there is only just enough arable capacity in the EU to produce 5.75% ethanol in gasoline; very little left over for oilseeds or exports.

Comparing the two scenarios, we see that the main effect of liberating rotational set-aside would be to increase cereals exports. In either case nearly 30 Mt of oilseeds (rapeseed equivalent) would be imported in a free agricultural market. Of course this could also be in the form of vegetable oil or processed bio-diesel. Importing processed bio-ethanol would lead to a little more oilseed production if set-asides are frozen, but mostly to more cereals exports in a free agricultural market.

Of course, EU could intervene in the market in various ways to promote use of EU-produced oilseeds for bio-diesel at the expense of cereals exports, but this would be at additional cost.

By-product markets

Large additional production of protein animal feed by-products would cause a price decrease

Both ethanol and bio-diesel lead to the production of protein animal feed by-products viz. DDGS and oil-cake respectively. They are produced in the EU if the processing is done there, regardless of whether the feedstock is imported or not. For the energy and emissions balance, we gave a credit representing the present main source of animal protein in the EU: soy meal made from imported beans. In version 1 of this study we used the same feed-replacement ratio to estimate the costs of the by-products. However, in this version we could use forecasts of the by-products themselves.

It is important to know the amount of animal-feed by-product in order to check that the market can absorb it all. An extra 218 PJ of ethanol is needed to replace 5.75% of EU gasoline consumption (above baseline). The DDGS by-product is most valuable as animal feed, replacing 7 Mt soybean meal. Replacing 5.75% diesel with bio-diesel would produce enough extra rapeseed and sunflower cake (compared to baseline) to replace a further 14 Mt soybean meal. The combined total of 21 Mt soybean meal equivalent compares to EU 2012 imports of 24.8 Mt (FAPRI forecast).

If biofuels are imported as fuels or vegetable oil, then of course a portion of these by-products will be produced outside EU, but they still impact on the world market price. At the moment the pattern is to import oilseeds rather than bio-diesel, so the by-products are still produced in EU, but by 2012 one may anticipate a shift to the use of palm oil and other oils not pressed in EU.

FAPRI quoted in [*DG-AGRI 2005*] project a 2012 world oilseed meal supply of 212 Mt. In [*Meilke 2005*]; the average supply flexibility for the major world producers is about 0.3. On this basis one expects the extra biofuels needed to meet the biofuels Directive to depress the price of oilseed cake by about **30%,** although the margin for error is wide, because of many unforeseeable factors in the market and the scarcity of clear statistical data on which to base the estimates of the market flexibility. This makes our **best-estimate prices 76 €/t for rapeseed cake and 66€/t for sunflower cake** (both at conventional 10% moisture). Both have an error margin of +/-20%.

DDGS prices

The market for DDGS is not sufficiently developed for world market prices to be quoted. Therefore we had to use a price based on the protein-replacement ratio with soybean meal (see *WTT Appendix 1*). Like oilseed cake, DDGS is considered a poorer quality feed than soy meal. Therefore we have linked both DDGS price and oilseed prices, via their protein-replacement ratios, to a "virtual soy meal price", which is lower than the expected soy meal price to take account of the quality differences. This virtual price (labelled "animal feed substitute" in the price table) is set to give the prices of oilseed cakes we already estimated in the last paragraph. The resulting **price estimate for DDGS is 74 €/tonne**.

Rapeseed cake, sunflower cake and DDGS are not as easily digested as soybean meal, so that they cannot replace it entirely. This would suggest that some of the output would have to be exported. Bearing in mind the cost of sterilization, packaging and shipping, the fall in price at the factory gate could be even more dramatic. Of course the figure given is very uncertain, but it warns that the glut of protein-animal feed from biofuels by-products is likely to severely impact protein-feed prices, which will increase the costs of biofuels production.

The market outlook for glycerine affects the choice of substitution (see *section 3.4.5*)

5.2.6 Advanced biofuels scenario

Farmed wood availability

Farmed wood price

The highest yield from forestry on an annualized basis comes from short-rotation forestry (SRF). The best-yielding varieties are willow and poplar in north of Europe and eucalyptus in the south. Willow is more suited to wet conditions. It is harvested (“coppiced”) every 2-4 years by cutting the shoots which grow up from the trunk. The remaining root system allows trees to re-grow biomass quicker than annual crops. After about five cuts, the whole tree is harvested. Poplar stems are cut after 8-15 years. The cost for establishing SRF and returning the land to arable again is very high, so there should be a long-term policy. Wood is the preferred type of biomass fuel: it has lower salt content and higher bulk density than other energy crops.

There is a huge range of farming costs for SRF in the literature: from about 39 €/dry tonne [*Bauen 2001*] up to 153 €/dry tonne [*FfE 1998*]. In version 1 of this study we could not find any commercial price information and had to infer the SRF cost from bottom-up costing studies of SRF profitability, comparing it to wheat. The cost in version 1 came out higher than the present one, partly because at the time of writing wheat prices were at a historic high, and partly because we probably overestimated the quality of the land in the SRF study.

In the present version, we have been able to calculate the cost-to-EU of SRF wood directly from the commercial price paid to UK willow farmers by power utilities, who buy it to meet their renewable energy obligation by co-firing in coal-burning power stations. These prices and the prevailing subsidy regime are sufficient to persuade some farmers to grow willow, without causing a rush to cover the countryside with willow plantations. So they seem a good basis for our cost estimate.

Industry sources told us that utilities pay about £38 (≈55 €) per dry tonne of delivered willow chips. This is broadly confirmed by the Renewable Energy Farmers' Association website, which quotes £30. However growers also get subsidies of £1000/ha (≈1450 €/ha) establishment grant from UK government and 45€/ha energy crop subsidy from CAP. We can treat the establishment subsidy like a plant investment, which also has a 15-20 year lifetime: we apply our standard capital charge of 12% (equivalent to 8% discount rate). For a typical UK yield of 10 dry tonnes/ha, the **unsubsidized cost** including delivery works out at
55 + (1450 * 0.12 + 45) / 10 = **77 €/dry tonne**.

The UK is generally very suited to growing willow and the first plantings are likely to be in the lower cost locations, so one could argue that we have underestimated the cost of SRF for large-scale planting of SRF elsewhere in the EU. On the other hand one expects costs to fall as farmers get more experience with the new crop. Our costs are towards the higher end of the range assumed in the VIEWLS project, but we should remember that ours are for 2015; theirs are for 2030 (see text box).

Best current practice gives SRF yields only 1.57 times cereals yield

In the 1980s people were very optimistic about the potential yields from SRF on the basis of trials by various research institutes. Experience in the 1990s with real plantations brought down yield expectations: [*Mitchell 1999*] wrote "realism is creeping in, lower yields than anticipated are being accepted, matched by lower costs".

[*Unseld 1998*] reported trials of short-rotation forestry on various sites in Germany. Annualized yields varied from 1 to 29 dry tonnes per year, depending mostly on the water availability. We can see that it will be difficult to establish an average EU yield. The concept of average yield can anyway be misleading when considering establishment of SRF on former arable land, because the productivity of arable land varies enormously itself. The best approach is to estimate the ratio between the yield of crops and SRF wood, because yield variations for different crops are strongly correlated: land which is good for one crop is usually good for another. The problem is that few trials of SRF state the cereals yield on the same land.

In the UK willow farming was established for the ARBRE project. Most SRF production goes now to co-firing in coal-burning power stations. Industry sources say that "grade 3" ex-cereals land yields 10-12 dry tonnes per ha, but that results on "grade 4" arable land are poor. On grade 3 agricultural land in the area wheat yield was estimated to be about 7 t/ha, also giving a yield ratio of 1.57.

On the other hand, an association of energy farmers told us that, as a rule of thumb, the yield of SRF is about equal to the winter wheat yield on the same field. This may be based on information from the earliest cuts, but [*Mitchell 1999*] states that the anticipated increases in yield on subsequent cuts did not materialise on commercial plantations; implying the yield ratio would stay at only 1.

Comparing returns from SRF to those from arable crops, [*Mitchell 1999*] implies that 10 dry t/ha SRF yield is to be expected from land with 8 t/ha winter wheat yield (a ratio of 1.25).

[*LWF 2000*] also states that previous average yield estimates were too optimistic for SRF in Bavaria. Their careful assessment of SRF potential in Bavaria gives an average yield of 8-10 dry t/ha. We can compare this to an average wheat yield in Bavaria of about 6 t/ha (yield ratio 1.57).

For 2012**, we assume a yield ratio of 1.57** dry tonnes of annualized SRF production per tonne of winter wheat production (mix of bread-making and feed varieties) at the standard 13% moisture. This implies wood farmers adopt current best practice.

So the resource potential for farmed wood is higher than "conventional" biofuels. The question marks are the costs, the time to develop the technology, infrastructure and plantations, and whether it is better to use the wood for electricity and heating.

SRF: The view from VIEWLS

[*VIEWLS 2005*] includes a sophisticated analysis of cost and availability of biofuels that could be produced in the EU by 2030. Basically, the study assumes maximum biofuels production by re-assigning the use of all land (not just agricultural land) not already built on or foreseen for urban development.

The land available for biofuel crops is assessed by subtracting from this total:
- the land needed for food crops to feed each country's population
- the forest area needed to grow the estimated wood requirements
- the land needed to grow fodder for animals (no grazing).

ALL the remaining land (predominantly grazing and unharvested forest) is assigned to a biofuel crop: either rapeseed, sugar beet, miscanthus or willow. The cost of growing the biofuels crops is then calculated on the basis of various agro-economic scenarios, bearing in mind the varying yields on different types of land. Curves of average production cost against availability for each crop and scenario are then derived.

The VIEWLS availabilities of sugar beet and rapeseed do not apparently take into account the limits imposed by crop rotations or the negative effect on soil carbon of the proposed land use changes from forest and grassland to arable. Therefore it is pointless to compare the arable crops results with our figures. But the rotation limits do not apply to the permanent crops, and the size of the soil carbon reduction by planting SRF or miscanthus on forest or grazing land is much less certain (although probably detrimental to some extent), so one may tentatively consider the VIEWLS estimate for these crops.

Willow gives the highest forecast availability at a given cost. To attain an availability figure for willow to compare with ours, we chose the VIEWLS agro-economic scenario closest to DG-AGRI forecasts ("scenario 3"). The availability–cost curve shows a broad plateau up to **8000 PJ** followed by a steep cost increase. This forecast 2030 availability would be at an estimated production cost of 3.2 €/GJ (HHV), or 62 €/ dry tonne. The reasons the availability is much higher than ours for EU25-2012 are as follows:
- SRF expands onto grazing, forest and other land, whereas we only considered arable land
- VIEWLS assumes much improved SRF yields by 2030

For another VIEWLS scenario (V5), where CEEC costs matched EU-15 costs, the corresponding plateau cost was about 4.2 €/GJ (HHV), or 82 €/dry tonne. In this scenario, the production cost on second-grade "suitable" land in Poland is 3.2 €/GJ (HHV) = 62 €/ dry tonne. These values compare with our delivered unsubsidized cost for willow chips of 77 €/dry tonne, or about 70 €/t at the farm gate. So the costs seem to be in the same ballpark.

The costs do not look much different, until one compares the corresponding wheat yields. VIEWLS propose SRF yields on their second-category "suitable" land in Poland to average about 11.2 t/ha. The record 2004 winter wheat yield in Poland averaged 4.28 t/ha and that was presumably mostly on "very suitable" land. So VIEWLS is expecting SRF yields to be at least 2.5 times higher than winter wheat yields. Comparing this with the present yield ratio of 1.57 at most, implies VIEWLS anticipates an increase in SRF yield of more than 60% from now to 2030. Although the tendency until now has been for SRF yield expectations to fall, it is not unreasonable to expect that from now on there will be rapid improvements in varieties and commercial farming techniques for this new crop.

Availability of agricultural and forestry wastes

Far more waste is available for energy than for biofuels production

Lignocellulosic materials can be converted to ethanol by the wet SSCF process or to other fuels via gasification. Both these are complex processes with economics dominated by the high plant investment costs: to make them viable it is important to use economies of scale. The straw-to-ethanol pilot plant of Iogen Corporation has a capacity of 140 MW_{th}, and gasifiers in general should be larger still for good economics. By contrast, reasonably efficient and clean biomass boilers are available at much smaller scales, for heating commercial buildings or small industrial processes, and the size of combined-heat-and power electricity generating plants is anyway limited by the demand for heat. Even straight biomass power stations are less complex and capital-intensive than a biofuel plant.

Thus, when estimating the availability of feedstock, one should consider not only how much is there in the field or forest and how much can technically environmentally and economically collected, but also how much can logistically be brought to large processing plants.

Straw and other agricultural residues

[*Edwards 2005*] reports on a GIS-based study on the availability of straw in EU for feeding power stations. Taking into account competing uses, they estimated that EU produced 820 PJ straw in excess of existing requirements, but that a maximum of only **230 PJ** (28%) would be logistically available to plants of 120 MW_{th} or larger. This is because of the dispersed nature of the resource and the need for spare resource capacity around a plant to account for annual variations in supply etc. We have used this figures in our study, even though some of the conversion plants in this study would be larger, and no account was taken of areas where straw-taking could degrade soils (although this is not as great a limitation as might be expected, because the areas with a concentrated supply are also areas where the soil conditions permit it to be taken). Therefore the figure is optimistic, when applied to biofuels.

The price of straw depends strongly on local conditions and the quantities involved; there is a great spread of cost data in EUROSTAT. However, a good basis for our purpose is the price paid at Ely straw-burning power station in the UK (the world’s largest). Straw is sourced from within 50 km of the plant and average transport distance is 35-40 km. The delivered price is 23-25 £/t at 15% water (≈33-36 €/t) on a fixed contract. Spot price delivered to power stations for co-firing is 28 £/t (41 €/t). There is no subsidy on the straw. On this basis we have adopted a **straw price of 35 +/-5 €/t**.

[*Edwards 2005*] dealt with straw from cereals which occupy 86% of the EU arable land. Of course many other crops produce prunings and residues, but these are far more dispersed, all have different processing characteristics, and many are already used for animal feed (a point overlooked in some surveys!). Therefore we think their possible contribution to making renewable transport fuels would be less than the uncertainty in our straw estimate. Again, they could contribute more to bio-energy resources than biofuels.

Waste wood

Sources of waste wood

There are several types of wood wastes:

- “Forest residuals”: branches, tops, undersize thinnings and, with latest forestry technology, roots.
- “Mill residues” bark and other wastes produced at the pulp mill.
- “Secondary wastes”: from the wood industry (sawdust, shavings etc)
- “Used wood” from building demolition, pallets etc
- “Agricultural residues” from woody plants such as fruit trees and vines
- Forest litter: dead wood removed from old stands or natural forest to reduce fire risk

There is no industrial-scale production of transport fuels from wood waste at present. Current EU total wood waste now used for energy production (heat/electricity) is 50 dry Mt/a

[*EUREC 2002*]. This represents 48% of total wood used for energy, the rest being non-industrial trees cut for firewood. It subdivides into 40% residues, 39% secondary residues and 21% used wood.

Apart from straw, very little woody agricultural residues are currently used to produce energy in EU commercial plant. Generally residues occur at a very low density over a wide geographical area and are only available once a year. The cost of transport makes waste wood cogeneration only marginally economic even in the middle of a forested region, where the density of production is high and the wood can be transported all year round. With the exception of cereal straw (see above), we therefore considered that there is no possibility to economically collect a significant part of the agricultural woody residues for energy use. The special situation of straw is considered above.

Secondary waste is the most consistent in quality and easy to obtain. It has been used in many pilot studies of gasification etc. However, it is already almost completely recycled within the wood industry (40% for products, 60% for heat and electricity). Life cycle analysis studies almost all agree that use in products is better for greenhouse gas than use as energy.

Used wood is the driest and therefore convenient for small pilot plant studies. At present it has near-zero or negative cost at source. But the source is extremely dispersed. Furthermore, there is a problem of contamination: only a fraction of the potential supply can be used within health regulations. Detoxification is under study by the wood industry, who would like to recycle more of it.

Mill waste is completely used within the pulp/paper mills (for process heat and electricity export) and so is not available for conversion to road fuel.

It is sometimes claimed that forest litter could be a useful woody biomass resource: the high cost of collection might be justified by the external credits from avoiding forest fires. We are not competent to make this calculation. However, the resource would certainly be very dispersed, making it suitable for energy use in local heating, for example, but probably not for transporting to large centralized plants for conversion to biofuels.

Summarising, it appears that **forest residuals are the only significant potential source of more woody waste for transport fuel**.

Availability of forest residuals

When harvesting trees in commercial forestry, the branches and tops are stripped from the trunk at the harvest site and forwarded to a baler or a roadside chipper. The bales or chips are carried to the mill by adapted log-trucks. Recently, integral harvesters have been developed. These remove the roots as well, but cannot be used in difficult terrain. An advantage of taking the roots is that they are better fuel: drier, and with a lower mineral content than branches; the disadvantage is that the disruption of the soil could lead to loss of soil carbon and soil erosion at sensitive sites.

As with many other sources of biomass for energy, studies conducted ten years ago were far more optimistic about availability than the latest studies. For example, estimates in six successive studies of the possible availability of Swedish forest residues have declined by a factor five from around 380 PJ in 1995 to 75 PJ in 2005 (of which 32 PJ already used) [*Lundmark 2005*]. Therefore the estimates in version 1 of this study, which were conservative compared to previous pan-European studies, are roughly confirmed by more recent work.

[*METLA 2004*] used broadly the same approach as we did in version 1 of this study to estimate the technically and economically available forest residuals in EU-25: they started from the statistics on fellings and then estimated extension factors to find the amount of residuals associated with these. However, the METLA study is more detailed and includes cost-supply curves for various countries. Therefore we adopted their results for the present study.

[*METLA 2004*] also considers using the excess roundwood for energy purposes (i.e. the annual excess of commercial forest growth over actual fellings). METLA assume 25% of the excess growth could be used. At present, some countries such as Portugal have no excess growth whereas others, for example Finland, have a large excess growth but are reluctant to cut it for energy use.

Forest residuals for replacement of gasified black liquor

Black liquor is the by-product of pulp-making containing the lignin fraction of the wood, mixed with process chemical in a slurry. In existing pulp mills, it is burnt in a recovery boiler for process heat. Instead, one can gasify the black liquor and make up the missing process heat using a boiler fired by forest residuals. The syngas from the gasifier can be used to produce either electricity or transport fuels.

The amount of fuels that can be made in pulp mills using the efficient black liquor route depends on how many mills have large enough boilers to make black liquor gasification economic. This is the case for about 80% of EU plants and they could be converted gradually as their recovery boilers come up for renewal over the next 20 years.

According to [*Ekbom 2003*], EU-15 produced 395 PJ black liquor in the year 2000. We first added 11% to this figure to account for pulp production in the new Member States (proportional to the pulp production figures from EUROSTAT). We then used the growth rates projected by [*Ekbom 2003*to calculate an EU-25 black liquor production of 527 PJ in 2012. However, only about 80% of this would come from plants large enough for economic conversion to black liquor gasification so the amount available for gasification would be 422 PJ. Again according to [*Ekbom 2003*] 408 GJ forest residuals would replace 487 GJ of gasified black liquor in their model black liquor gasification plant. This results in a potential demand of 353 PJ forest residuals to fully exploit the possibilities of black liquor gasification in EU-25 in 2012.

[*METLA 2004*] estimated the technical availability of forest residuals and roundwood balance country-by-country. Comparison of the results of [*METLA 2004*] with the black liquor potentials of [*Ekbom 2003*] gasification study shows that each pulp-producing country in EU-15 can supply just enough forest residuals to fully exploit its potential of black liquor gasification.

The cost-supply curves for Finland in [*METLA 2004*] and for Sweden in [*Lundmark 2005*] indicate that these two principal producers could provide just sufficient forest residuals at a price of 2.8 €/GJ. The cost-supply curve for Poland in [*METLA 2004*] indicates that new Member States could supply it for even less. The cost-supply curve for France indicates that almost no forest residuals would be available at 2.8 €/GJ, and the same is probably true of other small EU-15 pulp producers. But France, Austria and Spain could possibly supply the biomass at that price by exploiting some of their roundwood balance. Portugal has no roundwood balance to exploit, and Germany and the UK have no pulp industry. In all EU-25, we estimate **325PJ woody biomass would be available to pulp mills at 2.8 €/GJ**: 92% of that required for full exploitation of black liquor gasification.

A larger constraint is techno-political: even if the maximum number of EU pulp-mills were converted for black liquor gasification, some might prefer to produce electricity (or methanol rather than transport fuels) either for economic reasons or more likely as a result of renewable policies in certain countries. Even though black liquor gasification is a very efficient way of producing transport fuel from biomass, making electricity could save more GHG from the same biomass and for less money. In particular there is little enthusiasm for producing transport fuels in Finland, after some disappointing tests in the 1970s. And of course, the whole concept is still at the pilot plant stage: we do not yet know how long gasifiers will withstand the severe sulphidation conditions. Accordingly, we have assumed that a maximum of **2/3 of the black liquor gasification capacity could realistically be exploited to produce transport fuels. This would consume 238 PJ woody biomass, mostly forest residuals.**

Forest residuals for other conversion routes

In our advanced biofuels scenario, the cheapest sources of forest residuals have mostly been exploited for the black liquor at pulp plants, because collecting residues is a large-scale operation combined with clear-fell harvesting and can make use of the same transport infrastructure to bring the residuals to the pulp mills.

[*METLA 2004*] estimated the maximum technical availability of forest residuals and roundwood balance in EU-25 at 1008 PJ/a. If we subtract the 325 PJ available at pulp mills for processing by the black-liquor gasification route, we are left with 683 PJ for other uses. However, this resource is far more dispersed than the residuals at pulp mills: it could be brought to saw-mills (typically much smaller than pulp-mills) or supplied along with traditional fire-wood. A larger proportion is from forest thinnings. This is a comparable situation to straw availability: it is logistically difficult to get the resource to large plants of the type needed to convert it to transport fuel. It could much more easily be exploited for energy in the form of local heating and CHP plant. A detailed GIS study is needed for a proper estimate. Since none is available, we made our estimate congruent with the situation of straw supply and assumed that at most 1/3 of the supply could be brought to a plant with a capacity greater than 130 MW_{th}. That means about 230 PJ, similar to the maximum amount that could be processed into transport fuels via the black liquor route.

In [*METLA 2004*] the cost-supply curve for France shows that to collect most of the available residues here one would need to increase the price to around 4.1 €/GJ which is our price for SRF wood. We supposed that prices in other EU-15 countries, notably Germany and Austria, would be comparable.

Conservatively we did our cost calculations using the lower price of 2.8 €/GJ for the entire waste wood supply.

5.2.7 Organic waste for compressed biogas

The potential for biogas is much higher for energy than for transport fuel

As with other energy-from-waste schemes, the availability of compressed biogas as a transport fuel is much less than that of biogas as an energy source for heating and small-scale electricity generation. Heat and electricity can be made even on simple farm-size plants, but *compressed* biogas for transportation requires a purification plant, a compressor, consistent quality and preferably an output sufficient for at least one filling station. Because of all these factors compressed biogas for transport needs to be produced in large centralized plants of the scale presently seen in Denmark to be economically viable.

Animal manure from intensive livestock farms is the biggest resource for transport-biogas at our production price

[*FfE 1998*] and [*Holm-Nielsen 1997*] have estimated how much potentially-digestible waste is produced in EU-15. The largest resource is animal manure, and by far the largest contribution is from cattle ([*FfE 1998*] use 18 t/a for the average amount of manure produced by cattle, a very high figure compared to other studies which report between 8.5 and 15 t/a. We favour average figures of 11 t/a per head of cattle and 1.7 t/a for pigs). This size of plant is only possible in areas of intensive livestock farming, where animals are kept indoors and manure is collected as slurry.

Sewage is more dilute and more dispersed than animal manure, giving higher biogas production costs. Agricultural wastes could be made into biogas, but many of the suitable ones are more valuable as animal feed. There is also a problem of year-round availability.

Organic wastes from separated municipal waste and from the food industry are very suitable for biogas production: they produce much more biogas per tonne than does manure, and they cost money to dispose of by other routes. Furthermore, there are synergistic advantages in mixing manure and organic wastes: the temperature of the fermentation and the C:N ratio can be kept nearer the optimum. The problem is that there is much less of it than animal manure, and it is difficult to get enough together in one place to make a biogas plant large enough to make compressed biogas at our price.

Purpose-grown crops, or grass collected from surplus grassland can also be digested, but the cost is far higher than using wastes. Since our cost results show that compressed biogas from waste already has trouble to compete on price with conventional biofuels in EU, we do not think this option is likely to be developed in our time horizon. It could possibly be considered competing with more expensive advanced-biofuels concepts in the more distant future.

Capital costs dominate

Biogas production is highly capital intensive: the typical feedstock of manure has a low specific energy content, and the residence time in the reactor is much longer than for thermal conversion processes. This makes the plant very large for a specific energy output, so that capital servicing is the main component of the total gas cost.

Large Danish plants process 300 tonnes biomass a day and would produce 6000 m^3/day (1.6 MW) raw biogas if they were fed only from animal slurry. This is the amount of manure produced by about 8000 cattle or 50,000 pigs. In Denmark these plants typically collect manure from about 50 farms within a radius of less than 10 km.

Adding organic waste makes the process viable at 15.5 €/GJ

Usually manure slurry is not paid for. It is collected from the farm and the processed fertilizer returned without charge to the farmer (but farmers often own a share of the biogas plant). Danish plants are only economically viable because of co-feeding with organic wastes from the food industry (slaughterhouse waste, fisheries processing waste, dairy waste etc.), both because these boost the biogas yield and because, being expensive to dispose of by other safe routes (incineration etc.) the biogas producer actually gets paid to process them.

One tonne of a typical mix of 20% organic waste with 80% slurry produces a net 30 Nm^3 biogas ("net", because some of the total biogas production is used to warm the fermentor), whereas animal slurry alone produces only about 20 Nm^3/t. So the same size and cost of plant produces 50% more gas. Already biomass plants are competing for the supply of organic wastes, so that most are operating at the edge of profitability [*Hjort-Greersen 1999*].

Our best-estimate biogas price of 15.5 €/GJ corresponds to this model of biogas production, but with no gate fee for the organic waste. Thus our price does not take into account the cost of alternative treatments for the slurry and organic wastes. According to [*AEA 1998*] these are higher than for anaerobic digestion, but it is beyond the scope of this study to evaluate them. Note that this price does not include the considerable costs of compressed-gas distribution and vehicle modifications.

A typical mix is 80% animal slurry / 20% organic waste. It is cheaper to transport the organic waste than the animal slurry, so the plants would be located in areas of intensive indoor livestock farming, producing manure as slurry. EUROSTAT statistics show that 30% of EU cattle live on farms of more than 200 head, and 36% pigs live on farms of more than 2000 head. This may give a rough indication of the availability of slurry from intensive farms. The conclusion is that the biogas production at this price is limited by the availability of organic waste.

The availability of organic waste limits the EU supply of compressed biogas to 200 PJ at a maximum price of 15.5 €/GJ

Total municipal organic waste in EU-15 is estimated at 57 Mt/a [*Fazoino 2005*]. The figure is close to the estimate in [*FfE 1998*] and [*Barth 2000*]. The fraction collectable is difficult to estimate for the whole of the EU: at present it ranges from 0% in Greece to 78% in Germany. We took a figure of 62%: the present performance in Flanders. The estimate of food industry waste was from [*FfE 1998*].

If we assume ALL the organic waste could be brought to a biogas plant at a site where there is a sufficient local slurry to supply a plant of our size, we find that AT MAXIMUM about **200 PJ/a** purified biogas, suitable for compression, could be available at a price of **15.5 €/GJ.**

The problem is that intensive animal farming tends to be concentrated in a few regions of the EU: Western Denmark, Po Valley, etc. So even though one could afford to transport organic waste as far as 200 km, much of it could still be produced in areas far from where there is a sufficiently concentrated source of slurry. However, we could not find sufficient data on how slurry sources are distributed in EU, so we could not refine our estimate further.

Table 5.2.7 Biogas potential from animal slurry and organic waste at 15.5 €/GJ

		EU-15	EU-25*
Total digestible fraction of MSW	*Mt/a*	*57*	*69*
Realistically collectable as separate waste	Mt/a	34	41
PLUS food industry waste	Mt/a	12	14
Total digestible organic waste	Mt/a	46	56
Biogas potential from organic waste	PJ/a	76	92
Animal slurry for 4:1 mixture	Mt/a	185	223
Biogas potential from slurry + organic waste	PJ/a	164	197

* scaled by population

Of course, more biogas would be available if the *price* was increased to allow production from pure slurry (our estimate is 21.3 €/GJ), or the use of specially-grown crops. However, we reasoned that the most economic production of compressed biogas for transport is all that one could hope to develop within the next 10-20 years. We repeat that much more biogas could be available for small-scale *energy* use (heat or small-scale electricity generation).

5.2.8 Overview of biomass feedstock costs

Based on the foregoing we have used the following cost data. Note that the costs arrived at above have been assumed to pertain to a 25 €/bbl oil price scenario. An "oil cost factor" has been added (representing a notional fraction of the cost related to energy) so that these costs are higher when the cost of oil increases.

Table 5.2.8 Cost of biomass resources
(delivered to processing plant)

	Moisture content	LHV	Low oil price (oil at 25 €/bbl)		Own	High oil price		
						OCF	(oil at 50 €/bbl)	
		GJ/t	€ /t	€ /GJ	variability		€ /t	€ /GJ
Wheat grain	13%	14.8	95	6.4	16%	0.05	100	6.7
Sugar beet	77%	3.8	25	6.5	16%	0.05	26	6.8
Rapeseed	10%	23.8	237	9.9	14%	0.05	248	10.4
Sunflower seed	10%	23.8	265	11.1	14%	0.05	278	11.7
Wheat straw	16%	14.4	35	2.4	13%	0.05	37	2.5
Waste wood	0%	18.0	50	2.8	13%	0.05	53	2.9
Farmed wood	0%	18.0	77	4.3	5%	0.05	81	4.5
By-products substitutes								
Animal feed substitute		14.4	95	6.6	20%	0.10	105	7.3
Glycerine substitute		20.0	130	6.5	16%	0.68	218	

5.2.9 Potential production of advanced biofuels

Using the availability figures discussed above we have built a number of extreme scenarios illustrating the potential of a number of single options for using the available biomass. It must be noted that these scenarios are mutually exclusive inasmuch as they represent alternative ways of using the same resource. The numbers are shown in ***Table 5.2.9***.

The second and third columns show the availability of the different types of biomass. In all scenarios it is assumed that surplus sugar beet is still grown and is turned to ethanol, and so is straw which accounts for a base ethanol production of 117 PJ/a. All surplus cereals as well as the area currently used for oilseeds are converted to SRF or equivalent to produce woody biomass. This "wood" is then converted, together with waste wood to either ethanol, syndiesel (with co-production of naphtha), DME or hydrogen.

Because these fuels apply to different engine configurations, a full comparison of these scenarios must be done on a WTW basis. Reference is made to the *WTW report, section 8.6*.

Table 5.2.9 Advanced biofuels production potential

Resource	Mt/a	PJ/a	Ethanol PJ/a	Syn-diesel PJ/a	*(Naphtha)* PJ/a	DME PJ/a	Hydrogen PJ/a
Surplus sugar beet	8.0	31	16				
Wheat straw	15.9	230	97				
Surplus grain (as food grade wheat)							
Set-asides	*22.9*						
From net land released by sugar reform	*9.3*						
Improved yields	*14.9*		←		Or		→
	⇩						
As farmed wood	83.9	1511	518	472	*157*	771	942
Existing oil seeds for energy	*7.1*						
	⇩						
As farmed wood	19.7	355	122	111	*37*	181	221
Waste wood	26.2	471	162	167	*56*	274	332
Scenarios							
Max ethanol			914				
Max syn-diesel			113	750	*250*		
Max DME			113			1226	
Max hydrogen			113				1495

[1] i.e. gasoline for ethanol, diesel for syn-diesel and DME and combination for hydrogen

Assumptions for all scenarios:

Marginal sugar beet still grown

Straw only used for ethanol production

50% of waste wood used though black liquor route

5.3 Hydrogen production potential

Hydrogen is already produced in significant quantities today mostly for industrial applications. Oil refineries, in particular, are large hydrogen consumers for hydrodesulphurisation of various streams such as gasoils and heavy oil conversion processes.

The most widespread hydrogen production process is steam reforming of natural gas (see *section 3.2.5)*. The process is technically and commercially well-established and natural gas is a widely available and relatively cheap feedstock. Steam reforming of heavier hydrocarbons is also possible but little applied, if at all, in practice because the process equipment is more complex and the potential feedstocks such as LPG or naphtha have a higher alternative value. Existing reformers are mostly large industrial plants but small scale prototypes have been developed.

Partial oxidation of a carbonaceous feedstock in the presence of water also produces syngas and can be applied to a wide range of materials, in particular heavy feedstocks such as oil residues, coal (see *section 3.3*) as well as biomass feeds such as wood (see *section 3.4 and 5.2*). The front end of the process is essentially the same as for the manufacture of synthetic liquid fuels. The synthesis section is replaced by the CO-shift step. Small scale wood gasifiers for electricity production have been developed at the pilot plant stage and could conceivably be adapted for small scale hydrogen production.

Reformers and gasifiers produce CO_2 in one place and, when using oxygen rather than air, in a virtually pure form. Large scale installations may offer a viable platform for possible CO_2 capture and sequestration projects.

Electrolysis is also a well established technology both at large and small scale. Interest in large scale hydrogen production is likely to result in improvements in terms of efficiency and costs. One particularly promising development route is high pressure electrolysers. The use of electricity as the energy vector to produce hydrogen opens the door to the use of a large variety of primary energy sources including fossil and biomass but also wind energy and of course nuclear.
Direct solar energy can also, in principle, be used to produce hydrogen either by thermal splitting of water or electrolysis through photovoltaic electricity. The development of the former type of processes is in its infancy while the latter is not expected to be viable at very large scale within the timeframe of this study. We have therefore not considered these options.

All in all a lot of hydrogen can theoretically be produced. In practice though and in view of the availability of both feedstock and technology, only natural gas reforming provides a short term avenue for flexible large scale hydrogen production. The coal route requires large scale, costly plants with major financing and public acceptance issues. Biomass is of course an option but of a limited nature and where hydrogen competes with other uses (see further discussion in *section 9 of the WTW report*). The same applies to wind energy which can mostly be used directly as electricity. Only in “stranded wind” situations where electricity from wind could not practically be fed into the grid, would hydrogen production make sense. Nuclear energy is of course a potentially very large supplier of energy including in the form of hydrogen. Its development opens societal and political issues, the discussion of which does not have its place in this report.

5.4 Potential and cost of CC&S

From inspection of the pathways including CC&S described in section 4, it will be clear that these technologies have a real potential to reduce CO_2 emissions. ***Figure 5.4*** gives an overview of the achievable reductions against the associated energy penalty. As mentioned before these figures should be considered as preliminary and higher CO_2 recovery may be possible in the future.

There is considerable scope for CO_2 storage (***Table 5.4***). Depleted oil and gas reservoirs or deep underground aquifers containing saline water that is permanently unsuitable for other purposes, offer large storage potentials both in Europe and globally. CO_2 can be injected into operating oil wells to enhance petroleum production. In the U.S. this accounts for 4% of total oil production. 20% (5 Mt/a) of the CO_2 used has previously been captured at natural gas processing or fertilizer manufacturing plants and is transported by pipeline. In Turkey, 6 Mt/a of CO_2 have been injected for enhanced oil recovery. Deep coal seams for coal bed methane production also offer some space for sequestration. CO_2 displaces methane, thus enhancing its recovery, and is absorbed by the coal. The deep sea and biomass, both areas of large storage capacities, are also examined in academic research. Small amounts of carbon dioxide can be put to use, though not permanently fixed, in commercial applications, such as greenhouses (potential of 4 million tonnes per year in the Netherlands), feedstock for chemicals, freeze-drying, carbonating beverages and to grow algae for biofuels.

Aspects to consider for the various options are capacity, integrity, stability over time, safety, any environmental impact, and cost-effectiveness.

The actual facilities required for a CC&S scheme, and therefore the costs, are likely to be very dependent of the type of plant, the specific process scheme used, the distance to the storage location as well as possible installations for preparing, maintaining and monitoring the storage. We therefore decided to refrain from giving specific cost estimates for each pathway as this would be suggesting a level of knowledge and understanding of the issues that has as yet not been achieved. Instead we briefly discuss below the main factors that may influence the eventual cost of CC&S schemes.

Figure 5.4 WTT energy and GHG balance of selected pathways with and without CC&S

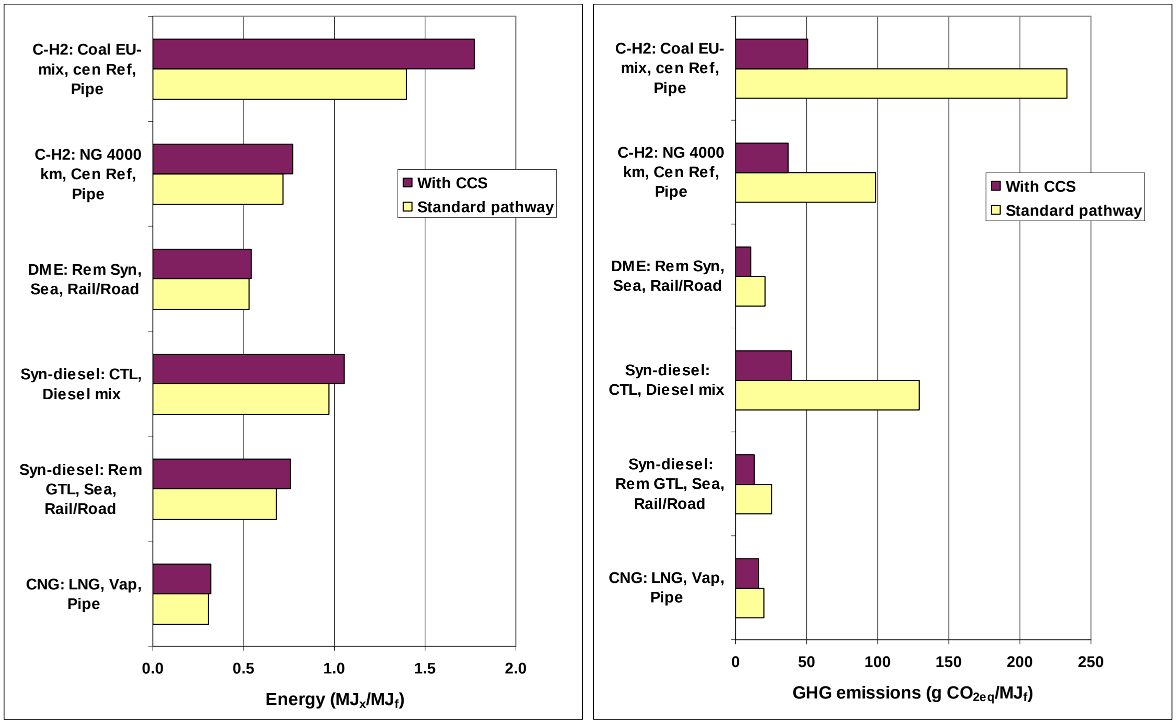


Table 5.4 Carbon dioxide reception areas and their capacities in comparison

Receptor	**Capacity (Gt CO_2)**	**Remarks**
Atmosphere	Holds 2750	
Depleted fields Gas Oil	 510-1140 150-700	Oil and gas fields offer space for 46% of emissions to 2050 according to the IPCC's IS92a projection
Enhanced oil recovery	240	
Aquifers	330-10,000	North Sea Utsira formation could hold 800 Gt. Deep saline aquifers could offer space for 20-500% of emissions to 2050 according to the IPCC's IS92a projection.
Oceans	Hold 150,000 Estimated potential several times that amount	
Forests	Hold 2200 Estimated additional potential through reforestation: 150-400	Takes 40-50 years for a large forestry plantation to grow sufficiently

Source : OGP

Some processes are effectively already capturing CO_2 (e.g. Fischer-Tropsch synthesis where CO_2 must be scrubbed from the syngas before the synthesis step). In such cases the in-plant costs would be limited to CO_2 compression.

Processes that do not use air as combustion medium produce relatively CO_2-rich gas streams from which CO_2 can be separated at a reasonable cost. The worst case is for conventional combustion processes where CO_2 is present in low concentration (typically around 15%) in the flue gases. Obviously the scale of the plant will also play a role. Rough estimates from the literature indicate costs between 5 and 40 €/t CO_2.

CO_2 may be transported by pipeline or even by ship in some cases. In the former case a figure of 500-1000 k€/km of pipeline should be reckoned with, depending on the diameter, pressure and location. In the case of a large plant producing a lot of CO_2 (e.g. large scale CTL), this may only account for a few €/t. For smaller scale plants it might prove prohibitively expensive.

Sequestration costs still have to be studied. They will depend on physical conditions i.e. what investment will be required to allow sequestration to proceed, but also on the regulatory framework under which CO_2 storage sites will have to operate, including potential costs for monitoring and maintaining the sites.

5.5 Fuel production and distribution costs

For all fuels produced in Europe and for those, such as DME which cannot be linked to a commodity price, we have estimated a cost of production based on published literature.

Unless there was clear evidence to support other numbers we have considered that a processing plant would have annual operating costs of 3% of the initial capital investment for established technologies and 4.5% for new technologies or high-tech plants. This included personnel and maintenance but not energy which was accounted for separately according to its source. For processes that already exist today, we used a range of ±20% for investment costs. For new or future processes we have used ±30%.

In order to express all costs on a common basis, capital investments need to be turned into a cost item expressed e.g. per annum or per MJ of product. We use the concept of capital charge which is the revenue that a facility must produce every year of the project life (in addition to operating costs) for the investment to be repaid and to produce a desired rate of return. The capital charge is a function of a number of factors such as lifetime of the project, building time, expected revenue profile, inflation and also tax on profits. As we are looking at cost for Europe as a whole we considered the tax element as an internal issue rather than an external cost. It would of course be taken into account by individual investors wishing to undertake a project. A commonly accepted rate of return for capital investment is 8% (real terms) being the long term return of stocks and shares. For a typical industrial project with a lifetime of 15-20 years and 2-3 years building time, this corresponds to a capital charge of about 12% which is the figure that we have used.

Distribution and retail costs include energy cost (transport, compression, dispensing etc), cost of incremental distribution infrastructure and cost of specific refuelling infrastructure. In line with our incremental approach, we have taken the view that the existing infrastructure for conventional fuels would not be significantly affected by a limited introduction of alternative fuels. As a consequence the savings from "not distributing" marginal conventional fuels were limited to variable costs (essentially energy-related). Conversely, however, the extra cost for refuelling infrastructure when required only related to the cost of the additional equipment and did not include any contribution to fixed costs e.g. for establishment and maintenance of a site and the like. According to the same philosophy we did not, for CNG, include the full contribution to the cost of the natural gas grid.

The calculations are shown in detail for each fuel in *WTW Appendix 2* where literature references are also indicated. These tables are therefore not repeated here.

