



Well-to-wheels Analysis of Future Automotive Fuels and Power trains in the European Context

Report Version 3c, July 2011

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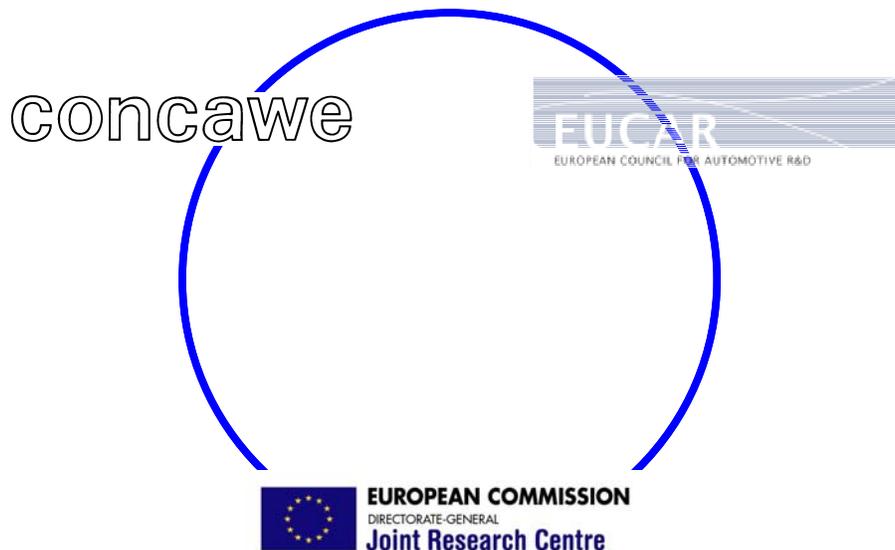
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WELL-TO-WHEELS ANALYSIS OF FUTURE AUTOMOTIVE FUELS AND POWERTRAINS IN THE EUROPEAN CONTEXT



WELL-to-TANK Report

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Notes on version number:

This is the third version of this report replacing version 2c published in March 2007.

Although the scope of the study has not been fundamentally altered, a number of additional pathways have been added, mostly in the area of biofuels. The cost data have been updated. The section on availability or potential volumes of biofuels has not been updated, as it is felt that this has now developed into a much wider debate involving many more stakeholders than are involved in our study. As such, a review will need to be performed outside this study.

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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.

We have not included emissions or changes in albedo caused by indirect land use change, or from marginal intensification due to extra biofuels demand, even though we think these are probably important. These points are discussed in section 3.4.1.

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. There used to be a widespread misconception that feedstocks for biofuels used in EU would be sourced from EU production until some limit of availability is reached, after which it would be imported. In version 2 of this report we endeavoured to assess the future “EU availability” of the different fuels and associated feedstocks, but we pointed out that this limit would never be reached in practice as imports would start to increase as soon as prices started to respond to the increased demand from biofuels. This now seems well understood, so the theoretical availability is rather irrelevant, and we have not updated our calculations in this version. The effect of crop demand for biofuels on EU food imports and generally on world agricultural markets has now become the object of many studies by agro-economic modellers, and has been covered in a broad way elsewhere [JRC 2008]. However, our analysis in WTT version 2 contained interesting data and discussion, so we have retained the original text as a reference.

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 **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 LBST¹ through whom we have had access to the comprehensive information database compiled by the TES consortium² 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. Over the course of this study, the original database has been extensively reviewed and updated and a number of new processes and pathways added that had not hitherto been considered.

Help update our database

Our database is continually updated as we receive and evaluate new information. Readers are invited to send suggestions for improvements in our INPUT DATA to

infoJEC@jrc.ec.europa.eu

(note: since the results of life-cycle analysis studies are greatly affected by the methodology used, we cannot comment on why the results of other studies may differ from ours).

Relation with data used by European Commission Renewable Energy Directive

Our input database has been used by the European Commission as the basis for calculations of typical and “default” greenhouse gas savings for biofuels compared to fossil fuels in the 2008 Renewable Energy Directive and its fore-runner the draft Biofuels Directive. Note that those Commission calculations use an entirely different methodology from the one in this report, and therefore give different results.

Since our database is continually updated, the data used by the Commission changed during the process of the legislation. Many figures in the database were updated or improved during contacts with stakeholders in the early part of 2008 in a consultation exercise initiated by DG-TREN. These changes were already incorporated in the version of the database used in the final draft of the RE directive (Nov-Dec 2008). However, other improvements were introduced into our database too late to be taken into account in the Directive text, but are included in this report. They concern the heat requirement for transesterification to biodiesel and the basis for the soy-based biodiesel pathway.

A subset of our database, containing only the data relevant to the calculation of default values for the Renewable Energies Directive is available at

http://re.jrc.ec.europa.eu/biof/html/documents_main.htm

Furthermore, after fixing the WTT data in this report for the purpose of integrating it with TTW data and writing the WTW and WTT reports, more suggestions continued to arrive (affecting, amongst others, soy and palm pathways), which we have not yet been able to evaluate.

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 LBST³ 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.

³ E³ database by L-B-Systemtechnik, Germany

Table 2.1 Fuels and resources

Fuel		Gasoline, Diesel, Naphtha (2010 quality)	CNG	LPG	Hydrogen (comp., liquid)	Synthetic diesel (Fischer-Tropsch)	DME	Ethanol	MT/ETBE	FAME/FAEE	HVO	Methanol	Electricity
Resource													
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	X		
	Sunflower									X	X		
	Soy beans									X	X		
	Palm fruit									X	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 CCS

⁽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 about a decade ahead: 2015-2020. The technologies considered are those that have the potential 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 and Appendix 3*.

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.

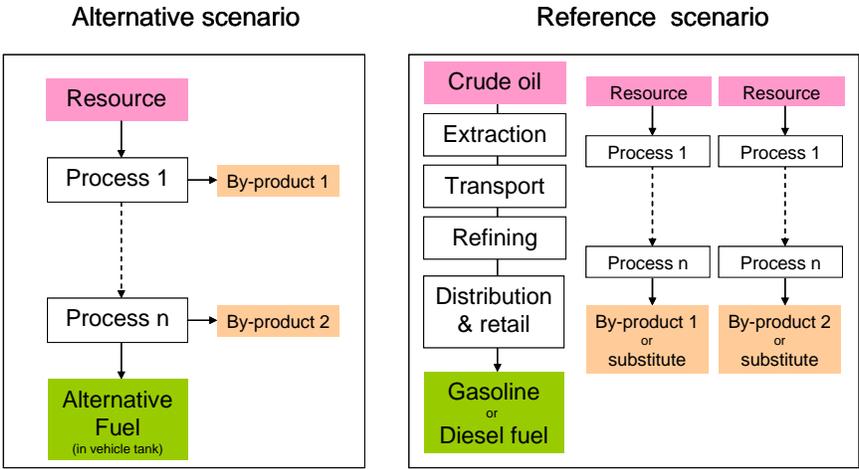
This logic is reflected in the following methodology (*Figure 2.4*):

- 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 oil seeds pressing is likely to be used as animal fodder displacing soy meal that would otherwise be imported into the EU.
--

For the purpose of analysing policy, we strongly favour this "substitution" method which attempts to model reality by tracking the likely fate of by-products. This approach (otherwise known as “extension of system boundaries” is increasingly used by scientists, and is the method of choice in the ISO standards for life-cycle analysis studies. Some 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**



Our substitution methodology attempts to estimate the energy and emissions in *the whole economy* which result from a particular fuel pathway, including the use of by-products. This may not meet the needs of legislation, where the emissions may need to be assigned between economic sectors (transport, electricity, heat, chemicals). This is because policy-makers have made separate emissions-savings targets for different sectors. Furthermore, as for instance in the case of substitution-credits for electricity exports, use of the substitution method in legislation can give rise to a “perverse incentive” to produce more by-product and less biofuel. A practical way to avoid these effects in legislation is to use some sort of allocation, even though this is not scientifically rigorous. For example, the European Commission proposes to allocate emissions to products and material by-products according to their energy-content.

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) produces 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. The way the credit for electricity export is calculated is explained for individual pathways in Appendix 2.

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 marginal 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 predominantly locally-produced feedstock (e.g. wood, straw) 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. 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 CO₂ 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.

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 CO₂ equivalence is applied to the non-CO₂ greenhouse gases according to the 100 year conversion coefficients recommended by the fourth assessment report of the Inter-governmental Panel for Climate Change [IPCC 2007a]. These figures vary slightly from the earlier IPCC recommended figures used in version 2 of this study.

Table 2.8.1 IPCC factors

Greenhouse gas	t CO ₂ eq / t
CO ₂	1
Methane (CH ₄)	25
Nitrous oxide (N ₂ O)	298

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

2.8.2 Energy content

All energy contents used are on LHV basis i.e. excluding the heat generated after the combustion process by the condensation of water vapour arising from the hydrogen-content of the material. For materials containing water (crops, animal feed, wood, manure etc), we consider the LHV of the *dry-matter content* of the material. Some other studies have subtracted from this LHV also the heat needed to evaporate the water content. In the case of wet material, like animal slurry the heat content then apparently becomes negative, and one cannot apply the principle of conservation of heat in a process (for example, wood apparently gains energy from no-where as it dries out during storage).

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 reproduces some of the calculations carried out in LBST’s E3 database. As a new addition in this version 3 we have provided a set of workbooks as *WTT Appendix 4* giving a step-by-step listing of the input data for each pathway.
- 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. As discussed above the availability part of this section has not been updated.

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. 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 ($1 MJ_f$), 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 2.8.1*) emitted in the process of obtaining 1 MJ 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 shown in *WTT Appendix 5* of this version 3. 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

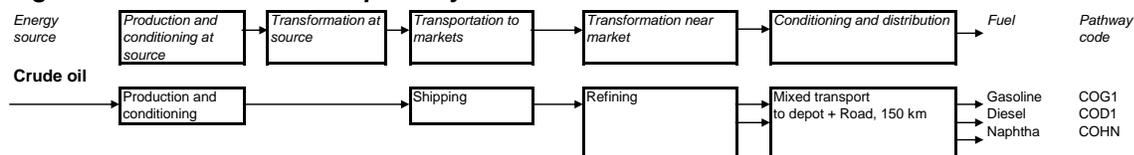
In this chapter we describe the pathways processes necessary to convert a certain primary resource into a final fuel. The stepwise description of the pathways together with the detailed input data and further detailed comments and remarks on individual processes are given in *WTT Appendix 1 & 4*.

3.1 Crude oil pathways

(See also *WTT Appendix 1 section 4* and *Appendix 4 section 1*)

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 in many cases either conditioned and shipped separately (e.g. LPG) or re-injected into the reservoirs. Significant flaring still occurs in certain producing regions notably Central Africa and, to a lesser extent, the FSU.

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 i.e. those relevant to the EU market. In the light of more recent data we have, in this version 3, revised upwards the energy and GHG figures relevant to crude oil production.

GHG emissions from crude oil production originate from two main sources:

- The energy required to extract and pretreat the oil,
- Flaring and venting (F&V) of associated hydrocarbons.

Although both sources were taken into account in the original JEC data, GHG reporting was not well developed at the time and hard data was not widely available. Since then, oil companies have developed GHG reporting protocols and standards that allows much more accurate and documented estimations of emissions.

There are few publicly available sources of comprehensive data on energy and GHG emissions associated with crude oil production. The International Association of Oil & gas Producers (OGP) has collected such data from its members for a number of years. **Table 3.3.3-1** shows the data collected for 2005 [*OGP 2005*] (reports are also available for 2006, 2007 and 2008 but do not report flaring and venting separately. Overall energy and emissions are at a similar level).

Table 3.3.1-1 Energy and GHG emissions from crude oil production [OGP 2005]

		Total	Africa	Asia	Europe	FSU	ME	NA	SA
OGP production	Mt/a	2103	390	298	515	51	235	366	248
Total production	Mt/a	6382	614	706	538	1262	1471	1318	473
Coverage	%	33%	64%	42%	96%	4%	16%	28%	52%
Energy									
Total	PJ/a	2688	325	441	476	59	142	820	425
Specific energy	MJ/MJ	0.030	0.020	0.035	0.022	0.027	0.014	0.053	0.041
Emissions									
CO2	Mt/a	283.2	106.8	39.8	33.5	7.1	27.5	41.5	27
	t/kt	134.7	273.8	133.6	65.0	139.2	117.0	113.4	108.9
CH4	kt/a	2361	674	566	122	49	139	389	422
	t/kt	1.12	1.73	1.90	0.24	0.96	0.59	1.06	1.70
CO2eq	Mt/a	342.2	123.7	53.9	36.6	8.3	31.0	51.2	37.5
	t/kt	162.7	317.1	181.0	71.0	163.2	131.8	140.0	151.4
% due to venting		21%	16%	36%	9%	17%	13%	23%	39%
% of C in crude		5.2%							
Specific emissions	g/MJ	3.87	7.55	4.31	1.69	3.89	3.14	3.33	3.60
Figures prorated to total production									
CO2 eq	Mt/a	1016.5	194.7	127.8	38.2	205.9	193.8	184.5	71.6
	t/kt	494	499	429	74	4038	825	504	289
Specific energy	MJ/MJ	0.030							
% of C in crude		5.1%	10.1%	5.7%	2.3%	5.2%	4.2%	4.4%	4.8%
Specific emissions	g/MJ	3.79							

The OGP coverage is very good for Europe, fair for Africa and South America but rather patchy for other regions, particularly the FSU (an important EU supplier). It must also be emphasized that grouping many producing provinces into such large regions is an oversimplification as there may be very large differences between producers in a single region.

In *Table 3.3.1-2* we applied the regional data from *Table 3.3.1-1* to the combination of crudes used in Europe in 2005 (as reported by the International Energy Agency, IEA).

Table 3.3.1-2 Estimate of Emissions from crudes used in the EU in 2005

		Total	Africa	Asia	Europe	FSU	ME	NA	SA
IEA consumption data (2005)									
Specific energy	MJ/MJ	0.022							
Specific emissions	g CO _{2eq} /MJ	3.9							

EU figures are lower than the overall for energy and higher for GHG emissions because of the comparatively large consumption of low energy / high emissions African crudes. The average figures for both energy and GHG emissions are well within the range used in earlier versions of this study but are somewhat lower than the median for energy and higher for GHG emissions.

The OGP report indicates that about 50% of the GHG emissions that have been attributed are related to F&V. However, 35% of the reported emissions have not been specified. If one assumes that these are not related to F&V, this would reduce the proportion of F&V emissions to about 33% of the total. In other words the OGP data point out to emissions of 2.0 to 2.6 g CO₂/MJ crude for production operations and 1.3 to 2 g CO₂/MJ crude for F&V.

Another source of comprehensive and up-to-date F&V emissions information has been collected by the National Oceanic and Atmospheric Administration [NOAA 2010] on the basis of satellite observations. *Table 3.3.1-3* has been constructed with the 2008 NOAA data combined with EU consumption figures for the same year from the International Energy Agency.

Table 3.3.1-3 Flaring and venting emissions per country and average for EU supply [NOAA 2010]

2008	EU-27+2 consumption Mt/a	Specific emissions from F&V					
		Oil only			Total Oil & Gas		
		CO ₂ /toe	Mt CO ₂ /a	g/MJ	CO ₂ /toe	Mt CO ₂ /a	g/MJ
Total	632.6		84.7	3.2		53.8	2.0
<i>Country of origin</i>							
Russia	161.5	23.9%	38.6		11.3%	18.3	
Norway	100.2	0.9%	0.9		0.5%	0.5	
Libya	60.0	12.7%	7.6		10.9%	6.5	
UK	53.0	4.9%	2.6		2.6%	1.4	
Saudi_Arabia	38.9	2.0%	0.8		1.7%	0.7	
Iran	30.4	14.3%	4.3		9.5%	2.9	
Nigeria	23.0	42.0%	9.7		32.2%	7.4	
Kazakhstan	22.8	20.9%	4.8		15.2%	3.5	
Iraq	18.9	16.9%	3.2		16.9%	3.2	
Azerbaijan	18.0	2.7%	0.5		2.1%	0.4	
Angola	14.9	9.7%	1.4		9.7%	1.4	
Algeria	14.8	18.6%	2.8		9.8%	1.4	
Denmark	13.5	3.1%	0.4		1.9%	0.3	
Other EU	12.5	2.6%	0.3		1.4%	0.2	
Venezuela	8.9	5.6%	0.5		4.7%	0.4	
Mexico	8.8	4.8%	0.4		3.6%	0.3	
Syria	7.0	13.0%	0.9		10.4%	0.7	
Kuwait	6.0	3.8%	0.2		3.5%	0.2	
Egypt	4.3	12.5%	0.5		4.9%	0.2	
Brazil	3.5	3.5%	0.1		3.1%	0.1	
Others	11.9	35.0%	4.1		31.9%	3.8	

Satellite observations provide a total figure for F&V but do not discriminate between oil and gas production. In some countries the latter is very large and it is reasonable to expect that a significant proportion of F&V is associated with gas production. To our knowledge there is no widely recognised method for apportioning emissions between all hydrocarbons produced. In the right hand columns, the table gives an indication of this contribution where we have assumed that F&V emissions are distributed in proportion of the energy content of all hydrocarbons produced. This reduces the specific F&V emissions from 3.2 to 2 g/MJ of hydrocarbon produced. It must be noted though, that this method of apportioning emissions is somewhat arbitrary. In any case there is considerable uncertainty attached to these figure. Indeed assigning a single F&V figure to a particular country is an oversimplification (particularly for large producers such as Russia) where real figures are likely to vary between producing provinces, fields and even individual wells.

In any case the figure is somewhat higher than suggested by the OGP data. This is plausible inasmuch as OGP members are primarily International Oil Companies which are believed to have a better performance on F&V reduction than National Oil Companies.

On this basis we have adopted a figure of 2.5 g/MJ with an uncertainty range of ±50%.

The resulting combined figures for crude production are

Energy: 0.058 (.044/0.072) MJ/MJ crude
 GHG emissions: 4.8 (3.5/6.2) g CO_{2eq}/MJ crude

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. World conventional oil reserves at 1 Jan 2008 were estimated at 1158 billion barrels [EIA1]⁴, with Saudi Arabia, the largest national resource, having about 23% of the world total. Conventional oil sources are expected to meet all of Europe's crude oil needs during the period covered by this study.

Substantial deposits of heavier oils also exist, notably in Canada and Venezuela. Canada's reserves of oil sands are very large (175 billion barrels), equivalent to 15% of world conventional oil reserves, and are already being exploited, almost exclusively for the US and Canadian markets. Venezuela, in addition to large conventional oil reserves (87 billion bbl) also has very large deposits of heavy oils, estimated at 100-270 billion barrels [EIA2]. These are located at depths where surface mining techniques are not practical, and so far they have not been developed in a major way.

In Canada, oil sands are concentrated in the Athabaska region of northern Alberta and can be exploited in two ways. Firstly, bitumen, which exists in solid or semi-solid state can be extracted in-situ using steam or solvents. Alternatively, the oil-containing sand can be extracted by surface mining, followed by treatment to separate the oil and treat it in a coker or hydrotreater to produce a light synthetic crude. Some of this is further processed locally, but much is distributed by pipeline to refineries in Canada, the USA and further afield.

Oil sand exploitation is contentious because of the effects of large scale mining, and concerns about air and water pollution as well as the large energy inputs and associated GHG emissions needed to produce and process the fuel. Efforts are continuing to reduce the environmental impact. Whether bitumen is separated from sand in-situ or the oil-sands are mined and processed together, the combined process of extraction and processing is more energy intensive than for conventional crude oil. Heavier oils tend to contain more carbon as a percentage than conventional fuels, so processing to a similar product slate requires more hydrogen. In Canada, most of the energy input is in the form of natural gas. Electricity may either be imported or produced on-site, and may include co-generation producing an excess of electricity for export.

A review of available studies shows a wide range of variation in the energy use and GHG emissions associated with different projects for non-conventional oil production. These range up to 24 gCO₂eq/MJ, equivalent to about 0.36 MJ/MJ, compared with our figures for conventional crude production of 4.5 gCO₂eq/MJ and 0.03 MJ/MJ⁵. A recent review of current Canadian operations [Trucost 2008] suggests lower figures, but [MIT 2008] projects that the energy needs for future projects will be even higher. Our best-estimate is for an emission of 20 gCO₂eq/MJ of syncrude and energy usage of 0.3 MJ/MJ: substantially higher than of any existing process.

These figures include a small refining credit for syncrude, because less refining energy is required to convert syncrude to gasoline and diesel than is the case for a conventional crude oil. GHG emissions depend on the energy source used to power the production process. In Canada, the source is mainly NG, which is abundant locally.

Figures for Venezuelan unconventional oil reserves are expected to be broadly similar, but will depend on the details of the extraction and processing processes. Where the oils are more fluid, extraction will be easier and heating may not be needed in all cases, which would reduce energy needs. Venezuela has extensive natural gas reserves, so the GHG figures should also be similar to those for Canada. Large

⁴ Total reserves of 1332 billion barrels, including 174 billion barrels of Canadian oil sands

⁵ The ratio between energy use and GHG emissions depends on the source of the energy used

amounts of oil also exist in shale rock formations, and US reserves alone could be as much as the world conventional oil resources. However, recovery of the oil is energy intensive and so far these resources have been less widely exploited.

The very large reserves mean that non-conventional oil may become more important in the future. Current Canadian production of non-conventional oil is 1.2 Mbbbl/d, and is expected to increase to around 4.0 Mbbbl/d by 2020. Current Venezuelan production is around 0.6 Mbbbl/d, and expected to double by 2020 [MIT 2008]. Most of this oil is used within the Americas, and we expect little of it to reach Europe in the period to 2020. Middle Eastern crude will remain the marginal oil supply for Europe over this period, so we have retained the same figures for crude oil production as in version 2 of this study.

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. Pipelines to the Black and Mediterranean seas already serve the developing region of the Caspian basin and several projects are being studied. 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% (0.01 MJ/MJ) has been used, corresponding to 0.8 g CO₂eq/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 1980'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 (mostly gasoils and jet fuel), 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 6-7% 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 overall importers of energy/fuels other than crude oil, the bulk of the energy used by refineries comes from their crude oil intake. 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 rules that can have a major influence on the results. Although allocation methods are often used for lack of better tools, such a simplistic approach ignores the complex interactions, constraints and synergies within a refinery and also between the different refineries in a certain region and is likely to lead to misguided 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.

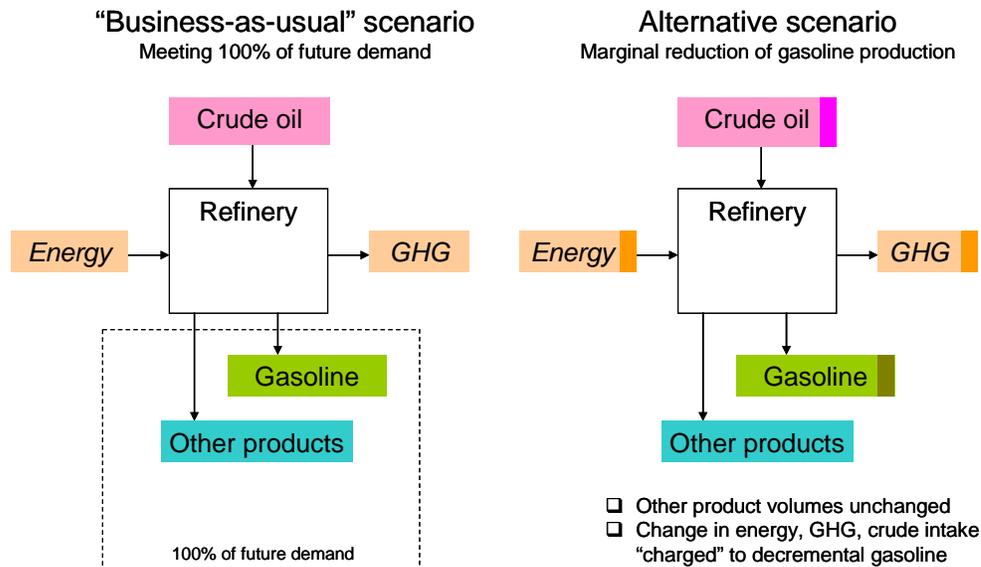
In order to estimate the savings from conventional fuels the question to consider was what could be saved by using less of these rather than how much they cost in absolute terms. We thus considered that, in the context of this study, the energy and GHG emissions associated with production and use of 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.

Note that this methodology is entirely consistent with the substitution methodology used for accounting for by-products in other pathways. Both arise from the over-arching principle of a marginal calculation which estimates the difference in emissions between a reference scenario and one with a changed output of the fuel in question. In the case of the oil refinery calculation, the production of by-products is kept constant. Then no substitutions need to be made for by-products, because they cancel out when we take the difference between the two scenarios. The only changes are the diesel (or gasoline) output, and the inputs of crude oil, gas and electricity. This marginal approach to crude oil refining is unique to our study and gives more reliable estimates than the allocation techniques used in other studies.

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 most forecasts, this trend will continue for some time, 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



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 ₂ eq/MJ	7.0	8.6	4.4

Calculations for the refining step were carried out on the basis of a 2010 base case including all foreseen fuel specifications including sulphur-free road fuels, but excluding any effects of biofuel blending. Although the additional quality requirements result in a higher absolute level of energy consumption in the refineries in 2010 compared to earlier fuel specifications, the effect on the marginal values are of a second order of magnitude. Further changes to the EU refining environment are expected beyond 2010 related to quality changes of non-road fuels (mostly marine fuels) and changes in the global EU demand with a further increase in the imbalance between diesel and gasoline. In spite of anticipated improvements in energy efficiency, this is expected to lead to an increase in the specific CO₂ emissions per tonne of crude processed, leading to some increase in the footprint of marginal road fuels. Although the change in the refining number is likely to be significant, it represents a small percentage of the total WTW footprint of a fossil fuel. Inasmuch as the figures produced in previous versions have been extensively used by others, including the EU Commission, we have at this stage not changed them.

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 CO₂eq 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 sections 5 to 7 and Appendix 4 section 2)

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 CO₂ emissions. As Europe's indigenous NG production declines, a greater proportion of this demand is coming from imports, mainly through pipeline from Russia, but increasingly via LNG.

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 origin of the gas used in Europe in 2002. 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 CO₂.

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 CO₂ content is high. In a limited number of cases, the separated CO₂ is re-injected into the wells and this may become more common in the future. Unless this is the case, this CO₂ ends up in the atmosphere either at the processing plant or at the end consumer. The CO₂ 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 CO₂ in a simple way in all pathways concerned, we have included a 1% v/v CO₂ venting at the production stage. The EU-mix used for the Tank-to-Wheels part of the study includes a small CO₂ content (see *WTT Appendix 1, section 2.2*). This has been included to reflect the correct gas parameters but no additional CO₂ emissions accrue from it.

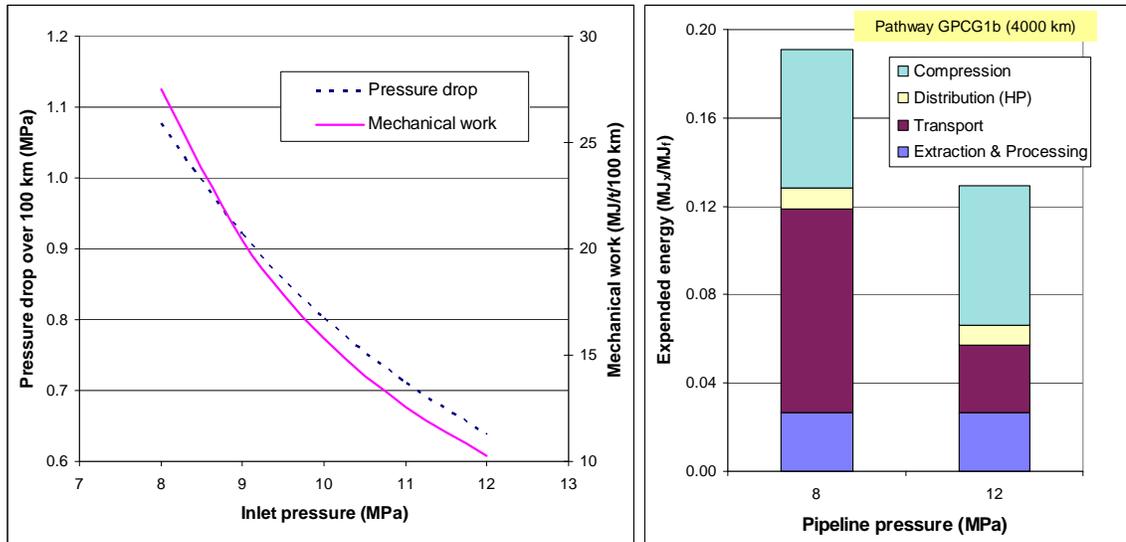
The energy associated with extraction and processing varies considerably with the producing region. This reflects different gas qualities, practices and climatic conditions. For extraction, most of the energy is supplied directly in the form of natural gas (typically through an on-site power plant). 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 CO₂ 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 the bulk of the future marginal gas supply.

As mentioned in *sections 3.2.1 and 3.2.3*, 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 CO₂ capture and storage (CCS, 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. 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 CO₂ 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 CO₂, making it an attractive proposition for CCS (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. The first commercial plant was the Shell Middle Distillate Synthesis (SMDS) plant in Malaysia, and two much larger plants are now being constructed in the Middle East. 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. In the previous version of this study, the assumed FT plant was 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 could 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. To reflect these developments, the mean efficiency figure for future plants in this study has been revised to 65%, with a range of 63-67%.

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 us 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 3.1.3* and through which the energy and CO₂ 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, their 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 could 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 because of a structural shortage of middle distillates in the European refining industry due to dieselisation of the light duty market and growth of freight transport. 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 CO₂ is produced and separated from the syngas upstream of the Fischer-Tropsch synthesis. This provides an opportunity for CCS (see also *section 3.6*).

DME

Di-methyl ether or DME is a potentially attractive fuel for diesel vehicles. It is volatile and must be kept under moderate pressure (similar to LPG) so would require specially adapted vehicles. 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 CO₂ is produced and separated from the syngas upstream of the synthesis step. This provides an opportunity for CCS (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

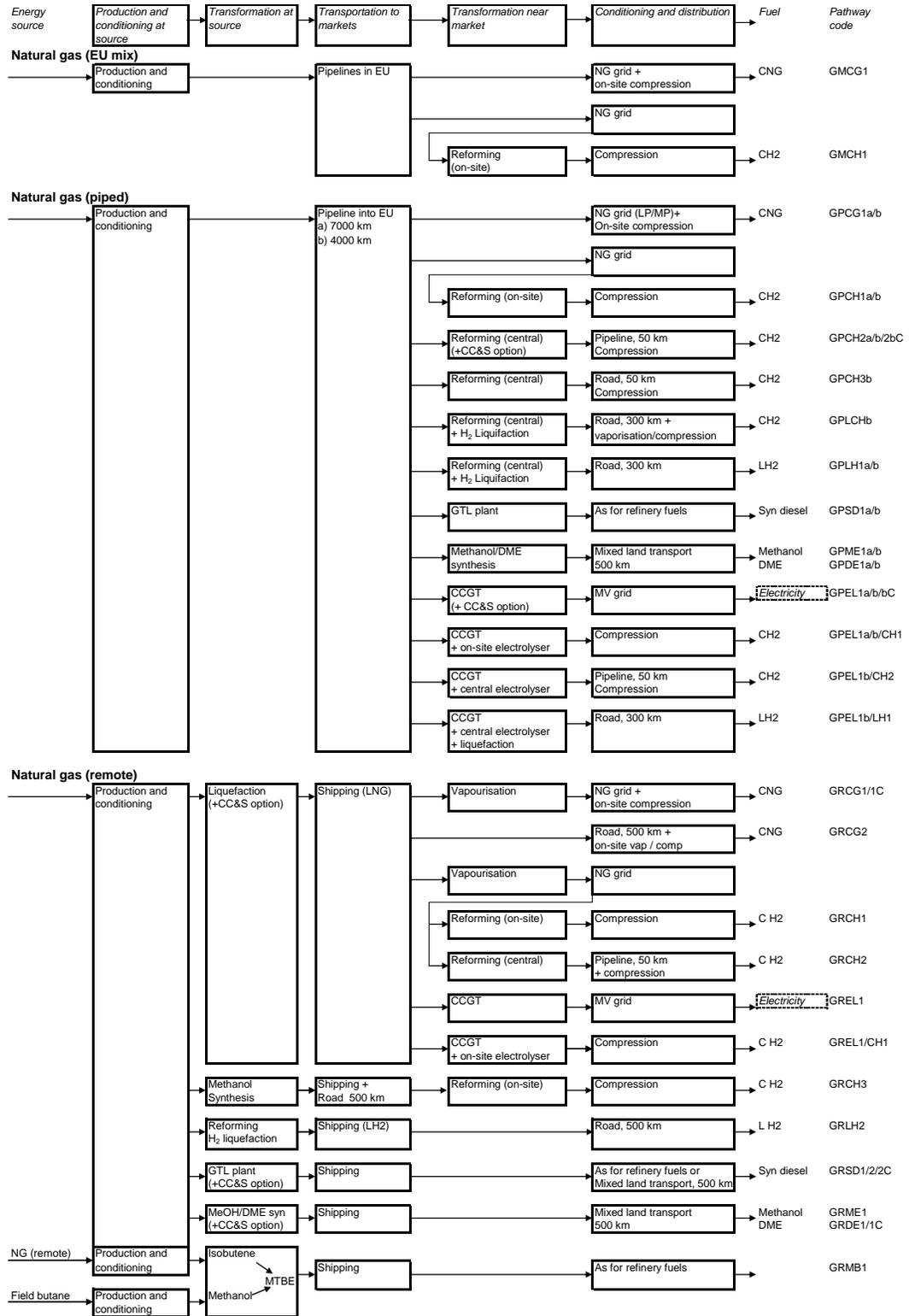
Methyl-Tertiary-Butyl Ether or MTBE is a high octane blending component for gasoline. Because of its ability to reduce emissions by bringing oxygen into the fuel, MTBE was widely used in US gasoline until water contamination issues led to a partial ban. In Europe MTBE was introduced as one of the measures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



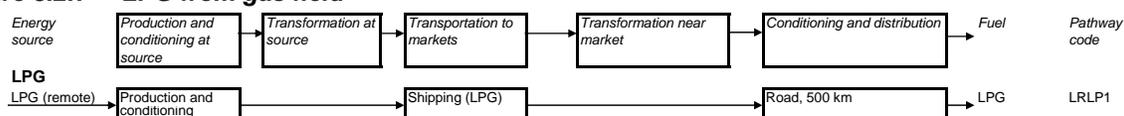
3.2.7 LPG

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 a by-product 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 8 and Appendix 4 section 1)

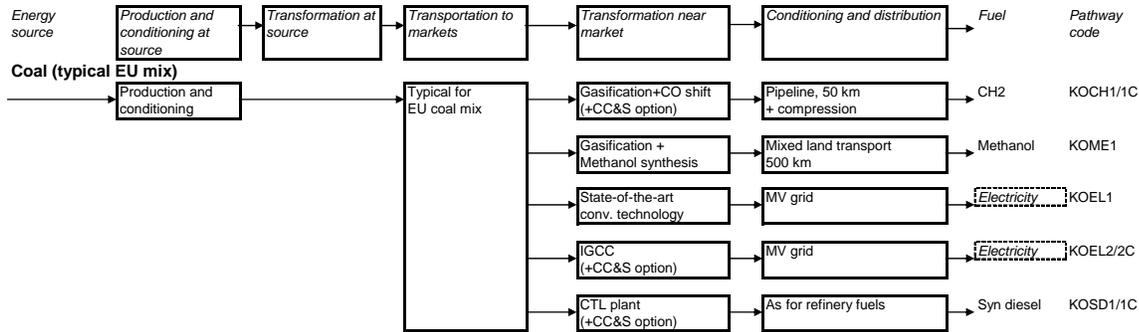
Although not fashionable in today's carbon-conscious world, coal still plays an important role in the world and even in Europe's energy supply, essentially for power generation. After a steady decline over many years, EU consumption has stabilized around 300 Mtoe since the beginning of the decade. It is, however, growing in most other parts of the world, particularly in China. 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 or by a Fischer-Tropsch plant to produce liquid hydrocarbons (Coal-To-Liquids or CTL). CO₂ 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 CCS for the hydrogen, synthetic diesel and IGCC pathways to illustrate the potential of this technology (see section 3.6).

Note: There is no 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 9 to 14 and Appendix 4 section 3)

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. New to this version are pathways for biodiesel from soy and palm oil, and from hydrogenation of plant oils. The range of pathways has also been extended to include further alternative uses of by-products, and we have shown more results for heat and/or power generation from biomass.

3.4.1 Land use change and marginal emissions

Emissions from land use change may be important, but are NOT INCLUDED in our WTW GHG balances

If crops for biofuels come from land which was not previously planted with row-crops (e.g. grazing land, pasture or forest) there will be a “direct land use change”, which may cause significant releases of carbon from the soil (see below). The “cross-compliance” requirements of the EU Common Agricultural Policy, largely prevent the conversion of grassland land for food crops in EU⁶, but one can suppose that if crop prices increase because of extra demand from biofuels, this will decrease the amount of land otherwise in voluntary (“nature”) set-aside.

If, on the other hand, the crop used for biofuel comes from arable land which would otherwise be used for food production, the displacement of food production is likely to cause “indirect land use change” (ILUC) somewhere else (often outside EU). The nature and magnitude of ILUC is currently a matter of debate and scientific investigation. There is a concern that it may in turn cause significant emissions of carbon as organic matter is lost from soil and cleared vegetation.

These land-use change emissions are NOT included in the results of this study. **This does not mean that we think they are not important.** It is because they are still very uncertain, and this consortium is not in the best position to evaluate them, since complex economic modelling is required. Understanding of these broader aspects is growing, but such is the level of uncertainty that they are not easy to include in a quantified way into this study.

⁶ However, there is a recent trend in Germany for intensive *non-food* crops (principally fodder-maize) to be planted on grassland in order to supply feedstock for biogas plants supplying the electricity and gas grids.

The only sources of biofuels which do not cause ILUC are:

- wastes which would otherwise not be used,
- Land which would otherwise be uncropped because of annual (compulsory) set-aside regulations as is the case in the EU (although taking an extra crop may result in a moderate reduction in soil carbon which in principle should be taken into account),

So one can think of our results for EU crops as applying roughly to biofuels from set-aside land⁷.

In 2005, when we produced version 2 of this study, a large part of the prevailing 5.75% EU biofuels target could have been met from crops on set-aside. Production of oilseeds and wheat for biofuels on compulsory set-aside land could produce 2-3% of EU road-fuels. As farmers can already grow crops for biofuels on rotational set-aside, most of the potential is already exploited, and set-aside cannot be expected to supply more than a fraction of the extra crops needed to meet the 10% renewable energy target by 2020 proposed with the Renewable Energy Directive.

Marginal emissions due to yield intensification are also not considered

If crops are diverted from food to energy use, this will cause relatively higher crop prices, and this can be expected to cause some extra intensification of farming. The incremental production from this intensification will be associated with incremental emissions from the farming (extra use of fertilizer, pesticides, diesel, more expensive seeds etc). The ratio of extra emissions to extra production is likely to be higher than the ratio of existing emissions to existing production (because of diminishing returns from further intensification). However, we have not attempted to evaluate how much larger the marginal extra emissions are, since they are presently uncertain and the subject of on-going research.

Another effect which is probably important but we cannot yet estimate with acceptable precision is the effect of intensification, or indeed any change in crop or management, on soil carbon stocks. Generally, intensification is thought to reduce soil carbon stocks, whilst low-tillage and organic farming can reverse the historical decline in EU soil carbon, but generally at the expense of lower yields. The soil chemistry model used by JRC to model N₂O emissions (*section 3.4.2*) also provides output on annual changes in soil carbon, which are of comparable magnitude to the N₂O emissions in terms of CO₂-equivalent emissions per year. However, the model is not optimized for those calculations, and one needs very good data on the use of the crop residues. This is why we have not reported the results.

GHG payback times for land use changes in EU

This discussion is retained from version 2 of this study: it introduced the concept of "GHG payback time".

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 CO₂ 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 CO₂ ($\pm > 50\%$) 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*].

⁷ However, even here, a correction should in principle be made for the long-term loss in soil carbon resulting from taking another harvest instead of a break-year. The DNDC soils-chemistry results used by JRC for their nitrous oxide emission calculations (see section below) indicated that even one extra harvest (instead of a year under a cover crop) could result in a significant reduction in soil carbon, but for a correct calculation it would be necessary to simulate soil carbon variations over the whole rotation.

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 $0.4 \times 50 = 20$ tonnes of C per hectare. This loss is equivalent to $20 \times 44/12 = 73$ 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 EU 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 grassland 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 JRC 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 CO₂ emission equivalent to 42 tonnes/ha. 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 of soil carbon loss for grazing-land to SRF as between zero and that for changing to arable.

3.4.2 Nitrous oxide emissions

The ability of biofuels to reduce fossil energy use and GHG emissions rests on the absorption of solar energy and carbon dioxide from the atmosphere by growing plants. These benefits are offset to some extent by the use of fossil energy in producing and processing the crop. Although not a major factor in energy terms in the whole pathway, farming is the primary source of GHG emissions associated with biofuels. CO₂ emissions associated with farm equipment use and manufacture of fertilizers and chemicals are not the only GHG emissions to be considered. Significant quantities of another greenhouse gas, nitrous oxide (N₂O), are produced from nitrogen fertilizer production and emissions of N₂O from the field.

Although N₂O emissions are not very large in absolute terms, the very high greenhouse effect of this gas (about 300 times as much as CO₂ 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 N₂O emissions from one field to another, depending on soil characteristics, climate, tillage, fertilizer rates and crop (in approximate descending order of importance). In Europe emissions generally show much greater local variation than in America, due to the heterogeneity of soils. 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 “tier 1” estimates under the IPCC guidelines. These are designed to estimate national greenhouse gas emission inventories, not emissions for particular crops or fields. The revised tier 1 method guidelines in [IPCC 2006] assume N₂O emissions from managed fields are a constant fraction of the nitrogen applied (as synthetic fertilizer, manure, crop residues or from nitrogen-fixing crops). The fraction is called an “emission factor”. Separate emission factors are used for “direct” emissions from the soil and for “indirect” emissions from nitrogen leached off the field.

To account for other variables, IPCC specifies a wide error range: the max/min ratio varies from 10 (for direct emissions) to 50 (for indirect emissions from leached nitrogen).

Life-cycle analysis studies often use the default (best-estimate) IPCC emission factors to calculate nitrous oxide emissions, but ignore the range IPCC attaches to them. This is probably because the uncertainty in the overall GHG balance would then become so great that it would be impossible to say whether any biofuel from agriculture saves GHG or not.

But even this IPCC range is by far not sufficient to cover the range of values which have been measured on individual fields. For example, emissions thirty times the *maximum* value of direct emissions from IPCC guidelines have been measured from crops on drained peat soils. The tier 1 guidelines [IPCC 2006] now include a range of emissions from organic soils; but this does not vary according to whether (or how) a crop is grown on those fields, so they are of no use to us.

This study uses a more sophisticated calculation of EU-average nitrous oxide emissions for each crop, exploiting the database-calculation-model of the soils-and-waste unit of the Institute for Environment and Sustainability at JRC-Ispra which was developed to estimate agricultural GHG emissions for monitoring compliance with the Kyoto commitment. This is built on well-validated soils chemistry model, DNDC (version 82N) [UNH 2003], which calculates daily direct nitrous oxide emissions from fields, as well as the amount of nitrogen leached off into the groundwater. Already for version 2 of this study, JRC applied the model to points from the LUCAS land-cover survey [Eurostat 2003], which reports land use and crop for measurement points on an 18-km grid covering EU-15, in the year 2000. Thus our calculation produces a “snapshot” of N₂O emissions in EU15 in the year 2000.

Another group at JRC has adopted a different approach: instead of the ground-truthed crop identification in the LUCAS dataset, they start off with the mix of crops within a NUTS3 region, and then model where they would be planted on the basis of satellite land-cover data and soils characteristics. That model has the advantage of covering more of the EU and is being linked to the CAPRI regionalized model of EU agriculture to allow emissions effects of future policy changes to be determined. However, we believe our approach, although less flexible, is at present a more reliable method for attaining the EU average emissions per crop, since it eliminates the layer of uncertainty in assigning crops to areas on the map.

The other main inputs were:

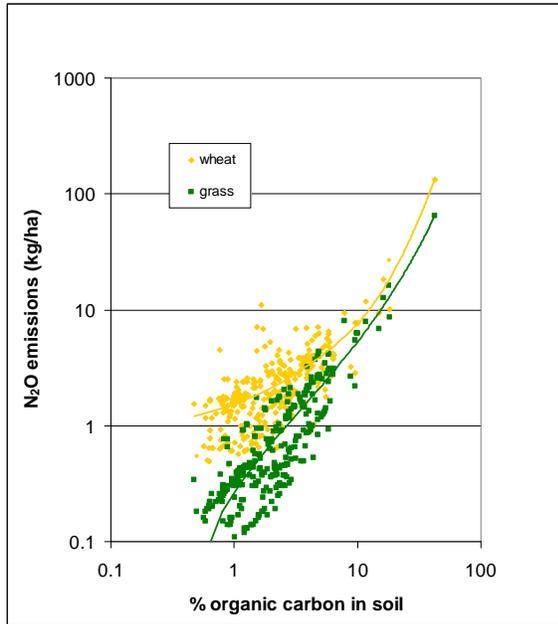
- The soil properties for each measurement point: from the soils database maintained by the European Soils Bureau at JRC-EIS, which attempts 1 km resolution by a disaggregating process based on GIS land-cover data.
- Daily weather for the year 2000, obtained from the 50 km meteo-grid of the MARS project 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] The most important correction is to reduce the nitrogen rate according to the organic carbon content of the soil. Less nitrogen fertilizer is needed on higher-organic soils, but a larger proportion is emitted as N₂O. The DEFRA recommendations only give (per crop) ranges of nitrogen rate for different categories of soil organic content: resulting in a conceptual bar-chart. For the calculation, we drew a continuous function through the bars. This function halves the N rates for each 13% increase in soil organic matter in the top 90cm of soil (DEFRA definition: we had to fit data on soil carbon profiles to convert this to the units of % soil-carbon in the top 30 cm, used by the DNDC program). 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].

Apart from the emissions from the soil, some nitrous oxide emissions arise from nitrate which is leached off the field into groundwater and rivers. These are called “indirect” nitrous oxide emissions (not to be confused with nitrous oxide emissions resulting from food production displaced by biofuels!). The DNDC model estimates the amount of nitrate leached from the soil at each grid-point we considered. From this, we estimated the indirect emissions using the new default IPCC 2006 range of emission-factor (EF₅) in [IPCC 2007] for indirect emissions. IPCC decreased the range attached to this emissions factor since the version 2 of this report was published, with the result that this range no longer dominates the uncertainty range of the total emissions. This means we have had to estimate the uncertainty in our direct emissions calculations more carefully, as explained below.

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 3.4.2-1 shows, for points from the LUCAS survey, the calculated N₂O emissions per hectare when growing wheat or unfertilized grass. The difference between the two represents the incremental N₂O emissions from growing wheat on set-aside (see text box).

Figure 3.4.2-1 Nitrous oxide emissions from 3459 EU fields growing either wheat or grass Year 2000



Background N₂O emissions and “reference land use”

Soils emit some N₂O even if they are not farmed (so-called “background emissions”). These can be quite significant, especially for organic soils. If we are to model the emissions from EU land in annual set-aside used for biofuels, we should subtract the background emissions which would otherwise have occurred. Where annual set-aside land is not already used for non-food crops, it is either left fallow or, increasingly, planted with a cover crop. We could estimate the background emissions by changing the crop specified in the DNDC soil chemistry model. However, DNDC restricts the possibilities to either another arable crop, fallow or grass.

Selecting “fallow” suppresses all vegetative growth; whereas in practice even a fallow field gets a partial covering of weeds, which also act as a cover crop, reducing the loss of nitrogen from the soil by absorbing and storing it until the next ploughing. So we considered that “unfertilized grass” was the best choice offered by DNDC for estimating background emissions. We ignored the small farming inputs for maintaining the field in set-aside.

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 N₂O 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: another reason for preferring grass to represent emissions from the reference scenario.

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 N₂O 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, along with the small emissions from establishing the cover crop, which work the other way.

[LBST 2002] 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 N₂O emissions to be 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.

The most sensitive parameter influencing agricultural N₂O emissions is the soil organic matter content (often indicated by the soil organic carbon (SOC) concentration. 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 (see text box). However, the *extra* N₂O 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.

In Europe, arable crops are unlikely to be grown on peat: the soil is likely to be too waterlogged and acid⁸. In the calculation, however, unlikely apparent combinations of soil type and crop arise because of a difference in the nature of the soils-database and the LUCAS database. The LUCAS dataset gives the actual crop observed on the ground at regular grid-points (in the year 2000). 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. It sometimes happens that a LUCAS measurement point is in an arable field which is not the *typical* land cover in that locality: for example, it could be an "island" of higher ground surrounded by peat-bog. The soils properties for the peat-bog would then falsely be associated with an arable field.

Although rare, these mis-matches have a significant effect on the EU-average results: according to our raw results about 20% of emissions apparently came from just 1% of the fields. The apparent soil carbon content at these locations is very high for an arable field: one suspects a soil-mismatch. Another point to bear in mind is that DNDC is calibrated with measured data: if the results are higher than any measurement, we cannot know if they are correct. We therefore "cap" suspiciously high calculated emissions, before averaging the emissions per crop.

Since the soil C content applies also to the same field under grass (used as a reference), we cap the *difference* in emissions between crop and reference crop (grass). So if the calculated emissions-difference-between-crop-and-grass-reference is above the cap level, we take it to be at the cap (that field is still likely to have a soil C content well above average, so it would be wrong to ignore the point altogether). The derivation of the range of cap levels is explained below:

- The MINIMUM plausible average of emissions-per-crop corresponds to the assumption that the crop is grown only on mineral soils (implying that all fields apparently with organic soils have a soil-mismatch). We approximate this by setting the cap at the average N₂O emissions calculated for soil with 10% soil carbon (to be consistent, we subtract the corresponding average "background" emissions of N₂O from fields with 10% soil carbon under unfertilized grass). This limits the N₂O emissions considered from any field to 2.6 kg/ha/yr N-as-N₂O.
- Our BEST-ESTIMATE of average emissions per crop assumes that the emissions from a field cannot exceed the typical values measured on cultivated peat soils. We use data from [Regina 2004], who measured annual N₂O emissions from cultivated peat soils at various sites in Finland. Because there were relatively few data points, and a significant spread, we average their measurements for all arable crops, and subtract the average emissions they measured on unfertilized pasture at the same sites. The resulting cap is 8 kg/ha/yr N as N₂O.
- The MAXIMUM plausible average-emissions-per-crop assumes that the emissions from any field cannot be higher than the highest measured emissions from cultivated EU fields. Again we subtract

⁸ However, on a global basis such soils are being deforested and converted to arable use, which will lead to high nitrous oxide emissions as well as the large carbon emissions described earlier in this section

the typical “background” emissions from the same sites. Following the results in [Flessa 1998], we set the cap at 50 kg/ha/yr of N as N₂O. One could argue that it is quite possible that some cultivated fields emit more N₂O than any of the few fields which have actually been measured. On the other hand, DNDC is not calibrated for even higher emissions, and including higher calculated emissions would make the EU average dependent on a few uncalibrated calculations.

Although the level of the “cap” is the largest source of error in our estimates of the average direct N₂O emissions, it is not the only one. In consultation with soils experts, we concluded that, even without the problem of capping, we could not claim better than +/-30% accuracy in the EU-average results, due to the approximations of the DNDC model and the experimental data by which it is calibrated. We combined the errors from the two sources, using the square root of the sum of the squares of the individual error ranges (treating the + errors separately from the - errors). This approximates the flank of the probability distribution to a normal distribution, even if the width of the + and - flanks are not quite the same for the direct emissions.

Finally the range of total average nitrous oxide emissions per crop in EU-15 is found by summing the minimum, best-estimate, and maximum average direct EU-15 soil-emissions with the corresponding range of indirect emissions from run-off nitrogen (here we did not use the square-root-of-the-sum of the squares procedure because the errors are not independent: high indirect emissions are more often than not associated with high direct soils emissions).

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). Yields in 2000 were typical for recent years.

We could only apply our N₂O emissions model to EU15 because that is all that is covered by the LUCAS dataset. National N₂O emissions depend mostly on soil carbon content and climate. The 12 new member-states show the same variation in these conditions as EU15: in the Baltic states they are comparable to those in Finland, whilst in Bulgaria they are comparable to Spain. So it is not clear in which direction inclusion of EU12 would affect the EU-average N₂O emissions. We can suppose that it will not change them outside our range of uncertainty.

The results are shown in *Table 3.4.2-1* for the main crops considered in this study.

Table 3.4.2-1 Average N₂O emissions from biofuels crops grown in the EU

AVERAGE N2O EMISSIONS FOR WHEAT (background emissions subtracted)				
Direct Emissions from Soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	0.880	1.187	1.746	kgN as N2O/ha
...combined with other uncertainty	0.717	1.187	1.850	kgN as N2O/ha
...converted to mass of N2O	1.126	1.865	2.907	kg N2O/ha
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	10.46	14.94	19.42	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0052	0.1120	0.4854	kgN/ha
...converted to mass of N2O	0.008	0.176	0.763	kg N2O/ha
TOTAL direct+indirect N2O	1.134	2.041	3.670	kg N2O/ha
EU15 2000 yield EUROSTAT	5.86	5.86	5.86	moist tonnes/ha
N2O per tonne moist crop	0.194	0.318	0.626	kg N2O/moist tonne

AVERAGE N2O EMISSIONS FOR SUGAR BEET (background emissions subtracted)				
Direct emissions from soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	1.511	1.776	2.970	kgN as N2O/ha
...combined with other uncertainty	1.181	1.776	3.083	kgN as N2O/ha
...converted to mass of N2O	1.855	2.790	4.845	kg N2O/ha
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	5.14	7.34	9.54	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0026	0.0551	0.2386	kgN/ha
...converted to mass of N2O	0.004	0.087	0.375	kg N2O/ha
TOTAL direct+indirect N2O	1.859	2.877	5.220	kg N2O/ha
EU15 2000 yield EUROSTAT	61.23	61.23	61.23	moist tonnes/ha
N2O per tonne moist crop	0.030	0.047	0.085	kg N2O/moist tonne

AVERAGE N2O EMISSIONS FOR RAPESEED (background emissions subtracted)				
Direct emissions from soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	1.621	1.848	2.554	kgN as N2O/ha
...combined with other uncertainty	1.249	1.848	2.746	kgN as N2O/ha
...converted to mass of N2O	1.963	2.904	4.315	kg N2O/ha
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	7.46	10.66	13.86	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0037	0.0800	0.3465	kgN/ha
...converted to mass of N2O	0.006	0.126	0.545	kg N2O/ha
TOTAL direct+indirect N2O	1.969	3.030	4.860	kg N2O/ha
EU15 2000 yield EUROSTAT	3.03	3.03	3.03	moist tonnes/ha
N2O per tonne moist crop	0.650	1.000	1.604	kg N2O/moist tonne

AVERAGE N2O EMISSIONS FOR SUNFLOWER (background emissions subtracted)				
Direct emissions from soil:	min.	best est.	max.	
cap on emissions	2.6	8	50	kgN as N2O/ha
Nitrogen emitted as N2O	0.581	0.643	0.643	kgN as N2O/ha
...combined with other uncertainty	0.441	0.643	0.836	kgN as N2O/ha
...converted to mass of N2O	0.692	1.011	1.314	kg N2O/ha
Indirect emissions from N leached from field in run-off water:				
leached N (estimate from model)	1.79	2.56	3.33	kgN /ha
IPCC "EF5" emission factor	0.0005	0.0075	0.0250	kg(NasN2O)/kgN leached
IPCC indirect N2O emission as N	0.0009	0.0192	0.0832	kgN/ha
...converted to mass of N2O	0.001	0.030	0.131	kg N2O/ha
TOTAL direct+indirect N2O	0.694	1.041	1.445	kg N2O/ha
EU15 2000 yield EUROSTAT	1.78	1.78	1.78	moist tonnes/ha
N2O per tonne moist crop	0.390	0.568	0.812	kg N2O/moist tonne

SUMMARY

N2O emitted per tonne moist crop				
	min.	best est.	max.	
wheat	0.19	0.32	0.63	kg N2O/moist tonne
sugar beet	0.03	0.05	0.09	kg N2O/moist tonne
rapeseed	0.65	1.00	1.60	kg N2O/moist tonne
sunflower seed	0.39	0.57	0.81	kg N2O/moist tonne

GJ per tonne moist crop				
	moisture%	LHV dry	LHV moist [1]	
wheat	14%	17.0	14.7	GJ/moist tonne
sugar beet	77%	16.3	3.8	GJ/moist tonne
rapeseed	10%	26.4	23.8	GJ/moist tonne
sunflower seed	10%	26.4	23.8	GJ/moist tonne

[1] LHV moist in this study is defined as the LHV of the dry-matter content of the moist material

N ₂ O emitted per GJ of crop				
	min.	best est.	max.	
wheat	13.2	21.6	42.6	g N ₂ O/GJ
sugar beet	7.9	12.3	22.3	g N ₂ O/GJ
rapeseed	27.3	42.1	67.5	g N ₂ O/GJ
sunflower seed	16.4	23.9	34.2	g N ₂ O/GJ

note: in this study we use the LHV heat content of the dry matter in the crop

Rapeseed has the highest emissions because it is grown in the Northern half of Europe, where soils generally have a higher organic content. Sunflower, grown in the drier South, has the lowest emissions per ha, which the low yield does not entirely compensate. It also has the lowest contribution from “indirect” emissions from leached nitrogen, which reduces the error range.

The high yield of sugar beet, and the fact that it cannot be grown on badly-drained soil, brings its emissions-per-GJ-crop below that of the others. Sometimes a low-yielding or a cover crop, such as mustard, is grown in the year preceding sugar beet, in order to condition the soil for the intensive cropping in the next year. It could be argued that emissions from that previous year should be attributed to the sugar beet crop. We have not done this as we have little information on crop rotations, and the same sort of considerations apply in principle to all the crops.

Significant as these emissions are, a recent study has suggested these 'bottom-up' calculations may still significantly underestimate the real emissions of N₂O from agriculture [Crutzen 2007]. The study compares the known emissions of N₂O to the levels actually found in the atmosphere. Taking into account the mechanisms that slowly remove N₂O from the atmosphere over time, they estimate that N₂O emissions from agriculture may be as much as three times higher than those produced by 'bottom up' calculations as used in our study. They also comment on the implications for biofuels. Although this part of their analysis is not very thorough, higher N₂O emissions would obviously reduce the GHG savings from biofuels, and could even lead to GHG increases. For example, for wheat to ethanol (WTET1a) we estimate a GHG benefit relative to gasoline of 29%. If N₂O emissions were three times higher, this reduces to 10%. For biodiesel (ROFA1), the impact of N₂O emissions is even greater. Our best estimate is for a 56% GHG emission saving compared with diesel. If N₂O emissions were ignored, the benefit would be 81%, but if they are three times higher, the benefit reduces to 5%.

One should note that the N₂O emissions estimates in the Crutzen paper are not beyond the *upper limit* of the IPCC tier 1 calculations, if these are made correctly, taking into account emissions from leached nitrogen, (and including nitrogen from manure and crop residues).

N₂O emissions from crops grown outside EU

We do not have detailed enough information to calculate the N₂O emissions from crops grown outside EU using a soils model. The best we can do is to use the tier 1 2006 IPCC guidelines. This leads to a larger uncertainty in emissions. Fortunately, however, the crops we consider do not have a high ratio of nitrogen input to yield (and therefore generate moderate emissions per tonne, under the IPCC assumption that emissions are proportional to Nitrogen rate), so the effect on the uncertainty in the overall GHG balance is still acceptable.

Between their 1996 and 2006 guidelines, IPCC changed their default emission guidelines for soybeans: this had the effect of drastically reducing the N₂O emissions calculated for soybean. We think the true emissions actually lie between the two, as described below. This discussion originated from the staff of E4tech, UK in 2008, working on behalf of the UK Renewable Fuels Agency. The resulting correction to the N₂O emissions for leguminous plants was incorporated in UK RFA default values for soybeans. Subsequently E4tech discussed their analysis with JRC. JRC agreed, only making a small correction,

described below. The text below is our interpretation of the survey in the original E4tech document, and appears with their permission.

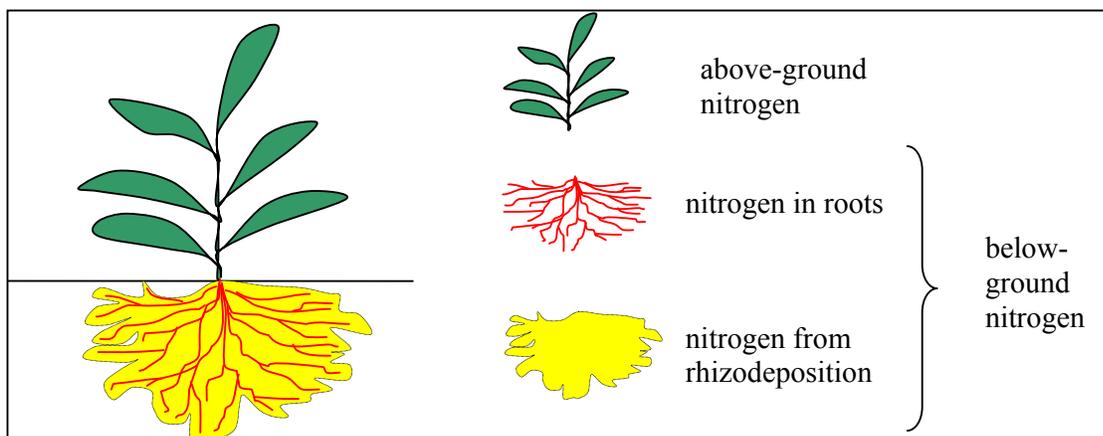
JRC agrees with E4tech that the 2006 IPCC (tier 1) approach significantly underestimates the N₂O emissions from soybeans and other leguminous plants. The old 1996 IPCC methodology for calculating N₂O emissions from soil (used in version 2 of this study) did not consider the below-ground nitrogen (BGN) in plants at all, but did assume that the nitrogen naturally fixed by leguminous plants (such as soybean) contributed to the release of N₂O. This would mean that the nitrogen-fixing bacteria in the roots were emitting N₂O at the same time as they were fixing nitrogen from the air.

However, a paper in 2005 by [Rochette 2005] argued that there was little evidence for significant N₂O emissions from legumes during the nitrogen fixation process. Therefore in the revised 2006 methodology (published in 2007), IPCC no longer include emissions directly from the natural nitrogen-fixing process. On the other hand, the 2006 guidelines *do* take into account the contribution of below-ground N content of the plants themselves to the nitrogen pool in the soil which contributes to N₂O emissions.

IPCC attribute these extra emissions to the current crop. However [Rochette 2004] shows that most of these will actually take place during the following season. He found that although the soil mineral N content under legumes were up to 10 times greater than under a grass, this was not closely related to the N₂O emissions measured during the growth phase of the plant. However, he found greater emissions of N₂O after the plant had been harvested, strongly dependent on the soil type.

So for the current season, what *should* be taken into account is the contribution of below-ground nitrogen from the residues of the *previous* crop. From the point of view of a national average, it does not matter much to which crop a certain amount of soil nitrogen is attributed. But it does make a difference if you are calculating N₂O emissions *per crop* in a rotation. Of course the distinction is not important if the *same* crop is grown in successive years, which is generally the case in Brazil (the assumed source of soybeans in our study).

Figure 3.4.2-2 Distribution of biologically-fixed nitrogen in leguminous plants



Part of the nitrogen biologically fixed by soy plants ends up in the above- and below-ground crop residues, and in principle IPCC 2006 takes emissions from this into account. However, we think they have seriously underestimated the amount of below-ground nitrogen. This comes from firstly underestimating the below-ground biomass and secondly from ignoring nitrogen from rhizodeposition.

Rhizodeposition [Jensen, 1995] is the process whereby N enters the soil from the plant roots in the

form of NH_4 , NO_3 , amino acids, cell lysates, as well as through decay of sloughed-off and senescent roots. It can now be quantified through techniques such as ^{15}N shoot labelling [Khan 2002a]. The literature shows that leguminous plants such as soy exude significant volumes of N from their roots [Martens, 2006].

Table 11.2 of the 2006 IPCC Guidelines gives default factors for estimation of N added to soil from crop residues. According to this, only 16% (= 0.19/1.19) of the soybean plant residues are in the underground biomass, and they all have the same nitrogen concentration. These default factors are based on an extensive literature review, the references for which they provide in Annex 11A.1. The default value for BGN content of soybean comes from a 1925 paper. Whilst E4tech could not obtain a copy of this reference, their review of more recent literature suggests such an old work will have missed not only the N released by rhizodeposition, but also that in fine root hairs that are very difficult to collect using the old techniques of physical root recovery. [Aruja *et al.* 2006] confirms that the roots recoverable by traditional methods only contain 5-10% of the total N accumulated by the plant. For comparison, [Alves 2003] report results using modern techniques of between 30-35% of total plant N. This implies IPCC has underestimated nitrogen in the roots themselves by at least a factor 3.

If we include also nitrogen from rhizodeposition, the IPCC defaults look even further out. [Khan 2002b] concluded that the traditional methods only recovered 20-30% of the total below-ground nitrogen (including that from rhizodeposition) obtained using N-labelling methods. [Mayer 2003] found that N rhizodeposition represented about 80% of the below ground plant N. These studies suggest that the N from rhizodeposition is roughly four times the below-ground nitrogen in the roots, so at least an order of magnitude greater than the below-ground nitrogen calculated from IPCC defaults

We think that in reality only the part of the biologically fixed nitrogen released by rhizodeposition counts towards N_2O emissions from the soil during a particular growing season. The rhizodeposition gradually builds up during the season, but after the harvest the plant residues gradually decay and release their nitrogen into the soil. There are not enough data to estimate the amount of rhizodeposited nitrogen from soy by direct measurements of soil nitrogen. A more pragmatic and accurate approach is to back-calculate the *effective* nitrogen related to below-ground biomass from the measured nitrous oxide emissions from soybeans grown without synthetic nitrogen. That figure would reflect the actual nitrogen content in the soil (we suppose, from rhizodeposition) which is giving rise to N_2O emissions. We only assume that this is proportional to the below-ground biomass. Referring to IPCC 2006 table 11.2, it does not matter if we do this by changing the default value “ $R_{\text{BG-BIO}}$ ”, (ratio of below-ground to above-ground biomass) or “ N_{BG} ”, the effective nitrogen concentration in the below-ground biomass (kgN/ kg dry matter). We have chosen the second option (both of these numbers we think are wrong, but do not know how much the error in each contributes to the overall error in the effective below-ground nitrogen estimation).

We start off by averaging the measurements of N_2O emissions from soy without N fertilizer quoted in [Rochette 2005]. The result is 1.075 kg N- N_2O /ha. We assume this all originated from from rhizodeposition and decay of crop residues from the previous season. Using the IPCC default **direct** emissions factor of 0.01 kg N- N_2O /kg N(CR)⁹, JRC estimates the total nitrogen which gave rise to those emissions to be 107.5 kgN/ha.

From this we need to subtract the nitrogen in the above-ground residues to find the effective below-ground nitrogen. First we need to estimate the yield. The N_2O data are mostly from USA, where the average yield from FAO (the source suggested by IPCC) *dry-matter* yield is 2.26 tonnes/ha. Using the formula in IPCC 2006 table 11.2, this yield corresponds to above ground residue of 3454 kgDM/ha. Combining this with the default concentration of nitrogen in above-ground biomass (0.008

⁹ Only the DIRECT N_2O emissions are measured in the field. E4tech inadvertently used total direct + indirect emissions

kgN/kgDM, confirmed by [NREL 2005]) gives 27.6 kgN/ha in above-ground residue. Subtracting this from the total N in plant-residue leaves us with an effective 79.9 kgN/ha in below-ground biomass.

To find our new value for the default nitrogen concentration in below-ground-biomass, we need to divide the last number by the amount of below-ground biomass. Following the IPCC 2006 method we calculated this was 1086 kg/ha¹⁰

Now our new value for the effective nitrogen associated with below-ground biomass is $N_{BG} = 79.9/1086 = \mathbf{0.074 \text{ kgN/kgDM below-ground biomass}}$. JRC recommends using this in place of the default value of 0.008 in IPCC 2006 - table 11.2 -, in order to calculate N₂O emissions from soy which are comparable with measurements¹¹.

We can check whether this value is reasonable by looking at which value it implies for the fraction of the total nitrogen associated with the plant. This can be checked against measurements in the literature, which mostly range from 30 to 35%, according to [Alvez 2003] and a wider literature survey by E4tech.

The nitrogen concentration in the beans is 6.5%DM according to [NREL 2005], corresponding to 147kgN/ha in beans. The total plant N is this plus below-ground nitrogen and above-ground nitrogen in residues. Adding this all up using the figures above gives a total of 255 kgN/ha associated with the plant. Then the fraction of below ground nitrogen implied by our method is 31%. This is indeed within the range of measured values, giving us confidence that we are at least approximately correct.

It is likely that non-leguminous crops also exude some nitrogen from the roots, but in this case it is only returned to the soil after having been absorbed from the soil, so correcting for it could lead to double-counting.

A significant fraction of oil palms are planted on peat or high-organic soils, and apply nitrogen fertilizer. However, [IPCC 2007] tier 1 methodology offers no method to estimate N₂O emissions due to adding nitrogen fertilizer to organic or peat soils. Results from soil chemistry models and field measurements in temperate zones show that the proportion of nitrogen fertilizer emitted as N₂O is far higher on organic and peat soils than on mineral soils. However, there is much variability, and there are very few results for tropical areas. Therefore we have not managed to quantify how much this could increase average GHG emissions from palm oil production.

3.4.3 Farming inputs and yields

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.

For transparency, in this version 3 we have adopted for all EU crops the fertilizer inputs reported by the European Fertilizer Manufacturers’ Association (EFMA) together with their preferred source of national yield data: FAO. In practice, this has had little impact on the results compared to version 2 of this study, where the figures came from [FfE 1998] and a variety of other sources. For farming outside EU, yields are also from FAO, and fertilizer data based where possible on values from the International Fertilizer Association. See details in *WTT Appendix 1*.

¹⁰ Following the formula underneath equation 11.6 in [IPCC 2007], this is calculated by applying the IPCC default ratio of below-ground to above-ground biomass (“R_{BG-BIO}” = 0.19 for soy) to the total above-ground-biomass found by summing the above-ground residue and crop yield shown above.

¹¹ By considering also indirect emissions, E4tech came to a slightly lower value for N_{BG}

Other farming inputs are taken from [FfE 1998] and a variety of other, more recent, sources as detailed for each crop in *WTT Appendix 1*. In all cases the farming inputs are converted to inputs-per-MJ crop using the yield which applies to the particular data. The heat value of crops and other substances are tabulated at the start of *WTT Appendix 1*.

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 up to 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 that 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*, N₂O emissions due to farming are very roughly proportional to nitrogen fertilizer rate.

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. In Southern Europe, where decomposition is fastest, the straw is sometimes 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.

3.4.4 Credits for animal feed by-products

In this version 3, we introduce a more sophisticated and consistent system for calculating animal feed credits for all pathways.

At present the main by-products of biofuel manufacture are rapeseed meal from biodiesel and DDGS from cereals-ethanol. These are rich in protein, but not as rich as soybean meal, the main protein concentrate feed in EU. Therefore they substitute a mix of soybean meal and carbohydrate feeds. In practice, a wide range of animal feed products are substituted in EU. However, many of these (such as

gluten feed, which is compositionally closest to DDGS) are themselves by-products of another process, so their supply hardly reacts to changes in biofuel production. The main *marginal* source of carbohydrate feed is cereals, which we represent by EU feed-wheat, whilst the main *marginal* source of protein is clearly soybean meal. We consider soybean meal from Brazil, because this is the largest soybean exporter and the best candidate to be the marginal producer.

The *maximum* proportion of soybean meal a feed can substitute is given by balancing total metabolized protein and digestible energy using a mix of soybean and cereals. The *minimum* proportion of soybean meal replaced is zero. In corn-ethanol producing areas of USA, the large availability of corn-DDGS means that there is effectively no more possibility to substitute soybean meal, and further increases in DDGS supply now substitute corn in animal feed, according to [Liska 2008] and several other sources.

For the substitution ratios used in our WTT calculations we chose the *average* of the maximum and minimum extremes. In practice the GHG credit is not very sensitive to the exact choice.

In the EU the present situation is between these extremes. More compound feed is used, and this gives greater flexibility in accommodating changing feed supplies by blending. Nevertheless, the proportion of soybean meal replaced can be expected to decline as the EU production of biofuels increases. As reflected in its higher price, soybean meal is regarded as the “Rolls-Royce” of protein feeds, with the best balance of amino acids and other properties. There are quality issues with substituting it.

Rapeseed meal is less palatable than soybean meal. Depending on the variety of rapeseed and type of farm animal, the animal will not eat more than about 5-15% (by dry mass) rapeseed meal in its diet as a general rule. The amount of rapeseed meal resulting from 10% diesel replacement by rapeseed biodiesel in 2020 would amount to roughly 10% of EU animal feed (according to our forecast of diesel consumption). This means it is close to how much could possibly be consumed if all EU livestock were eating as much rapeseed meal as they could stomach. However, they are unlikely to face this situation, because the fall in rapeseed meal price in EU would make it more economical to crush rapeseed outside EU. So palatability is probably not a limitation if the oilseed meals are uniformly spread amongst EU livestock.

DDGS is more easily tolerated by cattle: trials in US have fed them up to 40% (DM) wet distillers’ grains from corn (although the protein in dried DDGS can be less digestible, especially if heat-damaged in drying). However, the cattle can only utilize the protein content of the DDGS at incorporation rates up to 15%: beyond that, extra DDGS provides only digestible energy [Klopfenstein 2001].

- However, these figures are for cattle fed US corn plus corn-DDGS. But in Europe, we can expect protein-substitution to be exhausted at significantly lower levels of DDGS incorporation into feed. This is principally because the simultaneous growth of biodiesel in EU provides oilseed meals which also provide part of the overall protein requirement, but also because EU feed cereals already have higher protein content than US ones, and wheat DDGS has a slightly higher protein content too.

Thus, there may well be no soybean-meal imports left for the by-products to replace.

Other reasons to think that the by-products of biofuels will not replace soybean meal on an equal-metabolizable protein basis are:-

1. *Some soybean meal may be imported to supply essential amino acids which are deficient in the biofuel by-products*

Usually, the protein feed requirements for farm animals are determined by the minimum requirements for essential amino acids, rather than the total protein supply. An animal fed mostly on cereals tends to be deficient in certain essential amino acids, but DDGS tends to be deficient in the same ones, because it retains the amino acids from the cereal used to make the bioethanol. Therefore to satisfy the minimum essential amino acid requirements using only cereals and DDGS, the animal ends up much more total metabolizable protein than it needs: the excess protein is just used to provide energy like a carbohydrate feed.

To avoid this, essential amino acids can be added from other sources: soymeal, or more concentrated and expensive sources such as fish-meal or synthetic production. These also have environmental footprints.

2. *Animal diets become richer in protein due to relative price movements*

Increased production of 1st generation biofuels tends to depress the price of protein-rich feeds (like rapeseed meal, DDGS and, indirectly, soybean meal) and increase the price of carbohydrate-feeds like cereals. Even before soybean meal is completely replaced, animals will tend to receive a greater proportion of protein in their diet. The excess protein from the by-products is just used for energy, replacing carbohydrate feeds.

Details of the animal-feed substitution calculation

The calculation is made assuming that the by-products are eaten by cattle. They are not only the largest consumers of animal feed; they are also more suitable for the purpose than pigs and poultry. This is because cattle are relatively less efficient at digesting soybean meal, and are not troubled by the high fibre content of some by-products. To find the maximum proportion of soybean meal substituted, one should ideally balance all the essential amino acids as well as the overall metabolizable protein and digestible energy. Furthermore, depending on what else is fed to the animals, some by-products may improve the weight-gain per tonne of feed (“feed efficiency”) more (or less) than indicated by the digestible energy ratio. However, that would be a complex task to take these effects into account for all products and feed combinations. For simplicity we balance only digestible energy and total metabolizable protein.

In cattle, a large proportion of the protein is broken down (degraded) in the rumen, and then most of the decomposition products (notably N compounds) are reassembled by the bacteria there into bacterial protein which the cow later digests and (mostly) absorbs. According to [BOA 2000], p16-18, the efficiency of the degradation/reconstruction/absorption process is ~65%, whilst of the proteins which pass the rumen undegraded, about 80% are absorbed by cattle.

Thus the overall weight-fraction of metabolizable (= absorbed) protein (MP) in a feed is given by [BOA 2000]:

$$MP = CP * \{0.8 * RU + 0.65 * (1 - RU)\}$$

...where MP is the fraction of metabolizable protein (= absorbed protein) in the
CP is the total crude protein content of the feed
RU (ruminal undegradability) is the fraction of the crude protein which passes *through the rumen undegraded*.

Table 3.4.4-1 shows the properties of animal feeds. Unless otherwise stated, the data comes from [BOA 2000], a standard reference for livestock nutrition. We have used data for beef cattle only, because the equivalent data for dairy cows do not tabulate aggregated protein degradability. The protein content of the feed-wheat is taken to be 10.9% of dry matter: DG-AGRI experts confirmed that

this rather new type of low-protein, high-yield feed-wheat will be the cheapest and most suitable type of wheat for bioethanol production. The protein content is confirmed as typical for the most suitable wheat varieties for bioethanol production [HGCA 2006]. This has an effect also on the protein content of the DDGS. Our properties for wheat-DDGS are based on [Univ. Minnesota 2003], but that is for DDGS from Canadian feed-wheat, which has a higher protein content: 13.1% of dry matter. So we improved the estimate for the protein content for our EU-feedwheat-DDGS by interpolating between the Canadian data and that for US corn-DDGS, produced from maize containing only 10% dry-matter protein.

Table 3.4.4-1 Properties of animal feeds fed to beef cattle

our substitutes:-	Dry matter%	Digestible Energy [1] MJ/dry kg	Crude protein % m dry	"ruminal undegradability" of protein	% of crude protein metabolizable	metabolizable protein % m dry
soy meal	89%	15.48	51.8%	34.0%	70.1%	36.3%
feed wheat EU 2015 (DGAGRI)	87%	16.23	10.9%	23.0%	68.5%	7.5%
by-products from biofuels:-						
rapeseed meal	90%	13.64	40.9%	28.0%	69.2%	28.3%
sunflower meal de-hulled	90%	12.01	26.0%	26.0%	68.9%	17.9%
DDGS (from maize)	93%	16.23	30.4%	52.0%	72.8%	22.1%
DDGS/2015 EU feed-wheat [2]*	93%	16.12	33.2%	56.0%	73.4%	24.3%
dried sugar beet pulp	91%	13.64	9.8%	45.0%	71.8%	7.0%
palm kernel meal, physical crush	90%	12.95 [3]	18.3% [4]	33.8% [3]	70.1%	12.8%

[1] Metabolizable energy is arguably more suitable, as it takes into account losses in urine and gas, but it is practically proportional to digestible energy for a particular animal [BOA 200]. Data for ME is not available for all these by-products.

[2] based on [Univ. Minnesota 2008] – see text

[3] [O'Mara 1999]

[4] [FAO 2008]

Table 3.4.4-2 Substitution ratios calculated for by-products of biofuels

	dry kg soybean meal with same metabolizable protein as 1kg dry byproduct	kg dry feed wheat to balance digestible energy	dry kg feed-wheat for equal digestible energy WITHOUT soybean meal	DRY SUBST RATIOS		MOIST SUBS RATIOS	
				average kg DRY EU-feed-wheat replaced by 1kg dry by-product	average kg DRY soybean meal replaced 1 kg dry by-product	average kg MOIST EU feed wheat replaced by 1kg MOIST by-product	average kg MOIST soybean meal replaced by 1kg MOIST by-product
Soy meal	1.000	0.000	0.954				
EU feed wheat (bioethanol grade)	0.000	1.000	1.000				
by-products from biofuels:-							
rapeseed meal	0.755	0.121	0.840	0.480	0.377	0.497	0.382
sunflower meal (de-hulled)	0.424	0.335	0.740	0.537	0.212	0.556	0.215
Corn-DDGS (for comparison)	0.502	0.521	1.000	0.761	0.251	0.813	0.262
DDGS/ EU feed-wheat [2]	0.580	0.440	0.993	0.716	0.290	0.766	0.303
dried sugar beet pulp	0.026	0.816	0.840	0.828	0.013	0.866	0.013
palm kernel meal, physical crush	0.234	0.574	0.798	0.686	0.117	0.710	0.118

[1] Since SBP has lower protein content than feed-wheat, a little soybean meal is required (not substituted) for balance

Table 3.4.4-2 shows, for each by-product, first the calculation for the maximum-soymeal substitution ratio, and the corresponding balance of feed-wheat (all in dry-mass terms). Then the straight feed-wheat substitution ratio is calculated (minimum soybean meal). Next the average substitution is calculated in dry-matter terms and finally, in the last two columns this is converted to moist-mass substitution ratio, for use in the GHG and cost calculations.

In the pathways for soybean biodiesel, it is necessary to find a substitute for soybean meal itself. It is no good to say it replaces imported soybean meal: what does that replace? This is tricky: there is no other crop which yields anything like the same protein. But there must be a real market effect of by-producing soybean meal in EU. Bearing in mind the discussion above, we can see that adding soybean meal to a EU protein-meal market already struggling to accommodate the oilseed meal from other types of biodiesel will lead to an increase in the proportion of protein in the livestock diet. This means

that protein is now being used for digestible energy, replacing carbohydrate feedstock which we represent with feed-wheat. *Table 3.4.4-2* shows that 1kg dry soybean meal substitutes 0.954 kg dry feed-wheat. In terms of moist weights, 1 kg moist soybean meal substitutes 0.976 kg moist feed-wheat.

3.4.5 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]. Alternative data provided by stakeholders proved difficult to reconcile with thermodynamic principles, so after a thorough review we decided for the present version, to retain the existing estimates. Fertilizer transport is included, but is negligible.

3.4.6 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 as well as generally diminishing agricultural yields.

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, but require 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.

3.4.7 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 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. The above distances are relevant to the EU. Soy beans road transport in Brazil is estimated to be much longer - 700 km to a port where the crushing plant is deemed to be located.

3.4.8 Sugar beet to ethanol

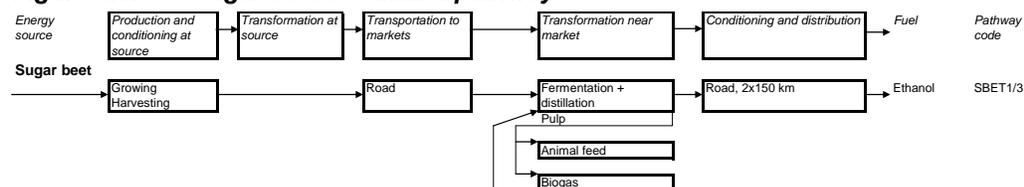
Sugar beet is a high yield crop. It produces carbohydrate already in the form of sugar and is easily crushed and mashed for fermentation which makes the processing into alcohol rather cheap. The economics of its cultivation are highly distorted by the CAP, as discussed in *section 5.2*.

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 protein content below that of feed-wheat (see *section 3.4.4*). Because of the cost these by-products are only dried if they are to be sold for animal feed. If they are to be used for providing process-energy, it is more attractive to add them to the process biogas digester (needed for cleaning the waste-water), than to burn them, which gives almost the same energy balance and emissions.

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.

We have therefore considered 3 sugar-beet-to-ethanol pathways as shown below. SBET1a/b consider use of pulp for animal feed with the slops either not used or added to the biogas digester, while SBET3 uses both pulp and slops for biogas production which is used for co-generation of electricity and heat.

Figure 3.4.8 Sugar beet to ethanol pathways



3.4.9 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. We chose wheat-to-ethanol to illustrate the effects of different fuel and CHP options. 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 is 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.

WTET5: DDGS to biogas

For each of pathways WTET1-4 alternative dispositions of the DDGS by-product (see below) as either animal feed or as co-feed fuel in a coal power station are considered. This pathway considers an alternative use of the DDGS to produce biogas, which is then used to produce heat and electricity to supply all the heat and most of the electricity needs of the ethanol plant. The residue from the biogas digester still has value as a fertiliser and generates a credit for the overall process. A more detailed explanation of the potential uses of DDGS is given in the section below.

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 emissions savings are divided only by the ethanol produced, all the GHG saved by making electricity is credited to making ethanol. One would conclude that the higher the electricity generation, and the lower the ethanol yield, the better the emissions and 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 an opportunity for CHP so 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 (i.e. it gets process heat practically free of emissions)..

DDGS

Ethanol production produces a by-product known as DDGS (Distiller's Dried Grain with Solubles) which is the solid residue after fermentation of the carbohydrates. DDGS is a protein-rich material and is therefore a useful animal feed component. Its nearest equivalent is corn gluten feed. However, since this is a by-product of maize milling, its supply cannot easily be changed. We consider the main marginal or "swing" sources of animal feed are feed-wheat and soymeal, and we assume DDGS

substitutes a mixture of these, as explained in section 3.4.4.. Details of the soymeal pathway are described below, under soybeans. Used as animal feed, DDGS also reduces the *indirect emissions* which could be ascribed to bioethanol production: it reduces the net diversion of crops from feed and food use.

Animal feed is by far the most lucrative usage and therefore the most likely at present; but increasing bioethanol production is likely to lead to lower DDGS prices (as already seen in US). 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. Alternatively, DDGS could be used to provide process heat to improve the GHG balance, in line with incentives for reducing the emissions from biofuels manufacture. Note that this foregoes the reduction in *indirect* GHG emissions implied by using DDGS as animal feed. 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 (since we do not consider indirect emissions here). We have illustrated these two options in sub-pathways:

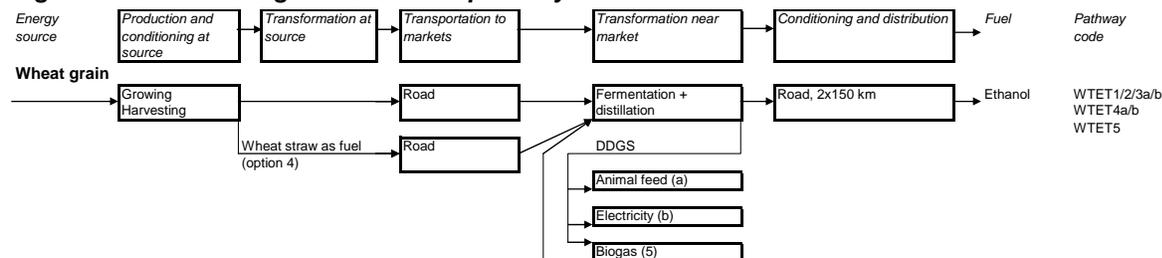
- WTET2/3/4a: DDGS as animal feed
- WTET2/3/4b: DDGS as fuel in a coal power station

An alternative way of extracting energy from DDGS is through production of biogas in the ethanol plant. This would then be used to co-produce heat and electricity, meeting all the heat needs of the plant, but still requiring a small electricity import.

- WTET/5: DDGS to biogas

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

Figure 3.4.9-1 Wheat grain to ethanol pathways

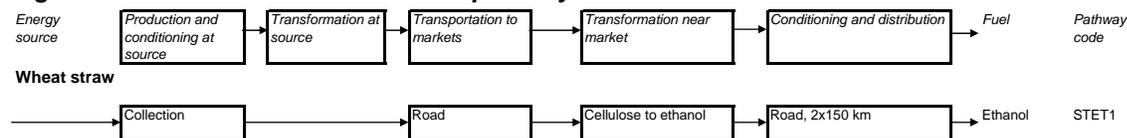


Straw to ethanol

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 3.4.9-2 Wheat straw to ethanol pathways



Ethanol to ETBE

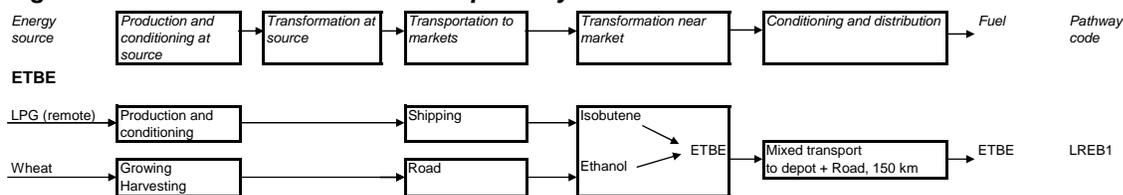
As an alternative to using ethanol directly as a gasoline blending component, it can be converted to ETBE (Ethyl-Tertiary-Butyl Ether). ETBE is a high octane component with very similar properties to MTBE but with a somewhat lower solubility in water. The main advantage of ETBE over ethanol as a gasoline 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 3.4.9-3 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 produce sugar in Europe. It resembles more a permanent biomass crop like miscanthus than it does an arable crop. In Brazil, 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. Yields may be much lower in areas that do not benefit from Brazil's favourable combination of warm temperatures and abundant rainfall.

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, mostly at the expense of rough grazing land. The sugar growing area is a very long way from any surviving rainforest, so moderate expansion should not have a direct impact. 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. However, new production areas in Mato Grosso and Mato Grosso del Sur may impinge on natural cerrado (savannah-type) land-cover, either directly, or indirectly through displaced ranching. Cerrado has high biodiversity, but does not store as much carbon as rainforest.

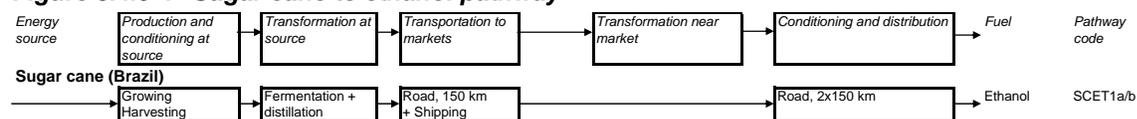
Unlike arable crops in Europe, planting sugar cane on grazing land is believed to actually increase the soil carbon stocks, although as shown in figure 3.4.1-1, some studies still show significant land change effects, but with a payback time less than for temperate climate crops. The risk of soil erosion (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 electricity and heat is entirely provided by the bagasse. 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. There is in fact a small surplus of bagasse which can provide fuel for a neighbouring food-processing plant (for example, orange juice production), generating a credit for saved fuel oil. There is also an initiative by Sao Paulo province to encourage co-generation of excess electricity to replace imported electricity from other provinces. However, the ability to capitalise on exports of surplus electricity or heat depend on the availability of infrastructure and local customers, Pathway SCET1a shows the case where exports are possible, while SCET1b considers a plant where bagasse is used solely to meet the needs of the ethanol plant.

We have taken our input data from a thorough analysis by Prof. Macedo et al. [Macedo 2004]. Since then, the same team has issued slightly revised figures [Macedo 2008], taking into account changes in practice in the Centre-South region of Brazil to 2005/6, and also projected values for 2020.. We have not yet taken these new figures into consideration, because we need to assess to what extent the data can be applied also to new producer regions in Brazil, which have perhaps less developed techniques.

Figure 3.4.9-4 Sugar cane to ethanol pathway



3.4.10 Oil seeds

In Europe the two most used oil seed crops are rape (also known as colza) and sunflowers. (“Canola” is a variety of rapeseed developed in Canada to be give palatable animal feed.) Agricultural yields are much lower than for wheat or sugar beet. In a crop rotation of ,say, one year in four with cereals, rapeseed gives a synergistic improvement of cereal yield. However, EU rapeseed production has increased so much in recent years that it is grown in alternate years or even in successive years, which negates the effect. Rapeseed grows better in the North of EU and is more intensive, whereas sunflower is more suited to southern Europe. Processing of the oil seeds from either source is similar. As demand for biofuels grows, imported oils are becoming of more importance.

Pure vegetable oil cannot be used as a conventional internal combustion engine fuel, because of its high viscosity and gum content. Although special engine modifications have been used to run on pure oils in limited applications, the oil generally needs to undergo processing to produce a fuel that is miscible with conventional diesel and can be used in standard engines. The most common process is 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, however ethanol can be used instead. 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). 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. This has the advantage of exploiting the GHG savings of bioethanol whilst replacing diesel, which eases the imbalance in the refining industry. However, if there is no economic advantage in improving the GHG performance of biodiesel beyond an already-attainable threshold, FAEE is unlikely to be produced extensively in practice.

Rapeseed processing

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 meal, a high-protein animal feed, replacing soy bean meal as described in soybean pathways. The production of soy bean meal also makes a by-product: soy oil. In this version of JEC-WTW we have calculated the credit for this based on sunflower oil because this is compositionally more similar than the rapeseed oil substitution used in our previous version. Rapeseed meal could also in principle be burned as a fuel, much in the same way as DDGS, although its high value as animal feed discourages this approach and we have not developed a pathway to cover this. However, consideration is being given to adding it to biogas digestors, and we have modelled this option.

The next step is purification, in which acidity is neutralized and the oil clarified. The transesterification 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 glycerol but can 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. Already in 2003, total EU glycerol consumption was 275 kt/a [NRC 2004] and the only remaining synthetic glycerol plant in EU had an output of 36 kt/a. By comparison 10% replacement of EU diesel fuel would pour about 2.3 million tonnes of glycerine onto the EU market (about 11 kg per person per year), more than 130 times the production of synthetic glycerol. Therefore we did not consider this substitution option.

Most non-biodiesel 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, from which it has not recovered. 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, whilst by October 2008 the price had recovered to 475 €/tonne.

However, [DOE 2004] states that crude 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 crude glycerine price is 130 €/tonne. This prediction (made in 2005) has been borne out in practice: that is roughly the price of crude glycerine in late 2008 (but low-grade material is worth almost nothing). Growing industrial uses include as fuel for steam-reforming, whilst much commercially-oriented research is going into converting glycerol to higher-value chemicals such as other glycols or even methanol.

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 (2008). It would be

technically feasible to replace half the synthetic glycols with glycerine. This market could absorb about 35% of the potential glycerine production from replacing 10% EU biodiesel in 2015-2020.

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, crude glycerine is already used as animal feed (in which application it has a digestible energy content of 14 MJ/kg). This gives a much lower energy and emissions credit. If glycerine is used as fuel, the energy and emissions credits lie half-way between these two extremes. We selected the chemical substitution and fuel substitution pathways on the - perhaps optimistic - basis that the chemicals industry will develop higher-value uses for glycerine than animal feed.

Sunflower

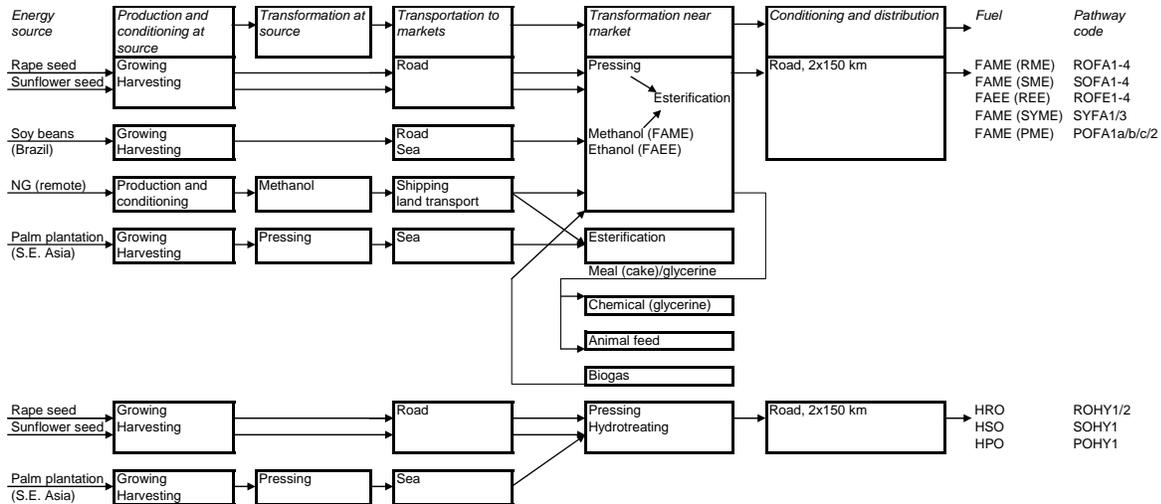
Sunflower processing differs from rapeseed mostly inasmuch as the pressing yield is slightly higher, and the sunflower meal by-product has a lower protein content.

Oil seed imports

Europe is short of oil seeds. Historically the trade pattern has been to import the raw materials (oil seeds) rather than vegetable oil. Perhaps this is because until now there has been a ready and profitable market for the animal-feed by-products in the EU. Imports of finished biodiesel from US (benefiting from subsidies on both production and use) are now much reduced after anti-dumping measures by EU. However, one can expect a growing trend to import vegetable oil or biodiesel from low-cost producers (such as Malaysia and Brazil), because continuing quantities of meals will depress their price in EU, and producers seek to improve the added value of their exports.

Palm has now overtaken soy as the largest global source of vegetable oil, although both sectors are expanding rapidly. Rapeseed production comes as a poor third, followed by many much more minor sources including sunflower.

Figure 3.4.10 Oil seeds to bio-diesel pathways



Soy beans

Soy beans are already a major element in world trade, and EU soy meal consumption is around 35MT/a.

Soy products are imported both in the form of beans and of separate oil and meal. Imports of soy beans would provide oil for biofuel production, together with additional soy meal. About half of the soy oil consumed in EU is imported as oil, and half as beans. Brazil is the largest overall producer of soy, and shows the fastest export growth. Argentina is the other main producer, where it competes for land with wheat, maize and ranching. Export taxes on beans have encouraged the development of the crushing industry there.

Our figures DO NOT include any provision for emissions from deforestation or other land use change.

Soy bean biodiesel is a particularly tricky pathway to treat using the substitution methodology, because of the high proportion of soy meal by-product compared to the oil. The net GHG savings depend very strongly on how the credit for the soy meal by-product is calculated. The choice of substitution for soy meal is especially difficult because soy meal is itself the main “swing-provider” of protein in animal feed. Other oilseed meals are more clearly by-products of vegetable oil production, and so their production is less influenced by changes in the price of feed-protein. Indeed, if one chooses to substitute another oilseed meal that in turn generates a second-order vegetable oil debit to the soy oil pathway which is larger than the amount of soy oil to start with.

After much thought, we have taken as the principal pathway soy bean farming in Brazil and crushing in Europe, with the meal replacing soy meal which would otherwise be imported from Brazil. In this way, the shipping to EU of the soy meal fraction of the soy beans is cancelled by the credit from avoided soy meal import.

Note that this is a **change from the v3 results put on-line** in November 2008. There, we reported a case where the soy bean meal from a crusher in EU is given a credit based on substituting EU wheat as an animal feed. But we realized afterwards that this was unfair, because it attributed the emissions from shipping of the meal part of the soy beans to the soy oil.

The extra soy meal left in Brazil has the effect of reducing protein feed prices, with the result that in the end livestock will eat a greater proportion of protein feed in their diets. This is in replacement of cereals: in Brazil, principally maize. The amount of maize-farming in the credit is estimated on the basis of equivalent digestible energy.

In fact, the result is practically the same if we assume the crushing takes place in Brazil: in this case the transport of the soy meal does not happen in the first place. The only difference is that the crushing plant uses Brazilian energy inputs. However, upstream emissions from Brazilian gas and electricity are similar to EU mix.

For comparison, we also calculated a pathway on the basis of allocation of soybean farming emissions on the basis of price. This gave much worse emissions for the soy oil than substitution, because soy bean farming has lower fertilizer input and N₂O emissions per unit of digestible energy than cereal farming. Furthermore, we calculated a more complex substitution pathway in which the farming remains in Brazil but the substitution between soy meal and maize takes place in US: this gave a result intermediate between the other two scenarios. To keep things simple, we do not tabulate the results of these comparison scenarios.

To enable fair comparison with other biodiesel pathways, we keep the same two possibilities for glycerine substitution: as a chemical feedstock after purification, and added to a biogas digester in its crude state (similar result to using it as a fuel). If we had considered glycerine as animal feed, the pathway GHG emissions would be slightly worse.

Palm oil

Oil palms offer a very high oil yield: typically 3-4 tonnes/ha of palm oil, and the recycling of other biomass from the palms reduces fertilizer requirements and makes it an energy-efficient pathway.

Two countries, Indonesia and Malaysia, currently account for 87% of world palm oil production. Indonesia has already overtaken Malaysia as the world's largest producer, and has more land available for expansion: by 2018 Indonesia's oil palm area is projected to expand by 28%, and production by 42% [FAPRI 2009]. Expansion of oil palm plantations has generated criticism from NGOs related to rain forest clearance, biodiversity loss, working conditions and displacement of native populations.

Mature palm oil plantations contain more carbon in *above*-ground biomass than natural forest. However the greenhouse balance including land use change effects depends critically on what happens beneath ground level. In the best case, a plantation established on mineral soil, on anthropomorphic grassland, will sequester ~135 tonnes of CO₂ per hectare. On the other hand plantations established by draining peat-land lead to a loss of at least 1300 tonnes of CO₂ equivalent over the first 25 years [Germer 2008], or roughly 50 tonnes of CO₂ per tonne of palm oil produced.

There is about twice as much carbon stored in peat as in the forests of the world, and tropical peatland contains about 96% of tropical carbon. So draining tropical peatland has the potential to release far more carbon than tropical deforestation. One can see why losing only a small part of this can give very large consequences in terms of greenhouse gas emissions.

If not drained, peat forest continues to sequester carbon as peat, at a rate of roughly 1 tonne per hectare per year. Once drained, the accumulated peat starts to decay aerobically. The level of the peat goes down year by year as the carbon is lost as CO₂. When the soil level approaches the water table, the plantation will die unless the drainage is deepened (in which case the process re-starts). Therefore the loss of soil carbon continues for the entire lifetime of the plantation, or until there is no peat left.

Figures for which proportion of oil palms grow on peat vary greatly. Official Malaysian figures claimed only 8% of *existing* palm oil plantations are on peat, whereas NGOs claim that more than half of *new* palm oil plantations in Indonesia are on peat-land. In many areas, peatland is the only remaining uncropped land available. There is relatively little natural land left to convert in peninsula Malaysia, so expansion is shifting increasingly to Borneo, which contains most of Malaysia's peat. In peninsula Malaysia palm area is still expanding due to displacement of other plantation crops: this does not cause large changes in soil carbon. (However, rubber production may shift to other areas of SE Asia where there is still forest to convert).

We can also expect increased palm oil production from improved yields on existing palm oil plantations, and from plantations established on mineral soils. The limits of this increase are discussed in [Corley 2008]. It is not clear whether average yield will increase in future, because expansion tends to be onto less suitable land. In the past 25 years average yield has hardly changed, but that is at least partly because the acceleration of area expansion has meant that there is an increasing proportion of immature plantations.

Trees have long been extracted from accessible areas of peat-forest, but this does not necessitate drainage, although some may result accidentally from digging ditches to transport out the logs (damming the ditches allows the peat to be re-wetted at modest expense). However, systematic deep and irreversible drainage of peat-land is only done to establish a plantation.

Oil palm is the most profitable of the few crops which grow well on peat, but the initial investment in a network of drainage canals means that the plantations on peat are generally considered less profitable than those on more traditional plantation soils¹². So one may reasonably expect that higher palm oil prices will incentivize peatland drainage.

Drainage not only affects the plantation itself, but also any forest nearby. The peat here also decays (reportedly at an even faster rate than in the plantation). Furthermore, the dry peat in the forest is prone to catch fire. Plantation operators maintain fire services to put out peat-fires on the plantation, but fires on the drained peat-forest often burn unchecked. Fires are often used to clear undergrowth before plantation. Total emissions from peat fires are estimated at 1.4 GT CO₂ per year, compared to 0.63 GT from tropical peat drainage [Carbopeat 2008].and 1.6+/- 0.8 GT from deforestation worldwide.

NGOs allege that regulations have been ineffective in preventing drainage of peat-forest, mostly because they are not respected, and partly because they only apply to areas with very deep peat. Voluntary schemes for certifying sustainability have the welcome effect of giving a small price premium for sustainably-produced palm oil. However, unless all producers or all customers sign up, unsustainable production will replace certified palm oil diverted to participating customers.

Our GHG emission calculations DO NOT include any emissions from land use change, including peat drainage or peat fires.

The life of a palm tree is 20-30 years, so energy inputs for cultivation are low compared with annual crops such as rape seed. Fertiliser needs are significant, but can be mitigated to some extent by return of biomass to the land as mulch. The fruit is harvested as Fresh Fruit Bunches (FFB), and because these deteriorate rapidly in storage the oil is generally extracted in small plants close to the plantation. The FFBs are heated and crushed, yielding palm oil, palm fibre residue, nuts and a slurry of palm oil mill effluent.

¹² Increased yields have been reported on experimental test-plots on peat, but these have used higher planting densities and fertilizer rates than in commercial plantations.

The nuts are separated and crushed separately, yielding palm kernel oil (PKO), palm kernel meal and nut shells. PKO (about 11% of palm oil volume) has different properties and specialist uses, but could be used for biodiesel production. For our calculations, we have added the PKO to the PO for biodiesel, on the basis that present specialist markets may saturate as PKO production continues to increase, and it is difficult to model all its possible substitutions.

Palm kernel meal is used as animal feed. We model the case where palm oil is then shipped to Europe where it is converted to FAME in the same way as for other oil feeds. Pure palm oil methyl ester (POME) has too high cloud-point to meet transport fuel specifications, but can be blended with other biodiesels. It can also be used in stationary applications (as can pure palm oil).

The operation of the palm plantation and crushing facilities can significantly influence the GHG emissions. We have assumed that empty fruit bunches are returned to the land, and that correct composting procedures are used. This is best-practice, but examples have been cited where they are allowed to rot in anaerobic conditions, generating considerable methane emissions.

We have assumed the mill is heated using part of the nut shells and palm fibre. In an efficient mill, there is a surplus of biomass, and sometimes, where transport is easy, the excess nut shells are exported for heating elsewhere. We model two alternatives: either no credit, or a credit based on fossil heat replaced.

The water/slurry effluent from the mill is sent to a treatment pond. In the best case, the methane emissions are recovered; but in present practice they are usually released from open ponds. We have modelled both alternatives. Hence there are four pathways:

- POFA1a, residues generate CH₄ emissions, heat credit for excess residue biomass
- POFA1b, CH₄ emissions recovered, heat credit for excess residue biomass
- POFA1c, residues generate CH₄ emissions, no heat credit for excess residue

In the above pathways, glycerine from the FAME plant is assumed to be used as a chemical. The effect of using it to produce biogas is assessed through a separate pathway:

- POFA2, heat credit for FFB residue, glycerine used as biogas to meet part of FAME plant needs

Hydrotreated Plant Oils

The amount of FAME that can be added to conventional EN590 diesel fuel is limited to maintain acceptable fuel quality and compatibility with the vehicles in the market. In addition, the transesterification process leaves the basic backbone of the molecule unchanged, so the fuel properties depend to some extent on the type of oil or fat used in the process. Where the oil or fat contains many double bonds, stability may be a problem and conversely if the chains are long and saturated it may be difficult to meet cold flow requirements.

As an alternative to trans-esterification the pure oil can be hydrotreated. This removes double bonds and oxygen from the molecule, yielding a paraffinic fuel similar in properties to Fischer-Tropsch diesel. This can either be used alone or blended with conventional diesel, and the final fuel properties are much less dependent on the original feedstock, so a wider range of feedstocks can be used.

The Neste Oil process (NexBTL®) is the first to be used in commercial production, and we have modelled this process using rapeseed, soy and palm oils. Similar processes are being developed by a number of other companies, and for comparison a process from UOP has been included, using rapeseed oil.

3.4.11 Wood

Wood waste is often presented as a vast untapped source of energy. Upon closer investigation, it appears that industrial wastes or recovered wood are already used as much as is possible (there are 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 transport sector with realistic economics is forest residuals from commercial forestry. These are the branches and tops which are left in the forest with conventional harvesting methods. 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).

Harvested forests absorb carbon dioxide much faster than mature forest stands, so harvesting them for energy use definitely increases the CO₂ uptake from the atmosphere.

If the felling residues and thinnings are left in the forest, they initially add to the stock of carbon in the forest litter, but they rot away with a characteristic exponential decay time of about 10 years. That means the initial rate is about 10% per year. (see fig. 5 in [Liski 2005]). That means the GHG emissions saved by collecting the residues are delayed compared to those saved by substituting fossil fuel.

According to our WTT results, each kg carbon in wood replaces about 0.3-0.65 kg fossil carbon (depending on the pathway: transport fuel or heating, and the carbon intensity of the fossil fuel replaced). So in the first year, more net carbon is emitted by burning than would be sequestered by leaving the residues in the forest. However, the balance of carbon emissions from using those residues turns positive after 3 to 7 years, and the cumulative carbon savings then go on to approach the time-independent values. We have not made any time-discounting of GHG emissions to account for the effect of this time-delay.

However, there is also a long-term effect on soil carbon, which is really a land-use change emission, but on a very long time-scale. If the rate of forest litter removal is changed, the soil carbon stock is modelled to exponentially approach long-term equilibrium, with a characteristic time of about 350 years (fig. 3 in [Liski 2005], which assumes regular 90-year clearcut fellings). On such a long time-scale, it seems reasonable to compare the annualized soil carbon loss with the annual CO₂ saved by using the residues.

[Liski 2005] estimate that reducing the rate of forest litter deposition by 1% causes ~0.36% reduction in the steady-state soil carbon. They estimate a litter rate of 0.4kgC/m²/y and a soil carbon stock of about 10kg/m². So removing an average of 1kg carbon in forest litter per year would result in 9 kg loss in steady-state soil carbon stock. Spread over 350 years, that is an annualized rate of soil carbon loss of 26 grams per year. So of the carbon removed in the form of forest residues, about 2.6% is lost from the soil carbon. Burning 1MJ wood releases about 100g CO₂, so the soil carbon loss is equivalent to a CO₂ release of 2.6gCO₂/MJ of forest residues. We neglect this.

There is also the nitrogen balance to consider. Removing residues removes some fixed nitrogen from the forest: one could consider replacing this with artificial fertilizer. This would generate N₂O emissions in the forest soils, but these are only about the same as those from the decomposition of the

forest residues. Overall, we think the effects on the GHG balance are small, and we do not consider them.

The commercial forests in EU grow slightly more than is harvested each year, so there is potential to increase the sustainable supply of stem-wood (as well as residuals) 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). 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. Apart from providing renewable energy, SRF grown on arable land sequesters carbon in the soil (see *section 3.4.1*).

Perennial crops, such as miscanthus, switchgrass and short-rotation forestry (SRF), are thought to have a higher potential biomass yield than annual crops because the root system is already established at the start of the growing season. However, in practice commercial SRF plantations give only slightly higher biomass yields than wheat on the same land (if the straw is also harvested, wheat will generally give even a greater biomass yield, although with more inputs - see also *section 5.2.2*). In the past, studies of biomass potential have taken yields from SRF on good arable land, for example 8-10tonnes/ha/y, and applied them to land too poor to support arable crops. In practice much lower SRF yields can be expected on such land; the crop can even fail altogether.

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 higher-yielding biomass crop than SRF, but it requires more inputs (fertilizer, diesel, labour...). In recent years, fodder-maize has been found to be a more economic high-yield, high-input energy crop.

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 plants. 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 as 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 being 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 gasifier 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 3.4.9*). 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 case” 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 (Na₂S) and sodium carbonate (Na₂CO₃) 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. Pilot plant operation is reported to be successful after one year.

In [Ekbon 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.

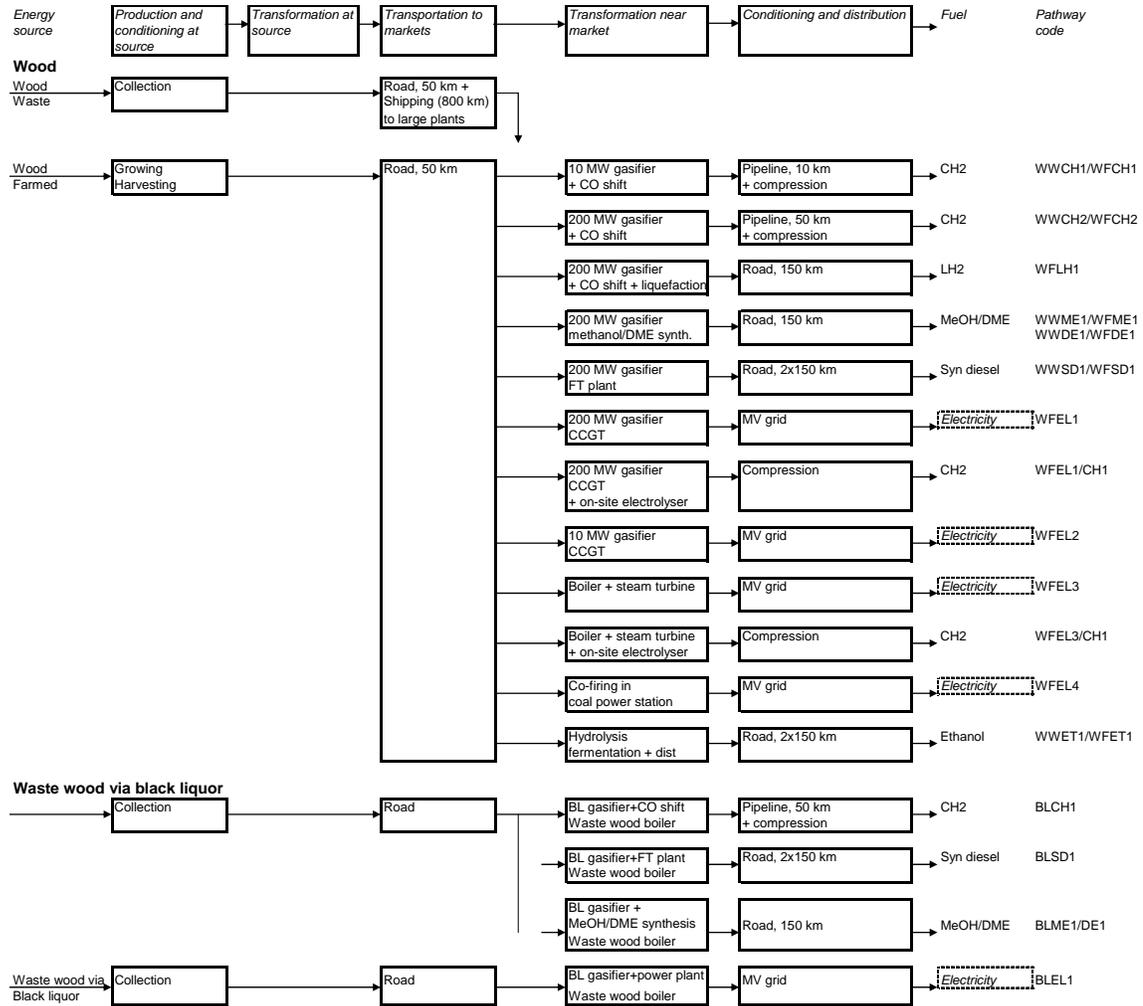
The following table summarises the "wood efficiency" of the various wood processes after correction for electricity production as discussed above.

Table 3.4.11 Wood efficiency of various wood conversion routes

MJ wood/ MJ final fuel (corrected for electricity production)	10 MW			200 MW			Black liquor route		
	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
Methanol/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.

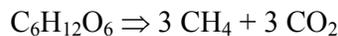
Figure 3.4.11 Wood pathways



3.4.12 Organic material to biogas

The anaerobic fermentation of organic matter produces a gaseous mixture, known as "biogas", consisting mainly of methane and CO₂ (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 H₂ (0-1%), N₂ (0-7%), H₂S (0-1%) and traces of NH₃ 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:



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 H₂S, and upgraded to a higher heating value or Wobbe index by removing the bulk of the CO₂. 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 waste feedstocks:

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

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

H₂S 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 H₂S 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, CO₂ 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 m³ per 100 Nm³ 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 CH₄/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 CH₄ 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:

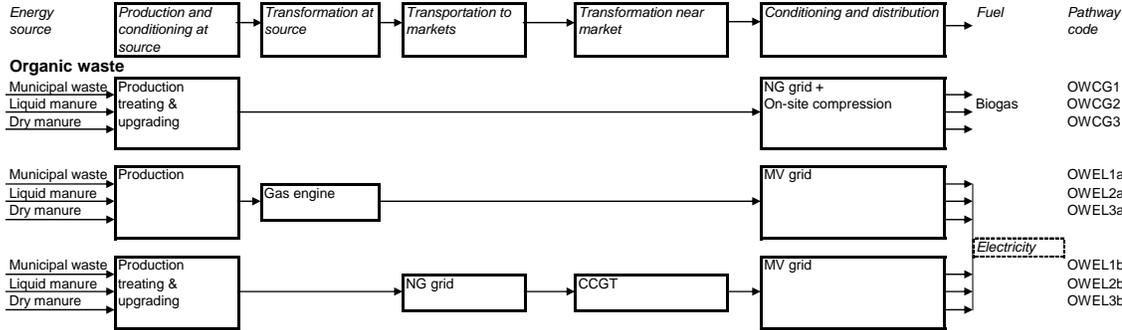
- Small scale plant where the raw biogas is used directly in a local power plant.
- Larger scale installation where upgraded gas is exported to the grid and subsequently used in a large power plant.

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 3.4.12-1 Organic waste to biogas pathways



Purpose-grown crops can of course also be used in principle to produce biogas 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. However, traditional fermentation processes to produce ethanol can use only the wheat grain, whereas production of biogas has the advantage that the whole plant including the straw can be used, and hence improve yield.

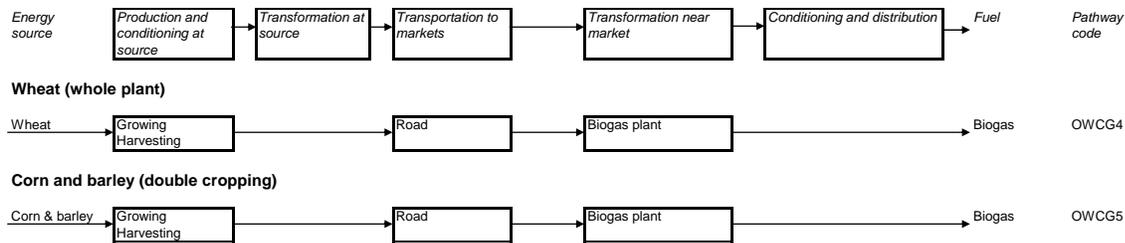
OWCG4: Farmed wheat to automotive biogas

In pathway OWCG4, the whole wheat plant is converted to biogas which is treated and upgraded before being fed into the NG grid to be used as an automotive fuel. The residue is returned to the fields, producing a credit by substituting chemical fertiliser.

OWCG5: Double-cropped Barley and Maize to automotive biogas

A wide range of organic material can be processed to produce biogas, so farming practices that maximise the amount of biomass produced are attractive. In some cases, two crops can be produced from the land in a single year. In this pathway, we consider maize followed by winter barley. Both crops are cultivated and harvested in the same year and organic agriculture is assumed. The fertilizer requirement is met by the residue of the downstream biogas plant.

Figure 3.4.12-2 Farmed crops to biogas pathways



3.5 Electricity production and electrolysis

(See also WTT Appendix 1 sections 15&16)

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 large-scale 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 CCS 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 3.2.3) with and without CCS 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 CCS 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 CCS 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 3.4.11*).

Organic waste via biogas

See *section 3.4.12*

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 CO₂ 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 an 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.

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 CO₂ 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.

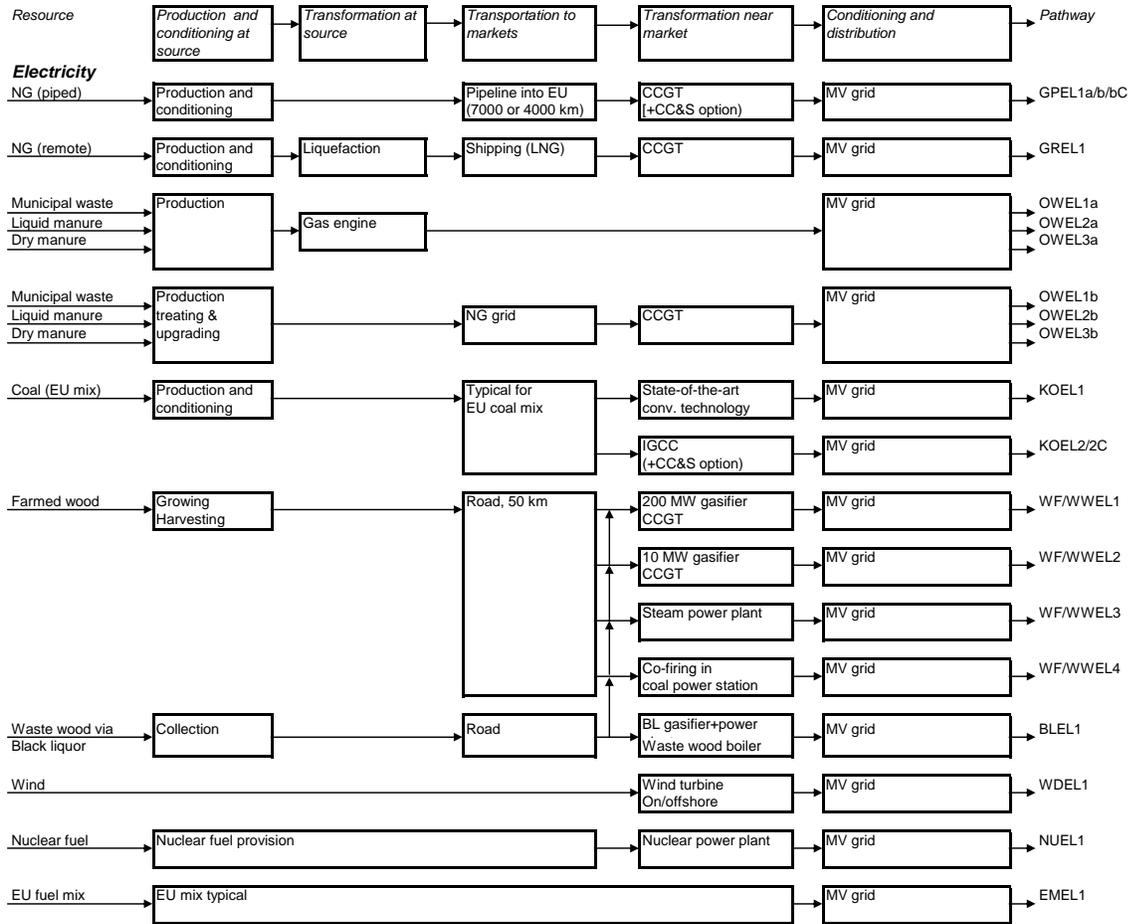
Table 3.5.1 ***EU-mix electricity sources***

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 CO₂eq/kWh_e (119 g CO₂eq/MJ_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 3*.

Note: the GHG figure quoted above is coincidentally 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.

Figure 3.5.1 Electricity generation pathways



3.5.2 Hydrogen via electrolysis

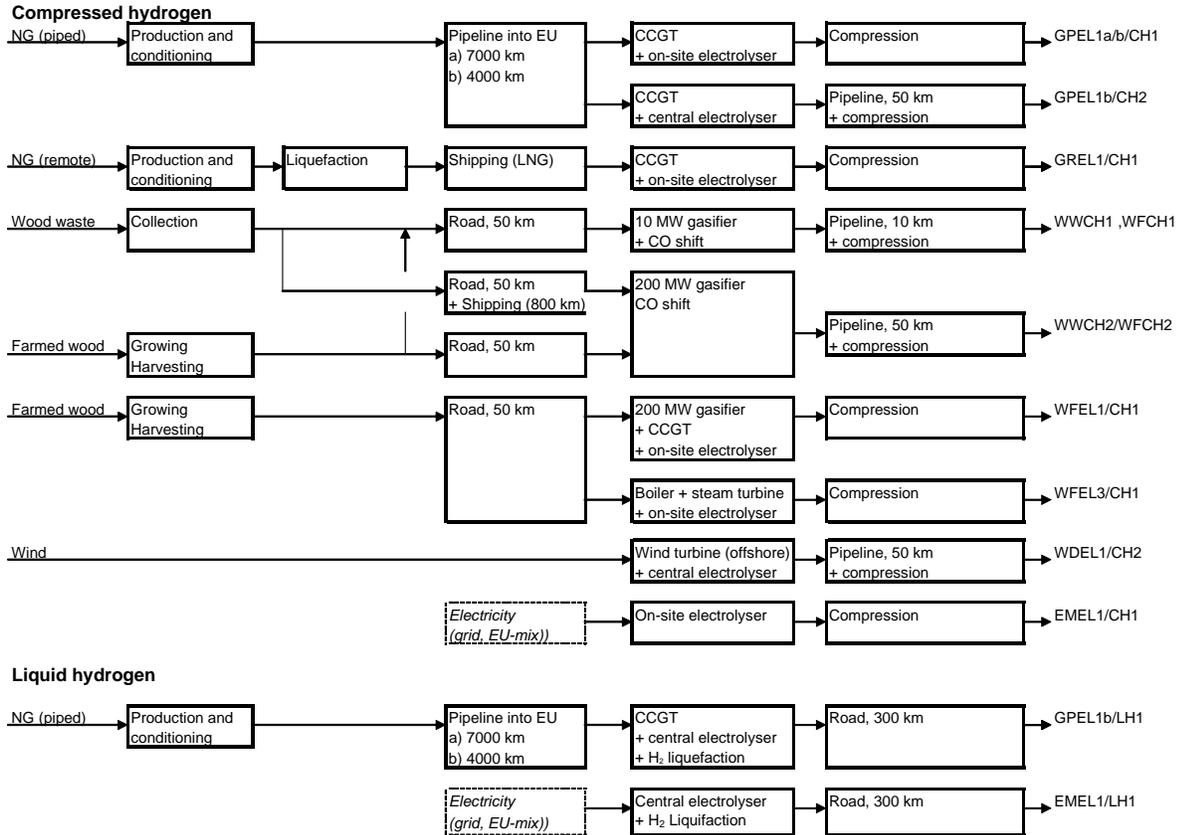
The electrolysis of water to hydrogen and oxygen is a long established process. It is possible to build electrolysis plants from very small to very large scale. The efficiency of the electrolysis process as such is largely unaffected by scale although the auxiliaries and the operating pressure can have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

Several sources of data are available, giving figures for both small and large (alkaline) electrolyzers 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 kWh/Nm³ 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.

3.5.3 Combined Heat and Power

Electricity generation enters into the WTT calculations primarily as an input to the various fuel production pathways. Some pathways also include generation of electricity as part of the process, either from NG or using the by-products of road fuel production. In these cases, waste heat can often be usefully employed in the production process. For purposes of comparison, we have therefore included new pathways describing typical performance of small and industrial case boilers and large scale CHP plants fed with heating oil, natural gas, biogas or wood. Heat is treated as a by-product, by comparing with stand-alone heat generation using the same fuel.

Figure 3.5.3-1 Heat pathways

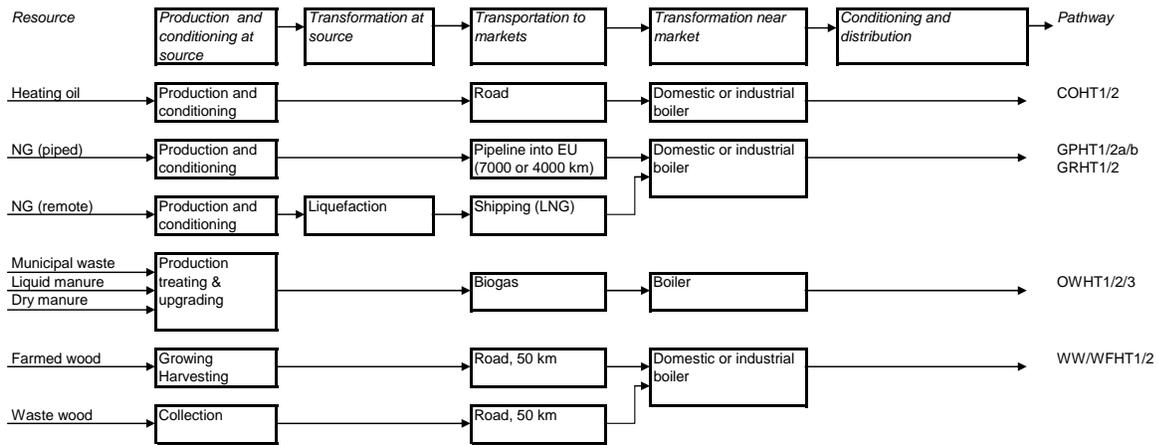
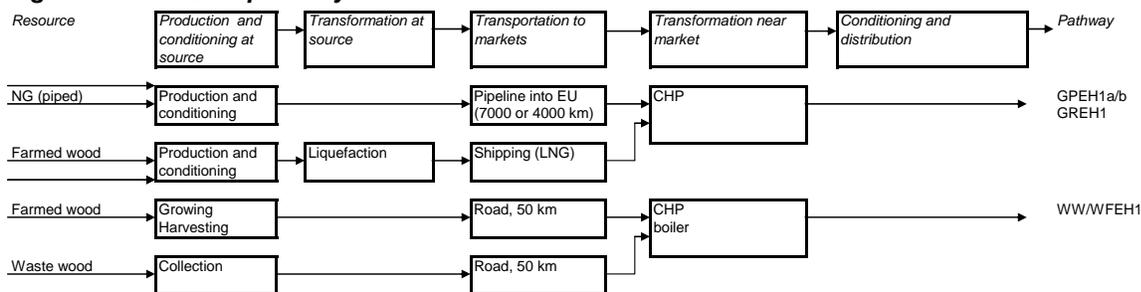


Figure 3.5.3-2 CHP pathways



3.6 CO₂ Capture and Storage (CCS)

The concept of isolating the CO₂ 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. CO₂ 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 include separation of CO₂ from other gases, compression and liquefaction, transport (by pipeline or ships) to the point of injection and injection under pressure.

Separation of CO₂ from other gases is a well-established process consisting in scrubbing the CO₂-containing gas mixture with a solvent or a physical absorbent. In combustion applications using air, scrubbing CO₂ 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 CO₂, although additional energy needs to be expended in the air separation unit. Reforming and gasification processes deliver CO/hydrogen/CO₂ mixtures or mostly hydrogen/CO₂ after the shift reaction. In these cases CO₂ scrubbing is more straightforward. In some cases, for example before syngas is fed to a Fischer-Tropsch reactor, CO₂ scrubbing is required irrespective of the CCS option.

