LOW GREENHOUSE GAS EMISSION TRANSPORT FUELS: THE IMPACT OF CO_2 CAPTURE AND STORAGE ON SELECTED PATHWAYS

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Background to the Study

The IEA Greenhouse Gas R&D Programme (IEA GHG) has focussed much of its attention on CO_2 capture and storage (CCS) and its application in power generation. Power generation is the global sector producing more CO_2 emissions than any other, but transport is the next biggest source of emissions and they are rapidly increasing. CCS can also be applied to the production of transport fuels; in particular hydrogen and (decarbonised) electricity.

IEA GHG has, in the past, examined options for reducing emissions from the transport sector through production of lower carbon energy carriers.[1]

Many stages in the transport system can give rise to emissions, from fuel extraction to use in a vehicle so, in order to understand the potential for emissions reduction, it is necessary to examine all parts of the system (i.e. from Well to Wheels). This approach was followed in IEA GHG's study of the Fischer-Tropsch process for gas-to-liquids, which involved use of published emissions data. Following the completion of this work it was decided to carry out a wider examination of the use of CCS in production of transport fuels with low greenhouse gas emissions. Fortunately, at the time that this decision was made, a European (JEC) study was just being completed which documented in a systematic manner the Well-to-Wheels (WTW) emissions of a large number of pathways to various transport fuels (but without CCS). The sponsors of this study agreed to make the results available so that IEA GHG could use them as the basis for its own study. Thus it was possible to estimate the potential contribution of CCS to reducing greenhouse gas emissions in the production and use of a variety of current and possible future transport fuels. One key limitation is that the EC study (and consequently this study) applies only to private cars. Approximately half of all transport fuel in used in private cars and the other half in commercial vehicles.

A contract was let to Dr C J Clark (U.K.), who had overseen the earlier Fischer-Tropsch study for IEA GHG, to assimilate the data from the JEC/WTW study and from previous IEA GHG studies.

The issue of this study was delayed for 2 reasons:

- The initial scope of work relied solely on a vehicle with a conventional gasoline 'spark-ignition' engine as the basis for the comparisons. Following comments received from the Expert Review, it was decided to include a modern diesel 'compression ignition', and a natural gas/CCS/electricity, pathway in the comparisons. Other work was added to make the study more comprehensive, e.g. the sensitivity of the conclusions to the distance travelled per year by the vehicle was examined.
- A second version of the European (JEC) WTW study was partially released in September 2005; their work now includes consideration of carbon capture and storage (CCS). The conclusions of the revised JEC study on to the potential for CCS were reviewed and found to be broadly in agreement with this report. Both studies conclude that in terms of the cost of CO_2 avoided the transport options start at around €200/tCO_2.[2] The detailed data in this report is based on the original complete European Study.

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[1] Previous studies have included use of CCS in hydrogen production (report Ph2/2), in methanol production (Ph3/13) and in the Fischer-Tropsch process for making liquid fuels from natural gas (Ph4/12).

[2] Costs in this report are presented in Euros (€) because it is inextricably linked with the JEC study. However, as is IEAGHG practice, the JEC study and this report assume 1€ ≡ 1US$.

Technical Background

Basis for study

In assessing the environmental impact of transport technology options, it is necessary to consider the impact of each of the stages of fuel extraction, refining, distribution and use in the vehicle. This needs to be done in a systematic way for the 'novel' systems considered, as well as for reference cases. The approach requires a form of life-cycle analysis which, in the transport, field has come to be known as Well-to-Wheels analysis (WTW). A subset of this analysis covers the production of the fuel up to the point where it is dispensed into the vehicle's fuel tank – this is known as Well-to-Tank analysis; the second part of the chain is Tank-to-Wheels analysis (WTT and TTW respectively). In the main report the component WTT and TTW data are discussed in depth but in this overview the emphasis is on the overall WTW results.

The study is set in the Netherlands; representative of a European location. The vehicle fleet for each type of fuel is assumed to be large enough that economies of scale can be expected in distribution and in vehicle costs. Some consideration is also given to how the results would be affected if set in a North American location.

JEC joint study

There have been several collaborative WTW studies by the oil and automotive industries. The most recent, a joint study in 2003, by EUCAR[3], CONCAWE[4] and the European Commission's Joint Research Centre (referred to subsequently as the JEC joint study) analysed a comprehensive set of low emission pathways from a variety of energy resources (coal, crude oil, natural gas and biomass) for European vehicles. A number of transport fuels were considered in this study including gasoline, diesel, compressed natural gas (CNG), hydrogen, synthetic fuels and bio-fuels. The JEC joint study makes use of a database established by LBST[5] in Germany for such studies. The results of the JEC joint study were made available to IEA GHG for this work. Although work is, at the time of writing, still in progress on a Version 2 of the JEC joint study it was partially released in September 2005. Details of the study can be accessed at: http://ies.jrc.cec.eu.int/wtw.htlm

Not all of the JEC joint study's pathways were suitable for this study; a selection of the more suitable ones was made on the basis of:

- availability of primary energy supply
- end-use fuel acceptability
- greenhouse gas reduction potential
- cost of CO_2 emission avoidance
- extension to the existing IEA GHG knowledge on transport fuels at a reasonable cost.

The IEA Greenhouse Gas R&D programme would like to thank the participants in the JEC joint study for making their data available and for their help and advice with this work.

Pathways

The various processes involved in supplying and using a particular fuel are referred to as a "pathway". A variety of pathways covering a range of possibilities was selected, including some which had been examined in the previous IEA GHG study (to check for consistency). The pathways were characterised by the type of fuel supplied to the vehicle, namely:

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[3] EUCAR: European Council for Automotive R&D
[4] CONCAWE: the oil companies' European association for environment, health and safety in refining and distribution
[5] LBST: L-B-Systemtechnik GmbH

- Synthetic fuels
- Hydrogen (delivered in compressed form)
- Electricity

Gasoline was used as the main reference case but modern diesel and hybrid vehicles were also considered. Compressed natural gas (supplied from distant gas fields by liquefied natural gas (LNG) tankers) was included for comparison with the earlier IEAGHG study (PH4/12). The fuels made from natural gas were a synthetic diesel-type fuel made by the Fischer-Tropsch process and DiMethyl Ether (DME). Three sources of hydrogen were examined – coal gasification, natural gas reforming and biomass gasification. All of these had been examined in the original JEC joint study but the electricity pathways had not; in order that this could be studied in a manner consistent with the other pathways, some further modelling of this pathway was done by IFP[6] using the same approach as used in the JEC joint study.

Processes incorporating CCS
In each of the pathways, opportunities to employ CCS were identified. The degree of emissions reduction would not be the same in each pathway because the point of application of CCS varied. For example, in the electricity pathways, CCS would be applied to the power plant in the way that IEA GHG had studied previously. Similarly CCS would be used in hydrogen production to make deep reductions in emissions at the fuel production plant. In contrast, for natural gas, CCS would be applied at the liquefaction plant, so that most of the CO_2 emissions from the pathway (i.e. from the vehicle) would be unaffected. In every case, where electricity is used in a pathway it is assumed to come from a generating plant using CCS.

Vehicles
The standard for vehicle design used in this study is a compact European 5-door car, such as the VW Golf, as used for the JEC joint study. Changes to the power train and associated modifications were assessed using the methodology described in the MIT study “On the road in 2020” which adjusts for changes in vehicle mass or vehicle cost by addition or subtraction of particular components. A 2010 gasoline-powered vehicle was used as the base case. The performance of all vehicles was simulated using the New European Drive Cycle; the range of the vehicle was standardised at 600km. Power train concepts examined in this study include:

- Diesel - Direct injection compression ignition engine (DICI)
- Gasoline - Port injection spark ignition engine (PISI)
- Hydrogen internal combustion engine (ICE)
- Direct hydrogen fuel cell
- Electric vehicle

In addition, the various combustion engines were also considered in a hybrid configuration where an electric motor driven by a relatively small Li-ion battery can supplement the main power source.

The DICI engines were used with conventional diesel (reference), synthetic diesel (FT), and DME; the PISI engines were used with gasoline (reference case) and compressed natural gas (CNG).

The electric vehicle was the only one with a reduced range – this had to be limited to 350km in order that the vehicle could provide the required passenger space as well as the necessary batteries.

System performance and cost estimation
The primary source of data used in this work was the JEC joint study, supplemented by IEA GHG process data for energy carriers and synthetic fuels made using processes employing CCS. In several cases, such as fuel cells, storage vessels and batteries, assumptions had to be made about technology

[6] Institut Français du Petrole

which is still in development. Hence, the results pertaining to these 'radical' technology developments should be treated with caution.

The effect of variation in the value of various parameters was assessed and is presented in the main report as sensitivity graphs which highlight key influences on the results.

Results and Discussion

During the course of the study, it became apparent that there were different views about the WTW data to be used for the manufacture of liquid fuel using the Fischer-Tropsch process. In particular there were significant differences between the figures used in the JEC joint study and those from a published WTW study carried out on behalf of some companies with commercial interests in production of FT materials. The 2 sets of figures are discussed in the report.

Some of the results from various pathways are summarised in Table S.1; this is a selection of the pathways considered, concentrating on those with lower WTW emissions than the reference cases. In most cases a hybrid vehicle was considered as well as the equivalent engine-driven vehicle although not all cases are shown in this table. In this assessment, the hybrid showed small reduction in WTW emissions but higher cost of avoided emissions. Because of the systematic differences between the cases with and without hybrids, most of the results shown in Table S.1 are for non-hybrid vehicles since this gives a good indication of the vehicles' performance. The exceptions are the synthetic fuels cases because the reductions in greenhouse gas emission are relatively small and are therefore particularly sensitive to the use of the hybrid configuration; the full data are available in the main report.

Costs

The cost of CO_2 avoidance is in all cases hundreds of € per tonne of CO_2 avoided. This compares to costs in the region of €50 per tonne for CCS applied to power generation. In the case of the zero-carbon energy carriers (hydrogen and electricity), the cost is largely attributable to the cost of the vehicle. In general, costs in the WTW analysis are dominated by the cost of the vehicle, the capital cost of which has to be charged against its being used only 5% or less of the time available.[7] At higher levels of utilisation, such as would, for example, be expected for taxis, the fuel cost becomes the determining factor and the costs are significantly lower. Some speculative data on this effect is presented in the report. In the case of the synthetic fuels (not specifically designed for greenhouse gas emissions reduction), the high cost is also due to the limited emissions reduction achieved.

It is important to note that the specific cost of the PEM fuel cell is assumed to be €80/kW (the mean value of the 3 reference sources used). This value is far removed from the current cost of fuel cells in production, so these results must be treated with great caution. The cost of the battery for the electric vehicle is related to the cost of the batteries for the hybrid vehicle (which is already in production) so can be regarded as more soundly based than the fuel cell's cost.

Another item which has not yet been developed to the stage at which it can be mass produced is the tank for holding compressed hydrogen – the tank is assumed to hold hydrogen at 70 Mpa pressure; so the cost of this should also be treated with caution.

[7] The reference cycle is for a vehicle that travels 16,000 km/year. If this is done at an average speed of, say, 50 km/hr this is 320hrs/year of driving (4% of the year).

Table S.1. Some of the pathways with lower greenhouse gas emissions than the base case

Pathway Fuel	Vehicle	Emissions g CO_2eq./km (mean)	Avoided cost relative to gasoline base case €/t CO_2 avoided
Gasoline (base case)	PISI	165	0
Diesel (conventional)	DICI	159	-
CNG	PISI hybrid	109	281
DME	DICI hybrid	139	1076
CNG with CCS	PISI hybrid	101	247
FT diesel with CCS	DICI hybrid	129	1089
DME with CCS	DICI hybrid	114	762
Hydrogen: coal with CCS	ICE	66	479
Hydrogen: natural gas with CCS	ICE	49	296
Hydrogen: biomass with CCS	ICE	-261	109
Hydrogen: coal with CCS	Fuel cell	37	510
Hydrogen: natural gas	Fuel cell	93	827
Hydrogen: natural gas with CCS	Fuel cell	37	420
Hydrogen: biomass with CCS	Fuel cell	-147	189
Electricity: natural gas with CCS	Electric vehicle	20	805
Electricity: coal with CCS	Electric vehicle	34	918
Electricity: biomass with CCS	Electric vehicle	-118	468

CO_2 emissions

Using compressed hydrogen in a vehicle with an internal combustion engine is demonstrated technology. Emissions reductions of 60-70% can be achieved if this is combined with the application of CCS to production of the hydrogen. The cost of avoided emissions is similar to that with synthetic fuels but the latter do not achieve the same degree of CO_2 emission reduction.

The emissions reduction from using a fuel cell in the compressed hydrogen pathway is greater than when using an internal combustion engine because the fuel cell vehicle is assumed to be more efficient.

The electric vehicle pathway has very similar emissions reductions to that of the compressed hydrogen pathway using a fuel cell.

Some alternative fuel types, (e.g. CNG, FT diesel, DME), whilst they are relatively inexpensive to implement, offer only moderate reductions (22-33%) in greenhouse gas emissions. This is not surprising since these fuels mainly attract attention for environmental reasons other than CO_2 mitigation. Slightly greater reductions in greenhouse gas emissions can be achieved in the CNG and synthetic fuel pathways by use of CCS. When looked at as investments in abatement of greenhouse gas emissions (i.e. no value being attributed to reductions in other pollutants), the cost of CO_2 avoidance is high (>240€/t CO_2 eq.) – this is not surprising since only small reductions in greenhouse gas emissions are being achieved even though there are little or no modifications to the vehicles.

Biomass
A number of options are examined that combine use of biomass with CCS. However, conclusions about this must be treated with caution because:

- Biomass as a fuel may be of limited availability; the relative merits of converting the biomass to electricity or transport fuels have not been assessed by IEAGHG. For example, no consideration is given in this work to that fact that biomass transport fuels require specific crops that may have to compete for land with food crops. On the other hand, a biomass crop for power generation might be selected to suit the land available.

- The way in which avoided costs are expressed lead to a perverse effect in that reductions in process efficiency reduce the cost of emissions avoided (this is because this causes more CO_2 to be sent for storage). This suggests that the cost per tonne of CO_2 avoided is not a good measure for calibrating the attractiveness of using CCS with biomass.

- Estimated supply costs of delivered biomass vary widely. The 'best-estimate' cost used in this study is 3.3 €/GJ. As discussed in the study, there are indications that the cost of large-scale biomass for transport fuels would be considerably more.

Results summary
Of the deep reduction pathways examined in this study, the one which seems to be closest to practical reality is the hydrogen vehicle using an internal combustion engine. CCS could be readily applied to the production of hydrogen and major reductions in the level of CO_2 emissions achieved. However, the cost of achieving these reductions is an order of magnitude greater than for reductions in emissions from power generation.

Whilst there is little technical doubt that the fuels considered can be produced and emission reductions (from 20 to 80% on WTW basis) could be achieved using CCS technology, wider issues need to be considered. For example, in addition to the wide choice of potential fuels and alternative drive possibilities, society has the possibility of making major changes to its patterns of vehicle use. Further, about half of all transport fuel is used in commercial vehicles rather than the private vehicles considered in this report. It seems clear, therefore, that no one option for CO_2 emission reduction from transport will predominate.

The pathway options for reducing emissions of CO_2 from vehicles are all considerably more expensive than emission reductions in power generation. It seems probable therefore, that alternative solutions to reducing emissions from transport, and CCS use in power generation, will be adopted before CCS is widely applied to the production of transport fuels for private vehicles.

The results that indicate "negative emissions" are, in principle, available using biomass with CCS should be treated with great caution. (See recommendations.)

The JEC study (and hence the IEAGHG study) is based on a standard vehicle able to achieve "minimum customer performance criteria". As these criteria include the ability to reach speeds of 180km/hr (above the legal speed limit in most counties) and a range between fuel stops of 600km (5 hours driving at 120km/hr) there is a need to review these restrictions when considering potentially radical changes to transport options.

Expert Group Comments

The report was reviewed by a number of experts familiar with this type of study and this area of technology from the oil and automotive industries, from academia and national research institutes, as well as representatives of the JEC joint study. IEA GHG is very grateful to all of those who contributed to this review.

In general there was praise for the study, more than one person saying "it will make an excellent addition to the existing literature." The analysis was recognised as orthodox by experts in the area. It was suggested that the report should be widely circulated among those who are interested in future automotive fuels.

Several reviewers commented on pathways which could usefully have been included. The absence of a nuclear power pathway was mentioned but this had not been part of the original specification, nor had bio-ethanol. Many other pathways might have been considered but there was a practical limitation as to how many could be tackled in the study. In response to suggestions from some experts, several additional pathways were included in the final report.

It was noted that there were various combinations possible for CCS, such as EOR, but these have not been discussed in the report – again this was a matter of choosing a representative selection which could be tackled within the budget and 'drawing-a-line' somewhere when reporting.

The most frequent comment was about the absence of a diesel base case, not least because the compression ignition engine has lower greenhouse emissions than the spark ignition engine, although the gap is narrowing. This case has now been included. The topic is dealt with extensively in the JEC joint study so, for the purposes of this work, it seemed less important to address that option in detail.

Major Conclusions

The effect of CCS on production of automotive fuels could be a useful way of reducing greenhouse gas emissions in the automotive sector but the cost of avoidance is high because of the dominance of vehicle cost in the WTW pathway.

More detailed conclusions from the body of the report include:

Energy consumption

- For all pathways, vehicle energy efficiency is the key determinant of the overall energy consumption and the energy ranking of each pathway. Differences in vehicle technology exceed the effect of CCS on the energy efficiency of the pathways.
- Electric vehicles and fuel cell vehicles powered by hydrogen from natural gas have the lowest overall energy consumption ca. 130 – 170 MJ/100km, even with CCS. CCS adds a penalty of up to 25%. All of these pathways are less energy intensive than the gasoline reference pathway (218 MJ/100km travelled).
- Hydrogen fuelled ICEs, where the hydrogen is derived from coal or biomass have the highest energy consumption ca. 400 - 550 MJ/100km travelled. However, virtually all of the energy consumption in the biomass pathway is from renewable sources.

Reduction in greenhouse gas emissions

- Synthetic fuels made from natural gas require little modification to the vehicle but produce less greenhouse gas emissions reduction than zero-carbon energy carriers such as hydrogen or electricity which require expenditure on vehicle modification as well as on fuel preparation.

- Electric vehicles and fuel cell vehicles (fuelled by hydrogen from natural gas) have lower greenhouse gas emissions than the gasoline reference pathway, even without CCS.
- With CCS, the electricity and hydrogen pathways show substantial emission reductions over the gasoline reference case. Fossil fuel based routes provide reductions of 60-80% in greenhouse gas emissions compared with the reference case. Biomass based routes benefit from a net removal of CO_2 but these figures should be treated with caution, since a decrease in system efficiency increases the net removal of CO_2 for storage.
- For CNG and DME made from natural gas from remote fields, CCS provides an additional 5 - 10% greenhouse gas emission reduction, making a total reduction of 30 - 40% over the gasoline base case. FT diesel with CCS shows a small benefit (5 - 22%) over the gasoline (spark ignition) base case; in this case, use of CCS has less impact on greenhouse gas emissions because the FT fuel has a relatively high carbon content and because, in the 2010 vehicle design, the diesel engine loses some of its fuel efficiency advantage over the spark ignition reference.

Cost of avoidance of greenhouse gas emission

- CO_2 avoidance costs are an order of magnitude greater than those for stationary applications of CCS, either due to the limited emissions reduction achieved (in the case of synthetic fuels) or due to cost of the vehicle and design modifications (in the case of electricity and hydrogen).
- The capital cost of the vehicle tends to dominate the cost calculations because it is only driven for some small percentage of the time available. At higher levels of vehicle utilisation (say 40,000 km/yr as opposed to the reference 16,000 km/yr) fuel costs become a more significant factor.
- Avoidance costs tend to increase with increasing powertrain complexity. For deep reductions in emissions, the lowest cost of avoidance is found in pathways employing CCS combined with a near-conventional powertrain (ICE).
- Hydrogen from natural gas provides the lowest avoidance cost of the fossil fuel options for deep reductions in CO_2 emissions.
- For more modest reductions in CO_2 emissions, CNG offers the lowest avoidance costs of the various routes making use of remote natural gas.
- Although biomass with CCS is reported to have the lowest (i.e. negative) emissions the conclusion should be qualified:
    - biomass resources are possibly limited and can probably make only a marginal contribution to hydrogen supply;
    - with CCS, a lower process efficiency (perversely) increases the net quantity of CO_2 stored, and reduces the cost of avoidance;
    - conversion technology is only at the demonstration stage and is yet to fulfil the high performance expectations.
- Applying similar analysis to the US market suggests that, with the lower efficiency of US vehicles and US refineries, CCS applied to alternative fuel pathways may provide a lower cost of CO_2 avoidance than that estimated for Northern Europe.

Recommendations

Working with researchers in the transport field was a productive way of developing this study from existing information and, importantly, they now include CCS in their on-going analyses.

It is recommended that consideration be given to further work focussing on the implications of CCS applied to the production of electricity and hydrogen for <u>commercial</u> vehicles. Commercial vehicles consume about half the fossil fuels used in transport and, as they are used far more intensively than private vehicles, should show a reduced cost of CO_2 avoidance. Additionally, government policy initiatives could possibly be more readily applied to public and commercial transport than to private motoring. Researchers in the transport field should be encouraged to take part in the work.

It is not clear that the cost of CO_2 avoided is the only major consideration to be taken into account when comparing options for the reduction of emissions from transport. Future work should also focus on the cost of fuel to the user.

It is not clear to what extent the conclusions of this study are limited by a restriction on meeting "minimum customer performance criteria" that include the ability to travel at 180km/hr and for 600km between fuel stops. Further work in the area of reducing emissions of CO_2 from transport should review these restrictions.

Fuel cells figure greatly in the emission reduction options considered by researchers in the transport area. It is assumed in this analysis that low-cost reliable fuel cells become widely available. The specific cost of the PEM fuel cell is assumed to be €80/kW which is much less than the current cost of fuel cells in production. IEAGHG has proposed a study to examine the state-of-the-art for fuel cell production and the prospects for their use; it is recommended that the study is authorised and includes detailed consideration of their prospects in transport applications.

Realistic appraisals of the prospects for production of biomass fuels are greatly needed both in the areas of transport and power generation. It is recommended that IEAGHG commission work to address three areas in particular:

(i) The quantities of energy that could be realistically provided by purpose-grown energy crops and the extent to which they could supplement fossil fuels.

(ii) An assessment of the potential applicability of CCS to biomass fuel use. In particular, addressing whether or not achieving 'negative emissions' leads to effective use of the biomass.

(iii) Whether or not the most efficient use of biomass is its direct use to produce electricity rather than to manufacture transport fuels.

Low Emission Fuels - the impact of CO_2 Capture and Storage on selected pathways

A report produced for the IEA Greenhouse Gas R&D programme

Executive Summary

This report assesses the impact of CO_2 capture and storage (CCS) on low emission pathways for road transport fuels. The study scenario is set in The Netherlands in a 2010–2020 timeframe and is based on a market of 1 million alternative fuel vehicles, some 16% of the country's current 6 million vehicles. Pathway data for energy and emissions have been taken from a recent series on European studies[1,2], which are now accepted as a primary reference source. In particular, the JEC study (see footnote 1 for full the reference) has been used as the principal source of data for this work. Where possible, these data have been combined with process data published by the IEA GHG programme studies. In total eight alternative fuel pathways have been evaluated and compared with a gasoline reference case based on 2010 fuel quality and vehicle technology. The eight pathways are:

- Three pathways producing compressed hydrogen
    - Coal gasification
    - Natural gas reforming
    - Biomass gasification

- Three pathways based on the monetisation of remote natural gas:
    - LNG marketed as a CNG transport fuel
    - Synthetic diesel produced by the Fischer Tropsch process
    - DiMethyl Ether

- Two electricity pathways powering electric vehicles
    - Coal gasification (CIGCC)[3]
    - Natural gas (NGCC)[4]
    - Biomass gasification (BIGCC)[5]

In all of the above cases, CCS has been evaluated at the fuel production stage. Fuel supply (Well to Tank) and full pathway (Well to Wheels) have been analysed and results presented separately for each case. For the full pathway, the impact of different powertrain technologies has been assessed, based on performance that might be expected by 2010. Electric vehicles, which were not included in the European studies, have also been studied as part of this work. Vehicle performance is based on simulation over the

[1] 'Well to Wheels analysis of future automotive fuels and powertrains in the European context', Well to Wheels Report Version 1, November 2003
[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] CIGCC Coal Integrated Gasifier Combined Cycle
[4] NGCC Natural Gas Combined Cycle
[5] BIGCC Biomass Integrated Gasifier Combined Cycle

New European Drive Cycle (see footnote 1). Vehicle energy consumption for powertrain technologies used in this study are summarised in the following table.

Table S1 - Vehicle energy and fuel (gasoline equivalent) consumption

	MJ/100km	Litre/100km gasoline equivalent
Gasoline PISI 2010 reference	190.0	5.9
Gasoline PISI 2010 hybrid	161.7	5.0
Diesel DICI 2010 with Particle filter	179.5	5.6
Diesel DICI 2010 hybrid with Particle filter	147.8	4.6
FT Diesel 2010 with Particle filter	179.7	5.6
FT Diesel Hybrid 2010 with Particle filter	147.8	4.6
DME DICI without Particle filter	172.4	5.4
DEM DICI hybrid without Particle filter	141.1	4.4
CNG PISI 2010	193.2	6.0
CNG Hybrid 2010	146.8	4.6
Direct Hydrogen Fuel Cell	94.0	2.9
Fuel Cell Hybrid	83.7	2.6
Electric vehicle	46.0	1.4

All pathways have been analysed to provide estimates of energy expended greenhouse gas (GHG) emissions and cost. In order to account for the effect of uncertainty of input data on outputs (energy loss, total GHG emissions, fuel costs, CO2 avoidance costs etc.), uncertainty has been included explicitly in data estimates to generate results that show the range of possible outcomes. Results are presented in the report in terms of the mean value and range corresponding to 5% and 95% probability levels.

The results indicate that both fuel production and vehicle powertrain efficiency are key determinants in pathway greenhouse gas emissions and energy loss. Similarly, fuel production costs and alternative vehicle costs are key determinants in the economic case for alternative fuels. While much of the fuel supply technology is proven, vehicle technology is more uncertain. WTW results presented in this report are highly sensitive to assumption made about powertrain efficiency and vehicle incremental cost. Conclusions reached should therefore be treated with caution, and further assessed as technology matures.

Although some general conclusion can be drawn from the study, the different combinations of technology employed in each pathway makes the results highly pathway specific, and the reader is directed to the full discussion of the report finding and conclusions in sections 3 and 4, respectively. Some general conclusions are as follows.