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Acronyms and abbreviations used in the WTW study

ADVISOR	A powertrain simulation model developed by the US-based National Renewable Energy Laboratory
BTL	Biomass-To-Liquids: denotes processes to convert biomass to synthetic liquid fuels, primarily diesel fuel
CAP	The EU's Common Agricultural Policy
CCGT	Combined Cycle Gas Turbine
CC&S	CO_2 capture and storage
C-H_2	Compressed hydrogen
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
CO	Carbon monoxide
CO_2	Carbon dioxide: the principal greenhouse gas
CONCAWE	The oil companies' European association for environment, health and safety in refining and distribution
DDGS	Distiller's Dried Grain with Solubles: the residue left after production of ethanol from wheat grain
DG-AGRI	The EU Commission's General Directorate for Agriculture
DICI	An ICE using the Direct Injection Compression Ignition technology
DME	Di-Methyl-Ether
DPF	Diesel Particulate Filter
DISI	An ICE using the Direct Injection Spark Ignition technology
ETBE	Ethyl-Tertiary-Butyl Ether
EUCAR	European Council for Automotive Research and Development
EU-mix	The average composition of a certain resource or fuel in Europe. Applied to natural gas, coal and electricity
FAEE	Fatty Acid Ethyl Ester: Scientific name for bio-diesel made from vegetable oil and ethanol
FAME	Fatty Acid Methyl Ester: Scientific name for bio-diesel made from vegetable oil and methanol
FAPRI	Food and Agriculture Policy Research Institute (USA)
FC	Fuel Cell
FSU	Former Soviet Union
FT	Fischer-Tropsch: the process named after its original inventors that converts syngas to hydrocarbon chains
GDP	Gross Domestic Product
GHG	Greenhouse gas
GTL	Gas-To-Liquids: denotes processes to convert natural gas to liquid fuels
HC	Hydrocarbons (as a regulated pollutant)
HRSG	Heat Recovery Steam Generator
ICE	Internal Combustion Engine
IEA	International Energy Agency
IES	Institute for Environment and Sustainability
IFP	Institut Français du Pétrole
IGCC	Integrated Gasification and Combined Cycle
IPCC	Intergovernmental Panel for Climate Change
JRC	Joint Research Centre of the EU Commission
LBST	L-B-Systemtechnik GmbH
LCA	Life Cycle Analysis
L-H_2	Liquid hydrogen
LHV	Lower Heating Value ('Lower" indicates that the heat of condensation of water is not included)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gases

MDEA	Methyl Di-Ethanol Amine
ME	The Middle East
MTBE	Methyl-Tertiary-Butyl Ether
MPa	Mega Pascal, unit of pressure (1 MPa = 10 bar). Unless otherwise stated pressure figures are expressed as "gauge" i.e. over and above atmospheric pressure
Mtoe	Million tonnes oil equivalent. The “oil equivalent” is a notional fuel with a LHV of 42 GJ/t
N_2O	Nitrous oxide: a very potent greenhouse gas
NEDC	New European Drive Cycle
NG	Natural Gas
NOx	A mixture of various nitrogen oxides as emitted by combustion sources
OCF	Oil Cost Factor
OGP	Oil & Gas Producers
PEM fuel cell	Proton Exchange Membrane fuel cell
PISI	An ICE using the Port Injection Spark Ignition technology
PSA	Pressure Swing Absorption unit
RME	Rapeseed Methyl Ester: biodiesel derived from rapeseed oil (colza)
SMDS	The Shell Middle Distillate Synthesis process
SME	Sunflower Methyl Ester: biodiesel derived from sunflower oil
SOC	State Of Charge (of a battery)
SRF	Short Rotation Forestry
SSCF	Simultaneous Saccharification and Co-Fermentation: a process for converting cellulosic material to ethanol
SUV	Sport-Utility Vehicle
Syngas	A mixture of CO and hydrogen produced by gasification or steam reforming of various feedstocks and used for the manufacture of synthetic fuels and hydrogen
TES	Transport Energy Strategy. A German consortium that worked on alternative fuels, in particular on hydrogen
TTW	Tank-To-Wheels: description of the burning of a fuel in a vehicle
ULCC	Ultra Large Crude Carrier
VLCC	Very Large Crude Carrier
WTT	Well-To-Tank: the cascade of steps required to produce and distribute a fuel (starting from the primary energy resource), including vehicle refuelling
WTW	Well-To-Wheels: the integration of all steps required to produce and distribute a fuel (starting from the primary energy resource) and use it in a vehicle
ZEV	Zero Emission Vehicle

Summary of WTT pathways codes and description

Code	*Short description*	*Details*
Conventional fuels		
COG1	Gasoline	
COD1	Diesel	
CON1	Naphtha	
LRLP1	LPG imports from remote gas field	
CNG		
GMCG1	EU-mix	Current average composition of NG supply in EU
GPCG1a	Pipeline 7000 km	NG piped over 7000 km
GPCG1b	Pipeline 4000 km	NG piped over 4000 km
GRCG1	LNG, Vap, Pipe	LNG from Middle East regasified and distributed by pipeline within EU
GRCG1C	LNG, Vap, Pipe, CC&S	As above with capture and sequestration of CO_2 produced in production process
GRCG2	LNG, Road, Vap	LNG from Middle East distributed by road within EU, regasified at filling station
CBG: Compressed Biogas		
OWCG1	Municipal waste	Biogas produced from municipal waste, cleaned and upgraded
OWCG2	Liquid manure	As above with liquid manure
OWCG3	Dry manure	As above with dry manure
Ethanol		
SBET1	Sugar beet, pulp to fodder	Ethanol from sugar beet, pulp used for animal fodder
SBET3	Sugar beet, pulp to heat	As above but pulp used as fuel to produce process heat
WTET1a	Wheat, conv NG boiler, DDGS as AF	Ethanol from wheat, process heat from conventional NG-fires boiler, DDGS to animal feed
WTET1b	Wheat, conv NG boiler, DDGS as fuel	As above but DDGS used as fuel
WTET2a	Wheat, NG GT+CHP, DDGS as AF	As WTET1a but process heat from NG-fired gas turbine with combined heat and power scheme
WTET2b	Wheat, NG GT+CHP, DDGS as fuel	As WTET1b but process heat from NG-fired gas turbine with combined heat and power scheme
WTET3a	Wheat, Lignite CHP, DDGS as AF	As WTET1a but process heat from lignite-fired combined heat and power scheme
WTET3b	Wheat, Lignite CHP, DDGS as fuel	As WTET1b but process heat from lignite-fired combined heat and power scheme
WTET4a	Wheat, Straw CHP, DDGS as AF	As WTET1a but process heat from straw-fired combined heat and power scheme
WTET4b	Wheat, Straw CHP, DDGS as fuel	As WTET1b but process heat from straw-fired combined heat and power scheme
WWET1	W Wood	Ethanol from waste wood
WFET1	F wood	Ethanol from farmed wood
STET1	Wheat straw	Ethanol from wheat straw
SCET1	Sugar cane (Brazil)	Ethanol from sugar cane in Brazilian conditions
Ethers		
GRMB1	MTBE: remote plant	MTBE produced in a remote plant from locally produced methanol (from NG) and associated butanes
LREB1	ETBE: imported C4 and wheat ethanol	ETBE produced in EU from imported butanes and wheat ethanol
Bio-diesel		
ROFA1	RME: Gly as chemical	Rapeseed Methyl Ester, glycerine used as chemical
ROFA2	RME: Gly as animal feed	Rapeseed Methyl Ester, glycerine used as animal feed
ROFE1	REE: Gly as chemical	Rapeseed Ethyl Ester, glycerine used as chemical
ROFE2	REE: Gly as animal feed	Rapeseed Ethyl Ester, glycerine used as animal feed
SOFA1	SME: Gly as chemical	Sunflower seed Methyl Ester, glycerine used as chemical
SOFA2	SME: Gly as animal feed	Sunflower seed Methyl Ester, glycerine used as animal feed

Synthetic diesel		
GRSD1	Rem GTL, Sea, Diesel mix	Synthetic diesel from NG in remote plant , sea transport, blended with conventional diesel at refinery
GRSD2	Rem GTL, Sea, Rail/Road	As above but distributed separately
GRSD2C	Rem GTL, Sea, Rail/Road, CC&S	As above with capture and sequestration of CO_2 produced in production process
KOSD1	CTL, Diesel mix	Synthetic diesel from coal in EU plant , blended with conventional diesel at refinery
KOSD1C	CTL, CC&S, Diesel mix	As above with capture and sequestration of CO_2 produced in production process
WWSD1	W Wood, diesel mix	Synthetic diesel from waste wood in EU plant, blended with conventional diesel at refinery
WFSD1	F wood, diesel mix	Synthetic diesel from farmed wood in EU plant, blended with conventional diesel at refinery
BLSD1	W Wood, Black liquor	Synthetic diesel from waste wood in EU paper mill (Black Liquor route) , blended with conventional diesel at refinery
Methanol		
GPME1a	NG 7000 km, Syn, Rail/Road	Methanol synthesis from NG piped over 7000 km, distributed by rail + road
GPME1b	NG 4000 km, Syn, Rail/Road	Methanol synthesis from NG piped over 4000 km, distributed by rail + road
GRME1	Rem Syn, Sea, Rail/Road	Methanol produced remotely from NG, transported by sea, distributed by rail + road
KOME1	Coal EU-mix, Cen, Rail/Road	Methanol from large coal (average EU supply quality) plant in EU, distributed by rail + road
WWME1	W Wood, Road	Methanol from waste wood, distributed by road
WFME1	F Wood, Road	Methanol from waste wood, distributed by road
BLME1	W Wood, Black liquor	Methanol from waste wood in EU paper mill (Black Liquor route), distributed by road
DME (Di-Methyl-Ether)		
GPDE1a	NG 7000 km, Syn, Rail/Road	DME from NG piped over 7000 km, distributed by rail + road
GPDE1b	NG 4000 km, Syn, Rail/Road	DME from NG piped over 4000 km, distributed by rail + road
GRDE1	Rem Syn, Sea, Rail/Road	DME produced remotely from NG, transported by sea, distributed by rail + road
KODE1	Coal EU-mix, Cen, Rail/Road	DME from large coal (average EU supply quality) gasification plant in EU, distributed by rail + road
GRDE1C	Rem Syn, Sea, Rail/Road, CC&S	As above with capture and sequestration of CO_2 produced in production process
WWDE1	W Wood, Road	DME from waste wood, distributed by road
WFDE1	F Wood, Road	DME from waste wood, distributed by road
BLDE1	W Wood, Black liquor	DME from waste wood in EU paper mill (Black Liquor route), distributed by road

Compressed Hydrogen		
GMCH1	EU-mix, O/S Ref	Compressed hydrogen from reforming of average NG supply in small plant at or near retail site
GPCH1a	NG 7000 km, O/S Ref	Compressed hydrogen from reforming of NG piped over 7000 km in small plant at or near retail site
GPCH1b	NG 4000 km, O/S Ref	Compressed hydrogen from reforming of NG piped over 4000 km in small plant at or near retail site
GPCH2a	NG 7000 km, Cen ref, Pipe	Compressed hydrogen from reforming of NG piped over 7000 km in large EU plant, distributed by pipeline
GPCH2b	NG 4000 km, Cen Ref, Pipe	Compressed hydrogen from reforming of NG piped over 4000 km in large EU plant, distributed by pipeline
GPCH2bC	NG 4000 km, Cen Ref, Pipe, CC&S	As above with capture and sequestration of CO_2 produced in production process
GPCH3b	NG 4000 km, Cen Ref, Road	Compressed hydrogen from reforming of NG piped over 4000 km in large EU plant, distributed by road
GPLCHb	NG 4000 km, Cen Ref, Liq, Road, Vap/comp.	Compressed hydrogen from reforming of NG piped over 4000 km in large EU plant, liquefied, distributed by road and compressed on retail site
GRCH1	LNG, O/S Ref	Compressed hydrogen from reforming of imported LNG in small plant at or near retail site
GRCH2	LNG, Cen Ref, Pipe	Compressed hydrogen from reforming of imported LNG in large EU plant , distributed by pipeline
GRCH3	Rem NG, methanol, O/S Ref	Compressed hydrogen from methanol produced remotely from NG in small plant at or near retail site.
KOCH1	Coal EU-mix, cen Ref, Pipe	Compressed hydrogen from large coal (average EU supply quality) gasification plant in EU , distributed by pipeline
KOCH1C	Coal EU-mix, cen Ref, Pipe, CC&S	As above with capture and sequestration of CO_2 produced in production process
WWCH1	Wood W, O/S gasif	Compressed hydrogen from waste wood in small plant at or near retail site
WWCH2	Wood W, Cen gasif. Pipe	Compressed hydrogen from waste wood in large plant, distributed by pipeline
BLCH1	Wood W, Black liquor	Compressed hydrogen from waste wood in EU paper mill (Black Liquor route), distributed by pipeline
WFCH1	Wood F, O/S gasif	Compressed hydrogen from farmed wood in small plant at or near retail site
WFCH2	Wood F, Cen gasif, pipe	Compressed hydrogen from farmed wood in large plant, distributed by pipeline
Compressed hydrogen by electrolysis		
GPEL1a/CH1	NG 7000 km, CCGT, O/S Ely	Electricity from NG piped over 7000 km, in Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
GPEL1b/CH1	NG 4000 km, CCGT, O/S Ely	Electricity from NG piped over 4000 km, small scale electrolyser at or near retail site
GPEL1b/CH2	NG 4000 km, CCGT, Cen Ely, Pipe	Electricity from NG piped over 4000 km, in Combined Cycle Gas Turbine, large scale electrolyser, distributed by pipeline
GREL1/CH1	LNG, O/S Ely	Electricity from imported LNG, in Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
WFEL2/CH1	F Wood, 200 MW gasif, CCGT, O/S Ely	Electricity from large farmed wood gasifier + Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
WFEL3/CH1	F Wood, Conv power, O/S Ely	Electricity from large farmed wood conventional power plant, small scale electrolyser at or near retail site
EMEL1/CH1	Elec EU-mix, O/S Ely	Electricity from average EU supply, small scale electrolyser at or near retail site
KOEL1/CH1	Elec coal EU-mix, O/S Ely	Electricity from coal (average EU supply quality), small scale electrolyser at or near retail site
KOEL1/CH2	Elec coal EU-mix, Cen ely, Pipe	Electricity from coal (average EU supply quality), large scale electrolyser, distributed by pipeline
NUEL1/CH1	Elec nuclear, O/S Ely	Electricity from nuclear plant, small scale electrolyser at or near retail site
WDEL1/CH2	Wind, Cen Ely, Pipe	Electricity from wind, large scale electrolyser, distributed by pipeline

Liquid hydrogen		
GPLH1a	NG 7000 km, Cen Ref, Liq, Road	Liquid hydrogen from reforming of NG piped over 7000 km in large EU plant, distributed by road
GPLH1b	NG 4000 km, Cen Ref, Liq, Road	Liquid hydrogen from reforming of NG piped over 4000 km in large EU plant, distributed by road
GRLH1	Rem Ref, Liq, Sea, Road	Liquid hydrogen from reforming of remote NG transported by sea, distributed by road
GRLH2	LNG, Cen Ref, Liq, Road	Liquid hydrogen from reforming of imported LNG in large EU plant distributed by road
WFLH1	Wood F, Cen gasif, Liq, Road	Liquid hydrogen from farmed wood in large EU plant distributed by road
Liquid hydrogen by electrolysis		
GPEL1b/LH1	NG 4000 km, CCGT, Cen Ely, Liq, Road	Electricity from NG piped over 4000 km, in Combined Cycle Gas Turbine, small scale electrolyser at or near retail site
EMEL1/LH1	Elec EU-mix, Cen Ely, Liq, Road	Electricity from average EU supply, large scale electrolyser, distributed by road
KOEL1/LH1	Elec coal EU-mix, Cen Ely, Liq, Road	Electricity from coal (average EU supply quality), large scale electrolyser, distributed by pipeline
Electricity		
KOEL1	EU-mix Coal conv.	Electricity from coal (average EU supply quality), conventional power plant
KOEL2	EU-mix Coal IGCC	Electricity from coal (average EU supply quality), IGCC
GPEL1a	NG 7000 km, CCGT	Electricity from NG piped over 7000 km, in Combined Cycle Gas Turbine
GPEL1b	NG 4000 km, CCGT	Electricity from NG piped over 4000 km, in Combined Cycle Gas Turbine
GREL1	LNG, CCGT	Electricity from imported LNG, in Combined Cycle Gas Turbine
WFEL1	F Wood, 10 MW gasif	Electricity from farmed wood , in small scale gasifier + gas turbine
WFEL2	F Wood, 200 MW gasif	Electricity from farmed wood , in large scale gasifier + Combined Cycle Gas Turbine
WFEL3	F Wood, Conv power	Electricity from farmed wood , in large scale conventional power plant
EMEL1	EU-mix	Electricity from average EU supply
WDEL1	Wind offshore	Electricity from offshore wind farm
NUEL1	Nuclear	Electricity from nuclear plant
OWEL1a	Biogas ex municipal waste, local	Electricity from small scale biogas plant ex municipal waste (gas engine)
OWEL1b	Biogas ex municipal waste, large	Electricity from biogas produced in small scale plant ex municipal waste, injected in grid and used in large power plant
OWEL2a	Biogas ex liquid manure, local	Electricity from small scale biogas plant ex liquid manure (gas engine)
OWEL2b	Biogas ex liquid manure, large	Electricity from biogas produced in small scale plant ex liquid manure, injected in grid and used in large power plant
OWEL3a	Biogas ex dry manure, local	Electricity from small scale biogas plant ex dry manure (gas engine)
OWEL3b	Biogas ex dry manure, large	Electricity from biogas produced in small scale plant ex dry manure, injected in grid and used in large power plant
BLEL1	Black liquor	Electricity from black liquor IGCC

WTT APPENDIX 3

Energy requirement and GHG emissions for marginal gasoline and diesel fuel production

This study is about alternative road fuels and their potential to replace conventional gasoline and diesel fuels. When we evaluate these alternatives we need to consider their potential to save energy and GHG. At the 2010-2020 horizon, alternative fuels can only be reasonably expected to supply say 10% to 20% of the road fuel demand. As far as the conventional fuels are concerned, the issue is therefore how much can be saved by not producing the marginal 10 or 20% of the 2010-2020 expected demand.

Oil refineries produce a number of different products simultaneously from a single feedstock. Whereas the total amount of energy (and other resources) used by refineries is well documented, there is no simple, non-controversial way to allocate energy, emissions or cost to a specific product. Distributing the resources used in refining amongst the various products invariably involves the use of arbitrary allocation keys that can have a major influence on the results.

For example energy content is a popular allocation key; there is, however, no physical reason why a product with higher energy content should systematically attract more production energy. Another example is provided by naphtha reforming, a ubiquitous refinery process that dehydrogenates virgin naphthas into a high octane gasoline component; a superficial analysis would call for allocating most of the energy requirement of this process to gasoline production; however the bulk of that energy is chemical energy related to the simultaneous production of hydrogen which, in turns, is used for the desulphurisation of diesel components.

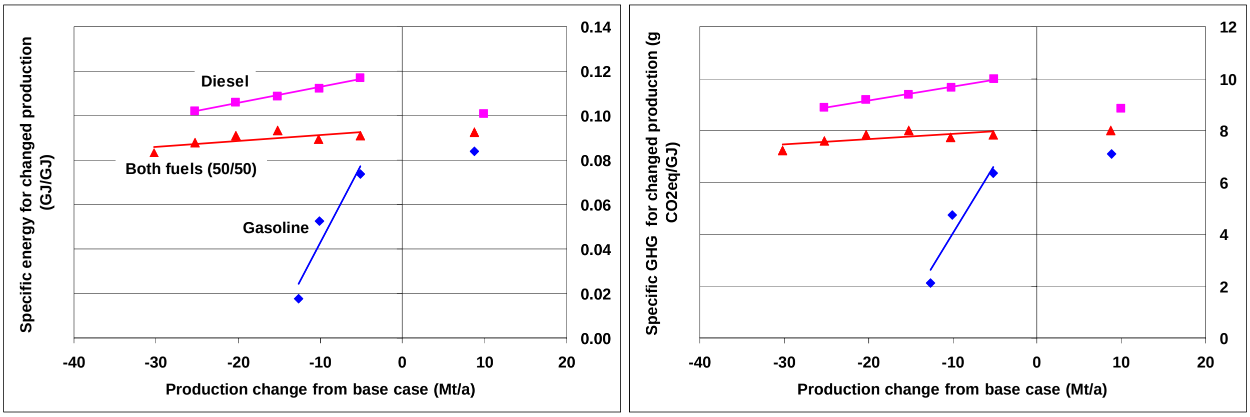
More to the point, such a simplistic allocation method ignores the complex interactions, constraints, synergies within a refinery and also between the different refineries in a certain region and is likely to lead to misleading conclusions. From an energy and GHG emissions point of view, this is also likely to give an incomplete picture as it ignores overall changes in energy/carbon content of feeds and products.

To approach the problem we performed a marginal analysis of the European refining system using the CONCAWE EU refining model. In a “business-as-usual” base case no alternative fuels are involved and the EU refineries have to substantially meet the total 2010 demand with minimum adaptation of the refining configuration. In the alternative cases conventional gasoline and/or diesel demand is reduced by a certain amount assumed to be substituted by other fuels. Demands for other oil products are fixed to the values expected to prevail in 2010. The crude oil supply is also fixed, with the exception of a balancing crude (heavy Middle Eastern considered as the marginal crude). Gasoline and diesel maximum sulphur content are assumed to be 10 ppm. All other fuel specifications are assumed to remain at the currently legislated levels i.e. maximum 35%v/v aromatics in gasoline from 2005 and other specifications remaining at current values.

The difference in energy consumption and GHG emissions between the base case and an alternative can be credibly attributed to the single change in gasoline or diesel fuel production

The CONCAWE model is fully carbon and energy balanced so that the differentials between two cases take into account small changes in energy and carbon content of all products.

The outcome of this work is shown in the figure below where the energy and CO_2 emissions associated to a certain marginal production of either diesel or gasoline are plotted as a function of that production. The data points represent the average value per MJ for the total amount produced.



Note: data points show the average saving at a given reduction level

The first striking point is that more energy/CO_2 can be saved through substituting diesel rather than gasoline. This goes somewhat against “conventional wisdom” according to which gasoline production is more energy-intensive than diesel’s. Whereas this assertion can be challenged for any modern refinery, this is particularly incorrect in Europe where the demand pattern is such that refineries struggle to produce the large middle distillate demand while having to export substantial quantities of gasoline.

The pattern is somewhat different when looking at either an increase or a decrease in production from the base case. The latter represents the point that was “planned for” i.e. for which the refineries invested.

Reducing production from the base case represents a situation where refineries would have over-invested. Diesel is in high demand in Europe and the marginal production routes are likely to be rather inefficient. At a lower production spare capacity becomes available and the system sheds first the least efficient production routes, thus the downward slope of the curve. Gasoline is in surplus and any reduction of production will increase the imbalance and therefore result in a low energy saving, the more so as the production is further decreased.

Increasing production from the base case represents a situation where refineries have correctly anticipated the level of demand for conventional fuels. The figures thus pertain to the additional “cost” that would have been incurred by having to produce more. The somewhat lower figure for diesel reflects the fact that additional new processes are likely to be efficient.

As refineries tend to adapt to the market as it develops rather than over-invest, we believe these latter figures are the most relevant. Accordingly we have proposed to use 0.08 and 0.10 MJ_{ex}/MJ_f and 6.5 and 8.6 g CO_2/MJ_f for gasoline and diesel fuel respectively.

It must be realised that the outcome of such an analysis is still dependent on a number of assumptions particularly with regard to the base case and the actual level of demand compared to the production capacity. Clearly a reduction of gasoline demand below general expectations could lead to very small energy savings.

Our base case includes a certain amount of diesel imports and it could be argued that these will be the first one to be substituted. Reality is likely to be more complex and some imports will undoubtedly still take place with or without alternative diesel sources. In any case, imported diesel will be made in non-European refineries, the level of complexity and conversion of which will have to be similar to the European ones inasmuch as the demand for residual products relative to lighter ones is globally decreasing. The energy and GHG emissions figures associated to this production would be at most similar to European figures or more likely lower as such refineries would produce a more balanced product basket. By using the European figures we therefore err on the conservative side.

There are further sources of uncertainty that may materially affect our results:

- Although our model includes a number of safeguards to avoid over-optimisation, there is a real possibility that actual refinery operations will be sub-optimum. As this would affect both the base case and the alternative cases in a similar way it does not materially affect the differential numbers.
- Historically, European refineries have improved their energy efficiency by about 1% per year. We have assumed this trend will continue a/o under pressure of site CO_2 emissions limitations. The effect of a change to this assumption would be small compared to the variability of the figures shown in the figures above.
- Refineries traditionally use part of their crude intake as fuel, in the form of gases produced in various process units, coke produced internally in the FCC supplemented by liquid (mainly residual) fuel. Some refineries have replaced part or all their liquid fuel by imported natural gas usually to meet local SO_2 emissions regulations. This trend has the potential to increase somewhat in the future either because of increased pressure on SO_2 emissions or actions to reduce site CO_2 emissions. Such a change would not impact energy efficiency figures, but would slightly reduce CO_2 emissions. Again the effect is small compared to other sources of variability.

WTT APPENDIX 2

Description and detailed energy and GHG balance of individual pathways

This appendix gives the detailed results of the energy and GHG balance for all pathways. Pathways new to this version have been highlighted in yellow.

It details the processes included in each pathway (discussed in ***WTT Appendix 1***) and gives the resulting energy and GHG balance for the total pathway as well as the contribution of each of the main stages.

Energy figures are expressed as net energy *expended* (MJ_x) (i.e. excluding the energy transferred to the final fuel) per MJ energy content of the final fuel (MJ_f). "Total primary" refers to all energy regardless of the primary energy source, i.e. including renewable energy. The portion of this total energy that comes from fossil sources is given in the "fossil" column.

Note: the use of the EU-mix electricity as a generic power source for e.g. transport or operation of refuelling stations introduces a small amount of renewable energy in most pathways.

The best estimate and the range of variability are given for both energy and GHG. The ranges are obtained via a Monte Carlo simulation combining the range of variation of individual processes (see ***WTT Appendix 1***). The minimum value is taken as P20 (20% of observed values will be below that value) and the maximum as P80. The range of energy variation is also indicated for those steps that make a significant contribution.

In order to facilitate comparison of pathways of a different nature the final table regroups the actual processes into five standard stages namely

Stage 1: Production and conditioning at source
Includes all operations required to extract, capture or cultivate the primary energy source. In most cases, the extracted or harvested energy carrier requires some form of treatment or conditioning before it can be conveniently, economically and safely transported.

Stage 2: Transformation at source
Is used for those cases where a major industrial process is carried out at or near the production site of the primary energy (e.g. gas-to-liquids plant).

Stage 3: Transportation to EU
Is relevant to energy carriers which are produced outside the EU and need to be transported over long distances. This step is also used where a significant transport vector is required to move the raw material to a processing plant (e.g. biomass).

Stage 4: Transformation in EU
Includes the processing and transformation that takes place near the market place in order to produce a final fuel according to an agreed specification (e.g. oil refineries or hydrogen reformers).

Stage 5: Conditioning and distribution
Relates to the final stages required to distribute the finished fuels from the point of import or production to the individual refuelling points (e.g. road transport) and available to the vehicle tank (e.g. compression in the case of natural gas).

Pathway list

1 Conventional fuels

Pathway code		**COD**	**COG**	**CON**
		1	**1**	**1**
Code	Process			
Crude oil				
CO1	Crude oil production	✓	✓	✓
CO2	Crude oil transportation	✓	✓	✓
CD1	Crude oil refining, marginal diesel	✓		
CD2	Diesel transport	✓		
CD3	Diesel depot	✓		
CD4	Diesel distribution and dispensing	✓		
CG1	Crude oil refining, marginal gasoline		✓	
CG2	Gasoline transport		✓	
CG3	Gasoline depot		✓	
CG4	Gasoline distribution and dispensing		✓	
CN1	Crude oil refining, marginal naphtha			✓
CN2	Naphtha transport			✓
CN3	Naphtha depot			✓
CN4	Naphtha distribution and dispensing			✓
Common processes				
Z1	Diesel production	✓	✓	✓
Z2	Road tanker	✓	✓	✓
Z3	HFO production	✓	✓	✓
Z5	Rail transport	✓	✓	✓
Z7a	Electricity (EU-mix, MV)	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓

COG1 Crude oil to gasoline

COD1 Crude oil to diesel

CON1 Crude oil to naphtha

The gasoline and diesel fuel pathways are the reference against which all others need to be evaluated. Naphtha is a potential fuel for fuel cells.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			Individual GHG		
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g CO_2/MJ	g CH_4/MJ	g N_2O/MJ
COG1	**Crude oil to gasoline**											
	Crude Extraction & Processing	1	0.03	0.01	0.04		3.6			3.6	0.00	0.000
	Crude Transport	3	0.01				0.9			0.9	0.00	0.000
	Refining	4	0.08	0.06	0.10		7.0			7.0	0.00	0.000
	Distribution and dispensing	5	0.02				1.0			1.0	0.00	0.000
	Total pathway		**0.14**	0.12	0.17	**0.14**	**12.5**	11.1	14.6	12.5	0.00	0.000
COD1	**Crude oil to diesel**											
	Crude Extraction & Processing	1	0.03	0.01	0.04		3.7			3.7	0.00	0.000
	Crude Transport	3	0.01				0.9			0.9	0.00	0.000
	Refining	4	0.10	0.08	0.12		8.6			8.6	0.00	0.000
	Distribution and dispensing	5	0.02				1.0			1.0	0.00	0.000
	Total pathway		**0.16**	0.14	0.18	**0.16**	**14.2**	12.6	16.0	14.2	0.00	0.000
CON1	**Crude oil to naphtha**											
	Crude Extraction & Processing	1	0.03	0.01	0.04		3.5			3.5	0.00	0.000
	Crude Transport	3	0.01				0.9			0.9	0.00	0.000
	Refining	4	0.05	0.04	0.06		4.4			4.4	0.00	0.000
	Distribution and dispensing	5	0.02				1.0			1.0	0.00	0.000
	Total pathway		**0.11**	0.10	0.13	**0.11**	**9.8**	8.5	11.3	9.7	0.00	0.000

2 Compressed gas from NG and biomass (CNG/CBG), LPG

2.1 Natural gas to CNG

Pathway code		**GMCG**	**GPCG**		**GRCG**		
		1	**1a**	**1b**	**1**	**1C**	**2**
Code	Process						
GG1	NG Extraction & Processing	✓	✓	✓	✓	✓	✓
NG from pipeline							
GP1a	Russian quality, 7000 km		✓				
GP1b	Average quality, 4000 km			✓			
GM1	EU-mix quality, 1000 km	✓					
LNG production & transport							
GR1	NG Liquefaction				✓		✓
GR1C	NG Liquefaction with CCS					✓	
GR2	LNG terminal (loading)				✓	✓	✓
GR3	LNG transport (average of two distances)				✓	✓	✓
GR4	LNG terminal (unloading)				✓	✓	✓
NG distribution							
GR5	LNG vaporisation				✓	✓	
GR6	LNG distribution (road tanker)						✓
GR7	LNG to CNG (vaporisation/compression)						✓
GG3	NG trunk distribution	✓	✓	✓	✓	✓	
GG4	NG local distribution	✓	✓	✓	✓	✓	
GG5	CNG dispensing (compression 0.4-25 MPa)	✓	✓	✓	✓	✓	
NG common processes							
GG2	Electricity generation from NG (CCGT)				✓	✓	✓
Common processes							
Z1	Diesel production						✓
Z2	Road tanker						✓
Z3	HFO production				✓	✓	✓
Z4	Product carrier 50 kt				✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓

GMCG1 EU-mix NG supply to CNG

For new applications such as CNG, the EU-mix is, in effect, irrelevant inasmuch as additional marginal gas needs to be used. This case is shown here for reference and to illustrate, when compared to the other cases, the large effect of the gas origin.

GPCG1a Piped NG (7000 km) to CNG

This pathway represents gas imported into the EU through pipelines from Western Siberia, one of the main current and future EU supply sources.

GPCG1b Piped NG (4000 km) to CNG

This pathway represents gas imported into the EU through pipelines from the Middle East or South Western Asia, both key regions for the future EU supplies.

GRCG1/1C LNG to CNG (gaseous distribution) (+CC&S option)

LNG can be imported into the EU from various remote sources, the Middle East being one of the most promising in terms of volumes (hence the assumed shipping distance of 5500 nautical miles). In this pathway, LNG is vaporised on receipt into the EU gas grid). Optionally the CO_2 produced in the liquefaction site power plant can be captured and re-injected into a nearby gas or oil field.

GRCG2 LNG to CNG (liquid distribution)

This pathway is similar to CRGC1 but now assumes that LNG is transported as such, by road, to the refuelling stations.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GMCG1	**NG current EU-mix (1000 km)**											
	Extraction & Processing	1	0.02	0.01	0.05		3.2			1.2	0.09	0.000
	Transport	3	0.02				1.9			1.1	0.03	0.000
	Distribution	5	0.01				0.6			0.6	0.00	0.000
	Compression	5	0.06	0.08	0.04		2.8			2.7	0.01	0.000
	Total pathway		**0.12**	0.09	0.14	**0.12**	**8.4**	7.2	9.6	5.5	0.13	0.000
GPCG1a	**Piped NG, 7000 km**											
	Extraction & Processing	1	0.03	0.01	0.06		3.6			1.3	0.10	0.000
	Transport	3	0.19	0.06	0.22		14.6			10.2	0.19	0.000
	Distribution	5	0.01				0.6			0.6	0.00	0.000
	Compression	5	0.06	0.08	0.04		2.8			2.7	0.01	0.000
	Total pathway		**0.30**	0.20	0.30	**0.29**	**21.7**	16.0	21.8	14.7	0.29	0.001
GPCG1b	**Piped NG, 4000 km**											
	Extraction & Processing	1	0.03	0.01	0.05		3.3			1.2	0.09	0.000
	Transport	3	0.09	0.03	0.10		7.3			4.8	0.11	0.000
	Distribution (HP)	5	0.01				0.6			0.5	0.00	0.000
	Compression	5	0.06	0.08	0.04		2.8			2.7	0.01	0.000
	Total pathway		**0.19**	0.14	0.21	**0.19**	**14.0**	11.0	14.8	9.2	0.20	0.000
GRCG1	**LNG, gaseous distribution**											
	Extraction & Processing	1	0.03	0.01	0.05		3.3			1.2	0.09	0.000
	Liquefaction	2	0.09	0.08	0.09		5.7			4.7	0.04	0.000
	Transport (shipping)	3	0.09				5.6			5.5	0.00	0.000
	Receipt + Vaporisation	5	0.03				1.8			1.8	0.00	0.000
	Distribution	5	0.01				0.6			0.5	0.00	0.000
	Compression	5	0.06	0.08	0.04		2.8			2.7	0.01	0.000
	Total pathway		**0.31**	0.29	0.33	**0.30**	**19.9**	19.0	21.2	16.5	0.14	0.000
GRCG1C	**LNG, gaseous distribution, CC&S**											
	Extraction & Processing	1	0.03	0.01	0.05		3.3			1.2	0.09	0.000
	Liquefaction (CCS)	2	0.10	0.09	0.10		2.3			1.2	0.04	0.000
	Transport (shipping)	3	0.09				5.5			5.5	0.00	0.000
	Receipt + Vaporisation	5	0.03				1.8			1.8	0.00	0.000
	Distribution	5	0.01				0.6			0.6	0.00	0.000
	Compression	5	0.06	0.08	0.04		2.8			2.7	0.01	0.000
	Total pathway		**0.32**	0.30	0.35	**0.32**	**16.4**	15.3	17.8	13.0	0.14	0.000
GRCG2	**LNG, liquid distribution (trucking)**											
	Extraction & Processing	1	0.03	0.01	0.05		3.3			1.2	0.09	0.000
	Liquefaction	2	0.09				5.7			4.7	0.04	0.000
	Transport (shipping)	3	0.09				5.6			5.5	0.00	0.000
	Receipt	5	0.01				0.7			0.7	0.00	0.000
	Distribution	5	0.02				3.6			1.2	0.10	0.000
	Compression	5	0.03				1.5			1.5	0.00	0.000
	Total pathway		**0.26**	0.25	0.28	**0.26**	**20.3**	19.9	21.6	14.8	0.24	0.000

2.2 Biomass to CBG

Pathway code		**OWCG**		
		1	**2**	**3**
Code	Process			
Biogas				
BG1a	Liquid manure transport, 10 km		✓	
BG1b	Dry manure transport, 10 km			✓
BG2a	Municipal waste to biogas (upgraded)	✓		
BG2b	Liquid manure to biogas (upgraded)		✓	
BG2c	Dry manure to biogas (upgraded)			✓
BG3a	Municipal waste to electricity (small scale, local)	✓		
BG3b	Liquid manure to electricity (small scale, local)		✓	
BG3c	Dry manure to electricity (small scale, local)			✓
NG distribution				
GG4	NG local distribution	✓	✓	✓
GG5	CNG dispensing (compression 0.4-25 MPa)	✓	✓	✓
Common processes				
Z7a	Electricity (EU-mix, MV)	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓

OWCG1 Municipal waste to CBG

Municipal waste, already collected is turned into biogas. The biogas is treated and upgraded before being fed into an existing NG grid to be used as automotive fuel.

OWCG2/3 Municipal waste to CBG

Liquid or dry manure is collected from farms and turned into biogas in a central plant serving a small community. The biogas is treated and upgraded before being fed into an existing NG grid to be used as automotive fuel.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
OWCG1	**CBG: municipal waste**											
	Production, treating and upgrading	4	0.81				32.31			-51.9	0.45	-0.006
	Distribution (pipeline)	5	0.00				0.00			0.0	0.00	0.000
	Refuelling station	5	0.06				2.85			2.7	0.01	0.000
	Total WTT GHG emitted						**35.2**	32.6	37.9	-49.2	0.46	-0.006
	Credit for renewable combustion CO_2						-75.5			-75.5		
	Total pathway		**0.87**	0.73	1.01	**0.17**	**-40.4**	-42.9	-37.7			
OWCG2	**CBG: liquid manure**											
	Manure transport	3	0.03				-86.92			2.1	-3.87	0.000
	Production, treating and upgrading	4	0.88				25.83			16.2	0.47	-0.004
	Distribution (pipeline)	5	0.00				0.00			0.0	0.00	0.000
	Refuelling station	5	0.06				2.85			2.7	0.01	0.000
	Total WTT GHG emitted						**-58.3**	-81.6	-28.5	21.0	-3.39	-0.004
	Credit for renewable combustion CO_2						-75.5			-75.5		
	Total pathway		**0.97**	0.79	1.12	**0.03**	**-133.8**	-157.1	-104.0			
OWCG3	**CBG: dry manure**											
	Manure transport	3	0.01				-8.22			0.7	-0.39	0.000
	Production, treating and upgrading	4	0.88				25.83			16.2	0.47	-0.004
	Distribution (pipeline)	5	0.00				0.00			0.0	0.00	0.000
	Refuelling station	5	0.06				2.85			2.7	0.01	0.000
	Total WTT GHG emitted						**20.5**	17.2	23.3	19.6	0.09	-0.004
	Credit for renewable combustion CO_2						-75.5			-75.5		
	Total pathway		**0.95**	0.77	1.11	**0.01**	**-55.1**	-58.3	-52.2			

2.3 LPG

LRLP1 Gas field condensate to LPG

C3 and C4 condensates from remote gas production are separated treated and liquefied prior to shipping to Europe and distribution as automotive LPG.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
LRLP1	**LPG from gas field (remote)**											
	Extraction & Processing	1	0.05				3.4			3.1	0.02	0.000
	Liquefaction	2	0.01				0.3			0.3	0.00	0.000
	Transport (shipping)	3	0.03				2.5			2.5	0.00	0.000
	Distribution	5	0.02				1.3			1.3	0.00	0.000
	Compression	5	0.01				0.4			0.4	0.00	0.000
	Total pathway		**0.12**	0.12	0.13	**0.12**	**7.9**	8.0	8.4	7.5	0.02	0.000

3 Ethanol

		S. beet		Wheat								S. cane	Straw			Wood waste via BL	
Pathway code		**SBET**		**WTET**								**SCET**	**STET**	**WFET**	**WWET**	**BLCH**	**BLME**
		1	**3**	**1a**	**1b**	**2a**	**2b**	**3a**	**3b**	**4a**	**4b**	**1**	**1**	**1**	**1**	**1**	**1**
Code	Process																
Farming																	
SB1	Sugar Beet Farming	✓	✓														
WT1	Wheat farming			✓	✓	✓	✓	✓	✓	✓	✓						
SC1	Sugar cane farming (Brazil)											✓	✓				
Crop transport and processing																	
SB2	Sugar beet road transport	✓	✓														
SB3a	Sugar beet to ethanol, pulp and slops to animal feed	✓															
SB3c	Sugar beet to ethanol, pulp and slop to biogas		✓														
WT2a	Wheat grain road transport			✓	✓	✓	✓	✓	✓	✓	✓						
WT2b	Wheat straw road transport									✓	✓		✓				
WT3	Wheat grain handling and drying (to dwg, 3%			✓	✓	✓	✓	✓	✓	✓	✓						
WT4a	Wheat grain to ethanol, conventional boiler			✓	✓												
WT4b	Wheat grain to ethanol, NG CCGT					✓	✓										
WT4c	Wheat grain to ethanol, Lignite CHP							✓	✓								
WT4d	Wheat grain to ethanol, Straw CHP									✓	✓						
WTDa	Credit for DDGS as animal feed			✓		✓		✓		✓							
WTDb	Credit for DDGS as fuel				✓		✓		✓		✓						
W3k	Wheat straw to ethanol (Iogen)												✓				
SC2	Sugar cane road transport											✓					
SC3	Sugar cane to ethanol											✓					
SC4	Sugar cane ethanol from Brazil											✓					
Wood (farmed)																	
WF1	Wood farming and chipping													✓			
Wood (waste)																	
WW1	Forest residuals to wood chips														✓	✓	✓
Wood transport & processing (all sources)																	
WC2a	Wood chips road transport, 50 km													✓	✓	✓	✓
WC2c	Coastal/river shipping wood ships (200MW plant)														✓		
W3j	Woody biomass to ethanol (SSCF)													✓	✓		
Biofuels transport & distribution																	
ETd	Ethanol distribution (blended)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		
Common processes																	
Z1	Diesel production	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Z2	Road tanker	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓
Z3	HFO production											✓					
Z4	Product carrier 50 kt											✓					
Z6	Marginal NG for general use (4000 km piped)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓				
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

SBET1/3 Sugar beet to ethanol

Two alternatives use for the pulp and slop by-products are described, namely animal feed and conversion to biogas for cogeneration.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
SBET1	**EtOH from sugar beet, animal feed export, IPPC N_2O**											
	Cultivation	1	0.16				20.83			10.5	0.01	0.034
	Road transport	3	0.03				2.12			2.1	0.00	0.000
	Ethanol plant	4	1.64				33.00			35.0	0.11	-0.016
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**57.5**	54.3	61.0	49.1	0.13	0.018
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.86**	1.74	1.99	**0.87**	**-13.9**	-17.1	-10.4			
SBET3	**Ethanol from Sugar beet, pulp to heat, IPPC N_2O**											
	Cultivation	1	0.16				20.83			10.5	0.01	0.034
	Road transport	3	0.03				2.12			2.1	0.00	0.000
	Ethanol plant	4	1.08				5.20			4.9	0.01	0.000
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**29.7**	27.0	31.6	19.0	0.03	0.034
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.30**	1.18	1.42	**0.31**	**-41.7**	-44.4	-39.8			

WTET Wheat grain to ethanol

The first version of the study only considered a single pathway depicting a production plant with a conventional steam boiler and imported electricity. DDGS was deemed to be used as animal feed. We have now incorporated more variants based on the work done in the framework of the UK's Low carbon Vehicle Partnership [*LowCVP 2004*].

1a/b This is the conventional process where heat for the ethanol plant is provided by a NG-fired steam boiler and electricity is imported from the grid. DDGS is used as either as animal feed (a) or as co-fuel in a coal power station (b). The straw is not used and assumed to be ploughed back into the field (the fertiliser inputs are adjusted accordingly).

2a/b The energy to the ethanol plant is provided by a NG-fired CCGT sized to provide the required heat. Surplus electricity is produced and exported, which generates a credit calculated by comparison to a state-of-the-art stand-alone NG-fired CCGT (the benefit stems from the use of CHP in the ethanol plant). DDGS is used either as animal feed (a) or as co-fuel in a coal power station (b). Although option b is more favourable from an energy point of view, option a is likely to be preferred for economic reasons. The straw is not used (see 1a).

3a/b The energy for the ethanol plant is provided by a lignite (or brown coal) -fired CHP power plant sized to provide the required heat. Surplus electricity is produced and exported, which generates a credit calculated by comparison to a state-of-the-art stand-alone lignite power plant (the benefit stems from the use of CHP in the ethanol plant). Both DDGS use options are presented (see 3a/b) and straw is not used (see 1a).

4a/b The energy for the ethanol plant is provided by a straw-fired CHP power plant sized to provide the required heat. Surplus electricity is produced and exported, which generates a credit calculated by comparison to a state-of-the-art stand-alone straw power plant (the benefit stems from the use of CHP in the ethanol plant). The fertiliser inputs are adjusted to compensate fort the lost of soil nutrients from straw. Both DDGS use options are presented (see 3a/b).

WTT APPENDIX 2

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
WTET1a	**Ethanol from Wheat, Conv NG boiler, DDGS as animal feed**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	1.49				25.17			32.2	0.10	-0.031
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**59.2**	51.8	67.2	48.5	0.13	0.026
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.78**	1.76	1.80	**0.89**	**-12.2**	-19.6	-4.1			
WTET1b	**Ethanol from Wheat, Conv NG boiler, DDGS as fuel**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	1.02				16.54			15.7	0.04	0.000
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**50.5**	43.7	57.2	32.0	0.07	0.057
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.30**	1.28	1.33	**0.44**	**-20.8**	-27.7	-14.1			
WTET2a	**Ethanol from Wheat, NG GT+CHP, DDGS as animal feed**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	1.24				12.56			20.8	0.07	-0.033
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**46.6**	39.2	53.2	37.2	0.09	0.025
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.53**	1.51	1.55	**0.65**	**-24.8**	-32.1	-18.2			
WTET2b	**Ethanol from Wheat, NG GT+CHP, DDGS as fuel**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	0.77				3.93			4.3	0.01	-0.002
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**37.9**	31.6	44.7	20.7	0.03	0.056
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.06**	1.04	1.08	**0.20**	**-33.5**	-39.8	-26.7			
WTET3a	**Ethanol from Wheat, lignite CHP, DDGS as animal feed**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	1.46				58.58			68.1	0.00	-0.032
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**92.6**	84.8	100.0	84.5	0.03	0.025
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.74**	1.74	1.75	**0.86**	**21.2**	13.5	28.6			
WTET3b	**Ethanol from Wheat, Lignite CHP, DDGS as fuel**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	0.98				49.95			51.6	-0.06	-0.001
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**83.9**	77.7	91.5	68.0	-0.03	0.056
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.27**	1.27	1.27	**0.41**	**12.6**	6.3	20.1			
WTET4a	**Ethanol from Wheat, Straw CHP, DDGS as animal feed**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	1.40				-9.18			-71.1	0.00	-0.032
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**24.8**	17.6	31.5	-54.7	0.03	0.025
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.69**	1.69	1.70	**0.28**	**-46.6**	-53.8	-39.9			
WTET4b	**Ethanol from Wheat, Straw CHP, DDGS as fuel**											
	Cultivation	1	0.24				31.92			14.3	0.03	0.058
	Road transport	3	0.03				0.54			0.5	0.00	0.000
	Ethanol plant	4	0.93				-17.82			-87.6	-0.06	-0.001
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**16.2**	8.5	22.9	-71.2	-0.03	0.056
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.22**	1.21	1.22	**-0.17**	**-55.2**	-62.9	-48.5			

SCET1 Sugar cane to ethanol (Brazil)

Sugar cane is grown and turned into ethanol in Brazil. The bagasse is used as fuel (as is current practice), also generating surplus heat. The data is based on [*Macedo 2004*]. Ethanol is shipped into Europe where it is blended with gasoline.

STET1 Wheat straw to ethanol

This pathway specifically refers to the Iogen process [*Iogen 2003*] which hydrolyses cellulose into fermentable sugars. Additional agricultural inputs to compensate for the removal of straw from soils are taken into account.

W/F-WET1 Waste/Farmed wood to ethanol

These are more generic cellulose-to-ethanol pathways where wood (poplar) is a proxy for a number of possible feedstocks (e.g. perennial grasses). The process is based on an earlier reference from NERL [*Wooley 1999*].

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
SCET1	**EtOH from sugar cane (Brazil)**											
	Cultivation	1	0.06				13.09			3.7	0.15	0.020
	Road transport	3	0.01				0.85			0.8	0.00	0.000
	Ethanol plant	4	1.63				-10.31			-10.2	0.00	0.000
	Ethanol transport	5	0.08				0.99			1.0	0.00	0.000
	Refuelling station	5	0.01				5.82			5.8	0.00	0.000
	Total WTT GHG emitted						**10.4**	10.2	10.7	1.1	0.15	0.020
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.79**	1.79	1.80	**0.02**	**-60.9**	-61.2	-60.7			
WWET1	**Ethanol from waste wood**											
	Waste collection and chipping	1	0.08				0.95			0.9	0.00	0.000
	Transport (road + sea)	3	0.04				3.18			3.0	0.01	0.000
	Ethanol plant	4	1.80				12.31			12.6	0.02	-0.002
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**18.0**	17.8	18.1	18.0	0.03	-0.002
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.94**	1.84	2.05	**0.27**	**-53.4**	-53.6	-53.3			
WFET1	**EtOH from farmed wood**											
	Cultivation	1	0.11				6.96			3.1	0.00	0.013
	Road transport	3	0.01				0.88			0.9	0.00	0.000
	Ethanol plant	4	1.80				12.31			12.6	0.02	-0.002
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**21.7**	19.0	28.2	18.1	0.02	0.010
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.95**	1.84	2.05	**0.27**	**-49.7**	-52.3	-43.2			
STET1	**EtOH from wheat straw (Iogen)**											
	Collection	3	0.05				3.35			3.3	0.00	0.000
	Road transport	3	0.01				0.62			0.6	0.00	0.000
	Ethanol plant	4	1.24				3.42			3.3	0.00	0.000
	Ethanol road transport, 150 km	5	0.02				1.10			1.1	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**8.9**	8.9	9.0	8.7	0.01	0.000
	Credit for renewable combustion CO_2						-71.4			-71.4		
	Total pathway		**1.32**	1.32	1.32	**0.11**	**-62.4**	-62.5	-62.4			

4 Bio-diesel

Pathway code		**ROFA**		**ROFE**		**SOFA**	
		1	**2**	**1**	**2**	**1**	**2**
Code	Process						
Farming							
RF1	Rapeseed Farming	✓	✓	✓	✓		
SF1	Sunflower seed Farming					✓	✓
Crop transport and processing							
WT2a	Wheat grain road transport			✓	✓		
WT3	Wheat grain handling and drying (to dwg, 3% moisture)			✓	✓		
WT4b	Wheat grain to ethanol, NG CCGT			✓	✓		
WTDa	Credit for DDGS as animal feed			✓	✓		
RO2	Rapeseed road transport	✓	✓	✓	✓		
RO3	Rapeseed to raw oil: extraction	✓	✓	✓	✓		
SO2	Sunflower seed road transport					✓	✓
SO3	Sunflower seed to raw oil: extraction					✓	✓
RO4/SO4	Raw oil to refined oil	✓	✓	✓	✓		
RO5/SO5	Refined oil to FAME: esterification						
5a	Glycerine as chemical	✓		✓		✓	
5b	Glycerine as animal feed		✓		✓		✓
Biofuels transport & distribution							
FAd	FAME distribution (blended)	✓	✓	✓	✓	✓	✓
Common processes							
Z1	Diesel production	✓	✓	✓	✓	✓	✓
Z2	Road tanker	✓	✓	✓	✓	✓	✓
Z6	Marginal NG for general use (4000 km piped)	✓	✓	✓	✓	✓	✓
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓

ROFA1/2 Rape to FAME (RME)

SOFA1/2 Sunflower seed to FAME

For both crops two alternatives disposal routes for the glycerine are considered either as a chemical (replacing a bulk chemical such as propylene glycol) or as animal feed. These represent the extremes of GHG and fossil energy credits: reality will be in between.