CO₂ 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 CCS in the following cases:

- Electricity from natural gas and coal (IGCC)
- LNG: CO₂ from the power plant associated to the liquefaction plant.
- Hydrogen from NG and coal: Process CO₂ after shift reaction
- GTL and CTL diesel: Process CO₂ after reforming / partial oxidation
- DME from NG: Process CO₂ after reforming

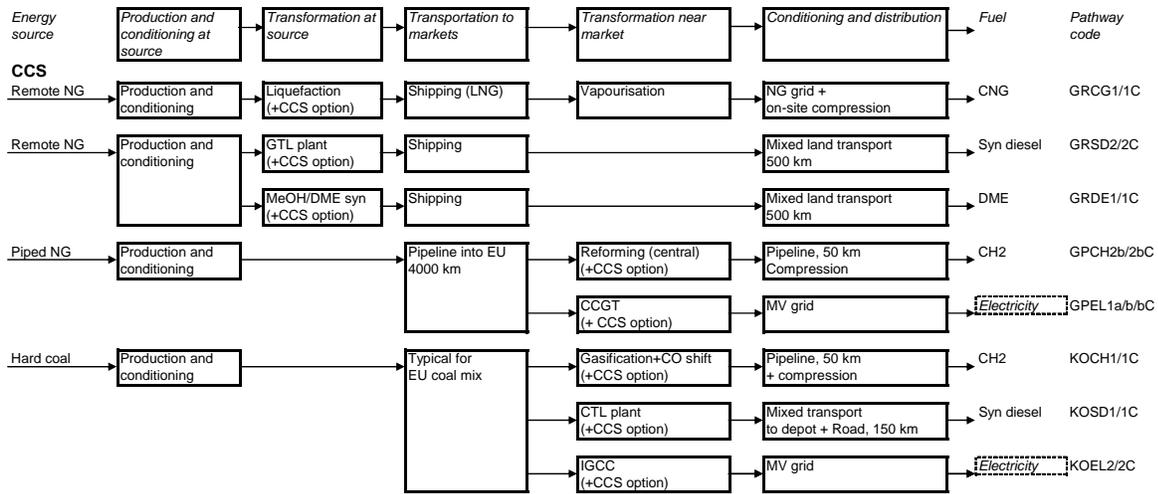
Note: the DME scheme could also be applied to methanol. We have not included it here because of the relatively minor importance of methanol as a potential automotive fuel.

In attempting to assess the CO₂ benefit and energy requirement of CCS 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 CCS 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 CCS and the case with CCS. Many of the process schemes are complex, involving multiple sources of CO₂. In a GTL plant, for instance, CO₂ 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 CO₂. Generally therefore the degree of CO₂ 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, CO₂ 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 CO₂ 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 CCS 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 CCS option



Electricity

For natural gas two different routes for CCS 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 CO₂ before burning the hydrogen in an adapted CCGT.

In this study we have considered the post-combustion option. Based on [Rubin 2004] the overall energy efficiency would decrease from 55% in the reference case to 47% with CCS, for a CO₂ recovery of 90% and including the energy required to compress and inject CO₂ 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 CCS based on [TAB 1999] and [ENEA 2004].

The table below shows the impact of CCS on energy and CO₂ emissions.

Table 3.6-1 Electricity production with/without CCS

Feedstock	Case	Natural gas		Coal	
		Base	with CC&S	Base	with CC&S
Natural gas	MJ/MJe	1.818	2.123		
Coal	MJ/MJe			2.083	2.439
Energy efficiency		55.0%	47.1%	48.0%	41.0%
Net GHG emissions	g CO _{2eq} /MJe	100.1	11.9	200.6	23.4
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 CO₂ 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.

CO₂ capture involves an additional scrubbing process between CO-shift and PSA followed by compression / liquefaction of CO₂ to 15 MPa. We have based our figures on a conceptual plant design described in [Foster Wheeler 1996]. The study includes base case (no CCS) and CCS case for both natural gas and coal. In the CCS cases, CO₂ is extracted chemically with activated MDEA as solvent. Heat and electricity are required for the regeneration of the solvent and CO₂ 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 CCS on energy and CO₂ emissions.

Table 3.6-2 Hydrogen production with/without CCS

Feedstock Case	Natural gas		Coal	
	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 CCS is much larger for coal but so is the absolute amount of CO₂ removed. In the coal case, virtually all CO₂ is produced in the gasifier and/or CO-shift reactor so that removal can be close to complete. In the natural gas case, the CO₂ 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, CO₂ has to be removed upstream of the synthesis step because CO₂ is not desired in the gas stream entering the synthesis reactor. Usually CO₂ is separated via a selective physical absorption process such as SELEXOL™ which uses an aqueous solution of a di-methyl ether or 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 CCS 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 CCS

Feedstock Case	Natural gas	
	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 no literature source where a NG FT plant with and without CCS 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 CCS. [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 CO₂ generated in the auxiliary power plant is not recovered in this scheme, so that the CO₂ recovery is relatively low at around 75%.

For coal-to-liquid [Gray 2001] gives a direct comparison of base and CCS cases.

Table 3.6-4 Syn-diesel production with/without CCS

Feedstock Case		Natural gas		Coal	
		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 CCS (as described above).

3.7 Synthetic fuels transport and distribution

3.7.1 Hydrogen transport and distribution

(see also WTT Appendix 1 section 17)

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 sections 18, 19)

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.

Biogas

Biogas is essentially methane, and after cleaning can take advantage of the general NG pipeline system for distribution. In this sense the points of production and use do not necessarily have to be close to each other, and the biogas can contribute wherever a refuelling infrastructure for CNG vehicles exists. In those areas where a NG pipeline system does not exist, a separate distribution system will be needed, and in this case local use of the biogas is more appropriate.

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

$$\text{MJ}_{\text{xt}}/\text{MJ}_{\text{f}} = \text{MJ expended total energy per MJ finished fuel (LHV basis)}$$

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

$$\text{MJ}_{\text{xf0}}/\text{MJ}_{\text{f}} = \text{MJ expended fossil energy per MJ finished fuel}$$

The reported WTT GHG figures exclude CO₂ 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 CO₂ 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 CO₂ 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 CO₂ emissions for the fossil fuels.

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

(see also *WTT Appendix 2 section 1*)

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

Gasoline and diesel fuel from conventional crude oil 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. As noted in Section 3.1.1 non-conventional sources of crude oil are not expected to impact the European market in the time frame of this study.

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 3.1.3* and *WTT Appendix 3*).

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

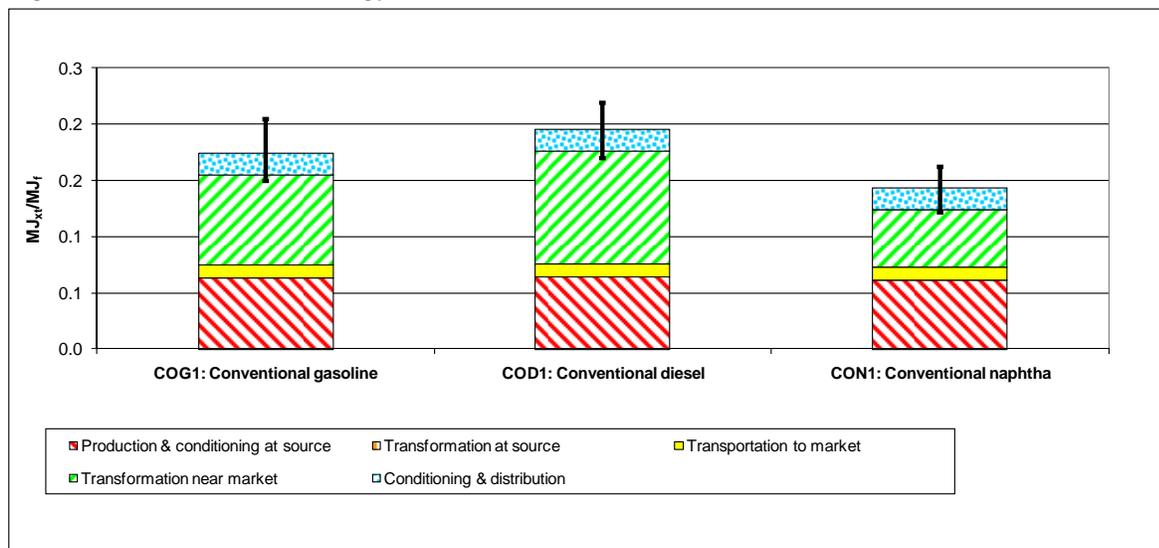
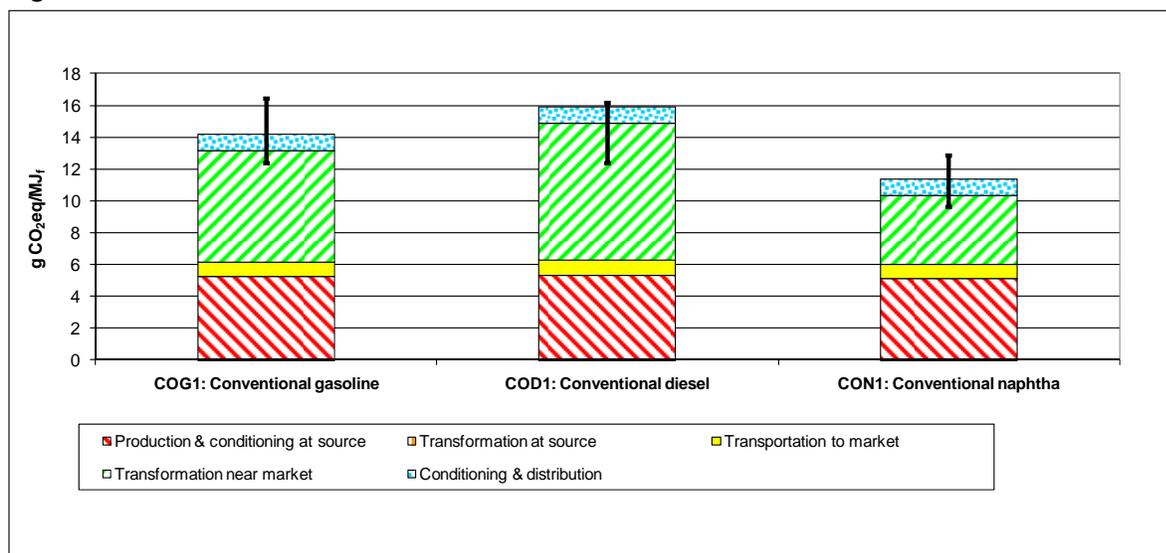


Figure 4.2-2 WTT GHG balance for crude oil based fuels



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)

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.

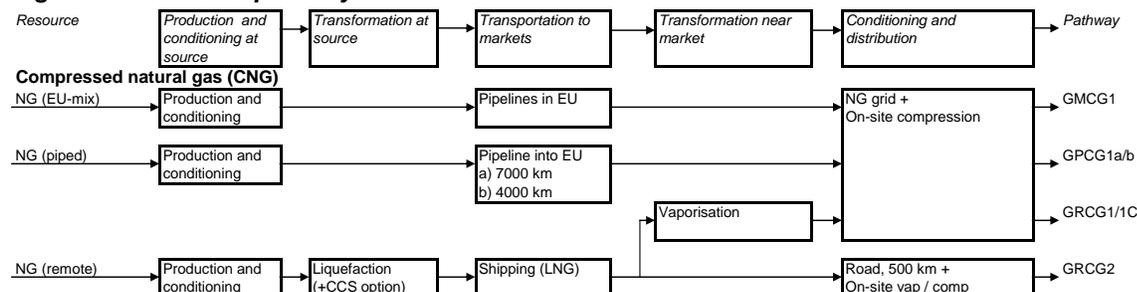
After reaching the refuelling station the gas needs to be compressed to a sufficient pressure to ensure fast refuelling. For on-board tanks at 20 MPa maximum a pressure of 25 MPa is required. Compression is an energy-intensive process, the energy consumption being strongly dependent on the outlet to 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 CCS 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 CCS 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 CCS comes close to the 4000 km pipeline option in terms of GHG. The potential of CCS 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

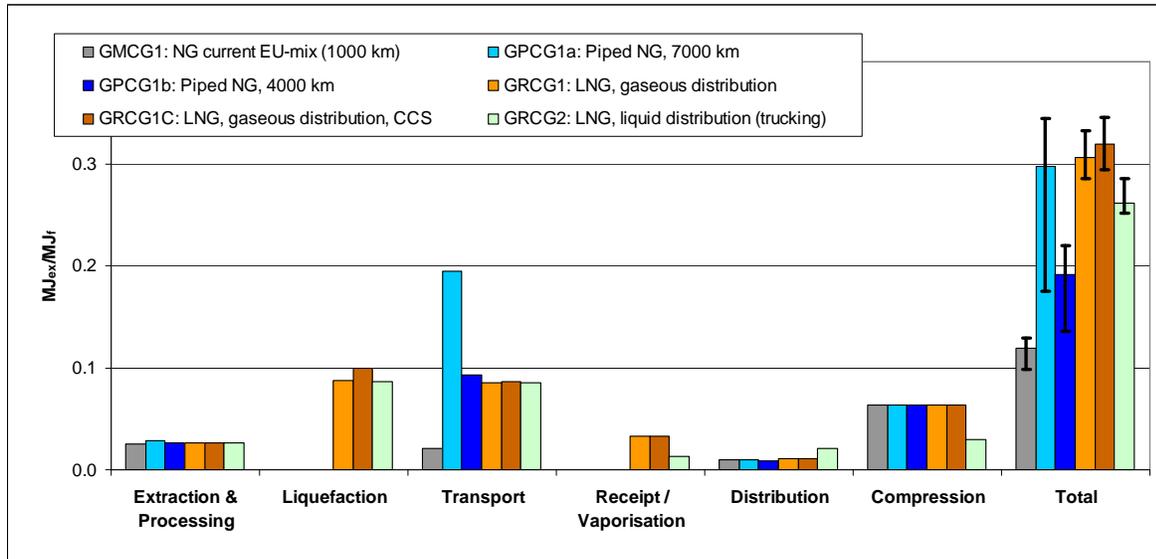
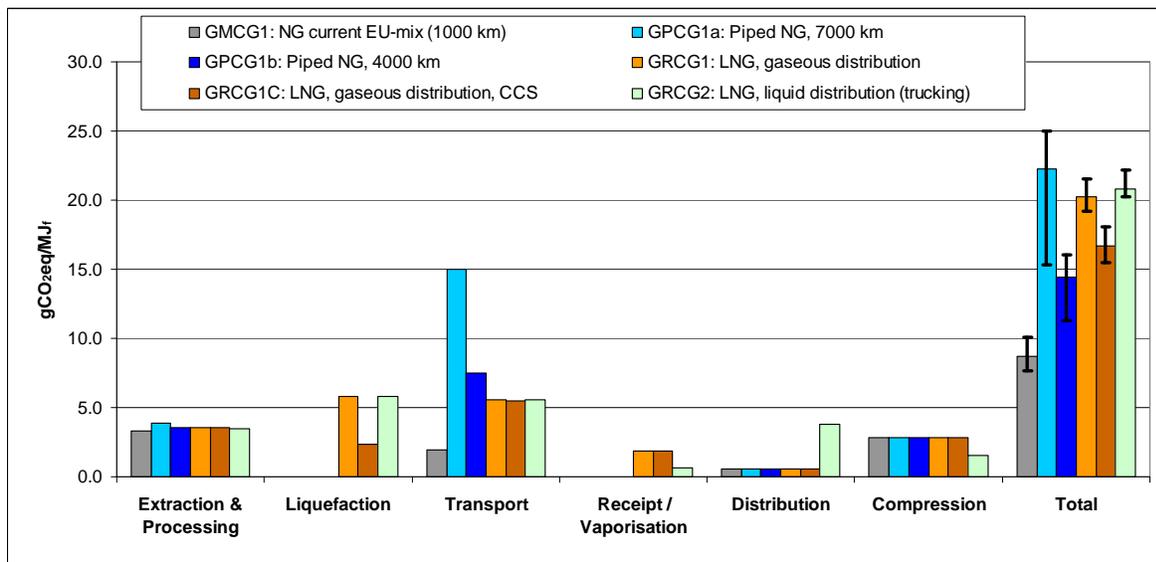


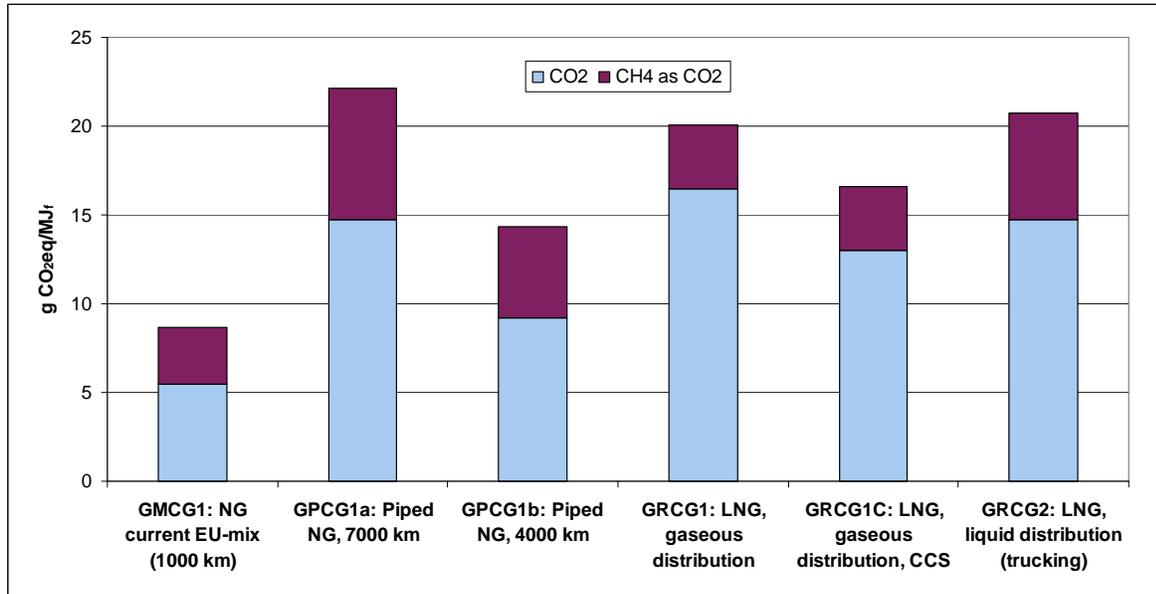
Figure 4.3.2-2 WTT GHG balance build-up for CNG pathways



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

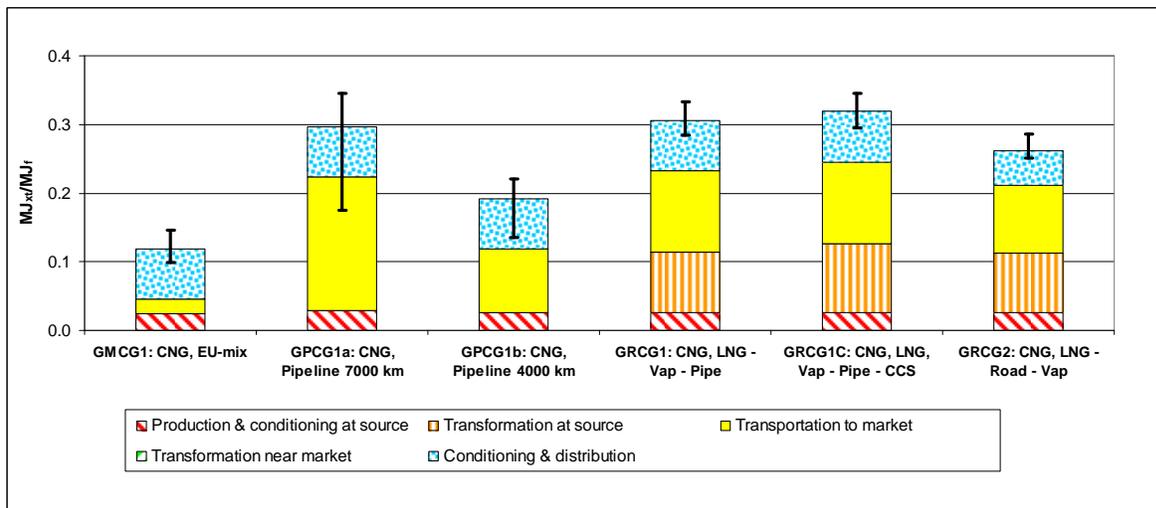
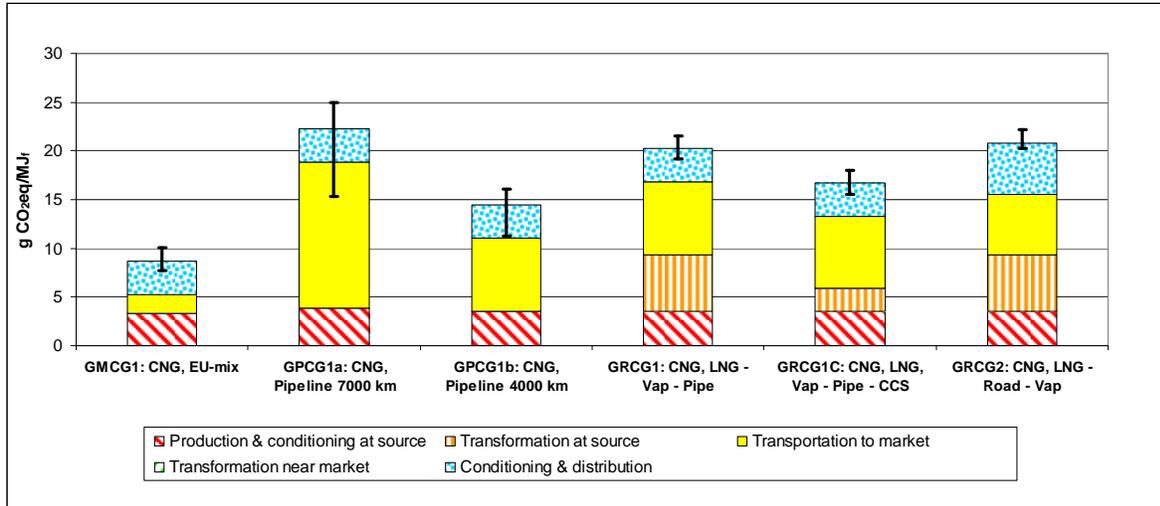


Figure 4.3.2-5 WTT GHG balance of CNG pathways



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

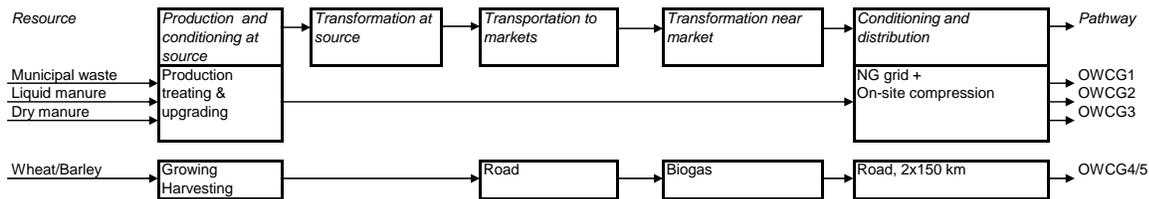


Figure 4.3.3-2 shows a relatively high total energy, mostly related to the limited conversion rate of the biomass used (assumed 70%). For waste materials, inasmuch as this represents the only practical way of using them for energy purposes, this is not important here. The fossil energy share of this is very small indeed ranging from 0.17 MJ_x/MJ_f for municipal waste to 0.01 for dry manure, and is equally low for biogas produced from wheat.

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).

For GHG emissions (**Figure 4.3.3-3**), the diamond symbols show the overall emissions in producing the fuel. The 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. For wheat, the GHG emissions are slightly higher, but comparable to those for production of CNG, and better than most of the wheat to ethanol pathways.

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

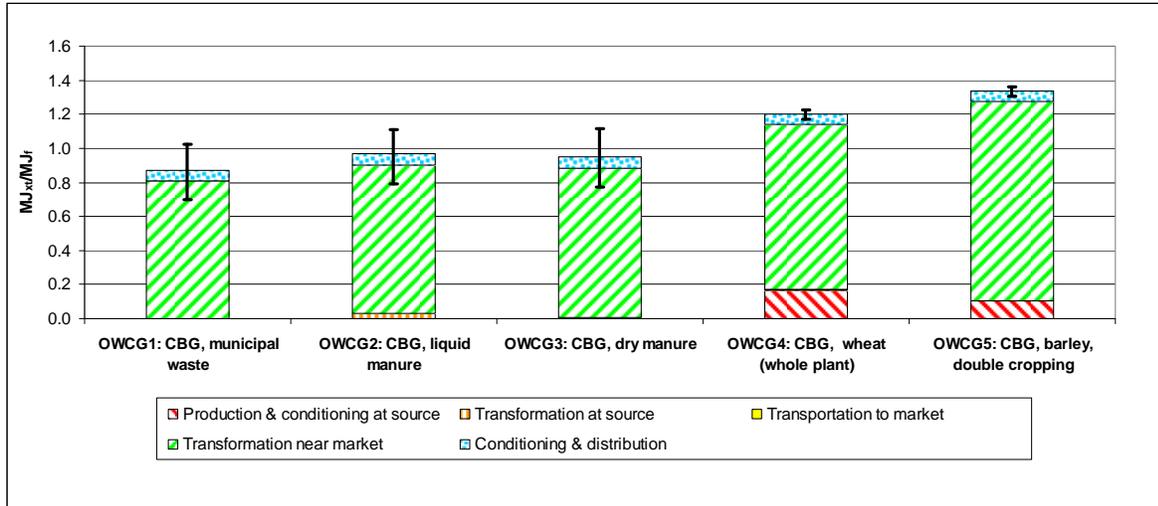
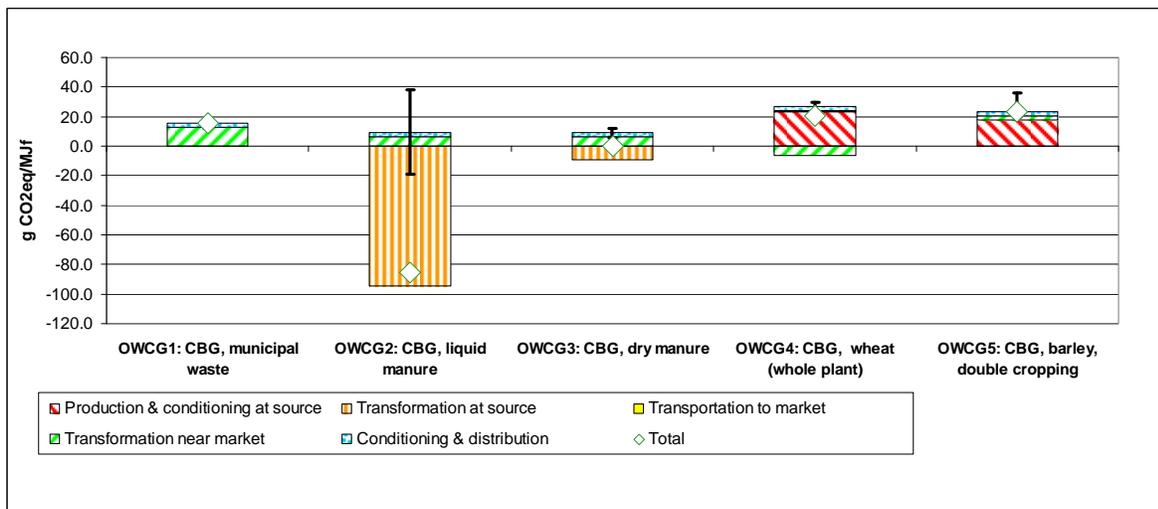


Figure 4.3.3-3 WTT GHG balance of CBG pathways

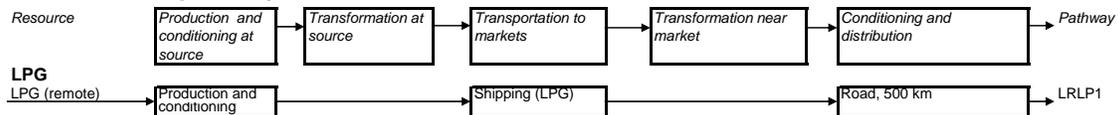


4.3.4 Liquefied Petroleum Gas (LPG)

(See also WTT Appendix 2 section 2.3)

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

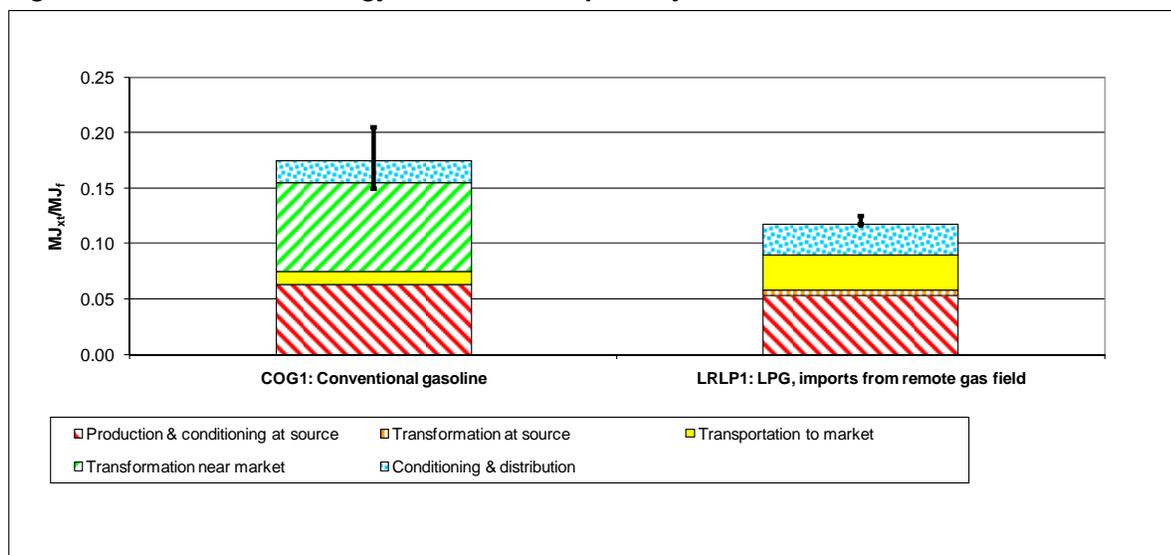
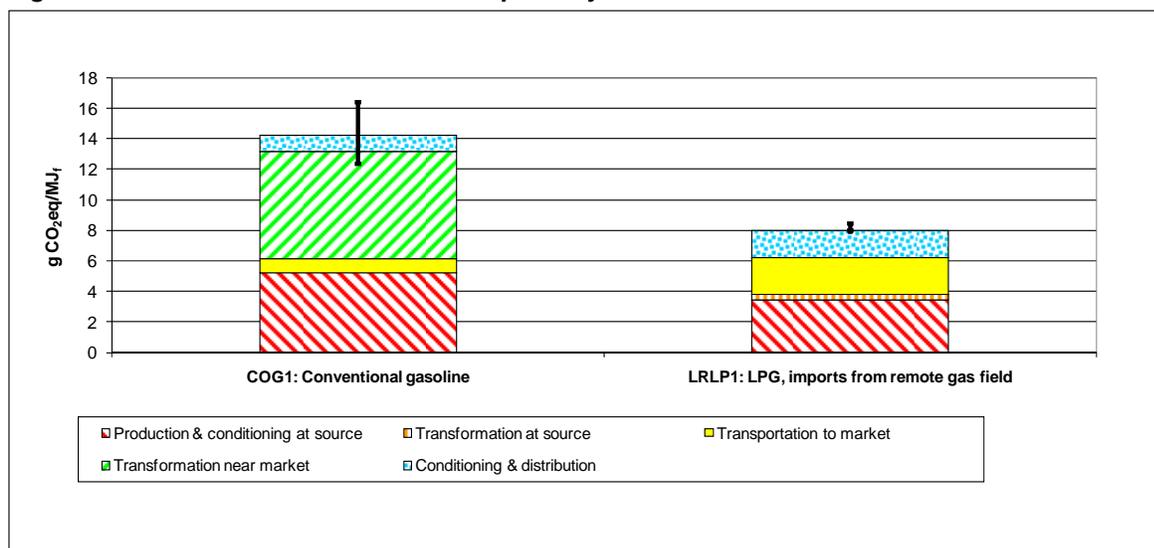


Figure 4.3.4-3 WTT GHG balance of LPG pathway



4.4 Ethanol

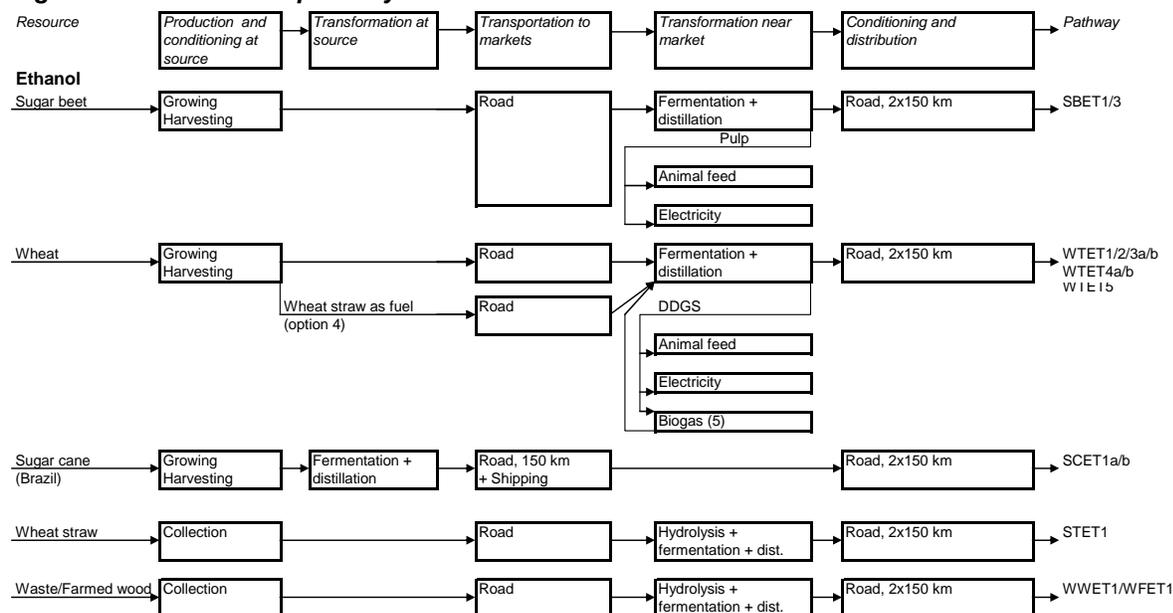
(See also *WTT Appendix 2 section 3*)

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 3.4.4/3.4.9*).

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/b show 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 sugar beet ethanol pathways

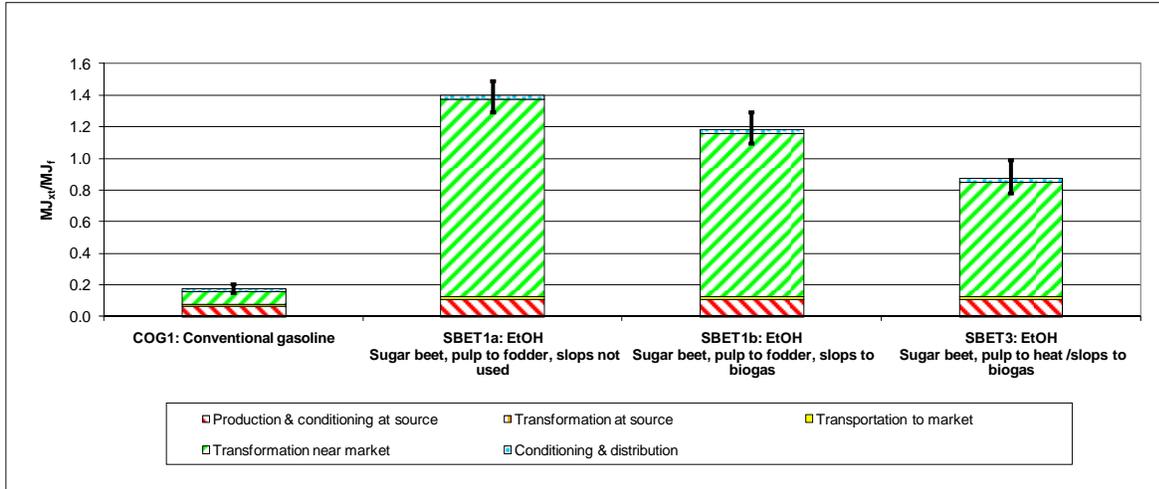


Figure 4.4.2-1b WTT total energy balance of wheat ethanol pathways

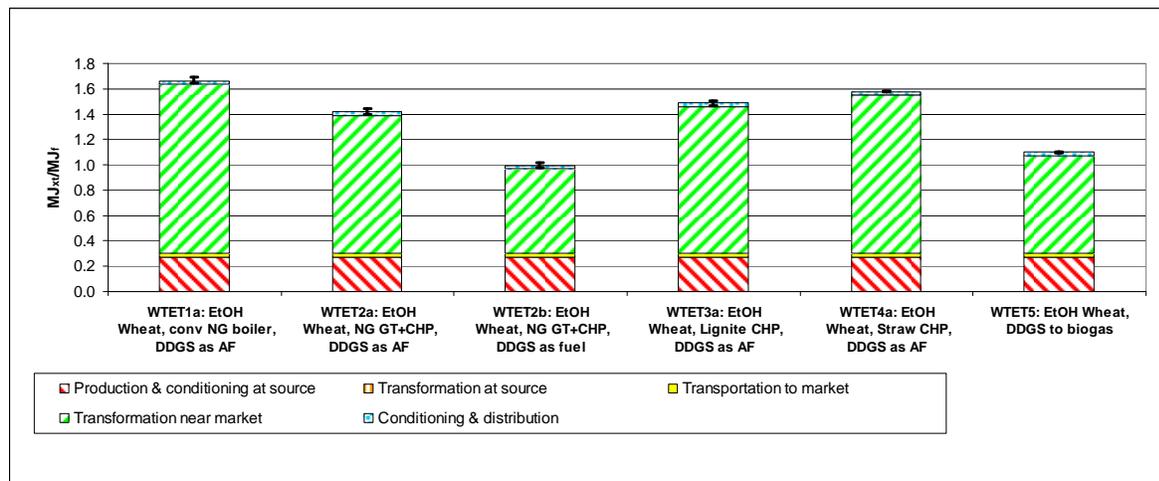


Figure 4.4.2-1c WTT total energy balance of ethanol pathways (various feedstocks)

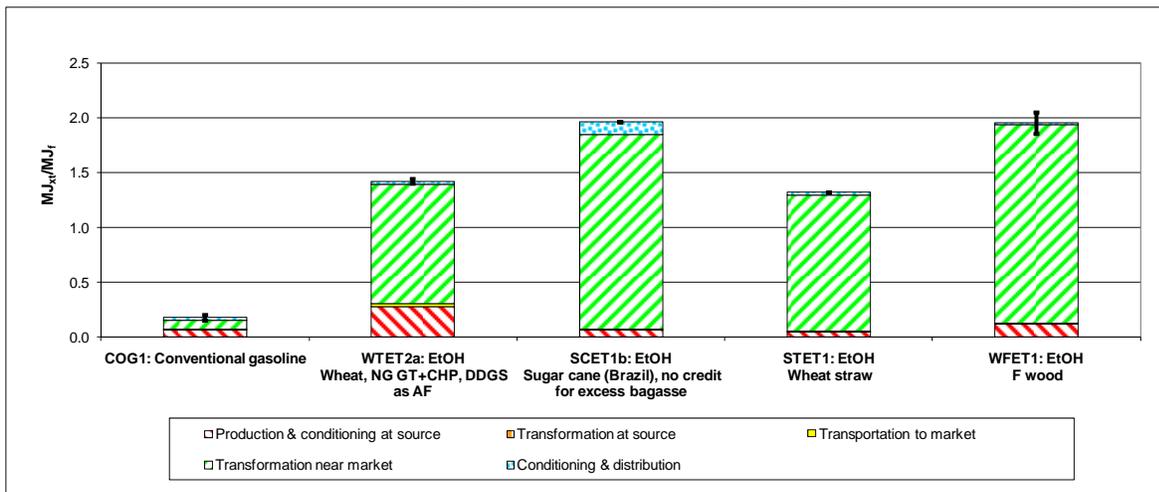


Figure 4.4.2-1c shows the total energy balance for more advanced biomass-to-ethanol pathways (WTET2a is repeated for comparison).

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/c compare 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.

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.

Figure 4.4.2-2a WTT fossil energy balance of sugar beet ethanol pathways

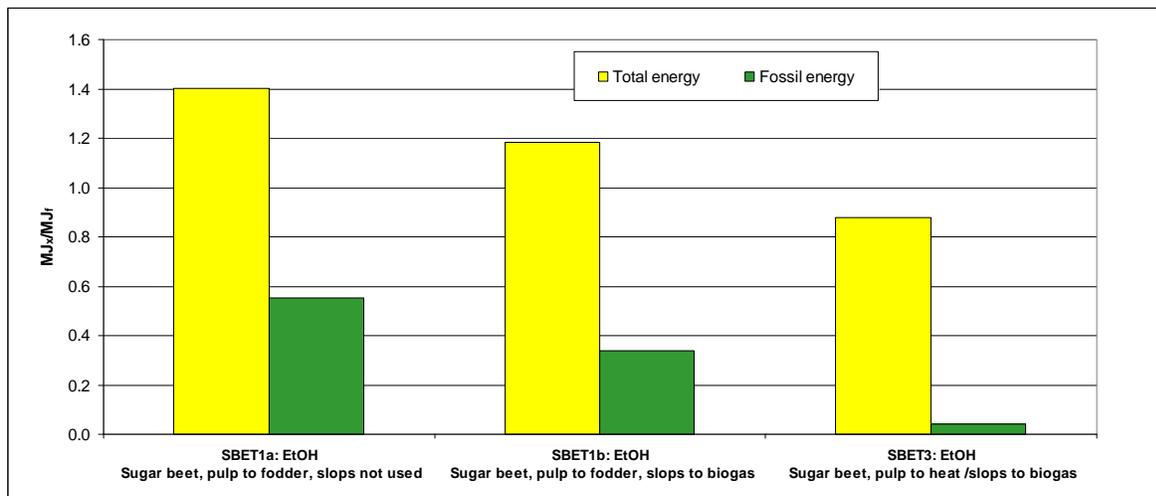


Figure 4.4.2-2b WTT fossil energy balance of wheat ethanol pathways

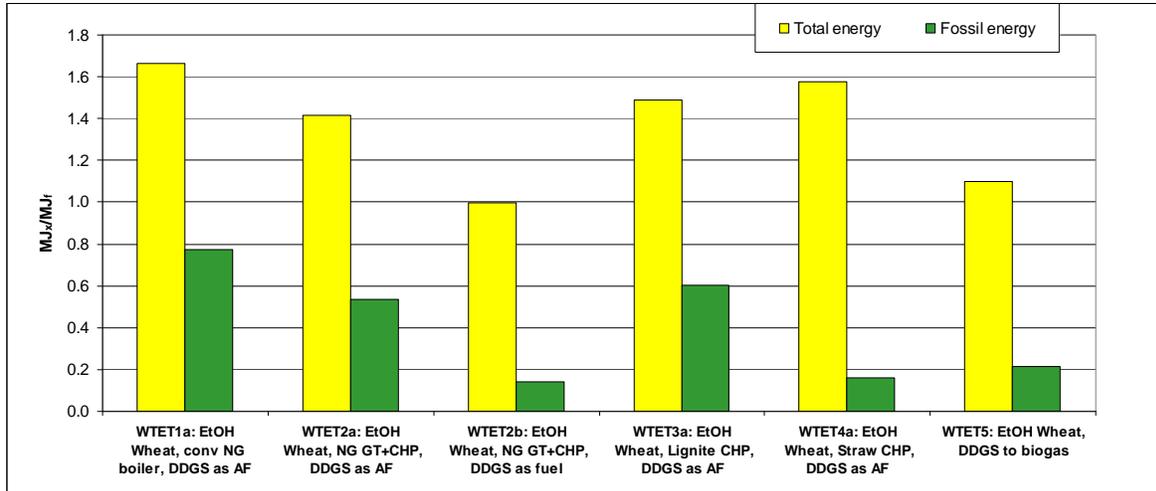
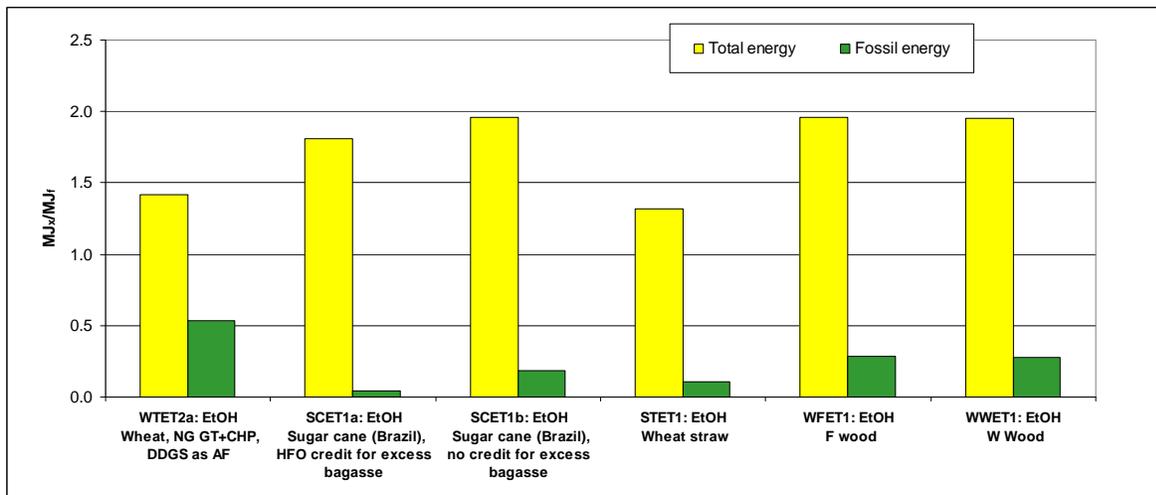


Figure 4.4.2-2c WTT fossil energy balance of ethanol pathways (various feedstocks)



4.4.3 Ethanol WTT GHG balance

Figure 4.4.3-1a/b/c show the total GHG build-up along the different stages of the pathways. The gasoline balance is also included in the first figure as reference (the gasoline combustion CO₂ has been added to make the GHG figures comparable).

The figures show the GHG emissions associated with producing the fuel, excluding the emissions when the fuel is used in the vehicle.

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 N₂O 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 N₂O 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 CO₂ 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 N₂O emissions from the fields).

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

Figure 4.4.3-1a GHG balance of sugar beet ethanol pathways

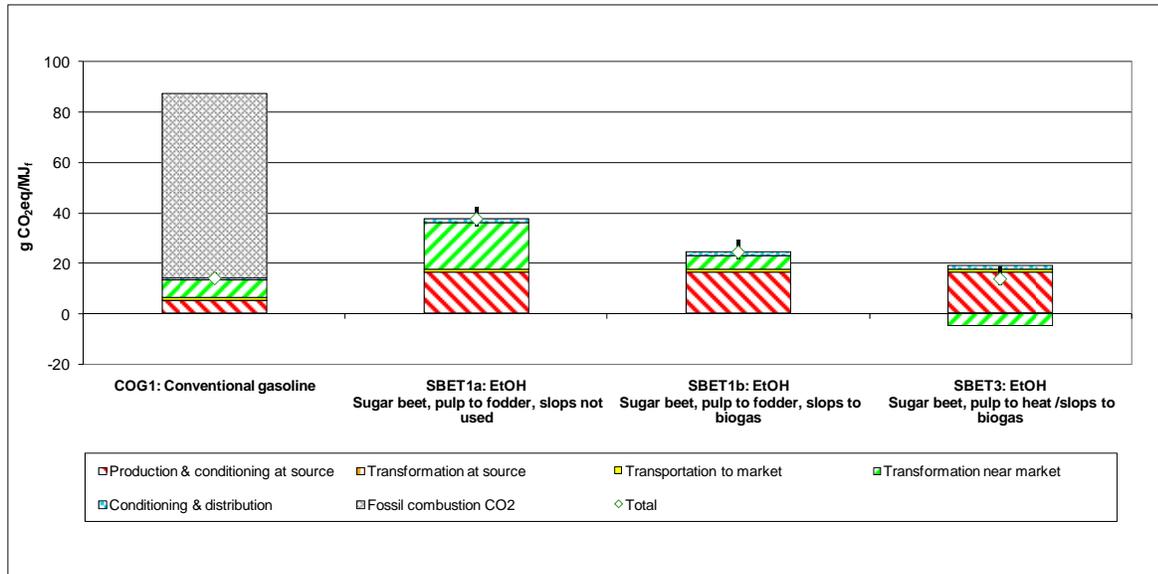


Figure 4.4.3-1b GHG balance of wheat ethanol pathways

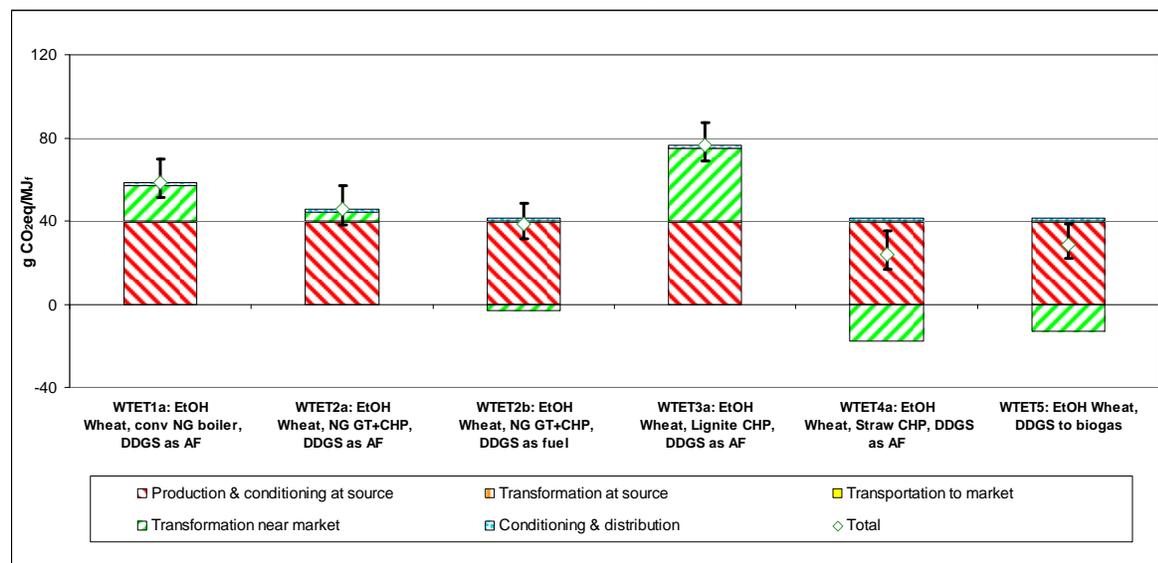
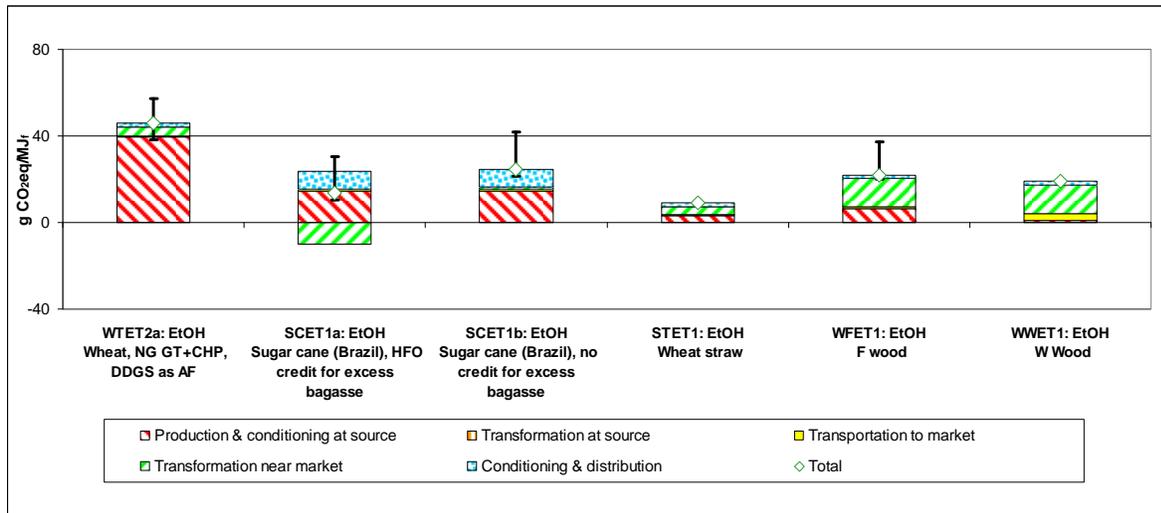


Figure 4.4.3-1c GHG balance of ethanol pathways (various feedstocks)



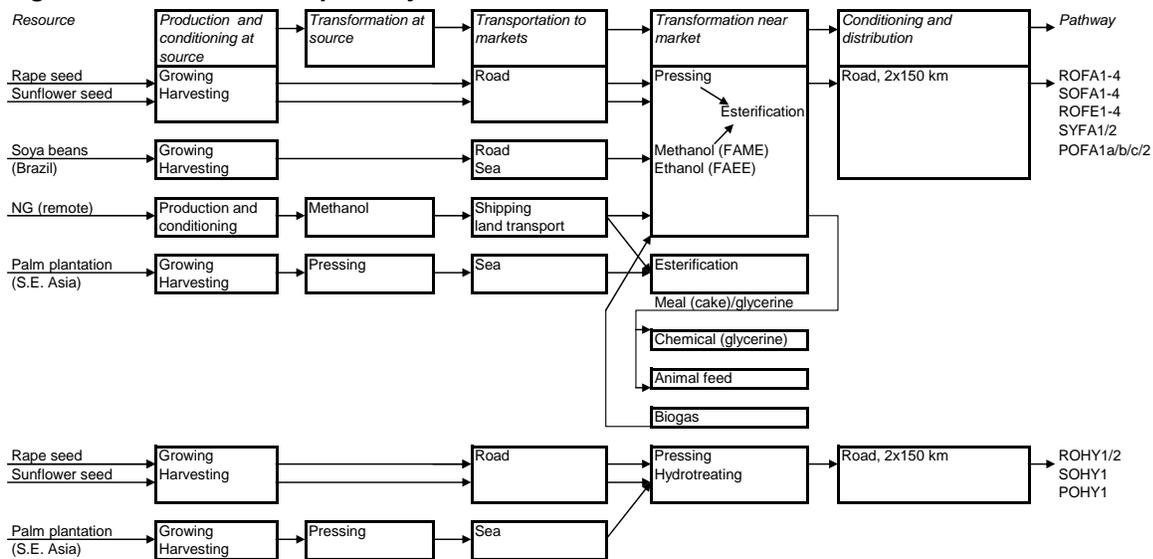
4.5 Bio-diesel (FAME, FAEE and hydrotreated vegetable oils)

(See also WTT Appendix 2 section 4)

4.5.1 Bio-diesel pathways

Bio-diesel is mostly produced from rapeseed as RME. Sunflower is also used in Southern Europe, and as demand grows imported soy beans/oil and palm oil may also contribute. 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. We have also added FAME from soy beans and for palm oil, with a range of pathways to show the impact of different production options. 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

Figures 4.5.2-1a/b show the total energy build-up along the different stages for selected bio-diesel pathways. The production energy for fossil diesel is also included as reference – to compare with the biofuels the combustion energy of 1MJ needs to be added. This simple comparison works because 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 3 times more total energy than fossil diesel. Rape seed and sunflower consume slightly less than conventional diesel, with sunflower somewhat more favourable than rape in this respect. Palm oil consumes more total energy than conventional diesel.

Soy has the highest total energy use, although this deserves some explanation. Unlike other crops, soy yields more than 4 times as much meal as it does oil. Following the substitution method all energy use for cultivation and processing is allocated to the oil. The credit recovered from the meal for substituting Brazilian corn does not fully compensate. In this case, allocation by economic value may be more appropriate (see pathway SYFA1c in *WTT Appendix 2*).

Using ethanol instead of methanol for esterification slightly increases the required total energy. Use of glycerine as a chemical or animal feed has only a marginal impact.

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

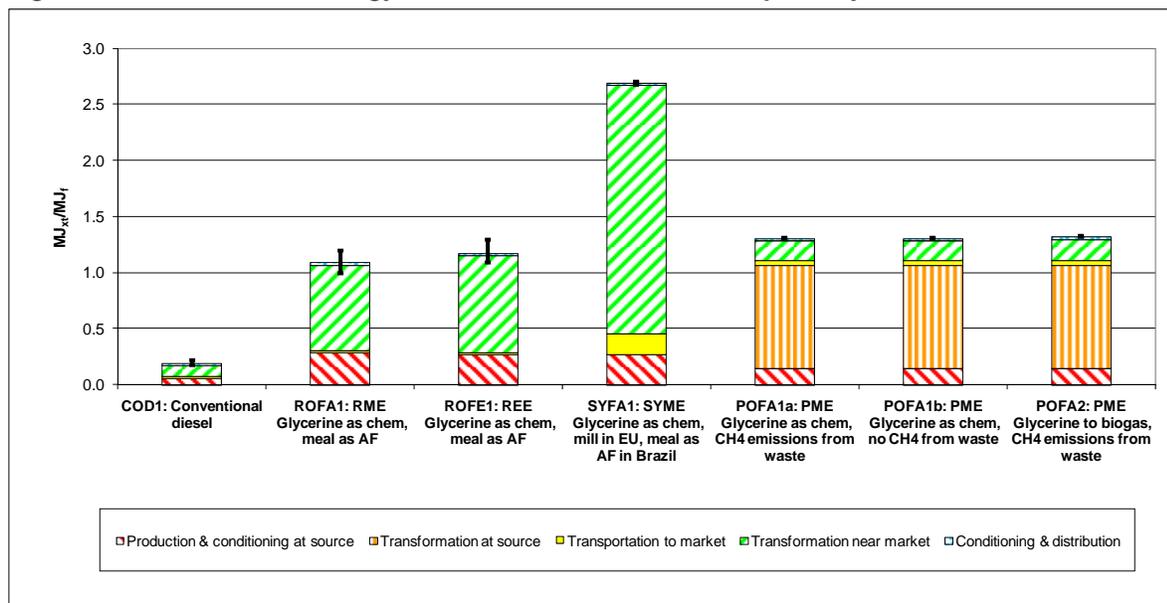
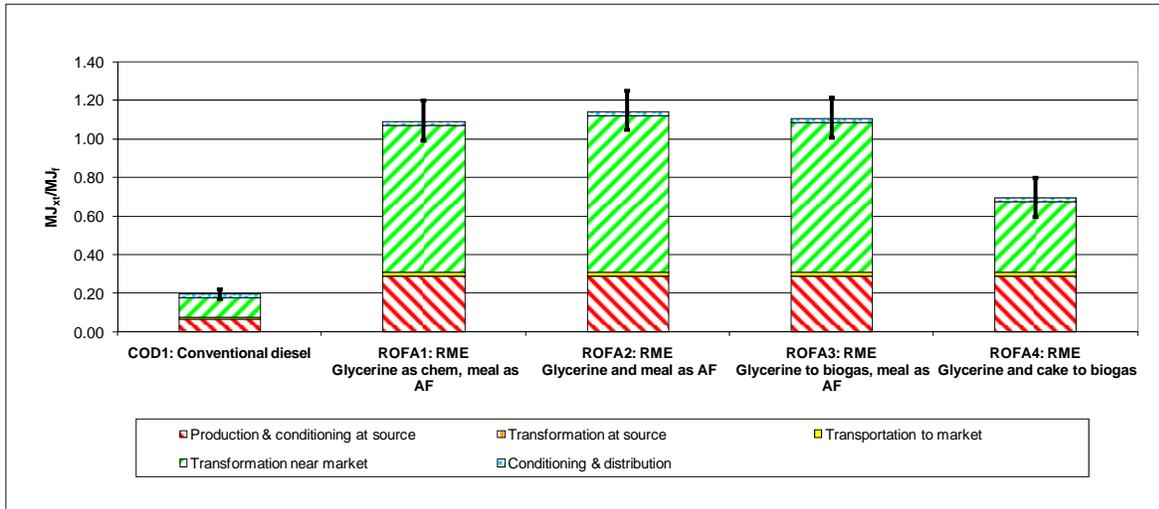


Figure 4.5.2-1b Impact of co-products fate on the WTT total energy balance of RME pathways



Fossil energy

Figures 4.5.2-2a/b 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 4.5.2-2a WTT fossil energy balance of bio-diesel pathways

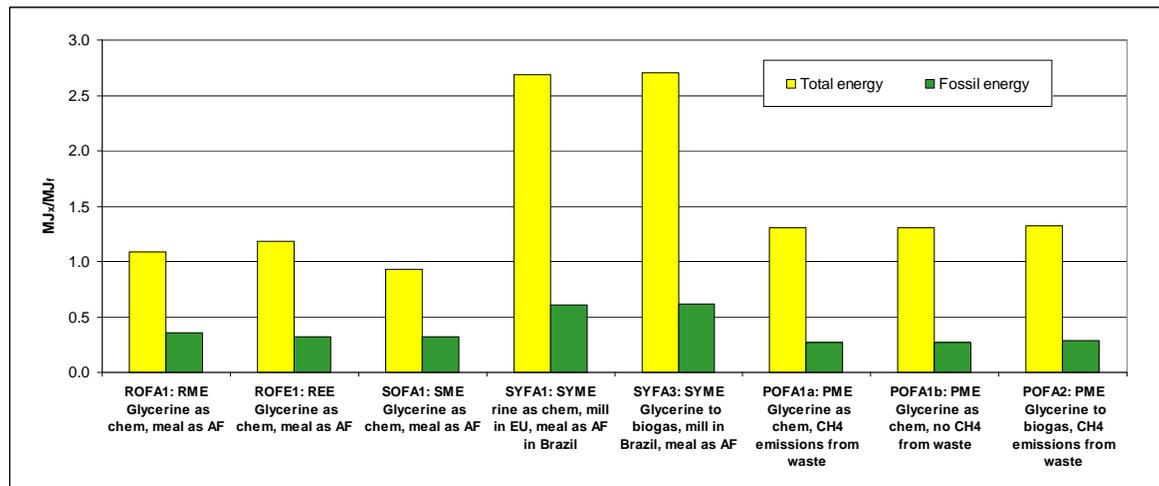
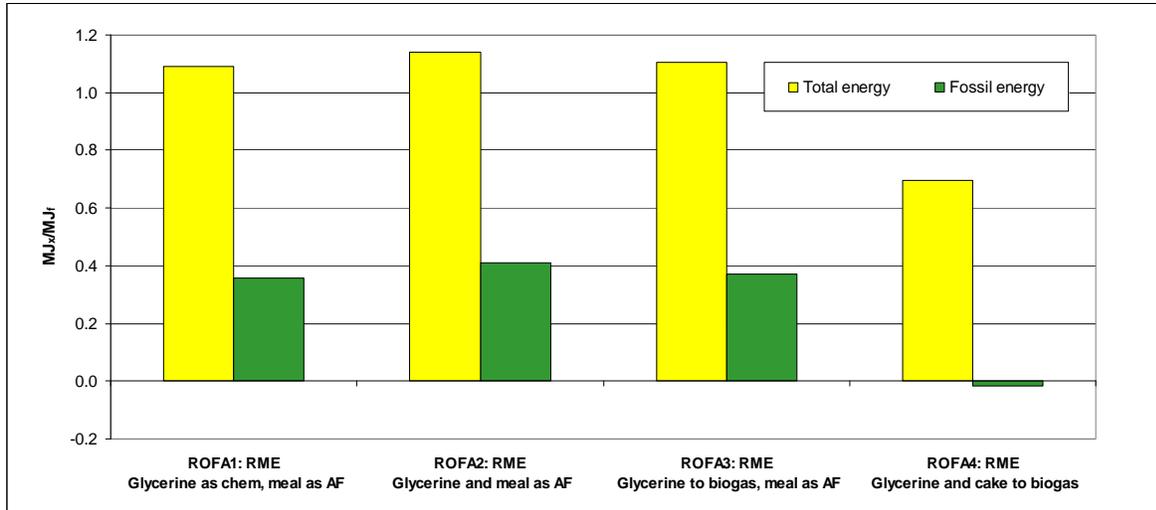


Figure 4.5.2-2b Impact of co-products fate on the energy balance of RME pathways



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.

Add comment about soy, palm

4.5.3 Bio-diesel WTT GHG balance

Figure 4.5.3-1a/b shows the total GHG build-up along the different stages of the pathways. The fossil diesel balance is also included in the first figure as reference (the fossil diesel combustion CO₂ has been added to make the GHG figures comparable).

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

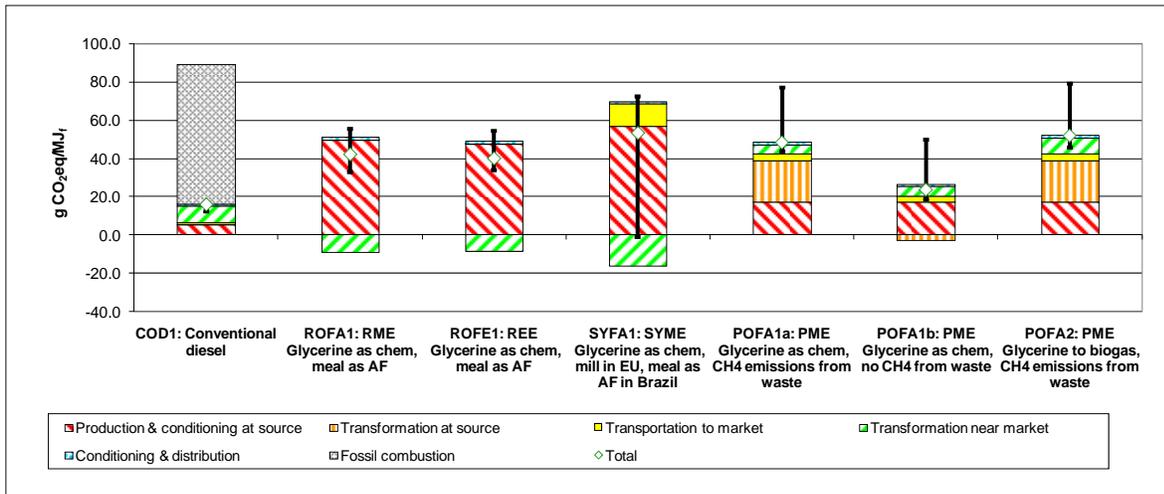
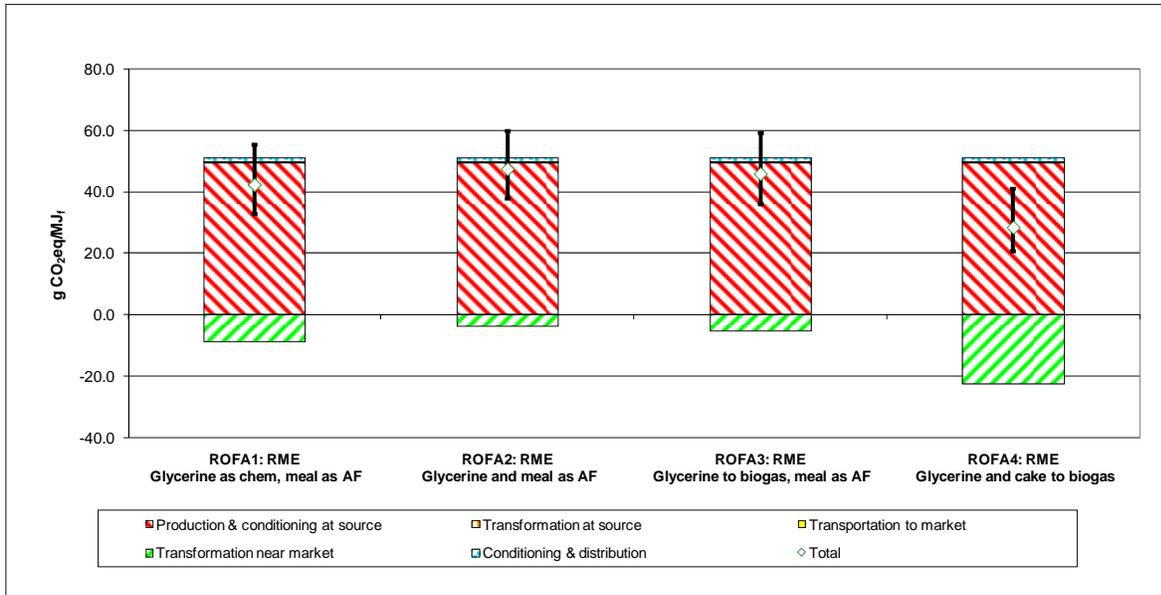


Figure 4.5.3-1b Impact of co-products fate on the WTT GHG balance of RME pathways



The GHG emissions are dominated by the seed production step, mostly through N₂O 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. In the case of SYFA1, the GHG emissions would decrease by 21.9 g CO₂eq/MJ if we calculate the N₂O emissions strictly using the IPCC 2006 tier 1 method, instead of our modification (but then the numbers would not agree with any field measurements).

Here again soy shows the highest values. Unlike energy though, the GHG balance is not significantly improved by changing the treatment of meal from substitution to allocation by economic values because the reductions due to allocation to the meal are compensated by the removal of the credit for meal substitution.

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.

Alternative uses of glycerine do not have a big impact.

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

4.5.4 Hydrotreated Plant Oils

As outlined in Section 3.4.10, deep-hydrotreating of rapeseed oil, soy oil and palm oil have been evaluated. In the figures that follow, the energy and GHG balances of these pathways are compared with the corresponding FAME pathways for the three feedstocks.

As shown in *Figure 4.5.4-1a/b*, hydrotreating uses less total and fossil energy than converting the oil to FAME. The UOP process uses slightly less total energy than the NexBTL process, but more fossil energy, probably because the latter makes use of cracking products from the bio feedstock as fuel for the process.

Figure 4.5.4-1a WTT total energy balance of hydrotreated plant oil pathways

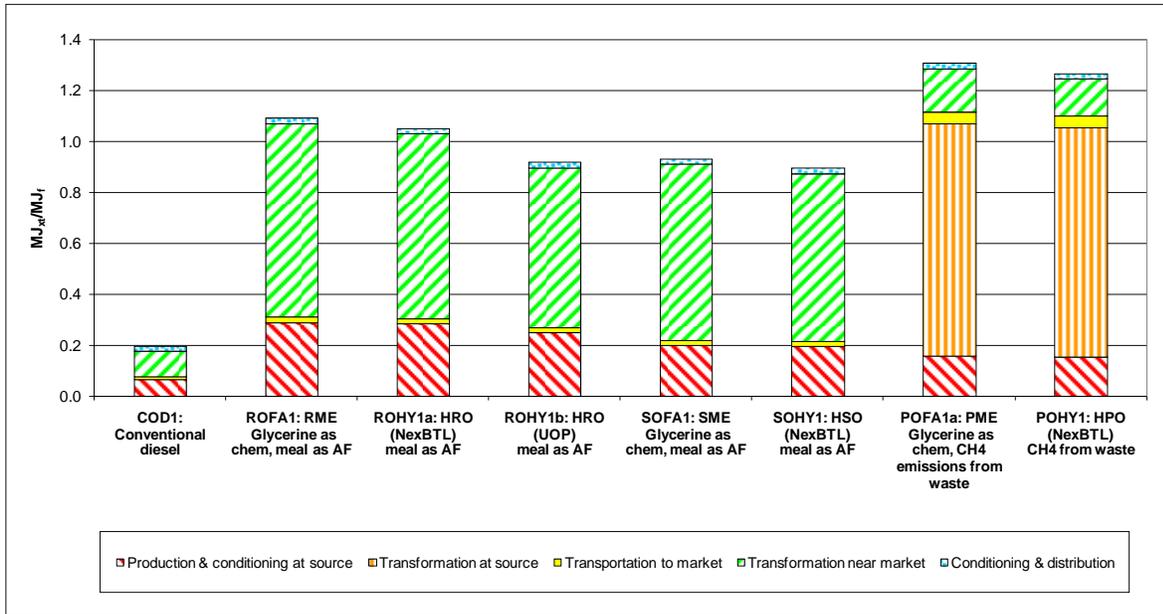
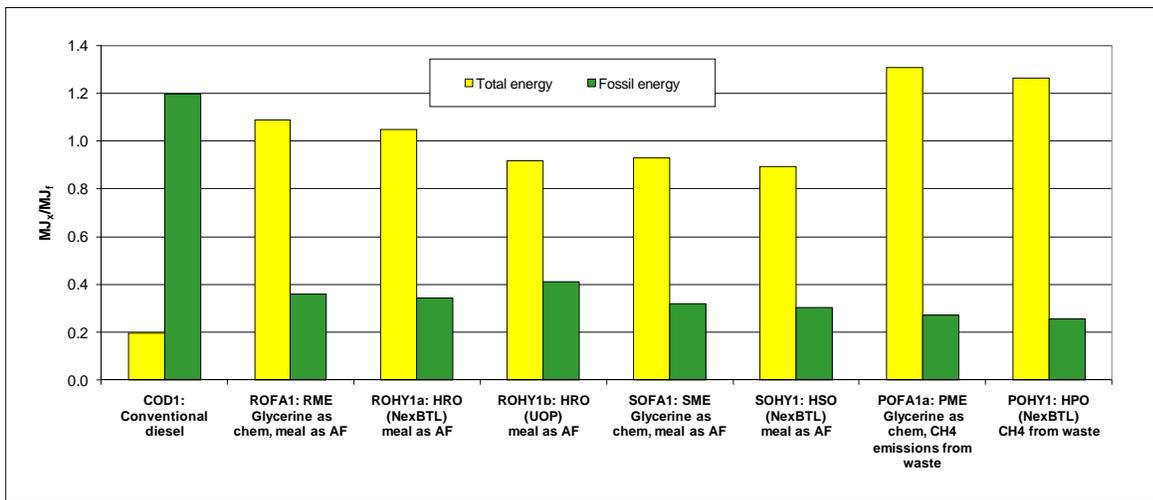


Figure 4.5.4-1b WTT fossil energy balance of hydrotreated plant oil pathways



In terms of GHG emissions there is little difference between FAME and hydrotreated plant oils.

Figure 4.5.4-2a WTT GHG emissions balance of hydrotreated plant oil pathways

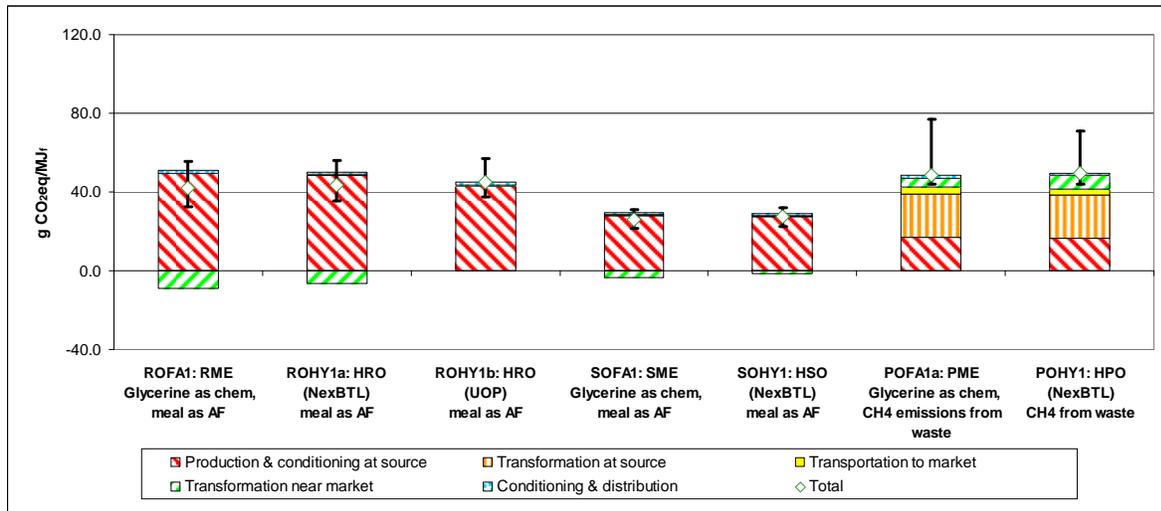
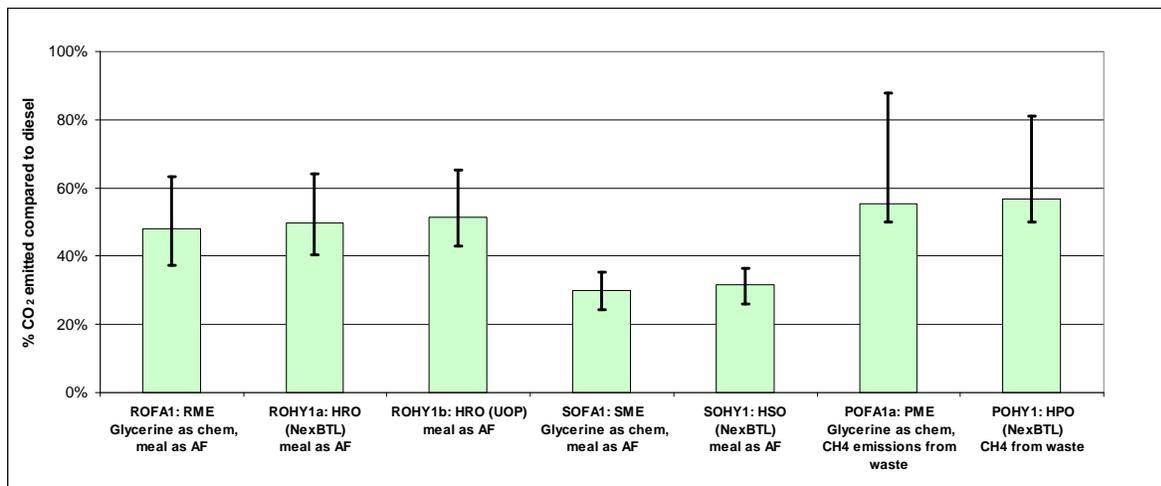


Figure 4.5.4-2b Relative WTT GHG emissions balance of hydrotreated plant oil pathways



4.6 Synthetic fuels

(See also WTT Appendix 2 section 5)

4.6.1 Synthetic fuels pathways

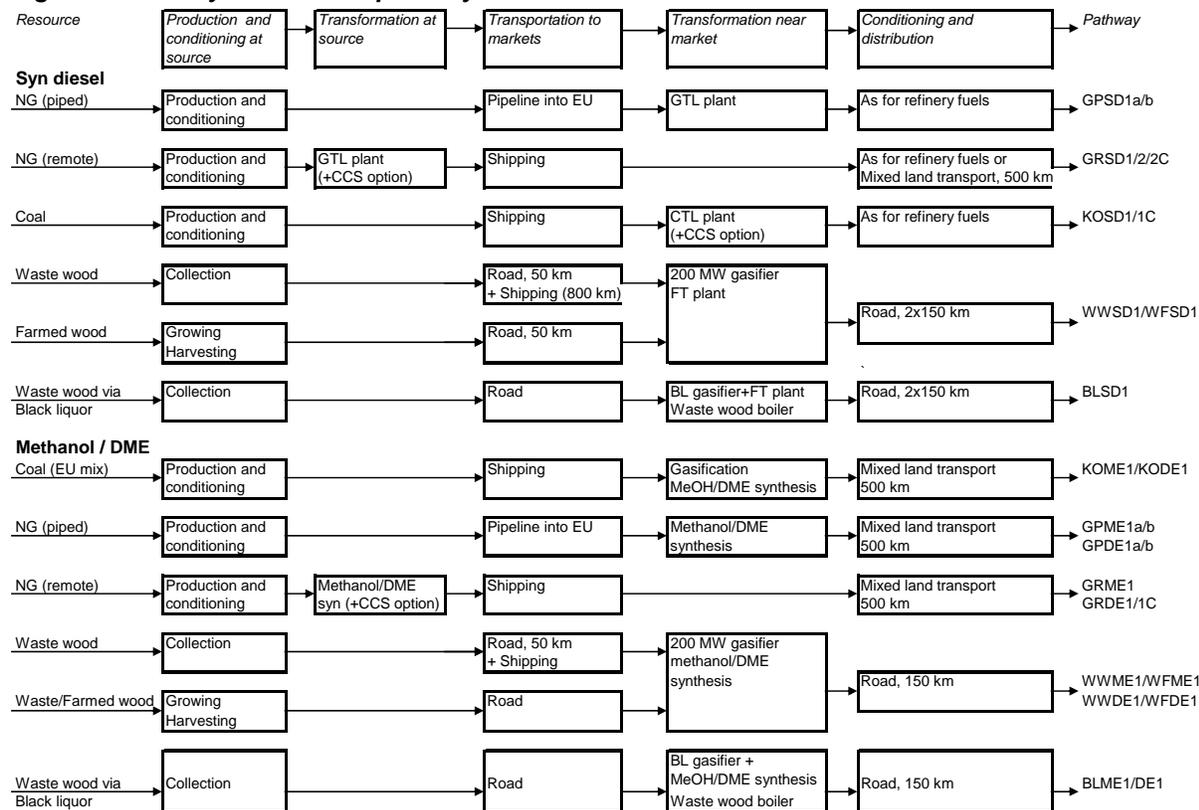
We have considered three synthetic fuels namely Fischer-Tropsch or syn-diesel, DME and methanol. DME has attractive characteristics as a fuel for diesel engines although the fact that it is gaseous at ambient conditions reduces its appeal. Methanol is only envisaged here as a potential fuel for on-board 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 3.4.11*).

Figure 4.6.1 Synthetic fuels pathways



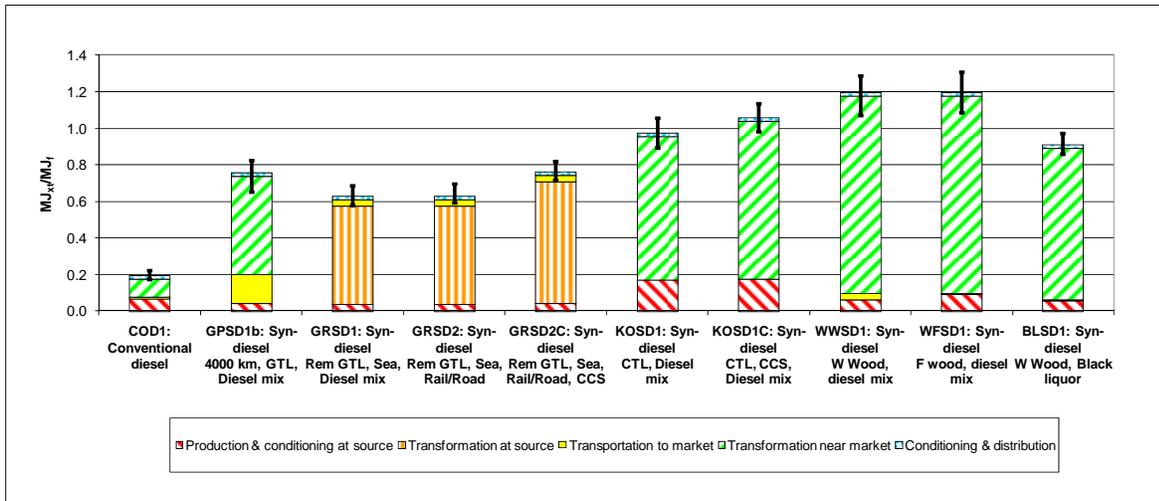
4.6.2 Syn-diesel

Total energy

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 N₂O emissions related to wood farming.

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



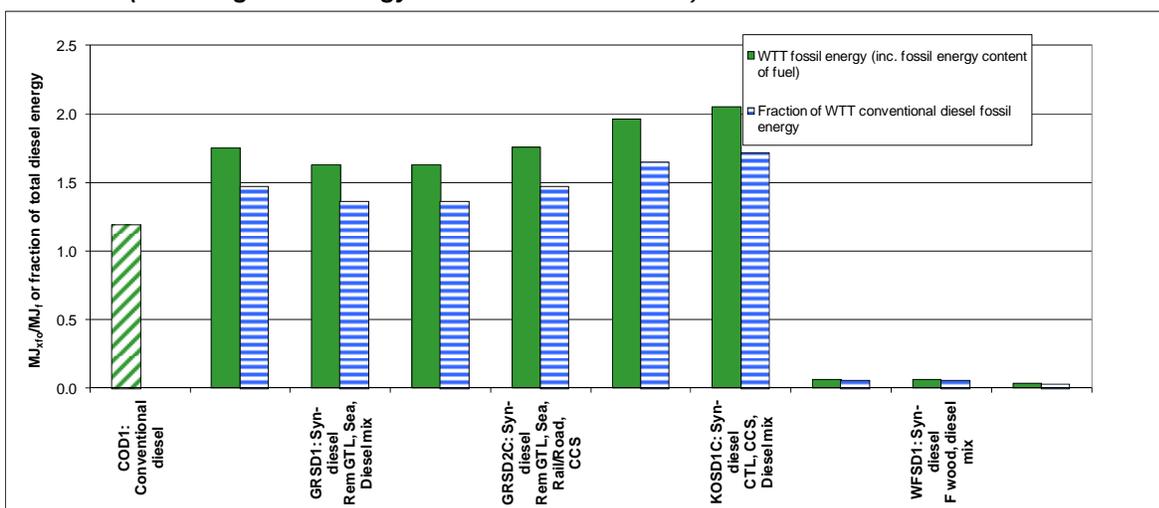
GTL production makes the most sense at a remote location when the large gas transport energy can be avoided and replaced by the much more efficient transport of a liquid (compare e.g. GRSD1 to GPSD1a/b).

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

Fossil energy

The total energy graph (Figure 4.6.2-1) 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**.

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



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 1.4 to 1.8 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*).

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). GHG emissions for GTL are slightly higher than for conventional diesel, but have the potential to match it in the most favourable conditions (lower end of confidence range), where economic conditions allow the most efficient projected processing options to be used. Using coal, however, results in very large GHG emissions. For wood, GHG emissions are mainly incurred for wood growing and collection/transport.

CCS offers an opportunity for substantial reductions of CO₂ 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 CO₂ emitted during the CTL process. With CCS, CTL becomes only marginally more GHG-intensive than conventional diesel. One has also to remember that the CCS data are only based on technical studies and are only indicative at this stage. As these processes develop, higher CO₂ recovery may be possible. The potential of CCS is further discussed in *section 5.4*.

Figure 4.6.2-3 WTT GHG balance of syn-diesel pathways (including fossil CO₂ content of final fuels)

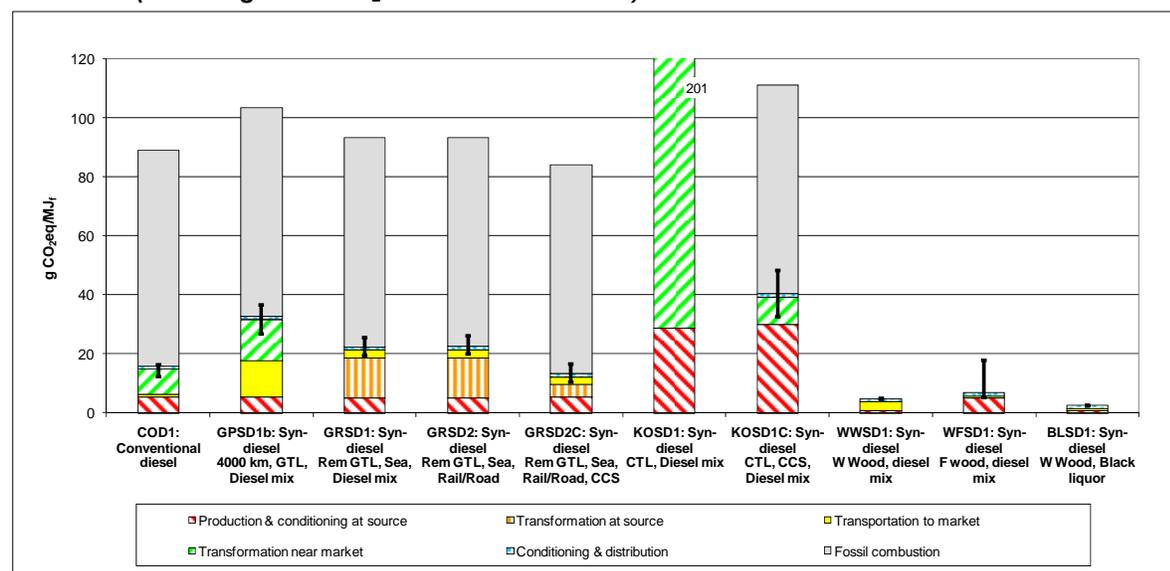
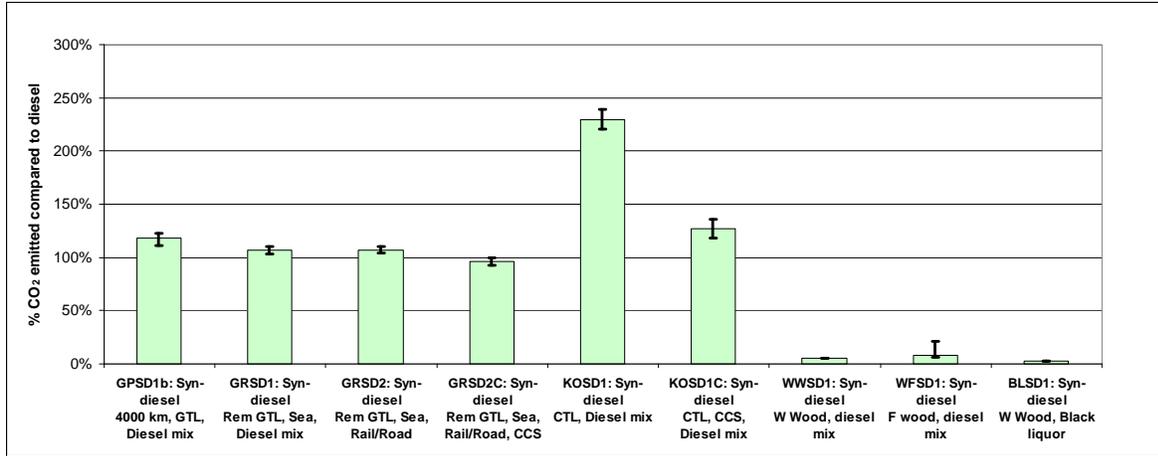


Figure 4.6.2-4 WTT GHG balance of syn-diesel pathways compared to conventional fossil diesel (including fossil CO₂ content of final fuels)



4.6.3 DME

The synthesis of DME is a more efficient than that of FT diesel, resulting in 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.

Figure 4.6.3-1 WTT total energy balance of DME pathways

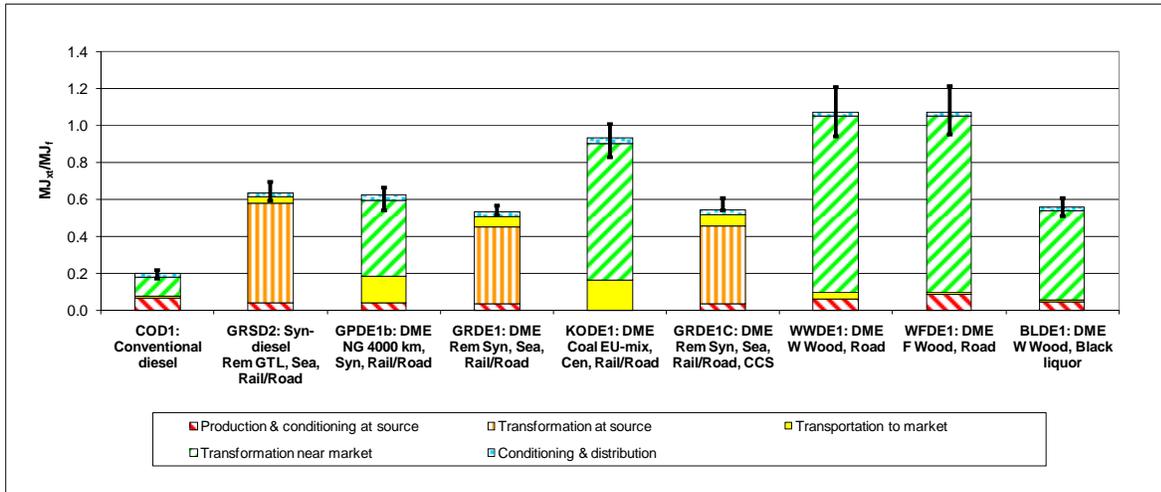
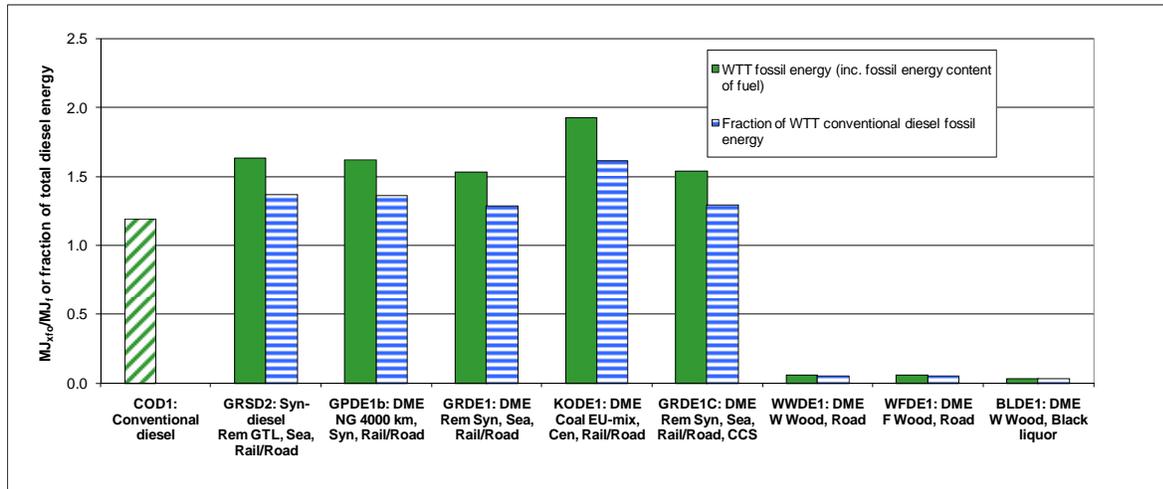


Figure 4.6.3-2 WTT fossil energy balance of DME pathways (including fossil energy content of the final fuel)



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 CCS could be envisaged to capture the CO₂ 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 allows a somewhat higher efficiency in the vehicle (see *TTW report*).

Figure 4.6.3-3 WTT GHG balance of DME pathways (including fossil CO₂ content of final fuels)

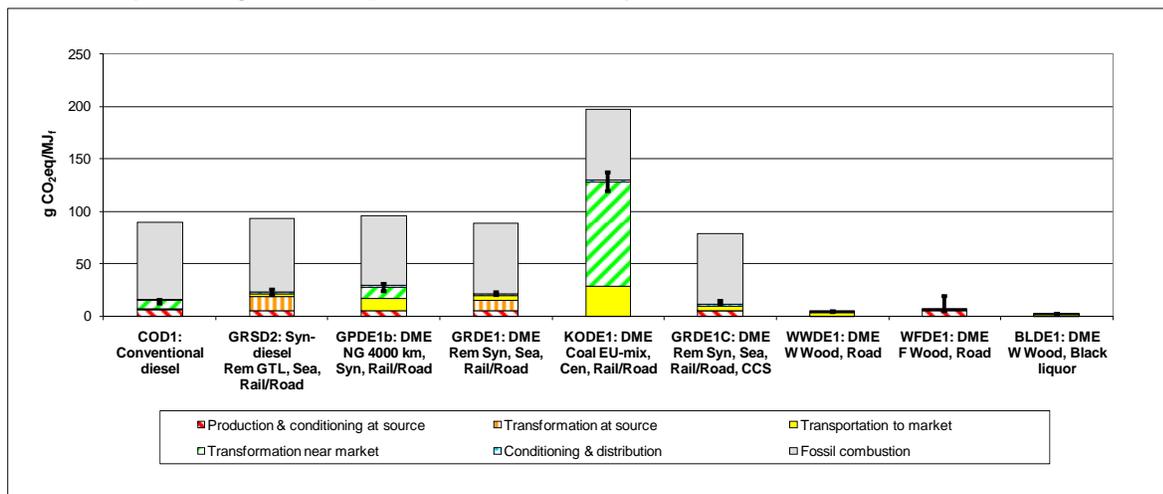
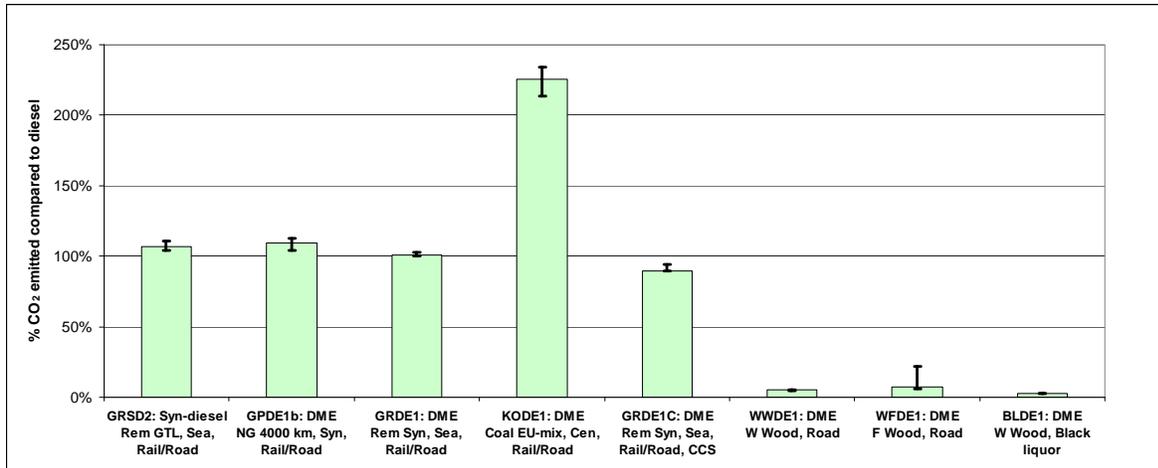


Figure 4.6.3-4 WTT GHG balance of DME pathways compared to conventional fossil diesel (including fossil CO₂ content of final fuels)



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 CCS 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

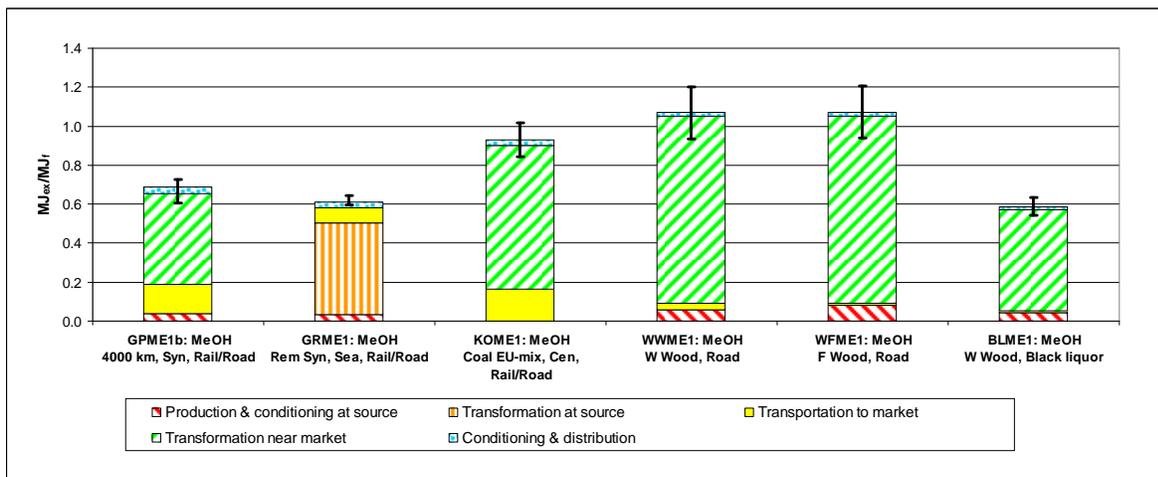
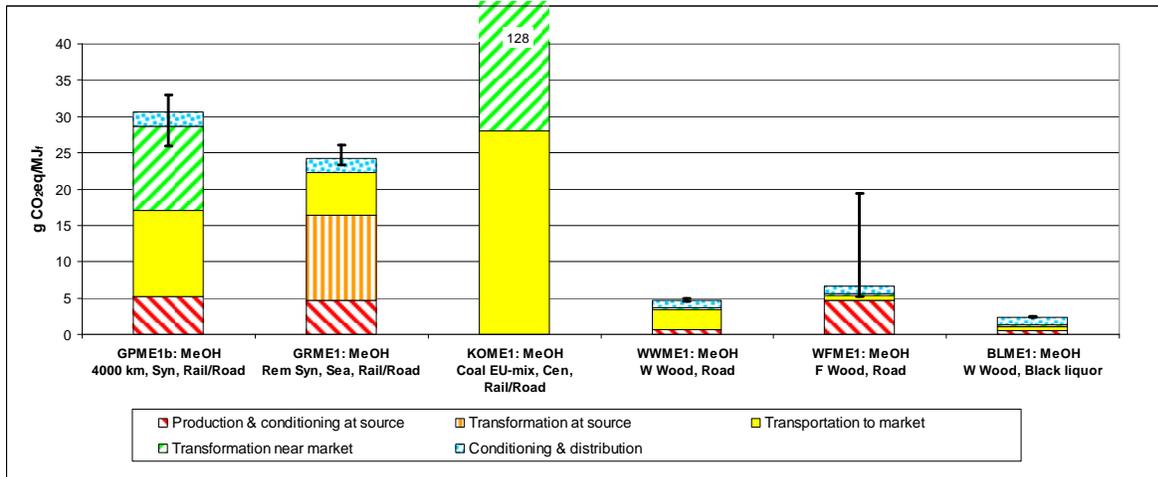


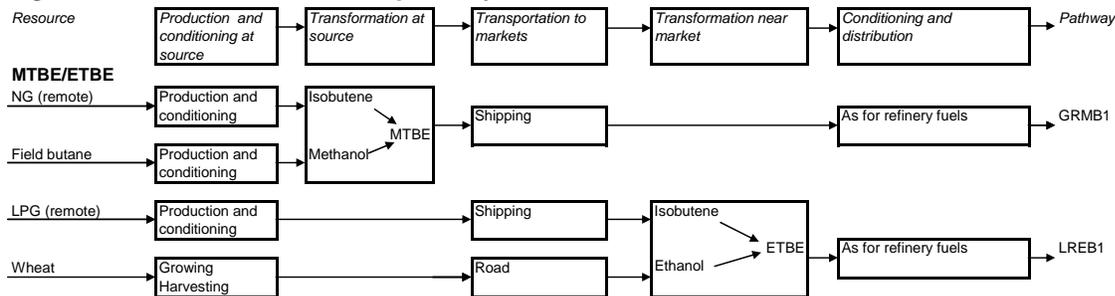
Figure 4.6.4-2 WTT GHG balance of methanol pathways



4.7 Ethers (MTBE/ETBE)

(See also WTT Appendix 2 section 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 3.4.9).

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 CO₂ combustion emissions (2/3) has to be factored in.

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

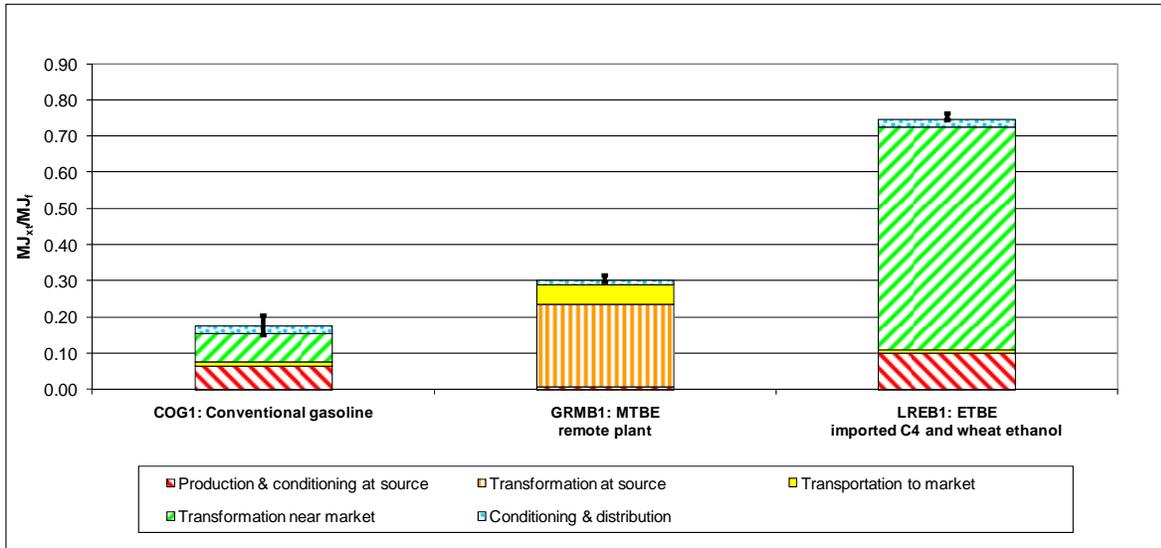
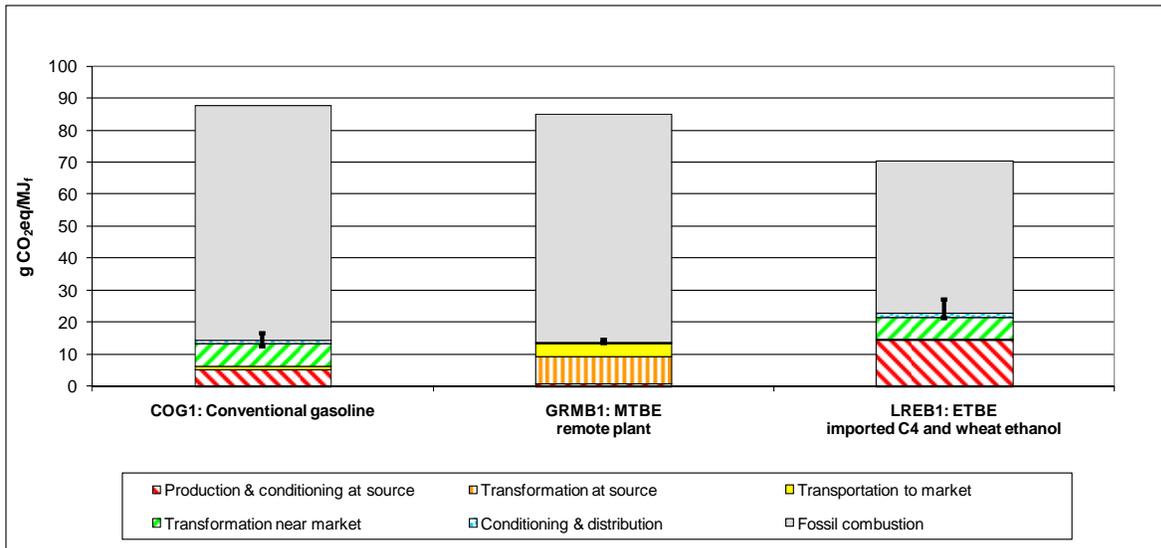


Figure 4.7-3 WTT GHG balance of MTBE and ETBE pathways



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.

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 CO₂ combustion emissions (2/3) has to be factored in.

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 /MJ EtOH
	MTBE	ETBE	Ethanol	Total		Isobutene	Methanol	Ethanol	/MJ MTBE	/MJ ETBE	
Use of ethanol as such											
Used or produced MJ _f	1.00		0.40	1.40		0.82	0.21				
Total energy MJ _{xt}			0.98						0.98		2.45
Fossil energy MJ _{xfo}			0.23						0.23		0.57
GHG g CO _{2eq}			19.37						19.37		48.5
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	0.98	0.88	0.73	2.20
Fossil energy MJ _{xfo}					0.23		-0.33	0.23	0.13	0.10	0.31
GHG g CO _{2eq}					17.3		-19.2	19.4	17.49	14.61	43.8
											-4.7

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.

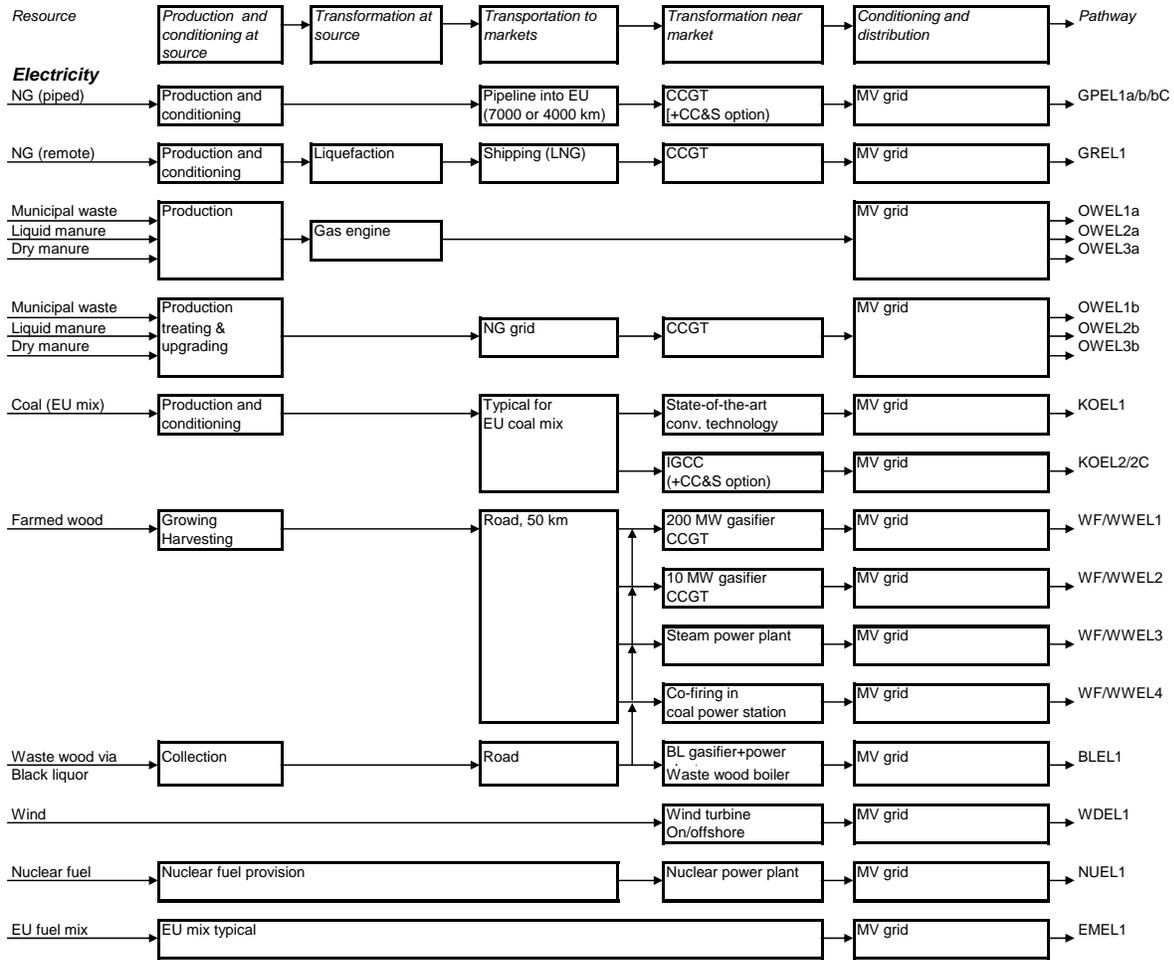
4.8 Heat and power generation

(See also WTT Appendix 2 section 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 are presented in the same way as for the road fuels, i.e. the energy needed to produce 1 MJ of electricity, less the energy in the produced electricity.

Since electricity is used as an intermediate energy source (e.g. for electrolysis) rather than a "road fuel", it is sometimes more useful to include the energy content of the electricity produced. to obtain these numbers a fixed quantity of 1 MJ should be added to the figures shown.

The overall efficiency of the power generation process through resource extraction, power station and distribution is then given by

$$\text{Efficiency}_{\text{overall}} = 1 / (1 + \text{MJ}_{\text{xt}})$$

Total energy

In terms of total energy (**Figures 4.8.2-1a/b/c**), 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 fossil and nuclear electricity pathways (excluding final electrical energy)

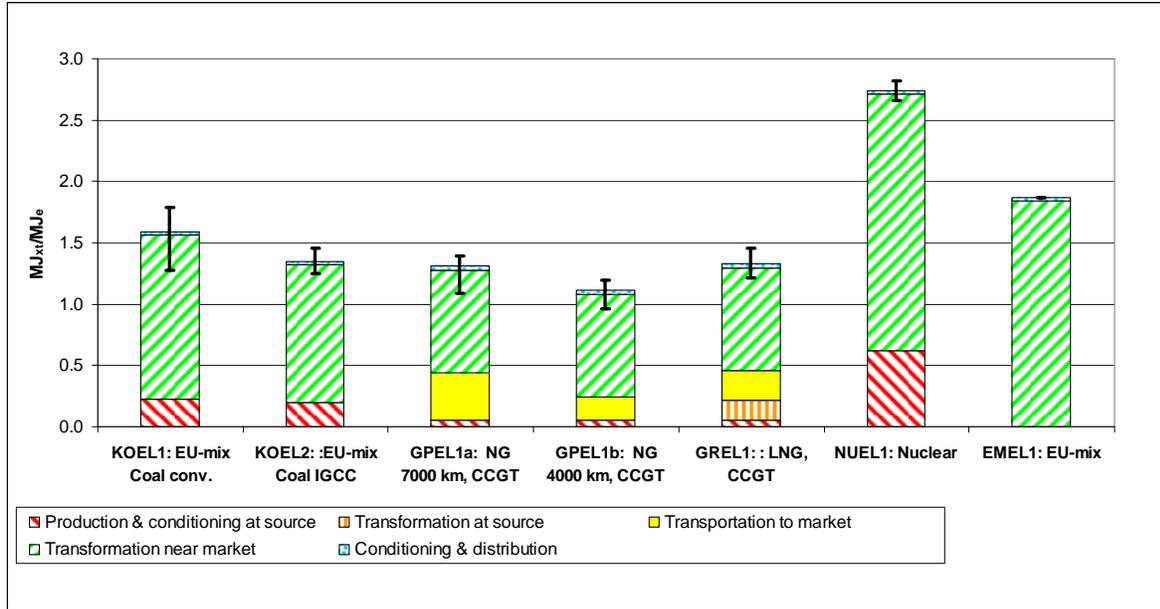


Figure 4.8.2-1b Total energy balance for various wood to electricity pathways (excluding final electrical energy)

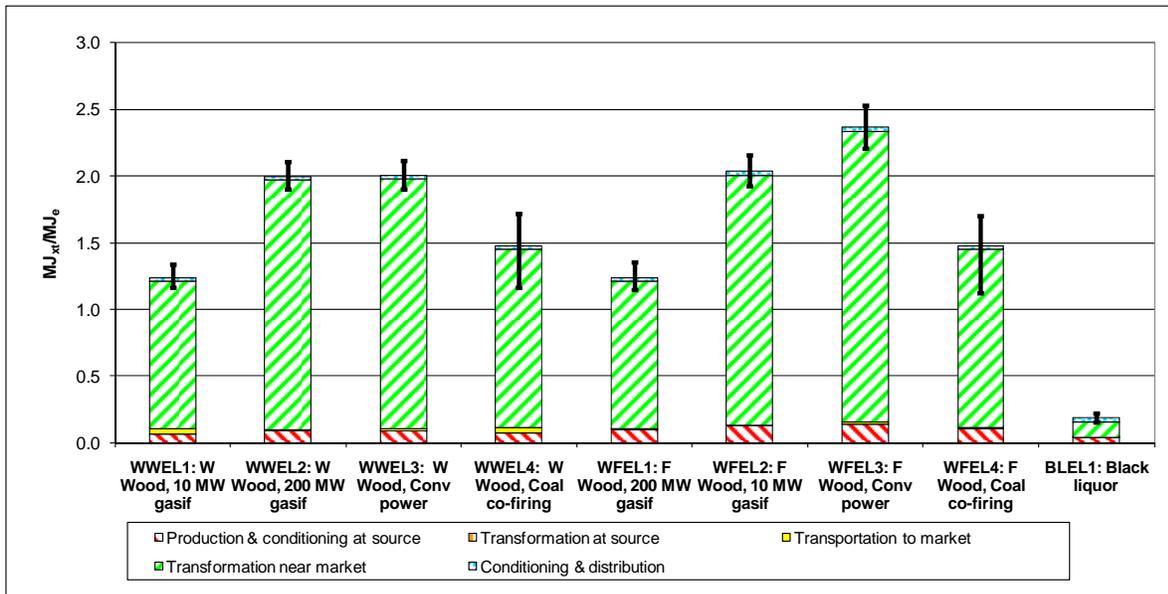
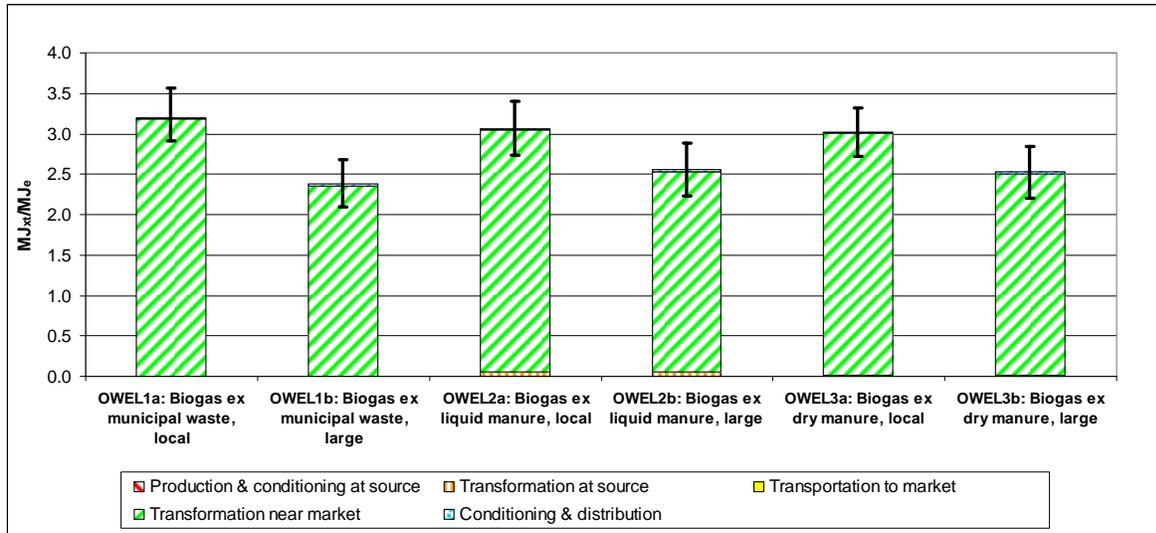


Figure 4.8.2-1c Total energy balance for biogas to electricity pathways (excluding final electrical energy)



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 than 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.

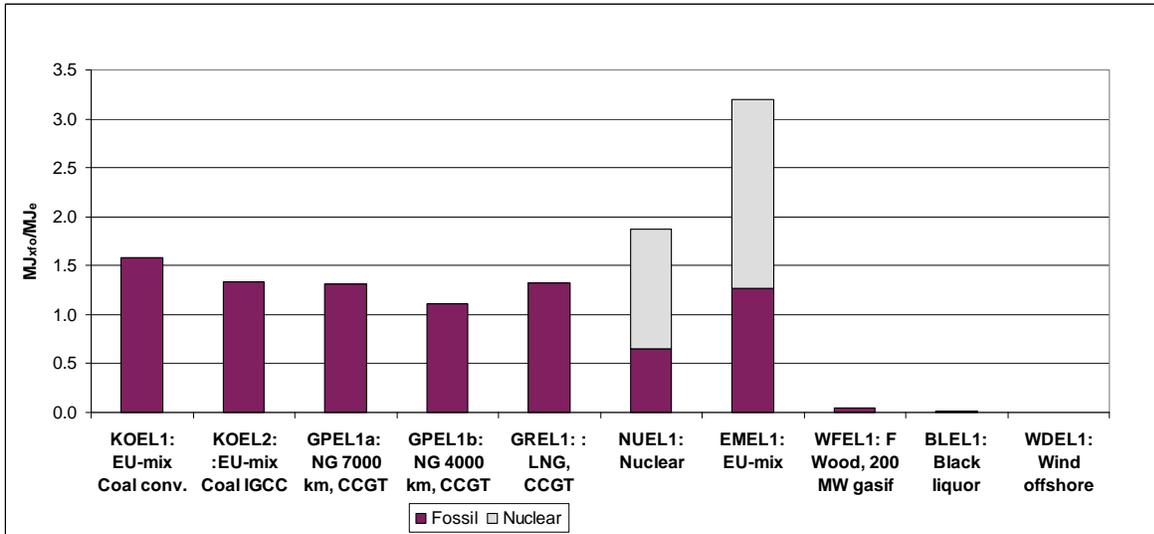
Fossil energy

When it comes to fossil energy only (*Figures 4.8.2-2a/b*), wood and wind fare very well of course.

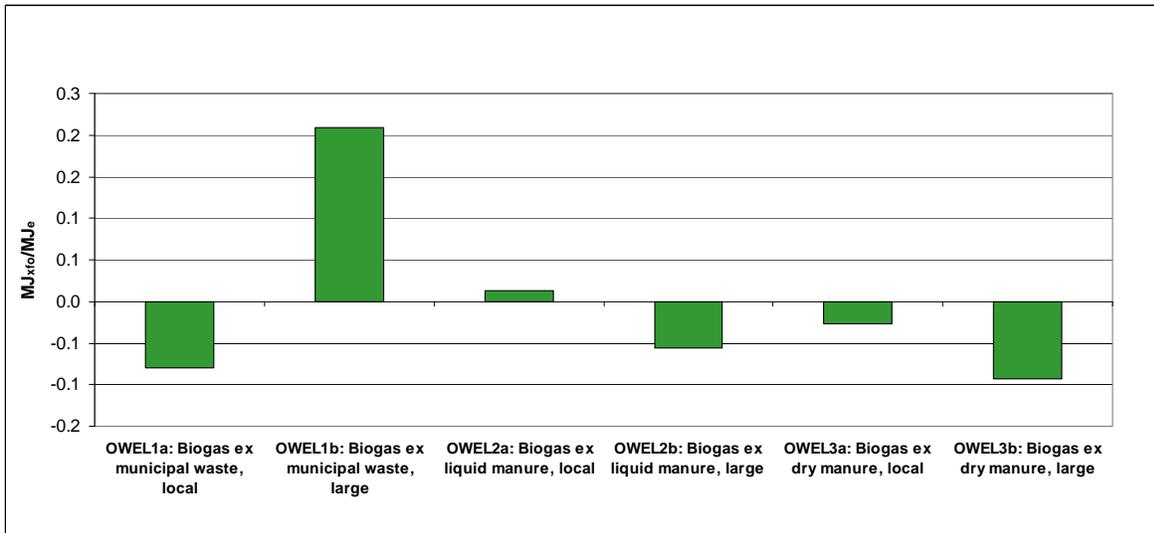
If nuclear energy is considered to be fossil the EU-mix figure is poor relative to fossil hydrocarbon options. When considering only the fossil hydrocarbons part, EU-mix has a fossil energy footprint similar to natural gas.

All of the biogas figures are less than 1 (i.e. there is a net saving in fossil energy), and most of them are negative (i.e. biogas saves more fossil energy than it uses). Please also note the difference in scale between *Figures 4.8.2-2a/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
(excluding final electrical energy)**



**Figure 4.8.2-2b Fossil energy balance for biogas to electricity pathways
(excluding final electrical energy)**



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. Again, please note the differences in scale between **Figures 4.8.2.-3a/b/c)**

Figure 4.8.2-3a GHG balance for various fossil and nuclear electricity pathways

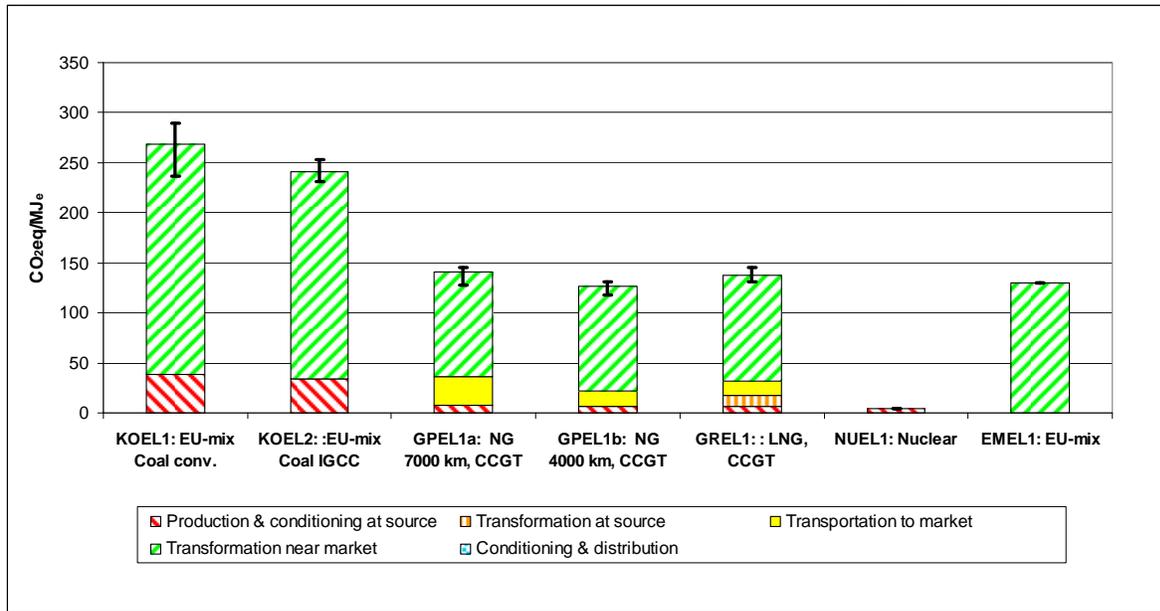


Figure 4.8.2-3b GHG balance for various wood to electricity pathways

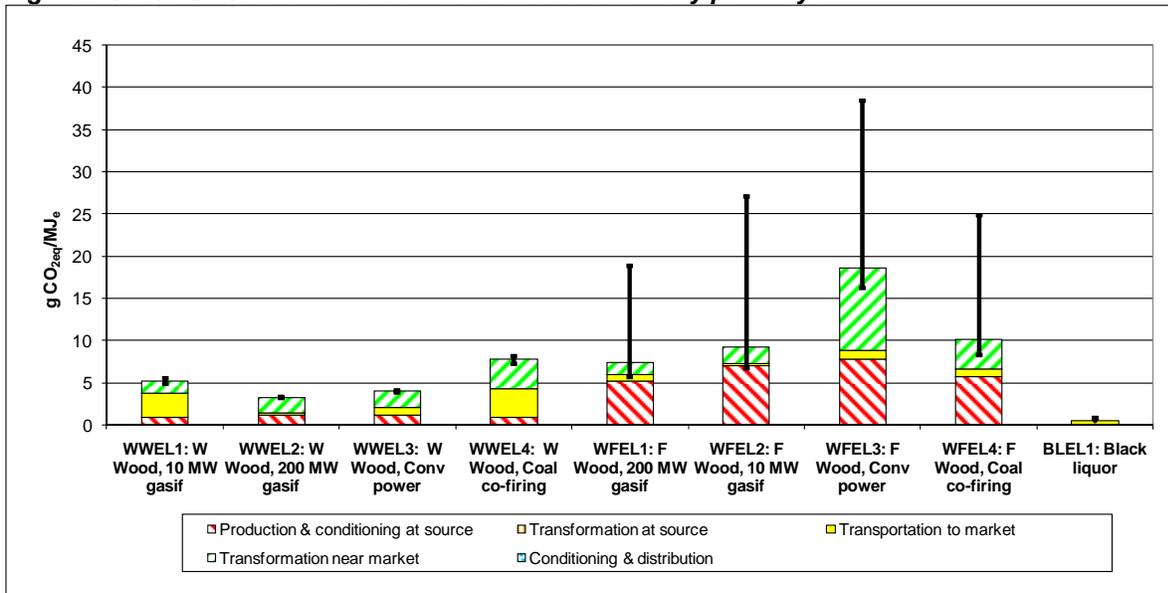
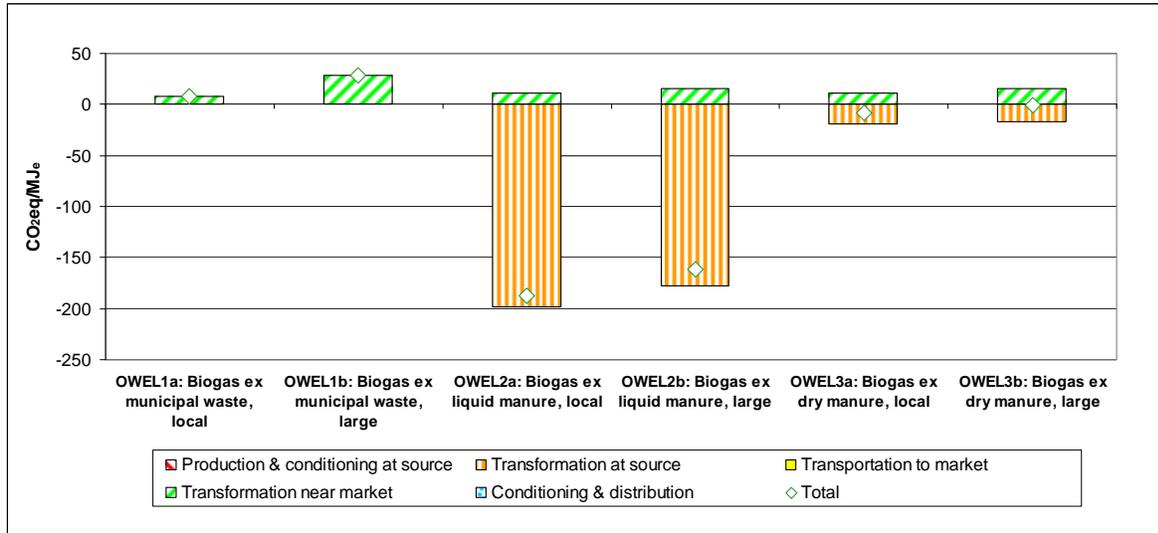


Figure 4.8.2-3c GHG balance for biogas to electricity pathways



4.8.3 Heat & Power

Heat is needed in many road fuel pathways as input to the process and has traditionally been produced in steam boilers fed with variety of fuels. In conventional power generation a significant amount of energy is rejected as heat. If this heat could be usefully employed, the overall efficiency of energy use could be improved.

The benefits of combined heat and power (CHP) are well known, and whether the primary product is heat or electricity, efficiency gains are possible if both can be produced together and any surplus exported and put to good use. A number of pathways have been included for comparative purposes. These describe typical performance of heat production in small and industrial case boilers and large scale CHP plants fed with various feedstocks. Several of the road fuel pathways (e.g. WTET1) include CHP options as a way of efficiently meeting the energy needs of the fuel production process. In these cases the primary product may be heat, with surplus electricity being exported to provide a credit. In the CHP pathways we focus first on electrical power as the primary product with the associated heat ‘exported’ and providing a credit, but also show the comparison where heat is the primary product and electricity considered as an export credit. The credit arising from exported heat depends very much on how that heat would be generated in the absence of a CHP scheme, and a very wide range of options exists. To preserve a degree of objectivity we have assumed if there were no CHP, the heat would be generated in a steam boiler using the same fuel as used for the CHP plant.

Heat Pathways

The scale of the boiler used to produce steam will affect the overall efficiency, so for each fuel considered, a domestic boiler and an industrial boiler are both modelled.