Well to Tank (WTT) energy expended and GHG emissions, and the cost of fuel supplied to the retail outlet with and without CCS are summarised as follows:

Table S2 Summary Well to Tank results without CCS

Pathway	WTT primary energy expended per MJ final fuel	WTT CO2 eq per MJ final fuel	Fuel supply costs 10% discount rate Euro/GJ
Gasoline reference	**0.14**	**12.6**	**8.7**[6]
Diesel reference	**0.16**	**14.2**	**8.4**
Coal to hydrogen	1.392	223	18.6
NG to hydrogen	0.715	99	14.1
Biomass to hydrogen	1.021	24	25.8
CNG	0.252	17	6.5
FT diesel	1.111	48	6.9
DME	0.550	23.	7.5
Coal to electricity	1.612	244	20.4
Natural gas to electricity	0.989	120	16.7
Biomass to electricity	1.679	23	32.8

Table S3 Summary Well to Tank results with CCS

Pathway	WTT primary energy expended per MJ final fuel	WTT CO2 eq per MJ final fuel	Fuel supply costs 10% discount rate Euro/GJ
Coal to hydrogen	1.766	39	23.5
NG to hydrogen	0.772	29	15.9
Biomass to hydrogen	1.314	-156	32.7
CNG	0.266	11	6.7
FT diesel	1.192	16	7.5
DME	0.557	12	7.7
Coal to electricity	2.063	75	23.2
Natural gas to electricity	1.217	40	19.6
Biomass to electricity	2.380	-255	48.2

Because of the chosen scenario assumptions, estimates without CCS are not directly comparable with the corresponding pathway in the JEC study. When computed using the same assumptions, however, estimates are in full agreement.

More energy is expended in the supply of alternative fuels than for the gasoline reference pathway. De-carbonisation of coal and woody biomass (to hydrogen and electricity) have the highest WTT energy expenditure. CCS can increase the energy loss by up to 40%; and de-carbonisation routes with their higher levels of carbon removal attract the highest penalty. CO_2 capture applied to non-biomass pathways reduces GHG emissions, in most cases, to levels within the range 11 – 40 g CO2 eq./MJ fuel supplied. The one exception is coal to electricity, where the relatively high emissions from coal supply are amplified by the low efficiency of power generation. Fuel costs vary widely and strongly dependent on primary energy costs and the scale of manufacturing plant. For the mid-point energy prices assumed in this report (see section 2.4.1) and world-scale plants sizes anticipated for 2010 – 2020 timeframe, results indicate fuel could be manufactured from remote gas and supplied into Europe at costs comparable with the cost of gasoline. De-carbonised fuels, however, cots between 1.5 and 4 times more than gasoline on energy

[6] Cost of supply for reference fuels taken from JEC Joint Study

content basis. CCS adds about a 15- 25% penalty to the cost of supplying de-carbonised fuels. The cost penalty is less (ca 2- 10%) for fuels from remote natural gas. Processes in which the CO_2 is present as a concentrated high-pressure stream have lower energy and cost penalties. Biomass routes are unique in that CCS results in a net removal of CO_2 from the pathway. Biomass results should be treated with caution, however, since a reduction in process efficiency leads to an increase in net CO_2 removal.

Well to Wheels (WTW) results obtained by integration vehicle performance data with WTT estimates are summarised as shown in table S4. For the WTW analysis, CO_2 is avoided relative to the 'business as usual' case of continuing with gasoline vehicle and fuel technology, and costs have been estimated on this basis (see section 2.4.7). As previously noted results are not directly comparable with the corresponding JEC pathway.

For all WTW pathways, vehicle energy efficiency is the key determinant of the overall energy consumption and greenhouse gas emissions. Vehicle energy efficiency determines the energy ranking of each pathway, and differences in vehicle technology generally exceed the penalties from CCS. Electric vehicles and fuel cell vehicles powered by hydrogen from natural gas have the lowest overall energy consumption ca. 100 – 170 MJ/100km, even with CCS. CCS adds a penalty of up to 25%. WTW energy consumption for each of these pathways is less than the gasoline reference pathway. With CCS, all decarbonisation routes show significant emission reductions over the gasoline reference case. Fossil fuel based routes provide for reductions of between 60 – 80% of GHG emissions over the reference case. Biomass routes benefit from a net removal of CO_2, but as noted previously these figures should be treated with caution, since an increase in vehicle energy efficiency reduces the net removal of CO_2.

WTW CO_2 avoidance costs are an order of magnitude greater than those expected for the cost of traded CO_2 in the immediate future, or costs estimated for avoiding CO_2 emissions in fuels manufacturing. The reason for this is that vehicle running costs are dominated by vehicle investment costs, which for some alternative fuel vehicles can be very significant.

Avoidance costs are lowest for hydrogen ICE vehicles, where the hydrogen is derived from biomass with or without CCS, and for CNG vehicles. Hydrogen from natural gas has, however, represents the lowest cost for avoiding significant quantities of CO_2 emissions. Avoidance costs tend to increase with increasing powertrain complexity. In nearly all cases, the most cost-effective pathways employ CCS combined with more 'conventional' powertrains.

Table S4 Summary WTW results

Alternative fuel pathway		Vehicle	WTW primary energy consumption MJ/100km	WTW GHG emissions gCO2eq/km	CO2 stored gCO2/km	CO2 avoidance costs relative to gasoline reference Euro/tonne 10% discount rate
Gasoline	-	Gasoline PISI 2010	218	165	-	-
FT diesel	without capture and storage	FT diesel with DPF	379	205	-	-
		FT diesel hybrid	312	169	-	-
	with capture and storage	FT diesel with DPF	393	157	52	-
		FT diesel hybrid	324	129	43	1089
DME	without capture and storage	DME DICI	267	158	-	-
		DME hybrid	219	129	-	1076
	with capture and storage	DME DICI	268	139	18	752
		DME hybrid	220	114	15	762
CNG	without capture and storage	CNG PISI 2010	239	141	-	475
		CNG Hybrid 2010	184	109	-	321
	with capture and storage	CNG PISI 2010	242	130	8	315
		CNG Hybrid 2010	186	101	6	282
Coal to hydrogen	without capture and storage	Hydrogen ICE	400	373	-	-
		Hydrogen ICE hybrid	356	332	-	-
		Direct hydrogen FC	224	209	-	-
		Direct hydrogen FC hybrid	200	186	-	-
	with capture and storage	Hydrogen ICE	463	66	356	479
		Hydrogen ICE hybrid	412	59	317	562
		Direct hydrogen FC	260	37	200	510
		Direct hydrogen FC hybrid	231	33	178	610
Natural gas to hydrogen	without capture and storage	Hydrogen ICE	288	167	-	-
		Hydrogen ICE hybrid	256	149	-	-
		Direct hydrogen FC	161	93	-	827
		Direct hydrogen FC hybrid	144	83	-	907
	with capture and storage	Hydrogen ICE	297	49	111	296
		Hydrogen ICE hybrid	265	44	99	392
		Direct hydrogen FC	167	37	62	420
		Direct hydrogen FC hybrid	148	33	56	524
Biomass to hydrogen	without capture and storage	Hydrogen ICE	339	41	-	293
		Hydrogen ICE hybrid	302	36	-	379
		Direct hydrogen FC	189	23	-	380
		Direct hydrogen FC hybrid	168	20	-	481
	with capture and storage	Hydrogen ICE	388	-261	294	109
		Hydrogen ICE hybrid	346	-233	262	144
		Direct hydrogen FC	217	-147	165	189
		Direct hydrogen FC hybrid	193	-130	147	249
Coal to electricity	without capture and storage	EV	133	111	-	-
	with capture and storage		156	34	108	918
Natural gas to electricity	without capture and storage	EV	101	61		-
	with capture and storage		112	20	48	805
Biomass to electricity	without capture and storage	EV	124	11	-	804
	with capture and storage		157	-118	144	468

Although biomass pathways have the lowest avoidance costs and greenhouse gas emissions these conclusion should be set in the additional context that:

- biomass resources are limited and only likely to make a marginal contribution to hydrogen supply;
- biomass conversion processes have low thermal efficiency;
- in the case of CCS, a lower efficiency increases the net quantity of CO2 stored, and has a beneficial impact on avoidance costs;
- conversion technology is only at the demonstration stage and is yet to fulfil the high performance expectations.

Transposing the findings of this study to the US market suggests that, with the lower efficiency of US vehicles and US refineries, CCS applied to alternative fuel pathways may provide a lower cost of avoiding CO_2 than that estimated for Northern Europe.

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1. Introduction

The IEA Greenhouse Gas Programme (IEA GHG) recently extended its range of activities to assess the potential for reducing greenhouse gas emissions from mobile sources (‘CO_2 abatement by production and use of gas to liquids transport fuels’, IEA GHG report Ph4/12). The study focused on the use of remote natural gas as a transport fuel and assessed the relative attractiveness of two routes by which remote gas can be brought to market:

- ‘direct use’ in which gas is liquefied, transported, vaporised, distributed through existing infrastructure and utilised as compressed natural gas (CNG);
- ‘indirect use’ in which the gas is first converted by the Fischer-Tropsch (F-T) process into a liquid hydrocarbon fuel and exported to market using existing infrastructure.

More recently, in December 2003, EUCAR[7], CONCAWE[8] and JRC (the Joint Research Centre of the EU Commission) published a joint evaluation of the Well to Wheels (WTW) energy use and greenhouse gas (GHG) emissions for a wide range of potential future fuel and powertrain options. Throughout the remainder of this report, the study is referred to as the JEC joint study[9]. The specific objectives of the JEC study were to:

- Establish, in a transparent and objective manner, a consensual WTW 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 study examined a comprehensive set of pathways by which a range of potential future transport fuels could be produced from primary energy resources.

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[7] EUCAR : The European Council for Automotive R&D
[8] CONCAWE : the oil companies’ European association for environment, health and safety in refining and distribution
[9] Well to Wheels analysis of future automotive fuels and powertrains in the European context TANK-TO-WHEELS Report Version 1, December 2003

The following matrix summarises the combinations that were included.

Resource	Crude oil	Natural gas	Coal	Nuclear	Wind	Land			
						Sugar beet	Wheat	Oil seeds	Wood
Fuel									
Gasoline	√								
Diesel	√	√							√
CNG		√							
Ethanol						√	√		√
FAME[10]								√	
DME[11]		√							√
Naphtha	√								
Methanol		√	√						√
Hydrogen		√	√	√	√				√

The JEC study results can be downloaded from the JRC web site:
http://ies.jrc.cec.eu.int/Download/eh

The study shows that the evolution of conventional gasoline vehicles will continue to improve and could yield 15-20% reduction in GHG emissions at modest incremental cost. Hybrid technologies offer the potential for deeper cuts, albeit at the expense of higher vehicle costs. If automobile systems with drastically lower GHG emissions are required in the longer term, hydrogen and electrical energy are the only identified options for “fuels”, but only if both are produced from non-fossil sources of primary energy (such as nuclear or solar) or from fossil primary energy with CO_2 capture and storage (CCS). Biomass has the potential to produce lower GHG emissions, although the supply of primary fuel sources is limited and the overall impact will be relatively small[12].

From an IEA GHG perspective, the next phase in its work is to leverage the substantial body of JEC study data in order to assess a wider range of alternative fuel and vehicle pathways, where capture and storage technologies could yield significant benefits. The specification for this work is as follows:

The study will focus on those fossil fuel pathways that, when combined with CCS, offer the potential for deep cuts in CO_2 emissions judged on a wells-to-wheels basis. The criteria for selecting the pathways for study are based on a combination of:

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10 FAME: Fatty Acid Methyl Esters, an alternative name for biodiesel, are produced by reacting vegetable oils with methanol.

11 DME: Dimethyl Ether produced by dehydration of methanol

12 See for example: ‘The market Development of Alternative Fuels – report of he Alternative Fuels Contact Group’, December 2003, page 3

- **Materiality of supply** – the primary energy source is sufficiently abundant at low cost to meet more that 30 % of transport fuel demand in the medium to long term;
- **Potential for deep cuts in GHG emissions** when combined with CO_2 capture and storage
- **Based upon demonstrated technology** - the fuel production technology should have been operated at a commercial or near commercial scale.
- **Require limited modification to the distribution and vehicle infrastructure.**

Applying these criteria, IEA GHG selected several pathways that employ either coal or gas as the primary energy source, with hydrogen as the energy vector for transport use. These pathways are of strategic importance to economies with substantial coal and gas reserves and represent a medium term step on the long-term path to an energy economy based on hydrogen. Synthetic diesel fuels based on DME, as carbon based transport fuels, and Fischer Tropsch liquids (i.e. paraffins) offer smaller GHG reductions but provide options that have little (or relatively little in the case of DME) impact on the vehicle or fuel distribution infrastructure. Synthetic fuels produced from remote natural gas, may also provide the means of monetising an otherwise stranded source of gas. The manufacture of these fuels is also proven commercially. Similarly, natural gas, liquefied at source with CCS, shipped, regasified and distributed within an existing pipeline network offers scope for moderate GHG reduction by a proven route.

Biomass, as a carbon-based renewable energy, has been added to the study to provide a comparison with a corresponding fossil fuel pathway.

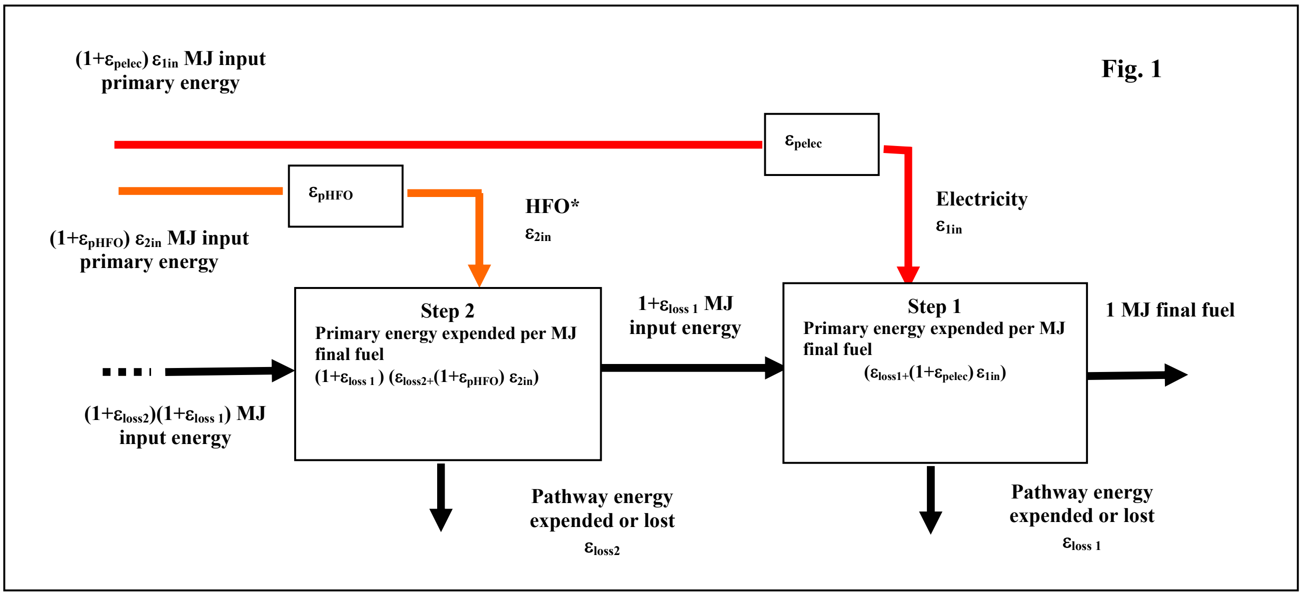
2. Study Assumptions

2.1 Methodology - supply pathway energy and emission balances

All supply pathways (Well to Tank) are divided into a subset of key steps (extraction and processing, transportation, conversion etc.) over which an energy balance is carried out. Balances over the full fuel cycle (Well to Wheels) are achieved by simple integration with vehicle performance data.

For each supply pathway, primary energy sources provide the upstream boundary and the transport fuel ready to be dispensed at the retail outlet provides the downstream boundary. The energy balance across each pathway step is based on the total energy expended per unit energy of main product. Expended energy is either imported (electricity, diesel etc.) or lost from the pathway. Where there are by-products, it is assumed that these displace an equivalent amount of production by another route and a credit/debit is taken for energy and emissions avoided/incurred. External energy expended in the process is traced back to its primary energy source and energy expended and emissions in its manufacture accounted for. Energy expended and emissions over the entire pathway are expressed per unit energy of final fuel. A typical energy balance is illustrated in Figure 1 for two hypothetical pathway steps. A primary energy supply (coal, crude, gas or biomass) flows through a series of steps to produce a transport fuel. The energy flow is termed the pathway energy. Pathway energy can be lost through auto-consumption[13](as in a chemical process) or by physical loss. External energy, say to provide motive power, can be added to the process (electricity for prime movers, fuel for transport etc.)

[13] Auto-consumption is a term often used to reflect that the inefficiency of a conversion process. Thus in the case of the conversion of natural gas to liquefied natural gas, a proportion of the gas is consumed to provide power for the liquefaction process.



* Heavy fuel oil

In Figure 1, the symbol ε represents energy expended from whatever source per unit of product energy (MJ). Step 1 represents a typical retail site. In order to dispense 1MJ of fuel to a vehicle, ε_{1in} units electrical energy is required to power pumps or compressors. Since ε_{pelec} units of primary energy are expended in producing 1MJ of electrical energy, the total input of external primary energy at the retail site is $(1+\varepsilon_{pelec})\,\varepsilon_{1in}$. There is also a small physical loss of dispensed fuel through leakage, $\varepsilon_{loss\,1}$. Adding these individual components, the total primary energy expended in step 1 is therefore $(\varepsilon_{loss1}+(1+\varepsilon_{pelec})\,\varepsilon_{1in})$ per MJ of final fuel dispensed. Because pathway energy is lost, $1+\varepsilon_{loss\,1}$ of fuel energy must enter step 1 in order to dispense 1MJ. This becomes an 'energy multiplier' for step 2. Step 2 represents a marine transport step. In order to deliver 1 MJ of fuel, ε_{2in} of HFO are consumed in marine boilers. Since ε_{pHFO} units of primary energy are expended in producing 1MJ of HFO, the total input of external primary energy is $(1+\varepsilon_{pHFO})\,\varepsilon_{2in}$. Again, a small quantity, ε_{loss2}, of transported fuel is expended in the shipping process (for example, in the case of LNG this would be vaporised natural gas fed to the marine boilers). The total primary energy expended in step 2 is therefore $(\varepsilon_{loss2}+(1+\varepsilon_{pHFO})\,\varepsilon_{2in})$ per MJ of transported fuel. The total energy expended per unit of final fuel is now $(1+\varepsilon_{loss\,1})(\varepsilon_{loss2}+(1+\varepsilon_{pHFO})\,\varepsilon_{2in})$. The 'energy multiplier' for step 3 is $(1+\varepsilon_{loss\,1})(1+\varepsilon_{loss2})$. Where there is significant auto-consumption of fuel in the pathway, as in a chemical conversion process, the 'energy multiplier' can have a significant impact on pathway energy consumption. This approach is continued up to source of pathway energy. The total primary energy expended in the pathway, is the sum individual estimates of primary energy per unit of final fuel dispensed in each step.

Where there are by-products, as in the case of FT diesel, a modified approach has been used. In this case, diesel fuel is the main product of the conversion process and naphtha is a by-product. Naphtha is assumed to displace, at the margin, an equivalent quantity that would be produced with the refining system (see section 2.3). Energy expenditure is expressed as the total energy consumed per MJ of FT diesel product. Since refinery naphtha is displaced, energy expenditure attracts a credit for the associated primary energy saved.

Calculation of Greenhouse gas emissions follows the same methodology. Emissions are estimated for the three key greenhouse gases per unit energy of the main product of the process. The aggregate figure, expressed as grams CO_2 eq. per MJ main products (see section 2.4.5), is then referenced to the final fuel dispensed using the "energy multiplier."

Individual data items for each stage of the pathway were sourced initially from the joint JEC study. Where necessary these were updated to be consistent with the study scenario and previous work by IEAGHG. Thus, for example, process data, which are a key determinant in assessing the impact of carbon capture were taken from previous IEAGHG studies or from data provided by process vendors. Similarly, JEC data were updated to reflect the different transport distances to and within the Netherlands market. All data used in the study are provided in Appendix I.

The calculation process described above is essentially the same as that used in the joint JEC study and has been validated using unmodified JEC data to generate WTT for the comparable JEC pathways.

2.2 Reference pathway

In order to assess the impact of alternative fuel pathways on overall primary energy consumption and greenhouse gas emissions, and to estimate the emission avoidance cost, each pathway has been compared with a "business-as-usual" base case where transport fuel demand continues to be met by conventional gasoline produced from crude oil.

Oil refineries produce a number of different products simultaneously from a single feedstock. Although, for a given refinery configuration, the total amount of energy used to produce the slate of products can be estimated, there is no easy 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 assumptions that can have a major influence on the results.

Inevitably, adoption of a single approach has led to controversy between advocates of alternative approaches, which seek to deal with the complex interactions within the refining system in a manageable way. In this study, we have adopted the marginal substitution approach developed in the JEC joint study (see section 2.3.1). All results presented in section 3 of this report are derived on this basis.

For the single case of synthetic diesel, a second approach, the life cycle approach developed for Gas to Liquids (GTL) products by Shell and others[14], has also been examined for comparison purposes. The GTL approach is discussed in section 2.3.2.

2.2.1 Marginal substitution

To approach the problem the JEC study performed a marginal analysis of the European refining system using a model called the JEC STUDY 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 fuel cases, conventional gasoline and/or diesel demand is reduced by an amount equivalent to the level of substitution (ca. 10-20%). 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). The maximum sulphur contents of gasoline and diesel are assumed to be10ppm. 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 is estimated from a marginal change in gasoline or diesel fuel production. Full fuel cycle supply figures used in this report are as summarised in Table 1.

Table 1. Estimated Well to Tank energy and GHG emissions for marginal conventional fuels [source: JEC joint study]

	Best estimate Energy expended MJ/MJ fuel supplied	Range of estimates	Best estimate CO2 eq. emitted g/MJ fuel supplied	Range of estimates
Marginal gasoline	0.14	0.12 – 0.17	12.6	11 - 15
Marginal diesel	0.16	0.14 – 0.18	14.4	12.5 - 16
Marginal naphtha (ex refinery)	0.06	-	7.9	-

2.3 Market supply scenario

The present study scenario is set in The Netherlands in a 2010–2020[15] timeframe assuming a general imperative to minimise greenhouse gas emissions in all sectors. It is assumed that power generation and other large-scale energy consumption industries have

[14] Gas to Liquids Life Cycle Assessment Synthesis Report August 2004 prepared for ConocoPhillips, SasolChevron and Shell International Gas by Four Winds International.

[15] The study examines a range of options of quite different technological maturity. The timeframe represents a future time when the technology has reached a commercial stage and transitions costs to build infrastructure have already been incurred.

already implemented low carbon strategies so that infrastructure exists and the technology supporting fuels manufacture is available. For pathways incorporating CCS, this implies that CO2 storage is practised and that external energy supplied to the pathway, for example electricity, reflects the extra cost.

The study is based on a market of 1 million alternative fuel vehicles, some 16% of the country's current 6 million vehicles. The Netherlands is heavily urbanized, with about 89% of the population living in towns and cities. The average distance between filling stations is small, and it is assumed that the retail market has moved beyond the transition stage and is approaching a steady state in which one sixth of the ca. 4000 filling stations, some 670, have needed to invest in alternative fuelling facilities to serve the 1 million cars[16]. Alternative fuel vehicles have the same utilisation and journey patterns as the average vehicle. Similarly, market maturity is such that insurance, maintenance and resale value will not incur additional cost penalties for alternative fuel vehicles.

2.3.1 GTL approach

The GTL life cycle approach used by Shell and others adopts a very different basis for assessing the impact of alternative fuels. In this case, two systems, one based on crude oil and the other based on natural gas, which provide an equivalent range of products and services to the market, are compared. In this report, data based on the Shell Middle Distillate Synthesis (SMDS) are used[17]. Figure 2 illustrates the components of the two systems.

The refinery system, the "business-as-usual" case, involves the production and use of a range of products arising from the refining of crude oil. Analysis is based on a 330kbbl/d refinery located in Western Europe operating with a thermal efficiency of 92%.

[16] The assumption implies a small number of large alternative fuel stations with an average distance between stations, which is larger than current practice. The assumption is not based on a detailed analysis of marker development but considered reasonable given a highly urbanized society.
[17] Private communication F Van Dijk GTL Global Development

Fig. 2

Crude oil →

Refinery products	Service provided
LPG	Space heating
Mogas	Road transport
Naphtha	Petrochemicals
Diesel	Road transport
Kerosene	Air transport
Light fuel oil	Space heating
Heavy fuel oil	Electricity generation
Base oil	lubricants

Remote gas →

GTL products	Service provided
LPG	Space heating
Naphtha	Petrochemicals
Diesel	Road transport
Base oil	Lubricants

+

Local gas providing additional products and services →

Additional products	Service provided
Mogas	Road transport
Kerosene	Air transport
Natural gas (LNG)	Space heating
Natural gas (LNG)	Electricity generation

The GTL system involves the production and use from SMDS plus production (and use) of other products meeting additional functions arising from the refining of crude oil (mogas and aviation kerosene). The SMDS comparison case is a 13,000 tonne/day plant operating with a thermal efficiency of 66% (note this figure higher than the 58% efficiency figure used in this report and the 63% figure used in the JEC joint study).

On a system-to-system comparison, the GTL system has the advantage that GHG emissions are reduced because carbon intense fuels (light and heavy fuel oil) are replaced by hydrogen-rich natural gas. Overall, primary energy consumption of the GTL is some 17% - 29% higher.

Shell's estimates for daily GHG emissions from the above systems are shown in Table 2.

Table 2. Comparative WTW GHG emissions for refinery and SMDS systems [source: F Van Dijk Shell GTL Global Development]

Product/Service	Refinery system WTW GHG emission tpd CO_2 eq.	SMDS system WTW GHG emission tpd CO_2 eq
Light duty vehicle - mogas	36,746	36,746
Light duty vehicle- diesel	10,841	12,362
Heavy duty vehicle	25,329	29,643
Aviation	15,981	15,981
Petrochemicals	6,823	8,317
Space heating	36,910	27,301
Electricity	32,265	21,877
Base oils and n-paraffins	673	1,375
Total	165,567	153,603

The data show that for the full system, the GHG impact of crude oil refining is 8% greater than SMDS; the higher emissions from the production of GTL fuels is more than offset by a reduction in emissions from lower carbon intensive fuels for space heating and electricity generation.

Estimates of GHG emissions for light duty diesel vehicles derived from the above data are summarised in Table 3. Data from the JEC joint study are included for comparison.