ROFE1/2 Rape to FAEE (REE)

The same pathways as ROFA above where methanol has been replaced by (bio)ethanol. Although it is technically feasible, this process has not been commercially used so far. It has been assumed that the process energy is the same for both alcohols.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO$_2$eq/MJf)			CO$_2$	CH4	N$_2$O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
ROFA1	**RME, glycerine as chemical**											
	Cultivation	1	0.29				51.26			18.2	0.03	0.109
	Drying	1	0.01				0.66			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.30			0.3	0.00	0.000
	FAME manufacture	4	0.80				-13.71			-4.6	0.03	-0.033
	Transport and distribution	5	0.02				1.26			1.2	0.00	0.000
	Total WTT GHG emitted						**39.8**	20.5	58.6	15.7	0.07	0.076
	Credit for renewable combustion CO$_2$						-75.4			-75.4		
	Total pathway		**1.14**	1.05	1.23	**0.41**	**-35.6**	-54.9	-16.8			
ROFA2	**RME, glycerine as animal feed**											
	Cultivation	1	0.29				51.26			18.2	0.03	0.109
	Drying	1	0.01				0.66			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.30			0.3	0.00	0.000
	FAME manufacture	4	0.85				-8.46			0.9	0.04	-0.035
	Transport and distribution	5	0.02				1.26			1.2	0.00	0.000
	Total WTT GHG emitted						**45.0**	23.9	65.3	21.2	0.08	0.074
	Credit for renewable combustion CO$_2$						-75.4			-75.4		
	Total pathway		**1.20**	1.09	1.31	**0.46**	**-30.4**	-51.5	-10.1			
ROFE1	**REE, glycerine as chemical**											
	Cultivation	1	0.28				48.42			17.2	0.03	0.103
	Drying	1	0.01				0.62			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	FAEE manufacture	4	0.87				-17.85			-10.0	0.03	-0.029
	Transport and distribution	5	0.02				1.25			1.2	0.00	0.000
	Total WTT GHG emitted						**32.7**	12.5	53.1	9.3	0.06	0.074
	Credit for renewable combustion CO$_2$						-75.4			-75.4		
	Total pathway		**1.21**	1.11	1.30	**0.36**	**-42.7**	-62.9	-22.3			
ROFE2	**REE, glycerine as animal feed**											
	Cultivation	1	0.28				48.42			17.2	0.03	0.103
	Drying	1	0.01				0.62			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	FAEE manufacture	4	0.92				-13.12			-5.0	0.03	-0.030
	Transport and distribution	5	0.02				1.25			1.2	0.00	0.000
	Total WTT GHG emitted						**37.5**	19.4	59.7	14.3	0.07	0.073
	Credit for renewable combustion CO$_2$						-75.4			-75.4		
	Total pathway		**1.25**	1.17	1.36	**0.41**	**-37.9**	-56.0	-15.7			
SOFA1	**SME, glycerine as chemical**											
	Cultivation	1	0.17				27.44			11.5	0.01	0.053
	Drying	1	0.01				0.61			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	FAME manufacture	4	0.69				-12.19			-3.2	0.03	-0.033
	Transport and distribution	5	0.02				1.26			1.2	0.00	0.000
	Total WTT GHG emitted						**17.4**	5.6	30.0	10.3	0.05	0.021
	Credit for renewable combustion CO$_2$						-75.4			-75.4		
	Total pathway		**0.91**	0.83	1.01	**0.30**	**-58.0**	-69.8	-45.4			
SOFA2	**SME, glycerine as animal feed**											
	Cultivation	1	0.17				27.44			11.5	0.01	0.053
	Drying	1	0.01				0.61			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	FAME manufacture	4	0.74				-6.94			2.3	0.03	-0.034
	Transport and distribution	5	0.02				1.26			1.2	0.00	0.000
	Total WTT GHG emitted						**22.7**	11.1	33.2	15.8	0.05	0.019
	Credit for renewable combustion CO$_2$						-75.4			-75.4		
	Total pathway		**0.97**	0.88	1.06	**0.35**	**-52.8**	-64.4	-42.2			

5 Synthetic fuels

5.1 Synthetic diesel

		Remote NG			**Coal**		**Farmed wood**	**Waste wood**	**Black liquor**
Pathway code		**G R S D**			**K O S D**		**W F S D**	**W W S D**	**B L S D**
		1	**2**	**2C**	**1**	**1C**	**1**	**1**	**1**
Code	Process								
GG1	NG Extraction & Processing	✓	✓	✓					
NG to syn diesel									
GD1	NG to syn-diesel (remote or central plant)	✓	✓						
GD1C	NG to syn-diesel (remote or central plant) with CC&S			✓					
NG common processes									
GG2	Electricity generation from NG (CCGT)	✓	✓	✓					
Coal									
KO1	Hard coal provision (EU-mix) (1)				✓	✓			
KD1	Coal to syndiesel				✓				
KD1C	Coal to syndiesel with CC&S					✓			
Wood (farmed)									
WF1	Wood farming and chipping						✓		
Wood (waste)									
WW1	Forest residuals to wood chips							✓	✓
Wood transport & processing (all sources)									
WC2a	Wood chips road transport, 50 km						✓	✓	✓
WC2b	Wood chips road transport, 12 km								
WC2c	Coastal/river shipping wood ships (200MW plant)							✓	
W3f	Wood to syn-diesel: gasification + FT						✓	✓	
Wood waste via black liquor									
BLS	Wood waste to syn diesel via black liquor								✓
Syn diesel transport & distribution									
DS1	Syn diesel handling and loading (remote)	✓	✓	✓					
DS2	Syn diesel sea transport	✓	✓	✓					
DS3	Syn diesel depot	✓	✓	✓			✓	✓	
DS4	Syn diesel distribution (blending component)	**CD2/3/4**			✓	✓			
DS5	Syn diesel distribution (neat)		✓	✓					
SDd	Bio-(synthetic diesel) distribution (blended)						✓	✓	✓
Common processes									
Z1	Diesel production	✓	✓	✓	✓	✓	✓	✓	✓
Z2	Road tanker	✓	✓	✓	✓	✓	✓	✓	✓
Z3	HFO production	✓	✓	✓					
Z4	Product carrier 50 kt	✓	✓	✓					
Z5	Rail transport	✓	✓	✓	✓	✓	✓	✓	
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓	✓	✓

GRSD1/2/2C GTL: Remote NG to synthetic diesel (remote plant) (+CC&S option)

This option of a GTL plant installed near a remote gas supply is the most likely. Transport is less energy-intensive for a liquid such as synthetic diesel than for any gaseous fuel. Synthetic diesel is either blended into conventional diesel or used neat for a niche application. A substantial part of the CO_2 emitted by the GTL plant is scrubbed out of the syngas before the FT synthesis and is available in virtually pure form. Compression and re-injection in a nearby gas or oil field (CC&S) could be an attractive option.

KOSD1/1C CTL: Coal to synthetic diesel (+CC&S option)

The typical EU coal mix is used in a large scale Coal-to-Liquids (CTL) plant located in Europe. Synthetic diesel is blended into conventional diesel. A large amount of CO_2 is produced during the gasification process and is separated from the syngas before the Fischer-Tropsch stage. This offers an attractive opportunity for CC&S, as long as a suitable geological formation is available within a reasonable distance for long-term storage.

W/F-WSD1 Waste/Farmed wood to synthetic diesel

This is the Biomass-to-Liquids (BTL) pathway: wood gasification followed by Fischer-Tropsch synthesis.

BLSD1 Waste wood via black liquor to synthetic diesel

Black liquor is the residue of extraction of cellulose fibres from wood for paper pulp manufacturing. It contains the lignin and is used as fuel for the large power plant required by a paper mill. Black liquor is also suitable for gasification, the syngas being then available for either electricity hydrogen or synthetic fuels production. The shortfall of energy available to the paper mill can be made up by burning waste wood. Compared to a reference case with a traditional black liquor boiler and all other parameters being the desired fuel can be produced with significantly higher net energy efficiency than in a more conventional scheme.

WTT APPENDIX 2

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
Syn diesel												
GRSD1	**Syn diesel, remote plant, diesel mix**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.8			1.8	0.13	0.000
	GTL plant	2	0.59	0.54	0.64		16.5			16.5	0.00	0.000
	GTL transport	3	0.04				2.7			2.7	0.00	0.000
	Diesel distribution & dispensing	5	0.02				1.0			1.0	0.00	0.000
	Total pathway		**0.68**	0.63	0.75	**0.68**	**25.0**	22.4	28.9	21.9	0.13	0.000
GRSD2	**Syn diesel, remote plant, neat**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.8			1.8	0.13	0.000
	GTL plant	2	0.59	0.54	0.64		16.5			16.5	0.00	0.000
	GTL transport	3	0.04				2.7			2.7	0.00	0.000
	Diesel distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total pathway		**0.68**	0.63	0.74	**0.68**	**25.1**	22.4	28.5	22.0	0.13	0.000
GRSD2C	**Syn diesel, remote plant, neat, CC&S**											
	NG Extraction & Processing	1	0.04	0.02	0.08		5.0			1.9	0.14	0.000
	GTL plant (CCS)	2	0.67	0.61	0.73		4.2			4.2	0.00	0.000
	GTL transport	3	0.04				2.7			2.7	0.00	0.000
	Diesel distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total pathway		**0.76**	0.71	0.82	**0.76**	**13.0**	10.1	16.3	9.7	0.14	0.000
WWSD1	**Syn diesel, wood waste**											
	Waste collection and chipping	1	0.06				0.8			0.7	0.00	0.000
	Transport (road + sea)	3	0.04				2.9			2.7	0.01	0.000
	Gasifier + FT plant	4	1.08				0.0		`	0.0	0.00	0.000
	Diesel distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total WTT GHG emitted						**4.8**	4.6	5.0	4.6	0.01	0.000
	Credit for renewable combustion CO_2						-70.8			-70.8		
	Total pathway		**1.19**	1.08	1.30	**0.07**	**-66.1**	-66.3	-65.9			
WFSD1	**Syn diesel, farmed wood**											
	Wood farming and chipping	1	0.09				5.5			2.5	0.00	0.010
	Road transport	3	0.01				0.7			0.7	0.00	0.000
	Gasifier + FT plant	4	1.08				0.0			0.0	0.00	0.000
	Diesel distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total WTT GHG emitted						**7.4**	4.4	13.8	4.3	0.00	0.010
	Credit for renewable combustion CO_2						-70.8			-70.8		
	Total pathway		**1.19**	1.08	1.29	**0.06**	**-63.4**	-66.4	-57.0			
BLSD1	**Syn diesel, black liquor**											
	Wood farming and chipping	1	0.05				0.7			0.6	0.00	0.000
	Road transport	3	0.01				0.6			0.6	0.00	0.000
	Black liquor gasifier + FT plant	4	0.83				0.0			0.0	0.00	0.000
	Diesel distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total WTT GHG emitted						**2.4**	2.4	2.5	2.4	0.00	0.000
	Credit for renewable combustion CO_2						-70.8			-70.8		
	Total pathway		**0.91**	0.86	0.97	**0.04**	**-68.4**	-68.4	-68.4			

5.2 DME

						Coal	**Farmed wood**	**Waste wood**	**Black liquor**
Pathway code		**GPDE**		**GRDE**		**KODE**	**WFDE**	**WWDE**	**BLDE**
		1a	**1b**	**1**	**1C**	**1**	**1**	**1**	**1**
Code	Process								
GG1	NG Extraction & Processing	✓	✓	✓	✓				
NG from pipeline									
GP1a	Russian quality, 7000 km	✓							
GP1b	Average quality, 4000 km		✓						
NG distribution									
GG3	NG trunk distribution	✓	✓						
NG to DME									
GT1	NG to DME (remote or central plant)	✓	✓	✓					
GT1C	NG to DME (remote or central plant) with CC&S				✓				
NG common processes									
GG2	Electricity generation from NG (CCGT)			✓	✓				
Coal									
KO1	Hard coal provision (EU-mix) (1)					✓			
KE1	Coal to DME					✓			
Wood (farmed)									
WF1	Wood farming and chipping						✓		
Wood (waste)									
WW1	Forest residuals to wood chips							✓	✓
Wood transport & processing (all sources)									
WC2a	Wood chips road transport, 50 km						✓	✓	✓
WC2b	Wood chips road transport, 12 km								
WC2c	Coastal/river shipping wood chips (200MW plant)							✓	
W3g	Wood to methanol or DME: gasification + synthesis						✓	✓	
Wood waste via black liquor									
BLD	Wood waste to DME via black liquor								✓
DME transport & distribution									
DE1	DME handling and loading (remote)			✓	✓				
DE2	DME sea transport			✓	✓				
DE3	DME depot			✓	✓	✓			
DE4a	DME distribution and dispensing	✓	✓	✓	✓				
DEd	Bio-DME distribution direct from plant						✓	✓	✓
Common processes									
Z1	Diesel production	✓	✓	✓	✓	✓	✓	✓	✓
Z2	Road tanker	✓	✓	✓	✓	✓	✓	✓	✓
Z3	HFO production	✓	✓	✓	✓				
Z5	Rail transport	✓	✓	✓	✓	✓	✓	✓	
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓	✓	✓

GPDE1a/b Piped NG to DME (EU plant)

This pathway foresees a DME plant located in Europe and fed by gas from a major gas pipeline source (7000 or 4000 km). Similarly to the GTL case, this is an unlikely scenario. As in all other pathways DME is distributed through a dedicated network similar to that for LPG.

GRDE1/1C Remote NG to DME (remote plant) (+CC&S option)

This option of a DME plant installed near a remote gas supply is the most likely. Transport is less energy-intensive for DME than for natural gas (as LNG). As for a GTL plant, CO_2 recovered from the process could relatively easily be compressed and re-injected in a nearby gas or oilfield.

W/F-WDE1 Waste/Farmed wood to DME

Wood gasification followed by DME synthesis.

BLDE1 Waste wood via black liquor to DME

Black liquor is the residue of extraction of cellulose fibres from wood for paper pulp manufacturing. It contains the lignin and is used as fuel for the large power plant required by a paper mill. Black liquor is also suitable for gasification, the syngas being then available for either electricity hydrogen or synthetic fuels production. The shortfall of energy available to the paper mill can be made up by burning waste wood. Compared to a reference case with a traditional black liquor boiler and all other parameters being the desired fuel can be produced with significantly higher net energy efficiency than in a more conventional scheme.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GPDE1a	**Piped NG, 7000 km, EU central plant**											
	NG Extraction & Processing	1	0.04	0.02	0.08		5.2			1.9	0.14	0.000
	NG Transport	3	0.28	0.09	0.31		20.7			14.4	0.26	0.001
	NG Distribution (HP)	3	0.01				0.8			0.8	0.00	0.000
	DME plant	4	0.41	0.39	0.43		10.6			10.5	0.00	0.000
	DME distribution & dispensing	5	0.03				1.7			1.6	0.00	0.000
	Total pathway		**0.77**	0.63	0.79	**0.77**	**38.9**	30.8	39.9	29.2	0.41	0.001
GPDE1b	**Piped NG, 4000 km, EU central plant**											
	NG Extraction & Processing	1	0.04	0.02	0.07		4.7			1.7	0.13	0.000
	NG Transport	3	0.13	0.04	0.15		10.3			6.8	0.15	0.000
	NG Distribution (HP)	3	0.01				0.8			0.8	0.00	0.000
	DME plant	4	0.41	0.39	0.43		10.6			10.5	0.00	0.000
	DME distribution & dispensing	5	0.03				1.7			1.6	0.00	0.000
	Total pathway		**0.62**	0.56	0.64	**0.62**	**28.1**	24.3	29.2	21.4	0.28	0.000
GRDE1	**Remote plant**											
	NG Extraction & Processing	1	0.03	0.02	0.07		4.3			1.6	0.12	0.000
	DME plant	2	0.41	0.39	0.43		10.6			10.5	0.00	0.000
	DME transport	3	0.06				4.3			4.3	0.00	0.000
	DME distribution & dispensing	5	0.03				1.7			1.6	0.00	0.000
	Total pathway		**0.53**	0.51	0.56	**0.53**	**20.9**	19.8	22.5	18.0	0.12	0.000
GRDE1C	**Remote plant, CC&S**											
	NG Extraction & Processing	1	0.03	0.02	0.07		4.3			1.6	0.12	0.000
	DME plant	2	0.42	0.40	0.42		0.6			0.6	0.00	0.000
	DME transport	3	0.06				4.3			4.3	0.00	0.000
	DME distribution & dispensing	5	0.03				1.7			1.6	0.00	0.000
	Total pathway		**0.54**	0.54	0.61	**0.54**	**10.9**	10.8	14.9	8.1	0.12	0.000
WWDE1	**Wood waste**											
	Waste collection and chipping	1	0.06				0.7			0.7	0.00	0.000
	Transport (road + sea)	3	0.03				2.7			2.6	0.01	0.000
	Gasifier + DME synthesis	4	0.96				0.1			0.1	0.00	0.000
	DME distribution & dispensing	5	0.02				1.0			1.0	0.00	0.000
	Total WTT GHG emitted						**4.5**	4.3	4.8	4.3	0.01	0.000
	Credit for renewable combustion CO_2						-67.3			-67.3		
	Total pathway		**1.07**	0.95	1.22	**0.06**	**-62.7**	-63.0	-62.5			
WFDE1	**Farmed wood**											
	Wood farming and chipping	1	0.08				5.2			2.3	0.00	0.010
	Road transport	3	0.01				0.7			0.7	0.00	0.000
	Gasifier + MeOH synthesis	4	0.96				0.1			0.1	0.00	0.000
	DME distribution & dispensing	5	0.02				1.0			1.0	0.00	0.000
	Total WTT GHG emitted						**7.0**	5.2	11.8	4.1	0.00	0.010
	Credit for renewable combustion CO_2						-67.3			-67.3		
	Total pathway		**1.07**	0.94	1.20	**0.06**	**-60.3**	-62.10	-55.45			
BLDE1	**DME from black liquor**											
	Waste collection and chipping	1	0.04				0.5			0.5	0.0	0.000
	Transport (road)	3	0.01				0.5			0.5	0.0	0.000
	Black liquor gasification + DME synthesis	4	0.49				0.1			0.1	0.0	0.000
	DME distribution & dispensing	5	0.02				1.0			1.0	0.0	0.000
	Total WTT GHG emitted						**2.2**	2.1	2.2	2.1	0.00	0.000
	Credit for renewable combustion CO_2						-67.3			-67.3		
	Total pathway		**0.55**	0.51	0.61	**0.03**	**-65.1**	-65.17	-65.10			

5.3 Methanol

					Coal	Farmed wood	Waste wood	Waste wood	Black liquor
Pathway code		**GPME**		**GRME**	**KOME**	**WFME**	**WWME**	**WWDE**	**BLME**
		1a	**1b**	**1**	**1**	**1**	**1**	**1**	**1**
Code	Process								
GG1	NG Extraction & Processing	✓	✓	✓					
NG from pipeline									
GP1a	Russian quality, 7000 km	✓							
GP1b	Average quality, 4000 km		✓						
NG distribution									
GG3	NG trunk distribution	✓	✓						
NG to Methanol									
GA1	NG to Methanol (remote or central plant)	✓	✓	✓					
NG common processes									
GG2	Electricity generation from NG (CCGT)			✓					
Coal									
KO1	Hard coal provision (EU-mix) (1)				✓				
KA1	Coal to methanol				✓				
Wood (farmed)									
WF1	Wood farming and chipping					✓			
Wood (waste)									
WW1	Forest residuals to wood chips						✓	✓	✓
Wood transport & processing (all sources)									
WC2a	Wood chips road transport, 50 km					✓	✓	✓	✓
WC2b	Wood chips road transport, 12 km								
WC2c	Coastal/river shipping wood chips (200MW plant)						✓	✓	
W3g	Wood to methanol or DME: gasification + synthesis					✓	✓	✓	
Wood waste via black liquor									
BLM	Wood waste to methanol via black liquor								✓
Methanol transport & distribution									
ME1	Methanol handling and loading (remote)			✓					
ME2	Methanol sea transport (average of two distances)			✓					
ME3	Methanol depot			✓					
ME4	Methanol distribution and dispensing	✓	✓	✓	✓				
MEd	Biomethanol distribution direct from plant					✓	✓		✓
Common processes									
Z1	Diesel production	✓	✓	✓	✓	✓	✓	✓	✓
Z2	Road tanker	✓	✓	✓	✓	✓	✓	✓	✓
Z3	HFO production	✓	✓	✓					
Z4	Product carrier 50 kt			✓					
Z5	Rail transport	✓	✓	✓	✓	✓	✓	✓	
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓	✓	✓

GPME1a/b Piped NG to methanol (EU plant)

This pathway foresees a methanol plant located in Europe and fed by gas from a major gas pipeline source (7000 or 4000 km). Similarly to the GTL case, this is an unlikely scenario. As in all other pathways methanol is used as a fuel for on-board reformers and distributed through a dedicated network.

GRME1 Remote NG to methanol (remote plant) (+CC&S option)

This option of a methanol plant installed near a remote gas supply is the most likely. Transport is less energy-intensive for methanol than for natural gas (as LNG).

KOME1 Hard coal to methanol

In this case a full size methanol synthesis plant is assumed with a wide distribution network (500 km average distance with mixed rail/road transport).

W/F-WME1 Waste/Farmed wood to methanol

Wood gasification followed by methanol synthesis.

BLME1 Waste wood via black liquor to methanol

Black liquor is the residue of extraction of cellulose fibres from wood for paper pulp manufacturing. It contains the lignin and is used as fuel for the large power plant required by a paper mill. Black liquor is also suitable for gasification, the syngas being then available for either electricity hydrogen or synthetic fuels production. The shortfall of energy available to the paper mill can be made up by burning waste wood. Compared to a reference case with a traditional black liquor boiler and all other parameters being the desired fuel can be produced with significantly higher net energy efficiency than in a more conventional scheme.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO$_2$eq/MJf)			CO$_2$	CH4	N$_2$O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GPME1a	**Piped NG, 7000 km, EU central plant**											
	NG Extraction & Processing	1	0.04	0.02	0.09		5.4			2.0	0.15	0.000
	NG Transport	3	0.29	0.10	0.32		21.5			15.0	0.27	0.001
	NG Distribution (HP)	3	0.01				0.8			0.8	0.00	0.000
	Methanol plant	4	0.47	0.44	0.49		11.7			11.7	0.00	0.000
	Methanol distribution & dispensing	5	0.03				1.9			1.8	0.00	0.000
	Total pathway		**0.84**	0.70	0.87	**0.84**	**41.2**	33.4	42.8	31.3	0.42	0.001
GPME1b	**Piped NG, 4000 km, EU central plant**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.9			1.8	0.13	0.000
	NG Transport	3	0.14	0.05	0.15		10.7			7.0	0.16	0.000
	NG Distribution (HP)	3	0.01				0.8			0.8	0.00	0.000
	Methanol plant	4	0.47	0.44	0.49		11.7			11.7	0.00	0.000
	Methanol distribution & dispensing	5	0.03				1.9			1.8	0.00	0.000
	Total pathway		**0.69**	0.63	0.70	**0.69**	**30.0**	26.6	30.9	23.2	0.29	0.000
GRME1	**NG, Remote plant**											
	NG Extraction & Processing	1	0.04	0.02	0.07		4.4			1.6	0.12	0.000
	Methanol plant	2	0.47	0.44	0.49		11.7			11.7	0.00	0.000
	Methanol transport	3	0.08				5.9			5.9	0.00	0.000
	Methanol distribution & dispensing	5	0.03				1.9			1.8	0.00	0.000
	Total pathway		**0.61**	0.59	0.64	**0.61**	**23.9**	22.9	25.6	21.0	0.12	0.000
WWME1	**Wood waste**											
	Waste collection and chipping	1	0.06				0.7			0.7	0.00	0.000
	Transport (road + sea)	3	0.03				2.7			2.6	0.01	0.000
	Gasifier + MeOH synthesis	4	0.96				0.2			0.2	0.00	0.000
	Methanol distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total WTT GHG emitted						**4.7**	4.5	5.0	4.5	0.01	0.000
	Credit for renewable combustion CO$_2$						-69.1			-69.1		
	Total pathway		**1.07**	0.94	1.20	**0.06**	**-64.4**	-64.6	-64.1			
WFME1	**Farmed wood**											
	Wood farming and chipping	1	0.08				5.2			2.3	0.00	0.010
	Road transport	3	0.01				0.7			0.7	0.00	0.000
	Gasifier + MeOH synthesis	4	0.96				0.2			0.2	0.00	0.000
	Methanol distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total WTT GHG emitted						**7.2**	5.2	11.5	4.3	0.00	0.010
	Credit for renewable combustion CO$_2$						-69.1			-69.1		
	Total pathway		**1.07**	0.93	1.19	**0.06**	**-61.9**	-63.8	-57.6			
BLME1	**Methanol from black liquor**											
	Waste collection and chipping	1	0.05				0.55			0.53	0.00	0.000
	Transport (road)	3	0.01				0.51			0.51	0.00	0.000
	Black liquor gasification + MeOH synthesis	4	0.52				0.2			0.2	0.00	0.000
	Methanol distribution & dispensing	5	0.02				1.1			1.1	0.00	0.000
	Total WTT GHG emitted						**2.4**	2.3	2.4	2.3	0.00	0.000
	Credit for renewable combustion CO$_2$						-69.1			-69.1		
	Total pathway		**0.59**	0.54	0.64	**0.03**	**-66.7**	-66.8	-66.7			

6 Ethers

Pathway code		**GRMB**	**LREB**
		1	**1**
Code	Process		
GG1	NG Extraction & Processing	✓	
NG to Methanol			
GA1	NG to Methanol (remote or central plant)	✓	
LPG			
LR1	LPG production	✓	✓
LR2	LPG sea transport		✓
Ether production			
BU1	n-butane to isobutene	✓	✓
EH1	Isobutene + ethanol to ETBE		✓
MH1	Isobutene + methanol to MTBE	✓	
Farming			
WT1	Wheat farming		✓
Crop transport and processing			
WT2a	Wheat grain road transport		✓
WT3	Wheat grain handling and drying (to dwg, 3%		✓
WT4b	Wheat grain to ethanol, NG CCGT		✓
WTDa	Credit for DDGS as animal feed		✓
Methanol transport & distribution			
ME1	Methanol handling and loading (remote)	✓	
ME2	Methanol sea transport (average of two distances)	✓	
ME3	Methanol depot	✓	
Common processes			
Z1	Diesel production	✓	✓
Z2	Road tanker	✓	✓
Z3	HFO production	✓	
Z4	Product carrier 50 kt	✓	
Z6	Marginal NG for general use (4000 km piped)	✓	✓
Z7a	Electricity (EU-mix, MV)	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓

GRMB1 Natural gas and field butane to MTBE

Methanol synthesised from remote natural gas and isobutene prepared from field butane are reacted together to form MTBE. MTBE is shipped to Europe and used in blend with gasoline.

LREB1 Bio-ethanol and field butane to ETBE

Isobutene prepared in Europe from imported field butane is reacted with bio-ethanol (from wheat according to pathway WTET2a) to form ETBE. ETBE is used in blend with gasoline.

Note: evaluating the fossil energy is a little more complex in this case as only part of the feedstock is renewable. The figure of 0.07 MJ_{xf}/MJ_f shown in the table below assumes that all combustion energy is fossil i.e. the total fossil energy for the WTW pathway is 1.07 MJ_{xf}/MJ_f. Following the same logic, only 1/3 of the CO_2 emissions is credited as renewable (2 out of 6 carbon atoms in the ETBE molecule).

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GRMB1	**MTBE from remote plant**											
	NG extraction and processing	1	0.01				0.84			0.3	0.02	0.000
	Methanol and iC4= synthesis	2	0.09				2.21			2.2	0.00	0.000
	MTBE plant	2	0.14				6.00			5.6	0.02	0.000
	MTBE transport	3	0.05				4.04			4.0	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total pathway		**0.30**	0.30	0.31	**0.30**	**13.5**	13.4	14.3			
LREB1	**ETBE from imported C4 and wheat ethanol (WTET2a)**											
	Wheat cultivation	1	0.09				11.63			5.2	0.01	0.021
	Road transport	3	0.01				0.20			0.2	0.00	0.000
	Ethanol plant	4	0.42				-0.23			2.8	0.02	-0.012
	ETBE plant	4	0.22				7.69			7.2	0.02	0.000
	ETBE road transport, 150 km	5	0.01				0.67			0.7	0.00	0.000
	Refuelling station	5	0.01				0.44			0.4	0.00	0.000
	Total WTT GHG emitted						**20.4**	65.5	70.8	16.4	0.05	0.009
	Credit for renewable combustion CO_2						-23.8			-23.8		
	Total pathway		**0.75**	0.75	0.77	**0.07***	**-3.4**	-5.9	-0.6			

7 Electricity generation

		Natural gas			Coal								Farmed wood			Black liquor	Wind	Nuclear	EU-mix
Pathway code		**GPEL**		**GREL**	**KOEL**		**OWEL**						**WFEL**			**BLEL**	**WDEL**	**NUEL**	**EMEL**
		1a	**1b**	**1**	**1**	**2**	**1a**	**1b**	**2a**	**2b**	**3a**	**3b**	**1**	**2**	**3**	**1**	**1**	**1**	**1**
Code	Process																		
GG1	NG Extraction & Processing	✓	✓	✓															
NG from pipeline																			
GP1a	Russian quality, 7000 km	✓																	
GP1b	Average quality, 4000 km		✓																
LNG production & transport																			
GR1	NG Liquefaction			✓															
GR1C	NG Liquefaction with CC&S																		
GR2	LNG terminal (loading)			✓															
GR3	LNG transport (average of two distances)			✓															
GR4	LNG terminal (unloading)			✓															
Biogas																			
BG1a	Liquid manure transport, 10 km								✓	✓									
BG1b	Dry manure transport, 10 km										✓	✓							
BG2a	Municipal waste to biogas (upgraded)							✓											
BG2b	Liquid manure to biogas (upgraded)									✓									
BG2c	Dry manure to biogas (upgraded)											✓							
BG3a	Municipal waste to electricity (small scale, local)						✓												
BG3b	Liquid manure to electricity (small scale, local)								✓										
BG3c	Dry manure to electricity (small scale, local)										✓								
NG distribution																			
GR5	LNG vaporisation			✓															
GG3	NG trunk distribution			✓				✓		✓		✓							
NG common processes																			
GG2	Electricity generation from NG (CCGT)	✓	✓	✓				✓		✓		✓							
Coal																			
KO1	Hard coal provision (EU-mix) (1)				✓	✓													
KE1	Electricity from Coal (conv. Boiler)				✓	✓													
Wood (farmed)																			
WF1	Wood farming and chipping												✓	✓	✓				
Wood (waste)																			
WW1	Forest residuals to wood chips															✓			
Wood transport & processing (all sources)																			
WC2a	Wood chips road transport, 50 km												✓		✓	✓			
WC2b	Wood chips road transport, 12 km													✓					
W3b	Wood to electricty: gasification, 200MW												✓						
W3c	Wood to electricity: gasification, 10MW													✓					
W3h	Wood cofiring in coal power station														✓				
Wood waste via black liquor																			
BLE	Electricity from waste wood via black liquor															✓			
Wind																			
DE	Electricity from wind																✓		
Nuclear																			
NE1	Nuclear fuel provision																	✓	
NE2	Electricity from nuclear																	✓	
Common processes																			
Z1	Diesel production															✓			
Z2	Road tanker															✓			
Z71	HV+MV losses	✓	✓														✓		
Z72	LV losses	✓	✓														✓		
Z7a	Electricity (EU-mix, MV)			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	
Z7b	Electricity (EU-mix, LV)			✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓

In this study, electricity is not used as such as automotive energy source. It is an intermediate for production of hydrogen by electrolysis. These pathways are shown separately to illustrate the amount of electrical energy that can be produced from certain sources, particularly biomass, and also to allow comparison of energy efficiency and GHG avoidance potential with other uses of the same resource.

GPEL1a/b Piped NG to electricity

Natural gas is already widely used for electricity generation and all forecasts agree that this will increase in the coming decades. The Combined Cycle Gas Turbine (CCGT) is now established as the state-of-the-art scheme.

GREL1 LNG to electricity

This pathway illustrates the use of remote gas (as LNG) for electricity generation in Europe (as a comparison with the previous pathways).

KOEL1/1C Hard coal to electricity

Coal is another standard energy source for electricity generation. This pathway represents the range of available technologies (with a fairly wide variability range).

WFEL1-3 Wood to electricity

1 and 2 represent the gasification + CCGT route at either large (200 MW biomass) or small (10 MW) scale. The former is considerably more efficient. 3 represent the conventional boiler + steam turbine route.

BLEL1 Waste wood via black liquor to electricity

See *section 2-5*

EMEL1 EU-mix electricity

This is the reference that is also used for all minor electricity consumptions in all pathways. GHG emissions from EU-mix are similar than those from natural gas CCGT.

WDEL1 Wind to electricity

Wind power is one of the most promising option for renewable electricity generation.

NUEL1 Nuclear energy to electricity

Although not popular at the moment, this option cannot be ignored as it has the potential to provide large amounts of essentially carbon-free electricity.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
KOEL1	**Coal, state-of-the-art conventional technology**											
	Coal provision	3	0.22				36.3			15.3	0.90	0.001
	Power plant	4	1.34				230.9			227.3	0.00	0.012
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**1.59**	1.23	1.78	**1.58**	**267.2**	231.0	286.8	242.6	0.91	0.012
KOEL2	**Coal, IGCC**											
	Coal provision	3	0.20				32.9			13.9	0.82	0.001
	Power plant	4	1.12				206.2			206.2	0.00	0.000
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**1.35**	1.25	1.46	**1.34**	**239.0**	228.8	250.4	220.0	0.82	0.001
GPEL1a	**Piped NG, 7000 km, CCGT**											
	NG Extraction & Processing	1	0.05	0.03	0.11		6.8			2.5	0.19	0.000
	NG Transport	3	0.36				27.4			19.1	0.35	0.001
	NG Distribution (HP)	3	0.02				1.1			1.0	0.00	0.000
	Power generation (CCGT)	4	0.84	0.80	0.88		104.6			102.9	0.01	0.005
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**1.31**	1.06	1.36	**1.31**	**139.8**	125.5	142.8	125.6	0.55	0.006
GPEL1b	**Piped NG, 4000 km, CCGT**											
	NG Extraction & Processing	1	0.05	0.02	0.10		6.2			2.3	0.17	0.000
	NG Transport	3	0.17				13.7			9.0	0.20	0.000
	NG Distribution (HP)	3	0.02				1.1			1.0	0.00	0.000
	Power generation (CCGT)	4	0.84	0.80	0.88		104.6			102.9	0.01	0.005
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**1.11**	0.97	1.20	**1.11**	**125.5**	117.2	130.8	115.2	0.38	0.005
GREL1	**LNG, CCGT**											
	Extraction & Processing	1	0.05	0.02	0.10		6.3			2.3	0.17	0.000
	Liquefaction	2	0.16				10.7			8.8	0.08	0.000
	Transport (shipping)	3	0.16				10.5			10.4	0.00	0.000
	Receipt	3	0.08				4.5			4.4	0.00	0.000
	Power generation (CCGT)	4	0.84				104.6			102.9	0.01	0.005
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**1.33**	1.23	1.46	**1.33**	**136.5**	130.7	144.5	128.8	0.26	0.006
WFEL1	**Farmed wood, 10 MW gasifier + CCGT**											
	Wood farming	1	0.12				7.8			3.5	0.00	0.014
	Road transport	3	0.00				0.2			0.2	0.00	0.000
	Power generation (CCGT)	4	1.88				1.9			0.0	0.04	0.003
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**2.03**	1.93	2.15	**0.05**	**9.9**	7.3	17.2	3.7	0.04	0.018
WFEL2	**Farmed wood, 200 MW gasifier + CCGT**											
	Wood farming	1	0.09				5.7			2.5	0.00	0.010
	Road transport	3	0.01				0.7			0.7	0.00	0.000
	Power generation (CCGT)	4	1.11				1.4			0.0	0.03	0.003
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**1.24**	1.15	1.34	**0.05**	**7.8**	5.6	13.1	3.3	0.03	0.013
WFEL3	**Farmed wood, steam power plant**											
	Wood farming	1	0.14				8.6			3.8	0.00	0.016
	Road transport	3	0.01				1.1			1.1	0.00	0.000
	Power generation (steam turbine)	4	2.19				9.5			0.0	0.09	0.025
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**2.37**	2.19	2.52	**0.07**	**19.2**	15.9	27.7	4.9	0.09	0.041
EMEL1	**EU-mix electricity**											
	EU-mix power generation	4	1.84				129.2			120.8	0.29	0.005
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**1.87**	1.87	1.87	**1.73**	**129.2**	129.2	129.2	120.8	0.29	0.005
	Non-nuclear fossil energy					1.27						
WDEL1	**Wind turbine (offshore)**											
	EU-mix power generation	4	0.00				0.0			0.0	0.00	0.000
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		**0.03**	0.03	0.03	**0.00**	**0.0**	0.0	0.0	0.0	0.00	0.000
NUEL1	**Nuclear**											
	Nuclear fuel provision	1	0.62				4.05			3.8	0.01	0.000
	Nuclear power station	4	2.09				0.30			0.3	0.00	0.000
	Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000
	Total pathway		**2.74**	2.66	2.81	**2.74**	**4.4**	4.2	4.5	4.1	0.01	0.000
	Non-nuclear fossil energy					0.65						

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
OWEL1a	**Electricity from municipal waste (local power plant)**											
	Biogas production	4	1.67				4.60			-4.6	0.60	-0.016
	Local power plant	4	1.52				1.81			0.0	0.08	0.000
	Electricity distribution (LV)	5	0.01				0.00			0.0	0.00	0.000
	Total pathway		**3.20**	2.92	3.55	**-0.08**	**6.4**	5.9	7.1	-4.6	0.68	-0.016
OWEL1b	**Electricity from municipal waste (large power plant)**											
	Biogas production	4	1.52				-80.86			-97.1	0.85	-0.011
	Gas distribution	3	0.00				0.00			0.0	0.00	0.000
	Large power plant	4	0.84				107.09			105.5	0.01	0.005
	Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000
	Total pathway		**2.39**	2.09	2.67	**0.21**	**26.2**	20.9	31.4	8.4	0.85	-0.006
OWEL2a	**Electricity from liquid manure (local power plant)**											
	Transport of liquid manure (10 km)	2	0.06				-181.78			4.5	-8.10	0.000
	Biogas production	4	1.47				7.71			-2.7	0.57	-0.009
	Local power plant	4	1.52				1.81			0.0	0.08	0.000
	Electricity distribution (LV)	5	0.01				0.00			0.0	0.00	0.000
	Total pathway		**3.06**	2.73	3.38	**0.01**	**-172.3**	-220.8	-122.5	1.8	-7.45	-0.009
OWEL2b	**Electricity from liquid manure (large power plant)**											
	Transport of liquid manure (10 km)	2	0.05				-162.69			4.0	-7.25	0.000
	Biogas production	4	1.64				-93.00			-111.0	0.89	-0.008
	Gas distribution	3	0.00				0.00			0.0	0.00	0.000
	Large power plant	4	0.84				107.09			105.5	0.01	0.005
	Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000
	Total pathway		**2.56**	2.26	2.89	**-0.06**	**-148.6**	-194.6	-98.3	-1.4	-6.35	-0.004
OWEL3a	**Electricity from dry manure (local power plant)**											
	Transport of dry manure (10 km)	2	0.02				-17.19			1.4	-0.81	0.000
	Biogas production	4	1.47				7.71			-2.7	0.57	-0.009
	Local power plant	4	1.52				1.81			0.0	0.08	0.000
	Electricity distribution (LV)	5	0.01				0.00			0.0	0.00	0.000
	Total pathway		**3.02**	2.70	3.31	**-0.03**	**-7.7**	-11.9	-2.6	-1.2	-0.16	-0.009
OWEL3b	**Electricity from dry manure (large power plant)**											
	Transport of dry manure (10 km)	2	0.02				-15.39			1.3	-0.72	0.000
	Biogas production	4	1.64				-93.00			-111.0	0.89	-0.008
	Gas distribution	3	0.00				0.00			0.0	0.00	0.000
	Large power plant	4	0.84				107.09			105.5	0.01	0.005
	Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000
	Total pathway		**2.53**	2.16	2.87	**-0.09**	**-1.3**	-6.6	3.7	-4.2	0.17	-0.004
BLEL1	**Electricity from black liquor**											
	Waste collection and chipping	1	0.03				0.42			0.4	0.00	0.000
	Transport (road, 50 km)	3	0.01				0.39			0.0	0.00	0.000
	Paper mill power plant	4	0.11				0.00			0.0	0.00	0.000
	Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000
	Total pathway		**0.18**	0.15	0.22	**0.01**	**0.8**	0.8	0.8	0.4	0.00	0.000

8 Hydrogen

8.1 Natural gas to hydrogen

Pathway code		**GMCH**	**GPCH**						**GPLCH**	**GRCH**			**GPLH**		**GRLH**	
		1	**1a**	**1b**	**2a**	**2b**	**2bC**	**3b**	**b**	**1**	**2**	**3**	**1a**	**1b**	**1**	**2**
Code	Process															
GG1	NG Extraction & Processing	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
NG from pipeline																
GP1a	Russian quality, 7000 km		✓		✓								✓			
GP1b	Average quality, 4000 km			✓		✓	✓	✓	✓					✓		
LNG production & transport																
GR1	NG Liquefaction									✓	✓	✓				✓
GR1C	NG Liquefaction with CC&S															
GR2	LNG terminal (loading)									✓	✓	✓				✓
GR3	LNG transport (average of two distances)									✓	✓	✓				✓
GR4	LNG terminal (unloading)									✓	✓	✓				✓
NG distribution																
GR5	LNG vaporisation									✓	✓	✓				✓
GG3	NG trunk distribution	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓		✓	✓		✓
NG common processes																
GG2	Electricity generation from NG (CCGT)								✓	✓	✓	✓	✓	✓	✓	✓
Hydrogen transport & distribution																
CH1a	Gasous Hyd distribution (pipeline from central plant)				✓	✓	✓				✓	✓				
CH1b	Gasous Hyd distribution (trucking from central plant)							✓								
CH2	Liquid Hyd compression/vaporisation								✓							
CH3	Gasous Hyd dispensing	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓				
LH1	Hyd liquefaction												✓	✓	✓	✓
LH2	Liquid Hyd long-distance transport														✓	
LH3	Liquid Hyd distribution and dispensing												✓	✓	✓	✓
Common processes																
Z1	Diesel production								✓				✓	✓	✓	✓
Z2	Road tanker								✓				✓	✓	✓	✓
Z71	HV+MV losses															
Z72	LV losses															
Z7a	Electricity (EU-mix, MV)															
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓		✓	✓	✓	✓	✓	✓	✓	✓

GMCH1 EU-mix NG supply to on-site hydrogen production and compression

GPCH1a/b Piped NG to on-site hydrogen production and compression

These three pathways describe the local production of hydrogen with a small steam reformer installed at the refuelling station followed by compression (88 MPa). The only difference is in the origin of the gas. Such schemes may be attractive as it avoids transporting hydrogen but they do require up front investment in a large number of locations.

GPCH2 a/b/bC Piped NG to central hydrogen production, pipeline distribution and on-site compression (+CC&S option)

Here hydrogen is produced by steam reforming of natural gas (pipeline 7 or 4000 km) in a central plant from where it is distributed through a local pipeline network (50 km average distance) before compression to 88 MPa at the refuelling station. The principal advantage of such a scheme is to allow large plants that can be made more efficient than small ones through heat integration and recovery and that can be build gradually as demand grows. As full decarbonisation occurs at the production stage CO_2 capture and storage could be an attractive option where suitable geological formations are available within a reasonable distance.

GPCH3b Piped NG to central hydrogen production, road distribution and on-site compression

This pathway is essentially the same as above except that hydrogen is now distributed by road in high pressure cylinders. This distribution mode may be more appropriate for limited markets where a pipeline network would not be justifiable.

GPLCHb Piped NG to central production of liquid hydrogen, road distribution and on-site vaporisation/compression

This is the same pathway as above but it is now assumed that the vehicle requires compressed hydrogen. The liquid hydrogen delivered to the refuelling station is compressed and vaporised on-site. Note that this operation is less energy-intensive than gaseous hydrogen compression.

GRCH1/2 Remote NG to hydrogen production and compression

LNG for remote location can offer an alternative to pipeline supplies. In these two pathways it is assumed that LNG is vaporised on receipt at the EU terminal and introduced into the grid. Hydrogen can then be produced either on-site or centrally as explained above.

GRCH3 Remote NG to methanol to hydrogen production and compression

Methanol can be used as a energy vector instead of NG. In this pathway methanol is produced from remote NG, transported to Europe, distributed within Europe and converted into hydrogen in an on-site reformer.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO$_2$eq/MJf)			CO$_2$	CH4	N$_2$O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GMCH1	**NG EU-mix, 1000 km, on-site reforming**											
	NG Extraction & Processing	1	0.04	0.02	0.07		4.6			1.7	0.1	0.0
	NG Transport	3	0.03	0.01	0.03		2.7			1.6	0.0	0.0
	NG Distribution	3	0.01				0.9			0.8	0.0	0.0
	On-site reforming	4	0.52	0.49	0.55		86.5			85.8	0.0	0.0
	Compression	5	0.24	0.22	0.26		9.9			9.3	0.0	0.0
	Total pathway		**0.84**	0.81	0.90	**0.83**	**104.7**	102.9	107.6	99.3	0.23	0.001
GPCH1a	**Piped NG, 7000 km, on-site reforming**											
	NG Extraction & Processing	1	0.04	0.02	0.09		5.4			2.0	0.15	0.000
	NG Transport	3	0.29	0.10	0.32		21.5			15.0	0.28	0.001
	NG Distribution	3	0.01				0.8			0.8	0.00	0.000
	On-site reforming	4	0.52	0.49	0.55		84.5			83.9	0.02	0.000
	Compression	5	0.24	0.22	0.26		9.9			9.3	0.02	0.000
	Total pathway		**1.11**	0.95	1.13	**1.09**	**122.2**	113.6	123.6	111.0	0.47	0.001
GPCH1b	**Piped NG, 4000 km, on-site reforming**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.9			1.8	0.13	0.000
	NG Transport	3	0.14	0.05	0.15		10.7			7.1	0.16	0.000
	NG Distribution	3	0.01				0.8			0.8	0.00	0.000
	On-site reforming	4	0.52	0.49	0.55		84.5			83.9	0.02	0.000
	Compression	5	0.24	0.22	0.26		9.9			9.3	0.02	0.000
	Total pathway		**0.95**	0.87	0.98	**0.94**	**110.9**	106.3	112.5	102.9	0.34	0.001
GPCH2a	**Piped NG, 7000 km, central reforming, pipeline**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.9			1.8	0.13	0.000
	NG Transport	3	0.26	0.09	0.29		19.6			13.7	0.25	0.001
	NG Distribution (HP)	3	0.01				0.8			0.7	0.00	0.000
	Central reforming	4	0.32	0.29	0.34		74.0			73.7	0.02	0.000
	Gaseous Hyd distribution & comp.	5	0.22	0.21	0.24		9.1			8.5	0.02	0.000
	Total pathway		**0.86**	0.71	0.88	**0.85**	**108.4**	100.1	109.9	98.4	0.42	0.001
GPCH2b	**Piped NG, 4000 km, central reforming, pipeline**											
	NG Extraction & Processing	1	0.04	0.02	0.07		4.5			1.6	0.12	0.000
	NG Transport	3	0.12	0.04	0.14		9.8			6.4	0.14	0.000
	NG Distribution (HP)	3	0.01				0.8			0.7	0.00	0.000
	Central reforming	4	0.32	0.29	0.34		74.0			73.7	0.02	0.000
	Gaseous Hyd distribution & comp.	5	0.22	0.21	0.24		9.1			8.5	0.02	0.000
	Total pathway		**0.72**	0.64	0.74	**0.71**	**98.2**	94.1	99.7	91.0	0.30	0.001
GPCH2bC	**Piped NG, 4000 km, central reforming, pipeline, CC&S**											
	NG Extraction & Processing	1	0.04	0.02	0.07		4.6			1.7	0.13	0.000
	NG Transport	3	0.13	0.04	0.14		10.2			6.7	0.15	0.000
	NG Distribution (HP)	3	0.01				0.8			0.8	0.00	0.000
	Central reforming (CC&S)	4	0.37	0.34	0.39		12.5			12.1	0.02	0.000
	Gaseous Hyd distribution & comp.	5	0.22	0.21	0.24		9.1			8.5	0.02	0.000
	Total pathway		**0.77**	0.70	0.80	**0.76**	**37.2**	32.8	38.8	29.8	0.31	0.001
GPCH3b	**Piped NG, 4000 km, central reforming, trucking**											
	NG Extraction & Processing	1	0.04	0.02	0.07		4.5			1.64	0.12	0.000
	NG Transport	3	0.12	0.04	0.14		9.8			6.44	0.14	0.000
	NG Distribution (HP)	3	0.01				0.8			0.74	0.00	0.000
	Central reforming	4	0.32	0.29	0.34		74.0			73.67	0.02	0.000
	Gaseous Hyd distribution & comp.	5	0.22	0.21	0.24		10.0			9.50	0.02	0.000
	Total pathway		**0.72**	0.65	0.74	**0.71**	**99.1**	95.3	100.4	92.0	0.30	0.001

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GPLCHb	**Piped NG, 4000 km, central reforming + liquefaction, vaporisation/compression**											
	NG Extraction & Processing	1	0.03	0.02	0.07		4.4			1.6	0.12	0.000
	NG Transport	3	0.12	0.11	0.13		9.6			6.3	0.14	0.000
	NG Distribution (HP)	3	0.01				0.8			0.7	0.00	0.000
	Central reforming	4	0.32	0.28	0.34		73.0			72.6	0.02	0.000
	Hyd liquefaction	4	0.62	0.43	0.80		36.8			33.8	0.11	0.002
	Liquid hyd distribution & vap/comp	5	0.17				8.2			7.8	0.02	0.000
	Total pathway		**1.28**	1.14	1.35	**1.27**	**132.8**	124.5	137.3	122.8	0.40	0.002
GRCH1	**LNG, on-site reforming**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.9			1.8	0.14	0.000
	NG Liquefaction	2	0.13				8.4			6.9	0.06	0.000
	Long-distance transport	3	0.13				8.2			8.2	0.00	0.000
	LNG Vaporisation + Distribution	3	0.06				3.5			3.5	0.00	0.000
	On-site reforming	4	0.52	0.49	0.55		84.4			83.8	0.02	0.000
	Compression	5	0.24	0.22	0.26		9.9			9.3	0.02	0.000
	Total pathway		**1.12**	1.08	1.18	**1.10**	**119.4**	117.4	122.7	113.4	0.25	0.001
GRCH2	**LNG, central reforming**											
	NG Extraction & Processing	1	0.04	0.02	0.07		4.5			1.6	0.12	0.000
	NG Liquefaction	2	0.12				7.7			6.3	0.06	0.000
	Long-distance transport	3	0.11				7.5			7.4	0.00	0.000
	LNG Vaporisation + Distribution	3	0.06				3.2			3.2	0.00	0.000
	Central reforming	4	0.32	0.29	0.34		74.0			73.7	0.02	0.000
	Gaseous Hyd distribution & comp.	5	0.22	0.21	0.24		9.1			8.5	0.02	0.000
	Total pathway		**0.87**	0.83	0.92	**0.86**	**106.0**	104.1	108.8	100.7	0.22	0.001
GRCH3	**Remote NG, methanol, on-site reforming**											
	NG Extraction & Processing	1	0.04	0.02	0.09		5.4			2.0	0.15	0.000
	Methanol synthesis	2	0.57				14.2			14.2	0.00	0.000
	Methanol shipping and distribution	3	0.08				5.3			5.3	0.00	0.000
	On-site reforming	4	0.22	0.21	0.23		84.6			84.5	0.00	0.000
	Hydrogen compression	5	0.22	0.21	0.24		9.1			8.5	0.02	0.000
	Total pathway		**1.13**	1.11	1.17	**1.12**	**118.5**	117.3	120.9	114.4	0.17	0.000

GPLH1a/b Piped NG to central production of liquid hydrogen and road distribution

Here hydrogen is produced by steam reforming of natural gas (pipeline 7 or 4000 km) in a central plant and subsequently liquefied. Liquid hydrogen is transported to the refuelling station by road tanker. Note that this pathway assumes that liquid hydrogen is used as such in the vehicle.