- COHT1/2 Heating oil in domestic or industrial boiler
- GPHT1/2 Piped NG (7000km or 4000km) in domestic or industrial boiler
- GRHT1/2 LNG in domestic or industrial boiler
- OWHT1/2/3 Gas boiler, biogas from municipal waste, liquid or dry manure
- WWHT1/2 Waste wood in domestic or industrial boiler
- WFHT1/2 Farmed wood in domestic or industrial boiler

Figures 4.8.3-1 and 4.8.3-2 show the energy use and GHG emissions to produce heat using fossil or renewable fuels. For the fossil fuels, the figures show the total fuel energy input, whereas for the renewables, only the energy expended is included and the energy in the biomass consumed is not

included. For NG, the domestic boiler is more efficient than the industrial boiler, because households can use lower temperatures and so less heat is wasted.

Figure 4.8.3-1 Energy and GHG balance of fossil heat pathways

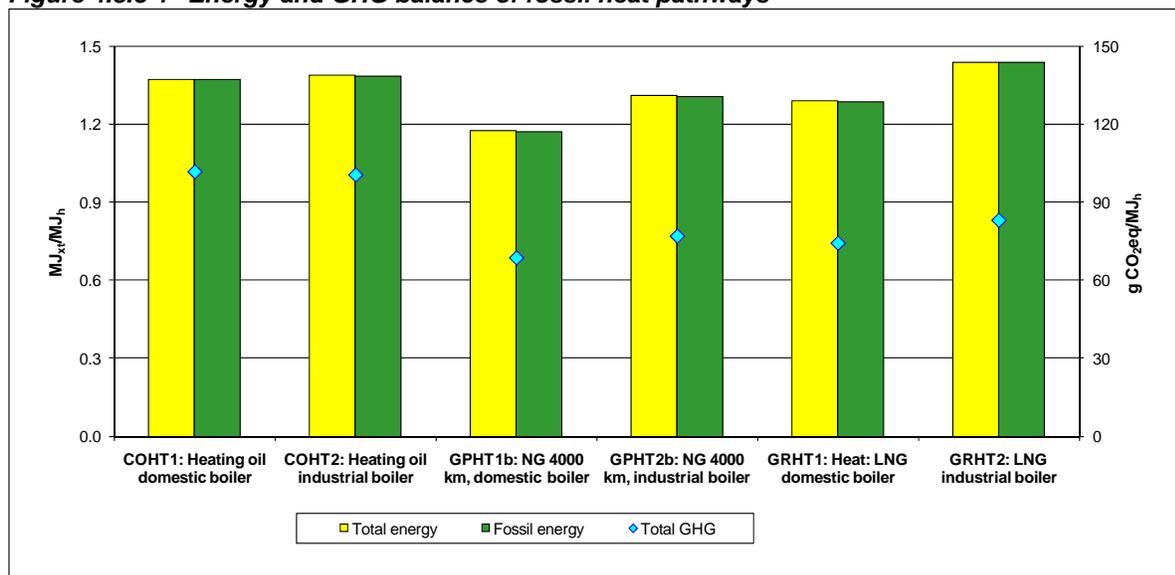
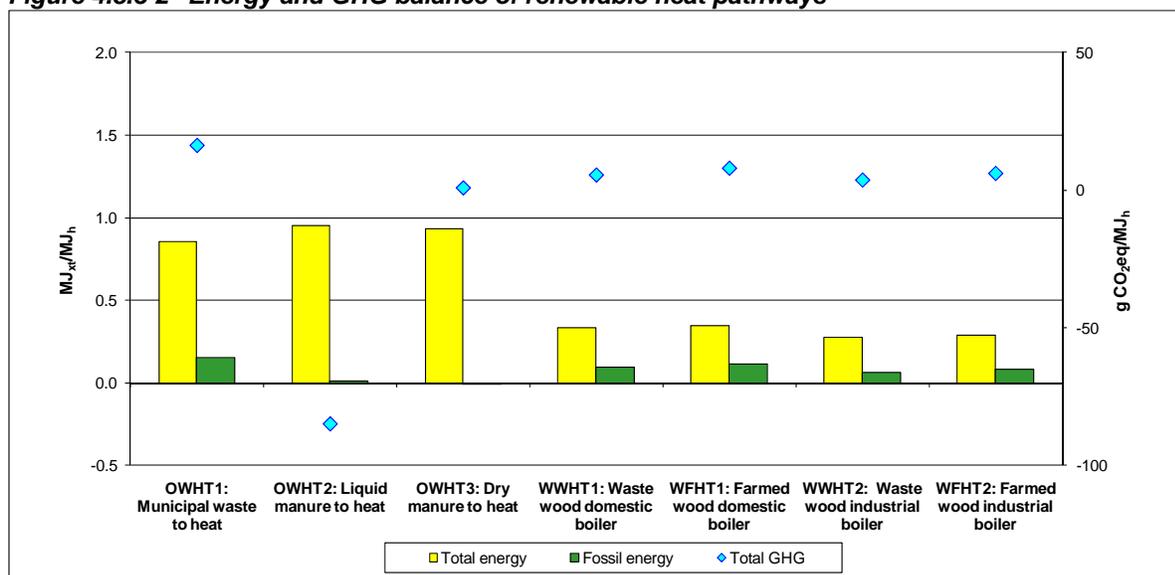


Figure 4.8.3-2 Energy and GHG balance of renewable heat pathways

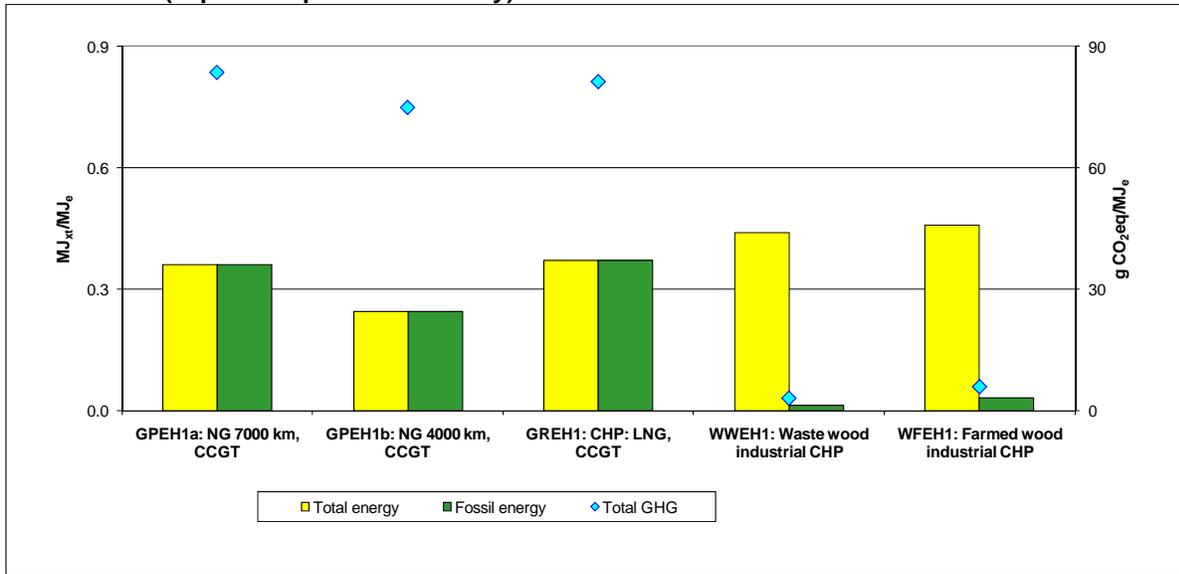


CHP Pathways

The CHP cases consider a large scale NG fired CCGT power plant operating in CHP mode, and a smaller scheme fired by waste or farmed wood. The primary product is electricity, and a credit is given for exported heat.

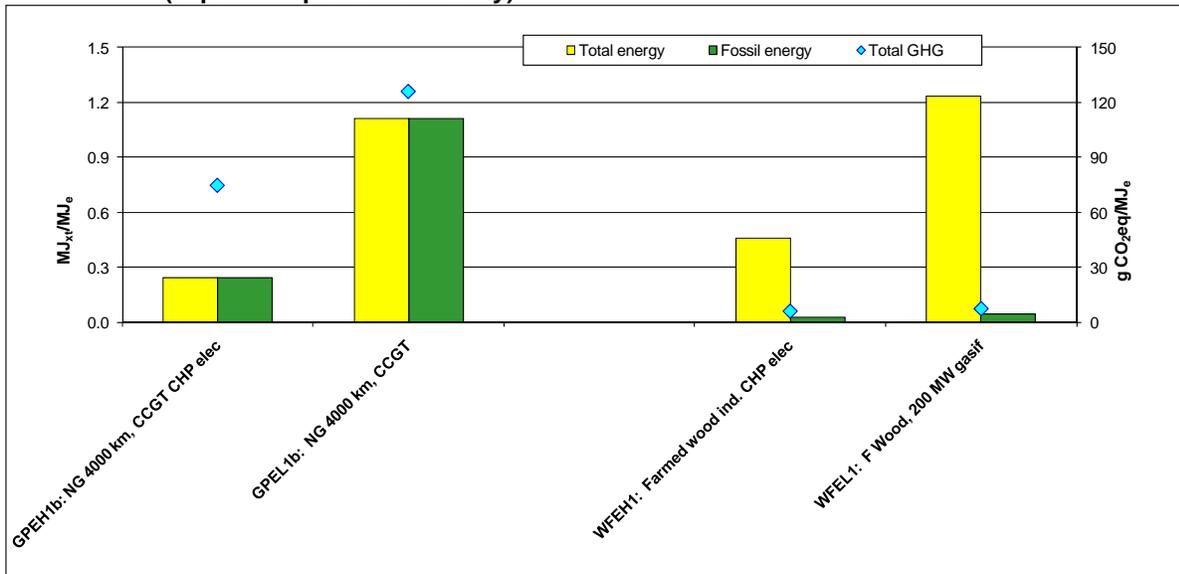
- GPEH1a Piped gas 7000km, CCGT
- GPEH1b Piped gas 4000km, CCGT
- GREH1 LNG, CCGT
- WWEH1 Waste wood boiler/steam turbine
- WFEH1 Farmed wood boiler/steam turbine

Figure 4.8.3-3 Energy and GHG balance CHP pathways (expressed per MJ electricity)



Where CHP is used, there is a benefit for producing both electricity and heat together instead of separately. In **Figure 4.8.3-4**, the energy use and GHG emissions for electricity production are compared for simple electricity generation and for the same process where heat is exported and a credit given based on production of heat using the same feedstock.

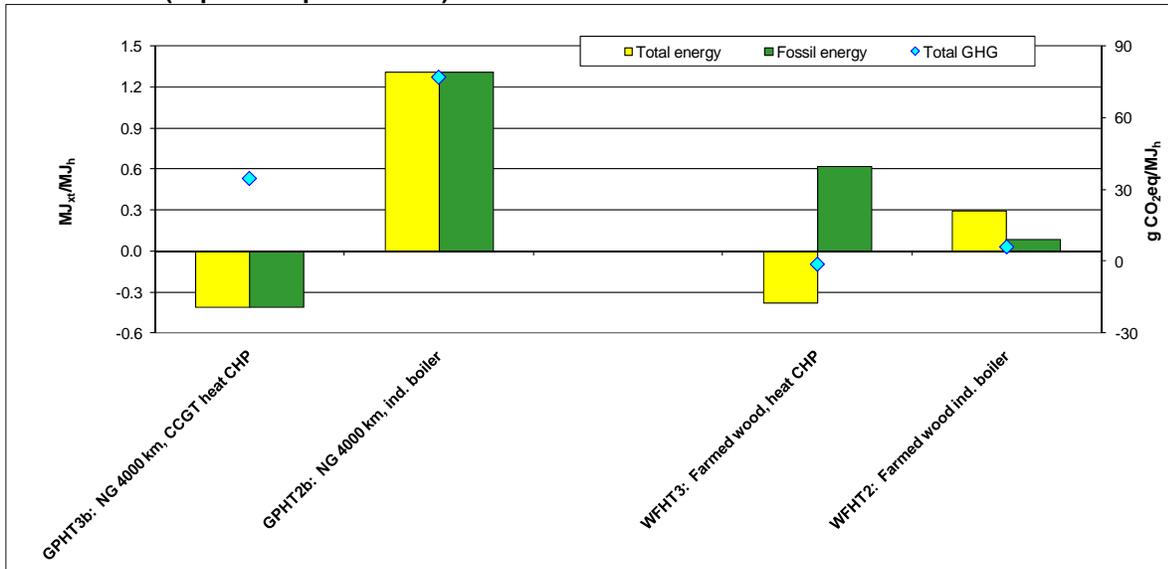
Figure 4.8.3-4 Energy and GHG balance for electricity production using CHP (expressed per MJ electricity)



In **Figure 4.8.3-5**, the figures for heat production are shown for stand-alone processes, and for comparable CHP schemes where a credit has been given for the exported electricity, based on CCGT production using the same feedstock.

- GPHT3b Piped gas 4000km, CCGT in CHP mode with electricity export
- WFHT3 Farmed wood, CCGT in CHP mode with electricity export

**Figure 4.8.3-5 Energy and GHG balance for heat production using CHP
(expressed per MJ heat)**



Compared to standalone production of heat and electricity, CHP uses less energy, whether it be from a fossil or renewable source.

4.9 Hydrogen

(See also WTT Appendix 2 section 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

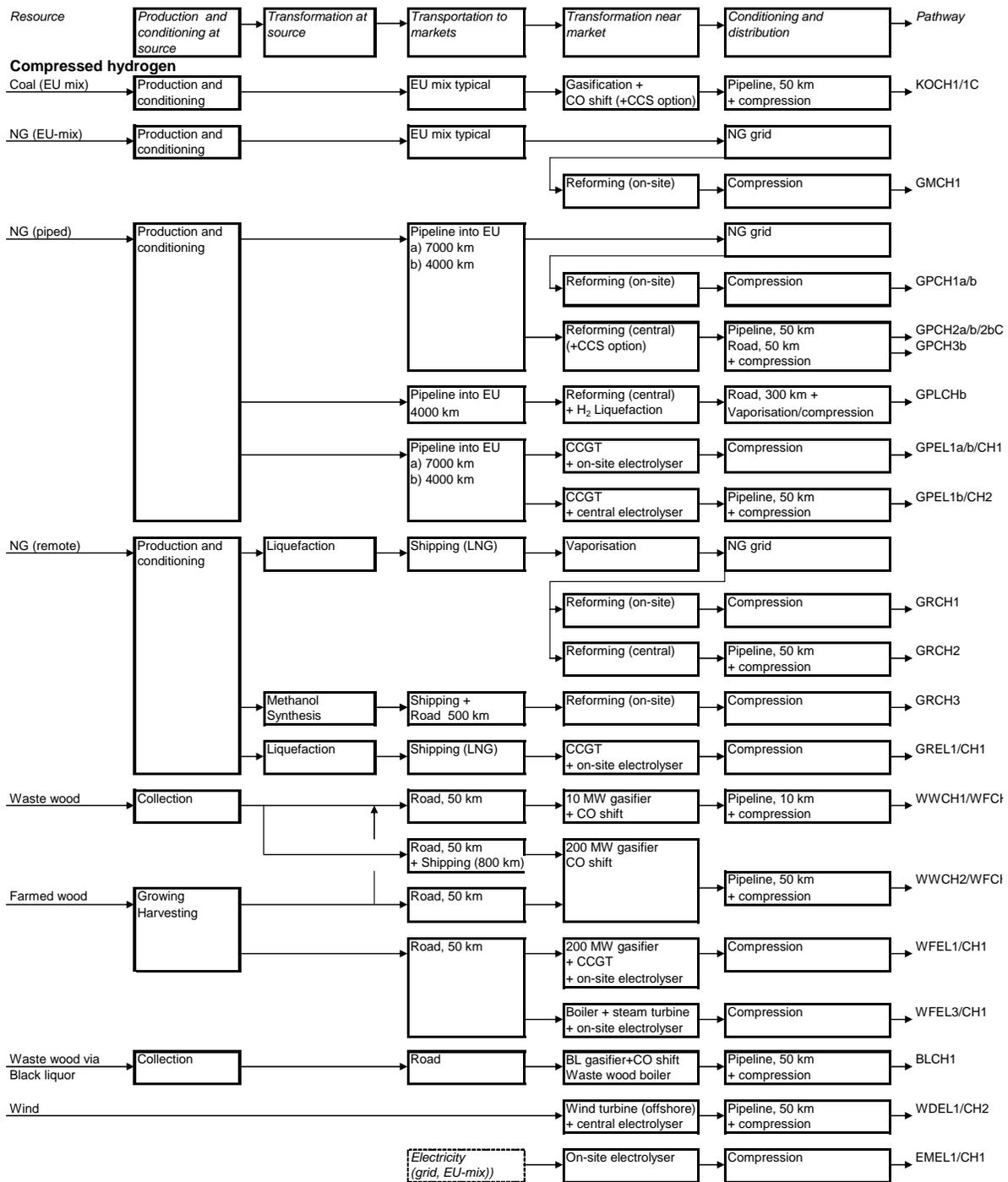
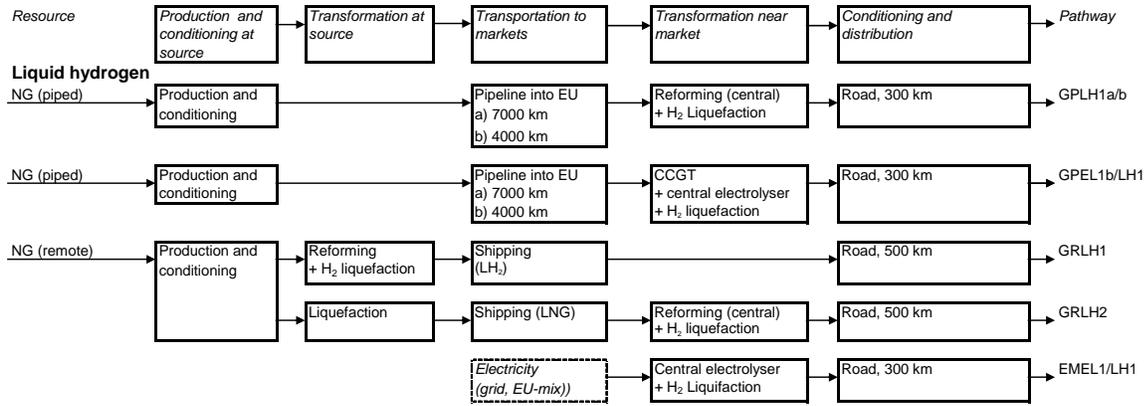


Figure 4.9.1b Liquid hydrogen pathways



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).

CCS is obviously a very attractive option for hydrogen because all carbon is turned into CO₂ 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 CO₂ recovery than has been assumed here could be possible in the future making the scheme even more beneficial. The potential of CCS is further discussed in *section 5.4*.

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

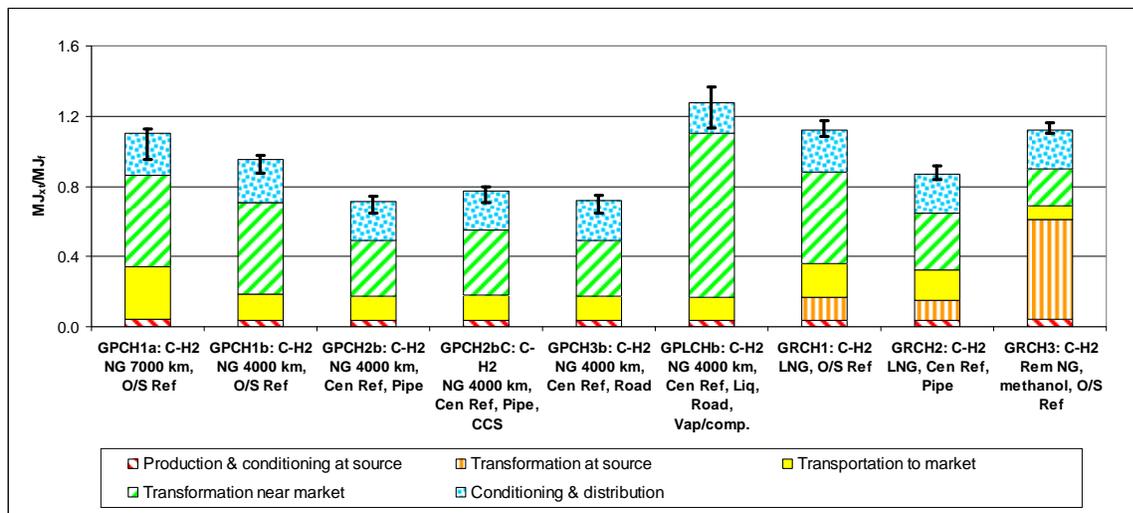
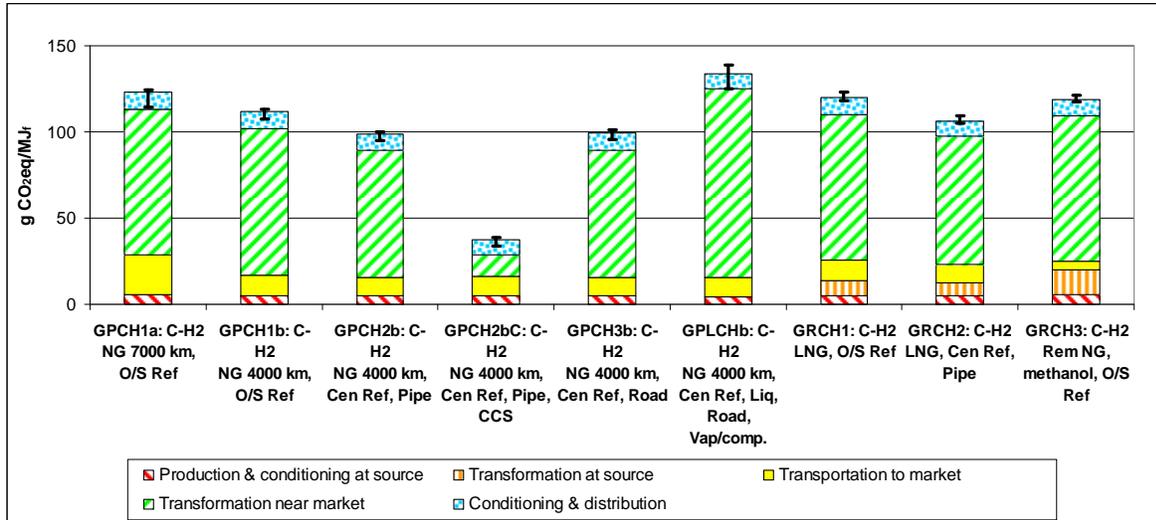


Figure 4.9.2-2 WTT GHG balance of selected NG to compressed hydrogen pathways



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

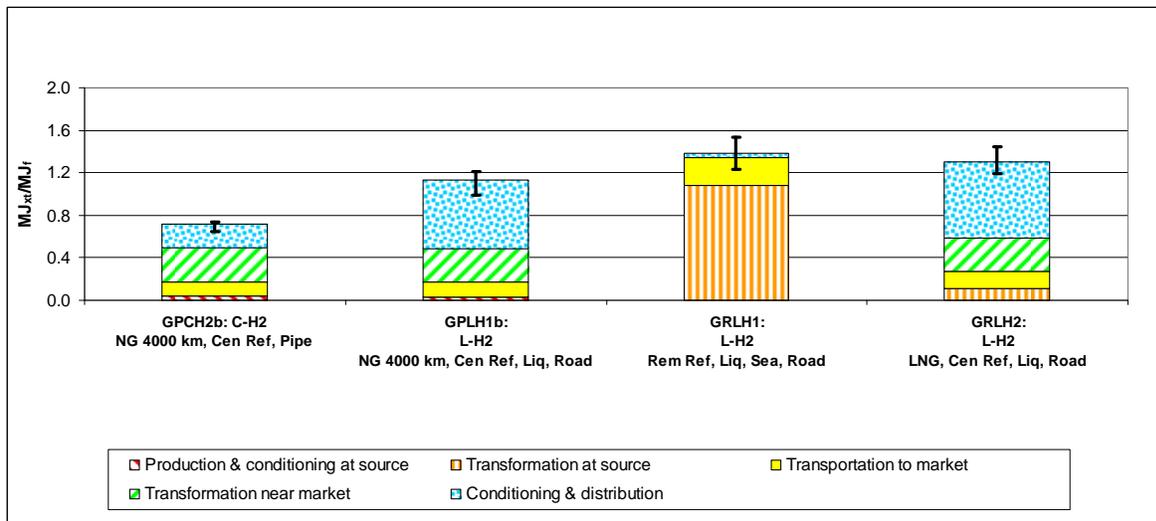
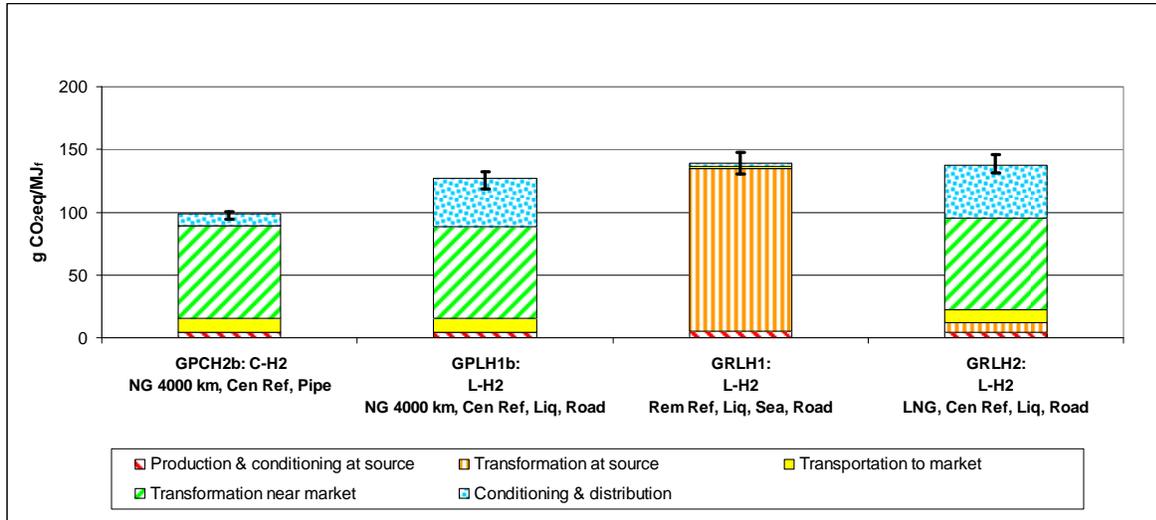


Figure 4.9.2-4 GHG balance of selected NG to liquid hydrogen pathways



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 CO₂ can be captured, albeit with an energy penalty. When applying CCS 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 CCS. The potential of CCS 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

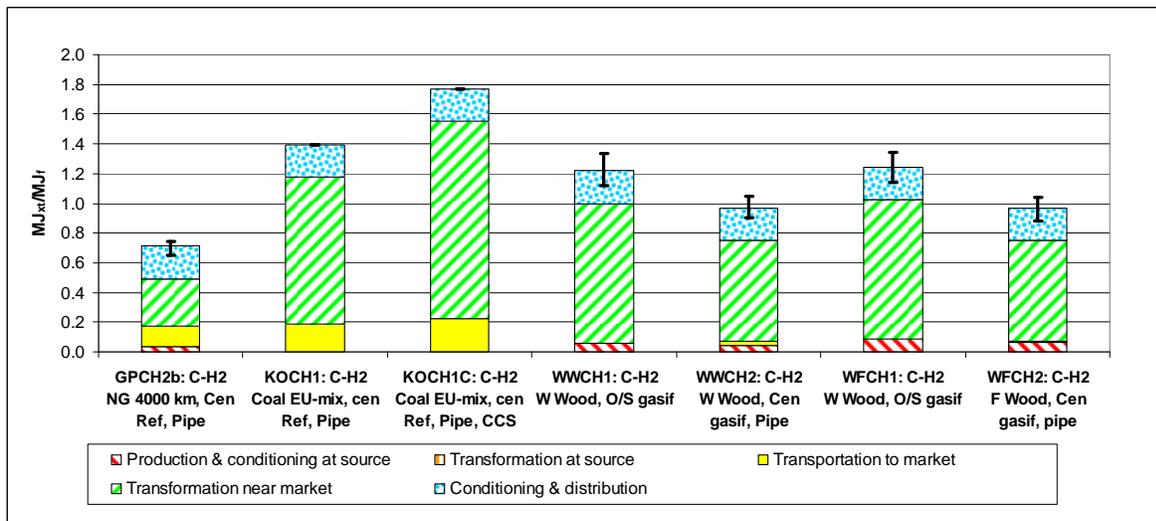
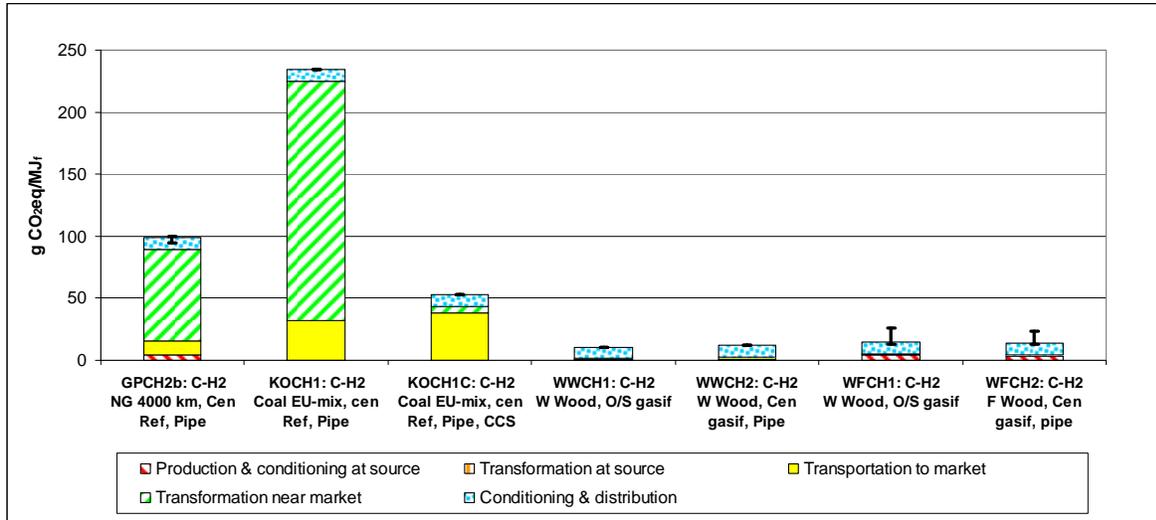


Figure 4.9.3-2 GHG balance of coal and wood to compressed hydrogen pathways



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. GPCL1b/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

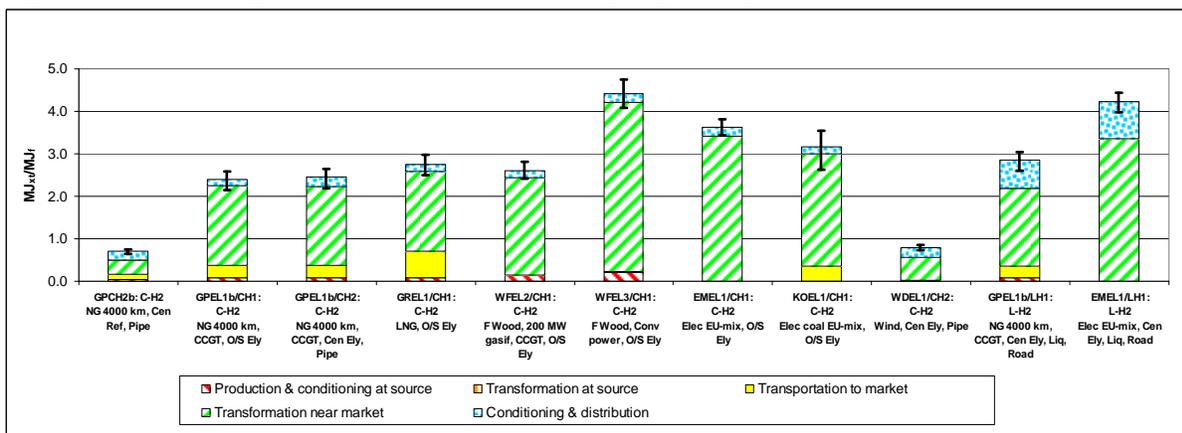
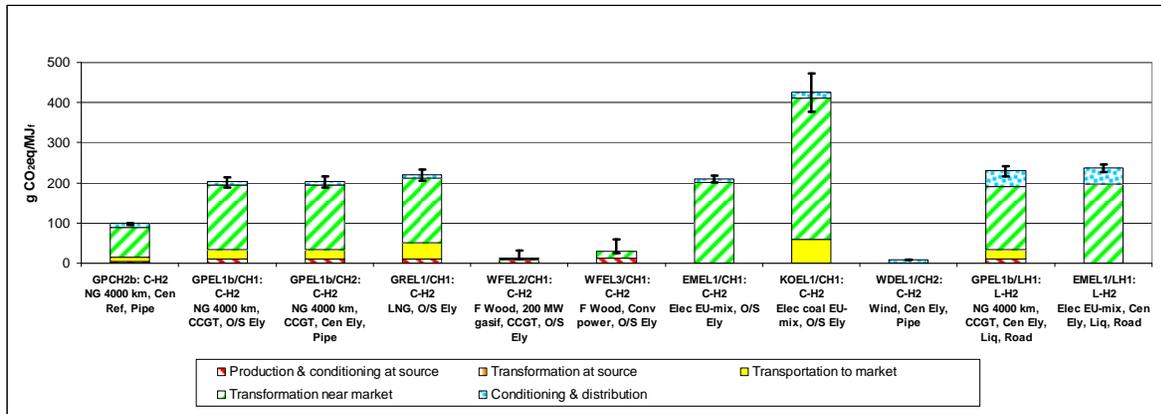


Figure 4.9.4-2 GHG balance of selected electrolysis pathways



Comparison of the straightforward NG to hydrogen pathway (GPCH1b, 112gCO_{2eq}/MJ_f) with the comparable electrolysis pathway (GPEL1b/CH1, 204gCO_{2eq}/MJ_f) 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 or 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

IMPORTANT NOTICE

This section remains largely unchanged since the last issue of this report. We recognise that regulations, market conditions and access to imports have changed since the last version and that a more thorough update is warranted at a later date. However the technical information may still be pertinent, so we have retained the earlier text virtually unchanged as a reference document, pending a more thorough update. The original text is shaded in grey to indicate its provisional nature. One addition to the earlier text is a simple estimate of the land needed to replace 10% of transport fuel with first generation biofuels, taking into account by-products. This and other significant additions or changes to the text are clearly marked by blue highlighting and black text.

The strong increase in crude oil prices over the past year seems to have abated, and current crude oil prices are consistent with our range of €25-50/bbl (equivalent to around \$35-70 at current exchange rates).

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 it is 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

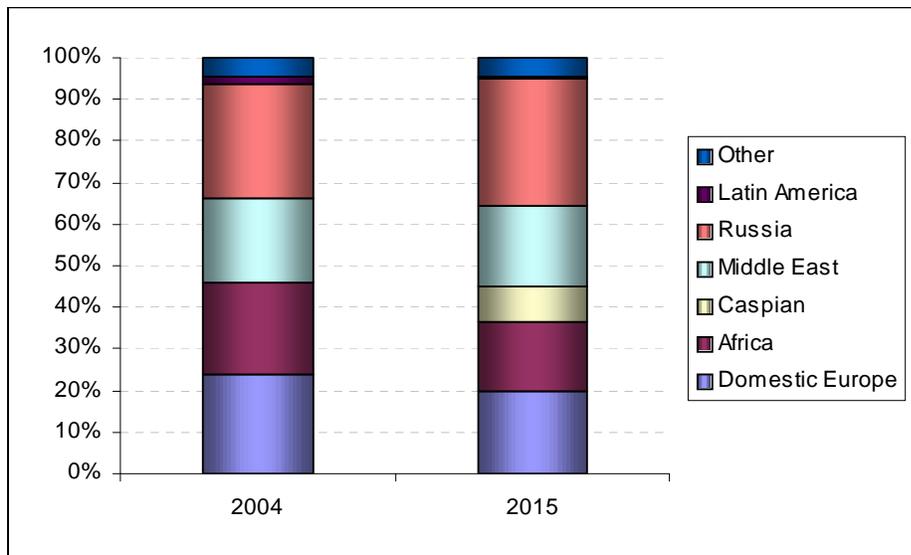
Crude oil is a worldwide commodity. Although most grades are traded on a wide geographical basis, consuming regions tend, for logistic and geopolitical reasons, to have preferred supply sources. In Europe the main sources are:

- 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. Non-conventional oil (oil sands and bitumen) are not expected to contribute to Europe's supply needs during the review period, however some information on these fuels is included in Section 3.1.1.

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 OGP¹³, 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.

¹³ Oil and Gas Producers association

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.

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
Caribbean	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
Caribbean	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 €/Nm³ 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

(Revised text, version 3c)

The Renewable Energy Directive (RED) requires 10% renewable energy in road transport by 2020. Although other alternatives may play a minor role, it is generally accepted that the bulk of the RED requirement will have to be met by biofuels, mostly first generation such as ethanol and FAME.

Within this context, a three-yearly technical exercise was launched by the JEC consortium at the beginning of 2008 with the objective of defining and assessing possible biofuel and other renewable fuel implementation scenarios for achieving the RED targets. Results of this collaboration are available at:

For illustration we discuss below a “maximum” case where first generation biofuels would have to fulfil the entire 10% target.

How much land would be needed to replace 10% of EU road fuels with biofuels from EU crops?

In version 2 of this study, we attempted to answer the question “how much biofuel feedstock could be produced by EU agriculture in 2012?” The exercise was illuminating, but we cannot update this approach because the forecasts from DG-AGRI now include biofuels in the baseline. We have therefore left the old text in grey, below. In reality, the “availability” of crops for biofuels in EU is not a fixed quantity. The extra demand for biofuels will impact on crop prices, which in turn will:

- o increase the area devoted to biofuels crops, mostly at the expense of other crops
- o increase the imports of biofuels-crops (as well as finished biofuels)
- o slightly increase the yield of crops by intensification
- o decrease food exports and increase food imports
- o generally increase the area devoted to row-crop farming in the world

These effects will be countered to some extent by the use of by-products from biofuel production for animal feed.

The actual amount of extra feedstock production in EU (compared with the increased volume of imports and decreased volume of exports) depends on the interplay of these factors in the commodities market: a full agro-economic model is required to assess the effects which is beyond the scope of the present study.

Nevertheless, it is useful to get an idea of the scale of the agricultural resources involved. We have opted to do this by making an estimate of the amount of land which would be required to produce enough biofuels crops to satisfy the 10% renewable energy target in 2020 in the European Union’s Renewable Energy directive, on the fictitious assumption that it would all come from EU production of first generation biofuels. For this, it is necessary to make some assumption on how the overall 10% transport-fuels-replacement target would be distributed between the diesel and gasoline markets. We make the arbitrary assumption that biofuels will substitute equal proportions of each.

Land for 10% biodiesel in EU-2020 diesel

10% first-generation biodiesel in 2020 diesel would require about 31 million tonnes of vegetable oil¹⁴, EU agriculture produced ~8 million tones/yr vegetable oil (for all uses), and about an equal amount was imported¹⁵.

For the purpose of scoping the land requirements, we shall pretend that all EU biodiesel could be sourced from EU production of rapeseed, although this is not what will happen¹⁶. The production of vegetable oils in EU generates animal-feed by-product, which should be taken into account when looking at the land requirements, but of course does not actually decrease the requirement for vegetable oil.

¹⁴ [DG AGRI 2007a] estimates that 10% of 2020 EU diesel demand is ~19.2 million tonnes-of-oil-equivalent, whilst our market forecast from Wood-Mackenzie gives 19.9 Mtoe. It takes 1.59 tonnes veg oil to make 1 toe biodiesel (see WTT app.1), principally because of the difference in heating value between vegetable oil and diesel..

¹⁵ EU oilseed production and net imports ran at about 20 Mt/yr in 2004-6 [DG-AGRI 2007b, table A.7]; the average oil yield is roughly 40% (42% for rapeseed, much less for soy, more for sunflower)

¹⁶ In practice biodiesel will be sourced from a mix of direct biodiesel and vegetable oil imports, oilseed imports, EU rapeseed diverted from the food market, and incremental EU rapeseed production. The by-product is produced where the oilseed is crushed, and the amount of useful by-product depends on which oilseed is used. For example, producing a tonne of rapeseed oil also generates 1.38 tonnes rapeseed meal, used for animal feed, whilst the main by-product of palm oil is only good for fertilizer.

First let us calculate the credit for the rapeseed meal byproduct. In section 3.4.4 we estimate that 1kg rapeseed meal substitutes a total of 0.88kg of a mix of wheat and soybean meal. How do we turn this into an EU land credit? For the wheat it is clear, but soybean meal is imported. It is obviously not appropriate to subtract areas of low-yielding land outside EU from high-yielding EU land. Hence, equivalence between soybean meal and cereals has to be reached.

The main sources of soybean meal are Argentina and Brazil. Argentina is the better place to examine, because there soybeans compete with wheat for non-irrigated land, whereas in Brazil the main soy production areas tend to be separated from cereals growing areas. The average soybean yield in Argentina has (to our surprise) overtaken that of wheat in recent years [FAOSTAT 2008], but let us assume they are the same. Then 1 tonne of soybeans replaces 1 tonne of wheat¹⁷, and 1 tonne rapeseed meal is equivalent to 0.88 tonnes of wheat. The 1.38 tonnes of rapeseed meal co-produced with 1 tonne of rapeseed oil will then replace 1.21 tonnes of wheat or similar cereal. The average EU soft wheat yield is expected to reach about 6 tonnes/ha by 2020¹⁸. Then the by-product from one tonne of rapeseed oil would save $1.21/6 = 0.20$ ha of the same type of land (since rapeseed rotates principally with soft wheat).

In 2020 the average oil yield of rapeseed cultivation in EU is expected to increase to 1.49 tonnes oil/ha¹⁹. So it will take 0.67 ha to make 1 tonne oil. From this we subtract the land credit for the by-product, leaving 0.47 ha net land needed per tonne of rapeseed oil. Of course, this is land which is suitable for growing rapeseed.

If we want to add this with other land requirements, we should take into account that the land suitable for rapeseed has significantly higher cereals yield than the EU-average: at least 6 tonnes/ha compared to 5.5t/ha for average cereals (in 2020). This means in terms of EU-average cereals land, the net requirement is at least 0.51 ha/t rapeseed oil. **1 toe biodiesel will then require net $1.59 \times 0.51 = 0.81$ ha of average-EU-2020-cereals-land.**

Then 31 Mt rapeseed oil for reaching 10% EU diesel substitution in 2020 would take at least **15.9 Mha** of average EU cereals land.

Land for 10% bioethanol in 2020-gasoline

1 toe bioethanol requires about 4.9 tonnes grain. However each tonne of cereals used for bioethanol also generates about 0.33 tonnes of DDGS by-product. According to our animal-feed substitution section, 1 kg DDGS is equivalent to 1.06 kg of a mix of wheat and some soybean meal. In the section on rapeseed, above, we showed that in the main place where soybeans and wheat compete for land, they have about the same yield, so we can say that 0.33 kg DDGS replace 0.35 kg cereals. So the *net* cereals requirement for 1 toe ethanol is $0.65 \times 4.9 = 3.19$ tonnes grain.

The average EU cereals yield in 2020 is projected to be about 5.5 tonnes/ha²⁰, so the **net average-EU-cereals-land required for 1 toe ethanol will be 0.58 ha**. Less land is required for bioethanol than for biodiesel basically because cereals have higher yield than rapeseed.

The Wood-Mackenzie projection of road fuel use, used in this study, foresees 92 Mtoe gasoline demand in 2020. Substituting 10% of that with ethanol would need ~45 Mt cereals gross. However, [DG AGRI 2007a] work from a different fuels projection, and estimate ~59 Mt gross cereals would be

¹⁷ Strictly, we should treat soybean meal and oil separately and give the soybean meal a second-order credit using rapeseed oil. This procedure would result a slightly higher land requirement for rapeseed oil, but is difficult to explain. Ignoring the difference in yield between wheat and soybeans also acts to underestimate the EU land requirement for rapeseed oil.

¹⁸ soft wheat yield in DG-AGRI's published agricultural outlook to 2013, extrapolated to 2020 by assuming a 0.7% per year yield increase.

¹⁹ FAPRI projected rapeseed yield (for 2017) extrapolated to 2020 is 3.54 tonnes seed/ha, and the oil crushing yield is ~42%

²⁰ It is appropriate to use average cereals yield (rather than soft wheat) because various cereals are used for bioethanol production. For simplicity we have assumed all bioethanol comes from cereals rather than sugar beet. Extrapolated to 2020, the average EU cereals yield projection from [DG AGRI 2007b] is 5.38 t/ha and that of [FAPRI 2007] is 5.79 tonnes/ha.

needed. Let us take the average: 52 Mt gross, which corresponds to $0.65 \times 52 = 33.4$ Mt net cereals, and an average-EU-2020-cereals-land area requirement of 6.1 Mha.

Combined land requirements for biodiesel and bioethanol

Reaching the 10%-2020 renewable energy target using only 1st generation bioethanol and biodiesel would need at least $15.9 + 6.1 = 22$ mill. ha of average EU cereal land. This corresponds to **37% of the combined area for cereals (52 mill. ha) and oilseeds (7.7 mill ha)** in EU-2005 [EUROSTAT].

So far, we have calculated as if there were two separate biofuel data points: 10% gasoline substitution and 10% diesel substitution. In practice there is only one combined target²¹. Since bioethanol has lower land requirements, one is tempted to substitute more gasoline than diesel. However, substituting more gasoline than diesel would aggravate problems in the refining industry, which is already struggling to produce a high enough ratio of diesel/gasoline.

These land requirements are all reduced if one assumes that 30% of the 10% biofuels target is met by 2nd generation biofuel instead of first-generation bioethanol and biodiesel. However, the reduction is less than 30%, inasmuch as some of the “freed” land would be needed for energy-crops for second-generation biofuels.

Important caveat on the use of equivalent land areas

There are huge differences in the productivity of agricultural land. Yields on any incremental arable area in EU will generally give much poorer yields, as well as possibly causing serious emissions of carbon from the soils. Furthermore, yields outside EU, are also generally lower.

What proportion of biofuel feedstock will be imported?

The latest DG-AGRI projection [DG_AGRI 2008], which assumes that compulsory set-aside rules are abolished, projects that an extra 10.2 Mtonnes/y of oilseeds²² will be used for energy purposes in 2015 compared to 2006, whilst EU production of oilseeds would rise by only 2.3 Mt/y. However, imports of oilseeds are projected to rise only 5.28 Mt/y in the same period, because a projected 12% *reduction* in EU non-energy oilseed consumption makes up the difference. Without this reduction, ~87% of that extra oilseed demand for energy use would need to be imported.

Non-energy uses of oilseeds are principally food and oleochemicals, and have historically shown a steady increase with time, (and previous DG-AGRI outlook projections extrapolated this trend), so a sudden reversal of this trend is surprising, especially since other food and feed consumption, as well as GDP, is projected to increase. Possibly the 2008 projection assumes that oilseeds will be diverted from the EU oleochemicals industry, because it would not be able to compete for feedstock with subsidized biodiesel production. If this is the case, the result would be oilseeds being imported indirectly in the form of oleochemical products. Thus we think the projection is consistent with our conclusion in v2 of this study (below) that most of the feedstock for increased biodiesel consumption will be imported (although possibly indirectly rather than directly).

²¹ Note that for the 2020 10% renewable energy target laid out by the RED, fuels beyond first generation biofuels in road, aviation, inland-navigation & rail could contribute to the target. However, it is assumed that FAME and Ethanol will be main contributors. See [JEC Biofuels Programme report](#)

²² (presumably rapeseed-equivalent)

Table 5.2:1: DG-AGRI projections for cereals and oilseed markets to 2015

DG-AGRI Outlook 2008			
OILSEEDS: Million tonnes per year	2006	2015	increase
consumption for bioenergy	8.3	18.5	10.2
other consumption	30.3	26.6	-3.7
EU production	22.5	24.8	2.3
imports	16.1	21.3	5.2
exports	0.9	0.9	0
CEREALS: Million tonnes per year	2006	2015	increase
bioenergy consumption	2.8	20.4	17.6
other consumption	263.2	267.6	4.4
EU prod	267.1	302	34.9
imports	10.1	10.5	0.4
exports	26.5	25.3	-1.2

[DG-AGRI-2008] projects an increase of 17.6 Mt/y in cereals used for energy (principally bioethanol production) between 2006 and 2015. This is almost matched by a projected 17.2 Mt increase in EU cereals production in the same period, so EU exports are decreased by only 4.5% compared to 2006.

This confirms our conclusion in v2 (below) that EU biofuels policy can be expected to have a much larger impact on the vegetable oil market than on the cereals market.

(original text of version 2 follows)

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

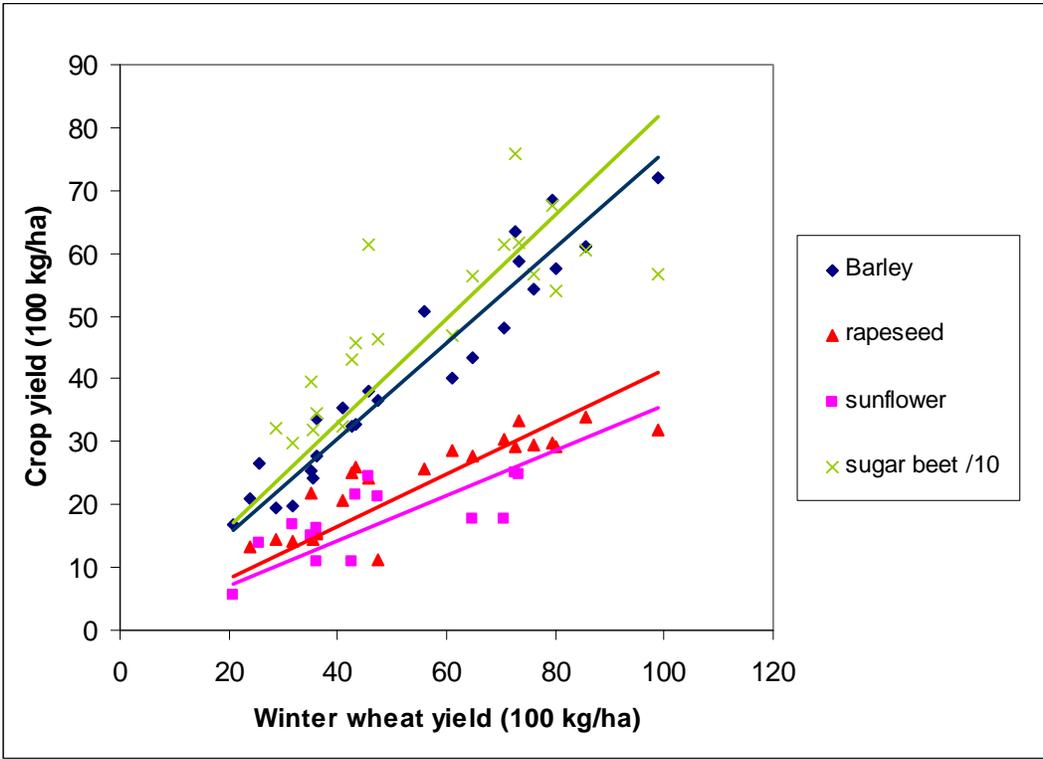
As much as possible, we have tried to avoid estimating the potential supply of crops for biofuels by multiplying an estimate of the available area by an estimate of a "typical yield". This is because of the extreme variation of yield between different types of land. Even within the area presently planted with

wheat, some EU-15 land yields seven times less than the best. If more marginal land was planted in order to increase EU 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 Average Cereals Equivalent”. 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.

Note added in Version 3c: The “break crop effect” described in the preceding paragraph hardly exists today. The increase in rapeseed production in EU (especially in Germany), due to the relatively higher price of rapeseed oil, means that rapeseed is grown more frequently in cereals rotations than was considered agronomically viable in 2003: instead of one harvest in four, rapeseed is now grown in alternating years or even in successive years. In this case, increasing oilseeds production will no longer

improve cereals yields, and so now it would be more appropriate to take the simple yield ratio. This has the effect of decreasing the amount of oilseeds expected from a given resource expressed in “average cereals equivalents”.

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 disinfect 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.

Note added in Version 3c: the availability estimates below neglected the availability-benefits of biofuel by-products being used as animal feed. On the other hand they were for the 5.75% (2010) transport fuel replacement target and not for the 10% (2020) target, and over-estimated the break crop effect (see above).

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

	Crop		Ethanol PJ/a	Bio-diesel PJ/a
	Mt/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 did not take it into consideration.
- On the other hand, biofuel production in Europe will generate animal feed as a by-product, reducing the need for purpose grown animal feed.
- 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 *compulsory* 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-aside 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.

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

(Revised text, version 3c)

Argent Energy in UK produce biodiesel from tallow as well as used cooking oil. Animal fats give FAME with high cetane number but also a high cloud point, so they need to be diluted with other biodiesels to reach transport specification.

Table 5.2.2.4 EU uses for animal fats, from [APAG 2008]

EU USES OF ANIMAL FAT 2007 (million tonnes/y)	
animal/pet feed	0.87
oleochemicals	0.75
industrial furnaces (unsubsidized)	0.60
subsidized burning for bioenergy	0.06
subsidized biodiesel manufacture	0.06
food	0.15
soap	0.07
TOTAL	2.56

There is a range of animal fat qualities, reflected in their price. The highest grades are used for food and feed; only the lowest grades are used for fuel. As by-products of meat production, their availability will hardly increase even if they become more valuable because of new (subsidized) uses. Burning tallow in industrial furnaces has been facilitated since it has been released from the list of materials covered by EU's waste incineration Directive. EU rendering plants produce about 2.5 Mtonnes animal fats per year, and more is imported by the EU oleochemical industry. About 0.6 Mt/y is used to fire furnaces, usually inside rendering plants. Together with what was already used in bio-electricity and biofuels schemes, about 0.72 Mt could potentially be diverted without detracting from non-energy uses.

The furnaces would then probably be converted to natural gas. Allowing for the likely better efficiency of a natural gas burner, the upstream emissions for animal fat use in biodiesel could be represented by ~95% of the equivalent amount of natural gas in terms of heating value.

[BioDieNet 2008] estimates that, 3.55 Mt of used cooking oil could be collected annually in EU, and somewhat more than 0.7 Mt/y are actually collected in EU at present. Of this, roughly 0.5 Mt/y is made into biodiesel.

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

5.2.4 Estimate of bio-fuel crop prices

(New text added for version 3, 2009)

In version 3 we base crop prices on the FAPRI projection

In JEC-WTW we have whenever possible always used market prices rather than bottom-up estimates of production costs. We believe market prices are more reliable indicators of marginal production cost, and they also represent both the cost-to-EU of importing feedstock, and the income-to-EU foregone if the feedstock is used for EU-biofuels production instead of export. We are pleased to see that other researchers have now almost all adopted the same approach.

For v3 we are fortunate to be able to use the latest world agricultural-commodity price projection to 2018 from [FAPRI 2009], which now takes into account price movements due to all present biofuels targets, including the 10% replacement in EU. Previously, we also considered price projections from DG-AGRI. However, DG-AGRI no longer specify the projected prices for oilseeds in their outlook, and they agglomerate the oilseeds sector, so we cannot extract prices for individual oils and meals. FAPRI is an inter-university organization set up by U.S. Congress to model developments in the food and agriculture industry for use by US government and others. Another well-respected annual agricultural outlook projection is produced by OECD/FAO, and generally the results do not differ very much from FAPRI. However, the OECD/FAO outlook agglomerates the oilseeds sector, and, at the time of writing, the latest OECD/FAO had not yet incorporated the effects of the EU RE biofuels target.

To arrive at the prices used in our calculations, we had to convert the projected 2018 prices in FAPRI from dollars in 2018 to net present value in 2008 euros. The oil price assumed for 2018 converts to 44 euros/barrel (using the exchange rates and inflation assumed by FAPRI) which is close to our lower oil price scenario. Finally, for the wheat price, we had to apply a quality correction to estimate the price of low-protein feed wheat used for distillation.

We cannot update the following analysis for the impact of the (then 5.75%) biofuels replacement target on crop prices, because crop price projections *without* biofuel targets are no longer published.

Market prices rather than bottom-up costs

Some 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 different 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 little 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 ($\pm 1.2\%$). 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⁾ Mt/a	Crop		Ethanol PJ/a	Biodiesel PJ/a
		Mt/a	PJ/a		
I Diverted baseline cereal exports:					
From land released by sugar reform	9.3				
From 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				
From 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-meal 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 meal (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 meal 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 meal and 66€t for sunflower meal** (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 meal, 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 meals we already estimated in the last paragraph. The resulting **price estimate for DDGS is 74 €tonne**.

Rapeseed meal, sunflower meal 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 3.4.10*)

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

$$55 + (1450 * 0.12 + 45) / 10 = 77 \text{ €dry tonne.}$$

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”.

[Unsel 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. Biomass power stations are less complex and capital-intensive than a second-generation biofuel plant, and so are likely to be economic at smaller scale.

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

Text modified for version 3

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 40 km of the plant making the average transport distance about 35 km.

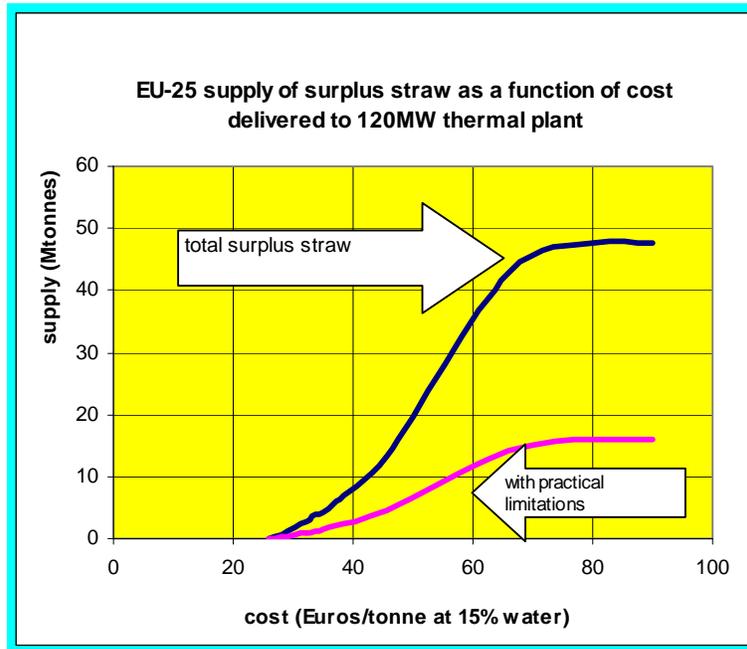
Straw price varies from season to season, and with the cost of fertilizer needed to replace the minerals lost in the straw. The power station can cope with relatively low quality, damp, straw, and so they can obtain supplies at less than the regional UK farm-gate straw prices quoted in the *Farmers Weekly*. On the other hand, transport to the plant and intermediate storage has to be considered. Altogether we estimate the delivered cost at the power station to be roughly 40 £/t (~45 €/t) at 15% water. There is no subsidy on the collection of straw. This cost is for a 120MW_{th} power plant sited in an area with a very high density of high-yield cereals farming. Costs would be higher in most areas of EU, except perhaps in new member states, where lower labour costs might outweigh the lower resource density.

[*Edwards 2005*] reported 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 the existing requirement. They used GIS techniques to map the cost of straw delivered to a 120Mw power plant. JRC subsequently held two expert consultations of the straw availability issue with industry, agronomists and soils experts [*JRC 2007*],[*JRC 2008b*]. The general conclusion was that the JRC estimate was too optimistic: it did not take sufficient account of the limitations imposed by:-

- year-on-year supply variability
- the need for straw to preserve soil texture and labile soil carbon, and avoid erosion of some fields
- inaccessible fields
- the need for the plant operator to maintain a bargaining position with farmers

The conclusion was that these practical limitations would restrict straw use to roughly 1/3 of the surplus straw (i.e. after subtracting existing uses). That means a maximum of about 16 Mt (270PJ) of straw in EU 25. Furthermore, especially for large plants, the collection cost rises as the density of cereals cultivation decreases. From the GIS data generated for [*Edwards 2005*], we have managed to construct the following approximate cost-supply curve for straw in EU27. The low-cost tail stems from the assumption that labour costs are 30% lower in new member states than in EU15: with time, one expects this differential to diminish.

Fig. 5.2.6.1 Approximate cost-supply curve for cereals straw delivered to 120 MW power stations in EU 25



[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 probably 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 residue is 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 15 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.

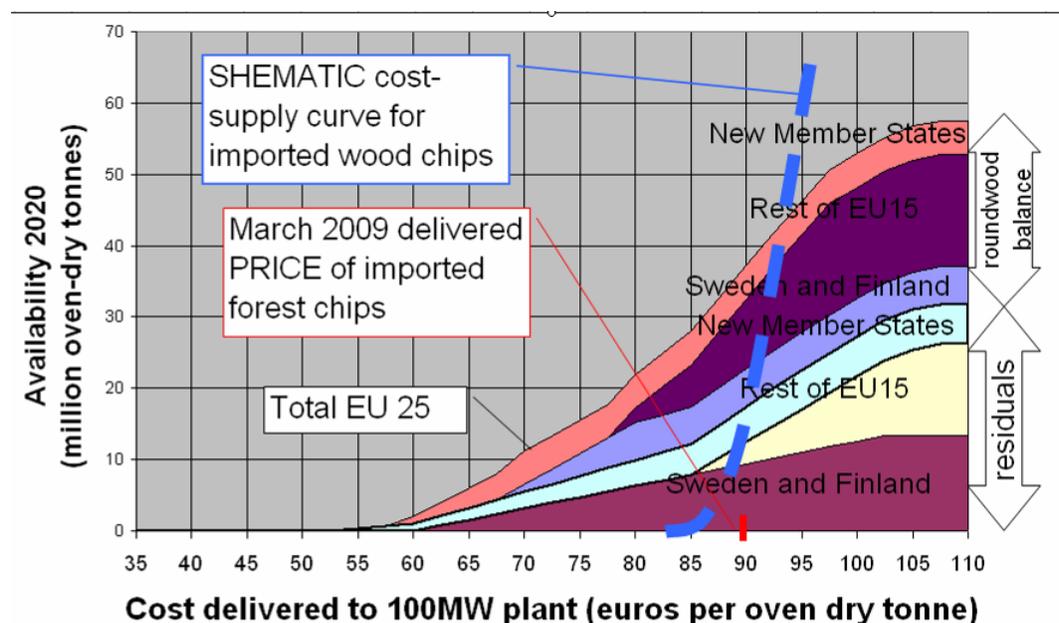
Additional material for version 3:

JRC [JRC 2008a] used the data in [METLA 2004], [Lundmark 2005], and other sources to construct a cost-supply curve for forest chips, comprising “waste” wood residues and wood-chips from cutting some of the marginal between the annual wood growth in exploited EU forests and the demand. Note these figures include those felling residues which are already used, but do not include other (traditional) firewood. Since then doubts have been raised whether this reserve of net growth increment really exists, or whether it is not due to data gaps [Mantau 2007]. UNECE (<http://timber.unece.org/>) is coordinating experts to produce a realistic picture of EU wood availability for energy and other markets.

Unlike [METLA 2004], [EEA 2006] (prepared by European Forest Institute) did not set an implicit limit on the maximum “reasonable” price of wood chips. This means they have a higher estimate than JRC/METLA of the maximum EU availability (the figure comparable to the maximum in the JRC curve is 115 Mt dry wood), but with a *much* higher price. Unfortunately, this price did not appear in the EEA summary report [EEA 2006], but the subsequent more detailed report [EEA 2007] on the forest-based studies specifies that the price for this level of supply in 2020 is 120 €/m³, or about 300 €/dry tonne!

The price-availability figures in [EEA 2007] correspond well with the lower part of the JRC curve, but the slope is lower meaning [EEA 2007] prices are higher for a given level of availability. The [EEA 2007] price comes from a market model of the forest and wood industries, whereas the JRC/METLA costs are bottom-up estimates of marginal production cost. It is indeed plausible that the market price of wood chips in EU would run ahead of the marginal production cost at times of rapidly-increasing energy-demand for wood chips.

Fig. 5.2.6.2 Estimated cost-supply curve for wood chips delivered to 100 MW EU plant



The order of the sources (Sweden and Finland, rest of EU...) is arbitrary: the graph just sums the wood chips available from each. Note these data do NOT include existing traditional firewood, and are calculated including transport costs to large processing plants, which would be needed to make economic sense of converting to liquid fuels.

The March 2009 market price of imported wood chips in railway trucks at Ukrainian/Polish border is about 75 Euros/oven-dried tonne (quoted as 45 Euros/tonne at ~40%water). To get that to a plant on

the railway in Germany (for example) would cost roughly an extra 15 Euros/dry-tonne, making a total delivered cost of 90 euros/dry-tonne.

This must represent one of the cheaper sources of EU energy-wood imports. However, once the EU price passes a level where the extra transportation costs of imported wood can be paid, the availability of imports increases much faster than that of EU-produced energy wood, because of the much higher potential production capacity in the rest of the world (assuming no trade barriers are erected). Therefore we expect the proportion of imported energy-wood to rise rapidly as the delivered price exceeds 90 euros/dry tonne. That limits further price rises in the long term, but means that most of the theoretical extra capacity of EU forests to provide extra energy supplies will never be used.

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 [Ekbon 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 [Ekbon 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 [Ekbon 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 [Ekbon 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 m³/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 our costs

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 Nm³ biogas ("net", because some of the total biogas production is used to warm the fermentor), whereas animal slurry alone produces only about 20 Nm³/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 biogas price estimates 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.

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 our biogas price

Total municipal organic waste in EU-15 is estimated at 57 Mt/a [Fazioino 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.

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, 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 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 3.4.11 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 CO₂ 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 CO₂ 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 electrolyzers. 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 CCS

From inspection of the pathways including CCS described in section 4, it will be clear that these technologies have a real potential to reduce CO₂ 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 CO₂ recovery may be possible in the future.

There is considerable scope for CO₂ 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. CO₂ 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 CO₂ used has previously been captured at natural gas processing or fertilizer manufacturing plants and is transported by pipeline. In Turkey, 6 Mt/a of CO₂ have been injected for enhanced oil recovery. Deep coal seams for coal bed methane production also offer some space for sequestration. CO₂ 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 CCS 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 CCS schemes.

Figure 5.4 WTT energy and GHG balance of selected pathways with and without CCS

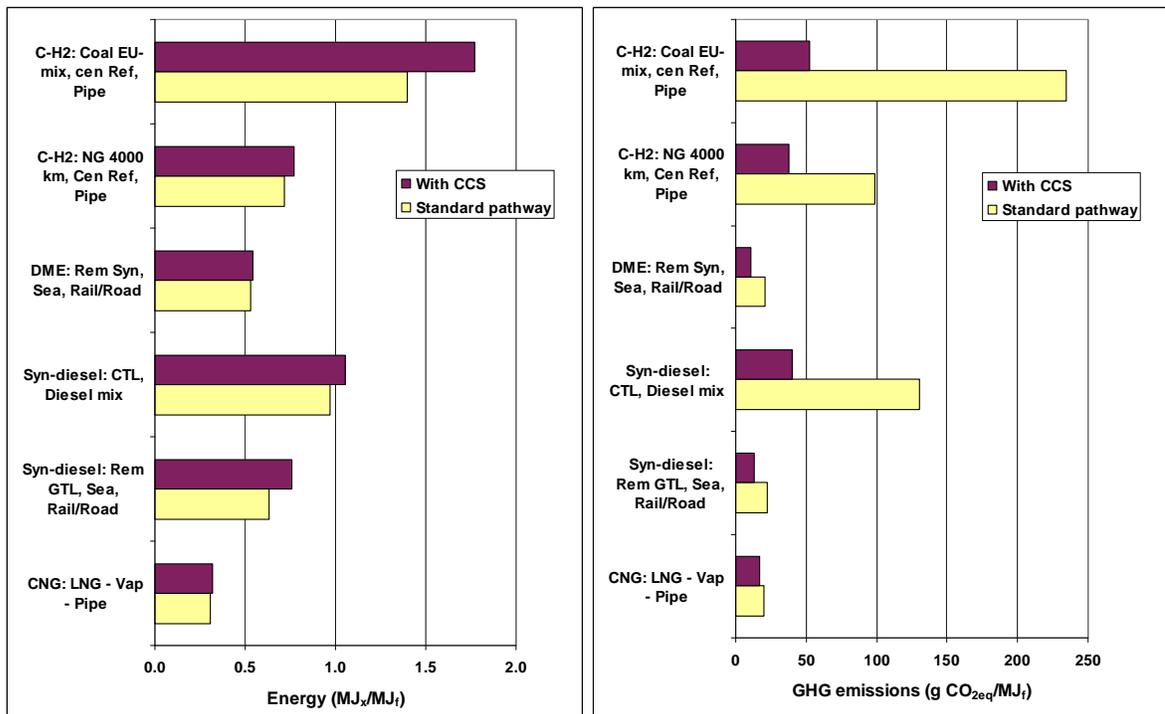


Table 5.4 Carbon dioxide reception areas and their capacities in comparison

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 CO₂ (e.g. Fischer-Tropsch synthesis where CO₂ must be scrubbed from the syngas before the synthesis step). In such cases the in-plant costs would be limited to CO₂ compression.

Processes that do not use air as combustion medium produce relatively CO₂-rich gas streams from which CO₂ can be separated at a reasonable cost. The worst case is for conventional combustion processes where CO₂ 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 CO₂.

CO₂ 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 CO₂ (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 CO₂ 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.

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
CCS	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 ₂ O	Nitrous oxide: a very potent greenhouse gas
NEDC	New European Drive Cycle
NG	Natural Gas
NO _x	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, CCS	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
OWCG4	Wheat (whole plant)	Biogas produced from the whole wheat plant
OWCG5	Wheat (whole plant, double cropping)	Biogas produced from the whole wheat plant with double cropping
Ethanol		
SBET1a	Sugar beet, pulp to fodder, slops not used	Ethanol from sugar beet, pulp used for animal fodder, slops not used
SBET1b	Sugar beet, pulp to fodder, slops to biogas	Ethanol from sugar beet, pulp used for animal fodder, slops used to produce biogas
SBET3	Sugar beet, pulp to heat/slops to biogas	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
WTET5	Wheat, DDGS to biogas	Ethanol from wheat with DDGS used to biogas production to supply part of the plant energy requirement
WWET1	W Wood	Ethanol from waste wood
WFET1	F wood	Ethanol from farmed wood
STET1	Wheat straw	Ethanol from wheat straw
SCET1a	Sugar cane (Brazil), not credit for excess bagasse	Ethanol from sugar cane in Brazilian conditions, no credit for excess bagasse
SCET1b	Sugar cane (Brazil), credit for excess bagasse	Ethanol from sugar cane in Brazilian conditions, heart credit for excess bagasse
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

<i>Code</i>	<i>Short description</i>	<i>Details</i>
Bio-diesel		
ROFA1	RME: Glycerine as chem., meal as AF	Rapeseed oil Methyl Ester, glycerine used as chemical, meal used as animal feed
ROFA2	RME: Glycerine and meal as AF	Rapeseed Methyl Ester, glycerine and meal used as animal feed
ROFA3	RME: Glycerine to biogas, meal as AF	Rapeseed oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, meal used as animal feed
ROFA4	RME: Glycerine and meal to biogas	Rapeseed oil Methyl Ester, glycerine and meal used to produce biogas to supply the plant energy requirement
ROFE1	REE: Glycerine as chem., meal as AF	Rapeseed oil Ethyl Ester, glycerine used as chemical, meal used a animal feed
ROFE2	REE: Glycerine and meal as AF	Rapeseed oil Ethyl Ester, glycerine and meal used as animal feed
ROFE3	REE: Glycerine to biogas, meal as AF	Rapeseed oil Ethyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, meal used a animal feed
ROFE4	REE: Glycerine and meal to biogas	Rapeseed oil Ethyl Ester, glycerine and meal used to produce biogas to supply the plant energy requirement
SOFA1	SME: Glycerine as chem., meal as AF	Sunflower oil Methyl Ester, glycerine used as chemical, meal used as animal feed
SOFA2	SME: Glycerine and meal as AF	Sunflower oil Methyl Ester, glycerine and meal used as animal feed
SOFA3	RME: Glycerine to biogas, meal as AF	Sunflower oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, meal used as animal feed
SOFA4	RME: Glycerine and meal to biogas	Sunflower oil Methyl Ester, glycerine and meal used to produce biogas to supply the plant energy requirement
SYFA1	SYME: Glycerine as chem., mill in EU, meal as AF in Brazil	Soy oil Methyl Ester, glycerine used as chemical, soy produced in Brazil, shipped and milled in EU. Meal credit for transport (replace meal import) and for animal feed in Brazil (corn)
SYFA1a	SYME: Glycerine as chem., mill in EU, meal as AF in EU	Soy oil Methyl Ester, glycerine used as chemical, soy produced in Brazil, shipped and milled in EU. Meal credit animal feed in EU (wheat)
SYFA1c	SYME: Glycerine as chem, mill in EU, market values	Soy oil Methyl Ester, glycerine used as chemical, soy produced in Brazil, shipped and milled in EU. Allocation by value between oil and meal.
SYFA3	SYME: Glycerine to biogas, mill in Brazil, meal as AF	Soy oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement. soy produced in Brazil, shipped and milled in EU. Meal credit for transport (replace meal import) and for animal feed in Brazil (corn)
POFA1a	PME: Glycerine as chem, CH ₄ emissions from waste	Palm oil Methyl Ester, glycerine used as chemical, methane emissions from waste, heat credit from burning fruit bunches crushing residue
POFA1b	PME: Glycerine as chem, no CH ₄ emissions from waste	Palm oil Methyl Ester, glycerine used as chemical, no methane emissions from waste, heat credit from burning fruit bunches crushing residue
POFA1c	PME: Glycerine as chem, CH ₄ emissions from waste, no heat credit	Palm oil Methyl Ester, glycerine used as chemical, methane emissions from waste, no heat credit from burning fruit bunches crushing residue
POFA2	PME: Glycerine to biogas, CH ₄ emissions from waste	Palm oil Methyl Ester, glycerine used to produce biogas to supply part of the plant energy requirement, methane emissions from waste, heat credit from burning fruit bunches crushing residue
Hydrotreated plant oil		
ROHY1	HRO (NExBTL), meal as AF	Hydrotreated rape oil (NExBTL process), meal used as animal feed
ROHY2	HRO (UOP), meal as AF	Hydrotreated rape oil (UOP process), meal used as animal feed
SOHY1	HSO (NExBTL), meal as AF	Hydrotreated sunflower oil (NExBTL process), meal used as animal feed
POHY1	HPO (NExBTL), CH ₄ from waste	Hydrotreated palm oil (NExBTL process), methane emissions from waste

<i>Code</i>	<i>Short description</i>	<i>Details</i>
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, CCS	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, CCS, 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, CCS	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

<i>Code</i>	<i>Short description</i>	<i>Details</i>
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, CCS	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, CCS	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

<i>Code</i>	<i>Short description</i>	<i>Details</i>
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
Heat		
COHT1/2	Heat from Heating Oil	In domestic or industrial boiler
GPHT1/2	Heat from NG	Piped gas (700km or 4000km) in domestic or industrial boiler
GRHT1/2	Heat from LNG	In domestic or industrial boiler
OWHT1/2/3	Heat from biogas	Biogas from municipal waste, liquid or dry manure in gas boiler
WWHT1/2	Heat from waste wood	In domestic or industrial boiler
WFHT1/2	Heat from farmed wood	In domestic or industrial boiler
Combined Heat and Power		
GPEH1	Piped gas 7000km, CCGT	Electricity production with credit for export ed heat
GPEH1b	Piped gas 4000km, CCGT	Electricity production with credit for export ed heat
GREH1	LNG, CCGT	Electricity production with credit for export ed heat
WWEH1	Waste wood, CCGT	Electricity production with credit for export ed heat
WFEH1	Farmed wood, CCGT	Electricity production with credit for export ed heat
GPHT3	Piped gas 4000km, CCGT	Heat production, with credit for exported electricity
WWHT3	Waste wood, CCGT	Heat production, with credit for exported electricity
WFHT3	Farmed wood, CCGT	Heat production, with credit for exported electricity

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

concaawe



TANK-to-WHEELS Report

Version 3c, July 2011

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Notes on version number:

This is the third version of this report replacing version 2c published in March 2007. The main changes and additions to the second version cover:

- Re-evaluation of 2010+ Diesel vehicle configurations (*section 5*)

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1 Introduction

This part of the study describes the final use of a fuel and the various powertrain options available. The issues related to fuel production and provision, are covered in the Well-to-Tank report. The Well-to-Wheels report provides the integrated view of the relative merits of the wide range of options studied.

The main issues addressed in this Tank-to-Wheels section are the fuel economy, the greenhouse gas (GHG) emissions and an evaluation of credible retail price for near and longer term technologies in Europe. The ADVISOR model¹ was used to simulate a virtual but credible and coherent, compact sized European sedan. The input fuel and technology data were checked and agreed by the EUCAR members. This model vehicle is used as a tool for comparing the various fuels and associated technologies; it is not deemed representative of the European fleet. This study makes no assumptions about the availability or market share of the technology options proposed for 2010 and beyond (2010+).

This version 3 of the Tank-to-Wheels report updates the previous one with regard to the following issues:

- Re-evaluation of 2010+ Diesel vehicle configurations (*section 5*).

¹ A vehicle simulation tool developed by NREL as open source. Now commercially available through AVL.

2 Fuels / Powertrain configurations

2.1 Fuel properties and vehicle characteristics

The key properties of the fuels considered are shown in *Table 2.1* (see also *WTT report*). For the 2010+ projections, gasoline and diesel fuel are assumed to comply with currently legislated specifications at that date, in particular with a maximum sulphur content of 10 mg/kg.

Table 2.1 Main properties of fuels

Fuel	Density kg/m ³	LHV MJ/kg	Carbon %m	CO ₂ emissions		
				kg/kg	g/MJ	
Gasoline	2002	750	42.9	87.0%	3.19	74.35
	2010	745	43.2	86.5%	3.17	73.38
Ethanol		794	26.8	52.2%	1.91	71.38
Gasoline/Ethanol blend 95/5	2002	752	42.1	85.2%	3.12	74.25
	2010	747	42.3	84.6%	3.10	73.31
MTBE ⁽¹⁾		745	35.1	68.2%	2.50	71.23
ETBE ⁽¹⁾		750	36.3	70.6%	2.59	71.40
LPG ⁽²⁾		550	46.0	82.5%	3.02	65.68
CNG/CBG ⁽³⁾			45.1	69.2%	2.54	56.24
Diesel	2002	835	43.0	86.2%	3.16	73.54
	2010	832	43.1	86.1%	3.16	73.25
Bio-diesel ⁽⁴⁾		890	36.8	76.5%	2.81	76.23
Diesel/bio-diesel blend 95/5	2002	838	42.7	85.7%	3.14	73.66
	2010	835	42.8	85.6%	3.14	73.39
Synthetic diesel		780	44.0	85.0%	3.12	70.80
DME ⁽⁵⁾		670	28.4	52.2%	1.91	67.36
Naphtha		720	43.7	84.9%	3.11	71.22
Methanol		793	19.9	37.5%	1.38	69.10
Hydrogen			120.1	0.0%	0.00	0.00

⁽¹⁾ Methyl (Ethyl) -Tertiary-Butyl Ether

⁽²⁾ Liquefied Petroleum Gas

⁽³⁾ Compressed Natural Gas / Compressed Bio Gas

⁽⁴⁾ Figures are for FAME (Fatty Acid Methyl Ester), more specifically RME (Rape seed Methyl Ester)

⁽⁵⁾ Di-Methyl-Ether

Further in the report the term "CNG" is used to represent a methane-rich gas as indicated above, regardless of its origin (which is only an issue for the WTT evaluation). The same applies to "bio-diesel" which represents a generic vegetable oil ester.

2.2 Vehicle characteristics

All simulations are based on a common, "virtual" vehicle, representing a typical European compact size 5-seater sedan, comparable to e.g. a VW Golf or others in that class. The theoretical vehicle is used as a tool for comparing the various fuels and associated technologies. It is not claimed to be representative of the European fleet. The reference is a 2002 Port Injected Spark Ignition gasoline (PISI) powertrain.

Table 2.2 Characteristics of the 2002 gasoline PISI reference vehicle

Curb weight	kg	1181
Weight class	kg	1250
Drag coefficient	-	0.321
Vehicle front area	m ²	2.1
Tyre radius	m ²	0.309
Tyre inertia	kg.m ²	0.7
Engine displacement	l	1.6
Engine inertia	kg.m ²	0.125
Efficiency differential+gear		0.9
Transmission ratio of differential gear		4.25
Transmission ratio 1 st to 5 th gear		3.455/1.944/1.370/1.032/0.850

2.3 Vehicle minimum performance criteria

To guarantee a fair comparison, minimum “customer performance” criteria were set so as to ensure that each fuel-powertrain combination met the same customer expectations (except where this was technically impossible). Depending on the fuels under consideration, the powertrain technologies were adapted to match these criteria.

Table 2.3 Minimum vehicle performance criteria

		Target
Time lag for 0-50 km/h	s	<4
Time lag for 0-100 km/h	s	<13
Time lag for 80-120 km/h in 4 th gear	s	<13
Gradeability at 1 km/h	%	>30
Top speed	km/h	>180
Acceleration	m/s ²	>4.0
Range ⁽¹⁾	km	>600

⁽¹⁾ Where applicable 20 km ZEV range

2.4 Fuel/powertrain configurations

The following combinations of fuels and powertrains were assessed. The entries in **Table 2.4** indicate the time horizons of the technology assessments. The 2002 baseline situation was simulated for conventional, available vehicles and fuels: gasoline port injection (PISI), gasoline direct injection (DISI) and diesel direct injection (DICI). For 2010 and beyond, viable technology options were considered without any assumptions regarding availability and market share.

Table 2.4 Simulated configurations

Powertrains	PISI	DISI	DICI	Hybrid PISI	Hybrid DISI	Hybrid DICI	FC	Hybrid FC	Ref. + hyb. FC
Fuels									
Gasoline	2002 2010+	2002 2010+		2010+	2010+				2010+
Diesel fuel			2002 2010+			2010+			2010+
LPG	2002 2010+								
CNG Bi-Fuel	2002 2010+								
CNG (dedicated)	2002 2010+			2010+					
Diesel/Bio-diesel blend 95/5			2002 2010+			2010+			
Gasoline/Ethanol blend 95/5	2002 2010+	2002 2010+			2010+				
Bio-diesel			2002 2010+			2002 2010+			
DME			2002 2010+			2010+			
Synthetic diesel fuel			2002 2010+			2010+			
Methanol									2010+
Naphtha									2010+
Compressed hydrogen	2010+			2010+			2010+	2010+	
Liquid hydrogen	2010+			2010+			2010+	2010+	

PISI: Port Injection Spark Ignition

DISI: Direct Injection Spark Ignition

DICI: Direct Injection Compression Ignition

FC: Fuel cell

Hybrid FC: Fuel cell with large battery

3 Powertrain simulation

The open source vehicle simulation tool ADVISOR, developed by NREL, was used for all powertrains. The validity of this tool was checked against the in-house simulation codes of a number of European manufacturers and found to deliver analogous results.

The simulation tool was adapted to specific technologies by using detailed "fuel efficiency" maps. For conventional internal combustion engines and fuel cells, European Manufacturers supplied the relevant "fuel efficiency" maps on a proprietary basis.

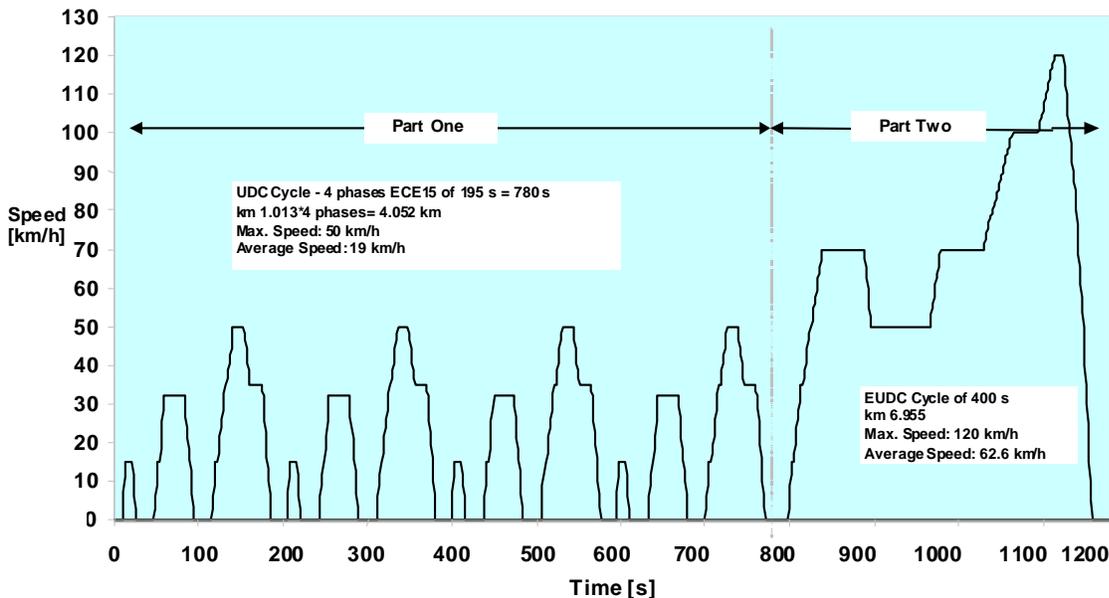
For gasoline direct injection, an adjusted map of the Mitsubishi 1.8 litre displacement engine was used.

For hybrids, the model existing in ADVISOR was adapted according to agreed strategies and constraints.

3.1 Test cycle, methodology

For each fuel/technology combination, the fuel consumption and the GHG emissions were simulated according to the standard European drive cycle, NEDC.

Figure 3.1 NEDC Cycle



To reflect accurately the "cold start" operation of the vehicle engine, the engine water temperature rise profile with time, and the evolution of the corresponding fuel efficiency figures, had to be implemented into ADVISOR. For the SI engine maps, this was done from experimental values. For Diesel (CI) engines, the equivalent sub-model was assumed and found in reasonable fit with the experience of the relevant experts.

For the simulated assessment of the various technologies the inertia class conditions were kept conform to the standard rules.

The figures were evaluated for each neat fuel separately (Gasoline, Diesel, CNG, LPG and hydrogen). For alternatives to gasoline (ethanol, MTBE/ETBE) and diesel (bio-diesel, synthetic diesel, DME) it was assumed that, whether used neat or in blends, the fuel consumption on energy basis would remain the same as for the base fuel. In other words these **alternatives fuels were deemed not to have any effect positive or negative on the energy efficiency of the engine**. The corresponding GHG emissions were then calculated from the compositional data (*Table 2.1*).

All fuel / vehicle combinations are meant to comply with the emissions standards in force at date i.e. EURO III in 2002 and EURO IV in 2010.

EURO III Diesel vehicles were assumed to be fitted only with an oxidation catalyst. EURO IV Diesel vehicles are considered to be equipped with a Diesel Particle Filter (DPF), with a fuel efficiency penalty resulting from the need for its periodic regeneration. A DPF system can be catalytic (C-DPF) or additive based (A-DPF). No distinction has been made here between the two systems although the A-DPF systems require somewhat less energy for the regeneration process. Hence, a general efficiency penalty was assigned to Diesel vehicles with DPFs of +2.5%². An exception was made for DME DIC1 vehicles which, because of the favourable properties of that fuel, would not require a DPF to meet the EURO IV standard. An alternative option was also calculated for 2010+ Diesel vehicles without DPF, to represent a case where advanced combustion strategy concepts alone would be able to achieve the EURO IV emissions standard.

AUXILIARIES and fuel economy

The fuel consumption simulation and the crosscheck tests included electrical or mechanical load due to components inherent to the powertrain. Fuel penalty due to auxiliary devices was assessed in terms of total GHG emissions (g CO_{2eq}/ km) for a typical additional load of 300 W.

For the performance tests, the following conditions applied:

- Vehicle mass: curb weight + 140 kg.
- Auxiliaries: Not powered
- Acceleration: time from 80 to 120 km/h in 4th gear to be less than 13 s; time from 80 to 120 km/h in top gear given for information only.
- Maximum acceleration: time from 0 to 50 km/h, 0 to 100, and 80 to 120 km/h: the original conventional ADVISOR model was used.
- Top speed is the result of an analytical calculation
- Gradeability (%): the vehicle speed is 1 km/h and the torque is maximum,
e.g. 100 % gradeability represents a 45 ° angle slope (Analytical calculation).

3.2 Total GHG emission

Total GHG emissions were calculated. Methane (CH₄) and N₂O emissions were taken into account as CO₂ equivalent through their IPCC factor:

- For CH₄, the IPCC factor is 23. For gasoline, LPG, diesel fuel and DME, CH₄ emissions were considered to be 20 % of the applicable unburnt hydrocarbons limit. For the CNG engine, 80% of the unburnt hydrocarbon emissions were estimated to be CH₄.
- For N₂O, the IPCC factor is 296. For all configurations, N₂O emissions were considered to be 2% of the NO_x emissions limit.

² Reduced from 4% in version 1 of this study

Table 3.2 Impact of CH₄ and N₂O emission as CO₂ equivalent

All figures in	g/km	Gasoline LPG	Diesel DME	CNG	Hydrogen
EURO III					
HC limit		0.20	0.06	0.20	
CH ₄ emissions		0.04	0.012	0.16	
CO ₂ equivalent		0.92	0.28	3.68	
NOx limit		0.15	0.5	0.15	
NO ₂ emissions		0.003	0.010	0.003	
CO ₂ equivalent		0.89	2.96	0.89	
EURO IV					
HC limit		0.10	0.05	0.10	
CH ₄ emissions		0.02	0.01	0.08	
CO ₂ equivalent		0.46	0.23	1.84	
NOx limit		0.08	0.25	0.08	0.08
NO ₂ emissions		0.002	0.005	0.002	0.002
CO ₂ equivalent		0.47	1.48	0.47	0.47

3.3 ADVISOR adaptation to NEDC and specific powertrains

In order to simulate the NEDC, a number of modifications were brought to ADVISOR. For conventional vehicles the modifications were:

- Gear ratio management: during the NEDC, the gear shift sequence is imposed as a function of time. In the original version of ADVISOR, it was not possible to run the vehicle at the same speed with two different gear ratios, as required under the NEDC (50 km/h has to be achieved in both 3rd and 4th gear).
- Fuel cut-off during vehicle deceleration.
- At idling, fuel consumption read from the data file.

Modifications to the energy management strategy were also required for hybrid and fuel cell vehicles.

3.4 Validation tests on the 2002 gasoline vehicle

Experimental data from Volkswagen for the Golf and the PISI 1.6 l engine were used to cross-check the simulation figures. Results were in close agreement: the simulated fuel consumption was 6.95 l/100 km, which is close to the measured result 7.0 l/100 km.

4 2002 configurations

4.1 Vehicles

All vehicles, except the CNG Bi-Fuel, complied with the performance criteria presented in *section 2.3*. A larger engine displacement, and consequently vehicle mass, was necessary for the CNG vehicle to achieve the minimum performance criteria (see *section 2.3*). Several iterations were necessary in ADVISOR to find the correct displacement allowing the dedicated CNG vehicle to achieve the specified acceleration criteria.

Table 4.1 Characteristics of 2002 ICE Euro III vehicles

		PISI				DISI	DICI
		Gasoline	LPG bi-fuel	CNG bi-fuel	CNG	Gasoline	Diesel/DME
Powertrain							
Displacement	l	1.6	1.6	1.6	1.9	1.6	1.9
Powertrain	kW	77	77/77	77/68	85	70	74
Engine mass	kg	120	120	120	150	120	145
Gearbox mass	kg	50	50	50	50	50	50
Storage System							
Tank pressure	MPa	0.1	1	25	25	0.1	0.1/1
Tank net capacity	kg	31.5	14/16.5	14/17.5	30	30	25/40
Tank mass empty	kg	15	12/12	12/61	103	15	15/30
Tank mass increase including 90% fuel	kg	0	8	59	87	0	0/28
Vehicle							
Reference mass	kg	1181	1181	1181	1181	1181	1248
Vehicle mass	kg	1181	1189	1240	1298	1181	1248/1276
Cycle test mass	kg	1250	1250	1360	1360	1250	1360
Performance mass	kg	1321	1329	1380	1438	1321	1388/1416

4.1.1 Gasoline

Both PISI and DISI configurations resulted in the same total mass.

4.1.2 Diesel

The Diesel version was powered by a 1.9 l turbo-charged engine (74 kW). The higher engine mass and corresponding structure reinforcements increased the total vehicle mass by about 70 kg compared to gasoline. We used the same vehicle characteristics for other potential liquid diesel fuels (bio- and synthetic diesel fuel) either neat or in blends with conventional diesel fuel.

DME needs a “LPG-type” steel tank. The excess mass of this 60 l tank was estimated at 28 kg (tank: 15, fuel: 13) as compared to the Diesel reference. The inertia class was kept at 1360 kg so that the fuel efficiency was unaffected.

4.1.3 Compressed Natural Gas (CNG)

2 options were considered for CNG vehicles:

Bi-Fuel adapted vehicle

An additional CNG injection system was fitted to the original gasoline 1.6 l engine, (as in the FIAT Multipla Bi Power). In order to respect the gasoline / gas range ratio of a typical CNG vehicle (57% CNG, 340 km / 43 % gasoline, 260 km), it was fitted with two fuel tanks: 18.7 l for gasoline and 121 l for CNG. The high pressure CNG vessel is made of composite and has a mass of 61 kg.

The gasoline operation must be preserved. As a result, due to the gaseous fuel volumetric occupancy the minimum acceleration criteria could not be met (*Table 4.1.4*). As the acceleration criteria could be met when operating on gasoline this was considered as an acceptable compromise.

Dedicated engine vehicle

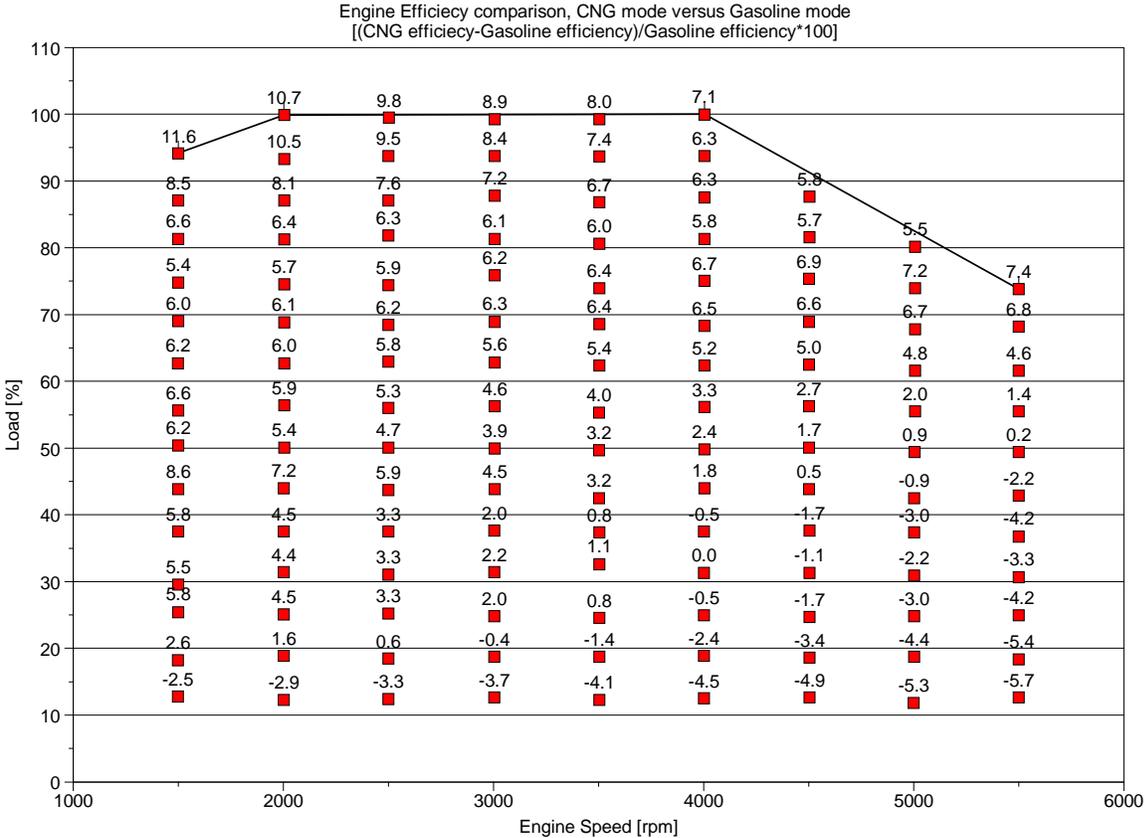
To compensate for the loss of torque due to the gaseous fuel and meet the performance criteria, the engine displacement was increased from 1.6 to 1.9 l, with a resulting 30 kg increase of engine mass (this was reduced from 2 l in version 1 of this study as a result of the more favourable engine map, see below). For a 600 km range, the amount of CNG required was calculated to be 30 kg and the high-pressure composite tank tare mass 103 kg. Subtracting the mass of the initial gasoline fuel system, the excess mass remained at 87 kg (*Table 4.1*).

With this “single fuel” engine, the compression ratio could be increased from 9.5:1 up to 12.5:1 to get the benefit from the higher “knock resistance” (octane number) of CNG.

Efficiency map of CNG vehicle

The original map used in version 1 of this study was replaced by a correction map (%) provided by EUCAR and presented in *Figure 4.1.3*. This map reflects also the basic CNG trends (high knocking resistance under high load conditions, no need for full load enrichment, and lower combustion velocity at high rpm). New consumption maps (for both CNG Bi-Fuel and CNG dedicated) were derived from the gasoline PISI 2002 data. The maximum torque curve was also updated.

Figure 4.1.3 Efficiency difference between Gasoline and CNG



4.1.4 Liquefied Petroleum Gas (LPG)

A bi-fuel gasoline/LPG vehicle was considered. Energy consumption when running on LPG was considered to be the same as for gasoline. A LPG liquid injection was assumed. Hence, the maximum torque with LPG was the same as for the gasoline engine.

For an autonomy of 340 km on LPG (the same as for the CNG bi-fuel configuration), the vehicle needed 16.5 kg of LPG equivalent to 30 l. The composite LPG tank had specific mass of 0.4 kg/l of LPG i.e. an empty mass of 12 kg. The inertia class was, however, kept unchanged and so was the fuel efficiency.

Other characteristics of the vehicle were unchanged from the reference. In this configuration the bi-fuel LPG vehicle met all performance criteria (see *Table 4.1.4*).

4.1.5 Conformance to performance criteria

With the adaptations described above, the closest available actual energy efficiency maps were implemented in the code. Consequently, all the vehicles (except the CNG bi-fuel as explained) were able to meet or exceed the performance criteria. Actual figures are summarised below.

Table 4.1.5 Performance of 2002 ICE vehicles

		Gasoline		LPG	CNG PISI		Diesel	Target
		PISI	DISI	PISI	Bi-fuel	Dedicated	DICI	
Time lag for 0-50 km/h	s	4.0	4.1	4.0	4.5	3.9	3.9	<4
Time lag for 0-100 km/h	s	11.7	12.9	11.7	13.6	11.8	11.5	<13
Time lag for 80-120 km/h in 4 th gear	s	11.3	11.7	11.3	13.8	11.4	9.6	<13
Time lag for 80-120 km/h in 5 th gear	s	15.1	15.8	15.1	18.6	15.1	12.4	-
Gradeability at 1 km/h	%	54	50	54	44	52	84	>30
Top speed	km/h	191	178	191	184	193	187	>180
Acceleration	m/s ²	4.3	4.2	4.3	3.8	4.4	4.8	>4.0

- Diesel fuel, DME, bio-diesel, synthetic diesel and diesel/bio-diesel blend configurations displayed the same performance as the diesel DICI configuration.
- The gasoline/ethanol blend configuration showed the same results as the gasoline configuration.
- The LPG bi-fuel configuration showed the same performance as the gasoline PISI.
- As expected the CNG bi-fuel configuration does not meet the acceleration and time lag criteria.

4.1.6 Energy and GHG Emissions (NEDC)

The fuel / energy consumption and GHG emissions results are presented for the NEDC.

The engine was started “cold” (20°C). The steady-state fuel over-consumption (in percentage by reference to hot operation) is only a function of the engine temperature. The rate of rise of the engine temperature and the resulting over-consumption over the cycle were validated with experimental data for the PISI gasoline reference configuration.

For the other configurations, such as DISI, the fuel over-consumption was calculated versus engine temperature with the same parameters. For the DISI configuration, the following assumptions were made:

- Below 50°C, the engine operates in “homogeneous” mode, at stoichiometric conditions (not “lean burn”),
- Above 50°C, in a range of low speed, low-to-mid load, the engine is under lean stratified conditions, with the typically lower fuel consumption of DI engines.

To account for the two different regimes on the DISI vehicle, a subsequent correction was applied. To comply with the “cold” stoichiometric conditions efficiency, the instantaneous fuel consumption was increased by 10% whenever the engine temperature was below 50°C and for the operating points appearing in the “lean burn stratified” “zone of the relevant map.

The average fuel consumption and total GHG emissions over the NEDC for all the 2002 ICE configurations are shown in the tables and figures below.

Table 4.1.6-1 Average energy/fuel consumption and GHG emissions over the NEDC 2002 ICE vehicles

	Fuel consumption (/100 km)			GHG emissions (g CO ₂ eq/km)				% change ⁽²⁾	
	MJ	l ⁽¹⁾	kg	as CO ₂	as CH ₄	as N ₂ O	Total	Energy	GHG
PISI									
Gasoline 2002 (ref)	223.5	6.95	5.21	166.2	0.9	0.9	168.0	Ref.	Ref.
Ethanol (neat)	223.5	10.50	8.34	159.5	0.9	0.9	161.3	0%	-4%
⁽³⁾ Gasoline/ ethanol 95/5	223.5	7.07	5.32	165.9	0.9	0.9	167.8	0%	0%
LPG bi-fuel	223.5	8.83	4.86	146.8	0.8	0.9	148.5	0%	-12%
CNG bi-fuel	226.9	7.05	5.03	127.6	3.7	0.9	132.2	2%	-21%
CNG dedicated	222.8	6.92	4.94	125.3	3.7	0.9	129.9	0%	-23%
DISI									
Gasoline	208.8	6.49	4.87	155.2	0.9	0.9	157.1	-7%	-7%
Ethanol (neat)	208.8	9.81	7.79	149.0	0.9	0.9	150.8	-7%	-10%
⁽³⁾ Gasoline/ ethanol 95/5	208.8	6.60	4.97	155.0	0.9	0.9	156.8	-7%	-7%
DICI									
Diesel	183.1	5.10	4.26	134.6	0.3	3.0	137.9	-18%	-18%
Bio-diesel (neat)	183.1	5.59	4.98	139.6	0.3	3.0	142.8	-18%	-15%
⁽³⁾ Diesel/Bio-diesel 95/5	183.1	5.12	4.29	134.9	0.3	3.0	138.1	-18%	-18%
DME	183.1	9.62	6.45	123.3	0.3	3.0	126.6	-18%	-25%
Synthetic diesel	183.1	5.34	4.16	129.6	0.3	3.0	132.9	-18%	-21%

⁽¹⁾ expressed in liters of equivalent gasoline for LPG and CNG

⁽²⁾ from reference 2002 gasoline PISI

⁽³⁾ blend figures were calculated assuming proportional contribution of each component

For each configuration except for gasoline PISI, an estimation of the variability of the energy consumption was made based on four main factors.

Table 4.1.6-2 Estimated energy consumption variability 2002 ICE vehicles

All figures in %	Gasoline	Blend ⁽¹⁾		LPG	Diesel	Blend ⁽²⁾	CNG PISI	
	DISI	PISI	DISI	PISI	DICI	DICI	Bi-fuel	Dedicated
Overall (sum of variances)	-4/4	-1/1	-4/4	-2/2	-3/3	-3/3	-5/3	-6/3
Cold start	-4/4		-4/4		-3/3	-3/3	-5/2	-5/2
Blend effect		-1/1	-1/1			-1/1		
Torque / disp.								-3/0
Fuel consumption map				-2/2			-2/2	-2/2

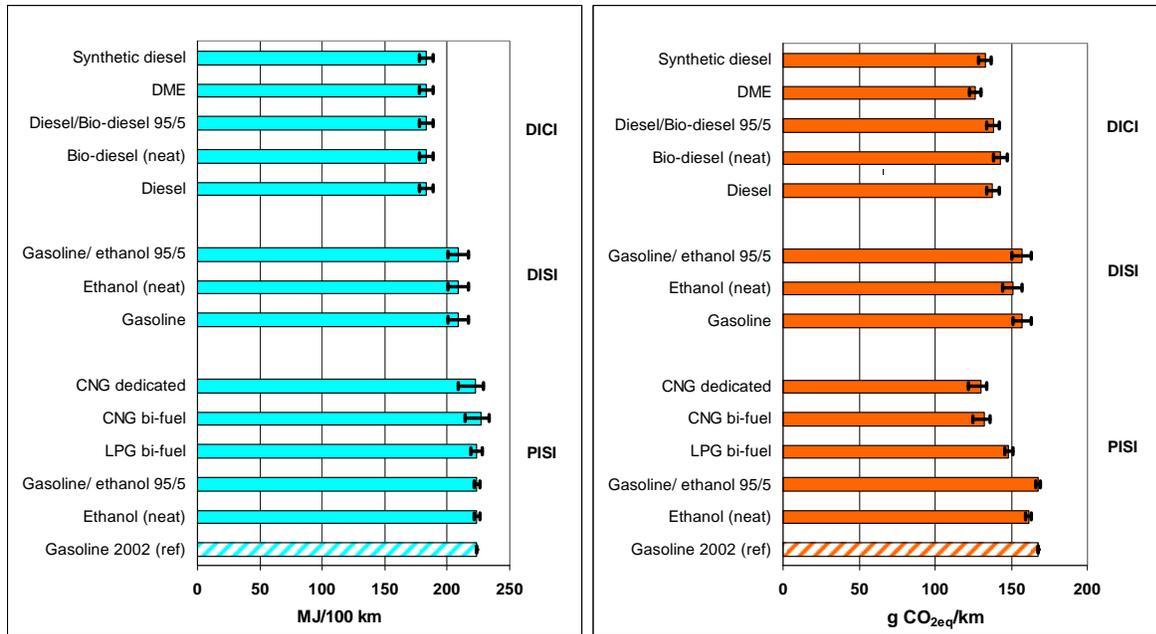
⁽¹⁾ Gasoline/Ethanol 95/5

⁽²⁾ Diesel/Bio-diesel 95/5

Some of these figures can be accurately calculated while for others, the estimation was done on the basis of expert opinions.

- The most important uncertainty is on the cold start of direct injection engines (equation-based model, with parameters fitted on the gasoline PISI engine configuration).
- The uncertainty related to blended fuels stems from the fact that the energy impact of the vaporisation of the blended component is not perfectly known.
- For CNG fuel maps, the uncertainty stems from the creation of these maps from the gasoline PISI fuel map. Due to better air/gas mixture in cold condition, a reduced effect of cold start is expected in this case.
- For LPG, the uncertainty stems from the use of the standard PISI fuel map.

Figure 4.1.6a/b Average energy/fuel consumption and GHG emissions over the NEDC 2002 ICE vehicles



For the LPG bi-fuel vehicle, the same engine efficiency as gasoline was assumed. In spite of a slightly higher engine efficiency when running on CNG, The CNG bi-fuel vehicle energy consumption increased by approximately 2%, however, as a result of the additional mass of the high pressure tank (1380 kg for the CNG tank versus 1321 kg for the reference gasoline PISI vehicle tank). For the LPG vehicle the mass increase was small and did not justify a change in inertia class, resulting in the same energy efficiency as gasoline.

For the dedicated CNG vehicle the optimised compression ratio increases the engine efficiency. To recover the required acceleration potential, the engine displacement was raised from 1.6 to 1.9 l. As a result, over the Urban Driving Cycle (part of NEDC), the engine was operated at lower load, in a range of lower efficiency. Coincidentally, the energy efficiencies obtained from both CNG engine configurations were similar, although the performance of the two vehicles was not equivalent: the bi-fuel CNG vehicle had slightly higher energy consumption than the gasoline reference (+1.5%) while the dedicated CNG vehicle showed a slightly lower figure (-0.3%).

The higher H/C ratio (4/1) of CNG played the major role, CO₂ emissions being about 24% lower than for the gasoline reference. This reduced to 22% after taking into account the contributions of methane and N₂O. This benefit remained discernible compared to the Diesel vehicle.

The “best in class” was obtained from DME with an adapted Diesel engine, with 126.8 g CO_{2eq}/km.

GHG emissions of the 2002 LPG configuration (148.5 g/km) have to be compared with the GHG emissions of the reference vehicle (168.0 g/km). The LPG configuration showed a GHG emissions saving of nearly 12% over the reference configuration due to lower carbon content of LPG compared with gasoline.

5 2010+ configurations

By 2010+ a diversification of fuels and powertrains is expected. In addition to the fuels and powertrains investigated for 2002 this study considered:

- Advanced internal combustion engines,
- Hybrid powertrains / vehicles,
- Fuel cell vehicles,
- Hydrogen as a new fuel, both for IC engines and fuel cells.

5.1 Fuels and Advanced Internal Combustion Engines

5.1.1 Projected improvements for advanced IC engines

The evolution of vehicle characteristics and the “technology-based” efficiency improvement assumed for 2010+ were widely discussed and agreed between the EUCAR members. These options were considered for their technical feasibility in 2010+. No consideration was given to actual implementation, availability, market share and customer acceptance. The expected fuel consumption reductions for the various technologies are presented below.

Table 5.1.1 2002-2010+ fuel efficiency improvements

Gasoline		LPG	Diesel		CNG	
PISI	DISI	PISI Bi-fuel	DICI no DPF ⁽¹⁾	DICI with DPF ⁽¹⁾	Bi-fuel	Dedicated
15%	10%	15%	12%	9.5%	17%	16%

For the vehicle-engine combinations using the SI engines, the main contribution to energy efficiency came from downsizing. The displacement of the gasoline engine could be reduced from 1.6 to 1.3 l, the full torque being restored by a turbo charging at 1.2:1.

This technology evolution had less scope for DISI engines as the “non-throttling” benefit is already included in the current engines.

Natural gas fuelled vehicles were credited with 1-2% extra energy efficiency improvement due to the mixing ability of the fuel with air, deemed to bring, after optimal aero kinetics, improved combustion essentially in the start-up phase.

2002 Diesel engines are already non-throttled and turbo-charged. Current developments showed a downsizing for Euro 4 Diesel applications, which were not anticipated at the initiation of the study. The “downsizing” route applied for 2010+ engines is from 1.9 to 1.6 l. If this trend will be continued in the future or maybe reversed due to tightened emission standards (Euro 5; Euro 6) can not be foreseen currently. The DPF option, when applied, does carry a fuel penalty of about 2.5% for the regeneration of the filter.

5.1.2 "Stop-and-Go" influence evaluation on fuel consumption

The "Stop-and-Go" fuel saving was evaluated with the gasoline PISI 2002 conventional configuration over the NEDC (with cold start). The fuel consumption when the vehicle is idling was calculated by post treatment of the results. Idling represented 7.5% of the total fuel consumption over the regulatory emission test cycle and could theoretically account for the maximum expected gain of the Stop-and-Go system.

Indeed, each time the engine restarts, no additional fuel consumption was taken into account. If the energy losses due to the engine restart was to be considered the fuel consumption gain due to the Stop-and-Go system would be lower. In addition, the thermal effect of this strategy was not taken into account either: the warm up of the engine would be slightly slower than with thermal engine idling and may influence the efficient treatment of pollutants under cold start conditions. These effects would decrease the fuel saving potential of the Stop-and-Go strategy. Therefore, taking into account some of the limitations mentioned above, the full theoretical potential of the Stop-and-Go could not be retained: a figure of 3% was considered more realistic and was applied on all 2010+ ICE configurations.

5.1.3 Hydrogen ICE Vehicle

The hydrogen engine considered for 2010+ was of newborn, advanced technology. It was a 1.3 l downsized turbocharged engine. Whatever the on-board storage mode (liquid or compressed), the same engine energy efficiency map was used for the simulation. The engine map was derived from experimental test bench data obtained from an actual single cylinder engine powered on hydrogen.

For stoichiometric air-fuel mixture, the volumetric energy content of a cylinder is slightly lower with hydrogen (3.17 kJ/l) than for gasoline (3.83 kJ/l). However, the poor octane number of hydrogen imposes operation of the engine in lean-burn mode. As a result, a torque curve equivalent to that of gasoline (1.3 litre, turbo-charged at 1.2:1) could be obtained through a higher turbo charging rate (about 1.8:1) in lean-burn mode ($R = 0.8$).

For compressed hydrogen (C-H₂) and a given fuel content the tank mass was nearly independent of the storage pressure. The shift from two 35 MPa tanks to a single 70 MPa tank was compensated by the increase in wall thickness.

For a range of 600 km, 9 kg hydrogen was needed. For a payload of 9 kg compressed hydrogen (C-H₂), the mass of the tank was 120 kg, an extra mass of 85 kg compared to the gasoline reference.

For liquid hydrogen (L-H₂) the tank was expected to be lighter than for compressed hydrogen (12.1 versus 13.1 kg / kg hydrogen).

Table 5.1.3 Characteristics of 2010 hydrogen ICE vehicles

		PISI	
		C-H ₂	L-H ₂
Powertrain			
Displacement	l	1.3	1.3
Powertrain	kW	77	77
Engine mass	kg	120	120
Gearbox mass	kg	50	50
Storage System			
Tank pressure	MPa	35/70	Atmo.
Tank net capacity	kg	9	9
Tank mass empty	kg	120	109
<i>Tank mass increase including 90% fuel</i>	kg	85	74
Vehicle			
Reference mass	kg	1181	1181
Vehicle mass	kg	1266	1255
Cycle test mass	kg	1360	1360
Performance mass	kg	1406	1395

5.1.4 ICE vehicles conformance to performance criteria

With the improvement described above, all vehicles (except the CNG bi-fuel, as explained), were able to meet or exceed the performance criteria. Actual figures are summarised hereunder.

Table 5.1.4 Performance of 2010+ ICE vehicles

		Gasoline		LPG	CNG PISI		Diesel	Hydrogen	Target
		PISI	DISI	PISI	Bi-fuel	Dedicated	DICI		
Time lag for 0-50 km/h	s	3.9	4.1	3.9	4.4	3.9	3.8	3.9	<4
Time lag for 0-100 km/h	s	11.3	12.4	11.3	13.2	11.4	11.2	12.4	<13
Time lag for 80-120 km/h in 4 th gear	s	10.8	11.2	10.8	13.2	11.0	9.2	12.6	<13
Time lag for 80-120 km/h in 5 th gear	s	14.5	15.0	14.5	17.7	14.4	12.1	16.2	-
Gradeability at 1 km/h	%	56	52	56.0	45	54	88	46	>30
Top speed	km/h	193	180	193	186	196	190	193	>180
Acceleration	m/s ²	4.5	4.3	4.5	3.9	4.5	4.8	4.0	>4.0

- The LPG bi-fuel PISI configuration delivered the same performance as the conventional gasoline.
- The CNG bi-fuel configuration remained “*off limits*” for the acceleration time: this was accepted as a specificity of this configuration.

5.1.5 Energy and GHG Emissions (NEDC)

The average fuel consumption and total GHG emissions over the NEDC are shown in the tables and figures below.

Table 5.1.5-1 Average energy/fuel consumption and GHG emissions over the NEDC 2010+ ICE vehicles

	Fuel consumption (/100 km)			GHG emissions (g CO ₂ eq/km)				% change ⁽²⁾	
	MJ	l ⁽¹⁾	kg	as CO ₂	as CH ₄	as N ₂ O	Total	Energy	GHG
PISI									
Gasoline	190.0	5.90	4.40	139.4	0.5	0.5	140.3	-15%	-16%
Ethanol (neat)	190.0	8.93	7.09	135.6	0.9	0.9	137.4	-15%	-18%
⁽³⁾ Gasoline/ ethanol 95/5	190.0	6.00	4.49	139.3	0.5	0.5	140.2	-15%	-17%
LPG bi-fuel	190.0	7.50	4.13	124.8	0.5	0.5	125.7	-15%	-25%
CNG bi-fuel	188.3	5.85	4.18	105.9	1.8	0.5	108.2	-16%	-36%
CNG dedicated	187.2	5.82	4.15	105.3	1.8	0.5	107.6	-16%	-36%
Hydrogen (comp.)	167.5	5.21	1.40	0.0	0.0	0.5	0.5	-25%	-100%
Hydrogen (liq.)	167.5	5.21	1.40	0.0	0.0	0.5	0.5	-25%	-100%
DISI									
Gasoline	187.9	5.84	4.35	137.9	0.5	0.5	138.8	-16%	-17%
Ethanol (neat)	187.9	8.83	7.01	134.1	0.9	0.9	135.9	-16%	-19%
⁽³⁾ Gasoline/ ethanol 95/5	187.9	5.94	4.44	137.8	0.5	0.5	138.7	-16%	-17%
DICI									
<i>Without DPF</i>									
Diesel	161.1	4.49	3.74	118.0	0.2	1.5	119.7	-28%	-29%
Bio-diesel (neat)	161.1	4.92	4.38	122.8	0.2	1.5	124.5	-28%	-26%
⁽³⁾ Diesel/Bio-diesel 95/5	161.1	4.51	3.78	118.7	0.2	1.5	120.4	-28%	-28%
DME	161.1	8.47	5.67	108.5	0.2	1.5	110.2	-28%	-34%
Synthetic diesel	161.1	4.69	3.66	114.1	0.2	1.5	115.8	-28%	-31%
<i>With DPF</i>									
Diesel	165.7	4.62	3.84	121.4	0.2	1.5	123.1	-26%	-27%
Bio-diesel (neat)	165.7	5.06	4.50	126.3	0.2	1.5	128.0	-26%	-24%
⁽³⁾ Diesel/Bio-diesel 95/5	165.7	4.64	3.88	122.1	0.2	1.5	123.8	-26%	-26%
Synthetic diesel	165.7	4.83	3.77	117.3	0.2	1.5	119.0	-26%	-29%

⁽¹⁾ expressed in liters of equivalent gasoline for LPG, CNG and hydrogen

⁽²⁾ from reference 2002 gasoline PISI

⁽³⁾ blend figures were calculated assuming proportional contribution of each component

The energy efficiency improvement (2010+ versus 2002) was a little less for CI Diesel engines than for their SI gasoline and CNG or LPG counterparts (see *section 5.1.1*). As a result, the advantage of the Diesel over the SI counterparts was slightly eroded from the current (2002) by 2010+.

For each configuration, an estimation of the variability of the energy consumption is shown in the table below. The sources of uncertainty are the same as for the 2002 configurations (see *Table 4.1.6-2*) with additional uncertainty stemming from the forecasts of expectable improvements by 2010+.

Table 5.1.5-2 Estimated energy consumption variability 2010+ ICE vehicles

All figures in %	Gasoline		Blend ⁽¹⁾		LPG ⁽²⁾	Diesel	Blend ⁽³⁾	CNG PISI		Hyd. ⁽⁴⁾
	PISI	DISI	PISI	DISI	PISI	DICI	DICI	Bi-fuel	Dedicated	PISI
Overall (sum of variances)	-3/3	-5/5	-3/3	-5/5	-4/4	-4/4	-4/4	-6/4	-7/4	-3/3
Improvement from 2002	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3
Cold start		-4/4		-4/4		-3/3	-3/3	-5/2	-5/2	-3/3
Blend effect			-1/1	-1/1			-1/1			
Torque / disp.									-3/0	
Fuel consumption map					-2/2			-2/2	-2/2	

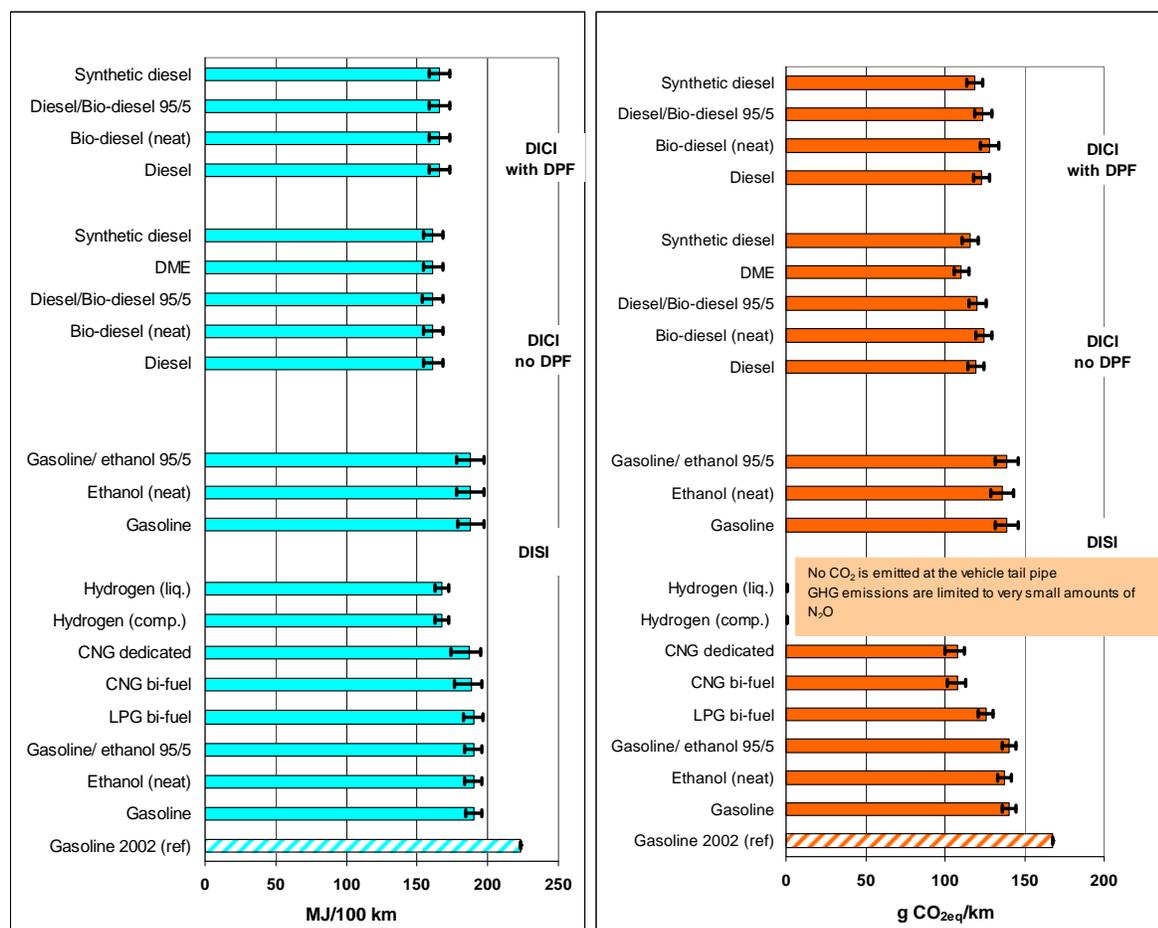
⁽¹⁾ Gasoline/Ethanol 95/5

⁽²⁾ Liquid injection

⁽³⁾ Diesel/Bio-diesel 95/5

⁽⁴⁾ Compressed or liquid

Figure 5.1.5a/b Average energy/fuel consumption and GHG emissions over the NEDC 2010+ ICE vehicles

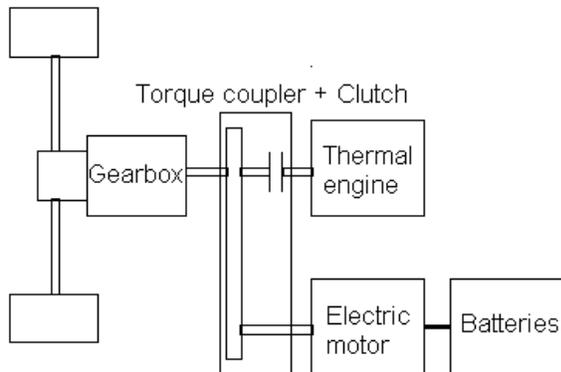


The lowest figures (<110 gCO₂/km) were obtained with the CNG ICEs on the gasoline side and with DME for the Diesel section, respectively. Hydrogen vehicles obviously do not emit any CO₂ and their TTW GHG emissions were limited to very small amounts of N₂O.

5.2 Hybrid powertrains

In this study a parallel hybrid configuration was selected, combining two torque generators namely the IC engine and an electric motor with batteries.

Figure 5.2 Simulated hybrid configuration



5.2.1 Energy management strategy and code evolutions

The parallel hybrid model available in ADVISOR was modified to represent our vision of the most appropriate way to control such a powertrain.

The first modification was to use the same gear ratio sequence during the cycle as for conventional engines.

The second essential point was to consider the vehicle's driveability from a customer point of view, an issue which was not properly addressed by the original energy management strategy. For instance, the engine could be operated stop-run-stop or run-stop-run for very short periods, a mode of operation that is considered highly uncomfortable for usual drivers and, therefore, rejected by car manufacturers. During deceleration and when the vehicle is at a standstill, the thermal engine was turned off but the time sequence was never allowed to be shorter than 3 seconds.

To determine the working duration of the thermal engine, 4 parameters were used:

- The **State Of Charge (SOC) of the battery** had to remain between 60 and 70 % of the maximum charge.
- The **Recharge Mode (RM)** defined whether the battery was in charging phase. When the SOC decreased to 60%, RM was activated (=1) until the SOC increased back to 65%. Further charging through recuperation of braking energy was always applied.
- The **Minimum vehicle speed (V1)** is the speed below which the thermal engine is off while the recharge mode is not activated.
- The **Minimum vehicle speed (V2)** is the speed below which the thermal engine is off while the recharge mode is activated.

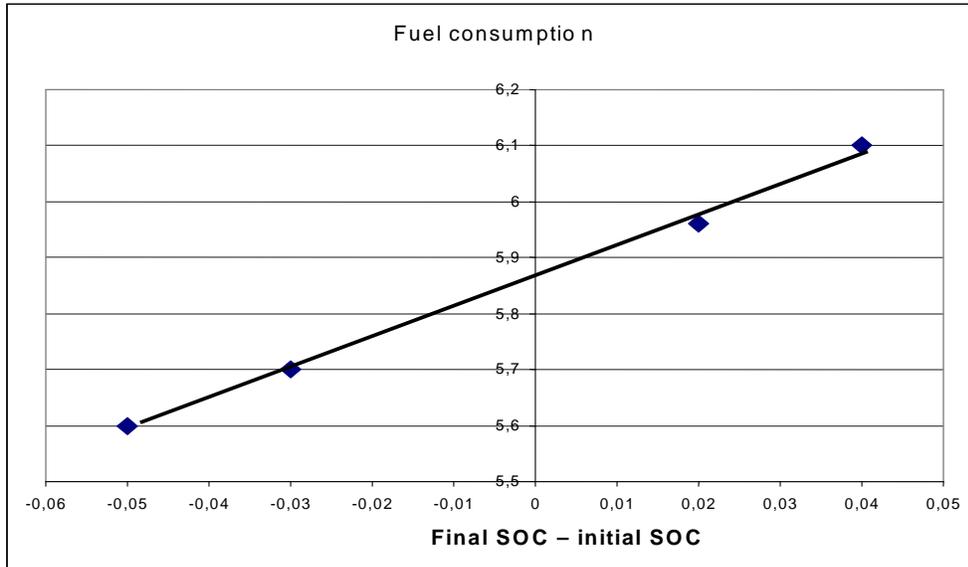
When the thermal engine charges the battery, the controller guaranteed optimum efficiency of the thermal engine while it is charging the battery.

In general, this energy management allowed the vehicle to drive the urban part of the NEDC mainly within the electrical mode. The thermal engine was activated according to the SOC and under the high load conditions of the EUDC part of the cycle (see also *Figure 5.2.5-3*).

Methodology

The fuel consumption had to be evaluated at constant energy level in the battery i.e. the SOC has to be the same at the beginning and at the end of the cycle. In most cases this could be achieved by adjusting the initial SOC. When this was not possible we used an extrapolated or interpolated figure. An example is given in the figure below.

Figure 5.2.1 Interpolation of the fuel consumption versus the delta SOC



The optimisation of the fuel consumption on the NEDC was done with the V1 and V2 parameters defined above, using the correction of the powertrain efficiency map as per *Figure 5.2.1* as an iterative subroutine.

In its basic configuration, ADVISOR only calculates “hot start” cycle operation. To assess the “cold start” NEDC cycle consumption of a hybrid vehicle, the “cold start” sub-model was applied only to the thermal engine model, as was done for ICEs when assessing the 2002 and 2010 configurations (see *section 3.1*).

5.2.2 Hybrid vehicle characteristics

Thermal engine

In general the 2002 and 2010+ engine configurations were base for this calculation.

Gasoline: At the 2010 horizon, both Port Injection (PISI) and Direct Injection (DISI) engines will be on the market. Both configurations were therefore considered for hybridisation. Results are given for the standard engine as well as for the downsized configuration.

Hydrogen ICE: The 2010 version was used for lack of a 2002 version, but taking into account that the benefits of hybridisation and downsizing are not entirely additive.

CNG: Only the dedicated CNG ICE configuration was considered. The availability of the electric engine allows the acceleration criteria to be met with the ICE displacement of 1.6 l.

Therefore, basically friction improvements, as shown below in Table 5.2.2-1, are used with hybridisation.

Table 5.2.2-1 Efficiency improvements with hybridisation

Gasoline	Diesel		CNG
DISI	DICI no DPF ⁽¹⁾	DICI with DPF ⁽¹⁾	PISI
3%	3%	0.5%	4%

⁽¹⁾ Diesel Particulate Filter

Electric motor

The main characteristics of the electric motor (electronic inverter included) were:

- Power: 14 kW
- Mass: 10 kg
- Voltage: 42 V
- Maximum efficiency: 92 %

Battery

The 40 kg Lithium / ion battery (42 V) was designed to ensure the 20 km full ZEV range.

Table 5.2.2-2 Characteristics of 2010+ hybrid vehicles

		PISI	DISI	DICI	PISI				DICI
		Gasoline	Gasoline	Diesel	Gasoline	CNG	C-H ₂	L-H ₂	Diesel
Powertrain		non-downsized			downsized				
Displacement	l	1.6	1.6	1.9	1.3	1.6	1.3	1.3	1.6
Powertrain	kW	77	70	74	62	68	77	77	63
Engine mass	kg	120	120	145	100	120	120	120	130
Gearbox mass	kg	50	50	50	50	50	50	50	50
Storage System									
Tank pressure	MPa	liquid	liquid	liquid	liquid	25	35/70	liquid	liquid
Tank net capacity	kg	22	22	20	22	19	8	7	20
Tank mass empty	kg	15	15	15	15	66	100	85	15
Tank mass increase including 90% fuel	kg	0	0	0	0	40	63	48	0
Electric Parts									
Battery	kg	40	40	40	40	40	40	40	40
electric motor	kg	10	10	10	10	10	10	10	10
Torque coupler	kg	30	30	30	30	30	30	30	30
Vehicle									
Reference mass	kg	1181	1181	1248	1181	1181	1181	1181	1248
Vehicle mass	kg	1261	1261	1328	1241	1301	1324	1309	1313
Cycle test mass	kg	1360	1360	1470	1360	1360	1470	1360	1360
Performance mass	kg	1401	1401	1468	1381	1441	1464	1449	1453

5.2.3 Conformance to Performance criteria

For hybrid vehicle configurations, the specified minimum criteria were the same as for conventional engines / vehicles and were estimated in the same way. It is worth noting that:

- Top speed was achieved without electrical assistance³ (continuous top speed),
- For acceleration, no peak power was taken into account for the electric motor⁴.