Table 3. Comparative WTW GHG emissions for light duty diesel vehicles meeting Euro III standards [source: F Van Dijk Shell GTL Global Development]

	Refinery system WTW GHG emission g CO_2/km.	SMDS system WTW GHG emission g CO_2/km.
Light duty DICI vehicle – Shell GTL life cycle assessment	172	196
Light duty DICI vehicle – JEC joint study	164 (159 – 168)[18]	187 (179 –196)

The data in Table 3 indicate that, within the range of uncertainty, the overall energy consumption and GHG emissions from the basic GTL system are very similar for both the Shell study and the JEC study. Where the Shell study differs is in considering the effect of GTL fuels on the overall product market. They assume that GTL will replace petroleum diesel and naphtha, but that gasoline and jet fuel will continue to be produced from crude oil. Crucially, the study assumes that there will be a reduction in crude oil refining, meaning that less heating oil and heavy fuel oil will be produced, and that the shortfall is replace by natural gas. As in the JEC study, the production process for GTL diesel and naphtha gives slightly higher GHG emissions than crude-derived products. The overall balance is influenced by a large credit for replacing heavy fuel oil in electricity generation. The assumptions in the Shell study are inputs to the model, they are not a consequence of the calculation methodology, and there is no industry consensus that introduction of GTL fuels will actually lead to these trends. Some industry experts consider that refineries will adapt progressively both to GTL availability and to demand

[18] Denotes maximum and minimum estimates from JEC joint study

growth, and that GTL introduction will have no effect on the switch from HFO to NG. Because of the complexity and uncertainty of forecasting future market movements, the simpler approach used in the JEC WTW study has been used in this work.

2.4 Economic assessment criteria

All costs assessment are in Euro and based on the fixed rate of 1Euro=1$US.

2.4.1 Energy prices

Primary energy prices are based on standard IEA assessment criteria (ref. Appendix III) and summarised below.

Table 4 Summary of primary energy prices

Primary energy Source	Heat Content (LHV) MJ/kg	Centre price Euro/GJ	Range Euro/GJ
Coal	25.9	1.5	0.60 – 2.6[19]
Gas delivered by pipeline to Netherlands border.	48.5	3.0	1.8 – 4.1[20]
Remote gas	48.5	1	0.5 – 1.5
Crude Oil cif	42	4.6[21]	-

Cif pricing assumes price at Netherlands border and excludes internal distribution to point of use.
In addition to primary energy costs, some pathways require the use of external energy sources (electricity, diesel and heavy fuel oil (HFO)). The price set used is that assumed in the joint JEC study is summarised in Table 5.

Table 5 Fuel and electricity prices

External fuel costs without CCS		
Electricity (MV –10kV)	5.8	Euro¢//kWh
Electricity (LV –0.4kV)	6.5	Euro¢//kWh
Road transport diesel (commodity price)	5.9	Euro/GJ
Road transport diesel (retail price)	8.4	Euro/GJ
HFO (commodity price)	2.5	Euro/GJ
Gasoline (retail price)	8.7	Euro/GJ
Diesel retail price	8.4	Euro/GJ

[19] Based on variability of imported European coal over 20 year period - BP Energy statistics
[20] Based on the variability of pipeline gas imported into the EU over a 20-year period - BP Energy statistics. Price standard deviation 0.7 Euro
[21] Equivalent to a price of 25$/bbl

For a scenario incorporating CCS, the technology would already be largely implemented in power generation. Prices have been amended to reflect such changes in Table 6.

Table 6 Electricity prices with CCS

External fuel costs with CCS		
Electricity (MV –10kV)	7.6[22]	Euro¢/kWh
Electricity (LV –0.4kV)	8.3	Euro¢/kWh

Where the energy is used as a feedstock, physical and chemical properties are those summarised in section 2.4.5. Where energy is locally imported, an appropriate EU-mix composition as specified in the JEC study has been used

2.4.2 Production plant

Where possible, process plant performance and cost data have been taken from previous IEA GHG studies, which are based upon a similar market scenario. Where these have not been available, data have been sourced from process suppliers or from the open literature. As a result, cost estimates are appropriate to the year in which the estimates have been made. Data have been brought to a base year, 2003, using a set of price escalation factors appropriate to plant constructed in Northern Europe[23] (see Table 7).

Table 7 Capital cost escalation factors

Year of estimate	Escalation factor
2003	1.00
2002	1.03
2001	1.05
2000	1.08
1999	1.10
1998	1.13
1997	1.16
1996	1.19
1995	1.22
1994	1.25

Uncertainty of capital cost estimates depends upon many factors, including the level of engineering definition, and potential technological advance in both process and construction technology. The majority of plants described here represent proven

[22] CO_2 Capture and storage add approximately 1-3 Euro¢/kWh to the cost of electricity depending on the reference technology. A figure of 1.8 Euro¢/kWh has been used which assumes that NGCC and IGCC are the main fossil fuel technologies
[23] Private communication Foster Wheeler

technology; and cost estimates are based on sufficient definition to be within +/-25%[24]. Biomass plants are, however, still in the development stage and costs are more speculative. In the absence of a consistent approach to cost estimation in each pathway, a level of uncertainty of +/- 30% has been assumed for all plant.

Assessment criteria for production plant are, unless contractor experience dictates otherwise, those specified in Appendix III. For consistency, labour costs are based on a basic cost per operator of 30,000 Euro/annum plus the additional overheads specified in Appendix 1. A decommissioning charge of 3.5% of the original investment is assumed. Capital expenditure phasing has been assumed the same for all plant.

For plant constructed in the Netherlands, a coastal site is assumed and plant is assumed self-sufficient in utilities. Cooling, where required, uses seawater. For plants processing remote natural gas, construction of a plant self-sufficient in utilities at a coastal site has also been assumed. For remote gas, investment costs relative to the Netherlands have been estimated using a location factor of 0.95, which is typical of the Gulf States. In all cases, world scale plant, based on process supplier guidance, has been assumed.

Estimates of manufacturing cost have been made using a full discounted cash flow approach.

2.4.3 Distribution networks and retail sites

Gaseous fuels and CO_2 to storage are distributed by pipeline. Cost estimates have been made using the IEA GHG Energy Distribution and CO_2 Capture Estimation Model [25]. Retail site cost data are those used in the joint JEC study. For both sets of assets, fuel supply cost estimates have been estimated using a capital charge factor based on an appropriate asset life.

Table 8 Summary of capital charge factors

Asset	Asset life Years	Investment period	Capital charge factor	
			5% discount rate	10% discount rate
Pipeline	25	50% year 1 50% year 2 full operation year 3	7.3	11.6
Retail site investments	15	100% year 1 full operation year 2	9.6	13.1

[24] A +/-25% estimate would normally imply that engineering has progressed to provide sufficient definition for estimating purposes (preliminary equipment sizes, equipment process / mechanical specifications, preliminary plot plans, layouts, etc). Costs are expected to have a 90% probability of being within this range.

[25] A model description can be found in 'Pipeline Transmission of CO2 and Energy Transmission Study' Woodhill Report No. 2164brt8001c – February 2001

2.4.4 Carbon Dioxide storage

For the purposes of comparison, CO2 separated from a process stream is compressed to 110 bara and transported via 100 km pipeline to an onshore storage location. The IEA GHG models cited above have been used to estimate storage costs and associated emissions.

2.4.5 Fuel properties and emission factors

Common parameters for each feedstock, intermediate and final products are summarised in Tables 9 - 11. CO_2 emission factors are the amount of CO_2 emitted when 1MJ of the material is completely combusted.

Table 9 Common parameters of gas streams

	Natural Gas IEA GHG reference[26]	Hydrogen
Heat content (LHV) MJ/kg	48.51	120.1
kg/kWh	0.074	0.030
kWh/kg	13.48	33.36
kWh/Nm^3	11.64	2.98
Molecular mass MM, g/mol	19.352	2.0
Carbon content % m	74%	-
CO2 emission factors g CO_2/MJ	56.1	-
kg CO_2/kg	2.72	-

Table 10 Common parameters of liquid streams

	FT diesel	DME[27]	HFO
Density kg/m3	780	670	970
Heat content (LHV) MJ/kg	44.0	28.4	40.5
kg/kWh	0.082	0.127	0.089
kWh/kg	12.22	7.90	11.25
Carbon content % m	85%	52%	89%
CO2 emission factors g CO_2/MJ	70.8	67.3	80.6
kg CO_2/kg	3.12	1.91	3.26

Table 11 Common parameters of solid streams

	Coal IEA GHG reference	Wood
Heat content (LHV dry) MJ/kg	28.6	18.0
kg/kWh	0.126	0.200
kWh/kg	7.94	5.00
Carbon content (dry) % m	72.4%	50.0%
CO2 emission factors g CO_2/MJ	92.9	101.9
kg CO_2/kg	2.66	1.83

[26] See Appendix III – IEA assessment criteria

[27] These data refer to pure DME fuel grade DME would contain small quantities of methanol and water and would have slightly higher density and lower heat content

The study provides estimates of the key greenhouse gas (GHG) emissions (CO_2, CH_4 and N_2O) at each stage within a pathway. For conversion of the different GHG gases to CO_2 equivalent, the following conversion factors have been used[28]

Table 12 IPCC emission factors

Global warming potential (reference to CO_2 = 1)	
Methane	23
N_2O	296

2.4.6 Vehicles

All vehicle data used in this study are those adopted in the joint JEC study and involve advanced powertrain concepts that could be commercial within the study timeframe. The concepts include advanced conventional and fuel cell powertrains and their associated hybrid vehicle architectures. All data are based on the simulation of a common 'virtual vehicle' based on a typical European compact-sized 5-seater sedan e.g. VW Golf. Advanced powertrains are incorporated in the same body shell and chassis configuration. The impact on mass and cost is assessed using the methodology described in the MIT study 'On the road in 2020'[29] in which mass and cost are adjusted based on added or eliminated components. A 2002 gasoline powered vehicle specification and performance is used as a reference. Emission targets for all vehicles are based on EURO IV[30] requirements. Powertrain efficiency and associated CO_2 emissions are based upon the ACEA[31] voluntary commitment of 140g/km for 2008 and the European Commission requirement aiming at 120g/km for 2012. Performance is assessed on a fuel storage capacity to ensure a minimum range of 600 km.

All vehicles have been simulated the New European Drive Cycle (NEDC) used for all certifications in Europe. The 2002 reference vehicle was based on real engine performance data. For 2010 vehicle performance data were modified to take into account improvements that could be expected within this timeframe.

The study examines full pathway energy efficiency, emissions and costs for the following powertrain and fuel combinations.

[28] IPCC 2001: Climate Change 2001: the Scientific Basis. Contribution of Working Group 1 to the Third Assessment Report of the Intergovernmental Panel on Climate Change.

[29] 'On the road in 2020 - A life-cycle analysis of new automobile technologies', Weiss et. Al. , MIT Energy Laboratory Report # MIT EL 00-003, October 2000.

[30] European Union emission regulations for light duty vehicles - the Euro IV emission standards for gasoline and diesel cars come into force on 1st January 2005

[31] The so-called ACEA Agreement is a voluntary agreement between the European Union and European, car manufacturers to reduce the average new car fleet carbon dioxide emission.

Table 13 Vehicle and powertrain concepts used in this study

Vehicle Power train concept	Comment
Gasoline port injection spark ignition (PISI) engine with 2010 level technology	Reference vehicle against which other powertrain/fuel systems are assessed – incorporates expected 2010 state-of-the-art powertrain technology; engine size – turbo-charged 1.6 Litre.
Direct injection compression ignition (DICI) engine with particle filter (PF) and 2010 level technology operating on synthetic diesel	Particulate filter may be required to meet Euro IV emission standards. Particle filter will certainly be required to meet Euro V standard; engine size turbo-charged 1.9 Litre
ICE hybrid	Parallel hybrid system with 2010 ICE and supplementary 14kW motor. 6kWh Li-ion batteries provide 20 km ZEV range
Direct injection compression ignition (DICI) engine without particle filter but including 2010 level technology operating on Dimethyl Ether (DME) fuel	Clean burn properties of DME make particle filter unnecessary
DME Hybrid 2010	Same as for synthetic diesel
CNG PISI engine with 2010 level technology	Dedicated CNG engine uprated to 2.0Litre and increased compression ratio. Requires high-pressure tank (20MPa) for fuel storage. Incorporates expected 2010 state-of-the –art powertrain technology leading to small efficiency improvements
CNG Hybrid 2010	The availability of the electric engine allows engine to be down rated to 1.6 Litre. Otherwise same as for synthetic diesel
Hydrogen internal combustion energy (ICE)	Dedicated hydrogen 1.3 Litre turbocharged engine operating at turbo charging rate (about 1.8:1) in lean-burn mode. Hydrogen stored at 70MPa[32] in state-of-the-art tank capable of holding 9kg fuel.
Hydrogen ICE hybrid	Same as for synthetic diesel
Direct Hydrogen PEM fuel cell	Proton exchange membrane (PEM) fuel cell supplied with on-board hydrogen in a high-pressure tank (70 MPa) driving an asynchronous electric motor.
PEM fuel cell hybrid	The term hybridisation here refers to the addition of a large battery capable of storing recovered braking energy and contributing to the powertrain energy supply.
Electric vehicle	75 kW motor powered by 58 kWh Li-ion batteries and incorporating braking energy recovery. This combination only sufficient for reduced range - minimum of 350 km

[32] Daimler-Chrysler and Hyundai are now using pressure vessels capable of ca 35 MPa. Research work is currently being conducted on pressure vessels of up to 70 MPa which permit a 600 km driving range. It is assumed that this technology is available within the scenario timeframe. Hydrogen is stored at higher pressure at the retail site to ensure rapid filling. Data reference ‘ Carbon to hydrogen roadmaps for passenger cars: report for the DTI’, Ricardo Engineering 2002.

In the WTW analysis presented in this report, all data are compared with the gasoline reference case. Gasoline reference vehicle performance and cost data are summarised in Table 14. Vehicle performance and cost data for other vehicles are summarised in the appropriate section of Appendix I.

Table 14 Energy consumption and GHG emissions from the gasoline reference vehicle

	Energy consumption MJ/100km	GHG emissions gCO2eq/km	Vehicle cost Euro
Gasoline 2010 PISI	190	140	19,280

This study includes a battery-powered vehicle, which had not been considered in the JEC study. Vehicle performance has, however, been based on an identical vehicle subsystem and components; its performance has been assessed using the same software[33] used for the JEC study, on identical drive cycles. For the EV, a range of 600km results in an unrealistic battery requirement and for this vehicle the range was reduced to 350km. Details of this vehicle are provided in Appendix I.

Assessment of the cost of substituting a certain quantity of gasoline and/or diesel with an alternative fuel can be done from different perspectives[34]:

- Overall cost for society in the longer term where a certain level of substitution (say 5-10%) will have taken place.
- Transition cost covering up-front additional investment and additional cost for infrastructure and vehicles until mass-production and full utilisation takes over.
- Cost of ownership, that is the cost structure for the owner or operator of the natural gas vehicle.

For any strategy aimed at substituting existing fuels, all elements have to be acceptable. Policy instruments such as taxation and regulation impact all elements. In this study, we have focused only on the long-term untaxed cost of ownership. The transition costs, which are critical to any substitution strategy, are deemed relevant only when the long-term benefits of the alternative fuels have been understood. The long-term cost of vehicle ownership comprises a number of elements:

- Vehicle retail price benefiting from mass production
- Vehicle resale price
- Fuel operating costs
- Maintenance

[33] The software is a modified version of ADVISOR; the electric vehicle case has been assessed for this study by IFP.
[34] 'The Market Development of Alternative Fuels - Report by the Alternative Fuels Contact Group', December 2003.

- Insurance

In this study, the market has been assumed to reach a level of maturity where full investment has been made in maintenance infrastructure (training facilities, etc.). Differential maintenance and insurance costs and resale value of alternatively fuelled vehicle is assumed to be small. The study estimates an annualised cost of ownership per 100km travelled based on an average annual mileage of 16,000km and vehicle cost amortised over 10 years with constant interest rate of 10%, with a 5% interest rate included as a comparison case.

2.4.7 Avoidance costs

In this study, the cost of avoiding the emission of greenhouse gases has been estimated for fuels manufacture and for WTW emissions. The definition in each case is different.

For fuels manufacture, emissions are avoided by incorporating CCS. The cost of avoidance (Euro/tonne CO2 avoided) for this case is defined as:

$$\frac{\text{(Fuel cost with CCS (Euro/GJ) – Fuel cost w/o CCS (Euro/GJ))}}{\text{(CO2 eq. emissions w/o CCS (tonne/GJ) – CO2 eq. emissions with CCS (tonne/GJ))}}$$

For the full Well to Wheels (WTW) analysis, CO_2 is avoided relative to the 'business as usual' case of continuing with gasoline vehicle and fuel technology. The cost of avoidance (Euro/tonne CO_2 avoided) for this case is defined as:

(Running cost[35] for alternative fuel and vehicle (Euro/100km) – Running cost for gasoline reference (Euro/100km))

((WTW CO_2 eq. emissions gasoline ref (tonne/100km) – WTW CO_2 eq. alternative fuel and vehicle (tonne/100km))

In the latter case the denominator can have zero or close to zero values. As a result, avoidance WTW avoidance costs can have a wide range of values.

2.5 Dealing with uncertainty

Virtually all data used in analysing fuel pathways is estimated and in many cases represents an average of data collected from a wide range of operating practices. Representation of a single value energy loss or emission level for a pathway implies a

[35] Running costs are defined as the annualised cost of ownership per 100km travelled based on an average annual mileage of 16,000km and vehicle cost amortised over 10 years with constant interest rate of 10%, with a 5% interest rate included as a comparison case (see section 2.4.6).

level of certainty, which may well be misplaced. In order to account for the effect of uncertainty of input data on outputs (energy loss, total GHG emissions, fuel costs, CO2 avoidance costs etc.), uncertainty has been included explicitly in data estimates to generate results that show the range of possible outcomes. Pathways have been modelled using the @RISK package for Excel supplied by the Palisade Corporation. @Risk uses simulation, sometimes called Monte Carlo simulation, to carry out the uncertainty analysis. Simulation in this sense refers to a method whereby the distribution of possible outcomes is generated by repetitive recalculation of a spreadsheet model for all valid combinations of the values of input variables.

In the analysis represented in this report, all key input data, that is those data that have a significant impact on outputs, have been represented by probability distributions. The distributions are:

- Normal – for data distributed symmetrically about the Mean value. All capital costs, some fossil fuel supply costs and process energy efficiency have been represented by normal distributions.
- Triangular – for data where and maximum and minimum and most likely values are assumed. The distribution need not be symmetrical. Data averaged from a range of reported operating practice have been represented in this way.
- Uniform – where there is an equal chance of a value being between the maximum and minimum value. The number of dispensers on a filling station has been represented in this way.

In this report, data are represented as a best estimate, based on what is judged to be the most likely value, and a range, representing and upper and lower bound for the data. In the case of data represented by normal distributions, two conventions have been used. In order to ensure fair comparison with published data (primarily that sourced from the joint JEC study), the upper and lower bounds for input data represent the 20% (P20) and 80% (P80) probability levels, that is 60% of the data are expected to lie within the range. The exception to this is capital costs. In this, following the convention used in evaluation of process plants, upper and lower bounds for input data represent the 5% (P5) and 95% (P95) levels, that is 90 % of the data are expected to lie within the range[36]. All output data presented in this report are based on the estimated mean, 5% and 95% probability points.

An important output of the analysis is the assessment of sensitivity, which identifies the sensitivity of the output values to changes in each of the input variables. This analysis highlights those steps in the pathways and their associated assumptions, which are important in determining the output values, and where attention should be focused in any future work.

[36] For a normally distributed variable, there is a 90% probability that the value will fall within a range of 1.65 standard deviations. The P5 and P95 points can therefore be used to estimate standard deviation.

The results of a sensitivity analysis using multivariate stepwise regression are illustrated in Figure 3. In such a regression analysis, the input data sets are fitted to a planar equation that provides a best estimate of the output data set. The sensitivity values are the normalised regression coefficients associated with each input; a coefficient of 1 indicates a change in output of one standard deviation for one standard deviation change in each of the input variables. Standard deviations can be estimated form the P5 and P 95 values. Since the coefficients are normalised to standard deviation, the likely impact on output variables will be reflected by the coefficients if variation of the input variables are at similar probability level within their assumed range of uncertainty.

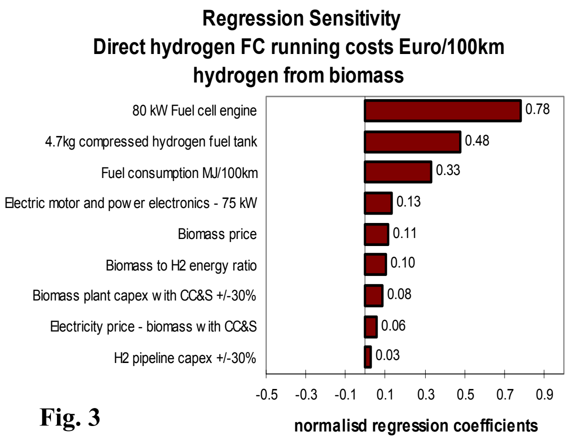


Fig. 3

In the illustration, the output variable is the running cost of a direct hydrogen fuel cell vehicle (hydrogen produced from biomass). In this example, 45 input variables were tested in the sensitivity analysis; in Figure 3, the nine highest coefficients of these variables are presented, ranked in order of significance. The analysis indicates that the running costs of the vehicle are particularly sensitive to variation in engine cost, fuel tank cost and fuel consumption and only slightly sensitive to the fuel supply cost variables. In this study, all variables with coefficients less than 0.1 are considered insignificant and have been ignored. The results for each pathway are presented in this form below, which is much more compact way of presenting the data than the traditional sensitivity diagram.

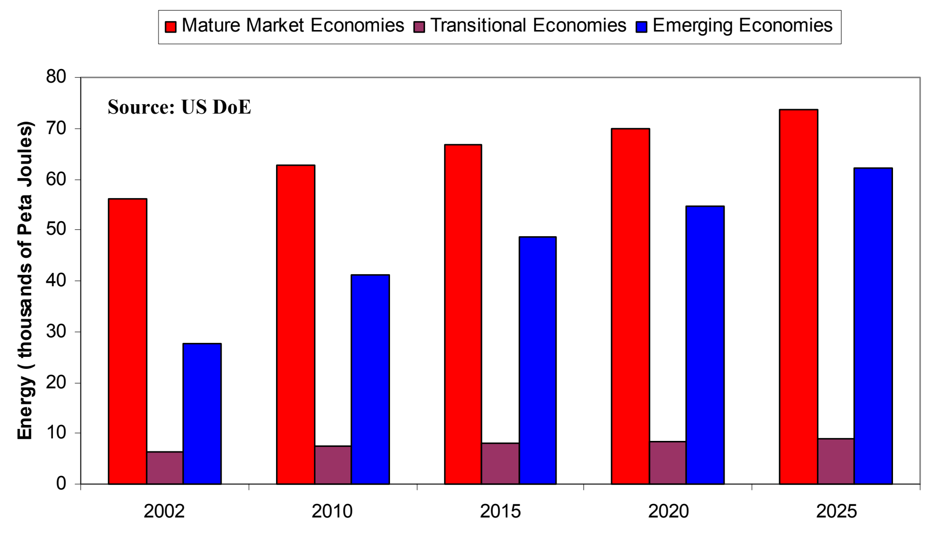
2.6 Outlook for transport fuel markets

In 2004[37] the US DOE projected an annual average growth in the world's energy use of 2.1 percent. Energy use in the transportation sector is dominated by petroleum product fuels, and barring any increase in the penetration of new technologies, such as hydrogen-fuelled vehicles, alternative fuels are not expected to become competitive with oil before 2025. Transport fuel growth is, therefore expected to mirror the growth in the world's energy.

[37] US DOE International Energy Outlook 2004

For the emerging economies as a whole, transportation sector energy consumption is projected to grow by 3.6percent per year. Energy use for the transportation sector is poised for its strongest growth in the Asian emerging economies. China is the key market that will lead regional consumption growth. India is also on a rapid growth path, and the region's mid-sized markets, such as Thailand and Indonesia are projected to post strong growth. In China, the number of cars has been growing by 20 percent per year, and the potential growth is almost unlimited. If the present patterns persist, China's car ownership would exceed the U.S. rate by 2030. Large infrastructure barriers will, however, have to be overcome for this to happen.

Fig 4a Transport energy demand forecast 2002-2025

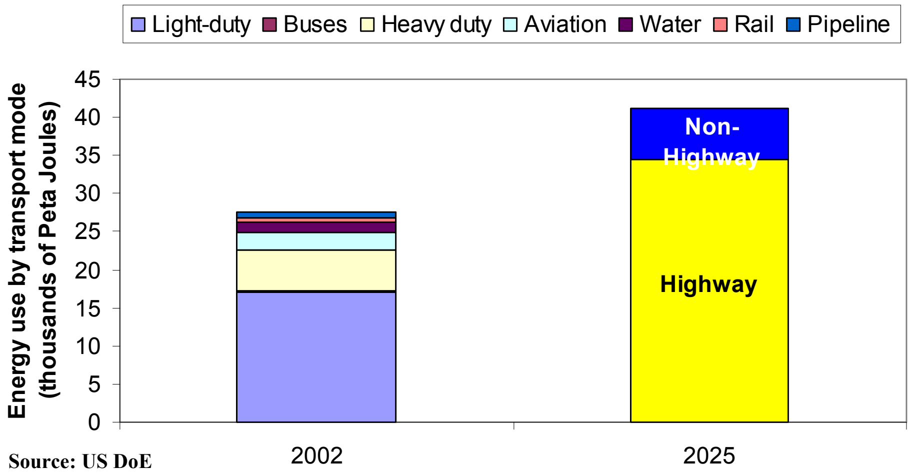


In general, the transportation sector of the mature market economies is fully established, with extensive infrastructure that includes road, railways and airports. Energy demand in the mature market economies is projected to grow at an average annual rate of 1.2 percent[38].

The United States is the largest user of transportation energy among the mature market economies and is projected to consume 56 percent of the mature market's total for the transportation sector in 2025. In the United States, transportation accounts for almost 25 percent of the country's total energy consumption and, of this some, 80 percent is consumed in road vehicles. Transport fuel growth is projected to rise at an average rate of 1.9 percent per year. Non-highway transportation modes accounted for about 20 percent of total U.S. transportation energy use in 2002, and their share is projected to be only 1 percentage point higher in 2025.

[38] US DOE World Energy Outlook 2005

Fig. 4b **Energy by transport mode for the United States**



Source: US DoE

Although strong macroeconomic and demographic factors are expected to increase the demand for larger, more powerful vehicles in the United States, advanced technologies and materials are also expected to improve new vehicle fuel economy. Fuel economy for the U.S. light-duty vehicle stock is projected to improve by 5 percent over the next 20 years. Over the same period, freight-truck fuel economy is projected to increase by ca 10 percent, whilst a larger gain of 24 percent is expected for aircraft.