GRLH1 Remote NG to liquid hydrogen transported by sea and distributed by road

Producing hydrogen at the “wellhead” is another option. It does require liquefaction and long-distance transportation of hydrogen which tends to be energy-intensive and would require complex dedicated ships. One attraction might be the possibility to capture all CO_2 at source for e.g. re-injection into the local gas/oil fields. In this case, it is also assumed that liquid hydrogen is used as such in the vehicle.

GRLH2 LNG to central production of liquid hydrogen and road distribution

This is the same as GPLH1 now based on LNG.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GPLH1a	**Piped NG, 7000 km, central reforming + liquefaction**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.8			1.8	0.13	0.000
	NG Transport	3	0.26	0.09	0.29		19.3			13.5	0.25	0.001
	NG Distribution (HP)	3	0.01				0.8			0.7	0.00	0.000
	Central reforming	4	0.32	0.28	0.34		73.0			72.6	0.02	0.000
	Hyd liquefaction	4	0.68	0.47	0.88		41.0			36.8	0.16	0.002
	Liquid hyd distribution & delivery	5	0.03				1.7			1.7	0.00	0.000
	Total pathway		**1.33**	1.11	1.39	**1.33**	**140.6**	128.0	144.2	127.1	0.56	0.002
GPLH1b	**Piped NG, 4000 km, central reforming + liquefaction**											
	NG Extraction & Processing	1	0.03	0.02	0.07		4.4			1.6	0.12	0.000
	NG Transport	3	0.12	0.04	0.14		9.6			6.3	0.14	0.000
	NG Distribution (HP)	3	0.01				0.8			0.7	0.00	0.000
	Central reforming	4	0.32	0.28	0.34		73.0			72.6	0.02	0.000
	Hyd liquefaction	4	0.62	0.43	0.80		36.8			33.8	0.11	0.002
	Liquid hyd distribution & delivery	5	0.03				1.7			1.7	0.00	0.000
	Total pathway		**1.13**	1.00	1.23	**1.13**	**126.3**	118.2	131.5	116.8	0.39	0.002
GRLH1	**Remote NG reforming + hyd liquefaction + liquid hyd shipping**											
	NG Extraction & Processing	1	0.04	0.02	0.08		4.9			1.8	0.14	0.000
	Remote reforming	2	0.39	0.35	0.41		89.8			89.4	0.02	0.000
	Remote hyd liquefaction	2	0.69	0.48	0.90		39.7			37.9	0.06	0.002
	Liquid hyd transport (shipping)	3	0.26	0.23	0.29		1.4			1.3	0.00	0.000
	Liquid hyd distribution & delivery	5	0.04				2.8			2.8	0.00	0.000
	Total pathway		**1.42**	1.30	1.58	**1.42**	**138.7**	131.5	147.8	133.2	0.22	0.002
GRLH2	**LNG, central reforming + liquefaction**											
	NG Extraction & Processing	1	0.03	0.02	0.07		4.4			1.6	0.12	0.000
	NG Liquefaction	2	0.11	0.00	0.00		7.5			6.1	0.06	0.000
	LNG Transport (shipping)	3	0.11	0.10	0.12		7.3			7.3	0.00	0.000
	LNG Receipt + Vaporisation	4	0.04				2.4			2.4	0.00	0.000
	Central reforming	4	0.32	0.29	0.34		72.9			72.6	0.02	0.000
	Hyd liquefaction	4	0.67	0.47	0.88		39.6			37.4	0.08	0.002
	Liquid hyd distribution & delivery	5	0.04				2.8			2.8	0.00	0.000
	Total pathway		**1.34**	1.23	1.47	**1.34**	**136.9**	130.3	144.8	130.1	0.27	0.002

8.2 Coal to hydrogen

The pathways described here assume gasification of hard coal (EU-mix origin) followed by processing to a final fuel (see also section 2-6 for electricity pathways).

Pathway code		**KOCH**	
		1	**1C**
Code	Process		
Coal			
KO1	Hard coal provision (EU-mix) (1)	✓	✓
KE1	Electricity from Coal (conv. Boiler)		
KH1	Coal to hydrogen	✓	
KH1C	Coal to hydrogen with CC&S		✓
Hydrogen transport & distribution			
CH1a	Gasous Hyd distribution (pipeline from central plant)	✓	✓
CH3	Gasous Hyd dispensing	✓	✓
Common processes			
Z7a	Electricity (EU-mix, MV)	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓

KOCH1/1C Hard coal to compressed hydrogen (+CC&S option)

Gasification is followed by CO shift for hydrogen production. Distribution is through a local pipeline network (50 km average distance). Although coal gasification plants are likely to be very large, the assumption of hydrogen production for only relatively local needs is justified inasmuch as such plants can easily be designed to produce both hydrogen and e.g. electricity. This is often the case in industrial IGCC projects where there is a need for hydrogen for processing purposes. As full decarbonisation occurs at the production stage CO_2 capture and storage could be an attractive option where suitable geological formations are available within a reasonable distance.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
KOCH1	**Coal EU-mix, gasifier + CO shift**											
	Coal provision	3	0.19				30.8			12.99	0.77	0.001
	Gasifier + CO shift	4	0.99				193.0			193.0	0.00	0.000
	Gaseous Hyd distribution & compression	5	0.22				9.1			8.5	0.02	0.000
	Total pathway		**1.40**	1.38	1.41	**1.38**	**232.8**	232.0	233.6	214.4	0.79	0.001
KOCH1C	**Coal EU-mix, gasifier + CO shift, CC&S**											
	Coal provision	3	0.22				36.0			15.2	0.90	0.001
	Gasifier + CO shift + CC&S	4	1.33				5.8			5.8	0.00	0.000
	Gaseous Hyd distribution & compression	5	0.22				9.1			8.5	0.02	0.000
	Total pathway		**1.77**	1.76	1.79	**1.76**	**50.9**	50.1	51.6	29.5	0.92	0.001

8.3 Wood to hydrogen

Pathway code		**WFCH**		**WFLH**	**WWCH**		**BLCH**
		1	**2**	**1**	**1**	**2**	**1**
Code	Process						
Coal							
KO1	Hard coal provision (EU-mix) (1)						
KE1	Electricity from Coal (conv. Boiler)						
KH1	Coal to hydrogen						
KH1C	Coal to hydrogen with CC&S						
Wood (farmed)							
WF1	Wood farming and chipping	✓	✓	✓			
Wood (waste)							
WW1	Forest residuals to wood chips				✓	✓	✓
Wood transport & processing (all sources)							
WC2a	Wood chips road transport, 50 km		✓	✓		✓	✓
WC2b	Wood chips road transport, 12 km	✓			✓		
WC2c	Coastal/river shipping wood chips (200MW plant)					✓	
W3d	Wood to hydrogen: gasification, 200MW		✓	✓		✓	
W3e	Wood to hydrogen: gasification, 10MW	✓			✓		
Wood waste via black liquor							
BLH	Wood waste to hydrogen via black liquor						✓
Hydrogen transport & distribution							
CH1a	Gasous Hyd distribution (pipeline from central plant)		✓			✓	
CH1b	Gasous Hyd distribution (trucking from central plant)						
CH2	Liquid Hyd compression/vaporisation			✓			
CH3	Gasous Hyd dispensing	✓	✓		✓	✓	
Common processes							
Z71	HV+MV losses	✓	✓				
Z72	LV losses	✓					
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓

WWCH1/2 Wood waste (200/10 MW) to compressed hydrogen

These pathways use the wood gasification route to hydrogen either small or large scale. The latter is notably more efficient. In the large scale case distribution is assumed to be by pipeline.

WFCH1//2 Farmed wood (200/10 MW) to compressed hydrogen

The same as above, with farmed wood (which requires slightly more energy).

WFLH1 Farmed wood (200 MW) to liquid hydrogen

Hydrogen from the large scale plant is liquefied and transported by road tanker.

BLCH1 Waste wood to compressed hydrogen via black liquor route

The black liquor gasification route described in *section 2-5* can be equally applied to hydrogen production.

		Standard step	Energy consumed (MJx/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
WWCH1	**Wood waste, on-site gasification, 10 MW (biomass)**											
	Waste collection and chipping	1	0.06				0.7			0.7	0.00	0.000
	Transport (road + sea)	3	0.00				0.2			0.2	0.00	0.000
	On-site gasifier (10 MW) + CO shift	4	0.94				0.7			-0.6	0.01	0.003
	On-site delivery	5	0.22				9.1			8.5	0.02	0.000
	Total pathway		**1.22**	1.12	1.32	**0.19**	**10.7**	9.9	11.4	8.8	0.03	0.004
WWCH2	**Wood waste, large scale gasification, 200 MW (biomass)**											
	Waste collection and chipping	1	0.04				0.5			0.5	0.00	0.000
	Transport (road + sea)	3	0.03				2.1			2.0	0.00	0.000
	Med scale gasifier (200 MW) + CO shift	4	0.68				0.3			0.3	0.00	0.000
	Gaseous Hyd distribution & delivery	5	0.22				9.1			8.5	0.0	0.0
	Total pathway		**0.97**	0.89	1.05	**0.23**	**12.1**	11.2	12.8	11.3	0.03	0.000
WFCH1	**Farmed wood , on-site gasification, 10 MW (biomass)**											
	Wood farming and chipping	1	0.08				5.3			2.3	0.00	0.01
	Road transport	2	0.00				0.2			0.2	0.00	0.00
	On-site gasifier (10 MW) + CO shift	4	0.94				0.7			-0.6	0.01	0.00
	On-site delivery	5	0.22				9.1			8.5	0.02	0.00
	Total pathway		**1.24**	1.14	1.35	**0.22**	**15.2**	13.1	19.7	10.4	0.03	0.013
WFCH2	**Farmed wood, large scale gasification, 200 MW (biomass)**											
	Wood farming	1	0.06				4.0			1.8	0.00	0.007
	Road transport	3	0.01				0.5			0.5	0.00	0.000
	Med scale gasifier (200 MW) + CO shift	4	0.68				0.6			0.3	0.00	0.001
	Gaseous Hyd distribution & delivery	5	0.22				9.1			8.5	0.02	0.000
	Total pathway		**0.97**	0.89	1.05	**0.23**	**14.2**	12.9	18.2	11.1	0.02	0.009
WFLH1	**Farmed wood, large scale gasification, 200 MW (biomass), liquefaction**											
	Wood farming	1	0.06				3.9			1.7	0.00	0.007
	Road transport	3	0.01				1.1			0.8	0.00	0.001
	Med scale gasifier (200 MW) + CO shift	4	0.67				2.1			1.1	0.00	0.003
	Hyd liquefaction	4	0.74				0.8			0.8	0.00	0.000
	Liquid hyd distribution & delivery	5	0.02				0.1			0.1	0.00	0.000
	Total pathway		**1.50**	1.33	1.63	**0.07**	**8.1**	6.6	12.9	4.6	0.00	0.012
BLCH1	**Waste wood via black liquor**											
	Waste collection and chipping	1	0.04				0.5			0.4	0.00	0.000
	Transport (road)	3	0.01				0.4			0.4	0.00	0.000
	Black liquor gasification + CO shift	4	0.25				0.0			0.0	0.00	0.000
	Gaseous Hyd distribution & delivery	5	0.22				9.1			8.5	0.0	0.0
	Total pathway		**0.51**	0.48	0.55	**0.20**	**10.0**	9.3	10.8	9.4	0.02	0.000

8.4 Electricity to hydrogen (electrolysis)

An electrolyser can obviously make use of any electricity source. It can be a large central plant or a small on-site installation. From a central plant hydrogen can be piped to the refuelling station and compressed or liquefied and transported by road. From an on-site plant hydrogen must be compressed. This potentially makes for a very large number of combinations out of which we have only selected a few for illustration.

Pathway code		**GPEL**				**GREL**	**KOEL**		**WFEL**		**WDEL**	**NUEL**	**EMEL**	
		1a	**1b**	**1b**	**1b**	**1**	**1**	**1**	**2**	**3**	**1**	**1**	**1**	
Code	Process	CH1	CH1	CH2	LH1	CH1	CH1	CH2	CH1	CH1	CH1	CH1	CH1	LH1
GG1	NG Extraction & Processing	✓	✓	✓	✓	✓								
NG from pipeline														
GP1a	Russian quality, 7000 km	✓												
GP1b	Average quality, 4000 km		✓	✓	✓									
LNG production & transport														
GR1	NG Liquefaction					✓								
GR2	LNG terminal (loading)					✓								
GR3	LNG transport (average of two distances)					✓								
GR4	LNG terminal (unloading)					✓								
NG distribution														
GR5	LNG vaporisation					✓								
GG3	NG trunk distribution					✓								
NG common processes														
GG2	Electricity generation from NG (CCGT)	✓	✓	✓	✓	✓								
Coal														
KO1	Hard coal provision (EU-mix) (1)						✓	✓						
KE	Electricity from Coal						✓	✓						
Wood (farmed)														
WF1	Wood farming and chipping								✓	✓				
Wood (waste)														
WW1	Forest residuals to wood chips													
Wood	**transport & processing (all sources)**													
WC2a	Wood chips road transport, 50 km									✓				
WC2b	Wood chips road transport, 12 km								✓					
WC2c	Coastal/river shipping wood ships (200MW plant)													
W3c	Wood to electricity: gasification, 10MW								✓					
W3h	Wood cofiring in coal power station									✓				
Wind														
DE	Electricity from wind										✓			
Nuclear														
NE1	Nuclear fuel provision											✓		
NE2	Electricity from nuclear											✓		
Electrolysis														
EK1	On-site electrolyser	✓	✓		✓	✓	✓		✓	✓	✓	✓	✓	✓
EK2	Central electrolyser			✓				✓						
Hydrogen transport & distribution														
CH1a	Gasous Hyd distribution (pipeline from central plant)			✓				✓						
CH3	Gasous Hyd dispensing	✓	✓			✓	✓		✓	✓	✓	✓	✓	
LH1	Hyd liquefaction				✓									✓
LH3	Liquid Hyd distribution and dispensing				✓									✓
Common processes														
Z1	Diesel production				✓									✓
Z2	Road tanker				✓									✓
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

GPEL1a/b CH1 Piped NG to compressed hydrogen via on-site electrolysis

These two pathways illustrate the use of natural gas as a source of electricity and the impact of the gas origin.

GPEL1b CH1/CH2/LH1 Piped NG to compressed or liquid hydrogen via electrolysis

These three pathways illustrate the relative impacts of the plant location and scale and of the hydrogen delivery mode.

GREL1 CH1 LNG to compressed hydrogen via on-site electrolysis

This pathway further illustrates the impact of the gas origin, to be compared to GPEL1 above.

WFEL2/3 CH1 Farmed wood to compressed hydrogen via on-site electrolysis

Pathway 2 uses the large scale gasifier (200 MW) followed by a CCGT for electricity generation and on-site electrolysis. Pathway 3 is the same with the electricity generated by a conventional boiler + steam turbine plant.

WDEL1 CH1 Wind to compressed hydrogen via central electrolysis

This pathway assumes central electrolysis and hydrogen distribution as it is mostly applicable to “stranded electricity” that cannot be fed into the grid.

EMEL1 CH1/LH1 EU-mix electricity to compressed/liquid hydrogen via on-site electrolysis

NUEL1 CH1 Nuclear to compressed hydrogen via on-site electrolysis

KOEL1 CH1/CH2/LH1 Hard coal to compressed/liquid hydrogen via on-site/central electrolysis

This is an indirect route to hydrogen to be compared to KOCH1 in section 2-5.

		Standard step	Energy consumed (MJex/MJf)				Net GHG emitted (g CO$_2$eq/MJf)			CO$_2$	CH4	N$_2$O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
GPEL1a/CH1	**Piped NG 7000 km, CCGT, on-site electrolysis**											
	NG Extraction & Processing	1	0.08	0.04	0.17		10.6			3.9	0.29	0.000
	NG Transport	3	0.57	0.48	0.63		45.0			29.6	0.65	0.001
	NG Distribution (HP)	3	0.03				1.7			1.6	0.00	0.000
	Power generation (CCGT)	4	1.31	1.24	1.37		162.1			159.6	0.01	0.008
	Electricity distribution (MV)	4	0.03				0.0			0.0	0.00	0.000
	Electrolysis (on-site)	4	0.55	0.53	0.55		0.0			0.0	0.00	0.000
	Compression	5	0.16				8.6			7.7	0.04	0.000
	Total pathway		**2.73**	2.50	2.98	**2.73**	**227.9**	214.1	243.4	202.3	1.00	0.009
GPEL1b/CH1	**Piped NG 4000 km, CCGT, on-site electrolysis**											
	NG Extraction & Processing	1	0.08	0.04	0.15		9.7			3.6	0.27	0.000
	NG Transport	3	0.27	0.23	0.30		22.7			13.9	0.37	0.001
	NG Distribution (HP)	3	0.03				1.7			1.6	0.00	0.000
	Power generation (CCGT)	4	1.31	1.24	1.37		162.1			159.6	0.01	0.008
	Electricity distribution (MV)	4	0.03				0.0			0.0	0.00	0.000
	Electrolysis (on-site)	4	0.55	0.53	0.57		0.0			0.0	0.00	0.000
	Compression	5	0.15				7.7			7.0	0.03	0.000
	Total pathway		**2.41**	2.23	2.63	**2.41**	**203.8**	193.1	217.1	185.7	0.68	0.009
GPEL1b/CH2	**Piped NG, 4000 km, CCGT, central electrolysis, pipe**											
	NG Extraction & Processing	1	0.08	0.04	0.15		9.6			3.5	0.26	0.000
	NG Transport	3	0.27	0.22	0.30		22.5			13.8	0.37	0.001
	NG Distribution (HP)	3	0.03				1.6			1.6	0.00	0.000
	Power generation (CCGT)	4	1.30	1.23	1.36		160.9			158.5	0.01	0.007
	Electricity distribution (HV)	4	0.02				0.0			0.0	0.00	0.000
	Electrolysis (central)	4	0.55	0.53	0.57		0.0			0.0	0.00	0.000
	Gaseous hyd distribution & comp.	5	0.22				9.1			8.5	0.02	0.000
	Total pathway		**2.46**	2.26	2.68	**2.45**	**203.8**	192.0	217.5	185.9	0.67	0.009
GPEL1b/LH1	**Piped NG 4000 km, CCGT, central electrolysis, liquefaction**											
	NG Extraction & Processing	1	0.08	0.04	0.15		9.5			3.5	0.26	0.000
	NG Transport	3	0.27	0.22	0.30		22.2			13.6	0.36	0.001
	NG Distribution (HP)	3	0.03				1.6			1.6	0.00	0.000
	Power generation (CCGT)	4	1.28	1.21	1.33		158.6			156.1	0.01	0.007
	Electricity distribution (HV)	4	0.02				0.0			0.0	0.00	0.000
	Electrolysis (central)	4	0.54	0.52	0.56		0.0			0.0	0.00	0.000
	Hyd liquefaction	4	0.62	0.55	0.69		37.2			33.9	0.12	0.002
	Liquid hyd distribution & delivery	1	0.04				2.8			2.8	0.00	0.000
	Total pathway		**2.87**	2.63	3.06	**2.87**	**231.9**	218.1	243.5	211.5	0.76	0.010
GREL1/CH1	**LNG, CCGT, on-site electrolysis**											
	NG Extraction & Processing	1	0.08	0.04	0.15		9.7			3.6	0.27	0.000
	NG Liquefaction	2	0.25				16.6			13.6	0.13	0.001
	Long-distance transport	3	0.25				16.2			16.1	0.00	0.000
	LNG Vaporisation + Distribution (HP)	3	0.13	0.12	0.13		7.0			6.9	0.00	0.000
	Power generation (CCGT)	4	1.31				162.1			159.6	0.01	0.008
	Electricity distribution (MV)	4	0.03				0.0			0.0	0.00	0.000
	Electrolysis (on-site)	4	0.55	0.53	0.57		0.0			0.0	0.00	0.000
	Compression	5	0.16				8.3			7.8	0.02	0.000
	Total pathway		**2.75**	2.53	3.00	**2.75**	**219.9**	206.8	235.1	207.5	0.42	0.009

		Standard step	Energy consumed (MJex/MJf)				Net GHG emitted (g CO_2eq/MJf)			CO_2	CH4	N_2O
			Total primary			Fossil						
			Best est.	min	Max		Best est.	min	Max	g/MJ	g/MJ	g/MJ
WFEL2/CH1	**Farmed wood, CCGT, on-site electrolysis**											
	Wood harvesting and chipping	1	0.14				8.7			3.9	0.00	0.016
	Mixed transport	3	0.01				1.1			1.1	0.00	0.000
	Gasification (200 MW)+ CCGT	4	1.71				2.1			0.0	0.04	0.004
	Electricity distribution (MV)	4	0.03				0.0			0.0	0.00	0.000
	Electrolysis (on-site)		0.55	0.53	0.57		0.0			0.0	0.00	0.000
	Compression	5	0.16				0.5			0.2	0.00	0.001
	Total pathway		**2.60**	2.42	2.82	**0.12**	**12.5**	9.1	21.6	5.2	0.05	0.021
WFEL3/CH1	**Farmed wood, conv. power plant, on-site electrolysis**											
	Wood harvesting and chipping	1	0.21				13.2			5.9	0.00	0.024
	Mixed transport	3	0.02				1.7			1.7	0.00	0.000
	Conv power plant (200 MW), cond. turbine	4	3.39				14.7			0.0	0.13	0.039
	Electricity distribution (MV)	4	0.03				0.0			0.0	0.00	0.000
	Electrolysis (on-site)	4	0.55	0.53	0.57		0.0			0.0	0.00	0.000
	Compression	5	0.23				1.2			0.3	0.01	0.003
	Total pathway		**4.42**	4.11	4.77	**0.19**	**30.7**	25.7	43.6	7.8	0.14	0.066
WDEL1/CH2	**Wind offshore, central electrolysis**											
	Wind offshore	1	0.00				0.0			0.0	0.00	0.000
	Electricity distribution (MV)	3	0.02				0.0			0.0	0.00	0.000
	Electrolysis (central)	4	0.55	0.53	0.57		0.0			0.0	0.00	0.000
	Gaseous hyd distribution & comp.	5	0.22				9.1			8.5	0.02	0.000
	Total pathway		**0.79**	0.72	0.85	**0.19**	**9.1**	8.4	9.9	8.5	0.02	0.000
EMEL1/CH1	**EU-mix electricity, on-site electrolysis**											
	EU-mix power generation	1	2.85				200.3			187.3	0.46	0.008
	Electricity distribution (MV)	3	0.03				0.0			0.0	0.00	0.000
	Electrolysis (on-site)	4	0.55	0.53	0.57		0.0			0.0	0.00	0.000
	Compression	5	0.19				7.9			7.4	0.02	0.000
	Total pathway		**3.62**	3.43	3.83	**3.39**	**208.1**	199.5	217.7	194.6	0.47	0.009
EMEL1/LH1	**EU-mix electricity, central electrolysis, liquefaction**											
	EU-mix power generation	1	2.79				195.9			183.2	0.45	0.008
	Electricity distribution (MV)	3	0.02				0.0			0.0	0.0	0.0
	Electrolysis (central)	4	0.54	0.52	0.56		0.0			0.0	0.0	0.0
	Hyd liquefaction	4	0.85	0.76	0.95		38.2			35.7	0.1	0.0
	Liquid hyd distribution & delivery	5	0.03				1.7			1.7	0.0	0.0
	Total pathway		**4.22**	4.04	4.47	**3.97**	**235.9**	227.8	246.9	220.7	0.53	0.010
NUEL1/CH1	**Nuclear electricity, on-site electrolysis**											
	Nuclear fuel provision	3	0.96				6.2			5.8	0.01	0.000
	Nuclear power station	4	3.26				0.5			0.5	0.00	0.000
	Electricity distribution (MV)	4	0.01				0.0			0.0	0.0	0.0
	Electrolysis (on-site)	4	0.55	0.53	0.57		0.0			0.0	0.0	0.0
	Compression	5	0.25				0.3			0.2	0.0	0.0
	Total pathway		**5.03**	4.79	5.31	**5.02**	**7.0**	6.6	7.4	6.6	0.01	0.000
KOEL1/CH1	**Coal electricity, on-site electrolysis**											
	Coal provision (EU-mix)	3	0.34				56.3			23.7	1.40	0.001
	Coal power station	4	2.07				357.9			352.4	0.01	0.018
	Electricity distribution (MV)	4	0.03				0.0			0.0	0.0	0.0
	Electrolysis (on-site)	4	0.55	0.53	0.57		0.0			0.0	0.0	0.0
	Compression	5	0.18				16.3			14.8	0.1	0.0
	Total pathway		**3.17**	2.64	3.60	**3.16**	**430.4**	376.4	473.7	390.9	1.46	0.020
KOEL1/CH2	**Coal electricity, central electrolysis**											
	Coal provision (EU-mix)	3	0.34				55.9			23.6	1.39	0.001
	Coal power station	4	2.06				355.4			349.9	0.01	0.018
	Electricity distribution (MV)	4	0.02				0.0			0.0	0.0	0.0
	Electrolysis (on-site)	4	0.55	0.53	0.57		0.0			0.0	0.0	0.0
	Compression	5	0.22				9.1			8.5	0.0	0.0
	Total pathway		**3.19**	2.66	3.60	**3.17**	**420.4**	367.2	461.5	382.0	1.42	0.019
KOEL1/LH1	**Coal electricity, central electrolysis, liquefaction**											
	Coal provision (EU-mix)	3	0.34				55.0			23.2	1.37	0.001
	Coal power station	4	2.03				350.2			344.8	0.01	0.018
	Electricity distribution (MV)	4	0.02				0.0			0.0	0.0	0.0
	Electrolysis (central)	4	0.54	0.52	0.56		0.0			0.0	0.0	0.0
	Hyd liquefaction	4	0.77	0.68	0.85		79.0			71.8	0.3	0.0
	Liquid hyd distribution & delivery	5	0.04				2.7			2.7	0.0	0.0
	Total pathway		**3.73**	3.18	4.10	**3.73**	**487.0**	430.5	524.4	442.5	1.65	0.022

9 Summary of energy and GHG balances

9.1 Oil-based fuels, CBG/CBG, Ethanol, Ethers, Bio-diesel

Pathway		**Energy expended (MJex/MJ final fuel)**											**Net GHG emitted (g CO_2eq/MJ final fuel)**											
Code	Description	**Total energy**	Fossil energy	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Range				**Total GHG inc. renew comb. CO2 credit**	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Total WTT GHG emitted	Credit for renewable combustion CO_2	Range			
COG1	Conventional gasoline	**0.14**	0.14	0.03		0.01	0.08	0.02	0.12	0.17	0.02	0.03	**13**	4		1	7	1	13		11	15	1	2
COD1	Conventional diesel	**0.16**	0.16	0.03		0.01	0.10	0.02	0.14	0.18	0.02	0.02	**14**	4		1	9	1	14		13	16	2	2
CON1	Conventional naphtha	**0.11**	0.11	0.03		0.01	0.05	0.02	0.10	0.13	0.01	0.02	**10**	4		1	4	1	10		9	11	1	2
LRLP1	LPG: imports from remote gas field	**0.12**	0.12	0.05	0.01	0.03		0.03	0.12	0.13	0.00	0.01	**8**	3	0	2		2	8		8	8	0	0
GMCG1	CNG: EU-mix	**0.12**	0.12	0.02		0.02		0.07	0.10	0.14	0.02	0.03	**8**	3		2		3	8		7	10	1	1
GPCG1a	CNG: Pipeline 7000 km	**0.30**	0.29	0.03		0.19		0.07	0.19	0.30	0.10	0.01	**22**	4		15		3	22		16	22	6	0
GPCG1b	CNG: Pipeline 4000 km	**0.19**	0.19	0.03		0.09		0.07	0.14	0.21	0.05	0.02	**14**	3		7		3	14		11	15	3	1
GRCG1	CNG: LNG, Vap, Pipe	**0.31**	0.30	0.03	0.09	0.12		0.07	0.28	0.33	0.02	0.03	**20**	3	6	7		3	20		19	21	1	1
GRCG1C	CNG: LNG, Vap, Pipe, CC&S	**0.32**	0.32	0.03	0.10	0.12		0.07	0.29	0.34	0.02	0.03	**16**	3	2	7		3	16		15	18	1	1
GRCG2	CNG: LNG, Road, Vap	**0.26**	0.26	0.03	0.09	0.10		0.05	0.25	0.29	0.01	0.02	**20**	3	6	6		5	20		20	22	1	1
OWCG1	CBG: municipal waste	**0.87**	0.17				0.81	0.06	0.74	1.02	0.13	0.15	**-40**				32	3	35	-76	-43	-37	3	3
OWCG2	CBG: liquid manure	**0.97**	0.03		0.03		0.88	0.06	0.79	1.12	0.18	0.15	**-134**		-87		26	3	-58	-76	-156	-107	23	27
OWCG3	CBG: dry manure	**0.95**	0.01		0.01		0.88	0.06	0.78	1.11	0.17	0.16	**-55**		-8		26	3	20	-76	-58	-52	3	3
SBET1	EtOH: Sugar beet, pulp to fodder	**1.86**	0.87	0.16		0.03	1.64	0.03	1.74	1.99	0.12	0.13	**-14**	21		2	33	2	57	-71	-17	-10	3	4
SBET3	EtOH: Sugar beet, pulp to heat	**1.30**	0.31	0.16		0.03	1.08	0.03	1.18	1.42	0.12	0.12	**-42**	21		2	5	2	30	-71	-44	-40	3	2
WTET1a	EtOH: Wheat, conv NG boiler, DDGS as AF	**1.78**	0.89	0.24		0.03	1.49	0.03	1.76	1.80	0.02	0.02	**-12**	32		1	25	2	59	-71	-20	-4	7	8
WTET1b	EtOH: Wheat, conv NG boiler, DDGS as fuel	**1.30**	0.44	0.24		0.03	1.02	0.03	1.28	1.33	0.02	0.02	**-21**	32		1	17	2	51	-71	-28	-14	7	7
WTET2a	EtOH: Wheat, NG GT+CHP, DDGS as AF	**1.53**	0.65	0.24		0.03	1.24	0.03	1.51	1.55	0.02	0.02	**-25**	32		1	13	2	47	-71	-32	-18	7	7
WTET2b	EtOH: Wheat, NG GT+CHP, DDGS as fuel	**1.06**	0.20	0.24		0.03	0.77	0.03	1.04	1.08	0.02	0.02	**-33**	32		1	4	2	38	-71	-40	-27	6	7
WTET3a	EtOH: Wheat, Lignite CHP, DDGS as AF	**1.74**	0.86	0.24		0.03	1.46	0.03	1.74	1.75	0.00	0.00	**21**	32		1	59	2	93	-71	13	29	8	7
WTET3b	EtOH: Wheat, Lignite CHP, DDGS as fuel	**1.27**	0.41	0.24		0.03	0.98	0.03	1.27	1.27	0.00	0.00	**13**	32		1	50	2	84	-71	6	20	6	8
WTET4a	EtOH: Wheat, Straw CHP, DDGS as AF	**1.69**	0.28	0.24		0.03	1.40	0.03	1.69	1.70	0.00	0.00	**-47**	32		1	-9	2	25	-71	-54	-40	7	7
WTET4b	EtOH: Wheat, Straw CHP, DDGS as fuel	**1.22**	-0.17	0.24		0.03	0.93	0.03	1.21	1.22	0.00	0.00	**-55**	32		1	-18	2	16	-71	-63	-49	8	7
WWET1	EtOH: W Wood	**1.94**	0.27	0.08		0.04	1.80	0.03	1.84	2.05	0.10	0.10	**-53**	1		3	12	2	18	-71	-54	-53	0	0
WFET1	EtOH: F wood	**1.95**	0.27	0.11		0.01	1.80	0.03	1.84	2.05	0.11	0.10	**-50**	7		1	12	2	22	-71	-52	-43	3	7
STET1	EtOH: Wheat straw	**1.32**	0.11	0.05		0.01	1.24	0.03	1.32	1.32	0.00	0.00	**-62**	3		1	3	2	9	-71	-62	-62	0	0
SCET1	EtOH: Sugar cane (Brazil)	**1.79**	0.02	0.06		0.01	1.63	0.09	1.79	1.80	0.00	0.00	**-61**	13		1	-10	7	10	-71	-61	-61	0	0
GRMB1	MTBE: remote plant	**0.30**	0.30	0.01	0.23	0.05		0.01	0.30	0.31	0.00	0.01	**14**	1	8	4		0	14		13	14	0	1
LREB1	ETBE: imported C4 and wheat ethanol	**0.75**	0.07	0.09		0.01	0.64	0.02	0.75	0.77	0.01	0.01	**-3**	12		0	7	1	20	-24	-6	-1	2	3
ROFA1	RME: Gly as chemical	**1.14**	0.41	0.31		0.02	0.80	0.02	1.05	1.23	0.10	0.09	**-36**	52		0	-14	1	40	-75	-55	-17	19	19
ROFA2	RME: Gly as animal feed	**1.20**	0.46	0.31		0.02	0.85	0.02	1.09	1.31	0.11	0.11	**-30**	52		0	-8	1	45	-75	-51	-10	21	20
ROFE1	REE: Gly as chemical	**1.21**	0.36	0.29		0.02	0.87	0.02	1.11	1.30	0.09	0.10	**-43**	49		0	-18	1	33	-75	-63	-22	20	20
ROFE2	REE: Gly as animal feed	**1.25**	0.41	0.29		0.02	0.92	0.02	1.17	1.36	0.08	0.11	**-38**	49		0	-13	1	37	-75	-56	-16	18	22
SOFA1	SME: Gly as chemical	**0.91**	0.30	0.18		0.02	0.69	0.02	0.83	1.01	0.08	0.09	**-58**	28		0	-12	1	17	-75	-70	-45	12	13
SOFA2	SME: Gly as animal feed	**0.97**	0.35	0.18		0.02	0.74	0.02	0.88	1.06	0.08	0.09	**-53**	28		0	-7	1	23	-75	-64	-42	12	11

9.2 Synthetic diesel, Methanol, DME

Pathway		Energy expended (MJex/MJ final fuel)											Net GHG emitted (g CO_2eq/MJ final fuel)											
Code	Description	**Total energy**	Fossil energy	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Range				**Total GHG inc. renew comb. CO2 credit**	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Total WTT GHG emitted	Credit for renewable combustion CO_2	Range			
GRSD1	Syn-diesel: Rem GTL, Sea, Diesel mix	**0.68**	0.68	0.04	0.59	0.04		0.02	0.63	0.75	0.05	0.07	**25**	5	16	3		1	25		22	29	3	4
GRSD2	Syn-diesel: Rem GTL, Sea, Rail/Road	**0.68**	0.68	0.04	0.59	0.04		0.02	0.63	0.74	0.05	0.06	**25**	5	16	3		1	25		22	29	3	3
GRSD2C	Syn-diesel: Rem GTL, Sea, Rail/Road, CC&S	**0.76**	0.76	0.04	0.67	0.04		0.02	0.71	0.82	0.05	0.06	**13**	5	4	3		1	13		10	16	3	3
KOSD1	Syn-diesel: CTL, Diesel mix	**0.97**	0.97	0.17			0.78	0.02	0.89	1.05	0.08	0.08	**129**	27			101	1	129		121	137	8	8
KOSD1C	Syn-diesel: CTL, CC&S, Diesel mix	**1.06**	1.05	0.17			0.86	0.02	0.98	1.14	0.08	0.08	**39**	29			9	1	39		31	47	8	8
WWSD1	Syn-diesel: W Wood, diesel mix	**1.19**	0.07	0.06		0.04	1.08	0.02	1.08	1.30	0.12	0.11	**-66**	1		3	0	1	5	-71	-66	-66	0	0
WFSD1	Syn-diesel: F wood, diesel mix	**1.19**	0.06	0.09		0.01	1.08	0.02	1.08	1.29	0.11	0.09	**-63**	6		1		1	7	-71	-66	-57	3	6
BLSD1	Syn-diesel: W Wood, Black liquor	**0.91**	0.04	0.05		0.01	0.83	0.02	0.86	0.97	0.05	0.06	**-68**	1		1		1	2	-71	-68	-68	0	0
GPME1a	MeOH: NG 7000 km, Syn, Rail/Road	**0.84**	0.84	0.04		0.30	0.47	0.03	0.70	0.87	0.14	0.03	**41**	5		22	12	2	41		33	43	8	2
GPME1b	MeOH: NG 4000 km, Syn, Rail/Road	**0.69**	0.69	0.04		0.15	0.47	0.03	0.63	0.70	0.06	0.02	**30**	5		12	12	2	30		27	31	3	1
GRME1	MeOH: Rem Syn, Sea, Rail/Road	**0.61**	0.61	0.04	0.47	0.08		0.03	0.59	0.64	0.02	0.03	**24**	4	12	6		2	24		23	26	1	2
KOME1	MeOH: Coal EU-mix, Cen, Rail/Road	**0.93**	0.93			0.16	0.74	0.03	0.84	1.03	0.09	0.10	**127**			27	98	2	127		118	137	9	10
WWME1	MeOH: W Wood, Road	**1.07**	0.06	0.06		0.03	0.96	0.02	0.94	1.20	0.13	0.13	**-64**	1		3	0	1	5	-69	-65	-64	0	0
WFME1	MeOH: F Wood, Road	**1.07**	0.06	0.08		0.01	0.96	0.02	0.93	1.19	0.14	0.12	**-62**	5		1	0	1	7	-69	-64	-58	2	4
BLME1	MeOH: W Wood, Black liquor	**0.59**	0.03	0.05		0.01	0.52	0.02	0.54	0.64	0.05	0.05	**-67**	1		1	0	1	2	-69	-67	-67	0	0
GPDE1a	DME: NG 7000 km, Syn, Rail/Road	**0.77**	0.77	0.04		0.29	0.41	0.03	0.63	0.79	0.14	0.02	**39**	5		21	11	2	39		31	40	8	1
GPDE1b	DME: NG 4000 km, Syn, Rail/Road	**0.62**	0.62	0.04		0.14	0.41	0.03	0.56	0.64	0.06	0.02	**28**	5		11	11	2	28		24	29	4	1
GRDE1	DME: Rem Syn, Sea, Rail/Road	**0.53**	0.53	0.03	0.41	0.06		0.03	0.51	0.56	0.02	0.03	**21**	4	11	4		2	21		20	23	1	2
KODE1	DME: Coal EU-mix, Cen, Rail/Road	**0.93**	0.92			0.16	0.74	0.03	0.83	1.01	0.10	0.08	**128**			27	100	2	128		118	137	10	8
GRDE1C	DME: Rem Syn, Sea, Rail/Road, CC&S	**0.54**	0.54	0.03	0.42	0.06		0.03	0.54	0.61	0.00	0.07	**11**	4	1	4		2	11		11	15	0	4
WWDE1	DME: W Wood, Road	**1.07**	0.06	0.06		0.03	0.96	0.02	0.95	1.22	0.12	0.15	**-63**	1		3	0	1	5	-67	-63	-63	0	0
WFDE1	DME: F Wood, Road	**1.07**	0.06	0.08		0.01	0.96	0.02	0.94	1.20	0.13	0.13	**-60**	5		1	0	1	7	-67	-62	-55	2	5
BLDE1	DME: W Wood, Black liquor	**0.55**	0.03	0.04		0.01	0.49	0.02	0.51	0.61	0.04	0.05	**-65**	1		1	0	1	2	-67	-65	-65	0	0

9.3 Hydrogen

Pathway		**Energy expended (MJex/MJ final fuel)**											**Net GHG emitted (g CO_2eq/MJ final fuel)**										
Code	Description	**Total energy**	Fossil energy	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Range				**Total GHG inc. renew comb. CO2 credit**	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Total WTT GHG emitted Credit for renewable combustion CO_2	Range			
GMCH1	C-H2, EU-mix, O/S Ref	**0.84**	0.83	0.04		0.05	0.52	0.24	0.81	0.90	0.03	0.05	**105**	5		4	87	10	105	103	108	2	3
GPCH1a	C-H2, NG 7000 km, O/S Ref	**1.11**	1.09	0.04		0.30	0.52	0.24	0.95	1.13	0.15	0.02	**122**	5		22	85	10	122	114	124	9	1
GPCH1b	C-H2, NG 4000 km, O/S Ref	**0.95**	0.94	0.04		0.15	0.52	0.24	0.87	0.98	0.08	0.03	**111**	5		12	85	10	111	106	113	5	2
GPCH2a	C-H2: NG 7000 km, Cen ref, Pipe	**0.86**	0.85	0.04		0.27	0.32	0.22	0.71	0.88	0.15	0.03	**108**	5		20	74	9	108	100	110	8	1
GPCH2b	C-H2: NG 4000 km, Cen Ref, Pipe	**0.72**	0.71	0.04		0.14	0.32	0.22	0.64	0.74	0.07	0.03	**98**	4		11	74	9	98	94	100	4	2
GPCH2bC	C-H2: NG 4000 km, Cen Ref, Pipe, CC&S	**0.77**	0.76	0.04		0.14	0.37	0.22	0.70	0.80	0.08	0.03	**37**	5		11	12	9	37	33	39	4	2
GPCH3b	C-H2: NG 4000 km, Cen Ref, Road	**0.72**	0.71	0.04		0.14	0.32	0.22	0.65	0.74	0.06	0.02	**99**	4		11	74	10	99	95	100	4	1
GPLCHb	C-H2: NG 4000 km, Cen Ref, Liq, Road, Vap/comp.	**1.28**	0.71	0.03		0.13	0.94	0.17	1.14	1.35	0.14	0.08	**133**	4		10	110	8	133	124	137	8	5
GRCH1	C-H2: LNG, O/S Ref	**1.12**	1.10	0.04	0.13	0.19	0.52	0.24	1.08	1.18	0.03	0.06	**119**	5	8	12	84	10	119	117	123	2	3
GRCH2	C-H2: LNG, Cen Ref, Pipe	**0.87**	0.86	0.04	0.12	0.17	0.32	0.22	0.83	0.92	0.04	0.05	**106**	4	8	11	74	9	106	104	109	2	3
GRCH3	C-H2: Rem NG, methanol, O/S Ref	**1.13**	1.12	0.04	0.57	0.08	0.22	0.22	1.11	1.17	0.02	0.04	**119**	5	14	5	85	9	119	117	121	1	2
KOCH1	C-H2: Coal EU-mix, cen Ref, Pipe	**1.40**	1.38			0.19	0.99	0.22	1.38	1.41	0.02	0.02	**233**			31	193	9	233	232	234	1	1
KOCH1C	C-H2: Coal EU-mix, cen Ref, Pipe, CC&S	**1.77**	1.76			0.22	1.33	0.22	1.76	1.79	0.02	0.02	**51**			36	6	9	51	50	52	1	1
WWCH1	C-H2: Wood W, O/S gasif	**1.22**	0.19	0.06		0.00	0.94	0.22	1.12	1.32	0.10	0.10	**11**	1		0	1	9	11	10	11	1	1
WWCH2	C-H2: Wood W, Cen gasif. Pipe	**0.97**	0.23	0.04		0.03	0.68	0.22	0.89	1.05	0.08	0.08	**12**	1		2	0	9	12	11	13	1	1
BLCH1	C-H2: Wood W, Black liquor	**0.51**	0.20	0.04		0.01	0.25	0.22	0.48	0.55	0.03	0.04	**10**	0		0		9	10	9	11	1	1
WFCH1	C-H2: Wood F, O/S gasif	**1.24**	0.22	0.08		0.00	0.94	0.22	1.14	1.35	0.10	0.10	**15**	5		0	1	9	15	13	20	2	4
WFCH2	C-H2: Wood F, Cen gasif, pipe	**0.97**	0.23	0.06		0.01	0.68	0.22	0.89	1.05	0.08	0.09	**14**	4		1	1	9	14	13	18	1	4
GPEL1a/CH1	C-H2: NG 7000 km, CCGT, O/S Ely	**2.72**	2.72	0.08		0.59	1.88	0.16	2.30	2.83	0.42	0.11	**225**	11		44	162	9	225	201	232	25	7
GPEL1b/CH1	C-H2: NG 4000 km, CCGT, O/S Ely	**2.40**	2.40	0.08		0.30	1.88	0.15	2.16	2.56	0.24	0.16	**202**	10		23	162	8	202	188	212	14	9
GPEL1b/CH2	C-H2: NG 4000 km, CCGT, Cen Ely, Pipe	**2.45**	2.44	0.08		0.29	1.86	0.22	2.19	2.64	0.26	0.19	**202**	10		23	161	9	202	187	213	16	11
GREL1/CH1	C-H2: LNG, O/S Ely	**2.75**	2.75	0.08		0.63	1.88	0.16	2.51	3.00	0.24	0.25	**220**	10		40	162	8	220	206	235	14	15
WFEL2/CH1	C-H2: F Wood, 200 MW gasif, CCGT, O/S Ely	**2.60**	0.08	0.14		0.01	2.29	0.16	2.39	2.82	0.21	0.22	**13**	9		1	2	0	13	9	22	3	9
WFEL3/CH1	C-H2: F Wood, Conv power, O/S Ely	**4.43**	0.11	0.21		0.02	3.97	0.23	4.05	4.71	0.38	0.29	**31**	13		2	15	1	31	26	44	5	13
EMEL1/CH1	C-H2: Elec EU-mix, O/S Ely	**3.62**	3.39				3.43	0.19	3.45	3.79	0.17	0.17	**208**				200	8	208	200	216	8	8
KOEL1/CH1	C-H2: Elec coal EU-mix, O/S Ely	**3.17**	3.16			0.34	2.65	0.18	2.64	3.60	0.53	0.42	**423**			56	352	15	423	376	473	47	50
KOEL1/CH2	C-H2: Elec coal EU-mix, Cen ely, Pipe	**3.19**	3.17			0.34	2.62	0.22	2.66	3.54	0.53	0.35	**414**			56	350	9	414	366	458	48	43
NUEL1/CH1	C-H2: Elec nuclear, O/S Ely	**5.03**	5.02			0.96	3.82	0.25	4.76	5.29	0.27	0.27	**7**			6	0	0	7	7	7	0	0
WDEL1/CH2	C-H2: Wind, Cen Ely, Pipe	**0.79**	0.19			0.02	0.55	0.22	0.72	0.84	0.06	0.06	**9**					9	9	8	10	1	1
GPLH1a	L-H2:NG 7000 km, Cen Ref, Liq, Road	**1.33**	1.33	0.04		0.27	0.32	0.71	1.11	1.37	0.22	0.04	**141**	5		20	73	43	141	128	143	13	2
GPLH1b	L-H2: NG 4000 km, Cen Ref, Liq, Road	**1.13**	1.13	0.03		0.13	0.32	0.65	1.00	1.22	0.14	0.08	**126**	4		10	73	39	126	118	131	8	5
GRLH1	L-H2: Rem Ref, Liq, Sea, Road	**1.42**	1.42	0.04	1.08	0.26		0.04	1.30	1.57	0.12	0.15	**139**	5	130	1		3	139	132	147	7	9
GRLH2	L-H2: LNG, Cen Ref, Liq, Road	**1.34**	1.34	0.03	0.11	0.16	0.32	0.72	1.22	1.47	0.11	0.13	**137**	4	8	10	73	42	137	130	144	7	7
WFLH1	L-H2: Wood F, Cen gasif, Liq, Road	**1.50**	0.07	0.06		0.01	1.41	0.02	1.33	1.63	0.17	0.13	**8**	4		1	3	0	8	7	13	1	5
GPEL1b/LH1	L-H2: NG 4000 km, CCGT, Cen Ely, Liq, Road	**2.86**	2.86	0.08		0.29	1.83	0.66	2.57	3.03	0.29	0.17	**230**	9		22	159	40	230	213	240	17	10
EMEL1/LH1	L-H2: Elec EU-mix, Cen Ely, Liq, Road	**4.22**	3.97				3.35	0.88	4.02	4.42	0.21	0.20	**236**				196	40	236	227	245	9	9
KOEL1/LH1	L-H2: Elec coal EU-mix, Cen Ely, Liq, Road	**3.73**	3.72			0.34	3.35	0.04	3.18	4.16	0.55	0.43	**474**			55	417	3	474	431	531	44	56

9.4 Electricity

Pathway		Energy expended (MJex/MJ final fuel)											Net GHG emitted (g CO_2eq/MJ final fuel)										
Code	Description	**Total energy**	Fossil energy	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Range				**Total GHG inc. renew comb. CO2 credit**	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Total WTT GHG emitted Credit for renewable combustion CO_2	Range			
KOEL1	Elec:EU-mix Coal conv.	**1.59**	1.58	0.22			1.34	0.03	1.23	1.78	0.35	0.19	**267**	36			231		267	231	287	36	20
KOEL2	Elec:EU-mix Coal IGCC	**1.35**	1.34	0.20			1.12	0.03	1.25	1.46	0.10	0.11	**239**	33			206		239	229	250	10	11
GPEL1a	Elec: NG 7000 km, CCGT	**1.31**	1.31	0.05		0.38	0.84	0.03	1.06	1.36	0.25	0.05	**140**	7		28	105		140	126	143	14	3
GPEL1b	Elec: NG 4000 km, CCGT	**1.11**	1.11	0.05		0.19	0.84	0.03	0.97	1.20	0.14	0.09	**126**	6		15	105		126	117	131	8	5
GREL1	Elec: LNG, CCGT	**1.33**	1.33	0.05	0.16	0.24	0.84	0.03	1.23	1.46	0.10	0.14	**137**	6	11	15	105		137	131	144	6	8
WFEL1	Elec: F Wood, 10 MW gasif	**2.03**	0.05	0.12		0.00	1.88	0.03	1.93	2.15	0.10	0.12	**10**	8		0	2		10	7	17	3	7
WFEL2	Elec: F Wood, 200 MW gasif	**1.24**	0.05	0.09		0.01	1.11	0.03	1.15	1.34	0.09	0.10	**8**	6		1	1		8	6	13	2	5
WFEL3	Elec: F Wood, Conv power	**2.37**	0.07	0.14		0.01	2.19	0.03	2.19	2.52	0.18	0.16	**19**	9		1	9		19	16	28	3	9
EMEL1	Elec: EU-mix	**1.87**	1.73				1.84	0.03	1.87	1.87	0.00	0.00	**129**				129		129	129	129	0	0
WDEL1	Elec: Wind offshore	**0.03**						0.03	0.03	0.03	0.00	0.00											
NUEL1	Elec: Nuclear	**2.74**	2.74	0.62			2.09	0.03	2.66	2.81	0.08	0.07	**4**	4			0		4	4	5	0	0
OWEL1a	Elec: Biogas ex municipal waste, local	**3.20**	-0.08				3.19	0.01	2.92	3.55	0.28	0.35	**6**				6		6	6	7	0	1
OWEL1b	Elec: Biogas ex municipal waste, large	**2.39**	0.21				2.36	0.03	2.09	2.67	0.30	0.29	**26**				26		26	21	31	5	5
OWEL2a	Elec: Biogas ex liquid manure, local	**3.06**	0.01		0.06		2.99	0.01	2.73	3.38	0.33	0.31	**-172**		-182		10		-172	-221	-123	48	50
OWEL2b	Elec: Biogas ex liquid manure, large	**2.56**	-0.06		0.05		2.48	0.03	2.26	2.89	0.30	0.32	**-149**		-163		14		-149	-195	-98	46	50
OWEL3a	Elec: Biogas ex dry manure, local	**3.02**	-0.03		0.02		2.99	0.01	2.70	3.31	0.32	0.29	**-8**		-17		10		-8	-12	-3	4	5
OWEL3b	Elec: Biogas ex dry manure, large	**2.53**	-0.09		0.02		2.48	0.03	2.16	2.87	0.36	0.34	**-1**		-15		14		-1	-7	4	5	5
BLEL1	Elec: Black liquor	**0.18**	0.01	0.03		0.01	0.11	0.03	0.15	0.22	0.04	0.04	**0**			0			0	1	1	0	0

WTT APPENDIX 1

Description of individual processes and detailed input data

All WTT data was stored in LBST's E^3 database and that software was used to calculate the energy and GHG balances of the pathways. This appendix provides full detail of the input data. It consists in two elements:

- A series of tables giving input data to each process,
- A textual description and justification of each process.