³ Top speed capability must be available at all times and for extended periods and cannot, therefore, rely on the battery.

⁴ Acceleration capability is considered as a safety feature, in case of overtaking for instance. It may rely on a contribution of the electric motor as long as only its nominal power is considered. Using the higher "peak power", which may be available but only for short periods, is not acceptable for safety reasons.

Table 5.2.3-1 Performance of 2010 hybrid vehicles

		Gasoline		CNG	Diesel	C-H ₂	L-H ₂	Target
		PISI	DISI	PISI	DICI	PISI		
Time lag for 0-50 km/h	s	3.7	3.7	3.7	3.7	3.4	3.4	<4
Time lag for 0-100 km/h	s	11.5	11.5	11.3	11.5	10.7	10.6	<13
Time lag for 80-120 km/h in 4 th gear	s	10.8	10.8	10.4	10.8	9.8	9.7	<13
Time lag for 80-120 km/h in 5 th gear	s	13.3	13.3	12.8	13.3	11.7	11.6	-
Gradeability at 1 km/h	%	77	77	72	77	68	69	>30
Top speed	km/h	180	178	183	180	192	192	>180
Acceleration	m/s ²	4.8	4.8	4.8	4.8	4.8	4.8	>4.0

The specificity of hybrids, combining the thermal engine with an electric complementary power, resides in the specific torque curve of the electric motor:

- Torque at maximal value with immediate rise time,
- Nominal value on a large range of rotation speed.

As a result, even with heavier masses, hybrids had a better acceleration performance in all configurations.

5.2.4 Energy and total GHG emissions (NEDC)

The average fuel consumption and total GHG emissions over the NEDC are shown in the tables and figures below.

Table 5.2.4-1 Average energy/fuel consumption and GHG emissions over the NEDC 2010 hybrid vehicles

	Fuel consumption (/100 km)			GHG emissions (g CO ₂ eq/km)				% change ⁽²⁾	
	MJ	l ⁽¹⁾	kg	as CO ₂	as CH ₄	as N ₂ O	Total	Energy	GHG
PISI									
Gasoline 1.6 l	161.7	5.02	3.74	118.6	0.5	0.5	119.6	-28%	-29%
Gasoline 1.28 l, 14 kW	152.9	4.75	3.54	112.2	0.5	0.5	113.1	-32%	-33%
Gasoline 1.28 l, 30 kW	150.8	4.69	3.49	110.7	0.5	0.5	111.6	-33%	-34%
CNG									
CNG 1.6l	139.4	4.33	3.09	78.4	1.8	0.5	80.7	-38%	-52%
Hydrogen (comp.)	148.5	4.62	1.24	0.0	0.0	0.5	0.5	-34%	-100%
Hydrogen (liq.)	141.4	4.39	1.18	0.0	0.0	0.5	0.5	-37%	-100%
DISI									
Gasoline 1.6l	163.0	5.06	3.77	119.6	0.5	0.5	120.5	-27%	-28%
Gasoline 1.3l	154.1	4.79	3.57	113.1	0.5	0.5	114.0	-31%	-32%
⁽³⁾ Gasoline/ ethanol 95/5	154.1	4.87	3.64	113.0	0.5	0.5	113.9	-31%	-32%
DICI									
<i>Without DPF</i>									
Diesel 1.9l	141.1	3.93	3.27	103.4	0.2	1.5	105.1	-37%	-37%
Diesel 1.6l	129.0	3.60	2.99	94.5	0.2	1.5	96.2	-42%	-43%
Bio-diesel (neat)	129.0	3.94	3.51	98.3	0.2	1.5	100.1	-42%	-40%
⁽³⁾ Diesel/Bio-diesel 95/5	129.0	3.61	3.02	95.0	0.2	1.5	96.7	-42%	-42%
DME	129.0	6.78	4.54	86.9	0.2	1.5	88.6	-42%	-47%
Synthetic diesel	129.0	3.76	2.93	91.3	0.2	1.5	93.0	-42%	-45%
<i>With DPF</i>									
Diesel 1.9l	145.6	4.06	3.38	106.6	0.2	1.5	108.4	-35%	-35%
Diesel 1.6l	133.0	3.71	3.09	97.4	0.2	1.5	99.1	-40%	-41%
Bio-diesel (neat)	133.0	4.06	3.61	101.4	0.2	1.5	103.1	-40%	-39%
⁽³⁾ Diesel/Bio-diesel 95/5	133.0	3.72	3.12	98.0	0.2	1.5	99.7	-40%	-41%
Synthetic diesel	133.0	3.88	3.02	94.2	0.2	1.5	95.9	-40%	-43%

⁽¹⁾ expressed in liters of equivalent gasoline for CNG and hydrogen

⁽²⁾ from reference 2002 gasoline PISI

⁽³⁾ blend figures were calculated assuming proportional contribution of each component

**Table 5.2.4-2 Estimated energy efficiency variability
2010 hybrid vehicles**

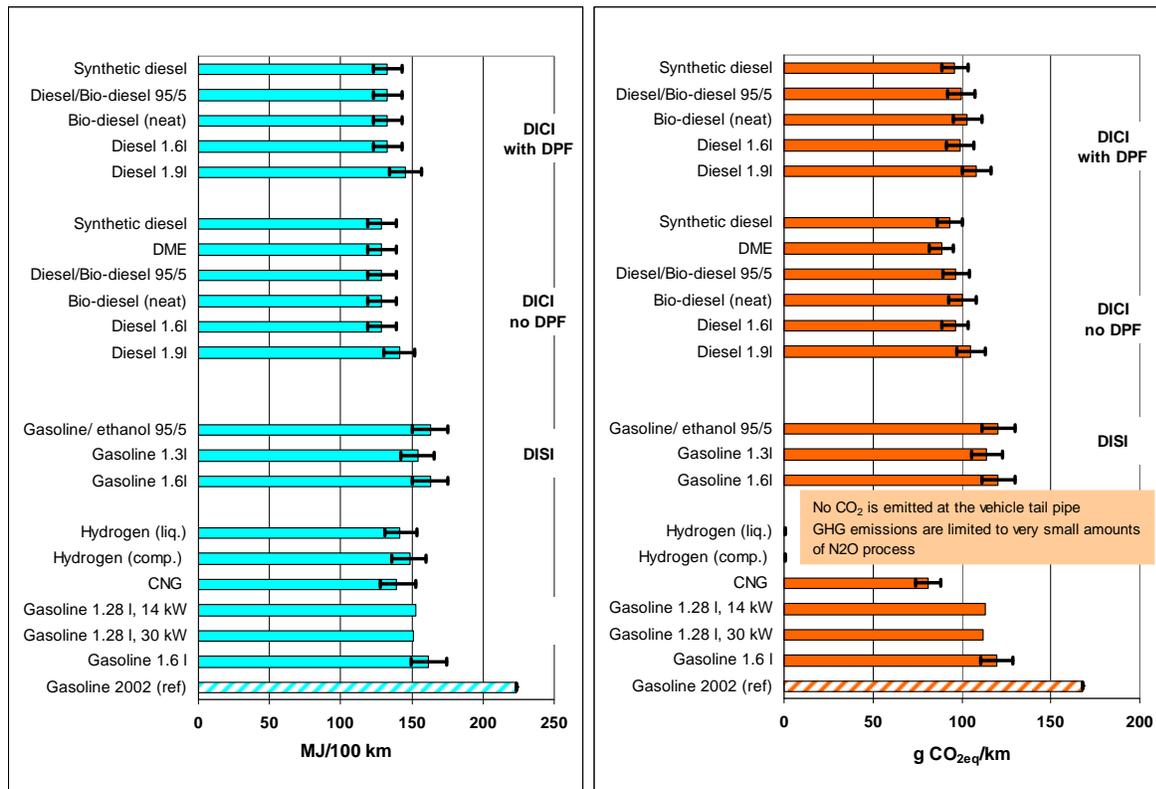
All figures in %	Gasoline		Blend ⁽¹⁾ DISI	Diesel DICI	Blend ⁽²⁾ DICI	CNG PISI	Hydrogen	
	PISI	DISI					C-H2	L-H2
Overall (sum of variances)	-8/8	-8/8	-8/8	-8/8	-8/8	-8/9	-9/8	-8/9
Improvement from 2002	-1/1	-1/1	-1/1	-1/1	-1/1	-3/3		
Cold start	-7/7	-7/7	-7/7	-7/7	-7/7	-7/7	-7/7	-7/0
Blend effect			-1/1		-1/1			
Energy management	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3	-3/3
Fuel consumption map						-2/2		
Mass estimate						-0/4	--4/0	-0/4

⁽¹⁾ Gasoline/Ethanol 95/5

⁽²⁾ Diesel/Bio-diesel 95/5

In addition to the effects listed for 2010, the energy management strategy was not optimised and the estimation of the masses, mainly for the configurations that are close to a change of the cycle test mass, may modify the consumption. Due to the strong hypothesis on the cold start calculation, values concerning the cold start were increased.

**Figure 5.2.4a/b Average energy/fuel consumption and GHG emissions over the NEDC
2010 hybrid vehicles**



The cumulated effect of continuous vehicle/powertrain improvements and of hybrid technology brought between 27 and 35 % energy efficiency improvement from the 2002 reference. As already seen with conventional engines in 2010, the gap between minimum and maximum energy consumptions was more modest for the hybrids than for the 2002 ICES.

The hybrid architecture and downsizing / turbocharging (considered for the 2010 conventional configurations) are two routes that allow the thermal engine to be operated in a domain of better

efficiency. The benefits are therefore not cumulative. The impact of both routes are summarised in the table below.

Table 5.2.4-3 Effects of hybridisation and other technology improvements

Energy figures in MJ/100 km	Gasoline		Diesel	CNG	L-H ₂
	PISI	DISI	DICI+DPF	PISI	PISI
2002 conventional	223.5	208.8	183.1	222.8	
2010 advanced	190.0	187.9	165.7	187.2	167.5
2010 hybrid	166.6	167.9	150.0	145.0	
2010 advanced + hybrid	152.9	154.1	133.0	139.4	141.4
2002-2010 Conv. Improvement	15.0%	10.0%	9.5%	16.0%	
Hybridisation benefit 2010	25.5%	19.6%	18.1%	25.5%	15.6%
Total 2002-2010	31.6%	26.2%	27.4%	37.4%	

The net benefit of hybridisation was affected by several parameters:

- Hybridisation increased the vehicle test mass.
- Engine fuel efficiency was deemed to improve for all engines between 2002 and 2010 (approximately 3% for diesel fuel and gasoline, 4% for CNG and hydrogen).
- Hybridisation in general allows smaller engine displacements, the electric assistance restoring the acceleration performance with the smaller engine.
- The benefit of hybridisation was more modest for hydrogen engines, not because of hydrogen, but because the engine considered here was deemed to have already received the highest technical options in downsizing and supercharging.

5.2.5 Impact of the hybrid powertrain configurations

Within certain boundary conditions various hybrid vehicle configurations can be set up. The critical conditions for this study are the customer performance criteria. As seen in *Table 5.2.3-1*, the above hybrid configurations exceeded some of the requirements, e.g. for accelerations. Hence, the current hybrid vehicle characteristics could be reconsidered with the objective of low fuel consumption but still fulfilling the performance requirements. Within this background, a limited set of simulations was carried out to optimize the PISI gasoline hybrid configuration towards low fuel consumption (ICE displacement / electric motor power).

Thermal Engine displacement

A set of simulations was performed to search for the minimum engine displacement but still keeping the vehicle top velocity of 180 km/h and also complying with the other performance criteria. The result was a reduction of the engine displacement to 1280 cc, with an engine power of 62 kW. With this new engine displacement, the vehicle mass was slightly lower (-20 kg), as shown in the table below.

Table 5.2.5-1 Characteristics of a optimized Gasoline PISI hybrid vehicle

		Gasoline hybrid PISI	
		Original	Optimised
Powertrain			
Displacement	l	1.6	1.28
Power	kW	77	62
Engine weight	kg	120	100
Gearbox weight	kg	50	50
Storage System (liquid hydrogen)			
Tank net capacity	kg	22	22
Tank mass empty	kg	15	15
Tank mass increase including 90% fuel	kg	0	0
Electric parts			
Battery mass	kg	40	40
Power electric motor	kg	10	10
Torque coupler + ...	kg	30	30
Vehicle			
Total Vehicle			
Reference mass	kg	1181	1181
Vehicle mass	kg	1261	1241
Cycle test mass	kg	1360	1360
Performance mass	kg	1401	1381

For the performance tests, the vehicle mass of this optimised hybrid configuration was 1381 kg. The performance results as well as fuel consumption and CO₂ emissions in the next two tables.

Table 5.2.5-2 Performances of the optimized Gasoline PISI hybrid configuration

		Gasoline PISI	Target
Time lag for 0-50 km/h	s	3.7	<4
Time lag for 0-100 km/h	s	11.5	<13
Time lag for 80-120 km/h in 4 th gear	s	10.8	<13
Time lag for 80-120 km/h in 5 th gear	s	13.3	-
Gradeability at 1 km/h	%	77	>30
Top speed	km/h	180	>180
Acceleration	m/s ²	4.8	>4.0

Table 5.2.5-3 Energy/fuel consumption and GHG emissions over the cold NEDC

	Fuel consumption (/100 km)			GHG emissions (g CO ₂ eq/km)			
	MJ	l ⁽¹⁾	kg	as CO ₂	as CH ₄	as N ₂ O	Total
Gasoline 1.6 l	161.7	5.02	3.74	118.6	0.5	0.5	119.6
Gasoline 1.28 l	152.9	4.75	3.54	112.2	0.5	0.5	113.1

For these two configurations, the electric motor and the energy management strategy were the same. As shown on **Figures 5.2.5-1/2** the use of a smaller engine displacement decreased the fuel consumption by 5%, the smaller engine operating in a higher efficiency range. This can be seen even more explicitly on **Figure 5.2.5-3**, which shows a comparison of the instantaneous engine efficiency during the NEDC.

It should be noted that the simulation was done with a hot start cycle. To obtain the final NEDC fuel consumption, a correction was applied as in the previous simulations.

Figure 5.2.5-1 1.6 l engine operating points during the NEDC

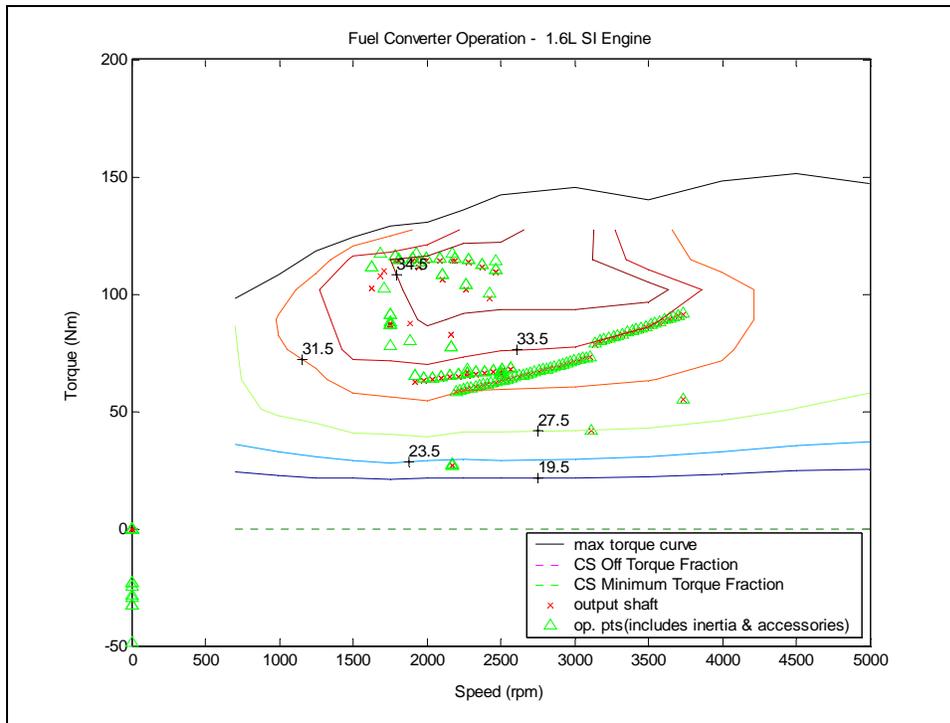


Figure 5.2.5-2 1.28 l engine operating points during the NEDC

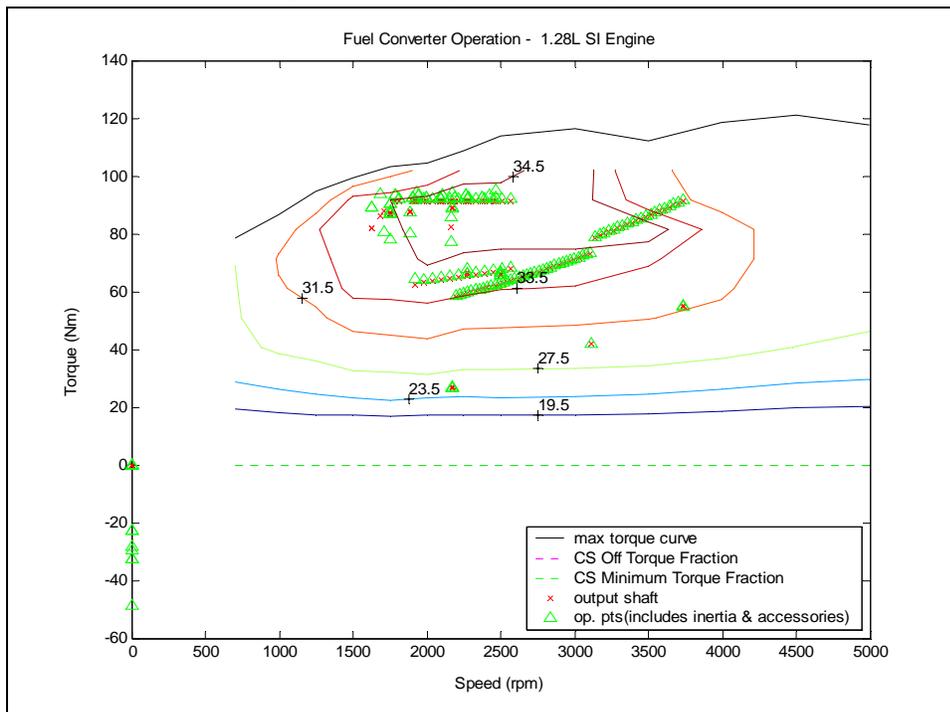
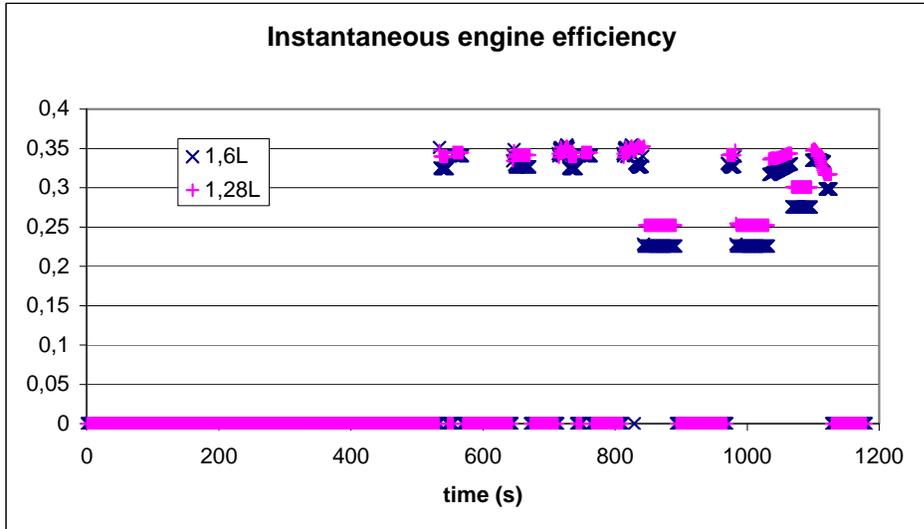


Figure 5.2.5-3 Comparison of the instantaneous engine efficiency on the NEDC

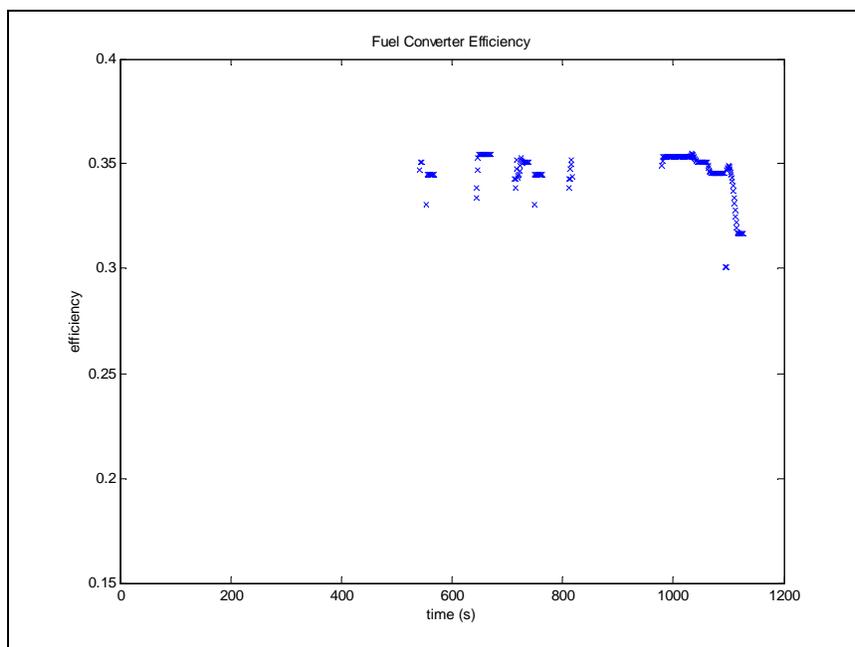


Electric motor power

To optimise the use of the thermal engine, an increase of the output power of the electric motor can be simulated. With the initial 14kW electric motor, the required performance criteria were already matched. With a more powerful electric motor, acceleration performance would obviously be even better. Therefore a hybrid configuration with a 30 kW power electric motor and with a 1.28 L engine was simulated.

Once the energy management strategy optimisation had been done, it appeared that the main difference with the previous configuration was the possibility to achieve a 70 km/h stabilised vehicle speed in pure electric mode. In **Figure 5.2.5-3**, with the 1.28 l / 14 kW hybrid configuration, the lowest thermal engine efficiency was obtained for a speed of 70 km/h. The instantaneous efficiency of the thermal engine in the hybrid with 30kW electric motor is presented **Figure 5.2.5-4** below.

Figure 5.2.5-4 Instantaneous engine efficiency during the NEDC (30kW electric motor)



The fuel consumption results are shown next.

Table 5.2.5-4 Energy/fuel consumption and GHG emissions over the cold NEDC for increased electrical power

	Fuel consumption (/100 km)			GHG emissions (g CO ₂ eq/km)			
	MJ	l ⁽¹⁾	kg	as CO ₂	as CH ₄	as N ₂ O	Total
Gasoline 1.28 l, 30 kW	150.8	4.69	3.49	110.7	0.5	0.5	111.6
Gasoline 1.28 l, 14 kW	152.9	4.75	3.54	112.2	0.5	0.5	113.1

The use of a more powerful electric motor allowed a slight (less than 2%) decrease of the fuel consumption.

Table 5.2.5-5 shows the mean efficiency and resulting fuel consumption of the different powertrain components of the hybrid vehicle configurations, on the NEDC with hot start. The figures for a conventional PISI engine 1.6 l, obtained using the same fuel consumption map as the hybrid 1.6 l vehicle with hot start, are also shown.

Table 5.2.5-5 Mean engine efficiency on the warm NEDC (with hot conditions)

	Mean Efficiency on the NEDC (%)					Fuel consumption kg/100 km
	Thermal engine	Electric motor		Battery	Vehicle	
		Motor	Generator			
Gasoline PISI						
Hybrid configuration						
1.28 l 30 kW	34.5	86.5	83.3	92.5	28	3.19
1.28 l 14 kW	32.3	84.3	80.6	94.1	27.7	3.24
1.6 l 14 kW	30.8	84.3	79.9	94	26.2	3.41
Conventional ICE						
1.6 l (hot start)	21.1				18.7	4.62

The effect of hybridisation of the gasoline 1.6 l PISI engine was to increase the mean efficiency of the thermal engine by about 50%. Even with the losses of the electric part, the total fuel consumption improvement on the warm NEDC was very noticeable, i.e. 26%.

The first improvement of the hybrid configuration was obtained with the decrease of the engine displacement (1.6 l to 1.28 l) resulting in an increase of the engine efficiency, with the same electric behaviour (the energy management strategy had been kept unchanged). The increase of the engine efficiency (nearly 5%) resulted in an equivalent fuel consumption decrease (about 5%).

The use of a more powerful electric motor allowed increasing the thermal engine efficiency by about 7%. However, the decrease of the fuel consumption was less than 2%. The use of a more powerful electric motor had different consequences on the fuel consumption. On the one hand, the mean efficiency of the 30 kW engine was slightly higher than the 14 kW engine, but on the other hand more electric power was charged and discharged from the battery and the electric losses were thus larger than with the smaller electric motor. Therefore, the fuel consumption decrease was lower than the thermal engine efficiency increase.

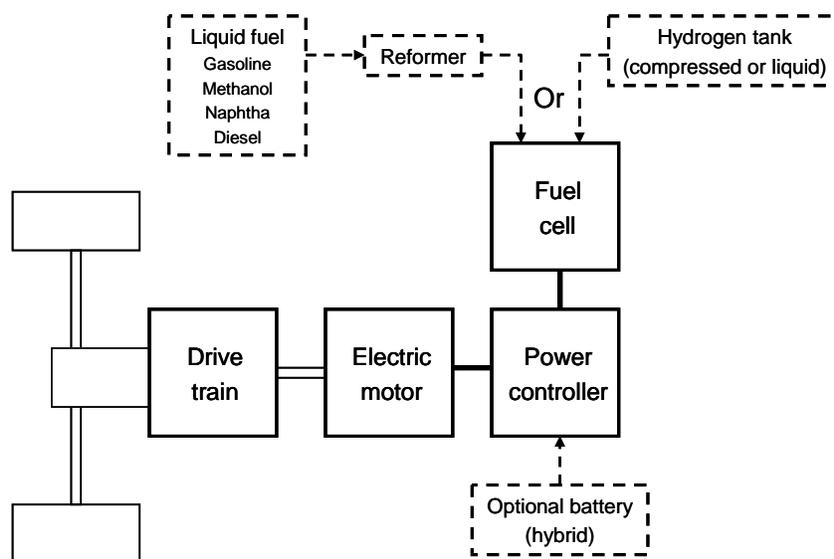
Optimisation of the hybrid powertrain configurations / Conclusions

Hybrid technology, whilst still under global cost optimisation, offers some new degrees of freedom for the improvement of the fuel economy over an ever-wider range of driving conditions while fulfilling ever more demanding polluting emission regulations. As described in this study, and for a large spectrum of foreseeable 2010 ICE / conventional fuel type configurations, the potential GHG reduction and related fuel economy of the hybrid technology when applied on standard size powertrains was estimated by the simulation model at around 19 % (19.3 % for DISI – 18,1% for DICI).

5.3 Fuel Cells

In this study, only PEM (Proton Exchange Membranes) fuel cells were considered. Alternative technologies (such as Solid Oxide Fuel Cells or SOFC) are also under development, but the level of maturity of these high temperature systems is not sufficient to make credible fuel efficiency assumptions for possible road transport applications. These PEM fuel cells can be either fed by hydrogen from a tank or combined with a reformer turning a liquid fuel into hydrogen on-board the vehicle. The former (“direct hydrogen”) option was further considered with or without hybridisation. The term hybridisation here refers to the addition of a large battery capable of storing recovered braking energy and to contribute to the powertrain energy supply. The non-hybrid version only had a conventional vehicle battery as required for e.g. start-up. The reformer could be fuelled by gasoline, methanol, naphtha or diesel fuel. The version with reformer was only considered in hybrid configuration.

Figure 5.3 Fuel cell powertrains configurations



5.3.1 Energy management strategy and ADVISOR code modifications

The following energy management strategy was adopted:

- The fuel cell was off during vehicle deceleration (all configurations)

In the hybrid configuration:

- The fuel cell was operated at idle⁵ when the vehicle was stopped or when the battery was supplying the motive power.
- At very low vehicle load level the fuel cell was kept at idle the battery providing the energy, thereby avoiding operation in the poor efficiency domain. This feature was obviously only active when the battery SOC was high enough (>60 %).
- When the battery needed to be charged, the fuel cell ran at its maximum efficiency power.
- The battery SOC was kept between 60% and 70%.

⁵ A Fuel Cell is considered “at idle” when it delivers just the minimal power needed to stabilise its temperature and to power its auxiliaries(see section 5.3.3)

Modifications, specific to our vision of the right way to control such a powertrain were brought to the basic fuel cell model available in ADVISOR.

The ADVISOR model required the overall efficiency of the system to be entered as a function of the power delivered.

- For direct hydrogen configurations, the efficiency curve of the fuel cell was used as input.
- For reformer configurations, the efficiency of the power module “Fuel cell + Reformer“ was used.

The main changes from the initial ADVISOR model included:

- The possibility to run the model without using the battery,
- Fuel cell cut off during vehicle deceleration,
- Fuel cell operating at maximum efficiency when the battery was being charged (in the original version a constant load was added),
- Addition of a specific fuel cell consumption at idle.

5.3.2 Fuels and vehicles

The fuels considered for the 2010+ fuel cell configuration are listed below:

- On-board stored hydrogen (liquid and compressed),
- On-board generated hydrogen (reformer) from gasoline, conventional diesel fuel, methanol, refinery naphtha.

Table 5.3.2 Mass characteristics of 2010+ fuel cell vehicles

	Non Hybrid		Hybrid		Hybrid+reformer		
	C-H ₂	L-H ₂	C-H ₂	L-H ₂	Gasoline ⁽¹⁾	Methanol	
Powertrain mass substitution							
Engine mass	kg	-120	-120	-120	-120	-120	-120
Gearbox mass	kg	-50	-50	-50	-50	-50	-50
Fuel Cell							
Fuel cell stack mass	kg	150	150	150	150	150	150
Reformer mass	kg	0	0	0	0	90	90
Cooling system additional mass	kg	50	50	50	50	50	50
Electric parts							
Battery mass	kg	0	0	20	20	40	40
Electric motor+electronics mass	kg	73	73	73	73	73	73
Storage System							
Tank netto capacity	kg	4.7	4.7	4.2	4.2	23	45
Tank mass empty	kg	69	57	56	51	15	15
Tank mass increase including 90% fuel	kg	30	18	16	11	-8	12
Vehicle							
Enlarged vehicle additional mass	kg	50	50	50	50	50	50
Reference mass	kg	1181	1181	1181	1181	1181	1181
Vehicle mass	kg	1364	1352	1370	1365	1456	1476
Cycle test mass	kg	1470	1470	1470	1470	1590	1590

⁽¹⁾ also valid for naphtha and diesel

Electric motor

The characteristics of the electric motor (including electronic inverter) used in the fuel cell configuration were:

Power	Mass	Maximum efficiency	Voltage
75 kW ⁶	73 kg	92 %	42 V

Battery

42 V Li-ion batteries was assumed, with a mass of 20 kg for the direct hydrogen configuration. For the reformer case a larger, 40 kg battery, was required in order to satisfy the full ZEV range criterion.

Storage tank

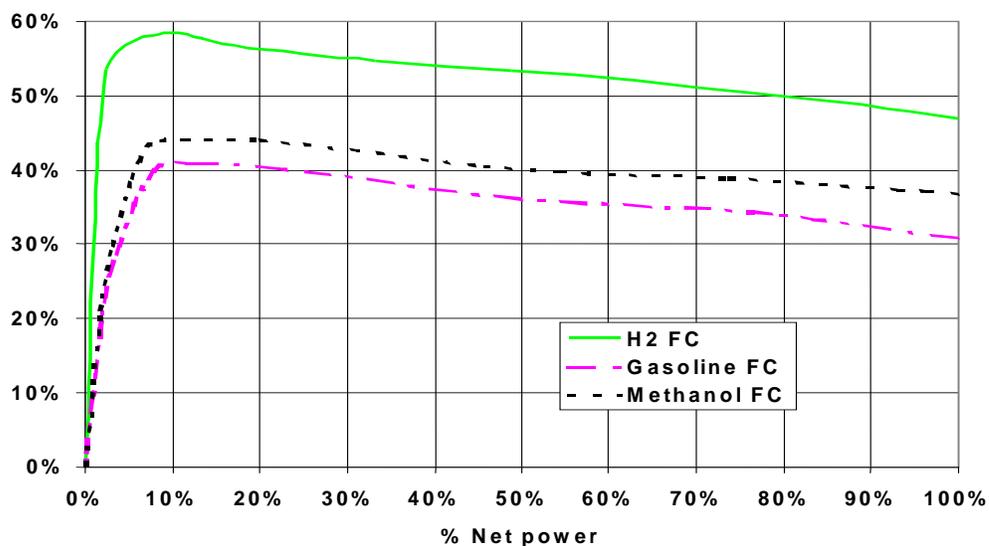
Storage tanks (liquid or compressed) had the same characteristics as for hydrogen ICE applications, albeit with a lower capacity consistent with the higher efficiency of the fuel cell and therefore the smaller hydrogen quantity necessary to comply with the range criterion.

5.3.3 Fuel cell system efficiency

For direct hydrogen fuel cells, efficiency maps were obtained from three different sources: General Motors (GM), DaimlerChrysler and the European programme FUERO (FUEL cell Research Organisation). The GM map, being close to the average of the other two, was used for the simulations and is shown in *Figure 5.3.3*.

For the reformer case gasoline and methanol maps were also provided by GM. They take into account the best estimate for the energy efficiency of the reformer. For lack of other data, the same efficiency was used for diesel fuel and naphtha.

Figure 5.3.3 Global fuel cell powertrain efficiency maps for different fuels



⁶ Taking into account the mass estimated for those vehicles and the “flat” characteristic of the torque (electric motor), this value was found adapted to comply with the specified performance criteria.

Relevant assumptions

Idle consumption (Source: GM)

- Direct hydrogen fuel cell: 0.3% of the consumption at full power.
- Gasoline and methanol with reformer: 2% of the consumption at full power

Cold start extra consumption (cycle is assessed under hot conditions)

- Direct hydrogen fuel cell: +3 %
- Gasoline and methanol reformer: 1.46 MJ fuel was added (warm-up, for each cycle) to take into account the energy burnt to bring the metal mass of the reformer at the operating temperature.

5.3.4 Conformance to performance criteria

The performance parameters achieved by the fuel cell powered vehicles are shown below and are all within the defined criteria.

Table 5.3.4 Performance of 2010+ fuel cell vehicles

		Non Hybrid		Hybrid		Hybrid+reformer		Target
		C-H ₂	L-H ₂	C-H ₂	L-H ₂	Gasoline ⁽¹⁾	Methanol	
Time lag for 0-50 km/h	s	3.5	3.4	3.2	3.2	3.3	3.3	<4
Time lag for 0-100 km/h	s	11.7	11.5	10.3	10.1	10.7	10.8	<13
Time lag for 80-120 km/h in 4 th gear	s	9.8	9.6	8.2	8.1	8.7	8.8	<13
Gradeability at 1 km/h	%	>100	>100	>100	>100	>100	>100	>30
Top speed	km/h	184	184	184	184	183	183	>180
Acceleration	m/s ²	4.8	4.8	4.8	4.8	4.8	4.8	>4.0

⁽¹⁾ also valid for naphtha and diesel

Fuel cell vehicles were the heaviest of all the simulated configurations. Two factors strongly influenced the acceleration performance:

- The torque of the electric motor at low speed (possible torque limitation due to mechanical or electrical design have not been considered).
- The power available from the fuel cell (the power rise rate was assumed to be 15 kW/s in all cases).

5.3.5 Energy and total GHG emissions (NEDC)

The average fuel consumption and total GHG emissions over the NEDC are shown in the tables and figures below.

Table 5.3.5-1 Average energy/fuel consumption and GHG emissions over the NEDC 2010+ fuel cell vehicles

	Fuel consumption (/100 km)			GHG emissions (g CO ₂ eq/km)				% change ⁽²⁾	
	MJ	l ⁽¹⁾	kg	as CO ₂	as CH ₄	as N ₂ O	Total	Energy	GHG
Direct hydrogen	94.0	2.92	0.78	0.0	0.0	0.0	0.0	-58%	-100%
Direct hydrogen hybrid	83.7	2.60	0.70	0.0	0.0	0.0	0.0	-63%	-100%
Reformer fuelled by									
Gasoline	162.4	5.05	3.76	119.2	0.5	0.5	120.1	-27%	-29%
Methanol	148.0	9.38	7.44	108.5	0.5	0.5	109.4	-34%	-35%
Naphtha	162.4	5.16	3.72	115.7	0.8	1.5	118.0	-27%	-30%
Diesel	162.4	4.53	3.77	119.0	0.8	1.5	121.3	-27%	-28%

⁽¹⁾ expressed in liters of equivalent gasoline for hydrogen

⁽²⁾ from reference 2002 gasoline PISI

The results are valid for both compressed and liquid hydrogen inasmuch as both corresponding vehicles have the same cycle test mass and efficiency map.

CO₂ emissions for fuel cell with reformer were all below 120 g/km, in the same range as most of the ICE hybrid configurations. Nevertheless, it has to be mentioned that the uncertainty on the simulation

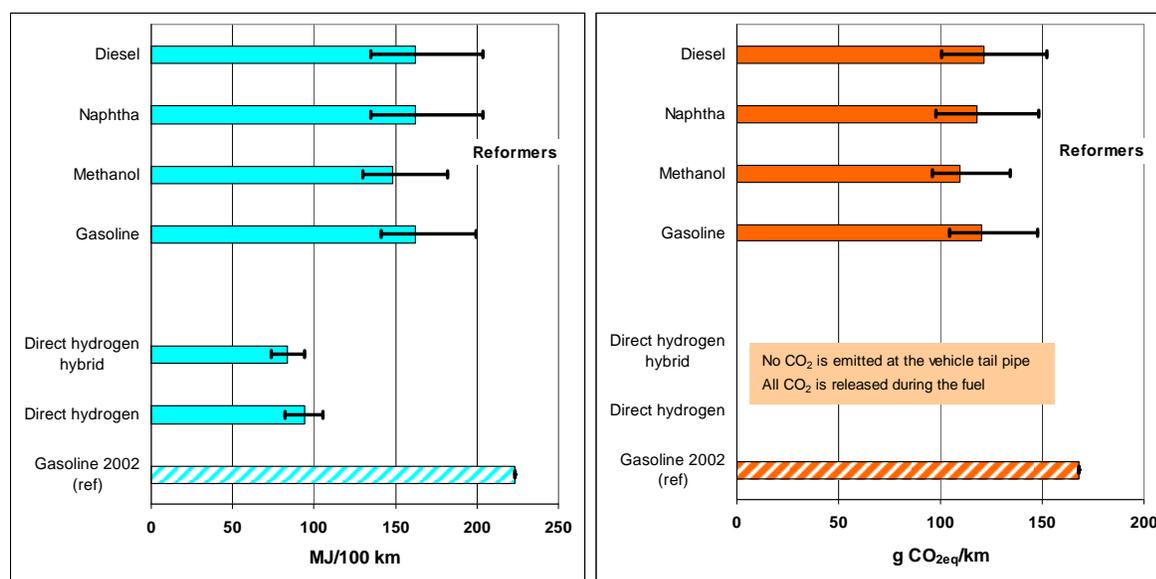
results was quite large for these fuel cell configurations (mainly due to the evaluation of the cold start over-consumption).

The uncertainty range on energy consumptions was estimated, for each vehicle-fuel combination, according to experts views and are presented here-under.

Table 5.3.5-2 Estimated energy efficiency variability 2010+ fuel cell vehicles

All figures in %	Direct hyd. FC		Reformer + FC			
	No bat.	Hybrid	Gasoline	Methanol	Naphtha	Diesel
Overall (sum of variances)	-12/12	-12/12	-13/23	-12/23	-17/25	-17/25
Cold start	-5/5	-5/5	-5/20	-5/20	-5/20	-5/20
Energy management	-5/5	-5/5	-5/5	-5/5	-5/5	-5/5
Fuel consumption map	-10/10	-10/10	-10/10	-10/10	-15/15	-15/15
Mass estimate			-4/0	-0/0	-4/0	-4/0

Figure 5.3.5-1a/b Average energy/fuel consumption and GHG emissions over the NEDC 2010+ fuel cell vehicles



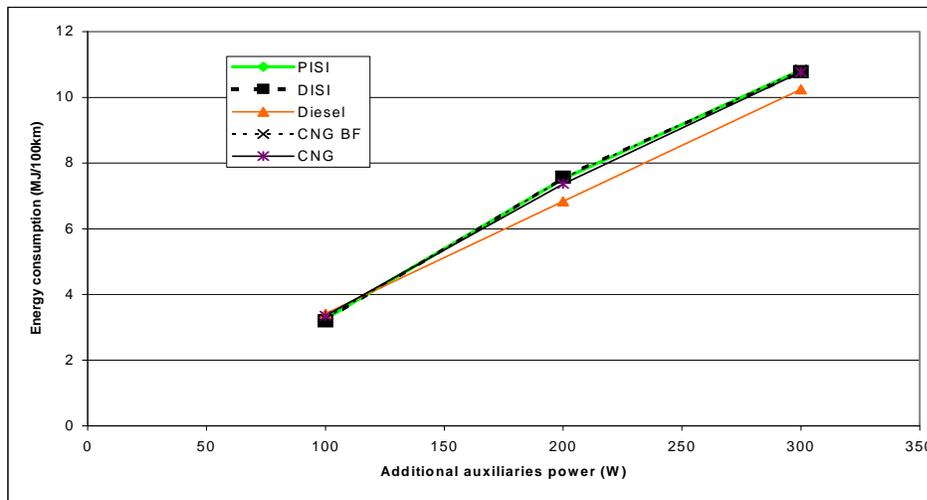
Once again these charts illustrate the limitation of the simple well-to-tank analysis, suggesting that hydrogen vehicles make no contribution to GHG emissions. Only the overall well-to-wheels analysis is relevant, particularly when it comes to hydrogen. Even if hydrogen vehicles applications are relevant for local regulated emissions control, the GHG impact of pure hydrogen applications is highly depending on the fuel production pathway. Some of the most usual hydrogen pathways will be found globally less attractive.

6 Impact of additional electric auxiliaries

The fuel penalty and GHG impact of additional auxiliaries were assessed for every configuration. Three levels of additional power consumption were considered namely 100, 200 and 300W. In this respect, the efficiency of the generator has a major influence. A value of 60 % was assumed for the present state of the art, increasing to 72 % in 2010+.

The following figure shows the additional energy consumption of 2002 ICE vehicles as a function of auxiliary power demand.

Figure 6 Energy consumption impact of auxiliaries power on the NEDC



Whatever the fuel/powertrain combination, the energy penalty versus the auxiliaries power demand is nearly linear. The slope depends on the mean energy conversion efficiency of the powertrain, as clearly shown by the Diesel line compared to the SI engines. The GHG contribution is directly related to the energy consumption through the specific energy and carbon content of the fuel.

For the 2002 state-of-the-art technology and on the NEDC cycle, the average power developed by the vehicle for propulsion is around 4 kW. Taking into account the 60 % efficiency of the alternator, 300 W of power demand for auxiliaries would impose an extra load of 500 W on the powertrain, i.e. and increase of 12.5 %. On the urban drive part of the cycle, the engine is under-loaded, usually resulting in low energy efficiency so that this extra load actually improves the intrinsic engine efficiency. As a result, the energy penalty is limited to around 10 MJ/100 km for 300 W, or roughly 5 % instead of 12.5 %. Depending on the efficiency maps of the different engines and the path of the operating point during the cycle, the result may be slightly different. This is illustrated in figure 6 where the diesel engine is shown to be somewhat more efficient.

In 2010+, the combined impacts of improved alternator efficiency and supplementary engine load reduce these figures some more, reducing the energy impact to 8.5 MJ/100 km for gasoline, or 4.5% instead of 5%, corresponding to 6.5 g CO₂ / km.

For hybrid configurations, two opposing effects play a part: the hybrid powertrain is, globally, a better energy converter than the thermal engine and this should reduce the fuel penalty. However, the thermal engine is already operated near its optimal efficiency and no noticeable benefit can be expected from the extra engine load. As a result, the net energy and GHG penalties due to auxiliaries are roughly the same as those for the conventional 2002 ICE.

The above effect also applies to hybrid fuel cells powertrains with reformers for which the energy penalty due to auxiliaries, added to that of the reformer system itself, bring to figures equivalent to the 2010 ICE engines.

The case of direct hydrogen fuel cells is very specific, as, contrarily to thermal powertrains, increasing the load decreases the energy converter efficiency, mainly in urban driving phases. As a result the energy impact of 300 W auxiliaries load over a NEDC cycle is assessed at 12 MJ/100 km or around 13 %.

7 Vehicle Retail Prices estimation

7.1 Introduction

The economical assessment of future technologies, in a trade competitive domain, is probably among the most risky challenge ever proposed to a crystal ball.

The methodology we selected intended to estimate the retail price increment expectable at the 2010+ horizons for the various technologies under consideration. Maintenance costs were not considered.

7.2 Methodology

Inspired from the MIT study "On the road in 2020"⁷, the calculation delivered orders of magnitude in a simple and transparent way. Subtracting the price impact of the original internal combustion engine and components and adding the impact of the new powertrain components obtained the retail price. Specific price increments for special tanks (hydrogen or natural gas), or electric components (batteries, electric motors) were also added when relevant.

For the retail prices detailed assessments, the following rules were used:

- When the powertrain could be identified as a spark ignition (SI) combustion technology, the retail price was evaluated relative to the 2002 PISI vehicle.
- When the powertrain could be identified as a compression ignition (CI) technology, the retail price was evaluated relative to the 2002 DICV vehicle.
- When the powertrain could not be identified as either a SI or a CI technology, the retail price was evaluated relative to the 2002 PISI vehicle.

Details of the sources, individual component price assumptions and calculations for each vehicle type can be found in *TTW Appendix 1*.

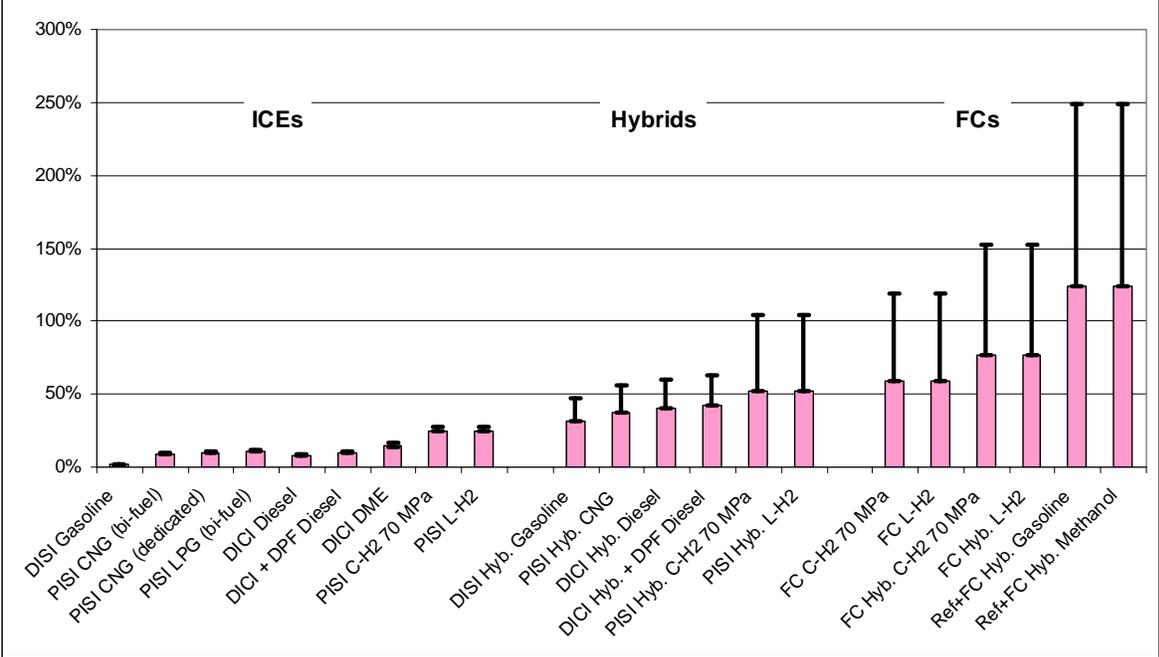
7.3 Results

The figure 7.3 shows the percent retail price increase for the 2010+ vehicles, compared to the PISI ICE Gasoline 2010+ vehicle (assumed retail price **19560 €**). These figures are deemed to represent fair price differentials based on commercial realities or reflecting the lack of reliable consolidated data. They are one of the components in the economic assessment of the alternative pathways in the Well-to-Wheels integration.

The figure also shows the estimated uncertainty ranges. The range is fairly narrow for established technologies but widens when it comes to less developed options such as hybrids. For fuel cell technology we have applied a 100% upwards range reflecting the many uncertainties attached to these technologies.

⁷ "On the road in 2020", Malcolm A. Weiss, John B. Heywood, Elisabeth M. Drake, Andreas Schafer and Felix F. Au Yeung, October 2000.

Figure 7.3 % increase of vehicle retail price compared to gasoline PISI vehicle

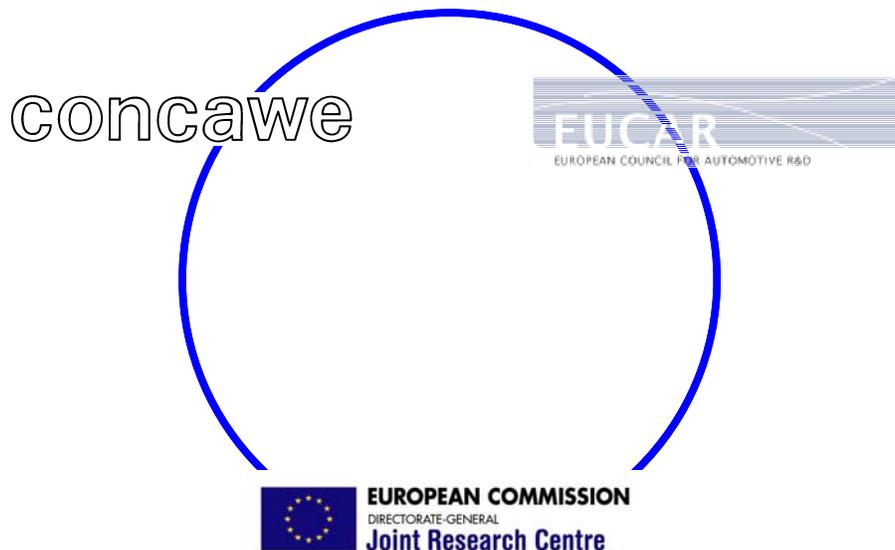


Acronyms and abbreviations used in the WTW study

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 ₂ O	Nitrous oxide: a very potent greenhouse gas
NEDC	New European Drive Cycle
NG	Natural Gas
NO _x	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

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



WELL-to-WHEELS Report

Version 3c, July 2011

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Notes on version number:

This document reports on the third release of this study replacing version 2c published in March 2007. The original version 1b was published in December 2003.

This is a partial revision of version 2c in that it does not include an update of section 8 on cost and availability.

Key Findings

EUCAR, CONCAWE and JRC (the Joint Research Centre of the European Commission) have updated their joint evaluation of the Well-to-Wheels energy use and greenhouse gas (GHG) emissions for a wide range of potential future fuel and powertrain options, first published in December 2003. The specific objectives of the study remained the same:

- Establish, in a transparent and objective manner, a consensual well-to-wheels energy use and GHG emissions assessment of a wide range of automotive fuels and powertrains relevant to Europe in 2010 and beyond.
- Consider the viability of each fuel pathway and estimate the associated macro-economic costs.
- Have the outcome accepted as a reference by all relevant stakeholders.

The main conclusions and observations are summarised below. We have separated the points pertaining to energy and GHG balance (in normal font) from additional points involving feasibility, availability and costs (in *italic*).

GENERAL OBSERVATIONS

A Well-to-Wheels analysis is the essential basis to assess the impact of future fuel and powertrain options.

Both fuel production pathway and powertrain efficiency are key to GHG emissions and energy use.

A common methodology and data-set has been developed which provides a basis for the evaluation of pathways. It can be updated as technologies evolve.

A shift to renewable/low fossil carbon routes may offer a significant GHG reduction potential but generally requires more total energy. The specific pathway is critical.

□ Large scale production of synthetic fuels or hydrogen from coal or gas offers the potential for GHG emissions reduction via CO₂ capture and storage and this merits further study.

➤ *Advanced biofuels and hydrogen have a higher potential for substituting fossil fuels than conventional biofuels*

➤ *High costs and the complexities around material collection, plant size, efficiency and costs, are likely to be major hurdles for the large scale development of these processes.*

Transport applications may not maximize the GHG reduction potential of renewable energies

Optimum use of renewable energy sources such as biomass and wind requires consideration of the overall energy demand including stationary applications.

CONVENTIONAL FUELS / VEHICLE TECHNOLOGIES

Developments in engine and vehicle technologies will continue to contribute to the reduction of energy use and GHG emissions:

Within the timeframe considered in this study, higher energy efficiency improvements are predicted for the gasoline and CNG engine technology (PISI) than for the Diesel engine technology.

Hybridization of the conventional engine technologies can provide further energy and GHG emission benefits.

Hybrid technologies would, however, increase the complexity and cost of the vehicles.

COMPRESSED NATURAL GAS, BIOGAS, LPG

Today the WTW GHG emissions for CNG lie between gasoline and diesel, approaching diesel in the best case.

Beyond 2010, greater engine efficiency gains are predicted for CNG vehicles, especially with hybridization.

WTW GHG emissions become lower than those of diesel.

WTW energy use remains higher than for gasoline except for hybrids for which it becomes lower than diesel.

- The origin of the natural gas and the supply pathway are critical to the overall WTW energy and GHG balance.
- LPG provides a small WTW GHG emissions saving compared to gasoline and diesel.
- *Limited CO₂ saving potential coupled with refuelling infrastructure and vehicle costs lead to a fairly high cost per tonne of CO₂ avoided for CNG and LPG.*
- *While natural gas supply is unlikely to be a serious issue at least in the medium term, infrastructure and market barriers are likely to be the main factors constraining the development of CNG.*
- *When made from waste material biogas provides high and relatively low cost GHG savings.*

ALTERNATIVE LIQUID FUELS

A number of routes are available to produce alternative liquid fuels that can be used in blends with conventional fuels and, in some cases, neat, in the existing infrastructure and vehicles.

The fossil energy and GHG savings of conventionally produced bio-fuels such as ethanol and bio-diesel are critically dependent on manufacturing processes and the fate of by-products.

The GHG balance is particularly uncertain because of nitrous oxide emissions from agriculture.

Land use change may also have a significant impact on the WTW balance. In this study, we have modelled only biofuels produced from land already in arable use.

- When upgrading a vegetable oil to a road fuel, the esterification and hydrotreating routes are broadly equivalent in terms of GHG emissions.
- ETBE can provide an option to use ethanol in gasoline as an alternative to direct ethanol blending. Fossil energy and GHG gains are commensurate with the amount of ethanol used.
- Processes converting the cellulose of woody biomass or straw into ethanol are being developed. They have an attractive fossil energy and GHG footprint.

High quality diesel fuel can be produced from natural gas (GTL) and coal (CTL). GHG emissions from GTL diesel are slightly higher than those of conventional diesel, CTL diesel produces considerably more GHG

In the medium term, GTL (and CTL) diesel will be available in limited quantities for use either in niche applications or as a high quality diesel fuel blending component.

New processes are being developed to produce synthetic diesel from biomass (BTL), offering lower overall GHG emissions, though still high energy use. Such advanced processes have the potential to save substantially more GHG emissions than current bio-fuel options.

BTL processes have the potential to save substantially more GHG emissions than current bio-fuel options at comparable cost and merit further study.

Issues such as land and biomass resources, material collection, plant size, efficiency and costs, may limit the application of these processes.

DME

DME can be produced from natural gas or biomass with better energy and GHG results than other GTL or BTL fuels. DME being the sole product, the yield of fuel for use for Diesel engines is high.

Use of DME as automotive fuel would require modified vehicles and infrastructure similar to LPG.

The "black liquor" route which is being developed offers higher wood conversion efficiency compared to direct gasification and is particularly favourable in the case of DME.

HYDROGEN

Many potential production routes exist and the results are critically dependent on the pathway selected.

If hydrogen is produced from natural gas:

WTW GHG emissions savings can only be achieved if hydrogen is used in fuel cell vehicles.

The WTW energy use / GHG emissions are higher for hydrogen ICE vehicles than for conventional and CNG vehicles.

In the short term, natural gas is the only viable source of large scale hydrogen. WTW GHG emissions savings can only be achieved if hydrogen is used in fuel cell vehicles albeit at high costs.

Hydrogen ICE vehicles will be available in the near-term at a lower cost than fuel cells. Their use would increase GHG emissions as long as hydrogen is produced from natural gas.

Electrolysis using EU-mix electricity results in higher GHG emissions than producing hydrogen directly from NG.

Hydrogen from non-fossil sources (biomass, wind, nuclear) offers low overall GHG emissions.

Renewable sources of hydrogen have a limited potential.

More efficient use of renewables may be achieved through direct use as electricity rather than road fuels applications.

Indirect hydrogen through on-board autothermal reformers offers little GHG benefit compared to advanced conventional powertrains or hybrids.

On-board reformers could offer the opportunity to establish fuel cell vehicle technology with the existing fuel distribution infrastructure.

- For hydrogen as a transportation fuel virtually all GHG emissions occur in the WTT portion, making it particularly attractive for CO₂ Capture & Storage.

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 (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 Study objectives and organisational structure

EUCAR, CONCAWE and JRC (the Joint Research Centre of the European Commission) have updated their joint evaluation of the Well-to-Wheels energy use and greenhouse gas (GHG) emissions for a wide range of potential future fuel and powertrain options, first published in December 2003. The original objectives of the study were:

- Establish, in a transparent and objective manner, a consensual well-to-wheels energy use and GHG emissions assessment of a wide range of automotive fuels and powertrains relevant to Europe in 2010 and beyond.
- Consider the viability of each fuel pathway and estimate the associated macro-economic costs.
- Have the outcome accepted as a reference by all relevant stakeholders.

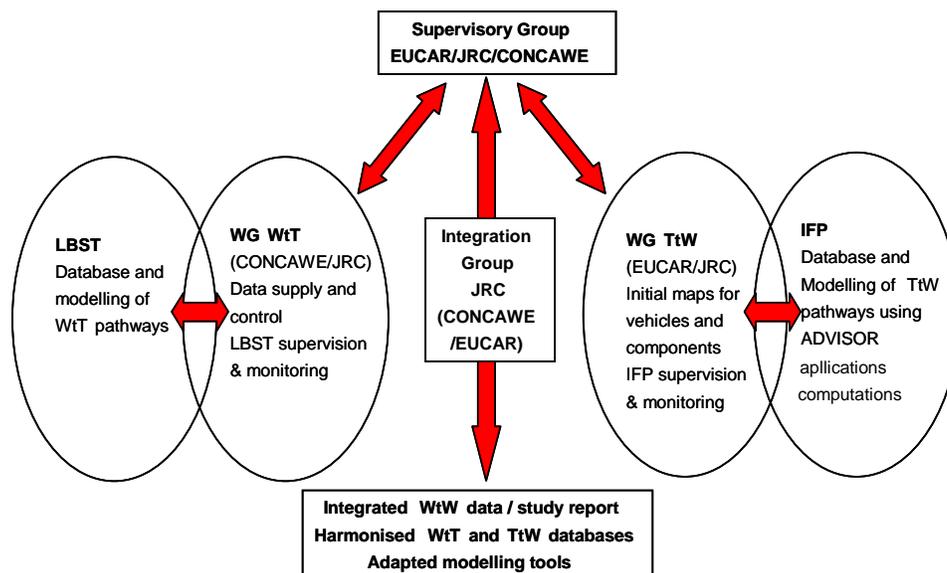
Cost and potential availability of alternative pathways were evaluated in version 1 and 2 of this study. With the development of specific legislation on introduction of alternative fuels, these issues have been receiving a lot of attention and generated a lot of debate. In this version 3 we opted out of this and concentrated on the evaluation of energy and GHG balances.

Notes:

- The study is not a Life Cycle Analysis. It does not consider the energy or the emissions involved in building the facilities and the vehicles, or the end of life aspects. It concentrates on fuel production and vehicle use, which are the major contributors to lifetime energy use and GHG emissions.
- No attempt has been made to estimate the overall “cost to society” such as health, social or other speculative cost areas.
- Regulated pollutants have only been considered in so far as all plants and vehicles considered are deemed to meet all current and already agreed future regulations.

This study was undertaken jointly by the JRC (Joint Research Centre of the European Commission), EUCAR and CONCAWE. It was supported by the structure illustrated in the diagram below.

Supporting structure



The “*Well to Tank*” Working Group was coordinated by CONCAWE/JRC assisted by LBST¹, a consultancy firm with a proven track record in WTW assessment and which had a major involvement in previous work by General Motors² and the TES consortium³. JRC provided a major contribution to the bio-fuel pathways characterization and the estimation of future biomass availability.

The “*Tank to Wheels*” Working Group was coordinated by EUCAR/JRC. EUCAR supplied the vehicle data, the engines energy efficiency maps and adaptation procedures. The simulation code adaptation (ADVISOR) and the simulated fuels-vehicle assessments were contracted to the Institut Français du Pétrole (IFP). JRC contributed to the initial ADVISOR code assessment and its adaptation to European market conditions.

The *Integration Group* was chaired by JRC and supervised by a Scientific Advisory Board representing the three partners.

¹ E² database by LBST

² GM Well-to-Wheels Analysis of Energy Use and Greenhouse Gas Emissions of Advanced Fuels/Vehicles Systems. A European study. LBST, September 2002.

³ Transport Energy Strategy Partnership

2 Scope and methodology

The **Well to Tank (WTT)** evaluation accounts for the energy expended and the associated GHG emitted in the steps required to deliver the finished fuel into the on-board tank of a vehicle. It also considers the potential availability of the fuels, through their individual pathways and the associated production costs.

The **Tank to Wheels (TTW)** evaluation accounts for the energy expended and the associated GHG emitted by the vehicle/fuel combinations. It also includes an assessment of the expected relative retail prices of the various vehicle configurations.

The related methodologies and findings are fully documented and discussed in the companion “Well-to-Tank” and “Tank-to-Wheels” reports. The main assumptions are summarised in *sections 2 and 3* of this report respectively.

This report describes the **Well to Wheels (WTW)** integration for the fuel/vehicle combinations considered, including:

- An overall assessment of the energy required and the GHG emitted per unit distance covered,
- An estimate of the costs associated with each pathway and the resulting costs of fuel substitution and of CO₂ avoidance,
- A discussion of practicality, potential and availability for the main alternative fuels and specifically for biomass-related fuels,
- Considerations of alternative (outside the road transport sector) and optimum use of limited energy resources.

Sections 3 to 6 cover the different fuel/vehicle groups from conventional fuels and powertrains to hydrogen fuel cells. *Section 7* is dedicated to CO₂ capture and storage. *Section 8* gives an overview of the costs of substitution and CO₂ avoidance and of the potential availability of alternative fuels. *Section 9* covers alternative uses of energy resources.

The evaluation of individual pathways calls for sound comparison of the various options from a variety of angles. We have endeavoured to shed some light on this by answering the questions:

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

Our aim has been to evaluate the impact of fuel and/or powertrain substitution in Europe on global energy usage and GHG emissions balance, i.e. taking into account induced changes in the rest of the world..

Throughout this study we have endeavoured to remain as neutral and objective as possible. In any such study, however, 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 personal preference. While we do not pretend to have escaped this fact, we have endeavoured to make our choices and decisions as transparent as possible.

Among the data that were available we chose what we judged to be the most appropriate sources. Some of the selected assumptions, such as the set of minimum driving performance criteria, are real and tangible. Others, relating to emerging technologies, extrapolated to 2010 and beyond, are closer to expectations than assumptions. The choices made are referenced, justified and documented. The

details of the calculations have been to the largest possible extent included in the appropriate appendices to allow the reader to access not only the results but also the basic data and the main calculation assumptions.

Data sources are referenced in the WTT and TTW reports but are, as a rule, not repeated in this WTW integration document.

In such a study, there are many sources of uncertainty. A large part of the data pertains to systems or devices that do not yet exist or are only partly tested. Future performance figures are expectations rather than firm figures. In each step of a pathway there are usually several options available. The main options have been singled out by defining a separate pathway but this has practical limits and is therefore another important source of variability. The variability ranges selected are identified in the respective WTT and TTW sections and as much as possible justified.

As an energy carrier, a fuel must originate from a form of primary energy, which can be either contained in a fossil feedstock or fissile material, or directly extracted from solar energy (biomass or wind power). Generally a given 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 for the foreseeable future. The number of conceivable fuels and fuel production routes is very large. We have tried to be as exhaustive as possible but, inevitably, certain combinations that we considered less relevant have been left out at this stage. The database is structured in such a way that new data from scientifically established changes, progress, or new applications can be easily taken into account in future updates. The following matrix summarises the main combinations that have been included.

Table 2-1 Primary energy resources and automotive fuels

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

⁽¹⁾ with/without CCS
⁽²⁾ Biogas
⁽³⁾ Associated with natural gas production

A common vehicle platform representing the most widespread European segment of passenger vehicles (compact 5-seater European sedan) was used in combination with a number of powertrain options shown in **Table 2-2** below. ADVISOR, an open source vehicle simulation tool developed by the US-based National Renewable Energy Laboratory (NREL), was used and adapted to European conditions.

Key to the methodology was the requirement for all configurations to comply with a set of minimum performance criteria relevant to European customers while retaining similar characteristics of comfort, driveability and interior space. Also the appropriate technologies (engine, powertrain and after-treatment) required to comply with regulated pollutant emission regulations in force at the relevant date were assumed to be installed. Finally fuel consumptions and GHG emissions were evaluated on the basis of the current European type-approval cycle (NEDC).

It is important to recognise that:

- The model vehicle is merely a comparison tool and is not deemed to represent the European average, a/o in terms of fuel consumption
- The results relate to compact passenger car applications, and should not be generalized to other segments such as Heavy Duty or SUVs.
- No assumptions or forecasts were made regarding the potential of each fuel/powertrain combination to penetrate the markets in the future. In the same way, no consideration was given to availability, market share and customer acceptance.

Table 2-2 Automotive fuels and powertrains

Powertrains	PISI	DISI	DICI	Hybrid PISI	Hybrid DISI	Hybrid DICI	FC	Hybrid FC	Ref. + hyb. FC
Fuels									
Gasoline	2002 2010+	2002 2010+		2010+	2010+				2010+
Diesel fuel			2002 2010+			2010+			2010+
LPG	2002 2010+								
CNG Bi-Fuel	2002 2010+								
CNG (dedicated)	2002 2010+			2010+					
Diesel/Bio-diesel blend 95/5			2002 2010+			2010+			
Gasoline/Ethanol blend 95/5	2002 2010+	2002 2010+			2010+				
Bio-diesel			2002 2010+			2002 2010+			
DME			2002 2010+			2010+			
Synthetic diesel fuel			2002 2010+			2010+			
Methanol									2010+
Naphtha									2010+
Compressed hydrogen	2010+			2010+			2010+	2010+	
Liquid hydrogen	2010+			2010+			2010+	2010+	

PISI: Port Injection Spark Ignition

DISI: Direct Injection Spark Ignition

DICI: Direct Injection Compression Ignition

FC: Fuel cell

Externally chargeable electric vehicles (pure battery-electric and plug-in hybrids) were not included in the core study. In view of recent renewed interest for such options, a separate assessment is included in [WTW Appendix 2](#).

2.1 WTT approach

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. All details of

assumptions and calculations are available in the *WTT report* and its appendices. We briefly discuss below some basic choices that have been made and that have a material impact on the results.

2.1.1 Pathways and processes

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

2.1.2 Costing basis

Cost data as published in version 2b are considered obsolete and have not been updated in this version.

2.1.3 Incremental approach

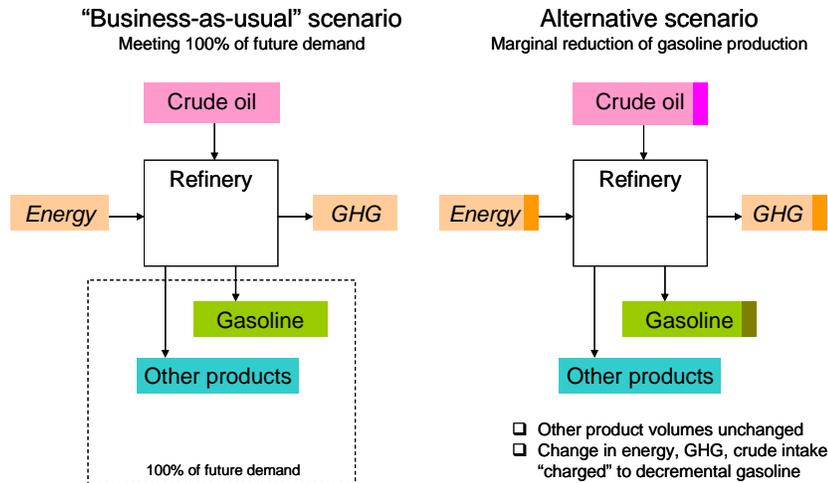
The ultimate purpose of this study is to guide those who have to make a judgement on the potential benefits of substituting conventional fuels by alternatives. It is clear that these benefits depend on the *incremental* resources required for alternative fuels and the *incremental* savings from conventional fuels saved.

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.

At the 2010-2020 horizon substitution is only plausible up to a limited level, say up to a maximum of 10-15% depending on the option considered. The incremental energy, GHG emissions and costs estimated through the above process must also be consistent with this level of substitution.

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 the energy and GHG emissions associated with production and use of conventional fuels pertained to the marginal rather than the average volumes. Marginal production figures representative of the European situation were obtained through modelling of the EU-wide refining system (see figure below and more details in *WTT Appendix 3*).

Figure 2.1.3 Impact of a marginal reduction of conventional gasoline demand



Distribution energy was taken as proportional to volumes. 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.

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.

2.1.4 By-product credits

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.

The implication of this logic is the following methodology (*Figure 2.1.4*):

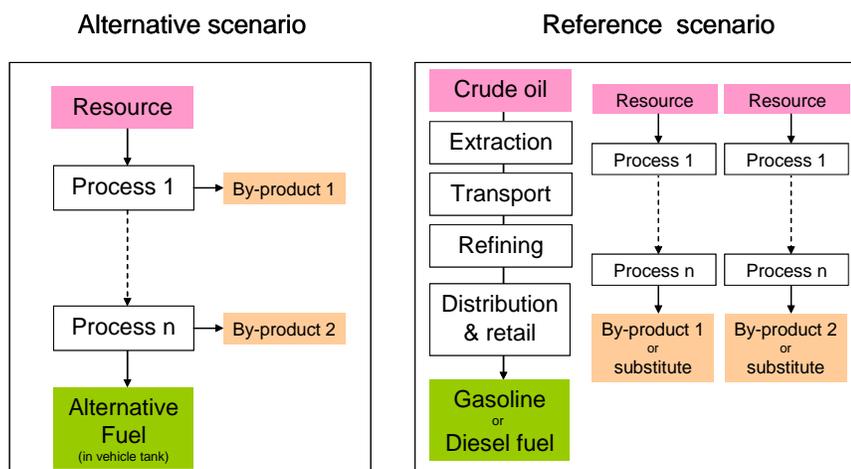
- All energy and emissions generated by the process are allocated to the main or desired product of that process.
- The by-product generates an energy and emission credit equal to the energy and emissions saved by not producing the material that the co-product is most likely to displace.

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 2.1.4 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.

2.1.5 Scale and availability

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. Particularly for biofuels, scale issues can be important. A certain amount of biofuel can be produced in Europe, but if additional amounts are needed import pathways will need to be considered with potentially different GHG and energy balances.

The issue of availability is being widely debated in Europe and addressed by others. This section has not been updated in this version of our study. Considerations published in version 2b are still available for reference in *section 5 of the WTT report*.

2.1.6 Other factors of importance for biofuels

Biofuels present particular challenges to produce reliable GHG and energy balances, because the agricultural part of the equation is complex. In addition to the impact of fossil energy used in producing and processing the crop, GHG emissions are emitted over the growing period as nitrous oxide (N₂O), a gas with 296 times the greenhouse-gas potency of CO₂, as nitrogen from fertiliser and natural sources is broken down in the soil. N₂O emissions depend on soil type, fertiliser addition, the type of crop and also the weather, so they are difficult to estimate with accuracy. To determine the effect of growing the biofuel crop, we must also consider to what use the land would have been otherwise put – the emissions attributed to the biofuel are the difference between the two crops. Over a longer time period, carbon can be sequestered or released from the soil as CO₂, so converting, for example, pasture land to arable land for biofuels would add significantly to GHG emissions over a period of decades. In this study, we model only biofuels produced from land already under arable cultivation. These issues are discussed in *WTT Report Section 3.4.1*.

2.1.7 Data sources

The collaboration with LBST allowed us access to the comprehensive database compiled by the TES consortium and in the course of the study carried out by General Motors et al. in 2001-2002. With the

agreement of these two organisations we have used the information extensively. Over the years the existing data has been extensively reviewed and updated, and a number of new processes and a number of new pathways not hitherto considered have been added.

2.2 TTW approach

This part of the study accounts for the energy expended and the associated GHG emitted by the vehicle/fuel combinations in the reference NEDC driving cycle.

2.2.1 Vehicle data and performance

All simulations were based on a common model vehicle, representing a typical European compact size 5-seater sedan, comparable to e.g. a VW Golf (see reference vehicle characteristics in the *TTW report*). This model vehicle was used as a comparison tool for the various fuels and associated technologies. The fuel consumption figures are not deemed to be representative of the average European fleet. All required data for the baseline PISI gasoline model vehicle were collected from EUCAR member companies

In order to obtain a valid comparison between the various powertrain/fuel combinations, it was deemed essential that they should all comply with a minimum set of performance criteria, given in the following table.

Table 2.2.1 Minimum vehicle performance criteria

		Target
Time lag for 0-50 km/h	s	<4
Time lag for 0-100 km/h	s	<13
Time lag for 80-120 km/h in 4 th gear	s	<13
Gradeability at 1 km/h	%	>30
Top speed	km/h	>180
Acceleration	m/s ²	>4.0
Range ⁽¹⁾	km	>600

⁽¹⁾ Where applicable 20 km ZEV range

Technologies (engine, powertrain and after-treatment) required to comply with regulated pollutant emission regulations were assumed to be installed i.e.

- EURO 3 for 2002 vehicles,
- EURO 4 for 2010+ vehicles.

Powertrain configurations and components were selected accordingly. Compliance with EURO 5 and EURO 6 emissions standards, as mandated in EC Regulation No 715/2007 of 20 June 2007⁴, is not yet included in the current revision of the WTW. The vehicle configurations required to achieve these performance criteria are detailed in the *TTW report*.

2.2.2 Vehicle simulations

ADVISOR, the open source vehicle simulation tool developed by the US-based National Renewable Energy Laboratory (NREL) was used and adapted to European conditions to comply with the study requirements. Conventional powertrains and fuels were simulated for the 2002 reference baseline. The 2010+ performance were derived by establishing percentage improvement over the 2002 level. 2010+ hybrids, fuel-cells and hydrogen applications were simulated directly.

⁴ See <http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2007:171:0001:0016:EN:PDF>

Simulations were carried out for each neat fuel separately (Gasoline, Diesel, CNG, LPG and hydrogen). For alternatives to gasoline (ethanol, MTBE/ETBE) and diesel (bio-diesel, synthetic diesel, DME) it was assumed that, whether used neat or in blends, the fuel consumption on energy basis would remain the same as for the base fuel. In other words these **alternatives fuels were deemed not to have any effect positive or negative on the energy efficiency of the engine**. The corresponding GHG emissions were then calculated from the compositional data.

The ADVISOR simulation model was adapted to the NEDC cycle. The main modifications were corrections to gear changes during the cycle, fuel cut-off during deceleration, and the energy management strategies for the hybrid and fuel cell vehicles.

The ADVISOR version we used presents some limitations to simulate transients. On the NEDC cycle (see section 3.3 below), this is not limiting the comparative nature of the exercise. This was confirmed by a cross-check performed between measured results on a roller test bench and simulated results on ADVISOR, applied to the reference vehicle (Gasoline PISI 2002): the verification showed similar results. Furthermore, the validity of the simulation tool was checked against in-house simulation codes of a number of European manufacturers, showing comparable results.

The main vehicle simulation results delivered by ADVISOR are:

- **Fuel energy (MJ/km)** necessary to perform the NEDC cycle
- **GHG (g CO_{2eq}/km)** emitted during the cycle.

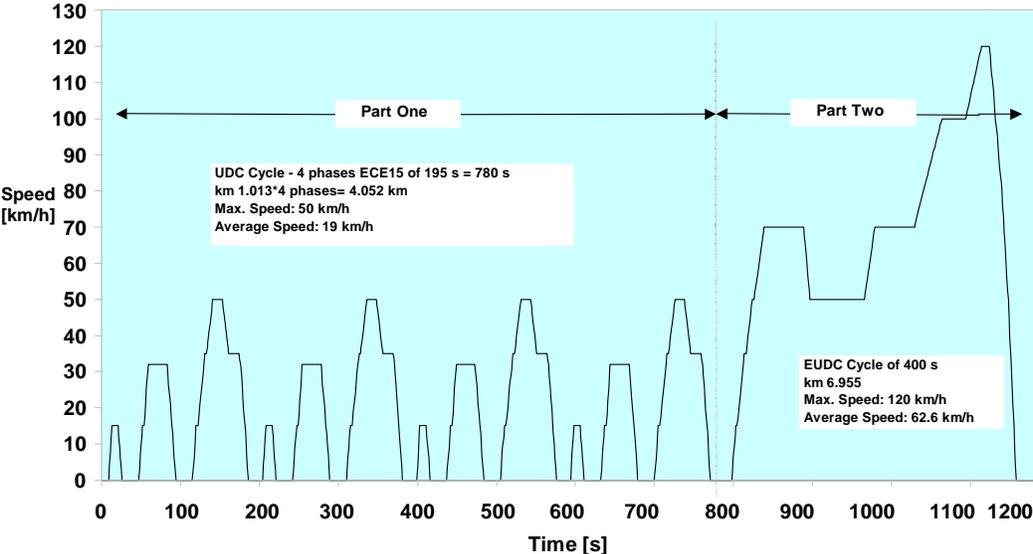
Note: total GHG emissions expressed in CO_{2eq} take N₂O and methane emissions into account, through estimates of their emissions, and using the appropriate IPCC factors (for details refer to the *TTW report section 3.2*).

A separate assessment of externally chargeable electric vehicles is presented in *WTW Appendix 2*.

2.2.3 Reference road cycle

The standard regulatory NEDC road driving cycle, as applied for measuring today’s passenger car emissions and fuel consumption in Europe, was used for simulating the TTW emissions.

Figure 2.2.3 Reference NEDC driving cycle



Cold start, as required by the standard certification tests, was included in the calculations. Experimental data from Volkswagen for a Golf with a PISI 1.6l engine were used to cross-check the simulation figures. Results were in close agreement: the simulated fuel consumption was 6.95 l/100 km, which is close to the measured result 7.0 l/100 km.

2.3 WTW integration

The results of the WTW integration are presented in the following sections. *Section 3 to 6* introduces the fuels, the characteristics of the relevant vehicles and presents the energy and GHG balances for the various pathways. *Section 7* deals with the cost aspects while potential fuel availability issues are discussed in *section 8*. Finally *section 9* briefly discusses the issue of optimum use of energy resources.

The WTW energy and GHG figures combine

- The WTT **expended** energy (i.e. excluding the energy content of the fuel itself) per unit energy content of the fuel (LHV basis),
- With the TTW energy consumed by the vehicle per unit of distance covered (on the NEDC cycle).

The energy figures are generally presented as **total** primary energy expended, regardless of its origin, to move the vehicle over 1 km on the NEDC cycle. These figures include both fossil and renewable energy. As such they describe the energy efficiency of the pathway.

Total WTW energy (MJ/100 km) = TTW energy (MJ_f/100 km) x (1 + WTT total expended energy (MJ_{xt}/MJ_f))

For fuels of renewable origin we have also evaluated the fossil energy expended in the pathway, illustrating the fossil energy saving potential of that pathway compared to conventional alternatives.

Fossil WTW energy (MJ_{f0}/100 km) = TTW energy (MJ_f/100 km) x (λ + WTT fossil expended energy (MJ_{xf0}/MJ_f))

λ = 1 for fossil fuels, 0 for renewable fuels

MJ_f refers to the energy contained in the fuel.

MJ_{xt} / MJ_{xf0} refer respectively to the total/fossil additional external energy needed to produce 1 MJ of fuel from the primary energy resource.

GHG figures represent the total grams of CO₂ equivalent emitted in the process of delivering 100 km of vehicle motion on the NEDC cycle.

WTW GHG (g CO_{2eq}/km) = TTW GHG (g CO_{2eq}/km) + TTW energy (MJ_f/100 km)/100 x WTT GHG (g CO_{2eq}/ MJ_f)

The uncertainty ranges from WTT and TTW have been combined as variances i.e. as the square root of the sum of squares.

Results for all pathways considered in the study are summarised in *WTW Appendix 1*.

3 Conventional Fuels and Powertrains 2002/2010⁺

3.1 Conventional gasoline and diesel fuel

Conventional road fuels are widely expected to provide the bulk of road transportation needs for many years to come and certainly within the time horizon of this study. Consequently, ICE engines fuelled by gasoline or diesel fuel from crude oil represent the reference against which all the alternatives were assessed.

The energy and GHG savings related to the replacement of gasoline and diesel by alternative fuels pertain therefore to marginal production up to say 10-15% of the total road fuels demand. Over the study time period, non-conventional crude sources are not expected to impact the European market and Middle East crude remains the appropriate marginal energy supply (see *WTT report, section 3.1*).

3.2 Fuels/vehicles combinations

The vehicles and powertrains already available today were simulated on the basis of available “real” 2002 data. Fuels, engine maps and vehicle characteristics, were precisely defined, constructed from a combination of existing and validated data. The 2002 conventional vehicle results are therefore considered as the starting reference for comparison.

Diversification of fuels and powertrains is expected from 2010 and beyond. For conventional vehicles the 2010 options essentially represent advances in conventional technologies including hybrids.

Table 3.2-1 Simulated combinations for conventional vehicles and fuels

Powertrains	PISI	DISI	DICI	Hybrid PISI	Hybrid DISI	Hybrid DICI
Fuels						
Gasoline	2002 2010+	2002 2010+		2010+	2010+	
Diesel fuel			2002 2010+			2010+

Fuel efficiency is expected to improve significantly over time. Achievable improvements were discussed and estimated among the EUCAR members on the basis of expected technological progress (e.g. friction reduction, engine control, combustion improvements etc). The 2010 Diesel vehicles are considered with and without particulate filter (DPF). The expected fuel consumption reductions for the various technologies are presented in the table below.

Table 3. 2-2 2002-2010 fuel efficiency improvements

Gasoline		LPG	Diesel	
PISI	DISI	PISI Bi-fuel	DICI no DPF ⁽¹⁾	DICI with DPF ⁽¹⁾
15%	10%	15%	12%	9.5%

For SI engines, the main contribution to fuel efficiency improvement comes from downsizing (minus 20%⁵) associated with supercharging. This contribution is reduced for DI engines as the “no-throttling” benefit is already included in the current 2002 engines.

⁵ The displacement of the gasoline engine was reduced from 1.6 litre down to 1.3 litre, the full torque being restored by a turbo charging at 1.2 : 1

Diesel engines are already non-throttled and turbo-charged in 2002, so that no additional benefits are expected through the “downsizing” route. Only standard technology improvement is accounted for (e.g. friction). The DPF option is assigned a fuel penalty of about 2.5% for the regeneration of the filter (reduced from 4% assumed in the first version of this study).

For hybrids, the additional fuel economy is a function of the ‘hybrid control strategy’ and of the power/mass ratio of the electric motor. The electric motor provides a high torque, available immediately upon start up and over a wide range of rotation speed. As a result, hybrid configurations deliver good acceleration performance, even though they tend to be heavier than conventional ones.

The hybrid configuration considered in the study is based on the following requirements:

- Capacity to run 20 km as ZEV on the battery,
- Top speed achieved without electrical assistance,
- Acceleration criteria achieved without electric motor peak power (for safety reasons).

Within these constraints the vehicle parameters have been set in order to obtain the best compromise between fuel economy and vehicle performance.

Hybrid configurations will benefit from all of the improvements applicable to conventional configurations for 2010+. In addition, it was considered that the hybrid architecture would allow further improvements from the 2002 engine efficiency maps, as shown in the following table.

Table 3.2-3 Additional fuel efficiency improvements for hybrids from 2002 engine maps

Gasoline	Diesel	
	DICI no DPF ⁽¹⁾	DICI with DPF ⁽¹⁾
3%	3%	0.5%

⁽¹⁾ Diesel Particulate Filter

Although the large variety of vehicle hybridization options has not been investigated in the present version, the *TTW report (section 5.2.5)* includes a discussion of the upside potential of hybrids for higher fuel economy of about 6%. This potential has been represented by an increase of the uncertainty range towards higher efficiency.

3.3 Energy and GHG balances

The aggregated WTT and TTW energy and GHG figures for the 2002 and 2010 vehicles (including hybrids) are shown on the figure below. The WTT energy and GHG figures for conventional fuels are relatively low, so that the ranking of the different options is overwhelmingly determined by the performance of the powertrain.

As a result of the relative imbalance between gasoline and diesel fuel demand in Europe, the production of marginal diesel fuel is more energy-intensive than that of gasoline. On a WTW basis the impact is modest and more than compensated by the superior efficiency of the Diesel CIDI engine compared to the gasoline PISI. Over the NEDC cycle, the gasoline DISI engine has a lower fuel consumption than the PISI, due to its capacity to run in lean-burn mode.

The 2010 figures result from the relative fuel efficiency improvements indicated in **Table 3.2-2**. By then, gasoline PISI and DISI are predicted to come much closer together, PISI technologies taking a higher benefit from Downsizing /Turbo-charging applications.

PISI/DISI technologies are also closer to diesel, particularly when the latter is penalised by the addition of a DPF.

Figure 3.3-1a/b WTW energy requirement and GHG emissions for conventional fuels ICE and hybrid powertrains

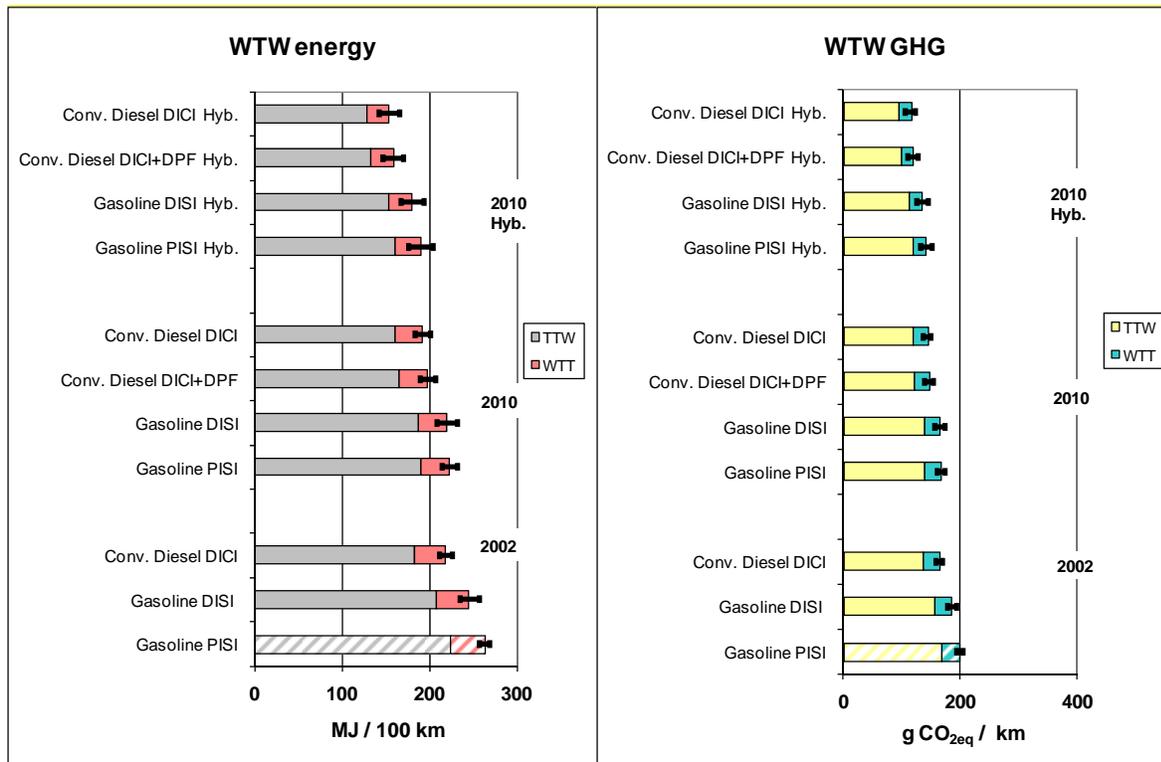
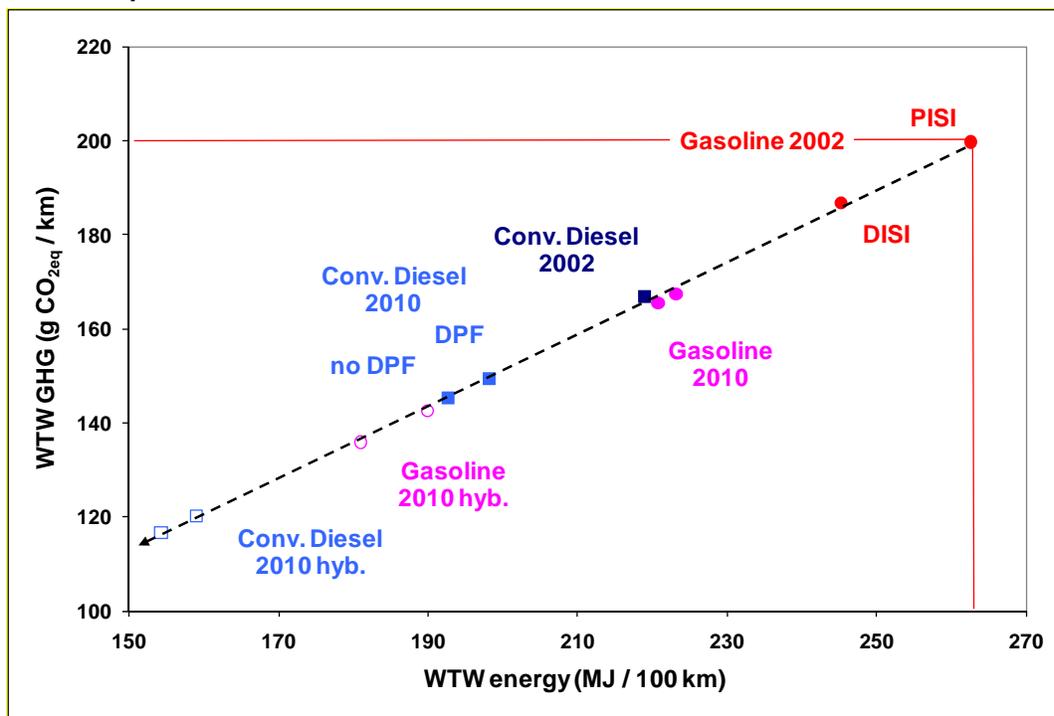


Figure 3.3-2 clearly illustrates the potential for improvement of conventional engines and fuels.

Figure 3.3-2 WTW energy requirement and GHG emissions for conventional fuels ICE and hybrid powertrains



The efficiency gap between SI and CI vehicles is narrowing

The hybridization option investigated brings an additional energy reduction of about 15% for gasoline and 18% for diesel. Further optimisation of hybrid configurations may bring additional savings.

Developments in engine efficiency and vehicle technology options including hybrids will continue to contribute to CO₂ emissions reductions through reduced fuel consumption

4 Compressed Natural Gas (CNG), biogas (CBG), LPG

4.1 CNG production and availability

4.1.1 Natural gas sourcing

Natural gas is widely available in Europe, distributed through a dense network of pipelines to industrial, commercial and domestic consumers. The European production (mainly from the UK, the Netherlands and Norway) is complemented by sizeable imports from Algeria and mainly Russia. Demand is expected to grow strongly mainly to feed the increasing demand for electricity, particularly in view of the coal and nuclear phase-out in some countries.

World natural gas reserves are very large but European production is set to decline during the coming decade so that the share of imports in the European supply will steadily increase. Russia, other countries of the FSU and the Middle East are the most credible long-term major supply sources for Europe.

Additional natural gas for road transport would have to be sourced from marginal supplies. We have considered three sourcing scenarios:

- 7000 km pipeline (typically from western Siberia),
- 4000 km pipeline (typically from south-west Asia),
- LNG shipping over a distance of about 10,000 km (typically the Middle East⁶).

These future marginal gas supplies to Europe are far away and the associated transport energy represents an important fraction of the total energy and GHG balance of CNG.

On the other hand volumes that can reasonably be expected to find their way into road fuels within the timeframe of this study would only represent a small fraction of the total European natural gas consumption (a 5% share of the 2020 European road fuels market would represent about 2.5% extra gas demand) and would not require extensive addition to the gas distribution network (but will of course require refuelling equipment).

4.1.2 Distribution and refuelling infrastructure

Like all gaseous fuels, CNG requires a dedicated infrastructure for distribution and refuelling. The natural gas grid, developed in most areas of Europe to serve domestic, commercial and industrial customers can be used for supplying natural gas to refuelling stations. For a road fuel market penetration up to the 10% mark, it is generally accepted that sufficient capacity would be available in the existing grid. Some areas of Europe are not served by the grid and it is unlikely that transport demand alone would justify extensive additions to the existing networks. For such areas LNG, distributed by road and vaporised at the refuelling station, may be an option.

Infrastructure issues and costs are essentially related to refuelling stations. Assuming the existing conventional fuels sites are used, the investment and operating costs would be mostly associated with storage, compression and refuelling hardware. The safety issues related to the widespread use of a flammable gas at high pressure are real but well understood for CNG and not considered as a significant barrier to introduction.

⁶ Shipping distance between the Arabian gulf and Western European ports via the Suez canal

4.2 CNG vehicles

CNG vehicles have been in use for many years in Europe and in the rest of the world. The very limited refuelling infrastructure and the additional cost of the equipment required for the vehicle have so far limited their development to fleet vehicles or geographic niches, generally supported by a favourable tax regime for the fuel and/or the vehicles. In order to represent the real commercial options existing in 2002, a bi-fuel (gasoline-NG) and a dedicated vehicle were simulated.

4.2.1 2002 Bi-fuel and dedicated CNG vehicles

Bi-Fuel adapted vehicle

In such a vehicle, an additional CNG fuel system is fitted to the original gasoline engine. An additional CNG tank is also added, while the gasoline tank capacity is reduced.

No specific engine optimisation is possible, as gasoline operation must be preserved. As a consequence, the torque curve is shifted down by 12% over the engine speed range when operating on CNG. Top speed is not affected but the acceleration capability is slightly below target. As the performance criteria are met in gasoline mode this was considered acceptable.

Dedicated engine vehicle

This engine is based on the same level of technology as the gasoline engine (this is an area where we significantly differ from the GM study where only a downsized turbo-charged CNG engine was considered).

In this single fuel engine, the compression ratio can be optimised to get the benefit from the highest “knock resistance” (octane number) of natural gas. The CNG engine compression ratio was raised from 9.5:1 to 12.5:1 for an energy efficiency increase of 9% over the gasoline reference.

In order to fulfil all performance criteria and particularly acceleration a higher torque is required. This was achieved by increasing the engine displacement. In the second version of the study a somewhat more favourable CNG engine map was used (see *TTW report, section 4.1.3* for a detailed discussion). As a result the engine displacement increase could be limited to 0.3 litres (from 1.6 to 1.9 litres) compared to 0.4 litres in the previous version. This, together with the larger and heavier CNG tank accounts for a significant overweight compared to the base gasoline vehicle. The resulting fuel consumption penalty nearly compensates the advantage gained from optimisation so that the dedicated vehicle has only a slight advantage over the bi-fuel configuration in this respect.

Table 4.2-1 Characteristics of 2002 CNG vehicles

		PISI		
		Gasoline	CNG bi-fuel	CNG
Powertrain				
Displacement	l	1.6	1.6	1.9
Powertrain	kW	77	77/68	85
Engine mass	kg	120	120	150
Gearbox mass	kg	50	50	50
Storage System				
Tank pressure	MPa	0.1	25	25
Tank net capacity	kg	31.5	14/17.5	30
Tank mass empty	kg	15	12/61	103
<i>Tank mass increase including 90% fuel</i>	kg	0	59	87
Vehicle				
Reference mass	kg	1181	1181	1181
Vehicle mass	kg	1181	1240	1298
Cycle test mass	kg	1250	1360	1360
Performance mass	kg	1321	1380	1438

4.2.2 2010 improvements expected from CNG engines

Being spark ignited, CNG engines are expected to enjoy the same 15% fuel efficiency improvement as their gasoline homologues through downsizing and turbo-charging. An additional 1% improvement is thought to be achievable, due to the mixing ability of the gaseous fuel with air, allowing optimal aerokinetics. The total improvement beyond 2010 was estimated at 16% compared to 2002.

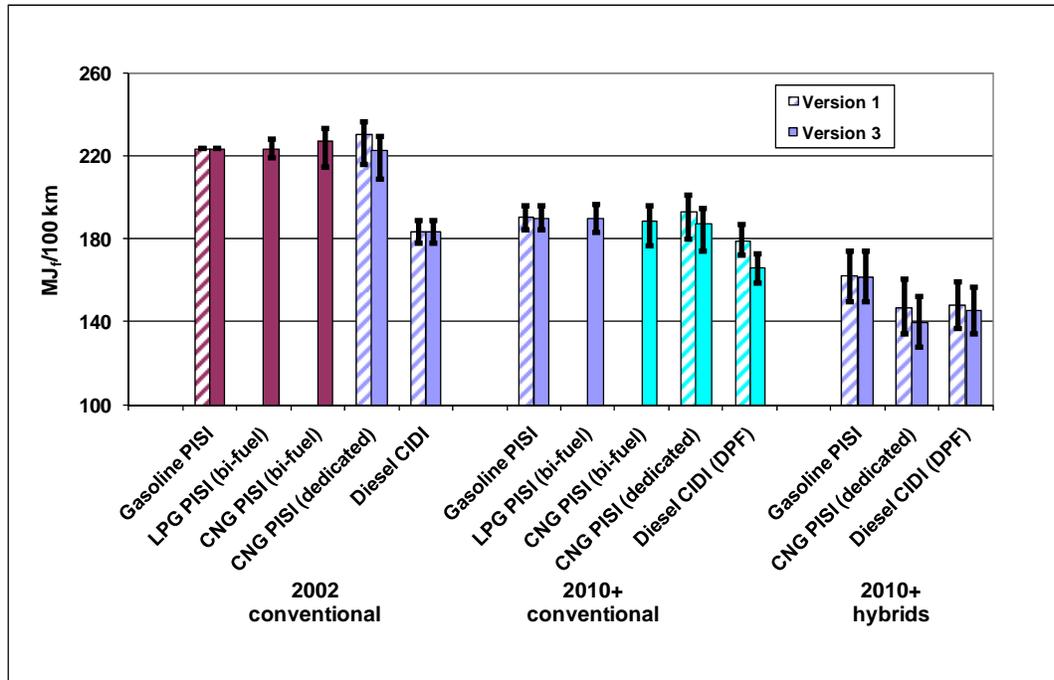
4.2.3 2010 hybrids

For CNG hybrids, only the dedicated engine was considered. The availability of the electric motor allows the acceleration criteria to be met with the original 1.6 l engine displacement. As a result hybridisation is particularly beneficial to CNG with a potential improvement of 24% over the conventional 2010 PISI.

4.3 CNG pathways energy and GHG balances

The fuel economy performance of dedicated CNG vehicles compared to conventional ones is illustrated in *Figure 4.3-1* which also shows the changes from the first version of this study. Note that the 2002 dedicated vehicle is shown here for comparison but does not correspond to a real option today.

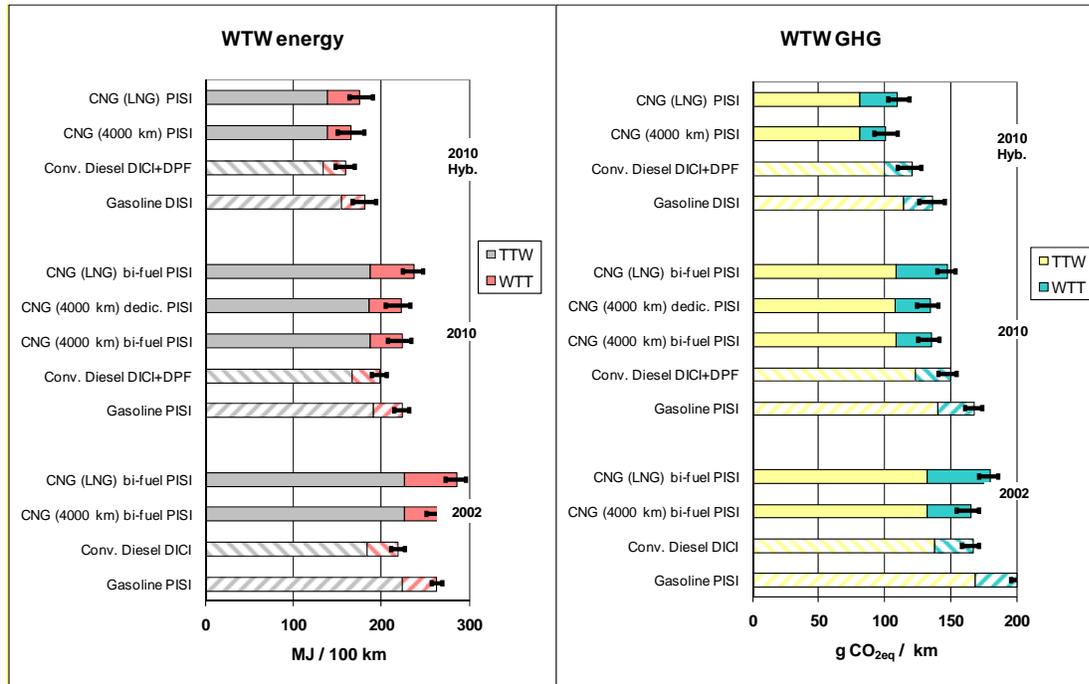
Figure 4.3-1 TTW fuel consumption for conventional and CNG vehicles



CNG vehicles are currently slightly less efficient than equivalent gasoline vehicles while diesel vehicles enjoy a net advantage. In the future, however, improvements in spark ignition engines will bring all technologies much closer together. Specific improvements in CNG engines will improve CNG beyond gasoline and bring it close to diesel. Hybridisation would be particularly favourable to CNG as it would resolve the issue of acceleration performance without having to revert to a larger engine, thereby delivering the full benefit of CNG's higher octane rating and associated higher compression ratio (see above, *section 4.2.1*).

Figure 4.3-2 shows the WTW figures, combining the impacts of vehicle technology and of the gas production route, particularly transport distance. The option of piped gas over 7000 km comes close to LNG and we have therefore not included it in these graphs for clarity. The higher hydrogen to carbon ratio gives natural gas an advantage over crude-based fuels in GHG terms but, on a WTW basis, this is compensated by extra energy requirement for fuel provision and somewhat lower vehicle fuel efficiency.

Figure 4.3-2a/b WTW energy requirement and GHG emissions for conventional and CNG pathways



In the 2002 configurations the only available CNG vehicles are bi-fuel. These configurations are more energy intensive than both gasoline and diesel and between gasoline and diesel in GHG terms. By 2010 both bi-fuel and dedicated vehicles may become realistic options. The dedicated vehicle has a slight advantage over the bi-fuel version although it should be borne in mind that our bi-fuel configuration is a compromise and does not quite meet all performance criteria. The CNG engine efficiency improvement brings GHG emissions below those of diesel, although energy use is still higher. The effect is even stronger for hybrids as explained above.

Currently, the WTW GHG emissions for CNG lie between gasoline and diesel, approaching diesel in the best case.

Beyond 2010, greater engine efficiency gains are predicted for CNG vehicles, especially with hybridization:

- *WTW GHG emissions becomes lower than those of diesel.*
- *WTW energy use remains higher than for gasoline except in the case of hybrids for which it is lower than diesel.*

The gas transport distance and route is critical to the overall balance. The 4000 km pipeline route is considered as a reasonable representation of Europe's marginal supply for a number of years to come. Longer term, a larger share of LNG and possibly also longer pipeline routes can be expected. Pipeline technology is evolving and higher operating pressures are nowadays possible. This may result in new pipelines consuming less transport energy although other considerations such as initial pipeline costs, may limit this effect (see more details in *WTT report, section 3.2.2*).

The origin of the natural gas and the supply pathway are critical to the overall WTW energy and GHG balance.

4.4 Biogas

The anaerobic fermentation of organic matter produces a gaseous mixture, known as "biogas", consisting mainly of methane and CO₂. A suitable feedstock is biomass containing components such as carbohydrates (i.e. saccharides such as glucose), fatty acids and proteins. Anaerobic decomposition and formation of methane commonly occurs when manure, crop residues or municipal waste are

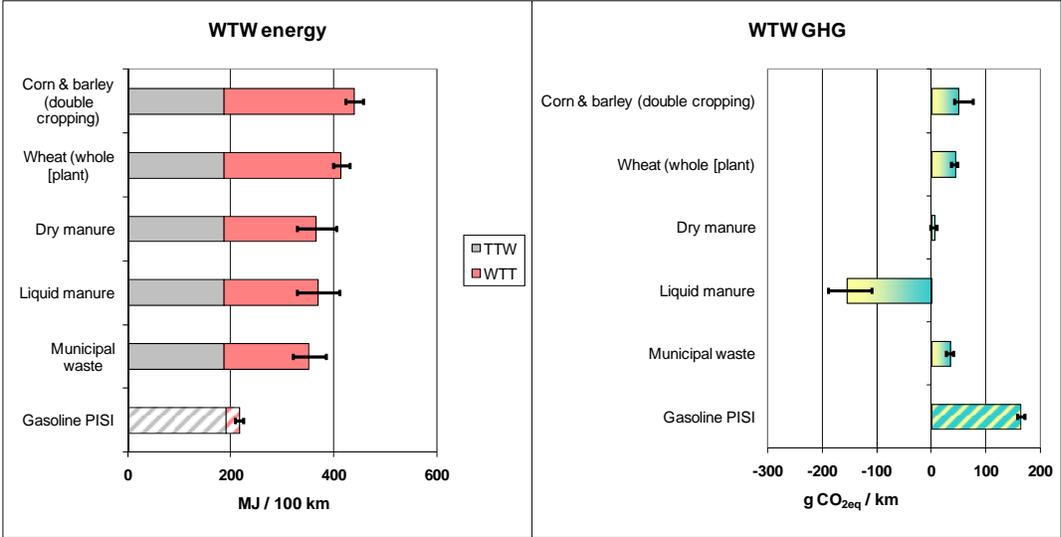
stockpiled or used as landfill, or when organic matter is immersed in water as occurs naturally in swamps, or is applied with liquid manure.

Although most biogas production installations have so far been at relatively small scale and geared to production of heat and power, concepts for larger plants have been developing with a view to produce a gas that can be used in combination with or as an alternative to natural gas as automotive fuel (Compressed Bio-Gas or CBG). This requires cleaning and upgrading of the gas to remove various impurities and the bulk of the CO₂. Some such plants already exist in Scandinavia.

We have considered five cases for upgraded biogas production. Three cases use waste material namely from municipal organic waste, dry manure and wet manure. In the last two cases it is assumed that farmed crops are used, namely wheat (as the whole plant) and a combination of corn and barley produced on the same land in a double cropping system. In all cases we have assumed that the upgraded gas joins an existing gas grid to reach the refuelling station.

The waste material used a feedstock is considered to be "GHG-free". Dedicated crops do carry a modest GHG footprint from farming activities (fossil carbon and N₂O emissions). In the production process, part of the biogas is used to fuel the process. As a result biogas has a generally favourable fossil energy and GHG emissions footprint. The total energy is relatively high but this is not very relevant for a process fuelled with a waste material that has no other uses. The overall GHG footprint is somewhat higher when dedicated crops are used. Biogas production occurs naturally with manure and particularly when diluted in water ("liquid" manure). Methane emissions can therefore be avoided by using that manure for dedicated biogas production. Note that the large resulting credit is the result of intensive livestock rearing rather than an intrinsic quality of biogas.

Figure 4.4a/b WTW energy requirement and GHG emissions for biogas (as CBG) (2010+ vehicles, CBG vehicles as Bi-fuel PISI)



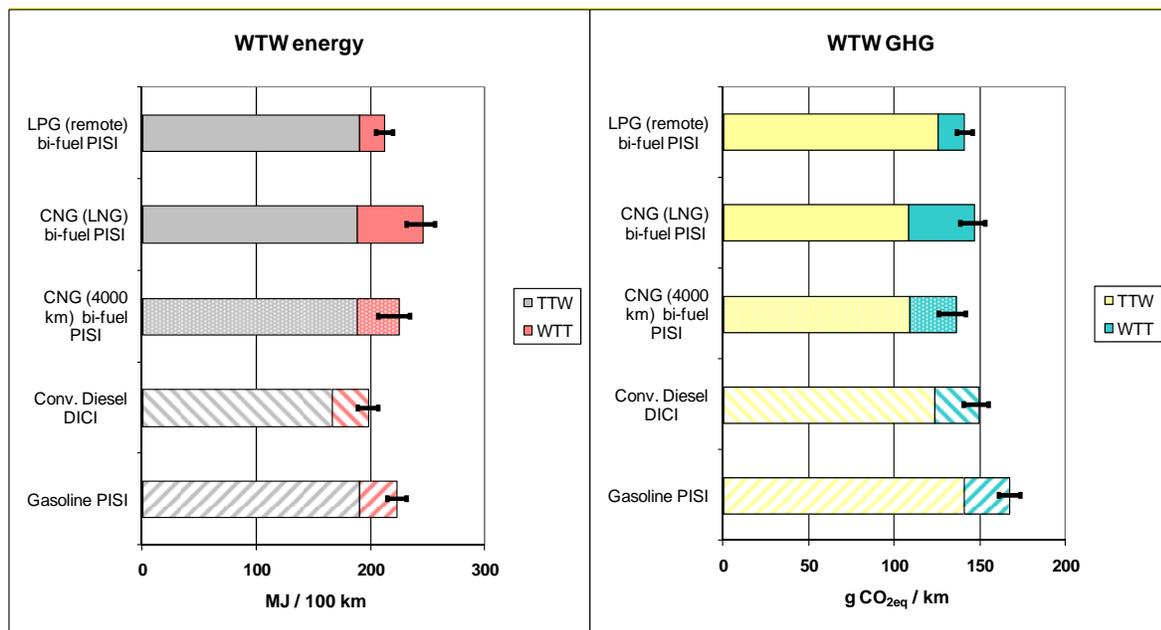
4.5 LPG

Liquefied Petroleum Gas (LPG) is a well-established niche automotive fuel in a number of EU countries. Although a large amount is produced by refineries, this production is entirely spoken for by existing markets such as domestic heating and cooking, various industrial applications and petrochemical feedstock. Indeed a large fraction of the LPG used in Europe today is imported, mostly originating from associated gases and liquids in crude oil and mainly natural gas production. The net effect of an increase in the use of LPG for automotive purposes would be to increase imports. Regardless of the physical source of supply, It is therefore the energy and GHG footprint of imported LPG that must be considered to gauge the impact on EU cost and global CO₂ emissions. We have therefore opted to represent the marginal case of LPG import into Europe from remote gas fields (Middle East).

The typical current LPG vehicle is bi-fuel (LPG/gasoline) PISI and this is not expected to change in the future. The engine efficiency remains the same on both fuels. Also we assumed liquid injection so that the torque characteristics and the associated acceleration performance remained the same. As a result the only change to the baseline gasoline PISI vehicle was the addition of an LPG tank, the extra mass being partly compensated by the smaller gasoline tank. Overall the mass increase was minimal and the same inertia class could be kept resulting in the same fuel economy for both vehicles.

The LPG WTW energy and GHG emissions balances are shown on the following figure, compared to the conventional and selected CNG figures. LPG's GHG emissions lie between diesel and CNG and energy between gasoline and diesel. Although not explicitly shown in the graph, transport distance has a significant impact, representing about 25% of the WTT energy in this case.

Figure 4.5a/b WTW energy requirement and GHG emissions for LPG 2010+ vehicles



5 Alternative liquid fuels / components

This section deals with all the non-conventional liquid fuels produced in a variety of ways and which can be used either neat or in blends with conventional gasoline or diesel fuel. We have considered ethanol, bio-diesel and synthetic diesel fuel. For completeness we have also added ETBE, as an alternative way of using ethanol and MTBE for reference. Such fuels share three undeniable advantages over gaseous fuels.

Infrastructure

If used in blends with conventional fuels, these fuels do not require any special distribution infrastructure except what is necessary to transport them to existing refineries or fuel depots. If used neat, the required infrastructure is more extensive but still much simpler than what would be required for gaseous fuels.

Vehicles

Generally these fuels can be used in existing vehicles with little or no modification as long as they are in small percentage blends with conventional fuels. For high percentage blends or neat fuels specially adapted vehicles may be required although changes are much less drastic than for gaseous fuels.

Flexible usage

Being miscible with conventional fuels they can be used in various proportions in relation to their availability in a certain area and at a certain time, of course within the limits imposed by the vehicle population.

The special case of DME

Di-Methyl-Ether or DME does not share the above advantages but is also discussed in this section as it falls into the category of direct substitute for diesel fuel and can be produced in a very similar way to synthetic diesel fuel. DME is gaseous at ambient conditions but can be liquefied under moderate pressure. Its use would require a dedicated distribution infrastructure very similar to that of LPG as well as specially adapted vehicles (fuel storage and injection system).

Effect on engine efficiency

Generally these fuels, when used in low volume blends, have not demonstrated any material effect on the intrinsic efficiency of the engines. There are various claims in the literature that certain fuels such as ethanol or synthetic diesel may increase energy efficiency. We considered that, at least at this stage, such claims have been neither proven in practice nor scientifically explained and have stuck to the constant engine efficiency concept.

Where new fuels are used in higher concentrations, e.g. E85, it is possible that engines could be adapted to take advantage of the higher octane to increase efficiency. However, this is only possible for dedicated vehicles,

Our calculations are based on constant energy efficiency which represents the use of the alternative liquid fuels as low level blends in the existing fleet, or in vehicles essentially similar.

A number of routes are available to produce alternative liquid fuels that can be used in blends with conventional fuels and, in some cases, neat, in the existing infrastructure and vehicles

In the WTT part of this study we have also included a number of pathways to produce methanol. The latter is not, however, envisaged as a fuel for ICE engines but as a vector for hydrogen (see further in *section 6*).

5.1 "Conventional" biofuels (ethanol and bio-diesel)

Ethanol is a well-established substitute for gasoline in spark-ignition engines. It has been used for many years in several parts of the world, occasionally neat, but more often in various blending ratios with conventional gasoline. It is generally accepted that engines developed and tuned for conventional gasoline can run with gasoline containing up to 5% ethanol without adverse short or long term effects. The European EN228 specification for gasoline allows blending of ethanol up to that level. Discussions are continuing on the potential to increase the ethanol level to 10%, and whether existing vehicles can use such fuels.

Bio-diesel is produced by reacting a vegetable oil with an alcohol, usually methanol to give a so-called Fatty Acid Methyl Ester (FAME). This process splits the tri-glyceride molecule, separating glycerine as a by-product and producing a fuel which boils at around 350°C and is a suitable diesel fuel. Pure vegetable oil is very viscous as well as unstable, and consequently unsuitable as a component in road diesel fuel. Bio-diesel can be used without problems in standard Diesel engines in blends up to 5% with conventional diesel fuel. Such blends are allowed by the EN590 diesel fuel specification

Although this has not been done in practice as yet, methanol can be substituted by ethanol to produce an Ethyl Ester (FAEE). Assuming ethanol is from bio origin, this has the advantage of boosting the "renewability" of the fuel. FAEE pathways have been included in this version of the study.

5.1.1 Sources and manufacturing processes of ethanol

Ethanol is traditionally produced by fermentation of sugars. Virtually any source of carbohydrates can be used. Sugars are readily converted whereas heavier compounds such as hemicellulose first need to be broken down in a hydrolysis step. For historical, economic and practical reasons, the main crops used for the industrial production of ethanol are sugar cane, corn (maize), wheat and sugar beet. The last two are currently, and for the foreseeable future the main sources of ethanol in Europe. Large scale ethanol production in Europe would rely mostly on wheat.

The fermentation process produces alcohol at a fairly low concentration in the water substrate. Purification of the ethanol by distillation is fundamentally energy-intensive.

In recent years there has been a lot of interest in processes to convert cellulose into ethanol via separation and breakdown of the cellulose into fermentable sugars. Such routes potentially make a much wider range of crops available including woody biomass in all shapes or form as well as by-products such as wheat straw or sugar beet pulp.

Amongst the vast number of possible options, we have elected to represent those that are the most relevant in Europe i.e. ethanol from sugar beet, wheat and woody biomass. For reference we have also added a pathway representing state-of-the-art production of ethanol from sugar cane in Brazil.

The basic processes for producing ethanol from sugar beet or wheat are well-established. One possible point of discussion is the energy associated to distillation. There have been significant advances in this respect and we have used data representing state-of-the-art plants. There are two essential elements that determine the final energy and GHG balances:

- The way the energy required for the production process is generated,
- The way the by-products are used.

One important point to remember is producers are likely to use energy and dispose of by-products in the most economic way, which is not necessarily the way that would maximise fossil energy saving and CO₂ avoidance. We have tried to represent the options that are most likely to “make sense” in practice but have also shown how currently less economic alternatives could alter the picture.

Sugar beet

We considered two options for utilising the pulp leftover after filtration of the diluted ethanol liquor:

- Animal feed,
- Fuel for the ethanol production process.

In practice only the first one is used today. The second option could be envisaged but, because of the cost, no-one would consider drying this by-product just to burn them. We considered instead the option of adding the pulp to the biogas digester (for cleaning the waste water), which gives almost the same energy balance and emissions as burning.

Wheat

Based on work done within the framework of the Low Carbon Vehicle Partnership in the UK, we have used the example of ethanol from wheat grain to illustrate the large impact of the process energy generation scheme on the overall energy and GHG balance. We have considered four options:

In the most basic (and low-capital) scheme, representative of many existing facilities (in Europe and elsewhere), a simple, usually gas-fired, boiler provides the steam while electricity is taken from the grid. Because heat is required at low temperature, ethanol plants offer, however, good opportunities for combined heat and power (CHP) schemes. Combining this with a natural gas fired gas turbine results in a very energy-efficient if capital-intensive process. In areas where coal or lignite is cheap and abundantly available, a simpler CHP scheme based on a coal-fired steam boiler combined with a backpressure steam turbine can also be envisaged. Finally surplus straw from the wheat itself can in principle be used as fuel through a similar CHP scheme. If this is likely to be a winner in terms of GHG emissions, this is also a very expensive and largely untested scheme to put on the ground and to operate.

Wheat grain processing leaves a protein-rich residue known as “distiller’s dried grain with solubles” or DDGS which is traditionally used as animal feed because of its high protein content. DDGS has a high energy content and, after drying, could conceivably be used for energy generation e.g. through co-firing in a coal-fired power station.

Woody biomass and straw

The possibility of extending the range of feedstocks available for ethanol production from sugars and starch to cellulose is very attractive and a lot of research is being devoted to developing such routes.

Apart from the IOGEN straw conversion process (see below), we have represented all ligno-cellulose to ethanol routes under the single label of “wood”. Accordingly, the underlying data represent a range of processes described in the literature although it must be realised that no such process has been proven at commercial scale. In such schemes the biomass input of the conversion plant includes non-cellulose material (e.g. the lignine of the wood) which is best used as an energy source. As the conversion energy represents most of the total energy requirement of the complete pathway, these pathways use very little external (fossil) energy.

As a separate option we have considered straw as a feedstock for ethanol production through the IOGEN process currently under development and which appears to be closer to commercial application. The conversion process is similar to the wood to ethanol process although the IOGEN data suggests higher efficiency than other sources.

5.1.2 Sources and manufacturing processes of bio-diesel

In Europe the main crops are rape (also known as colza) in the centre and north and, of less importance, sunflower in the south. Waste cooking oils are also used to a limited extent. Soy oil is the main crop in the Americas (mostly USA, Brazil and Argentina) while palm oil is produced in large quantities in South East Asia (Indonesia and Malaysia).

The processes to produce vegetable oil have been used for many years to produce food grade oil. The additional trans-esterification process is also well-established. The traditional alcohol used is methanol although (bio)ethanol can also be used. Oils from the crops mentioned above are all suitable for esterification although bio-diesels from some oils need to be blended with others (e.g. palm oil ester that has a high cloud point). There are a number of by-products the most important being the residue after pressing (or cake) and glycerine produced during the esterification step. The cake is a protein-rich animal feed used in substitution of otherwise imported soy meal. Glycerine could in principle be burned to fuel the process but, as it will command a much higher value as a chemical or as animal feed, this scenario is extremely unlikely. Glycerine itself is used in many food and cosmetics applications but the market is limited. In the future it could also be used as a substitute for alcohol and glycols in the manufacturing of e.g. paints, resins and antifreeze (see *WTT report, section 3.4.10* for details).

5.1.3 Hydrotreated vegetable oils (HVO)

The amount of FAME that can be added to conventional EN590 diesel fuel is limited to maintain acceptable fuel quality and compatibility with the vehicles in the market. In addition, the trans-esterification process leaves the basic backbone of the molecule unchanged, so the fuel properties depend to some extent on the type of oil or fat used in the process. Where the oil or fat contains many double bonds, stability may be a problem and conversely if the chains are long and saturated it may be difficult to meet cold flow requirements.

As an alternative to trans-esterification the pure oil can be hydrotreated. This removes double bonds and oxygen from the molecule, yielding a paraffinic fuel similar in properties to Fischer-Tropsch diesel (see *section 5.3*). This has all the advantages of such fuels, can either be used alone or blended with conventional diesel, and the final fuel properties are virtually independent of the original feedstock, so a wider range of feedstocks can be used.

The Neste Oil process (NexBTL®) was the first to be used in commercial production, and we have modelled this process using rapeseed, soy and palm oils. Similar processes are being developed by a number of other companies, and for comparison a process from UOP has been included, using rapeseed oil.

5.1.4 N₂O emissions from agriculture

The routes described above rely on traditional "food" crops, typically produced through intensive farming which is responsible for a large portion of the GHG emissions from these pathways. There are essentially two sources: nitrogen fertilizer production and emissions of nitrous oxide (N₂O) from the field. Because of the very powerful greenhouse effect of this gas (300 times that of CO₂), even relatively small emissions can have a significant impact on the overall GHG balance. N₂O emissions from different fields vary a by more than two orders of magnitude, depending on a complex combination of soil composition, climate, crop and farming practices.

LCA or WTT studies of biofuels have estimated N₂O emissions either from measurements on individual fields, or from calculations based on IPCC guidelines. The resulting error margins, if considered, are so enormous that it can be impossible to say for certain whether any pathway has a positive or negative GHG balance.

In this study we have exploited the expertise of the Soils and Waste Unit at the Institute for Environment and Sustainability at EC's Joint Research Centre at Ispra, and more particularly the results of a project for estimating greenhouse gas emissions from agricultural soils in Europe, in the context of GHG accounting for the Kyoto protocol. Emissions for the whole of the EU were calculated by combining GIS information on soil, daily climate and crop distribution with national data on fertilizer use and farm calendar. The emissions were then calculated day-by-day from the soils chemistry model and the data was segregated for different crops, to give EU-average N₂O emissions for each crop.

In this version of the study the data and tools available allowed us to carry out the simulations at a higher resolution level thereby minimising uncertainties due to uneven land quality. In v.1 we used soils and crop-distribution data available on a NUTS3 (1070 regions) level. This time we could make use of the LUCAS land-cover survey, which gives land cover at points on an 18km-grid, linked to soil parameters from the European Soil Bureau at JRC-Ispra. We also improved the model by adjusting the Nitrogen fertilizer rates according to recommendations for different soil types. We also used a reference-crop (see next paragraph).

Our method reduced the error margin to about 30%, mostly from the component of emissions from leached nitrogen, for which we still used the IPCC procedure. The improved values in this version are mostly slightly lower than those in the previous version, but still probably somewhat higher than those calculated using default IPCC values (depending on fertilizer assumptions). The IPCC procedure assumes that emissions are proportional to the nitrogen fertilizer rate. Interestingly, our results indicate that soil type, climate, and ground cover are more important than the fertilizer rate.

The soils model used in our calculations does not include short-rotation forestry in its crop-list. Therefore in this case only we used IPCC default factors. Fortunately the emissions are low anyway so that the additional uncertainty on emissions is moderate.

In spite of the thoroughness of these calculations, significant uncertainty remains, and some recent studies have suggested that field N₂O emissions may be significantly underestimated in such 'bottom-up' calculations.

(For more details see *WTT report, section 3.4.2*).

5.1.5 Reference scenario for crops

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 we argued that since most of the ethanol in EU would come from wheat diverted from export, we should not consider a reference crop. In this version, as in Version 2, we use as a baseline the updated 2005 projections of DG AGRI, which have a much smaller projected export, and much more set-aside area. As a result, most of the extra EU crops for biofuels would come from set-aside. We therefore had to consider as reference crop the use of the land on set-aside. We chose unfertilized, unharvested grass. This has negligible energy inputs, but a significant N₂O emission, which is subtracted from our calculation of N₂O from wheat and other crops.

Note that our reference scenario is for temporary grassland on land already brought into agriculture. Bringing permanent grassland or uncultivated land into arable use has longer term negative implications for GHG balances and is discussed in Section 5.1.6.

5.1.6 Energy and GHG balances

The figures in this section pertain to the **neat fuels** (ethanol and bio-diesel respectively). In practise they are most likely to be used in blend and the effects will be spread over a large number of vehicles.

Ethanol

Figure 5.1.6-1 shows the WTW fossil energy requirement and GHG emissions for a number of ethanol pathways. **Figure 5.1.6-2** shows the same information expressed as % savings compared to conventional gasoline.

Conventional production of ethanol from wheat as practiced in Europe gives modest fossil energy/GHG savings compared with gasoline. With a conventional energy production scheme and the currently most economic way of using DDGS (animal feed) the savings of fossil energy and GHG emissions are just over 30% compared to gasoline.

Figure 5.1.6-1a/b WTW fossil energy requirement and GHG emissions for ethanol pathways (2010+ vehicles)
(GHG bars represent the total WTT+TTW)

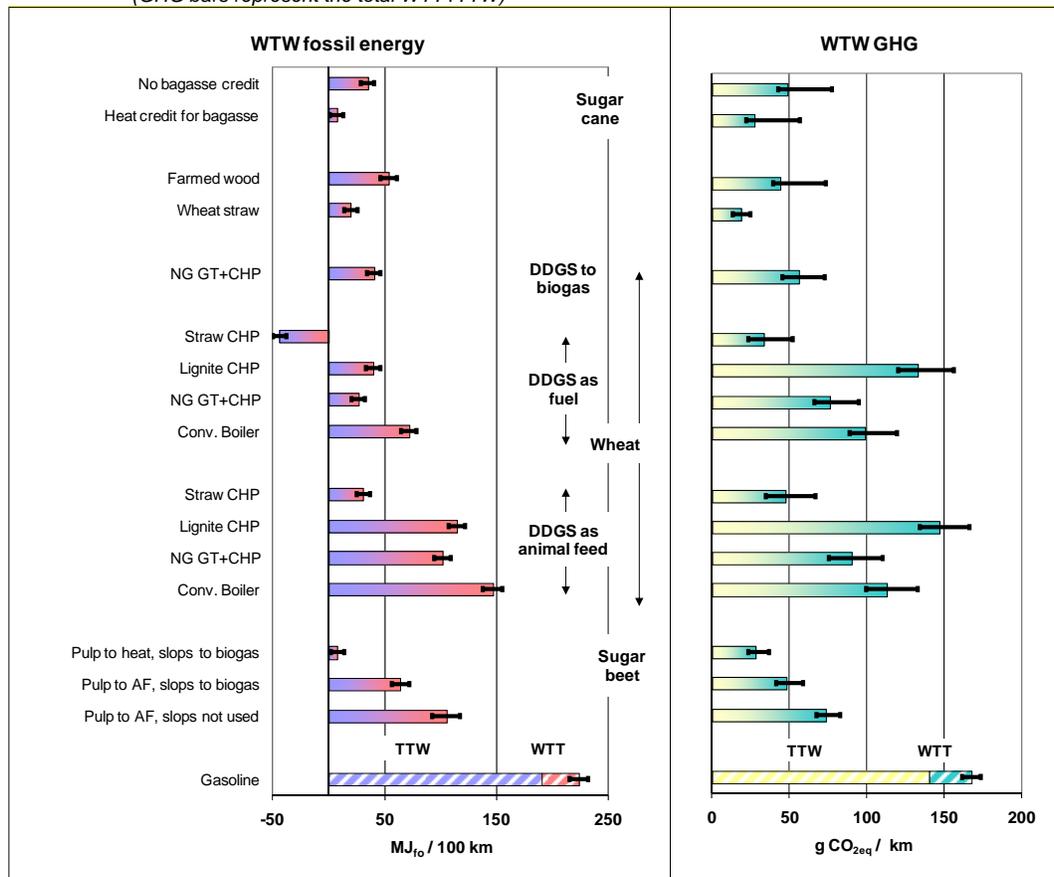
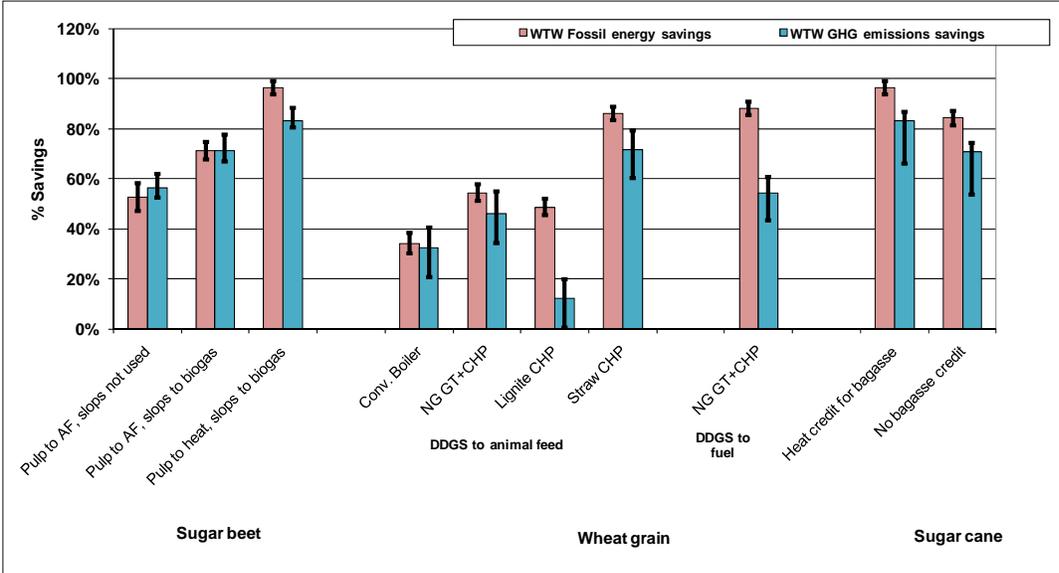


Figure 5.1.6-2 WTW fossil energy and GHG emissions savings for ethanol pathways compared to conventional gasoline- - (2010+ vehicles)



Use of co-generation particularly in combination with a gas-fired gas turbine can significantly improve these figures to 55% for fossil energy and 46% for GHG emissions. Even with the advantage of CHP, using coal wipes out most of these gains for GHG emissions. Straw burning is of course very favourable from this point of view but has other limitations as discussed below.