Alternative fuels are projected to displace some light-duty vehicle fuel consumption in 2025, in response to current environmental and State energy legislation intended to reduce oil use, such as the California Low Emission Vehicle Program, which sets sales mandates for low-emission, ultra-low-emission, and zero-emission vehicles. Advanced technology vehicles, representing automotive technologies that use alternative fuels or require advanced engine technology, are projected to reach 3.9 million vehicle sales per year in the United States and make up 19 percent of total light-duty vehicle sales in 2025. Alcohol flexible-fueled vehicles are projected to continue to lead advanced technology vehicle sales, at 1.4 million vehicles in 2025. Hybrid electric vehicles, introduced into the U.S. market by Honda and Toyota in 2000, are expected to sell well: 750,000 units areprojected to be sold in 2010, increasing to 1.1 million units in 2025. Sales of turbo direct injection diesel vehicles are projected to increase to 716,000 units in 2010 and 1 million units in 2025.

Energy demand for transportation in Western Europe is projected to grow at the comparatively slow pace of an average of 0.3 percent per annum. The transportation sector’s share of total energy use is projected to decline from 23 percent in 2001 to 21 percent in 2025. Low population growth, high taxes on transportation fuels, and environmental policies are expected the main factors limiting growth. Demand for aviation fuel shows the fastest growth among transportation fuels. Demand for diesel fuel is projected to increase more rapidly than demand for gasoline, because of tax advantages.

3. Summary results

Table 15 summarises the pathways examined in this study.

Table 15 Summary of pathways examined in this study

Transport energy vector	Description	Comment
Gasoline and diesel	Gasoline and diesel produced in an average EU refinery configuration to anticipated 2010 specification and transported to retail site.	Gasoline used as a "business as usual" reference case with data taken from the JEC joint study
CNG from LNG	Remote natural gas, liquefied locally, shipped, regasified near-to-market and distributed by existing medium pressure/low pressure network and compressed at retail outlet	CO_2 capture offers the opportunity to reduce CO2 emissions at the liquefaction step and so enhance the CNG pathway. Inclusion of this pathway provides comparability with the earlier IEA GHG study.
FT diesel	Remote natural gas converted locally to synthetic liquid fuels, shipped and distributed using existing infrastructure.	CO_2 capture offers the opportunity for moderate CO2 reductions within an existing distribution and vehicle infrastructure. Manufacturing technology has been demonstrated and commercial scale plant is planned. Inclusion of this pathway provides comparability with the earlier IEA GHG study.
DiMethyl Ether	Remote natural gas converted locally to DME, shipped and distributed using modified LPG infrastructure	Alternative route for natural gas entering diesel fuel market. Modification to distribution and vehicle infrastructure the same as LPG which already serves a significant vehicle fleet. Manufacturing technology is proven.
Compressed hydrogen	Coal is gasified to hydrogen via POx and CO shift, hydrogen distributed via pipeline to the refuelling station and compressed.	As for the coal to electricity pathway.
Compressed hydrogen	Natural gas supplied by long distance pipeline to EU market, reformed centrally to hydrogen and distributed by pipeline to the refuelling station and compressed.	Least energy /CO_2 intensive of all routes to H_2 from Natural gas if the gas is sourced within a 4000km range. Inclusion of carbon capture limits the GHG emissions at the reforming step.
Compressed hydrogen	Biomass is converted locally to hydrogen, and distributed by pipeline to the refuelling station.	As for the biomass to electricity case
Electricity	Coal is converted to electricity in IGCC and transmitted to customer via high, medium and low voltage power lines	Coal has the largest potential for substitution of conventional petroleum-based fuels, and could offer significant scope for CO_2 abatement using capture and storage technologies, based on materiality of supply, emission reduction potential and cost of avoidance.
Electricity	Biomass is converted to electricity in BIGCC and transmitted to customer via high, medium and low voltage power lines	Although biomass energy supplies are limited to less than 15% of the transport energy market[39], with CCS, this offers the potential for a net reduction of CO_2 emissions and is included as a reference case.

A full description and detailed analysis of the supply pathways and vehicle data is provided in **Appendix I - Pathways definition.** Full DCF analysis of each pathway is

[39] See for example: 'The Market Development of Alternative Fuels - Report by the Alternative Fuels Contact Group', December 2003 page 3.

also provided in **Appendix II -Pathway Economic Assessment.** The fully integrated results across the full fuel cycle are presented in the remainder of the section

3.1 Well to Tank results

In the following sections, results are summarised in the following form for the fuel supply chain (Well to Tank[40]):

- Energy expenditure MJ expended/ MJ fuel supplied at retail outlet
- GHG emissions gCO_2 eq. /MJ fuel supplied at retail outlet
- Cost of fuel manufacture Euro/GJ
- Cost of fuel supplied at the retail outlet Euro/GJ[41]
- Cost of GHG avoided in the production process Euro/tonne CO_2 avoided

In all cases, results can be compared with the 'business as usual' gasoline and diesel cases summarised in Table 16. Mean P5 and P95 (see section 2.5) estimates are provided for each variable. In some cases the mean data will differ from the single point estimates presented in Appendix I. The differences are small, and arise when asymmetric distributions have been assumed for the range of input variables.

Table 16 Estimated energy expenditure, emissions and costs for "business as usual" 2010 gasoline and diesel cases

	Primary energy expended/fuel supplied MJ_{ex} /$MJ_{fuel\ supplied}$			GHG emissions gCO_2 eq. /$MJ_{fuel\ supplied}$			Cost of fuel supplied to vehicle[42]	
	Mean	P5	P95	Mean	P5	P95	Euro/GJ	Euro¢/litre
Gasoline delivered to retail outlet	0.14	00.09	0.19	12.6	10	16	8.7	28.2
Diesel delivered to retail outlet	0.16	0.12	0.21	14.2	11	18	8.4	29.4

3.1.1 CNG

CNG from LNG pathway results are summarised in the following Figures and Tables. Single point estimates for each step in the supply chain are summarised in Appendix I section I.ii.v -**Well to Tank analysis**.

[40] For consistency, in the case of electric vehicle Well- to-Tank refers to supply chain up to an including electric supply at 0.4 kV. Energy is lost during the charging cycle and this is accounted for in the Well to Wheels analysis.
[41] All costs are exclusive of tax.
[42] Includes distribution and retail costs but excludes taxation, data taken form Joint JEC study.

Table 17 Estimated energy expenditure and GHG emissions for CNG supplied from LNG imports

LNG to CNG at 25MPa		Primary energy expended MJ_{ex} /MJ $_{fuel\ supplied}$			GHG emissions gCO2 eq. /MJ $_{fuel\ supplied}$		
		Mean	P5	P95	Mean	P5	P95
CNG	without capture and storage	0.252	0.233	0.271	17	15	18
	with capture and storage	0.266	0.246	0.286	11	10	12

Table18 Estimated supply costs for CNG supplied from LNG imports – 5% discount rate

LNG to CNG at 25MPa		Cost of LNG manufacture Euro/GJ fuel produced			Cost of fuel supplied at the retail outlet Euro/GJ fuel supplied			Cost of CO2 avoided in the production process Euro/tonne CO2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
CNG	without capture and storage	1.4	1.0	1.7	5.4	4.9	5.9	21	19	24
	with capture and storage	1.4	1.1	1.8	5.6	5.1	6.1			

Table 19 Estimated supply costs for CNG supplied from LNG imports – 10% discount rate

LNG to CNG at 25MPa		Cost of LNG manufacture Euro/GJ fuel produced			Cost of fuel supplied at the retail outlet Euro/GJ fuel supplied			Cost of CO2 avoided in the production process Euro/tonne CO2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
CNG	without capture and storage	1.5	1.2	2.0	5.6	5.1	6.1	30	26	33
	with capture and storage	1.7	1.3	2.1	6.7	6.1	7.3			

With the scale of plant assumed in this study (see Appendix I section I.ii.iii), energy loss and GHG emissions are distributed throughout the supply pathway with no single step dominant. The impact of CCS is therefore modest. The CNG pathway is more energy

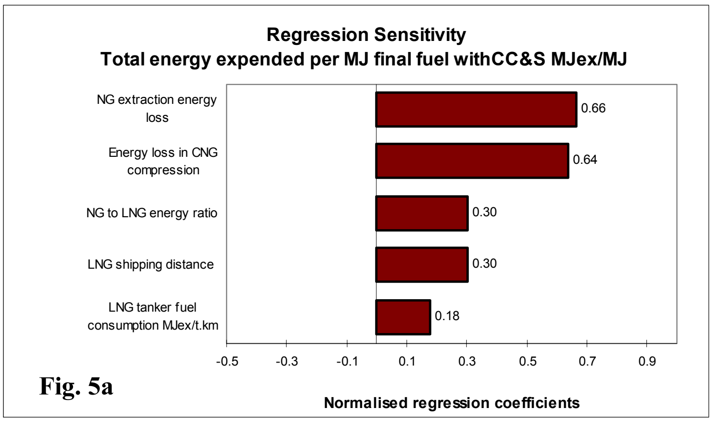


Fig. 5a

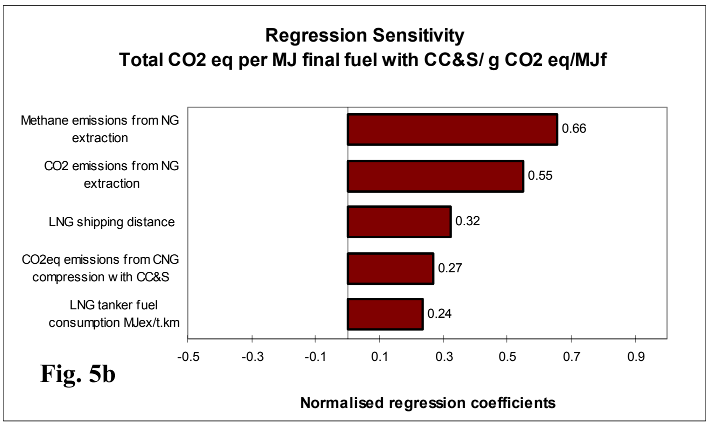


Fig. 5b

intensive than the gasoline reference but GHG emissions are comparable. Energy loss is sensitive to a number of variables with energy expended in natural gas production and CNG compression the most significant (Figure 5a). By comparison, GHG emissions are most sensitive to natural gas production, since this varies with natural gas source and has a wider range of uncertainty (Figure 5b).

The analysis indicates (see Appendix I Table I-22,23) that, for remote gas at an average price of 1Euro/GJ, the next generation of world-scale plants could produce natural gas in Europe at a cost of ca. 3.5 Euro/GJ, which is comparable with current price of pipeline imports. For comparison, the long term average cost of LNG supply to Japan is ca. \$4/GJ[43]. The cost of CNG supplied at retail outlets at a pressure of 25MPa is about 20-30% less than gasoline. This low estimate reflects the trend to lower manufacturing costs from larger and more efficient plants and lower shipping cost as a result of increased LNG tanker capacity.

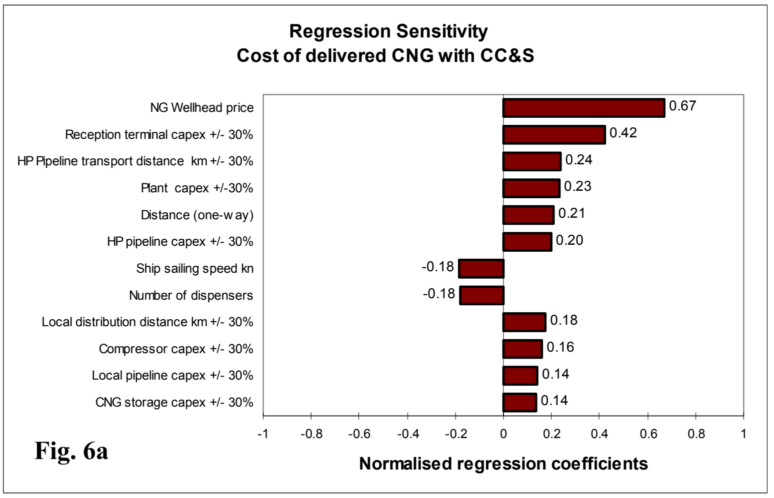


Fig. 6a

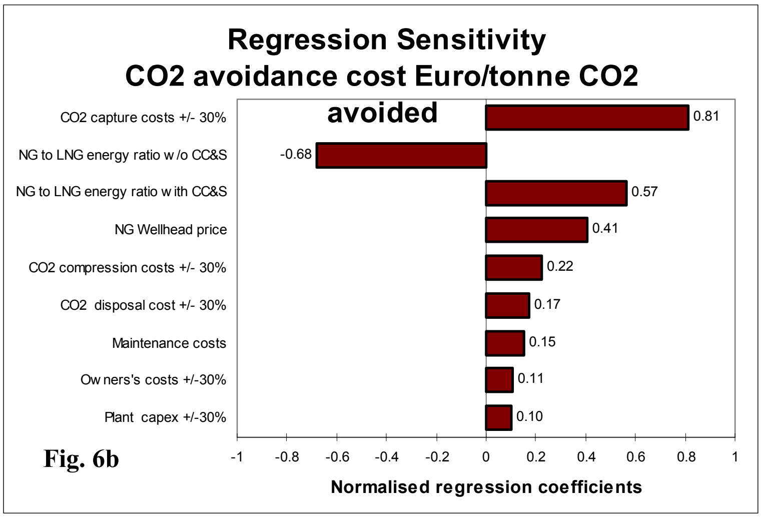


Fig. 6b

[43] BP World Energy Statistics 2003

CNG prices at the retail outlet are sensitive to a wide number of variables (Figure 6a), though wellhead price and cost of the reception terminal are the most significant.

CO_2 avoidance costs from use of CCS are estimated to be in the range 19 – 33 Euro/tonne CO_2 avoided. Costs reflect the higher cost of removing CO_2 from gas turbine exhausts. Avoidance costs are similarly sensitive to a wide range of variables (Figure 6b), with the capital cost of capture plant and the process energy consumption, with and without capture, being the most significant.

3.1.2 Synthetic fuels

The results of synthetic fuels produced from remote natural gas pathways are summarised in the following Tables and Figures. Single point estimates for each stage of the supply chain are summarised in Appendix I section I.iv.vii. –**Well to Tank analysis**

Table 20 Estimated energy expenditure and GHG emissions for synthetic fuels supplied from remote natural gas

Synthetic fuels from remote natural gas		Primary energy expended MJ_{ex} /$MJ_{fuel\ supplied}$			GHG emissions gCO_2 eq. /$MJ_{fuel\ supplied}$		
		Mean	P5	P95	Mean	P5	P95
FT diesel	without capture and storage	1.105	0.827	1.431	42	29	56
	with capture and storage	1.192	0.891	1.516	16	13	19
DME	without capture and storage	0.551	0.451	0.654	23	22	25
	with capture and storage	0.557	0.456	0.661	12	11	14

Table 21 Estimated supply costs for synthetic fuels produced from remote natural gas – 5% discount rate

Remote FT diesel		Cost of FT fuel manufacture Euro/GJ produced			Cost of fuel supplied at the retail outlet Euro/GJ fuel supplied			Cost of CO_2 avoided in the production process Euro/tonne CO_2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
FT diesel	without capture and storage	2.9	2.0	3.9	5.9	4.9	7.0	23	17	32
	with capture and storage	3.4	2.4	4.4	6.4	5.4	7.4			
DME	without capture and storage	2.6	2.0	3.2	6.5	5.7	7.2	6.2	5.4	6.8
	with capture and storage	2.7	2.1	3.3	6.6	5.9	7.3			

Table 22 Estimated supply costs for synthetic fuels produced from remote natural gas – 10% discount rate

Remote FT diesel		Cost of FT diesel manufacture Euro/GJ produced			Cost of fuel supplied at the retail outlet Euro/GJ fuel supplied			Cost of CO2 avoided in the production process Euro/tonne CO2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
FT diesel	without capture and storage	3.8	2.8	5.0	6.9	5.9	8.0	30	23	41
	with capture and storage	4.4	3.4	5.6	7.5	6.5	8.7			
DME	without capture and storage	3.1	2.5	3.9	7.5	6.7	8.3	9.3	8.2	10.4
	with capture and storage	3.3	2.6	4.1	7.7	6.9	8.5			

The supply of FT diesel from natural gas (based on the marginal substitution of conventional diesel) expends twice as much energy, and emits twice the amount of greenhouse gases as the supply of fuel grade DME. Energy loss and emissions from fuel manufacture dominate the supply chains (See Appendix I Tables I 45-48). For DME overall losses are only sensitive to process losses (see Figure 7b). For synthetic diesel, the ratio of naphtha to diesel is also a significant factor (see Figure 7a), because increasing selectivity to diesel significantly reduces energy loss and emissions per unit of diesel production. For DME production, a small proportion of the CO2 is extracted

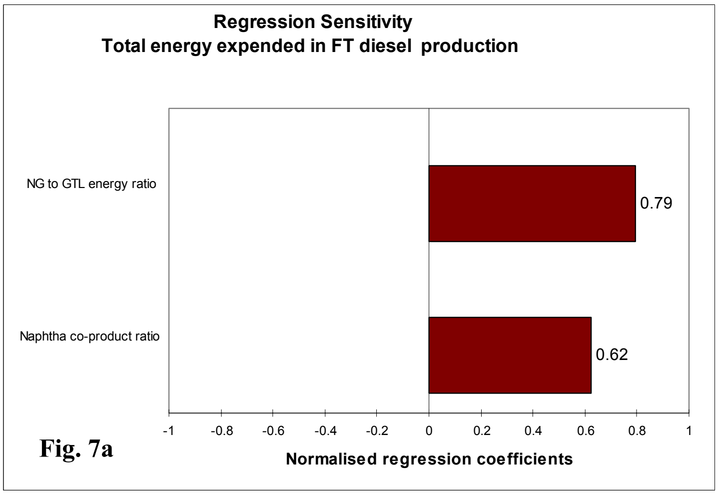


Fig. 7a

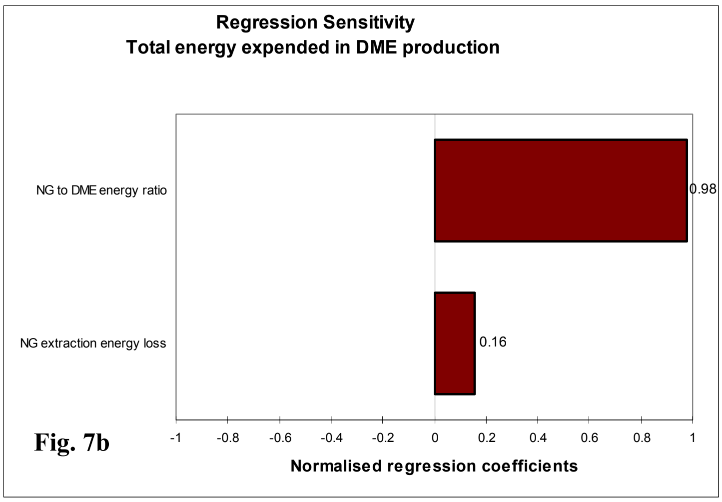


Fig. 7b

within the process, which would normally be vented (see Appendix I). Capture only imposes a small energy penalty to compress the gas for export and this is reflected in the data presented in Table 22.

In the case of GHG emissions with CCS, emissions from natural gas production are a significant factor for both fuels (Figures 8a,b). Because a very high proportion of CO_2 is removed as part of the DME production process, sensitivity to process energy loss is low (Figure 8b)

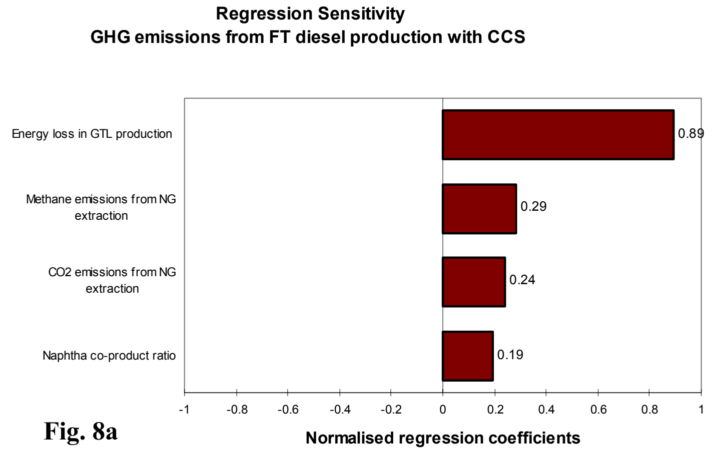


Fig. 8a

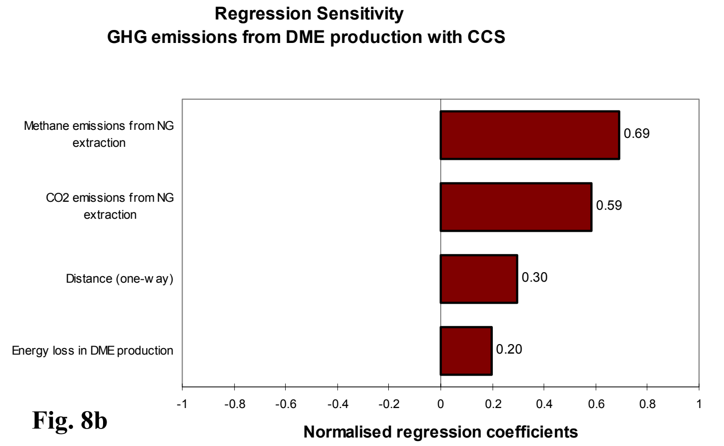


Fig. 8b

The results indicate that for remote gas at an average price of 1Euro/GJ, future world-scale plants could produce synthetic fuels at the retail outlet at a cost below that of gasoline on an energy basis. It should be noted, however, that plants of this size have yet to be built. Supply costs in both cases are primarily sensitive to wellhead gas price and plant capex, with other supply chain variables having a lesser effect (Figures 9 – 10).

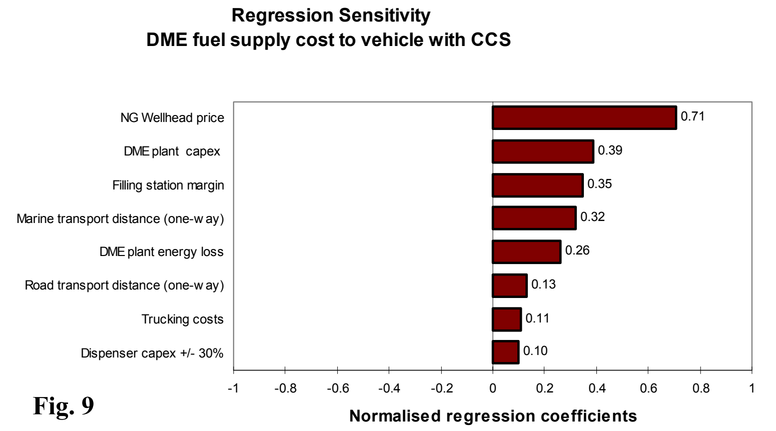


Fig. 9

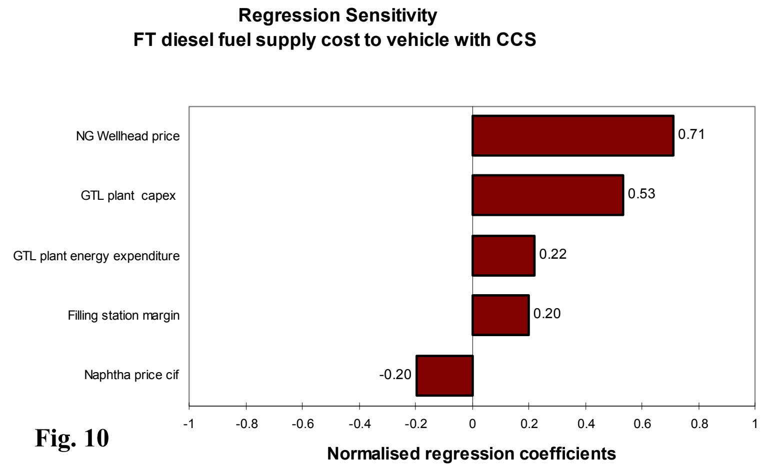


Fig. 10

Since, as part of the DME process, CO2 is removed as a pure stream, the CCS costs only relate to compression and disposal. Avoidance costs are therefore comparable with those estimated for IGCC.

3.1.3 Hydrogen

Hydrogen pathway results incorporating uncertainty are summarised in Tables 23 - 25. Single point estimates for each stage of the supply chain are summarised in Appendix I section I.iii.vi – **Well to Tank analysis.** Mean data differ slightly from single point estimates because asymmetric distributions have been assumed for a number of input variables. The differences are, however, only significant in the case of the biomass to hydrogen pathway, where the large upside potential on biomass prices skews the data.

Table 23 Estimated energy expenditure and GHG emissions hydrogen produced centrally from coal, pipeline natural gas and biomass

Primary fuel to compressed hydrogen at 88MPa[44]		Primary energy expended MJex /MJ fuel supplied			GHG emissions gCO2 eq. /MJ fuel supplied		
		Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	1.392	1.277	1.501	223	212	233
	with capture and storage	1.766	1.618	1.909	39	34	43
Natural gas	without capture and storage	0.715	0.655	0.779	99	96	102
	with capture and storage	0.773	0.708	0.837	29	27	31
Biomass	without capture and storage	1.021	0.866	1.175	24	18	29
	with capture and storage	1.314	1.153	1.470	-156	-170	-144

Table 24 Estimated supply costs for hydrogen produced centrally from coal, pipeline natural gas and biomass – 5% discount rate

Primary fuel to compressed hydrogen at 88MPa		Cost of fuel manufacture Euro/GJ produced			Cost of fuel supplied at the retail outlet Euro/GJ fuel supplied			Cost of CO2 avoided in the production process Euro/tonne CO2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	8.3	6.9	9.7	15.0	13.4	16.5	21	18	23
	with capture and storage	11.9	10.1	13.8	19.0	16.9	20.9			
Natural gas	without capture and storage	5.5	4.0	7.1	12.1	10.5	13.7	17	13	21
	with capture and storage	6.6	4.9	8.2	13.6	11.8	15.3			
Biomass	without capture and storage	15.3	12.3	18.9	22.0	18.8	25.6	48	38	58
	with capture and storage	21.4	17.9	25.6	28.5	24.8	32.5			

Table 25 Estimated supply costs for hydrogen produced centrally from coal, pipeline natural gas and biomass – 10% discount rate

Primary fuel to compressed hydrogen at 88MPa		Cost of fuel manufacture Euro/GJ produced			Cost of fuel supplied at the retail outlet Euro/GJ fuel supplied			Cost of CO2 avoided in the production process Euro/tonne CO2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	10.6	8.8	12.6	18.6	16.6	20.7	26	22	30
	with capture and storage	15.2	12.7	17.8	23.5	20.9	26.3			
Natural gas	without capture and storage	6.1	4.5	7.7	14.1	12.4	15.9	23	18	28
	with capture and storage	7.6	5.8	9.3	15.9	14.1	17.9			
Biomass	without capture and storage	17.8	14.6	21.6	25.8	22.3	29.7	52	42	62
	with capture and storage	24.4	20.2	28.4	32.7	28.8	36.8			

[44] Following the JEC joint study, this study assumes a site storage pressure of 88MPa to provide ensure rapid fill to a final on-board storage pressure of 70MPa.