The information has been split into logical sections each incorporating the processes involved in a number of related pathways. The process that are new to this version are highlighted in yellow.

Both energy and GHG figures are shown per unit energy content of the output of the particular process (MJ), NOT of the output of the total pathway (e.g. the energy required for wheat farming is shown per MJ of wheat grain, rather than MJ of ethanol).

The energy figures are expressed as net total energy expended (MJ_{xt}) in each process (i.e. excluding the energy transferred to the final fuel) per unit energy content of the output of the process (MJ). Where intermediate energy is involved (e.g. electricity) the relation between primary and intermediate energy is expressed in efficiency terms and in terms of total primary energy (MJ_p) per unit energy actually expended in the process (MJ_x).

Example:

- If a process requires 0.1 MJ of electricity per MJ final fuel, the expended energy is expressed as 0.1 MJ_x/MJ.
- If electricity is generated with a 33% efficiency, the primary energy associated to 1 MJ of electricity is 3 MJ_p.
- The total primary energy associated to the process is then 3 x 0.1 = 0.3 MJ_p/MJ.

All energy is accounted for regardless of the primary energy source, i.e. including renewable energy. This is necessary to estimate the energy efficiency of each process and each pathway. The share of fossil energy in each complete pathway is shown in the overall pathway energy balance (*see* ***WTT Appendix 2***).

The CO_2 figures represent the actual emissions occurring during each process. When CO_2 emissions stem from biomass sources only the net emissions are counted. The figures exclude the CO_2 emissions associated with the combustion of the final fuel when it is of fossil origin. For carbon-containing fuels of renewable origin, however, a credit is given for an amount of CO_2 equivalent to that released during combustion. In the TTW section of the study, all fuels can then be treated in the same way and allocated CO_2 emissions corresponding to their carbon content regardless of its origin.

The figures used in this study and described in this appendix are generally based on literature references as given. In a number of cases, particularly with regards to oil-based pathways, we have used figures considered as typical in the industry and generally representing the combined views of a number of experts. Where no specific reference is given, the figures are the result of standard physical calculations based on typical parameters. This is the case for instance for CNG or hydrogen compression energy.

Most processes include a line labelled "Primary energy consumption and emissions": this is an approximate and simplified calculation intended for the reader's guidance. The full calculation has been carried out by LBST's E^3 database resulting in the figures in ***WTT Appendix 2***.

Where appropriate we have specified a range of variability associated to a probability distribution either normal (Gaussian), double-triangle for asymmetrical distribution or equal (all values in the range equally probable). The equal distribution has been used when representing situations where a range of technologies or local circumstances may apply, all being equally plausible. For the complete pathway, a variability range is estimated by combining the individual ranges and probability distributions with the Monte-Carlo method.

Table of contents

1 Useful conversion factors and calculation methods

1.1 General

1 kWh = 3.6 MJ = 3412 Btu
1 Mtoe = 42.6 GJ
1 MW = 1 MJ/s = 28.8 PJ/a (8000 h)

1 t crude oil ~ 7.4 bbl
1 Nm^3 of EU-mix NG ~ 0.8 kg ~ 40 MJ
(i.e. 1 Nm^3 of NG has approximately the same energy content as 1 kg of crude oil)

1.2 Factors for individual fuels

Gases

NG EU-mix	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	Nm$_3$/h
MW (MJ/s)		86.4	28.8	80.4	1929	643	102
GJ/d	0.012		0.333	0.930	22.3	7.4	1.18
PJ/a (8000 h)	0.035	3		2.79	67.0	22.3	3.53
kg/h	0.012	1.07	0.36		24	8	1.27
kg/d		0.04	0.01			0.33	0.05
t/a (8000 h)		0.13	0.04	0.13	3		0.16
Nm$_3$/h		0.85	0.28	0.79	19.0	6.3	

Methane	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	Nm$_3$/h
MW (MJ/s)		86.4	28.8	72.0	1728	576	101
GJ/d	0.012		0.333	0.833	20.0	6.7	1.17
PJ/a (8000 h)	0.035	3		2.50	60.0	20.0	3.50
kg/h	0.014	1.20	0.40		24	8	1.40
kg/d		0.05	0.02			0.33	0.06
t/a (8000 h)		0.15	0.05	0.13	3		0.18
Nm$_3$/h		0.86	0.29	0.71	17.1	5.7	

Hydrogen	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	Nm$_3$/h
MW (MJ/s)		86.4	28.8	30.0	719	240	336
GJ/d	0.012		0.333	0.347	8.3	2.8	3.89
PJ/a (8000 h)	0.035	3		1.04	25.0	8.3	11.66
kg/h	0.033	2.88	0.96		24	8	11.20
kg/d		0.12	0.04			0.33	0.47
t/a (8000 h)		0.36	0.12	0.13	3		1.40
Nm$_3$/h		0.26	0.09	0.09	2.1	0.7	

Liquids

Gasoline	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	m_3/d
MW (MJ/s)		86.4	28.8	83.1	1995	665	2.68
GJ/d	0.01		0.33	0.96	23.1	7.70	0.03
PJ/a (8000 h)	0.03	3		2.89	69.3	23.1	0.09
kg/h	0.01	1.04	0.35		24	8	0.03
kg/d		0.04	0.01			0.333	
t/a (8000 h)		0.13	0.04	0.13	3		
m_3/d		32.3	10.8	31.0	745	248	

Diesel	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	m_3/d
MW (MJ/s)		86.4	28.8	83.5	2005	668	2.41
GJ/d	0.01		0.33	0.97	23.2	7.73	0.03
PJ/a (8000 h)	0.03	3		2.90	69.6	23.2	0.08
kg/h	0.01	1.03	0.34		24	8	0.03
kg/d		0.04	0.01			0.333	
t/a (8000 h)		0.13	0.04	0.13	3		
m_3/d		35.9	12.0	34.7	832	277	

Methanol	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	m_3/d
MW (MJ/s)		86.4	28.8	180.9	4342	1447	5.48
GJ/d	0.01		0.33	2.09	50.3	16.75	0.06
PJ/a (8000 h)	0.03	3		6.28	150.8	50.3	0.19
kg/h	0.01	0.48	0.16		24	8	0.03
kg/d		0.02	0.01			0.333	
t/a (8000 h)		0.06	0.02	0.13	3		
m_3/d		15.8	5.3	33.0	793	264	

FT diesel	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	m_3/d
MW (MJ/s)		86.4	28.8	81.8	1964	655	2.52
GJ/d	0.01		0.33	0.95	22.7	7.58	0.03
PJ/a (8000 h)	0.03	3		2.84	68.2	22.7	0.09
kg/h	0.01	1.06	0.35		24	8	0.03
kg/d		0.04	0.01			0.333	
t/a (8000 h)		0.13	0.04	0.13	3		
m_3/d		34.3	11.4	32.5	780	260	

DME	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	m_3/d
MW (MJ/s)		86.4	28.8	126.6	3039	1013	4.54
GJ/d	0.01		0.33	1.47	35.2	11.72	0.05
PJ/a (8000 h)	0.03	3		4.40	105.5	35.2	0.16
kg/h	0.01	0.68	0.23		24	8	0.04
kg/d		0.03	0.01			0.333	
t/a (8000 h)		0.09	0.03	0.13	3		
m_3/d		19.0	6.3	27.9	670	223	

Ethanol	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	m_3/d
MW (MJ/s)		86.4	28.8	134.3	3224	1075	4.06
GJ/d	0.01		0.33	1.55	37.3	12.44	0.05
PJ/a (8000 h)	0.03	3		4.66	111.9	37.3	0.14
kg/h	0.01	0.64	0.21		24	8	0.03
kg/d		0.03	0.01			0.333	
t/a (8000 h)		0.08	0.03	0.13	3		
m_3/d		21.3	7.1	33.1	794	265	

Solids

Hard Coal	MW	GJ/d	PJ/a	kg/h	kg/d	t/a
MW (MJ/s)		86.4	28.8	135.8	3260	1087
GJ/d	0.01		0.33	1.57	37.7	12.58
PJ/a (8000 h)	0.03	3		4.72	113.2	37.7
kg/h	0.01	0.64	0.21		24	8
kg/d		0.03	0.01			0.333
t/a (8000 h)		0.08	0.03	0.13	3	

Wood	MW	GJ/d	PJ/a	kg/h	kg/d	t/a
MW (MJ/s)		86.4	28.8	200.0	4800	1600
GJ/d	0.01		0.33	2.31	55.6	18.52
PJ/a (8000 h)	0.03	3		6.94	166.7	55.6
kg/h	0.01	0.43	0.14		24	8
kg/d		0.02	0.01			0.333
t/a (8000 h)		0.05	0.02	0.13	3	

1.3 GHG calculations

CO_2-equivalence coefficients

Methane	23
Nitrous oxide	296

CO_2 emissions from combustion (assuming total combustion)

1 kg of a fuel with C% carbon emits:

$1 \times C\% / 100 / 12 \times 44 = (0.0367 \times C\%)$ kg of CO_2

1 MJ of a fuel with λ MJ/kg (LHV) and C% carbon emits:

$1 / \lambda \times C\% / 100 / 12 \times 44 = (0.0367 / \lambda \times C\%)$ kg of CO_2

2 Fuels properties

2.1 Standard properties of fuels

Gases		NG EU-mix	NG (Rus)	Methane	Hydrogen	LPG
LHV	MJ/kg	45.1	49.2	50.0	120.1	46.0
	kg/kWh	0.080	0.073	0.072	0.030	0.078
	kWh/kg	12.53	13.67	13.89	33.36	12.78
	MM, g/mol	17.7	16.3	16.0	2.0	50.0
	kWh/Nm^3	9.90	9.94	9.92	2.98	28.52
C content	% m	69.4%	73.9%	75.0%	0.0%	82.4%
CO$_2$ emission factor (assuming total combustion)						
	g CO$_2$/MJ	56.4	55.1	55.0		
	kg CO$_2$/kg	2.54	2.71	2.75		
	kg CO$_2$/Nm^3	3.22	3.72	3.85		

Liquids		Crude	Gasoline	Diesel	Naphtha	HFO	Syn diesel	Methanol	DME	Ethanol	RME	REE	MTBE	ETBE
Density	kg/m^3	820	745	832	700	970	780	793	670	794	890	890	745	750
LHV	MJ/kg	42.0	43.2	43.1	44.0	40.5	44.0	19.9	28.4	26.8	37.2	37.9	35.1	36.3
	kg/kWh	0.086	0.083	0.084	0.082	0.089	0.082	0.181	0.127	0.134	0.097	0.095	0.103	0.099
	kWh/kg	11.67	12.00	11.97	12.22	11.25	12.22	5.53	7.90	7.44	10.33	10.53	9.75	10.07
C content	% m	86.5%	86.4%	86.1%	85.0%	89.0%	85.0%	37.5%	52.2%	52.2%	76.5%	76.5%	68.2%	70.6%
CO$_2$ emission factor (assuming total combustion)														
	g CO$_2$/MJ	75.5	73.3	73.2	70.8	80.6	70.8	69.1	67.3	71.4	75.4	74.0	71.2	71.4
	kg CO$_2$/kg	3.17	3.17	3.16	3.12	3.26	3.12	1.38	1.91	1.91	2.81	2.81	2.50	2.59

Solids		Hard Coal	Wood	Wheat	S beet	Rapeseed	SunFseed	SB pulp	SB slops	Wheat straw	DDGS	Sugar cane
Moisture content			0.3	0.16	0.765	0.1	0.1	0.09	0.09	0.16	0.1	73%
LHV (dry matter)	MJ/kg	29.4	18.0	17.0	16.3	26.4	26.4	15.6	15.6	17.2	16.0	19.6
	kg/kWh	0.122	0.200	0.212	0.221	0.136	0.136	0.231	0.231	0.209	0.225	0.184
	kWh/kg	8.2	5.0	4.7	4.5	7.3	7.3	4.3	4.3	4.8	4.4	5.4
C content	% m	77.2%	50.0%									
CO$_2$ emission factor (assuming total combustion)												
	g CO$_2$/MJ	96.3	101.9									
	kg CO$_2$/kg	2.83	1.83									

2.2 Detailed composition of natural gas per source

Origin	CIS	NL	UK	Norway	Algeria	EU-mix	
						%mol	%m
Share in EU-mix	21.4%	22.0%	30.4%	11.8%	14.4%		
H_2	0.0%	0.0%	0.5%	0.5%	0.8%	0.3%	0.0%
C1	98.4%	81.5%	86.0%	86.0%	92.1%	88.5%	79.9%
C2	0.4%	2.8%	8.8%	8.8%	1.0%	4.6%	7.7%
C3	0.2%	0.4%	2.3%	2.3%	0.0%	1.1%	2.7%
C4	0.1%	0.1%	0.1%	0.1%	0.0%	0.1%	0.3%
C5	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C6	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
C7	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
CO_2	0.1%	1.0%	1.5%	1.5%	0.0%	0.9%	2.2%
N_2	0.8%	14.2%	0.8%	0.8%	6.1%	4.5%	7.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
MM (g/mol)	16.3	18.5	18.4	18.4	16.8	17.7	
Density (kg/Nm3)	0.727	0.827	0.820	0.820	0.750	0.791	
LHV (MJ/Nm3)	35.7	31.4	38.6	38.6	33.7	35.7	
LHV (GJ/t)	49.2	38.0	47.1	47.1	44.9	45.1	
MON (CARB)	138.2	132.9	122.3	122.3	138.0	129.2	
Methane number (CARB)	105.3	96.8	79.6	79.6	105.0	90.7	
Methane number (DK)	96.6	93.3	75.7	75.7	98.3	84.1	

Source: GEMIS

MON and Methane number methods references:

'Algorithm for methane number determination for natural gasses' (sic) by Paw Andersen, Danish gas Technology Centre, Report R9907, June 1999
http://uk.dgc.dk/publications/algotitme.htm

CARB: http://www.arb.ca.gov/regact/cng-lpg/cng-lpg.htm

The EU-mix is the gas that is deemed to be available to the vehicle as CNG.

2.3 Deemed composition of LPG

Component	% m/m	% v/v	MM	LHV (GJ/t)	C (%m/m)	H (%m/m)
C1	0.1	0.3	16	50.1	75.0	25.0
C2	2.4	4.0	30	47.5	80.0	20.0
C2=	0.5	0.9	28	47.2	85.7	14.3
C3	40.0	45.4	44	46.4	81.8	18.2
C3=	1.0	1.2	42	45.8	85.7	14.3
nC4	30.0	25.8	58	45.8	82.8	17.2
iC4	22.0	19.0	58	45.7	82.8	17.2
C4=	1.5	1.3	56	45.3	85.7	14.3
iC4=	1.5	1.3	56	45.1	85.7	14.3
nC5	1.0	0.7	72	45.4	83.3	16.7
Total	**100.0**	**100.0**	**50**	**46.0**	**82.4**	**17.6**
Total						
C2-	3.0					
C3	41.0					
C4	55.0			**CO2 emission factor**		
C5+	1.0			3.02	t CO2 / t	
Olefins	4.5			65.7	kg CO2 / GJ	

3 Common processes

Code	Process	Assoc. process	MJex/ MJ	g CO2/ MJ	g CH4/ MJ	g N2O/ MJ	g CO2 eq/ MJ	Eff	MJp/ MJex	g CO2/ MJex	g CH4/ MJex	g N2O/ MJex	MJex/ t.km	Min	Max	Probability distribution	Reference
	Transport fuels simplified production processes (used for auxiliary transport fuel requirements)																
Z1	**Diesel production**																CONCAWE
	Crude oil		0.1600	14.30													
Z2	**Road tanker**																LBST
	Diesel									73.25			0.936				
Z3	**HFO production**																TFE 2001
	Crude oil		0.0880	6.65													
Z4	**Product carrier 50 kt**									gCO2/tkm							Oko inventar
	Energy (ship's fuel) as HFO)									9.99			0.124	0.112	0.136	Dble tri	
Z5	**Rail transport**		MJex/ t.km	g CO2/ t.km	g CH4/ t.km	g N2O/ t.km	g CO2 eq/ t.km										Okoinventar
	Electricity (EU-mix, MV)	Z7a											0.210				
	Primary energy consumption and emissions		*0.1653*	*25.05*	*0.06*	*0.00*	*26.79*										
Z6	**Marginal NG for general use (4000 km piped)**								1.1306	63.12	0.20	0.00					

As electricity is used as an intermediate rather than final energy source, the figures below are shown in total primary energy (MJp) to produce one unit of electricity (MJe)

Code	Process	Assoc. process	MJp/ MJe	g CO2/ MJe	g CH4/ MJe	g N2O/ MJe	g CO2 eq/ MJe	Eff		Reference
Z7	**Electricity (EU-mix)**									
	Production									GEMIS 4.07
	Biomass		0.0074							
	Coal brown		0.1956							
	Coal hard		0.5512							
	Geothermal		0.0016							
	Hydro		0.1239							
	Oil		0.2397							
	NG		0.3440							
	Nuclear		1.1354							
	Waste		0.1838							
	Wind		0.0044							
			2.7868					35.9%		
Z71	HV+MV losses		0.0172							
Z72	LV losses		0.0120							
Z7a	Electricity (EU-mix, MV)		2.8347	119.36	0.2911	0.0054	127.65	35.3%		GEMIS 3.03
Z7b	Electricity (EU-mix, LV)		2.8687	120.79	0.2946	0.0055	129.18	34.9%		GEMIS 3.03

Z1 Diesel production

This process is used to compute the energy associated to the consumption of diesel fuel for transportation purposes in a given pathway. The figures stem from the Diesel provision pathway COD.

Z2 Road tanker

This process represents the diesel fuel consumption and CO_2 emissions of a standard diesel-powered road tanker per t.km transported, including the return trip of the empty vehicle.

When calculating the total energy and emissions associated to road transport, the figures corresponding to diesel production are added.

Z3 Heavy Fuel Oil (HFO) production

This process is used to compute the energy associated to the consumption of HFO for transportation purposes (essentially shipping) in a given pathway. Evaluating the energy associated to HFO production is a difficult issue. It can be argued that increasing HFO demand would “rebalance the barrel”, resulting in decreased requirement for conversion of residue into distillates; this could even result in an energy saving in the refineries. Conversely, decreasing HFO demand would increase the need for conversion and increase energy requirements. In our pathways, HFO is essentially used for long-distance shipping of fossil-based fuels and the share of the HFO production energy in the total for the pathway is very small. For simplicity we have opted for a single value showing a net energy consumption.

Z4 Product carrier (50 kt)

This process represents the energy and CO_2 emissions associated with long-distance sea transport of a number of liquid products such as FT diesel or methanol (per t.km and including the return trip of the empty ship) [*ESU 1996*]. This does not concern crude oil which is generally transported in larger ships). The variability range represents the diversity of ships available for such transport.

Z5 Rail transport

This process represents the energy and CO_2 emissions associated to transport of liquid products by rail (per t.km), assuming the use of EU-mix electricity as energy source [*GEMIS 2002*].

Z6 Marginal use of natural gas

This process represents the energy and CO_2 emissions associated with use of marginal natural gas (assumed to be Russian gas quality transported to Europe over 4000 km by pipeline.

Z7 Electricity (EU-mix)

Unless the process produces its own electricity, the electrical energy used in processes deemed to take place within the EU is assumed to have been generated by the EU electrical mix in 2010. There are several sources of information for this a/o the IEA, Eurelectric and the EU Commission’s “Poles” model. All sources report slightly different figures for the past years and of course show different forecasts. There is, however, a general agreement to show a decrease of nuclear, solid fuels and heavy fuel oil compensated mainly by natural gas. Renewables, although progressing fast in absolute terms, do not achieve a significant increase in relative terms because of the sharp increase in electricity demand. As a result, although the primary energy composition of the 2010 “kWh” is different from that of 2000, the resulting CO_2 emissions are not very different.

We have opted for the figures compiled in the German GEMIS database for the year 1999 [*GEMIS 2002*]. A correction is applied to account for typical transmission losses to the medium and low voltage levels.

4 Crude oil – based fuels provision

4.1 Crude oil, diesel fuel

Code	Process	Assoc. processes	Expended energy and emissions per MJ of main product of the process					Transport distance	Transport energy	Transport requirement	Range		Probability distribution	Reference
			MJex/ MJ	g CO2/ MJ	g CH4/ MJ	g N2O/ MJ	g CO2eq/ MJ	km or Nm	MJex/ t.km	t.km/ MJ	Min	Max		
CO1	**Crude oil production**													
	Energy as crude oil		0.0250	1.89			1.89				0.010	0.040	Normal	Oil companies average value
	CO2 eq emissions			1.45			1.45							
	Total CO2 eq			3.33			3.33							
CO2	**Crude oil transportation**													
	Energy as HFO	Z3	0.0101	0.81			0.81				0.0096	0.0106	Normal	Shell 2001
CD1	**Crude oil refining, marginal diesel**													
	Crude oil		0.1000	8.60			8.60				0.0800	0.1200	Normal	CONCAWE
CD2	**Diesel transport**													Total
	Barge, 9000 t (33%)													
	Energy as Diesel	Z1	0.0011	0.08			0.08							
	Energy as HFO		0.0052	0.39			0.39							
	Total CO2			0.48			0.48							
	Primary energy consumption and emissions		*0.0070*	*0.53*			*0.53*							
	Rail, 250 km (33%)													
	Distance	Z5						250		0.0058				
	Primary energy consumption and emissions		*0.0035*	*0.15*	*0.0004*	*0.0000*	*0.16*							
	Pipeline (33%)													
	Electricity (EU-mix, LV)	Z7b	0.0002											
	Primary energy consumption and emissions		*0.0006*	*0.02*	*0.0001*	*0.0000*	*0.03*							
	Total Primary energy consumption and emissions		*0.0037*	*0.23*	*0.0001*	*0.0000*	*0.24*							
CD3	**Diesel depot**													
	Electricity (EU-mix, LV)	Z7b	0.0008											Total
	Primary energy consumption and emissions		*0.0024*	*0.10*	*0.0002*	*0.0000*	*0.11*							
CD4	**Diesel distribution and dispensing**													
	Tanker load and distance	Z2, Z1						150		0.0037				
	Diesel consumption and emissions		0.0035	0.31			0.31							
	Retail, Electricity (EU-mix, LV)	Z7b	0.0034											Total
	Primary energy consumption and emissions		*0.0138*	*0.72*	*0.0010*	*0.0000*	*0.75*							

CO1 Crude oil production

These figures include all the energy and GHG emissions associated with crude oil production and conditioning at or near the wellhead (such as dewatering and associated gas separation). The total CO_2eq figure includes emissions of GHGs other than combustion CO_2.

Production conditions vary considerably between producing regions, fields and even between individual wells and it is only meaningful to give typical or average energy consumption and GHG emission figures for the range of crudes under consideration, hence the wide variability range indicated. These figures are best estimates for the basket of crude oils available to Europe [*Source: CONCAWE*].

CO2 Crude oil transportation

Crude oil is mostly transported by ship. The type of ship used depends on the distance to be covered. The bulk of the Arab Gulf crude is shipped in large ships (VLCC or even ULCC Very/Ultra Large Crude Carrier) that can carry between 200 and 500 kt and travel via the Cape of Good Hope to destinations in Western Europe and America or directly to the Far East. North Sea or African crudes travel shorter distances for which smaller ships (100 kt typically) are used.

Pipelines are also extensively used from the production fields to a shipping terminal. Some Middle Eastern crudes are piped to a Mediterranean port. The developing regions of the Caspian basin will rely on one or several new pipelines to be built to the Black Sea. Crude from central Russia is piped to the Black Sea as well as directly to Eastern European refineries through an extensive pipeline network.

Although the majority of refineries tend to be at coastal locations, a number of them are inland. Within Western Europe, there are several inland pipelines from the Mediterranean to North Eastern France and Germany as well as from the Rotterdam area to Germany.

Here again, there is a wide diversity of practical situations. The figures used here are typical for marginal crude originating from the Middle East. The energy is supplied in the form of HFO, the normal ship’s fuel [*Source: Shell*]. Note that North Sea or North African crudes or again pipeline transport would command somewhat smaller figures.

CD1 Crude oil refining, marginal diesel

This represents the energy and GHG emissions that can be saved, in the form of crude oil, by not producing a marginal amount of diesel in Europe, starting from a 2010 “business-as-usual” base case [*Source: CONCAWE*, see ***WTT Appendix 3*** for details].

CD2 Diesel transport

Road fuels are transported from refineries to depots via a number of transport modes. We have included water (inland waterway or coastal), rail and pipeline (1/3 each). The energy consumption and distance figures are typical averages for EU.

Barges and coastal tankers are deemed to use a mixture of marine diesel and HFO. Rail transport consumes electricity. The consumption figures are typical [*Source: Total*]. The road tanker figures pertain to a notional 40 t truck transporting 26 t of diesel in a 2 t tank (see also process Z2).

CD3 Diesel depot

A small amount of energy is consumed in the depots mainly in the form of electricity for pumping operations [*Source: Total*].

CD4 Diesel distribution

From the depots, road fuels are normally trucked to the retail stations where additional energy is required, essentially as electricity, for lighting, pumping etc. This process includes the energy required for the truck as well as the operation of the retail station [*Source: Total*].

4.2 Gasoline

Code	**Process**	Assoc. processes	Expended energy and emissions per MJ of main product of the process					Transport distance	Transport energy	Transport requirement	Range		Probability distribution	Reference
			MJex/ MJ	g CO2/ MJ	g CH4/ MJ	g N2O/ MJ	g CO2eq/ MJ	km or Nm	MJex/ t.km	t.km/ MJ	Min	Max		
CG1	**Crude oil refining, marginal gasoline**													
	Crude oil		0.0800	6.50			6.50				0.0600	0.1000	Normal	CONCAWE
CG2	**Gasoline transport**													Total
	Barge, 9000 t (33%)													
	Energy as Diesel	Z1	0.0011	0.08			0.08							
	Energy as HFO	Z3	0.0052	0.39			0.39							
	Evaporation losses		0.0000											
	Total CO2			0.47			0.47							
	Primary energy consumption and emissions		*0.0070*	*0.53*			*0.53*							
	Rail, 250 km (33%)													
	Distance	Z5						250		0.0058				
	Primary energy consumption and emissions		*0.0034*	*0.14*	*0.0004*	*0.0000*	*0.16*							
	Evaporation losses		0.0004											
	Pipeline (33%)													
	Electricity (EU-mix, LV)	Z7b	0.0002											
	Primary energy consumption and emissions		*0.0006*	*0.02*	*0.0001*	*0.0000*	*0.03*							
	Total Primary energy consumption and emissions		*0.0037*	*0.23*	*0.0001*	*0.0000*	*0.01*							
CG3	**Gasoline depot**													
	Electricity (EU-mix, LV)	Z7b	0.0008											Total
	Primary energy consumption and emissions		*0.0024*	*0.10*	*0.0002*	*0.0000*	*0.11*							
	Evaporation losses		0.0000											
CG4	**Gasoline distribution and dispensing**													
	Tanker load and distance	Z2, Z1						150		0.0037				
	Diesel consumption and emissions		0.0035	0.31										
	Filling station, Electricity (EU-mix, LV)	Z7b	0.0034											Total
	Primary energy consumption and emissions		*0.0138*	*0.72*	*0.0010*	*0.0000*	*0.75*							
	Evaporation losses		0.0008											

CG1/4 Gasoline

These processes are essentially the same as for diesel with some specific adjustments for the gasoline case, mostly in terms of evaporation losses.

4.3 Naphtha

Code	Process	Assoc. processes	Expended energy and emissions per MJ of main product of the process					Transport distance	Transport energy	Transport requirement	Range		Probability distribution	Reference
			MJex/ MJ	g CO2/ MJ	g CH4/ MJ	g N2O/ MJ	g CO2eq/ MJ	km or Nm	MJex/ t.km	t.km/ MJ	Min	Max		
CN1	**Crude oil refining, marginal naphtha**													
	Crude oil		0.0510	4.36			4.36				0.0450	0.0550	Normal	CONCAWE
CN2	**Naphtha transport**													Total
	Barge, 9000 t (33%)													
	Energy as Diesel	Z1	0.0011	0.08			0.08							
	Energy as HFO	Z71	0.0051	0.00			0.00							
	Evaporation losses		0.0000	0.00										
	Total CO2			0.08			0.08							
	Primary energy consumption and emissions		*0.0069*	*0.13*			*0.13*							
	Rail, 250 km (33%)													
	Distance	Z5						250		0.0057				
	Primary energy consumption and emissions		*0.0075*	*0.14*	*0.0003*	*0.0000*	*0.15*							
	Evaporation losses		0.0004											
	Pipeline (33%)													
	Electricity (EU-mix, LV)	Z7b	0.0002											
	Primary energy consumption and emissions		*0.0006*	*0.02*	*0.0001*	*0.0000*	*0.03*							
	Total Primary energy consumption and emissions		*0.0050*	*0.10*	*0.0001*	*0.0000*	*0.01*							
CN3	**Naphtha depot**													
	Electricity (EU-mix, LV)	Z7b	0.0008											Total
	Primary energy consumption and emissions		*0.0024*	*0.10*	*0.0002*	*0.0000*	*0.11*							
	Evaporation losses		0.0000											
CN4	**Naphtha distribution and dispensing**													
	Tanker load and distance	Z2, Z1						150		0.0037				
	Diesel consumption and emissions		0.0028	0.00										
	Filling station, Electricity (EU-mix, LV)	Z7b	0.0034											Total
	Primary energy consumption and emissions		*0.0000*	*0.41*	*0.0010*	*0.0000*	*0.44*							
	Evaporation losses		0.0008											

CN1/4 Naphtha

These processes are essentially the same as for diesel with some specific adjustments for the naphtha case, mostly in terms of evaporation losses.

5 Natural gas (NG) provision (including CNG)

5.1 Natural gas extraction and processing

Code	Process	Assoc. processes	Expended energy	GHG emissions				Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	Reference
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.		MJ/ MJx	g CO_2/ MJx	g CH_4/ MJx	g N_2O/ MJx	km or N m	MJx/ t.km	MJx/MJ /100km	Min	Max		
GG1	**NG Extraction & Processing**																		Shell
	Energy as NG		0.0200	1.13			1.13									0.0100	0.0400	Dble tri	
	CO2 venting			0.55															
	Methane losses		0.0042		0.0833		1.92												
	Primary energy consumption and emissions		*0.0242*	*1.68*	*0.0833*		*3.59*												
GG2	**Electricity generation from NG (CCGT)**																		GEMIS 3.03
	Energy efficiency							55.0%	1.8178							52.3%	57.8%		LBST
	CO2 emissions									100.11									
	Methane losses								0.0004		0.0075								
	N2O emissions											0.0047							
	Total NG input to power plant								1.8182							1.7300	1.9100		
GG2C	**Electricity generation from NG (CCGT) with CC&S**																		Rubin 2004
	Energy efficiency							47.1%	2.1228							44.8%	49.5%		
	CO2 emissions									11.94									
	Methane losses								0.0004		0.0075								
	N2O emissions											0.0000							
	Total NG input to power plant								2.1231							2.0202	2.2304	Normal	

GG1 NG extraction & processing

This process includes all energy and GHG emissions associated with the production and processing of the gas at or near the wellhead. Beside the extraction process itself, gas processing is required to separate heavier hydrocarbons, eliminate contaminants such as H_2S as well as separate inert gases, particularly CO_2 when they are present in large quantities.

The associated energy and GHG figures are extremely variable depending a/o on the location, climatic conditions and quality of the gas. The figures used here are reasonable averages, the large variability being reflected in the wide range [*Source: Shell*]. We have not accounted for any credit or debit for the associated heavier hydrocarbons, postulating that their production and use would be globally energy and GHG neutral compared to alternative sources. The figure of 1% v/v for venting of separated CO_2 reflects the low CO_2 content of the gas sources typically available to Europe. For sources with higher CO_2 content, it is assumed that re-injection will be common at the 2010 and beyond horizon. 0.4% methane losses are included [*Source: Shell*].

GG2 On-site electricity generation

In all gas transformation schemes requiring significant amounts of electricity, we have assumed the latter is produced on-site by a state-of-the-art gas-fired combined cycle gas turbine (CCGT) with a typical efficiency of 55% [*GEMIS 2002*], [*TAB 1999*]. The high end of the range represents potential future improvements to the technology that are thought to be achievable in the next ten years.

G2C On-site electricity generation with CC&S (CO_2 capture and storage)

This process would consist in scrubbing CO_2 out of the gas turbine flue gases [*Rubin 2004*]. It has been estimated that some 88% of the CO_2 could be recovered. The energy penalty is sizeable, the overall efficiency being reduced by about 8 percentage points.

Long distance pipeline transport

Code	Process	Assoc. processes	Expended energy and emissions per MJ of main product of the process					Energy efficiency	Total energy and emissions per MJ of expendable energy				Transport distance	Transport energy		Range		Probability distribution	Reference
			MJex/ MJ	g CO2/ MJ	g CH4/ MJ	g N2O/ MJ	g CO2eq/ MJ		MJp/ MJex	g CO2/ MJex	g CH4/ MJex	g N2O/ MJex	km or N m	MJex/ t.km	MJex/MJ /100km	Min	Max		
	NG long-distance pipeline																		
GP1a	Russian quality, 7000 km												7000						
	Average specific compression energy													0.360		0.300	0.400		CONCAWE/LBST
	Compression energy (Russian gas quality)		0.0512													0.043	0.057	Square	
	Compressors powered by GT fuelled by NG																		GEMIS 4.07
	Energy efficiency							27.8%	3.6000										
	CO2 emissions									197.97									
	Methane losses								0.0015		0.0306								
	N2O emissions											0.0083							
	NG consumption and emissions		0.1844	10.14	0.0016	0.0004	10.30												
	Methane losses		0.0111		0.2210										0.016%				GEMIS 4.07
	Primary energy consumption and emissions		*0.1954*	*10.14*	*0.2226*		*15.26*												
GP1b	Average quality, 4000 km												4000						
	Average specific compression energy													0.300					
	Compression energy (Russian gas quality)		0.0244													0.020	0.027		
	NG consumption and emissions		0.0878	4.83	0.0007	0.0002	4.91												
	Methane losses		0.0063		0.1263														
	Primary energy consumption and emissions		*0.0941*	*4.83*	*0.1270*		*7.75*												
GM1	EU-mix quality, 1000 km												1000						
	Average specific compression energy													0.260					
	Compression energy (EU-mix gas quality)		0.0058													0.005	0.006	Square	
	NG consumption and emissions		0.0209	1.15	0.0002	0.0000	1.17												
	Methane losses		0.0016		0.0316														
	Primary energy consumption and emissions		*0.0225*	*1.15*	*0.0317*		*1.88*												

GP1 Long-distance pipeline

(GM1) As gas is transported through a pipeline, it needs to be compressed at the start and recompressed at regular intervals. In long-distance lines, the compression energy is normally obtained from a portion of the gas itself, e.g. with a gas-fired gas turbine and a compressor. The gas flow therefore decreases along the line so that the average specific energy tends to be higher for longer distances. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. The figures used here represent the average from several sources [*LBST 1997/1*] [*LBST 1997/2*], [*GEMIS 2002*] the range used representing the spread of the data obtained. They are typical for the existing pipelines operating at around 8 MPa. For new pipelines, the use of higher pressures may result in lower figures although economics rather than energy efficiency alone will determine the design and operating conditions. This would in any case only apply to entirely new pipeline systems as retrofitting existing systems to significantly higher pressures is unlikely to be practical. In order to represent this potential for further improvement we have extended the range of uncertainty towards lower energy consumption to a figure consistent with a pressure of 12 MPa.

The distances selected are typical of Western Siberia (7000 km) and the Near/Middle East (4000 km), being the two most likely sources of marginal gas for Europe. For the typical EU-mix the average distance has been taken as 1000 km.

Methane losses associated to long-distance pipeline transport, particularly in Russia, have often been the subject of some controversy. Evidence gathered by a joint measurement campaign by Gazprom and Ruhrgas [*LBST 1997/1*], [*LBST 1997/2*], [*GEMIS 2002*] suggested a figure in the order of 1% for 6000 km (0.16% per 1000 km). More recent data [*Wuppertal 2004*] proposes a lower figure corresponding to 0.13% for 1000 km, which is the figure that we used. Note that higher losses may still be prevalent in distribution networks inside the FSU but this does not concern the exported gas.

5.2 LNG

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	Reference
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.		MJ/ MJx	g CO_2/ MJx	g CH_4/ MJx	g N_2O/ MJx	km or Nm	MJx/ t.km	MJx/MJ /100km	Min	Max		
GR1	**NG Liquefaction**																		LBST
	Electricity (on-site generation)	GG2	0.0360													0.034	0.038	Normal	Bauer 1996
	NG consumption and emissions		0.065455	3.60	0.0003	0.0002	3.66												
	Methane losses		0.0042	0.14	0.0340														
	Primary energy consumption and emissions		*0.0697*	*3.74*	*0.0343*		*4.53*												
GR1C	**NG Liquefaction with CC&S**																		LBST
	Electricity (on-site generation)	GG2C	0.0360													0.034	0.038	Normal	Bauer 1996
	NG consumption and emissions		0.0764	0.43	0.0003	0.0000	0.44												
	Methane losses		0.0042	0.14	0.0340														
	Primary energy consumption and emissions		*0.0807*	*0.57*	*0.0343*		*1.36*												
GR2	**LNG terminal (loading)**																		Total
	Energy as NG		0.0100	0.55															
	Electricity (on-site generation)	GG2	0.0007																
	Primary energy consumption and emissions		*0.0113*	*0.55*	*0.0000*		*0.55*												
GR3	**LNG transport (average of two distances)**																		LBST
	Distance (nautical miles)												5500			5000	6000		Mitsubishi 2000
	NG evaporation		0.0365													0.0331	0.0400	Square	Hanjin 2000
	Methane losses		0.0000		0.0002		0.00												
	NG to ship's fuel		0.0365	2.01			2.01												Total
	HFO to ship's fuel		0.0309	2.49			2.49												
	Total ship's CO2			4.50			4.50												
	Primary energy consumption and emissions		*0.0674*	*4.50*	*0.0002*		*4.50*									*0.0613*	*0.0736*		
GR4	**LNG terminal (unloading)**																		Total
	Energy as NG		0.0100	346.50															
	Electricity (EU-mix, MV)	Z7a	0.0007																
	Primary energy consumption and emissions		*0.0120*	*2.49*	*0.0000*	*0.0000*	*2.49*												
GR5	**LNG vaporisation**																		LBST
	NG for heat		0.0194	1.07			1.07												
	Energy to LNG pump drive		0.0005																
	Pump overall efficiency of which							33.3%	3.0000	165.00									
	Methane losses								0.0006		0.0113								
	NG for energy							33.3%	2.9994	164.97									
	Pump NG consumption and emissions		0.0014	0.08	0.0000		0.08												
	Primary energy consumption and emissions		*0.0208*	*1.14*	*0.0000*		*1.14*												
GR6	**LNG distribution (road tanker)**													t.km/ MJ					
	Tanker load and distance (Road tanker Z3)	Z2, Z1											500	0.0147					
	Diesel consumption and emissions		0.0160	1.23			1.23												
GR7	**LNG to CNG (vaporisation/compression)**																		Messer 1998/1999
	Electricity (EU-mix, LV)	Z7b	0.0228																
	Primary energy consumption and emissions		0.0654	2.75	0.0067	0.0001	2.95												
	Methane losses		0.0000		0.0002		0.00												
	Primary energy consumption and emissions		*0.0654*	*2.75*	*0.0069*	*0.0001*	*2.95*												

GR1 NG liquefaction

The energy required for the liquefaction process is well documented and not subject to a large uncertainty [*FfE 1996*], [*Osaka Gas 1997*]. It is assumed here that the electrical power for the compressors is supplied by a gas fired on-site combined cycle gas fired power plant (see process GG2).

GR1C Liquefaction with CO_2 capture

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO_2 could be captured (see process CG2C). The proximity of gas and possibly oil field where the CO_2 could be injected would enhanced the feasibility of such a scheme.

GR2 LNG loading terminal

A small amount of electricity is required for the operation of the terminals. In addition the evaporation losses (estimated at 1%) are flared resulting in CO_2 emissions [*Source: Total*]. The electricity is deemed to be produced by the on-site gas-fired power plant (process GG2).

GR3 LNG transport

LNG is transported in specially designed cryogenic carriers. Heat ingress is compensated by gas evaporation. The evaporation rate is estimated at 0.15% per day, the number of days being based on an average speed of 19.5 knots. The average distance has been taken as 5500 nautical miles (5-6000 range), typical of e.g. Arab Gulf to Western Mediterranean (via Suez canal) or Nigeria to North West Europe.

The evaporated gas is used as fuel for the ship, the balance being provided by standard marine bunker fuel (HFO). This practice is also valid for the return voyage inasmuch as the LNG tanks are never completely emptied in order to keep them at low temperature (required for metallurgical reasons). The figures include an allowance for the return trip in accordance with the “admiralty formula” (see process Z4: LNG carriers have a typical gross tonnage of 110,000 t, including a payload of 135,000 m^3 or 57,000 t [*Hanjin 2000*] [*MHI 2000*]. This results in a ratio of 0.8 between the full and empty ship).

GR4 LNG unloading terminal

The terminal electricity requirement is deemed to be the same as for the loading terminal (see process GR2). The electricity, however, is now assumed to be supplied by the EU grid. If LNG is vaporised on receipt no evaporation losses are included; if LNG is further transported as such, the same figures as for the loading terminal are used. A small additional electricity consumption (0.0007 to 0.0010 MJ/MJ of LNG) is added for the LNG terminal. The road tanker loading and unloading is carried out by a truck mounted LNG pump. The additional diesel requirement for the LNG pump is very low (approximately 0.0002 MJ/MJ of LNG).

GR5 LNG vaporisation

If it is to be used in the gas distribution grid, LNG needs to be vaporised and compressed. Although small amounts can be vaporised with heat taken from the atmosphere, this is impractical for large evaporation rates and heat at higher temperature must be supplied. The figures used here assume compression (as liquid) to 4 MPa followed by vaporisation and heating of the gas from -162 to 15°C.

GR6 LNG distribution (road tanker)

This process assumes road transport of LNG from the import terminal directly to a local storage at the refuelling station (diesel truck carrying 19 t of LNG and 9 t of steel, see also process Z2).

GR7 LNG to CNG (vaporisation/compression)

LNG needs to be vaporised and compressed into CNG at 25 MPa (at the refuelling station). This can be done in and energy-efficient manner by pumping the liquid to the required pressure followed by vaporisation. We have assumed that the vaporisation and reheating energy has to be provided by an auxiliary heat source (electricity) as ambient air would not provide sufficient heat flow for the rates of vaporisation required. The total electricity requirement of 0.0228 MJ/MJ includes 0.0032 for pumping [*Messer 1998*]. It is assumed that the vaporization and reheating is carried out by a water bath heat exchanger. The electricity requirement is 0.0118 MJ/MJ for vaporisation and 0.0078 MJ/MJ for reheating (100% efficiency).

5.3 Natural gas distribution, CNG dispensing

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	Reference
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.		MJ/ MJx	g CO_2/ MJx	g CH_4/ MJx	g N_2O/ MJx	km or N m	MJx/ t.km	MJx/MJ /100km	Min	Max		
GG3	**NG trunk distribution**																		
	Distance												500						
	Average specific compression energy													0.269					LBST
	Compression energy (EU-mix gas quality)		0.0030																
	Compressors powered by GT fuelled by NG																		GEMIS 4.07
	Energy efficiency							30.0%	3.3300										
	CO2 emissions									187.64									
	Methane losses								0.0007		0.0139								
	N2O emissions											0.0083							
	NG consumption and emissions		0.0099	0.00	0.0000	0.0000	0.01												
	Methane losses		0.0000		0.0006										0.0006%				GEMIS 4.07
	Primary energy consumption and emissions		*0.0100*	*0.00*	*0.0007*	*0.0000*	*0.02*												
GG4	**NG local distribution**																		
	No energy requirement																		
	Methane losses to atmosphere		0.0000		0.0000		0.00												
GG5	**CNG dispensing (compression 0.4-25 MPa)**																		LBST
	Electricity (EU-mix, LV)	Z7b	0.0220													0.027	0.014	Triangular	
	Primary energy consumption and emissions		*0.0631*	*2.66*	*0.0065*	*0.0001*	*2.84*												

GG3 NG trunk distribution

The European gas distribution systems consist of high pressure trunk lines operating at 4 to 7 MPa and a dense network of lower pressure lines. Operation of the high pressure system is fairly similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are assumed to be driven by electricity generated by gas turbines using the gas itself as fuel. Here again the energy consumed depends on the relative size and throughput of the lines as well as of the distance considered. A distance of 500 km for an average energy consumption of 0.27 MJ/(t.km) are typical of European networks [*GEMIS 2002*]. Gas losses are reportedly very small.