The sugar beet pathways are more favourable delivering between 53% fossil energy and between 56% GHG savings respectively in the base case where pulp is used for animal fodder and slops are discarded.

Using by-products for energy production rather than animal feed has a very large positive impact as more of the biomass is used towards energy production. Using DDGS to produce biogas improves the wheat-to-ethanol scheme savings to 82% fossil energy and 66% GHG emissions. In the sugar beet case, using slops to produce biogas significantly increases the savings. In principle pulp could also be used to produce biogas which would result in very high savings of 97% fossil energy and 83% GHG emissions. At the moment, and as long as the EU imports animal feed components such as soy meal, economics are, however, unlikely to favour use of co-products such as DDGS and sugar beet pulp as fuels.

For most pathways the error bars are noticeably larger for GHG than for energy because of the wide range of possible nitrous oxide emissions.

Advanced processes (from wood or straw) can also result in high savings, mostly because these processes use part of the biomass intake as fuel and therefore involve little fossil energy. The relatively large difference between the straw and wood case stem almost entirely from the process chemicals requirements indicated in the literature reference used. This is another indication that the actual processing scheme used is not indifferent to the final outcome in terms of energy and GHG.

For sugar cane "bagasse", the leftover after extraction of the sugar, is a convenient and abundant fuel for which there is no alternative use and which can meet all the needs of the processing plant. In the best cases surplus heat or electricity can be produced, further boosting the energy balance (we have accounted for a heat surplus displacing heating oil).

Bio-diesel

Figure 5.1.6-3 shows the WTW fossil energy requirement and GHG emissions for a number of bio-diesel pathways. **Figure 5.1.6-4** shows the same information expressed as % savings compared to conventional diesel fuel.

Bio-diesel is less energy-intensive than ethanol as the manufacturing process involves only relatively simple, low-temperature / low pressure steps. In GHG terms the picture is different because of the nitrous oxide emissions which account for an important fraction of the total and for most of the large variability ranges.

The impact of the fate of the glycerine by-product is discernable but much less marked than was the case for e.g. wheat DDGS. Note that the manufacture of the chemical products substituted by the glycerine is very energy-intensive, so that, in this case, economics are likely to accord with GHG saving. Animal feed is the next most economic route (more valuable than fuel), but gives the lowest GHG savings. Using the cake for producing energy (biogas) would indeed tremendously increase the GHG savings but, as mentioned above for DDGS, it is currently unlikely to be economically justified.

With cake used as animal fodder, RME (Rapeseed Methyl Ester) can save up to 70% of the fossil energy and 52% of the GHG emissions required for conventional diesel fuel. This could increase to 101% and 68% if cake was used for biogas production. As would have been expected the balance of REE (Rapeseed Ethyl Ester) is somewhat more favourable than that of RME because of the use of partly renewable ethanol. SME (Sunflower seed Methyl Ester) gives even more favourable results for a variety of reasons including a smaller requirement for fertilisers. Most of the intensive farming areas of Europe are, however, more favourable to rape and this crop provides virtually all the European bio-diesel production today.

Soy bean biodiesel is a particularly tricky pathway to treat using the substitution methodology, because of the high proportion of soy meal by-product compared to the oil. The choice of substitution for soy meal is especially difficult because soy meal is itself the main “swing-provider” of protein in animal feed. The net GHG savings depend very strongly on how the credit for the soy meal by-product is calculated. We have taken as the principal pathway soy bean farming in Brazil and crushing in Europe, with the meal replacing soy meal which would otherwise be imported from Brazil. In this way, the shipping to EU of the soy meal fraction of the soy beans is cancelled by the credit from avoided soy meal import. The resulting SYME pathway is more energy-intensive than RME and also potentially leads to more GHG emissions. The latter, however, have a very large uncertainty range mostly because of the uncertain field N₂O emissions, compounded in this case by the large amount of meal co-product.

Palm oil methyl ester (POME) is less energy intensive than RME. The associated GHG emissions are much impacted by management of the plant effluent which is traditionally sent to an open pond where methane is released during the treatment process. Capturing this methane can tremendously reduce the overall footprint but this is not yet general practice.

It has also to be noted that there is much debate regarding the impact of increased Soy and Palm oil production on deforestation and, in the latter case, peatland drainage potentially leading to very large indirect GHG emissions. These effects are not included in the present figures.

Figure 5.1.6-3a/b WTW fossil energy requirement and GHG emissions for bio-diesel pathways (2010+ vehicles)
 (GHG bars represent the total WTT+TTW)

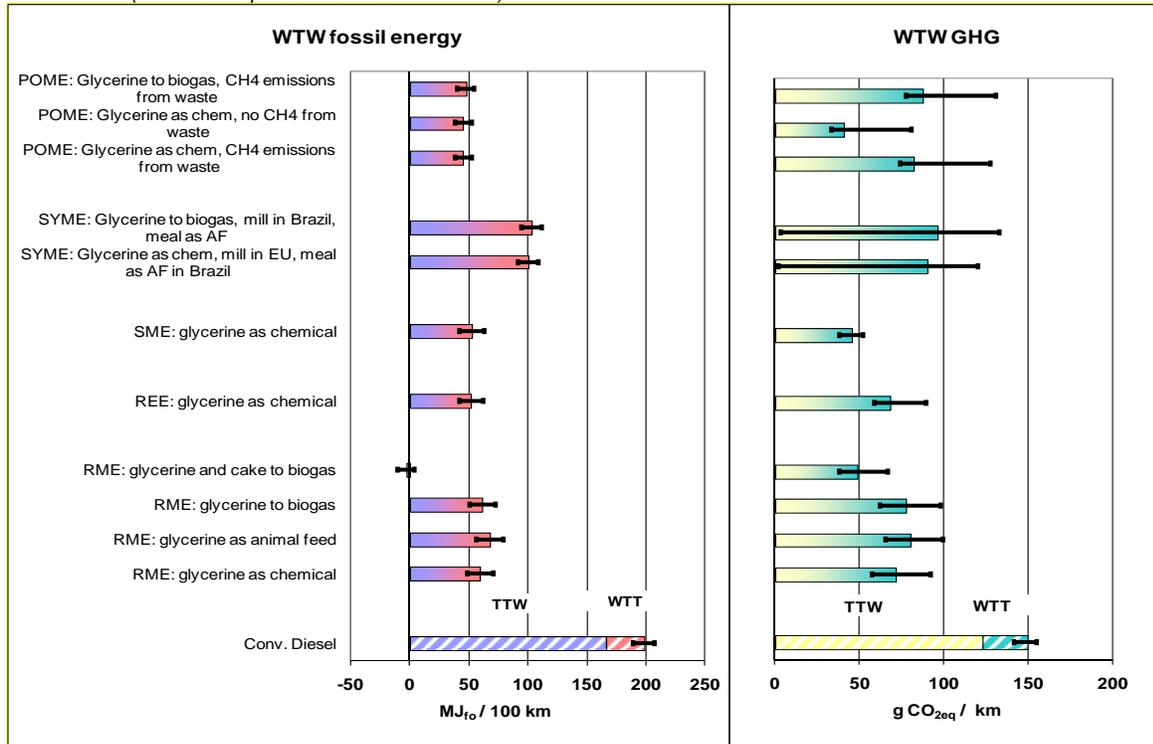
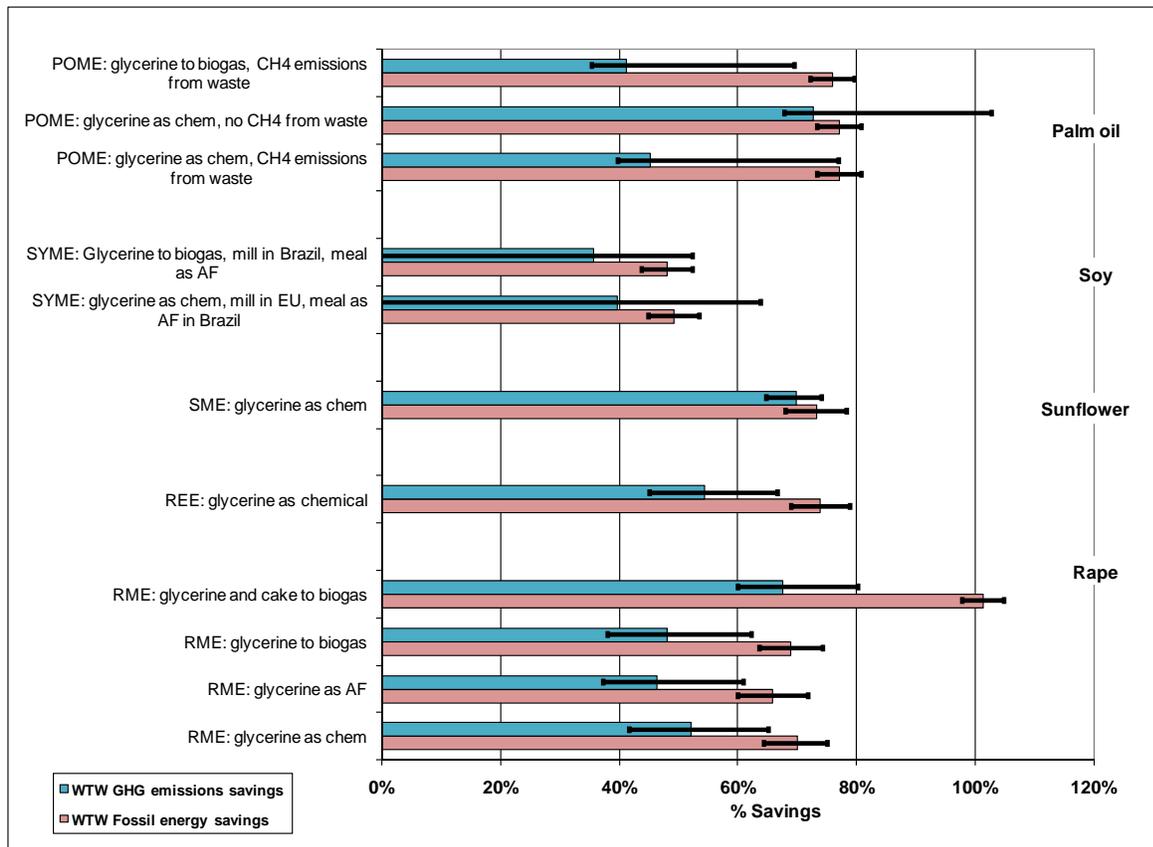


Figure 5.1.6-4 WTW fossil energy and GHG emissions savings for bio-diesel pathways compared to conventional diesel fuel - (2010+ vehicles)



Hydrotreated vegetable oil

Figure 5.1.6-5 shows a selection of HVO pathways compared to the corresponding bio-diesel from the same oil. Figure 5.1.6-6 shows the same information expressed as % savings compared to conventional diesel fuel.

Although hydrogen manufacture is energy and GHG intensive (we have assumed it is made by steam reforming of natural gas), this is compensated by the higher energy content of the final product as compared to conventional bio-diesel. Overall HVO is slightly somewhat more energy-intensive than a bio-diesel from the same oil and very slightly more GHG-intensive, although the uncertainty ranges are overlapping. There is a small difference between the two technologies considered, although not significant for GHG emissions.

Figure 5.1.6-5a/b WTW fossil energy requirement and GHG emissions for selected HVO and bio-diesel pathways - (2010+ vehicles)

(GHG bars represent the total WTT+TTW)

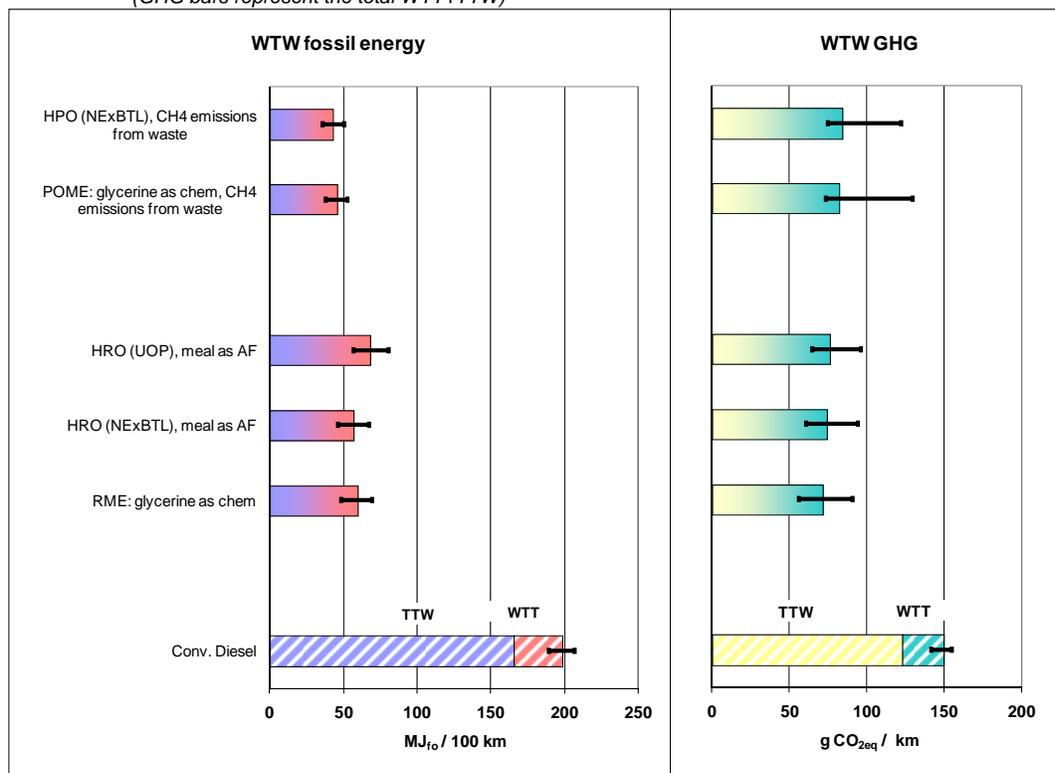
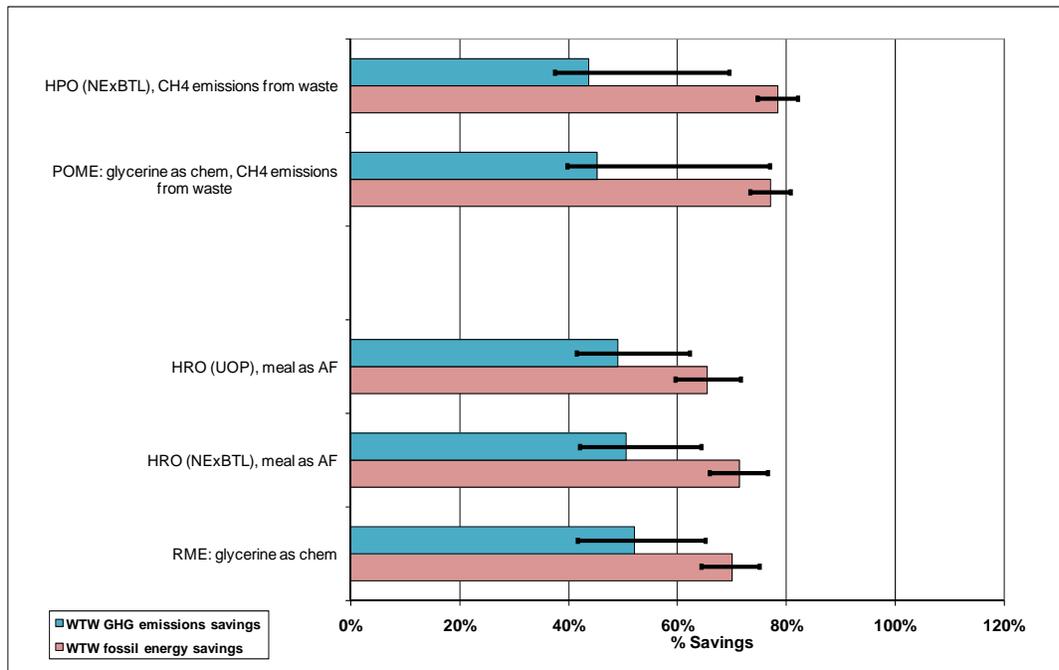


Figure 5.1.6-6 WTW fossil energy and GHG emissions savings for selected bio-diesel and HVO pathways compared to conventional diesel fuel - (2010+ vehicles)



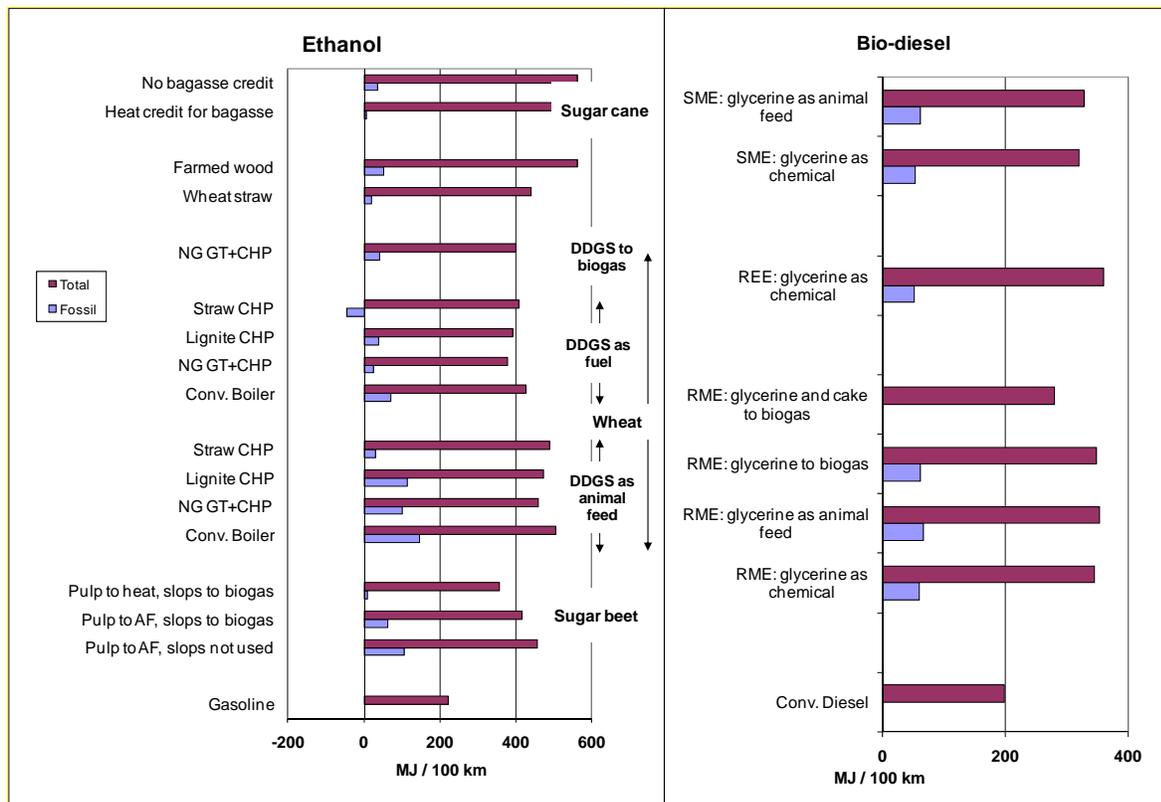
The fossil energy and GHG savings of conventionally produced bio-fuels such as ethanol and bio-diesel are critically dependent on manufacturing processes and the fate of by-products.

The GHG balance is particularly uncertain because of nitrous oxide emissions from agriculture.

When upgrading a vegetable oil to a road fuel, the esterification and hydrotreating routes are broadly equivalent in terms of GHG emissions.

The fossil energy savings discussed above should not lead to the conclusion that these pathways are energy-efficient. Taking into account the energy contained in the biomass resource one can calculate the total energy involved. **Figure 5.1.6-4** shows that this is several times higher than the fossil energy involved in the pathway itself and two to three times higher than the energy involved in making conventional fuels. These pathways are therefore fundamentally inefficient in the way they use biomass, a limited resource.

Figure 5.1.6-4a/b *WTW total versus fossil energy*



5.1.7 Impact of land use changes on GHG balances

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 the carbon released would negate the GHG savings of biofuels for many decades. Similar considerations apply to use of forest land for short rotation forestry.

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.**

Currently, government aspirations for biofuel production go beyond the levels that can be produced on existing arable land: the Renewable Energy Directive mandates 10% renewable energy in transport energy by 2020, and the US ethanol mandate calls for 36 million US gallons of ethanol by 2022, enough to replace about a quarter of US gasoline consumption. There is an on-going debate regarding the indirect impact of such policies on land utilisation in Europe, the USA and the rest of the world. This is a complex issue involving many parameters and variables and the outcome is highly uncertain. In this study we have purposely not taken into account such impacts which should therefore be added whenever a consensus is formed with regards to methodology and magnitude.

Land use changes are discussed in more depth in *WTT Report, Section 3.4.1.*

5.1.8 Other environmental impacts of biofuels production

Soil quality/erosion

Sugar beet can cause soil erosion, especially if grown on the light soils typical of southern Europe. New techniques of inter-sewing between cover crops can help. However, we do not expect that sugar

beet production would spread beyond areas of northern Europe with heavy 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 plants.

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 energy crops instead of permanent crops and on “nature” land now in voluntary set-aside, would decrease biodiversity. A 2004 study by the European Environmental Agency 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 the 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

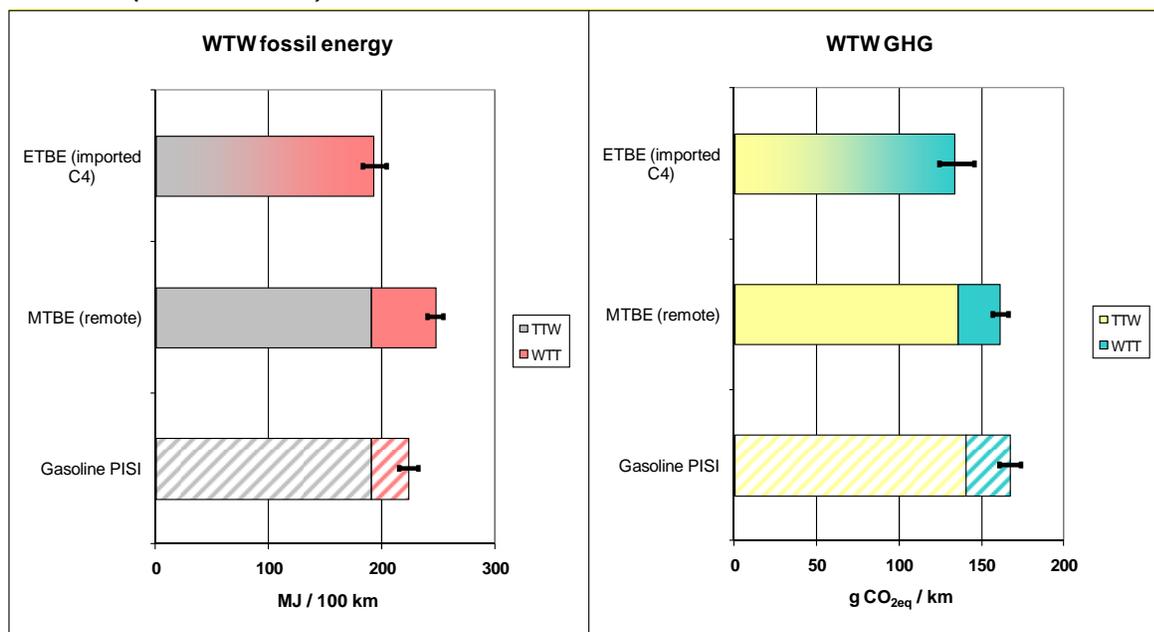
There is some risk that non-native energy crops could spread in the wild, because they lack natural predators. Using sterile varieties (including GMOs) greatly reduce this risk. Some are concerned about GMOs in general, though.

5.2 MTBE and ETBE

Methyl-Tertiary-Butyl Ether or MTBE is a high octane blending component for gasoline. MTBE was widely used in US gasoline until water contamination issues led to it being withdrawn in some areas.

In Europe MTBE was introduced as one of the measures to recover octane after phasing out of lead in gasoline.

Figure 5.2a/b WTW fossil energy requirement and GHG emissions for MTBE and ETBE pathways (2010+ vehicles)



Note: Ethanol for ETBE assumed to be from wheat, NG gas turbine CHP, DDGS to animal feed (see section 5.1).

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.

Ethanol can be used as a substitute to methanol to produce ETBE (Ethyl-Tertiary-Butyl Ether) which has very similar properties to MTBE. The main advantage of ETBE over ethanol as a gasoline component is its low vapour pressure. 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.

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.

MTBE requires more energy than gasoline although the GHG balances are more or less the same because MTBE manufacture uses essentially natural gas as energy source. ETBE has a lower fossil energy and GHG footprint as a result of the partial "renewability" of ethanol.

The case of "refinery" ETBE is described in the table below (see also *WTT report, section 4.7*).

Table 5.2 WTW fossil energy and GHG emissions balances for "refinery" ETBE

Use of ethanol	Fossil energy MJ _{xfo} /MJ _{EtOH}	GHG g CO _{2eq} / MJ _{EtOH}
As ethanol	0.53	45.8
As ETBE	0.28	41.0
<i>Gasoline (for ref.)</i>	<i>1.14</i>	<i>85.9</i>

Overall, using ethanol as ETBE, through replacing methanol in a refinery, results in lower fossil energy and consumption and marginally lower GHG emissions than would be the case when using ethanol as such. The reason is that it is equivalent to eliminating methanol and replacing it by extra gasoline which has a significantly lower energy footprint and marginally lower GHG emissions.

With more favourable blending properties than ethanol, ETBE can provide an alternative to direct ethanol blending into gasoline. Fossil energy and GHG gains are commensurate with the amount of ethanol used.

5.3 Synthetic diesel fuel and DME

5.3.1 Sources and manufacturing processes

Synthetic diesel fuel

By synthetic diesel fuel we mean the product made by Fischer-Tropsch (FT) synthesis from "syngas" the mixture of carbon monoxide and hydrogen obtained by partial oxidation of hydrocarbons (e.g. coal) or wood or by steam reforming of natural gas. The products of this process scheme are long-chain paraffins essentially free of sulphur and other impurities.

A hydrocracking unit is usually included in the FT process scheme to control the type of product being produced by splitting the chains appropriately. The main commercial products envisaged are diesel fuel (with or without the kerosene fraction), naphtha and some LPG. Most early plants are also likely to produce lubricant base oils and specialty products such as waxes but it anticipated that these markets will soon be saturated and future plants will concentrate on producing large volume products.

We have considered three routes i.e.

- From natural gas (known as Gas-to-Liquids of GTL),
- From coal (know as Coal-to-Liquids of CTL),
- From woody biomass (known as Biomass-to-Liquids or BTL).

GTL

The GTL process is technically well-established although the economics have, in the past, not been sufficiently favourable for large scale development to occur. This has been changing in recent years with a combination of technological advances and more favourable economics and a number of large scale plants are being built or are under design while more are being actively considered. All such plants will be built near a gas field usually at locations where the only alternative or bringing gas to market would be LNG.

There is a debate regarding the credits that should be allocated to GTL diesel compared to conventional diesel. Two studies by PriceWaterhouseCoopers (PWC) and one study by Nexant have

considered functionally equivalent hydrocarbon processing systems with and without GTL products, and calculated the energy and GHG balances for a portfolio of fuel products meeting the market demand. These 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 overall GHG emissions, thereby generating a credit for GTL diesel. In this way it is argued that the GHG emissions from the complete system are broadly equivalent for the scenarios with and without GTL fuels.

This study starts from the present situation with European oil refineries supplying the virtual entirety of the road fuels market. Within the timeframe considered 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 through which the energy and CO₂ emissions associated with a marginal change in either gasoline or diesel fuel production are estimated.

The key assumption made in the PWC and Nexant studies 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 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. We consider, however, that this is not an appropriate assumption in the 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.

CTL

Coal gasification is a well understood process that can be coupled to Fischer-Tropsch synthesis to deliver products very similar to GTL. There are very few plants in operation today but these schemes are attracting a lot of interest especially in combination with CO₂ capture and storage (see *section 8*).

BTL

Wood gasification is of the same nature than coal gasification although using biomass creates specific issues related to, amongst others, the mineral content of certain biomass feedstocks, problems of slagging etc, each biomass feed creating different problems. Adaptation of the Fischer-Tropsch synthesis to syngas of different origins revolves around purity, cleanliness and CO/H₂ ratio of the gas.

Another challenge is the scale at which such processes could be practically used. Integrated gasification and FT plants are complex and expensive with any feedstock and benefit enormously from economies of scale. Biomass as a low energy density and relatively dispersed feedstock does not fit well within the traditional industrial model and novel ways have to be developed to find acceptable compromises.

The current search for alternative transport fuels has increased the level of interest for the BTL route and a number of pilot and demonstration projects are at various stages of development. These will always be complex engineering projects and will require many practical problems to be resolved before they become reliable and commercially viable. The major challenges for achieving this should not be underestimated. The potential rewards from these processes in terms of feed flexibility, quality of the products and very low GHG emissions justify further research and development.

The pulp and paper industry may provide a promising route for making significant amounts of synthetic fuels from woody material. This is the so-called "black liquor" route. Black liquor is a by-product of paper pulping that contains the lignin part of the wood. It is commonly used as internal fuel to power the paper mills. Through gasification of the black liquor rather than simple burning one can

generate syngas and therefore synthetic fuels. The energy balance of the paper mill must then be re-established by burning additional waste or low value wood. The net result is production of synthetic fuels from wood at a very high combined efficiency.

DME

DME is to diesel what LPG is to gasoline. It is gaseous at ambient conditions but can be liquefied at moderate pressure. As a fuel for compressed ignition engines it has very attractive characteristics, burning very cleanly and producing virtually no particulates (a dedicated DME vehicle would probably not require a particulate filter but would need a purpose-designed fuel handling and injection system).

DME is synthesised from syngas and can therefore be produced from a range of feedstocks. The synthesis process is very similar to that of methanol and has a similar efficiency, somewhat higher than the efficiency of the synthetic hydrocarbons processes. The most likely feedstock in the short term is natural gas but coal or wood can also be envisaged. The black liquor route mentioned above is eminently suitable for DME (or methanol) and is in fact more likely to be developed to produce these fuels rather than BTL, chiefly in Scandinavia.

A dedicated distribution network and dedicated vehicles would be required. The practical and commercial magnitude of the task of building such a network, building and marketing the vehicles as well as customer acceptance must not be underestimated. Use of this otherwise attractive fuel in fleets may be worth considering in certain cases, albeit with specially adapted vehicles.

5.3.2 Energy and GHG balances

The GTL, CTL and BTL processes can produce a variety of products. When focussing on the diesel fuel product from these processes, one is confronted with the issue of allocation of production energy. Although diesel fuel often is the main product in volume terms, its fraction in the total product will not, in practice, exceed 75% (higher yields may be achieved by recycling lighter products but at a considerable cost in energy). Naphtha takes the largest share of the balance and can hardly be considered as a by-product being of the same nature as diesel fuel and usable in applications where it also would displace petroleum 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 (see also *WTT report, section 3.2.5*).

The combined process of primary energy conversion and FT synthesis is energy-intensive, more so for coal and wood than for natural gas. This is mainly because the overall process is more straightforward and more energy efficient with gas. Also future GTL and CTL plants are expected to be very large and highly heat integrated. This is likely to be less so in smaller wood conversion plants where the size may be dictated by the raw material availability/collection and such complexity may not be economically justified.

The GTL scheme represented is for a plant sited near a remote gas field. The high energy requirement for the conversion process is partly compensated by the lower transportation energy. The GTL pathway is notably more energy-intensive than conventional diesel fuel. In GHG terms the difference is small because of the beneficial effect of using natural gas rather than crude oil as primary energy source.

Figure 5.3.2-1 shows a selection of HVO pathways compared to the corresponding bio-diesel from the same oil. **Figure 5.3.2-2** shows the same information expressed as % savings compared to conventional diesel fuel.

Figure 5.3.2-1a/b WTW energy requirement and GHG emissions for synthetic diesel and DME pathways (2010+ vehicles)
 (GHG bars represent the total WTT+TTW)

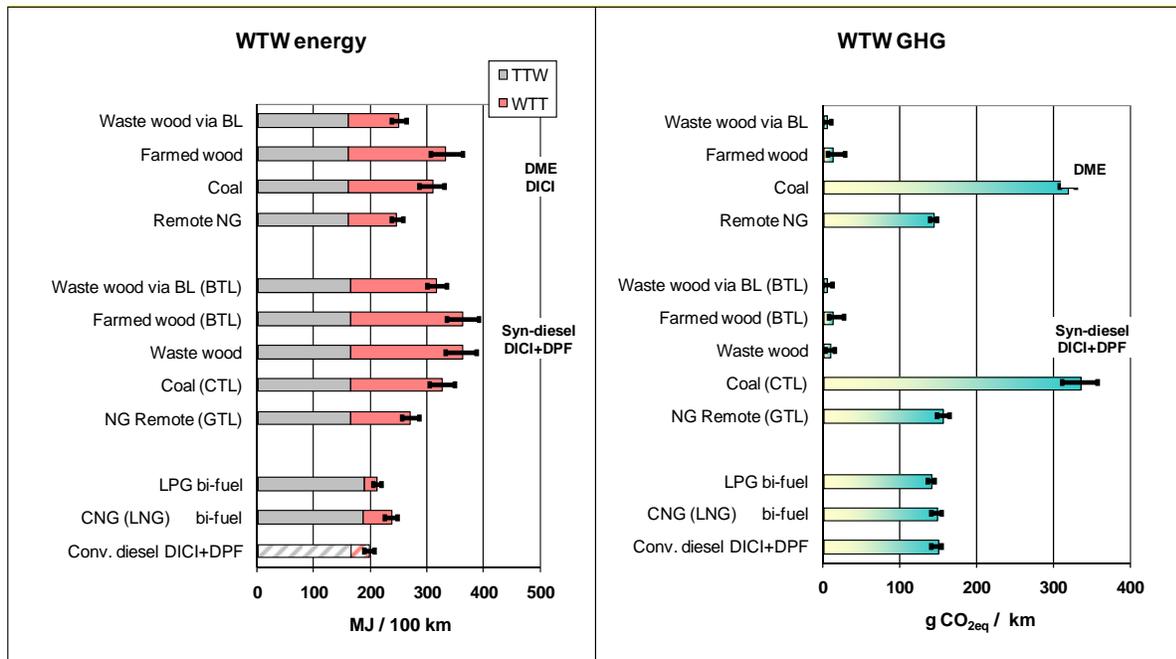
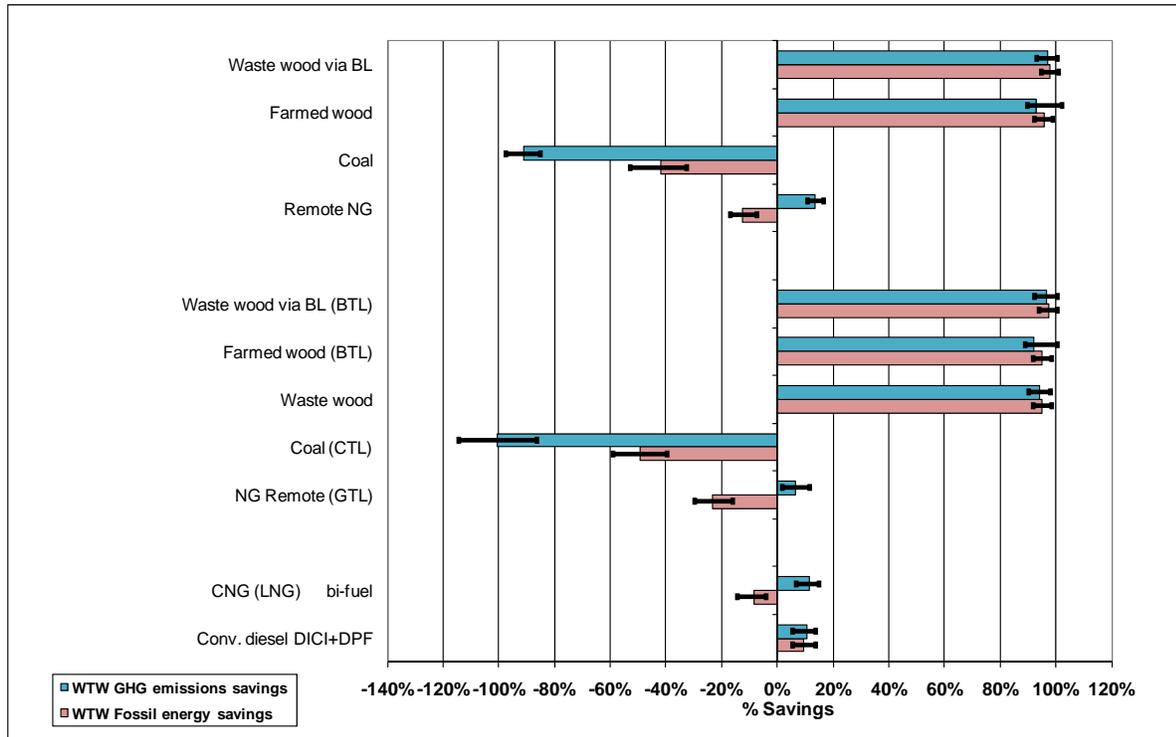


Figure 5.3.2-2 WTW fossil energy and GHG emissions savings for pathways compared to conventional diesel fuel - (2010+ vehicles)



High quality diesel fuel can be produced from natural gas (GTL) and coal (CTL). GHG emissions from GTL diesel are slightly higher than those of conventional diesel, CTL diesel produces considerably more GHG.

The higher efficiency of the synthesis process gives DME a slight advantage on the synthetic diesel fuel from the same source. In the DME process, the sole product is DME which translates into high

yield of fuel for Diesel engines compared to FT diesel in the case of which other products (mostly naphtha) are also produced.

DME can be produced from natural gas or biomass with better energy and GHG results than other GTL or BTL fuels. DME being the sole product, the yield of fuel for use for Diesel engines is high.

CNG obtained with liquefied gas from the same remote location is still more advantageous than either GTL diesel or DME in WTW both energy and GHG terms.

Here again the wood pathways hardly produce any GHG because the main conversion process is fuelled by the wood itself although they are not particularly energy efficient. The black liquor route (BL) is even more favourable with lower energy consumption and very low GHG emissions.

New processes are being developed to produce synthetic diesel from biomass (BTL), offering lower overall GHG emissions, though still high energy use. Such advanced processes have the potential to save substantially more GHG emissions than current bio-fuel options.

6 Hydrogen

Hydrogen as a transportation fuel conjures up images of quiet, efficient, non-polluting vehicles and is therefore the focus of much attention. Reality is of course more complex and both the desirability to develop hydrogen as a road fuel and the way to get there need to be considered very carefully.

Although hydrogen can be used in an internal combustion engine, the real efficiency breakthrough comes from fuel cells, the commercial development of which is a crucial issue.

As the lightest of all gases, hydrogen has a low energy density and must be either compressed at very high pressures or liquefied at very low temperatures to be stored in any meaningful quantity. This presents significant challenges particularly for mobile applications.

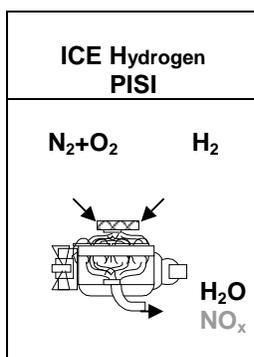
Hydrogen is not a primary energy source but an energy vector. Although it is the most widespread element in the universe, free hydrogen does not occur in nature. It needs to be “extracted” from compounds such as hydrocarbons and of course water, at the cost of an energy input. This results in emissions of GHG to varying degrees depending on the source of that energy and the specific pathway chosen.

There are many possible routes to a “hydrogen alternative” leading to a very wide range of energy usage, GHG emissions and costs. If the WTW approach is required when considering any transport fuel, it is absolutely essential for hydrogen where a large part of the energy usage and all of the GHG emissions occur at the production stage.

In this section we first consider the “hydrogen users” i.e. the vehicles and powertrains that can use hydrogen as a fuel. Based on their requirements we then examine the routes to produce, transport and distribute hydrogen.

6.1 Hydrogen-fuelled powertrains and vehicles

6.1.1 Hydrogen Internal Combustion Engine



PISI internal combustion engines can be adapted to burn hydrogen. The high temperature combustion process results in the production of traces of NO_x (the N_2O part of which was accounted for as GHG in our calculations, even if practically insignificant). NO_x emissions can be further reduced e.g. through a lean burn strategy. These vehicles are considered by California Air Resources Board as AT-PZEV regarding regulated pollutants. The maximum efficiency of these hydrogen ICEs is expected to be very close to the best 2010 Diesel engines. Although more advanced and efficient hydrogen engines can be envisaged, the same technologies can also be applied to gasoline and natural gas engines.

Hydrogen can be carried on board the vehicle either in compressed form at ambient temperature ($C-H_2$) in a high-pressure vessel, or in liquid form at atmospheric pressure ($L-H_2$) in a cryogenic tank. Although early prototypes have used pressures of 35 MPa, it is anticipated that 70 MPa will become the standard. This pressure level is necessary to store a sufficient quantity of hydrogen in a reasonable volume to provide a realistic vehicle range. For the same quantity of hydrogen, the $C-H_2$ tank is slightly heavier than the $L-H_2$ tank, slightly increasing the total mass of the vehicle. $L-H_2$ does, however, require some energy for vaporisation prior to use as well as additional equipment to reduce

boil-off so that, in practice there is no significant difference in energy efficiency terms between the two options. The use of liquid hydrogen also poses the problem of long term storage as heat ingress into a tank at some -253°C cannot be avoided, and there is a gradual loss of hydrogen from the tank if the vehicle is not used for some time. Compression or liquefaction account for a significant portion of the WTW energy requirement.

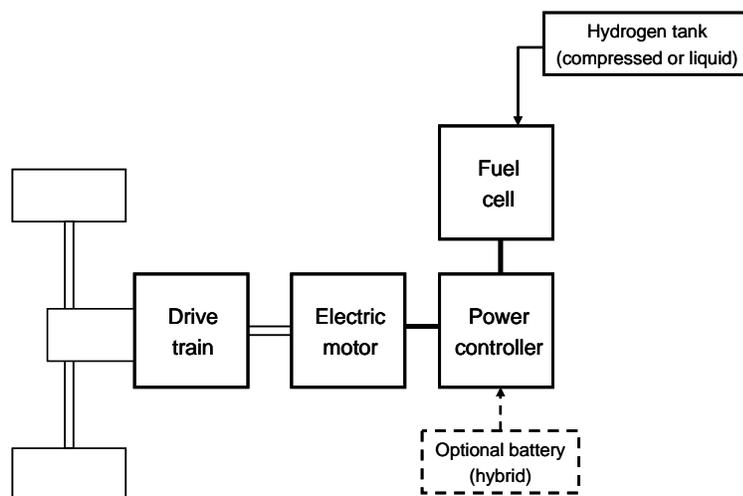
Table 6.1.1 2010 hydrogen ICE vehicles characteristics

		PISI	
		C-H ₂	L-H ₂
Powertrain			
Displacement	l	1.3	1.3
Powertrain	kW	77	77
Engine mass	kg	120	120
Gearbox mass	kg	50	50
Storage System			
Tank pressure	MPa	35/70	Atmo.
Tank net capacity	kg	9	9
Tank mass empty	kg	120	109
Tank mass increase including 90% fuel	kg	85	74
Vehicle			
Reference mass	kg	1181	1181
Vehicle mass	kg	1266	1255
Cycle test mass	kg	1360	1360
Performance mass	kg	1406	1395

6.1.2 Fuel Cells

Fuel cells (FC) are chemical converters fed by gaseous hydrogen and ambient air, producing DC voltage/current, heat and water. Their principal attraction is their high energy conversion efficiency compared to thermal engines. If fuelled directly by hydrogen they emit no pollutants at the point of use, and so have true ZEV capability. The configurations of the two FC vehicle options considered in the study are schematically represented below.

Fig 6.1.2 2010 “direct” hydrogen FC powertrains



One of the many challenges facing FC developers is to reduce the heating up time to normal operation. The additional large battery pack in the hybrid FC offers the possibility to start on the battery without waiting for the FC heating delay, and also to benefit from braking energy recovery. The downside is of course the additional mass and cost.

With regard to on-board hydrogen storage the options are the same as for ICEs (i.e. compressed or liquid). Fuel cells being more efficient than ICEs, a smaller quantity of hydrogen is necessary to comply with the range criterion and the tank can therefore be smaller and lighter. No significant difference in overall fuel efficiency is expected between the two fuel storage options.

Table 6.1.2 Mass characteristics of 2010 hydrogen FC vehicles
(all figures in kg)

	Non Hybrid		Hybrid		Hybrid+reformer	
	C-H ₂	L-H ₂	C-H ₂	L-H ₂	Gasoline ⁽¹⁾	Methanol
Powertrain mass substitution						
Engine mass	-120	-120	-120	-120	-120	-120
Gearbox mass	-50	-50	-50	-50	-50	-50
Fuel Cell						
Fuel cell stack mass	150	150	150	150	150	150
Reformer mass	0	0	0	0	90	90
Cooling system additional mass	50	50	50	50	50	50
Electric parts						
Battery mass	0	0	20	20	40	40
Electric motor+electronics mass	73	73	73	73	73	73
Storage System						
Tank netto capacity	4.7	4.7	4.2	4.2	23	45
Tank mass empty	69	57	56	51	15	15
<i>Tank mass increase including 90% fuel</i>	30	18	16	11	-8	12
Vehicle						
Enlarged vehicle additional mass	50	50	50	50	50	50
Reference mass	1181	1181	1181	1181	1181	1181
Vehicle mass	1364	1352	1370	1365	1456	1476
Cycle test mass	1470	1470	1470	1470	1590	1590

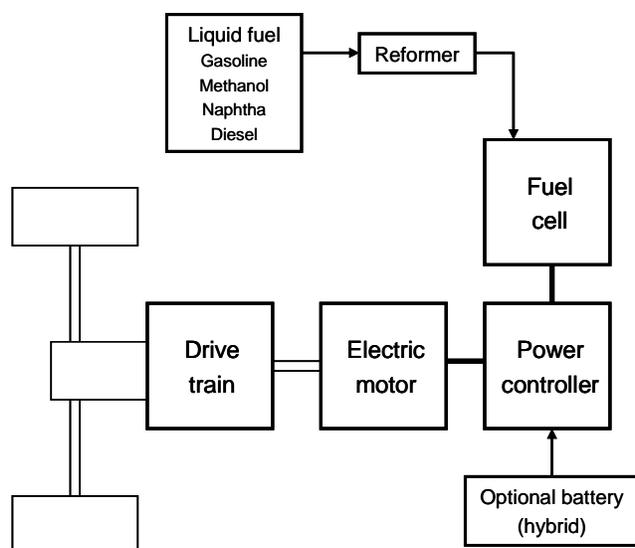
⁽¹⁾ also valid for naphtha and diesel

6.1.3 Indirect hydrogen: on-board reformers

As an alternative to a hydrogen infrastructure and the range of issues and challenges it raises, hydrogen generation from a liquid fuel on-board the vehicle has been proposed.

Such vehicles would be equipped with small scale reformers, able to convert gasoline, methanol, naphtha or even diesel fuel into hydrogen which is then directly fed to the fuel cell. These vehicles represent a completely different approach combining on-board hydrogen production and usage. The advantages of avoiding the hydrogen distribution infrastructure and on-board storage are counterbalanced by the much greater complexity of the vehicle, the challenge of building a reformer that is small and efficient, the control system involving the reformer, the fuel cell and their interface, and the additional vehicle mass. Using “normal” liquid fuels, these vehicles also emit CO₂ and other pollutants. Here again the WTW approach is the only way to validly compare this option with others.

Fig 6.1.3 2010 Indirect FC vehicles



6.2 Hydrogen production routes and potential

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 of water.

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 (essentially methane). 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 CO₂ and hydrogen. 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 and coal, as well as biomass feeds such as wood. 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.

In these processes and particularly for heavy feedstocks, the bulk of the hydrogen comes from water, the carbon in the feed providing the energy required for splitting the water molecule.

Reformers and gasifiers produce CO₂ at a single location and, when using oxygen rather than air, in a virtually pure form. Large scale installations may offer a viable platform for possible CO₂ capture and sequestration projects (see also *section 7*).

Electrolysis uses electricity to split the water molecule. This is a well-established technology both at large and small scale. Interest in large scale hydrogen production may result in improvements in terms of efficiency and costs. One particularly promising development route is high pressure electrolyzers (higher production pressure means less compression energy for storage). 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 thermal splitting process is in its infancy while photovoltaic electricity is not expected to be viable at very large scale within the timeframe of this study. We have therefore not included these options.

For on-board hydrogen production, several options are in principle available. From a purely technical point of view, methanol is likely to be the most attractive as the reformer would operate at comparatively low temperatures and would be more tolerant to intermittent demand. Using methanol would once again open the issue of infrastructure and distribution. Gasoline may be the only practical one as it is already available on the forecourts and would enable these vehicles to be introduced even in very small numbers.

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 and needs more research. Biomass is of course an option but of a limited nature particularly as they are many other potential uses for biomass (see *section 9*). The same constraint applies to wind energy which can 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 give more benefit than electricity generation. Nuclear energy is potentially a very large supplier of energy with currently low GHG emissions, and could contribute to the supply of hydrogen. However, its development opens societal, political as well as technical issues (*uranium ore availability & extraction process*), the discussion of which *is not considered* in this report.

6.3 Distribution and refuelling infrastructure

As mentioned in the previous section, hydrogen production can be envisaged either centrally in a large plant or, in a number of cases, locally in a small plant serving one or a few refuelling sites. This “on-site” option is plausible for natural gas reformers, wood gasifiers and electrolyzers.

Although central plants tend to be more efficient, the downside is the need to transport hydrogen rather than e.g. natural gas or wood. Technologies are available for this and are in use in the industrial hydrogen transport networks in existence in Europe and other parts of the world. Hydrogen is commonly transported in gaseous form in pipelines and road pressurised cylinders or as a liquid in cryogenic tanks (mostly by road).

The development of a large scale hydrogen pipeline distribution network likely requires a European regulatory framework to ensure safety and public acceptance. Existing hydrogen pipelines in Europe link major industrial sites over relatively short distances and would be of limited use in this respect.

For small volumes, transport of gaseous hydrogen using tube trailers is feasible, but the mass of the containers is very high compared with the amount of hydrogen transported. It has been estimated that up to 19 trucks might be needed to deliver the same amount of energy delivered by one gasoline truck.

Even in liquid form, hydrogen remains a low-density energy carrier with implications on the options for road distribution channels (as an illustration supplying a hydrogen refuelling site might take five times as many trucks as is the case for conventional fuels).

This study includes options for pipeline distribution (over an area typical of a major urban community), road transport in pressurised cylinders or in liquid form in cryogenic tanks, as well as distributed hydrogen generation schemes that would reduce the transport problems.

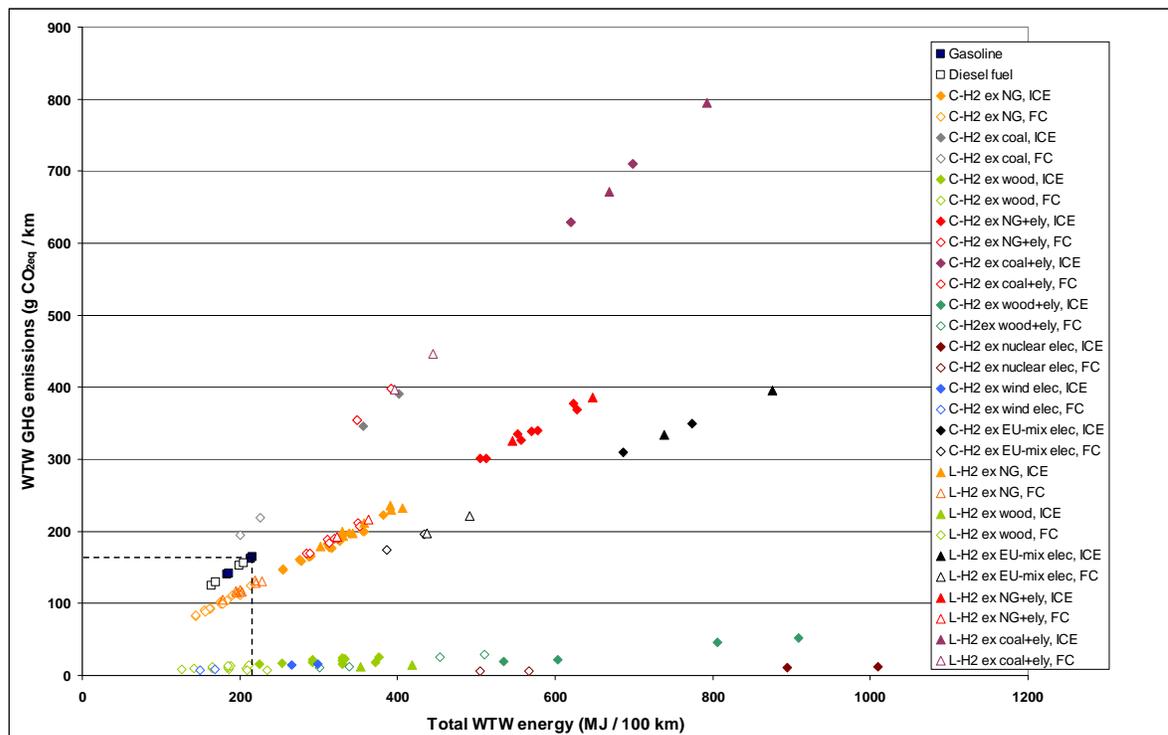
For the refuelling stations, considerations similar to those applicable to CNG apply. Hydrogen dispensers operating at pressures of either 35 or 70MPa have been built and tested, demonstrating safe and reliable refuelling in a public environment.

6.4 Energy and GHG balances

We have considered a large number of alternatives hydrogen pathways and the reader may refer to *Appendix 1* of this report or to *the WTT and TTW reports* for details. In this section we only discuss some of the options to illustrate the most important findings.

The combination of the many routes available for hydrogen production with the choice of final converters makes the global picture rather complex as illustrated in *Figure 6.4*.

Figure 6.4 WTW energy requirement and GHG emissions for hydrogen pathways (2010+ vehicles)



The WTW figures show a very large spread suggesting that, from an energy and GHG point of view, there are favourable and unfavourable ways of producing hydrogen. GHG reduction tends to be at the cost of extra energy although the high efficiency of the fuel cells can compensate for the high hydrogen production energy. Pathways based on electrolysis are very energy-intensive, reflecting the relatively low energy efficiency of electricity generation compared with chemical extraction of hydrogen.

Many potential hydrogen production routes exist and the energy and GHG balances are critically dependent on the pathway selected.

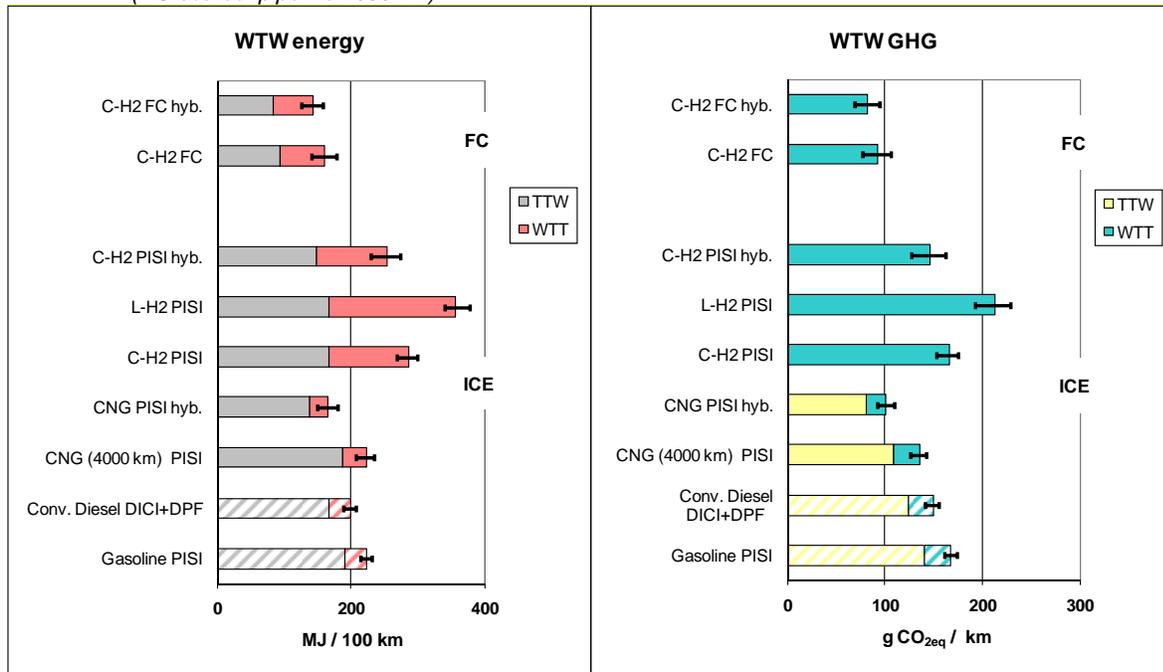
There is clearly a big difference between ICE and fuel cells with respect to energy use and GHG emissions. We first consider in more detail the effect of the final converter on the WTW performance by comparing various vehicles fed with hydrogen produced from natural gas. Focussing then on the fuel cell, we compare the different production routes available.

6.4.1 The impact of the vehicle technology

ICEs and direct fuel cells

Figures 6.4.1-1a/b compare the WTW performance of hydrogen ICE and FC vehicle options, for a common hydrogen source based on NG, to conventional fuel/vehicle and CNG pathways.

Figure 6.4.1-1a/b WTW total energy requirement and GHG emissions for conventional, CNG and natural gas based hydrogen pathways (2010+ vehicles)
 (NG source: pipeline 4000 km)



Although hydrogen ICEs have a good fuel efficiency, their WTW balance is unfavourable compared to direct use of NG as CNG. The vehicle cost increase is moderate and these vehicles could potentially be bi-fuel (gasoline-hydrogen). If used as a transition technology to support the development of a hydrogen infrastructure this would be at the cost of significant additional GHG emissions.

For ICE vehicles, direct use of NG as CNG is more energy/GHG efficient than hydrogen

This holds for C-H₂ and even more so for L-H₂ which requires noticeably more energy.

Liquid hydrogen is more energy intensive than compressed hydrogen

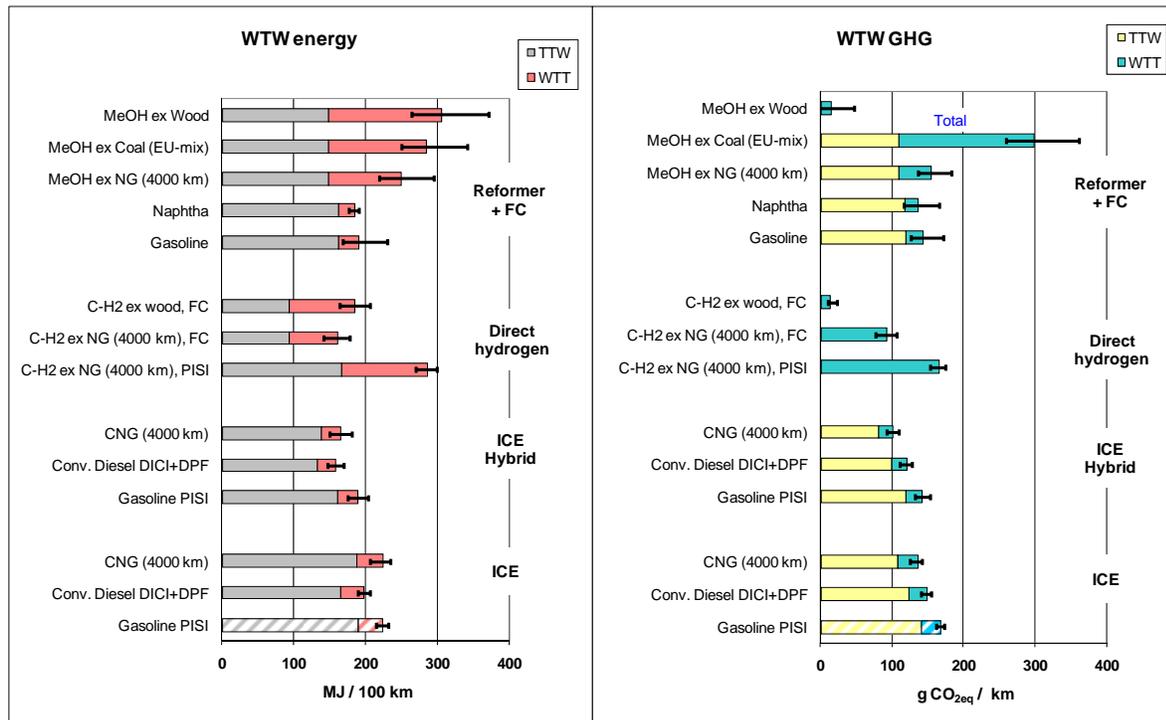
With fuel cells the hydrogen alternative becomes clearly better.

If hydrogen is produced from natural gas, WTW GHG emissions savings can only be achieved with fuel cell vehicles.

Note: in all these pathways the energy and GHG profiles are very similar as the bulk of the primary energy is expended in the form of natural gas.

Combined on-board reformers and fuel cells

Figure 6.4.1-2a/b WTW total energy requirement and GHG emissions for indirect hydrogen pathways (2010+ vehicles)



The combination of reforming of a hydrocarbon feedstock and of a fuel cell is less favourable than the direct route to hydrogen from NG combined with a fuel cell. The main reason for this is the lower expected efficiency of the on-board reformers because of their small size. Reforming of heavier feedstocks is also likely to be less efficient than is the case for natural gas while the GHG balance is further affected by the lower H/C ratio of heavier compounds.

With gasoline as the fuel, the on-board reformer option would do slightly better than the ICE but would be on a par with a hybrid version. Its main advantage would be as a transition technology to help growth of the fuel cell market.

On-board hydrogen production associated to a fuel cell

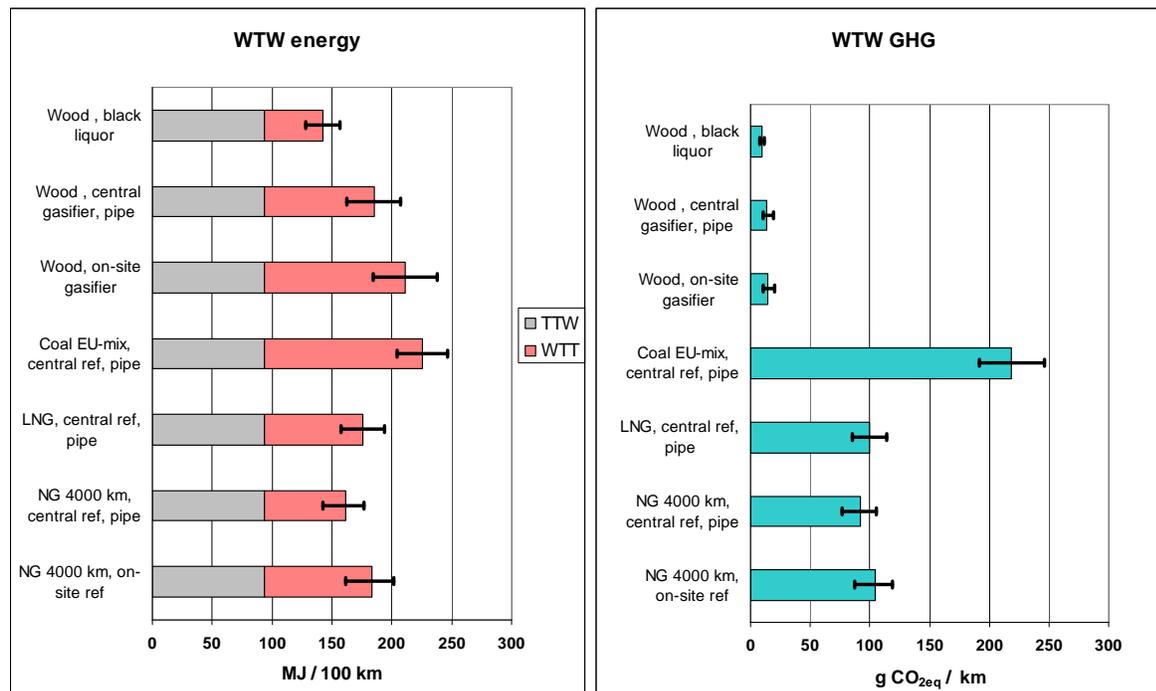
- Is more energy and GHG intensive than options using stationary hydrogen production,
- Does not offer any GHG benefit compared to advanced ICEs / hybrids.

Methanol provides a vector to use natural gas and other non-liquid feeds for such vehicles but is penalised by the energy loss attached to the methanol synthesis. For natural gas this is partly compensated by the more favourable H/C ratio but there is still no advantage compared to more conventional solutions. Wood of course provides a low GHG route but there are other ways to use wood in a more efficient manner (*see section 9*).

6.4.2 The impact of the hydrogen production route

Direct hydrogen production

Figure 6.4.2-1a/b WTW total energy requirement and GHG emissions for direct compressed hydrogen pathways (2010+ non-hybrid fuel cell vehicles)



Natural gas reforming is more efficient when carried out centrally in a large plant, where waste energy can be recovered to produce electricity, rather than in a small local or on-site plant because, where this is not practical. In energy terms the contribution of hydrogen transport to the total is minor.

The source of natural gas plays a role through the transportation energy to deliver gas to Europe.

Gasification processes tend to be less energy-efficient than natural gas reforming because of the nature of the feedstock.

The GHG picture is very much consistent with the type of primary feedstock used.

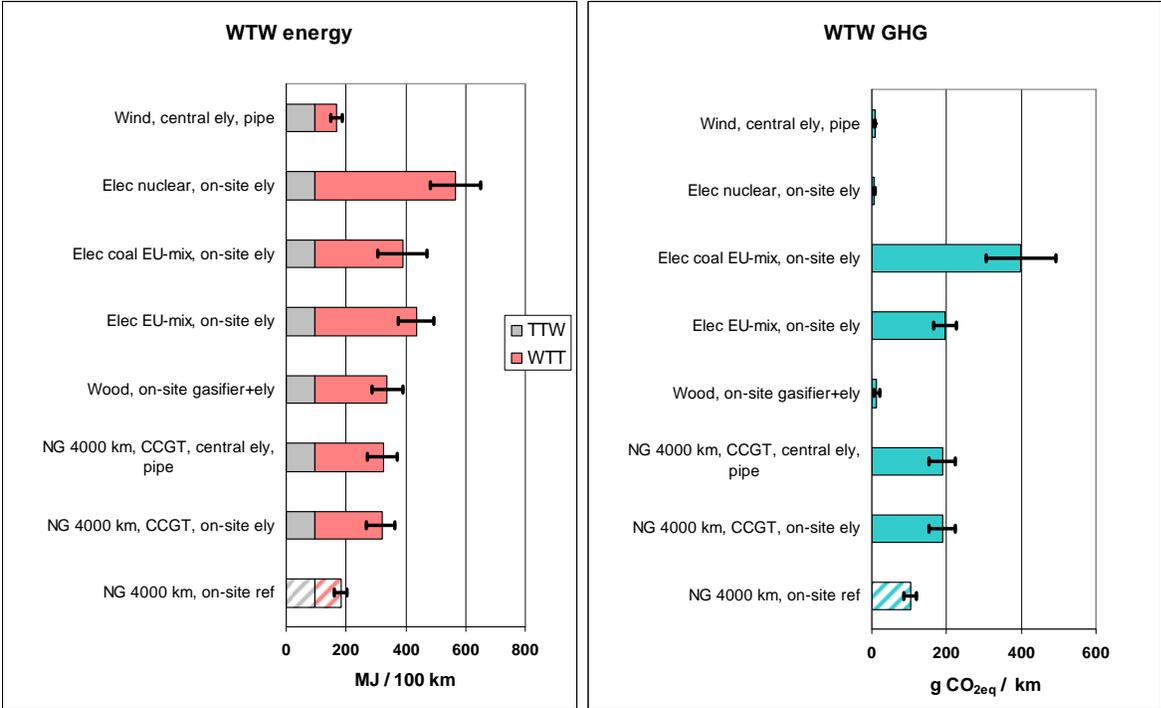
Hydrogen via electrolysis

Turning primary energy into electricity and then electricity into hydrogen is not an energy-friendly route. Even when combined with the most efficient converter, the energy consumption remains higher than for conventional fuels and powertrains.

Note that the energy balance for wind and nuclear energy are somewhat arbitrary. In the case of wind, it is common practice to consider the electricity output of the wind turbine as primary which explains the seemingly low energy requirement. For nuclear, the balance is based on the energy released by the nuclear reaction.

Non-carbon routes obviously emit practically no GHG but here again the real issue for those is optimum use of limited resources (see section 9).

Figure 6.4.2-2a/b *WTW total energy requirement and GHG emissions for compressed hydrogen via electrolysis pathways and 2010+ fuel cell vehicles*



Ely = electrolysis

Electrolysis using EU-mix electricity results in higher GHG emissions than producing hydrogen directly from NG. Hydrogen from non-fossil sources (biomass, wind, nuclear) offers low overall GHG emissions.

7 CO₂ capture and storage (CCS)

The concept of isolating the CO₂ 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. CO₂ 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 include separation of CO₂ from other gases, compression and liquefaction, transport (by pipeline or ships) to the point of injection and injection under pressure.

Separation of CO₂ from other gases is a well-established process. In combustion applications using air, scrubbing CO₂ 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 CO₂, although additional energy needs to be expended in the air separation unit. Reforming and gasification processes deliver CO/hydrogen/CO₂ mixtures or mostly hydrogen/CO₂ after the shift reaction. In these cases CO₂ scrubbing is more straightforward. In some cases, for example before syngas is fed to a Fischer-Tropsch reactor, CO₂ scrubbing is required irrespective of the CCS option.

Following capture at the point of emission, CO₂ must be compressed and liquefied, transported to the point of storage and injected. Transport is usually envisaged via pipelines when distance between production and storage sites is relatively short. Long-distance transport by ship has also been considered. 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 CO₂ by pipeline over a reasonable distance (typically 100-150 km) and inject it into the geological storage.

In attempting to assess the CO₂ benefit and energy requirement of CCS 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 CCS 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 CCS and the case with CCS. Many of the process schemes are complex, involving multiple sources of CO₂. In a GTL plant, for instance, CO₂ 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 CO₂. Generally therefore the degree of CO₂ recovery, the energy involved and the cost of the installations required will depend on which gas streams are being tackled.

Because of all these uncertainties and possible lack of consistency between the sources, we consider that the figures for the CCS schemes presented in this report 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.

For the same reason we do not report cost figures as the data that can be inferred from the available literature did not seem consistent with the limited practical experience.

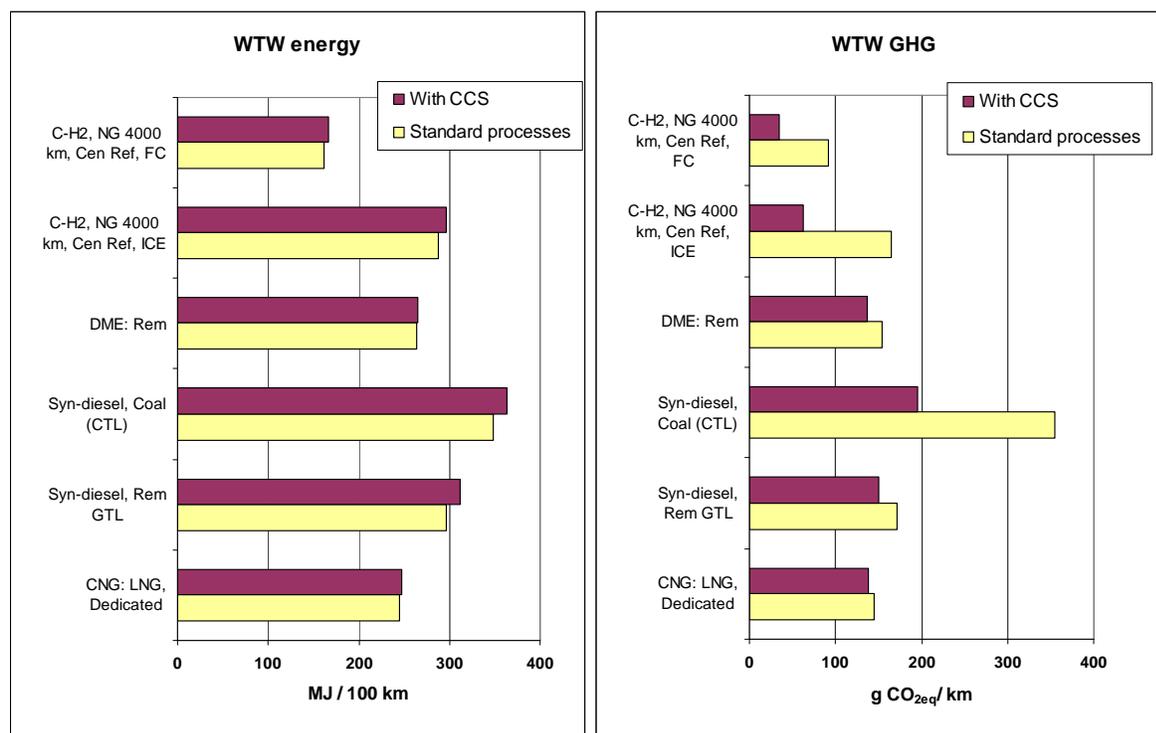
The concept can in principle be applied to many fuel production pathways. As illustration of its potential, we have included CCS in the following cases:

- Electricity from natural gas and coal (IGCC)
- LNG: CO₂ from the power plant associated to the liquefaction plant.

- Hydrogen from NG and coal: Process CO₂ after shift reaction
- GTL and CTL diesel: Process CO₂ after reforming / partial oxidation
- DME from NG: Process CO₂ after reforming

The compared energy and GHG balances of schemes with and without CCS are shown in the following figures.

Figure 7 WTW total energy and GHG balance of selected pathways with and without CCS (2010+ vehicles)



Clearly the potential benefits of CCS are much larger for certain pathways. Not surprisingly coal-based processes such as CTL stand to benefit the most as they involve low energy efficiency and high-carbon primary resource.

Hydrogen pathways involve complete decarbonisation of the feedstock and make therefore the majority of the original carbon available for capture. We have only represented a limited number of options but it stands to reason that pathways such as coal to hydrogen would show an even more favourable picture. It must also be pointed out that, in hydrogen pathways, CO₂ is already available in more or less pure form whether or not CCS is intended. As a result the extra energy requirement and cost are likely to be more limited than in other schemes.

Applying CCS to LNG or GTL schemes can also offer CO₂ reduction but of a more limited nature. The justification for such schemes comes from the fact that such plants would be located very near gas or oil fields where the CO₂ could be re-injected.

Large scale production of synthetic fuels or hydrogen from coal or gas offers the potential for GHG emissions reduction via CO₂ capture and sequestration and this merits further study.

8 Costs and potential availability

This section has not been updated in this version 3. The figures computed in version 2b are considered obsolete and are not supported.

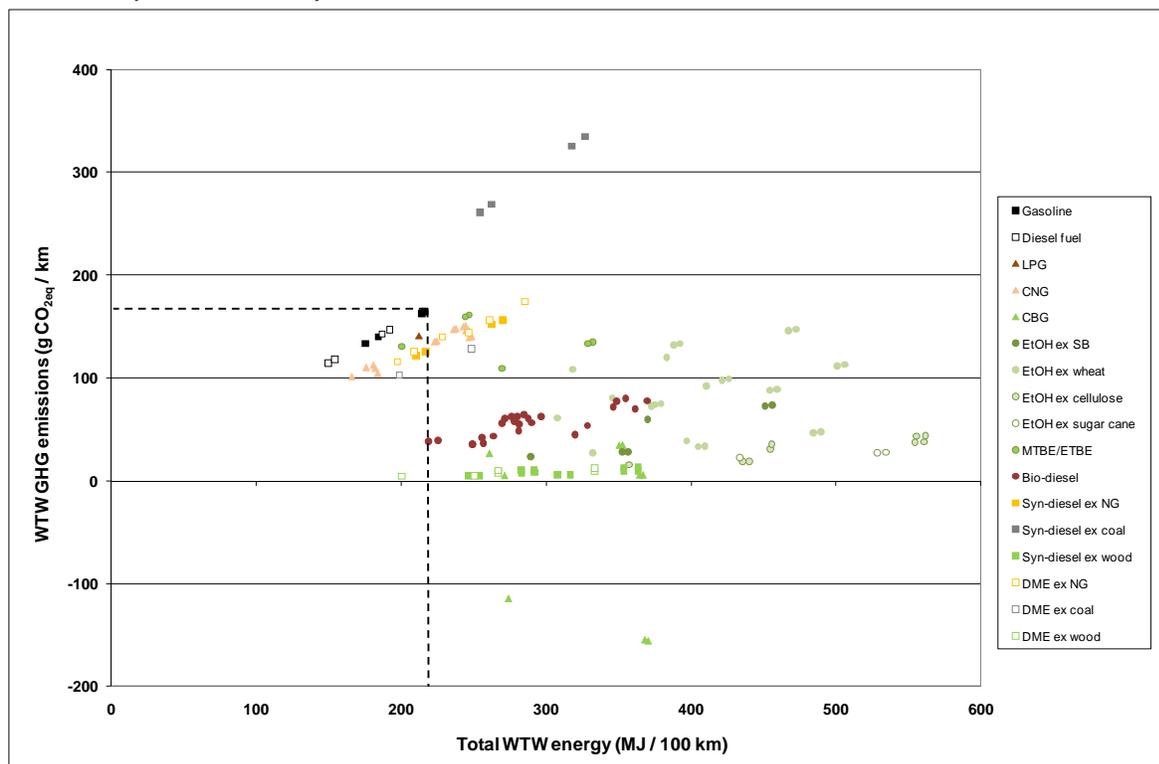
9 Alternative uses of primary energy resources

The previous sections cover the original scope and objectives of the study and the main key conclusions are summarised at the beginning of this report.

The present section 9 is extending the analysis, using the WTW data generated to highlight important aspects regarding primary energy resources. Indeed, their availability for transport fuels, in particular when assessing the biomass, merits considerations in a more general context of competing uses.

Figure 9 shows the relationship between total WTW energy usage and WTW GHG emissions for all non-hydrogen pathways. **Figure 6.4** gives the same information for hydrogen pathways. These figures clearly highlight the fact that, in general, a reduction of GHG emissions has to be paid for by more primary energy usage. Although GHG emissions are of prime concern today, energy conservation and efficient use of energy resources are also desirable goals.

Figure 9 WTW energy requirement and GHG emissions for non-hydrogen pathways (2010+ vehicles)



Virtually all primary energy resources are in practice available in limited quantities. For fossil fuels the limit is physical, expressed in barrels or m³ actually present in the ground and recoverable. For biomass the limit is total available land use. The planet is unlikely to run out of sun or out of wind in the foreseeable future but our capacity to harness these energies is very much limited by our ability to build enough converters at a reasonable cost and find acceptable sites to install them. In other words, access to primary energy is limited and it is therefore important to consider how GHG reductions could be achieved at minimum energy.

In the following sections we look at the various ways of using primary resources to produce road fuels and use electricity generation as a reference point. An exhaustive analysis would require consideration not only of road transport and electricity but of the whole energy sector.

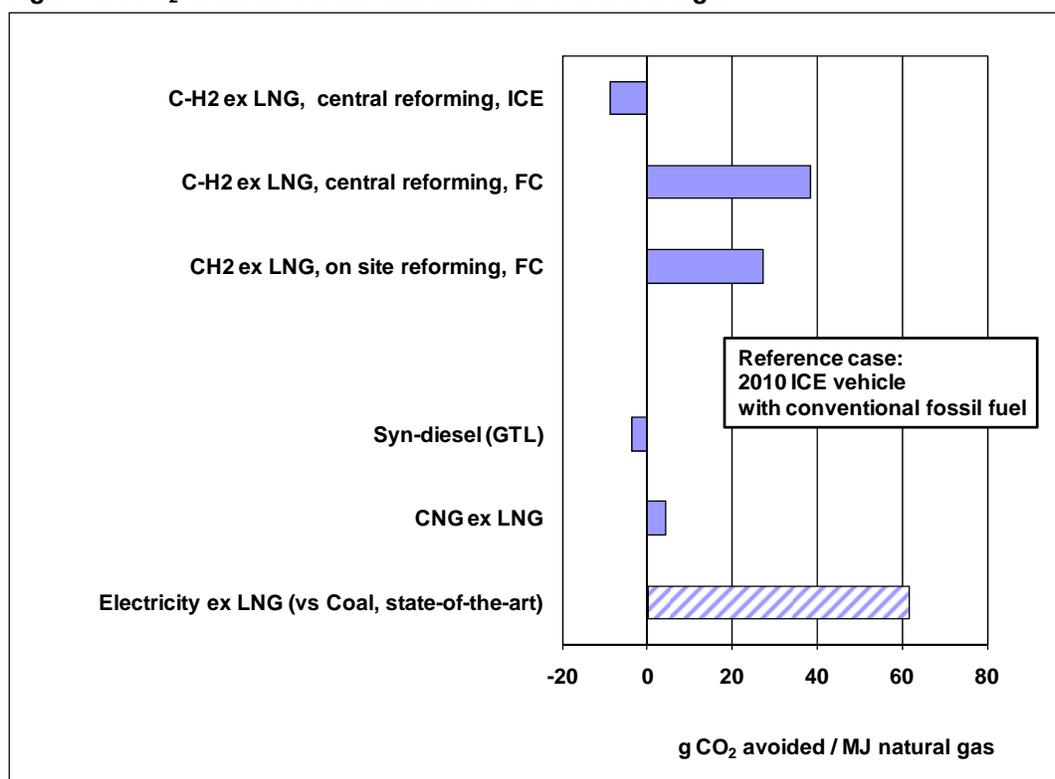
9.1 Natural gas

Within the limited scope considered in this study for using natural gas as a source of transportation, availability of natural gas is not a real issue. There are, however, large differences in the amount of GHG that can be avoided with one MJ of natural gas.

To illustrate this point we have considered 5 possible substitution options:

- NG is commonly used to produce electricity and could replace coal, often considered as the marginal fuel for electricity production. Electricity from coal is GHG-intensive and this provides large GHG savings.
- CNG only provides small savings because its global GHG balance is close to that of the gasoline and diesel fuels it would replace.
- The opposite holds for FT diesel fuel which is slightly more GHG-intensive than conventional diesel fuel.
- Direct hydrogen production has the potential to save large amounts of GHG as long as the hydrogen is used in a fuel cell thereby reaping the energy efficiency benefit. The savings are, however, still much less than in the coal substitution case.

Figure 9.1 CO₂ avoidance from alternative uses of natural gas

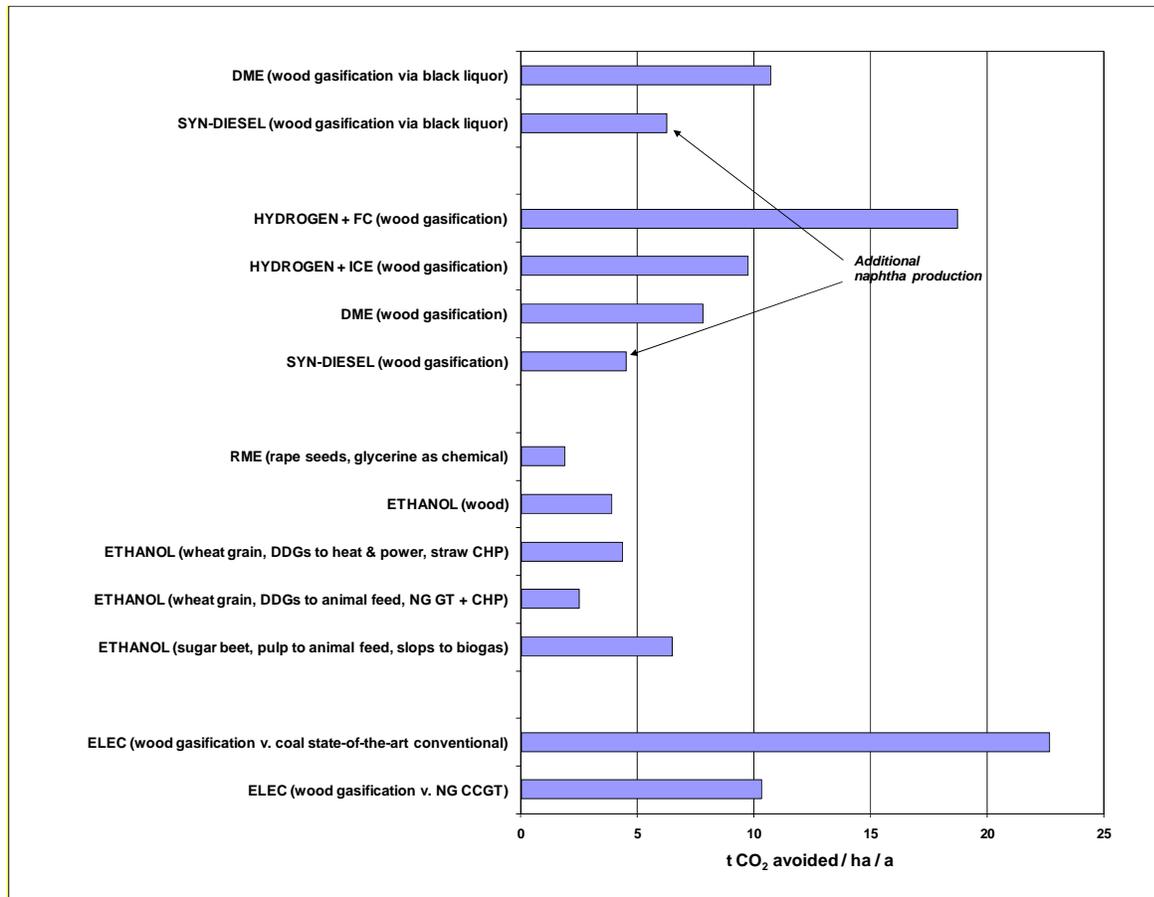


9.2 Biomass

Except for straw, which in suitable areas can be taken from food crops, and organic waste, land is the common biomass resource. It can be used in a myriad of ways some of which have been described in this study, but its availability for growing crops is essentially limited, particularly for energy crops that have to compete with food crops.

In the following figure we consider a hypothetical hectare of land and compare its “CO₂ avoidance potential” when used with different crops. The range shown for each option corresponds to the different pathways available.

Figure 9.2 CO₂ avoidance from alternative uses of land



Electricity production is energy intensive and substitution by biomass results in large CO₂ savings, particularly when coal is being substituted. The technology used for biomass conversion can make a lot of difference, the IGCC concept (top end of the range) being far superior to a conventional boiler + steam turbine system (but also a lot more expensive). Note that wood is used here as a proxy for all high yield energy plants. Substitution of biomass for coal in electricity generation provides one of the best CO₂ savings.

Direct hydrogen production from wood is also attractive because of the reasonable efficiency of the conversion plants, particularly large ones. It can be better than substituting natural gas for electricity but only as long as the final converter is an efficient fuel cell. Even in the latter case, electrolysis (bottom of the range) is worse than the natural gas case. The high end of the range corresponds to wood conversion via the "black liquor" route, a particularly efficient option though limited in scope.

Ethanol and FAME are much less attractive partly because of yields but also because they do not allow a gain in efficiency on the vehicle side. Synthetic diesel fuel and DME are in the same range as natural gas electricity substitution.

This analysis is of course a little simplistic. Each hectare of land has its specific characteristics that make it most suitable for a certain kind of crop or crops (in rotation). Rape is for instance an attractive break crop on a land dedicated to cereals. One could obviously not grow wood for a year between two cereal cycles. Also yields can vary a great deal between areas and one should refrain from using the above figures to estimate the CO₂ that could be saved with a certain area of land.

The point is that there are significant overall differences between the options and one must look both at relative and absolute figures.

9.3 Wind

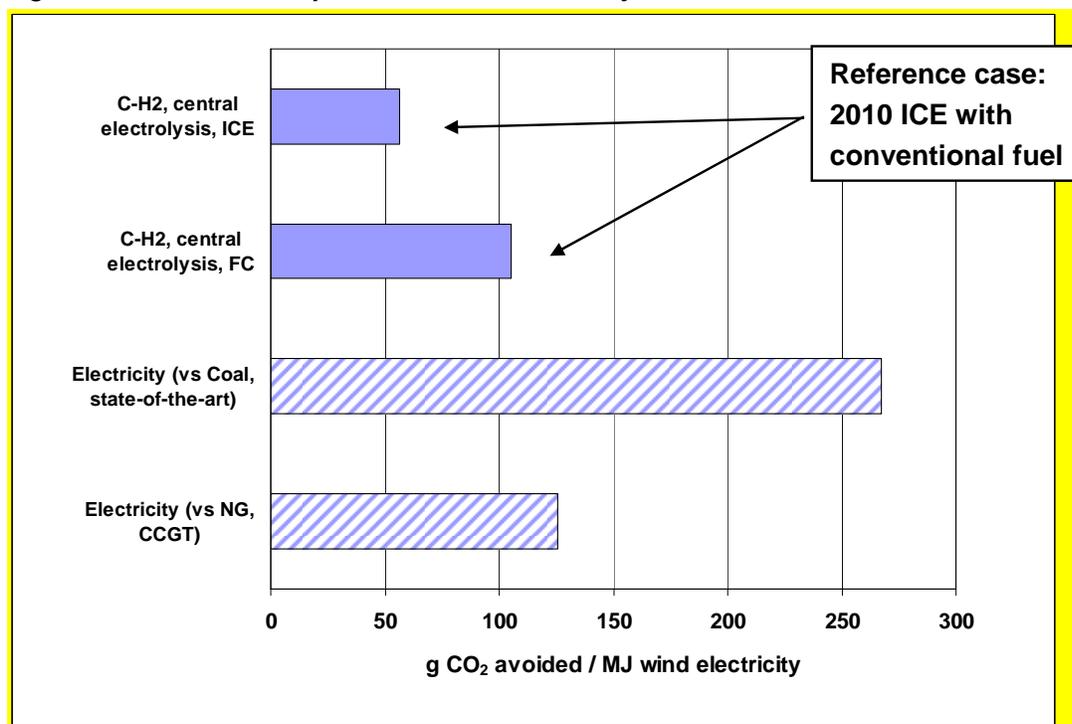
How much energy can be harnessed from wind can be a matter of endless debates. The main issue is first to find suitable sites, get the appropriate approvals and public acceptance and then to construct a suitable financial structure to make a project feasible. The rate of success in doing this, rather than the number of potential sites, will determine how much wind power is installed.

Technology is moving fast with increasingly large and more efficient turbines. The impact on wind farm on the environment is a big issue and one of the major stumbling blocks. People have generally nothing against wind farms as long as they can't see or hear them. Noise is indeed one of the problems although it is being addressed by manufacturers. In the long term, offshore installations are the most promising. They cause less environmental nuisance, can be very large and can benefit from much stronger and steadier winds.

In any case, there is no serious scenario suggesting that enough wind power could be installed to produce all of the European electricity demand. Because of its intermittent and partly unpredictable nature wind electricity can be difficult to integrate into the grid without risking major upsets. Figures of 10 to 20% have been mentioned as the maximum acceptable fraction of wind electricity in the total. Any surplus, either structural or occasional, could be used to produce e.g. hydrogen. Whether enough wind capacity is developed remains to be seen.

The following figure illustrates the CO₂ avoidance potential of wind electricity.

Figure 9.3 CO₂ avoidance potential of wind electricity



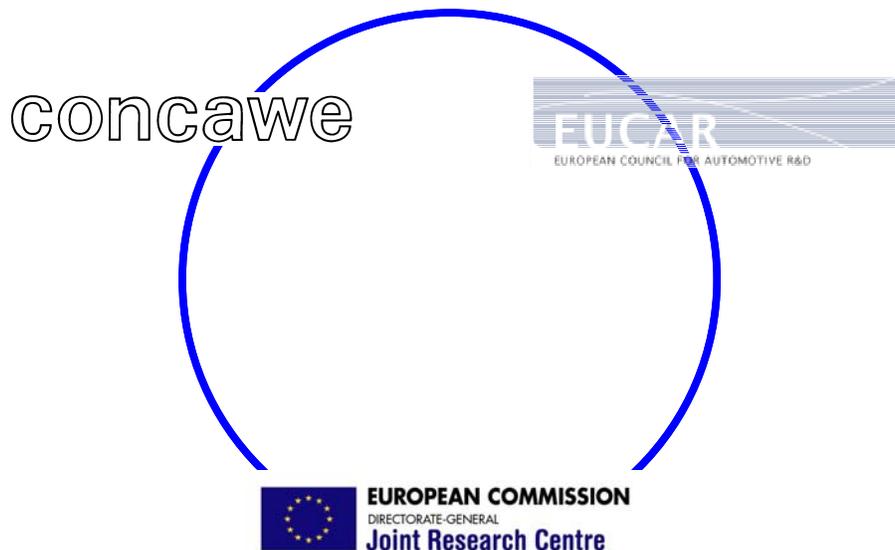
Substituting fossil electricity generally gives higher GHG reductions, even when the final converter is a fuel cell (this is because of the extra inefficiency introduced by the electrolyser).

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
CCS	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 ₂ O	Nitrous oxide: a very potent greenhouse gas
NEDC	New European Drive Cycle
NG	Natural Gas
NO _x	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

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



WELL-to-TANK Report - Appendix 1

Version 3c, July 2011

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This report is available as an ADOBE pdf file on the JRC/IES website at:

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Notes on version number:

This document reports on the third release of this study replacing data made available since November 2008.

The original version 1b was published in December 2003.

Description of individual processes and detailed input data

All WTT data is stored in LBST's E³ 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 3 or have been updated, as compared to version 2c are highlighted in yellow.

In this appendix both energy and GHG figures are shown per unit energy content of the output of the particular process (MJ), i.e. 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). This has to be kept in mind when comparing figures in the appendix with those in **WTT Appendix 2** where figures pertaining to each step of a pathway are expressed per MJ of the final fuel.

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 fuels or intermediate energy sources (e.g. electricity) are used in a process the total primary energy (MJ_p) is allocated to the process including the energy necessary to make the fuel or the electricity.

Example:

- If a process requires 0.1 MJ of electricity per MJ output, 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 $3 \times 0.1 = 0.3 \text{ MJ}_p/MJ$.

All energy is accounted for regardless of the primary energy source, i.e. including renewable energy. This is necessary to estimate the energy footprint 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 CO₂ figures represent the actual emissions occurring during each process. When CO₂ emissions stem from biomass sources only the net emissions are counted i.e. excluding CO₂ emitted when burning the biomass.

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 E³ database resulting in the figures in *WTT Appendix 2*.

Where appropriate we have specified a range of variability associated with 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.

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1 Useful conversion factors and calculation methods

1.1 General

1 kWh = 3.6 MJ = 3412 Btu

1 Mtoe = 42.6 PJ

1 MW = 1 MJ/s = 28.8 PJ/a (8000 h)

1 t crude oil ~ 7.4 bbl

1 Nm³ of EU-mix NG ~ 0.8 kg ~ 40 MJ

(i.e. 1 Nm³ 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)	1	86.4	28.8	80.4	1929	643	102
GJ/d	0.012	1	0.333	0.930	22.3	7.4	1.18
PJ/a (8000 h)	0.035	3	1	2.79	67.0	22.3	3.53
kg/h	0.012	1.07	0.36	1	24	8	1.27
kg/d		0.04	0.01		1	0.33	0.05
t/a (8000 h)		0.13	0.04	0.13	3	1	0.16
Nm ₃ /h		0.85	0.28	0.79	19.0	6.3	1

Methane	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	Nm ₃ /h
MW (MJ/s)	1	86.4	28.8	72.0	1728	576	101
GJ/d	0.012	1	0.333	0.833	20.0	6.7	1.17
PJ/a (8000 h)	0.035	3	1	2.50	60.0	20.0	3.50
kg/h	0.014	1.20	0.40	1	24	8	1.40
kg/d		0.05	0.02		1	0.33	0.06
t/a (8000 h)		0.15	0.05	0.13	3	1	0.18
Nm ₃ /h		0.86	0.29	0.71	17.1	5.7	1

Hydrogen	MW	GJ/d	PJ/a	kg/h	kg/d	t/a	Nm ₃ /h
MW (MJ/s)	1	86.4	28.8	30.0	719	240	336
GJ/d	0.012	1	0.333	0.347	8.3	2.8	3.89
PJ/a (8000 h)	0.035	3	1	1.04	25.0	8.3	11.66
kg/h	0.033	2.88	0.96	1	24	8	11.20
kg/d		0.12	0.04		1	0.33	0.47
t/a (8000 h)		0.36	0.12	0.13	3	1	1.40
Nm ₃ /h		0.26	0.09	0.09	2.1	0.7	1

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

CO₂-equivalence coefficients [IPPC 2007]

Methane 25

Nitrous oxide 298

CO₂ emissions from combustion (assuming total combustion)

1 kg of a fuel with C% carbon emits:

$$1 \times C\% / 100 / 12 \times 44 = (0.0367 \times C\%) \text{ kg of CO}_2$$

1 MJ of a fuel with λ MJ/kg (LHV) and C% carbon emits:

$$1 / \lambda \times C\% / 100 / 12 \times 44 = (0.0367 / \lambda \times C\%) \text{ kg of CO}_2$$

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			65.7							
	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	XME	REE	MTBE	ETBE
Density	kg/m ³	820	745	832	720	970	780	793	670	794	890	890	745	750
LHV	MJ/kg	42.0	43.2	43.1	43.7	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	12.14	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%	84.9%	89.0%	85.0%	37.5%	52.2%	52.2%	77.3%	76.5%	68.2%	70.6%
CO ₂ emission factor (assuming total combustion)														
	g CO ₂ /MJ	75.5	73.3	73.2	71.2	80.6	70.8	69.1	67.3	71.4	76.2	74.0	71.2	71.4
	kg CO ₂ /kg	3.17	3.17	3.16	3.11	3.26	3.12	1.38	1.91	1.91	2.83	2.81	2.50	2.59
Solids		Hard Coal	Wood	Wheat	S beet	Rapeseed	SunFseed	SB pulp	SB slops	Wheat straw	DDGS	Sugar cane	Corn	
Moisture content			30.0%	13.5%	76.5%	10.0%	10.0%	9.0%	9.0%	16.0%	10.0%	72.5%		
LHV (dry matter)	MJ/kg	26.5	18.0	17.0	16.3	26.4	26.4	15.6	15.6	17.2	16.0	19.6		
	kg/kWh	0.136	0.200	0.212	0.221	0.136	0.136	0.231	0.231	0.209	0.225	0.184		
	kWh/kg	7.4	5.0	4.7	4.5	7.3	7.3	4.3	4.3	4.8	4.4	5.4		
C content	% m	69.4%	50.0%											
CO ₂ emission factor (assuming total combustion)														
	g CO ₂ /MJ	96.0	101.9											
	kg CO ₂ /kg	2.54	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/Nm ³)	0.727	0.827	0.820	0.820	0.750	0.791	
LHV (MJ/Nm ³)	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			CO2 emission factor 3.02 t CO2 / t 65.7 kg CO2 / GJ			
C2-	3.0					
C3	41.0					
C4	55.0					
C5+	1.0					
Olefins	4.5					

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 Crude oil		0.1600	14.30													CONCAWE
Z2	Road tanker Diesel									73.25			0.936				LBST
Z3	HFO production Crude oil		0.0880	6.65													TFE 2001
Z4	Product carrier 50 kt Energy (ship's fuel) as HFO)									gCO2/tkm 9.99			0.124	0.112	0.136	Dble tri	Oko inventar
Z5	Rail transport Electricity (EU-mix, MV) <i>Primary energy consumption and emissions</i>	Z7a	MJex/ t.km 0.5949	g CO2/ t.km 25.05	g CH4/ t.km 0.06	g N2O/ t.km 0.00	g CO2 eq/ t.km 26.92						0.210				Okoinventar
Z6a	Marginal NG for general use Piped 7000 km								1.2346	68.65	0.2884	0.0000					
Z6b	Piped 4000 km								1.1306	63.12	0.1995	0.0000					
Z6c	LNG								1.2218	69.02	0.1351	0.0000					

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	128.24	35.3%	GEMIS 3.03
Z7b	Electricity (EU-mix, LV)		2.8687	120.79	0.2946	0.0055	129.78	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 COD1.

Z2 Road tanker

This process represents the diesel fuel consumption and CO₂ 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 with 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 with 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 always 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 CO₂ 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 CO₂ emissions associated with 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 CO₂ emissions associated with use of marginal natural gas of various origins (based on NG processes described in *section 5*).

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 2015-20. 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 2015-20 “kWh” is different from that of 2000, the resulting CO₂ emissions are not very different.

We have used 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	GHG emissions					Transport distance km or Nm	Transport energy MJex/ t.km	Transport requirement t.km/ MJ	Range		Probability distribution
				MJx/ MJ prod.	g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ MJ prod.				Min	Max	
CO1	Crude oil production													
	Energy as crude oil		0.0580	4.38			4.38				0.044	0.072	Normal	
	CO2 eq emissions Total CO2 eq					0.45 4.83				3.53	6.17	Normal		
CO2	Crude oil transportation													
	Energy as HFO <i>Primary energy consumption and emissions</i>	Z3	0.0101 0.0110	0.81 0.88			0.81 0.88				0.0096	0.0106	Normal	
CD1	Crude oil refining, marginal diesel													
	Refinery fuel		0.1000	8.60			8.60				0.0800	0.1200	Normal	
CD2	Diesel transport													
	Barge, 9000 t (20%)													
	Distance						500			0.0116				
	Diesel consumption and emissions	Z2	0.0058	0.43			0.43							
	Evaporation losses			0.00			0.00							
	<i>Primary energy consumption and emissions</i>		0.0064	0.51			0.51							
	Rail, 250 km (20%)													
Distance	Z5						250			0.0058				
<i>Primary energy consumption and emissions</i>		0.0035	0.15	0.0004	0.0000	0.16								
Pipeline (60%)														
Electricity (EU-mix, LV)	Z7b		0.0002											
<i>Primary energy consumption and emissions</i>		0.0006	0.02	0.0001	0.0000	0.03								
	<i>Total Primary energy consumption and emissions</i>		0.0023	0.15	0.0001	0.0000	0.15							
CD3	Diesel depot													
	Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z7b	0.0008 0.0024											
CD4	Diesel distribution and dispensing													
	Tanker load and distance						150			0.0037				
	Diesel consumption and emissions	Z2, Z1	0.0035	0.26			0.00							
Retail, Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z7b	0.0034 0.0138												
			0.0138	0.72	0.0010	0.0000	0.75							

CO1 Crude oil production

Figures include all 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 CO₂eq figure includes an element of flaring and emissions of GHGs other than combustion CO₂.

Production conditions for conventional crude oil 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 wide range of crudes relevant to Europe, hence the wide variability range indicated. These figures are best estimates for the basket of crude oils available to Europe [*Source: CONCAWE*]. They have been revised upwards in this version 3 (see *WTT Report Section 3.1.1*).

Substantial deposits of heavier oils also exist, notably in Canada and Venezuela. The process of extracting and processing these oils is more energy intensive than for conventional crude oil. The very large reserves mean that these resources may become more important in the future, however most of the current production is used within the Americas, and we expect little or none of it to reach Europe in the period to 2020. 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. Non-conventional crude oil is discussed in more detail in the *WTT Report, Section 3.1.1*.

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 transported 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.

The majority of EU refineries are located at coastal locations with direct access to a shipping terminal. Those that are inland are generally supplied via one of several pipelines such as from the Mediterranean to North Eastern France and Germany, from the Rotterdam area to Germany and from Russia into Eastern and Central Europe.

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 those that require shorter transport distances such as North Sea or North African crudes or those that can be transported by pipeline (e.g. Russian crude) 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	GHG emissions					Transport distance km or Nm	Transport energy MJex/ t.km	Transport requirement t.km/ MJ	Range		Probability distribution
				MJx/ MJ prod.	g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ MJ prod.				Min	Max	
CG1	Crude oil refining, marginal gasoline Refinery fuel		0.0800	7.00			7.00				0.0600	0.1000	Normal	
CG2	Gasoline transport													
	Barge, 9000 t (20%)													
	Distance						500		0.0116					
	Diesel consumption and emissions	Z2	0.0058	0.43			0.43							
	Evaporation losses		0.0000											
	<i>Primary energy consumption and emissions</i>		0.0068	0.51			0.51							
	Rail, 250 km (20%)													
Distance	Z5						250		0.0058					
<i>Primary energy consumption and emissions</i>		0.0034	0.14	0.0004	0.0000	0.16								
Evaporation losses		0.0004												
Pipeline (60%)														
Electricity (EU-mix, LV)	Z7b	0.0002												
<i>Primary energy consumption and emissions</i>		0.0006	0.02	0.0001	0.0000	0.03								
<i>Total Primary energy consumption and emissions</i>			0.0024	0.15	0.0001	0.0000	0.15							
CG3	Gasoline depot													
Electricity (EU-mix, LV)	Z7b	0.0008												
<i>Primary energy consumption and emissions</i>		0.0024	0.10	0.0002	0.0000	0.11								
Evaporation losses		0.0000												
CG4	Gasoline distribution and dispensing													
Tanker load and distance							150		0.0037					
Diesel consumption and emissions	Z2, Z1	0.0035	0.26											
Filling station, Electricity (EU-mix, LV)	Z7b	0.0034												
<i>Primary energy consumption and emissions</i>		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	GHG emissions					Transport distance	Transport energy	Transport requirement	Range		Probability distribution
				MJx/ MJ prod.	g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ MJ prod.				km or Nm	MJex/ t.km	
CN1	Crude oil refining, marginal naphtha Crude oil		0.0510	4.36				4.36				0.0450	0.0550	Normal
CN2	Naphtha transport													
	Barge, 9000 t (20%)													
	Distance							500		0.0114				
	Diesel consumption and emissions	Z2	0.0058	0.42				0.42						
	Evaporation losses		0.0000	0.00										
	<i>Primary energy consumption and emissions</i>		0.0067	0.50				0.50						
Rail, 250 km (20%)														
Distance	Z5							250		0.0057				
<i>Primary energy consumption and emissions</i>		0.0034	0.14	0.0003	0.0000		0.15							
Evaporation losses		0.0004												
Pipeline (60%)														
Electricity (EU-mix, LV)	Z7b	0.0002												
<i>Primary energy consumption and emissions</i>		0.0006	0.02	0.0001	0.0000		0.03							
<i>Total Primary energy consumption and emissions</i>			0.0024	0.14	0.0001	0.0000		0.15						
CN3	Naphtha depot													
	Electricity (EU-mix, LV)	Z7b	0.0008											
	<i>Primary energy consumption and emissions</i>		0.0024	0.10	0.0002	0.0000		0.11						
Evaporation losses		0.0000												
CN4	Naphtha distribution and dispensing													
	Tanker load and distance							150		0.0037				
	Diesel consumption and emissions	Z2, Z1	0.0035	0.25										
	Filling station, Electricity (EU-mix, LV)	Z7b	0.0034											
	<i>Primary energy consumption and emissions</i>		0.0138	0.71	0.0010	0.0000		0.74						
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
				MJx/MJ prod.	g CO ₂ /MJ prod.	g CH ₄ /MJ prod.	g N ₂ O/MJ prod.		g CO ₂ eq/MJ prod.	MJ/MJx	g CO ₂ /MJx	g CH ₄ /MJx	g N ₂ O/MJx	km or N m	MJx/t.km	MJx/MJ/100km	Min	
GG1	NG Extraction & Processing Energy as NG CO2 venting Methane losses <i>Primary energy consumption and emissions</i>		0.0200 0.0042 0.0242	1.13 0.55 1.68		0.0833 0.0833	1.13 2.08 3.76										0.0100 0.0400	Dble tri
GG2	Electricity generation from NG (CCGT) Energy efficiency CO2 emissions Methane losses N2O emissions Total NG input to power plant						55.0%	1.8178 0.0004 1.8182	100.11 0.0075 0.0047								52.3% 1.7300 1.9100	57.8%
GG2C	Electricity generation from NG (CCGT) with CO2 capture Energy efficiency CO2 emissions Methane losses N2O emissions Total NG input to power plant						47.1%	2.1228 0.0004 2.1231	11.94 0.0075 0.0000								44.8% 2.0202 2.2304	49.5% 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 H₂S as well as separate inert gases, particularly CO₂ 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 CO₂ reflects the low CO₂ content of the gas sources typically available to Europe. For sources with higher CO₂ content, it is assumed that re-injection will be common at the 2015-20 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.

GG2C On-site electricity generation with CCS (CO₂ capture and storage)

This process would consist in scrubbing CO₂ out of the gas turbine flue gases [Rubin 2004]. It has been estimated that some 88% of the CO₂ could be recovered. The energy penalty is sizeable, the overall efficiency being reduced by about 8 percentage points.

5.2 Long distance pipeline transport

Code	Process	Assoc. processes	Expended energy	GHG emissions					Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution
				MJ/MJ prod.	g CO ₂ /MJ prod.	g CH ₄ /MJ prod.	g N ₂ O/MJ prod.	g CO ₂ eq/MJ prod.		MJ/MJx	g CO ₂ /MJx	g CH ₄ /MJx	g N ₂ O/MJx	km or N m	MJ/t.km	MJx/MJ /100km	Min	Max	
GP1a	NG long-distance pipeline																		
	Russian quality, 7000 km												7000						
	Average specific compression energy		0.0512										0.360				0.120	0.400	Square
	Compression energy (Russian gas quality)																0.017	0.057	
	Compressors powered by GT fuelled by NG																		
Energy efficiency							27.8%	3.6000	197.97	0.0306	0.0083								
CO ₂ emissions								0.0015											
Methane losses																			
N ₂ O emissions																			
NG consumption and emissions			0.1844	10.14	0.0016	0.0004	10.31												
Methane losses			0.0092		0.1839														
<i>Primary energy consumption and emissions</i>			0.1936	10.14	0.1855		14.78												
GP1b	Average quality, 4000 km												4000						
	Average specific compression energy		0.0244										0.300				0.008	0.027	Square
	Compression energy (Russian gas quality)																		
	NG consumption and emissions																		
	Methane losses																		
<i>Primary energy consumption and emissions</i>			0.0931	4.83	0.1058		7.47												
GM1	EU-mix quality, 1000 km												1000						
	Average specific compression energy		0.0058										0.260				0.002	0.006	Square
	Compression energy (EU-mix gas quality)																		
	NG consumption and emissions																		
	Methane losses																		
<i>Primary energy consumption and emissions</i>			0.0221	1.14	0.0264		1.80												

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 with 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.

5.3 LNG

Code	Process	Assoc. processes	Expended energy	GHG emissions				Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	
				MJx/MJ prod.	g CO ₂ /MJ prod.	g CH ₄ /MJ prod.	g N ₂ O/MJ prod.		g CO ₂ eq/MJ prod.	MJ/MJx	g CO ₂ /MJx	g CH ₄ /MJx	g N ₂ O/MJx	km or N m	MJx/t.km	MJx/MJ/100km	Min		Max
GR1	NG Liquefaction	GG2																	
	Electricity (on-site generation)		0.0360																
	NG consumption and emissions		0.065455	3.60	0.0003	0.0002	3.66										0.034	0.038	Normal
	Methane losses		0.0042	0.14	0.0340														
<i>Primary energy consumption and emissions</i>	0.0697	3.74	0.0343		4.60														
GR1C	NG Liquefaction with CO2 capture	GG2C																	
	Electricity (on-site generation)		0.0360																
	NG consumption and emissions		0.0764	0.43	0.0003	0.0000	0.44									0.034	0.038	Normal	
	Methane losses		0.0042	0.14	0.0340														
<i>Primary energy consumption and emissions</i>	0.0807	0.57	0.0343		1.43														
GR2	LNG terminal (loading)	GG2																	
	Energy as NG		0.0100	0.55															
	Electricity (on-site generation)		0.0007																
	<i>Primary energy consumption and emissions</i>		0.0113	0.55	0.0000		0.55												
GR3	LNG transport (average of two distances)																		
	Distance (nautical miles)												5500						
	NG evaporation	0.0365																	
	Methane losses	0.0000		0.0002		0.00												Square	
	NG to ship's fuel	0.0365	2.01			2.01													
	HFO to ship's fuel	0.0309	2.49			2.49													
	Total ship's CO2		4.50			4.50													
<i>Primary energy consumption and emissions</i>	0.0674	4.50	0.0002		4.50										0.0613	0.0736			
GR4	LNG terminal (unloading)	Z7a																	
	Energy as NG		0.0100	1.83															
	Electricity (EU-mix, MV)		0.0007																
	<i>Primary energy consumption and emissions</i>		0.0120	2.49	0.0000	0.0000	2.49												
GR5	LNG vaporisation																		
	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										
	<i>Primary energy consumption and emissions</i>	0.0014	0.08	0.0000		0.08													
GR6	LNG distribution (road tanker)	Z2, Z1																	
	Tanker load and distance (Road tanker Z3)		0.0160	1.23			1.23												
GR7	LNG to CNG (vaporisation/compression)	Z7b																	
	Electricity (EU-mix, LV)		0.0228																
	Primary energy consumption and emissions		0.0654	2.75	0.0067	0.0001	2.96												
	Methane losses		0.0000		0.0002		0.01												
<i>Primary energy consumption and emissions</i>	0.0654	2.75	0.0069	0.0001	2.96														

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 CO₂ capture

A significant amount of natural gas is used to generate the electrical energy required for liquefaction. The corresponding CO₂ could be captured (see process CG2C). The proximity of gas and possibly oil field where the CO₂ could be injected would enhance 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 CO₂ 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 m³ 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 an 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).

5.4 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
				MJ/MJ prod.	g CO ₂ /MJ prod.	g CH ₄ /MJ prod.	g N ₂ O/MJ prod.	g CO ₂ eq/MJ prod.		MJ/MJx	g CO ₂ /MJx	g CH ₄ /MJx	g N ₂ O/MJx	km or N m	MJx/t.km	MJx/MJ /100km	Min	Max	
GG3	NG trunk distribution Distance Average specific compression energy Compression energy (EU-mix gas quality) Compressors powered by GT fuelled by NG Energy efficiency CO2 emissions Methane losses N2O emissions NG consumption and emissions Methane losses <i>Primary energy consumption and emissions</i>		0.0030						30.0%	3.3300	187.64	0.0139	0.0083	500	0.269				
			0.0099	0.00	0.0000	0.0000	0.01			0.0007									
			0.0000		0.0006														0.0006%
			0.0100	0.00	0.0007	0.0000	0.03												
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) Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z7b	0.0220 0.0631	2.66	0.0065	0.0001	2.86										0.027	0.014	Triangular

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 CO₂ emissions from natural gas combustion:

The CO₂ 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	Expende d energy	GHG emissions					Efficiency	Total energy and emissions per MJ of expendable energy				Transport requirement			Range		Probability distribution	
				MJ/ MJ prod.	g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ MJ prod.		MJ/ MJx	g CO ₂ / MJx	g CH ₄ / MJx	g N ₂ O/ MJx	km or N m	MJx/ t.km	MJx/MJ /100km	Min	Max		
GD1	NG to syn-diesel (remote or central plant)																			
	Overall efficiency							65.0%										67.0%	63.0%	Normal
	Energy as NG		0.5385	13.78													0.4925	0.5873		
Primary energy consumption and emissions		0.53846	13.78																	
GD1C	NG to syn-diesel (remote or central plant) with CO2 capture																			
	Overall efficiency							60.0%										63.2%	57.1%	Square
	Energy as NG		0.6667	4.17													0.5834	0.7500		
Primary energy consumption and emissions		0.6667	4.17																	
GA1	NG to Methanol (remote or central plant)																			
	Overall efficiency							68.3%										69.4%	67.3%	
	Energy as NG		0.4632	41.36																
Methane losses		0.0000		0.0003																
Primary energy consumption and emissions		0.4632	41.36	0.0003			41.37										0.4406	0.4857		
GT1	NG to DME (remote or central plant)																			
	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																		
	Steam plant NG							85.0%	0.02 (MJe/MJex)	1.1765	64.79	0.0028						1.1176	1.2353	Normal
Oxygen												MJe/kg								
Oxygen plant	GG2											1.6999	kg/MJ	0.0013			0.0045	0.0047	Equal	
Primary energy consumption and emissions		0.4124	10.49	0.0035	0.0000		10.58	70.8%									0.1246	0.1377	Normal	
GT1C	NG to DME (remote or central plant) with CO2 capture																			
	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																			
Oxygen												MJe/kg								
Oxygen plant	GG2											0.4722	kg/MJ	0.0046			0.4486	0.4958	Equal	
Primary energy consumption and emissions		0.4254	0.58	0.0035			0.67	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. GTL is a relatively new technology, and we can expect that with continued development the process efficiency will improve. We expect plants designed in the next few years to have a typical overall efficiency of 65% [Source: Shell, SasolChevron], slightly higher than in the 63% assumed in *version 2c* of this study. This means that 100 MJ of NG in will deliver 65 MJ of combined product, 35 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 than 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 considered that allocation on energy content basis between the different co-products is a reasonable simplifying assumption if this case and assumed that all products are produced independently with the same energy efficiency.

GD1C NG to syn-diesel plant with CO₂ capture

The "chemical" CO₂ from the reforming or partial oxidation reactions and the CO-shift reaction (required to adjust the hydrogen/CO ratio) is scrubbed from the syngas feed to the FT process. The solvent absorption processes commonly used for this purpose produce a virtually pure CO₂ stream so that only compression is required for potential transport (and eventual storage). Most GTL plants will be built near gas or oil fields where the CO₂ can be re-injected. For FT liquids from NG there is not literature source where a NG FT plant with and without CCS 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 CCS. [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 CO₂ generated in the auxiliary power plant is not recovered in this scheme, so that the CO₂ 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 DME. 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 CO₂ capture

CO₂ formed during the steam reforming process is produced in nearly pure form (see process GD1C above) 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 CCS 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	
				MJx/MJ prod.	g CO ₂ /MJ prod.	g CH ₄ /MJ prod.	g N ₂ O/MJ prod.	g CO ₂ eq/MJ prod.		MJ/MJx	g CO ₂ /MJx	g CH ₄ /MJx	g N ₂ O/MJx	km or Nm	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														0.4118	0.4694	Normal
	Energy as NG			0.4406		0.0159														
	CO ₂ emissions																			
GH1a	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	
GH1b	NG to hydrogen (reforming, central plant, 100-300 MW hydrogen)																			
	Energy as NG (Russian gas quality)			0.3150	72.38	0.0159		72.78	76.0%									0.289	0.341	Normal
GH1bC	NG to hydrogen (reforming, central plant, 100-300 MW hydrogen) with CO₂ capture																			
	Energy as NG (Russian gas quality)			0.3650	11.86	0.0159		12.26	73.3%									0.338	0.3920	Normal

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, in the larger plant, 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.

GHIbC NG to hydrogen (steam reforming, central plant, 100-300 MW hydrogen) with CO₂ capture

Steam reforming of natural gas followed by the CO-shift reaction produces a mixture of hydrogen and CO₂ with some residual CO as well as unconverted methane. Depending on the purity requirement of the hydrogen, the CO₂ is either separated from the hydrogen chemically by solvent absorption or physically using molecular sieves in a Pressure Swing Absorption (PSA) unit [*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	
				MJ/MJ prod.	g CO ₂ /MJ prod.	g CH ₄ /MJ prod.	g N ₂ O/MJ prod.		g CO ₂ eq/MJ prod.	MJ/MJx	g CO ₂ /MJx	g CH ₄ /MJx	g N ₂ O/MJx	km or Nm	MJx/t.km	MJx/MJ/100km	Min		Max
LR1	LPG production Energy as LPG Electricity <i>Primary energy consumption and emissions</i>	GG2	0.0529 0.0028 0.0580	3.47													0.0500	0.0700	Equal
BU1	n-butane to isobutene Electricity NG for steam (90% eff.) Hydrogen Credit for hydrogen produced by NG steam ref. <i>Primary energy consumption and emissions</i>	Z7a Z6b	0.0022 0.1627 -0.0196 -0.0258 0.1430		10.27	0.0325	0.0000	11.08											
EH1	Isobutene + ethanol to ETBE Isobutene Ethanol Electricity NG <i>Primary energy consumption and emissions</i>	BU1 Z7a Z6b	0.7000 0.3640 0.0010 0.0240 0.0028		0.1194	0.0003	0.0000	0.13											
MH1	Isobutene + methanol to MTBE Isobutene Methanol Electricity NG <i>Primary energy consumption and emissions</i>	BU1 Z7a Z6b	0.8122 0.1886 0.0012 0.0290 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 (condensate) 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 MJx/ MJ prod.	GHG emissions					Efficiency	Range		Probability distribution
				g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ MJ prod.	Min		Max		
KB1	Lignite (brown coal) provision											
	Primary energy as											
	Brown coal		0.0148									
	Oil		0.0008									
	<i>Primary energy consumption and emissions</i>		0.0156				1.77					
KO1	Hard coal provision (EU-mix) (1)											
	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									
		<i>Primary energy consumption and emissions</i>		0.0940	6.47	0.3818	0.0003	16.10				
KH1	Coal to hydrogen											
	Energy as hard coal (EU-mix)		0.967	188.77	0.0061			50.8%				
	<i>Primary energy consumption and emissions</i>		0.9670	188.77	0.0061	0.0000	188.9254					
KH1C	Coal to hydrogen with CO2 capture											
	Energy as hard coal (EU-mix)		1.303	5.64	0.0000			43.4%				
	<i>Primary energy consumption and emissions</i>		1.3030	5.64	0.0000	0.0000	5.638889					
KA1	Coal to methanol											
	Energy as hard coal (EU-mix)		0.6759	91.74	0.0069		91.91	59.7%				
	Electricity (ex coal)		0.0294									
	<i>Primary energy consumption and emissions</i>		0.7371	91.74	0.0069		91.91					
KE1	Coal to DME											
	Energy as hard coal (EU-mix)		0.6759	93.55	0.0069		93.72	59.7%				
	Electricity (ex coal)		0.0294									
	<i>Primary energy consumption and emissions</i>		0.7371	93.55	0.0069		93.72					
KD1	Coal to syndiesel											
	Energy as hard coal (EU-mix)		1.4710	166.31				40.5%	1.3470	1.5950	Equal	
	Energy as electricity		-0.3300									
	Credit for electricity based on coal IGCC		-0.6875	-65.98	0.0000	0.0000	-65.98	48%				
	<i>Primary energy consumption and emissions</i>		0.7835	100.33	0.0000	0.0000	100.33	56%				
KD1C	Coal to syndiesel with CO2 capture											
	Energy as hard coal (EU-mix)		1.444	14.92				40.9%	1.3220	1.5660	Equal	
	Energy as electricity		-0.239									
	Credit for electricity based on coal IGCC+CCS		-0.5829	-5.60				41.0%	50.0%	40.0%		
	<i>Primary energy consumption and emissions</i>		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 CO₂ capture

Same as above with additional capture of CO₂. 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 CO₂ capture

Same as above with CO₂ 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 related processes for agrochemicals are described in *section 10*.

As explained in the WTT main report, the GHG balances in this report do not include emissions from changes in land use, even though we think these are important. In other words, our figures refer to annual farming emissions, and not to land use change emissions, which should be added separately. However, when we calculate nitrous oxide emissions, we must take into account that soil produces significant “background” N₂O emissions even if it is not cultivated. As explained in the WTT main report, the best of a limited range of options is to choose “unfertilized grass” as the land-cover for the calculation of background emissions. This also happens to give a reasonable representation of growing crops on compulsory set-aside land, even though now only a small fraction of the increased crop demand for biofuels targets is considered attainable from abolishing set-aside [DG-AGRI 2007a]

All figures are related to the Lower Heating Value of the **dry matter** (i.e. water-free) of the biomass products. In calculating the lower heating value (LHV), the condensation energy of the water vapour in the flue gas is not counted. In our convention, this arises only from the hydrogen content of the dry-matter. However, some other workers (for example, in the Netherlands) include also the energy for evaporating the water from moist materials. The heat of vaporization is not recovered in the flue gas, so this gives a lower LHV than ours. We do not do this because it causes problems: wood apparently increases in heating value during storage, sewage sludge apparently has a negative LHV, and in the “Dutch” convention energy is not conserved in processes whenever the water content of the products differs from those of the feedstocks. Of course, we take the water content into account when calculating the weight of biomass transported.

For easy comparison with other studies, we express agricultural yields in terms of the “conventional” % moisture: 13.5% for EU-wheat; 10% for oilseeds; 9% for DDGS by-product of wheat-ethanol, sugar beet pulp and dried slops (“solubles”); 0% for wood (see complete table on p.12 of this appendix).

The primary energy and emissions from diesel use in biomass processes include the LHV and the carbon (as CO₂) content of the diesel itself, because the fossil CO₂ 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 N₂O emission calculation (details in the WTT main report).

We call seeds “seeding materials” to avoid confusion with oilseeds as a crop.

Code	Process	Assoc. processes	Input		Expended energy		GHG emissions				N2O emissions		Probability distribution	
			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		
SB1	Sugar Beet Farming													
	CaO fertilizer	AC4	0.0014		2.04	0.0029	0.17	0.0004	0.0000	0.18				
	K2O fertilizer	AC3	0.0005		9.73	0.0047	0.26	0.0007	0.0000	0.28				
	P2O5 fertilizer	AC2	0.0002		15.47	0.0033	0.21	0.0003	0.0000	0.22				
	N fertilizer	AC1	0.0004		49.17	0.0210	1.29	0.0035	0.0041	2.61				
	Pesticides	AC5	0.0000		272.55	0.0013	0.08	0.0001	0.0000	0.08				
	Seeding material		0.0000		33.38	0.0007	0.04	0.0000	0.0000	0.04				
	Diesel	Z1		0.0226	4.18	0.0262	1.98	0.0000	0.0000	1.98				
	Net emissions from field							0.0001	0.0117	3.48	0.0075	0.0208		
	<i>Farm primary energy consumption and emissions ...including 4.5% sugar loss during storage</i>					0.0601	4.03	0.0052	0.0158	8.86				
					0.0628	4.21	0.0054	0.0165	9.26					
	Yields		t/ha/a											
	Sugar beet (dry matter)		17.22											
WT1a	Wheat farming (grain)													
	K2O fertilizer	AC3	0.0002		9.73	0.0021	0.12	0.0003	0.0000	0.13				
	P2O5 fertilizer	AC2	0.0003		15.47	0.0044	0.28	0.0004	0.0000	0.29				
	N fertilizer	AC1	0.0014		49.17	0.0702	4.31	0.0118	0.0138	8.71				
	Pesticides	AC5	0.0000		272.55	0.0083	0.51	0.0008	0.0000	0.53				
	Seeding material		0.0016		2.88	0.0045	0.26	0.0000	0.0000	0.26				
	Diesel	Z1		0.0486	4.18	0.0564	4.25	0.0000	0.0000	4.25				
	Net emissions from field							0.0087	2.58	0.0131	0.0043			
	<i>Sum primary energy consumption and emissions</i>					0.1459	9.73	0.0133	0.0224	16.74				
		Yields		t/ha/a										
	Wheat grain (13.5% moisture, non-food variety)		5.20											
	Straw		4.10											
WT1b	Wheat farming (whole plant)													
	K2O fertilizer	AC3	0.0005		9.7284	0.0049	0.27	0.0008	0.0000	0.29				
	P2O5 fertilizer	AC2	0.0003		15.4653	0.0050	0.32	0.0004	0.0000	0.33				
	N fertilizer	AC1	0.0009		49.1728	0.0419	2.58	0.0071	0.0082	5.20				
	Pesticides	AC5	0.0000		272.5524	0.0010	0.06	0.0001	0.0000	0.06				
	Seeding material		0.0007		2.8772	0.0020	0.06	0.0000	0.0000	0.06				
	Diesel	Z1		0.0240	1.1600	0.0278	2.10	0.0000	0.0000	2.10				
	Net emissions from field							0.0122	3.64	0.0039	0.0203			
	<i>Sum primary energy consumption and emissions</i>					0.0826	5.39	0.0084	0.0204	11.69				
		Yields		t/ha/a										
	Wheat grain (13.5% moisture, non-food variety)		5.20											
	Straw		4.10											
WT1c	Double cropping (maize & barley)													
	N fertilizer	AC1	0.0003		49.1728	0.0164	1.01	0.0028	0.0032	2.03				
	Diesel	Z1		0.0260	1.1600	0.0302	2.28	0.0000	0.0000	2.28				
	Net emissions from field						0.0002	0.0053	1.58					
	<i>Sum primary energy consumption and emissions</i>					0.1815	14.07	0.0195	0.0441	27.70				
		Yields		t/ha/a										
		Maize (6-year average)		68.70										
		Barley (6-year average)		10.00										
		Net emissions from field						0.39	0.0528	0.0067	3.70	0.0027	0.0264	
		<i>Sum primary energy consumption and emissions</i>				0.0210	1.75	0.0550	0.0083	5.61				
SC1	Sugar cane farming (Brazil)													
	CaO fertilizer	AC4	0.0010		0.5669	0.0020	0.11	0.0003	0.0000	0.12				
	K2O fertilizer	AC3	0.0002		2.7023	0.0019	0.11	0.0003	0.0000	0.12				
	P2O5 fertilizer	AC2	0.0001		4.2959	0.0012	0.07	0.0001	0.0000	0.08				
	N fertilizer	AC1	0.0002		13.6591	0.0083	0.51	0.0014	0.0016	1.03				
	Pesticides	AC5	0.0000		75.7090	0.0014	0.09	0.0001	0.0000	0.09				
	Diesel	Z1		0.0053	1.1600	0.0061	0.46	0.0000	0.0000	0.46				
	Net emissions from field						0.39	0.0528	0.0067	3.70	0.0027	0.0264		
	<i>Sum primary energy consumption and emissions</i>					0.0210	1.75	0.0550	0.0083	5.61				
		Yields		t/ha/a										
	Sugar cane (6-year average)		68.70											
WF1	Wood farming and chipping													
	N fertilizer	AC1	0.0005			0.0246	1.51	0.0041	0.0048	3.05				
	Diesel for harvest, sowing etc.	Z1		0.0060		0.0070	0.53	0.0000	0.0000	0.53				
	Land emissions								0.0034	1.02				
	Diesel for chipping			0.0040	4.18	0.0046	0.35	0.0000	0.0000	0.35				
	<i>Primary energy consumption and emissions ...including 2.5% dry-mass losses in chipping and storage</i>					0.0362	2.39	0.0041	0.0082	4.94				
	<i>Sum primary energy consumption and emissions</i>					0.0371	2.45	0.0042	0.0084	5.07				
		Yields		t/ha/a										
		Wood (dry matter)		10.00										

SB1 Sugar Beet Farming

Fertiliser inputs are based on the weighted average of national fertilizer inputs in [EFMA 2008], for countries with sugar-beet ethanol production. They were converted from tonnes/ha to tonnes/MJ of grain using the corresponding yield 68.9 tonnes/ha at 75% moisture. Diesel use per ha was from [FFE 1998] (similar to [ADEME 2003]) and converted to MJ/MJ grain using the same yield. Pesticides/herbicides data are from [Kaltschmitt 1997], amount of seeding material from [FFE 1998].