Considerably more energy is expended in the manufacture and supply of hydrogen than in the gasoline reference pathway. Since the manufacturing process involves decarbonisation, these pathways also generate considerably more GHG emissions within the supply chain than the gasoline reference case. The production of hydrogen from natural gas is the most energy efficient, consuming about a half the energy of coal and a third of the energy of biomass. Since biomass gasification is almost net CO2 neutral, GHG emissions for the fossil fuel based pathways with CCS are comparable with the overall emissions from biomass without CCS. When the pathway incorporates CCS there is a significant net reduction in GHG emissions, albeit achieved at low energy efficiency (<30% overall).

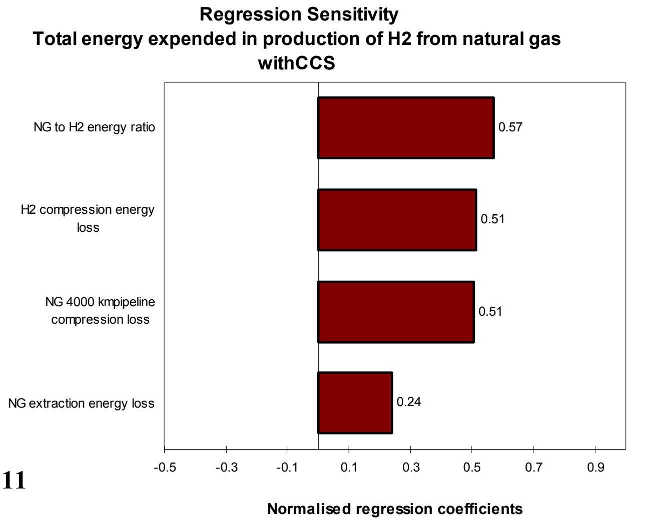


Fig. 11

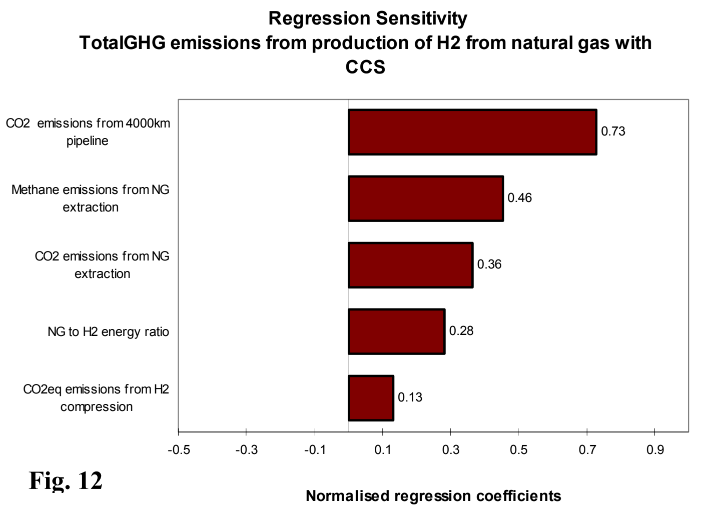


Fig. 12

Although CCS reduces direct emissions, indirect emissions throughout the supply chain can account for approximately a quarter of the total. Figures 11 - 12 show, as an illustration, that energy expenditure and GHG emissions from the natural gas pathway are primarily sensitive to energy loss in manufacturing, gas compression and natural gas extraction and processing.

At the centre point of the prices used in this study, it is approximately twice as expensive to make hydrogen from coal as it is from natural gas. Hydrogen from biomass is the most expensive option, with hydrogen costing almost three times that of that produced from natural gas. On a cost per unit of energy basis, hydrogen from natural gas is approximately the same as the commodity price for gasoline (5.9 Euro/GJ). The high cost of biomass, and of the electricity derived from it, is a major factor in determining the

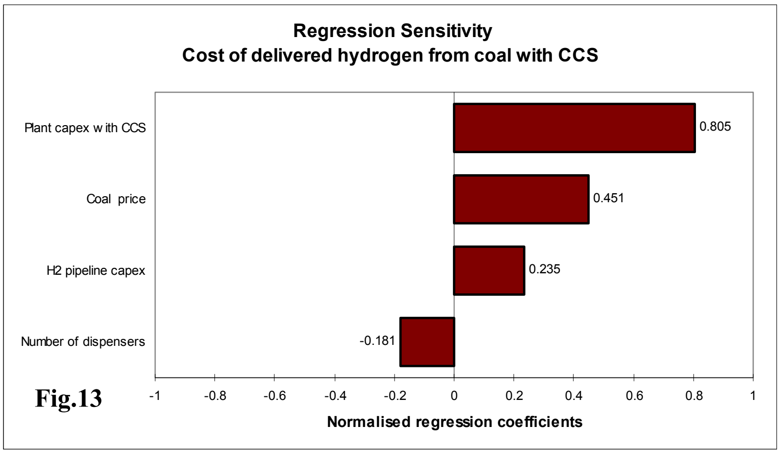


Fig.13

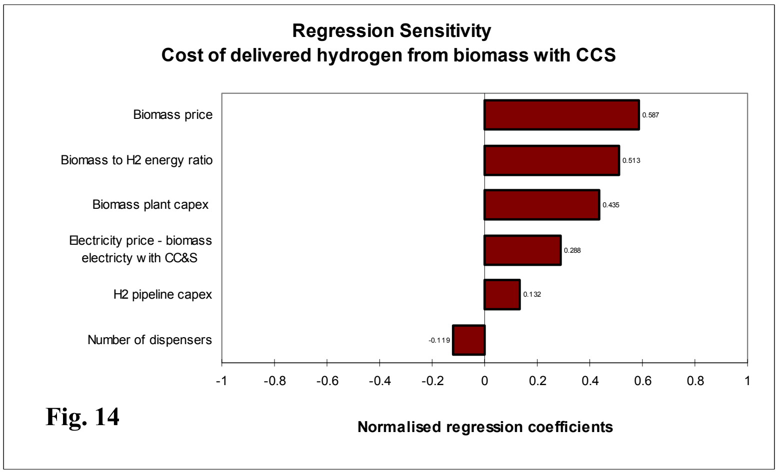


Fig. 14

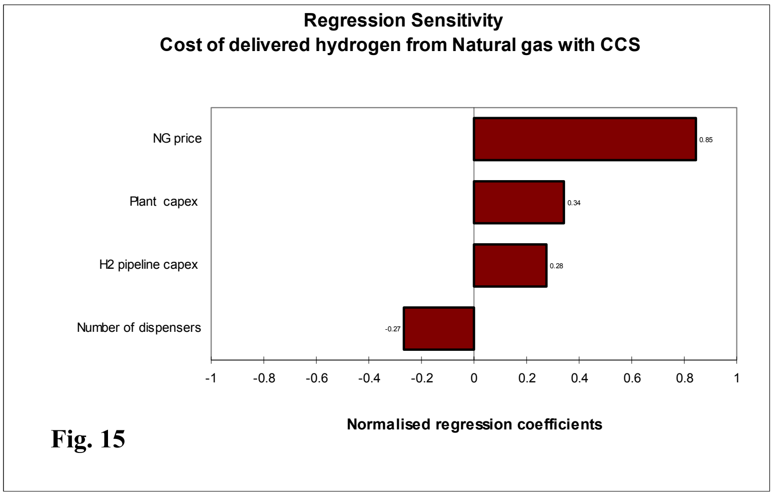


Fig. 15

hydrogen price. The relative inefficiency of the biomass to electricity process also drives up the cost of capturing CO2 from the process and results in the biomass pathway having the highest cost of avoiding CO2 emissions. Additionally, because of feedstock supply limitations, biomass is disadvantaged compared with fossil fuel based pathways, which benefit from economies of scale. The distribution and dispensing of hydrogen is relatively expensive and adds between 7-8 Euro/GJ to the price of hydrogen. Most of this additional cost (ca. 5Euro/GJ) is added at the retail site to compress and store the hydrogen prior to dispensing (see Appendix I Tables I 30 – 35).

The costs of hydrogen produced from fossil fuels are sensitive to a few key variables: capital costs and feedstock prices (Figures 13 and 15). The cost of hydrogen from biomass is additionally sensitive to the energy efficiency of biomass production and the cost of biomass electricity used in the process (Figure 14). In all cases, the assumption made on the number of dispensers makes a small contribution to the hydrogen supply cost; increasing the number of dispensers, with the associated economies of scale, lowers the retail costs.

CO_2 avoidance costs by use of CCS are estimated to be in the range 15- 30 Euro/tonne CO_2 avoided for coal and natural gas. Costs for biomass are approximately twice this figure. Cost is sensitive to assumptions in biomass electricity price and electric power demand in the manufacturing process (see Figure 16).

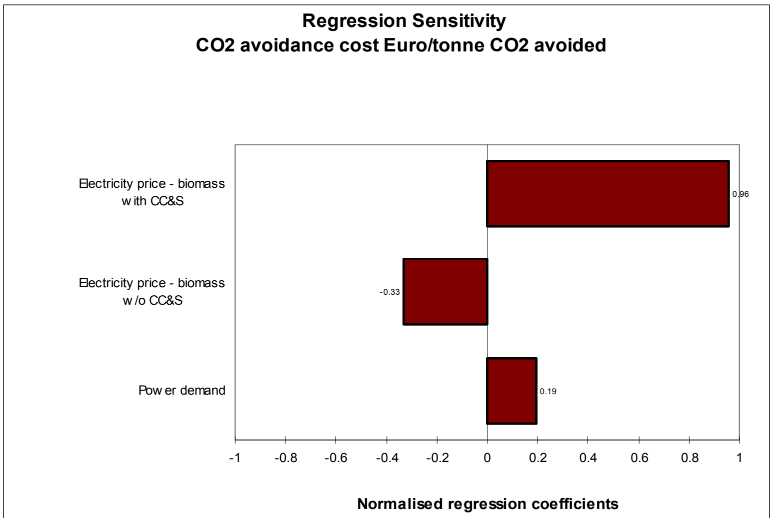


Fig. 16

3.1.4 Electricity

Electricity pathway results incorporating uncertainty are summarised in Tables 26 – 28. Single point estimates for each stage of the supply chain are summarised in Appendix I section I.i.v –**Well to Tank analysis.** Mean data differ slightly from single point estimates because asymmetric distributions have been assumed for a number of input variables. The differences are, however, only significant in the case of the biomass to electricity pathway, where the large upside potential on biomass price skews the data.

Table 26 Estimated energy expenditure and GHG emissions for electricity supply from coal and biomass

Primary fuel to electricity at 0.4kV		Primary energy expended/ electricity supplied MJ_{ex} /MJ $_{electricity\ supplied}$			GHG emissions gCO_2 eq. /MJ $_{electricity\ supplied}$		
		Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	1.612	0.988	2.268	243	186	302
	with capture and storage	2.063	1.145	3.024	745	53	99
Natural gas	without capture and storage	0.989	0.784	1.187	120	107	132
	with capture and storage	1.217	0.960	1.463	40	34	45
Biomass	without capture and storage	1.679	1.270	2.097	24	15	3
	with capture and storage	2.380	2.045	2.678	-254	-283	-227

Table 27 Estimated supply costs for electricity produced from coal and biomass – 5% discount rate

Primary fuel to electricity at 0.4kV		Cost of electricity manufacture Euro¢ /kWh produced			Cost of electricity supplied at the retail outlet Euro/GJ electricity supplied			Cost of CO2 avoided in the production process Euro/tonne CO2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	3.5	2.8	4.2	18.1	16.2	20.2	13	12	15
	with capture and storage	4.3	3.4	5.2	20.4	18.0	22.9			
Natural gas	without capture and storage	2.6	1.8	3.4	15.9	13.7	18.2	29	24	34
	with capture and storage	3.5	2.6	4.5	18.3	15.7	20.9			
Biomass	without capture and storage	7.5	5.7	9.6	29.4	24.4	35.3	63	35	101
	with capture and storage	12.1	9.9	15.0	42.1	36.0	50.7			

Table 28 Estimated supply costs for electricity produced from coal and biomass – 10% discount rate

Primary fuel to electricity at 0.4kV		Cost of electricity manufacture Euro¢ /kWh produced			Cost of electricity supplied at the retail outlet Euro/GJ electricity supplied			Cost of CO2 avoided in the production process Euro/tonne CO2 avoided		
		Mean	P5	P95	Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	4.2	3.4	5.1	20.4	18.0	23.0	16	14	19
	with capture and storage	5.2	4.1	6.2	23.2	20.2	26.1			
Natural gas	without capture and storage	2.9	2.2	3.8	16.7	14.6	19.1	36	30	42
	with capture and storage	4.0	3.1	5.0	19.6	17.1	22.6			
Biomass	without capture and storage	8.7	6.7	11.2	32.8	27.3	39.9	77	40	120
	with capture and storage	14.3	11.6	17.4	48.2	40.5	57.0			

More energy is expended in the production of electricity from coal and biomass gasification than supplied by the process (energy efficiencies less than 50%). Because of the energy multiplier effect, GHG emissions in the supply of primary energy are therefore quite significant. For IGCC, although 85 % of CO2 is captured in the generation process, CO2 emissions for the entire supply pathway are only reduced by 70%. The production of electricity from biomass is CO_2 neutral, and virtually all emissions arise from supply of biomass. Use of CCS results in the net removal of 250gCO2 eq./MJ electricity supplied from the atmosphere, and a reduction in emissions of ca. 500gCO2 eq./MJ electricity when compared with IGCC. However, the comparisons should be viewed with caution as reducing energy efficiency of the biomass process leads to a greater removal of CO2.

IGGC CO2 avoidance costs are also relatively low compared with flue gas removal options (typically 25- 30 Euro/tonne CO2 avoided). By comparison, with IGCC, BIGCC is an expensive option with electricity prices of 2-3 times that of the comparable coal route. Higher cost feedstock and economies of scale account for much of the difference. Despite the beneficial impact on net CO2 emissions, the cost of avoidance is almost 5 times that of the coal pathway.

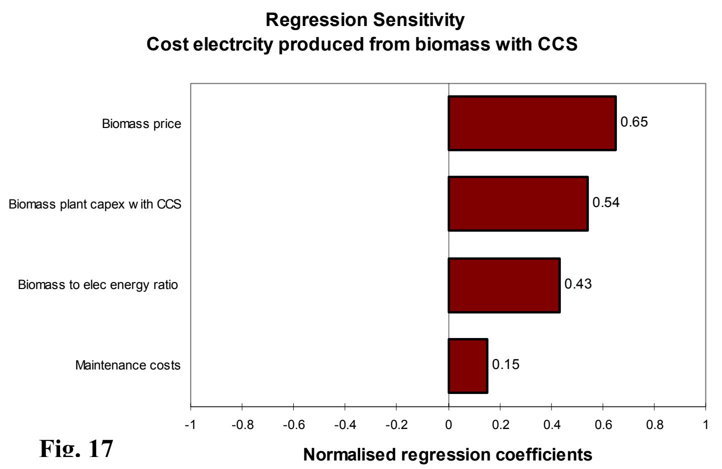


Fig. 17

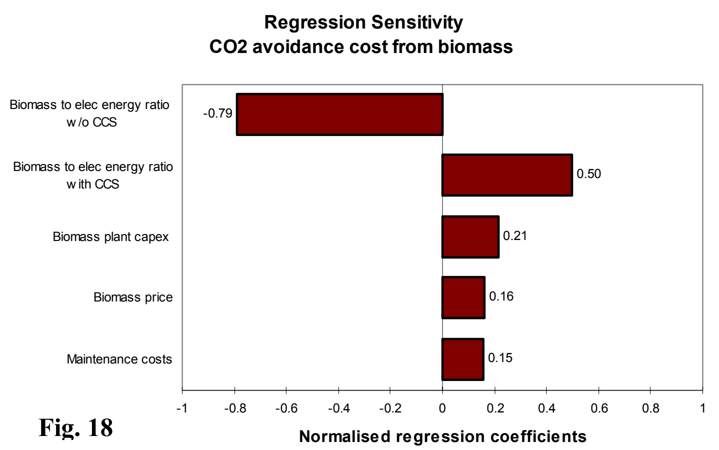


Fig. 18

In the biomass pathway, the sensitivities of the cost of generating electricity and CO_2 avoidance costs are shown in Figures 17 and 18. Costs are most sensitive to changes in the cost of biomass, BIGCC capex and energy efficiency.

Electricity from natural has the lowest energy expenditure, and it can be produced at the lowest cost. The cost per tonne of CO2 avoided is intermediate between the coal and biomass case, mainly because CO2 is removed from the flue gas where concentrations are low and large volume of gas have to be processed.

3.2 Well to Tank – comparative assessment

Well to Tank (WTT) energy expended and GHG emissions over each of the fuel supply pathways are compared in Figures 19 and 20 respectively. Energy expended in all fuel supply pathways is far greater than for gasoline, only CNG from remote natural gas is comparable. Values of energy expended are estimated to be in the range 0.25 – 2.0 MJ per MJ fuel supplied. This compares with a Figure of 0.14 MJ per MJ fuel supplied for

Fig. 19 Comparison of WTT energy expended over all pathways

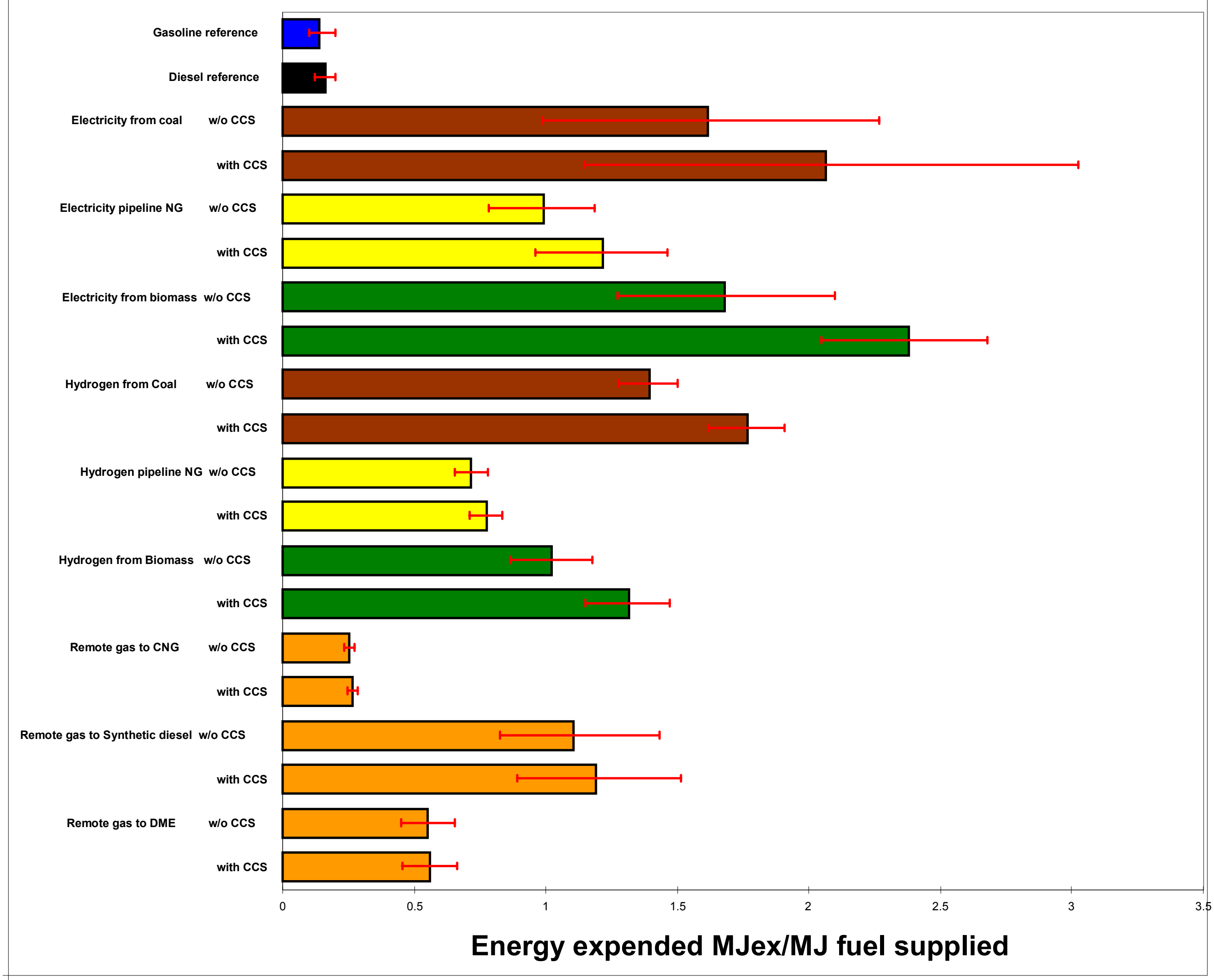
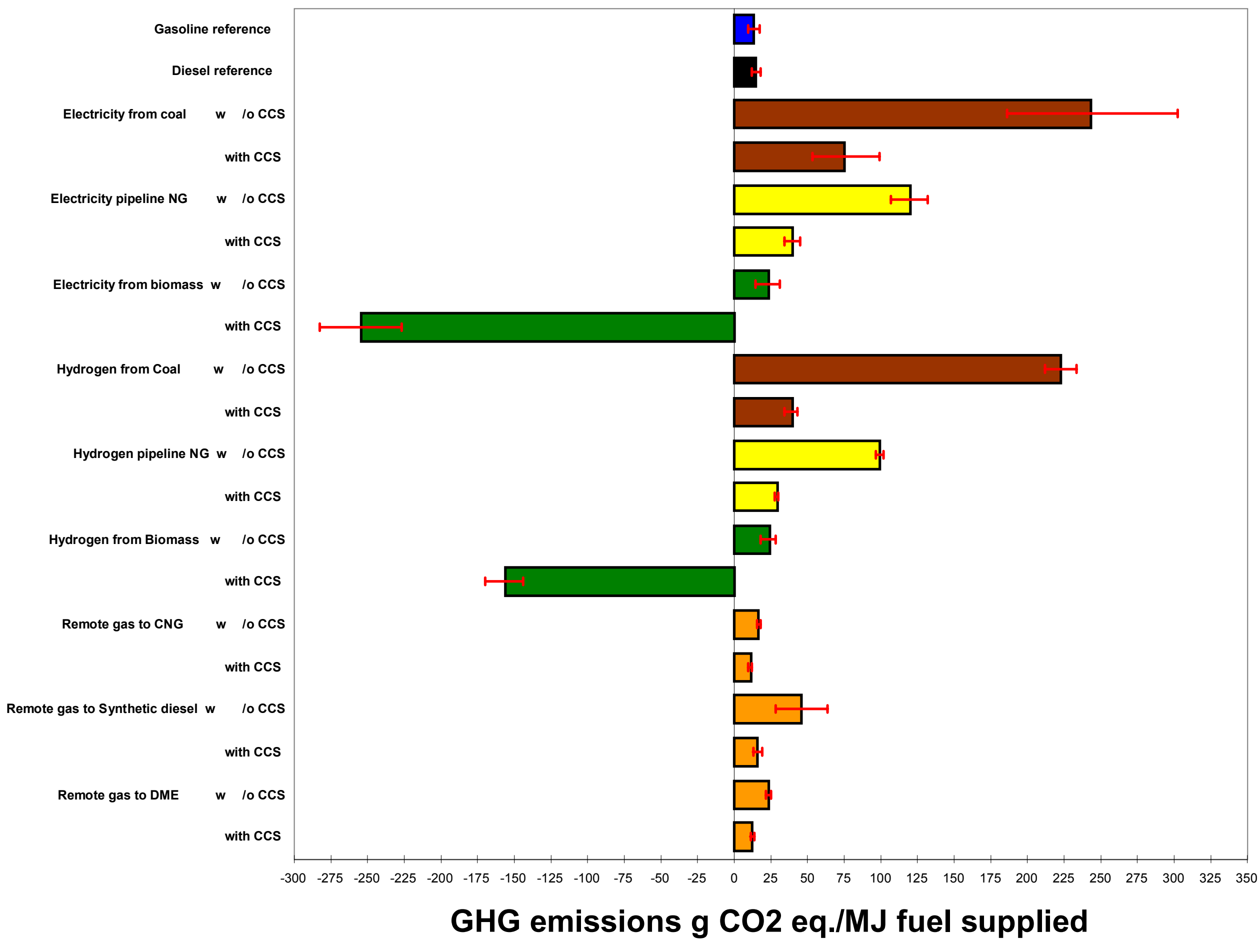


Fig. 20 Comparison of WTT GHG emissions for all pathways



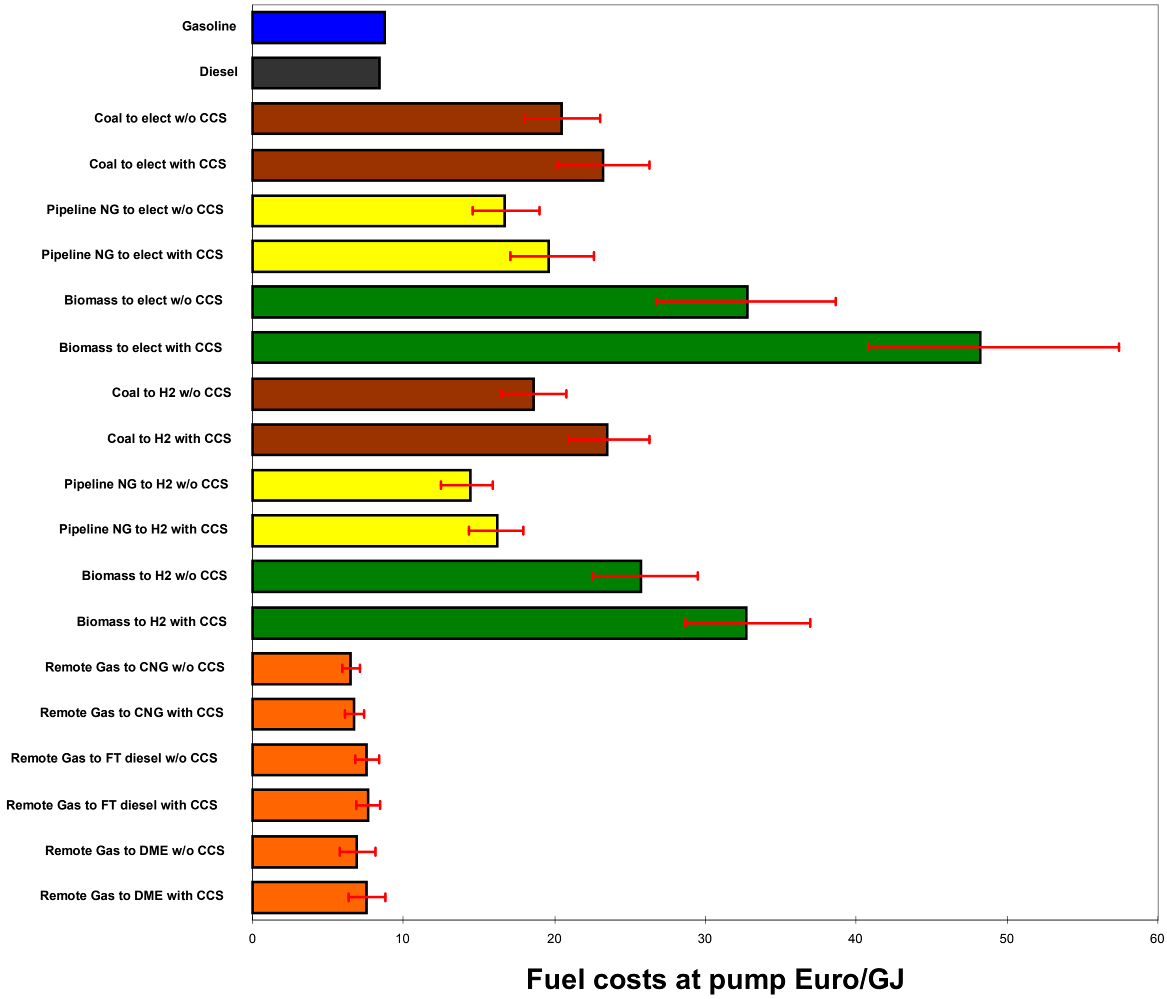
gasoline. Energy expended in de-carbonisation routes (hydrogen and electricity) is at the top end of the range. The relatively large uncertainty in the coal to electricity supply pathway reflects the significant improvement in generation efficiency expected from new technology in by 2020; IEA PH4/19 anticipates that up to an 11 percentage point increase (from 38% to 49%) may be possible.