GG4 NG local distribution

The low pressure networks are fed from the high pressure trunk lines and supply small commercial and domestic customers. No additional energy is required for these networks, the pressure energy from the trunk lines being more than adequate for the local transport.

Various pressure levels are used in different countries and even within countries. Although some local networks are still at very low pressure (<100 mbar(g)) the modern European standard is 0.4 MPa(g) (with pressure reduction at the customer boundary). Very low pressure networks also need to be fed by higher pressure systems at regular intervals (e.g. 0.7 MPa in the UK). As a result, it is reasonable to assume that, as long as a gas network is present in the area, a supply at a few bars pressure will be available for CNG refuelling stations in the vast majority of cases. Pressures up to 2 MPa are also available in some areas and may be available to some sites, particularly fleet refuelling stations. We have assumed that the typical refuelling station will be supplied at 0.4 MPa.

Significant methane losses have been reported for these local networks. They appear, however, to be based on overall gas accounting and therefore include measurement accuracy. Some losses are associated with purging operations during network maintenance. It is difficult to believe that local networks would have sizeable continuous losses. In any case all such losses would be related to the extent of the network rather than the throughput. NG used for road transport would only represent a modest increase of the total amount transported in the network and would therefore not cause significant additional losses.

GG5 CNG dispensing (compression)

The current standard for CNG vehicle tanks is 20 MPa maximum which satisfies the range requirements of CNG vehicles. Higher pressures may be used in the future but have not been envisaged at this stage. In order to fill the tank, the compressor must deliver a higher pressure which we have set at 25 MPa.

The pressure level available to a CNG refuelling station is critical for its energy consumption as compression energy is strongly influenced by the compression ratio (changing the inlet pressure from atmospheric (0.1 MPa absolute) to 0.1 MPa gauge (= 0.2 MPa absolute) results in half the compression ratio and a 20% reduction of the compression energy). We have taken 0.4 MPa (g) as the typical figure with a range of 0.1 to 2.0. The energy figures represent 4-stage isentropic compression with 75% compressor efficiency and 90% electric driver efficiency.

It is considered that the vast majority of CNG refuelling points will be setup on existing sites for conventional fuels and therefore attract no additional marginal energy.

The methane losses have been deemed to be insignificant. After the refuelling procedure about 0.2 l of NG or 0.15 g methane is released when the refuelling nozzle is disconnected. If the amount of CNG dispensed per refuelling procedure were assumed to be 1100 MJ the methane emissions would be about 0.00014 g/MJ of NG. According to [*Greenfield 2002*] the methane emissions during NG compression can be lowered to virtually zero.

Note on CO_2 emissions from natural gas combustion:

The CO_2 emissions resulting from the combustion of natural gas vary somewhat with the composition of the gas. We have adopted the following convention

- Gas used at or near the production point is deemed to be of Russian quality
- Gas used within Europe is deemed to be of the quality of the current EU-mix

6 Synthetic fuels and hydrogen production from NG

6.1 Syn-diesel, Methanol, DME

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	Reference
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.		MJ/ MJx	g CO_2/ MJx	g CH_4/ MJx	g N_2O/ MJx	km or Nm	MJx/ t.km	MJx/MJ /100km	Min	Max		
GD1	**NG to syn-diesel (remote or central plant)**																		
	Overall efficiency							63.0%								65.0%	61.0%		Senden 1996
	Energy as NG		0.5873	16.47			16.47									0.5385	0.6393	Normal	
	Primary energy consumption and emissions		*0.587302*	*16.47*			*16.47*												
GD1C	**NG to syn-diesel (remote or central plant) with CC&S**																		
	Overall efficiency							60.0%								63.2%	57.1%		Senden 1996
	Energy as NG		0.6667	4.17			4.17									0.5834	0.7500	Square	
	Primary energy consumption and emissions		*0.6667*	*4.17*			*4.17*												
GA1	**NG to Methanol (remote or central plant)**																		Larsen 1998
	Overall efficiency							68.2%								69.2%	67.1%		LBST
	Energy as NG		0.4668	11.69															
	Methane losses		0.0000		0.0001														
	Primary energy consumption and emissions		*0.4668*	*11.6895*	*0.0001*		*11.69*									*0.4442*	*0.4894*		
GA2	**Methanol to hydrogen (on-site reforming)**																		
GT1	**NG to DME (remote or central plant)**																		Haldor Topsoe 2002/2001
	Energy as NG		0.4033	9.99	0.0035			71.3%								0.3752	0.4314	Equal	
	Electricity (on-site generation)	GG2	0.0043													0.0042	0.0044	Equal	
	Steam		-0.0022																
	Steam plant electricity (on-site generation)	GG2							0.02	(MJe/MJex)									
	Steam plant NG							85.0%	1.1765	64.79	0.0028					1.1176	1.2353	Normal	
													MJe/kg	kg/MJ					
	Oxygen													0.0013		0.0045	0.0047	Equal	
	Oxygen plant	GG2											1.6999			0.1246	0.1377	Normal	
	Primary energy consumption and emissions		*0.412399*	*10.49*	*0.0035*	*0.0000*	*10.58*	*70.8%*											
GT1C	**NG to DME (remote or central plant) with CC&S**																		IEA 2004
	Energy as NG		0.4254	0.58	0.0035			70.2%								0.4000	0.5000	Equal	
	Electricity (on-site generation)	GG2	-0.0022																
	Steam																		
	Steam plant electricity (on-site generation)	GG2																	
	Steam plant NG																		
													MJe/kg	kg/MJ					
	Oxygen													0.0046					
	Oxygen plant	GG2											0.4722			0.4486	0.4958	Equal	
	Primary energy consumption and emissions		*0.4254*	*0.58*	*0.0035*		*0.66*	*70.2%*											

GD1 NG to syn-diesel plant (GTL)

This is the so-called GTL process including NG reforming or partial oxidation followed by the Fischer-Tropsch (FT) synthesis. The plant also includes hydrocracking of the FT product. Plants to be designed in the next few years will have a typical overall efficiency of 63% [*Source: Shell*], i.e. 100 MJ of NG in will deliver 63 MJ of combined product, 37 MJ being expended in the process. The selectivity of the process for a specific product can be adjusted to a large degree, notably with a hydrocracking step after the FT synthesis. The maximum practically achievable diesel yield (including the kerosene cut) is considered to be around 75% of the total product, the remainder being mainly naphtha and some LPG. In this case we assume that the plant is built for the primary purpose of producing diesel. Many future plants will not produce any specialties such as base oils and waxes as these markets will soon be saturated.

Naphtha and LPG are also potential automotive fuels. The energy required to produce them from refineries is of the same order of magnitude as diesel. The GTL process produces all these products simultaneously but, contrary to the refinery case, there is no technical argument for allocating proportionally more or less energy to one product then to the others (a yield change between e.g. naphtha and diesel would not significantly affect the overall energy balance of the process). We have therefore assumed that all products are produced independently with the same energy efficiency.

GD1C NG to syn-diesel plant with CO_2 capture

The "chemical" CO_2 from the reforming or partial oxidation reactions as well as the CO-shift reaction (required to adjust the hydrogen/CO ratio) is separated from the syngas feed to the FT process. This CO_2 is virtually pure so that only compression and liquefaction are required for potential recovery. Most GTL plants will be built near gas or oil fields where the CO_2 can be re-injected. For FT liquids from NG there is not literature source where a NG FT plant with and without CC&S is compared. FT plants are very complex. The layout differs from licensor to licensor and this can have a large impact on the energy penalty for CC&S. [*IEA 2005*] suggests an energy efficiency penalty of 3%. We have used this figure as a basis for our calculation, starting from an overall plant efficiency of 63% in the base case. The CO_2 generated in the auxiliary power plant is not recovered in this scheme, so that the CO_2 recovery is relatively low at around 75%.

GA1 NG to methanol plant

The plant energy efficiency selected here corresponds to a current state-of-the-art installation [*Statoil 1998*]. The upper value (29.64 GJ/t of methanol) is the value guaranteed by the manufacturer, the lower value (28.74 GJ/t of methanol) is a measured value for the methanol plant located in Tjeldbergodden in Norway.

This process is applicable to both a remote plant and a large “central” plant located in Europe.

GT1 NG to DME plant

There is limited data available on DME and there are no full scale commercial plants on the ground at the moment. The data used here is from Haldor Topsoe [*Haldor Topsoe 2002*], the main proponent of this compound. This process is applicable to both a remote plant and a large “central” plant located in Europe. In both cases electricity is deemed to be produced by a dedicated gas-fired power plant (CCGT, see process GG2).

GT1C NG to DME plant with CO_2 capture

Application of CC&S to DME synthesis. CO_2 formed during the steam reforming process is produced in nearly pure form and removed before the synthesis step. Capture is therefore relatively easy and cheap. The figures used here have been derived from [*IEA 2005*], [*Haldor Topsoe 2001*], [*Haldor Topsoe 2002*]. The resulting extra energy consumption for CC&S is, however, very low and these figures should be taken with great caution.

6.2 Natural gas to hydrogen

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	Reference
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.		MJ/ MJx	g CO_2/ MJx	g CH_4/ MJx	g N_2O/ MJx	km or N m	MJx/ t.km	MJx/MJ /100km	Min	Max		
GH1a	**NG to hydrogen (reforming, on-site, 2 MW hydrogen)**																		
	NG comp. (0.4 to 1.6 MPa), electricity (EU-mix	Z7b	0.0059																
	Energy as NG		0.4406		0.0159											0.4118	0.4694	Normal	Haldor Topsoe 1998
	CO2 emissions																		
	EU-mix quality			81.19												0.0705	0.0842	Normal	
	Russian quality			79.30															
	Electricity (EU-mix, LV)		0.0161																
	Primary energy consumption and emissions		*0.5037*													*0.4749*	*0.5325*		
	EU-mix quality			*83.85*			*84.50*												
	Russian quality			*81.95*			*82.60*												
GH1b	**NG to hydrogen (reforming, central plant, 100-300 MW hydrogen)**																		
	Energy as NG (Russian gas quality)		0.3150	72.38	0.0159		72.75	76.0%								0.289	0.341	Normal	Foster Wheeler 1996
GH1bC	**NG to hydrogen (reforming, central plant, 100-300 MW hydrogen) with CC&S**																		
	Energy as NG (Russian gas quality)		0.3650	11.86	0.0159		12.23	73.3%								0.338	0.3920	Normal	Foster Wheeler 1996

GH1a NG to hydrogen (steam reforming, on-site, 2 MW hydrogen,)

GH1b NG to hydrogen (steam reforming, central plant, 100-300 MW hydrogen)

The efficiency of the steam reforming proper is largely independent of the size of the plant. In a large plant, however, there are opportunities for optimisation of heat recovery. In this case we have assumed that waste heat is recovered to produce electricity, the surplus of which is exported to the grid (substituting EU-mix quality). This results in a much improved overall efficiency in the case of the central plant. The figures used here are from a conceptual plant design *[Foster Wheeler 1996]*. In the first version of this report we based the NG-to-hydrogen pathway on [*Linde 1992*]. The latter involved a larger NG input but also surplus electricity production. Taking the appropriate credit into account the net energy balance falls within 1% of the Foster Wheeler case.

GH1bC NG to hydrogen (steam reforming, central plant, 100-300 MW hydrogen) with CO_2 capture

Steam reforming of natural gas followed by the CO-shift reaction produces a mixture of hydrogen and CO2 with some residual CO. Depending on the purity requirement of the hydrogen, the CO_2 is either separated from the hydrogen with a solvent or a PSA unit is used to produce *[Foster Wheeler 1996]*.

7 LPG and ethers

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	Reference
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.		MJ/ MJx	g CO_2/ MJx	g CH_4/ MJx	g N_2O/ MJx	km or N m	MJx/ t.km	MJx/MJ /100km	Min	Max		
LR1	**LPG production**																		
	Energy as LPG		0.0529	3.47												0.0500	0.0700	Equal	
	Electricity	GG2	0.0028																
	Primary energy consumption and emissions		*0.0580*	*3.75*	*0.0000*	*0.0000*	*3.76*												
BU1	**n-butane to isobutene**																		CONCAWE
	Electricity	Z7a	0.0044																
	NG for steam (90% eff.)	Z6	0.1627	10.27	0.0325	0.0000	11.02												
	Hydrogen		-0.0196																
	Credit for hydrogen produced by NG steam ref.		-0.0062	-1.42	-0.0003	0.0000	-1.43												
	Primary energy consumption and emissions		*0.1690*	*9.38*	*0.0334*	*0.0000*	*10.16*												
EH1	**Isobutene + ethanol to ETBE**																		CONCAWE
	Isobutene	BU1	0.7000																
	Ethanol		0.3640																
	Electricity	Z7a	0.0010																
	NG	Z6	0.0240																
	Primary energy consumption and emissions		*0.0028*	*0.1194*	*0.0003*	*0.0000*	*0.13*												
MH1	**Isobutene + methanol to MTBE**																		CONCAWE
	Isobutene	BU1	0.8122																
	Methanol		0.1886																
	Electricity	Z7a	0.0012																
	NG	Z6	0.0290																
	Primary energy consumption and emissions		*0.0028*	*0.1194*	*0.0003*	*0.0000*	*0.13*												

LR1 LPG production

It is assumed here that LPG is produced as part of the heavier hydrocarbons (condendate) associated with natural gas. Energy is required for cleaning the gas and separating the C3 and C4 fractions. Reliable data is scarce in this area and this should only be regarded as a best estimate.

BU1 n-butane to isobutene

This process of isomerisation and dehydrogenation is required to produce isobutene, one of the building blocks of MTBE or ETBE. It is an energy-intensive process.

EH1 ETBE manufacture (large plant)

This process describes the manufacture of ETBE from isobutene and ethanol. This could occur in Europe with imported butanes (turned into isobutene with BU1) and domestically produced bio ethanol.

MH1 MTBE manufacture (large plant)

This represents a typical large scale plant, usually located near a source of natural gas, manufacturing MTBE from isobutene (from field butanes) and methanol (synthesised from natural gas).

8 Synthetic fuels and hydrogen production from coal

Code	Process	Assoc. processes	Expended energy	GHG emissions				Efficiency	Range		Probability distribution	Reference
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.		Min	Max		
KB1	**Lignite (brown coal) provision**											GEMIS
	Primary energy as											
	Brown coal		0.0148									
	Oil		0.0008									
	Primary energy consumption and emissions		*0.0156*				*1.77*					
KO1	**Hard coal provision (EU-mix) (1)**											GEMIS
	Primary energy as											
	Hard coal		0.0250									
	Brown coal		0.0020									
	Oil		0.0410									
	Natural gas		0.0100									
	Hydro power		0.0030									
	Nuclear		0.0110									
	Waste		0.0020									
	Primary energy consumption and emissions		*0.0940*	*6.47*	*0.3818*	*0.0003*	*15.33*					
KH1	**Coal to hydrogen**											Foster Wheeler 1996
	Energy as hard coal (EU-mix)		0.967	189.39	0.0061			50.8%				
	Primary energy consumption and emissions		*0.9670*	*189.39*	*0.0061*	*0.0000*	*189.5256*					
KH1C	**Coal to hydrogen with CC&S**											Foster Wheeler 1996
	Energy as hard coal (EU-mix)		1.303	5.64	0.0000			43.4%				
	Primary energy consumption and emissions		*1.3030*	*5.64*	*0.0000*	*0.0000*	*5.638889*					
KA1	**Coal to methanol**											
	Energy as hard coal (EU-mix)		0.6759	92.26	0.0069		92.42	59.7%				Katofsky 1993
	Electricity (ex coal)		0.0294									
	Primary energy consumption and emissions		*0.7371*	*92.26*	*0.0069*		*92.42*					
KE1	**Coal to DME**											
	Energy as hard coal (EU-mix)		0.6759	94.07	0.0069		94.23	59.7%				Katofsky 1993
	Electricity (ex coal)		0.0294									
	Primary energy consumption and emissions		*0.7371*	*94.07*	*0.0069*		*94.23*					
KD1	**Coal to syndiesel**											Gray 2001, 2005
	Energy as hard coal (EU-mix)		1.4710	167.08				40.5%	1.3470	1.5950	Equal	
	Energy as electricity		-0.3300									
	Credit for electricity based on coal IGCC		-0.6875	-66.19	0.0000	0.0000	-66.19	48%				TAB 1999
	Primary energy consumption and emissions		*0.7835*	*100.89*	*0.0000*	*0.0000*	*100.89*	56%				
KD1C	**Coal to syndiesel with CC&S**											
	Energy as hard coal (EU-mix)		1.444	14.92				40.9%	1.3220	1.5660	Equal	Winslow 2004
	Energy as electricity		-0.239									Gray 2001,2005
	Credit for electricity based on coal IGCC+CC&S		-0.5829	-5.60				41.0%	50.0%	40.0%		ENEA 2004
	Primary energy consumption and emissions		*0.8611*	*9.31*	*0.0000*	*0.0000*	*9.31*	54%				

(1) Data calculated from composition of current EU-mix and specific energy requirements and efficiencies for each source

Coal EU-mix as follows

Source	%
Australia	12
CIS	3
Columbia	7
Germany	21
Poland	7
South Africa	16
Spain	6
UK	18
USA	10

KB1 Lignite/brown coal provision

This process is typical of brown coal extraction in Germany and Eastern Europe [*GEMIS 2002*]. Lignite is used as fuel for the ethanol plant in pathways WTET3a/b.

KO1 Hard coal provision (EU-mix)

These figures approximate the average primary energy associated to the production and provision of hard coal to Europe [*El Cerrejon 2002*], [*DOE 2002*], [*EUROSTAT 2001*], [*GEMIS 2002*], [*IDEAM 2001*], [*IEA Statistics 2000*].

KH1 Coal to hydrogen

This represents the total process from coal gasification through CO shift, PSA etc [*Foster Wheeler 1996*].

KH1C Coal to hydrogen with CO_2 capture

Same as above with additional capture of CO_2. The figures with and without capture are based on a conceptual plant design [*Foster Wheeler 1996*].

KA1/E1 Coal to methanol or DME

This represents the total process from coal gasification through methanol or DME synthesis. The same reference was used for both products [*Katofsky 1993*].

KD1 Coal to synthetic diesel

This is the "CTL" route, including coal gasification and Fischer-Tropsch synthesis [*Gray 2001*], [*Gray 2005*], [*TAB 1999*].

KD1C Coal to synthetic diesel with CO_2 capture

Same as above with CO_2 capture between gasification and FT synthesis [*Winslow 2004*], [*Gray 2001*], [*Gray 2005*], [*ENEA 2004*].

9 Farming processes

Here we tabulate and sum the fossil energy and GHG emissions attributable to farming processes, including the upstream emissions and energy needed to make the fertilizers etc. The agrochemicals processes described later describe these upstream processes in more detail. In the first version of this report, most of the agricultural resources for growing biofuels came from land which would otherwise be used for growing export cereals, in accordance with [*DG-AGRI 2002*] agricultural outlook. This led to the conclusion that no “reference crop” was needed. However, DG-AGRI have since updated their outlook: due to changes in the agricultural subsidy regime, they now expect more set-aside and a smaller cereals surplus in EU25-2012. That means that most of the biofuel crops would now come from set-aside. The result is that there is now a reference crop representing the land cover in set-aside: we have chosen unfertilized grass. Because this has low agricultural inputs, the only significant GHG effect is in the reference nitrous oxide emissions. [*LBST 2002*], which otherwise shares much of the same agricultural data with this report, has more intensive reference crops..

All figures are related to the **water-free** Lower Heating Value of the biomass products. This is necessary to avoid confusion: for example apparent increases in LHV as wood dries out during transport and storage. However, the actual water content is taken into account when calculating transport and processes. Agricultural yields are expressed at the conventional % moisture: 16% for wheat; 10% for oilseeds; 9% for DDGS by-product of wheat-ethanol, sugar beet pulp and dried slops (“solubles”); 0% for wood. This helps comparability with other studies.

Unlike with a process making fossil fuel from a fossil resource, the primary energy and emissions from diesel use in biomass processes include the LHV and the carbon (as CO_2) content of the diesel itself, because the fossil CO_2 is released at this stage.
.
Best estimate figures are shown. It is not worth including a range of energy inputs, because these are low for farming compared to the whole chain. The main source of uncertainty is in the GHG emissions, caused by the N_2O emission calculation (details below).

The processes for making fertilizers and “pesticides” (in which we include other complex agro-chemicals such as fungicides and plant hormones) are detailed in the table below.

We call seeds “seeding materials” to avoid confusion with oilseeds as a crop.

Code	Process	Assoc. processes	Input		Expended energy		GHG emissions				N2O emissions	
			kg/ MJ prod.	MJ/ MJ prod.	Primary MJx/ kg or MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O/ MJ prod.	g CO2eq/ MJ prod.	Min	Max
WF1	**Wood farming and chipping**											
	N fertilizer	AC1	0.0005			0.0246	1.51	0.0041	0.0048	3.03		
	Diesel for harvest, sowing etc.	Z1		0.0060		0.0070	0.53	0.0000	0.0000	0.53		
	Land emissions								0.0034	1.01		
	Diesel for chipping			0.0040	4.18	0.0046	0.35	0.0000	0.0000	0.35		
	Primary energy consumption and emissions					*0.0362*	*2.39*	*0.0041*	*0.0082*	*4.92*		
	…including 2.5% dry-mass losses in chipping and storage					***0.0371***	*2.45*	*0.0042*	*0.0084*	***5.04***		
SB1	**Sugar Beet Farming**											
	CaO fertilizer	AC4	0.0020		2.04	0.0042	0.24	0.0006	0.0000	0.25		
	K2O fertilizer	AC3	0.0007		9.73	0.0068	0.38	0.0011	0.0000	0.41		
	P2O5 fertilizer	AC2	0.0003		15.47	0.0043	0.28	0.0004	0.0000	0.29		
	N fertilizer	AC1	0.0005		49.17	0.0253	1.55	0.0043	0.0050	3.12		
	Pesticides	AC5	0.0000		272.55	0.0018	0.11	0.0002	0.0000	0.11		
	Seeding material		0.0000		33.38	0.0010	0.06	0.0000	0.0000	0.06		
	Diesel	Z1		0.0320	4.18	0.0371	2.80	0.0000	0.0000	2.80		
	Net emissions from field							0.0001	0.0118	3.50	0.0081	0.0156
	Farm primary energy consumption and emissions					*0.0806*	*5.42*	*0.0066*	*0.0168*	*10.53*		
	…including 4.5% sugar loss during storage					***0.0842***	*5.66*	*0.0069*	*0.0175*	***11.01***		
WT1	**Wheat farming**											
	K2O fertilizer	AC3	0.0005		9.73	0.0051	0.29	0.0008	0.0000	0.31		
	P2O5 fertilizer	AC2	0.0005		15.47	0.0081	0.52	0.0007	0.0000	0.53		
	N fertilizer	AC1	0.0013		49.17	0.0646	3.97	0.0109	0.0127	7.96		
	Pesticides	AC5	0.0000		272.55	0.0069	0.42	0.0006	0.0000	0.44		
	Seeding material		0.0011		2.88	0.0030	0.17	0.0000	0.0000	0.17		
	Diesel (includes drying)	Z1		0.0369	4.18	0.0428	3.23	0.0000	0.0000	3.23		
	Net emissions from field								0.0189	5.59	0.0064	0.0314
	Sum primary energy consumption and emissions					***0.1306***	*8.60*	*0.0130*	*0.0315*	***18.24***		
SC1	**Sugar cane farming (Brazil)**											
	CaO fertilizer	AC4	0.0036		0.5669	0.0020	0.11	0.0003	0.0000	0.12		
	K2O fertilizer	AC3	0.0007		2.7023	0.0019	0.11	0.0003	0.0000	0.12		
	P2O5 fertilizer	AC2	0.0003		4.2959	0.0012	0.07	0.0001	0.0000	0.08		
	N fertilizer	AC1	0.0006		13.6591	0.0083	0.51	0.0014	0.0016	1.02		
	Pesticides	AC5	0.0000		75.7090	0.0014	0.09	0.0001	0.0000	0.09		
	Seeding material		0.0000		1.9837	0.0000	0.00	0.0000	0.0000	0.00		
	Diesel	Z1		0.0053	1.1600	0.0062	0.46	0.0000	0.0000	0.46		
	Net emissions from field						0.39	0.0531	0.0055	3.24		
	Sum primary energy consumption and emissions					***0.0211***	*1.75*	*0.0553*	*0.0071*	***5.13***		

WF1 Wood Farming

This represents short-rotation forestry on agricultural land. Poplar or willow are generally the best-yielding species in central and Northern Europe. Willow shoots are harvested typically every 3 years; poplar trunks after 8-15 years. After about 15-20 years the trees are uprooted and new ones planted. Inputs comprise sowing, thinning, fertilizer, but mostly harvesting. Yields for a given amount of fertilizer are better than for annual crops because roots are already established at the start of the growing season. Perennial grasses share this advantage. A neutral review of European experiments with *miscanthus* [*Scurlock 1999*] indicates a realistic yield is similar to farmed wood. Switchgrass has lower yield, but has better drought resistance, enabling it to be grown in more marginal areas. Grasses generally have a higher mineral content than wood, which can cause problems of ash sintering and corrosion if one tries to use the same conversion plant (the salt content can however be lowered by delayed harvesting or washing). For this reason, farmed wood chips command a higher price at power stations, which makes it the preferred biomass crop in EU at the moment. LCA studies show results for perennial grasses between wood and arable bio-crops. We have considered SRF because there is more data, but do not wish to exclude grasses as a possible alternative with fairly similar characteristics.

Inputs vary widely, depending on soil quality, yield and the intensiveness of the farming; [*Bauen 2000*] gives a range of 0.004 to 0.065 MJ primary energy per MJ dry wood. [*Mathews 1994*] quotes figures of 0.03 to 0.04 MJ/MJ. Our data on wood farming (short rotation forestry) are from original Oeko-Institut studies in the [*GEMIS 2002*] database, used also in [*LBST 2002*]. Inputs are low compared to other energy crops, so the uncertainty is not important when comparing pathways.

Nitrous oxide emissions for forestry cannot be calculated with the JRC soil model. Instead, we used the range of measured values for direct emissions from poplar, reported by [*Flesse 1998*]*.* A range for indirect emissions was estimated, using the procedure based on IPCC guidelines described in [*LBST 2002*], for the 25 kg/ha nitrogen fertilizer rate reported by [*Murach 2003*] for poplar plantation. Since this procedure assumes that nitrous oxide emissions are proportional to the nitrogen fertilizer rate, the emissions from our reference crop (unfertilized grass) are effectively already subtracted. For the nitrous oxide and farming input calculations, the yield is taken to be 10 tonnes/ha, and the LHV of dry farmed wood (poplar) chips 18 GJ/ dry tonne [*GEMIS 2002*]*.*

Dry mass losses during chipping and storage are partly from dust and spillage, and partly from respiration, rotting and evaporation of volatiles, in line with *[Hamelinck 2002]*.

SB1 Sugar Beet Farming

Sugar beet gives a high yield of easily-fermented sugar. Following [*LBST 2002*], we selected the data on farming inputs given by [*FfE 1998*], which are also close to the input data of the [*ADEME 2003*] study. The yield in [*FfE 1998*] is 51.2 t/ha/a at a water content of 76%. This is about the present average yield for EU-25 (but bear in mind that sugar beet is only grown on good farmland). Better growing conditions generally increase the optimum amount of N fertilizer together with the yield, so the exact yield considered is not very critical in terms of nitrogen input per MJ product. However, there is considerable variation in the literature on optimum nitrogen inputs even for similar yields [*LBST 2002*]. Processes for making fertilizer are detailed in the following table.

N_2O emissions from the field dominate the GHG emissions. An average for sugar beet grown in EU15 is calculated using the JRC's EU GHG emissions model, as detailed in the *WTT main report*. The reference crop is unfertilized grass. We assume that the sugar beet leaves are ploughed back into the soil after harvest, which is the usual practice.

We have included storage of sugar beet in this farming process, even though it may take place at the processing site. That is so that we can compare sugar beet results with those of wheat farming, where drying and storage is already included in our input data. In store, beet loses about 0.1% of its sugar per day by respiration [*Wiltshire 2000*]. For a representative beet processing campaign of 90 days (see sugar beet to ethanol process SB3a) the average loss on storage is therefore about 4.5%.

WT1 Wheat Farming

Wheat is the highest-yielding cereals crop, but it also takes the highest inputs. This process is for ‘soft wheat’, which accounts for most of EU production, gives the highest yield, and has the highest fermentable content. Straw use is discussed in the main WTT report. Data on wheat farming inputs is not included in [*FfE 1998*], so we took data from [*ETSU 1996*], which includes energy for drying and storage. N_2O emissions are calculated from GREASE. There is no “reference crop” (see main *WTT report*).

SC1 Sugar cane farming (Brazil)

Figures are derived from data for “scenario 2” in the thorough LCA study by [*Macedo 2004*] which describes best-current-practice in the Centre-South region, where 85% of Brazil’s sugar cane is grown, and where it is claimed there is still plenty of grazing land which could be planted to increase the supply if there is a market. It is a very long way from any rainforest. Some sugar cane is also produced in NE Brazil, near some areas of surviving Atlantic rainforest, but the conditions are much less suitable there, so that production needed subsidies, and is unlikely to increase.

There are usually 5 harvests, with an average yield of 82.4 t/ha (moist), but these take place over 6 years, so the annualized yield is 68.7 t/ha/y. Macedo gives inputs per tonne of moist cane. We converted these to figures per MJ (LHV) dry cane using 72.5%, water content of harvested sugar cane [*Kaltschmitt 2001*] and LHV heat content of 19.6 MJ per kg dry matter [*Dreier 2000*] (Macedo also describes the process per tonne of cane, so these conversion factors cancel out in the overall calculation). To keep the pathway comparable with other crops, we used our usual chemical processes to calculate the energy and emissions from producing the agricultural inputs, not the values used by Macedo.

In this best-practice scenario, the solid “filter mud cake” and liquid “vinasse” residue from the distillation process (equivalent of wet DDGS in the wheat-to-ethanol process) are sent to the closer fields to recycle the water and much of the minerals. The figures represent a weighted average of nearer and more distant fields. The average nitrogen rate over 5 years is about 75 kg/ha.

The farming emissions include CO2, methane and nitrous oxide from burning the foliage to make harvesting easier: this is still the most common practice, although it is banned near towns. We used Macedo’s calculation of N_2O, CH_4 and CO_2 emissions from burning, using factors recommended in [*IPCC 2001*].

Nitrous oxide emissions were calculated from the nitrogen fertilizer additions using IPCC default coefficients. Fortunately they are low, so the related uncertainty is acceptable in this case.

Sugar cane resembles more a perennial biomass crop like miscanthus than it does an arable crop. Unlike arable crops in Europe, planting sugar cane on grazing land is believed to actually increase the soil carbon stocks. The risk of soil erosion (a major concern in Brazil) is heightened in the first year of establishment, compared to grazing land, but not in subsequent years.

Code	Process	Assoc. processes	Input		Expended energy		GHG emissions				N2O emissions	
			kg/ MJ prod.	MJ/ MJ prod.	Primary MJx/ kg or MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O/ MJ prod.	g CO2eq/ MJ prod.	Min	Max
RF1	**Rapeseed Farming**											
	CaO fertilizer	AC4	0.0003		2.04	0.0005	0.03	0.0001	0.0000	0.03		
	K2O fertilizer	AC3	0.0004		9.73	0.0041	0.23	0.0007	0.0000	0.24		
	P2O5 fertilizer	AC2	0.0007		15.47	0.0115	0.73	0.0010	0.0000	0.75		
	N fertilizer	AC1	0.0020		49.17	0.1001	6.16	0.0169	0.0196	12.35		
	Pesticides	AC5	0.0000		272.55	0.0047	0.29	0.0004	0.0000	0.30		
	Seeding material		0.0001		7.14	0.0006	0.02	0.0000	0.0000	0.02		
	Diesel	Z1		0.0414	4.18	0.0480	3.62	0.0000	0.0000	3.62		
	Net emissions from field							0.0001	0.0436	12.91	0.0261	0.0611
	drying (electricity EU mix LV)	Z7b		0.0028	10.33	0.0080	0.34	0.0008	0.0000	0.36		
	Sum primary energy consumption and emissions					***0.1776***	*11.42*	*0.0199*	*0.0633*	***30.60***		
SF1	**Sunflower seed Farming**											
	K2O fertilizer	AC3	0.0004		9.73	0.0037	0.21	0.0006	0.0000	0.22		
	P2O5 fertilizer	AC2	0.0005		15.47	0.0080	0.51	0.0007	0.0000	0.53		
	N fertilizer	AC1	0.0007		49.17	0.0331	2.03	0.0056	0.0065	4.08		
	Pesticides	AC5	0.0000		272.55	0.0094	0.57	0.0009	0.0000	0.60		
	Seeding material		0.0001			0.0006	0.02	0.0000	0.0000	0.02		
	Diesel	Z1		0.0510	4.18	0.0592	4.46	0.0000	0.0000	4.46		
	Net emissions from field							0.0001	0.0264	7.81	0.0186	0.0342
	drying (electricity)			0.0028	10.33	0.0080	0.33	0.0008	0.0000	0.36		
	Sum primary energy consumption and emissions					***0.1220***	*8.14*	*0.0086*	*0.0329*	***18.08***		

RF1 Rapeseed Farming

Plant oils are the closest nature gets to a liquid transport fuel, so relatively little energy is lost in the conversion process. Rape gives the highest oil yield in the Northern half of Europe. However, it still has much lower yield than cereals: it is grown as a low-input break crop, to rest the soil between more profitable cereal crops. The rape straw is invariably ploughed back into the soil, because it contains most of the nitrogen and minerals taken up by the crop, is needed to improve the organic content of the soil.

Again, N_2O emissions are calculated from the JRC's EU soil emissions model, and farming inputs are from [*FfE 1998*]. The yield from these inputs is 3 t/ha, which is also about the average EU-15 yield [*EUROSTAT 2003*]. No reference crop (see main *WTT report*).

Nitrogen fertilizer rates (and rapeseed yields) in UK are typically higher than in Germany: 180kg N/ha *[Groves 2002]* compared to 145 in our data from [*FfE 1998*]. Our diesel farming inputs are between those in [*Groves 2002*] and [*ADEME 2002*]. The dry LHV of rapeseed is 23.8 GJ/t at standard 10% moisture [*FfE 1998*].

SF1 Sunflower Seed Farming

Rapeseed does not grow well in the drier parts of Europe: here, sunflower is grown in rather the same way, mostly as a break-crop between cereals, although average yields are lower. Inputs are from [*FfE 1998*], and average EU-15 N_2O emissions from the rapeseed field are calculated from JRC soil model. We assume the straw is ploughed in the soil, which is the usual practice. No reference crop. We assume the same LHV for sunflower seed as for rapeseed.

We found no literature data on energy and emissions for providing seeding materials for sunflower. Farming experts told us that sunflower requires slightly less kg seed-per-MJ-crop than rapeseed; however, we know that the energy inputs for sunflower seed crop production are higher. Therefore, our best estimate is that fraction of energy input due to seeding materials is very roughly the same as for rapeseed: small compared to the other farming inputs.

Code	Process	Assoc. processes	Input		Expended energy		GHG emissions			
			kg/kg	MJ/ kg prod.	MJx /MJ	MJx/ kg prod.	g CO_2/ kg prod.	g CH_4/ kg prod.	g N_2O/ kg prod.	g CO_2eq/ kg prod.
SY1	**Soya bean farming (US) for finding animal feed credits**									
	K2O fertilizer	AC3	0.0080			0.0778	4.37	0.0125	0.0000	4.67
	P2O5 fertilizer	AC2	0.0040			0.0619	3.94	0.0052	0.0000	4.07
	N fertilizer	AC1	0.0020			0.0983	6.05	0.0165	0.0000	12.13
	Pesticides	AC5	0.0005			0.1363	8.31	0.0127	0.0001	8.63
	Diesel (US)	Z1		0.8400	1.1860	0.9962	75.19	0.0000	0.0000	75.19
	Net emissions from field								1.2530	370.89
	Sum primary energy consumption and emissions					**1.3706**	97.86	0.0470	1.2531	**475.57**

SY1 Soy Bean Farming

Soy bean meal is the main protein-rich animal feed in EU. Most is imported from the US. We need to calculate primary energies and emissions for growing it in order to find the credits to apply to by-products which would substitute it. The substitution is done on a mass basis, taking into account the protein contents of the different feeds. So we need to know the inputs per kg, not per MJ.

Fertilizer and diesel inputs for growing soy in the USA are derived from *[UBA 1999]*. We used the data for US refineries [*ANL/1 1999*] in calculating primary energy and emissions from the diesel consumed. In the absence of better data, nitrous oxide emissions are calculated from IPCC default values, using the procedure explained in [*LBST 2002*].

N_2O EMISSIONS CALCULATION FOR ARABLE CROPS IN EU

Nitrous oxide emissions dominate the greenhouse gas emissions from farming, and are important for all biomass-based pathways. Therefore we were careful to use the best possible estimate of EU emissions. The IPCC guidelines are highly simplified and therefore need a very wide error range. The method used by JRC to estimate average GHG emissions for the different biofuels crops is described in the main *WTT report*. This is for EU-15, but we expect the average nitrous oxide emissions per MJ crop produced to be similar for EU-25. The method could not be used for short-rotation forestry and for sugar cane farming in Brazil, because these crops are not covered in the DNDC soils model we used. Here, we were forced to use IPCC default emission factors [*IPCC 1996/1*] which estimated nitrous oxide emissions based on nitrogen fertilizer rates.

10 Production of agro-chemicals

All data on fertilizer and fuel inputs for agro-chemicals provision come from [*Kaltschmitt 1997*]. These data include the transport of the fertilizer. In these processes, the “MJ primary energy per MJ input” of fuel inputs includes the LHV and fossil carbon (as CO2) content of the fuel itself, as well as the upstream energy/emissions to make it. However, [*Kaltschmitt 1997*] do not include upstream energies and emissions, so our figures are moderately higher, especially where a lot of electricity is used. Our primary energies are similar to those in the new [*ADEME 2003*] report.

Code	Process	Assoc. processes	Input	Expended energy			GHG emissions			
			kg/ kg prod.	As used MJ/ kg prod.	MJx/ MJ	Primary MJx/ kg prod.	g CO_2/ kg prod.	g CH_4/ kg prod.	g N_2O/ kg prod.	g CO_2eq/ kg prod.
AC1	**Nitrogen Fertilizer Provision**									
	Electricity (EU-mix, MV)	Z7a		0.6	2.83	1.78	74.8	0.18	0.0034	80.0
	Hard coal	KO1		3.9	1.09	4.32	405.8	1.51	0.0011	440.8
	Diesel	Z1		0.9	1.16	1.00	75.3	0.00	0.0000	75.3
	Heavy fuel oil	Z3		4.4	1.09	4.77	384.1	0.00	0.0000	384.1
	NG	Z6		33.0	1.13	37.31	2083.0	6.58	0.0008	2234.7
	N2O from process								*9.6300*	
	Primary energy and emissions/kg					***49.17***	*3022.9*	*8.27*	*9.6353*	***6065.3***
AC2	**P fertilizer provision**									
	Electricity (EU-mix, MV)	Z7a		1.6	2.83	4.54	191.2	0.47	0.0086	204.5
	Hard coal	KO1		0.6	1.09	0.62	58.6	0.22	0.0002	63.6
	Diesel	Z1		1.1	1.16	1.30	98.1	0.00	0.0000	98.1
	Heavy fuel oil	Z3		5.0	1.09	5.44	438.3	0.00	0.0000	438.3
	NG	Z6		3.2	1.13	3.56	198.8	0.63	0.0001	213.3
	Primary energy and emissions/kg					***15.47***	*985.0*	*1.31*	*0.0089*	***1017.8***
AC3	**K fertilizer provision**									
	Electricity (EU-mix, MV)	Z7a		0.2	2.83	0.62	26.2	0.06	0.0012	28.0
	Diesel	Z1		0.5	1.16	0.63	47.3	0.00	0.0000	47.3
	NG	Z6		7.5	1.13	8.48	473.4	1.50	0.0002	507.8
	Primary energy and emissions/kg					***9.73***	*546.9*	*1.56*	*0.0014*	***583.2***
AC4	**CaO fertilizer provision (85%CaCO3+15%CaO,Ca(OH)2)**									
	Electricity (EU-mix, MV)	Z7a		0.4	2.83	1.13	47.7	0.12	0.0022	51.0
	Coal	KO1		0.3	1.09	0.35	33.3	0.12	0.0001	36.2
	Diesel	Z1		0.2	1.16	0.21	16.2	0.00	0.0000	16.2
	NG	Z6		0.3	1.13	0.34	18.9	0.06	0.0000	20.3
	Primary energy and emissions/kg					***2.04***	*116.1*	*0.30*	*0.0023*	***123.7***
AC5	**Pesticides (etc) provision**									
	Electricity (EU-mix, MV)	Z7a		28.5	2.83	80.72	3398.9	8.29	0.1535	3635.0
	Hard coal	KO1		7.6	1.09	8.35	784.2	2.91	0.0021	851.9
	Diesel	Z1		58.1	1.16	67.40	5086.9	0.00	0.0000	5086.9
	Heavy fuel oil	Z3		32.5	1.09	35.37	2849.9	0.00	0.0000	2849.9
	NG	Z6		71.4	1.13	80.71	4505.9	14.24	0.0018	4834.0
	Primary energy and emissions/kg					***272.55***	*16625.8*	*25.45*	*0.1573*	***17257.6***

All inputs are quoted PER kg ACTIVE INGREDIENT. The kg/MJ input of fertilizer to the farming processes are also per kg active ingredient. The name of the process indicates what is considered the active ingredient. Thus, for example, “K2O fertilizer provision” is per kg potassium content as K_2O. The quantities of fertilizer specified in the farming pathways use the same convention. The active ingredient may actually be present in a mixture of compounds.

AC1 Nitrogen Fertilizer Provision

This is the main source of GHG emissions from agro-chemicals manufacture. Most of the GHG emissions come from NOx released from the process itself. The active ingredient is considered the nitrogen content, so the data are per kg nitrogen.

AC4 Lime ($CaO+CaCO_3$) Provision

Lime contains roughly 85 % m/m $CaCO_3$ and15% CaO, partially hydrated to $Ca(OH)_2$. When used as a fertilizer, the CaO content neutralizes the carbonic acid produced by decaying vegetable matter. This carbonic acid would otherwise release its CO_2 to the air. Therefore the CO_2 produced by the calcining process (“process emissions” in [*Kaltschmitt 1997*]) is later effectively reabsorbed, and should be left out of GHG calculations.

Lime requirements for a particular crop vary greatly depending on soil type. Fortunately, though, it never represents a major energy input to our farming pathways, so the effect of the uncertainty is small.

AC5 Pesticides (etc.) Provision

This comprises all complex organic compounds; pesticides, fungicides, plant hormones…; used in the farming processes. The input energy and emissions data (from [*Kaltschmitt 1997*]) are necessarily a very approximate guess. [*ADEME 2003*] give range of 175-576 MJ/kg primary energy for various ‘plant health products’: our value of 266 MJ/kg compares with their best-estimate of 297 MJ/kg. Our emissions are considerably higher than those calculated by [*Kaltschmitt 1997*] from the same data: it looks like they forgot to add in the process emissions. The final fate of the carbon in the pesticides themselves is uncertain, but the amount of CO_2 involved is negligible. In fact, in general, the mass of pesticides in farming processes is so small that the choice of data has negligible influence on the calculations of farming emissions.

11 Biomass transport

Code	Process	Assoc processes	one-way distance km	t.km/ MJ prod.	MJ diesel/ t.km	MJx/ t.km	gCO$_2$eq/ t.km	MJx/ MJ prod.	gCO$_2$eq/ MJ prod.	Loss MJ/MJ
Standard biomass transporters										
Z8	**Truck for dry product (round trip considered)**									
	Diesel	Z1,Z2			0.97	1.13	85.10			
Z9	**Ship for inland/coastal navigation**									
	Marine diesel	Z1			0.43	0.50	37.76			
Z10	**Ocean-going bulk carrier**									
	Fuel oil	Z3			0.20	0.22	17.77			
Solid biomass road transport										
WC2a	**Wood chips road transport, 50 km**	Z8	50	0.004	0.97	1.13	85.10	**0.0045**	**0.34**	0.000
WC2b	**Wood chips road transport, 12 km**	Z8	12	0.001	0.97	1.13	85.10	**0.0011**	**0.08**	0.000
SB2	**Sugar beet road transport**	Z8	50	0.013	0.97	1.13	85.10	**0.0147**	**1.11**	0.000
WT2a	**Wheat grain road transport**	Z8	50	0.004	0.97	1.13	85.10	**0.0039**	**0.30**	0.010
WT2b	**Wheat straw road transport**	Z8	50	0.003	0.97	1.13	85.10	**0.0039**	**0.29**	0.000
SC2	**Sugar cane road transport**	Z8	20	0.004	0.00	0.00	0.00	**0.0000**	**0.00**	0.000
RO2	**Rapeseed road transport**	Z8	50	0.002	0.97	1.13	85.10	**0.0024**	**0.18**	0.010
SO2	**Sunflower seed road transport**	Z8	50	0.002	0.97	1.13	85.10	**0.0024**	**0.18**	0.010
Solid biomass shipping										
WC2c	**Coastal/river shipping wood ships (200MW plant)**	Z8	400	0.034	0.43	0.50	37.76	**0.0171**	**1.29**	0.000
Manure transport										
BG1a	**Liquid manure transport, 10 km**	Z2	10	0.013	0.94	1.09	81.95	**0.0146**	**1.10**	
BG1b	**Dry manure transport, 10 km**	Z2	10	0.004	0.94	1.09	81.95	**0.0047**	**0.35**	
Long-distance biofuel transport			Naut. Miles							
SC4	**Sugar cane ethanol from Brazil**	Z4	5500	0.380				**0.0512**	**4.11**	
SY2	**Soya bean transport**			t.km/kg prod.						
	Truck transport of soya beans	Z8	50	0.050	0.97	1.13	85.10	**0.0564**	**4.25**	
	River transport of soya beans	Z9	250	0.250	0.43	0.50	37.76	**0.1251**	**9.44**	
	Ocean transport of soya beans	Z10	5000	5.000	0.20	0.22	17.77	**1.1085**	**88.86**	0.010
	Primary energy consumption and emissions							***1.2899***	***102.56***	

Z8 Truck for dry products

Nominal 23 t truck from [*ESU 1996*] obeying EURO IV emissions restrictions. Fuel consumption takes an empty return trip into account. The actual payload depends on the density of the material. This is taken into account when calculating effective t-km in each individual trucking process. According to [*Kaltschmitt 2001*] such a truck can actually carry up to 27 t for dense material, but usually for biomass the capacity is often limited by the maximum volume, which is 100 m^3. For rapeseed, for example, the actual payload is 22 t, close to the nominal payload. Cost is approximately 0.07EUR/t.km [*ESU 1996*].

Z9 Ship for inland/coastal navigation

For 8,800 t dry product carrier for coastal navigation (e.g. Baltic) or on inland waterways (e.g. Rhine) from [*ESU 1996*]; emissions data from [*Kaltschmitt 1997*]. Marine gasoil is the fuel: emissions are approximated to those of diesel. For discussion of transport distances, see below. Empty return trip considered.

Z10 **Ocean-going bulk carrier**

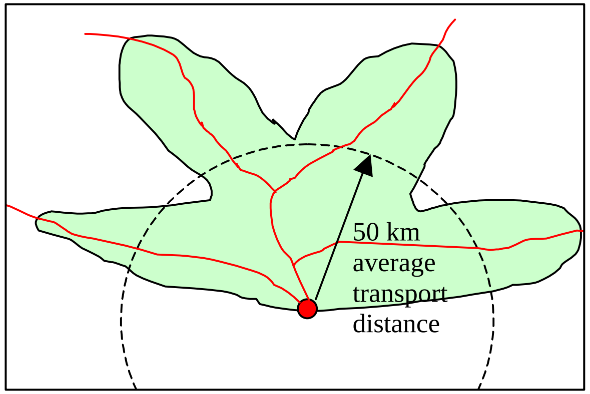
40,000 t dry product carrier; consumption of heavy fuel oil from [*Kaltschmitt 1997*]. Calculation methodology is the same as for oil transport (see above).