N₂O emissions from the field dominate the GHG emissions. An average for sugar beet grown in EU15 is calculated using the updated **JRC soil emissions model**, as detailed in the *WTT report, section 3.4*. We assume that the sugar beet leaves are ploughed back into the soil after harvest, which is the usual practice.

In the previous version of this study (2c) we took into account losses of sugar by respiration during storage. However, stakeholders informed us that the quoted sugar beet yield already took into account storage losses, so we eliminated this correction in this version.

WT1a-c Wheat Farming

Wheat is the highest-yielding cereal 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*. As for other crops, **fertiliser inputs** are based on [EFMA 2008], converted from tonnes/ha to tonnes/MJ of grain using the average EU yield of 5.2 tonnes grain per ha at 13.5% moisture, provided by EFMA. Diesel use per ha was averaged between [Crop Energies 2008] and [ADEME 2002] (which gave similar numbers) and converted to MJ/MJ grain using the same yield. Pesticides/herbicides data are from [Crop Energies 2008], amount of seeding material from [ETSU 1996]. The N₂O emissions are calculated by the **updated JRC soils emissions model** (*WTT report, section 3.4*). There is no “reference crop” (see main *WTT report*).

In this version we have introduced **3 sub-versions** for cereal farming. WT1a represents conventional farming for wheat grain. WT1b represents the case where the whole wheat plant is harvested for biogas production (Pathway OWCG4). WT1c is for a ‘double-cropping’ scenario, where two crops are grown each year with the whole plant being harvested in an immature state, again for production of biogas. In practice, a rotation of maize and barley is more suited to this technique than wheat, and it is this case that has been modelled (Pathway OWCG5).

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 over a 6 year period, with an average yield of 82.4 t/ha (moist), so the annualized yield is 68.7 t/ha/a. 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 manual harvesting easier. This is still the most common practice, although it is banned near towns. We used Macedo’s calculation of N₂O, CH₄ and CO₂ emissions from burning, using factors recommended in [IPCC 2001].

Nitrous oxide emissions were calculated from the nitrogen fertilizer additions together (in this version) with the nitrogen content of the vinasse and filter cake 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.

WF1 Wood Farming

This represents Short-Rotation Forestry (SRF) 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, fertilizers, 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 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 Europe 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-Institute 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].

Code	Process	Assoc. processes	Input		Expended energy		GHG emissions				N2O emissions		Probability distribution	
			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	0.0007		9.73	0.0065	0.37	0.0010	0.0000	0.39				
	P2O5 fertilizer	AC2	0.0005		15.47	0.0070	0.45	0.0006	0.0000	0.46				
	N fertilizer	AC1	0.0019		49.17	0.0914	5.62	0.0154	0.0179	11.34				
	Pesticides	AC5	0.0000		272.55	0.0045	0.28	0.0004	0.0000	0.29				
	Seeding material		0.0001		7.14	0.0006	0.02	0.0000	0.0000	0.02				
	Diesel (including drying and storage)	Z1		0.0403	4.18	0.0467	3.53	0.0000	0.0000	3.53				
	Net emissions from field							0.0001	0.0419	12.50	0.0272	0.0675	Double triangle	
	Drying & storage electricity (EU mix LV)	Z7b		0.0031	10.33	0.0088	0.37	0.0009	0.0000	0.40				
	<i>Sum primary energy consumption and emissions</i>				0.1661	10.66	0.0186	0.0599	28.96					
	Yields		t/ha/a											
	Rape seed (dry matter)		2.70											
SF1	Sunflower seed Farming													
	K2O fertilizer	AC3	0.0004		9.7284	0.0037	0.21	0.0006	0.0000	0.22				
	P2O5 fertilizer	AC2	0.0005		15.4653	0.0080	0.51	0.0007	0.0000	0.53				
	N fertilizer	AC1	0.0007		49.1728	0.0331	2.03	0.0056	0.0065	4.10				
	Pesticides	AC5	0.0000		272.5524	0.0091	0.55	0.0008	0.0000	0.58				
	Seeding material		0.0001			0.0006	0.02	0.0000	0.0000	0.02				
	Diesel	Z1		0.0528	4.1760	0.0613	4.62	0.0000	0.0000	4.62				
	Net emissions from field							0.0002	0.0247	7.37	0.0164	0.0342	Normal	
	drying (electricity)			0.0031	10.3273	0.0088	0	0.0009	0.0000	0.39				
		<i>Sum primary energy consumption and emissions</i>				0.1245	8.31	0.0087	0.0312	17.84				
	Yields		t/ha/a											
	Sunflower seed (10% moisture)		2.44											

RF1 Rapeseed Farming

Rape gives the highest oil yield in the Northern half of Europe. However, it still has much lower yield than cereals: it is typically 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 and is needed to improve the organic content of the soil.

Fertiliser inputs are based on [EFMA 2008], converted from tonnes/ha to tonnes/MJ of grain using the average EU yield of 3.1 tonnes per ha at 10 % moisture, provided by EFMA. Diesel use per ha is from [FfE 1998], (which lies between those in [Groves 2002] and [ADEME 2002]), and is converted to MJ/MJ grain using the same yield. Pesticides/herbicides data are from [UBA 1999], amount of seeding material from [Kaltschmitt 1997]. The N₂O emissions are calculated by the **updated JRC soils emissions model** (*WTT report, section 3.4*). 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, in rotation with cereals, although average yields are lower. Inputs are from [FfE 1998], and average EU-15 N₂O field emissions are calculated from the JRC soil model. We assume the straw is ploughed in the soil, which is the usual practice. We assumed the same LHV for sunflower seed as for rapeseed.

The data from EFMA do not specifically include sunflower as a crop. Therefore our fertiliser inputs are based on [ADEME 2002], converted from tonnes/ha to tonnes/MJ of grain using their yield of 2.44 tonnes/ha at 10 % moisture. Diesel use per ha is from [FfE 1998], and is converted to MJ/MJ grain using the same yield. Pesticides/herbicides data are from [ADEME 2002]. The N₂O emissions are calculated by the **updated JRC soils emissions model** (*WTT report, section 3.4*). There is no “reference crop” (see *WTT report*). The dry LHV of rapeseed is 23.8 GJ/t at standard 10% moisture [FfE 1998].

Code	Process	Assoc. processes	Input		Expended energy		GHG emissions				N2O emissions		Probability distribution
			kg/ MJ prod.	MJ/ MJ prod.	Primary MJx/ kg or MJ	Primary MJx/ MJ prod.	g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ MJ prod.	Min	Max	
SY1	Soya bean Farming (Brazil, for oil production)												
	K2O fertilizer	AC3	0.0011		9.7284	0.0108	0.61	0.0017	0.0000	0.65			
	P2O5 fertilizer	AC2	0.0012		15.4653	0.0183	1.16	0.0015	0.0000	1.20			
	N fertilizer	AC1	0.0001		49.1728	0.0070	0.43	0.0012	0.0014	0.86			
	Pesticides	AC5	0.0000		272.5524	0.0132	0.80	0.0012	0.0000	0.84			
	Diesel	Z1		0.0375	1.1600	0.0435	3.28	0.0000	0.0000	3.28			
	Net emissions from field <i>Sum primary energy consumption and emissions</i>					0.0927	6.28	0.0057	0.0411	18.68	0.0147	0.0647	Normal
PO1	Oil palm tree plantation (FFB)												
	K2O fertilizer	AC3	0.0007		9.7284	0.0065	0.36	0.0010	0.0000	0.39			
	P2O5 fertilizer	AC2	0.0005		15.4653	0.0074	0.47	0.0006	0.0000	0.49			
	N fertilizer	AC1	0.0004		49.1728	0.0209	1.28	0.0035	0.0041	2.59			
	Pesticides	AC5	0.0000		272.5524	0.0076	0.46	0.0007	0.0000	0.48			
	Diesel	Z1		0.0069	1.1600	0.0080	0.60	0.0000	0.0000	0.60			
	Net emissions from field <i>Sum primary energy consumption and emissions</i>					0.0503	3.18	0.0060	0.0158	8.03	0.0028	0.0556	Double triangle
CR1	Corn farming Brazil (mass based)		kg/kg corn	MJ/ kg corn		MJ/ kg corn	g CO ₂ / kg corn	g CH ₄ / kg corn	g N ₂ O/ kg corn	g CO ₂ eq/ kg corn			
	K2O fertilizer	AC3	0.0027		9.7284	0.0951	5.35	0.02	0.00	5.73			
	P2O5 fertilizer	AC2	0.0029		15.4653	0.1604	10.21	0.01	0.00	10.58			
	N fertilizer	AC1	0.0033		49.1728	0.5827	35.81	0.10	0.11	72.28			
	Pesticides	AC5	0.0002		272.5524	0.1853	11.30	0.02	0.00	11.77			
	Diesel	Z1		1.0267	1.1600	1.1910	89.89	0.00	0.00	89.89			
	Net emissions from field <i>Sum primary energy consumption and emissions</i>					2.2145	152.56	0.1442	0.5414	317.50	0.1030	1.9450	Double triangle

SY1 Soy Bean Farming

Soy bean meal is the main protein-rich animal feed in Europe. Brazil was the main exporter of soy beans to EU until the recent boom in US soy bean-biodiesel, driven by anomalies in biofuels subsidies between US and EU. This is expected to be a transient phenomenon, so we have retained Brazil as the largest source of future soy beans. Data relative to soy bean farming and downstream processes is required for two purposes:

- As was already the case in previous versions of this study, we use soy meal as the notional “swing” source of animal feed i.e. as a basis for substitution calculations of various biofuels co-products (the substitution calculation methodology, which now also involves wheat, is described in *section 13.1*).
- In this version, we have also included pathways for production of soy bean methyl ester in Europe, which uses the same data (although it now needs to be expressed on an energy basis). Brazil is the largest producer of soy beans and we have modelled production from this source.

Nitrogen fertilizer rates and yields are taken from Brazilian data [FAO 2004] (produced in collaboration with IFA). Pesticide/herbicide application rates are from [Altieri 2005]. Diesel use is from [UBA 1999]. Nitrous oxide emissions are calculated from [IPCC 2006] default values, but the nitrogen content of the below-ground biomass was corrected as described in the main *WTT report section 3.4.2*.

PO1 Palm Oil Plantation

Palm oil methyl ester pathways are also a new addition to this version. A general description of palm oil production is given in the *WTT Report, Section 3.4.10*.

In our calculations, synthetic fertilizer inputs are the recommended use from [FAO 2004], based on replacing nitrogen extracted from the plantation. This nitrogen fertilizer rate is considerably lower than reported by [Teoh 2004], but about the same if we subtract the nitrogen content of the empty palm bunches recycled as mulch. On the other hand, the *actual* fertilizer use reported by FAO is about 1/3 lower and cannot be reconciled with the [Teoh 2004] data. These data are used as the lower uncertainty limit of average fertilizer use. It may represent farming practice close to the mill where there is an excess of mulch available from other growers' palm bunches, or it includes plantations where soil nitrogen has been allowed to fall, and will need to be made up at some point in the future if yields are to be maintained. Another possibility is that the average is lowered by including plantations on drained peat, which need less synthetic nitrogen because of nitrogen mineralized as a result of the decay of organic matter in the soil. Pesticides and diesel use are from [Teoh 2004]. As cited by [S&T Consultants 2007] nitrous oxide emissions were calculated from the nitrogen content of synthetic fertilizer and mulch using [IPCC 2006] guidelines. We think this is probably an underestimate for the part of palm oil grown on drained peat. We do not include the very high emissions of CO₂ (and N₂O) due to decay of peat, since they are due to land use change. However, if synthetic N fertilizer or organic mulch is also applied, the acidic, high-organic, soil is very likely to convert a much larger proportion of the additional nitrogen to N₂O than indicated by the default emission factor in the IPCC guidelines we have used.

CR1 Corn farming

This new process is provided for the calculation of credit for soy meal production (see *section 13.1*) in process SY3b (*section 13.5*). Figures are based on available data for corn farming in Romania (under the assumption that farming input are similar in other parts of the world).

N₂O EMISSIONS CALCULATION FOR ARABLE CROPS

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**, section 3.4.2. 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, sugar cane farming or oil palms 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.

Soy beans are also not covered by the JRC model for EU. However, the results using the IPCC (tier 1) methodology hugely changed from the 1996 guidelines and the 2006 guidelines. Investigating the subject in detail, our colleagues at E4Tech in the UK found that the IPCC 2006 guidelines were seriously in error for leguminous plants in general and for soy beans in particular. We checked their reasoning, and agree with them, as explained in **WTT report** section 3.4.2. Therefore our best estimate of N₂O emissions from soy bean farming uses a corrected form of the 2006 IPCC guidelines, which gives a result between that of the 1996 and 2006 IPCC tier 1 guidelines.

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 kg/ kg prod.	Expended energy			GHG emissions			
				As used MJ/ kg prod.	MJx/ MJ	Primary MJx/ kg prod.	g CO ₂ / kg prod.	g CH ₄ / kg prod.	g N ₂ O/ kg prod.	g CO ₂ eq/ kg prod.
AC1	Nitrogen Fertilizer Provision (as N)									
	Electricity (EU-mix, MV)	Z7a		0.6	2.83	1.78	74.8	0.18	0.0034	80.3
	Hard coal	KO1		3.9	1.09	4.32	404.6	1.51	0.0011	442.6
	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	Z6b		33.0	1.13	37.31	2083.0	6.58	0.0008	2247.8
	N ₂ O from process <i>Primary energy and emissions/kg</i>					49.17	3021.7	8.27	9.6353	6099.9
AC2	P fertilizer provision (as P₂O₅)									
	Electricity (EU-mix, MV)	Z7a		1.6	2.83	4.54	191.2	0.47	0.0086	205.4
	Hard coal	KO1		0.6	1.09	0.62	58.4	0.22	0.0002	63.9
	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	Z6b		3.2	1.13	3.56	198.8	0.63	0.0001	214.6
	<i>Primary energy and emissions/kg</i>					15.47	984.8	1.31	0.0089	1020.3
AC3	K fertilizer provision (as K₂O)									
	Electricity (EU-mix, MV)	Z7a		0.2	2.83	0.62	26.2	0.06	0.0012	28.2
	Diesel	Z1		0.5	1.16	0.63	47.3	0.00	0.0000	47.3
	NG	Z6b		7.5	1.13	8.48	473.4	1.50	0.0002	510.8
<i>Primary energy and emissions/kg</i>					9.73	546.9	1.56	0.0014	586.3	
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	51.2
	Coal	KO1		0.3	1.09	0.35	33.2	0.12	0.0001	36.3
	Diesel	Z1		0.2	1.16	0.21	16.2	0.00	0.0000	16.2
	NG	Z6b		0.3	1.13	0.34	18.9	0.06	0.0000	20.4
<i>Primary energy and emissions/kg</i>					2.04	116.0	0.30	0.0023	124.2	
AC5	Pesticides (etc) provision									
	Electricity (EU-mix, MV)	Z7a		28.5	2.83	80.72	3398.9	8.29	0.1535	3651.9
	Hard coal	KO1		7.6	1.09	8.35	781.8	2.91	0.0021	855.3
	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	Z6b		71.4	1.13	80.71	4505.9	14.24	0.0018	4862.5
<i>Primary energy and emissions/kg</i>					272.55	16623.4	25.45	0.1573	17306.4	

Nitrogen fertilizer inputs are quoted per kg N, whereas the others are expressed per kg P₂O₅, K₂O or CaO equivalent (in practice the active ingredient may actually be present in a mixture of compounds). The kg/MJ inputs of fertilizer to the farming processes use the same convention.

AC1-3 N/P/K Fertilizer Provision

Nitrogen fertilizer is the main source of GHG emissions from agro-chemicals manufacture. Most of the GHG emissions come from N₂O released from the process itself. We thoroughly reviewed data contributed by stakeholders, but found internal inconsistencies for which we could not obtain a satisfactory explanation. Therefore we continue to use the values in [Kaltschmitt 1997] used in previous versions of this study. These figures are also consistent with those in [ECFIN DG241]. In the future, we hope that the data submission in the context of the EU Emission Trading Scheme will provide us with reliable updated industry-average figures.

AC4 Lime (CaO+CaCO₃) Provision

Lime contains roughly 85 % m/m CaCO₃ and 15% 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 CO₂ to the air. Therefore the CO₂ 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 Provision of other farming inputs

This comprises all complex organic compounds used in the farming processes such as pesticides, fungicides, plant hormones etc. The input energy and emissions data (from [Kaltschmitt 1997]) are necessarily a very approximate guess. [ADEME 2003] give a range of 175-576 MJ/kg primary energy for various “plant health products”. Our value of 266 MJ/kg compares well with their best-estimate of 297 MJ/kg. Our emissions are considerably higher than those calculated by [Kaltschmitt 1997] from the same data (they may have overlooked the process emissions). The final fate of the carbon in the pesticides themselves is uncertain, but the amount of CO₂ involved is negligible. In fact, in general, the mass of pesticides in farming processes is so small that the choice of data has negligible effect on the total 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										
Z8a	40 t truck for dry product (round trip considered) Diesel	Z1,Z2			0.94	1.09	81.95			
Z8b	12 t truck for dry product (round trip considered) Diesel	Z1,Z2			2.01	2.01	176.18			
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	Z8a	50	0.004	0.94	1.09	81.95	0.0043	0.33	0.000
WC2b	Wood chips road transport, 12 km	Z8a	12	0.001	0.94	1.09	81.95	0.0010	0.08	0.000
SB2	Sugar beet road transport	Z8a	50	0.013	0.94	1.09	81.95	0.0142	1.07	0.000
WT2a	Wheat grain road transport	Z8a	50	0.003	0.94	1.09	81.95	0.0037	0.28	0.010
WT2b	Wheat straw road transport	Z8a	50	0.003	0.94	1.09	81.95	0.0038	0.28	0.000
WT2c	Wheat whole plant road transport	Z8a	20	0.001	0.94	1.09	81.95	0.0015	0.11	0.000
SC2	Sugar cane road transport	Z8a	20	0.004	0.94	1.09	81.95	0.0040	0.30	0.000
RO2	Rapeseed road transport	Z8a	50	0.002	0.94	1.09	81.95	0.0023	0.17	0.010
SO2	Sunflower seed road transport	Z8a	50	0.002	0.94	1.09	81.95	0.0023	0.17	0.010
PO2	Palm FFB road transport	Z8a	50	0.003	2.01	1.09	176.18	0.0034	0.56	0.020
SY2	Soya bean road transport (Brazil)	Z8a	700	0.126	0.94	1.09	81.95	0.1368	10.33	
Solid biomass shipping										
WC2c	Coastal/river shipping wood chips	Z8a	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										
SC4a	Sugar cane ethanol road transport to port	Z2	700	0.028	0.94	1.09	81.95	0.0305	2.31	
PO4a	Palm oil road transport to port	Z2	150	0.004	0.94	1.09	81.95	0.0048	0.36	
SC4b	Sugar cane ethanol shipping from Brazil	Z4	Naut. Miles 5500	0.380				0.0512	4.11	
PO4b	Vegetable oil shipping	Z4	5500	0.275				0.0371	2.75	

Z8a 40 tonne truck for dry products

This corresponds to the nominal 23 t payload truck from [ESU 1996], consistent with EURO IV emissions limits. 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 for biomass the capacity is often limited by the maximum volume, which is 100 m³. For rapeseed, for example, the actual payload is 22 t, close to the nominal payload. This module is used for all pathways that use truck transport, unless otherwise stated.

Z8b 12 tonne truck for dry products

For transport of palm oil FFB we modelled a smaller truck, which consequently has higher fuel consumption per t.km.

Z10 Ocean-going bulk carrier

This represents a 40,000 t dry product carrier. Heavy fuel oil consumption is from [Kaltschmitt 1997]. The calculation methodology is the same as for liquid transport (see above).

BIOMASS TRANSPORT DISTANCES

FARMED WOOD

For a catchment area 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 the catchment area is 300 dry kt.

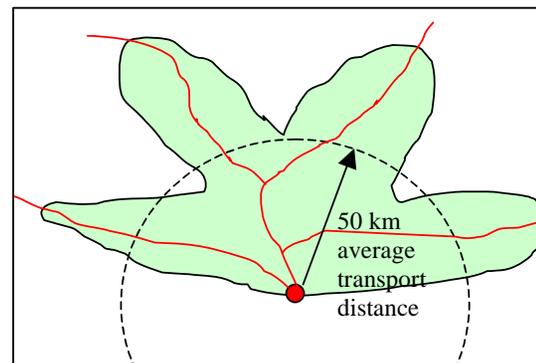
A 10 MW plant (based on feed) requires 16.8 dry kt wood per year (at 18 GJ/t). By quadratic scaling, we need an average transport distance of 12 km. For a 200 MW plant we need 336 dry kt wood per year; implying a single catchment area with an average transport distance of about 50 km.

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 proportion of cereals farms. If we assume 60% of the land is arable, and 70% of that grows wheat (or other suitable cereals), 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 m³ forestry residues per year, with a maximum transport distance of 80 km [TEKES 2002]. That means 90 dry kt/a for a dry-matter density of 0.4 dry t/m³. The average transport distance would then be about 50 km. These forestry residues give a total dry matter 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. Considering the geography of the Baltic this would correspond to maybe 400 km average shipping distance. A central-European scenario, with barge transport on the Rhine or Danube, gives similar results.

For a 10 MW plant, we get about 12 km road transport distance by quadratic scaling from the Pietarsaari example.

BIOENERGY-CROPS

In the literature one can find transport distances from the farm gate to the processing plant anywhere from 10 to almost 200 km. The lower end represents theoretical calculations of the radius needed to grow sufficient crop to feed the factory, on the assumption that all farmers cooperate. 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 finely divided 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.

SY2 Soy bean transport

As explained in *WTT report section 3.4.10* we have assumed that whole beans are transported to Europe where crushing takes place. However the extra soy meal available in Europe as a result replaces soy meal that we otherwise be imported so that the transport cost of the meal is cancelled out. As a result the transport vectors in the soy biodiesel pathways consist in soy bean road transport within Brazil (700 km) and sea shipping of oil only (5500 nautical miles, see PO4b below). The crushing plant is notionally located at an EU port and uses European energy vectors.

As mentioned in *section 9*, SY1 soy meal is also used for calculating animal feed credits in other pathways. Everything in this pathway is related to mass of soy meal, since animal feed replacements are calculated in terms of mass, not lower heating value.

PO2 Palm FFB

The fresh fruit bunches are transported about 50 km to the crushing plant. Stakeholders told us that transport of the FFB takes place using fairly small trucks. We assumed 12 tonne trucks with 7 tonne payloads, and hence relatively high fuel consumption per tonne-km (Z8b).

PO4a Palm oil road transport

After crushing the oil is transported 150 km by road to the port in 40 t trucks (Z8a).

PO4b Vegetable oil shipping

For sea transport of oil to Europe, we used a generic distance of 5500 nautical miles.

12 Biogas from organic materials

12.1 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 CO₂). 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. This should be larger for liquid manure than solid, but we only have an average figure.

Code	Process	Assoc. processes	Bio-feed MJ bio-en/ MJ prod.	Expended energy			GHG emissions				70%	Range		Probability distribution	
				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		1.4286												
	Municipal waste														
	Heat (for info, internally generated)			0.0865									1.2286	1.6286	Square
	Electricity (for info, internally generated)			0.0622									0.0778	0.0952	Square
	Methane losses							0.2000					0.0311	0.0933	Square
	Raw biogas production from liquid manure		1.4286												
	Municipal waste														
	Heat (for info, internally generated)			0.1500											
	Electricity (for info, internally generated)			0.0430											
	Methane losses							0.2000							
	Methane field emissions credit							-2.8571					-1.4286	-4.2857	
	Raw biogas production from dry manure		1.4286												
	Municipal waste														
	Heat (for info, internally generated)			0.1500											
	Electricity (for info, internally generated)			0.0430											
	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											
	Methane losses							0.2000							
	Biogas CHP plant														
	Raw biogas			1.7000											
	Heat generation			-1.0000											
	Electricity generation			-0.5000											
	Methane losses							0.0533							
	Raw biogas to electricity (small scale, local)														
	Raw biogas		2.5000												
	Heat generation			-1.2500											
	Electricity generation			-1.0000											
	Methane losses							0.0778							

Heat and power generation in the biogas plant

Power generation is carried out using a gas engine driving an electrical generator. Where the primary product is biogas, only a small part of the biogas is used in the CHP plant, and the electrical efficiency is 29%. Where the whole biogas production is used to generate electricity a larger engine/generator can be used, with an electrical efficiency of 40%.

heat for the plant needs are generated on site, with a small excess of electricity exported. There is a fertilizer credit from the use of digester residues on the fields.

BG3 Waste biomass to electricity (small scale)

Processes BG3a/b/c follow the same form, but all the biogas is used to produce electricity. The upgrading step is not needed, since the gas engine is tolerant of some impurities in the fuel.

12.2 Biogas from crops

While waste is the most economic source of biomass, biogas digesters can in principle handle a wide range of organic material. In these pathways we explore the options of using cereal crops to produce biogas as an alternative to ethanol. A key difference between the two routes is that, for biogas production, the whole plant, rather than just the grain can be used.

WB1	Whole wheat to biogas (upgraded)												
	Wheat (whole plant)		2.0314										
	Heat (self-generated in CHP)			0.1590									
	Electricity (self-generated in CHP)			0.029									
	Electricity surplus credit			-0.0094	2.8347	-0.0267	-1.12	0.00	0.00	-1.21			
	Fertilizer credit			kg/MJ prod.									
	N			-0.0017		-0.0824	-5.06	-0.01	-0.02	-10.22			
	P2O5			-0.0004		-0.0061	-0.39	0.00	0.00	-0.40			
	K2O			-0.0010		-0.0099	-0.56	0.00	0.00	-0.60			
	Methane losses							0.20	0.00	5.00			
<i>Primary energy consumption and emissions</i>					-0.1250	-7.13	0.18	-0.02	-7.42				
WB2	Double cropping (maize and barley) (upgraded)												
	Wheat (whole plant)		2.1384										
	Heat (self-generated in CHP)			0.1590									
	Electricity (self-generated in CHP)			0.0290									
	Electricity surplus credit			-0.0125	2.8347	-0.0355	-1.49	-0.0036	-0.0001	-1.60			
	Fertilizer credit			kg/MJ prod.									
	N			-0.0004		-0.0210	-1.29	0.00	0.00	-2.61			
	Methane losses							0.20	0.00	5.00			
<i>Primary energy consumption and emissions</i>					-0.0565	-2.79	0.19	0.00	0.79				
Biogas CHP plant													
Biogas		1.7000											
Heat				1.0000									
Power				0.5000									

WB1 Whole wheat to biogas

Wheat is grown to maturity in the normal way and the whole plant (grain and straw) is used in a biogas digester. The residue is used on the fields, reducing fertilizer requirements. A small part of the gas is used to produce electricity and heat for the plant, with the excess electricity being exported. The remainder of the gas is cleaned and upgraded so that it can be fed into the natural gas grid.

WB2 Double cropping whole plant maize and barley to biogas

This process is similar to WB1 except for the source of biomass. Two crops are grown each year, with the whole plant being harvested perhaps before it reaches maturity. In European conditions, maize and barley look the best crops for this purpose where the objective is simply to maximise the amount of biomass produced.

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 N₂O emissions. Therefore we do not attempt to indicate an uncertainty 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 Credit Calculation for Animal Feed By-Products

In this version we have introduced a consistent method for calculating the credit for animal feed, based on balancing protein and digestible energy requirements off animal feeds. This is detailed in *WTT report section 3.4.4*.

By-products often require drying before they can be used conveniently as animal feed, and this can consume more energy than the credit for the feedstocks replaced. Usually, however, waste heat from the process can be used, as detailed for particular processes below. Using by-products as animal feed reduces imports of agricultural commodities. If one is calculating also the emissions due to indirect land use change (which we do not), this could be a significant effect: it could turn out that using by-products for animal feed ends up saving more GHG emissions (overall) than using them for energy purposes.

13.2 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
SB3a	Sugar beet to ethanol, pulp to animal feed, slops not used														
	Sugar beet		1.8395			0.8395						1.7475	1.9315	Normal	
	Energy for main process														
	NG for steam at 90% eff.	Z6b		0.3118	1.1306	0.3525	70.84	0.22	0.00	76.45		0.2963	0.3273	Normal	
	Electricity (MV)	Z7a		0.0401	2.8347	0.1137	17.24	0.0420	0.0008	18.52		0.0384	0.3676	Normal	
	Sugar beet pulp (9% moisture)			kg/MJ prod.							kg/kg				
	Credit for substitution of														
Wheat grain (13% moisture)	WT1a		-0.0241	0.6889	-0.0598	-3.99	-0.0055	-0.0153	-8.70	0.866					
Soy meal (11% moisture)	SYML		-0.0004	1.2557	-0.0016	-0.09	0.00	0.00	-0.14	0.013					
	<i>Net primary energy consumption and emissions</i>					1.2442	20.38	0.0683	-0.0152	17.55					
SB3b	Sugar beet to ethanol, pulp to animal feed, slops to biogas														
	Sugar beet		1.8395			0.8395						1.7475	1.9315	Normal	
	Energy for main process														
	NG for steam at 90% eff.	Z6b		0.1159	1.1306	0.1310	26.33	0.08	0.00	28.42		1.1011	0.1217	Normal	
	Electricity (MV)	Z7a		0.0454	2.8347	0.1287	19.51	0.0476	0.0009	20.97		0.0399	0.4201	Normal	
	Sugar beet pulp (9% moisture)			kg/MJ prod.							kg/kg				
	Credit for substitution of														
Wheat grain (13% moisture)	WT1a		-0.0241	0.6889	-0.0598	-3.99	-0.0055	-0.0153	-8.70	0.866					
Soy meal (11% moisture)	SYML		-0.0004	1.2557	-0.0016	-0.09	0.00	0.00	-0.14	0.013					
	<i>Net primary energy consumption and emissions</i>					1.0378	8.65	0.0308	-0.0152	4.88					
SB3c	Sugar beet to ethanol, pulp to fuel, slop to biogas digester and CHP														
	Sugar beet		1.8395			0.8395						1.7475	1.9315	Normal	
	Electricity credit (MV)	Z7a		-0.0404	2.8347	-0.1145	-17.36	-0.0423	-0.0008	-18.65					
	<i>Net primary energy consumption and emissions</i>					0.7250	-17.36	-0.0423	-0.0008	-18.65					

SB3a Ethanol from sugar beet, pulp used as animal feed, slops not used

Following [LBST 2002] we chose a conventional fermentation plant, not integrated with a sugar refinery, as analysed by [FfE 1998]. 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 kJ electricity (from the grid) and 0.28 MJ heat [FfE 1998], which we assume is supplied by a natural gas boiler with 90% efficiency i.e. 0.31 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 and the slops filtered from the fermented. When the equivalent products from cereals fermentation are sold for animal feed, they are called “distiller’s dried grains” and “solubles”, usually sold together. Both beet by-products have a dry LHV of 15 MJ/kg [FfE 1998], contain initially 35-40% water, and have to be dried to about 9% water [FfE 1998], [NRC 1998]. In addition there is a small amount of electricity required for the blowers. In this version we have assumed that the pulp is dried evaporatively using waste heat which considerably reduces the overall energy requirement and GHG emissions compared to the previous version where conventional drying using natural gas generated heat was assumed.

Sugar factories using beet do not work all year round because sugar beet have to be processed quickly after harvest to avoid sugar loss in storage (see SB1 farming pathway). Beet processing “campaigns” typically last between 60 days (Poland) and 150 days (Britain). Average for EU-25 is about 90 days (also the German figure). However, it is possible to keep the ethanol part of the plant working continuously by storing pasteurised syrup. The size of the plant is not very important for efficiency, but has a large effect on costs. [FfE 1998] made a cost analysis on a hypothetical 59 MW (ethanol) plant.

SB3b Sugar beet to ethanol, pulp to animal feed, slops to biogas

This pathway is new. The slops are treated in an anaerobic digester to produce biogas, providing some of the plant energy needs, and reducing natural gas consumption. Electricity consumption increases slightly to power the biogas plant. We assume 1 MJ biogas substitutes 1 MJ 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 we do not account for this.

SB3c Ethanol from sugar beet, pulp burned to produce heat and electricity, slops to biogas

This pathway is also new. The sieved pulp mash is burned in a boiler and the slops continue to produce biogas. Both are used in a CHP plant to produce electricity and heat with an electrical efficiency of 20% (typical for a small scale steam turbine). This is sufficient to fully meet the needs of the plant. There is excess electricity and heat. The former is exported and produces a credit, while the surplus heat is considered to have no value.

13.3 Ethanol from wheat grain

Code	Process	Assoc. processes	Bio-feed MJ bio-en/ MJ prod.	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
				As used MJ/ MJ prod.	MJ/ MJ	Primary MJ/ MJ prod.	g CO2/ MJ prod.	g CH4/ MJ prod.	g N2O / MJ prod.	g CO2eq / MJ prod.		Min	Max	
WT3	Wheat grain handling Wheat grain Electricity (MV) <i>Net primary energy consumption and emissions</i>		1.0000	0.0004	2.8347	0.0011 0.0011	0.05 0.05	0.0001 0.0001	0.0000 0.0000	0.05 0.05				
WT4a	Wheat grain to ethanol, conventional boiler Wheat grain Heat to process NG for steam at 90% eff. Electricity (MV) <i>Net primary energy consumption and emissions</i>	Z6b Z7a	1.8644	0.3640 0.4044 0.0540	1.1306 2.8347	0.8644 0.4573 0.1531 1.4747	25.53 6.45 31.97	0.0807 0.0157 0.0964	0.0000 0.0003 0.0003	27.55 6.93 34.47			tdw g/t EtOH 3.0300	
WT4b	Wheat grain to ethanol, NG CCGT Wheat grain Heat to process Electricity to process NG to CCGT Electricity net surplus Credit for electricity surplus based on NG to state-of-the-art stand-alone CCGT <i>Net primary energy consumption and emissions</i>		1.8644	0.3640 0.0540 0.6794 -0.1867 -0.3395	1.1306 1.1306	0.8644 0.7681 -0.3839 1.2486	42.88 -21.43 21.45	0.1356 -0.0677 0.0678	0.0000 0.0000 0.0000	46.27 -23.13 23.15			tdw g/t EtOH 3.0300	
WT4c	Wheat grain to ethanol, Lignite CHP Wheat grain Heat to process Electricity to process Lignite to CHP plant Electricity net surplus Credit for electricity surplus based on lignite-fired conv. power station <i>Net primary energy consumption and emissions</i>		1.8644	0.3640 0.0540 0.7761 -0.0775 -0.1937	1.0156 1.0156	0.8644 0.7882 -0.1967 1.4559	89.28 -22.15 67.13	0.0000 0.0000 0.0000	0.0000 0.0000 0.0000	89.28 -22.15 67.13			tdw g/t EtOH 3.0300	
WT4d	Wheat grain to ethanol, Straw CHP Wheat grain Heat to process Electricity to process Straw to CHP plant Debit for additional fertilisers (net) N P2O5 K2O Total Electricity net surplus Credit for electricity surplus based on straw-fired conv. power station <i>Net primary energy consumption and emissions</i>		1.8644	0.3640 0.0540 0.7761	1.0165 13.6591 4.2959 2.7023 0.0047 1.0165	0.8644 0.7889 0.0000 0.0011 0.0037 0.0047 1.4080	0.96 0.00 0.07 0.21 0.27 -0.31 0.93	0.0000 0.0000 0.0001 0.0006 0.0007 0.0000 0.0007	0.0000 6.10 0.07 0.22 0.205 -0.31 0.0205	0.97 6.10 0.07 0.22 6.39 -0.31 7.06			tdw g/t EtOH 3.0300	
WTDa	Credit for DDGS as animal feed Credit for substitution of Wheat grain (13% moisture) Soy meal (11% moisture) <i>Net primary energy consumption and emissions</i>			kg/MJ EtOH -0.043 -0.0326 -0.0129	0.6889 1.2557	-0.0808 -0.0583 -0.1391	-5.39 -3.33 -8.72	-0.0074 -0.0030 -0.0103	-0.0207 -0.0051 -0.0258	-11.74 -4.91 -16.65			kg/kg 0.766 0.303	
WTDb	Credit for DDGS as fuel Electricity (MV)	Z7a		kg/MJ EtOH -0.043 -0.2042	2.8347	-0.5788	-24.37	-0.0594	-0.0011	-26.18				

WT3 Wheat Grain Handling

The data used here are essentially derived from [LowCVP 2004]. On the advice of stakeholders, the drying step in process WT3 has been removed which results in no diesel and lower electricity consumption in this step compared to *version 2c* of this study. 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 a number 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. After consultation with stakeholders we increased the efficiency of the combined heat and power plant in line with actual plant data resulting in lower energy consumption and emissions compared to version 2c of this study.

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 5.2.6*). 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 is 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

The DDGS credit is calculated according to the methodology referred to in *section 13.1*.

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.

WT4e Wheat grain to ethanol, DDGS to biogas

So far, use of DDGS has been modelled either as animal feed or as a fuel, directly producing heat and electricity. This new pathway considers an alternative route where the DDGS is fed to a biogas digester. The biogas is fed to a CHP plant providing all the energy required for the plant as well as a surplus of electricity which is exported, thereby generating a credit. We assume that surplus heat cannot be used and so does not generate a credit.

13.4 Ethanol from sugar cane (Brazil)

Code	Process	Assoc. processes	Bio-feed MJ bio-en/ MJ prod.	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
				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	
SC3a	Sugar cane to ethanol, heat credit for surplus bagasse													
	Sugar cane		2.7720			1.7720								
	Credit for surplus heat (NG)			-0.1278	1.1306	-0.1445	-8.0651							
					kg/MJ EtOH	MJ/kg								
	H2SO4	C7			0.00042	4.0052	0.0017	0.08	0.0002	0.0000	0.09			
	CaO	C6			0.00047	4.9835	0.0024	0.50	0.0004	0.0000	0.51			
	Cyclohexane			0.00003	9.9000	0.0003	0.00	0.0000	0.0000	0.00				
	<i>Primary energy consumption and emissions</i>					1.6318	-7.48	-0.0249	0.0000	-8.10				
SC3b	Sugar cane to ethanol, no credit for surplus bagasse													
	Sugar cane		2.7720			1.7720								
					kg/MJ EtOH	MJ/kg								
	H2SO4	C7			0.0004	4.0052	0.0017	0.08	0.0002	0.0000	0.09			
	CaO	C6			0.0005	4.9835	0.0024	0.50	0.0004	0.0000	0.51			
		Cyclohexane			0.0000	9.9000	0.0003	0.01	0.0000	0.0000	0.01			
	<i>Primary energy consumption and emissions</i>					1.7763	0.59	0.0006	0.0000	0.61				

SC3a Sugar cane ethanol with credit for surplus bagasse

Data for this process were taken from the comprehensive life-cycle analysis by [Macedo 2004], adopting his “scenario 2” which describes 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 neglected to be consistent with our calculations for other processes.

The data refer to the production of *anhydrous* ethanol. 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, operating for 180 days per year. A very important factor is that the bagasse is used to raise steam which provides all the process heat, and electricity via a steam turbine. In fact modern plants have a surplus of bagasse, usually sold as a fuel for nearby factories (e.g. for food processing), where it mostly replaces fuel oil (almost identical to diesel which we used for credit calculation), and this is what we have modelled. In the future excess bagasse will increasingly be used to generate electricity for export

SC3b Sugar cane ethanol, no credit for surplus bagasse

This new pathway represents a case where external uses for the surplus bagasse cannot be found. In other aspects it is identical to SC3a. Bagasse is still used to meet the energy needs of the ethanol plant, so overall GHG emissions remain low.

13.5 Biodiesel for 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
RO3a	Rapeseed to raw oil: extraction														
	Rapeseed		1.6326			0.6326							1.5510	1.7142	Normal
	Electricity (MV)	Z7a		0.0092	2.8347	0.0261	1.10	0.0027	0.0000	1.18					
	NG for steam at 90% eff.	Z6b		0.0442	1.1306	0.0500	2.79	0.0088	0.0000	3.01			0.0420	0.0464	Normal
	n-hexane		0.00	0.0031	1.1600	0.0036	0.27	0.0000	0.0000	0.27					
	Rapeseed meal (10% moisture)														
	Credit for rapeseed meal														
Soya meal (11% moisture)	SYML			-0.0156	4.5205	-0.0705	-4.02	-0.0036	-0.0061	-5.94	0.382				
Wheat grain (13% moisture)	WT1a			-0.0195	2.2213	-0.0434	-2.91	-0.0039	-0.0109	-6.24	0.479				
<i>Primary energy consumption and emissions</i>						0.5983	-2.77	0.0041	-0.0169	-7.71					
RO3b	Rapeseed to raw oil: extraction, meal to biogas														
	Rapeseed		1.6326			0.6326							1.5510	1.7142	Normal
	Electricity export (MV)	Z7a		-0.1182	2.8347	-0.3351	-14.11	-0.0344	-0.0006	-15.16					
	Heat surplus (for info, no credit given)			0.0924											
	n-hexane			0.0031	1.1600	0.0036	0.27	0.0000	0.0000	0.27					
	Credit for N fertilizer														
<i>Primary energy consumption and emissions</i>						0.1815	-21.19	-0.0545	-0.0241	-29.73					
SO3a	Sunflower seed to raw oil: extraction														
	Sunflower seed		1.5200			0.5200							1.4440	1.5960	Normal
	Electricity (MV)	Z7a		0.0085	2.8347	0.0242	1.02	0.0025	0.0000	1.10					
	NG for steam at 90% eff.	Z6b		0.0411	1.1306	0.0465	2.59	0.0082	0.0000	2.80			0.0390	0.0431	Normal
	n-hexane		0.00	0.0029	1.1600	0.0034	0.25	0.0000	0.0000	0.25					
	Sunflower seed meal (10% moisture)														
	Credit for sunflowerseed meal														
Soya meal (11% moisture)	SYML			-0.0088	4.5205	-0.0397	-2.2646	-0.0020	-0.0034	-3.3423	0.215				
Wheat grain (13% moisture)	WT1a			-0.0227	2.2213	-0.0504	-3.3721	-0.0045	-0.0126	-7.2376	0.556				
<i>Primary energy consumption and emissions</i>						0.5040	-1.77	0.0042	-0.0160	-6.43					
SO3b	Sunflower seed to raw oil: extraction, meal to biogas														
	Sunflower seed		1.5201			0.5201							1.4440	1.5960	Normal
	Electricity (MV)	Z7a		0.0209	2.8347	0.0592	2.49	0.0061	0.0001	2.68					
	NG for steam at 90% eff.	Z6b		-0.2872	1.1306	-0.3247	-18.13	-0.0573	0.0000	-19.56					
	n-hexane			0.0029	1.1600	0.0034	0.25	0.0000	0.0000	0.25					
	Credit for N fertilizer														
<i>Primary energy consumption and emissions</i>						0.1884	-19.65	-0.0629	-0.0135	-25.25					

RO3a/b 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.

In RO3a the rapeseed cake is used as animal feed, substituting a mix of soy bean and feed wheat according to the generic methodology described in Section 13.1. RO3b is a new process where the rapeseed cake is used to generate biogas which provides all the heat and a large part of the electricity for the process, improving the energy and GHG balance.

SO3a/b Sunflower Oil Extraction

The process is similar to rapeseed oil extraction with data from [UBA 1999]. The sunflower 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 and wheat is smaller.

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
SY3a	Soya beans to raw oil: extraction, meal substituting wheat														
	Soya beans			2.9066			1.9066								
	Electricity (MV)	Z7a		0.0343	2.8347	0.0972	4.09	0.0100	0.0002	4.40					
	NG for steam at 90% eff.	Z6b		0.1614	1.1306	0.1825	10.19	0.0322	0.0000	11.00		0.1533	0.1696	Square	
	n-hexane			0.0046	1.1600	0.0053	0.40	0.0000	0.0000	0.40					
					kg/MJ prod.	MJ/kg									
	Soya meal (11% moisture) Credit for soya meal				-0.118						kg/kg	1.0784			
Wheat grain (13% moisture)	WT1a			-0.4581	0.6889	-0.3156	-21.05	-0.0288	-0.0809	-45.86					
<i>Primary energy consumption and emissions</i>						1.8761	-6.36	0.0134	-0.0807	-30.06					
SY3b	Soya beans to raw oil: extraction, meal substituting corn														
	Soya beans			2.9066			1.9066								
	Electricity (MV)	Z7a		0.0343	2.8347	0.0972	4.09	0.0100	0.0002	4.40					
	NG for steam at 90% eff.	Z6b		0.1614	1.1306	0.1825	10.19	0.0322	0.0000	11.00		0.1533	0.1696	Square	
	n-hexane			0.0046	1.1600	0.0053	0.40	0.0000	0.0000	0.40					
					kg/MJ prod.	MJ/kg									
	Soya meal (11% moisture) Credit for soya meal				-0.118						kg/kg	0.976			
Corn	CR1			-0.4146	0.6152	-0.2550	-17.57	-0.0166	-0.0624	-36.57					
<i>Primary energy consumption and emissions</i>						1.9367	-2.88	0.0256	-0.0622	-20.77					
SY3c	Soya beans to raw oil: extraction, allocation by market value											Assumptions:			
	Soya beans			1.6869			0.6869					- Oil/meal yields: 0.188/0.812			
	Electricity (MV)	Z7a		0.0182	2.8347	0.0516	2.17	0.0053	0.0001	2.33	- Oil/meal value: 1356/227 \$/t				
	NG for steam at 90% eff.	Z6b		0.0937	1.1306	0.1059	5.91	0.0187	0.0000	6.38	- Oil/meal resulting allocation factors: 0.58/0.42				
	n-hexane			0.0027	1.1600	0.0031	0.23	0.0000	0.0000	0.23					
	<i>Primary energy consumption and emissions</i>						0.8475	8.32	0.0240	0.0001	8.95				

SY3a/b Soya beans to raw oil: extraction

Soy beans only yield about 20 %m/m of oil, the balance being meal. As a result, when applying a substitution methodology the fate of the meal as a co-product becomes overwhelming in the energy and GHG balance of the oil. Finding a substitute for the meal is difficult since soy bean meal itself is considered the swing source of protein for animal feed.

The data for raw oil extraction is taken from [UBA 1999]. In the main *WTT report section 3.4.10*, we describe how we modified the present “default” SYFA1 pathway scenario. *Note that it gives a better GHG balance than that reported in our intermediate posting of results on the internet in November 2008.* It uses SY3b process, which assumes that Brazilian soy beans are crushed in EU, and the soy meal by-product substitutes soy meal previously imported from Brazil (unlike the November 2008 scenario, this compensates for the transportation emissions of the soy meal part of the soy beans). Back in Brazil, the reduced price of protein leads to greater inclusion of soy meal in animal diets, at the expense of maize.

Our previous “default” SYFA1 scenario used SY3a for the extraction phase, which grants a credit for soy bean meal produced in EU, replacing EU-wheat. In that case the oil supports the energy burden of transporting the whole beans from Brazil to Europe, so an unfairly poor GHG result was obtained. That pathway is now denoted SYFA1b.

For comparison, we also show, SY3c (used in pathway SYFA1c) the result of allocating the soy bean inputs between the oil and the meal on the basis of economic values.

Note that the processes as shown do not include the impact of transport for which processes from *section 11* are used.

Code	Process	Assoc. processes	Bio-feed MJ bio-en/ MJ prod.	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution		
				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			
PO3	Palm FFB to raw oil: extraction		1.9000			0.9000										
	FFB			kg/MJ	0.0000	0.0000										
	Palm kernel meal			0.0030												
	Credit for palm kernel meal											kg/kg				
	Soya meal (11% moisture)			-0.0048	1.2557	-0.0218	-1.24	-0.0011	-0.0019	-1.83	0.118					
	Wheat grain (13% moisture)		-0.0290	0.6889	-0.0719	-4.79	0.0433	-0.0127	-7.49	0.71						
	<i>Primary energy consumption and emissions</i>				0.8064	-6.04	0.0422	-0.0146	-9.32							
PO3a	Methane emissions from waste						0.9441		23.60							
PO3b	Credit for surplus heat (diesel)			-0.0187	1.1653	-0.0218	-0.27									

PO3 Palm FFB to raw oil: extraction

The FFB yields around 20% oil (90% of which is from the flesh, 10% from the kernal). The composition of the two oils is different, but they can both be used to make biofuels. In addition, a small amount of palm kernel meal is produced (about 2.5% of the FFB by mass). This is given credit as animal feed using a mix of soy meal and wheat (See *section 13.1*). Because there is a large amount of residual biomass, the heat and electricity mill can be powered from this source. Empty fruit bunches are returned to nearby plantations and used as mulch. Methane emissions from waste are assumed to be collected in this process.

Figures for yield, heat output from mesocarp fibre and shell palm kernel meal are taken from [*Teoh 2004*].

PO3a Palm Oil - Methane emissions from waste

Waste material from palm oil production can produce significant quantities of methane if stored in anaerobic conditions. There are still differences between the best and worst practices, and even with the best care some emissions from wastewater ponds will occur. We have estimated emissions from wastewater for current best practice using figures from oil industry sources.

PO3b Palm Oil - Credit for surplus heat (diesel)

Palm biomass provides sufficient energy to meet the needs of the crushing plant. In addition there is an excess that can be exported to provide local heat where opportunities exist.

Code	Process	Assoc. processes	Bio-feed MJ bio-en/ MJ prod.	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
				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	
RO4	Raw oil to refined oil Crude plant oil Electricity, MV NG for steam at 90% eff. <i>Primary energy consumption and emissions</i>	Z7a Z6b	1.0417	0.0008 0.0091	2.8347 1.1306	0.0417 0.0022 0.0103 0.0541	0.09 0.58 0.67	0.0002 0.0018 0.0020	0.0000 0.0000 0.0000	0.10 0.62 0.72				

RO4 Plant Oil Refining

The refining step purifies the plant oil so it is ready for esterification and is assumed to be the same regardless of whether rapeseed, sunflower, soy or palm oil is used. 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].

Code	Process	Assoc. processes	Bio-feed MJ bio-en/ MJ prod.	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution	
				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		
RO5a	Refined oil to FAME: esterification Refined plant oil Electricity EU mix, MV Methanol NG for steam at 90% eff. Various other chemicals <i>Primary energy and emissions (no glycerine credit)</i>	Z7a GA1 Z6b 0.00	1.0065			0.0065									
				0.0037	2.8347	0.0106	0.45	0.0011	0.0000	0.48					
				0.0585	1.6543	0.0968	5.40	0.0171	0.0000	5.83	0.0556	0.0614			
				0.0461	1.1306	0.0521	2.91	0.0092	0.0000	3.14	0.0438	0.0484			
					0.0103	0.14	0.0000	0.0000	0.14						
					0.1763	8.90	0.0274	0.0000	9.59						
				kg/MJ prod.											
						-0.0028									
5a	Credit for propylene glycol replaced by glycerine <i>Primary energy consumption and emissions</i>	C10				-0.0589	-5.94	-0.0070	-0.0002	-6.16					
						0.1173	2.96	0.0204	-0.0001	3.43					
				kg/kg											
5b	Credit for glycerine replacing wheat grain (LHV basis) <i>Primary energy consumption and emissions</i>	WT1a				-0.0072	-0.48	-0.0007	-0.0018	-1.04					
						0.1691	8.42	0.0267	-0.0018	8.55					
				kg/kg											
RO5c	Refined oil to FAME: esterification with glycerine to biogas Refined plant oil Electricity EU mix, MV Methanol NG for steam at 90% eff. Various other chemicals <i>Primary energy and emissions</i>	Z7a GA1 Z6b	1.0065	0.0031	2.8347	0.0065	0.37	0.0009	0.0000	0.39					
				0.0585	1.6543	0.0968	5.40	0.02	0.00	5.83	0.0556	0.0614	Normal		
				0.0092	1.1306	0.0104	0.58	0.0018	0.0000	0.63	0.0088	0.0097	Normal		
						0.0103	0.14	0.0000	0.0000	0.14					
						0.1327	6.49	0.0198	0.0000	6.99					
				kg/MJ prod.											
						-0.0026									
RO6a	Refined oil to FAEE: esterification Refined plant oil Electricity EU mix, MV Ethanol NG for steam at 90% eff. Various other chemicals Primary energy and emissions (no glycerine credit)	Z7a WTET2a Z6b	0.9627	0.0037	2.8347	-0.0373	0.45	0.0011	0.0000	0.48					
				0.1100	1.4178	0.1560	0.94	0.0026	0.0013	1.40	0.1045	0.1155			
				0.0461	1.1306	0.0521	2.91	0.0092	0.0000	3.14	0.0438	0.0484			
						0.0030	0.14	0.0000	0.0000	0.14					
						0.1844	4.43	0.0129	0.0014	5.16					
				kg/MJ prod.											
						-0.0026									
6a	Credit for typical chemical replaced by glycerine <i>Primary energy consumption and emissions</i>	C10				-0.0589	-5.94	-0.0070	-0.0002	-6.16					
						0.1254	-1.51	0.0059	0.0012	-1.00					
				kg/kg											
6b	Credit for glycerine replacing wheat grain (LHV basis) <i>Primary energy consumption and emissions</i>	WT1a				-0.0003	-0.02	0.0000	0.0000	-0.02					
						0.1841	4.41	0.0129	0.0014	5.13					
				kg/kg											
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															
RO6b	Refined oil to FAEE: esterification with glycerine to biogas Refined plant oil Electricity EU mix, MV Ethanol NG for steam at 90% eff. Various other chemicals <i>Primary energy and emissions</i>	Z7a WTET2a Z6b	1.0065	0.0031	2.8347	0.0065	0.37	0.0009	0.0000	0.40					
				0.1100	1.4178	0.1560	0.94	0.0026	0.0013	1.40	0.1045	0.1155	Normal		
				0.0123	1.1306	0.0139	0.78	0.0025	0.0000	0.84					
						0.0103	0.14	0.0000	0.0000	0.14					
						0.1956	2.23	0.0060	0.0014	2.78					

RO/SO5 Esterification (methanol)

The process is the same for rapeseed, sunflower soy and palm oils. 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 of FAME is taken at 37.2 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 from a list of minor inputs (NaOH, Na₂CO₃, H₃PO₄, 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. Compared to version 2c of this study, **the steam requirement for glycerine distillation was corrected downwards and we also removed the glycerine purification step**, which was found to be unnecessary. RO5b/SO5b include a credit for glycerine replacing wheat as an animal feed. We know that glycerine is easily digestible by cattle: we assumed 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.

In the new RO5c glycerine is used to produce biogas, significantly reducing the energy input into the process.

RO/SO6 Esterification (ethanol)

Same as RO/SO5 replacing methanol by ethanol.

13.6 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 CO₂) content of the input fuels in our “MJ primary energy” and CO₂ emissions figures associated with fuels inputs.

Code	Process	Assoc. processes	Input kg/ kg prod.	Expended energy			GHG emissions			
				As used MJ/ kg prod.	MJx/ MJ	Primary MJx/ kg prod.	g CO ₂ / kg prod.	g CH ₄ / kg prod.	g N ₂ O/ kg prod.	g CO ₂ eq/ kg prod.
C6	Pure CaO for processes									
	Natural gas	Z6b		4.08	1.1306	4.62	257.7	0.8146	0.0001	278.1
	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
	CaCO ₃ =CaO+CO ₂ <i>Primary energy and emissions/kg</i>					4.98	1067.6	0.8326	0.0004	1088.6
C7	Sulphuric acid									
	Electricity (EU mix-MV)	Z7a		0.76	2.8347	2.15	90.7	0.2211	0.0041	97.4
	NG	Z6b		1.64	1.1306	1.85	103.4	0.3268		111.6
	<i>Primary energy and emissions/kg</i>					4.01	194.1	0.5479	0.0041	209.0
C8	Ammonia									
	NG	Z6b			10.90	1.0462	11.40	2323.3	4.3077	2431.0
C10	Propylene glycol (alternative credit for esterification process)									
	Propylene from crude oil					0.0000	6.63	1500.0		1532.8
	Electricity (EU mix-MV)	Z7a		5.00	2.8347	14.17	596.8	1.4554	0.0269	641.2
	<i>Primary energy and emissions/kg</i>					20.80	2096.8	1.4554	0.0269	2174.0
SY3	Soya meal from crushing beans (same process as for production of soya oil with meal as by-product, now expressed per kg meal)									
	Electricity (EU mix-MV)	Z7a		0.29	2.8347	0.82	34.7	0.0846	0.0016	37.3
	NG for steam at 90% eff.	Z6b		1.37	1.1306	1.55	86.4	0.2730	0.0000	93.2
	n-hexane			0.04	1.1600	0.05	4.0			4.0
	Plant oil by-product credit (based on sunflower) <i>Primary energy and emissions/kg</i>			-0.23		-1.47	-119.5	-0.2684	-0.6211	-311.3
						0.94	5.6	0.0892	-0.6195	-176.8
SYML	Soya meal supply (for calculation of rape and sunflower meal credit)									
					kg biomass/kg meal					
	Soy beans farming/kg meal			4.43	0.0927	2.28	154.8	0.1399	1.0125	460.0
	Soy beans transport/kg meal	SY1		4.43	0.0526	1.30	97.8			97.8
	Soy meal from beans crushing <i>Primary Energy and emissions per kg</i>	SY2/PO4b		3.60		0.94	5.6	0.0892	-0.6195	-176.8
					4.52	258.1	0.2291	0.3930	381.0	

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 CO₂ emissions from the calcining process should be included. Data is from [GEMIS 2002].

C7 Sulphuric Acid

Used in SSCF digestion. Data is from [ESU 1996]. Sulphur mining is neglected.

C8 Ammonia

Used in SSCF processes. Data is from [Kadam 1999].

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 CO₂) in its “primary energy and emissions”. This saves having to add them separately when we come to calculate the credit.

SY3 Soy 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 CO₂ credit by substituting sunflower oil (*in the version 2c of this study we took rapeseed oil as the substitute, but sunflower oil is more similar to soy oil*). This is how we calculated the credit: we found the energy and emissions for making 1MJ sunflower oil starting with the energy and emissions from the oil mill (process SO3), and adding (energy and emissions from the sunflower farming, per MJ SFseed)*(MJ of SFseed 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 sunflower oil extraction itself has a credit for sunflower meal, which partly replaces soy bean meal, we have a loop. However, this is not a problem: one merely iterates the calculation: the result converges on the correct solution, which can also be attained by elementary algebra. Effectively, a little of the soy oil product needs to be diverted to replace the missing sunflower oil due to the sunflower meal credit: this slightly increases the emissions per MJ of product.

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. The transport calculation has been updated from Version 2.

13.7 Hydrotreated Plant Oil

Code	Process	Assoc. processes	Bio-feed MJ bio-en/ MJ prod.	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution		
				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			
OY1a	Plant oil hydrotreating (NexBTL)		1.0341													
	Plant oil	GH1b				0.0341										
	Hydrogen (from NG)			0.0857	1.3150	0.1127	6.20	0.0014	0.0000	6.24			0.0771	0.0943	Square	
	Credits for energy export NG for steam at 90% eff.	Z6b		-0.0089	1.1306	-0.0100	-0.56	-0.0018	0.0000	-0.61						
	Electricity (EU-mix MV)	Z7a		-0.0017	2.8347	-0.0047	-0.20	-0.0005	0.0000	-0.21						
<i>Primary energy and emissions</i>				0.1320	5.44	-0.0009	0.0000	5.42								
OY1b	Plant oil hydrotreating (UOP)		0.9100			-0.0900										
Plant oil	GH1b				0.1447	7.96	0.0018	0.0000	8.01							
Hydrogen (from NG)		0.1100		1.3150	0.0011	0.09	0.0000	0.0000	0.09							
HFO	Z3	0.0130		0.0880	0.0163	0.91	0.0029	0.0000	0.98							
NG for steam at 90% eff.	Z6b	0.0144		1.1306	0.0149	0.63	0.0015	0.0000	0.67							
Electricity (EU-mix MV)	Z7a	0.0053	2.8347		9.59	0.0062	0.0000	9.75								
	<i>Primary energy and emissions</i>			0.0870												

We have included two options representing the two processes that are currently on the market i.e. Neste Oil's NexBTL process and UOP's Ecofining process. Data were obtained directly from the process licensors in the form of studies carried out on their behalf by consultants. Both processes are similar in purpose although there are differences in implementation.

OY1a Plant Oil Hydrotreating (NexBTL)

The data is from [IFEU 2006], a study sponsored by Neste Oil. The process as described produces only diesel i.e. uses the lighter products presumably to produce some of the required hydrogen.

OY1b Plant Oil Hydrotreating (UOP)

The data is from an unpublished report provided by UOP. The process as described produces diesel as well as small quantities of naphtha and lighter hydrocarbons. In line with what we did for GTL (see *section 6.1, process GDI*), we allocated the inputs according to the energy content of the products. This results in a higher hydrogen import compared to NexBTL but a lower plant oil consumption.

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 Diesel	Z1	1.0250	0.0040	1.1600	0.0250 0.0046	0.35	0.0000	0.0000	0.35								
W3d	Wood to hydrogen: gasification, 200MW Wood Electricity from wood <i>Primary energy consumption and emissions</i>	W3i	1.4624	0.0820		0.4624 0.1929 0.6553	0.00 0.00 0.00	0.00 0.00 0.0000	0.00 0.00 0.0000	0.00 0.00 0.00	60%	1.3893	1.5355	Triangular				
W3e	Wood to hydrogen: gasification, 10MW Wood Process emissions from gasifier Electricity (EUmix, MV) for 1. gasifier 2. syngas compression and CO shift 3. PSA , CO to gas engine for electric <i>Primary energy and emissions (tiny surplus electricity)</i>	Z7a Z7a Z7a	1.9313	0.0369 0.1025 -0.1440	2.8347 2.8347 2.8347	0.9313 0.1046 0.2906 -0.4082 0.9183	0.00 4.40 12.24 -17.19 -0.55	0.0150 0.0107 0.0298 -0.0419 0.0136	0.0045 0.0002 0.0006 -0.0008 0.0044	1.70 4.73 13.15 -18.47 1.11	52%	1.8339	2.0272	Triangular				
W3f	Wood to syn-diesel: gasification + FT Wood Credit for wood-to-electricity <i>Primary energy consumption and emissions</i>	W3i	2.6384	-0.2394		1.6384 -0.5633 1.0751	0.00 0.00 0.00	0.00 0.00 0.0000	0.00 0.00 0.0000	0.00 0.00 0.00	48%	1.9725 0.0000	2.9600 -0.7859	Triangular				
W3g	Wood to methanol or DME: gasification + synthesis Wood <i>Primary energy consumption and emissions</i>		1.9586			0.9586 0.9586	0.00 0.00	0.0000 0.0000	0.0000 0.0000	0.00 0.00	51%	1.7021	2.1700	Square				
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-type gasifier up to 200MW because of the heat transfer limit 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 H₂, followed by a 2-stage shift reactor to adjust the H₂/CO ratio. Hydrogen is separated by PSA and the remaining CO is burnt in a combined cycle electricity power-plant.

However, the process is so optimised for hydrogen production that the electricity generated by the waste gas in the power plant 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 would appear on the bottom line. This would give 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 made all processes electricity-neutral by giving electricity credits or debits using the nearest equivalent wood-to-electricity process. In the case of W3d, 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 W3i. 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 CO₂ 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 W3i: 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, H₂S...) before the gas is pure enough for synthesis. In the Altrax process the purification is combined with CO₂ removal by scrubbing with methanol (Rectisol Process). The DME synthesis process (by Haldor Topsøe 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 H₂/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 MJ bio-en/ MJ prod.	Expended energy			GHG emissions				Overall energy efficiency	Range		Probability distribution
				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)		2.9170								kgex/ MJprod. 2.7550	3.0790	Square	
	Biomass input				1.9170									
	Credit for wood-to-electricity	W3a		-0.0995	3.125	-0.3108	0.00	-0.0026	-0.0002	-0.14				
	Diesel	Z1		0.0358	1.160	0.0415	3.13	0.0000	0.0000	3.13				
	H ₂ SO 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	6.61				0.0027
	(NH ₄) ₂ SO ₄	C7,C8			3.983	0.0107	0.55	0.0011	0.0000	0.58				0.0007
	Antifoam				5.778	0.0090	0.90	0.0011	0.0000	0.94				0.0004
	Corn Steep Liquor				0.000	0.0000	0.00	0.0000	0.0000	0.00				0.0038
	CaO	C6			1.384	0.0068	1.45	0.0011	0.0000	1.48				0.0014
	<i>Primary energy consumption and emissions</i>				1.8089		13.03	0.0144	-0.0002	13.33				36%
W3k	Wheat straw to ethanol (logen)		2.3770			1.3770					0.4891			
	Straw				0.0089	0.22	0.0000	0.0000	0.22					
	Transport of straw	WT2b				0.0089	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 ₂ SO ₄	C7			1.113	0.0167	0.81	0.0023	0.0000	0.87		0.0042		
	NH ₃	C8			0.000	0.0000	0.00	0.0000	0.0000	0.00		0.0000		
	(NH ₄) ₂ SO ₄	C7,C8			0.000	0.0000	0.00	0.0000	0.0000	0.00		0.0000		
	Antifoam				0.000	0.0000	0.00	0.0000	0.0000	0.00		0.0000		
	Corn Steep Liquor				0.000	0.0000	0.00	0.0000	0.0000	0.00		0.0000		
	CaO	C6			1.384	0.0119	2.54	0.0020	0.0000	2.59		0.0024		
	Debit for additional fertilisers													
	N				13.6591	0.0000	0.00	0.00	0.00	0.00		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	0.99		0.0017		
<i>Primary energy consumption and emissions</i>				1.2707		4.80	0.0059	-0.0001	4.92	44%				

W3j Ethanol from woody biomass; worst/best case

This corresponds to the “base case” of the detailed study by NREL [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	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 <i>Primary energy consumption and emissions</i>		1.2410			0.2410 0.2410	0.00	0.0000	0.0000	0.00	81%	1.1790	1.3031	Square
BLD	Wood waste to DME via black liquor Wood waste <i>Primary energy consumption and emissions</i>		1.4851			0.4851 0.4851	0.00	0.0000	0.0000	0.00	67%	1.4108	1.5594	Square
BLM	Wood waste to methanol via black liquor Wood waste <i>Primary energy consumption and emissions</i>		1.5180			0.5180 0.5180	0.00	0.0000	0.0000	0.00	66%	1.4421	1.5939	Square
BLS	Wood waste to syn diesel via black liquor Wood waste <i>Primary energy consumption and emissions</i>		1.8280			0.8280 0.8280	0.00	0.0000	0.0000	0.00	55%	1.7366	1.9194	Square

BLD/M Wood waste to DME/Methanol

Black liquor is the residue of the paper pulp making process. It is 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.

Alternatively the organic portion of the black liquor can be converted into syngas in an oxygen-blown gasifier. An air separation unit is needed. The syngas can then be either burnt to produce electricity or converted into hydrogen, methanol, DME or hydrocarbons. 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.

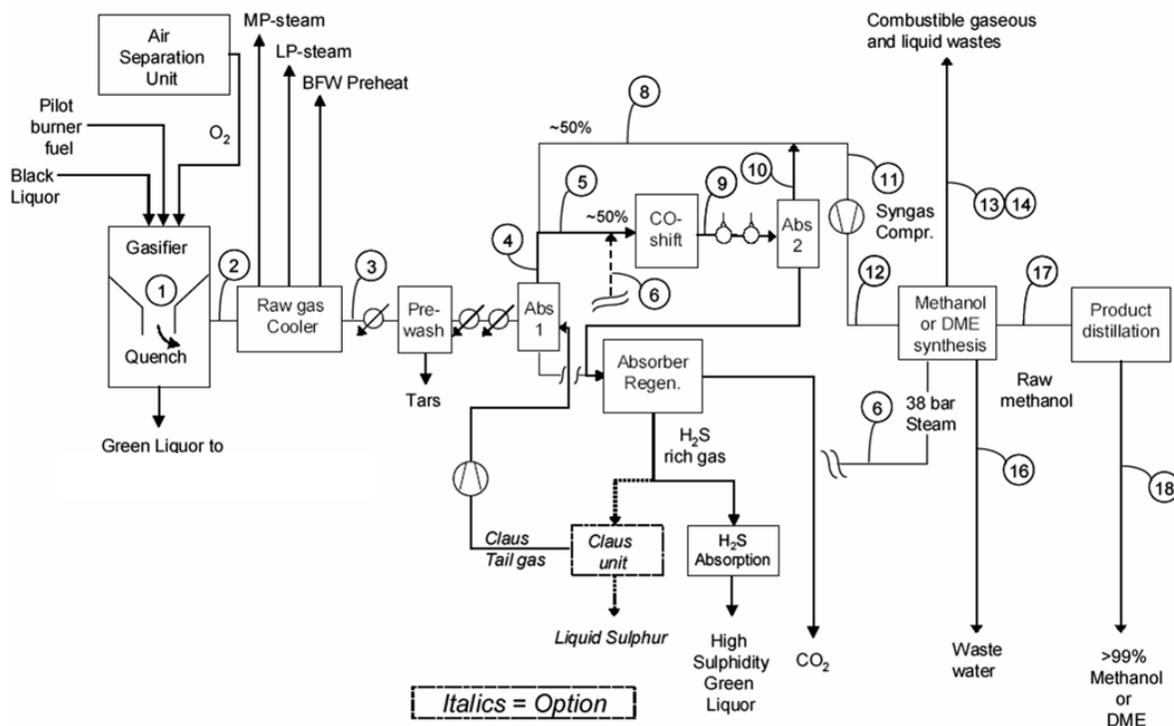
Taking the original pulp mill as reference, and adjusting the new process to give the same pulp production and electricity balance, one can calculate the extra wood residuals required to produce a given amount of fuel product. This effective efficiency turns out to be appreciably higher than that of a stand-alone gasifier conversion process. 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 [Ekbon 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 [Ekbon 2003] modelled the BLGMF ("Black Liquor Gasifier for Motor Fuels") plant to be also self-sufficient on heat and with the same pulp production and electricity export. The electricity is 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 $\pm 5\%$ error range to these figures.

[Ekbon 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 [Ekbon 2003]



BLS Wood waste to FT via black liquor gasification

We estimated the efficiency of this route by replacing the methanol synthesis in [Ekbon 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 may be fortuitous, but it was comforting to have independent confirmation.

We 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%.

BLH 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 CO₂ absorption (Abs 2) is not required because CO₂ 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 H₂ and 108.3 MW of 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 [Ekbohm 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 Heat and Electricity (co)Generation

15.1 Electricity only

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	
GE	Electricity from NG (CCGT)									
KE1	Electricity from Coal (conv. Boiler) Energy as hard coal	1.3000	221.45			221.45	43.5%	1.0000	1.5000	Dble tri
KE2	Electricity from Coal (IGCC) Energy as hard coal	1.0833	200.58			200.58	48.0%	0.9231	1.2435	Equal
KE2C	Electricity from Coal (IGCC) + CO2 capture Energy as hard coal	1.4390	23.44			23.44	41.0%	1.2680	1.6100	Equal
W3a	Electricity from wood steam boiler Energy as wood	2.1250		0.0828	0.0247	9.44	32.0%	1.9688	2.2813	Normal
W3b	Electricity from 200 MWth wood gasifier Energy as wood	1.0747		0.0262		1.40	48.2%	1.0000	1.1739	Normal
W3c	Electricity from 10 MWth wood gasifier Energy as wood	1.8228		0.0356		1.90	35.4%	1.6817	1.9639	Normal
BLE	Electricity from waste wood via black liquor Waste wood	0.1111	0.00	0.0000	0.0000	0.00	90.0%	0.0555	0.1667	Equal
W3h	Wood cofiring in coal-fired power station Wood	1.3000	0.00	0.0041	0.0114	3.49	43.5%	1.0000	1.5000	Double triangle
DE	Electricity from wind Energy as wind	0.0000								
NE1	Nuclear fuel provision Nuclear NG Crude oil Waste Hard coal Brown coal Hydropower Total	0.1805 0.0045 0.0025 0.0018 0.0053 0.0012 0.1977					0.0%			
NE2	Electricity from nuclear Energy as diesel Energy as uranium	0.0000 2.0303	0.07				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 $\pm 5\%$ range representing the range of existing and foreseeable technologies [*GEMIS 2002*], [*TAB 1999*] (see also *section 5.1, process GG2*).

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 [Ekbon 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 [Ekbon 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 H₂S 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 H₂S 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 1430°C, with a pressure ratio 20, and the maximum steam temperature is 530°C. 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.

W3h Wood co-firing in coal-fired power station

Wood energy is assumed to be converted to electricity with the same efficiency as the generic KE1 coal process above.

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].

15.2 Heat only

Code	Process	Expended energy	GHG emissions				Energy efficiency	Range		Probability distribution
			MJx/ MJ heat	g CO ₂ / MJ heat	g CH ₄ / MJ heat	g N ₂ O/ MJ heat		g CO ₂ eq/ MJ heat	Min	
BDo	Heating oil domestic boiler									
	Diesel	0.1111	81.39			81.39	90%	0.0793	0.1429	Square
	Electricity (EU-mix, LV)	0.0200								
N2O emissions				0.0021	0.62					
Blo	Heating oil industrial boiler									
	Diesel	0.1111	81.39			81.39	90%	0.0793	0.1429	Square
	Electricity (EU-mix, LV)	0.0250								
N2O emissions				0.0021	0.62					
BDg	NG domestic boiler									
	NG (Russian quality)	0.0000	55.07			55.07	100%			
	Electricity (EU-mix, LV)	0.0158								
Non-combustion emissions			0.0011	0.0003	0.11					
Blg	NG industrial boiler									
	NG (Russian quality)	0.1111	61.19			61.19	90%			
	Electricity (EU-mix, LV)	0.0200								
Non-combustion emissions			0.0056	0.0011	0.47					
BDw	Wood domestic boiler									
	Wood	0.1100					90%	0.0500	0.1700	Square
Electricity (EU-mix, LV)	0.0300									
Blw	Wood industrial boiler									
	Wood	0.1765					85%	0.1177	0.2353	Square
Electricity (EU-mix, LV)	0.0200									

These processes are straightforward representation of standard domestic (small scale) or industrial scale boilers using a variety of fuels.

15.3 Combined Heat and Power (CHP)

Code	Process	Total energy	GHG emissions				Energy efficiency	Range		Probability distribution
		MJ	g CO ₂	g CH ₄	g N ₂ O	g CO ₂ eq		Min	Max	
The energy figures are shown in total energy input to produce one unit of heat+power. Only direct emissions from the boilers are shown										
HPg	CHP plant, gas fired									
	NG (Russian quality)	2.3280	128.21			128.21	90%	2.2220	2.4340	Square
	Electricity (HV)	-1.0000								
	Heat	-1.0950								
	Non-combustion emissions			0.0097	0.0056	1.90				
HPw	CHP plant, wood fired									
	Wood	4.4500	0.00			0.00	79%	4.2300	4.6700	Square
	Electricity (HV)	-1.0000								
	Heat	-2.5000								
	Non-combustion emissions			0.0922	0.0028	3.13				

In this case the energy input shown is the total energy relating to 1 MJ of electricity produced. Usable heat is produced at the same time resulting in a very high total efficiency (defined as the sum of the energy content of the heat + electricity divided by the heat content of the feedstock). In the corresponding full pathways the figures are shown as energy expanded per MJ of electricity produced, with a credit calculated for the heat (see *WTT Appendix 2*).

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) electrolyzers with and without auxiliaries:

- Stuart Energy Europe (the former Hydrogen Systems) offers a 60 Nm³/h, 2.5 MPag electrolyser (IMET technology 1000 series) with an electricity consumption of 4.8 kWh/Nm³ or 62.5% based on hydrogen LHV. For the cell block alone (cell module without any auxiliaries) the electricity consumption is 4.2 kWh/Nm³ or 71% efficiency. For a 800 Nm³/h unit the electricity consumption is 4.3 kWh/Nm³ including all auxiliaries or 69.8% efficiency [*Stuart Energy 2005*].
- Norsk Hydro indicates an electricity consumption of 4.75 kWh/Nm³ including all auxiliaries for a 4,000 Nm³/h electrolysis (63.2% efficiency). For a 60 Nm³/h unit (HPE 60) the electricity consumption including all auxiliaries is indicated with 4.8 kWh/Nm³ (thereof auxiliaries: 0.5 kWh/Nm³) leading to an efficiency of 62.5% based on the LHV of the delivered hydrogen.
- AccaGen SA indicates an electricity consumption of 4.45 kWh/Nm³ for its 50 Nm³/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/Nm³ including all auxiliaries leading 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 Nm³/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/Nm³ 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/Nm³ of hydrogen) [*Proton Energy 2000*].

17 Hydrogen distribution and dispensing (all sources)

Code	Process	Assoc. processes	Expended energy MJx/ MJ prod.	GHG emissions				Transport requirement			Range		Probability distribution
				g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ 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) <i>Primary energy consumption and emissions</i>	Z2, Z1	0.0185	1.40			1.40	50		0.0171			
CH2	Liquid Hyd compression/vaporisation Energy as electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>		0.0196 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 <i>Primary energy consumption and emissions (EU-mix, LV)</i>		0.0200										
CH3a		Z7b	0.2406	9.29	0.0227	0.0004	9.98				0.2222	0.2615	
CH3b		Z7b	0.2220	8.50	0.0207	0.0004	9.14				0.2050	0.2412	
CH3c		Z7b	0.1970	7.45	0.0182	0.0003	8.01				0.1824	0.2139	
LH1	Hyd liquefaction Energy as Electricity (on-site generation) <i>Primary energy consumption and emissions</i>	GG2	0.3000 0.5455	30.03	0.0023	0.0014	30.51				0.2100	0.3900	Normal
LH2	Liquid Hyd long-distance transport Distance (nautical miles) Ship's fuel (hydrogen) including return voyage							5500		0.0848	5000 0.0771	6000 0.0925	
			0.2304			0.0093	2.7840		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	<i>Primary energy consumption and emissions</i>		0.0292	1.73	0.0003	0.0000	1.74						
LH3b	<i>Primary energy consumption and emissions</i>		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 MJx/ MJ prod.	GHG emissions				Transport requirement			Range		Probability distribution
				g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ 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) <i>Primary energy consumption and emissions</i>	GG2	0.0008 0.0015	0.08	0.0000	0.0000	0.09						
DS2	Syn diesel sea transport Distance (nautical miles) Energy requirement as HFO for product carrier <i>Primary energy consumption and emissions</i>	0.00	0.0312	2.50			2.50	5500		0.2315	5000 0.2105 0.0284	6000 0.2525 0.0341	Square
DS3	Syn diesel depot Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z7b	0.0008 0.0024	0.36	0.0009	0.0000	0.39						
DS4	Syn diesel distribution (blending component)	CD2/3/4	See conventional diesel processes										
DS5	Syn diesel distribution (neat) Distance, Rail Distance, road <i>Primary energy consumption and emissions</i>	Z5, Z7a Z2, Z1						250 250		0.0057 0.0061			
DS5a	<i>Rail+Road</i>		0.0100	0.6413	0.0003	0.0000	0.65						
DS5b	<i>Road only</i>		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 MJx/ MJ prod.	GHG emissions				Transport requirement			Range		Probability distribution
				g CO ₂ / MJ prod.	g CH ₄ / MJ prod.	g N ₂ O/ MJ prod.	g CO ₂ eq/ 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) NG consumption and emissions	GG2	0.0018 0.0033	0.18	0.0000	0.0000	0.19						
ME2	Methanol sea transport (average of two distances) Distance (nautical miles) <i>Primary energy consumption and emissions</i>	Z3, Z4	0.0627	5.03			5.03	5000		0.465	0.465		Normal
	Distance (nautical miles) <i>Primary energy consumption and emissions</i>	Z3, Z4	0.0753	6.04			6.04	6000		0.558	0.558		
ME3	Methanol depot Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z7b	0.0018 0.0052	0.79	0.0019	0.0000	0.85						
ME4	Methanol distribution and dispensing Distance, Rail Distance, road Filling station, Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z5, Z7a Z2, Z1 Z7b	0.0034					250 250		0.0126 0.0135			
ME4a	<i>Rail+Road</i>		0.0319	1.83	0.0018	0.0000	1.89						
ME4b	<i>Road only</i>		0.0244	1.52	0.0010	0.0000	1.55						
DE1	DME handling and loading (remote) Energy as Electricity (on-site generation) NG consumption and emissions	GG2	0.0013 0.0024	0.13	0.0000	0.0000	0.13						
DE2	DME sea transport Distance (nautical miles) Energy to DME carrier (as HFO) <i>Primary energy consumption and emissions</i>	Z3	0.06343	gCO ₂ /tkm 13.11 5.09			5.09	5500	0.163	0.358	0.326	0.391	Normal
DE3	DME depot Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z7b	0.0013 0.0037	0.56	0.0014	0.0000	0.60						
DE4a	DME distribution and dispensing Distance, Rail Distance, road Filling station, Electricity (EU-mix, LV) <i>Primary energy consumption and emissions</i>	Z5, Z7a Z2, Z1 Z7b	0.0034					250 250		0.0088 0.0123			
DE4a	<i>Rail+Road</i>		0.0284	1.64	0.0015	0.0000	1.69						
DE4b	<i>Road only</i>		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 ₂ O/ MJ prod.	g CO ₂ eq/ 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 (elec. 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	
	<i>Primary energy consumption and emissions</i>						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	
	<i>Primary energy consumption and emissions</i>						0.026	1.41	0.0017	0.0000	1.47	
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	
	<i>Primary energy consumption and emissions</i>						0.019	1.08	0.0010	0.0000	1.11	
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	
	<i>Primary energy consumption and emissions</i>						0.018	1.02	0.0010	0.0000	1.05	
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	
	<i>Primary energy consumption and emissions</i>						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	9.14	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	38.93	
	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	
	<i>Sum primary energy and emissions</i>						0.874	37.16	0.0887	0.0016	39.86	

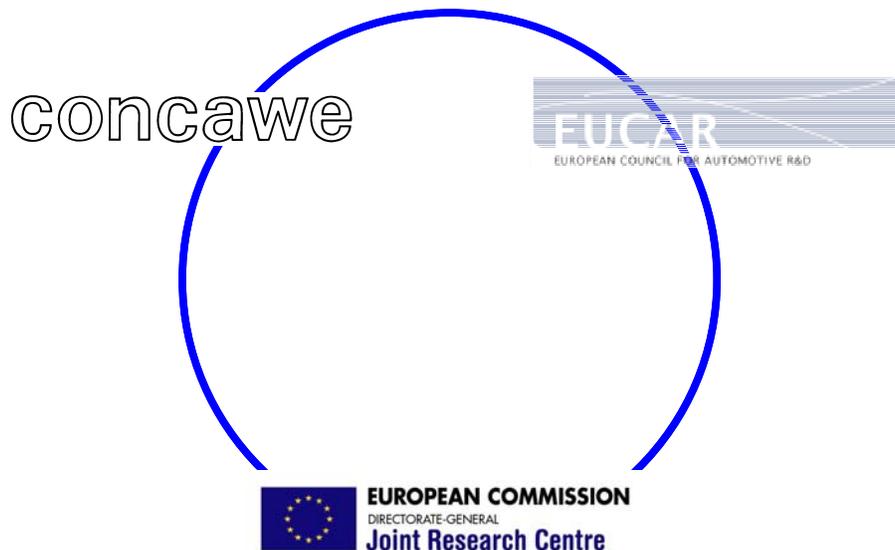
The energy for biofuel distribution is not very important to the overall pathway. Ethanol and FAME, and synthetic diesel are blended with fossil fuels, so they are transported to the appropriate depot, and then distributed like fossil fuel. Bio-methanol, DME and hydrogen are identical to the fossil products 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 available in *WTT Appendix 5*.

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



WELL-to-TANK Report - Appendix 2

Version 3c, July 2011

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Notes on version number:

This document reports on the third release of this study replacing data made available since November 2008.

The original version 1b was published in December 2003.

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 3 have been highlighted in yellow.

It details the processes included in each pathway and gives the resulting energy and GHG balance for the total pathway as well as the contribution of each of the main stages. In addition to *WTT Appendix 1* which shows some of the calculations carried out by the E3 database, this version includes *WTT Appendix 4* which details the process-by-process input data for each pathway.

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.

GHG figures are expressed in $g\ CO_2eq/MJ_f$ as the sum of the contributions of CO_2 , CH_4 and N_2O taking into account their respective Global Warming Potential. Individual contributions are also shown. The figures shown for each step of a pathway 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. Figures without and with that credit are shown in the tables.

The figures shown for individual steps of a pathway all refer to final product i.e. as the contribution of each step to the total. This is unlike *WTT Appendix 1* where figures are expressed based on the product of that step.

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).

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1 Conventional fuels

Pathway code		C O D	C O G	C O N
		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			✓
BDo	Heating oil domestic boiler			
Blo	Heating oil industrial boiler			

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. The figures for crude oil extraction and processing relate to conventional crudes. Reserves of non-conventional crudes (Canadian oil-sands and Venezuelan heavy crude) are very large, and these may become important in the longer term, however in the period to 2020 we expect Middle Eastern crude to remain the marginal supply source for Europe. Information on non-conventional crudes has been included for reference in the *WTT Report Section 3.1.1*.

In this version 3, the “upstream” figures (i.e. for crude oil production and processing) have been revised upwards to take into account more recent data (see *WTT Report Section 3.1.1*).

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂	CH ₄	N ₂ O	
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ	
		Best est.	min	Max								
COG1	Crude oil to gasoline											
	Crude Extraction & Processing	1	0.06	0.05	0.08		5.2		5.2	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		0.17	0.15	0.20	0.17	14.2	12.3	16.4	14.1	0.00	0.000
COD1	Crude oil to diesel											
	Crude Extraction & Processing	1	0.06	0.05	0.08		5.3		5.3	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		0.19	0.17	0.22	0.19	15.9	12.3	16.2	15.8	0.00	0.000
CON1	Crude oil to naphtha											
	Crude Extraction & Processing	1	0.06	0.05	0.08		5.1		5.1	0.00	0.000	
	Crude Transport	3	0.01				0.9		-0.7	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		0.14	0.12	0.16	0.14	11.4	9.6	12.9	9.7	0.00	0.000

2 Compressed gas from NG and biomass (CNG/CBG), LPG

2.1 Natural gas to CNG

Pathway code		G M C G	G P C G	G R C G			
		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) (+CCS 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 CO₂ 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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂	CH ₄	N ₂ O			
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ			
		Best est.	min	Max										
GMC1	NG current EU-mix (1000 km)													
	Extraction & Processing	1	0.02	0.01	0.05				3.3			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				2.9			2.7	0.01	0.000
	Total pathway		0.12	0.10	0.15	0.12			8.7	7.7	10.1	5.5	0.13	0.000
GPCG1a	Piped NG, 7000 km													
	Extraction & Processing	1	0.03	0.01	0.06				3.8			1.3	0.10	0.000
	Transport	3	0.19	0.06	0.22				15.0			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				2.9			2.7	0.01	0.000
	Total pathway		0.30	0.18	0.34	0.29			22.3	15.3	25.0	14.7	0.29	0.001
GPCG1b	Piped NG, 4000 km													
	Extraction & Processing	1	0.03	0.01	0.05				3.5			1.2	0.09	0.000
	Transport	3	0.09	0.03	0.10				7.5			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				2.9			2.7	0.01	0.000
	Total pathway		0.19	0.14	0.22	0.19			14.5	11.3	16.0	9.2	0.20	0.000
GRCG1	LNG, gaseous distribution													
	Extraction & Processing	1	0.03	0.01	0.05				3.5			1.2	0.09	0.000
	Liquefaction	2	0.09	0.08	0.09				5.8			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				2.9			2.7	0.01	0.000
	Total pathway		0.31	0.29	0.33	0.30			20.2	19.2	21.6	16.5	0.14	0.000
GRCG1C	LNG, gaseous distribution, CCS													
	Extraction & Processing	1	0.03	0.01	0.05				3.5			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				2.9			2.7	0.01	0.000
	Total pathway		0.32	0.29	0.35	0.32			16.7	15.5	18.0	13.0	0.14	0.000
GRCG2	LNG, liquid distribution (trucking)													
	Extraction & Processing	1	0.03	0.01	0.05				3.5			1.2	0.09	0.000
	Liquefaction	2	0.09						5.8			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						3.8			1.2	0.10	0.000
	Compression	5	0.03						1.5			1.5	0.00	0.000
	Total pathway		0.26	0.25	0.29	0.26			20.8	20.3	22.1	14.8	0.24	0.000

2.2 Biomass to CBG

Pathway code		O W C G				
		1	2	3	4	5
Code	Process					
Biogas from waste						
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)	✓	✓	✓	✓	✓
Farming						
WT1b	Wheat farming (whole plant)				✓	
WT1c	Wheat farming (double cropping)					✓
Crop transport and processing						
WT2c	Wheat whole plant road transport				✓	✓
WB1	Whole wheat to biogas (upgraded)				✓	
WB2	Whole wheat to biogas, double cropping (upgraded)					✓
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.

OWCG4 Wheat (whole plant) to CBG

The whole wheat plant is harvested and converted into biogas. There is a net fertiliser credit as the fermentation residue is sent back to the field. The biogas is treated and upgraded before being fed into an existing NG grid to be used as automotive fuel.

OWCG5 Maize and barley (whole plant) to CBG, double cropping

A variant of the above using the double cropping technique to increase yield and decrease fertiliser application and, as a consequence, field N₂O emissions. Maize is followed by winter barley. Both crops are cultivated and harvested in the same year and

organic agriculture is assumed. The fertilizer requirement is met by the residue of the downstream biogas plant.

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂	CH ₄	N ₂ O			
		Total primary		Fossil		Best est.	min	Max	g/MJ	g/MJ	g/MJ			
		Best est.	min	Max										
OWCG1	CBG: municipal waste													
	Production, treating and upgrading	4	0.81						12.69			3.1	0.45	-0.006
	Distribution (pipeline)	5	0.00						0.00			0.0	0.00	0.000
	Refuelling station	5	0.06						2.86			2.7	0.01	0.000
	Total WTT GHG emitted								15.5	12.6	18.5	5.8	0.46	-0.006
	Credit for renewable combustion CO ₂								-55.0			-55.0		
	Total pathway		0.87	0.74	1.03	0.17			-39.5	-42.4	-36.5			
OWCG2	CBG: liquid manure													
	Manure transport	2	0.03						-94.67			2.1	-3.87	0.000
	Production, treating and upgrading	4	0.88						6.25			-4.3	0.47	-0.004
	Distribution (pipeline)	5	0.00						0.00			0.0	0.00	0.000
	Refuelling station	5	0.06						2.86			2.7	0.01	0.000
	Total WTT GHG emitted								-85.6	-110.0	-55.1	0.5	-3.39	-0.004
	Credit for renewable combustion CO ₂								-55.0			-55.0		
	Total pathway		0.97	0.80	1.13	0.03			-140.6	-165.0	-110.1			
OWCG3	CBG: dry manure													
	Manure transport	2	0.01						-9.00			0.7	-0.39	0.000
	Production, treating and upgrading	4	0.88						6.25			-4.3	0.47	-0.004
	Distribution (pipeline)	5	0.00						0.00			0.0	0.00	0.000
	Refuelling station	5	0.06						2.86			2.7	0.01	0.000
	Total WTT GHG emitted								0.1	-3.0	3.0	-0.9	0.09	-0.004
	Credit for renewable combustion CO ₂								-55.0			-55.0		
	Total pathway		0.95	0.80	1.10	0.01			-54.9	-58.0	-52.0			
OWCG4	CBG: wheat (whole plant)													
	Cultivation	1	0.17						23.38			10.6	0.02	0.041
	Manure transport	2	0.00						0.35			0.3	0.00	0.000
	Production, treating and upgrading	4	0.97						-6.39			-12.6	0.46	-0.018
	Distribution (pipeline)	5	0.00						0.00			0.0	0.00	0.000
Refuelling station	5	0.06						2.86			2.7	0.01	0.000	
	Total WTT GHG emitted								20.2	16.7	23.3	-9.6	0.46	-0.018
	Credit for renewable combustion CO ₂								-55.0			-55.0		
	Total pathway		1.20	1.17	1.23	0.01			-34.8	-38.3	-31.7			
OWCG5	CBG: corn and barley, double cropping													
	Cultivation	1	0.10						17.42			11.8	0.01	0.018
	Manure transport	2	0.00						0.26			0.3	0.00	0.000
	Production, treating and upgrading	4	1.17						2.92			-7.5	0.47	-0.005
	Distribution (pipeline)	5	0.00						0.00			0.0	0.00	0.000
Refuelling station	5	0.06						2.86			2.7	0.01	0.000	
	Total WTT GHG emitted								23.5	20.4	36.6	-4.6	0.48	-0.005
	Credit for renewable combustion CO ₂								-55.0			-55.0		
	Total pathway		1.34	1.31	1.36	0.03			-31.5	-34.6	-18.4			

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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂	CH ₄	N ₂ O	
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ	
		Best est.	min	Max								
LRLP1	LPG from gas field (remote)											
	Extraction & Processing	1	0.05			3.5			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	8.0	8.0	8.5	7.5	0.02	0.000

3 Ethanol

		Sugar beet			Wheat										Sugar cane		Straw	Farmed wood	Waste wood
Pathway code		S	B	E	W	T	E	T											
		1a	1b	3	1a	1b	2a	2b	3a	3b	4a	4b	5	1a	1b	1	1	1	
Code	Process																		
Farming																			
SB1	Sugar Beet Farming	✓	✓	✓															
WT1a	Wheat farming (grain)				✓	✓	✓	✓	✓	✓	✓	✓	✓						
SC1	Sugar cane farming (Brazil)													✓	✓				
Crop transport and processing																			
SB2	Sugar beet road transport	✓	✓	✓															
SB3a	Sugar beet to ethanol, pulp to animal feed, slops not used	✓																	
SB3b	Sugar beet to ethanol, pulp to animal feed, slops to biogas		✓																
SB3c	Sugar beet to ethanol, pulp and slop to biogas digester and			✓															
WT2a	Wheat grain road transport				✓	✓	✓	✓	✓	✓	✓	✓	✓						
WT2b	Wheat straw road transport																✓		
WT3	Wheat grain handling				✓	✓	✓	✓	✓	✓	✓	✓	✓						
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										✓	✓							
WT4e	Wheat grain to ethanol, DDGS to biogas												✓						
WTDa	Credit for DDGS as animal feed				✓		✓	✓	✓	✓	✓	✓							
WTDb	Credit for DDGS as fuel						✓	✓	✓	✓	✓	✓							
W3k	Wheat straw to ethanol (logen)																✓		
SC2	Sugar cane road transport													✓	✓				
SC3a	Sugar cane to ethanol, heat credit for surplus bagasse													✓	✓				
SC3b	Sugar cane to ethanol, no credit for surplus bagasse													✓	✓				
SC4a	Sugar cane ethanol road transport to port													✓	✓				
SC4b	Sugar cane ethanol shipping 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 chips (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

The three pathways cover three alternative uses for the pulp and slops by-products. In SBET1a/b the pulp is used as animal feed while slops are either not valorised or used as feedstock to biogas. In SBET3 both pulp and slops are used for producing biogas. The latter is used for cogeneration partially covering the plant heat requirement in SBET1b and covering the whole plant heat requirement in SBET3 while also generating export electricity (excess heat does not generate a credit). Note that all data for these pathways, including farming and manufacturing, has been extensively reviewed and updated.

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ
		Total primary		Fossil		Best est.	min	Max			
		Best est.	min	Max							
SBET1a	EtOH from sugar beet, pulp to animal feed, slops not used										
	Cultivation	1	0.11			16.21			7.2	0.01	0.029
	Road transport	3	0.02			1.18			1.2	0.00	0.000
	Ethanol plant	4	1.25			18.71			21.0	0.07	-0.013
	Distribution & retail	5	0.03			1.54			1.5	0.00	0.000
	Total WTT GHG emitted					37.6	34.5	42.4	30.9	0.08	0.016
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		1.40	1.30	1.48	0.55	-33.7	-36.9	-29.0		
SBET1b	Ethanol from Sugar beet, pulp to animal feed, slops to biogas										
	Cultivation	1	0.11			16.21			7.2	0.01	0.029
	Road transport	3	0.02			1.18			1.2	0.00	0.000
	Ethanol plant	4	1.03			5.54			8.9	0.03	-0.014
	Distribution & retail	5	0.03			1.54			1.5	0.00	0.000
	Total WTT GHG emitted					24.5	21.2	30.0	18.7	0.04	0.016
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		1.18	1.09	1.29	0.34	-46.9	-50.1	-41.4		
SBET3	Ethanol from Sugar beet, pulp to heat /slops to biogas										
	Cultivation	1	0.11			16.21			7.2	0.01	0.029
	Road transport	3	0.02			1.18			1.2	0.00	0.000
	Ethanol plant	4	0.73			-5.05			-4.7	-0.01	0.000
	Distribution & retail	5	0.03			1.54			1.5	0.00	0.000
	Total WTT GHG emitted					13.9	11.4	19.1	5.2	0.00	0.029
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		0.88	0.77	0.97	0.04	-57.5	-60.0	-52.3		

WTET Wheat grain to ethanol

- 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 for the loss of soil nutrients from straw. Both DDGS use options are presented (see 3a/b).

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The heat and power requirement of the ethanol plant is provided by biogas produced from DDGS. A small electricity import is still required. A credit is generated for export of fermentation residue returned to the wheat field as fertiliser.

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary		Fossil	Best est.	min	Max					
		Best est.	min					Max				
WTET1a	Ethanol from Wheat, Conv NG boiler, DDGS as animal feed											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	1.34				16.81			22.5	0.09	-0.026
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						58.4	51.5	70.0	42.0	0.12	0.045
Credit for renewable combustion CO ₂												
Total pathway		1.66	1.64	1.69	0.77	-12.9	-19.9	-1.4	-71.4			
WTET1b	Ethanol from Wheat, Conv NG boiler, DDGS as fuel											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	0.92				9.48			8.6	0.04	0.000
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						51.1	45.8	61.2	28.0	0.07	0.071
Credit for renewable combustion CO ₂												
Total pathway		1.24	1.22	1.27	0.38	-20.3	-25.6	-10.2	-71.4			
WTET2a	Ethanol from Wheat, NG GT+CHP, DDGS as animal feed											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	1.09				4.14			11.1	0.05	-0.028
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						45.8	38.3	57.1	30.6	0.09	0.044
Credit for renewable combustion CO ₂												
Total pathway		1.42	1.40	1.44	0.53	-25.6	-33.1	-14.3	-71.4			
WTET2b	Ethanol from Wheat, NG GT+CHP, DDGS as fuel											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	0.67				-3.20			-2.8	0.01	-0.002
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						38.4	31.3	48.7	16.7	0.04	0.070
Credit for renewable combustion CO ₂												
Total pathway		1.00	0.98	1.02	0.14	-33.0	-40.1	-22.7	-71.4			
WTET3a	Ethanol from Wheat, lignite CHP, DDGS as animal feed											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	1.16				34.87			41.8	-0.01	-0.023
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						76.5	69.0	87.3	61.3	0.02	0.049
Credit for renewable combustion CO ₂												
Total pathway		1.49	1.48	1.49	0.60	5.1	-2.4	16.0	-71.4			
WTET3b	Ethanol from Wheat, Lignite CHP, DDGS as fuel											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	0.74				27.54			27.9	-0.05	0.003
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						69.2	63.4	80.4	47.4	-0.02	0.075
Credit for renewable combustion CO ₂												
Total pathway		1.07	1.06	1.07	0.21	-2.2	-8.0	9.0	-71.4			
WTET4a	Ethanol from Wheat, Straw CHP, DDGS as animal feed											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	1.25				-17.70			-9.4	-0.01	-0.027
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						23.9	16.9	35.2	10.0	0.02	0.045
Credit for renewable combustion CO ₂												
Total pathway		1.58	1.57	1.58	0.16	-47.5	-54.5	-36.2	-71.4			
WTET4b	Ethanol from Wheat, Straw CHP, DDGS as fuel											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	0.83				-25.02			-23.4	-0.06	-0.001
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						16.6	10.5	28.2	-3.9	-0.03	0.071
Credit for renewable combustion CO ₂												
Total pathway		1.16	1.15	1.16	-0.23	-54.8	-60.9	-43.2	-71.4			
WTET5	Ethanol from Wheat, DDGS to biogas											
	Cultivation	1	0.27				39.45			17.3	0.03	0.072
	Road transport	3	0.03				0.63			0.6	0.00	0.000
	Ethanol plant	4	0.77				-12.96			-6.0	-0.02	-0.022
	Distribution & retail	5	0.03				1.54			1.5	0.00	0.000
	Total WTT GHG emitted						28.7	22.1	38.8	13.5	0.01	0.050
Credit for renewable combustion CO ₂												
Total pathway		1.10	1.10	1.10	0.21	-42.7	-49.2	-32.6	-71.4			

SCET1a/b 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). Ethanol is shipped into Europe where it is blended with gasoline.

In variant 1a surplus bagasse is used externally to generate heat, displacing fossil diesel. In variant 1b (new to this version) this option is disallowed and no corresponding credit is generated.

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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ
		Total primary		Fossil	Best est.	min	Max				
		Best est.	min					Max			
SCET1a	EtOH from sugar cane (Brazil), HFO credit for excess bagasse										
	Cultivation	1	0.06			14.45			3.7	0.15	0.023
	Road transport	3	0.01			0.85			0.8	0.00	0.000
	Ethanol plant	4	1.63			-9.84			-10.2	0.00	0.001
	Ethanol shipping	5	0.10			7.69			7.7	0.00	0.000
	Distribution & retail	5	0.01			0.44			0.4	0.00	0.000
	Total WTT GHG emitted					13.6	10.4	30.6	2.4	0.16	0.024
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		1.81	1.81	1.82	0.04	-57.8	-60.9	-40.8		
SCET1b	EtOH from sugar cane (Brazil), no credit for excess bagasse										
	Cultivation	1	0.06			14.45			3.7	0.15	0.023
	Road transport	3	0.01			0.85			0.8	0.00	0.000
	Ethanol plant	4	1.78			1.20			0.7	0.00	0.001
	Ethanol shipping	5	0.10			7.69			7.7	0.00	0.000
	Distribution & retail	5	0.01			0.44			0.4	0.00	0.000
	Total WTT GHG emitted					24.6	21.6	41.9	13.4	0.16	0.025
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		1.96	1.95	1.96	0.18	-46.8	-49.8	-29.5		
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			3.19			3.0	0.01	0.000
	Ethanol plant	4	1.81			13.33			13.5	0.02	-0.002
	Distribution & retail	5	0.03			1.54			1.5	0.00	0.000
	Total WTT GHG emitted					19.0	18.8	19.2	18.9	0.03	-0.002
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		1.95	1.85	2.06	0.28	-52.4	-52.5	-52.2		
WFET1	EtOH from farmed wood										
	Cultivation	1	0.11			6.28			3.1	0.00	0.010
	Road transport	3	0.01			0.88			0.9	0.00	0.000
	Ethanol plant	4	1.81			13.33			13.5	0.02	-0.002
	Distribution & retail	5	0.03			1.54			1.5	0.00	0.000
	Total WTT GHG emitted					22.0	19.9	37.4	19.0	0.02	0.008
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		1.96	1.85	2.06	0.28	-49.4	-51.5	-34.0		
STET1	EtOH from wheat straw (Iogen)										
	Collection	3	0.04			3.08			3.0	0.00	0.000
	Road transport	3	0.01			0.62			0.6	0.00	0.000
	Ethanol plant	4	1.24			3.72			3.3	0.01	0.001
	Distribution & retail	5	0.03			1.54			1.5	0.00	0.000
	Total WTT GHG emitted					9.0	8.9	9.0	8.4	0.01	0.001
	Credit for renewable combustion CO ₂					-71.4			-71.4		
	Total pathway		1.32	1.32	1.32	0.10	-62.4	-62.5	-62.4		

4 Bio-diesel

		Rape seed				Sunf seed				Soy				Palm									
Pathway code		ROFA		ROHY		ROFE		SOF A		SOHY		SYFA		POFA		POHY							
		1	2	3	4	1a	1b	4a	1	2	3	4	1	1a	1c	3	1a	1b	1c	2	1a	1b	1c
NG to Hydrogen																							
GH1b	NG to hydrogen (reforming, central plant, 100-300 MW hydrogen)					✓	✓	✓					✓								✓	✓	✓
Farming																							
WT1a	Wheat farming (grain)								✓	✓	✓	✓											
RF1	Rapeseed Farming	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓												
SF1	Sunflower seed Farming											✓	✓	✓	✓								
SY1	Soya bean Farming (Brazil, for oil)												✓	✓	✓	✓							
CR1	Corn farming Brazil (mass based)												✓			✓							
PO1	Oil palm tree plantation (FFB)															✓	✓	✓	✓	✓	✓	✓	✓
Crop transport and processing																							
RO2	Rapeseed road transport	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓												
RO3a	Rapeseed to raw oil: extraction	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓												
RO3b	Rapeseed to raw oil: extraction, meal to											✓	✓	✓	✓	✓							
SO2	Sunflower seed road transport											✓	✓	✓	✓	✓							
SO3a	Sunflower seed to raw oil: extraction											✓	✓	✓	✓	✓							
PO2	Palm FFB road transport																✓	✓	✓	✓	✓	✓	✓
PO3	Palm FFB to raw oil: extraction																✓	✓	✓	✓	✓	✓	✓
PO3a	Methane emissions from waste																✓	✓	✓	✓	✓	✓	✓
PO3b	Credit for surplus heat (diesel)																✓	✓	✓	✓	✓	✓	✓
PO4a	Palm oil road transport to port																✓	✓	✓	✓	✓	✓	✓
PO4b	Vegetable oil shipping																✓	✓	✓	✓	✓	✓	✓
RO4	Raw oil to refined oil	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓			✓	✓	✓	✓	✓	✓	✓
SY2	Soya bean road transport (Brazil)																✓	✓	✓	✓	✓	✓	✓
SY3a	Soya beans to raw oil: extraction, meal substituting wheat																✓	✓	✓	✓	✓	✓	✓
SY3b	Soya beans to raw oil: extraction, meal substituting corn																✓	✓	✓	✓	✓	✓	✓
RO5a	Refined oil to FAME: esterification																	✓	✓	✓			
5a	Glycerine as chemical	✓							✓								✓	✓	✓				
5b	Glycerine as animal feed		✓							✓													
RO5c	Refined oil to FAME: esterification with glycerine to biogas			✓	✓					✓	✓	✓	✓	✓	✓					✓			
OY1a	Plant oil hydrotreating (NexBTL)					✓		✓						✓							✓	✓	✓
OY1b	Plant oil hydrotreating (UOP)						✓														✓	✓	✓
Syn diesel transport & distribution																							
SDd	Bio-(synthetic diesel) distribution (blended)					✓	✓	✓						✓							✓	✓	✓
Biofuels transport & distribution																							
FAd	Bio-diesel distribution (blended)	✓	✓	✓	✓				✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Common processes																							
Z1	Diesel production	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z2	Road tanker	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z3	HFO production																						
Z4	Product carrier 50 kt																						
Z6b	Marginal NG for general use	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓

ROFA1/2/3/4 Rapeseed to FAME (RME)

Four alternatives disposal routes for the meal and glycerine co-products are considered. Meal is either used as animal feed (variant 1/2/3) or to generate biogas to provide heat and power for the plant (variant 4). Glycerine is used either as a chemical (replacing a bulk chemical such as propylene glycol, variant 1) or as animal feed (variant 2) or to generate biogas (variant 3 and 4). Surplus biogas is used to generate electricity for export. No credit is given for surplus heat.

ROFE1/2/3/4 Rape to FAEE (REE)

The same pathways as ROFA above where methanol has been replaced by (bio)ethanol. Although this 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 expended (MJx/MJ)			Net GHG emitted (g CO ₂ eq/MJ)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ		
		Total primary		Fossil	Best est.	min	Max					
		Best est.	min	Max								
ROFA1	RME, glycerine as chemical, meal as animal feed											
	Cultivation	1	0.27				48.65			16.9	0.03	0.104
	Drying	1	0.02				0.72			0.7	0.00	0.000
	Transport, road 50 km	3	0.02				0.30			0.3	0.00	0.000
	Oil mill	4	0.59				-13.58			-6.4	0.00	-0.024
	Esterification	4	0.17				4.75			4.2	0.02	0.000
	Distribution & retail	5	0.02				1.27			1.2	0.00	0.000
	Total WTT GHG emitted						42.1	32.6	55.3	16.9	0.06	0.079
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		1.09	0.99	1.20	0.36	-34.1	-43.6	-20.8			
ROFA2	RME, glycerine and meal as animal feed											
	Cultivation	1	0.27				48.65			16.9	0.03	0.104
	Drying	1	0.02				0.72			0.7	0.00	0.000
	Transport, road 50 km	3	0.02				0.30			0.3	0.00	0.000
	Oil mill	4	0.59				-13.58			-6.4	0.00	-0.024
	Esterification	4	0.22				9.86			9.6	0.03	-0.002
	Distribution & retail	5	0.02				1.27			1.2	0.00	0.000
	Total WTT GHG emitted						47.2	37.8	59.7	22.4	0.07	0.078
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		1.14	1.04	1.25	0.41	-29.0	-38.4	-16.5			
ROFA3	RME, glycerine to biogas, meal as animal feed											
	Cultivation	1	0.27				48.65			16.9	0.03	0.104
	Drying	1	0.02				0.72			0.7	0.00	0.000
	Transport, road 50 km	3	0.02				0.30			0.3	0.00	0.000
	Oil mill	4	0.59				-13.58			-6.4	0.00	-0.024
	Esterification	4	0.19				8.30			7.7	0.02	0.000
	Distribution & retail	5	0.02				1.27			1.2	0.00	0.000
	Total WTT GHG emitted						45.7	35.8	59.0	20.5	0.06	0.080
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		1.10	1.01	1.21	0.37	-30.5	-40.4	-17.2			
ROFA4	RME, glycerine and cake to biogas											
	Cultivation	1	0.27				48.65			16.9	0.03	0.104
	Drying	1	0.02				0.72			0.7	0.00	0.000
	Transport, road 50 km	3	0.02				0.30			0.3	0.00	0.000
	Oil mill	4	0.19				-30.73			-21.7	-0.06	-0.025
	Esterification	4	0.17				8.01			7.4	0.02	0.000
	Distribution & retail	5	0.02				1.27			1.2	0.00	0.000
	Total WTT GHG emitted						28.2	20.7	40.9	4.8	0.00	0.079
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		0.70	0.60	0.80	-0.02	-48.0	-55.5	-35.3			
ROFE1	REE, glycerine as chemical, meal as animal feed											
	Cultivation	1	0.26				46.54			16.2	0.03	0.099
	Drying	1	0.02				0.69			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	Oil mill	4	0.56				-12.99			-6.1	0.00	-0.023
	Esterification	4	0.30				4.21			2.4	0.02	0.005
	Distribution & retail	5	0.02				1.25			1.2	0.00	0.000
	Total WTT GHG emitted						40.0	33.7	54.2	14.7	0.05	0.081
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		1.17	1.09	1.29	0.31	-36.2	-42.5	-22.0			
ROFE2	REE, glycerine and meal as animal feed											
	Cultivation	1	0.26				46.54			16.2	0.03	0.099
	Drying	1	0.02				0.69			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	Oil mill	4	0.56				-12.99			-6.1	0.00	-0.023
	Esterification	4	0.34				8.97			7.5	0.02	0.003
	Distribution & retail	5	0.02				1.25			1.2	0.00	0.000
	Total WTT GHG emitted						44.7	37.4	58.1	19.8	0.06	0.079
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		1.22	1.12	1.33	0.36	-31.4	-38.8	-18.1			
ROFE3	REE, glycerine to biogas, meal as animal feed											
	Cultivation	1	0.26				46.54			16.2	0.03	0.099
	Drying	1	0.02				0.69			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	Oil mill	4	0.56				-12.99			-6.1	0.00	-0.023
	Esterification	4	0.31				7.56			5.7	0.02	0.005
	Distribution & retail	5	0.02				1.25			1.2	0.00	0.000
	Total WTT GHG emitted						43.3	35.7	56.2	18.0	0.05	0.081
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		1.19	1.10	1.29	0.32	-32.9	-40.5	-20.0			
ROFE4	REE, glycerine and cake to biogas											
	Cultivation	1	0.26				46.54			16.2	0.03	0.099
	Drying	1	0.02				0.69			0.6	0.00	0.000
	Transport, road 50 km	3	0.02				0.28			0.3	0.00	0.000
	Oil mill + esterification	4	0.18				46.80			55.4	-0.06	-0.024
	Distribution & retail	5	0.29				-69.00			-70.8	0.02	0.005
	Total WTT GHG emitted						25.3	76.2	76.2	1.7	-0.01	0.080
	Credit for renewable combustion CO ₂						-76.2			-76.2		
	Total pathway		0.77	0.00	0.00	-0.07	-50.9	0.0	0.0			

SOFA1/2/3/4 Sunflower seed to FAME

The same pathways as ROFA above, now with sunflower seeds as feedstock.

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ
		Total primary		Fossil		Best est.	min	Max			
		Best est.	min	Max							
SOFA1	SME, glycerine as chemical, meal as animal feed										
	Cultivation	1	0.18			27.37			12.0	0.01	0.051
	Drying	1	0.01			0.67			0.6	0.00	0.000
	Transport, road 50 km	3	0.02			0.28			0.3	0.00	0.000
	Oil mill	4	0.52			-8.17			-2.8	0.00	-0.018
	FAME manufacture	4	0.17			4.75			4.2	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
	Total WTT GHG emitted					26.2	21.6	30.3	15.4	0.04	0.032
	Credit for renewable combustion CO ₂					-76.2			-76.2		
	Total pathway		0.93	0.84	1.03	0.32	-50.0	-54.6	-45.9		
SOFA2	SME, glycerine and meal as animal feed										
	Cultivation	1	0.18			27.37			12.0	0.01	0.051
	Drying	1	0.01			0.67			0.6	0.00	0.000
	Transport, road 50 km	3	0.02			0.28			0.3	0.00	0.000
	Oil mill	4	0.52			-8.17			-2.8	0.00	-0.018
	FAME manufacture	4	0.22			9.86			9.6	0.03	-0.002
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
	Total WTT GHG emitted					31.3	26.2	36.2	19.7	0.05	0.031
	Credit for renewable combustion CO ₂					-76.2			-76.2		
	Total pathway		0.98	0.89	1.07	0.37	-44.9	-50.0	-40.0		
SOFA3	SME, glycerine to biogas, meal as animal feed										
	Cultivation	1	0.18			27.37			12.0	0.01	0.051
	Drying	1	0.01			0.67			0.6	0.00	0.000
	Transport, road 50 km	3	0.02			0.28			0.3	0.00	0.000
	Oil mill	4	0.52			-8.17			-2.8	0.00	-0.018
	FAME manufacture	4	0.19			8.30			7.7	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
	Total WTT GHG emitted					29.7	24.5	34.3	19.0	0.04	0.032
	Credit for renewable combustion CO ₂					-76.2			-76.2		
	Total pathway		0.95	0.85	1.04	0.33	-46.5	-51.7	-41.9		
SOFA4	SME, glycerine and cake to biogas										
	Cultivation	1	0.18			27.37			12.0	0.01	0.051
	Drying	1	0.01			0.67			0.6	0.00	0.000
	Transport, road 50 km	3	0.02			0.28			0.3	0.00	0.000
	Oil mill	4	0.17			-22.37			-16.8	-0.04	-0.015
	FAME manufacture	4	0.17			7.99			7.4	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
	Total WTT GHG emitted					15.2	11.7	19.5	4.7	0.00	0.036
	Credit for renewable combustion CO ₂					-76.2			-76.2		
	Total pathway		0.58	0.58	0.59	-0.01	-61.0	-64.5	-56.7		

SYFA1/3 Soy beans to FAME

These pathways are based on soy bean farming in Brazil with transport of soy beans over land, sea transport to Europe and FAME production there. However, soy meal produced in Europe as a result avoids imports of meal from Brazil so that the sea transport cost of meal cancels out, leaving only sea transport for oil. Soy meal further attracts a credit related to corn substitution in Brazil. In variant 1, glycerine is used as animal feed. In variant 3 it is used to generate biogas to supply part of the FAME plant energy requirement.

In SYFA1a soy meal substitutes European wheat while soy oil supports the full cost of transporting the meal, resulting in a rather high energy/GHG balance. This was our original pathway published in November 2008. We now believe the previous view is more realistic.

In SYFA1c we have applied market value allocation between meal and oil, still assuming sea transport of beans to Europe. Energy is much lower than for the other variants as a significant part of it (about 42%) is allocated to the meal. In terms of GHG

the outcome is similar to SYFA1 because the reductions due to allocation to the meal are compensated by the removal of the credit for meal substitution.

POFA1/2 Palm oil to FAME

The palm fruit bunches (FFB) are crushed near the plantation (typically in South-East Asia) to produce palm oil which is shipped to Europe for processing into FAME. Variants 1a and 1b cover an important aspect of palm oil production management viz. how the organic waste material is disposed of. Traditionally it is left to rot in anaerobic conditions in a lagoon, generating CH₄ (variant 1a). In variant 1b these emissions are deemed to have been avoided. In variant 1a/b a heating oil credit is given for heat generated with the crushed FFBs. In variant 1c, this credit is removed. In variant 2, glycerine from FAME production is used as biogas to generate biogas to supply part of the FAME plant energy requirement instead of chemical substitution as in variant 1; all other parameters are as per variant 1a.

	Standard step	Energy expended (Mjx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ
		Total primary		Fossil	Best est.	min	Max				
		Best est.	min					Max			
SYFA1	Net import of soy oil, glycerine as chemical, displaced soy meal replaces corn in Brazil										
	Cultivation	1	0.28			56.40			18.1	0.02	0.127
	Beans transport	2	0.15			8.76			8.7	0.00	0.000
	Oil shipping	2	0.04			3.10			3.1	0.00	0.000
	Oil mill	4	2.03			-20.97			-2.2	0.03	-0.065
	FAME manufacture	4	0.17			4.74			4.2	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					53.3	-0.8	72.2	33.1	0.07	0.062	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		2.69	2.68	2.71	0.61	-22.9	-77.0	-4.0			
SYFA1a	Imported soy beans, glycerine as chemical, soya meal replaces EU wheat										
	Cultivation	1	0.28			56.40			18.1	0.02	0.127
	Beans road transport	2	0.15			8.76			8.7	0.00	0.000
	Beans shipping	2	0.34			27.12			26.8	0.00	0.001
	Oil mill	4	2.04			-20.70			-1.1	0.02	-0.067
	FAME manufacture	4	0.17			4.74			4.2	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					77.6	52.1	99.8	58.0	0.06	0.061	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		3.00	2.98	3.01	0.92	1.4	-24.1	23.6			
SYFA1c	Imported soy beans, allocation by economic values										
	Cultivation	1	0.16			32.73			10.5	0.01	0.074
	Beans transport	2	0.08			5.08			5.1	0.00	0.000
	Oil shipping	2	0.04			3.10			3.1	0.00	0.000
	Oil mill	4	0.89			9.70			9.0	0.03	0.000
	FAME manufacture	4	0.17			4.75			4.2	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					56.6	42.3	69.4	33.0	0.06	0.074	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		1.37	1.36	1.38	0.58	-19.6	-33.9	-6.8			
SYFA3	Net import of soy oil, glycerine to biogas, displaced soy meal replaces corn in Brazil										
	Cultivation	1	0.28			56.40			18.1	0.02	0.127
	Beans transport	2	0.15			8.76			8.7	0.00	0.000
	Oil shipping	2	0.04			3.10			3.1	0.00	0.000
	Oil mill	4	2.03			-20.97			-2.2	0.03	-0.065
	FAME manufacture	4	0.19			8.30			7.7	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					56.8	0.1	79.6	36.7	0.07	0.062	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		2.71	2.69	2.72	0.62	-19.4	-76.1	3.4			
POFA1a	Imported palm oil, glycerine as chemical, CH₄ emissions from waste										
	Plantation	1	0.10			15.73			5.8	0.01	0.032
	FFB transport and storage	2	0.06			1.16			1.1	0.00	0.000
	Pressing	2	0.91			21.98			-2.3	0.99	-0.002
	Oil shipping	3	0.05			3.45			3.4	0.00	0.000
	FAME manufacture	4	0.17			4.75			4.2	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					48.3	43.8	76.9	13.5	1.03	0.031	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		1.31	1.30	1.31	0.27	-27.9	-32.4	0.7			
POFA1b	Imported palm oil, glycerine as chemical, no CH₄ emissions from waste										
	Plantation	1	0.10			15.73			5.8	0.01	0.032
	FFB transport and storage	2	0.06			1.16			1.1	0.00	0.000
	Pressing	2	0.91			-2.77			-2.3	0.00	-0.002
	Oil shipping	3	0.05			3.45			3.4	0.00	0.000
	FAME manufacture	4	0.17			4.75			4.2	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					23.6	18.6	49.6	13.5	0.04	0.031	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		1.31	1.30	1.31	0.27	-52.6	-57.6	-26.6			
POFA1c	Imported palm oil, glycerine as chemical, CH₄ emissions from waste, no heat credit for crushed FFB										
	Plantation	1	0.10			15.73			5.8	0.01	0.032
	FFB transport and storage	2	0.06			1.16			1.1	0.00	0.000
	Pressing	2	0.94			23.86			-0.4	0.99	-0.002
	Oil shipping	3	0.05			3.45			3.4	0.00	0.000
	FAME manufacture	4	0.17			4.75			4.2	1.03	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					50.2	44.8	74.7	15.4	2.03	0.031	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		1.33	1.32	1.34	0.30	-26.0	-31.4	-1.5			
POFA2	Imported palm oil, glycerine to biogas, CH₄ emissions from waste										
	Plantation	1	0.10			15.73			5.8	0.01	0.032
	FFB transport and storage	2	0.06			1.16			1.1	0.00	0.000
	Pressing	2	0.91			21.98			-2.3	0.99	-0.002
	Oil shipping	3	0.05			3.45			3.4	0.00	0.000
	FAME manufacture	4	0.19			8.31			7.7	0.02	0.000
	Distribution & retail	5	0.02			1.27			1.2	0.00	0.000
Total WTT GHG emitted					51.9	45.8	78.8	17.1	1.03	0.031	
Credit for renewable combustion CO ₂					-76.2			-76.2			
Total pathway		1.32	1.32	1.33	0.29	-24.3	-30.4	2.6			

ROHY1a/b/4a, SOHY1, POHY1a/b/c Hydrotreated vegetable oil

These pathways describe the recently developed processes for deep hydrotreatment of plant oil. These processes turn plant oil (or animal fats) into a essentially straight chain paraffins and a product very similar to synthetic diesel obtained by Fischer-Tropsch conversion of syngas (see section 5).

All pathways describe the Neste Oil process (NexBTL®) except ROHY1b uses data provided by UOP for a similar process.

The pathways codes are consistent with those for the corresponding biodiesel pathways with the same process and procedures for the production of the vegetable oil.

	Standard step	Energy expended (MJx/MJ)				Net GHG emitted (g CO ₂ eq/MJ)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ
		Total primary		Fossil	Best est.	min	Max				
		Best est.	min					Max			
ROHY1a	Hydrogenated rape oil (NExBTL process), meal to animal feed										
	Cultivation	1	0.27			47.99			16.71	0.03	0.102
	Drying	1	0.02			0.71			0.66	0.00	0.000
	Transport, road 50 km	3	0.02			0.29			0.29	0.00	0.000
	Oil mill	4	0.58			-13.39			-6.28	0.00	-0.024
	Hydrotreating	4	0.15			6.75			6.22	0.02	0.000
	Distribution & retail	5	0.02			1.15			1.11	0.00	0.000
	Total WTT GHG emitted					43.5	40.6	62.1	18.7	0.06	0.078
Credit for renewable combustion CO ₂					-70.8			-70.8			
Total pathway		1.05	0.95	1.15	0.34	-27.3	-35.6	-14.1			
ROHY1b	Hydrogenated rape oil (UOP process), meal to animal feed										
	Cultivation	1	0.24			42.23			14.70	0.03	0.090
	Drying	1	0.01			0.62			0.58	0.00	0.000
	Transport, road 50 km	3	0.02			0.26			0.26	0.00	0.000
	Oil mill	4	0.51			-11.79			-5.53	0.00	-0.021
	Hydrotreating	4	0.12			12.45			11.56	0.03	0.000
	Distribution & retail	5	0.02			1.15			1.11	0.00	0.000
	Total WTT GHG emitted					44.9	43.1	62.9	22.7	0.07	0.069
Credit for renewable combustion CO ₂					-70.8			-70.8			
Total pathway		0.92	0.83	1.01	0.41	-25.9	-33.1	-13.3			
ROHY4a	Hydrogenated rape oil (NExBTL process), cake to biogas										
	Cultivation	1	0.27			47.99			16.71	0.03	0.102
	Drying	1	0.02			0.71			0.66	0.00	0.000
	Transport, road 50 km	3	0.02			0.29			0.29	0.00	0.000
	Oil mill	4	0.19			-30.31			-21.45	-0.06	-0.025
	Hydrotreating	4	0.15			6.74			6.20	0.02	0.000
	Distribution & retail	5	0.02			1.15			1.11	0.00	0.000
	Total WTT GHG emitted					26.6	23.4	45.2	3.5	0.00	0.077
Credit for renewable combustion CO ₂					-70.8			-70.8			
Total pathway		0.66	0.55	0.75	-0.03	-44.3	-52.8	-31.0			
SOHY1	Hydrogenated sunflower oil (NExBTL process), meal to animal feed										
	Cultivation	1	0.18			26.99			11.8	0.01	0.050
	Drying	1	0.01			0.66			0.6	0.00	0.000
	Transport, road 50 km	3	0.02			0.27			0.3	0.00	0.000
	Oil mill	4	0.51			-8.05			-2.79	0.00	-0.018
	Hydrotreating	4	0.15			6.75			6.2	0.02	0.000
	Distribution & retail	5	0.02			1.15			1.1	0.00	0.000
	Total WTT GHG emitted					27.8	28.1	37.5	17.2	0.04	0.032
Credit for renewable combustion CO ₂					-70.8			-70.8			
Total pathway		0.89	0.80	1.00	0.30	-43.1	-48.0	-38.7			
POHY1a	Hydrogenated palm oil (NExBTL process), CH₄ from waste										
	Plantation	1	0.10			15.52			5.8	0.01	0.032
	FFB transport & storage	1	0.05			1.14			1.1	0.00	0.000
	Pressing	2	0.90			21.68			-2.2	0.98	-0.002
	Oil shipping	3	0.04			3.40			3.4	0.00	0.000
	Hydrotreating	4	0.15			6.76			6.2	0.02	0.000
	Distribution & retail	5	0.02			1.15			1.1	0.00	0.000
	Total WTT GHG emitted					49.6	49.3	78.9	15.4	1.01	0.030
Credit for renewable combustion CO ₂					-70.8			-70.8			
Total pathway		1.26	1.26	1.27	0.26	-21.2	-26.8	2.7			
POHY1b	Hydrogenated palm oil (NExBTL process), no CH₄ from waste										
	Plantation	1	0.10			15.52			5.8	0.01	0.032
	FFB transport & storage	1	0.05			1.14			1.1	0.00	0.000
	Pressing	2	0.90			-2.73			-2.2	0.00	-0.002
	Oil shipping	3	0.04			3.40			3.4	0.00	0.000
	Hydrotreating	4	0.15			6.76			6.2	0.02	0.000
	Distribution & retail	5	0.02			1.15			1.1	0.00	0.000
	Total WTT GHG emitted					25.2	25.9	58.8	15.4	0.03	0.030
Credit for renewable combustion CO ₂					-70.8			-70.8			
Total pathway		1.26	1.26	1.27	0.26	-45.6	-50.3	-17.4			
POHY1c	Hydrogenated palm oil (NExBTL process), CH₄ from waste, no heat credit for crushed FFB										
	Plantation	1	0.10			15.52			5.8	0.01	0.032
	FFB transport & storage	1	0.05			1.14			1.1	0.00	0.000
	Pressing	2	0.92			23.53			-0.4	0.98	-0.002
	Oil shipping	3	0.04			3.40			3.4	0.00	0.000
	Hydrotreating	4	0.15			6.76			6.2	0.02	0.000
	Distribution & retail	5	0.02			1.15			1.1	0.00	0.000
	Total WTT GHG emitted					51.5	52.5	82.7	17.2	1.01	0.030
Credit for renewable combustion CO ₂					-70.8			-70.8			
Total pathway		1.29	1.28	1.30	0.28	-19.3	-23.7	6.5			

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	W	W	B
		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 chips (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) (+CCS option)

This option of a GTL plant installed near a remote gas supply is the most likely (note that the efficiency of the GTL plant has been slightly increased to reflect state-of-the-art performance). 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 CO₂ 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 (CCS) could be an attractive option.

KOSD1/1C CTL: Coal to synthetic diesel (+CCS 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 CO₂ is produced during the gasification process and is separated from the syngas before the Fischer-Tropsch stage. This offers an attractive opportunity for CCS, 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.