Capture and storage reduces the process energy efficiency of all decarbonisation pathways by up to 7-8 percentage points. Because of the low efficiency of the coal and biomass conversion and the high carbon content of the primary energy source, these pathways carry the highest penalty for CCS, typically 30 – 40% increase in energy expenditure over the full pathway. By contrast, the increase in energy expenditure for the natural gas pathway is only 23%.

Hydrogen production from natural gas is relatively efficient (ca 75% compared with ca 50% for coal), and gas transmission and hydrogen compression losses are of similar magnitude to process losses. CCS increases the energy expenditure over the full pathway by 8%.

CNG and synthetic fuel pathways remove only a small percentage of input carbon, and as a result, the energy penalty in the supply pathway is marginal. Of these pathways, the production of synthetic diesel from remote gas has the highest energy expenditure because the manufacturing process is the least energy efficient.

Fig. 21 Comparison estimated fuel supply costs for all pathways Euro/GJ 10% discount rate



Greenhouse gas emissions without CO_2 capture mirror the trends for energy expenditure in all cases apart from biomass, which as a renewable energy source is CO_2 neutral. In those cases, use of CO_2 capture and storage provides a significant net removal of CO_2 from the atmosphere. CO_2 capture applied to other pathways, with the exception of coal to electricity, reduces GHG emissions to within the range 11 – 40 g CO_2 eq./MJ fuel supplied. Emissions from CNG and synthetic fuels produced from remote gas are, with CCS, in the range 11 – 13 g CO_2 eq./MJ fuel supplied, which is comparable with the gasoline pathway (12.8 g CO_2 eq./MJ fuel supplied).

Estimated cost of fuel supplied to vehicles at a retail outlet, assuming a discount rate of 10% are summarised in Figure 21. Gasoline and diesel prices given in Table 16 are included as a comparison. Data indicate that, for the range of assumptions, the costs of fuels produced from remote gas are comparable with gasoline. De-carbonised fuels produced from fossil fuels are 1.5 to 2.7 times more expensive than gasoline. Fuels produced from biomass are the most expensive. Biomass has higher feedstock costs and does not benefit from economies of scale to the same extent as fossil fuels. CCS adds about a 15- 25% cost penalty to supply of de-carbonised fuels. The cost penalty is less (ca 2- 10%) for fuels from remote natural gas.

3.3 Well to Wheels integration

In the following sections, WTW results are summarised without discussion as in the form:

- GHG emissions g CO_2 eq. / km travelled.
- Energy consumption MJ / 100 km travelled
- Cost of CO_2 avoided relative to the 2010 gasoline reference case Euro/tonne CO_2 avoided[45]

In all cases, results have been compared with the 'business as usual' gasoline and diesel cases including the impact of hybridisation. Data are summarised in Table 29.

Table 29 energy and emissions for the marginal gasoline and diesel cases

<table>
<tr><th colspan="2" rowspan="2">Marginal diesel and gasoline</th><th colspan="3">WTW primary energy consumption MJp/100km</th><th colspan="3">WTW GHG emissions gCO2 eq. / km</th><th rowspan="2">Avoidance costs relative to gasoline reference Euro/tonne 1 0% discount rate[46]</th></tr>
<tr><th>Mean</th><th>P5</th><th>P95</th><th>Mean</th><th>P5</th><th>P95</th></tr>
<tr><td></td><td>vehicle</td><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td rowspan="4">Crude</td><td>Gasoline - 2010 PISI</td><td>218</td><td>201</td><td>234</td><td>165</td><td>157</td><td>172</td><td>-</td></tr>
<tr><td>Gasoline – 2010 PISI hybrid</td><td>185</td><td>155</td><td>214</td><td>140</td><td>121</td><td>161</td><td>379</td></tr>
<tr><td>Diesel – 2010 DICI</td><td>208</td><td>188</td><td>227</td><td>159</td><td>146</td><td>172</td><td>2717</td></tr>
<tr><td>Diesel – 2010 DICI hybrid</td><td>171</td><td>144</td><td>200</td><td>131</td><td>113</td><td>147</td><td>1016</td></tr>
</table>

[45] GHG emissions are not avoided in all cases considered and avoidance cost therefore has no meaning. Where this is the case, data tables are left blank. Similarly, where the Well to Wheels emissions are comparable with the gasoline reference, avoidance costs can be extremely large and subject to very high levels of uncertainty, a cut-off figure of 1100 Euro/tonne CO_2 avoided has been adopted. Where estimates exceed this figure, they are not reported.

[46] Note that the discount rate only applies to vehicle costs.

The results are discussed on a comparative basis in section 3.4. Mean P5 and P95 (see section 2.5) estimates are again provided for each variable. As previously noted, mean data will in some cases differ from the single point estimates presented in Appendix I. The differences are small, and arise when asymmetric distributions have been assumed for the range of input variables

3.3.1 Fuels from remote gas

Table 30 CNG – WTW energy and emissions

LNG to CNG at 25MPa			WTW primary energy consumption MJp/100km			WTW GHG emissions gCO_2 eq./ km		
			Mean	P5	P95	Mean	P5	P95
		vehicle						
CNG	without capture and storage	CNG PISI 2010	239	214	264	141	129	152
		CNG Hybrid 2010	184	150	213	109	94	124
	with capture and storage	CNG PISI 2010	242	216	267	130	118	141
		CNG Hybrid 2010	186	152	215	101	87	115

Table 31 CNG - CO2 avoidance costs relative to gasoline reference Euro/tonne

LNG to CNG at 25MPa			5% discount rate			10% discount rate		
			Mean	P5	P95	Mean	P5	P95
		Vehicle						
CNG	without capture and storage	CNG PISI 2010	262	45	581	475	191	919
		CNG Hybrid 2010	215	102	355	321	181	497
	with capture and storage	CNG PISI 2010	171	40	350	315	152	513
		CNG Hybrid 2010	189	95	297	282	164	420

Table 32 Synthetic fuels from remote gas - WTW energy and emissions

Remote synthetic fuels			WTW primary energy consumption MJp/100km			WTW GHG emissions gCO_2 eq. /km		
			Mean	P5	P95	Mean	P5	P95
		vehicle						
FT diesel	without capture and storage	FT diesel with PF	379	321	442	205	176	234
		FT diesel hybrid	312	255	378	169	145	198
	with capture and storage	FT diesel with PF	393	332	462	157	145	169
		FT diesel hybrid	324	263	395	129	112	146
DME	without capture and storage	DME DICI	267	238	296	158	147	169
		DME hybrid	219	186	255	129	113	144
	with capture and storage	DME DICI	268	239	297	139	129	150
		DME hybrid	220	187	256	114	99	128

Table 33 Synthetic fuels from remote gas - CO2 avoidance costs relative to gasoline reference Euro/tonne

Remote synthetic fuels			5% discount rate			10% discount rate		
			Mean	P5	P95	Mean	P5	P95
		vehicle						
FT diesel	without capture and storage	FT diesel with PF	-	-	-	-	-	-
		FT diesel hybrid	-	-	-	-	-	-
	with capture and storage	FT diesel with PF	-	-	-	-	-	-
		FT diesel hybrid	820	448	1410	1089	594	1973
DME	without capture and storage	DME DICI	-	-	-	-	-	-
		DME hybrid	831	464	1364	1076	625	1728
	with capture and storage	DME DICI	519	309	843	752	451	1243
		DME hybrid	587	400	835	762	532	1078

3.3.2 Hydrogen

Table 34 Hydrogen - WTW energy and emissions

Primary fuel to compressed hydrogen at 88MPa			WTW primary energy consumption MJp/100km			WTW GHG emissions gCO_2 eq. / km		
			Mean	P5	P95	Mean	P5	P95
		vehicle						
Coal	without capture and storage	Hydrogen ICE	400	368	430	373	344	402
		Hydrogen ICE hybrid	356	297	415	332	277	389
		Direct hydrogen FC	224	169	281	209	158	261
		Direct hydrogen FC hybrid	200	151	250	186	140	232
	with capture and storage	Hydrogen ICE	463	424	500	66	57	75
		Hydrogen ICE hybrid	412	343	481	59	47	71
		Direct hydrogen FC	260	196	326	37	27	47
		Direct hydrogen FC hybrid	231	175	290	33	24	42
Natural gas	without capture and storage	Hydrogen ICE	288	268	307	167	156	178
		Hydrogen ICE hybrid	256	216	298	149	125	172
		Direct hydrogen FC	161	122	200	93	71	115
		Direct hydrogen FC hybrid	144	109	179	83	63	103
	with capture and storage	Hydrogen ICE	297	278	318	49	45	53
		Hydrogen ICE hybrid	265	222	308	44	37	51
		Direct hydrogen FC	167	128	207	37	27	47
		Direct hydrogen FC hybrid	148	113	183	33	24	42
Biomass	without capture and storage	Hydrogen ICE	339	303	373	41	31	49
		Hydrogen ICE hybrid	302	250	353	36	26	46
		Direct hydrogen FC	189	141	242	23	16	31
		Direct hydrogen FC hybrid	168	126	212	20	13	27
	with capture and storage	Hydrogen ICE	388	353	422	-261	-288	-237
		Hydrogen ICE hybrid	346	289	402	-233	-274	-195
		Direct hydrogen FC	217	162	274	-147	-184	-109
		Direct hydrogen FC hybrid	193	146	244	-130	-165	-99

Table 35 Hydrogen - CO2 avoidance costs relative to gasoline reference Euro/tonne

Primary fuel to compressed hydrogen at 88MPa			5% discount rate			10% discount rate		
			Mean	P5	P95	Mean	P5	P95
		vehicle						
Coal	without capture and storage	Hydrogen ICE	-	-	-	-	-	-
		Hydrogen ICE hybrid	-	-	-	-	-	-
		Direct hydrogen FC	-	-	-	-	-	-
		Direct hydrogen FC hybrid	-	-	-	-	-	-
	with capture and storage	Hydrogen ICE	362	187	544	479	260	701
		Hydrogen ICE hybrid	435	279	612	562	370	763
		Direct hydrogen FC	399	258	548	510	336	697
		Direct hydrogen FC hybrid	481	344	632	610	448	781
Natural gas	without capture and storage	Hydrogen ICE	-	-	-	-	-	-
		Hydrogen ICE hybrid	-	-	-	-	-	-
		Direct hydrogen FC	650	343	1067	827	457	1305
		Direct hydrogen FC hybrid	726	457	1057	907	576	1316
	with capture and storage	Hydrogen ICE	227	80	370	296	120	471
		Hydrogen ICE hybrid	307	181	436	392	241	549
		Direct hydrogen FC	331	208	459	420	273	566
		Direct hydrogen FC hybrid	419	296	543	524	380	672
Biomass	without capture and storage	Hydrogen ICE	232	67	380	293	110	476
		Hydrogen ICE hybrid	304	155	448	379	217	549
		Direct hydrogen FC	297	165	422	380	224	545
		Direct hydrogen FC hybrid	382	255	518	481	333	638
	with capture and storage	Hydrogen ICE	90	43	134	109	59	162
		Hydrogen ICE hybrid	118	75	163	144	94	196
		Direct hydrogen FC	151	96	204	189	122	254
		Direct hydrogen FC hybrid	200	141	256	249	178	320

3.3.3 Electricity

Table 36 Electric vehicle - WTW energy and emissions

Electricity supply to 0.4kV			WTW primary energy consumption MJp/100km			WTW GHG emissions gCO2 eq. / km		
			Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	EV	133	91	180	111	77	150
	with capture and storage		156	100	218	34	22	48
Natural gas	without capture and storage		101	76	129	61	45	78
	with capture and storage		112	85	145	20	15	26
Biomass	without capture and storage		124	87	160	11	7	15
	with capture and storage		157	117	203	-118	-151	-88

Table 37 Electric vehicle - CO2 avoidance costs relative to gasoline reference Euro/tonne

Electricity supply to 0.4kV			5% discount rate			10% discount rate		
			Mean	P5	P95	Mean	P5	P95
Coal	without capture and storage	EV	-	-	-	-	-	-
	with capture and storage		744	579	896	918	728	1107
Natural gas	without capture and storage		915	690	1192	1141	876	1520
	with capture and storage		650	519	780	805	667	969
Biomass	without capture and storage		659	529	781	804	671	947
	with capture and storage		383	307	456	468	382	559

3.4 Well to Wheels integration – comparative assessment

Well to Wheels (WTW) energy consumption data for all the pathways and vehicle combinations presented in section 3 are compared in Figures 22.

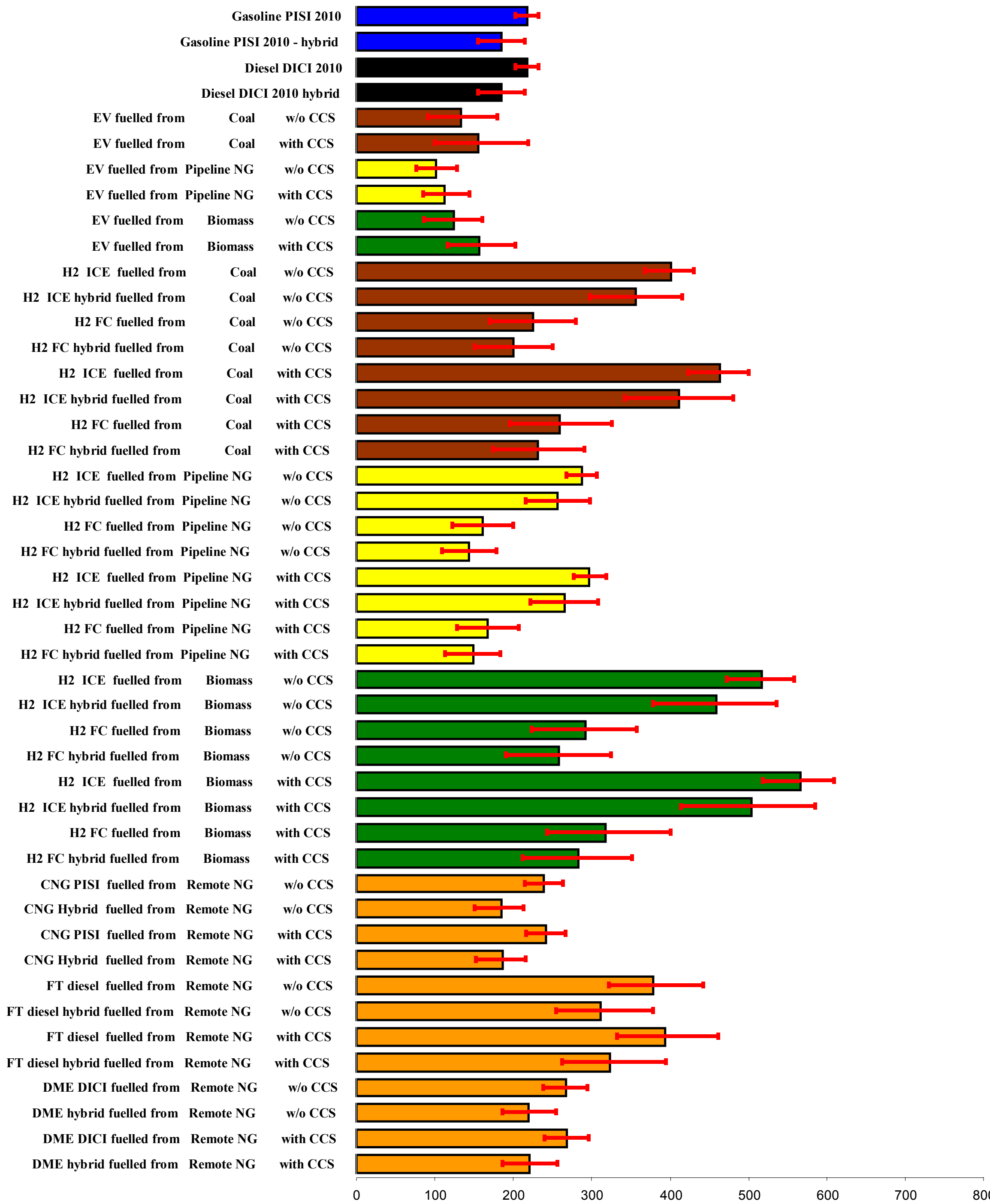
Electric vehicles and fuel cell vehicles powered by hydrogen from natural gas have the lowest overall energy consumption ca. 130 – 170 MJ/100km, even with CO_2 capture and storage. CCS adds a penalty of up to 25%. All of the electric pathways have lower WTW energy consumption than the gasoline reference pathway (218 MJ/100km travelled). Hydrogen fuelled ICEs, where the hydrogen is derived from coal and biomass, have the highest WTW energy consumption ca. 400 - 550 MJ/100km travelled, although virtually all of the energy consumption in the biomass pathway is renewable. WTW energy consumption for CNG and synthetic fuels from remote natural gas are all greater than the gasoline reference apart from the case of CNG fuelled hybrid vehicles. WTW energy consumption for the FT diesel pathways is highest (312 – 379 MJ/100km travelled) because of the relatively low thermal efficiency of the fuel manufacturing process. As evidenced by the uncertainty in these estimates, improvements in process energy efficiency and selectivity to diesel could reduce the energy intensity to a level comparable with the other remote gas pathways.

For all pathways, vehicle energy efficiency is the key determinant of the overall energy consumption. Vehicle energy efficiency determines the energy ranking of each pathway, and differences in vehicle technology exceed the penalties from CO_2 capture and storage. The dominance of the vehicle is further reflected in Figures 23 and 24.

WTW energy consumption for the case of hydrogen fuelled ICE, where hydrogen is derived from pipeline natural gas, is mainly sensitive to vehicle energy efficiency, other supply chain variables having a relatively small impact. For the case of a hydrogen fuel cell hybrid, vehicle performance, which has a much greater uncertainty, it is the only significant variable - nothing else matters.

WTW greenhouse gas emission data for all the pathways and vehicle combinations presented in section 3 are compared in Figures 25.

Fig. 22 Comparison of WTW primary energy consumption for all pathways



WTW energy consumption MJ/100km travelled

WTW GHG emissions show similar trends to those discussed in Figure 22, although biomass as a renewable energy supply has by definition the lowest net GHG emissions. Electric vehicles and fuel cell vehicles fuelled by hydrogen from natural gas generally have up to 25% lower GHG emissions than the gasoline reference pathway even without CCS. FT diesel without CCS, based on the marginal substitution of conventional diesel, however, has between 2 – 24% higher emissions than the gasoline reference depending on the vehicle type

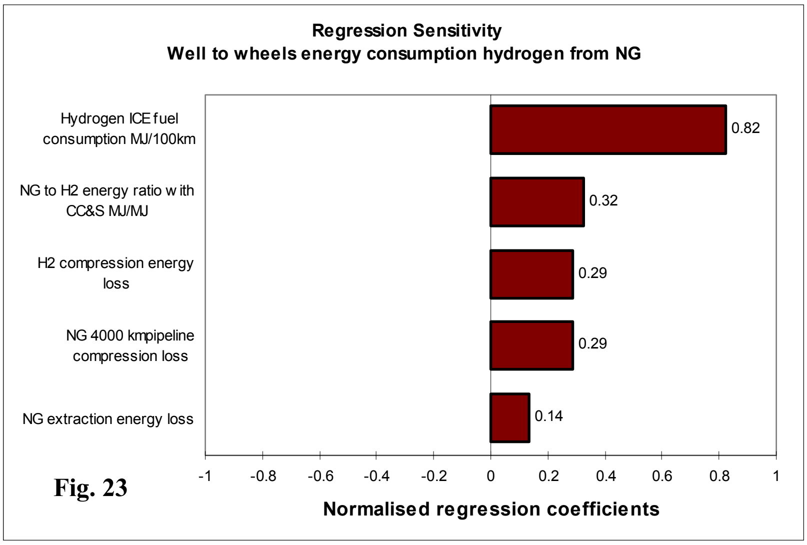


Fig. 23

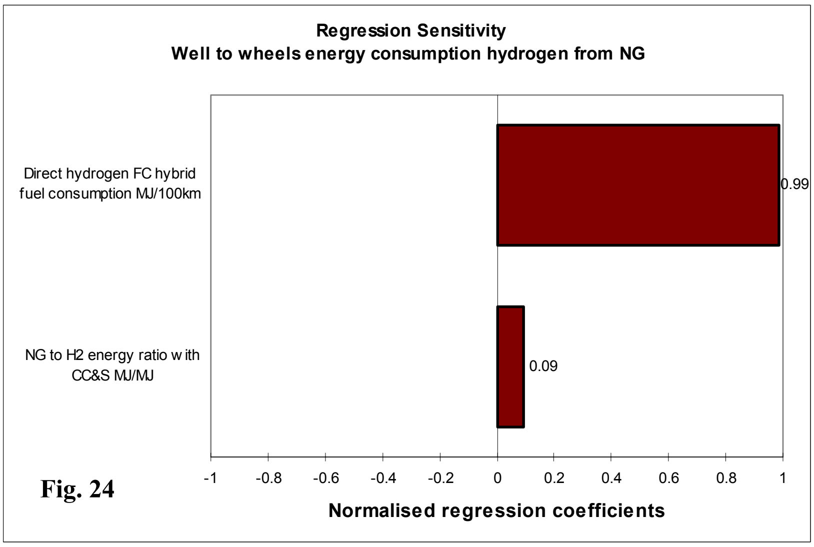
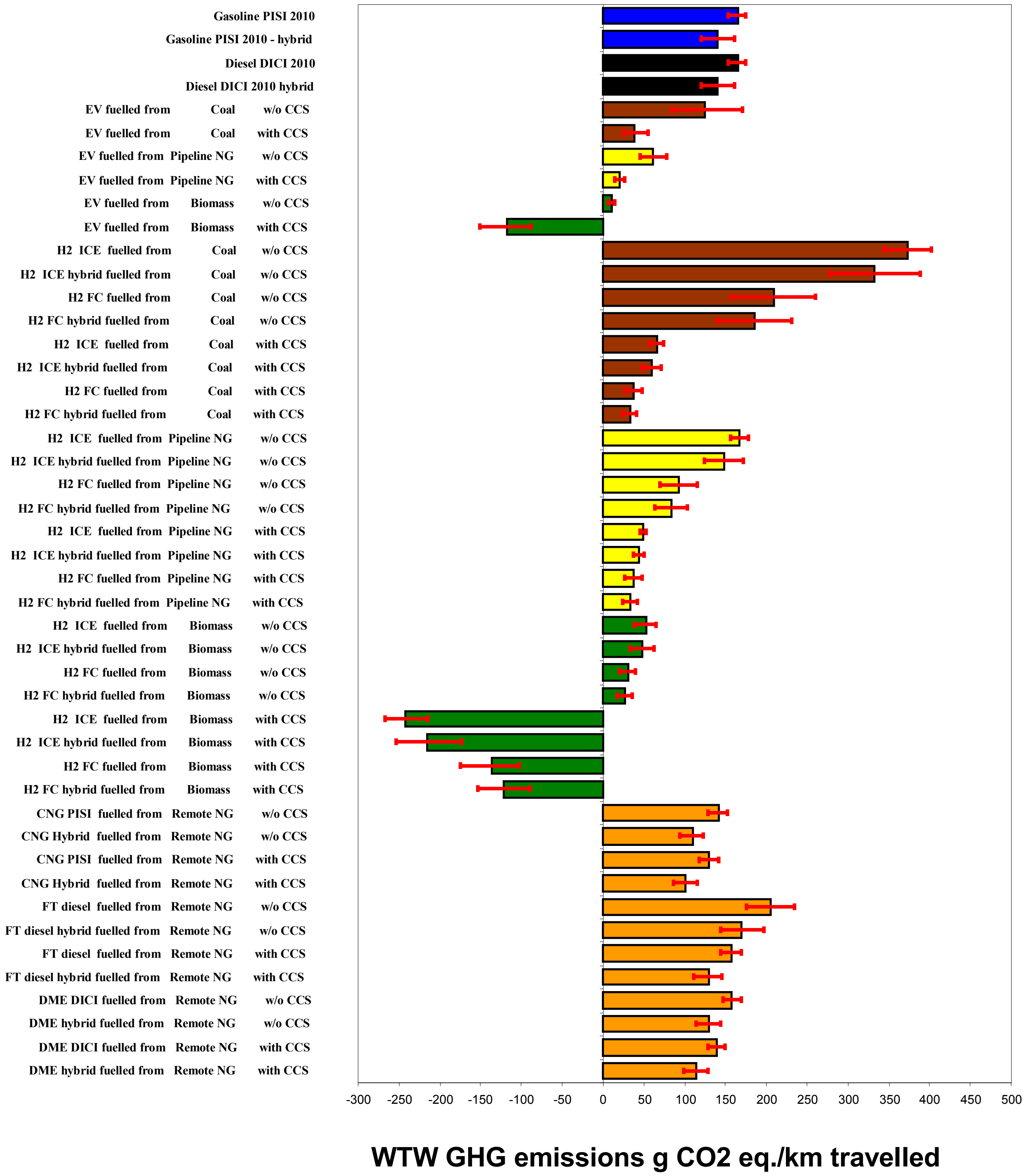


Fig. 24

With CCS, all decarbonisation routes (electricity or hydrogen) show significant emission reductions over the gasoline reference case. Fossil fuel based routes provide for reductions of between 60 –80% of GHG emissions over the reference case. Biomass routes benefit from a net removal of CO2, but as noted previously these figures should be treated with caution, since an increase in vehicle or production energy efficiency would reduce the net removal of CO2. For CNG and DME from remote natural gas, CCS provides an additional 5-10 % GHG reduction, making for a 30 –40% benefit over the reference case. Since the FT produces fuel with a relatively high carbon content and because the 2010 fuel efficiency benefit of diesel vehicles is eroded relative to the gasoline, CCS can only have a limited impact on GHG emissions relative to gasoline.