BIOMASS TRANSPORT DISTANCES

FARMED WOOD

For a catchment area is shaped like our map, 50 km average transport distance gives access to about 0.6 Mha. If we assume 50% of this area is arable land, and 10% of this arable land is farmed wood, with a yield of 10 dry t/ha, then annual production from whole area is 300 dry kt.

A 10 MW plant (based on feed) requires 16.8 dry kt wood per year (at 18 GJ/t). By quadratic scaling, we need transport distance of 12 km. For a 200 MW plant we need 336 dry kt wood per year; implying a single catchment area with transport distance about 50 km.



STRAW

In the good wheat-growing areas where straw may be harvested, the straw yield from wheat is about 5 t/ha. But these are prime agricultural areas with a high % of cereals farms. If we assume 60% of the land is arable, and 70% of that grows wheat (or other suitable cereal), then the transport distance is reduced to 25 km for a 200 MW plant. Note that the projected Iogen plant is about 150 MW.

FOREST RESIDUALS

The Pietarsaari cogeneration plant in Finland collects up to 200 000 m^3 per year forest residuals, with MAX transport distance 80 km [*TEKES 2002*]. That means 90 dry kt/a for a dry-matter density of 0.4 dry t/m^3. The average transport distance would then be about 50km. These forest residuals give a total water-free-LHV energy input of 54 MW. For a 200 MW plant, for example on the Baltic coast, one would need to ship wood in from about 4 collecting points like this. Looking at a map of the Baltic that means maybe 400km average shipping distance. A central-European scenario, with barge transport on the Rhine or Danube, gives a similar results.

For a 10 MW plant, we get about 12 km road transport distance by quadratic scaling from the Pietarsaari example.

BIO-CROPS

In the literature one can find transport distances from the farm gate to the processing plant anything from 10 to almost 200 km. The first represents theoretical calculations of the radius needed to grow sufficient crop to feed the factory. The second represents the actual trucking distance for some existing plants: their supplies come from scattered farms which have opted to grow designated energy crops under existing rules for agricultural subsidies. Our distance represents what we think is reasonable for the medium-term future, if energy farming becomes much more common.

The calculation of t.km per MJ product takes into account the real payload of the truck, bearing in mind the volume limitation of the truck (see trucking processes). The return journey is already taken into account in the truck fuel consumption. For fine materials, 1% losses during loading and transport are considered.

MANURE
This is used for biogas, usually at fairly small scale, hence the short transport distance taken into account.

SB2 Soy bean transport

This process is used in the pathway for calculating animal feed (soy meal) credits (see after 'biofuels processes'): everything in this pathway is related to mass of soy meal, since we have no LHV data on soy bean meal. The pathway represents soy bean trucking to a river-port, and than trans-shipping to a transatlantic vessel (e.g. near New Orleans). This scenario is from [*UBA 1999*].

12 Biogas from organic waste

Three sources of organic waste are considered namely municipal waste, "liquid" manure and dry manure. The process is described in the main *WTT report*. The anaerobic fermentation produces raw biogas that, depending on the intended use may need to be treated (to remove contaminants such as sulphur) and/or upgraded (to remove CO_2). The plant usually produces its own heat and electricity (CHP). Data for municipal waste is from [*Börjesson 2004*], [*Börjesson 2005*] and from [*Boisen 2005*] for manure. All three options include a small credit for use of the residual organic material as fertiliser. When left untreated, stored manure produces methane that is vented to the atmosphere. This is particularly so for liquid manure where the right conditions for anaerobic fermentation are met. Using manure for biogas production therefore offers a credit for avoided field methane emissions, particularly large for liquid manure.

Code	**Process**	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
	Raw biogas production from municipal waste													
	Municipal waste		1.4286								*70%*	1.2286	1.6286	
	Heat (for info, internally generated)			0.0865								0.0778	0.0952	
	Electricity (for info, internally generated)			0.0622								0.0311	0.0933	
	Methane losses							0.2000						
	Raw biogas production from liquid manure													
	Municipal waste		1.4286								*70%*	1.2286	1.6286	
	Heat (for info, internally generated)			0.1500								0.1400	0.1700	
	Electricity (for info, internally generated)			0.0430								0.0400	0.0500	
	Methane losses							0.2000						
	Methane field emissions credit							-2.8571				-1.4286	-4.2857	
	Raw biogas production from dry manure													
	Municipal waste		1.4286								*70%*	1.2286	1.6286	
	Heat (for info, internally generated)			0.1500								0.1400	0.1700	
	Electricity (for info, internally generated)			0.0430								0.0400	0.0500	
	Methane losses							0.2000						
	Methane field emissions credit							0.2857				-0.1429	-0.4286	
	Biogas treatment and upgrading													
	Raw biogas		1.0100											
	Electricity (for info, internally generated)			0.0300								0.0200	0.0400	
	Methane losses							0.2000						
	Biogas CHP plant													
	Raw biogas		1.7000									1.6200	1.7900	
	Heat generation		0.0000											
	Electricity generation		0.0000											
	Methane losses							0.0533						

Processes BG2a/b/c represent the integration of these steps to produce upgraded biogas from the different feedstocks. This gas is then suitable for use as automotive fuel or to be introduced into a natural gas grid. Processes BG3a/b/c represent direct small scale electricity production from raw biogas.

Code	**Process**	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
BG2a	**Municipal waste to biogas (upgraded)**													
	Municipal waste		1.6916			0.6916								
	Electricity import	Z7a		0.0524	2.8347	0.1485				6.69				
	Methane losses							0.4423			g/MJ			
	N-fertiliser credit					-0.0299				-1.01	-0.18			
	Primary energy consumption and emissions					***0.8102***		*0.4423*		***15.85***				
BG2b	**Liquid manure to biogas (upgraded)**													
	Liquid manure		1.9367			0.9367								
	Electricity import	Z7a		-0.0134	2.8347	-0.0380				-1.71				
	Methane losses							0.4820		11.09				
	Methane field emissions credit							-3.8773		-89.18	g/MJ			
	N-fertiliser credit					-0.0215				-0.73	-0.13			
	Primary energy consumption and emissions					***0.8772***		*-3.3953*		***-80.53***				
BG2c	**Dry manure to biogas (upgraded)**													
	Dry manure		1.9367			0.9367								
	Electricity import	Z7a		-0.0134	2.8347	-0.0380				-1.71				
	Methane losses							0.4820		11.09				
	Methane field emissions credit							-0.3877		-8.92	g/MJ			
	N-fertiliser credit					-0.0215				-0.73	-0.13			
	Primary energy consumption and emissions					***0.8772***		*0.0943*		***-0.27***				
	Raw biogas to electricity (small scale, local)													
	Raw biogas		2.5000								*40%*	2.6316	2.3810	
	Heat generation			-1.2500										
	Electricity generation			-1.0000										
	Methane losses							0.0778						
BG3a	**Municipal waste to electricity (small scale, local)**													
	Municipal waste		4.2213			3.2213								
	Heat surplus (for info, no credit given)			-1.2241										
	Methane losses							0.2737		6.30	g/MJ			
	N-fertiliser credit					-0.0745				-9.09	-0.44			
	Primary energy consumption and emissions					***3.1468***		*0.2737*		***-2.79***				
BG3b	**Liquid manure to electricity (small scale, local)**													
	Liquid manure		3.9946			2.9946								
	Heat surplus (for info, no credit given)			-0.9809										
	Methane losses							0.3133		7.21				
	Methane field emissions credit							-7.9977		-183.95	g/MJ			
	N-fertiliser credit					-0.0443				-5.40	-0.26			
	Primary energy consumption and emissions					***2.9503***		*-7.6844*		***-182.14***				
BG3c	**Dry manure to electricity (small scale, local)**													
	Dry manure		3.9946			2.9946								
	Heat surplus (for info, no credit given)			-0.9809										
	Methane losses							0.3133		7.21				
	Methane field emissions credit							-0.7998		-18.39	g/MJ			
	N-fertiliser credit					-0.0443				-5.40	-0.26			
	Primary energy consumption and emissions					***2.9503***		*-0.4865*		***-16.59***				

13 Conversion processes for "conventional biofuels"

The range of energy and emissions reported by different authors for processing biomass into 'conventional biofuels' is much smaller than the uncertainty in farming emissions, especially N_2O emissions. Therefore we do not complicate by giving an error range. Where there are significantly different processes (e.g. lignocellulose-to-ethanol) we have made separate calculations for the two processes.

Large variations in the energy and emissions reported in the literature are due to different treatment of by-products, as discussed in the main body of this report.

13.1 Ethanol from sugar beet

Code	**Process**	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
Sugar beet to ethanol														
SB3a	**Sugar beet to ethanol, pulp and slops to animal feed**													
	Basic process without slop or pulp credits													
	Sugar beet		1.8930			0.8930						1.7980	1.9880	
	Energy for main process													
	NG for steam at 90% eff.	Z6		0.3038	1.1306	0.3435	19.18	0.0606	0.0000	20.57		0.2886	1.1872	
	Electricity (MV)	Z7a		0.0172	2.8347	0.0488	2.05	0.0050	0.0001	2.20		0.0163	2.9788	
	Primary energy and emissions (no by-product credits)					**1.2852**	21.23	0.0656	0.0001	**22.77**	kg/kg biomass			
	Sugar beet pulp			-0.3850							0.050			
	Slops			-0.1770							0.023			
	Combined pulp and slops by-products			-0.5620							0.073			
	Pulp and slops drying													
	NG			0.2361	1.1306	0.2669	14.90	0.0471	0.0000	15.99	kWh	0.2243	1.1872	
	Electricity (MV)	Z7a		0.0182	2.8347	0.0516	2.17	0.0053	0.0001	2.32	wheat/kWh	0.0173	2.9788	
	Credit for pulp+slops replacing wheat grain (LHV basis)	WT1		-0.4665	0.1306	-0.0609	-4.01	-0.0061	-0.0147	-8.51	0.83			
	Net primary energy consumption and emissions					***1.5429***	*34.29*	*0.1120*	*-0.0145*	***32.57***				
SB3c	**Sugar beet to ethanol, pulp and slop to biogas digestor and CHP**													
	Basic process without credits		1.8930			**1.2852**	21.23	0.0656	0.0001	**22.77**		1.7980	1.9880	
	Pulp plus slops to biogas digester			-0.5620										
	Credits from biogas plant													
	NG	Z6		-0.2279	1.1306	-0.2577	-14.39	-0.0455	0.0000	-15.43				
	Electricity (MV)	Z7a		-0.0214	2.8347	-0.0607	-2.56	-0.0062	-0.0001	-2.73				
	Net primary energy consumption and emissions					***0.9668***	*4.29*	*0.0139*	*0.0000*	***4.60***				

SB3a Ethanol from sugar beet; by-products used as animal feed

Sugar factories usually dry the by-product sugar beet pulp and sell it for animal feed, because it is worth more as feed than as fuel. Dried slop from the fermentation is a more valuable feed than the pulp.

Sugar factories using beet do not work all year round because of sugar loss from the beet in storage (see SB1 farming pathway). Beet processing 'campaigns' last between 60 days (Poland) and 150 days (Britain). Average for EU25 is about 90 days (also the German figure). However, it may be possible to keep the ethanol part of the plant working continuously by storing pasteurised syrup.

Following [*LBST 2002*] we choose a conventional fermentation plant, not integrated with a sugar refinery, as analysed by [*FfE 1998*]. First the process is shown without any credits for use of the pulp or slop. The size of the plant is not very important for efficiency, but has a big effect on costs. [*FfE 1998*] made a cost analysis on a hypothetical 59MW (ethanol) plant.

The main steps in the basic process are cleaning, slicing, sieving out the pulp by-product, syrup pasteurisation, fermentation, distillation, and final purification. Per MJ ethanol output, these steps use a total of 4.8KJ electricity and 0,27 MJ heat [*FfE 1998*], which we assume is supplied by a natural gas burner with 90% efficiency; i.e. 0,30 MJ natural gas. Distillation and final ethanol purification (drying with zeolite) consumes most of the energy. It takes 2.02 Kg sugar beet (at 76.5% water content) to make 1MJ ethanol.

There are two by-products: sugar beet pulp sieved from the syrup (0.050 kg/kg pulp, or 0.385 MJ/MJ ethanol), and the slop filtered from the fermented mash (0.023 dry kg/kg pulp, or 0.177 MJ/MJ ethanol). When the equivalent products from cereals fermentation are sold for animal feed, they are called "brewers' dried grains" and "solubles"; usually sold together. Both beet by-products have a dry LHV of 15MJ/kg [*FfE 1998*], contain initially 35-40% water, and have to be dried to about 9% water [*FfE 1998*], [*NRC 1998*]. The heat energy for drying and pelleting pulp is given in [*FfE 1998*] as 0.295MJ/moist kg sugar beet input: if we assume slops needs the same heat-per-dry-kg, the heat for drying both, per MJ ethanol, is 0.295*(0.05+0.023)/0.05/2.02 = 0,213 MJ/MJ ethanol. Again heat comes from a natural gas burner with 90% efficiency. In addition there is a small amount of electricity required for the blowers: 0.007 kWh/(kg moist sugar beet) for the pulp drying, or 0.018 MJ/MJ ethanol for drying both sugar beet and slop.

FODDER CREDIT CALCULATION

There is only 8.6 dry % m/m protein in dried sugar beet pulp [*NRC 1998]*, but slop contains protein from the yeast: "solubles" from maize fermentation contain 26.7%m protein [; we can guess about 25 dry %m for dried slops. So the combined feed has about 13.4 dry % m/m protein, which is within the range for wheat. But wheat grain has a greater digestible energy content: according to [*NRC 1998*], pigs can digest 16.2 MJ/dry kg, compared to 13.2 MJ/dry kg for sugar beet pulp, and 13.9 MJ in "solubles". Taking into account the difference in LHV values; 17 MJ/dry kg for wheat grain [*Kaltschmitt 2001*] compared to 15.6 MJ/dry kg for pulp and slop [*FfE 1998*]; we calculate that 1 water-free MJ pulp replaces 0.83 water-free MJ wheat grain. The primary energy and emissions credits are then easily calculated from our wheat farming process WT1. The feed must be transported to the animals whatever they eat, so we assume the transport energy for the feed cancels out.

Note it costs more energy (and emissions) to dry the animal feed than you get credit for fodder saved. Nevertheless, this is the most likely destination for the by-products on economic grounds. To improve the energy balance and keep rational economics, one could make a process in which process heat comes from woody waste or straw, for example, but that applies to any process using heat.

SB3c Ethanol From Sugar Beet; Pulp Added To The Biogas Fermentor

The sieved pulp mash and is added to an anaerobic digester, which is already producing biogas from the waste-water. Furthermore, the slop is no longer filtered from the waste-water, and also makes biogas. The plant is simpler than one burning the by-products because they do not need to be dried. But the process is still probably less attractive economically than selling the by-products as animal feed.

To calculate the heat credit from the biogas burning we used the efficiency data of the biogas plant in [*FfE 1998*] (proposed for making methane for transport fuel). This plant incorporates a small gas engine for providing its own electricity, together with a small excess, which we treated as an electricity credit (you would not bother with this engine in practice but its effect on the overall energy and emissions balance is negligible). For each MJ biomass in, this plant produces 0.405 MJ biogas and 0.038 MJ electricity. We assume 1MJ biogas substitutes 1MJ natural gas.

The waste from the biomass fermentor would probably be used as fertilizer. However, the quantity is much smaller than the uncertainty in fertilizer use in the sugar beet farming process, so it is pointless to account for this.

Ethanol From Sugar Beet; By-Products Burnt For Process Heat

Animal feed is usually worth much more per MJ than biomass fuel: it would normally be cheaper to fuel the burner on some sort of waste. However, in order to allow comparison with other studies, we have included this option. The drying process for pulp and slop (taken from the SB3a) consumes about half the heat content of the by-products. The dried (9% water) by-products are burnt in a biomass boiler at 85% efficiency [*GEMIS 2002*], and replace natural gas burnt at 90% efficiency. The results of this process are almost the same as those for SB3c; pulp added to the biogas fermentor.

13.2 Ethanol from wheat grain

Code	Process	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
WT3	**Wheat grain handling and drying (to dwg, 3% moisture)**													
	Wheat grain (16% moisture)		1.0000											
	Electricity (MV)			0.0026	2.8347	0.0072	0.30	0.0007	0.0000	0.33				
	Diesel			0.0400	1.1600	0.0464	0.57	0.0000	0.0000	0.57				
	Net primary energy consumption and emissions					***0.0536***	*0.88*	*0.0007*	*0.0000*	***0.90***				
WT4a	**Wheat grain to ethanol, conventional boiler**												t dw g/t EtOH	
	Dried wheat grain (dwg, 3% moisture)		1.8644			0.8644							3.03	
	Heat to process			0.3640										
	NG for steam at 90% eff.	Z6		0.4044	1.1306	0.4573	25.53	0.0807	0.0000	27.39				
	Electricity (MV)	Z7a		0.0540	2.8347	0.1531	6.45	0.0157	0.0003	6.89				
	Net primary energy consumption and emissions					***1.4747***	*31.97*	*0.0964*	*0.0003*	***34.28***				
WT4b	**Wheat grain to ethanol, NG CCGT**												t dw g/t EtOH	
	Dried wheat grain (dwg, 3% moisture)		1.8644			0.8644							3.03	
	Heat to process			0.3640										
	Electricity to process			0.0540										
	NG to CCGT			0.6794	1.1306	0.7681	42.88	0.1356	0.0000	46.00				
	Electricity net surplus			-0.1867										
	Credit for electricity surplus based on NG to state-of-the-art stand-alone CCGT			-0.3395	1.1306	-0.3839	-21.43	-0.0677	0.0000	-22.99				
	Net primary energy consumption and emissions					***1.2486***	*21.45*	*0.0678*	*0.0000*	***23.01***				
WT4c	**Wheat grain to ethanol, Lignite CHP**												t dw g/t EtOH	
	Dried wheat grain (dwg, 3% moisture)		1.8644			0.8644							3.03	
	Heat to process			0.3640										
	Electricity to process			0.0540										
	Lignite to CHP plant			0.7761	1.0156	0.7882	89.28	0.0000	0.0000	89.28				
	Electricity net surplus			-0.0775										
	Credit for electricity surplus based on lignite-fired conv. power station			-0.1937	1.0156	-0.1967	-22.15	0.0000	0.0000	-22.15				
	Net primary energy consumption and emissions					***1.4559***	*67.13*	*0.0000*	*0.0000*	***67.13***				
WT4d	**Wheat grain to ethanol, Straw CHP**												t dw g/t EtOH	
	Dried wheat grain (dwg, 3% moisture)		1.8644			0.8644							3.03	
	Heat to process			0.3640										
	Electricity to process			0.0540										
	Straw to CHP plant			0.7761	1.0165	0.7889	0.96	0.0000	0.0000	0.97				
	Debit for additional fertilisers (net)				kWh/kg						kgex/MJ EtOH			
	N				13.6591	0.0000	0.00	0.0000	0.0205	6.06	0.0000			
	P				4.2959	0.0011	0.07	0.0001	0.0000	0.07	0.0001			
	K				2.7023	0.0037	0.21	0.0006	0.0000	0.22	0.0004			
	Total					0.0047	0.27	0.0007	0.0205	6.35				
	Electricity net surplus			-0.0775										
	Credit for electricity surplus based on Straw-fired conv. power station			-0.2460	1.0165	-0.2500	-0.31	0.0000	0.0000	-0.31				
	Net primary energy consumption and emissions					***1.4080***	*0.93*	*0.0007*	*0.0205*	***7.01***				
WTDa	**Credit for DDGS as animal feed**										kg/MJ EtOH	Protein factor		
	Soya substitution	SYML				-0.3074	-4.01	-0.0115	-0.0199	-10.17	0.043	0.78		
WTDb	**Credit for DDGS as fuel**										kg/MJ EtOH			
	Electricity			-0.2042	1.1306	-0.4197	-23.43	-0.0741	0.0000	-25.14	0.043			

The data used here are essentially derived from [*LowCVP 2004*]. Process Wt3 describes the grain drying step to arrive at "dry wheat grain" (dwg, 3% moisture). Processes WT4a/b/c/d describe the ethanol plant proper. They all assume the same energy requirement for the plant but different utility generation schemes.

WT4a Conventional natural gas boiler

Heat is supplied by a conventional natural gas fired boiler and electricity is imported. This can be considered as representative of the vast majority of existing installations and is also by far the cheapest solution.

WT4b Combined cycle gas turbine

A natural gas fired gas turbine with a heat recovery steam generator (HRSG) provides both heat and electricity. As more heat than electricity is required supplementary firing is applied in the HRSG. As the heat is required only as low pressure steam, a back pressure turbo-generator is also installed behind the HRSG. The plant is assumed to be sized and operated to produce the heat required for ethanol manufacture. There is, however, a surplus of electricity which is exported into the grid, thereby generating an energy and GHG credit.

This solution is considerably more energy efficient but also significantly more complex and expensive to build and operate.

WT4c Lignite boiler CHP

High pressure steam is produced in a lignite boiler. A back pressure turbo-generator produces electricity and low pressure steam for the process. Here again the plant is assumed to be sized and operated to produce the heat required for ethanol manufacture but it nevertheless generates an electricity surplus.

Lignite (or brown coal) is a cheap and abundant fuel in certain parts of Europe and actual plants are either operating or under construction in Eastern Germany.

WT4d Straw boiler CHP

Wheat cultivation produces large amounts of straw. Some LCA studies have considered straw as a by-product but this is not necessarily the case. In most of the EU it should be ploughed back to maintain the water-retention properties of the soil (see also straw availability, *WTT report, section 5*). Where it may be removed from the field it is partly already used for litter and other applications. Therefore it is misleading to systematically assume that straw can be used to fuel the ethanol production process. In practice this should only be proposed where there is little water stress, a high density of cereals production and a low density of livestock. These conditions would apply to concentrated wheat-producing areas in Northern Europe excluding the Low Countries and Denmark. In any case removing straw will reduce soil nutrients, which needs to be compensated by an additional fertiliser input.

This scheme is similar to the previous case but straw in used instead of lignite. The main advantage of this scheme is to use a renewable source of energy to drive the process. It must be realised, however, that handling and burning of solids is considerably more complex and costly than with liquids or gases, particularly in the case of a low energy density material such as straw. This will therefore be the most expensive option.

WTDa Credits for DDGS as animal feed

Ethanol production produces a by-product known as DDGS (Distiller's Dried Grain with Solubles) which is the solid residue after digestion of the carbohydrates. DDGS is a protein-rich material and is therefore a useful animal feed component. Its nearest equivalent is corn gluten feed, a by-product of maize milling the supply of which is fixed by the amount of maize milled. Wheat DDGS contains 38.5% dry matter crude protein [*Univ. Minnesota 2002*] more than DDGS from maize). In the EU marginal animal feed is soy bean meal imported from the USA. The meal made from pure soy beans has a protein content of 49% [*NRC 1998*]. Since protein feeds are much more valuable than energy feeds [*DG-AGRI 2003*], farmers would use 1kg DDGS to replace 38.5/49 = 0.78 kg soy bean meal (the digestible energy ratio is anyway similar). The equivalent quantity of soy bean meal is calculated on the basis of the protein content using data from [*NRC 1998*]. The energy and emissions for the soy meal is calculated according to a scenario of soy beans grown in the US, and crushed in EU, following [*UBA 1999*] (see *section 13.6*).

WTDb Credits for DDGS as fuel

Although animal feed is by far the most lucrative usage and therefore the most likely, DDGS may also be used as fuel, for instance in solid-burning (i.e. coal) power plants that need to meet their renewable energy obligations. The calorific energy content of DDGS is considerably greater than the energy required to produce the equivalent animal feed, so burning DDGS gives a higher energy credit.

13.3 Ethanol from sugar cane (Brazil)

Code	Process	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
SC3	**Sugar cane to ethanol**													
	Sugar cane		2.7720			1.7720								
	Credit for surplus heat (diesel)			-0.1150	1.2609	-0.1450	-10.94			-10.94				
				kg/kWh EtOH	kWh/kg									
	H2SO4	C7		0.00047	4.0052	0.0019	0.09	0.0003	0.0000	0.10				
	CaO	C6		0.00043	4.9835	0.0021	0.46	0.0004	0.0000	0.47				
	Cyclohexane			0.00003	9.9000	0.0003	0.01			0.01				
	Primary energy consumption and emissions					***1.6313***	*-10.39*	*0.0006*	*0.0000*	***-10.37***				

Data for this process were taken from the careful life-cycle analysis by [*Macedo 2004*],adopting his “scenario 2” describing best-current-practice in the Centre-South region of Brazil, where 85% Brazilian ethanol is produced. His analysis also takes into account the energy for plant construction and some minor inputs which we neglect to be consistent with our calculations for other processes.

The data refer to the production of *anhydrous* ethanol, in Macedo’s best-current-practice scenario. Cyclohexane is used in the drying process. The yield corresponds to 91.8 litres ethanol per tonne of moist cane. Inputs were converted from quantities per-tonne-of-cane to per-MJ-ethanol using the same LHV and water content for sugar cane as used in the sugar cane farming process, and standard values for ethanol (see section 1.2).

Plant capacity is 120 000 litres ethanol per day, and it operates for 180 days per year. A very important factor is that the bagasse to raise steam which provides all the process heat, and electricity via a steam turbine. In fact modern plants have a surplus of bagasse. Although this could be used to generate electricity exports, usually the surplus bagasse is simply sold as a fuel for nearby factories (e.g. for food processing), where it mostly replaces fuel oil (almost identical to diesel; used for our credit).

13.4 Bio-diesel from plant oil

Code	**Process**	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
RO3	**Rapeseed to raw oil: extraction**													
	Rapeseed		1.6326			0.6326								
	Electricity (MV)	Z7a		0.0084	2.8347	0.0238	1.00	0.0024	0.0000	1.07				
	NG for steam at 90% eff.	Z6		0.0442	1.1306	0.0500	2.79	0.0088	0.0000	2.99				
	n-hexane	see notes		0.0031	1.1600	0.0036	0.27	0.0000	0.0000	0.27	kg/MJ prod.			
	Rapeseed cake										-0.0408			
	Soya meal / rapeseed cake replacement ratio										0.80			
	Credit for rapeseed cake	SYML			-0.8005	0.1176	-8.09	-0.0020	-0.0221	-14.67				
	Primary energy consumption and emissions					***0.8276***	*-4.03*	*0.0092*	*-0.0220*	***-10.33***				
SO3	**Sunflower seed to raw oil: extraction**													
	Sunflower seed		1.5201			0.5201								
	Electricity (MV)	Z7a		0.0078	2.8347	0.0222	0.93	0.0023	0.0000	1.00				
	NG for steam at 90% eff.	Z6		0.0412	1.1306	0.0465	2.60	0.0082	0.0000	2.79				
	n-hexane	see notes		0.0029	1.1600	0.0033	0.25	0.0000	0.0000	0.25	kg/MJ prod.			
	Sunflower seed cake										-0.0361			
	Soya meal / sunflower seed cake replacement ratio										0.61			
	Credit for sunflower cake	SYML				0.0793	-5.46	-0.0014	-0.0149	-10.05				
	Primary energy consumption and emissions					***0.6714***	*-1.67*	*0.0091*	*-0.0148*	***-6.01***				
RO4	**Raw oil to refined oil**													
/SO4	Crude plant oil		1.0417			0.0417								
	Electricity, MV	Z7a		0.0006	2.8347	0.0017	0.07	0.0002	0.0000	0.08				
	NG for steam at 90% eff.	Z6		0.0091	1.1306	0.0103	0.58	0.0018	0.0000	0.62				
	Primary energy consumption and emissions					***0.0537***	*0.65*	*0.0020*	*0.0000*	***0.70***				
RO5	**Refined oil to FAME: esterification**													
/SO5	Refined plant oil		1.0065			0.0065								
	Electricity EU mix, MV	Z6a		0.0029	2.8347	0.0082	0.35	0.0008	0.0000	0.37				
	Methanol	GA1		0.0585	0.4668	0.0273	0.68	0.0000	0.0000	0.68		0.0556	0.0614	
	NG for steam at 90% eff.	Z6		0.0410	1.1306	0.0464	2.59	0.0082	0.0000	2.78		0.0401	0.0430	
	Various other chemicals	see notes				0.0030	0.14	0.0000	0.0000	0.14				
	Primary energy and emissions (no glycerine credit)					0.0914	3.76	0.0090	0.0000	3.97	kg/MJ prod.			
	Glycerine										-0.0028			
5a	Credit for typical chemical replaced by glycerine	C10				-0.2087	-14.42	-0.0041	-0.0001	-14.53				
	Primary energy consumption and emissions					***-0.1173***	*-10.66*	*0.0049*	*-0.0001*	***-10.56***				
5b	Credit for glycerine replacing wheat grain (LHV basis)	WT1				-0.0062	-0.41	-0.0006	-0.0015	-0.87	0.99	kg/kg dry wheat grain		
	Primary energy consumption and emissions					***0.0851***	*3.35*	*0.0084*	*-0.0015*	***3.10***				
RO6	**Refined oil to FAEE: esterification**													
/SO6	Refined plant oil		0.9509			-0.0491								
	Electricity EU mix, MV	Z6a		0.0029	2.8347	0.0082	0.35	0.0008	0.0000	0.37				
	Ethanol	GA1		0.1100	1.5318	0.1685	1.14	0.0028	0.0007	1.42		0.1045	0.1155	
	NG for steam at 90% eff.	Z6		0.0410	1.1306	0.0464	2.59	0.0082	0.0000	2.78		0.0401	0.0430	
	Various other chemicals	see notes				0.0030	0.14	0.0000	0.0000	0.14				
	Primary energy and emissions (no glycerine credit)					0.1770	4.21	0.0118	0.0008	4.71	kg/MJ prod.			
	Glycerine										-0.0026			
6a	Credit for typical chemical replaced by glycerine	C10				-0.2087	-14.42	-0.0041	-0.0001	-14.53				
	Primary energy consumption and emissions					***-0.0317***	*-10.21*	*0.0077*	*0.0007*	***-9.82***				
6b	Credit for glycerine replacing wheat grain (LHV basis)	WT1				-0.0003	-0.02	0.0000	0.0000	-0.02	0.99	kg/kg dry wheat grain		
	Primary energy consumption and emissions					***0.1767***	*4.19*	*0.0118*	*0.0008*	***4.69***				
Note: in the case of FAEE methanol is replaced by bio-ethanol from pathway WTET2a. The energy used in this process is deemed to remain the same														

RO3 Rapeseed Oil Extraction

Rapeseed is crushed and the oil is extracted with the aid of n-hexane solvent and heat. Our data is from [*UBA 1999*], [*Groves 2002*] and [*ADEME 2002*] have slightly better yield, with slightly higher inputs. The hexane is a refinery product made almost entirely from crude oil: we simplified the other primary energy inputs listed in [*FfE 1997*] to crude oil equivalents. In all conversion processes, we assume process heat or steam is supplied by a NG boiler working at 90% efficiency.

Rapeseed cake is the by-product: a high-protein animal feed. Farmers decide how much of it to feed to animals on the basis of the protein content. The crude protein content of rapeseed cake (39.6% dry mass) and pure soy bean meal (49% dry mass) is given in [*NRC 1998*]. Therefore one kg rapeseed cake will replace 39.6/49 = 0.80 kg soy bean meal. The process for making 1 kg soy meal is described below. The LHV of plant oil is 36 MJ/kg [*FfE 1998*].

SO3 Sunflower Oil Extraction

A similar process to rapeseed oil extraction: data from [*UBA 1999*]: the oil yield is slightly lower than for rapeseed, so more kg of cake are produced per MJ. However, the sunflower seed cake contains less protein (30% dry matter), so the credit for replacing soy beans meal is smaller.

RO/SO4 Plant Oil Refining

This process, from [*UBA 1999*], uses, in addition to the fossil energy inputs listed, 6 kg fullers' earth per t of plant oil for adsorbing impurities. Fullers' earth is a cheap mineral, with negligible energy input for this quantity. Data are similar to [*Groves 2002*] and [*ADEME 2002*].

RO/SO5 Esterification (methanol)

The process is the same for rapeseed oil and sunflower seed oil. Plant oil consists of 3 fatty acid chains on a 3-carbon backbone. 3 molecules of methanol combine with the fatty acids to make 3 molecules of fatty acid methyl ester (FAME), leaving their three alcohol groups stuck on the 3-carbon backbone to form glycerine. 0.1 t methanol reacts with 1 t plant oil to make 0.1 t glycerine and 1 t FAME.

Input data are similar to [*Groves 2002*] and [*ADEME 2002*]. The LHV RME is 36.8 GJ/t, that of glycerine is 16.0 GJ/t [JRC calculation] and methanol is 19.9 GJ/t. Methanol is made mostly from natural gas. “Various other chemicals” aggregates the primary energy inputs and emissions fro a list of minor inputs (NaOH, Na_2CO_3, H_3PO_4, HCl) detailed in [*UBA 1999*] and [*GM 2002*].

Two credit calculations are made for glycerine. In RO5a/SO5a it is for a typical chemical product; we found data for propylene glycol, in [*GEMIS 2002*], which differs from glycerine only by 1 oxygen atom, and is one of many chemicals which glycerine might displace. It uses much less primary energy than synthetic glycerine according to [*GM 2002*], presumably because the data for the latter includes energy for distilling a pharmaceutical-quality product. RO5b/SO5b include a credit for glycerine replacing wheat as an animal feed credit. We know that glycerine is easily digestible, but there is no numerical data in the literature. We assume that its digestible energy content is 95% of the LHV: the same fraction as for wheat. Then glycerine replaces wheat 1:1 on an LHV basis; we can use our wheat-farming process to calculate the credit.

RO/SO6 Esterification (ethanol)

Same as RO/SO5 replacing methanol by ethanol.

13.5 Processes to make materials needed for biomass processing and credit calculations

These processes make ingredients for biofuels. As with other biomass processes, we include the LHV and fossil C (as CO_2) content of the input fuels in our "MJ primary energy" and CO_2 emissions figures associated with fuels inputs.

Code	Process	Assoc. processes	Input	Expended energy			GHG emissions			
			kg/ kg prod.	As used MJ/ kg prod.	MJx/ MJ	Primary MJx/ kg prod.	g CO_2/ kg prod.	g CH_4/ kg prod.	g N_2O/ kg prod.	g CO_2eq/ kg prod.
C6	**Pure CaO for processes**									
	Natural gas	Z6		4.08	1.1306	4.62	257.7	0.8146	0.0001	276.5
	Diesel	Z1		0.17	1.1600	0.19	16.9			16.9
	Electricity (EU-mix, MV)	Z7a		0.06	2.8347	0.17	7.4	0.0179	0.0003	7.9
	CaCO3=CaO+CO2						785.7			785.7
	Primary energy and emissions/kg					*4.98*	*1067.6*	*0.8326*	*0.0004*	*1086.9*
C7	**Sulphuric acid**									
	Electricity (EU mix-MV)	Z7a		0.76	2.8347	2.15	90.7	0.2211	0.0041	97.0
	NG	Z6		1.64	1.1306	1.85	103.4	0.3268		110.9
	Primary energy and emissions/kg					*4.01*	*194.1*	*0.5479*	*0.0041*	*207.9*
C8	**Ammonia**									
	NG	Z6		10.90	1.0462	***11.40***	*2323.3*	*4.3077*		***2422.3***
C9	**Synthetic glycerol (to calculate a credit for esterification process)**									
	Electricity (EU mix-MV)	Z6a		3.24	2.8347	9.18	386.7	0.9431	0.0175	413.6
	NG for steam at 90% eff.	Z6		66.67	1.1306	75.37	4207.9	13.3018	0.0017	4514.3
				MJ/kg						
	Electricity to make Cl2 input	Z7a	2.00	4.57	2.8347	25.92	1091.4	2.6617	0.0493	1167.2
	Electricity to make NaOH input	Z7a	1.40	4.07	2.8347	16.14	679.8	1.6578	0.0307	727.0
	Propylene (LHV 12,7kWh/kg) from crude oil		0.80	45.72	1.6223	59.34	4480.9			4480.9
	Primary energy and emissions/kg					*185.96*	*10846.7*	*18.5643*	*0.0991*	*11303.0*
C10	**Propylene glycol (alternative credit for esterification process)**									
	Propylene from crude oil				1.6223	59.34	4480.9			4480.9
	Electricity (EU mix-MV)	Z7a		5.00	2.8347	14.18	597.3	1.4566	0.0270	638.8
	Primary energy and emissions/kg					*73.52*	*5078.2*	*1.4566*	*0.0270*	*5119.7*

C6 Pure CaO for Processes

Calcium oxide is used for neutralization in SSCF processes and elsewhere. A more pure grade is required than the lime used in agriculture. Another difference is that the carbon dioxide driven off from limestone in the calcining process is not reabsorbed when the product is used for neutralizing sulphuric acid, for example. So, unlike in lime-for-agriculture, the CO_2 emissions from the calcining process should be included. Data from [*GEMIS 2002*].

C7 Sulphuric Acid

Used in SSCF digestion. Data from [*ESU 1996*]. Sulphur mining is neglected

C8 Ammonia

Used in SSCF processes. Data from [*Kadam 1999*].

C9 Synthetic Glycerol

This process make PHARCACEUTICAL quality glycerol, and is only included to show what a high fossil energy is used. Only a tiny part of glycerol from FAME production could substitute this product.

C10 Propylene Glycol

This is a solvent and antifreeze which could represent the sort of bulk chemical replaced by glycerol from FAME, considering that the extra supply far exceeds the amount of synthetic glycerine still produced The electricity consumption is a preliminary estimate in [*GEMIS 2002*], and this source also gives primary energies for propylene. Propylene is a refinery product: almost all the input energy is from crude oil, but there are minor credits for gas and coke by-products which we converted to crude-oil equivalents. To convert to MJ, JRC calculated the LHV of propylene; 45.9GJ/tonne, using "HSC for Windows" thermo-chemistry programme. Propylene is a chemical input here, not a fuel being processed. That means we include its LHV and fossil carbon contents (as CO_2) in its "primary energy and emissions". This saves having to add them separately when we come to calculate the credit

13.6 Soy bean meal production

Code	Process	Assoc. processes	Input	Expended energy			GHG emissions			
			kg/ kg prod.	As used MJ/ kg prod.	MJx/ MJ	Primary MJx/ kg prod.	g CO_2/ kg prod.	g CH_4/ kg prod.	g N_2O/ kg prod.	g CO_2eq/ kg prod.
SY3	**Soya bean meal from crushing US beans, per kg bean meal (inc.transport from US)**									
	Electricity (EU mix-MV)	Z7a		0.27	2.8347	0.75	31.8	0.0774	0.0014	34.0
	NG for steam at 90% eff.	Z6		1.37	1.1306	1.55	86.4	0.2730	0.0000	92.7
	n-hexane			0.04	1.1600	0.05	3.9			3.9
	Plant oil by-product credit		-0.23			-9.26	-121.0	-0.3458	-0.6003	-306.6
	Primary energy and emissions/kg					*-6.92*	*1.1*	*0.0046*	*-0.5989*	*-176.1*
SYML	**Soya bean meal supply**									
				kg biomass	/kg meal					
				4.43	0.3807	1.69	120.5	0.0579	1.5433	585.7
	Soybeans farming/kg meal	SY1		4.43	0.3583	1.59	126.3			126.3
	Soyabeans transport/kg meal	SY2		3.60	-1.9215	-6.92	1.1	0.0046	-0.5992	-176.1
	Soyabean meal from beans crushing					*-3.64*	*247.9*	*0.0625*	*0.9441*	*535.8*

SY3 Soy bean meal from crushing soy beans

This is a mass-based process which is needed to calculate the credits per kg of protein-rich animal feeds. The overall process comes from [*UBA 1999*].

Hexane (solvent used to increase oil recovery) is an oil-refinery product made almost entirely from crude oil. The primary energy inputs listed in [*Kaltschmitt 1997*] were simplified by converting them to crude oil equivalents.

The soy bean oil is treated as a by-product. It attracts an energy and CO_2 credit by substituting rapeseed oil. This is how we calculated the credit: we found the energy and emissions for making 1MJ rapeseed oil starting with the energy and emissions from the oil mill (process RO3), and adding (energy and emissions from the rapeseed farming, per MJ rapeseed)*(MJ of rapeseed need to make 1 MJ oil). Then we multiplied all this by the LHV of plant oil (always around 36 MJ/kg) to find the energy and emissions per kg of oil.

Astute readers will have noticed that, since rape oil extraction itself has a credit for rapeseed cake, which replaces soy bean meal, we have a loop here. However, this is not a problem: even Excel is sometimes capable of an iterative calculation to converge on the correct solution.

SYML Complete soy bean meal production chain

Soy bean extraction is the last step in the production chain for soy bean meal. Soy bean farming is included with the farming processes and the transport with the transport processes. Following the scenario in [*UBA 1999*], the soy beans are imported from the USA and crushed in EU, where the oil replaces rapeseed oil: there is no transport of soy oil. So now we have all the data needed to link the three together to get the total primary energy and emissions from provision of soy meal.

14 Synthetic fuels and hydrogen production from farmed wood and wood waste

Code	**Process**	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
WW1	**Forest residuals to wood chips**													
	Losses during chipping and storage		1.0250			0.0250								
	Diesel	Z1		0.0040	1.1600	0.0046	0.35	0.0000	0.0000	0.35				
W3d	**Wood to hydrogen: gasification, 200MW**													
	Wood		1.4624			0.4624						1.3893	1.5355	Triangular
	Electricity from wood	W3j		0.0820		0.1929	0.00	0.00	0.00	0.00				
	Primary energy consumption and emissions					***0.6553***	*0.00*	*0.0000*	*0.0000*	***0.00***	*60%*			
W3e	**Wood to hydrogen: gasification, 10MW**													
	Wood		1.9313			0.9313						1.8339	2.0272	Triangular
	Process emissions from gasifier						0.00	0.0150	0.0045	1.66				
	Electricity (EUmix, MV) for													
	1. gasifier	Z7a		0.0369	2.8347	0.1046	4.40	0.0107	0.0002	4.71				
	2. syngas compression and CO shift	Z7a		0.1025	2.8347	0.2906	12.24	0.0298	0.0006	13.09				
	3. PSA , CO to gas engine for electri	Z7a		-0.1440	2.8347	-0.4082	-17.19	-0.0419	-0.0008	-18.38				
	Primary energy and emissions (tiny surplus electricity)					***0.9183***	*-0.55*	*0.0136*	*0.0044*	***1.08***	*52%*			
W3f	**Wood to syn-diesel: gasification + FT**													
	Wood		2.6384			1.6384						1.9725	2.9600	Triangular
	Credit for wood-to-electricity	W3i		-0.2394		-0.5633	0.00	0.00	0.00	0.00		0.0000	-0.7859	
	Primary energy consumption and emissions					***1.0751***	*0.00*	*0.0000*	*0.0000*	***0.00***	*48%*			
W3g	**Wood to methanol or DME: gasification + synthesis**													
	Wood		1.9586			0.9586						1.7021	21.7000	Equal
	Primary energy consumption and emissions					*0.9586*	*0.00*	*0.0000*	*0.0000*	*0.00*	*51%*			
W3h	**Wood cofiring in coal power station**													
	Wood		2.6667			1.6667	0.00	0.04	0.02	8.17	*38%*	2.5000	2.8571	Normal
W3i	**Wood to electricity: BCL 25MW for calculating electricity credits in BCL-based processes**													
	Wood (emissions unknown but very small)		2.3529			1.3529	0.00	0.00	0.00	0.00	42.5%			

WW1 Forest residuals chipping

The branches, tops and roots are stripped from the trunks in the forest: losses of forest residuals during collection and forwarding to the chipper stay in the forest, and are already taken into account in the ratio of residuals to stemwood. The losses which remain are from chip making, handling and storage, due to spillage, evaporation of volatiles, respiration and rotting. The figures (from forestry experts) are more or less in line with those in [*Hamelinck 2002*]. Diesel use by the roadside chipper is from [*Hartmann 1995*]. There are some lower values for different scenarios in the literature, but anyway this energy is insignificant for the whole pathway.

14.1 Wood gasification to hydrogen

W3d Large scale (200 MW)

200 MW was considered the largest scale of gasifier consistent with economic wood supply from EU-grown forest residuals or farmed wood; it is about the consumption of the largest existing power plant using forest residuals and pulp-mill waste [*TEKES 2002*]. It is impossible to scale the DM2-typoe gasifier up to 200MW because of the limit on how fast heat can be injected through the gasifier walls. For this larger scale, we used a process described in detail by [*Katofsky 1993*] and [*Mann 1997*], based on a scale-up of the Batelle-Columbus BCL indirectly-heated circulating fluidized bed gasifier.

Sand carries heat to pyrolyse the dried biomass. The cooled sand and coke left from the pyrolysis returns to a separate combustion section, where it is burnt in air. In this way the syngas from the pyrolysis section is not diluted with nitrogen. The syngas goes through conventional cold (wet) gas-cleaning and is then compressed into a 950°C reformer, to convert hydrocarbons to CO and H_2, followed by a 2-stage shift reactor to improve the H_2/CO ratio. Hydrogen is separated by PSA and the remaining CO is burnt in a combined cycle condensing electricity power-plant.

However, the process is so optimised for hydrogen production that the electricity generated by the waste gas in the CCC is not sufficient to cover all the needs of the plant. If we were to give a debit for provision of grid electricity, GHG emissions and fossil energy use appear on the bottom line. This gives an unfair impression when comparing with other processes which maybe produce much less fuel but a little more electricity. Effectively these other processes have improved their energy/GHG per MJ fuel by incorporating part of a wood-to-electricity process. To even things up, we make all processes electricity-neutral by giving electricity credits or debits using the nearest equivalent wood-to-electricity process. In the case of W3E, we chose a wood-to-electricity pathway from the literature which uses the same gasifier (BCL). It is shown at the bottom of the table as W3K. The overall result is about the same as the [*Katofsky 1993*] process de-optimized to give a little more electricity and a little less hydrogen.

In doing this, we have not departed from our principle of subtracting a “reference scenario” from a “biofuels” scenario. The nature of the process forces us to produce both hydrogen and bio-electricity in the biofuel scenario: to find the contribution only of the hydrogen production, we should produce the same quantity of bio-electricity in the reference scenario. This is the same as a bio-electricity credit.

W3e Small scale (10MW)

This is a process intended for hydrogen production from local wood resources. It was calculated by LBST, based on the CHOREN DM2 10 MW_{th} externally-heated gasifier [*Schmid 2001*]. The moist wood is pyrolysed (with a simultaneous reforming reaction) using heat from the coke by-product. It can cope with wood with up to 35% moisture, but the process efficiency is calculated for 30% moisture in the wood, when the cold gas efficiency of the gasifier is 76.4% [*Schmid 2001*]. The syngas is compressed into a catalytic shift reactor to increase the hydrogen content up to about 66% at the expense of CO. The hydrogen is separated in a Pressure-Swing-Adsorption (PSA) system. The rest of the syngas is burnt for process power and heat in a micro turbine with 24% electrical efficiency and 51% process heat recovery. The process is very nearly electricity-neutral.

14.2 Synthetic fuels from wood gasification

W3f Synthetic Diesel from Wood

Our “best estimate” is based on the study by [*Tijmensen 2002*]. In the variant we chose, syngas from the BCL gasifier (the same as in the 200 MW_{th} hydrogen process) passes cold gas cleaning, a reformer and shift-reactor as in the hydrogen process. An amine process removes the CO_2, and the rest of the syngas enters a fixed-bed Fischer-Tropsch reactor, which builds alkanes from reacting CO and hydrogen on the surface of the catalyst. The reaction conditions are adjusted to maximize the direct production of liquids (gasoil, kerosene and naphtha), which are condensed from the off-gas. Co-products are unreacted gas, LPG vapour and wax. The wax is hydrocracked to make more diesel and naphtha. In our chosen variant, which maximizes diesel yield, up to 2/3 of the unreacted gas (+LPG) is recycled to pass the FT reactor again. The LPG in the recycle does not react: once the alkyl chain is terminated, it cannot be re-opened by the FT catalyst.

The off-gas that is not recycled in our variant is burnt in a condensing combined cycle for process heat and electricity. This produces an excess of electricity, for which we give a wood credit, using process W3K: electricity from BCL gasifier. This simulates an electricity-neutral process as explained above.

The process yield, efficiency and the product mix depends on the performance of the FT catalyst, which determines the chain growth probability (CGP). [*Tijmensen 2002*] took a range of likely CGP values, because the catalyst performance is difficult to predict. We took their average CGP (0.85) for our best-estimate case.

The composition of the FT liquids condensed after the reactor has to be found from figure 2 of [*Tijmensen 2002*]: about 35% m/m naphtha and 65% m/m middle distillates (= gasoil + kerosene). To this should be added the products of wax cracking. The mass of wax produced is 19% of the FT liquids, and if cracked so as to maximize gasoil, yields 15% of its mass in naphtha and 85% diesel. Bearing in mind also that naphtha has slightly higher LHV than diesel (44.5 vs. 44.0 MJ/kg) the overall product mix turns out to be 68% diesel and 32% naphtha in energy terms.