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary			Fossil	Best est.	min	Max				
		Best est.	min	Max								
GRSD1	Syn diesel, remote plant, diesel mix											
	NG Extraction & Processing	1	0.04	0.02	0.07	4.9			1.7	0.13	0.000	
	GTL plant	2	0.54	0.49	0.59	13.8			13.8	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		0.63	0.57	0.69	0.63	22.4	19.3	25.6	19.1	0.13	0.000
GRSD2	Syn diesel, remote plant, neat											
	NG Extraction & Processing	1	0.04	0.02	0.07	4.9			1.7	0.13	0.000	
	GTL plant	2	0.54	0.49	0.59	13.8			13.8	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		0.63	0.59	0.69	0.63	22.5	20.1	26.0	19.2	0.13	0.000
GRSD2C	Syn diesel, remote plant, neat, CCS											
	NG Extraction & Processing	1	0.04	0.02	0.08	5.3			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	13.3	10.5	16.6	9.7	0.14	0.000
KOSD1	Coal EU-mix, gasifier + FT synthesis											
	Coal provision	1	0.17			28.7			11.5	0.68	0.001	
	Gasifier + FT synthesis	4	0.78			100.3			100.6	0.00	-0.001	
	Syndiesel distribution & dispensing	5	0.02			1.1			1.1	0.00	0.000	
		Total pathway		0.97	0.89	1.05	0.97	130.1	121.9	138.5	113.2	0.68
KOSD1C	Coal EU-mix, gasifier + FT synthesis, CCS											
	Coal provision	1	0.17			30.0			112.8	0.68	0.000	
	Gasifier + FT synthesis + CCS	4	0.86			9.3			0.4	0.00	0.000	
	Syndiesel distribution & dispensing	5	0.02			1.1			-98.0	0.22	0.001	
		Total pathway		1.06	0.98	1.13	1.05	40.4	32.6	48.4	15.2	0.90
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			1.2			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	1.09	1.30	0.07	-66.0	-66.2	-65.9			
WFSD1	Syn diesel, farmed wood											
	Wood farming and chipping	1	0.09			5.0			2.5	0.00	0.008	
	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			1.2			1.1	0.00	0.000	
	Total WTT GHG emitted					6.9	5.4	18.8	4.3	0.00	0.008	
	Credit for renewable combustion CO ₂					-70.8			-70.8			
	Total pathway		1.19	1.09	1.29	0.06	-64.0	-65.5	-52.1			
BLS1	Syn diesel, black liquor											
	Wood collection 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			1.2			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	0.85	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	WFDE	BLDE		
		1a	1b	1	1C	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) (+CCS 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, CO₂ 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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary			Fossil	Best est.	min	Max				
		Best est.	min	Max								
GPDE1a	Piped NG, 7000 km, EU central plant											
	NG Extraction & Processing	1	0.04	0.02	0.08	5.4			1.9	0.14	0.000	
	NG Transport	3	0.28	0.09	0.31	21.2			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	0.57	0.84	0.77	39.7	28.4	43.6	29.2	0.41	0.001
GPDE1b	Piped NG, 4000 km, EU central plant											
	NG Extraction & Processing	1	0.04	0.02	0.07	5.0			1.7	0.13	0.000	
	NG Transport	3	0.13	0.04	0.15	10.6			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	0.54	0.66	0.62	28.7	24.0	31.1	21.4	0.28	0.000
GRDE1	Remote plant											
	NG Extraction & Processing	1	0.03	0.02	0.07	4.5			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	21.1	20.1	22.9	18.0	0.12	0.000
GRDE1C	Remote plant, CCS											
	NG Extraction & Processing	1	0.03	0.02	0.07	4.5			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	11.1	11.0	14.8	8.1	0.12	0.000
KODE1	Coal EU-mix, gasifier + DME synthesis											
	Coal provision	3	0.16			27.97			11.2	0.66	0.000	
	Gasifier + DME synthesis	4	0.74			99.98			99.8	0.01	0.000	
	DME distribution & dispensing	5	0.03			1.69			1.6	0.00	0.000	
	Total pathway		0.93	0.83	1.01	0.92	129.6	119.4	137.6	112.7	0.67	0.001
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 (CCS)	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					4.6	4.3	4.8	4.3	0.01	0.000	
Credit for renewable combustion CO ₂					-67.3			-67.3				
	Total pathway		1.07	0.93	1.20	0.06	-62.7	-63.0	-62.5			
WFDE1	Farmed wood											
	Wood farming and chipping	1	0.08			4.7			2.3	0.00	0.008	
	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					6.5	5.1	18.9	4.1	0.00	0.008	
Credit for renewable combustion CO ₂					-67.3			-67.3				
	Total pathway		1.07	0.94	1.21	0.06	-60.8	-62.18	-48.41			
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	0.50	0.60	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	WWD	BLME
		1a	1b	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) (+CCS 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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂	CH ₄	N ₂ O	
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ	
		Best est.	min	Max								
GPME1a	Piped NG, 7000 km, EU central plant											
	NG Extraction & Processing	1	0.04	0.02	0.09	5.6			2.0	0.15	0.000	
	NG Transport	3	0.29	0.10	0.32	22.0			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	0.66	0.92	0.84	42.1	31.8	46.4	31.3	0.42	0.001
GPME1b	Piped NG, 4000 km, EU central plant											
	NG Extraction & Processing	1	0.04	0.02	0.08	5.2			1.8	0.13	0.000	
	NG Transport	3	0.14	0.05	0.15	11.0			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	0.61	0.73	0.69	30.6	25.9	33.0	23.2	0.29	0.000
GRME1	NG, Remote plant											
	NG Extraction & Processing	1	0.04	0.02	0.07	4.7			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	0.60	0.64	0.61	24.2	23.4	26.1	21.0	0.12	0.000
KOME1	Coal EU-mix, gasifier + MeOH synthesis											
	Coal provision	3	0.16			27.97			11.2	0.66	0.000	
	Gasifier + MeOH synthesis	4	0.74			98.31			98.1	0.01	0.000	
	Methanol distribution & dispensing	5	0.03			1.89			1.8	0.00	0.000	
	Total pathway		0.93	0.84	1.02	0.93	128.2	118.8	137.1	111.2	0.67	0.001
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					4.8	4.5	5.0	4.5	0.01	0.000	
Credit for renewable combustion CO ₂								-69.1				
	Total pathway		1.07	0.94	1.20	0.06	-64.3	-64.6	-64.1			
WFME1	Farmed wood											
	Wood farming and chipping	1	0.08			4.7			2.3	0.00	0.008	
	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					6.7	5.2	19.4	4.3	0.00	0.008	
Credit for renewable combustion CO ₂								-69.1				
	Total pathway		1.07	0.94	1.20	0.06	-62.4	-63.8	-49.7			
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				
	Total pathway		0.59	0.54	0.63	0.03	-66.7	-66.8	-66.7			

6 Ethers

Pathway code		G R M B	L R E B
		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_x/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_x/MJ_f. Following the same logic, only 1/3 of the CO₂ emissions is credited as renewable (2 out of 6 carbon atoms in the ETBE molecule).

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂	CH ₄	N ₂ O	
		Total primary		Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ		
		Best est.	min								Max	
GRMB1	MTBE from remote plant											
	NG extraction and processing	1	0.01			0.88			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			6.04			5.6	0.02	0.000	
	MTBE transport	3	0.05			4.05			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	13.6	13.5	14.5	12.5	0.04	0.000
LREB1	ETBE from imported C4 and wheat ethanol (WTET2a)											
	Wheat cultivation	1	0.10			14.37			6.3	0.01	0.026	
	Road transport	3	0.01			0.20			0.2	0.00	0.000	
	Ethanol plant	4	0.40			-0.97			1.7	0.02	-0.011	
	ETBE plant	4	0.22			7.98			7.4	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					22.7	68.8	74.8	16.7	0.05	0.016	
	Credit for renewable combustion CO ₂								-23.8			
	Total pathway		0.75	0.74	0.76	0.01*	-1.1	-2.5	3.4			

7 Heat and power generation

7.1 Electricity only

		Natural gas		Coal								Farmed wood				Waste wood				Black liquor		Wind	Nuclear	EU-mix		
Pathway code		GPEL		KREL		OWEEL						WFEL				WFEL				BLEL		WDEL	NUEL	EMEL	EMEL	
		1a	1b	1	1	2	1a	1b	2a	2b	3a	3b	1	2	3	4	1	2	3	4	1	1	1	1	1	1
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)			✓																						
Biogas from waste																										
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 electricity: gasification, 200MW												✓	✓	✓	✓	✓	✓	✓	✓	✓					
W3c	Wood to electricity: gasification, 10MW												✓	✓	✓	✓	✓	✓	✓	✓	✓					
W3a	Biomass to electricity: Conventional wood boiler with steam turbine												✓	✓	✓	✓	✓	✓	✓	✓	✓					
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.

GPHEL1bC Piped NG to electricity with CCS

As above with CCGT flue gas CO₂ capture.

GPHEL1a/bC Piped NG to electricity via hydrogen CCGT and CCS

In this scheme natural gas is reformed to hydrogen, CO₂ is captured and hydrogen is used to generate electricity in an adapted CCGT.

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).

OWEL1/2/3 Biogas to electricity

Biogas produced from municipal waste or manure is used to produce electricity in a gas engine. Upgrading is not required.

W/F-WEL1-4 Farmed or waste 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 represents the conventional boiler + steam turbine route. 4 is co-firing in a coal power station.

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 to those from natural gas CCGT.

WDEL1 Wind to electricity

Wind power is one of the most promising options 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 expended (MJx/MJelec)				Net GHG emitted (g CO ₂ eq/MJelec)			CO ₂	CH ₄	N ₂ O	
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ	
		Best est.	min	Max								
GPEL1a	Piped NG, 7000 km, CCGT											
	NG Extraction & Processing	1	0.05	0.03	0.11	7.2			2.5	0.19	0.000	
	NG Transport	3	0.36			28.1			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	1.09	1.39	1.31	141.0	128.0	145.8	125.6	0.55	0.006
GPEL1b	Piped NG, 4000 km, CCGT											
	NG Extraction & Processing	1	0.05	0.02	0.10	6.6			2.3	0.17	0.000	
	NG Transport	3	0.17			14.0			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	0.96	1.20	1.11	126.3	117.3	131.1	115.2	0.38	0.005
GPEL1bC	Piped NG, 4000 km, CCGT + CCS											
	NG Extraction & Processing	1	0.06	0.03	0.12	7.7			2.7	0.20	0.000	
	NG Transport	3	0.20			16.4			10.5	0.23	0.000	
	NG Distribution (HP)	3	0.02			1.2			1.2	0.00	0.000	
	Power generation (CCGT)	4	1.16	1.10	1.22	12.5			12.3	0.01	0.000	
	Electricity distribution (LV)	5	0.03			0.0			0.0	0.00	0.000	
	Total pathway		1.47	1.30	1.57	1.47	37.8	27.9	43.7	26.7	0.44	0.001
GPHL1aC	Piped NG, 7000 km, Hydrogen CCGT + CCS											
	NG Extraction & Processing	1	0.07	0.04	0.14	9.3			3.3	0.24	0.000	
	NG Transport	3	0.47			36.5			24.8	0.46	0.001	
	NG Distribution (HP)	3	0.02			1.4			1.3	0.00	0.000	
	Power generation (CCGT)	4	1.40	1.33	1.47	13.4			13.4	0.00	0.000	
	Electricity distribution (LV)	5	0.03			0.0			0.0	0.00	0.000	
	Total pathway		2.00	1.67	2.07	2.00	60.7	41.5	65.0	42.8	0.70	0.001
GPHL1bC	Piped NG, 4000 km, Hydrogen CCGT + CCS											
	NG Extraction & Processing	1	0.06	0.03	0.13	8.5			3.0	0.22	0.000	
	NG Transport	3	0.22			18.2			11.7	0.26	0.001	
	NG Distribution (HP)	3	0.02			1.4			1.3	0.00	0.000	
	Power generation (CCGT)	4	1.40	1.33	1.47	13.4			13.4	0.00	0.000	
	Electricity distribution (LV)	5	0.03			0.0			0.0	0.00	0.000	
	Total pathway		1.74	1.55	1.86	1.74	41.6	30.1	48.6	29.4	0.48	0.001
GREL1	LNG, CCGT											
	NG Extraction & Processing	1	0.05	0.02	0.10	6.6			2.3	0.17	0.000	
	NG Liquefaction	2	0.16			10.9			8.8	0.08	0.000	
	LNG transport (shipping)	3	0.16			10.5			10.4	0.00	0.000	
	LNG 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	1.21	1.46	1.33	137.0	130.6	144.8	128.8	0.26	0.006
KOEL1	Coal, state-of-the-art conventional technology											
	Coal provision	3	0.22			38.1			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	1.28	1.79	1.58	269.0	236.9	289.3	242.6	0.91	0.012
KOEL2	Coal, IGCC											
	Coal provision	3	0.20			34.5			13.9	0.82	0.001	
	Power plant	4	1.12			207.0			206.2	0.01	0.002	
	Electricity distribution (LV)	5	0.03			0.0			0.0	0.00	0.000	
	Total pathway		1.35	1.25	1.45	1.34	241.5	231.5	252.6	220.0	0.83	0.003

	Standard step	Energy expended (MJx/MJelec)				Net GHG emitted (g CO ₂ eq/MJelec)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary		Fossil	Best est.	min	Max					
		Best est.	min					Max				
OWEL1a	Electricity from municipal waste (local power plant)											
	Biogas production	4	1.67				5.77			-4.6	0.60	-0.016
	Local power plant	4	1.52				1.97			0.0	0.08	0.000
	Electricity distribution (LV)	5	0.01				0.00			0.0	0.00	0.000
	Total pathway		3.20	2.91	3.57	-0.08	7.7	7.1	8.4	-4.6	0.68	-0.016
OWEL1b	Electricity from municipal waste (large power plant)											
	Biogas production	4	1.52				-79.19			-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				107.11			105.5	0.01	0.005
	Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000
Total pathway		2.39	2.10	2.68	0.21	27.9	22.2	33.1	8.4	0.85	-0.006	
OWEL2a	Electricity from liquid manure (local power plant)											
	Transport of liquid manure (10 km)	2	0.06				-197.98			4.5	-8.10	0.000
	Biogas production	4	1.47				8.82			-2.7	0.57	-0.009
	Local power plant	4	1.52				1.97			0.0	0.08	0.000
	Electricity distribution (LV)	5	0.01				0.00			0.0	0.00	0.000
Total pathway		3.06	2.74	3.40	0.01	-187.2	-243.7	-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				-177.18			4.0	-7.25	0.000
	Biogas production	4	1.64				-91.24			-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				107.11			105.5	0.01	0.005
Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000	
Total pathway		2.56	2.24	2.88	-0.06	-161.3	-209.4	-107.5	-1.4	-6.35	-0.004	
OWEL3a	Electricity from dry manure (local power plant)											
	Transport of dry manure (10 km)	2	0.02				-18.81			1.4	-0.81	0.000
	Biogas production	4	1.47				8.82			-2.7	0.57	-0.009
	Local power plant	4	1.52				1.97			0.0	0.08	0.000
	Electricity distribution (LV)	5	0.01				0.00			0.0	0.00	0.000
Total pathway		3.02	2.72	3.32	-0.03	-8.0	-13.6	-2.0	-1.2	-0.16	-0.009	
OWEL3b	Electricity from dry manure (large power plant)											
	Transport of dry manure (10 km)	2	0.02				-16.84			1.3	-0.72	0.000
	Biogas production	4	1.64				-91.24			-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				107.11			105.5	0.01	0.005
Electricity distribution (LV)	5	0.03				0.00			0.0	0.00	0.000	
Total pathway		2.53	2.21	2.84	-0.09	-1.0	-5.9	4.8	-4.2	0.17	-0.004	

	Standard step	Energy expended (MJx/MJelec)				Net GHG emitted (g CO ₂ eq/MJelec)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary		Fossil	Best est.	min	Max					
		Best est.	min					Max				
WWEL1 Waste wood, 200 MW gasifier + CCGT	Waste collection and chipping	1	0.06				0.8			0.7	0.00	0.000
	Wood chips road transport	3	0.04				3.0			2.8	0.01	0.000
	Power generation (gasifier+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	1.16	1.34	0.05	5.2	4.9	5.6	3.5	0.03	0.003
WWEL2 Waste wood, 10 MW gasifier + GT	Waste collection and chipping	1	0.09				1.1			1.0	0.00	0.000
	Wood chips road transport	3	0.00				0.2			0.2	0.00	0.000
	Power generation (gasifier+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		2.00	1.90	2.10	0.02	3.2	3.2	3.3	1.3	0.04	0.004
WWEL3 Waste wood, steam power plant	Waste collection and chipping	1	0.09				1.1			1.0	0.00	0.000
	Wood chips road transport	3	0.01				1.0			1.0	0.00	0.000
	Power generation (boiler + steam turbine)	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		2.01	1.90	2.12	0.03	4.0	3.9	4.0	2.0	0.04	0.004
WWEL4 Waste wood, co-fired with coal	Waste collection and chipping	1	0.07				0.9			0.8	0.00	0.000
	Wood chips road transport	3	0.04				3.3			3.1	0.01	0.000
	Coal power station (boiler + steam turbine)	4	1.34				3.6			0.0	0.00	0.012
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		1.48	1.16	1.72	0.05	7.7	7.2	8.2	3.9	0.01	0.012
WFEL1 Farmed wood, 200 MW gasifier + CCGT	Wood farming	1	0.03				4.4			1.8	0.00	0.008
	Wood chipping	1	0.06				0.8			0.7	0.00	0.000
	Wood chips road transport	3	0.01				0.7			0.7	0.00	0.000
	Power generation (gasifier+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	1.35	0.05	7.3	5.6	18.9	3.3	0.03	0.011
WFEL2 Farmed wood, 10 MW gasifier + GT	Wood farming	1	0.04				5.9			2.4	0.00	0.011
	Wood chipping	1	0.09				1.1			1.0	0.00	0.000
	Wood chips road transport	3	0.00				0.2			0.2	0.00	0.000
	Power generation (gasifier+GT)	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	1.92	2.15	0.05	9.2	6.8	27.1	3.7	0.04	0.015
WFEL3 Farmed wood, steam power plant	Wood farming	1	0.04				6.6			2.7	0.00	0.013
	Wood chipping	1	0.10				1.2			1.1	0.00	0.000
	Wood chips road transport	3	0.01				1.1			1.1	0.00	0.000
	Power generation (boiler + steam turbine)	4	2.19				9.7			0.0	0.09	0.025
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		2.37	2.20	2.53	0.07	18.5	16.2	38.4	4.9	0.09	0.038
WFEL4 Farmed wood, co-firing with coal	Wood farming	1	0.03				4.8			2.0	0.00	0.009
	Wood chipping	1	0.07				0.9			0.8	0.00	0.000
	Wood chips road transport	3	0.01				0.8			0.8	0.00	0.000
	Coal power station (boiler + steam turbine)	4	1.34				3.6			0.0	0.00	0.012
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		1.48	1.12	1.70	0.05	10.1	8.2	24.9	3.6	0.01	0.021
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
EMEL1 EU-mix electricity	EU-mix power generation	4	1.84				129.8			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	129.8	129.8	129.8	120.8	0.29	0.005
WDEL1 Wind turbine (offshore)	Non-nuclear fossil energy											
	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	Non-nuclear fossil energy											
	Nuclear fuel provision	1	0.62				4.07			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	2.82	2.74	4.4	4.2	4.6	4.1	0.01	0.000	
												0.65

7.2 Heat and CHP

These pathways are provided for reference purposes and are not further used in the WTW analysis. They describe typical performance of small and industrial boilers and large scale CHP plants fed with various feedstocks.

		Crude oil		Natural gas						Biogas			Farmed wood		Waste wood							
Pathway code		C O H T		G P H T		G P E H		G R H T		G R E H			O W H T			W F H T		W F E H		W W H T		W W E H
		1	2	1a	1b	2a	2b	1a	1b	1	2	1	1	2	3	1	2	1	1	2	1	
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	✓																				
BD0	Heating oil domestic boiler	✓																				
Bl0	Heating oil industrial boiler	✓	✓																			
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)									✓	✓	✓										
Biogas from waste																						
BG1a	Liquid manure transport, 10 km													✓								
BG1b	Dry manure transport, 10 km														✓							
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			✓	✓			✓	✓	✓	✓											
GG4	NG local distribution			✓	✓			✓	✓	✓	✓											
NG common processes																						
BDg	NG domestic boiler			✓	✓					✓			✓	✓	✓							
Blg	NG industrial boiler					✓					✓											
HPg	CHP plant, gas fired							✓	✓			✓										
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)																					
BDw	Wood domestic boiler																					
Blw	Wood industrial boiler																					
HPw	CHP plant, wood fired																				✓	✓
Common processes																						
Z1	Diesel production	✓	✓										✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z2	Road tanker	✓	✓										✓	✓	✓	✓	✓	✓	✓	✓	✓	✓
Z71	HV+MV losses											✓										

Heat

COHT1/2 Heating oil boiler

Two variants describing either a small domestic (1) or large industrial boiler (2).

GPHT1/2 Piped natural gas boiler

Four variants describing either a small domestic (1) or large industrial boiler (2) fed with piped natural gas, with, in each case two supply distances (a: 7000 km, b: 4000 km).

GRHT1/2 Natural gas (ex LNG) boiler

Two variants describing either a small domestic (1) or large industrial boiler (2) fed with natural gas from imported LNG.

	Standard step	Energy expended (MJx/MJheat)				Net GHG emitted (g CO ₂ eq/MJheat)			CO ₂	CH ₄	N ₂ O	
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ	
		Best est.	min	Max								
COHT1	Heating oil domestic boiler											
	Crude Extraction & Processing	1	0.07			5.9			5.9	0.00	0.000	
	Crude Transport	3	0.01			1.0			-0.8	0.00	0.000	
	Refining	4	0.11			9.6			9.6	0.00	0.000	
	Distribution and dispensing	5	0.01			0.6			0.6	0.00	0.000	
	Domestic boiler	5	1.17			84.7			83.8	0.01	0.002	
	Total pathway		1.37	1.34	1.41	1.37	101.8	99.6	104.4	99.1	0.01	0.002
COHT2	Heating oil industrial boiler											
	Crude Extraction & Processing	1	0.07			4.1			4.1	0.00	0.000	
	Crude Transport	3	0.01			1.0			1.0	0.00	0.000	
	Refining	4	0.11			9.6			9.6	0.00	0.000	
	Distribution and dispensing	5	0.01			0.6			0.6	0.00	0.000	
	Industrial boiler	5	1.18			85.3			84.4	0.01	0.002	
	Total pathway		1.39	1.36	1.43	1.38	100.6	98.5	103.6	99.7	0.01	0.002
GPHT1a	Piped NG 7000 km domestic boiler											
	NG Extraction & Processing	1	0.03			3.8			1.3	0.10	0.000	
	NG Transport	3	0.19			15.0			10.2	0.19	0.000	
	NG Distribution (LP)	5	0.01			0.6			0.6	0.00	0.000	
	Domestic boiler	5	1.05			57.2			56.9	0.01	0.000	
	Total pathway		1.28	0.18	0.29	1.28	76.6	71.0	77.4	69.0	0.29	0.001
GPHT1b	Piped NG 4000 km domestic boiler											
	NG Extraction & Processing	1	0.03			3.5			1.2	0.09	0.000	
	NG Transport	3	0.09			7.5			4.8	0.11	0.000	
	NG Distribution (LP)	5	0.01			0.6			0.5	0.00	0.000	
	Domestic boiler	5	1.05			57.2			56.9	0.01	0.000	
	Total pathway		1.17	0.13	0.19	1.17	68.8	66.4	69.5	63.5	0.20	0.001
GPHT2a	Piped NG 7000 km industrial boiler											
	NG Extraction & Processing	1	0.03			4.3			1.5	0.11	0.000	
	NG Transport	3	0.22			16.7			11.3	0.21	0.000	
	NG Distribution (HP)	5	0.01			0.6			0.6	0.00	0.000	
	Industrial boiler	5	1.17			64.2			63.5	0.01	0.001	
	Total pathway		1.43	0.32	0.43	1.43	85.8	79.5	86.1	77.0	0.33	0.002
GPHT2b	Piped NG 4000 km industrial boiler											
	NG Extraction & Processing	1	0.03			3.9			1.4	0.10	0.000	
	NG Transport	3	0.10			8.3			5.3	0.12	0.000	
	NG Distribution (HP)	5	0.01			0.6			0.6	0.00	0.000	
	Industrial boiler	5	1.17			64.2			63.5	0.01	0.001	
	Total pathway		1.31	0.26	0.32	1.31	77.1	74.2	77.6	70.8	0.23	0.001
GRHT1	LNG domestic boiler											
	NG Extraction & Processing	1	0.03			3.5			1.2	0.09	0.000	
	NG Liquefaction	2	0.09			5.8			4.7	0.04	0.000	
	LNG transport (shipping)	3	0.09			5.6			5.5	0.00	0.000	
	LNG Receipt + vaporisation	5	0.03			1.8			1.8	0.00	0.000	
	NG distribution (LP)	5	0.01			0.6			0.5	0.00	0.000	
Domestic boiler	5	1.05			57.0			56.8	0.01	0.000		
	Total pathway		1.29	0.28	0.31	1.29	74.4	73.8	75.7	70.6	0.14	0.001
GRHT2	LNG industrial boiler											
	NG Extraction & Processing	1	0.03			3.9			1.4	0.10	0.000	
	NG Liquefaction	2	0.10			6.5			5.2	0.05	0.000	
	LNG transport (shipping)	3	0.10			6.2			6.2	0.00	0.000	
	LNG Receipt + vaporisation	5	0.04			2.1			2.0	0.00	0.000	
	NG distribution (HP)	5	0.01			0.6			0.6	0.00	0.000	
Industrial boiler	5	1.17			63.9			63.2	0.01	0.001		
	Total pathway		1.44	0.42	0.46	1.44	83.2	82.4	84.4	78.6	0.16	0.002

OWHT1/2/3 Gas (ex biogas) boiler

Three variants corresponding to three biogas sources: municipal waste, liquid or dry manure.

W/F-W1/2 Wood boiler

Four variants corresponding to either farmed or waste wood feeding either a small or industrial scale boiler.

	Standard step	Energy expended (MJx/MJheat)				Net GHG emitted (g CO ₂ eq/MJheat)			CO ₂	CH ₄	N ₂ O			
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ			
		Best est.	min	Max										
OWHT1	Municipal waste to biogas to heat													
	Biogas production	4	0.81						-42.3			-51.9	0.45	-0.006
	Gas distribution	5	0.00						0.0			0.0	0.00	0.000
	Gas boiler	5	0.05						58.6			58.3	0.01	0.000
	Total pathway		0.86	0.71	0.99	0.15	16.2	13.3	18.9	6.4	0.46	-0.006		
OWHT2	Liquid manure to biogas to heat													
	Transport of liquid manure (10 km)	4	0.03						-94.7			2.1	-3.87	0.000
	Biogas production, treating and upgrading	4	0.88						-48.7			-59.3	0.47	-0.004
	Local gas distribution	5	0.00						0.0			0.0	0.00	0.000
	Gas boiler	5	0.05						58.6			58.3	0.01	0.000
	Total pathway		0.95	0.78	1.12	0.01	-84.9	-111.9	-54.8	1.2	-3.39	-0.004		
OWHT3	Dry manure to biogas to heat													
	Transport of dry manure (10 km)	4	0.01						-9.0			0.7	-0.39	0.000
	Biogas production, treating and upgrading	4	0.88						-48.7			-59.3	0.47	-0.004
	Local gas distribution	5	0.00						0.0			0.0	0.00	0.000
	Gas boiler	5	0.05						58.6			58.3	0.01	0.000
	Total pathway		0.93	0.76	1.08	-0.01	0.8	-2.2	3.6	-0.3	0.09	-0.004		
WWHT1	Waste wood domestic boiler													
	Waste collection and chipping	1	0.04						0.4			0.4	0.00	0.000
	Wood chip transport	3	0.01						0.4			0.4	0.00	0.000
	Wood pellets manufacture	4	0.09						0.0			0.0	0.00	0.000
	Wood pellets distribution	5	0.00						0.3			0.3	0.00	0.000
	Domestic boiler	5	0.20						4.4			3.6	0.01	0.002
	Total pathway		0.33	0.29	0.37	0.10	5.5	5.5	5.5	4.7	0.01	0.002		
WFHT1	Farmed wood domestic boiler													
	Wood plantation	1	0.02						2.5			1.0	0.00	0.005
	Wood chipping	1	0.04						0.4			0.4	0.00	0.000
	Wood chip transport	3	0.01						0.4			0.4	0.00	0.000
	Wood pellets manufacture	4	0.09						0.0			0.0	0.00	0.000
	Wood pellets distribution	5	0.00						0.3			0.3	0.00	0.000
	Domestic boiler	5	0.20						4.4			3.6	0.01	0.002
	Total pathway		0.35	0.31	0.39	0.11	7.9	7.1	14.7	5.7	0.01	0.006		
WWHT2	Waste wood industrial boiler													
	Waste collection and chipping	1	0.03						0.4			0.4	0.00	0.000
	Wood chip transport	3	0.01						0.4			0.4	0.00	0.000
	Industrial boiler	5	0.23						2.8			2.4	0.01	0.001
	Total pathway		0.27	0.24	0.31	0.07	3.7	3.6	3.7	3.2	0.01	0.001		
WFHT2	Farmed wood industrial boiler													
	Wood plantation	1	0.02						2.4			1.0	0.00	0.005
	Waste collection and chipping	1	0.03						0.4			0.4	0.00	0.000
	Wood chip transport	3	0.01						0.4			0.4	0.00	0.000
	Industrial boiler	5	0.23						2.8			2.4	0.01	0.001
	Total pathway		0.29	0.25	0.33	0.08	6.1	5.3	13.0	4.2	0.01	0.005		

CHP (with heat credit)

GPEH1a/b Natural gas CHP plant

Two variants corresponding to a large scale CCGT-based CHP plant fed with piped gas with a supply distance of either 7000 km (a) or 4000 km (b).

GREH1 Natural gas (ex LNG) CHP plant

As above but now with gas from imported LNG.

W/F-WEH1 Wood CHP plant

Wood CHP plant fed with either farmed or waste wood.

	Standard step	Energy expended (MJx/MJelec)				Net GHG emitted (g CO ₂ eq/MJelec)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary		Fossil	Best est.	min	Max					
		Best est.	min					Max				
GPEH1a	Piped NG 7000 km, CCGT CHP											
	NG Extraction & Processing	1	0.07				9.2			3.2	0.24	0.000
	NG Transport	3	0.47				36.0			24.4	0.45	0.001
	NG Distribution (HP)	3	0.02				1.4			1.3	0.00	0.000
	CHP plant (CCGT)	4	1.37				133.8			131.8	0.01	0.006
	Heat export credit	4	-1.60				-96.8			-86.8	-0.38	-0.002
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		0.36	0.05	0.56	0.36	83.5	65.7	95.0	74.0	0.32	0.005
<i>Heat/power production ratio</i>												
1.10												
GPEH1b	Piped NG 4000 km, CCGT CHP											
	NG Extraction & Processing	1	0.06				8.4			2.9	0.22	0.000
	NG Transport	3	0.22				18.0			11.5	0.25	0.000
	NG Distribution (HP)	3	0.02				1.4			1.3	0.00	0.000
	CHP plant (CCGT)	4	1.37				133.8			131.8	0.01	0.006
	Heat export credit	4	-1.46				-86.7			-79.6	-0.26	-0.002
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		0.24	0.11	0.37	0.24	74.9	67.2	82.3	67.9	0.22	0.005
<i>Heat/power production ratio</i>												
1.10												
GREH1	LNG, CCGT CHP											
	NG Extraction & Processing	1	0.06				8.5			2.9	0.22	0.000
	NG Liquefaction	2	0.21				13.9			11.2	0.10	0.000
	LNG transport (shipping)	3	0.21				13.4			13.3	0.00	0.000
	LNG Receipt + vaporisation	3	0.08				4.4			4.4	0.00	0.000
	NG distribution (HP)	3	0.03				1.3			1.3	0.00	0.000
	CHP plant (CCGT)	4	1.37				133.5			131.5	0.01	0.006
	Heat export credit	4	-1.61				-93.8			-88.7	-0.18	-0.002
Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000	
Total pathway		0.37	0.33	0.42	0.37	81.2	79.0	84.0	76.0	0.15	0.005	
<i>Heat/power production ratio</i>												
1.10												
WWEH1	Waste wood boiler + steam turbine CHP											
	Waste collection and chipping	1	0.14				1.7			1.6	0.00	0.000
	Wood chips road transport	3	0.02				1.5			1.5	0.00	0.000
	CHP plant (boiler + steam turbine)	4	3.55				3.2			0.0	0.09	0.003
	Heat export credit	4	-3.30				-3.4			-2.2	-0.01	-0.003
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
	Total pathway		0.44	0.19	0.67	0.01	3.1	2.9	3.2	1.0	0.08	0.000
<i>Heat/power production ratio</i>												
2.50												
WFEH1	Farmed wood boiler + steam turbine CHP											
	Wood farming	1	0.06				9.4			3.8	0.01	0.018
	Wood chipping	1	0.14				1.7			1.6	0.00	0.000
	Wood chips road transport	3	0.02				1.5			1.5	0.00	0.000
	CHP plant (boiler + steam turbine)	4	3.55				3.2			0.0	0.09	0.003
	Heat export credit	4	-3.34				-9.9			-4.9	-0.02	-0.015
	Electricity distribution (LV)	5	0.03				0.0			0.0	0.00	0.000
Total pathway		0.46	0.21	0.72	0.03	5.9	-7.7	27.4	2.1	0.09	0.006	
<i>Heat/power production ratio</i>												
2.50												

CHP (with electricity credit)

GPHT3b

Gas fired GT with heat recovery

WFHT3

Wood fired CHP

	Standard step	Energy expended (MJx/MJheat)				Net GHG emitted (g CO ₂ eq/MJheat)			CO ₂	CH ₄	N ₂ O	
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ	
		Best est.	min	Max								
GPHT3b	Piped NG 4000 km, Heat CHP											
	NG Extraction & Processing	1	0.06			8.3			2.9	0.22	0.000	
	NG Transport	3	0.22			17.7			11.3	0.25	0.000	
	NG Distribution (HP)	3	0.02			1.3			1.3	0.00	0.000	
	CHP plant (CCGT) inc. elec credit	4	-0.83			7.3			16.4	-0.36	0.000	
	Heat distribution	5	0.11			0.0			0.0	0.00	0.000	
	Total pathway		-0.42	0.00	0.00	-0.42	34.7	0.0	0.0	31.9	0.10	0.001
WFHT3	Farmed wood, Heat CHP											
	Wood farming	1	0.03			4.0			1.7	0.00	0.008	
	Wood chipping	1	0.06			0.7			0.7	0.00	0.000	
	Wood chips road transport	3	0.01			0.7			0.7	0.00	0.000	
	CHP plant (boiler + steam turbine), inc. elec credit	4	-0.59			-6.6			-2.1	0.00	-0.015	
	Electricity distribution (LV)	5	0.11			0.0			0.0	0.00	0.000	
	Total pathway		-0.38	0.00	0.00	0.62	-1.2	0.0	0.0	0.9	0.01	-0.007

8 Hydrogen

8.1 Natural gas to hydrogen

Pathway code		G M C H						G P L C H						G P L H		G R L H	
		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 (+CCS 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 CO₂ 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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ			
		Total primary			Fossil	Best est.	min	Max						
		Best est.	min	Max										
GMCH1	NG EU-mix, 1000 km, on-site reforming													
	NG Extraction & Processing	1	0.04	0.02	0.07				4.9		1.7	0.1	0.0	
	NG Transport	3	0.03	0.01	0.03				2.8		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				86.6		85.8	0.0	0.0	
	Compression	5	0.24	0.22	0.26				10.0		9.3	0.0	0.0	
	Total pathway		0.84	0.81	0.89	0.83			105.2	103.3	108.0	99.3	0.23	0.001
GPCH1a	Piped NG, 7000 km, on-site reforming													
	NG Extraction & Processing	1	0.04	0.02	0.09				5.7		2.0	0.15	0.000	
	NG Transport	3	0.29	0.10	0.32				22.1		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				84.7		83.9	0.03	0.000	
	Compression	5	0.24	0.22	0.26				10.0		9.3	0.02	0.000	
	Total pathway		1.11	0.94	1.18	1.09			123.2	113.5	127.7	111.0	0.48	0.001
GPCH1b	Piped NG, 4000 km, on-site reforming													
	NG Extraction & Processing	1	0.04	0.02	0.08				5.2		1.8	0.13	0.000	
	NG Transport	3	0.14	0.05	0.15				11.0		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				84.7		83.9	0.03	0.000	
	Compression	5	0.24	0.22	0.26				10.0		9.3	0.02	0.000	
	Total pathway		0.95	0.86	1.00	0.94			111.7	106.7	114.7	102.9	0.34	0.001
GPCH2a	Piped NG, 7000 km, central reforming, pipeline													
	NG Extraction & Processing	1	0.04	0.02	0.08				5.2		1.8	0.13	0.000	
	NG Transport	3	0.26	0.09	0.29				20.1		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				74.1		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	0.93	0.85			109.3	100.9	113.6	98.4	0.42	0.001
GPCH2b	Piped NG, 4000 km, central reforming, pipeline													
	NG Extraction & Processing	1	0.04	0.02	0.07				4.7		1.6	0.12	0.000	
	NG Transport	3	0.12	0.04	0.14				10.1		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				74.1		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	0.63	0.76	0.71			98.8	94.0	101.3	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				4.9		1.7	0.13	0.000	
	NG Transport	3	0.13	0.04	0.14				10.5		6.7	0.15	0.000	
	NG Distribution (HP)	3	0.01						0.8		0.8	0.00	0.000	
	Central reforming (CCS)	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	0.69	0.82	0.76			37.8	33.1	40.4	29.8	0.31	0.001
GPCH3b	Piped NG, 4000 km, central reforming, trucking													
	NG Extraction & Processing	1	0.04	0.02	0.07				4.7		1.64	0.12	0.000	
	NG Transport	3	0.12	0.04	0.14				10.1		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				74.1		73.67	0.02	0.000	
	Gaseous Hyd distribution & comp.	5	0.22	0.21	0.24				10.1		9.50	0.02	0.000	
	Total pathway		0.72	0.63	0.77	0.71			99.7	94.7	102.4	92.0	0.30	0.001

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary			Fossil	Best est.	min	Max				
		Best est.	min	Max								
GPLCHb	Piped NG, 4000 km, central reforming + liquefaction, vaporisation/compression											
	1	0.03	0.02	0.07		4.7			1.6	0.12	0.000	
	3	0.12	0.11	0.13		9.9			6.3	0.14	0.000	
	3	0.01				0.8			0.7	0.00	0.000	
	4	0.32	0.28	0.34		73.0			72.6	0.02	0.000	
	4	0.62	0.43	0.80		37.0			33.8	0.11	0.002	
	5	0.17				8.3			7.8	0.02	0.000	
	Total pathway		1.28	1.13	1.36	1.27	133.6	125.0	138.8	122.8	0.40	0.002
GRCH1	LNG, on-site reforming											
	1	0.04	0.02	0.08		5.2			1.8	0.14	0.000	
	2	0.13				8.6			6.9	0.06	0.000	
	3	0.13				8.2			8.2	0.00	0.000	
	3	0.06				3.5			3.5	0.00	0.000	
	4	0.52	0.49	0.55		84.5			83.8	0.02	0.000	
	5	0.24	0.22	0.26		10.0			9.3	0.02	0.000	
	Total pathway		1.12	1.08	1.16	1.10	119.9	117.6	122.6	113.4	0.25	0.001
GRCH2	LNG, central reforming											
	1	0.04	0.02	0.07		4.7			1.6	0.12	0.000	
	2	0.12				7.8			6.3	0.06	0.000	
	3	0.11				7.5			7.4	0.00	0.000	
	3	0.06				3.2			3.2	0.00	0.000	
	4	0.32	0.29	0.34		74.1			73.7	0.02	0.000	
	5	0.22	0.21	0.24		9.1			8.5	0.02	0.000	
	Total pathway		0.87	0.83	0.91	0.86	106.5	104.5	109.0	100.7	0.22	0.001
GRCH3	Remote NG, methanol, on-site reforming											
	1	0.04	0.02	0.09		5.7			2.0	0.15	0.000	
	2	0.57				14.2			14.2	0.00	0.000	
	3	0.08				5.3			5.3	0.00	0.000	
	4	0.21	0.20	0.22		84.4			84.4	0.00	0.000	
	5	0.22	0.21	0.24		9.1			8.5	0.02	0.000	
	Total pathway		1.12	1.10	1.16	1.11	118.8	117.6	121.0	114.3	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 CO₂ 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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary			Fossil	Best est.	min	Max				
		Best est.	min	Max								
GPLH1a	Piped NG, 7000 km, central reforming + liquefaction											
	NG Extraction & Processing	1	0.04	0.02	0.08	5.1			1.8	0.13	0.000	
	NG Transport	3	0.26	0.09	0.29	19.8			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	41.3			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	1.44	1.33	141.7	128.6	148.4	127.1	0.56	0.002
GPLH1b	Piped NG, 4000 km, central reforming + liquefaction											
	NG Extraction & Processing	1	0.03	0.02	0.07	4.7			1.6	0.12	0.000	
	NG Transport	3	0.12	0.04	0.14	9.9			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	37.0			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	0.99	1.22	1.13	127.0	118.5	132.2	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	5.2			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	39.9			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	1.31	1.55	1.42	139.1	132.4	146.7	133.2	0.22	0.002
GRLH2	LNG, central reforming + liquefaction											
	NG Extraction & Processing	1	0.03	0.02	0.07	4.6			1.6	0.12	0.000	
	NG Liquefaction	2	0.11	0.00	0.00	7.6			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	73.0			72.6	0.02	0.000	
	Hyd liquefaction	4	0.67	0.47	0.88	39.7			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	1.22	1.49	1.34	137.5	130.6	146.2	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		K O C H	
		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 (+CCS 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 CO₂ capture and storage could be an attractive option where suitable geological formations are available within a reasonable distance.

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary		Fossil		Best est.	min	Max				
		Best est.	min	Max	Fossil							
KOCH1	Coal EU-mix, gasifier + CO shift											
	Coal provision	3	0.19			32.3			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	1.40	1.40	1.38	234.4	234.4	234.4	214.4	0.79	0.001
KOCH1C	Coal EU-mix, gasifier + CO shift, CCS											
	Coal provision	3	0.22			37.8			15.2	0.90	0.001	
	Gasifier + CO shift + CCS	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	1.77	1.77	1.76	52.7	52.7	52.7	29.5	0.92	0.001

8.3 Wood to hydrogen

Pathway code		W F C H	W F L H	W W C H	B L C H	
		1	2	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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eg/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary			Fossil	Best est.	min	Max				
		Best est.	min	Max								
WFCH1	Farmed wood , on-site gasification, 10 MW (biomass)											
	Wood farming and chipping	1	0.08			4.7			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	1.15	1.35	0.22	14.8	13.1	27.2	10.4	0.03	0.012
WFCH2	Farmed wood, large scale gasification, 200 MW (biomass)											
	Wood farming	1	0.06			3.6			1.8	0.00	0.006	
	Road transport	3	0.01			0.5			0.5	0.00	0.000	
	Med scale gasifier (200 MW) + CO shift	4	0.68			0.5			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	13.8	13.1	25.2	11.1	0.02	0.007
WFLH1	Farmed wood, large scale gasification, 200 MW (biomass), liquefaction											
	Wood farming	1	0.06			3.5			1.7	0.00	0.006	
	Road transport	3	0.01			1.0			0.8	0.00	0.001	
	Med scale gasifier (200 MW) + CO shift	4	0.67			1.9			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	1.37	1.67	0.07	7.5	6.6	21.2	4.6	0.00	0.009
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	1.11	1.31	0.19	10.7	10.7	10.8	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	12.0	12.2	11.3	0.03	0.000
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	0.47	0.55	0.20	10.0	10.0	10.1	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		G P E L				G R E L	K O E L		W F E L	W D E L	N U E L	E M E L				
		1a	1b	1b	1b	1	1	1	1	2	3	1	1	1	1	
Code	Process	CH1	CH1	CH2	LH1	CH1	CH1	CH2	LH1	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)						✓	✓	✓							
KE1	Electricity from Coal (conv. Boiler)						✓	✓	✓							
Wood (farmed)																
WF1	Wood farming and chipping									✓	✓					
Wood transport & processing (all sources)																
WC2a	Wood chips road transport, 50 km									✓	✓					
WC2b	Wood chips road transport, 12 km									✓	✓					
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				✓				✓						✓	
LH2	Liquid Hyd long-distance transport								✓						✓	
LH3	Liquid Hyd distribution and dispensing				✓				✓						✓	
Common processes																
Z1	Diesel production				✓										✓	
Z2	Road tanker				✓										✓	
Z7a	Electricity (EU-mix, MV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	
Z7b	Electricity (EU-mix, LV)	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	

GP1a/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 expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ
		Total primary			Fossil	Best est.	min	Max			
		Best est.	min	Max							
GPEL1a/CH1	Piped NG 7000 km, CCGT, on-site electrolysis										
	NG Extraction & Processing	1	0.08	0.04	0.17	11.2			3.9	0.29	0.000
	NG Transport	3	0.57	0.19	0.63	43.6			29.6	0.54	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	0.03	0.000
Total pathway		2.72	2.30	2.87	2.72	227.1	202.1	236.1	202.3	0.88	0.009
GPEL1b/CH1	Piped NG 4000 km, CCGT, on-site electrolysis										
	NG Extraction & Processing	1	0.08	0.04	0.15	10.2			3.6	0.27	0.000
	NG Transport	3	0.27	0.09	0.30	21.8			13.9	0.31	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	0.02	0.000
Total pathway		2.40	2.15	2.58	2.40	203.5	188.7	214.0	185.7	0.61	0.009
GPEL1b/CH2	Piped NG, 4000 km, CCGT, central electrolysis, pipe										
	NG Extraction & Processing	1	0.08	0.04	0.15	10.1			3.5	0.26	0.000
	NG Transport	3	0.27	0.09	0.30	21.6			13.8	0.30	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	161.0			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		2.45	2.19	2.65	2.44	203.5	188.0	215.3	185.9	0.60	0.009
GPEL1b/LH1	Piped NG 4000 km, CCGT, central electrolysis, liquefaction										
	NG Extraction & Processing	1	0.08	0.04	0.15	10.0			3.5	0.26	0.000
	NG Transport	3	0.26	0.09	0.29	21.3			13.6	0.30	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	0.11	0.002
Liquid hyd distribution & delivery	1	0.04			2.8			2.8	0.00	0.000	
Total pathway		2.86	2.59	3.05	2.86	231.5	215.8	242.4	211.5	0.69	0.010
GREL1/CH1	LNG, CCGT, on-site electrolysis										
	NG Extraction & Processing	1	0.08	0.04	0.15	10.2			3.6	0.27	0.000
	NG Liquefaction	2	0.25			16.9			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	2.49	2.97	2.75	220.8	205.9	234.0	207.5	0.42	0.009

	Standard step	Energy expended (MJx/MJf)				Net GHG emitted (g CO ₂ eq/MJf)			CO ₂ g/MJ	CH ₄ g/MJ	N ₂ O g/MJ	
		Total primary		Fossil	Best est.	min	Max					
		Best est.	min					Max				
KOEL1/CH1	Coal electricity, on-site electrolysis											
	Coal provision (EU-mix)	3	0.34			59.1			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			16.4			14.8	0.1	0.0	
	Total pathway		3.17	2.62	3.54	3.16	433.4	376.6	471.8	390.9	1.46	0.020
KOEL1/CH2	Coal electricity, central electrolysis											
	Coal provision (EU-mix)	3	0.34			58.6			23.6	1.39	0.001	
	Coal power station	4	2.06			355.5			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	2.70	3.60	3.17	423.2	372.9	466.0	382.0	1.42	0.019
KOEL1/LH1	Coal electricity, central electrolysis, liquefaction											
	Coal provision (EU-mix)	3	0.34			57.8			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	79.6			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	3.20	4.08	3.72	490.3	436.6	526.1	442.5	1.65	0.022
WFEL2/CH1	Farmed wood, CCGT, on-site electrolysis											
	Wood harvesting and chipping	1	0.14			8.0			3.9	0.00	0.013	
	Mixed transport	3	0.01			1.1			1.1	0.00	0.000	
	Gasification (200 MW)+ CCGT	4	1.71			2.2			0.0	0.04	0.004	
	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			0.4			0.2	0.00	0.001		
	Total pathway		2.60	2.41	2.82	0.08	11.8	9.7	32.6	5.3	0.05	0.018
WFEL3/CH1	Farmed wood, conv. power plant, on-site electrolysis											
	Wood harvesting and chipping	1	0.21			12.0			5.9	0.01	0.020	
	Mixed transport	3	0.02			1.7			1.7	0.00	0.000	
	Conv power plant (200 MW), cond. turbine	4	3.39			15.1			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			1.1			0.3	0.01	0.002		
	Total pathway		4.43	4.08	4.74	0.11	29.9	26.1	58.9	7.9	0.14	0.062
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	0.74	0.86	0.19	9.1	9.1	9.1	8.5	0.02	0.000
NUEL1/CH1	Nuclear electricity, on-site electrolysis											
	Nuclear fuel provision	3	0.96			6.3			5.9	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	4.75	5.27	5.02	7.0	6.7	7.4	6.6	0.01	0.000
EMEL1/CH1	EU-mix electricity, on-site electrolysis											
	EU-mix power generation	1	2.85			201.2			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	3.81	3.39	209.1	200.4	217.5	194.6	0.47	0.009
EMEL1/LH1	EU-mix electricity, central electrolysis, liquefaction											
	EU-mix power generation	1	2.79			196.9			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	38.4			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	3.98	4.43	3.97	237.0	225.9	246.4	220.7	0.53	0.010

9 Summary of energy and GHG balances

9.1 Oil-based fuels, CBG/CBG

Pathway		Energy expended (MJex/MJ final fuel)									Net GHG emitted (g CO ₂ eq/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. CO ₂ 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	0.17	0.17	0.06		0.01	0.08	0.02	0.15	0.20	0.02	0.03	14.2	5.2		0.9	7.0	1.0	14.2		12	16	2	2
COD1	Conventional diesel	0.20	0.19	0.06		0.01	0.10	0.02	0.17	0.22	0.03	0.02	15.9	5.3		0.9	8.6	1.0	15.9		12	16	4	0
CON1	Conventional naphtha	0.28	0.28	0.06		0.05	0.09	0.09	0.12	0.16	0.16	-0.13	11.4	5.1		0.9	4.4	1.0	11.4		5	6	6	-5
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	8.0	3.5	0.3	2.5		1.7	8.0		8	8	0	0
GMCG1	CNG: EU-mix	0.12	0.12	0.02		0.02		0.07	0.10	0.15	0.02	0.03	8.7	3.3		1.9		3.4	8.7		8	10	1	1
GPCG1a	CNG: Pipeline 7000 km	0.30	0.29	0.03		0.19		0.07	0.18	0.34	0.12	0.05	22.3	3.8		15.0		3.4	22.3		15	25	7	3
GPCG1b	CNG: Pipeline 4000 km	0.19	0.19	0.03		0.09		0.07	0.14	0.22	0.06	0.03	14.5	3.5		7.5		3.4	14.5		11	16	3	2
GRCG1	CNG: LNG - Vap - Pipe	0.31	0.30	0.03	0.09	0.12		0.07	0.29	0.33	0.02	0.03	20.2	3.5	5.8	7.4		3.4	20.2		19	22	1	1
GRCG1C	CNG: LNG, Vap - Pipe - CCS	0.32	0.32	0.03	0.10	0.12		0.07	0.29	0.35	0.02	0.03	16.7	3.5	2.3	7.4		3.4	16.7		16	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	20.8	3.5	5.8	6.2		5.3	20.8		20	22	1	1
OWCG1	CBG: municipal waste	0.87	0.17				0.81	0.06	0.72	1.00	0.15	0.13	-39.5				12.7	2.9	15.5	-55.0	-42	-37	3	3
OWCG2	CBG: liquid manure	0.97	0.03		0.03		0.88	0.06	0.79	1.14	0.18	0.17	-140.6		-94.7		6.3	2.9	-85.6	-55.0	-166	-110	26	30
OWCG3	CBG: dry manure	0.95	0.01		0.01		0.88	0.06	0.78	1.11	0.17	0.16	-54.9		-9.0		6.3	2.9	0.1	-55.0	-58	-52	3	3
OWCG4	CBG: wheat (whole plant)	1.20	0.01	0.17	0.00		0.97	0.06	1.17	1.23	0.03	0.03	-34.8	23.4	0.3		-6.4	2.9	20.2	-55.0	-38	-32	4	3
OWCG5	CBG: corn and barley, double cropping	1.34	0.03	0.10	0.00		1.17	0.06	1.30	1.36	0.04	0.03	-31.5	17.4	0.3		2.9	2.9	23.5	-55.0	-34	-16	3	15

9.2 Ethanol, Ethers, Bio-diesel

Pathway		Energy expended (MJex/MJ final fuel)										Net GHG emitted (g CO ₂ eq/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. CO ₂ 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					
SBET1a	EiOH: Sugar beet, pulp to fodder, slops not used	1.40	0.55	0.11		0.01	1.25	0.03	1.30	1.50	0.10	0.10	-33.8	16.2	1.1	18.7	1.5	37.6	-71.4	-37	-28	3	5	
SBET1b	EiOH: Sugar beet, pulp to fodder, slops to biogas	1.18	0.34	0.11		0.01	1.03	0.03	1.08	1.28	0.10	0.10	-47.0	16.2	1.1	5.5	1.5	24.4	-71.4	-50	-42	3	5	
SBET3	EiOH: Sugar beet, pulp to heat /slops to biogas	0.88	0.04	0.11		0.01	0.73	0.03	0.79	0.98	0.09	0.11	-57.6	16.2	1.1	-5.0	1.5	13.8	-71.4	-60	-52	2	6	
WTET1a	EiOH: Wheat, conv NG boiler, DDGS as AF	1.66	0.77	0.27		0.03	1.34	0.03	1.64	1.69	0.02	0.02	-13.0	39.5	0.6	16.8	1.5	58.4	-71.4	-20	-2	7	11	
WTET1b	EiOH: Wheat, conv NG boiler, DDGS as fuel	1.24	0.38	0.27		0.03	0.92	0.03	1.22	1.27	0.02	0.03	-20.3	39.5	0.6	9.5	1.5	51.1	-71.4	-26	-9	6	11	
WTET2a	EiOH: Wheat, NG GT+CHP, DDGS as AF	1.42	0.53	0.27		0.03	1.09	0.03	1.40	1.44	0.02	0.02	-25.0	39.5	0.6	4.8	1.5	46.4	-71.4	-33	-14	8	11	
WTET2b	EiOH: Wheat, NG GT+CHP, DDGS as fuel	1.00	0.14	0.27		0.03	0.67	0.03	0.97	1.01	0.02	0.02	-32.3	39.5	0.6	-2.6	1.5	39.1	-71.4	-38	-22	6	11	
WTET3a	EiOH: Wheat, Lignite CHP, DDGS as AF	1.49	0.60	0.27		0.03	1.16	0.03	1.48	1.49	0.00	0.00	5.0	39.5	0.6	34.8	1.5	76.4	-71.4	-1	15	6	10	
WTET3b	EiOH: Wheat, Lignite CHP, DDGS as fuel	1.06	0.21	0.27		0.03	0.74	0.03	1.06	1.07	0.01	0.00	-2.3	39.5	0.6	27.5	1.5	69.1	-71.4	-9	10	6	12	
WTET4a	EiOH: Wheat, Straw CHP, DDGS as AF	1.58	0.16	0.27		0.03	1.25	0.03	1.57	1.58	0.00	0.00	-47.5	39.5	0.6	-17.7	1.5	23.9	-71.4	-55	-36	8	11	
WTET4b	EiOH: Wheat, Straw CHP, DDGS as fuel	1.15	-0.23	0.27		0.03	0.83	0.03	1.15	1.16	0.00	0.01	-54.8	39.5	0.6	-25.0	1.5	16.6	-71.4	-61	-43	6	11	
WTET5	EiOH: Wheat, DDGS to biogas	1.10	0.21	0.27		0.03	0.77	0.03	1.10	1.10	0.00	0.00	-42.7	39.5	0.6	-13.0	1.5	28.6	-71.4	-49	-33	6	10	
WWET1	EiOH: W Wood	1.95	0.28	0.08		0.04	1.81	0.03	1.85	2.05	0.10	0.10	-52.4	0.9	3.2	13.3	1.5	19.0	-71.4	-53	-52	0	0	
WFET1	EiOH: F wood	1.96	0.28	0.11		0.01	1.81	0.03	1.86	2.07	0.09	0.11	-49.4	6.3	0.9	13.3	1.5	22.0	-71.4	-52	-32	2	17	
STET1	EiOH: Wheat straw	1.32	0.10	0.04		0.01	1.24	0.03	1.32	1.32	0.00	0.00	-62.4	3.1	0.6	3.7	1.5	9.0	-71.4	-62	-62	0	0	
SCET1a	EiOH: Sugar cane (Brazil), HFO credit for excess bagasse	1.81	0.04	0.06		0.01	1.63	0.11	1.81	1.82	0.00	0.00	-57.8	14.5	0.8	-9.8	8.1	13.6	-71.4	-61	-41	4	17	
SCET1b	EiOH: Sugar cane (Brazil), no credit for excess bagasse	1.96	0.18	0.06		0.01	1.78	0.11	1.95	1.96	0.00	0.00	-46.8	14.5	0.8	1.2	8.1	24.6	-71.4	-50	-30	3	16	
GRMB1	MTBE: remote plant	0.30	0.30	0.01	0.23	0.05	0.01	0.30	0.31	0.00	0.00	0.02	13.6	0.9	8.2	4.0	0.4	13.6			13	15	0	1
LREB1	ETBE: imported C4 and wheat ethanol	0.75	0.01	0.10		0.01	0.62	0.02	0.74	0.76	0.01	0.01	-0.9	14.4	0.2	7.3	1.1	22.9	-23.8	-3	2	4	2	
ROFA1	RME: Glycerine as chem, meal as AF	1.09	0.36	0.29		0.02	0.76	0.02	0.98	1.18	0.11	0.09	-34.1	49.4	0.3	-8.8	1.3	42.1	-76.2	-44	-21	10	13	
ROFA2	RME: Glycerine and meal as AF	1.14	0.41	0.29		0.02	0.81	0.02	1.04	1.25	0.11	0.11	-29.0	49.4	0.3	-3.7	1.3	47.2	-76.2	-38	-15	9	14	
ROFA3	RME: Glycerine to biogas, meal as AF	1.11	0.37	0.29		0.02	0.78	0.02	1.02	1.20	0.08	0.10	-30.5	49.4	0.3	-5.3	1.3	45.7	-76.2	-40	-17	10	14	
ROFA4	RME: Glycerine and cake to biogas	0.70	-0.02	0.29		0.02	0.36	0.02	0.58	0.80	0.11	0.11	-48.0	49.4	0.3	-22.7	1.3	28.2	-76.2	-56	-35	8	13	
ROFE1	REE: Glycerine as chem, meal as AF	1.17	0.31	0.27		0.02	0.86	0.02	1.07	1.28	0.10	0.11	-36.1	47.2	0.3	-8.7	1.3	40.1	-76.2	-45	-24	9	12	
ROFE2	REE: Glycerine and meal as AF	1.22	0.36	0.27		0.02	0.91	0.02	1.13	1.33	0.10	0.10	-31.4	47.2	0.3	-3.9	1.3	44.8	-76.2	-39	-19	8	12	
ROFE3	REE: Glycerine to biogas, meal as AF	1.19	0.33	0.27		0.02	0.87	0.02	1.10	1.28	0.09	0.09	-32.8	47.2	0.3	-5.3	1.3	43.4	-76.2	-41	-21	8	12	
ROFE4	REE: Glycerine and cake to biogas	0.77	-0.07	0.27		0.02	0.18	0.29		0.77	-0.77		-50.8	47.2	0.3	46.8	-68.9	25.4	-76.2			-51	51	
SOFA1	SME: Glycerine as chem, meal as AF	0.93	0.32	0.20		0.02	0.69	0.02	0.83	1.02	0.10	0.09	-50.0	28.0	0.3	-3.4	1.3	26.2	-76.2	-55	-46	5	4	
SOFA2	SME: Glycerine and meal as AF	0.98	0.37	0.20		0.02	0.74	0.02	0.89	1.07	0.09	0.09	-44.9	28.0	0.3	1.7	1.3	31.3	-76.2	-50	-40	5	5	
SOFA3	SME: Glycerine to biogas, meal as AF	0.95	0.33	0.20		0.02	0.71	0.02	0.87	1.03	0.08	0.08	-46.5	28.0	0.3	0.2	1.3	29.7	-76.2	-51	-42	5	5	
SOFA4	SME: Glycerine and cake to biogas	0.58	-0.01	0.20		0.02	0.34	0.02	0.58	0.59	0.01	0.01	-61.0	28.0	0.3	-14.4	1.3	15.2	-76.2	-65	-56	4	5	
SYFA1	SYME: Glycerine as chem, mill in EU, meal as AF in Brazil	2.69	0.61	0.28		0.19	2.21	0.02	2.67	2.71	0.02	0.02	-22.9	56.4	11.9	-16.2	1.3	53.3	-76.2	-72	0	49	22	
SYFA1a	SYME: Glycerine as chem, mill in EU, meal as AF in EU	3.00	0.92	0.28		0.49	2.21	0.02	2.98	3.02	0.02	0.02	1.4	56.4	35.9	-15.9	1.3	77.6	-76.2	-24	24	26	23	
SYFA1c	SYME: Glycerine as chem, mill in EU, economic values	1.37	0.58	0.16		0.12	1.07	0.02	1.36	1.38	0.01	0.01	-19.5	32.7	8.2	14.5	1.3	56.6	-76.2	-33	-6	13	14	
SYFA2	SYME: Glycerine as AF, mill in Brazil, meal as AF	2.74	0.66	0.28		0.19	2.26	0.02	2.73	2.76	0.01	0.02	-17.8	56.4	11.9	-11.1	1.3	58.4	-76.2	-73	3	55	21	
SYFA3	SYME: Glycerine to biogas, mill in Brazil, meal as AF	2.71	0.62	0.28		0.19	2.22	0.02	2.69	2.72	0.01	0.01	-19.3	56.4	11.9	-12.7	1.3	56.9	-76.2	-78	-4	58	15	
POFA1a	PME: Glycerine as chem, CH4 emissions from waste	1.31	0.27	0.15	0.91	0.05	0.17	0.02	1.30	1.31	0.01	0.01	-27.8	16.9	22.0	3.5	4.8	1.3	48.4	-76.2	-33	2	5	30
POFA1b	PME: Glycerine as chem, no CH4 from waste	1.31	0.27	0.15	0.91	0.05	0.17	0.02	1.30	1.31	0.01	0.01	-52.6	16.9	-2.8	3.5	4.8	1.3	23.6	-76.2	-58	-23	5	29
POFA1c	PME: Glycerine as chem, no CH4 from waste, no heat credit	1.33	0.30	0.15	0.94	0.05	0.17	0.02	1.32	1.34	0.01	0.01	-26.0	16.9	23.9	3.5	4.8	1.3	50.2	-76.2	-32	0	6	26
POFA2	PME: Glycerine to biogas, CH4 emissions from waste	1.32	0.29	0.15	0.91	0.05	0.19	0.02	1.32	1.33	0.01	0.01	-24.3	16.9	22.0	3.5	8.3	1.3	51.9	-76.2	-29	2	5	26
ROHY1a	HRO (NExBTL), meal as AF	1.05	0.34	0.28		0.02	0.73	0.02	0.95	1.15	0.10	0.10	-27.3	48.7	0.3	-6.6	1.2	43.5	-70.8	-36	-14	8	13	
ROHY1b	HRO (UOP), meal as AF	0.92	0.41	0.25		0.02	0.63	0.02	0.83	1.01	0.09	0.09	-25.9	42.9	0.3	0.7	1.2	44.9	-70.8	-33	-13	7	13	
ROHY4a	HRO (NExBTL), cake to biogas	0.66	-0.03	0.28		0.02	0.33	0.02	0.55	0.75	0.10	0.10	-44.3	48.7	0.3	-23.6	1.2	26.6	-70.8	-53	-31	9	13	
SOHY1	HSO (NExBTL), meal as AF	0.89	0.30	0.19		0.02	0.66	0.02	0.80	1.00	0.09	0.10	-43.1	27.7	0.3	-1.3	1.2	27.8	-70.8	-48	-39	5	4	
POHY1a	HPO (NExBTL), CH4 from waste	1.26	0.26	0.15	0.90	0.04	0.15	0.02	1.26	1.27	0.01	0.01	-21.2	16.7	21.7	3.4	6.8	1.2	49.6	-70.8	-27	3	6	24
POHY1b	HPO (NExBTL), no CH4 from waste	1.26	0.26	0.15	0.90	0.04	0.15	0.02	1.26	1.27	0.01	0.01	-45.6	16.7	-2.7	3.4	6.8	1.2	25.2	-70.8	-50	-17	5	28
POHY1c	HPO (NExBTL), CH4 from waste, no heat credit	1.29	0.28	0.15	0.92	0.04	0.15	0.02	1.28	1.30	0.01	0.01	-19.3	16.7	23.5	3.4	6.8	1.2	51.5	-70.8	-24	6	4	26

9.3 Synthetic diesel, Methanol, DME

Pathway		Energy expended (MJex/MJ final fuel)								Net GHG emitted (g CO ₂ eq/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. CO ₂ credit	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Total WTT GHG emitted (renewable combustion CO ₂)	Range
GRSD1	Syn-diesel: Rem GTL, Sea, Diesel mix	0.63	0.63	0.04	0.54	0.04		0.02	0.57 0.69 0.06 0.06	22.4	4.9	13.8	2.7		1.0	22.4	19 26 3 3
GRSD2	Syn-diesel: Rem GTL, Sea, Rail/Road	0.63	0.63	0.04	0.54	0.04		0.02	0.59 0.69 0.04 0.06	22.5	4.9	13.8	2.7		1.1	22.5	20 26 2 4
GRSD2C	Syn-diesel: Rem GTL, Sea, Rail/Road, CCS	0.76	0.76	0.04	0.67	0.04		0.02	0.71 0.82 0.05 0.06	13.3	5.3	4.2	2.7		1.1	13.3	10 17 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	130.1	28.7			100.3	1.1	130.1	122 139 8 8
KOSD1C	Syn-diesel: CTL, CCS, Diesel mix	1.06	1.05	0.17			0.86	0.02	0.98 1.13 0.08 0.08	40.4	30.0			9.3	1.1	40.4	33 48 8 8
WWSD1	Syn-diesel: W Wood, diesel mix	1.19	0.07	0.06		0.04	1.08	0.02	1.08 1.29 0.11 0.10	-66.0	0.8		2.9		1.2	4.8	-70.8 -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 0.10	-64.0	5.0		0.7		1.2	6.9	-70.8 -65 -51 1 13
BLSD1	Syn-diesel: W Wood, Black liquor	0.91	0.04	0.05		0.01	0.83	0.02	0.85 0.96 0.06 0.05	-68.4	0.7		0.6		1.2	2.4	-70.8 -68 -68 0 0
GPME1a	MeOH: NG 7000 km, Syn, Rail/Road	0.84	0.84	0.04	0.30	0.47	0.03	0.03	0.66 0.92 0.18 0.08	42.1	5.6	22.9	11.7	1.9	1.9	42.1	32 46 10 4
GPME1b	MeOH: NG 4000 km, Syn, Rail/Road	0.69	0.69	0.04		0.15	0.47	0.03	0.61 0.73 0.08 0.04	30.6	5.2		11.8	11.7	1.9	30.6	26 33 5 2
GRME1	MeOH: Rem Syn, Sea, Rail/Road	0.61	0.61	0.04	0.47	0.08		0.03	0.60 0.64 0.01 0.03	24.2	4.7	11.7	5.9		1.9	24.2	23 26 1 2
KOME1	MeOH: Coal EU-mix, Cen, Rail/Road	0.93	0.93			0.16	0.74	0.03	0.84 1.02 0.09 0.09	128.2			28.0	98.3	1.9	128.2	119 137 9 9
WWME1	MeOH: W Wood, Road	1.07	0.06	0.06		0.03	0.96	0.02	0.95 1.22 0.12 0.15	-64.3	0.7		2.7	0.2	1.1	4.8	-69.1 -65 -64 0 0
WFME1	MeOH: F Wood, Road	1.07	0.06	0.08		0.01	0.96	0.02	0.94 1.21 0.13 0.14	-62.4	4.7		0.7	0.2	1.1	6.7	-69.1 -64 -50 2 13
BLME1	MeOH: W Wood, Black liquor	0.59	0.03	0.05		0.01	0.52	0.02	0.54 0.63 0.05 0.04	-66.7	0.6		0.5	0.2	1.1	2.4	-69.1 -67 -67 0 0
GPDE1a	DME: NG 7000 km, Syn, Rail/Road	0.77	0.77	0.04	0.29	0.41	0.03	0.03	0.57 0.84 0.20 0.07	39.7	5.4	22.0	10.6	1.7	1.7	39.7	28 44 11 4
GPDE1b	DME: NG 4000 km, Syn, Rail/Road	0.62	0.62	0.04		0.14	0.41	0.03	0.54 0.66 0.08 0.04	28.7	5.0		11.4	10.6	1.7	28.7	24 31 5 2
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	21.1	4.5	10.6	4.3		1.7	21.1	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	129.6			28.0	100.0	1.7	129.6	119 138 10 8
GRDE1C	DME: Rem Syn, Sea, Rail/Road, CCS	0.54	0.54	0.03	0.42	0.06		0.03	0.54 0.61 0.00 0.07	11.1	4.5	0.6	4.3		1.7	11.1	11 15 0 4
WWDE1	DME: W Wood, Road	1.07	0.06	0.06		0.03	0.96	0.02	0.94 1.20 0.13 0.13	-62.7	0.7		2.7	0.1	1.0	4.6	-67.3 -63 -63 0 0
WFDE1	DME: F Wood, Road	1.07	0.06	0.08		0.01	0.96	0.02	0.93 1.20 0.14 0.13	-60.8	4.7		0.7	0.1	1.0	6.5	-67.3 -62 -47 2 13
BLDE1	DME: W Wood, Black liquor	0.55	0.03	0.04		0.01	0.49	0.02	0.51 0.60 0.04 0.05	-65.1	0.5		0.5	0.1	1.0	2.2	-67.3 -65 -65 0 0

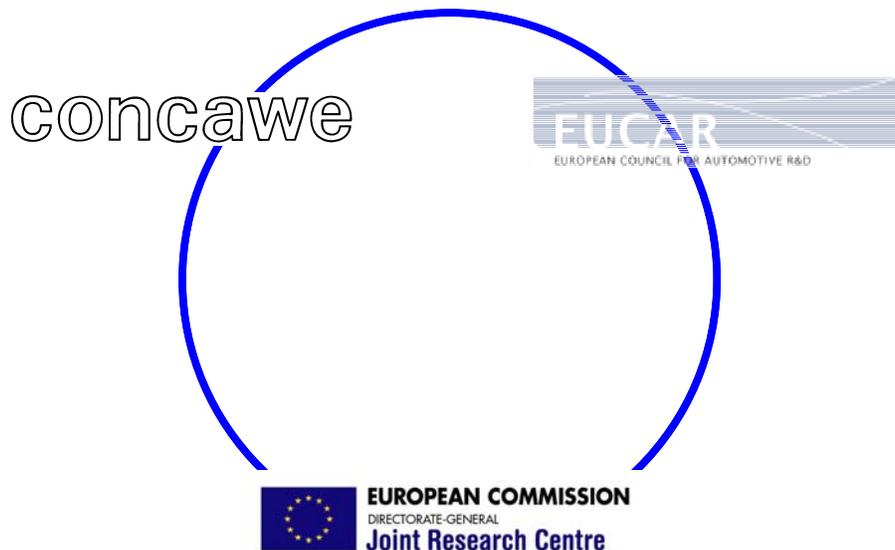
9.4 Hydrogen

Pathway		Energy expended (MJex/MJ final fuel)								Net GHG emitted (g CO ₂ eq/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. CO ₂ credit	Production & conditioning at source	Transformation at source	Transportation to market	Transformation near market	Conditioning & distribution	Total WTT GHG emitted (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	0.89	0.03	0.05	105.2	4.9		3.7	86.6	10.0	105.2	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	0.94	1.18	0.17	0.08	123.2	5.7		22.9	84.7	10.0	123.2	113	128	10	5
GPCH1b	C-H2, NG 4000 km, O/S Ref	0.95	0.94	0.04		0.15	0.52	0.24	0.86	1.00	0.09	0.05	111.7	5.2		11.9	84.7	10.0	111.7	107	115	5	3
GPCH2a	C-H2: NG 7000 km, Cen ref, Pipe	0.86	0.85	0.04		0.27	0.32	0.22	0.71	0.93	0.14	0.08	109.3	5.2		20.9	74.1	9.1	109.3	101	114	8	4
GPCH2b	C-H2: NG 4000 km, Cen Ref, Pipe	0.72	0.71	0.04		0.14	0.32	0.22	0.63	0.76	0.08	0.04	98.8	4.7		10.8	74.1	9.1	98.8	94	101	5	2
GPCH2bc	C-H2: NG 4000 km, Cen Ref, Pipe, CCS	0.77	0.76	0.04		0.14	0.37	0.22	0.69	0.82	0.08	0.05	37.8	4.9		11.2	12.5	9.1	37.8	33	40	5	3
GPCH3b	C-H2: NG 4000 km, Cen Ref, Road	0.72	0.71	0.04		0.14	0.32	0.22	0.63	0.77	0.09	0.05	99.7	4.7		10.8	74.1	10.1	99.7	95	102	5	3
GPLCHb	C-H2: NG 4000 km, Cen Ref, Liq, Road, Vap/comp.	1.28	0.71	0.03		0.13	0.94	0.17	1.13	1.36	0.14	0.09	133.6	4.7		10.7	110.0	8.3	133.6	125	139	9	5
GRCH1	C-H2: LNG, O/S Ref	1.12	1.10	0.04	0.13	0.19	0.52	0.24	1.08	1.16	0.04	0.05	119.9	5.2	8.6	11.8	84.5	10.0	119.9	118	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	0.91	0.04	0.05	106.5	4.7	7.8	10.7	74.1	9.1	106.5	104	109	2	3
GRCH3	C-H2: Rem NG, methanol, O/S Ref	1.12	1.11	0.04	0.57	0.08	0.21	0.22	1.10	1.16	0.02	0.04	118.8	5.7	14.2	5.3	84.4	9.1	118.8	118	121	1	2
KOCH1	C-H2: Coal EU-mix, cen Ref, Pipe	1.40	1.38			0.19	0.99	0.22	1.40	1.40	0.00	0.00	234.4			32.3	193.0	9.1	234.4	234	234	0	0
KOCH1C	C-H2: Coal EU-mix, cen Ref, Pipe, CCS	1.77	1.76			0.22	1.33	0.22	1.77	1.77	0.00	0.00	52.7			37.8	5.8	9.1	52.7	53	53	0	0
WWCH1	C-H2: W Wood, O/S gasif	1.22	0.19	0.06		0.00	0.94	0.22	1.12	1.33	0.10	0.11	10.7	0.7		0.2	0.7	9.1	10.7	11	11	0	0
WWCH2	C-H2: W Wood, Cen gasif, Pipe	0.97	0.23	0.04		0.03	0.68	0.22	0.90	1.05	0.07	0.08	12.1	0.5		2.1	0.3	9.1	12.1	12	12	0	0
BLCH1	C-H2: W Wood, Black liquor	0.51	0.20	0.04		0.01	0.25	0.22	0.47	0.55	0.04	0.04	10.0	0.5		0.4		9.1	10.0	10	10	0	0
WFCH1	C-H2: W Wood, O/S gasif	1.24	0.22	0.08		0.00	0.94	0.22	1.14	1.34	0.11	0.10	14.8	4.7		0.2	0.7	9.1	14.8	13	28	2	13
WFCH2	C-H2: F Wood, Cen gasif, pipe	0.97	0.23	0.06		0.01	0.68	0.22	0.89	1.05	0.07	0.08	13.8	3.6		0.5	0.5	9.1	13.8	13	24	1	10
GPCL1a/CH1	C-H2: NG 7000 km, CCGT, O/S Ely	2.72	2.72	0.08		0.59	1.88	0.16	2.30	2.87	0.42	0.15	227.1	11.2		45.2	162.1	8.6	227.1	202	236	25	9
GPCL1b/CH1	C-H2: NG 4000 km, CCGT, O/S Ely	2.40	2.40	0.08		0.30	1.88	0.15	2.15	2.58	0.25	0.18	203.5	10.2		23.4	162.1	7.7	203.5	189	214	15	11
GPCL1b/CH2	C-H2: NG 4000 km, CCGT, Cen Ely, Pipe	2.45	2.44	0.08		0.29	1.86	0.22	2.19	2.65	0.26	0.20	203.5	10.1		23.3	161.0	9.1	203.5	188	215	16	12
GREL1/CH1	C-H2: LNG, O/S Ely	2.75	2.75	0.08		0.63	1.88	0.16	2.49	2.97	0.25	0.23	220.8	10.2		40.1	162.1	8.3	220.8	206	234	15	13
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	2.41	2.82	0.19	0.22	11.8	8.0		1.1	2.2	0.4	11.8	10	33	2	21
WFEL3/CH1	C-H2: F Wood, Cen power, O/S Ely	4.43	0.11	0.21		0.02	3.97	0.23	4.08	4.74	0.34	0.32	29.9	12.0		1.7	15.1	1.1	29.9	26	59	4	29
EMEL1/CH1	C-H2: Elec EU-mix, O/S Ely	3.62	3.39				3.43	0.19	3.43	3.81	0.19	0.19	209.1				201.2	7.9	209.1	200	218	9	8
KOEL1/CH1	C-H2: Elec coal EU-mix, O/S Ely	3.17	3.16			0.34	2.65	0.18	2.62	3.54	0.55	0.37	426.2			59.1	352.4	14.8	426.2	377	472	50	46
KOEL1/CH2	C-H2: Elec coal EU-mix, Cen ely, Pipe	3.19	3.17			0.34	2.62	0.22	2.70	3.60	0.49	0.41	417.1			58.6	349.9	8.5	417.1	373	466	44	49
NUEL1/CH1	C-H2: Elec nuclear, O/S Ely	5.03	5.02			0.96	3.82	0.25	4.75	5.27	0.27	0.24	7.0			6.3	0.5	0.3	7.0	7	7	0	0
WDEL1/CH2	C-H2: Wind, Cen Ely, Pipe	0.79	0.19			0.02	0.55	0.22	0.74	0.86	0.05	0.07	9.1					9.1	9.1	9	9	0	0
GPLH1a	L-H2: NG 7000 km, Cen Ref, Liq, Road	1.33	1.33	0.04		0.27	0.32	0.71	1.11	1.44	0.22	0.11	141.7	5.1		20.6	73.0	43.0	141.7	129	148	13	7
GPLH1b	L-H2: NG 4000 km, Cen Ref, Liq, Road	1.13	1.13	0.03		0.13	0.32	0.65	0.99	1.22	0.14	0.09	127.0	4.7		10.7	73.0	38.7	127.0	119	132	8	5
GRLH1	L-H2: Rem Ref, Liq, Sea, Road	1.42	1.42	0.04	1.08	0.26		0.04	1.31	1.55	0.12	0.13	139.1	5.2	129.7	1.4		2.8	139.1	132	147	7	8
GRLH2	L-H2: LNG, Cen Ref, Liq, Road	1.34	1.34	0.03	0.11	0.16	0.32	0.72	1.22	1.49	0.12	0.15	137.5	4.6	7.6	9.7	73.0	42.5	137.5	131	146	7	9
WFLH1	L-H2: F Wood, Cen gasif, Liq, Road	1.50	0.07	0.06		0.01	1.41	0.02	1.35	1.67	0.15	0.17	7.5	3.5		1.0	2.8	0.1	7.5	7	19	1	12
GPCL1b/LH1	L-H2: NG 4000 km, CCGT, Cen Ely, Liq, Road	2.86	2.86	0.08		0.29	1.83	0.66	2.59	3.05	0.27	0.19	231.5	10.0		22.9	158.6	40.0	231.5	216	242	16	11
EMEL1/LH1	L-H2: Elec EU-mix, Cen Ely, Liq, Road	4.22	3.97				3.35	0.88	3.98	4.43	0.24	0.21	237.0				196.9	40.1	237.0	226	246	11	9
KOEL1/LH1	L-H2: Elec coal EU-mix, Cen Ely, Liq, Road	3.73	3.72			0.34	3.35	0.04	3.20	4.08	0.53	0.35	477.0			57.8	416.6	2.7	477.0	437	526	40	49

9.5 Heat and power

Pathway		Energy expended (MJex/MJ final fuel)								Net GHG emitted (g CO ₂ eq/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. CO ₂ 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	1.28 1.79 0.31 0.20	269.0						269.0		237 289 32 20	
KOEL2	Elec:EU-mix Coal IGCC	1.35	1.34	0.20			1.12	0.03	1.25 1.45 0.10 0.11	241.5	34.5				207.0	241.5		232 253 10 11	
GPPEL1a	Elec: NG 7000 km, CCGT	1.31	1.31	0.05		0.38	0.84	0.03	1.09 1.39 0.22 0.08	141.0	7.2		29.2		104.6	141.0		128 146 13 5	
GPPEL1b	Elec: NG 4000 km, CCGT	1.11	1.11	0.05		0.19	0.84	0.03	0.96 1.20 0.15 0.09	126.3	6.6		15.1		104.6	126.3		117 131 9 5	
GPPEL1bC	Elec: NG 4000 km, CCGT + CCS	1.47	1.47	0.06		0.22	1.16	0.03	1.30 1.57 0.17 0.10	37.8	7.7		17.7		12.5	37.8		28 44 10 6	
GPPEL1aC	Elec: NG 7000 km, Hydrogen CCGT + CCS	2.00	2.00	0.07		0.50	1.40	0.03	1.67 2.07 0.33 0.07	60.7	9.3		37.9		13.4	60.7		42 65 19 4	
GPPEL1bC	Elec: NG 4000 km, Hydrogen CCGT + CCS	1.74	1.74	0.06		0.25	1.40	0.03	1.55 1.86 0.19 0.12	41.6	8.5		19.6		13.4	41.6		30 49 12 7	
GREL1	Elec: LNG, CCGT	1.33	1.33	0.05	0.16		0.84	0.03	1.21 1.46 0.11 0.13	137.0	6.6	10.9			104.6	137.0		131 145 6 8	
WWEL1	Elec: W Wood, 10 MW gasif	1.24	0.05	0.06		0.04	1.11	0.03	1.16 1.34 0.08 0.10	5.2	0.8		3.0		1.4	5.2		5 6 0 0	
WWEL2	Elec: W Wood, 200 MW gasif	2.00	0.02	0.09		0.00	1.88	0.03	1.90 2.10 0.10 0.11	3.2	1.1		0.2		1.9	3.2		3 3 0 0	
WWEL3	Elec: W Wood, Conv power	2.01	0.03	0.09		0.01	1.88	0.03	1.90 2.12 0.11 0.11	4.0	1.1		1.0		1.9	4.0		4 4 0 0	
WWEL4	Elec: W Wood, Coal co-firing	1.48	0.05	0.07		0.04	1.34	0.03	1.16 1.72 0.32 0.24	7.7	0.9		3.3		3.6	7.7		7 8 1 0	
WFEL1	Elec: F Wood, 200 MW gasif	1.24	0.05	0.09		0.01	1.11	0.03	1.15 1.35 0.09 0.11	7.3	5.1		0.7		1.4	7.3		6 19 2 12	
WFEL2	Elec: F Wood, 10 MW gasif	2.03	0.05	0.12		0.00	1.88	0.03	1.92 2.15 0.11 0.12	9.2	7.0		0.2		1.9	9.2		7 27 2 18	
WFEL3	Elec: F Wood, Conv power	2.37	0.07	0.14		0.01	2.19	0.03	2.20 2.53 0.16 0.16	18.5	7.7		1.1		9.7	18.5		16 38 2 20	
WFEL4	Elec: F Wood, Coal co-firing	1.48	0.05	0.10		0.01	1.34	0.03	1.12 1.70 0.35 0.22	10.1	5.7		0.8		3.6	10.1		8 25 2 15	
EMEL1	Elec: EU-mix	1.87	1.73				1.84	0.03	1.87 1.87 0.00 0.00	129.8					129.8	129.8		130 130 0 0	
WDEL1	Elec: Wind offshore	0.03					0.03	0.03	0.00 0.00 0.00										
NUEL1	Elec: Nuclear	2.74	2.74	0.62			2.09	0.03	2.66 2.82 0.08 0.08	4.4	4.1				0.3	4.4		4 5 0 0	
OWEL1a	Elec: Biogas ex municipal waste, local	3.20	-0.08				3.19	0.01	2.91 3.57 0.29 0.37	7.7					7.7	7.7		7 8 1 1	
OWEL1b	Elec: Biogas ex municipal waste, large	2.39	0.21				2.36	0.03	2.10 2.68 0.29 0.29	27.9					27.9	27.9		22 33 6 5	
OWEL2a	Elec: Biogas ex liquid manure, local	3.06	0.01		0.06		2.99	0.01	2.74 3.40 0.33 0.33	-187.2		-198.0			10.8	-187.2		-244 -123 56 65	
OWEL2b	Elec: Biogas ex liquid manure, large	2.56	-0.06		0.05		2.48	0.03	2.24 2.88 0.33 0.32	-161.3		-177.2			15.9	-161.3		-209 -107 48 54	
OWEL3a	Elec: Biogas ex dry manure, local	3.02	-0.03		0.02		2.99	0.01	2.72 3.32 0.30 0.30	-8.0		-18.8			10.8	-8.0		-14 -2 6 6	
OWEL3b	Elec: Biogas ex dry manure, large	2.53	-0.09		0.02		2.48	0.03	2.21 2.84 0.32 0.31	-1.0		-16.8			15.9	-1.0		-6 5 5 6	
BLEL1	Elec: Black liquor	0.18	0.01	0.03		0.01	0.11	0.03	0.15 0.22 0.03 0.04	0.4					0.4	0.4		1 1 0 0	
COHT1	Heat: Heating oil dom. boiler	1.37	1.37	0.07		0.01	0.11	1.18	1.00 1.00 0.37 -0.37	101.8	5.9		1.0		9.6	101.8		102 -102	
COHT2	Heat: Heating oil ind. boiler	1.39	1.38	0.07		0.01	0.11	1.19	1.00 1.00 0.39 -0.39	100.6	4.1		1.0		9.6	100.6		98 103 3 2	
GPHT1a	Heat: NG 7000 km, dom. boiler	1.28	1.28	0.03		0.19	1.06	0.17	0.33 1.11 -0.94	76.6	3.8		15.0		57.7	76.6		70 80 7 3	
GPHT1b	Heat: NG 4000 km, dom. boiler	1.17	1.17	0.03		0.09	1.05	0.12	0.20 1.05 -0.97	68.8	3.5		7.5		57.7	68.8		66 70 3 1	
GPHT2a	Heat: NG 7000 km, ind. boiler	1.43	1.43	0.03		0.22	1.18	0.28	0.49 1.15 -0.94	85.8	4.3		16.7		64.8	85.8		77 89 9 3	
GPHT2b	Heat: NG 4000 km, ind. boiler	1.31	1.31	0.03		0.10	1.18	0.25	0.34 1.06 -0.97	77.1	3.9		8.3		64.8	77.1		74 79 3 2	
GRHT1	Heat: LNG dom. boiler	1.29	1.29	0.03	0.09	0.09	1.09	0.28	0.31 1.01 -0.98	74.4	3.5	5.8	5.6		59.4	74.4		74 76 1 1	
GRHT2	Heat: LNG ind. boiler	1.44	1.44	0.03	0.10	0.10	1.22	0.43	0.47 1.01 -0.97	83.2	3.9	6.5	6.2		66.6	83.2		82 85 1 1	
OWHT1	Heat: Municipal waste to heat	0.86	0.15				0.81	0.05	0.72 1.01 0.14 0.16	16.2					-42.3	58.6		13 19 3 3	
OWHT2	Heat: Liquid manure to heat	0.95	0.01				0.90	0.05	0.79 1.11 0.16 0.16	-84.9					-143.4	58.6		-113 -56 29 29	
OWHT3	Heat: Dry manure to heat	0.93	-0.01				0.88	0.05	0.76 1.08 0.17 0.15	0.8					-57.7	58.6		-2 4 3 3	
WWHT1	Heat: Waste wood dom.c boiler	0.33	0.10	0.04		0.01	0.09	0.20	0.29 0.38 0.04 0.04	5.5	0.4		0.4		4.6	5.5		5 6 0 0	
WFHT1	Heat: Farmed wood dom. boiler	0.35	0.11	0.05		0.01	0.09	0.20	0.31 0.39 0.04 0.04	7.9	2.9		0.4		0.0	4.6	7.9		7 15 1 7
WWHT2	Heat: Waste wood ind. boiler	0.27	0.07	0.03		0.01	0.23	0.24	0.31 0.04 0.04	3.7	0.4		0.4		2.8	3.7		4 4 0 0	
WFHT2	Heat: Farmed wood ind. boiler	0.29	0.08	0.05		0.01	0.23	0.25	0.33 0.04 0.04	6.1	2.8		0.4		2.8	6.1		5 13 1 7	
GPEH1a	CHP: NG 7000 km, CCGT	0.36	0.36	0.07		0.49	-0.23	0.03	0.06 0.59 0.30 0.22	83.5	9.2		37.4		36.9	83.5		66 97 17 13	
GPEH1b	CHP: NG 4000 km, CCGT	0.24	0.24	0.06		0.24	-0.09	0.03	0.10 0.36 0.14 0.12	74.9	8.4		19.4		47.1	74.9		67 82 8 7	
GREH1	CHP: LNG, CCGT	0.37	0.37	0.06	0.21	0.31	-0.24	0.03	0.33 0.42 0.04 0.05	81.2	8.5	13.9	19.2		39.7	81.2		79 84 2 3	
WWEH1	CHP: Waste wood ind.	0.44	0.01	0.14		0.02	0.25	0.03	0.17 0.71 0.27 0.27	3.1	1.7		1.5		-0.1	3.1		3 3 0 0	
WFEH1	CHP: Farmed wood ind.	0.46	0.03	0.19		0.02	0.21	0.03	0.18 0.68 0.28 0.22	5.9	11.0		1.5		-6.6	5.9		-9 23 15 17	
GPHT3b	CHP: NG 4000 km, CCGT heat	-0.42	-0.42	0.06		0.24	-0.83	0.11		34.7	8.3		19.1		7.3	34.7		35 -35	
WFHT3	CHP: Farmed wood, heat	-0.38	0.62	0.08		0.01	-0.59	0.11		-1.2	4.8		0.7		-6.6	-1.2		-1 1	

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



WELL-to-TANK Report - Appendix 3

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This is a partial revision of version 2c in that it does not include an update of section 8 on cost and availability.

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.

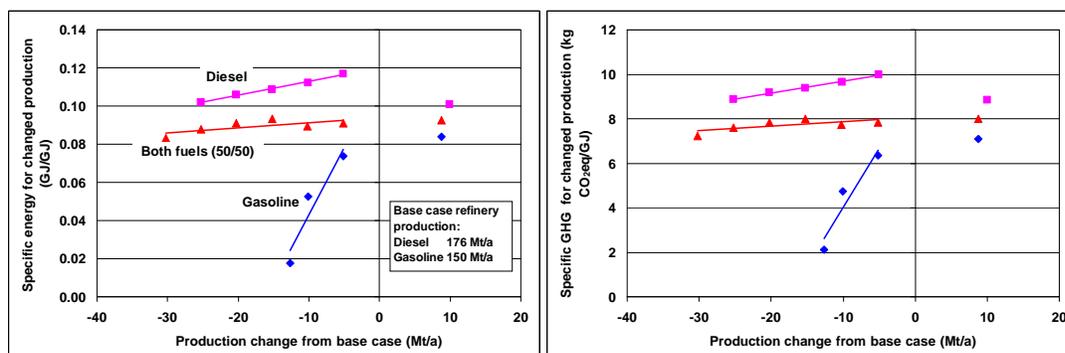
More to the point, such a simplistic allocation method ignores the complex interactions, constraints, synergies within a refinery and also between the different refineries in a certain region and is likely to lead to misleading conclusions. From an energy and GHG emissions point of view, this is also 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 CO₂ 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/CO₂ 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 7.0 and 8.6 g CO₂/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.

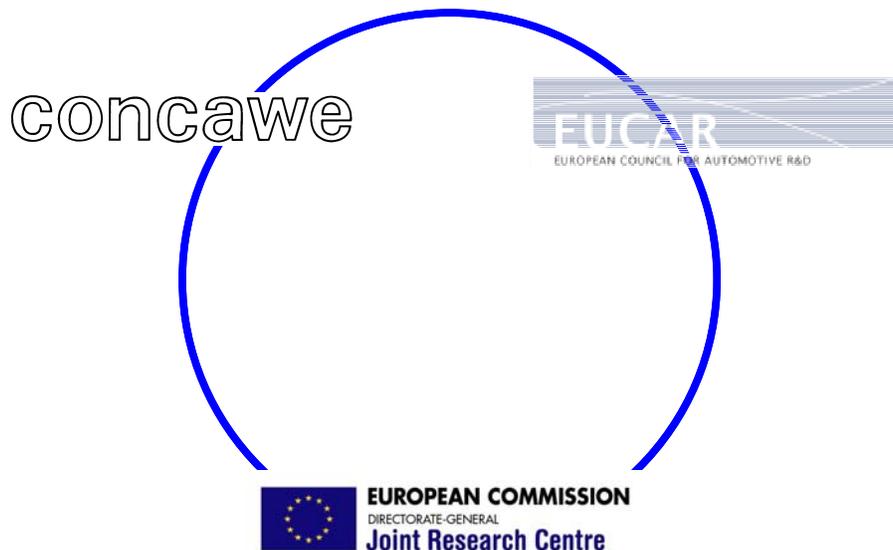
Our base case includes a certain amount of diesel imports and it could be argued that these will be the first one to be substituted. Reality is likely to be more complex and some imports will undoubtedly still take place with or without alternative diesel sources. In any case, imported diesel will be 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 CO₂ 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 SO₂ emissions regulations. This trend has the potential to increase somewhat in the future either because of increased pressure on SO₂ emissions or actions to reduce site CO₂ emissions. Such a change would not impact energy efficiency figures, but would slightly reduce CO₂ emissions. Again the effect is small compared to other sources of variability.

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



WELL-to-TANK - Appendix 4

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Notes on version number:

This document reports on the third release of this study replacing data made available since November 2008.

The original version 1b was published in December 2003.

Step-by-step input data for individual pathways

1 Oil and coal



Input data OIL &
COAL 250910.xls

2 Natural gas



Input data NG
150609.xls

3 Biomass



Input data BIO
300410.xls

4 Electrolysis



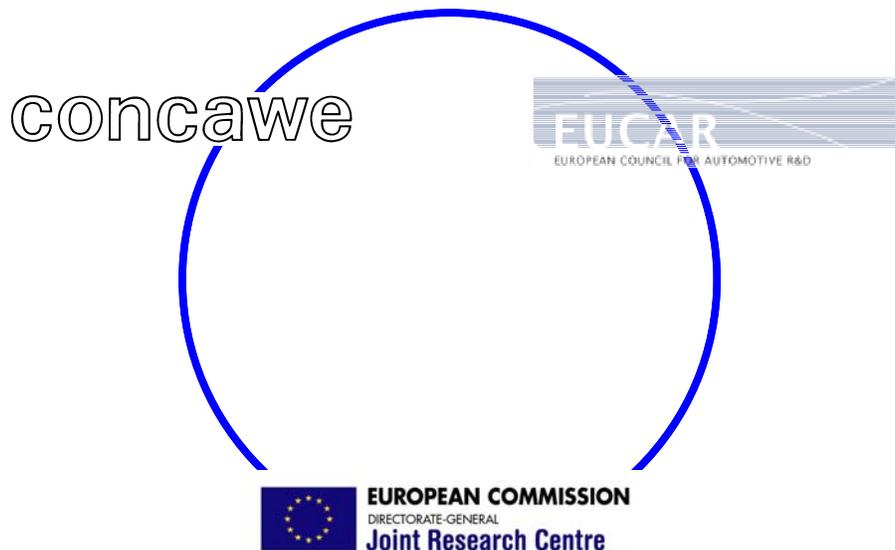
Input data ELY
150609.xls

5 Heat and Power



Input data H&P
150609.xls

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



WELL-to-TANK Report - Appendix 5

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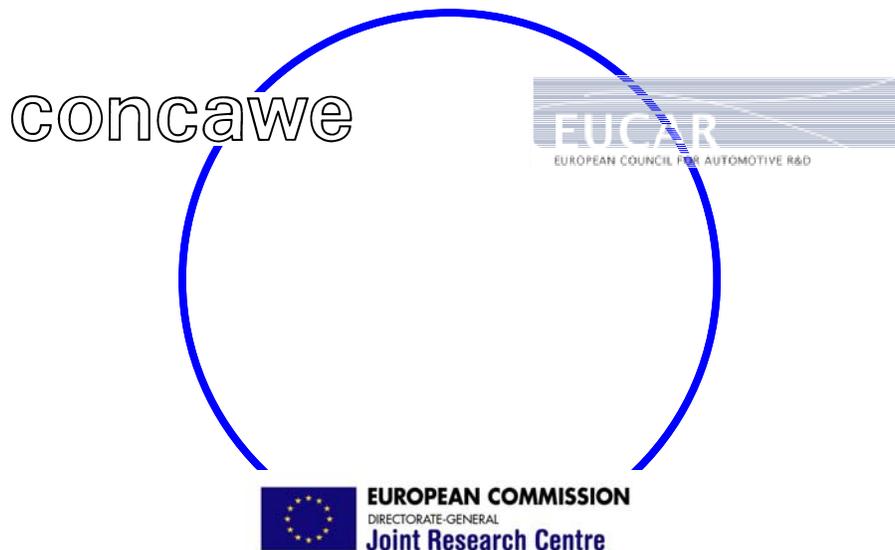
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WELL-TO-WHEELS ANALYSIS OF FUTURE AUTOMOTIVE FUELS AND POWERTRAINS IN THE EUROPEAN CONTEXT



TANK-to-WHEELS Report - Appendix 1

Version 3c, July 2011

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Notes on version number:

This document reports on the third release of this study replacing version 2c published in March 2007.

The original version 1b was published in December 2003.

Vehicle retail price estimation

Table of contents

This document has changed from version 2c of March 2007 with regard to the Diesel and CNG vehicle price estimation

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1 Main price assumptions for components and systems

- Prices given for specific components are on a 'supplier retail' (equivalent to delivered costs to vehicle manufacturers). A mark-up to include further costs, e.g. warranty, is not included.
- The cost estimates are based on recent cost studies (see Chapter References) and we have focused on estimating the costs for various key powertrain components, such as motors, batteries, hybrid and fuel cell systems. Costs for upgrading some vehicle components were included for some configurations.
- Costs assume a volume of >50k units per annum and are projected for 2010+. The cost reduction estimates through volume production for some of the key components could be very optimistic and it is uncertain how much and at what rate future costs will decline under different circumstances.
- To cover these uncertainties a large upward range is included for future technologies.
- The study does not consider other associated costs beyond the key components for a certain technology. For example, vehicle body modifications are likely to vary depending on the base vehicle and the technology systems integration. For a more detailed cost calculation these additional costs need to be added.

The components or systems costs assessed for the technologies are shown Table 1.

Table 1 Components, systems costs

Component or system		Price	Reference
ICE			
Engine + transmission	€/kW	30	a
DICI	€	1500	b
DISI	€	500	b
Turbo	€	180	c
Friction improvement	€	60	j
20% downsizing SI	€	220	j
20% downsizing CI	€	200	j
Stop & go system SI	€	200	a
Stop & go system CI	€	300	a
Double inj. system for CNG or LPG Bi-fuel	€	700	c
EURO IV SI	€	300	a
EURO IV Diesel	€	300	a
EURO IV Diesel with DPF	€	700	c
Credit for three way catalyst	€	430	b
Fuel tank			
Gasoline	€	125	a
CNG	€	1838	d
DME or LPG	€	1500	a
Comp. Hydrogen @70 MPa ⁽¹⁾	€/kg H ₂	575	e
Liquid hydrogen ⁽¹⁾	€/kg H ₂	575	e,f
Electric motor			
Electric motor	€/kW	8	c
Motor controller	€/kW	19	j
Total electric motor + controller	€/kW	27	j
Hybrid electric powertrains			
Powertrain and vehicle components upgrade ⁽²⁾	€	2630	j
Credit for standard alternator + starter	€	-300	j
Li-Ion battery⁽³⁾	€/kWh	600	g
Fuel cells			
FC system ⁽⁴⁾	€/kWnet	105	h
FC system + reformer	€/kWnet	251	h

Notes:

- Hydrogen tank: Current costs are approximately twice as high. The figures used were estimated based on expectations of improvement.
- Cooling system upgrade (Battery, E-Motor), High Voltage Wiring, Electric Steering for E-Drive mode, Electric driven AC compressor, Power electronics, DC/DC Converter, Modifications for a regenerative braking system.
- Batteries: current battery costs are considerably higher (700-1500€, Reference h). The figures used were estimated based on expectations of improvement for the time horizon of the study. Although recent target values of the battery industry are considerably lower (200-300€), the technical advancement and cost reductions needed may not be achieved.
- Fuel cells: current fuel cell costs are considerably higher. The figures above should be considered as aspirational and may not be achieved until the end of the next decade. To put them further into perspective it is worth mentioning that the current US fuel cell research programme includes a target value of 45 \$/kW in 2010 and 35 \$/kW by 2015.

2 2002 vehicles

The retail prices assessed for the 2002 technologies are shown in **Table 2**. All technologies are assessed against the reference gasoline PISI engine vehicle.

Table 2 2002 vehicles

Fuel	Gasoline		LPG	CNG		Diesel	DME
	PISI (reference)	DISI	PISI bi-fuel	PISI bi-fuel	PISI dedicated	DICI	DICI
Engine Power (kW)	<i>77</i>	<i>70</i>	<i>77</i>	<i>77</i>	<i>85</i>	<i>74</i>	<i>74</i>
Prices (€)							
Baseline vehicle	18,600	18,600	18,600	18,600	18,600	20,300	20,300
Gasoline tank	125				-125		-125
Alternative fuel tank			1,500	1,050	1,838		1,500
Baseline engine + transmission	2,310	-2,310			-2,310	2,220	2,220
Alternative engine + transmission		2,100			2,550		
DISI		500					
DICI						1500	1,500
Double injection system			700	700			
Total Vehicle Retail Price	18,600	18,890	20,800	20,350	20,553	20,300	21,675
Difference to the 2002 reference		290	2,200	1,750	1,953	1,700	3,075
		<i>1.6%</i>	<i>11.8%</i>	<i>9.4%</i>	<i>10.5%</i>	<i>9.1%</i>	<i>16.5%</i>

Numbers in italic are for information only. They are not used in the calculations

Notes:

- Although the cost of the direct injection system is partly compensated by the lower power requirement the DISI vehicle is slightly more expensive than the reference.
- The need for two fuel systems increases the cost of both the LPG and the CNG bi-fuel vehicles.
- In spite of its larger engine, the dedicated CNG vehicle is cheaper than the bi-fuel version and only slightly more expensive than the diesel vehicle.
- The price of the DME vehicle includes the special tank.

3 2010+ vehicles

3.1 ICE vehicles (except hydrogen)

For all 2010+ vehicles the reference is the 2010+ gasoline PISI vehicle, the price of which is derived from the 2002 version including additional cost for downsizing, turbo-charging, stop & go system and Euro IV exhaust after treatment. The overall price increase is 5%.

Table 3.1 2010+ conventional ICE vehicles

Fuel	Gasoline		LPG	CNG		LPG	Diesel		DME
	PISI (reference)	DISI	PISI bi-fuel	PISI bi-fuel	PISI dedicated	PISI dedicated	DICI +DPF	DICI	DICI
Engine Power (kW)	77	70	77	77	85	77	74	74	74
Prices (€)									
Baseline vehicle	18,600	18,600	18,600	18,600	18,600	18,600	20,300	20,300	20,300
Gasoline tank					-125	-125			-125
Alternative fuel tank			1,500	1,050	1,838	1,500			1,500
Baseline engine + transmission	-2,310	-2,310	-2,310	-2,310	-2,310	-2,310	-3,720	-3,720	-3,720
Alternative engine + transmission ⁽¹⁾	2,590	2,380	2,590	2,590	2,830	2,590	2,480	2,480	2,480
Turbo	180	180	180	180	180	180			
DISI		500							
DICI							1500	1500	1500
Stop & go system	200	200	200	200	200	200	300	300	300
EURO IV exhaust after treatment	300	300	300	300	300	300	700	300	300
Double injection system			700	700					
Total Vehicle Retail Price	19,560	19,850	21,760	21,310	21,513	20,935	21,560	21,160	22,535
Difference to the 2010 reference		290	2,200	1,750	1,953	1,375	2,000	1,600	2975
		1.5%	11.2%	8.9%	10.0%	7.0%	10.2%	8.2%	15.2%

⁽¹⁾ Gasoline, LPG & CNG: includes downsizing and friction improvement; Diesel: friction improvement only

Notes:

- The differential between gasoline DISI and PISI generally remains the same as in 2002. The same applies to the LPG and CNG vehicles.
- The diesel vehicle price increases by 300 € to cover the EURO IV exhaust after treatment requirements and by 700 € if a DPF is installed. The stop & go system is also dearer than for SI engines.
- The DME vehicle price remains higher than its diesel counterpart because of the cost of the tank.

3.2 Hybrid ICE vehicles (except hydrogen)

Table 3.2 2010+ Hybrid ICE vehicles (except hydrogen)

Fuel	Gasoline	CNG	Diesel	Diesel
	DISI	PISI	DICI+DPF	DICI
Propulsion system: hybrid				
Engine Power (kW)	70	68	74	74
Electric motor power (kW)	14	14	14	14
Battery size (kWh)	6	6	6	6
Prices (€)				
Baseline vehicle	18,600	18,600	20,300	20,300
Gasoline tank		-125		
Alternative fuel tank		1,838		
Baseline engine + transmission	-2,310	-2,310	-3,720	-3,720
Alternative engine + transmission ⁽²⁾	2,160	2,100	2,480	2,480
DISI	500			
DICI			1500	1500
Euro IV exhaust after treatment	300	300	700	300
Electric Motor + modified transmission	600	600	600	600
Battery (Li-Ion)	3,600	3,600	3,600	3,600
Powertrain and vehicle components upgrade	2,630	2,630	2,630	2,630
Credit for standard alternator + starter	-300	-300	-300	-300
Total Vehicle Retail Price	25,780	26,933	27,790	27,390
Difference to the 2010 reference	6,220	7,373	8,230	7,830
	31.8%	37.7%	42.1%	40.0%

⁽²⁾ Including friction improvement

Note:

In comparison with standard ICE vehicles, hybrids are penalised by the price of the battery, the electric motor with the power electronics and other additional requirements for vehicle component upgrades. The price differentials between the different fuel versions basically remain the same.

3.3 Hydrogen ICE vehicles

Table 3.3 2010+ Hydrogen ICE vehicles

Fuel	C-H ₂ @70 MPa	L-H ₂
Propulsion system	PISI	
Engine Power (kW)	77	
Hydrogen storage capacity (kg)	9	
Prices (€)		
Baseline vehicle	18,600	18,600
Gasoline tank	-125	-125
Hydrogen tank	5,175	5,175
Baseline engine + transmission	-2,310	-2,310
Alternative engine + transmission ⁽³⁾	2,590	2,590
Turbo	180	180
Stop & go system	200	200
Total Vehicle Retail Price	24,310	24,310
Difference to the 2010 reference	4,750	4,750
	24.3%	24.3%

⁽³⁾ Including downsizing and friction improvement

Although the hydrogen tank cost used here is based on an estimate (current costs are about twice that figure), it remains a very expensive piece of equipment that strongly penalises hydrogen vehicles.

3.4 Hydrogen hybrid ICE vehicles

Table 3.4 2010+ Hydrogen hybrid ICE vehicles

Fuel	C-H ₂ @70 MPa	L-H ₂
Propulsion system	Hybrid PISI	
Engine Power (kW)	77	
Electric motor power (kW)	14	
Battery size (kWh)	6	
Hydrogen storage capacity (kg)	7.5	
Prices (€)		
Baseline vehicle	18,600	18,600
Gasoline tank	-125	-125
Hydrogen tank	4,313	4,313
Baseline engine + transmission	-2,310	-2,310
Alternative engine + transmission ⁽³⁾	2,590	2,590
Turbo	180	180
Electric Motor + modified transmission	600	600
Battery (Li-Ion)	3,600	3,600
Powertrain and vehicle components	2,630	2,630
Credit for standard alternator + starter	-300	-300
Total Vehicle Retail Price	29,778	29,778
Difference to the 2010 reference	10,218	10,218
	52.2%	52.2%

⁽³⁾ Including downsizing and friction improvement

3.5 Direct hydrogen fuel cell vehicles

Table 3.5 2010+ Direct Hydrogen fuel cell vehicles

Fuel	C-H ₂ @70 MPa	L-H ₂	C-H ₂ @70 MPa	L-H ₂
Propulsion system	FC		Hybrid FC	
Fuel cell Power (kW)	80		80	
Electric motor power (kW)	75		75	
Battery size (kWh)			6	
Hydrogen storage capacity (kg)	4.7		4.2	
Prices (€)				
Baseline vehicle	18,600	18,600	18,600	18,600
Gasoline tank	-125	-125	-125	-125
Hydrogen tank	2,703	2,703	2,415	2,415
Baseline engine + Transmission	-2,310	-2,310	-2,310	-2,310
Fuel cell system	8,400	8,400	8,400	8,400
Electric Motor + controller	2,025	2,025	2,025	2,025
Battery (Li-Ion)			3,600	3,600
Powertrain and vehicle components	2,630	2,630	2,630	2,630
Credit for standard alternator + starter	-300	-300	-300	-300
Credit for three-way catalyst	-430	-430	-430	-430
Total Vehicle Retail Price	31,193	31,193	34,505	34,505
Difference to the 2010 reference	11,633	11,633	14,945	14,945
	59.5%	59.5%	76.4%	76.4%

Although this assessment of fuel cell cost is very optimistic in regards to current figures, there is no doubt that fuel cells will remain significantly more expensive than conventional powertrains as systems complexity is higher and the use of expensive materials, e.g. precious metal for the electrocatalyst and perfluorinated membrane. The additional battery cost further penalises the hybrid configuration.

3.6 On-board reformer and fuel cell vehicles

Table 3.6 2010+ indirect hydrogen hybrid fuel cell vehicles

Fuel	Gasoline	Methanol
Propulsion system	Reformer + hybrid FC	
Fuel cell Power (kW)	80	80
Electric motor power (kW)	75	75
Battery size (kWh)	6	6
Prices (€)		
Baseline vehicle	18,600	18,600
Baseline engine + Transmission	-2,310	-2,310
Fuel cell + reformer	20,080	20,080
Electric Motor + controller	2,025	2,025
Battery (Li-Ion)	3,600	3,600
Powertrain and vehicle components	2,630	2,630
Credit for standard alternator + starter	-300	-300
Credit for three-way catalyst	-430	-430
Total Vehicle Retail Price	43,895	43,895
Difference to the 2010 reference	24,335	24,335
	124.4%	124.4%

The combination of the reformer and fuel cell results in a very high cost. In addition these vehicles are assumed to have a hybrid configuration i.e. including the additional battery. On the positive side these vehicles do not require a hydrogen tank.

4 Results

The following table summarises the results and also shows the estimated uncertainty ranges. The range is fairly narrow for established technologies but widens when it comes to less developed options such as hybrids. For fuel cell technology we have applied a 100% upwards range reflecting the many uncertainties attached to these technologies.

Table 4 Cost differentials of 2010+ vehicles compared to the 2010+ PISI vehicle

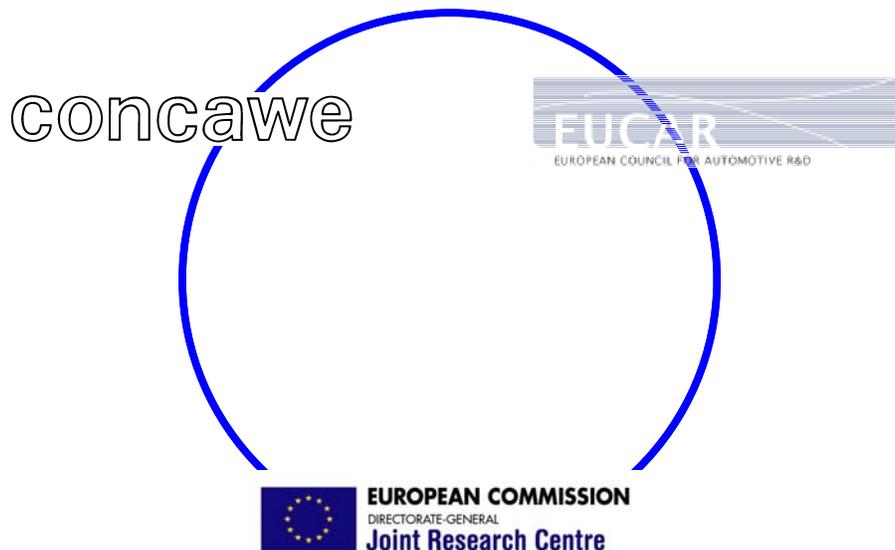
Engine technology	Fuel	Price differential (€)	Uncertainty range	
			-	+
ICEs conventional				
DISI	Gasoline	290	5%	5%
PISI	CNG (bi-fuel)	1,750	5%	5%
PISI	CNG (dedicated)	1,953	5%	5%
PISI	LPG (bi-fuel)	2,200	5%	5%
DICI	Diesel	1,600	5%	5%
DICI + DPF	Diesel	2,000	5%	5%
DICI	DME	2,975	10%	10%
PISI	C-H ₂ 70 MPa	4,750	0%	15%
PISI	L-H ₂	4,750	0%	15%
ICEs Hybrid				
DISI Hyb.	Gasoline	6,220	0%	50%
PISI Hyb.	CNG	7,373	0%	50%
DICI Hyb.	Diesel	7,830	0%	50%
DICI Hyb. + DPF	Diesel	8,230	0%	50%
PISI Hyb.	C-H ₂ 70 MPa	10,218	0%	100%
PISI Hyb.	L-H ₂	10,218	0%	100%
Fuel cells				
FC	C-H ₂ 70 MPa	11,633	0%	100%
FC	L-H ₂	11,633	0%	100%
FC Hyb.	C-H ₂ 70 MPa	14,945	0%	100%
FC Hyb.	L-H ₂	14,945	0%	100%
Ref+FC Hyb.	Gasoline	24,335	0%	100%
Ref+FC Hyb.	Methanol	24,335	0%	100%

5 References

The data in the above table stem in part from literature references. Where no suitable reference was available, the matter was discussed amongst EUCAR experts to arrive at consensual figures.

- a Institut Français du Pétrol (IFP), unpublished
- b "On the road in 2020", Malcolm A. Weiss, John B. Heywood, Elisabeth M. Drake, Andreas Schafer, and Felix F. Au Yeung, MIT, October 2000
- c Renault, Daimler Chrysler; unpublished
- d "Toward a Hydrogen Based Transportation System", Ogden & al., May 2001
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- f BMW, unpublished
- g "Battery costs for electric energy storage issues", Battery Industry Position Paper, July 2005; www.eurobat.org
"Costs of Lithium-Ion Batteries for Vehicles", Linda Gaines, Roy Cuenca, Argonne National Laboratory, May 2000
- h "DFMA Cost Estimates of Fuel-Cell/Reformer Systems at Low/Medium/High Production Rates", Brian D. James, Greg D. Ariff, Reed C. Kuhn Future Car Congress 2002 4 June 2002
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- j EUCAR experts consensual view

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



WELL-to-WHEELS Report - Appendix 1

Version 3c, July 2011

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Notes on version number:

This document reports on the third release of this study replacing version 2c published in March 2007. The original version 1b was published in December 2003.

This is a partial revision of version 2c in that it does not include an update of section 8 on cost and availability.

Summary of WTW Energy and GHG balances

This appendix gives, for each WTW pathway, i.e. a combination of a fuel production route and a powertrain, the energy and GHG figures including uncertainty ranges for WTT, TTW and WTW.

Pathways or data new to this version 3 or modified from version 2c are highlighted in yellow.

Note that fossil energy is only indicated where lower than total energy (i.e. for partly renewable pathways).