Fig. 25 Comparison of WTW GHG emissions for all pathways



GHG emissions tend to be more sensitive to wider variation of input variables. WTW GHG emissions for the case of a hydrogen-fuelled ICE, where hydrogen is derived from pipeline natural gas are sensitive to a wider range of input variables than noted above for energy consumption see (Figure 26). For GHG emissions, supply chain variables are far more significant (cf. Figure 23). In the case of a fuel cell hybrid powertrain (Figure 27), vehicle performance (with its wider range of uncertainty) is the dominant variable, although supply chain variables are also significant. Reduction in GHG emissions from production and transportation would therefore improve the impact of the natural gas to hydrogen pathway.

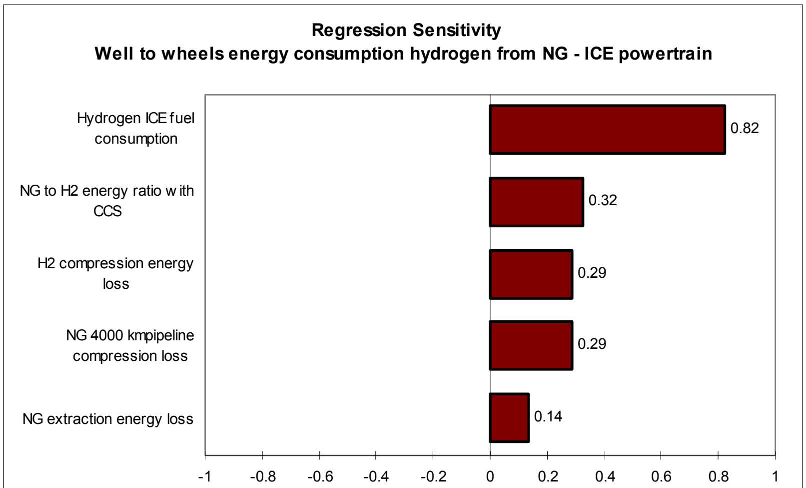


Fig. 26

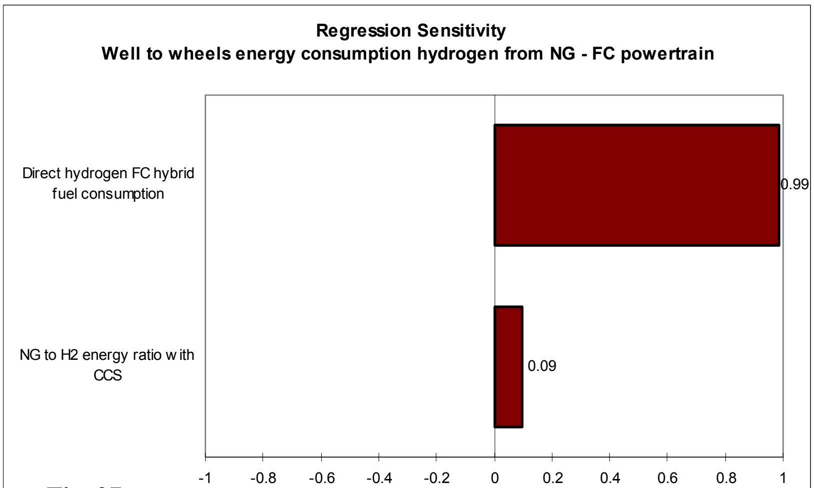
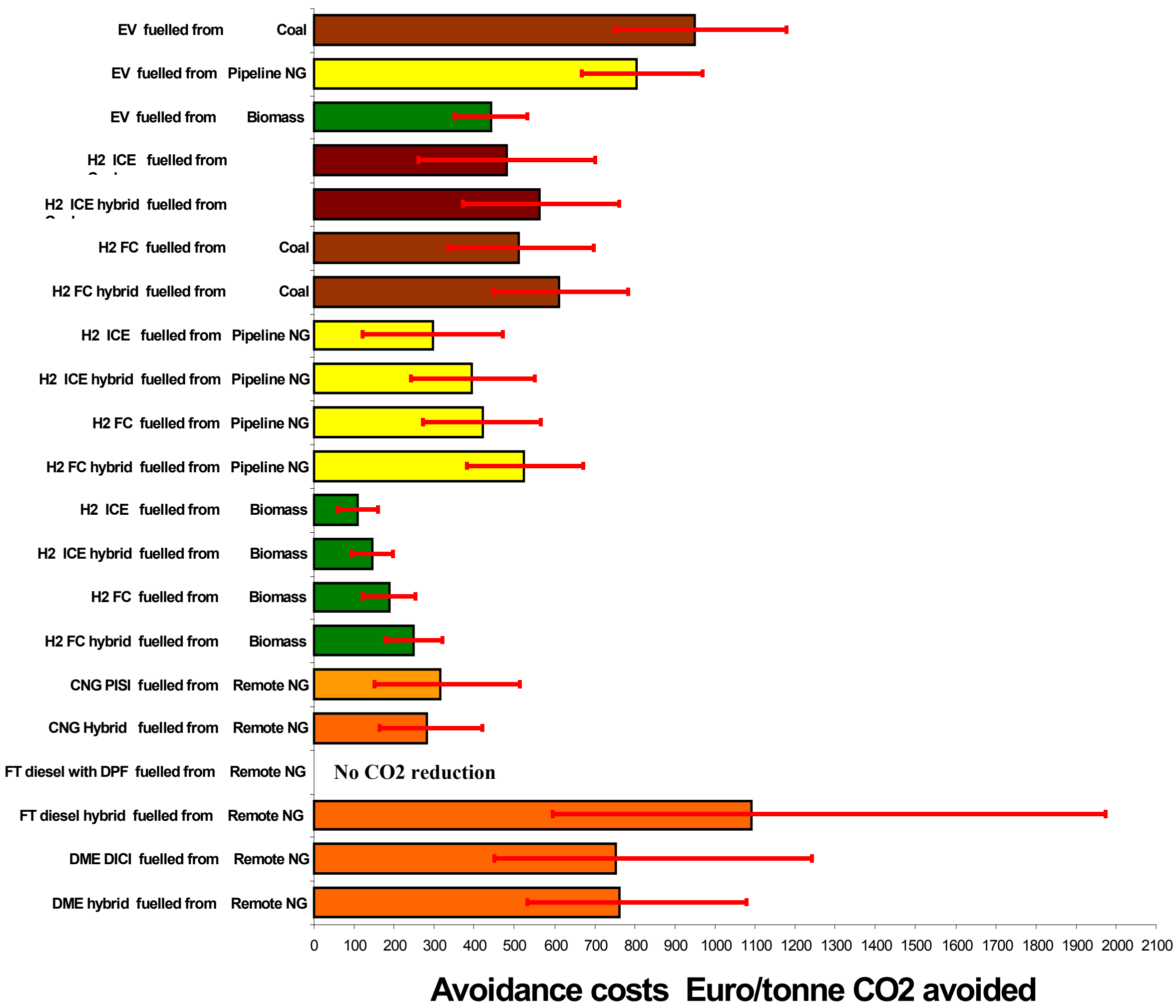


Fig. 27

Estimates of the cost of avoiding CO2 emissions based on 5% and 10% discount rates are shown in Figures 28 and 29 respectively. The data all apply to CCS. Avoidance cost is measured relative to the gasoline reference pathway as defined in section 2.4.7. The data have a high level of uncertainty because they are calculated from a ratio of differences.

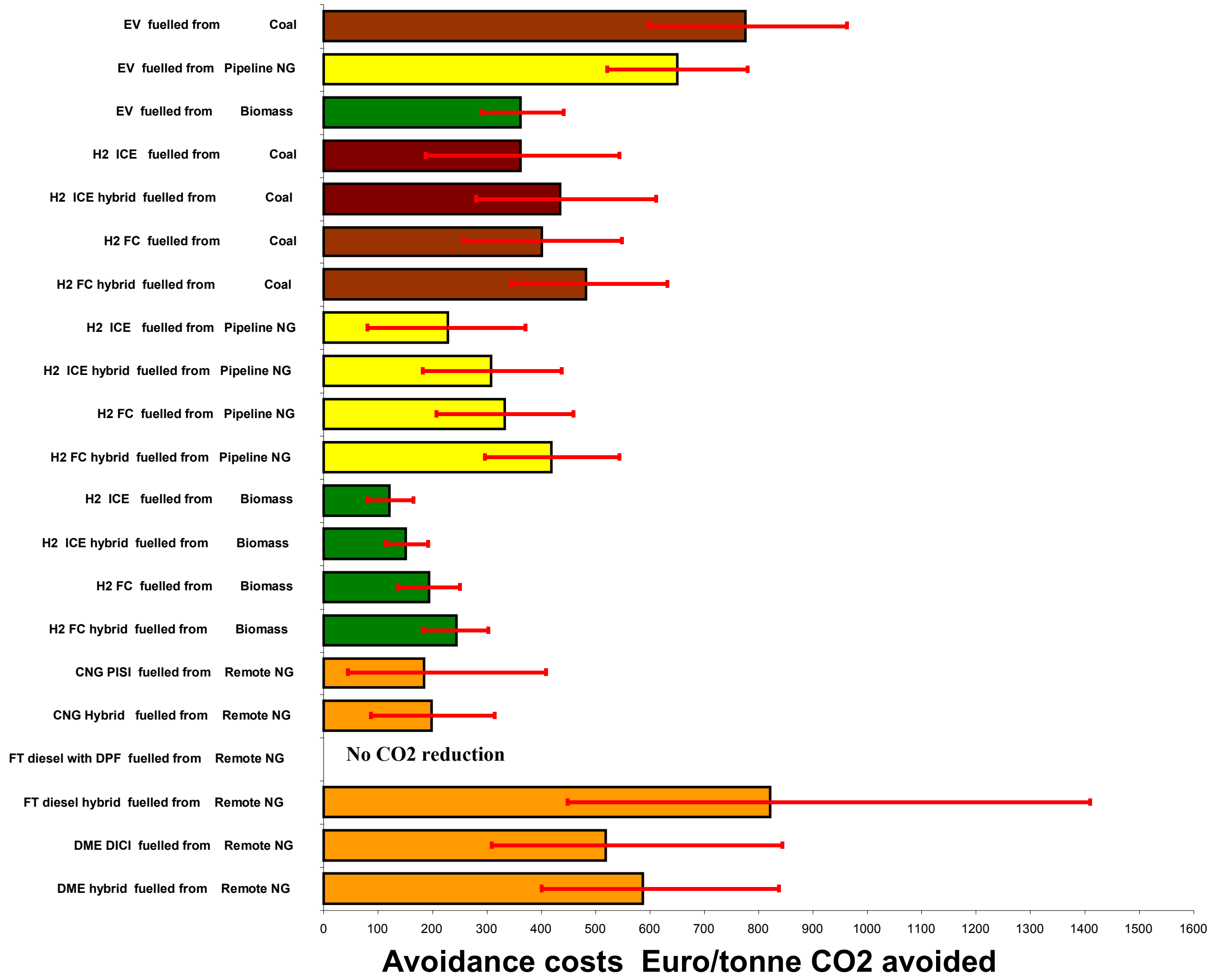
Fig. 28 Comparison of WTW CO2 avoidance costs with CCS 10% discount rate



Avoidance costs are an order of magnitude greater than those expected to apply when the market in traded CO2 emission reductions begins to operate in 2005, as well as being much greater than the costs estimated for avoiding CO_2 emissions in fuels manufacturing and electricity generation. The reason for this is that running costs (calculated as the sum of fuel operating costs and vehicle investment costs see section 2.4.6) are dominated by vehicle investment costs. To set the figures into context, the calculated avoidance cost for conventional diesel-powered vehicle with a particle filter to meet Euro IV/V requirements are estimated using JEC data to be ca. 3000 Euro/tonne CO2 avoided (compared with the gasoline pathway reference see Table 29.). The higher cost of a diesel powertrain over a gasoline powertrain (ca. 2000 Euros including the cost of a diesel particulate filter)) more than outweighs the benefits from higher vehicle efficiency and lower fuel costs.

Avoidance costs are lowest for hydrogen ICE vehicles, where the hydrogen is derived from biomass, and for CNG vehicles. Avoidance costs tend to increase with increasing powertrain complexity. In nearly all cases, the least cost pathways employ CO_2 capture and storage combined with the more ‘conventional’ powertrains. Hydrogen from natural gas is the lowest cost pathway for avoiding significant quantities of GHG emissions from passenger cars.

Fig. 29 Comparison of WTW CO2 avoidance costs with CCS 5% discount rate



The dominant role of vehicle costs is reflected in the sensitivity analysis. The accompanying figures illustrate the impact of input variables on avoidance cost for the least cost pathways. In the case of biomass to hydrogen (Figure 30), the large net reduction in CO2 emissions is a key determinant in achieving the lowest overall cost. The high cost of hydrogen and hydrogen on-board storage, however, tend to offset these benefits. As a result, avoidance cost is sensitive to the cost of a pressurised hydrogen tank and to a range of variables that determine hydrogen supply costs. On-board storage cost is, by far, the most significant factor. A reduction of estimated cost of hydrogen storage by Euro 1300 would reduce the avoidance cost by 31 euro/tonne at a 10% discount rate.

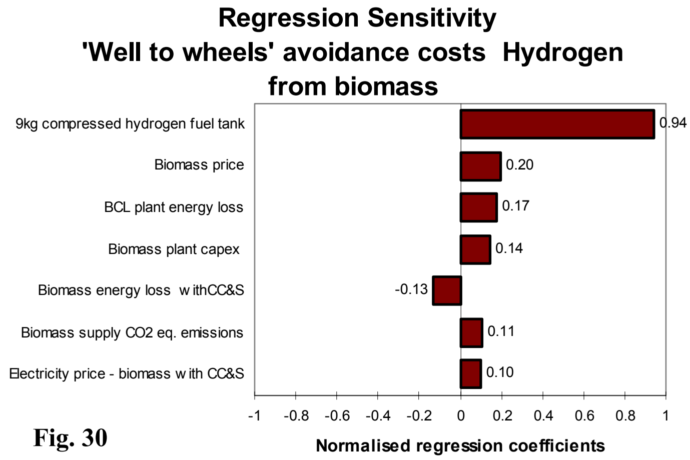


Fig. 30

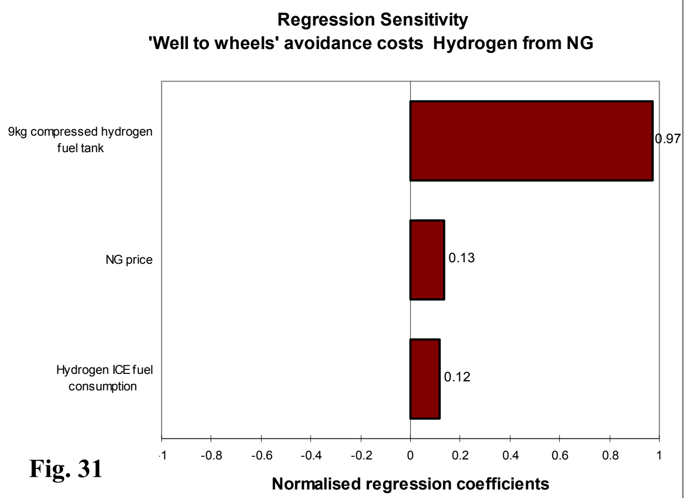


Fig. 31

For the pipeline natural gas to hydrogen fuelled ICE (Figure 31), avoidance costs are only sensitive to on-board hydrogen storage costs and only marginally sensitive to gas price and engine efficiency - nothing else matters. In this case, reduction of the cost of hydrogen storage by Euro 1300 would reduce the avoidance cost by 100 Euro/tonne at 10% discount rate.

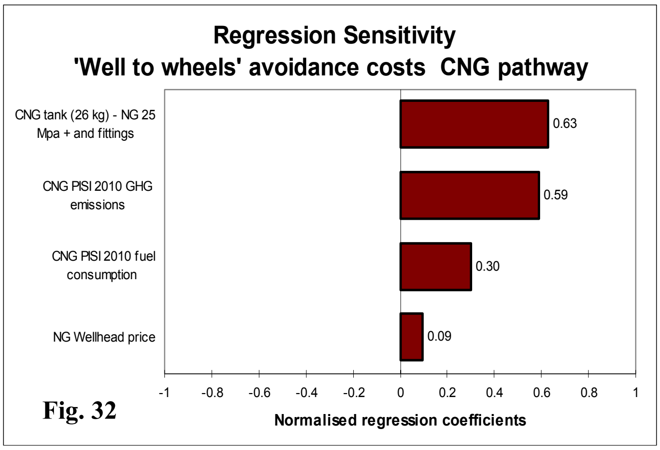


Fig. 32

Avoidance costs for remotely sourced CNG (Figure 32) are equally sensitive to vehicle cost and performance variables and very little else.

Avoidance cost data are re-plotted in Figures 33 – 36 against GHG emission reduction for each of the each of the fuel pathways. Data on the biomass to hydrogen pathway without CCS has also been included for comparison (Figure 35).

Figure 33 compares avoidance costs and GHG emission reduction for each of the remote gas pathways. CNG appears to be the lowest cost way of reducing GHG emissions from remote natural gas. In comparison, FT diesel, based on the marginal substitution of conventional diesel, is the least cost-effective because of the limited impact of this pathway on GHG emissions relative to the gasoline reference. Indeed as noted in section 3.3.1 Table 33, only one FT diesel pathway, namely that combining FT diesel with CCS and a hybrid DICI vehicle has GHG emissions significantly below the gasoline reference, and hence a meaningful estimated avoidance cost. All remaining pathways have

Fig 33. Avoidance cost 10% discount rate VS. Emission reduction relative to gasoline reference - remote gas pathways

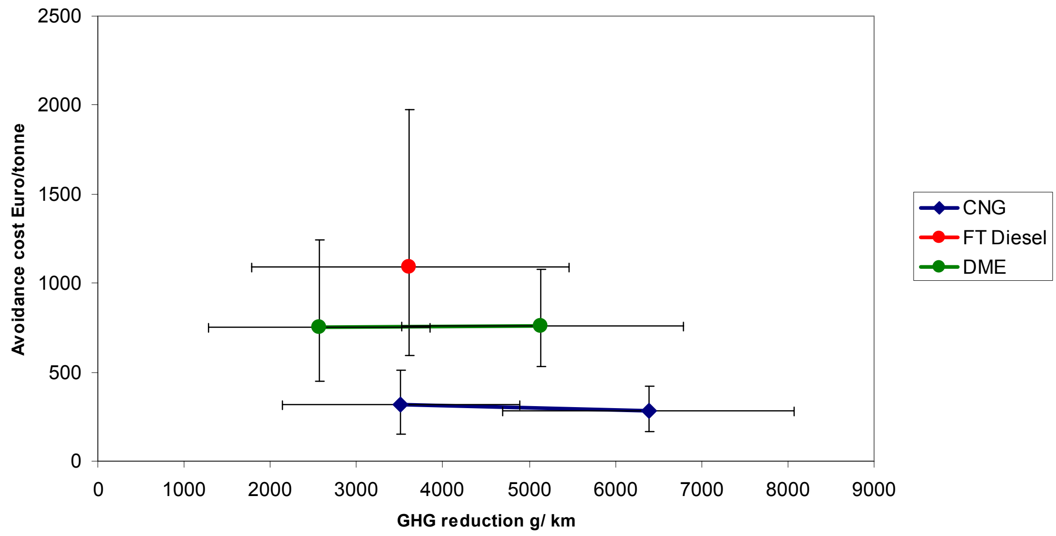
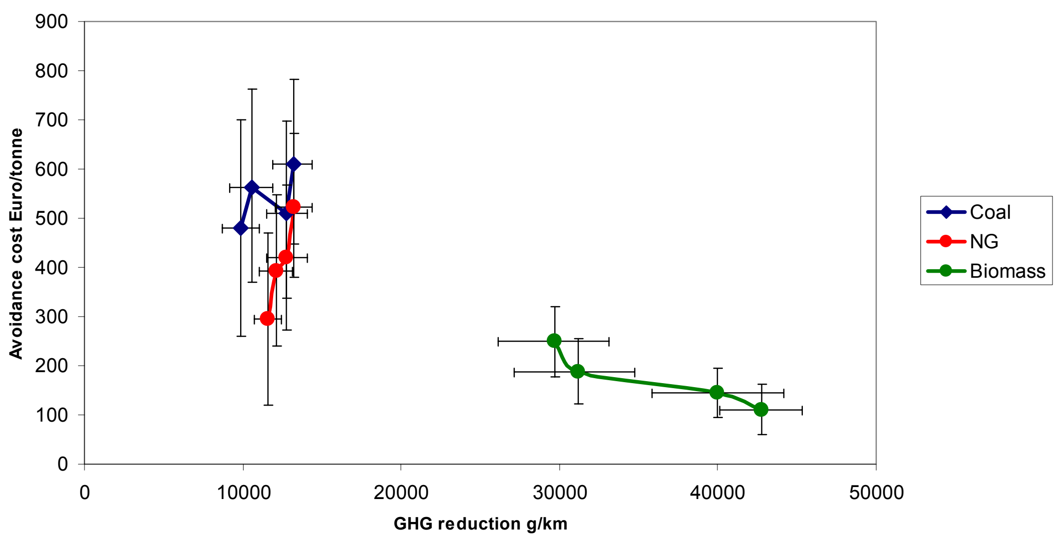


Fig 34. Avoidance cost 10% discount rate VS. Emission reduction relative to gasoline reference - Hydrogen pathways with CCS



WTW GHG emissions comparable with or greater than the gasoline reference. For both CNG and DME, the greater reductions in GHG emissions achieved by hybrid powertrains are obtained without increasing the avoidance cost; increased vehicle cost if offset by increased efficiency and lower fuel consumption. CNG and DME combined with hybrid powertrains achieve a WTW GHG emission reduction of between 50 – 65 g/km, approximately a third of the gasoline reference pathway (165 g/km)

Fig. 35 Avoidance cost 10% discount rate VS. Emission reduction relative to gasoline reference - Biomass to hydrogen pathways

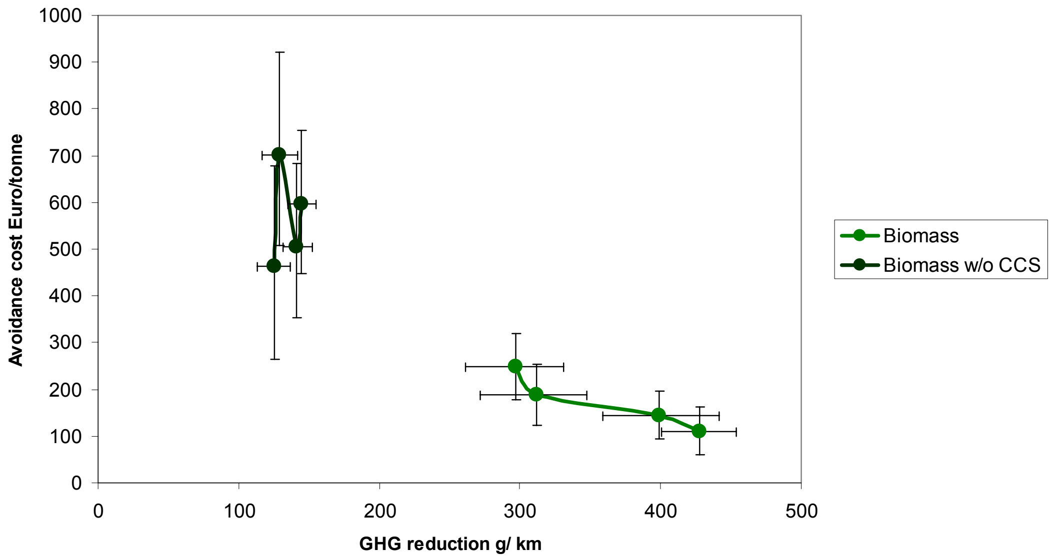


Fig. 36 Avoidance cost 10% discount rate VS. Emission reduction relative to gasoline reference - EV pathways

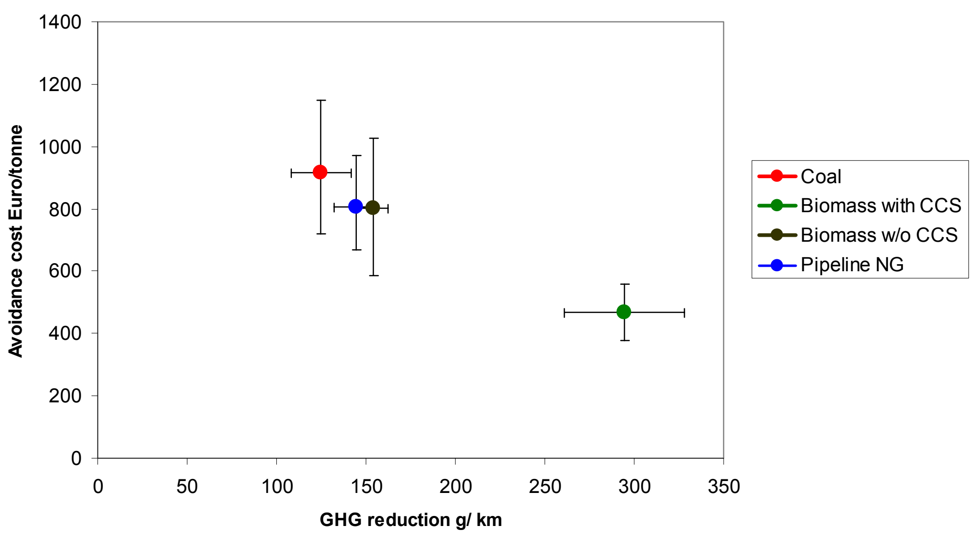


Figure 34 summarises all of the hydrogen pathways with CCS. For those pathways based on coal and natural gas, a greater reduction in GHG emissions leads to increased cost of avoidance. The combination of hydrogen with CCS and a conventional ICE powertrain has the lowest avoidance costs; increased powertrain complexity and the associated increase vehicle fuel efficiency achieve modest further reductions in GHG emissions at a significant increase in vehicle cost. In the case of biomass, pathways with CCS provide greater reduction in GHG emissions at lower vehicle efficiencies because of the increased net removal of CO_2. As noted previously, this conclusion should be treated with caution. Figure 35 compares biomass pathways with and without CCS. Biomass without CCS, which is an inherently low carbon route, achieves GHG reduction similar to fossil fuels with CCS, and at a comparable cost. The data also follow a similar trend with vehicle efficiency; avoidance cost increases with increase in vehicle efficiency. All fossil fuel pathways achieve reductions of 100 – 130 g/km, approximately two thirds of the gasoline reference pathway.

Figure 36 summarises the data for electric vehicles. Again, biomass, as a primary energy source, is included with and without CCS. Biomass without CCS, as a low carbon pathway, is comparable with the coal pathway with CCS.