For our worst-case we took the lowest CGP (0.8) considered by [*Tijmensen 2002*]. Then we calculated the overall product mix is 57% diesel and 43% naphtha in LHV terms. There is a wood credit for electricity as before.

For our best case, no variant in [*Tijmensen 2002*] can match the yield and efficiency (51%) claimed by [*CHOREN 2003*] for a projected biogas-to-liquids process based on the DMT gasifier. The CHOREN process is electrically neutral. They project 100% diesel product. That means all the non-diesel components, which are an inevitable product of the FT reaction, have to be fed back to the gasifier (the FT reactor cannot grow chains which are already terminated). For calculations using W3f we chose a triangular probability distribution drawn between the three cases.

W3g Wood to methanol or DME

DME can be thought of as dehydrated methanol: the only difference between the synthesis processes is in the final catalyst reactor so that the efficiencies are more or less the same.

Our “best-case” process is based on [*Katofsky 1993*], using the BCL indirectly-heated gasifier with wet gas cleaning and reforming of higher hydrocarbons. The rest of the process is similar to methanol synthesis from natural gas. A conventional, fixed bed methanol reactor is used. With all fuel synthesis routes, it might be possible to improve efficiency by using slurry reactors or hot gas cleaning. However, neither has been demonstrated for synthesis from bio-syngas: there are question marks about gas quality [*Tijmensen 2002*]. Furthermore, the use of conventional processes enables us to compare all routes on a fair basis.

Our “worst case” is based on oxygen-blowing the Värnamo autothermal pressurized fluidized bed gasifier, modelled by [*Atrax 1999*]. Although this is a state-of-the art gasifier, it is not as sophisticated and expensive as the BCL gasifier. The process uses the hot gas filtration demonstrated at Värnamo to allow the gas to go hot into the 950°C steam reformer, where some tar is also decomposed. However, after the shift water-gas shift reactor (to boost the H2/CO ratio), it is still necessary to use a scrubbing process to remove impurities (including HCl, H_2S…) before the gas is pure enough for synthesis. In the Altrax process the purification is combined with CO_2 removal by scrubbing with methanol (Rectisol Process). The DME synthesis process (by Haldor Topsoe A/S) is similar to that in the 200 MW plant.

The efficiency is lower than the BCL-gasifier process because of the energy consumption by the oxygen separation plant, and because the H_2/CO ratio in the raw syngas is lower. Again we assume that methanol could be produced at the same efficiency as DME.

14.3 Ethanol from cellulosic biomass (farmed wood, wood waste and straw)

Code	Process	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
W3j	**Woody biomass to ethanol (SSCF)**										kgex/			
	Biomass input		2.9170			1.9170					MJprod.	2.7550	3.0790	Equal
	Credit for wood-to-electricity	W3a		-0.0995	3.125	-0.3108	0.00	-0.0026	-0.0002	-0.13				
	Diesel	Z1		0.0358	1.160	0.0415	3.13	0.0000	0.0000	3.13				
	H_2SO_4	C7			1.113	0.0142	0.69	0.0019	0.0000	0.74	0.0035			
	NH_3	C8			12.324	0.1205	6.31	0.0117	0.0000	6.58	0.0027			
	$(NH_4)_2SO_4$	C7,C8			3.983	0.0107	0.55	0.0011	0.0000	0.58	0.0007			
	Antifoam	see notes			50.000	0.0776	0.43	0.0000	0.0000	0.43	0.0004			
	Corn Steep Liquor	see notes			0.500	0.0068	0.03	0.0000	0.0000	0.03	0.0038			
	CaO	C6			1.384	0.0068	1.45	0.0011	0.0000	1.47	0.0014			
	Primary energy consumption and emissions					***1.8843***	*12.59*	*0.0133*	*-0.0002*	***12.83***	*35%*			
W3k	**Wheat straw to ethanol (Iogen)**													
	Straw		2.3770			1.3770					0.4891			
	Transport of straw	WT2b				0.0093	0.22	0.0000	0.0000	0.22				
	Credit for straw-to-electricity	W3a		-0.0520	3.125	-0.1651	0.00	-0.0014	-0.0001	-0.07				
	H_2SO_4	C7			1.113	0.0167	0.81	0.0023	0.0000	0.87	0.0042			
	NH_3	C8			12.324	0.0456	2.39	0.0044	0.0000	2.49	0.0010			
	$(NH_4)_2SO_4$	C7,C8			3.983	0.0040	0.21	0.0004	0.0000	0.22	0.0003			
	Antifoam	see notes			50.000	0.0292	0.16	0.0000	0.0000	0.16	0.0002			
	Corn Steep Liquor	see notes			0.500	0.0025	0.03	0.0000	0.0000	0.03	0.0014			
	CaO	C6			1.384	0.0079	1.70	0.0013	0.0000	1.73	0.0016			
	Debit for additional fertilisers													
	N				13.6591	0.0000	0.00	0.00	0.09	26.57	0.0000			
	P				4.2959	0.0049	0.31	0.00	0.00	0.32	0.0003			
	K				2.7023	0.0164	0.92	0.00	0.00	0.98	0.0017			
						0.0213	1.23	0.0030	0.0898	27.88				
	Primary energy consumption and emissions					***1.3485***	*6.75*	*0.0101*	*0.0897*	***33.53***	*43%*			

W3j Ethanol from woody biomass; worst/best case

This corresponds to the “base case” of the detailed study by NERL [*Wooley 1999*] on wood-to-ethanol via SSCF (Simultaneous Saccharification and Co-Fermentation). The base case combined the best equipment and processes which were had been demonstrated in 1999. Our “best case” is the ”best of industry” case in [*Wooley 1999*], which incorporates the technical advances which could be foreseen to flow from laboratory developments known in 1999. It was not considered that NREL’s more futuristic projections fitted in the time-frame of this study.

Wood consists principally of hemicellulose, cellulose and lignin. Wood chips are ground, steamed and then hydrolysed in dilute sulphuric acid to release the sugars from the hemicellulose. The product is neutralised and detoxified, and part goes to breed enzyme-producing aerobic bacteria with the aid of additional nutrients (such as corn steep liquor). The bacteria-rich stream then joins the main stream in the main fermentor, where enzymatic breakdown of cellulose (saccharification) occurs simultaneously with fermentation of the different sugars released. After several days, the “beer” is sent for distillation. The slops (including lignin) are dried and burnt to raise steam, along with biogas from the waste water treatment. Surplus steam goes to turbine to make electricity.

The NREL process has an excess of electricity. Like the other wood conversion processes, our process is made electricity-neutral by giving a wood credit for the electricity produced. Since this is not a gasifier-based process, we calculated the credit using a conventional wood-fired steam turbine condensing power station, based on LBST data from the plant at Altenstadt, Germany (see wood-to-electricity processes)..

The processes to make the input chemicals are described above (section 1.10: chemicals), with two exceptions, for which we could find no quantitative data: corn steep liquor (CSL) and antifoam. CSL is a by-product from corn syrup manufacture, used as a culture medium for bacteria, and as animal feed. Usually it is neglected in LCA studies. To check if it could be significant, we gave it a (MJ primary energy input)/ (MJ digestible energy) ratio the same as wheat. This confirmed that it could have been neglected. Antifoam is a simple silicone compound. Instead of neglecting it *a priori* we attributed a primary energy per kg typical of a process chemical, which showed it to be of no unimportant in the energy balance.

W3k Ethanol from straw

Data for a 150 MW straw-to-ethanol SSCF plant was supplied to the study by Iogen corp., who operate a commercial plant for straw to ethanol in Iowa [*Iogen 2003*]. A biomass credit is given for electricity export again based on the Altenstadt wood-burning power station (the straw-burning power plant at Sanguesa in Spain has a similar efficiency). Of the chemicals inputs, Iogen only specified sulphuric acid consumption, which is lower than for the wood-to-ethanol process because of a more favourable composition. We assumed that the other chemicals (e.g. for neutralization) mentioned by [*Wooley 1999*] are also needed by the straw process, in proportion to the lower sulphuric acid requirements.

The yield calculation applied to wood gives about the wood-to-ethanol yields claimed in [*Wooley 1999*]. Furthermore, we used the same procedure for the straw-to-SSCF part of process, and came up with energy and emissions figures almost the same as for a commercial state-of-the art straw-to-ethanol process.

The distillation steps and possibly fermentation steps could be combined with the main process: however, for the sake of energy calculation the processes are kept separate. The first paragraph shows that to get 1 MJ ethanol from the combined process we need we need 0.198/(1+0.198) = 0.165 MJ from our new pulp-to SSCF process (without pulp credits), and 0.835 MJ from the conventional sugar-beet process.

14.4 Synthetic fuels and hydrogen from waste wood via Black Liquor

Code	**Process**	Assoc. processes	Bio-feed	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
			MJ bio-en/ MJ prod.	As used MJ/ MJ prod.	MJx/ MJ	Primary MJx/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
BLH	**Wood waste to hydrogen via black liquor**													
	Wood waste		1.2410			0.2410						1.1790	1.3031	Equal
	Primary energy consumption and emissions					***0.2410***	*0.00*	*0.0000*	*0.0000*	***0.00***	*81%*			
BLD	**Wood waste to DME via black liquor**													
	Wood waste		1.4851			0.4851						1.4108	1.5594	Equal
	Primary energy consumption and emissions					***0.4851***	*0.00*	*0.0000*	*0.0000*	***0.00***	*67%*			
BLM	**Wood waste to methanol via black liquor**													
	Wood waste		1.5180			0.5180						1.4421	1.5939	Equal
	Primary energy consumption and emissions					***0.5180***	*0.00*	*0.0000*	*0.0000*	***0.00***	*66%*			
BLS	**Wood waste to syn diesel via black liquor**													
	Wood waste		1.8280			0.8280						1.7366	1.9194	Equal
	Primary energy consumption and emissions					***0.8280***	*0.00*	*0.0000*	*0.0000*	***0.00***	*55%*			

Wood waste to methanol or DME via black liquor gasification

Black liquor is the residue of the pulp making process: a water-based slurry, 70 to 80% of which consists of lignin and spent pulping chemicals. In conventional pulp mills it is burned in a so-called "recovery boiler" to provide process heat; boiler efficiency is limited to about 65% because of the corrosive nature of the molten salts present (mostly Na_2S and Na_2CO_3). With the addition of steam from a “hog boiler” burning bark and other wood waste produced on site, a modern pulp mill is self-sufficient in heat, and can even export some electricity.

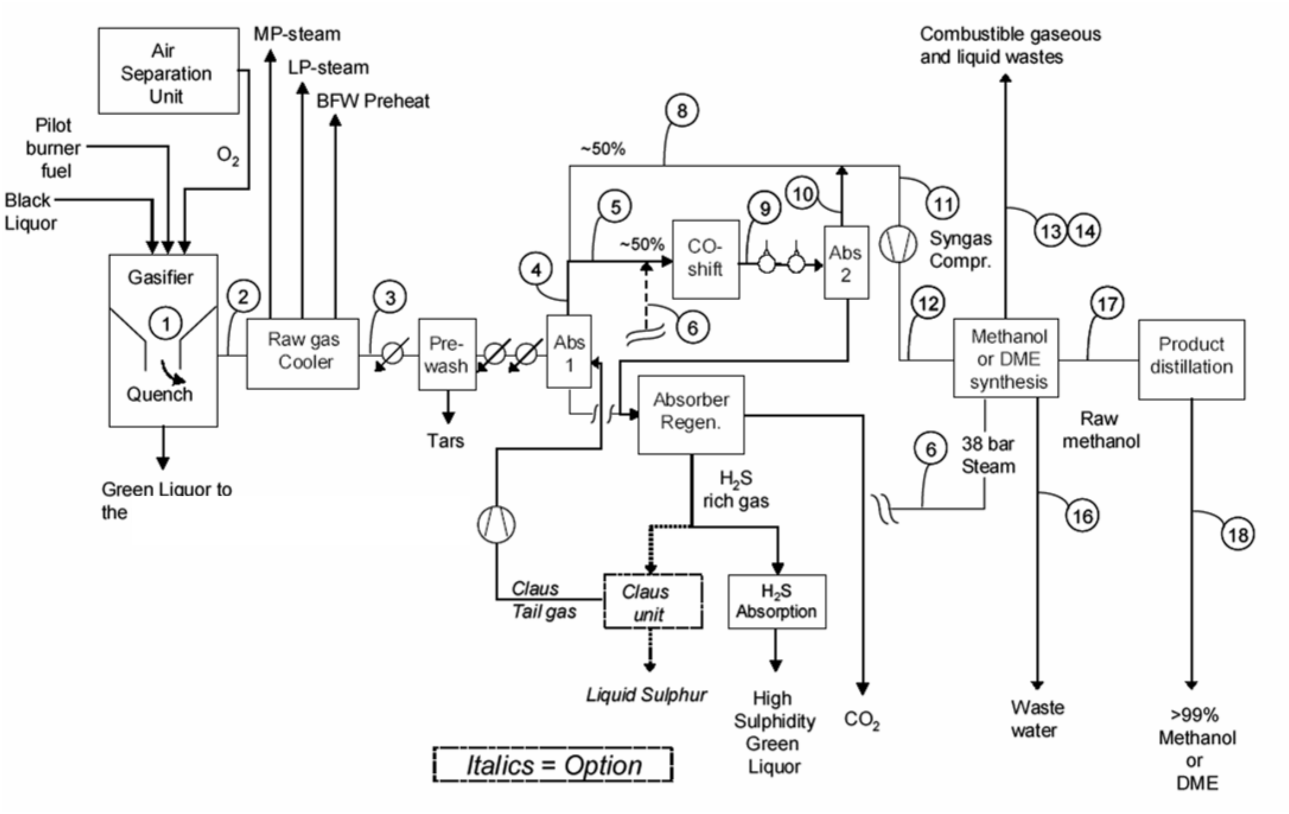
For “black liquor gasification for motor fuels” (BLGMF), one gasifies the black liquor instead of burning it in a recovery boiler. The gasifier is oxygen-blown, so an air separation unit is needed. The syngas produced is then transformed to motor fuel. As part of the energy content of the black liquor ends up in the fuel, additional heat is needed for the pulping process. This is provided by increasing the amount of biomass fed to the hog boiler. The cheapest source of extra biomass is forest residuals (branches, tops, undersize trees and occasionally roots), which can be collected at the time of felling and brought to the pulp mill using the same transport infrastructure as the stem-wood.

Taking the original pulp mill as reference, and adjusting the new process to give the same pulp production and electricity balance, one can calculate the extra wood residuals required to produce a given amount of road-fuel. This effective efficiency turns out to be appreciably higher than that of a stand-alone gasifier conversion processes. The reason is that the additional burning of forest residuals increases the thermal capacity of the plant, whilst the stack losses are reduced because the hog-fuel boiler has higher efficiency than the replaced recovery boiler. Almost all the heat from the syngas is recovered.

Our data are from the thorough technical and commercial feasibility study of methanol and DME production via black liquor gasification carried out for DG-TREN’s ALTENER programme [*Ekbom 2003*]. The study first modelled a modern reference pulp mill (“KAM2” model mill), recycling all wood wastes produced in the mill, but not importing residuals from the forest. This is self-sufficient in heat, and produces a small electricity surplus from a condensing steam turbine generator. Production capacity is 2000 dry tonnes pulp per day. Then [*Ekbom 2003*] model the BLGMF plant also self-sufficient on heat and with the same pulp production and electricity export. The electricity is also produced by a condensing steam turbine, even though higher efficiencies could be obtained from an advanced combined cycle generator incorporating a gas turbine. The difference between the BLGMF model and the KAM2 reference mill showed that 272.8 MW methanol would be produced with an additional biomass consumption of 414.1 MW biomass. Thus 1 MJ methanol requires 1.518 MJ biomass, and the energy conversion efficiency is 65.9%. For the process producing DME, which differs from the methanol process only in the catalyst and conditions in the final synthesis stage, 275 MW DME are produced from 408 MW biomass, so **1 MJ methanol requires 1.485 MJ biomass, a conversion efficiency of 71**%. We added a ±5% error range to these figures.

[*Ekbom 2003*] also provides estimates of the incremental plant investment, assuming that the recovery boiler in the pulp mill was anyway due for replacement. We used their estimates of 150.3 M€ for the methanol plant and 164.2 M€ for the DME plant in our costing calculations.

Fig. 14.4 Schematic process flow diagram of the BLGMF-methanol plant, reproduced with permission from [Ekbom 2003]



Wood waste to FT via black liquor gasification

We made a calculation of this efficiency by replacing the methanol synthesis in [*Ekbom 2003*] with the FT process described in [*Shell 1990*]. The process uses stream 11 in ***Figure 14.4***. The FT process consists of an FT synthesis step in which hydrocarbons are grown on catalysts by the reaction of CO and hydrogen. To get a high diesel yield and little unreacted gas, FT synthesis is allowed to continue to produce heavy hydrocarbons, which are then cracked downstream in a hydrogen cracker. Nevertheless, a distribution of hydrocarbons is produced. [*Shell 1990*] does not specify the distribution of <C10, so this had to model it from chain growth statistics, in order to calculate the energy balance. The Shell process yields about 77 % m/m C10-C20 products (diesel+kerosene; usable in diesel engines) and 23% naphtha on either energy or mass basis. Compared to the reference pulp mill, the whole BGLF-FT process produces 194 MW C10-C20 hydrocarbons and 59.1 MW naphtha from 414 MW extra biomass. Thus 1 MJ extra biomass would produce a total of 0.47 MJ of kerosene/diesel mixture together with 0.14 MJ naphtha (<C9).

If one wishes to produce only diesel and kerosene (to compare with the claims for the Choren wood-FT process, for example), the other products must be recycled. We assumed that the naphtha is added to the hog boiler to produce electricity. To keep the electricity generation the same as the reference pulp plant, we should remove the same MJ of biomass. Therefore only 0.86 MJ biomass are needed to make 0.47 MJ kerosene/diesel by itself. Thus the **efficiency to kerosene/diesel is 55% and 1.83 MJ biomass are needed to make 1 MJ kerosene/diesel.**

Before this report was finalized, [*Ekbom 2005*] produced their own, more detailed, calculation of FT-diesel efficiency using BLGMF process, incorporating product fractionation. It is difficult to compare our model with theirs, because they calculated product mixtures from fractionation rather than simply assigning carbon numbers. Their results indicate that each 1MJ extra biomass would produce 0.43 MJ diesel-quality distillate together with 0.22 MJ naphtha. If we perform the same credit for recycling the naphtha as for our calculation above, we deduce that an extra 0.78 MJ biomass in the pulp mill would give 0.43 MJ diesel-quality distillate. That corresponds to an efficiency to diesel fuel of 55%: exactly the same as in our own calculation. Such close agreement is fortuitous, but we are happy to have independent confirmation.

The consortium estimated that the incremental cost of installing a BLGMF-FT plant in a pulp mill which needs a new recovery boiler would be about 260 M€ ±20%. Subsequently, [*Ekbom 2005*] estimated the figure to be 205 M€. Considering that this is the cost of the new plant minus 171 M€, representing the saved cost of a new recovery boiler, the difference between the two estimates of the cost of a BLGMF-FT plant is only 13%.

Wood waste to hydrogen via black liquor gasification

Neither [*Ekbom 2003*] nor [*Ekbom 2005*] considered this process. We took their detailed description of the BLGMF plant, and considered what modifications would be needed to make hydrogen instead of methanol. The methanol synthesis and distillation are not needed, but a larger CO shift reactor is required, coupled to a pressure swing absorption (PSA) to purify the hydrogen.

The hydrogen process starts from stream 4 in ***Figure 14.4***. All this goes to the CO-shift instead of only half for the methanol plant. Therefore more steam is required for the CO shift reactor, but on the other hand the outlet of the CO shift contains more steam, because more is formed in the reaction. The net amount of steam compared with the methanol plant depends on whether the shift reaction is exothermic or endothermic. If we calculate this starting from steam, it is slightly exothermic, but if we include the energy for generating the steam from water, it is slightly endothermic. In practice, one could find a source of steam, but a little less heat would be recovered. Thus the difference in steam requirements is approximately zero.

The CO_2 absorption (Abs 2) is not required because CO_2 is anyway removed downstream in the PSA. The pressure at the outlet of the CO shift reactor (2.9 MPa; [*Ekbom 2003*]) is sufficient to drive the PSA process. Hydrogen recovery is assumed to be 86%; the tail-gases can be burnt for steam and electricity.

Compared to the reference pulp mill, the BGLF-hydrogen process produces 247 MW H_2 and 108.3 MW in the other gases. Thus 1MJ extra biomass would produce 0.594 MJ hydrogen and leave 0.261 MJ in the tail-gas. If the tail gas is added to the boiler of the existing condensing steam-turbine generator, it will save the same energy input of biomass. Therefore only 0.839 MJ biomass are needed to 0.594 MJ hydrogen by itself. Thus the **efficiency to hydrogen is 81% and 1.24 MJ biomass are needed to make 1 MJ hydrogen.**

In [*Katofsky 1993*], the cost of a hydrogen plant based on the BCL wood gasifier is 27 M€ less than that of a methanol plant based on the same gasifier. The hydrogen and methanol synthesis processes are similar to the ones described here, and have roughly the same scale. Since the BLGMF-methanol plant costs 150.3 M€ in [*Ekbom 2003*] (taking into account the saving on a new recovery boiler), we expect a BLGMF hydrogen plant would cost **123 M€** on the same basis.

15 Electricity generation

Code	Process	Expended energy	GHG emissions				Eff	Range		Probability distribution
		MJx/ MJe	g CO2/ MJe	g CH4/ MJe	g N2O/ MJe	g CO2eq/ MJe		Min	Max	
As electricity is used as an intermediate rather than final energy source, the figures below are shown in total primary energy (kWhp) to produce one unit of electricity (kWhe)										
GE	**Electricity from NG (CCGT)**	**Same process as GG2**								
KE1	**Electricity from Coal (conv. Boiler)**									
	Energy as hard coal	2.3000	221.45			221.45	43.5%	2.0000	2.5000	Dble tri
KE2	**Electricity from Coal (IGCC)**									
	Energy as hard coal	2.0833	200.58			200.58	48.0%	1.9231	2.2435	Equal
KE2C	**Electricity from Coal (IGCC) +CC&S**									
	Energy as hard coal	2.4390	23.44			23.44	41.0%	2.2680	2.6100	Equal
W3a	**Electricity from wood steam boiler**									
	Energy as wood	3.1250		0.0828	0.0247	9.22	32.0%	2.9700	3.2800	Normal
W3b	**Electricity from 200 MWth wood gasifier**									
	Energy as wood	2.0747		0.0262		1.34	48.2%	2.0000	2.1739	Normal
W3c	**Electricity from 10 MWth wood gasifier**									
	Energy as wood	2.8228		0.0356		1.83	35.4%	2.6817	2.9639	Normal
BLE	**Electricity from waste wood via black liquor**									
	Waste wood	1.1111	0.00	0.0000	0.0000	0.0000				
DE	**Electricity from wind**									
	Energy as wind	1.0000								
NE1	**Nuclear fuel provision**									
	Nuclear	0.1805					84.7%			
	NG	0.0045								
	Crude oil	0.0025								
	Waste	0.0018								
	Hard coal	0.0053								
	Brown coal									
	Hydropower	0.0012								
	Total	0.1977	1.21	0.0029	0.0001	1.29				
NE2	**Electricity from nuclear**									
	Energy as diesel	0.0010	0.07							
	Energy as uranium	3.0303					33.0%			

GE Electricity from NG

This process represents the now standard route for efficient and cost-effective production of electric power from gas i.e. a combined cycle gas turbine complex. The overall efficiency of 55% is typical of modern state-of-the-art plants, the ± 5% range representing the range of existing and foreseeable technologies [*GEMIS 2002*], [*TAB 1999*].

KE1 Electricity from coal (conv. boiler)

This state-of-the-art conventional route is assumed to have a typical efficiency of 43.5%.

KE2 Electricity from coal (IGCC)

The IGCC (integrated gasification and combined cycle) alternative reaches an efficiency of 50% [*TAB 1999*].

For electricity from wood, 4 alternatives are considered, i.e. via a steam boiler plus turbine plant (W3a), wood gasification at either large or small scale (W3b/c) and finally indirectly via gasification of black liquor in a paper mill. All incorporate drying of fuel using heat from the flue gas. Forest residuals chipping is the same process as in the wood-to-hydrogen and synthetic fuels process table above. It includes dry matter losses during storage and ex-forest handling. For farmed wood, chipping is included in the farming process.

W3a Electricity from wood steam boiler

The small conventional plant is based on LBST data for the 11.5 MW fluidized-bed condensing steam-turbine power plant at Altenstadt, Germany. Fluidized bed combustors cope better with the varying quality of fuel from wood chips than conventional grate boilers.

W3b Electricity from 200 MW_{th} wood gasifier

The large gasifier power station is taken from the study by [*Sydcraft 2001*] of an IGCC based on the Värnamo pressurized fluidized bed gasifier, using a state-of-the-art GTX 100 gas turbine with flue gas condensation (140 MW_{th}). This configuration maximizes the electrical efficiency. The lower efficiency limit is for the existing turbine at Värnamo, whilst the upper limit projects a further 2% in gas turbine efficiency by 2010. We selected this power station because the Värnamo gasifier is the only one which has been demonstrated to work with hot gas filtration, which gives a significant improvement in efficiency since the syngas enters hot into the turbine, and will surely become the norm for future IGCC power stations.

W3c Electricity from 10 MW_{th} wood gasifier

Data are from the Oeko-Institut’s EM generic database, which also supplies cost data. We consider 5% uncertainty in the LHV efficiency. Gasifiers give higher electrical efficiency and can cope with varying fuel quality. But the investment cost is higher: not worth it if one can use the waste heat for district heating.

BLE Electricity from waste wood via black liquor

Instead of using the output of the gasifier in a BLGMF plant for motor-fuel synthesis (section 14.4), one can burn the syngas for electricity cogeneration. Again, the heat balance of the plant is restored by burning additional biomass in the hog boiler. In the same way that [*Ekbom 2003*] analysed fuel-producing BLGMF [*Berglin 1999*] analysed different options for electricity production by replacing the black liquor recovery boiler with an oxygen-blown gasifier. The efficiency of electricity production is found by dividing the increased electricity production by the increased biomass consumption, compared to the reference mill. A little confusingly, [*Berglin 1999*] adopts a modern integrated pulp/paper mill as the reference mill, instead of the modern pulp-only-mill in [*Ekbom 2003*]. However, the changes are all in the pulp section, this should not affect the results (Berglin does this to demonstrate that the extra electricity produced could be sufficient to make the whole paper mill self-sufficient on energy, instead of consuming electricity, as at present).

The syngas is cleaned, and burnt in a combined cycle of back-pressure steam turbine, condensing steam turbine and gas turbine. Berglin discusses many different options, including three ways to remove the H_2S from the syngas. We chose the variant (“case 6”, table 7 in [*Berglin 1999*]) which produces the highest electricity export, though not at the highest incremental efficiency. It removes H_2S from the syngas by reabsorbing it in the white liquor. That means it uses more lime, but the lime is regenerated in a closed cycle as part of the system, so the energy implications are fully taken into account. The gas turbine assumed in this variant has an input temperature of 1430ºC, with a pressure ratio 20, and the maximum steam temperature is 530ºC. The gasifier operates at 37 bar.

The plant produces electricity from biomass (bark or forest residuals) at an incremental efficiency of 90%, because it benefits from the reduction in stack losses and increased thermal capacity in the paper mill.

DE Electricity from wind

Contrary to biomass, wind energy is in effect inexhaustible, the limitation being in the equipment used to harness it. The notion of efficiency becomes therefore academic in this case. We have shown it as 100% efficient. The energy associated with operation and maintenance is very small.

NE1 Nuclear fuel provision

The figures used are typical of the European supply of nuclear fuel [*GEMIS 2002*].

NE2 Electricity from nuclear

The figures used here pertain to conventional nuclear reactors turning the nuclear reaction heat into steam feeding turbines. The efficiency figure is the fraction of the heat released by the nuclear reaction and transferred to the steam that is turned into electricity [*GEMIS 2002*].

16 Hydrogen from electrolysis

Code	**Process**	MJex/ MJ					Eff	Min	Max	Probability distribution
YH	**Hydrogen from electrolysis**									
	Energy as electricity	0.5385					65.0%	0.4760	0.6000	Normal

YH Hydrogen from electrolysis

Several sources of data are available, giving figures for both small and large (alkaline) electrolysers with and without auxiliaries:

- Stuart Energy Europe (the former Hydrogen Systems) offers a 60 Nm^3/h, 2.5 MPag electrolyser (IMET technology 1000 series) with an electricity consumption of 4.8 kWh/Nm^3 or 62.5% based on hydrogen LHV. For the cell block alone (cell module without any auxiliaries) the electricity consumption is 4.2 kWh/Nm^3 or 71% efficiency. For a 800 Nm^3/h unit the electricity consumption is 4.3 kWh/Nm^3 including all auxiliaries or 69.8% efficiency [*Stuart Energy 2005*].
- Norsk Hydro indicates an electricity consumption of 4.75 kWh/Nm^3 including all auxiliaries for a 4,000 Nm^3/h electrolysis (63.2% efficiency of 63.2%. For a 60 Nm^3/h unit (HPE 60) the electricity consumption including all auxiliaries is indicated with 4.8 kWh/Nm^3 (thereof auxiliaries: 0.5 kWh/Nm^3) leading to an efficiency of 62.5% based on the LHV of the delivered hydrogen.
- AccaGen SA indicates an electricity cosumption of 4.45 kWh/Nm^3 for its 50 Nm^3/h electrolyzer including all auxiliaries leading to an efficiency of 67.4%. The hydrogen pressure is 30 bar.
- Giovanola indicates an electricity consumption of 4.3 to 4.6 kWh/Nm^3 including all auxiliariesleading to an efficiency of 65.2 to 69.8%.
- The data derived from GHW lead to an average efficiency of 65% including all auxiliaries based on the LHV of the delivered hydrogen. Recent publications of GHW [*GHW 2004*] indicate an efficiency of up to 70% based on the LHV (3 MW$_e$ for 700 Nm^3/h) including all auxiliaries.

Many studies e.g. *[Dreier 1999]* assume a far higher efficiency for the hydrogen generation via electrolysis (up to 77% related to the LHV and up to 91% related to the HHV including all auxiliaries).

The efficiency of an electrolyser does not vary significantly with size. We have therefore represented all electrolysis cases with a single process. The outlet pressure of commercially available pressurized electrolysers ranges between 1.1 and 3 MPa. The electrolyser outlet pressure is assumed to be 3 MPa. Higher pressures may be possible in the future but this is somewhat speculative at this stage. The efficiency of commercially available pressurized alkaline electrolysers ranges between 62 and 70% related to the LHV of the delivered hydrogen (or 4.3 to 4.8 kWh$_e$/Nm^3 of hydrogen) [*GHW 2001*], [*Hydrogen Systems 2000*], [*Vandenborre 2003*].

Membrane electrolysers are still in the development stage. A version is offered by Proton Energy Systems, USA, but their energy efficiency is rather low (5.7 to 6.4 kWh$_e$/Nm^3 of hydrogen) [*Proton Energy 2000*].

17 Hydrogen distribution and dispensing (all sources)

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Transport requirement			Range		Probability distribution
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.	km or Naut. Miles	MJx/ t.km	t.km/ MJ prod.	Min	Max	
CH1a	**Gasous Hyd distribution (pipeline from central plant)**												
	No distribution energy (high pressure at plant outlet, 50 km)												
CH1b	**Gasous Hyd distribution (trucking from central plant)**												
	Distance, road (ex piped gas)	Z2, Z1						50		0.0171			
	Primary energy consumption and emissions		*0.0185*	*1.40*			*1.40*						
CH2	**Liquid Hyd compression/vaporisation**												
	Energy as electricity (EU-mix, LV)		0.0196										
	Primary energy consumption and emissions		*0.0556*	*2.34*	*0.0057*	*0.0001*	*2.34*						
CH3	**Gasous Hyd dispensing**												
CH3a	Compression energy, 1.5-8.8 MPa		0.0769								0.0705	0.0842	Normal
CH3b	Compression energy, 2.0-8.8 MPa		0.0704								0.0645	0.0771	Normal
CH3c	Compression energy, 3.0-8.8 MPa		0.0617								0.0566	0.0676	Normal
	Hyd losses		0.0200										
	Primary energy consumption and emissions (EU-mix, LV)												
CH3a		*Z7b*	*0.2406*	*9.29*	*0.0227*	*0.0004*	*9.93*				*0.2222*	*0.2615*	
CH3b		*Z7b*	*0.2220*	*8.50*	*0.0207*	*0.0004*	*9.09*				*0.2050*	*0.2412*	
CH3c		*Z7b*	*0.1970*	*7.45*	*0.0182*	*0.0003*	*7.97*				*0.1824*	*0.2139*	
LH1	**Hyd liquefaction**												
	Energy as Electricity (on-site generation)	GG2	0.3000								0.2100	0.3900	Normal
	Primary energy consumption and emissions		*0.5455*	*30.03*	*0.0023*	*0.0014*	*30.51*						
LH2	**Liquid Hyd long-distance transport**												
	Distance (nautical miles)					g/t.km		5500			5000	6000	
						0.1460				0.0848	0.0771	0.0925	
	Ship's fuel (hydrogen) including return voyage		0.2304			0.0093	2.7653		2.2075		0.2051	0.2567	
LH3	**Liquid Hyd distribution and dispensing**												
LH3a	Distance, road (ex piped gas)	Z2, Z1						300		0.0196			
LH3b	Distance, road (ex remote gas)	Z2, Z1						500		0.0327			
	Transport Hyd losses		0.0050										
	Filling station, Electricity (EU-mix, LV)	Z7b	0.0010										
LH3a	*Primary energy consumption and emissions*		*0.0292*	*1.73*	*0.0003*	*0.0000*	*1.74*						
LH3b	*Primary energy consumption and emissions*		*0.0434*	*2.80*	*0.0003*	*0.0000*	*2.81*						

CH1a/b Gaseous hydrogen distribution

Hydrogen is available from the various producing plants at pressures generally above 3 MPa. This is considered sufficient for distribution through a local pipeline network over a distance of maximum 50 km, without additional compression energy. The resulting pressure at the refuelling station is taken at typically 2 MPa. Gaseous hydrogen can also be transported by road in high pressure cylinders (about 20 MPa, 0.45 t of hydrogen for 26 t of steel and composite material [*Worthington 2000*]). The compression energy for this is accounted for process CH2. The energy included here is for the operation of the truck.

CH2 Liquid hydrogen vaporisation/compression

Hydrogen delivered in liquid form to the refuelling station may have to be vaporised and compressed if the vehicles require compressed hydrogen. This process is less energy-intensive than compression of gaseous hydrogen, essentially as the liquid can be pumped to the required pressure before vaporisation [*BOC 1997*], [*Linde 2001*].

CH3 Gaseous hydrogen compression

Gaseous is available at the refuelling station at a pressure of between 1.5 for a small scale on-site electrolyser and 3.0 MPa for on-site production via electrolysis. 2 MPa corresponds to piped hydrogen (see above). In the case of road transport of high pressure cylinders, the pressure is of course higher at the refuelling station but the total energy cost of compression remains essentially the same.

LH1 Hydrogen liquefaction

Liquefaction is a highly energy intensive process. Energy requirement figures vary within a wide range. One reason for this is that many of the existing liquefaction plants were not built with the objective of maximum energy efficiency as they are mostly relatively small and making hydrogen as a premium product for the chemical industry. Figures in the region of 0.35-0.40 MJ_e/MJ are not uncommon but experts agree that much lower figures down nearly 0.2 can be achieved [*LBST 2001*], [*Quack 2001/1* [*Quack 2001/2*] have therefore taken a wide range with a square probability distribution. Note that this process refers to process GG2 i.e. electricity produced with a natural gas CCGT.

In wood-based pathways electricity is assumed to be made on site also with wood. In such cases, although the energy requirement for liquefaction remains the same, the energy and GHG balances are different (more total energy and less GHG).

LH2 Liquid hydrogen long-distance transport

This process pertains to a scenario where hydrogen would be produced and liquefied at a remote location to be shipped to markets in specially built liquid hydrogen carriers. Such a so-called SWATH carrier has been proposed [*Würsig 1996*] and we have used the figures as quoted. The SWATH carrier would burn exclusively hydrogen.

LH3 Liquid hydrogen distribution

This is envisaged exclusively by road. The average distance to cover varies with the scenario. Large reformers fed with LNG would have to be located near the coastal terminal, with potential higher distribution distances (500 km) than other central plants fed with more “local” material such as piped NG, wood or electricity (300 km). The liquid hydrogen road tanker is assumed to transport 3.5 t of hydrogen in a 24 t tank [*Linde 1998*]

18 Synthetic fuels distribution and dispensing (all sources)

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Transport requirement			Range		Probability distribution
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.	km or Naut. Miles	MJx/ t.km	t.km/ MJ prod.	Min	Max	
DS1	**Syn diesel handling and loading (remote)**												
	Energy as Electricity (on-site generation)	GG2	0.0008										
	Primary energy consumption and emissions		*0.0015*	*0.08*	*0.0000*	*0.0000*	*0.09*						
DS2	**Syn diesel sea transport**												
	Distance (nautical miles)							5500			5000	6000	
	Energy requirement as HFO for product carrier									0.2315	0.2105	0.2525	Square
	Primary energy consumption and emissions	*0.00*	*0.0312*	*2.50*			*2.50*				*0.0284*	*0.0341*	
DS3	**Syn diesel depot**												
	Electricity (EU-mix, LV)	Z7b	0.0008										
	Primary energy consumption and emissions		*0.0024*	*0.36*	*0.0009*	*0.0000*	*0.38*						
DS4	**Syn diesel distribution (blending component**	CD2/3/4	See conventional diesel processes										
DS5	**Syn diesel distribution (neat)**												
	Distance, Rail	Z5, Z7a						250		0.0057			
	Distance, road	Z2, Z1						250		0.0061			
	Primary energy consumption and emissions												
DS5a	*Rail+Road*		*0.0100*	*0.6413*	*0.0003*	*0.0000*	*0.65*						
DS5b	*Road only*		*0.0066*	*0.4995*	*0.0004*	*0.0000*	*0.51*						

DS1 Synthetic diesel loading and handling (remote)

This represents the energy required to store, handle and load the synthetic diesel near its (remote) production site. The assumed electricity consumption is that of a standard conventional diesel depot (see process CD3). This process (and the next one), are only relevant to GTL plants inasmuch as diesel from biomass is unlikely to be transported across large distances. The source of electricity is here deemed to be the gas-fired power plant part of the GTL complex (process GG2).

DS2 Synthetic diesel sea transport

Synthetic diesel can be transported in essentially standard product carriers (see process Z4). The distance considered here is typical of a trip from the Arab gulf to North West Europe (via Suez). The energy figure includes an allowance for the return trip.

DS3 Synthetic diesel depot

This is the same process as CD3. This energy is deemed to be spent at a receiving terminal.

DS4 Synthetic diesel distribution (blending component)

Synthetic diesel is a valuable blending component for modern diesel and the limited quantities available are most likely to be used as such. In this case the product will enter the refinery system near the point of production. The applicable processes are thus the same as for conventional diesel (CD2/3/4).

DS5a/b Synthetic diesel distribution (neat)

The use of neat synthetic diesel in niche applications cannot be ruled out. Transport of neat synthetic diesel within Europe can be envisaged either by road, rail or a combination of both. The limited volumes involved would make pipeline transportation inappropriate. We have considered two scenarios depending on the synthetic diesel source. Material imported from remote plants would have to be transported from a small number of ports for which we consider an average distance of 500 km (split 50/50 between rail and road). Material manufactured within Europe would be more “distributed” and we have considered a distance of 250 km (road) as appropriate. The transport mode parameters are in accordance with processes Z5 and Z2.

Code	**Process**	Assoc. processes	Expended energy	GHG emissions				Transport requirement			Range		Probability distribution
			MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.	km or Naut. Miles	MJx/ t.km	t.km/ MJ prod.	Min	Max	
ME1	**Methanol handling and loading (remote)**												
	Energy as Electricity (on-site generation)	GG2	0.0018										
	NG consumption and emissions		0.0033	0.18	0.0000	0.0000	0.19						
ME2	**Methanol sea transport (average of two distances)**												
	Distance (nautical miles)							5000		0.465	0.465		
	Primary energy consumption and emissions	*Z3, Z4*	*0.0627*	*5.03*			*5.03*						Normal
	Distance (nautical miles)							6000		0.558		0.558	
	Primary energy consumption and emissions	Z3, Z4	*0.0753*	*6.04*			*6.04*						
ME3	**Methanol depot**												
	Electricity (EU-mix, LV)	Z7b	0.0018										
	Primary energy consumption and emissions		*0.0052*	*0.79*	*0.0019*	*0.0000*	*0.85*						
ME4	**Methanol distribution and dispensing**												
	Distance, Rail	Z5, Z7a						250		0.0126			
	Distance, road	Z2, Z1						250		0.0135			
	Filling station, Electricity (EU-mix, LV)	Z7b	0.0034										
	Primary energy consumption and emissions												
ME4a	*Rail+Road*		*0.0319*	*1.83*	*0.0018*	*0.0000*	*1.88*						
ME4b	*Road only*		*0.0244*	*1.52*	*0.0010*	*0.0000*	*1.55*						
DE1	**DME handling and loading (remote)**												
	Energy as Electricity (on-site generation)	GG2	0.0013										
	NG consumption and emissions		0.0024	0.13	0.0000	0.0000	0.13						
DE2	**DME sea transport**												
	Distance (nautical miles)			gCO2/tkm				5500		0.358	0.326	0.391	Normal
	Energy to DME carrier (as HFO)	Z3		13.11					0.163				
	Primary energy consumption and emissions		*0.06343*	*5.09*			*5.09*						
DE3	**DME depot**												
	Electricity (EU-mix, LV)	Z7b	0.0013										
	Primary energy consumption and emissions		*0.0037*	*0.56*	*0.0014*	*0.0000*	*0.59*						
DE4a	**DME distribution and dispensing**												
	Distance, Rail	Z5, Z7a						250		0.0088			
	Distance, road	Z2, Z1						250		0.0123			
	Filling station, Electricity (EU-mix, LV)	Z7b	0.0034										
	Primary energy consumption and emissions												
DE4a	*Rail+Road*		*0.0284*	*1.64*	*0.0015*	*0.0000*	*1.68*						
DE4b	*Road only*		*0.0231*	*1.42*	*0.0010*	*0.0000*	*1.45*						

ME1 Methanol handling and loading (remote)

This process relates to the small amount of energy (electricity) required to handle methanol from a remote NG-based plant to the loading terminal, including loading onto a ship. The figures have been inferred from those listed for gasoline (process CG3). The electricity is assumed to come from the on-site gas-fired power plant.

ME2 Methanol sea transport

Methanol can be transported in essentially standard product carriers (see process Z3). The distance considered here is typical of a trip from the Arab gulf to North West Europe (via Suez). The energy figure includes an allowance for the return trip.

ME3 Methanol depot

A small amount of energy is added to account for this intermediate handling step between unloading from the ship and further transport to customers.

ME4a/b Methanol distribution and dispensing

Transport of methanol within Europe can be envisaged either by road, rail or a combination of both. Pipeline transportation is not considered likely inasmuch as a dedicated pipeline system would be difficult to justify in all credible scenarios. Transporting methanol in the existing oil products pipelines is not a practical option for a number of reasons including, interface management, water contamination and corrosion issues. We have considered two scenarios depending on the methanol source. Methanol imported from remote plants would have to be transported from a small number of ports for which we consider an average distance of 500 km (split 50/50 between rail and road). Methanol manufactured within Europe would be more “distributed” and we have considered a distance of 250 km (road) as appropriate. The road tanker is assumed to transport 26 t of methanol in a 2 t tank. The transport mode parameters are in accordance with processes Z5 and Z2. The filling station energy requirement is inferred from the gasoline figure (see process CG4).

DE1-4 DME distribution and dispensing

These processes are similar to those for methanol with figures adapted to DME which is transported in compressed liquid form. DME is deemed to be carried on a ship similar to an LPG carrier [*Kawasaki 2000*]. The road tanker is assumed to transport 2 t of DME in a 20 t tank.

19 Bio-fuels distribution

Code		Assoc processes	one-way distance km	t.km/ MJ prod.	MJ/ MJ prod.	MJx/ MJ	MJx/ MJ prod.	g CO_2/ MJ prod.	g CH_4/ MJ prod.	g N_2O/ MJ prod.	g CO_2eq/ MJ prod.	Loss MJ/MJ
ETd	**Ethanol distribution (blended)**											
	Road tanker to gasoline depot	Z1,Z2	150	0.022	0.0056	1.1600	0.0065	0.49			0.49	
	Gasoline depot (elect. EU-mix, LV)	CG3, Z7b			0.0024	2.8687	0.0069	0.29	0.0007	0.0000	0.31	
	Road tanker to filling station	Z1,Z2	150	0.022	0.0056	1.1600	0.0065	0.49			*0.49*	
	Filling station	CG4, Z7b			0.0034	2.8687	0.0098	0.41	0.0010	0.0000	*0.44*	
	Primary energy consumption and emissions						***0.0298***	*1.69*	*0.0017*	*0.0000*	***1.74***	
FAd	**Bio-diesel distribution (blended)**											
	FAME road tanker to diesel depot	Z1,Z2	150	0.004	0.0041	1.1600	0.0047	0.36	0.0000	0.0000	0.36	
	Diesel depot (elec. EU-mix, LV)	CD3, Z7b			0.0024	2.8687	0.0069	0.29	0.0007	0.0000	0.31	
	Road tanker to filling station	Z1,Z2			0.0041	1.1600	0.0047	0.36	0.0000	0.0000	0.36	
	Filling station	CD4, Z7b			0.0034	2.8687	0.0098	0.41	0.0010	0.0000	0.44	
	Primary energy consumption and emissions						***0.026***	*1.41*	*0.0017*	*0.0000*	***1.46***	
MEd	**Biomethanol distribution direct from plant**											
	Methanol road tanker	Z1,Z2	150	0.008	0.0076	1.16	0.009	0.67	0.0000	0	0.67	
	Filling station, Electricity (EU-mix, LV)	Z7b			0.0034	2.87	0.010	0.41	0.0010	0.0000	0.44	
	Primary energy consumption and emissions						***0.019***	*1.08*	*0.0010*	*0.0000*	***1.10***	
DEd	**Bio-DME distribution direct from plant**											
	DME road tanker	Z1,Z2	150	0.007	0.0069	1.16	0.008	0.61	0.0000	0	0.61	
	Filling station, Electricity (EU-mix, LV)	Z7b			0.0034	2.87	0.010	0.41	0.0010	0.0000	0.44	
	Primary energy consumption and emissions						***0.018***	*1.02*	*0.0010*	*0.0000*	***1.04***	
SDd	**Bio-(synthetic diesel) distribution (blended)**											
	Road tanker to diesel depot	Z1,Z2	150	0.004	0.0034	1.16	0.004	0.30	0.0000	0	0.30	
	Diesel depot (elec. EU-mix, LV)	CD3, Z7b			0.0008	2.87	0.002	0.10	0.0002	0.0000	0.11	
	Road tanker to filling station	Z1,Z2	150	0.004	0.0034	1.16	0.004	0.30	0.0000	0.0000	0.30	
	Filling station	CD4, Z7b			0.0034	2.87	0.010	0.41	0.0010	0.0000	0.44	
	Primary energy consumption and emissions						***0.020***	*1.11*	*0.0012*	*0.0000*	***1.15***	
CHd	**Bio-(compressed H2 gas) distribution**											
	Distribution and dispensing	CH1a,CH3b			0.0704	2.87	**0.202**	8.50	0.0207	0.00	**9.09**	*0.020*
LHd	**Bio-(liquid hydrogen) distribution**											
	LH2 / Liquefaction / CONCAWE / p (in) = 30 bar	LH1			0.3000	2.87	0.861	36.24	0.0884	0.0016	38.75	
	Liquid hydrogen road tanker		150	0.010			0.011	0.80	0.0000	0	0.80	*0.005*
	Liquid hydrogen filling station				0.0010	2.87	0.003	0.12	0.0003	0.0000	0.13	
	Sum primary energy and emissions						***0.874***	*37.16*	*0.0887*	*0.0016*	***39.68***	

The energy for biofuel distribution is not very important to the overall pathway. Ethanol and FAME, and synthetic diesel are blended with fossil fuels, so they are transported to the appropriate depot, and then distributed like fossil fuel. Bio-methanol, DME and hydrogen are identical to the fossil products and could be distributed directly to local filling stations. Compressed hydrogen is distributed to filling stations by pipeline.

20 References

References such as “[*Source: xxx*]" denote personal communications between CONCAWE/LBST and experts from member companies, not supported by a published document.

The complete reference list is given in the main body of the *WTT report*.