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2 CNG / CBG

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2eq} / km												
		Total						Fossil						TTW			WTT			WTT						
		TTW (MJ/100 km)		WTT (MJ/100 km)		WTW (MJ/100km)		WTW (MJ/100km)		WTW (MJ/100km)		WTW (MJ/100km)		Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	
CNG pathways																										
GMCG1	CNG: EU-mix	227	12	6	27	5	6	254	14	9								133	7	4	20	2	3	153	8	5
	PISI bi-fuel 2002	223	14	6	27	5	6	249	15	9								131	8	4	19	2	3	150	9	5
	PISI bi-fuel 2010	188	12	8	22	4	5	211	13	10								109	7	4	16	2	3	125	7	6
	PISI dedicated 2010	187	13	8	22	4	5	209	14	10								108	7	4	16	2	3	124	8	6
	PISI hybrid	139	12	13	17	3	4	156	12	14								81	7	8	12	1	2	93	7	8
GPCG1a	CNG: Pipeline 7000 km	227	12	6	67	28	11	294	34	14								133	7	4	5	16	6	183	20	8
	PISI bi-fuel 2002	223	14	6	66	27	11	289	34	14								131	8	4	50	16	6	180	20	8
	PISI bi-fuel 2010	188	12	8	56	23	9	244	29	14								109	7	4	42	13	5	151	17	8
	PISI dedicated 2010	187	13	8	56	23	9	243	30	14								108	7	4	42	13	5	150	18	8
	PISI hybrid	139	12	13	41	17	7	181	24	17								81	7	8	3	10	4	112	14	10
GPCG1b	CNG: Pipeline 4000 km	227	12	6	43	13	7	270	19	10								133	7	4	3	7	4	166	11	6
	PISI bi-fuel 2002	223	14	6	43	12	6	265	20	10								131	8	4	3	7	3	163	12	6
	PISI bi-fuel 2010	188	12	8	36	11	5	224	17	10								109	7	4	2	6	3	136	10	6
	PISI dedicated 2010	187	13	8	36	10	5	223	18	10								108	7	4	2	6	3	135	11	6
	PISI hybrid	139	12	13	27	8	4	166	15	15								81	7	8	20	4	2	101	9	9
GRCG1	CNG: LNG - Vap - Pipe	227	12	6	69	5	6	296	15	10								133	7	4	46	2	3	179	9	6
	PISI bi-fuel 2002	223	14	6	68	5	6	291	16	10								131	8	4	45	2	3	176	9	6
	PISI bi-fuel 2010	188	12	8	58	4	5	246	14	11								109	7	4	38	2	3	147	8	6
	PISI dedicated 2010	187	13	8	57	4	5	244	15	11								108	7	4	38	2	3	146	9	6
	PISI hybrid	139	12	13	43	3	4	182	13	15								81	7	8	26	1	2	109	8	9
GRCG1C	CNG: LNG, Vap - Pipe - CCS	227	12	6	72	5	6	299	16	10								133	7	4	36	3	3	171	9	6
	PISI bi-fuel 2002	223	14	6	71	5	6	294	17	10								131	8	4	37	3	3	168	9	6
	PISI bi-fuel 2010	188	12	8	60	5	5	248	14	11								109	7	4	3	2	3	140	8	6
	PISI dedicated 2010	187	13	8	60	5	5	247	15	11								108	7	4	3	2	3	139	9	6
	PISI hybrid	139	12	13	44	3	4	184	14	15								81	7	8	23	2	2	104	8	9
GRCG2	CNG: LNG - Road - Vap	227	12	6	59	2	5	286	13	10								133	7	4	47	1	3	180	8	6
	PISI bi-fuel 2002	223	14	6	58	2	5	281	15	9								131	8	4	46	1	3	177	9	6
	PISI bi-fuel 2010	188	12	8	49	2	4	238	13	10								109	7	4	39	1	2	148	8	6
	PISI dedicated 2010	187	13	8	49	2	4	236	14	10								108	7	4	39	1	2	147	8	6
	PISI hybrid	139	12	13	36	1	3	176	13	15								81	7	8	29	1	2	110	8	9
CBG pathways																										
OWCG1	CBG: municipal waste	227	12	6	198	35	30	425	47	36	39	15	9	133	7	4	-90	7	6	43	7	5	43	7	5	
	PISI bi-fuel 2002	223	14	6	195	34	29	417	48	35	38	16	9	131	8	4	-88	7	6	43	8	5	43	8	5	
	PISI bi-fuel 2010	188	12	8	164	29	25	353	41	32	32	14	10	109	7	4	-74	6	5	34	7	5	34	7	5	
	PISI dedicated 2010	187	13	8	163	29	24	351	42	32	32	15	10	108	7	4	-74	6	5	34	7	5	34	7	5	
	PISI hybrid	139	12	13	122	21	18	261	34	32	24	13	14	81	7	8	-55	4	4	26	7	8	26	7	8	
OWCG2	CBG: liquid manure	227	12	6	219	40	39	446	54	46	7	12	7	133	7	4	-319	59	68	-186	42	59	-186	42	59	
	PISI bi-fuel 2002	223	14	6	215	40	39	438	55	45	7	14	6	131	8	4	-313	58	67	-183	39	58	-183	39	58	
	PISI bi-fuel 2010	188	12	8	182	34	33	370	46	41	6	12	8	109	7	4	-265	49	57	-156	33	46	-156	33	46	
	PISI dedicated 2010	187	13	8	181	33	32	368	46	41	6	13	8	108	7	4	-265	49	56	-155	31	46	-155	31	46	
	PISI hybrid	139	12	13	135	25	24	274	36	39	4	12	13	81	7	8	-196	36	42	-115	21	25	-115	21	25	
OWCG3	CBG: dry manure	227	12	6	215	39	36	442	52	43	2	12	6	133	7	4	-125	7	7	8	7	5	8	7	5	
	PISI bi-fuel 2002	223	14	6	211	38	35	434	53	42	2	14	6	131	8	4	-122	7	7	8	8	5	8	8	5	
	PISI bi-fuel 2010	188	12	8	179	32	30	367	45	38	2	12	8	109	7	4	-103	6	6	5	7	5	5	7	5	
	PISI dedicated 2010	187	13	8	177	32	30	365	46	38	2	13	8	108	7	4	-103	6	6	5	7	5	5	7	5	
	PISI hybrid	139	12	13	132	24	22	272	37	37	1	12	13	81	7	8	-77	5	5	5	7	8	5	7	8	
OWCG4	CBG: wheat (whole plant)	227	12	6	273	8	6	500	25	15	3	12	6	133	7	4	-79	8	7	54	8	6	54	8	6	
	PISI bi-fuel 2002	223	14	6	268	7	6	491	26	15	3	14	6	131	8	4	-77	8	7	53	9	6	53	9	6	
	PISI bi-fuel 2010	188	12	8	226	6	5	415	23	16	3	12	8	109	7	4	-66	7	6	43	7	6	43	7	6	
	PISI dedicated 2010	187	13	8	225	6	5	412	23	16	3	13	8	108	7	4	-66	7	6	43	8	6	43	8	6	
	PISI hybrid	139	12	13	168	5	4	307	22	23	2	12	13	81	7	8	-46	5	4	33	7	8	33	7	8	
OWCG5	CBG: corn and barley, double cropping	227	12	6	304	8	6	531	27	16	8	12	6	133	7	4	-72	6	35	61	8	33	61	8	33	
	PISI bi-fuel 2002	223	14	6	298	8	6	521	30	15	8	14	6	131	8	4	-70	6	34	60	8	32	60	8	32	
	PISI bi-fuel 2010	188	12	8	252	7	5	440	25	17	7	12	8	109	7	4	-59	5	29	49	7	27	49	7	27	
	PISI dedicated 2010	187	13	8	250	7	5	438	27	17	6	13	8	108	7	4	-59	5	29	49	8	27	49	8	27	
	PISI hybrid	139	12	13	187	5	3	326	24	25	5	12	13	81	7	8	-44	4	21	37	7	19	37	7	19	

3 Ethanol

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2e} / km									
		Total						Fossil						TTW			WTT			WTW			
		TTW (MJ _e /100 km)		WTT (MJ _e /100 km)		WTW (MJ/100km)		WTT (MJ _e /100km)		TTW		WTT			WTW								
Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max			
Ethanol pathways, as blended fuels																							
SBET1a	EtOH: Sugar beet, pulp to fodder, slops not used	224	2	2	48	39	38	272	39	39	258				168	2	2	28	4	5	196	5	6
	PISI 2002 95/5	224	2	2	48	39	38	272	39	39	258				168	2	2	28	4	5	196	5	6
	DISI 2002 95/5	209	9	9	45	36	36	254	39	39	241				157	6	6	26	4	5	183	8	9
	PISI 2010 95/5	190	6	6	41	33	33	231	35	34	219				140	4	4	24	4	4	164	6	7
	DISI 2010 95/5	188	10	10	41	32	32	228	36	36	217				139	7	7	24	4	4	162	9	9
	DISI hybrid 95/5	154	12	12	33	27	26	187	32	31	178				114	9	9	19	3	4	133	10	10
SBET1b	EtOH: Sugar beet, pulp to fodder, slops to biogas	224	2	2	47	6	7	270	7	8	256				168	2	2	27	4	5	195	5	6
	PISI 2002 95/5	224	2	2	47	6	7	270	7	8	256				168	2	2	27	4	5	195	5	6
	DISI 2002 95/5	209	9	9	44	6	7	252	11	12	239				157	6	6	25	4	5	182	8	9
	PISI 2010 95/5	190	6	6	40	5	6	230	9	10	218				140	4	4	23	4	4	163	6	7
	DISI 2010 95/5	188	10	10	39	5	6	227	12	13	215				139	7	7	23	4	4	162	8	9
	DISI hybrid 95/5	154	12	12	32	4	5	186	14	14	177				114	9	9	19	3	4	133	10	10
SBET3	EtOH: Sugar beet, pulp to heat /slops to biogas	224	2	2	44	6	7	268	7	8	254				168	2	2	26	4	5	194	5	6
	PISI 2002 95/5	224	2	2	44	6	7	268	7	8	254				168	2	2	26	4	5	194	5	6
	DISI 2002 95/5	209	9	9	41	5	7	250	11	12	237				157	6	6	25	4	5	182	8	9
	PISI 2010 95/5	190	6	6	38	5	6	228	9	10	216				140	4	4	22	4	4	163	6	7
	DISI 2010 95/5	188	10	10	37	5	6	225	12	13	214				139	7	7	22	3	4	161	8	9
	DISI hybrid 95/5	154	12	12	31	4	5	185	13	14	175				114	9	9	18	3	4	132	10	10
WTET1a	EtOH: Wheat, conv NG boiler, DDGS as AF	224	2	2	50	11	9	274	12	9	259				168	2	2	30	4	6	198	5	6
	PISI 2002 95/5	224	2	2	50	11	9	274	12	9	259				168	2	2	30	4	6	198	5	6
	DISI 2002 95/5	209	9	9	47	10	8	256	15	13	242				157	6	6	28	4	5	185	8	9
	PISI 2010 95/5	190	6	6	43	10	7	233	12	11	221				140	4	4	25	4	5	165	6	7
	DISI 2010 95/5	188	10	10	42	9	7	230	15	13	218				139	7	7	25	4	5	164	9	9
	DISI hybrid 95/5	154	12	12	35	8	6	189	16	15	179				114	9	9	20	3	4	134	10	10
WTET1b	EtOH: Wheat, conv NG boiler, DDGS as fuel	224	2	2	47	8	9	271	9	9	257				168	2	2	29	4	5	197	5	6
	PISI 2002 95/5	224	2	2	47	8	9	271	9	9	257				168	2	2	29	4	5	197	5	6
	DISI 2002 95/5	209	9	9	44	8	8	253	13	13	240				157	6	6	27	4	5	184	8	9
	PISI 2010 95/5	190	6	6	40	7	7	230	10	10	218				140	4	4	25	4	5	165	6	7
	DISI 2010 95/5	188	10	10	40	7	7	227	13	13	216				139	7	7	24	4	5	163	9	9
	DISI hybrid 95/5	154	12	12	32	6	6	187	14	15	177				114	9	9	20	3	4	134	10	10
WTET2a	EtOH: Wheat, NG GT+CHP, DDGS as AF	224	2	2	48	9	9	272	10	9	258				168	2	2	29	5	6	197	5	6
	PISI 2002 95/5	224	2	2	48	9	9	272	10	9	258				168	2	2	29	5	6	197	5	6
	DISI 2002 95/5	209	9	9	45	9	8	254	14	13	241				157	6	6	27	4	5	184	8	9
	PISI 2010 95/5	190	6	6	41	8	7	231	11	10	219				140	4	4	24	4	5	165	6	7
	DISI 2010 95/5	188	10	10	41	8	7	229	14	13	217				139	7	7	24	4	5	163	9	9
	DISI hybrid 95/5	154	12	12	33	6	6	187	15	15	178				114	9	9	20	3	4	134	10	10
WTET2b	EtOH: Wheat, NG GT+CHP, DDGS as fuel	224	2	2	45	6	9	269	7	9	255				168	2	2	28	4	6	196	5	6
	PISI 2002 95/5	224	2	2	45	6	9	269	7	9	255				168	2	2	28	4	6	196	5	6
	DISI 2002 95/5	209	9	9	42	6	8	251	12	13	238				157	6	6	26	4	5	183	8	9
	PISI 2010 95/5	190	6	6	38	5	7	228	9	10	217				140	4	4	24	4	5	164	6	7
	DISI 2010 95/5	188	10	10	38	5	7	226	12	13	214				139	7	7	24	4	5	163	9	9
	DISI hybrid 95/5	154	12	12	31	4	6	185	14	15	176				114	9	9	19	3	4	132	10	10
WTET3a	EtOH: Wheat, Lignite CHP, DDGS as AF	224	2	2	49	10	9	272	11	9	258				168	2	2	31	5	6	199	5	6
	PISI 2002 95/5	224	2	2	49	10	9	272	11	9	258				168	2	2	31	5	6	199	5	6
	DISI 2002 95/5	209	9	9	46	9	8	254	14	13	241				157	6	6	29	4	5	186	8	9
	PISI 2010 95/5	190	6	6	42	8	7	232	11	10	219				140	4	4	26	4	5	167	6	7
	DISI 2010 95/5	188	10	10	41	8	7	229	14	13	217				139	7	7	26	4	5	165	9	9
	DISI hybrid 95/5	154	12	12	34	7	6	188	15	15	178				114	9	9	21	3	4	135	10	10
WTET3b	EtOH: Wheat, Lignite CHP, DDGS as fuel	224	2	2	46	7	9	269	8	9	255				168	2	2	30	4	6	198	5	6
	PISI 2002 95/5	224	2	2	46	7	9	269	8	9	255				168	2	2	30	4	6	198	5	6
	DISI 2002 95/5	209	9	9	43	6	8	252	12	13	238				157	6	6	28	4	5	185	8	9
	PISI 2010 95/5	190	6	6	39	6	7	229	9	10	217				140	4	4	26	4	5	166	6	7
	DISI 2010 95/5	188	10	10	38	6	7	226	12	13	215				139	7	7	26	4	5	164	9	9
	DISI hybrid 95/5	154	12	12	32	5	6	186	14	15	176				114	9	9	21	3	4	135	10	10
WTET4a	EtOH: Wheat, Straw CHP, DDGS as AF	224	2	2	50	7	9	273	7	9	255				168	2	2	27	4	6	195	5	6
	PISI 2002 95/5	224	2	2	50	7	9	273	7	9	255				168	2	2	27	4	6	195	5	6
	DISI 2002 95/5	209	9	9	46	6	8	255	12	13	238				157	6	6	25	4	5	182	8	9
	PISI 2010 95/5	190	6	6	42	6	7	232	9	10	217				140	4	4	23	4	5	163	6	7
	DISI 2010 95/5	188	10	10	42	6	7	230	12	13	214				139	7	7	23	4	5	162	9	9
	DISI hybrid 95/5	154	12	12	34	5	6	188	14	15	176				114	9	9	19	3	4	133	10	10
WTET4b	EtOH: Wheat, Straw CHP, DDGS as fuel	224	2	2	46	4	9	270	5	9	252				168	2	2	26	4	6	194	5	6
	PISI 2002 95/5	224	2	2	46	4	9	270	5	9													

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2e} / km								
		Total						Fossil						TTW			WTT			WTW		
		TTW (MJ/100 km)		WTT (MJ _f /100 km)		WTW (MJ/100km)		WTT (MJ _f /100km)		TTW		WTT			WTW							
		Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max			
EIOH pathways contribution based on neat fuel																						
SBET1a	EtOH: Sugar beet, pulp to fodder, slops not used																					
	PISI 2002	224	2	2	313	25	20	536	28	23	124	11	9	161	2	2	-75	7	11	86	6	10
	DISI 2002	209	9	9	292	23	18	501	36	32	116	16	15	151	6	6	-70	6	10	81	6	8
	PISI 2010	190	6	6	266	21	17	456	30	26	105	13	12	138	4	4	-64	6	9	73	6	9
	DISI 2010	188	10	10	263	21	16	451	36	31	104	17	15	136	7	7	-63	6	9	68	8	9
	DISI hybrid	154	12	12	216	17	14	370	36	32	85	18	17	112	9	9	-52	5	8	60	9	10
SBET1b	EtOH: Sugar beet, pulp to fodder, slops to biogas																					
	PISI 2002	224	2	2	265	21	24	488	21	24	76	6	7	161	2	2	-105	7	10	57	7	10
	DISI 2002	209	9	9	247	20	22	456	21	24	71	10	11	151	6	6	-98	6	10	53	9	12
	PISI 2010	190	6	6	225	18	20	415	19	21	64	8	8	138	4	4	-89	6	9	48	7	10
	DISI 2010	188	10	10	223	18	20	411	20	22	64	11	11	136	7	7	-88	6	9	48	9	11
	DISI hybrid	154	12	12	183	15	16	337	19	20	52	13	13	112	9	9	-72	5	7	40	10	11
SBET3	EtOH: Sugar beet, pulp to heat /slops to biogas																					
	PISI 2002	224	2	2	196	21	25	419	23	27	9	2	3	161	2	2	-128	6	11	33	5	10
	DISI 2002	209	9	9	183	20	23	392	29	32	9	9	9	151	6	6	-120	5	10	31	6	8
	PISI 2010	190	6	6	167	18	21	356	24	27	8	6	6	138	4	4	-109	5	9	28	5	7
	DISI 2010	188	10	10	165	18	21	353	28	31	8	10	10	136	7	7	-108	5	9	28	7	8
	DISI hybrid	154	12	12	135	15	17	289	28	30	6	12	12	112	9	9	-89	4	8	23	9	9
WTET1a	EtOH: Wheat, conv NG boiler, DDGS as AF																					
	PISI 2002	224	2	2	372	5	5	595	9	9	173	5	5	161	2	2	-29	16	22	133	16	22
	DISI 2002	209	9	9	347	4	5	556	21	21	161	12	12	151	6	6	-27	15	20	124	15	20
	PISI 2010	190	6	6	316	4	5	506	15	16	147	9	9	138	4	4	-25	13	19	113	13	18
	DISI 2010	188	10	10	313	4	4	501	22	23	145	13	13	136	7	7	-24	13	18	112	14	19
	DISI hybrid	154	12	12	256	3	4	411	26	26	119	16	16	112	9	9	-20	11	15	92	13	16
WTET1b	EtOH: Wheat, conv NG boiler, DDGS as fuel																					
	PISI 2002	224	2	2	278	5	6	501	8	9	85	3	3	161	2	2	-45	16	21	116	16	21
	DISI 2002	209	9	9	259	4	5	468	17	18	79	10	10	151	6	6	-42	15	20	109	15	19
	PISI 2010	190	6	6	236	4	5	426	13	14	72	7	7	138	4	4	-39	13	18	99	13	17
	DISI 2010	188	10	10	233	4	5	421	18	19	71	11	11	136	7	7	-38	13	18	98	13	17
	DISI hybrid	154	12	12	191	3	4	346	22	22	58	13	13	112	9	9	-31	11	15	81	12	15
WTET2a	EtOH: Wheat, NG GT+CHP, DDGS as AF																					
	PISI 2002	224	2	2	317	4	5	540	8	8	119	4	4	161	2	2	-57	16	23	104	16	23
	DISI 2002	209	9	9	296	4	4	505	18	19	112	11	11	151	6	6	-54	15	22	97	15	21
	PISI 2010	190	6	6	269	4	4	459	14	14	102	8	8	138	4	4	-49	14	20	89	13	19
	DISI 2010	188	10	10	266	4	4	454	20	20	100	12	12	136	7	7	-48	14	20	88	13	19
	DISI hybrid	154	12	12	218	3	3	373	23	23	82	14	14	112	9	9	-39	11	16	72	12	16
WTET2b	EtOH: Wheat, NG GT+CHP, DDGS as fuel																					
	PISI 2002	224	2	2	223	4	5	446	7	7	31	2	2	161	2	2	-74	12	22	88	11	21
	DISI 2002	209	9	9	208	4	5	417	15	16	29	9	9	151	6	6	-69	11	20	82	11	19
	PISI 2010	190	6	6	189	4	4	379	11	12	27	6	6	138	4	4	-63	10	19	75	9	17
	DISI 2010	188	10	10	187	4	4	375	16	17	26	10	10	136	7	7	-62	10	18	74	10	17
	DISI hybrid	154	12	12	153	3	3	308	19	19	22	12	12	112	9	9	-51	8	15	61	10	14
WTET3a	EtOH: Wheat, Lignite CHP, DDGS as AF																					
	PISI 2002	224	2	2	332	1	1	556	5	5	135	3	3	161	2	2	11	19	21	173	19	21
	DISI 2002	209	9	9	310	1	1	519	16	16	126	10	10	151	6	6	11	18	20	162	19	22
	PISI 2010	190	6	6	282	1	1	472	11	11	115	7	7	138	4	4	10	16	18	147	17	19
	DISI 2010	188	10	10	279	1	1	467	18	18	113	11	11	136	7	7	10	16	18	146	18	20
	DISI hybrid	154	12	12	229	1	1	383	22	22	93	14	14	112	9	9	8	13	15	120	16	18
WTET3b	EtOH: Wheat, Lignite CHP, DDGS as fuel																					
	PISI 2002	224	2	2	238	1	1	462	4	4	47	2	2	161	2	2	-5	12	25	156	12	25
	DISI 2002	209	9	9	222	1	1	431	13	13	44	9	9	151	6	6	-5	11	23	146	13	24
	PISI 2010	190	6	6	202	1	1	392	10	9	40	6	6	138	4	4	-4	10	21	133	11	21
	DISI 2010	188	10	10	200	1	1	388	15	15	39	10	10	136	7	7	-4	10	21	132	12	22
	DISI hybrid	154	12	12	164	1	1	318	18	18	32	12	12	112	9	9	-3	8	17	108	12	19
WTET4a	EtOH: Wheat, Straw CHP, DDGS as AF																					
	PISI 2002	224	2	2	352	1	1	576	5	5	36	2	2	161	2	2	-106	16	25	55	15	24
	DISI 2002	209	9	9	329	1	1	538	17	17	34	9	9	151	6	6	-99	15	23	52	13	20
	PISI 2010	190	6	6	299	1	1	489	12	12	31	6	6	138	4	4	-90	13	21	47	12	19
	DISI 2010	188	10	10	296	1	1	484	19	19	31	10	10	136	7	7	-89	13	21	47	11	18
	DISI hybrid	154	12	12	243	1	1	397	23	23	25	12	12	112	9	9	-73	11	17	39	10	15
WTET4b	EtOH: Wheat, Straw CHP, DDGS as fuel																					
	PISI 2002	224	2	2	258	1	1	482	4	4	-52	2	2	161	2	2	-122	12	24	39	11	22
	DISI 2002	209	9	9	241	1	1	450	14	14	-48	9	9	151	6	6	-114	11	22	37	9	18
	PISI 2010	190	6	6	219	1	1	409	10	10	-44	6	6	138	4	4	-104	10	20	33	8	17
	DISI 2010	188	10	10	217	1	1	405	15	15	-43	10	10	136	7	7	-103	10	20	33	8	16
	DISI hybrid	154	12	12	178	1	1	332	19	19	-36	12	12	112	9	9	-84	8	16	27	9	13
WTET5	EtOH: Wheat, DDGS to biogas																					
	PISI 2002	224	2	2	246	0	0	469	3	3	48	2	2	161	2	2	-95	13	26	66	12	25
	DISI 2002	209	9	9	229	0	0	438	13	13	44	9	9	151	6	6	-89	12	24	62	11	22
	PISI 2010	190	6	6	209	0	0	399	9	9	40	6	6	138	4	4	-81	11	22	56	10	20
	DISI 2010	188	10	10	206	0	0	394	14	14	40	10	10	136	7	7	-80	11	22	56	10	19
	DISI hybrid	154	12	12	169	0	0	323	18	18	33	12	12	112	9	9	-66	9	18	46	10	16
WWET1	EtOH: W Wood																					

4 Ethers

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2eq} / km												
		Total									Fossil			TTW			WTT			WTW						
		TTW (MJ/100 km)			WTT (MJ/100 km)			WTW (MJ/100km)			WTW (MJ/100km)			Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	
Ethers (as neat fuels)																										
GRMB1	MTBE: remote plant	224	2	2	67	0	3	290	3	5								159	2	30	0	2	190	2	3	
	PISI 2002	209	9	9	63	0	3	271	9	10								149	6	6	26	0	2	177	7	7
	PISI 2010	190	6	6	57	0	3	247	6	8								135	4	4	26	0	2	161	4	5
	DiSI 2010	188	10	10	56	0	3	244	10	11								134	7	7	26	0	2	159	7	8
	DiSI hybrid	154	12	12	46	0	2	200	12	13								110	9	9	2	0	1	131	9	9
LREB1	ETBE: imported C4 and wheat ethanol	224	2	2	167	1	3	391	4	5	226	5	7	160	2	2	-1	5	9	159	5	9	159	5	9	
	PISI 2002	209	9	9	156	1	3	365	12	13	211	13	15	149	6	6	-1	4	8	148	8	10	148	8	10	
	PISI 2010	190	6	6	142	1	3	332	8	9	192	10	11	136	4	4	-1	4	7	135	6	8	135	6	8	
	DiSI 2010	188	10	10	141	1	3	329	13	14	190	15	16	134	7	7	-1	4	7	133	8	10	133	8	10	
	DiSI hybrid	154	12	12	115	1	2	270	15	16	156	18	19	110	9	9	-1	3	6	109	9	10	109	9	10	

5 Bio-diesel

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2eq} / km												
		Total						Fossil						TTW			WTT			WTT						
		TTW (MJ/100 km)			WTT (MJ _f /100 km)			WTT (MJ/100km)			WTT (MJ _f /100km)			Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	
Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max			
Bio-diesel pathways, as blended fuels																										
ROFA1	RME: Glycerine as chem, meal as AF	183	6	6	43	8	6	227	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2002 95/5	183	6	6	43	8	6	227	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2010 no DPF 95/5	161	7	7	38	7	6	199	11	10	186							120	5	5	22	6	2	142	9	6
	DICI 2010 DPF 95/5	166	7	7	39	7	6	205	11	10	192							124	5	5	22	6	2	146	9	6
	DICI hybrid n DPF 95/5	129	10	10	31	5	5	160	13	12	149							97	7	7	17	5	1	113	10	8
	DICI hybrid DPF 95/5	133	10	10	32	6	5	165	13	13	154							100	8	8	17	5	1	117	10	8
ROFA2	RME: Glycerine and meal as AF	183	6	6	44	8	6	227	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2002 95/5	183	6	6	44	8	6	227	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2010 no DPF 95/5	161	7	7	39	7	6	200	11	10	187							120	5	5	22	6	2	142	9	6
	DICI 2010 DPF 95/5	166	7	7	40	7	6	205	12	10	192							124	5	5	23	6	2	146	9	6
	DICI hybrid n DPF 95/5	129	10	10	31	6	5	160	13	12	149							97	7	7	17	5	1	114	10	8
	DICI hybrid DPF 95/5	133	10	10	32	6	5	165	13	13	154							100	8	8	18	5	1	117	10	8
ROFA3	RME: Glycerine to biogas, meal as AF	183	6	6	44	8	6	227	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2002 95/5	183	6	6	44	8	6	227	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2010 no DPF 95/5	161	7	7	38	7	6	199	11	10	186							120	5	5	22	6	2	142	9	6
	DICI 2010 DPF 95/5	166	7	7	39	7	6	205	11	10	192							124	5	5	22	6	2	146	9	6
	DICI hybrid n DPF 95/5	129	10	10	31	5	5	160	13	12	149							97	7	7	17	5	1	114	10	8
	DICI hybrid DPF 95/5	133	10	10	32	6	5	165	13	13	154							100	8	8	18	5	1	117	10	8
ROFA4	RME: Glycerine and cake to biogas	183	6	6	40	4	6	223	8	10	208							138	4	4	24	7	2	162	9	5
	DICI 2002 95/5	183	6	6	40	4	6	223	8	10	208							138	4	4	24	7	2	162	9	5
	DICI 2010 no DPF 95/5	161	7	7	35	4	6	196	9	10	183							120	5	5	20	6	2	141	9	6
	DICI 2010 DPF 95/5	166	7	7	36	4	6	202	9	10	189							124	5	5	21	6	2	145	9	6
	DICI hybrid n DPF 95/5	129	10	10	28	3	5	157	11	12	147							97	7	7	15	5	1	112	10	8
	DICI hybrid DPF 95/5	133	10	10	29	3	5	162	12	12	151							100	8	8	16	5	1	116	10	8
ROFE1	REE: Glycerine as chem, meal as AF	183	6	6	44	7	6	227	10	10	211							138	4	4	25	7	2	163	9	5
	DICI 2002 95/5	183	6	6	44	7	6	227	10	10	211							138	4	4	25	7	2	163	9	5
	DICI 2010 no DPF 95/5	161	7	7	39	6	6	200	11	10	186							120	5	5	21	6	2	142	9	6
	DICI 2010 DPF 95/5	166	7	7	40	7	6	206	11	10	191							124	5	5	22	6	2	146	9	6
	DICI hybrid n DPF 95/5	129	10	10	31	5	4	160	12	12	149							97	7	7	16	5	2	113	10	8
	DICI hybrid DPF 95/5	133	10	10	32	5	5	165	13	12	153							100	8	8	17	5	2	117	10	8
ROFE2	REE: Glycerine and meal as AF	183	6	6	45	8	6	228	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2002 95/5	183	6	6	45	8	6	228	11	10	212							138	4	4	25	7	2	163	9	5
	DICI 2010 no DPF 95/5	161	7	7	39	7	6	200	11	10	186							120	5	5	22	6	2	142	9	6
	DICI 2010 DPF 95/5	166	7	7	40	7	6	206	11	10	192							124	5	5	22	6	2	146	9	6
	DICI hybrid n DPF 95/5	129	10	10	31	5	4	160	13	12	149							97	7	7	17	5	1	114	10	8
	DICI hybrid DPF 95/5	133	10	10	32	6	5	165	13	13	154							100	8	8	17	5	2	117	10	8
ROFE3	REE: Glycerine to biogas, meal as AF	183	6	6	44	7	6	227	10	10	211							138	4	4	25	7	2	163	9	5
	DICI 2002 95/5	183	6	6	44	7	6	227	10	10	211							138	4	4	25	7	2	163	9	5
	DICI 2010 no DPF 95/5	161	7	7	39	6	6	200	11	10	186							120	5	5	22	6	2	142	9	6
	DICI 2010 DPF 95/5	166	7	7	40	7	6	206	11	10	191							124	5	5	22	6	2	146	9	6
	DICI hybrid n DPF 95/5	129	10	10	31	5	4	160	13	12	149							97	7	7	17	5	1	113	10	8
	DICI hybrid DPF 95/5	133	10	10	32	5	5	165	13	12	154							100	8	8	17	5	1	117	10	8
ROFE4	REE: Glycerine and cake to biogas	183	6	6	41	4	6	224	8	10	208							138	4	4	23	2	5	161	5	7
	DICI 2002 95/5	183	6	6	41	4	6	224	8	10	208							138	4	4	23	2	5	161	5	7
	DICI 2010 no DPF 95/5	161	7	7	36	3	6	197	9	10	183							120	5	5	20	1	5	140	6	8
	DICI 2010 DPF 95/5	166	7	7	37	4	6	203	9	10	188							124	5	5	21	1	5	144	6	8
	DICI hybrid n DPF 95/5	129	10	10	29	3	4	158	11	12	147							97	7	7	15	0	5	112	8	10
	DICI hybrid DPF 95/5	133	10	10	30	3	5	163	12	12	151							100	8	8	16	0	5	115	8	10
SOFA1	SME: Glycerine as chem, meal as AF	183	6	6	42	7	6	225	10	9	211							138	4	4	23	7	1	162	9	5
	DICI 2002 95/5	183	6	6	42	7	6	225	10	9	211							138	4	4	23	7	1	162	9	5
	DICI 2010 no DPF 95/5	161	7	7	37	6	5	198	11	10	186							120	5	5	20	6	1	141	9	6
	DICI 2010 DPF 95/5	166	7	7	38	7	5	204	11	10	191							124	5	5	21	6	1	145	9	6
	DICI hybrid n DPF 95/5	129	10	10	30	5	4	159	12	12	149							97	7	7	15	5	1	112	10	8
	DICI hybrid DPF 95/5	133	10	10	31	5	4	164	13	12	153							100	8	8	16	5	1	116	10	8
SOFA2	SME: Glycerine and meal as AF	183	6	6	43	8	6	226	11	9	212							138	4	4	24	7	1	162	9	5
	DICI 2002 95/5	183	6	6	43	8	6	226	11	9	212							138	4	4	24	7	1	162	9	5
	DICI 2010 no DPF 95/5	161	7	7	37	7	5	199	11	10	186							120	5	5	21</					

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2eq} / km										
		Total						Fossil						TTW			WTT			WTW				
		TTW (MJ _f /100 km)			WTT (MJ _f /100 km)			WTT (MJ/100km)			WTT (MJ _f /100km)			Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min
Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	
Bio-diesel pathways, as blended fuels																								
SYFA1	SYME: Glycerine as chem, mill in EU, meal as AF in Brazil																							
	DICI 2002 95/5	183	6	6	57	10	7	240	13	10	214				138	4	4	26	10	2	164	12	5	
	DICI 2010 no DPF 95/5	161	7	7	50	9	6	211	13	11	188				120	5	5	22	9	2	143	11	6	
	DICI 2010 DPF 95/5	166	7	7	52	9	6	217	13	11	193				124	5	5	23	9	2	147	12	6	
	DICI hybrid n DPF 95/5	129	10	10	40	7	5	169	14	13	151				97	7	7	18	8	2	114	12	8	
DICI hybrid DPF 95/5	133	10	10	41	7	5	174	15	13	155				100	8	8	18	8	2	118	12	9		
SYFA3	SYME: Glycerine to biogas, mill in Brazil, meal as AF																							
	DICI 2002 95/5	183	6	6	57	10	7	240	13	10	214				138	4	4	26	11	2	164	12	5	
	DICI 2010 no DPF 95/5	161	7	7	50	9	6	211	13	11	188				120	5	5	22	10	2	143	12	6	
	DICI 2010 DPF 95/5	166	7	7	52	9	6	217	13	11	194				124	5	5	23	10	2	147	12	6	
	DICI hybrid n DPF 95/5	129	10	10	40	7	5	169	14	13	151				97	7	7	18	9	2	115	13	8	
DICI hybrid DPF 95/5	133	10	10	42	7	5	175	15	13	155				100	8	8	18	9	2	118	13	8		
POFA1a	PME: Glycerine as chem, CH4 emissions from waste																							
	DICI 2002 95/5	183	6	6	45	7	6	228	10	9	211				138	4	4	25	6	3	163	8	6	
	DICI 2010 no DPF 95/5	161	7	7	40	6	5	204	11	10	186				120	5	5	22	5	3	142	8	6	
	DICI 2010 DPF 95/5	166	7	7	41	6	5	207	11	10	191				124	5	5	23	6	3	146	9	7	
	DICI hybrid n DPF 95/5	129	10	10	32	5	4	161	12	12	149				97	7	7	17	4	3	114	9	9	
DICI hybrid DPF 95/5	133	10	10	33	5	4	166	13	12	153				100	8	8	18	5	3	117	10	9		
POFA1b	PME: Glycerine as chem, no CH4 from waste																							
	DICI 2002 95/5	183	6	6	45	7	6	228	10	9	211				138	4	4	23	6	3	161	8	6	
	DICI 2010 no DPF 95/5	161	7	7	40	6	5	201	11	10	186				120	5	5	20	5	3	140	8	6	
	DICI 2010 DPF 95/5	166	7	7	41	6	5	207	11	10	191				124	5	5	21	6	3	144	8	7	
	DICI hybrid n DPF 95/5	129	10	10	32	5	4	161	12	12	149				97	7	7	15	4	3	112	9	8	
DICI hybrid DPF 95/5	133	10	10	33	5	4	166	13	12	153				100	8	8	16	5	3	115	10	9		
POFA2	PME: Glycerine to biogas, CH4 emissions from waste																							
	DICI 2002 95/5	183	6	6	45	7	6	228	10	9	211				138	4	4	26	6	3	164	8	6	
	DICI 2010 no DPF 95/5	161	7	7	40	6	5	204	11	10	186				120	5	5	22	5	3	143	8	6	
	DICI 2010 DPF 95/5	166	7	7	41	7	5	207	11	10	191				124	5	5	23	6	3	147	9	6	
	DICI hybrid n DPF 95/5	129	10	10	32	5	4	161	13	12	149				97	7	7	17	4	2	114	9	8	
DICI hybrid DPF 95/5	133	10	10	33	5	4	166	13	12	153				100	8	8	18	5	3	118	10	9		
ROHY1a	HRO (NEXBTL), meal as AF																							
	DICI 2002 95/5	183	5	5	43	8	7	226	11	10	211				138	4	4	25	6	1	163	8	5	
	DICI 2010 no DPF 95/5	161	7	7	38	7	6	199	11	10	186				120	5	5	22	6	1	142	8	6	
	DICI 2010 DPF 95/5	166	7	7	39	7	6	205	11	10	191				123	5	5	23	6	1	146	9	6	
	DICI hybrid n DPF 95/5	129	10	10	30	5	5	159	13	12	149				96	8	8	17	5	1	113	10	8	
DICI hybrid DPF 95/5	133	10	10	31	6	5	164	13	13	154				99	8	8	18	5	1	117	10	8		
ROHY1b	HRO (UOP), meal as AF																							
	DICI 2002 95/5	183	5	5	42	8	6	225	11	9	212				138	4	4	26	6	1	163	8	5	
	DICI 2010 no DPF 95/5	161	7	7	37	7	6	198	11	10	187				120	5	5	22	6	1	142	8	6	
	DICI 2010 DPF 95/5	166	7	7	38	7	6	204	11	10	192				123	5	5	23	6	1	146	9	6	
	DICI hybrid n DPF 95/5	129	10	10	30	6	5	159	13	12	149				96	8	8	17	5	1	113	10	8	
DICI hybrid DPF 95/5	133	10	10	30	6	5	163	13	12	154				99	8	8	18	5	1	117	10	8		
ROHY4a	HRO (NEXBTL), cake to biogas																							
	DICI 2002 95/5	183	5	5	40	5	7	223	8	10	208				138	4	4	24	6	1	162	8	5	
	DICI 2010 no DPF 95/5	161	7	7	35	4	6	196	9	10	183				120	5	5	21	6	1	140	8	6	
	DICI 2010 DPF 95/5	166	7	7	36	4	6	202	9	10	189				123	5	5	21	6	1	144	9	6	
	DICI hybrid n DPF 95/5	129	10	10	28	3	5	157	11	12	147				96	8	8	16	5	1	112	10	8	
DICI hybrid DPF 95/5	133	10	10	29	3	5	162	12	12	151				99	8	8	16	5	1	115	10	8		
SOHY1	HRO (NEXBTL), meal as AF																							
	DICI 2002 95/5	183	5	5	42	7	6	225	10	9	211				138	4	4	24	6	1	162	8	4	
	DICI 2010 no DPF 95/5	161	7	7	37	6	5	198	11	10	186				120	5	5	21	5	1	140	8	5	
	DICI 2010 DPF 95/5	166	7	7	38	7	5	204	11	10	191				123	5	5	21	6	1	144	8	5	
	DICI hybrid n DPF 95/5	129	10	10	29	5	4	158	12	12	149				96	8	8	16	4	1	112	10	8	
DICI hybrid DPF 95/5	133	10	10	30	5	4	163	13	12	153				99	8	8	16	5	1	115	10	8		
POHY1a	HPO (NEXBTL), CH4 from waste																							
	DICI 2002 95/5	183	5	5	45	7	6	228	10	9	211				138	4	4	26	6	2	164	8	5	
	DICI 2010 no DPF 95/5	161	7	7	40	6	5	201	10	10	185				120	5	5	23	6	2	142	8	6	
	DICI 2010 DPF 95/5	166	7	7	41	6	5	206	11	10	191				123	5	5	23	6	2	146	8	6	
	DICI hybrid n DPF 95/5	129	10	10	32	5	4	161	12	12	148				96	8	8	18	5	2	114	10	8	
DICI hybrid DPF 95/5	133	10	10	33	5	4	166	13	12	153				99	8	8	18	5	2	117	10	8		
POHY1b	HPO (NEXBTL), no CH4 from waste																							
	DICI 2002 95/5	183	5	5	45	7	6	228	10	9	211				138	4	4	24	6	3	161	8	5	
	DICI 2010 no DPF 95/5	161	7	7	40	6	5	201	10	10	185				120	5	5	21	5	3	140	8	6	
	DICI 2010 DPF 95/5	166	7	7	41	6	5	206	11	10	191				123	5	5	21	6	3	144	8	6	
	DICI hybrid n DPF 95/5	129	10	10	32	5	4	161	12	12	148				96	8	8	16	4	3	112	10	9	
DICI hybrid DPF 95/5	133	10	10	33	5	4	166	13	12	153				99	8	8	16	5	3	115	10	9		
POHY1c	HPO (NEXBTL), CH4 from waste, no heat credit																							
	DICI 2002 95/5	183	5	5	45	7	6	228	10	9	211				138	4	4	26	6	3	164	8	5	
	DICI 2010 no DPF 95/5	161	7	7	40	6	5	201	11	10	186				120	5	5	23	5	3	142	8	6	
	DICI 2010 DPF 95/5	166	7	7	41	6	5	207	11	10	191				123	5	5	23	6	3	146	8	6	
	DICI hybrid n DPF 95/5	129	10	10	32	5	4	161	12	12	149				96	8	8	18	4	2	114	10	9	
DICI hybrid DPF 95/5	133	10	10	33	5	4	166	13	12	153				99	8	8	18	5	2	117	10	9		

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2e} / km								
		Total						Fossil						TTW			WTT			WTW		
		TTW (MJ _t /100 km)		WTT (MJ _t /100 km)		WTW (MJ/100km)		WTW (MJ _t /100km)		TTW		WTT			WTW							
		Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
Bio-diesel pathways contribution based on neat fuel (netback calculation)																						
ROFA1	RME: Glycerine as chem, meal as AF	183	5	5	199	19	19	383	25	26	66	10	10	143	4	4	-62	17	24	80	16	23
	DICI 2002	161	7	7	176	16	17	337	25	25	58	10	11	124	5	5	-55	15	21	70	14	20
	DICI 2010 no DPF	166	7	7	181	17	18	346	25	26	59	11	11	128	5	5	-56	16	22	72	14	20
	DICI 2010 DPF	129	10	10	141	13	14	270	26	26	46	13	13	100	8	8	-44	12	17	56	12	16
	DICI hybrid n DPF	133	10	10	145	13	14	272	27	27	48	13	13	103	8	8	-45	13	18	58	12	16
ROFA2	RME: Glycerine and meal as AF	183	5	5	209	18	20	392	25	26	75	10	11	143	4	4	-53	17	23	90	16	22
	DICI 2002	161	7	7	184	16	17	345	24	26	66	11	11	124	5	5	-47	15	20	78	14	19
	DICI 2010 no DPF	166	7	7	189	16	18	355	25	27	68	11	12	128	5	5	-48	16	21	80	15	19
	DICI 2010 DPF	129	10	10	147	12	14	272	26	27	53	13	13	100	8	8	-37	12	16	63	12	15
	DICI hybrid n DPF	133	10	10	152	13	14	285	27	28	54	13	14	103	8	8	-39	12	17	65	12	16
ROFA3	RME: Glycerine to biogas, meal as AF	183	5	5	202	18	20	385	25	27	68	10	10	143	4	4	-56	18	24	87	17	23
	DICI 2002	161	7	7	178	16	18	339	24	26	60	10	11	124	5	5	-49	16	21	75	15	20
	DICI 2010 no DPF	166	7	7	183	16	18	349	25	27	62	11	11	128	5	5	-51	16	22	77	15	21
	DICI 2010 DPF	129	10	10	143	13	14	272	26	27	48	13	13	100	8	8	-39	13	17	61	12	16
	DICI hybrid n DPF	133	10	10	147	13	15	280	26	28	49	13	13	103	8	8	-41	13	18	62	13	17
ROFA4	RME: Glycerine and cake to biogas	183	5	5	127	18	19	310	23	23	-3	6	6	143	4	4	-88	14	23	55	12	21
	DICI 2002	161	7	7	112	16	17	273	22	22	-3	7	7	124	5	5	-77	12	20	47	10	18
	DICI 2010 no DPF	166	7	7	115	17	17	281	23	23	-3	7	7	128	5	5	-79	12	21	48	11	19
	DICI 2010 DPF	129	10	10	90	13	13	219	22	23	-2	10	10	100	8	8	-62	10	16	38	9	14
	DICI hybrid n DPF	133	10	10	93	13	14	226	23	23	-2	10	10	103	8	8	-64	10	17	39	9	14
ROFE1	REE: Glycerine as chem, meal as AF	183	5	5	216	17	20	399	25	27	58	8	9	143	4	4	-64	14	24	79	12	22
	DICI 2002	161	7	7	190	15	18	352	24	27	51	9	10	124	5	5	-57	12	21	68	11	19
	DICI 2010 no DPF	166	7	7	196	16	19	362	25	28	53	10	10	128	5	5	-58	12	22	70	11	20
	DICI 2010 DPF	129	10	10	152	12	14	281	26	28	41	12	12	100	8	8	-45	10	17	55	10	15
	DICI hybrid n DPF	133	10	10	157	13	15	290	27	29	42	12	13	103	8	8	-47	10	17	56	10	16
ROFE2	REE: Glycerine and meal as AF	183	5	5	225	19	19	408	27	26	67	10	9	143	4	4	-56	15	22	87	14	21
	DICI 2002	161	7	7	198	17	17	359	26	26	59	10	10	124	5	5	-49	14	20	76	13	18
	DICI 2010 no DPF	166	7	7	204	18	17	370	27	27	61	10	10	128	5	5	-50	14	20	78	13	19
	DICI 2010 DPF	129	10	10	159	14	13	288	28	27	47	13	12	100	8	8	-39	11	16	61	11	15
	DICI hybrid n DPF	133	10	10	164	14	14	297	29	28	49	13	13	103	8	8	-40	11	16	63	11	15
ROFE3	REE: Glycerine to biogas, meal as AF	183	5	5	219	18	18	402	25	25	61	9	9	143	4	4	-58	16	21	85	15	20
	DICI 2002	161	7	7	193	16	16	354	25	25	54	10	10	124	5	5	-51	14	19	73	13	18
	DICI 2010 no DPF	166	7	7	198	16	16	364	26	26	55	10	10	128	5	5	-53	15	19	75	13	18
	DICI 2010 DPF	129	10	10	154	13	13	283	27	26	43	12	12	100	8	8	-41	11	15	59	11	14
	DICI hybrid n DPF	133	10	10	159	13	13	292	27	27	44	12	12	103	8	8	-42	12	16	61	12	15
ROFE4	REE: Glycerine and cake to biogas	183	5	5	141	141	-141	324	146	137	-13	15	14	143	4	4	-93	-93	93	50	96	90
	DICI 2002	161	7	7	124	124	-124	286	130	119	-12	14	13	124	5	5	-82	-82	82	43	85	78
	DICI 2010 no DPF	166	7	7	128	128	-128	294	134	123	-12	14	14	128	5	5	-84	-84	84	44	88	81
	DICI 2010 DPF	129	10	10	100	100	-100	229	108	92	-9	14	13	100	8	8	-65	-65	65	35	71	61
	DICI hybrid n DPF	133	10	10	103	103	-103	236	111	95	-10	15	14	103	8	8	-67	-67	67	36	73	63
SOFA1	SME: Glycerine as chem, meal as AF	183	5	5	170	17	18	353	23	24	58	10	10	143	4	4	-92	9	8	51	8	7
	DICI 2002	161	7	7	150	15	16	311	23	23	51	10	10	124	5	5	-81	8	7	44	7	7
	DICI 2010 no DPF	166	7	7	154	16	16	320	23	24	53	10	11	128	5	5	-83	8	8	45	7	7
	DICI 2010 DPF	129	10	10	120	12	13	249	24	24	41	12	12	100	8	8	-65	6	6	35	8	8
	DICI hybrid n DPF	133	10	10	124	13	13	257	24	25	42	13	13	103	8	8	-67	6	6	37	8	8
SOFA2	SME: Glycerine and meal as AF	183	5	5	180	18	17	363	24	23	68	10	10	143	4	4	-82	9	9	61	8	7
	DICI 2002	161	7	7	158	16	15	319	24	23	59	11	11	124	5	5	-72	8	8	52	7	7
	DICI 2010 no DPF	166	7	7	163	17	16	328	25	24	61	11	11	128	5	5	-74	9	8	54	8	7
	DICI 2010 DPF	129	10	10	127	13	12	256	25	24	48	13	13	100	8	8	-58	7	6	42	8	7
	DICI hybrid n DPF	133	10	10	131	13	13	264	25	25	49	13	13	103	8	8	-60	7	6	43	8	8
SOFA3	SME: Glycerine to biogas, meal as AF	183	5	5	173	14	18	356	20	24	61	9	10	143	4	4	-85	9	10	58	8	9
	DICI 2002	161	7	7	152	12	16	314	20	24	54	10	10	124	5	5	-75	8	9	50	7	8
	DICI 2010 no DPF	166	7	7	157	13	17	322	21	24	55	10	11	128	5	5	-77	8	9	51	7	8
	DICI 2010 DPF	129	10	10	122	10	13	251	22	24	43	12	13	100	8	8	-60	6	7	40	8	8
	DICI hybrid n DPF	133	10	10	126	10	13	259	22	25	44	12	13	103	8	8	-62	6	8	41	8	8
SOFA4	SME: Glycerine and cake to biogas	183	5	5	107	1	1	290	7	7	-2	5	5	143	4	4	-112	8	9	31	6	7
	DICI 2002	161	7	7	94	1	1	255	8	8	-2	7	7	124	5	5	-98	7	8	26	6	6
	DICI 2010 no DPF	166	7	7	96	1	1	262	9	9	-2	7	7	128	5	5	-101	7	8	27	6	7
	DICI 2010 DPF	129	10	10	75	1	1	204	12	12	-2	10	10	100	8	8	-79	6	6	21	8	8
	DICI hybrid n DPF	133	10	10	77	1	1	210	12	12	-2	10	10	103	8	8	-81	6	6	22	8	8

6 Synthetic diesel fuel

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2eq} / km											
		Total						Fossil						TTW			WTT			WTT					
		TTW (MJ/100 km)		WTT (MJ _d /100 km)		WTW (MJ/100km)		TTW (MJ _d /100km)		WTT (MJ _d /100km)		Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max		
SD pathways, as blended fuels																									
GP1SD1a	Syn-diesel: NG 7000 km, GTL, Diesel mix	183	5	5	42	7	5	226	10	8							138	4	4	32	7	1	169	9	5
	DICI 2002	161	7	7	37	11	4	198	15	9							120	5	5	28	6	1	147	9	5
	DICI 2010 no DPF	166	7	7	38	12	4	204	15	9							123	5	5	29	7	1	152	9	6
	DICI hybrid n DPF	129	10	10	30	9	3	159	15	11							96	8	8	22	5	1	118	10	8
	DICI hybrid DPF	133	10	10	31	9	3	164	16	12							99	8	8	23	5	1	122	10	8
GP1SD1b	Syn-diesel: NG 4000 km, GTL, Diesel mix	183	5	5	41	5	5	224	9	8							138	4	4	31	7	1	168	9	4
	DICI 2002	161	7	7	36	5	4	197	9	9							120	5	5	27	6	1	146	9	5
	DICI 2010 no DPF	166	7	7	37	5	4	203	10	9							123	5	5	28	6	1	151	9	6
	DICI hybrid n DPF	129	10	10	29	4	3	158	12	11							96	8	8	22	5	1	118	10	8
	DICI hybrid DPF	133	10	10	30	4	3	163	12	12							99	8	8	22	5	1	121	10	8
GRSD1	Syn-diesel: Rem GTL, Sea, Diesel mix	183	5	5	40	5	4	223	8	8							138	4	4	30	6	1	167	8	4
	DICI 2002	161	7	7	35	4	4	196	9	9							120	5	5	26	6	1	146	8	5
	DICI 2010 no DPF	166	7	7	36	5	4	202	9	9							123	5	5	27	6	1	150	9	6
	DICI hybrid n DPF	129	10	10	28	4	3	157	11	11							96	8	8	21	5	1	117	10	8
	DICI hybrid DPF	133	10	10	29	4	3	162	12	12							99	8	8	22	5	1	120	10	8
WWSD1	Syn-diesel: W Wood, diesel mix	183	5	5	45	6	5	228	9	8	209						138	4	4	22	6	1	159	8	4
	DICI 2002	161	7	7	40	5	4	201	10	9	184						120	5	5	19	5	0	138	8	5
	DICI 2010 no DPF	166	7	7	41	5	4	206	10	9	189						123	5	5	20	6	0	142	8	5
	DICI hybrid n DPF	129	10	10	32	4	3	161	12	12	147						96	8	8	15	4	0	111	9	8
	DICI hybrid DPF	133	10	10	33	4	4	166	12	12	152						99	8	8	16	4	0	115	9	8
WFSD1	Syn-diesel: F wood, diesel mix	183	5	5	45	6	5	228	9	8	209						138	4	4	22	6	2	159	8	5
	DICI 2002	161	7	7	40	5	4	201	9	9	184						120	5	5	19	6	1	139	8	6
	DICI 2010 no DPF	166	7	7	41	5	5	206	10	9	189						123	5	5	20	6	1	143	8	6
	DICI hybrid n DPF	129	10	10	32	4	4	161	12	12	147						96	8	8	15	4	1	111	10	8
	DICI hybrid DPF	133	10	10	33	4	4	166	12	12	152						99	8	8	16	5	1	115	10	8
BLSD1	Syn-diesel: W Wood, Black liquor	183	5	5	42	5	5	225	8	8	209						138	4	4	21	6	1	159	8	4
	DICI 2002	161	7	7	37	4	4	198	9	9	184						120	5	5	19	5	0	138	8	5
	DICI 2010 no DPF	166	7	7	38	5	4	204	9	9	189						123	5	5	19	6	0	142	8	5
	DICI hybrid n DPF	129	10	10	30	4	3	159	11	11	147						96	8	8	15	4	0	111	9	8
	DICI hybrid DPF	133	10	10	31	4	3	164	12	12	152						99	8	8	16	4	0	114	9	8
SD pathways as neat fuel																									
GRSD1	Syn-diesel: Rem GTL, Sea, Diesel mix	183	5	5	115	10	10	298	15	15							133	4	4	41	6	6	174	8	8
	DICI 2002	161	7	7	101	9	9	262	15	15							116	5	5	36	5	5	152	8	8
	DICI 2010 no DPF	166	7	7	104	9	9	270	15	15							119	5	5	37	5	5	156	8	9
	DICI hybrid n DPF	129	10	10	81	7	7	210	17	17							93	7	7	29	4	4	122	9	10
	DICI hybrid DPF	133	10	10	84	7	7	217	17	17							96	7	7	30	4	4	126	10	10
GRSD2	Syn-diesel: Rem GTL, Sea, Rail/Road	183	5	5	115	8	11	299	12	16							133	4	4	41	4	6	174	7	9
	DICI 2002	161	7	7	102	7	10	263	13	16							116	5	5	36	4	6	152	7	9
	DICI 2010 no DPF	166	7	7	104	7	10	270	13	16							119	5	5	37	4	6	156	7	9
	DICI hybrid n DPF	129	10	10	81	5	8	210	15	17							93	7	7	29	3	5	122	9	10
	DICI hybrid DPF	133	10	10	84	6	8	217	16	18							96	7	7	30	3	5	126	9	10
GRSD2C	Syn-diesel: Rem GTL, Sea, Rail/Road, CCS	183	5	5	139	9	11	323	14	16							133	4	4	24	5	6	157	7	8
	DICI 2002	161	7	7	123	8	9	284	15	16							116	5	5	21	4	5	137	7	8
	DICI 2010 no DPF	166	7	7	126	8	10	292	15	17							119	5	5	22	5	5	141	7	8
	DICI hybrid n DPF	129	10	10	98	6	8	227	17	18							93	7	7	17	4	4	110	9	9
	DICI hybrid DPF	133	10	10	101	7	8	234	18	19							96	7	7	18	4	4	114	9	9
KOSD1	Syn-diesel: CTL, Diesel mix	183	5	5	178	15	15	361	21	21							133	4	4	238	15	15	371	23	23
	DICI 2002	161	7	7	157	13	13	318	21	21							116	5	5	210	13	14	325	23	23
	DICI 2010 no DPF	166	7	7	161	13	14	327	21	22							119	5	5	216	14	14	335	23	24
	DICI hybrid n DPF	129	10	10	125	10	11	254	22	23							93	7	7	168	11	11	261	25	25
	DICI hybrid DPF	133	10	10	129	11	11	262	23	23							96	7	7	173	11	11	269	25	26
KOSD1C	Syn-diesel: CTL, CCS, Diesel mix	183	5	5	194	14	14	377	20	21							133	4	4	74	14	15	207	17	17
	DICI 2002	161	7	7	170	12	13	331	21	21							116	5	5	65	13	13	181	16	16
	DICI 2010 no DPF	166	7	7	175	13	13	341	21	22							119	5	5	67	13	13	186	17	17
	DICI hybrid n DPF	129	10	10	136	10	10	265	23	23							93	7	7	52	10	10	145	16	16
	DICI hybrid DPF	133	10	10	141	10	10	274	23	24							96	7	7	54	10	11	150	16	16
WWSD1	Syn-diesel: W Wood, diesel mix	183	5	5	219	23	17	402	30	24	12	6	6				133	4	4	-121	0	0	12	5	5
	DICI 2002	161	7	7	192	20	15	353	29	24	11	7	7				116	5	5	-106	0	0	9	6	6
	DICI 2010 no DPF	166	7	7	198	21	16	363	30	25	11	7	7				119	5	5	-109	0	0	10	7	7
	DICI hybrid n DPF	129	10	10	154	16	12	283	30	26	8	10	10				93	7	7	-85	0	0	8	10	10
	DICI hybrid DPF	133	10	10	159	17	12	292	31	27	9	10	10				96	7	7	-88	0	0	8	10	10
WFSD1	Syn-diesel: F wood, diesel mix	183	5	5	219	20	20	402	27	27	12	6	6				133	4	4	-117	3	20	16	4	17
	DICI 2002	161	7	7	192	17	18	353	27	27	10	7	7				116	5	5	-103	3	18	13	5	14
	DICI 2010 no DPF	166	7	7	198	18	18	363	27	28	11	7	7				119	5	5	-106	3	18	13	5	14
	DICI hybrid n DPF	129	10	10	154	14	14	283	28	28	8	10	10				93	7	7	-83	2	14	11	8	10
	DICI hybrid DPF	133	10	10	159	14	15	292	28	29	9	10	10				96	7	7	-85	2	14	11	8	11
BLSD1	Syn-diesel: W Wood, Black liquor	183	5	5	167	9	11	350	15	17	7	6	6				133	4	4	-125	0	0	8	5	5
	DICI 2002	161	7	7	147	8	10	308	16	17	6	7	7				116	5	5	-110	0	0	6	7	7
	DICI 2010 no DPF	166	7	7	151	9	10	317	16	18	6	7													

7 Methanol and DME

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2eq} / km												
		Total						Fossil						TTW			WTT			WTT						
		TTW (MJ/100 km)			WTT (MJ/100 km)			WTTW (MJ/100km)			WTTW (MJ/100km)			Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	
Methanol pathways																										
GPME1a	MeOH: NG 7000 km, Syn, Rail/Road Reformer + FC	148	18	34	125	3	3	273	26	46								109	10	25	62	15	6	172	27	33
GPME1b	MeOH: NG 4000 km, Syn, Rail/Road Reformer + FC	148	18	34	102	12	6	250	30	45								109	10	25	46	7	4	155	18	29
GRME1	MeOH: Rem Syn, Sea, Rail/Road Reformer + FC	148	18	34	90	2	5	238	22	43								109	10	25	36	1	3	145	15	27
KOME1	MeOH: Coal EU-mix, Cen, Rail/Road Reformer + FC	148	18	34	138	14	13	286	35	56								109	10	25	190	14	13	299	39	62
WWME1	MeOH: W Wood, Road Reformer + FC	148	18	34	158	19	20	306	42	65	9	18	34					109	10	25	-95	0	0	14	18	33
WFME1	MeOH: F Wood, Road Reformer + FC	148	18	34	158	20	20	306	43	65	9	18	34					109	10	25	-92	2	18	17	16	25
BLME1	MeOH: W Wood, Black liquor Reformer + FC	148	18	34	87	7	7	235	25	43	5	18	34					109	10	25	-99	0	0	11	18	34
DME pathways																										
GPDE1a	DME: NG 7000 km, Syn, Rail/Road DICI 2002	183	5	5	141	36	12	324	4	18								126	4	4	70	21	7	199	23	10
	DICI 2010 no DPF	161	7	7	124	32	11	285	36	18								110	5	5	64	18	6	174	21	10
	DICI hybrid n DPF	129	10	10	99	25	9	228	35	19								89	7	7	5	15	5	140	20	11
GPDE1b	DME: NG 4000 km, Syn, Rail/Road DICI 2002	183	5	5	114	15	8	297	19	13								126	4	4	52	8	4	179	11	7
	DICI 2010 no DPF	161	7	7	100	13	7	261	18	13								110	5	5	46	7	4	156	10	7
	DICI hybrid n DPF	129	10	10	80	10	6	209	19	15								89	7	7	37	6	3	126	11	9
GRDE1	DME: Rem Syn, Sea, Rail/Road DICI 2002	183	5	5	97	3	6	280	8	10								126	4	4	39	0	0	165	4	4
	DICI 2010 no DPF	161	7	7	86	3	5	247	9	11								110	5	5	34	0	0	144	5	5
	DICI hybrid n DPF	129	10	10	69	2	4	198	12	14								89	7	7	27	0	0	116	7	7
KODE1	DME: Coal EU-mix, Cen, Rail/Road DICI 2002	183	5	5	170	18	14	353	24	20								126	4	4	237	1	0	364	9	8
	DICI 2010 no DPF	161	7	7	150	16	13	311	23	20								110	5	5	209	1	1	319	11	11
	DICI hybrid n DPF	129	10	10	120	13	10	249	24	22								89	7	7	167	1	1	256	15	15
GRDE1C	DME: Rem Syn, Sea, Rail/Road, CCS DICI 2002	183	5	5	99	0	12	282	6	16								126	4	4	20	0	0	147	4	4
	DICI 2010 no DPF	161	7	7	87	0	11	248	8	16								110	5	5	18	0	0	128	5	5
	DICI hybrid n DPF	129	10	10	70	0	9	199	1	17								89	7	7	14	0	0	103	7	7
WWDE1	DME: W Wood, Road DICI 2002	183	5	5	196	23	25	379	30	31	11	6	6					126	4	4	-115	0	0	12	5	5
	DICI 2010 no DPF	161	7	7	172	20	22	333	29	30	10	7	7					110	5	5	-10	0	0	9	6	6
	DICI hybrid n DPF	129	10	10	138	16	18	267	29	30	8	10	10					89	7	7	-8	0	0	8	9	9
WFDE1	DME: F Wood, Road DICI 2002	183	5	5	196	21	26	379	28	32	11	6	6					126	4	4	-111	3	23	15	4	20
	DICI 2010 no DPF	161	7	7	172	19	23	333	27	31	10	7	7					110	5	5	-98	2	20	12	5	17
	DICI hybrid n DPF	129	10	10	138	15	18	267	27	30	8	10	10					89	7	7	-78	2	16	10	8	12
BLDE1	DME: W Wood, Black liquor DICI 2002	183	5	5	101	8	9	284	12	13	6	6	6					126	4	4	-119	0	0	7	5	5
	DICI 2010 no DPF	161	7	7	89	7	8	250	13	14	5	7	7					110	5	5	-105	0	0	5	6	6
	DICI hybrid n DPF	129	10	10	71	6	7	200	15	16	4	10	10					89	7	7	-84	0	0	5	9	9

8 Compressed hydrogen (C-H₂)

8.1 C-H₂ from natural gas reforming and coal gasification

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO ₂ eq / km											
		Total						Fossil						TTW			WTT			WTW					
		TTW (MJ/100 km)			WTT (MJ/100 km)			WTW (MJ/100km)			WTW (MJ/100km)			Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
C-H₂ pathways																									
GMCH1	C-H ₂ EU-mix, O/S Ref	180	0	0	152	6	9	332	6	9															
	PISI 2002	180	0	0	152	6	9	332	6	9															
	PISI 2010	168	5	5	141	5	8	309	11	13															
	PISI hybrid	149	13	11	125	5	7	274	20	20															
	FC	94	12	12	79	3	5	173	17	18															
GPCH1a	C-H ₂ NG 7000 km, O/S Ref	180	0	0	199	30	14	379	30	14															
	PISI 2002	180	0	0	199	30	14	379	30	14															
	PISI 2010	168	5	5	185	28	13	353	34	19															
	PISI hybrid	149	13	11	164	25	11	313	41	26															
	FC	94	12	12	104	16	7	198	31	23															
GPCH1b	C-H ₂ NG 4000 km, O/S Ref	180	0	0	171	16	10	351	16	10															
	PISI 2002	180	0	0	171	16	10	351	16	10															
	PISI 2010	168	5	5	159	15	9	327	20	15															
	PISI hybrid	149	13	11	141	13	8	290	28	22															
	FC	94	12	12	89	8	5	183	22	20															
GPCH2a	C-H ₂ NG 7000 km, Cen ref, Pipe	180	0	0	154	26	14	334	26	14															
	PISI 2002	180	0	0	154	26	14	334	26	14															
	PISI 2010	168	5	5	144	24	13	311	29	18															
	PISI hybrid	149	13	11	127	21	11	276	35	24															
	FC	94	12	12	81	13	7	175	26	21															
GPCH2b	C-H ₂ NG 4000 km, Cen Ref, Pipe	180	0	0	129	15	8	309	15	8															
	PISI 2002	180	0	0	129	15	8	309	15	8															
	PISI 2010	168	5	5	120	14	7	287	19	12															
	PISI hybrid	149	13	11	106	12	7	255	25	18															
	FC	94	12	12	67	8	4	161	20	17															
GPCH2bC	C-H ₂ NG 4000 km, Cen Ref, Pipe, CCS	180	0	0	139	15	8	319	15	8															
	PISI 2002	180	0	0	139	15	8	319	15	8															
	PISI 2010	168	5	5	129	14	8	297	19	13															
	PISI hybrid	149	13	11	115	12	7	263	25	19															
	FC	94	12	12	73	8	4	167	20	18															
GPCH3b	C-H ₂ NG 4000 km, Cen Ref, Road	180	0	0	129	15	9	309	15	9															
	PISI 2002	180	0	0	129	15	9	309	15	9															
	PISI 2010	168	5	5	120	14	8	288	19	13															
	PISI hybrid	149	13	11	107	13	7	255	25	19															
	FC	94	12	12	67	8	5	161	20	17															
GPLCHb	C-H ₂ NG 4000 km, Cen Ref, Liq, Road, Vap/comp.	180	0	0	230	26	15	410	26	15															
	PISI 2002	180	0	0	230	26	15	410	26	15															
	PISI 2010	168	5	5	214	24	14	382	31	21															
	PISI hybrid	149	13	11	190	21	13	338	40	29															
	FC	94	12	12	120	13	8	214	30	25															
GRCH1	C-H ₂ LNG, O/S Ref	180	0	0	202	7	8	382	7	8															
	PISI 2002	180	0	0	202	7	8	382	7	8															
	PISI 2010	168	5	5	188	7	8	355	13	14															
	PISI hybrid	149	13	11	166	6	7	315	24	22															
	FC	94	12	12	105	4	4	199	20	21															
GRCH2	C-H ₂ LNG, Cen Ref, Pipe	180	0	0	157	6	8	337	6	8															
	PISI 2002	180	0	0	157	6	8	337	6	8															
	PISI 2010	168	5	5	146	6	8	313	11	13															
	PISI hybrid	149	13	11	129	5	7	278	21	20															
	FC	94	12	12	82	3	4	176	18	18															
GRCH3	C-H ₂ Rem NG, methanol, O/S Ref	180	0	0	202	4	7	382	4	7															
	PISI 2002	180	0	0	202	4	7	382	4	7															
	PISI 2010	168	5	5	188	3	7	355	10	13															
	PISI hybrid	149	13	11	166	3	6	315	22	22															
	FC	94	12	12	105	2	4	199	19	20															
KOCH1	C-H ₂ Coal EU-mix, cen Ref, Pipe	180	0	0	252	0	0	432	0	0															
	PISI 2002	180	0	0	252	0	0	432	0	0															
	PISI 2010	168	5	5	234	0	0	402	9	9															
	PISI hybrid	149	13	11	207	0	0	356	22	19															
	FC	94	12	12	131	0	0	225	20	20															
KOCH1C	C-H ₂ Coal EU-mix, cen Ref, Pipe, CCS	180	0	0	319	0	0	499	0	0															
	PISI 2002	180	0	0	319	0	0	499	0	0															
	PISI 2010	168	5	5	297	0	0	464	10	10															
	PISI hybrid	149	13	11	263	0	0	412	26	23															
	FC	94	12	12	167	0	0	261	23	23															
	FC hybrid	84	10	10	148	0	0	232	21	21															

8.2 C-H₂ from biomass processing

WTT Code	Powertrain	Energy MJ / 100 km									GHG g CO _{2e} / km											
		Total						Fossil			TTW			WTT			WTW					
		Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max			
WWCH1	C-H2: W Wood, O/S gasif	180	0	0	220	16	20	400	16	20	34	2	3	0	0	0	19	0	0	19	0	0
	PISI 2002	168	5	5	204	15	18	372	21	25	32	6	6	0	0	0	18	0	0	18	1	1
	PISI 2010	149	13	11	181	13	16	330	31	32	28	14	12	0	0	0	16	0	0	16	1	1
	PISI hybrid	94	12	12	115	8	10	209	25	27	18	12	12	0	0	0	10	0	0	10	1	1
	FC	84	10	10	102	7	9	186	22	24	16	11	11	0	0	0	9	0	0	9	1	1
WWCH2	C-H2: W Wood, Cen gasif, Pipe	180	0	0	175	13	15	355	13	15	41	3	4	0	0	0	22	0	0	22	0	0
	PISI 2002	168	5	5	162	12	14	330	18	20	38	6	7	0	0	0	20	0	0	21	1	1
	PISI 2010	149	13	11	144	11	13	293	27	26	34	14	13	0	0	0	18	0	0	18	2	2
	PISI hybrid	94	12	12	91	7	8	185	21	22	22	12	12	0	0	0	11	0	0	11	2	2
	FC	84	10	10	81	6	7	165	19	20	19	11	11	0	0	0	10	0	0	10	1	1
WFCH1	C-H2: W Wood, O/S gasif	180	0	0	224	19	18	404	19	18	39	3	3	0	0	0	27	3	22	27	3	22
	PISI 2002	168	5	5	208	17	17	376	24	23	36	6	6	0	0	0	25	2	20	25	3	21
	PISI 2010	149	13	11	185	15	15	333	34	31	32	14	12	0	0	0	22	2	18	22	4	20
	PISI hybrid	94	12	12	117	10	9	211	27	26	20	12	12	0	0	0	14	1	11	14	3	13
	FC	84	10	10	104	9	8	188	24	23	18	11	11	0	0	0	12	1	10	12	3	12
WFCH2	C-H2: F Wood, Cen gasif, pipe	180	0	0	175	13	14	355	13	14	41	3	3	0	0	0	25	1	18	25	1	18
	PISI 2002	168	5	5	162	12	13	330	18	19	38	6	7	0	0	0	23	1	17	24	2	17
	PISI 2010	149	13	11	144	11	12	292	27	25	34	14	12	0	0	0	20	1	15	21	3	16
	PISI hybrid	94	12	12	91	7	7	185	22	22	22	12	12	0	0	0	13	1	9	13	2	11
	FC	84	10	10	81	6	7	165	19	19	19	11	11	0	0	0	12	1	8	12	2	10
BLCH1	C-H2: W Wood, Black liquor	180	0	0	92	7	8	272	7	8	37	3	3	0	0	0	18	0	0	18	0	0
	PISI 2002	168	5	5	86	7	7	253	10	11	34	6	6	0	0	0	17	0	0	17	1	1
	PISI 2010	149	13	11	76	6	6	224	10	17	30	14	12	0	0	0	15	0	0	15	1	1
	PISI hybrid	94	12	12	48	4	4	142	15	15	19	12	12	0	0	0	9	0	0	9	1	1
	FC	84	10	10	43	3	4	126	13	13	17	11	11	0	0	0	8	0	0	8	1	1

8.3 C-H₂ from electrolysis (all electricity sources)

WTT Code	Powertrain	Energy MJ / 100 km									GHG g CO _{2e} / km											
		Total						Fossil			TTW			WTT			WTW					
		Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max			
GP1a/CH1	C-H2: NG 7000 km, CCGT, O/S Ely	180	0	0	490	75	21	670	75	21				0	0	0	406	45	13	406	45	13
	PISI 2002	168	5	5	456	70	19	623	84	33				0	0	0	377	41	12	378	53	23
	PISI 2010	149	13	11	404	62	17	552	98	49				0	0	0	335	37	11	335	65	36
	PISI hybrid	94	12	12	256	39	11	350	72	44				0	0	0	212	23	7	212	49	33
	FC	84	10	10	228	35	10	311	64	39				0	0	0	189	21	6	189	44	29
GP1b/CH1	C-H2: NG 4000 km, CCGT, O/S Ely	180	0	0	433	43	29	613	43	29				0	0	0	364	25	17	364	25	17
	PISI 2002	168	5	5	402	40	27	570	52	40				0	0	0	339	24	16	339	34	26
	PISI 2010	149	13	11	357	35	24	505	67	52				0	0	0	300	21	14	301	47	37
	PISI hybrid	94	12	12	226	22	15	320	51	44				0	0	0	190	13	9	190	37	32
	FC	84	10	10	201	20	14	285	46	40				0	0	0	169	12	8	169	33	29
GP1b/CH2	C-H2: NG 4000 km, CCGT, Cen Ely, Pipe	180	0	0	442	47	34	622	47	34				0	0	0	364	28	20	364	28	20
	PISI 2002	168	5	5	411	44	32	578	56	44				0	0	0	339	26	19	339	36	29
	PISI 2010	149	13	11	364	39	28	513	71	57				0	0	0	300	23	17	301	49	39
	PISI hybrid	94	12	12	231	24	18	325	54	47				0	0	0	190	15	10	190	38	34
	FC	84	10	10	205	22	16	289	48	42				0	0	0	169	13	9	169	34	30
GREL1/CH1	C-H2: LNG, O/S Ely	180	0	0	495	43	45	675	43	45				0	0	0	396	25	26	396	25	26
	PISI 2002	168	5	5	460	40	42	628	54	56				0	0	0	366	23	24	369	34	36
	PISI 2010	149	13	11	408	36	37	557	72	69				0	0	0	327	21	22	327	49	47
	PISI hybrid	94	12	12	258	23	24	352	55	56				0	0	0	207	13	14	207	38	39
	FC	84	10	10	230	20	21	314	49	50				0	0	0	184	12	12	184	34	35
WF2/CH1	C-H2: F Wood, 200 MW gasif, CCGT, O/S Ely	180	0	0	469	38	39	649	38	39	14	1	1	0	0	0	23	6	16	23	6	16
	PISI 2002	168	5	5	436	35	37	603	48	50	13	5	5	0	0	0	21	5	15	22	6	16
	PISI 2010	149	13	11	386	31	32	535	66	63	11	13	11	0	0	0	19	5	13	19	6	15
	PISI hybrid	94	12	12	245	20	21	339	51	52	7	12	12	0	0	0	12	3	9	12	4	10
	FC	84	10	10	218	18	18	301	45	46	6	10	10	0	0	0	11	3	8	11	4	9
WF3/CH1	C-H2: F Wood, Conv power, O/S Ely	180	0	0	797	68	52	977	68	52	20	2	1	0	0	0	56	9	24	56	9	24
	PISI 2002	168	5	5	741	64	49	909	86	71	19	5	5	0	0	0	52	8	22	52	10	24
	PISI 2010	149	13	11	657	56	43	806	114	94	17	13	12	0	0	0	46	7	20	46	11	23
	PISI hybrid	94	12	12	416	36	27	510	87	79	11	12	12	0	0	0	29	5	12	29	8	16
	FC	84	10	10	370	32	24	454	78	70	9	10	10	0	0	0	26	4	11	26	7	14
EM1/CH1	C-H2: Elec EU-mix, O/S Ely	180	0	0	652	31	31	833	31	31				0	0	0	375	14	14	375	14	14
	PISI 2002	168	5	5	607	29	29	774	47	47				0	0	0	349	13	13	349	23	23
	PISI 2010	149	13	11	538	26	25	686	73	67				0	0	0	309	11	11	310	38	35
	PISI hybrid	94	12	12	340	16	16	434	59	59				0	0	0	196	7	7	196	31	31
	FC	84	10	10	303	14	14	387	53	52				0	0	0	174	6	6	174	28	28
KO1/CH1	C-H2: Elec coal EU-mix, O/S Ely	180	0	0	571	96	76	751	96	76				0	0	0	763	85	90	763	85	90
	PISI 2002	168	5	5	531	89	71	699	105	87				0	0	0	709	79	84	710	101	105
	PISI 2010	149	13	11	471	79	63	619	120	99				0	0	0	629	70	74	629	124	122
	PISI hybrid	94	12	12	298	50	40	392	87	77				0	0	0	398	44	47	398	93	96
	FC	84	10	10	265	45	36	349	78	69				0	0	0	354	40	42	354	83	85
KO1/CH2	C-H2: Elec coal EU-mix, Cen Ely, Pipe	180	0	0	571	96	76	751	96	76				0	0	0	763	85	90	763	85	90
	PISI 2002	168	5	5	531	89	71	699	105	87				0	0	0	709	79	84	710	101	105
	PISI 2010	149	13	11	471	79	63	619	120	99				0	0	0	629	70	74	629	124	122
	PISI hybrid	94	12	12	298	50	40	392	87	77				0	0	0	398	44	47	398	93	96
	FC	84	10	10	265	45	36	349	78	69				0	0	0	354	40	42	354	83	85
NU1/CH1	C-H2: Elec nuclear, O/S Ely	180	0	0	905	48	48	1085	48	48				0	0	0	19	1	1	13	1	1
	PISI 2002	168	5	5	842	45	45	1010	70	70				0	0	0	12	1	1	12		

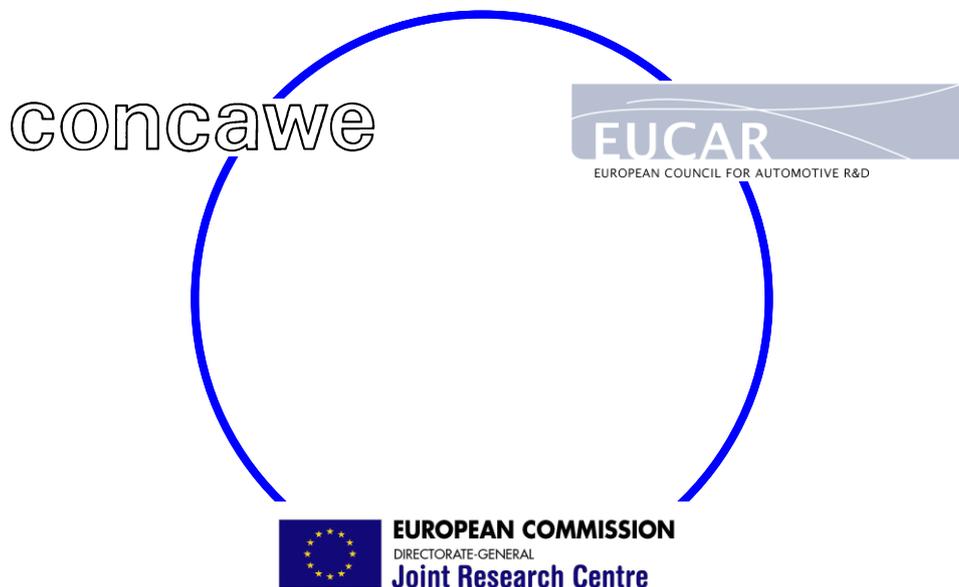
9 Liquid hydrogen (L-H₂)

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2e} / km											
		Total						Fossil						TTW			WTT			WTT					
		TTW (MJ/100 km)			WTT (MJ _e /100 km)			WTT (MJ/100km)			WTT (MJ _e /100km)			Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max
L-H2 pathways																									
GPLH1a	L-H2:NG 7000 km, Cen Ref, Liq, Road	180	0	0	240	40	6	420	40	6							0	0	0	253	23	4	253	23	4
	PISI 2002	168	5	5	223	37	6	391	44	14				0	0	0	236	21	4	236	28	11			
	PISI 2010	141	11	12	188	31	5	330	47	24				0	0	0	199	18	3	199	33	20			
	PISI hybrid	94	12	12	125	21	3	219	38	22				0	0	0	132	12	2	132	28	18			
	FC	84	10	10	111	18	3	195	34	20				0	0	0	116	11	2	116	25	16			
GPLH1b	L-H2: NG 4000 km, Cen Ref, Liq, Road	180	0	0	204	25	15	384	25	15				0	0	0	227	15	9	227	15	9			
	PISI 2002	168	5	5	190	23	14	357	29	20				0	0	0	212	14	8	212	20	15			
	PISI 2010	141	11	12	160	19	12	302	33	28				0	0	0	179	11	7	179	25	22			
	PISI hybrid	94	12	12	107	13	8	201	28	24				0	0	0	119	8	5	119	22	19			
	FC	84	10	10	95	11	7	179	25	21				0	0	0	106	7	4	106	20	17			
GRLH1	L-H2: Rem Ref, Liq, Sea, Road	180	0	0	256	22	27	437	22	27				0	0	0	250	13	15	250	13	15			
	PISI 2002	168	5	5	238	21	25	406	28	32				0	0	0	232	12	14	233	19	21			
	PISI 2010	141	11	12	201	18	21	343	35	40				0	0	0	196	10	12	197	25	29			
	PISI hybrid	94	12	12	134	12	14	228	30	32				0	0	0	130	7	8	130	23	24			
	FC	84	10	10	119	10	12	203	27	29				0	0	0	116	6	7	116	20	21			
GRLH2	L-H2: LNG, Cen Ref, Liq, Road	180	0	0	241	21	23	421	21	23				0	0	0	247	12	13	247	12	13			
	PISI 2002	168	5	5	224	19	21	392	26	28				0	0	0	229	11	12	230	18	19			
	PISI 2010	141	11	12	189	16	18	331	32	36				0	0	0	194	9	10	194	24	27			
	PISI hybrid	94	12	12	126	11	12	220	29	30				0	0	0	129	6	7	129	22	23			
	FC	84	10	10	112	10	11	196	25	26				0	0	0	115	6	6	115	20	20			
WFLH1	L-H2: Wood F, Cen gasif, Liq, Road	180	0	0	270	30	24	450	30	24	12	1	1	0	0	0	16	3	9	15	3	9			
	PISI 2002	168	5	5	251	28	22	418	36	30	11	5	5	0	0	0	14	2	8	14	3	9			
	PISI 2010	141	11	12	212	24	19	353	41	39	9	11	12	0	0	0	11	2	7	12	3	8			
	PISI hybrid	94	12	12	141	16	13	235	35	32	6	12	12	0	0	0	8	1	5	8	2	5			
	FC	84	10	10	125	14	11	209	31	28	5	10	10	0	0	0	7	1	4	7	2	5			
GPPEL1b/LH1	L-H2: NG 4000 km, CCGT, Cen Ely, Liq, Road	180	0	0	516	53	30	696	53	30				0	0	0	415	31	18	415	31	18			
	PISI 2002	168	5	5	480	49	28	647	64	43				0	0	0	386	29	17	386	40	28			
	PISI 2010	141	11	12	405	41	24	546	73	60				0	0	0	325	24	14	326	49	42			
	PISI hybrid	94	12	12	269	28	16	363	62	50				0	0	0	216	16	9	216	43	36			
	FC	84	10	10	240	25	14	323	52	45				0	0	0	193	14	8	193	38	32			
EMEL1/LH1	L-H2: Elec EU-mix, Cen Ely, Liq, Road	180	0	0	761	38	36	941	38	36				0	0	0	425	17	16	425	17	16			
	PISI 2002	168	5	5	708	35	33	875	56	55				0	0	0	395	16	15	396	28	27			
	PISI 2010	141	11	12	597	30	28	739	76	80				0	0	0	334	13	13	334	39	41			
	PISI hybrid	94	12	12	397	20	19	491	69	68				0	0	0	222	9	8	222	36	36			
	FC	84	10	10	354	17	17	437	62	61				0	0	0	197	8	7	197	32	32			
KOEL1/LH1	L-H2: Elec coal EU-mix, Cen Ely, Liq, Road	180	0	0	672	99	77	852	99	77				0	0	0	854	79	101	854	79	101			
	PISI 2002	168	5	5	625	93	72	793	111	91				0	0	0	795	73	94	795	97	118			
	PISI 2010	141	11	12	528	78	61	669	119	107				0	0	0	671	62	80	671	113	137			
	PISI hybrid	94	12	12	351	52	40	445	96	84				0	0	0	446	41	53	446	96	108			
	FC	84	10	10	312	46	36	396	85	75				0	0	0	397	37	47	397	85	96			

10 Summary of pathways with CCS

WTT Code	Powertrain	Energy MJ / 100 km												GHG g CO _{2e} / km												
		Total						Fossil						TTW			WTT			WTW						
		TTW (MJ/100 km)			WTT (MJ/100 km)			WTW (MJ/100km)			WTW (MJ/100km)			Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	
CCS pathways																										
GRCG1C	CNG: LNG, Vap - Pipe - CCS	227	12	6	72	5	6	299	15	10																
	PISI bi-fuel 2002	223	14	6	71	5	6	294	17	10																
	PISI dedicated 2002	188	12	8	60	5	5	248	14	11																
	PISI bi-fuel 2010	187	13	8	60	5	5	247	15	11																
	PISI dedicated 2010	139	12	13	44	3	4	184	14	15																
	PISI hybrid																									
GPCH2bC	C-H2: NG 4000 km, Cen Ref, Pipe, CCS	180	0	0	139	15	8	319	15	8																
	PISI 2002	168	5	5	129	14	8	297	18	13																
	PISI 2010	149	13	11	115	12	7	263	25	19																
	PISI hybrid	94	12	12	73	8	4	167	20	18																
	FC	84	10	10	65	7	4	148	18	16																
	FC hybrid																									
KOCH1C	C-H2: Coal EU-mix, cen Ref, Pipe, CCS	180	0	0	319	0	0	499	0	0																
	PISI 2002	168	5	5	297	0	0	464	10	10																
	PISI 2010	149	13	11	263	0	0	412	26	23																
	PISI hybrid	94	12	12	167	0	0	261	23	23																
	FC	84	10	10	148	0	0	232	21	21																
	FC hybrid																									
GRSD2C	Syn-diesel: Rem GTL, Sea, Rail/Road, CCS	183	5	5	139	9	11	323	14	16																
	DICI 2002	161	7	7	123	8	9	284	15	16																
	DICI 2010 no DPF	166	7	7	126	8	10	292	15	17																
	DICI 2010 DPF	129	10	10	98	6	8	227	17	18																
	DICI hybrid n DPF	133	10	10	101	7	8	234	18	19																
	DICI hybrid DPF																									
KOSD1C	Syn-diesel: CTL, CCS, Diesel mix	183	5	5	194	14	14	377	20	21																
	DICI 2002	161	7	7	170	12	13	331	21	21																
	DICI 2010 no DPF	166	7	7	175	13	13	341	21	22																
	DICI 2010 DPF	129	10	10	136	10	10	265	23	23																
	DICI hybrid n DPF	133	10	10	141	10	10	274	23	24																
	DICI hybrid DPF																									
GRDE1C	DME: Rem Syn, Sea, Rail/Road, CCS	183	5	5	99	0	12	282	6	16																
	DICI 2002	161	7	7	87	0	11	248	8	16																
	DICI 2010 no DPF	129	10	10	70	0	9	199	11	17																
	DICI hybrid n DPF																									

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



Appendix 2

Version 3c, July 2011

<http://iet.jrc.ec.europa.eu/about-jec>
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This report is available as an ADOBE pdf file on the JRC/IES website at:

<http://iet.jrc.ec.europa.eu/about-jec>

Questions and remarks may be sent to:

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Notes on version number:

This document reports on the third release of this study replacing version 2c published in March 2007. The original version 1b was published in December 2003.

This is a partial revision of version 2c in that it does not include an update of section 8 on cost and availability.

WTW GHG-Emissions of Externally Chargeable Electric Vehicles

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1 Abbreviations

The following terms and abbreviations are used within this appendix. In many cases they are explained in more detail at the relevant text passages, where they are introduced or defined or explained.

Abbreviation	Description
BEV	Battery Electric Vehicle
cd	Charge depleting: test condition when vehicle test is started with battery at maximum level of battery state of charge. During test, battery energy is depleted until minimum state of charge is reached and vehicle switches to charge sustaining operation mode.
cs	Charge sustaining: test condition when vehicle test is started with battery at minimum level of battery state of charge. During test, battery charge is sustained within certain limits, defined by manufacturer's calibration strategy.
EE	Electric Energy Consumption
E-REV	Extended Range Electric Vehicle
FC	Fuel Consumption
FCEV	Fuel Cell Electric Vehicle
GHG	Greenhouse Gas
HEV	Hybrid Electric Vehicle
ICE	Internal Combustion Engine Vehicle
NOVC HEV	Not Off-Vehicle Chargeable HEV = not externally chargeable HEV
OEM	Original Equipment Manufacturer (in our context: vehicle manufacturers)
OVC HEV	Off-Vehicle Chargeable HEV = externally chargeable HEV
SOC	State Of Charge
UN ECE	United Nations Economic Commission for Europe
xEV	Umbrella term for all considered electric vehicle concepts: PHEV + E-REV + BEV + FCEV. FCEV are excluded in this report, they are covered in the WTW study

2 Introduction

Version 2 of the WTW study exclusively dealt with conventional internal combustion vehicle (ICEV) and hybrid electric vehicle (HEV) and FCEV concepts, which don't have the capability to store externally generated electricity onboard.

Due to global climate challenges and the high reliance of the road transport sector on fossil fuels, the automotive industry increasingly investigates further sustainable propulsion alternatives:

- to reduce the dependence on petroleum,
- to expand the global energy portfolio and
- to reduce the carbon footprint of driving

Therefore the OEM's advanced propulsion strategies are aiming at increased fuel efficiency (reduction of fossil fuel consumption) and energy diversity (displacement of fossil fuels).

Based on the accelerated technological development and affordability of electric energy storing devices (e.g. Li-Ion batteries), electrification concepts of the automobile are becoming increasingly important in this respect. This leads to a range of new electrified vehicle and powertrain concepts that will enter the market in the foreseeable future.

As these vehicle concepts will use electricity from the grid as sole energy source or in addition to the on-board stored consumable (liquid or gaseous) fuel, the GHG methodology of current WTW study must be extended to take into account the GHG-emissions of the utilized grid energy in order to determine the GHG emissions of such vehicle concepts.

To be able to compare the GHG balance of externally chargeable electric vehicles that can store a certain amount of externally generated energy onboard for the use of mechanical propulsion, it is necessary to take account of the GHG-emissions of the utilized electric energy from the grid.

This appendix explores the methodology to assess the GHG emissions of certain externally chargeable electric vehicle concepts with different levels of utilization of grid electricity:

- PHEV: an externally chargeable hybrid electric vehicle with limited electric performance and electric range ("urban capable" PHEV), although the possibility to drive in electric mode is expanded by the possibility to plug the battery on the grid
- E-REV: externally chargeable hybrid electric vehicle with full performance in electric mode and with an auxiliary ICE engine for extended range
- BEV: a pure battery electric vehicle since there is no ICE, but only an electric motor to propel the vehicle, with full performance in electric mode and enlarged - but still limited - electric range

3 Approach

The vehicle data for the reference vehicles in the initial WTW study was simulated based on defined performance criteria of an average compact size vehicle.

Currently the automotive industry gains first experience with different electrified vehicle concept layouts (“xEV”), system architectures, operating strategies for the use of electric propulsion parts, component and battery properties and future possibilities. Therefore no final picture for a generic modeling of reference vehicles like in the initial WTW study is currently available.

The vehicle data utilized for the GHG calculations of the considered electric vehicle concepts (xEV: = PHEV + E-REV + BEV) is based on the experience of OEMs with current prototypes and development vehicles.

As all the different xEV concepts are very much differing in the way they are designed (degree of electrification; targeted customer group; basic vehicle architecture; utilization of additional CO₂-efficiency measures like light weight design and aero dynamic measures; calibration strategies), it was not possible to generate one dataset for each electric vehicle category.

Therefore for each electric vehicle category a range of the relevant parameters (e.g. electric energy consumption; fuel consumption; battery capacity; electric driving range) was defined. This range of parameter reflects the experience with the various xEV concepts currently followed by the OEMs. However it must be considered, that the communicated numbers are less mature than the ones simulated for conventional vehicles, and therefore reflect a lower level of confidence.

For this reason, further updates of this WTW study will consider to model and simulate the electric vehicle concepts more accurately. At that point in time there may also be more reliable data available of first serial production electric vehicle concepts to verify the assumptions taken within this appendix.

Nevertheless the results of the appendix at hand should allow the interested parties and policy makers to generally assess the benefits as well as the limitations of electrifying the road transport sector with respect to energy usage and to GHG emissions.

The methodology to assess the GHG emissions of xEV concepts is based on the official test procedure UN ECE R101 that is used to certify fuel consumption, electric energy consumption, range and CO₂-emissions of electrified vehicle concepts (including PHEV, E-REV, BEV) on a TTW basis.

By this, the GHG emissions of xEV can be compared to the ones of conventional vehicles.

For simplification reasons, the assessment is restricted according to following considerations:

- Currently only externally chargeable hybrid electric vehicles (“OVC HEV”) with gasoline engine are considered, diesel OVC HEV are not yet considered

- OVC HEV are only compared to fossil fuel (gasoline) – impact of biofuels is not considered in calculation/comparison
- Fuel Cell vehicles are not considered in this appendix (they are already covered in the initial study)
- Auxiliaries and their energy consumption are not considered as they are not considered in the test procedure (consistently with WTW methodology)

- The data range for xEV categories reflects a compact size vehicle similar to the reference vehicle of the initial WTW study. However, based on the additional weight of the traction battery, the xEV concepts are about 200kg – 300kg heavier than the reference vehicle.
- There is a smooth transition between the three considered xEV categories. Depending on the degree of certain design characteristics, an xEV could be assigned to different categories or fall in between two categories (e.g. a PHEV with a strong electric driving performance and a high electric range could also be considered an E-REV)

The basic assumptions about the vehicle configurations are outlined in more detail in chapter 8.

4 Definition of externally chargeable HEVs and pure battery electric vehicles BEVs

Conventional hybrid electric vehicles (HEV) draw their propulsion energy exclusively from a consumable fuel stored onboard the vehicle. In contrast, externally chargeable HEVs can draw a part of their propulsion energy from electric energy that was generated outside the vehicle and is stored onboard the vehicle in a battery. Finally, pure battery electric vehicles draw their complete propulsion energy from externally produced electricity that is stored onboard (see *Table 4-1* and Figure 4-2).

Table 4-1: Vehicle- and Powertrain- Configurations considered in WTW study – with new items #4 and #5 added with WTW Appendix 2

		Energy Source		Abbreviation Synonym	Name / Description
		external energy sources - stored onboard	internally generated energy - stored onboard		
WTW V2	1		consumable fuel	-	ICEV Internal Combustion Engine Vehicle
	2		consumable fuel	electricity: - regenerative braking - generated onboard from consumable fuel	NOVC HEV Not Off-Vehicle Chargeable HEV
	3		consumable fuel	in case of FC HEV: electricity: - regenerative braking - generated onboard from consumable fuel	FCEV Fuel Cell Electric Vehicle
WTW V3	4		consumable fuel	electricity: - regenerative braking - generated onboard from consumable fuel	OVC HEV Off-Vehicle Chargeable HEV
			electricity		PHEV Plug-In HEV
	5		electricity	electricity: - regenerative braking	E-REV Extended-Range EV
				BEV Battery Electric Vehicle	

Regarding externally chargeable HEVs (“off-vehicle charging HEV”, OVC HEV), it is necessary to further distinguish several unique powertrain configurations, that show different vehicle characteristics and efficiencies.

4.1 Plug-In HEV ('PHEV')

In general PHEV are conventional HEV with off-board charging capability. PHEV are in most cases mainly propelled by the combustion engine, with some support by the electric motor and limited capability of pure electric driving. Normally these PHEV are derived from conventional full hybrid architectures with an increased battery capacity. Therefore they show limited benefits by underlying constraints of the base hybrid system if a conventional full hybrid architecture is the base. The propulsion system is designed to share electric and combustion energy and has therefore a limited electric performance for urban driving conditions only. There are different operating strategies for PHEV:

- PHEV with Initial EV Operation: starts as an EV then switches to hybrid operation. Always requires engine on for full performance

- PHEV with blended operation: starts and drives like a conventional hybrid with engine on

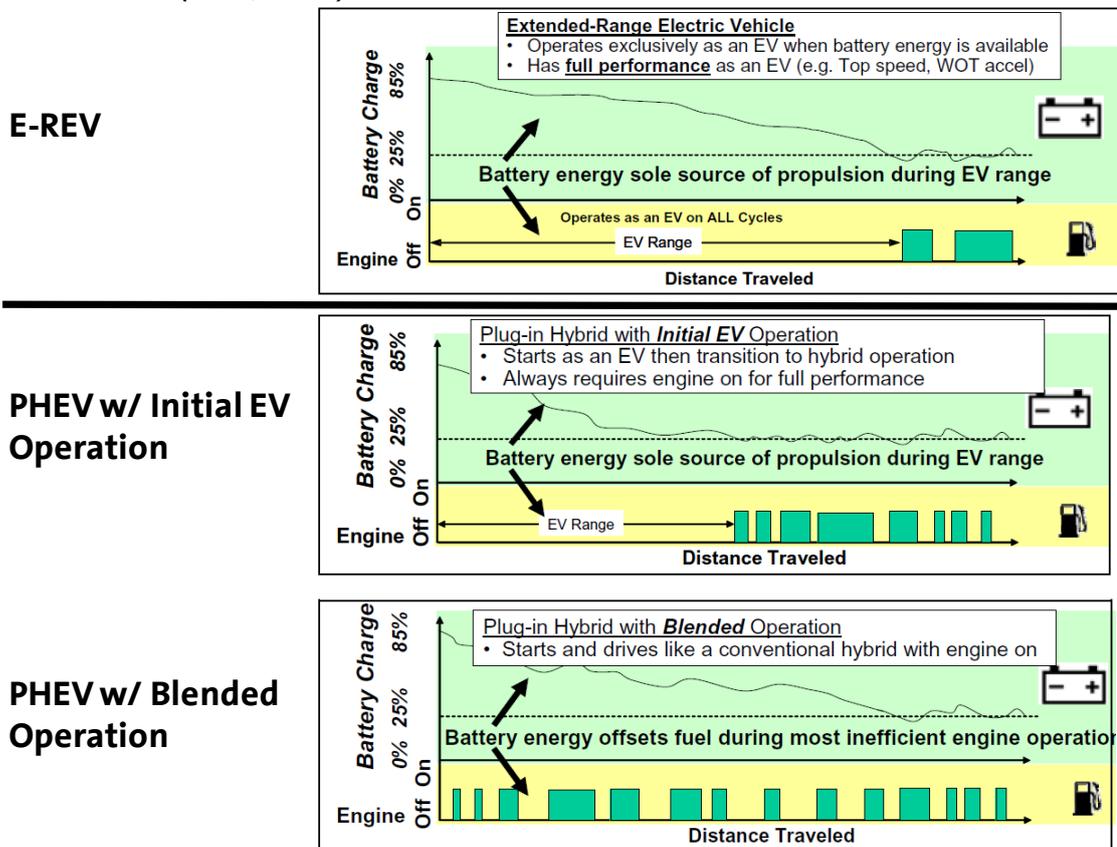
4.2 Extended-Range Electric Vehicle ('E-REV')

In contrast to PHEVs, an E-REV operates as an electric vehicle when battery energy is available with full performance provided by the electric drive train exclusively. The auxiliary energy supply, which can be a small combustion engine or a fuel cell, is only engaged when the energy from battery is not available. Thus the generator/combustion engine can be operated at a favorable engine speed range with high efficiencies in the charge sustaining driving condition, as the vehicle is predominantly propelled by the electric motor. However, the total efficiency of such a concept is also impacted by the efficiency of transformation from mechanical to electric to mechanical energy.

An electric vehicle with range extender potentially offers the opportunity to overcome the “range anxiety” that customers might experience with pure electric vehicles, and thereby increases the acceptance for electric vehicle concepts, if the total efficiency is sufficient.

Figure 4-1 explains the different OVC concepts based on the battery state of charge profile and the combustion engine operation profile.

Figure 4-1: Explanation of OVC concepts based on the battery state of charge profile and the combustion engine operation profile (SAE, 2008)



4.3 Battery Electric Vehicles BEV

A battery electric vehicle is solely propelled by an electric motor and has no additional combustion engine or fuel cell on board. If the battery energy is depleted, the vehicle cannot be moved further until the battery is recharged or changed.

4.4 Utilization of the different OVC HEV architectures

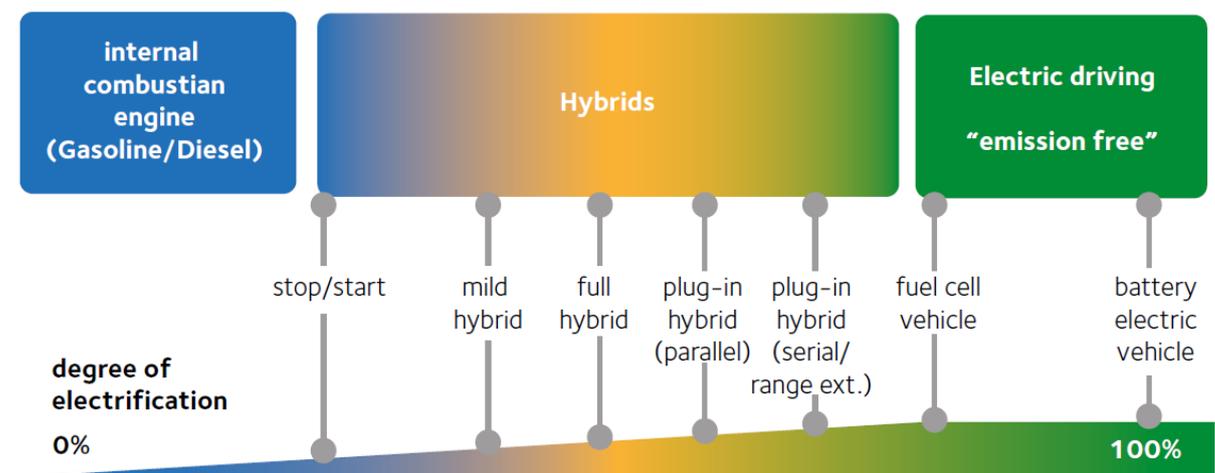
There are different reasons for choosing a certain electrification concept. As PHEVs are mainly based on conventional hybrid architecture with limited possibility to utilize onboard stored electric energy, the main focus of these concepts is keeping the main properties of conventional vehicles but displace a certain amount of fossil fuel. The degree of the limit depends on the used battery capacity, however. PHEVs are a further step towards an “emission free” electric driving.

The next step to reach this goal is an Electric Vehicle with Range Extender (E-REV). An Electric Vehicle with Range-Extender (E-REV) offers potentially the advantage to overcome the range anxiety. Both concepts, PHEVs and E-REV are actually a bridge and enabler of future electric vehicle mobility, as it eliminates the problem whether first to install the charging infrastructure or to bring the vehicle technology to the market. These concepts allow designing hybrid electric vehicles that are fully suitable for daily use without restrictions regards range or trunk capacity.

E-REV with full electric performance offers the opportunity of purely electric propulsion if operated in charge depleting mode.

Finally, BEV enables purely electric propulsion without local emissions in use. Nevertheless, based on the current battery technology limitations, there are some restrictions regarding usages under all conditions. Therefore this concept currently is mainly of interest for urban vehicle configurations.

Figure 4-2: *Electrification of the Powertrain (EUCAR, 2009)*



5 Methodology to assess GHG-emissions from externally chargeable HEVs

The total GHG balance of off-vehicle charging HEV (OVC HEV) and electric vehicles is not only determined by the consumption of an onboard stored consumable fuel, but also by the origin of the consumed electric energy that was produced outside of the vehicle and stored onboard.

This creates the need to establish a methodology to assess the overall WTW GHG emissions of OVC HEV to make them comparable to conventional vehicles and conventional hybrid electric vehicles.

5.1 Standardized Measurement Procedure for HEV

The TTW emissions of conventional vehicles and HEV are determined by the application of the standard European driving cycle (NEDC) and the related measurement procedures according to the applicable regulation UN ECE R101.

For the purpose of certification of externally chargeable HEV, regulators have also laid down rules to determine the fuel consumption, CO₂-emissions, electric energy consumption and electric range. The measurement procedure is similar to the one for conventional combustion powertrains and the same test cycle (NEDC) is applied. Nevertheless, to account for the additional external electric energy consumed, the methodology had to be adapted as follows:

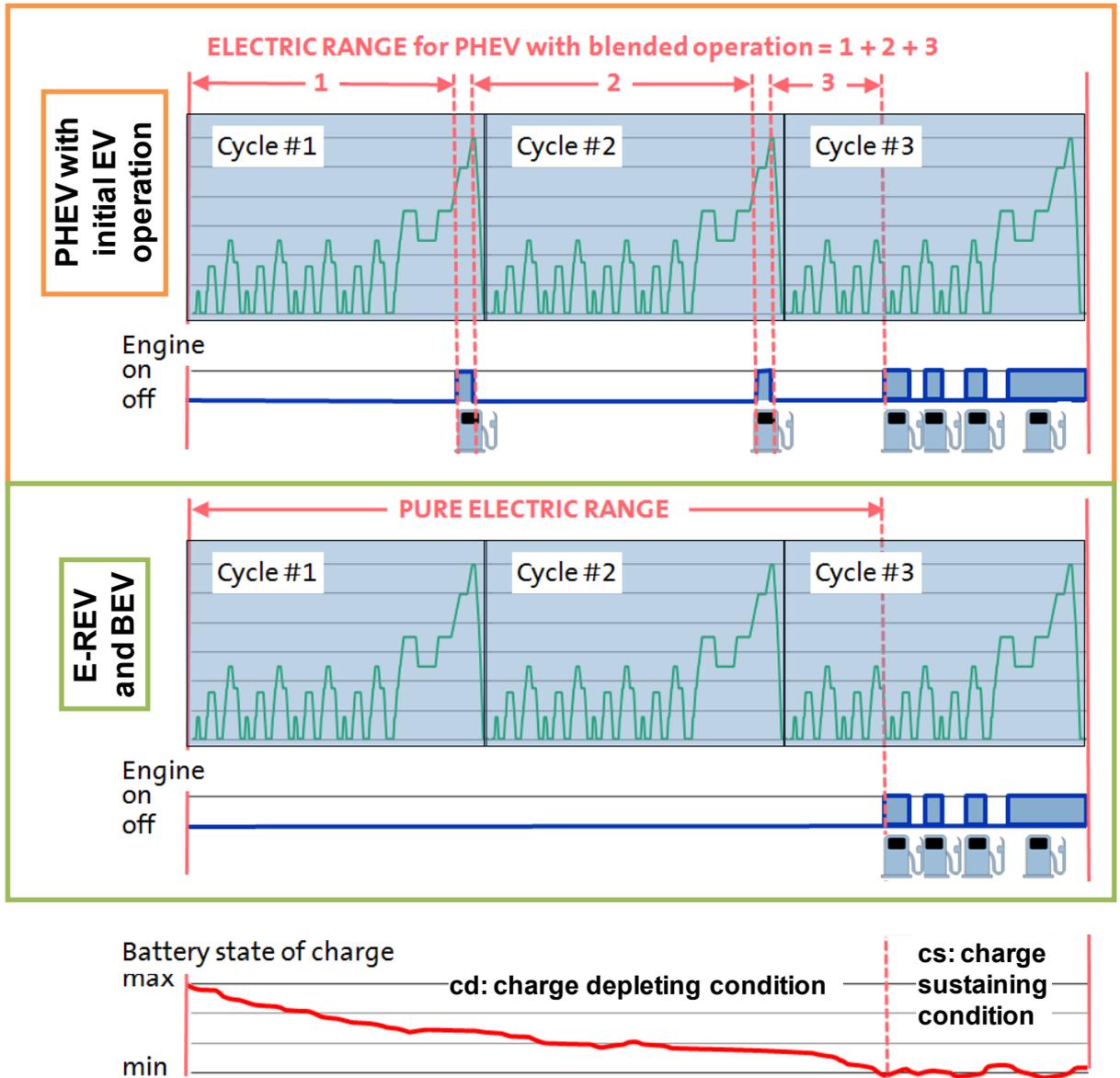
- for OVC HEV
 - In addition to the fuel consumption and CO₂-emissions values, the electric energy consumption is measured and the electric range is determined
 - The tests are carried out under two test conditions, determined by the battery “State of Charge” (SOC)
 - Weighted averages for: 1.) fuel consumption, 2.) CO₂-emissions and 3.) electric energy consumption are calculated from the results of these two test conditions
- for BEV
 - Only the electric energy consumption is measured and the electric range is determined
 - To determine the electric energy consumption, the BEV is tested by driving two consecutive NEDC cycles
 - The electric energy consumption is the average of the electric energy consumption for the test distance covered
 - There is no weighting of test results

5.1.1 Determination of the Range

For externally chargeable electric vehicle concepts (pure battery electric vehicles (BEV) and off-vehicle charging HEVs (OVC HEV), the legislation provides different possibilities to determine the range, depending on the operation strategy of the xEV (see *Figure 5-1*). The so called “OVC-range” gives an indication of the **total distance** covered until the energy imparted by external charging of the battery is depleted. In

contrast, the “Electric Range” determines the distance that can be driven **purely electrically** on one fully charged battery. The distance travelled with the ICE operating is excluded. This “Electric Range” is the relevant figure to consider when determining the electric energy consumption of xEV concepts and the related GHG emissions.

Figure 5-1: *Definition of electric range and operation modes (cd and cs) – illustrative example only, e.g. a BEV does not have the “engine on” option of course*



5.1.2 Fuel consumption, CO₂-emissions and electric energy consumption test procedure

Test procedure for OVC HEV

The vehicles are tested under two test conditions:

- Condition A – test with fully charged electrical energy/storage device: “charge depleting” condition (cd)
- Condition B – test with electrical energy/storage device at minimum SOC: “charge sustaining” (cs)

The test cycle is the same as for vehicles with ICE and NOVC HEV (“EU NEDC”).

For each of the two test conditions, the following values are determined:

1. Fuel Consumption (“FC”) for Cond. A
2. CO₂-Emissions (“CO₂”) for Cond. A
3. Electric Energy Consumption (“EE”) for Cond. A
4. FC for Cond. B
5. CO₂ for Cond. B
6. EE for Cond. B

The electric energy consumption determined by this test procedure (EE; cd EE; cs EE) is measured at the mains socket and therefore already considers the charging efficiency and the charging losses. This value directly correlates to the electric energy provided from the grid and is used to determine the GHG emissions originating from the grid electricity utilized by the vehicle.

Test results of OVC HEV: Averaging and Weighting

To be able to determine the weighted average value for the two test conditions, one has to make an assumption about the weighting of the two conditions: how often and how long is the vehicle operated in each condition? For the purpose of the testing procedure applicable in Europe, the average distance travelled in charge sustaining operation mode before the battery is recharged is assumed to be 25 km by the legislator.

$$X = \frac{(X^{cd} \times \text{range}) + (X^{cs} \times 25)}{(\text{range} + 25)}$$

With:

X: denotes one of the emission values (fuel consumption or electric energy consumption or CO₂ emissions)

X^{cd}: denotes one of the emission values in charge depleting operation mode

X^{cs}: denotes one of the emission values in charge sustaining operation mode

range: electric range of the OVC HEV

This equation can be equally expressed in the following way:

$$X = UF \times X^{cd} + (1 - UF) \times X^{cs}$$

With

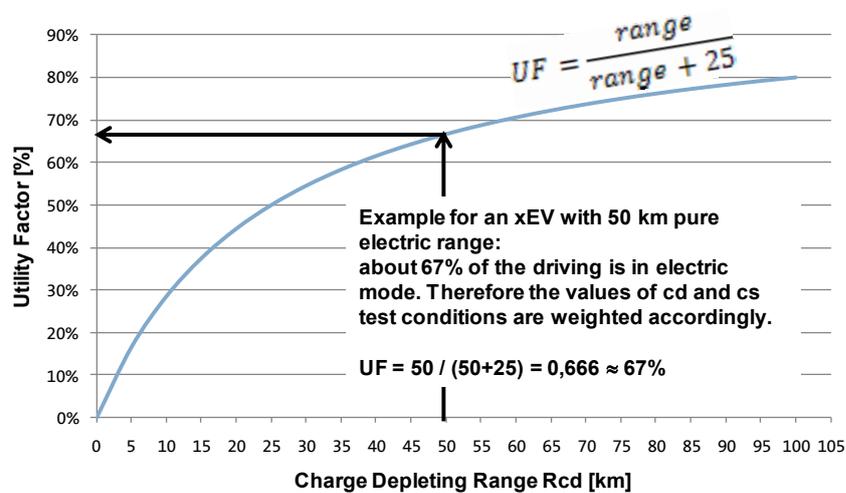
$$UF = \frac{\text{range}}{\text{range} + 25}$$

With

UF: Utility Factor – percentage of driving in charge depleting mode

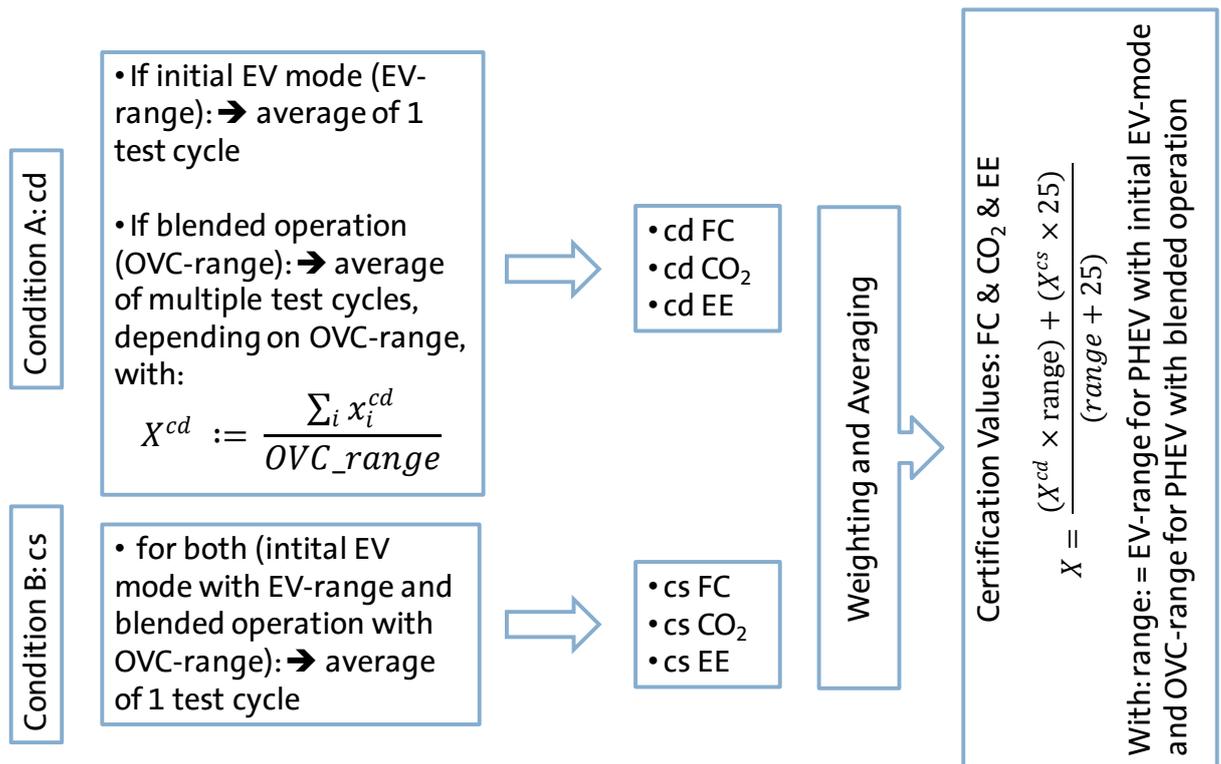
Thus, with this implicitly defined “Utility Factor” UF, the emission values for the charge depleting and the charge sustaining mode are weighted as a function of the electric range, see **Figure 5-2**.

Figure 5-2: Representation of the implicit utility factor of regulation UN ECE R101



By weighting the two conditions cd and cs in this way, one derives an average weighted fuel consumption and CO₂-emission number that can be compared to the certification numbers of conventional vehicles (see **Figure 5.3**).

Figure 5-3: ECE R101: Test- and Calculation Methodology – Weighting and Averaging of the Test Results



For vehicle concepts with pure electric operation and without ICE operation during charge depleting operation like E-REV, there are no fuel consumption and GHG-emissions associated to combustion of a consumable fuel at charge depleting operation mode.

In this case the equation for the weighted average of the fuel consumption and CO₂ emission results becomes:

$$X = \frac{X^{cs} \times 25}{range + 25} \quad (\text{for fuel consumption and CO}_2 \text{ emissions only})$$

In contrary, it is assumed that within charge sustaining operation mode no consumption of externally charged electric energy occurs, as per definition the charge sustaining mode starts when battery energy is depleted. Therefore during charge sustaining operation no further electrical energy from the battery is available (despite potentially some electrical energy from regenerative braking, but not originating from the electric grid). With this, the equation for the electric energy consumption reduces to:

$$X = \frac{X^{cd} \times range}{range + 25} \quad (\text{for electric energy consumption only})$$

Test procedure for battery electric vehicles (BEV)

As pure battery electric vehicles have an electric motor as sole propulsion source, there are no fuel consumption and exhaust emissions associated to these vehicles. Therefore the electric energy consumption is the only “emission” to be considered.

To determine the electric energy consumption of pure electric vehicles, they are driven two times on a chassis dynamometer through the standard driving cycle (“NEDC”) that is also used for conventional vehicles or hybrid electric vehicles.

Thus, there are no further averaging or weighting of the test results required.

5.2 Proposed GHG evaluation methodology to determine WTW emissions of electrified vehicle concepts

Up to now, for conventional vehicles and HEVs, only the GHG-emissions of onboard consumable fuels had to be considered. With the utilization of electrical energy that is externally produced and stored onboard, the GHG emissions of this electrical energy consumption must be considered in addition.

Assuming the electrical energy coming from renewable wind energy, these GHG-emissions will be zero. If the electricity is produced from coal, there will be significant GHG-emissions associated with the use of the electric energy in the vehicle.

Thus, the overall GHG-emission of an OVC HEV is also a function of the GHG intensity of the utilized electricity.

The WTW GHG emissions of OVC HEV are therefore the sum of the WTW GHG emissions associated with the combustion of the fossil fuel plus the amount of GHG emissions associated with producing and distributing the electricity to recharge the batteries:

$$CO2_{WTW} := CO2_{fuel_{WTW}} + CO2_{factor_{grid}} \times EE_{@ plug}$$

With:

$$CO2_{fuel_{WTW}} := CO2_{TtW} + \frac{14,2}{73,3} \times CO2_{TtW}$$

$$CO2_{TtW} := CO2 \text{ emissions according to test procedure}$$

$$WtT \text{ emission factor for petrol: } 14,2 \frac{g \text{ CO}_2}{MJ}$$

$$TtW \text{ emission factor for petrol: } 73,3 \frac{g \text{ CO}_2}{MJ}$$

$$CO2_{factor_{grid}} := \text{emission factor of the electric grid @ mains socket (production and distribution)}$$

$$EE_{@ plug} := \text{electric energy consumption @ plug (mains socket) according to test procedure}$$

For pure electric vehicles (BEV) the WTW CO_{2eq} emissions are only associated to the CO_{2eq} emissions of the consumed electricity that is externally produced, and thus the equation for BEV reduces like follows:

$$CO2_{WTW} := CO2_{factor_{grid}} \times EE_{@ plug}$$

5.3 Further improvement of the methodology

The above proposed methodology is a simple approach to approximate the GHG saving potentials of externally chargeable HEVs, based on anyhow available certification data.

For resource reasons, it was decided to abstain from additional “Advisor” vehicle simulations for the considered HEV and BEV configurations, but rather to utilize data obtained from the member company’s research and development programs.

Nevertheless, it is assumed that this approach delivers reasonable results that are sufficient to determine the impact of increased powertrain electrification on the GHG-emissions in the transport sector.

However, there are a lot of external parameters that influence the impact the GHG-emissions of electric vehicles and that are not yet considered:

- Charging strategy (overnight charging every night; intermediate charging during the day)
- Vehicle to Grid communication (“smart grid”)
- Electricity source depending on charging strategy; utilization of marginal electricity mix

Therefore the proposed methodology may be further elaborated in future, as knowledge on HEV and BEV configurations evolve, insight in “smart grid” opportunities develops and consumer charging behavior and consumer daily driving patterns are better explored.

6 GHG-Emissions from electricity

As explained above, the WTW GHG emissions are a function of the GHG intensity of the electricity charged to the xEV traction battery. This GHG intensity depends on various factors like:

- the type of electricity and its source (renewable; natural gas; mineral oil; coal; nuclear power)
- the national electricity mix
- the regional electricity mix
- the transmission/distribution losses of the grid
- the customers' contract with the electricity provider
- the time when the vehicle is charged (“marginal electricity mix”)
- future development of the respective electricity mix (fuel switch; increased share of renewable;..) and infrastructure changes (reduction of transmission losses; decentralized power generation;..)

Due to this fact, the WTW GHG emissions are not calculated for a certain electricity mix, but are given as a function of the GHG intensity of the electricity. It is then up to the user of this study to choose the electricity pathway that is most suitable for the respective analysis.

Nevertheless, for a holistic assessment of the impact of electrified vehicle concepts on the European road transport sector, one may want to choose the current EU-mix as a starting point.

The JEC WTW study uses a number of electricity pathways that are described in detail in WTT Appendix 2 (JRC, EUCAR, CONCAWE, 2011). The assessment of the electricity pathways includes the following process steps: extraction of the resource and processing – transport of the resource – distribution of the resource – power generation – electricity distribution. **Figure 6.1** shows an example of GHG calculation for electricity produced from natural gas (piped 7000km, with Combined Cycle Gas Turbine CCGT) as presented in *WTT Appendix 2*.

Table 6-1: GHG calculation of example of electricity pathway in WTT Appendix 2

	Standard step	Energy expended (MJx/MJelec)				Net GHG emitted (g CO ₂ eq/MJelec)			CO ₂	CH ₄	N ₂ O	
		Total primary			Fossil	Best est.	min	Max	g/MJ	g/MJ	g/MJ	
		Best est.	min	Max								
GPEL1a	Piped NG, 7000 km, CCGT											
	NG Extraction & Processing	1	0.05	0.03	0.11				2.5	0.19	0.000	
	NG Transport	3	0.36						19.1	0.35	0.001	
	NG Distribution (HP)	3	0.02						1.0	0.00	0.000	
	Power generation (CCGT)	4	0.84	0.80	0.88				102.9	0.01	0.005	
	Electricity distribution (LV)	5	0.03						0.0	0.00	0.000	
	Total pathway		1.31	1.09	1.39	1.31	141.0	128.0	145.8	125.6	0.55	0.006

Table 6-2 below shows selected electricity pathways that can be used for further analysis:

Table 6-2: Excerpt from WTT Appendix 2: selected electricity pathways as indication for GHG intensity from electricity

Pathway	Description	Net GHG emitted (g CO ₂ eq/kWhelec) Best estimate	Net GHG emitted (g CO ₂ eq/MJelec) Best estimate
GPEL1a	Piped NG, 7000km, CCGT	508	141
KOEL1	Coal, state-of-the-art conventional technology	968	269
OWEL1a	Electricity from municipal waste (local power plant)	28	8
OWEL1b	Electricity from municipal waste (large power plant)	100	28
WWEL1	Waste wood, 200 MW gasifier + CCGT	19	5
EMEL1	EU-mix electricity	467	130
WDEL1	Wind turbine (offshore)	0	0
NUEL1	Nuclear	16	4

The two pathways KOEL1 (coal) and EMEL1 (EU-mix electricity) are also represented as vertical lines within the figures (e. g. **Figure 8.1**) of *chapter 8* for orientation.

These values represent the current technical state of the art and current EU Mix. Because significant fleet penetrations of electric vehicles are expected in 2020 and beyond, it is relevant to look at the future development of GHG emissions of power generation.

The European Commission set an outlook on the carbon intensity for the power generation by 2030 in the publication "EU energy trends to 2030 — Update 2009" (EC 2010). Compared to the 2010 GHG emissions, the "Baseline 2009" assumes reductions of carbon intensity of -13% by 2020 and -43% by 2030.

EURELECTRIC, the Union of European Electricity Industry, has set up a future scenario in a study called "Power Choices" (EURELECTRIC, 2010), which indicates a potential way to carbon-neutral electricity in Europe by 2050. The results of this studied scenario can be used as an indication for future decarbonization potentials in xEV power supply. Approximate outlooks for the carbon intensity reduction of EU-grid mix is ~ -28% by 2020 and ~ -67% by 2030 both compared to 2010.

Weak points of both publications are that they use the emissions at power plant level only and do not use Well-to-Tank methodology and they also cover CO₂-emissions per kWh alone and not GHG emissions in CO₂-equivalents per kWh. Hence, an additional source shall be considered.

The Renewable Energy Snapshot 2010 (JRC 2010) shows the renewable share in electricity generation was almost 20% in 2009. If we use the EU grid mix (at WTT level) of 467 g CO₂eq/kWh and assume that the renewable share is 0 g CO₂eq/kWh, then the 80% non-renewable electricity generation emits 584 g CO₂eq/kWh. In the Renewable Energy Snapshot 2010 the JRC estimates that 35% to 40% of the electricity has to come from renewable energy sources by 2020. For the purpose of the WTW analysis an average renewable electricity share of 37.5% is chosen. Due to the uncertainty of the GHG emission development, it is supposed that the specific GHG emissions of renewable and the non-renewable electricity production remain at current levels.

Applying these assumptions leads to the estimate of 365 g CO₂eq/kWh, a reduction of approx. -22% compared to the EU-mix electricity of 467g CO₂eq/kWh. This reduction value for 2020 is in the range of the EURELECTRIC (-28%) and EC (-13%)

publications. An outlook beyond 2020 is not done in this report but it is fair to assume a continued decrease in EU mix electricity GHG emissions.

7 OVC HEV and BEV Vehicle Configurations

There are three xEV concepts considered: E-REV, PHEV and BEV. For each of these concepts a set of relevant data was established based on current experience with prototype- and development- vehicles. Due to the spectrum of various design solutions for each category, for most parameters a range was defined rather than an individual value.

Definition of xEV categories as used in this study:

Plug-In Hybrid Electric Vehicle (“PHEV”):

- HEV with off-board charging capability
- Limited electric performance depending on performance of electric motor
- PHEV with Initial EV Operation: starts as an EV then transition to hybrid operation. Always requires engine on for full performance
- PHEV with Blended operation: starts and drives like a conventional hybrid with engine on

Extended-Range Electric Vehicle (“E-REV”):

- Operates exclusively as an EV when battery energy is available
- Has full performance as an EV (e. g. top speed, acceleration)
- Auxiliary energy supply (e.g. a small ICE) only engaged when energy from battery is not available

Battery Electric Vehicle (“BEV”):

- Pure battery electric vehicle
- Only energy source: externally produced electricity, stored on-board
- Electric range mainly depending on battery size
- Cannot be driven further after battery has depleted

The most relevant data to categorize the xEV concepts and to execute the calculations are summarized below:

	Useable Battery Capacity	Range	Charging Efficiency	cd electric energy consumption @ plug	additional mass (against Reference Vehicle)
	[kWh]	[km]	[%]	[kWh / km]	[kg]
PHEV	3 - 6	20 - 40	85	0,16 - 0,19	200 - 300
E-REV	7 - 12	60 - 80		0,13 - 0,18	
BEV	13 - 22	120 - 160		0,13 - 0,16	

8 WTW Calculation Results

As outlined in *chapter 5*, the WTW results of externally chargeable vehicles depend on the vehicle configuration (e. g. electric range) and the GHG intensity of the utilized electricity. For comparing the results of externally chargeable vehicles with the results of conventional vehicles (as shown in *WTW Appendix 1*), it is proposed to evaluate the WTW GHG-emissions of the different xEV categories as a function of the GHG intensity of the utilized electricity.

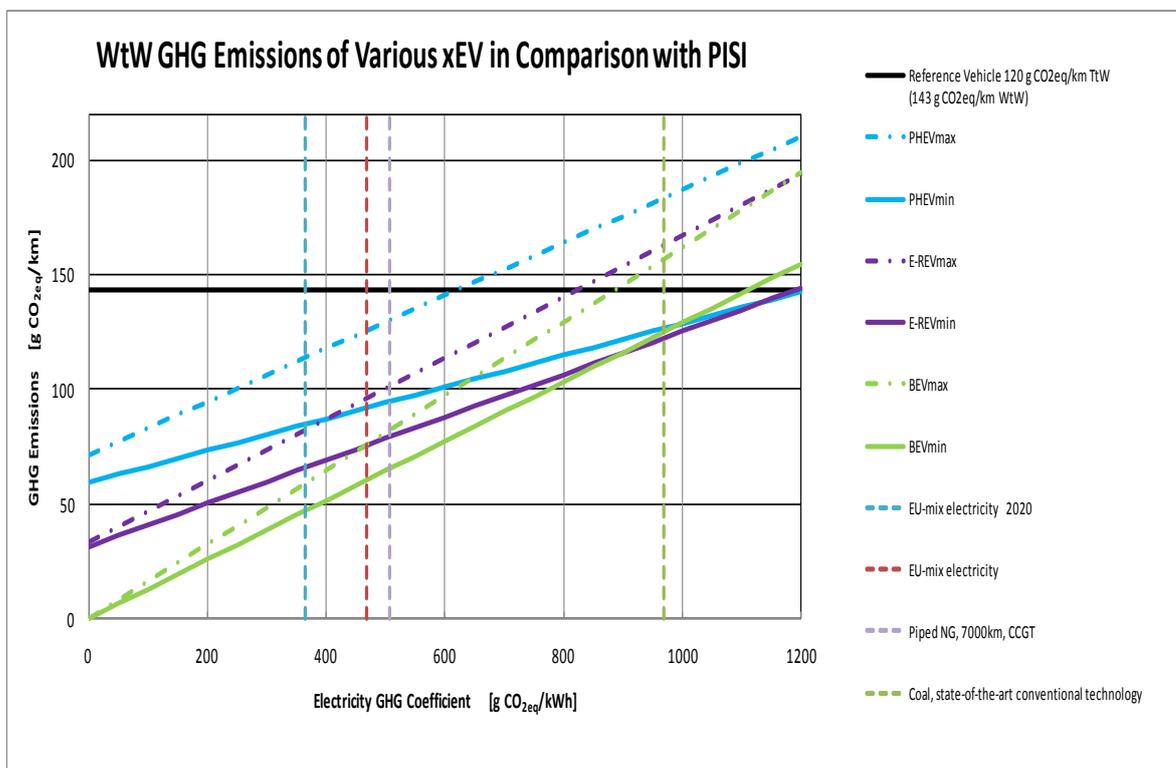
Based on the methodology laid down in *chapter 5*, one can easily create numbers for typical xEV configurations.

shows the WTW GHG-emissions of different OVC HEC and BEV configurations as a function of the GHG intensity of the electricity. For comparison, the WTW GHG emission of a conventional ICE reference vehicle with 120 g CO_{2eq}/kWh on TTW basis (which equals 143 g CO_{2eq}/kWh on a WTW basis) are shown.

As the GHG-emissions of conventional ICE vehicles are independent of the GHG intensity of the electricity, these vehicles are shown up as straight horizontal lines in the graph.

The curves of the xEV categories in contrast are continuously ascending straight lines. The starting points as well as the gradient of the curves depend on the vehicle efficiency and the vehicle configuration.

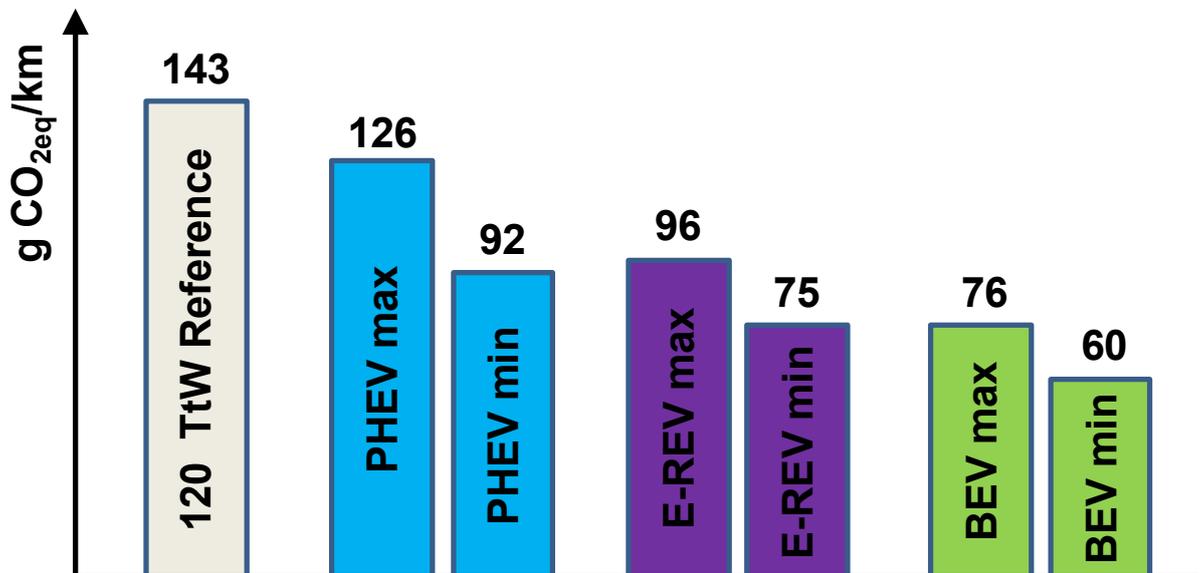
Figure 8-1: WTW GHG-emissions of different OVC Vehicle concepts as function the GHG intensity of the utilized electricity



Within the spectrum of xEV concepts and the assumptions taken in this report, the BEV shows the lowest GHG emissions and PHEV the highest, with E-REV concepts ranging in-between. However, based on the variety of design concepts and operating strategies, the GHG emission ranges of the xEV concepts are widely overlapping, especially for higher electricity GHG intensities above the current average EU mix.

For pure electric vehicles (BEV), the WTW GHG emissions are zero if the charged electricity is provided through renewable energy sources assuming the specific emissions to be 0 g CO_{2eq}/kWh. Depending on the mix, with an increased GHG intensity of the electricity, the WTW GHG emissions of BEV are increasing. At a GHG intensity of the electricity of about greater than 900 g CO_{2eq}/kWh, the BEV starts emitting more than the ICE reference vehicle. At the EU electricity mix of about 467 g CO_{2eq}/kWh the BEV emits about half as the reference vehicle, see *Figure 8-2*.

Figure 8-2: WTW GHG Emissions @ EU Electricity-Mix (467 g CO_{2eq}/kWh)

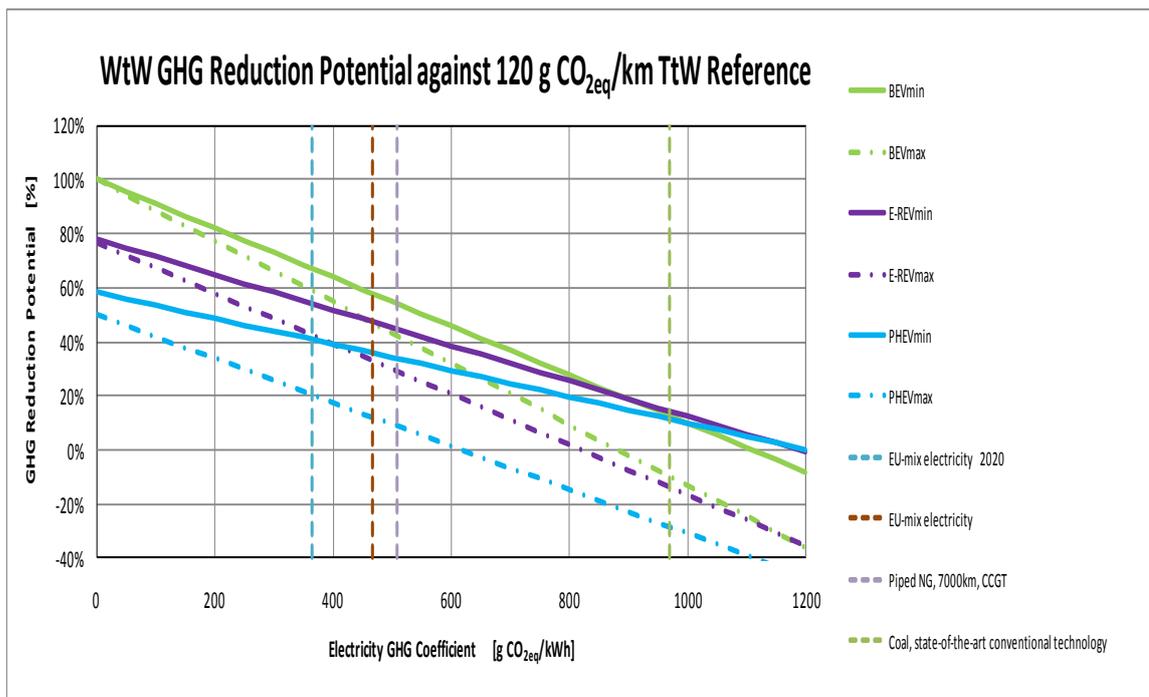


The PHEV concepts mark the upper spectrum of the GHG emission range of the considered xEV concepts. The curves for the PHEV configurations are starting at WTW GHG emission levels of about 60 – 70 g CO_{2eq}/kWh for pure renewable electricity utilization. The PHEV curve in the best case intersects with the “worst” BEV configuration approximately at an electricity GHG intensity of about 650 g CO_{2eq}/kWh. Beyond that point, this PHEV configuration performs better than the BEV. Reason is the fact, that at a certain point – depending on the vehicle configuration and the share of electric drive versus ICE utilization – the GHG emissions related to the electricity are becoming dominant over the GHG emissions associated to the on-board combustion of the fossil fuel. For this PHEV configuration, the GHG emission at EU electricity mix is about 64% of the reference vehicle. In the worst case, the PHEV configuration always shows higher CO_{2eq} emissions than the E-REV and the BEV. In the worst case, the WTW CO_{2eq} emissions of the PHEV are becoming worse than the ICE reference at about 600 g CO_{2eq}/kWh GHG intensity of the electricity.

The E-REV configuration is ranging in the middle between PHEV and BEV. The curves for the E-REV configuration are starting at about 30 g CO_{2eq}/kWh GHG emission levels, even for pure renewable electricity utilization. This results from the described test procedure for externally chargeable hybrid-electric vehicles (PHEV and E-REV) that establishes a weighted average fuel consumption determined from the two test conditions (charge depleting operation and charge sustaining operation). The E-REV curve in the best case intersects with the worst BEV configuration approximately at GHG intensity of EU mix. Beyond that point, this E-REV configuration performs better than the BEV. This is based on the fact, that at a certain point – depending on the vehicle configuration and the share of electric drive versus ICE utilization – the GHG emissions related to the electricity are becoming dominant over the GHG emissions associated to the on-board combustion of the fossil fuel. In this case, the GHG emission of the E-REV for EU electricity mix is also about half of the reference vehicle. In the worst case, the E-REV configuration always shows higher GHG emissions than the BEV, with the distance to the BEV becoming closer with higher GHG intensities of the utilized electricity. Up to a GHG intensity of about 800 g CO_{2eq}/kWh, the E-REV always performs better than the ICE reference. The “best” E-REV configuration always performs better with regard to WTW GHG emissions compared to the “best” PHEV configuration.

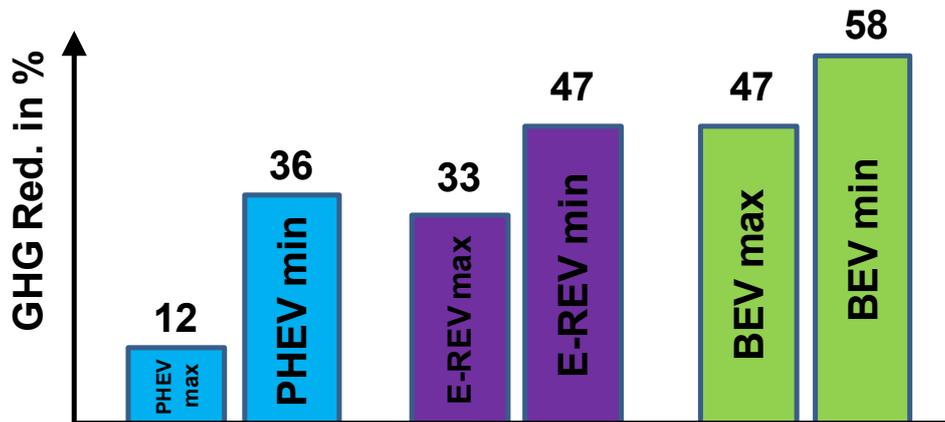
Another possible illustration is presented in **Figure 8-3**, representing the GHG-emission savings of different OVC HEC and BEV configurations as a function of the electricity GHG intensity in comparison to the conventional vehicle baseline. In this case the ICE reference again is a vehicle with 120 g CO_{2eq}/kWh on a TTW basis (which equals 143 g CO_{2eq}/kWh on a WTW basis).

Figure 8-3: GHG emission savings of different OVC and BEV vehicle configurations as a function of the GHG intensity of the utilized electricity in comparison to the conventional vehicle baseline (@ 120 g CO_{2eq}/kWh TTW = 143 g CO_{2eq}/kWh WTW)



All xEV concepts show the highest GHG saving potentials in the range of about 50 – 100%, when utilizing pure renewable electricity. With increasing GHG emissions of the electricity, the GHG savings are declining. Theoretically, at very high GHG emissions of the electricity (beyond 650 – 900 g CO_{2eq}/kWh), the GHG saving of the worst case of either xEV category are getting negative, meaning that in this case these xEV concepts would emit more CO_{2eq} than the ICE reference on a WTW basis. However, for the EU electricity mix of about 467 g CO_{2eq}/kWh, all xEV concepts show GHG emission savings of about 30% – 60%, with only the “worst” PHEV having a lower potential of about 12% saving, see *Figure 8-4*.

Figure 8-4: WTW GHG Reduction @ EU Electricity Mix compared to Reference (120 g CO_{2eq}/km TTW equal to 143 g CO_{2eq}/km WTW)



9 Discussion & Conclusions

As already discussed and outlined in chapters 5 and 8, the climate impact of externally chargeable HEV and BEV strongly depends on two main factors:

1. The utilization of electric energy from the grid versus the utilization of fossil fuel (which is a function of the initial pure electric range and the calibration strategy) and
2. The GHG intensity of the grid electricity.

In case of utilization of renewable electricity only, WTW GHG emissions in the range of 0 – 70 g CO_{2eq}/kWh can be demonstrated with the considered xEV concepts. Battery electric vehicles (including externally chargeable HEV with initial electric mode for travel distances below the pure electric range) in that case have no WTW GHG emissions at all. In case of OVC concepts with blended operation strategies (e.g. PHEV), the GHG emissions are in the upper range of 60 – 70 g CO_{2eq}/kWh. Considering the weighted average between the charge depleting condition and the charge sustaining condition for E-REV concepts as determined by the standardized test procedure delivers significantly lower GHG emissions.

With increasing GHG emissions from the considered electricity mix, the WTW GHG emissions of the OVC concepts are also constantly rising. Compared to an ICE reference vehicle (@ 120 g CO_{2eq}/km TTW = 143 g CO_{2eq}/kWh WTW), PHEV show higher GHG emissions if the electricity mix shows emissions beyond 600 g CO_{2eq}/kWh and E-REV and BEV beyond about 850 - 900 g CO_{2eq}/kWh in the worst case. Beyond 1100 to 1200 g CO_{2eq}/kWh electricity mix emissions, all best case OVC concepts have higher WTW GHG emissions than the ICE reference.

Considering the electricity mix at about 467 g CO_{2eq}/kWh the OVC concepts with a range of 60 – 96 g CO_{2eq}/kWh still perform much better than the ICE reference. Only the PHEV in the worst case shows slightly higher WTW emission of about 126 g CO_{2eq}/kWh, but still staying below the ICE reference.

Thus, for current EU-mix, total WTW GHG emission savings of up to 58% are possible. When utilizing renewable electricity, up to 100% GHG savings are possible with pure BEV and battery electric vehicles with range extender for travel distances below the pure electric range. OVC concepts with blended operation strategies or range extender with travel ranges beyond the electric range still show GHG emission savings of about 50 – 80%.

Finally, the conducted assessment showed the large GHG saving potential of different OVC concepts compared to an ICE reference vehicle of the same vehicle category. However, the potential savings are dependent on a lot of factors like the architecture and calibration strategy of the OVC concepts as well as the GHG emission of the electricity mix used to externally charge the batteries.

As a consequence, to further increase the environmental benefits of OVC concepts, it is essential to improve the electric range by further improving the battery technology, the overall vehicle/powertrain efficiency, weight reduction, aerodynamic measures, and so on.

In addition, the reduction of the GHG intensity of the electric grid as well as development of technologies for charging predominantly renewable energy (“wind to vehicle”) in smart grids are the most important enablers of future sustainable electric propulsion.

As outlined before, further updates of the WTW study may reconsider the input data based on better established data derived from increasing experience with serial production vehicles and more detailed simulations. However, for holistic assessments of the impact of electric vehicle concepts on the European transport sector, the data provided with this appendix is sufficient and accurate.

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Abstract

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

The JEC research partners [Joint Research Centre of the European Commission, EUCAR and CONCAWE] have updated their joint evaluation of the well-to-wheels energy use and greenhouse gas emissions for a wide range of potential future fuel and powertrain options.

This document reports on the third release of this study replacing Version 2c published in March 2007.

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