3.5 Sensitivities

Sensitivity of output variables to changes in certain key input variables have been discussed at some length in the preceding sections. Sensitivities vary with each pathway and some parameters are specific to that pathway or set of pathways. For instance, hydrogen compression is a significant component of energy consumption and emissions, particularly in the case of hydrogen produced from natural gas (see section 3.1.2). Similarly, energy loss in the supply of pipeline natural gas is also an important factor, and

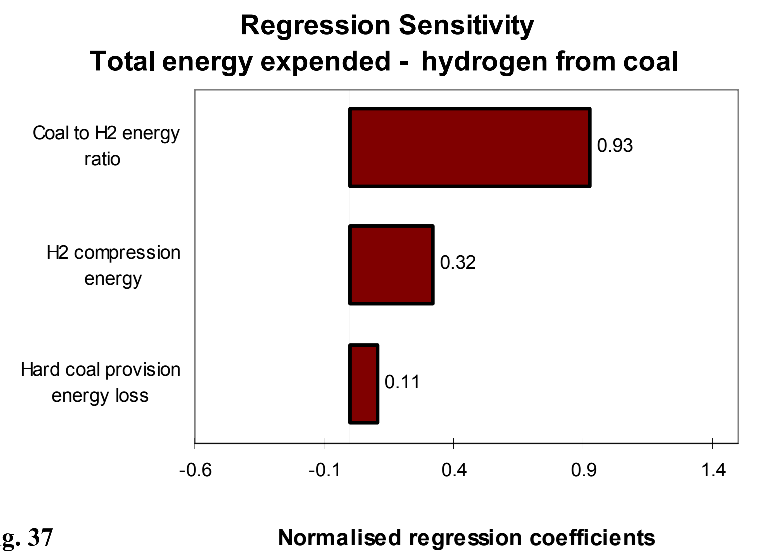


Fig. 37

unique to this pathway. However, as noted in Figure 37, hydrogen produced from coal is mainly sensitive to energy loss in the production process (termed hard coal provision in Figure 37).

Some generalisations are, however, possible. For fuel supply, conversion process performance is usually the dominant factor in determining energy loss and emissions. Primary fuel cost and plant capital cost are almost invariably, the most significant factors in determining the cost of the delivered fuel.

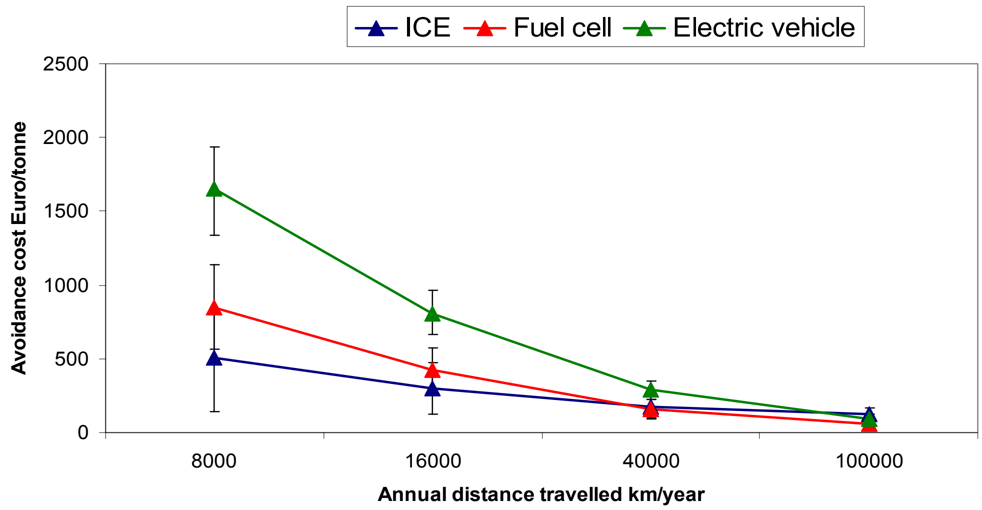
For WTW output variables, vehicle cost (which includes the additional costs of powertrain and fuel storage), and vehicle performance parameters are almost invariably the most significant variables in determining the performance and cost based on distance travelled.

Cost of emissions abatement is sensitive to assumptions made on the average distance travelled per annum, which determines the vehicle capital utilisation. The study is based upon cars that are driven 16,000km/year. In order to assess the impact of distance travelled, running costs (Euro/100km) and CO2 avoidance costs have been estimated for a range of distances (8,000km/year, 16,000km/year, 40000 km/year and 100000 km/year) for three technology options:

- Hydrogen ICE vehicle fuelled from pipeline natural gas
- Hydrogen fuel cell vehicle fuelled from pipeline natural gas
- Electric vehicle fuelled from pipeline natural gas

While it recognised that maintenance costs may well differ significantly as a function of powertrain technology, such information is not yet available and has therefore been

Fig. 38 **Sensitivity of avoidance cost to annual distance travelled 10% discount rate**



ignored.

Figure. 38 illustrates the effect of varying annual distance travelled. At a distance of 40,000km/year, avoidance costs for all technologies are comparable. At this level of vehicle utilisation, capital charge per kilometre is reduced and differences in fuel costs become a significant factor. At higher levels of utilisation, fuel costs becomes the determining factor and the high efficiency of the fuel cell and EV result in these technologies having the lowest avoidance costs.

3.6 Implications for the US market

The analysis presented in this report has been set against a background of alternative fuels substitution in Northern Europe to be consistent with assumptions and data from earlier IEA GHG studies. Included in these assumptions are standardised price sets, plant installation costs, shipping distances from the Middle East to Northern Europe and national distribution distances representative of high population densities. In the USA, refineries are configured to upgrade crude oil to a greater extent than in Europe and are also geared to gasoline production. As a result, energy consumption in US refineries tends to be higher than refineries in Europe. A generic refinery[47] typical of Northern Europe would have an overall efficiency of ca. 92 –94%, whereas US refineries (having had large investments in residue upgrading) would have efficiencies typically in the range 85 – 90%.

Given the sensitivity and estimates to the vehicle energy efficiency, differences between the US and European average vehicles has a significant impact. The MIT study 'On the road 202'' carried out an analysis similar to that of the JEC study for a range of alternative fuels and advanced vehicle concepts. In this study vehicle performance was estimated by simulation using a US average size passenger car to validate the results. The JEC study adopted the MIT methodology, adapting it for Northern Europe. The characteristics of the baseline vehicle (cost, size, mass, engine capacity, drag resistance, etc.) are similar. Despite different drive cycles, efficiencies of such advanced concepts as the direct hydrogen fuel cell vehicle and the electric vehicle are broadly the same within the respective ranges of uncertainty.

Table 38 Comparison of estimated alternative vehicle performance from the MIT and JEC studies

	MIT EV	EV this study	MIT H2 fuel cell	JEC H2 fuel cell
Fuel efficiency MJ/100km	51	46 +/- 6	81	84 +/-10

In order to assess the implications for the US market, this study uses the results of the MIT study to provide some indicative data for US primary fuels costs, energy and emissions over the supply pathway, and to provide a baseline vehicle performance. Because of the convergence of alternative vehicle performance suggested in Table 38, JEC vehicle performance data are assumed to apply in the US. Using MIT data and assuming that the baseline vehicle in that study has the same improvements as expected

[47] Such a refinery is taken to include a fluid catalytic cracker.

for the JEC study, the comparative energy and emission data for fuel supply and for the full WTW pathways are summarised in Tables 39 and 40 respectively.

Table 39 Comparison of pathway energy and emissions for European and US gasoline

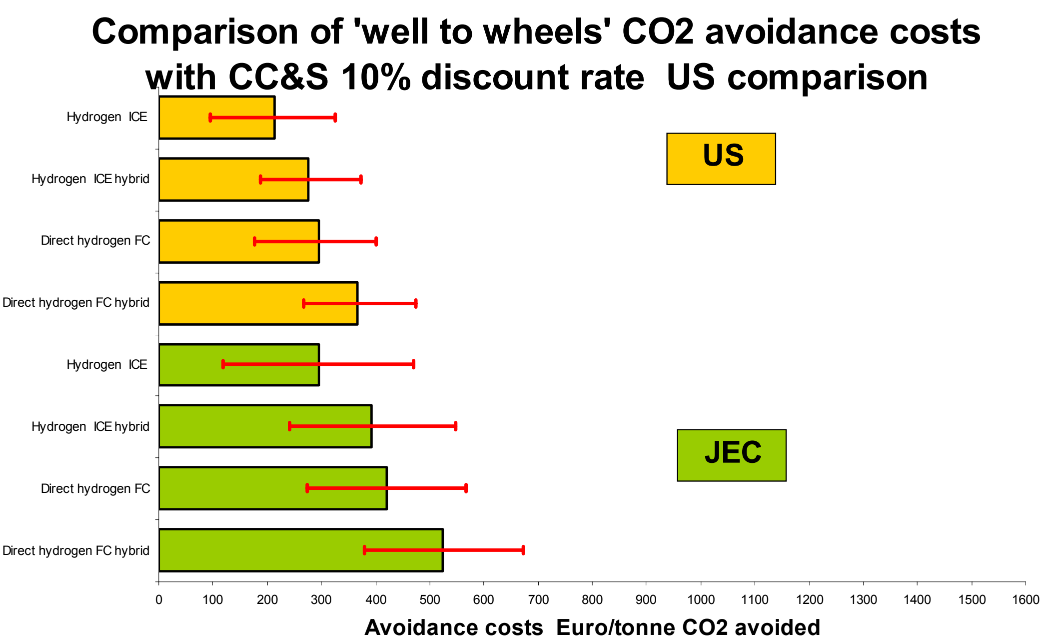
Gasoline supply	Energy expended MJ_{ex} /MJ $_{fuel\ supplied}$			GHG emissions gCO2 eq. /MJ $_{fuel\ supplied}$		
	Mean	P5	P95	Mean	P5	P95
European refining (JEC)	0.145	0.120	0.170	13.0	11.0	15.0
US refining US (MIT)	0.211			20.3		

Table 40 Comparison of WTW energy and emissions for European and US gasoline

WTW gasoline		Total pathway energy consumption MJp/100km			Total pathway GHG emissions gCO2 eq. / km		
		Mean	P5	P95	Mean	P5	P95
Gasoline - European refining	JEC - 2010 PISI	218	201	234	165	157	172
Gasoline US refining	MIT - US 1996	331			261		
	MIT - US assumed 2010	281			221		

The combined effect of higher pathways emissions and a lower vehicle efficiency indicate 35% increase in CO_2 for the US market, if US vehicles achieve comparable fuel efficiency improvements.

Fig. 39



In order to illustrate the impact of an alternatively fuelled vehicle, the gasoline fuel cycle is compared with a natural gas to hydrogen fuel cycle also rebased for US market conditions. Vehicle efficiencies are those in Table 38. Assuming marginal gas supplies are from the Gulf region, pipeline transport distances would be ca 3000 km, marginally

reducing supply emissions (27 vs. 29 g CO_2 eq. /MJ hydrogen supplied). The price of gas to US commercial customer is projected by the US DOE for 2020 to be $5.7 +/- 0.4 per GJ. The cost of hydrogen supply to the retail outlet would, under this gas price scenario, increase to $14 -$18 /GJ without CCS and from $15.7 - 20 /GJ with CCS, assuming $/Euro parity. However, despite a higher energy price, the cost of avoidance would decrease because of the higher emissions of the US gasoline WTW reference pathway. The changes are illustrated in Figure 39
The benefits of CCS may well be more cost effective when set against higher pathways emissions from US vehicles.

4. Conclusions

The main findings of this study have been presented separately for fuel supply to the retail outlet (Well to Tank -WTT) and the full Well to Wheels (WTW) pathway.

The main conclusions related to fuel supply (WTT) are:

- WTT energy expenditure of all alternative fuel pathways are greater than gasoline, only CNG from remote natural gas is comparable. Values of energy expended are estimated to be in the range 0.25 – 2.0 MJ per MJ fuel supplied. This compares with a figure of 0.14 MJ for gasoline.
- WTT energy expenditure of de-carbonisation routes (hydrogen and electricity) are at the top end of the range.
- CCS increases the energy expended in de-carbonisation routes for coal and biomass pathways by between 15 – 40%.
- Hydrogen production from natural gas is relatively efficient (ca 75% compared with ca 50 % for coal), and gas transmission and hydrogen compression losses are of similar magnitude to process losses. As a result, the impact of CCS is less apparent over the entire pathway. The energy penalty of CCS for this pathway is only ca 8%.
- CNG and synthetic fuel pathways remove only a small percentage of input carbon and as a result, the energy penalty for CCS is marginal (1-8%).
- Greenhouse gas emissions without CO_2 capture mirror the trends for energy expenditure in all cases apart from biomass. As a result, use of CO_2 capture provides a significant net removal of CO_2 for biomass pathways.
- CO_2 capture applied to non-biomass pathways reduces GHG emissions in most cases to levels within a range of 11 – 40 g CO2 eq./MJ fuel supplied. The one exception is coal to electricity (75 g CO_2 eq./MJ electricity supplied), where the relatively high emissions from coal supply are amplified by the low efficiency of power generation.

- Emissions from CNG and synthetic fuels produced from remote gas are, with CCS, in the range 11 – 13 g CO2 eq./MJ fuel supplied, which are comparable with the gasoline pathway (12.8 g CO2 eq./MJ fuel supplied).
- The estimated costs of fuels produced from remote gas are comparable with gasoline on an energy basis. De-carbonised fuels produced from fossil fuels are 1.5 to 2.5 times more expensive than gasoline. Fuels produced from biomass are the most expensive - 3-5 times that of gasoline. Biomass has higher feedstock costs and does not benefit from economies of scale to the same extent as fossil fuels.
- Fuel supply costs are most sensitive to primary fuel costs and plant capex.
- CCS adds about a 15- 25% cost penalty to the cost of supplying de-carbonised fuels. The cost penalty is less (ca 2- 10%) for fuels from remote natural gas.

The main conclusions related to the full fuel cycle (Well to Wheels) are:

- Electric vehicles with a reduced driving ranger (ca 350 km) are estimated to have a vehicle (Tank to Wheels) energy consumption of 46MJ/ 100km, approximately on quarter of the equivalent 2010 gasoline vehicle (190 MJ/100km)
- Electric vehicles and fuel cell vehicles powered by hydrogen from natural gas have the lowest overall WTW energy consumption ca. 130 – 170 MJ/100km, even with CCS. CCS adds a penalty of up to 25%. WTW All of these pathways are less energy intensive than the gasoline reference pathway (218 MJ/100km travelled).
- Hydrogen fuelled ICEs, where the hydrogen is derived from coal and biomass have the highest WTW energy consumption ca. 400 - 550 MJ/100km travelled, although virtually all of the energy consumption in the biomass pathway is renewable.
- WTT energy consumption for CNG and synthetic fuels from remote natural gas are a greater than the gasoline reference pathway apart from the case of CNG fuelled hybrid vehicles. Of these particular pathways, FT diesel is the most energy intensive (312 – 379 MJ/100km travelled) because of the relatively low efficiency of the fuel manufacturing process. Improvements in process energy efficiency and selectivity to diesel could reduce WTW energy consumption to a level comparable with the other remote gas pathways.
- For all pathways, vehicle energy efficiency is the key determinant of the WTW energy consumption. Vehicle energy efficiency determines the energy ranking of each pathway, and differences in vehicle technology exceed the penalties from CCS.
- WTW GHG emissions follow the trends noted for energy expenditure, although biomass as a renewable energy supply has by definition the lowest net GHG emissions.

- Electric vehicles and fuel cell vehicles fuelled by hydrogen from natural gas generally have up to 25% lower WTW GHG emissions than the gasoline reference pathway, even without CCS.
- FT diesel without CCS has between 2 – 24% higher WTW GHG emissions than the gasoline reference depending on the vehicle type. This finding is a direct result of the JEC conclusion that gasoline vehicle energy efficiency will approach that of diesel engines for 2010 technology.
- With CCS, all decarbonisation routes (electricity and hydrogen) show significant emission reductions over the gasoline reference case. Fossil fuel based routes provide for reductions of between 60 –80% of GHG emissions over the reference case. Biomass routes benefit from a net removal of CO_2, but as noted previously these figures should be treated with caution, since an increase in vehicle energy efficiency reduces the net removal of CO_2.
- For CNG and DME from remote natural gas, CCS provides an additional 5-10 % GHG reduction, making the 30–40% benefit over the reference case. FT diesel with CCS shows a small benefit (5 - 22%) over the reference case. Since the FT produces fuel with a relatively high carbon content and because the 2010 fuel efficiency benefit of diesel vehicles is eroded relative to the gasoline reference, CCS can only have a limited impact on GHG emissions relative to gasoline.
- CO_2 avoidance costs are an order of magnitude greater than those expected for the cost of traded CO_2 in the immediate future, or costs estimated for avoiding CO_2 emissions in fuels manufacturing. The reason for this is that running costs are dominated by vehicle investment costs at typical levels of utilisation (16,000 km/year). At higher levels of vehicle utilisation (>40,000km/yer) fuel costs become a more significant factor.
- Avoidance costs are lowest for hydrogen ICE vehicles, where the hydrogen is derived from biomass with or without CCS, and for CNG vehicles. Avoidance costs tend to increase with increasing powertrain complexity. In nearly all cases, the most cost-effective pathways employ carbon CCS combined with more 'conventional' powertrains.
- Although, from the previous point, biomass (woody biomass only) has the lowest avoidance cost the conclusion should be set in the additional context that:
    - Woody biomass resources are limited and only likely to make a marginal contribution to hydrogen supply;
    - in the case of CCS, a lower efficiency increases the net quantity of CO2 stored , and has a beneficial impact on avoidance costs;
    - conversion technology is only at the demonstration stage and is yet to fulfil the high performance expectations.
- Hydrogen from natural gas provides the lowest avoidance cost for significant quantities of CO_2 emissions.

- Based on avoidance costs, CNG appears to be the most cost-effective way of reducing GHG emissions from remote natural gas. FT diesel is the least cost-effective because of the limited impact of this pathway on GHG emissions relative to the gasoline reference, and because of the relatively high cost of diesel vehicles.
- Transposing the findings of this study to the US market suggest that, with the lower efficiency of US vehicles and US refineries, CCS applied to alternative fuel pathways may provide a lower cost of avoiding CO_2 than that estimated for Northern Europe.

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Appendix I Fuel Supply Pathways

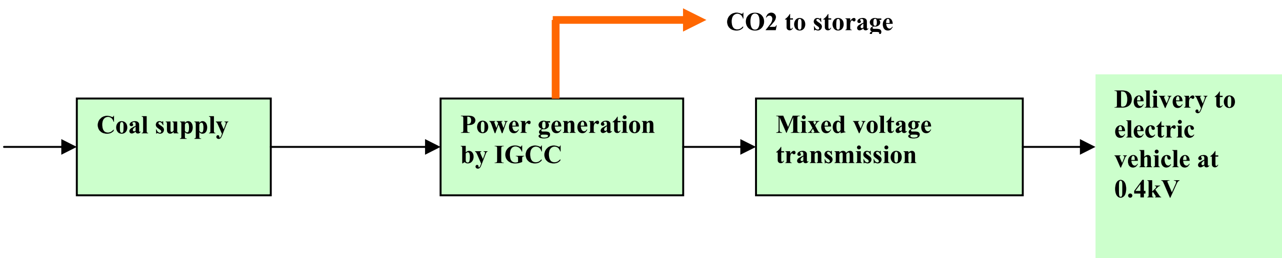
I. Pathway definition

I.i Electricity

Netherlands domestic electricity consumption in the year 2000 was 105 TWh (378PJ[1]). Consumption projected to rise to 145 TWh (522 PJ) by 2020, an average annual rate of 1.6%[2]. This figure currently excludes demand for road transport applications, which under the scenario assumptions would be ca. 10PJ for an electric vehicle (EV). An additional 2% increase in electricity supply would therefore be required to power 1 million electric vehicles.

I.i.i Coal to electricity

Electricity is manufactured from a range of sources, with coal representing ca. 25 % of the primary energy mix within the EU[3]. Whilst conventional and advanced steam cycles fired by pulverised coal will be the practice in the short to medium term, integrated coal gasification combined cycles (IGCC) offer a potentially more attractive route for carbon capture from coal in the longer term. Electricity generation in this study is based on IGCC technology. Coal is mined in a non-specified location and transported to coastal generating site in the Netherlands where it is gasified to hydrogen via partial oxidation (POx) and CO shift reactors. Acid gases (CO_2 and H_2S) are removed and hydrogen is fed under pressure to a gas turbine. Electricity is distributed via a high, medium and low voltage transmission system and delivers to the customer at 0.4kV.



[1] 1 Peta Joule (PJ) = 10^{15} Joule
[2] Energy Research Centre of the Netherlands 2002 Ybema et al.
[3] Eurostat 2001, Hard Coal and Coke, Imports 1998 - 2000; Statistics in focus; Environment and Energy

I.i.i.i Coal supply

Primary energy used in the provision of coal (mining and transport) will vary according to the depth, type and location of the mine and the mode of transportation used. Best estimate data used in this study, approximate the average primary energy associated to the production and provision of hard coal to Europe[4,5]. European coal is widely sourced, with half of the EU-mix mined within the EU. Almost half the energy is expended as electrical energy and it is assumed that, over time, the average efficiency of generation will increase as NG and renewable energies account for an increasing proportion of capacity. If electricity consumption in all source countries follows the pattern forecast for EU-25[6], then the average generating efficiency will increase by ca. 10-12 percentage points. Similarly, methane emissions represent over half the greenhouse gas emissions from coal provision, and it is assumed that these will be reduced by a factor of two over time. Based on these assumptions, a lower bound estimate of energy and emissions has been derived. The upper bound is assumed to be close to current average figures.

Table I- 1 Estimated energy efficiency and emissions from coal supply

	Energy expended MJ/MJ coal produced	Range	CO2 eq. emitted g/MJ coal produced	Range
Primary energy and emissions	0.0940	0.08 – 0.01	15.3	9.6 – 15.5

I.i.i.ii Electricity production and carbon capture

Coal based IGCC plants based on Texaco and Shell gasification technology were assessed in IEA report PH4 –19. The study concluded that the Shell gasifier had higher efficiency, capital costs and cost of electricity than the corresponding Texaco gasifier. The cost of carbon capture was also higher for Shell gasification. The study identified a series of technology improvements that could be implemented within the study timeframe to increase performance and reduce costs. These were combined in a logical scheme to provide an upper bound to the best available technology (BAT) by 2020.

In this study, we have assumed that some of the technology improvements have been implemented to provide a base case IGCC performance. Texaco technology (case 1 in the IEA study) is assumed to set the lower bound on performance and the 2020 BAT (case G1 in the IEA study) sets the upper bound. Similarly for the case with capture Texaco technology (case D1) sets the lower bound on performance and 2020 BAT sets the upper bound.

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[4] Coal production and extra EU imports in the year 1999, Source: Oil, Gas, Coal & Electricity, IEA Statistics 2000

[5] 'Well to Wheels analysis of future automotive fuels and powertrains in the European context WELL TO TANK Report Version 1', Appendix 1, November 2003

[6] Energy projections as input to the CAFÉ baseline - PRIMES projections and national perspectives L Mantzos , 2004

Case C1 comprises a slurry-fed gasifier operating at 65 bar with product gas cooling by water quench. Acid gas removal is based on the Selexol process. Power is generated by two frame 9FA gas turbines providing a net power output of ca 750 MWe. Sulphur is recovered as a by-product in an O_2 assisted Claus unit. In common with most state-of-the-art plants, the process incorporates cryogenic air separation, with 50% integration with the gas turbine. For the case with capture (case D1), the process incorporates a sour shift reactor following the gasifier quench and subsequent H_2S and CO_2 removal based on the Selexol wet scrubbing process. CO_2 is dehydrated and compressed to 110 bara.

2020 plant has the following key technology improvements:

- 2020 generation gas turbines
- Dry feed, double stage gasification without refractory
- Hot gas clean-up
- Once through supercritical steam generation
- Air separation based on ion transfer membranes

Performance data for the process with and without capture are as follows:

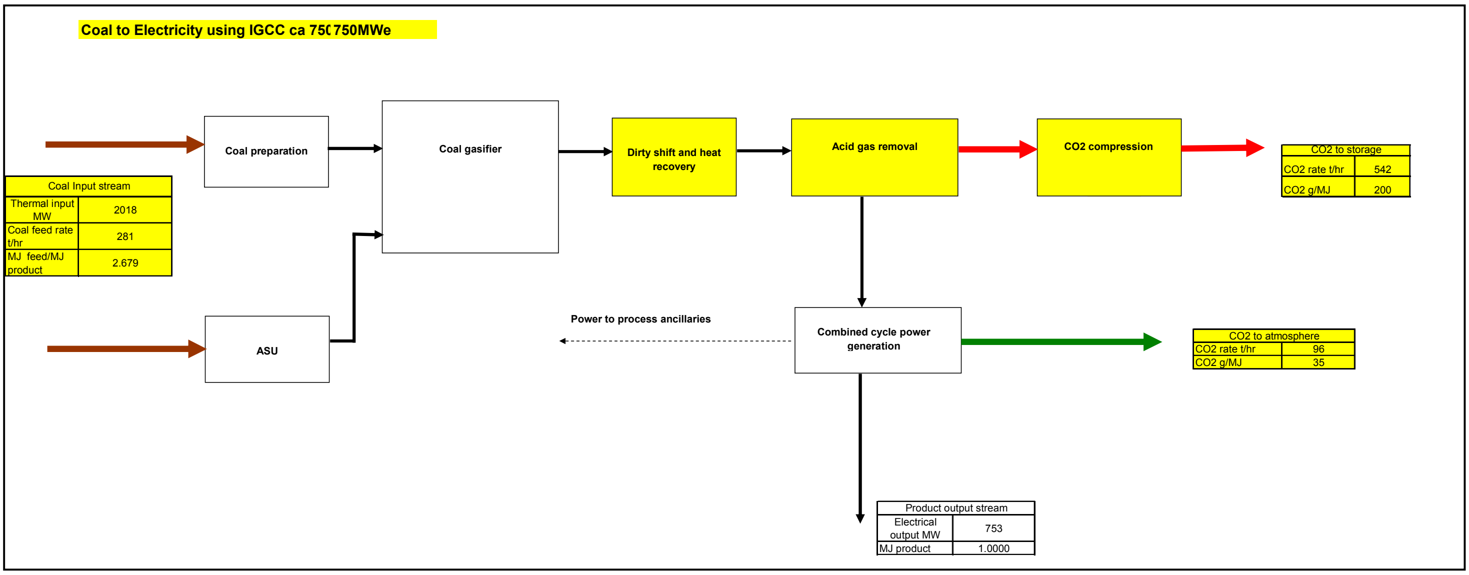
Table I – 2 Estimated energy efficiency, emissions and costs for a 750MWe IGCC with and without carbon capture

	IGCC plant without capture	Range P20 – P80	IGCC plant with capture	Range P20 – P80
Overall efficiency %	43.4	38 - 49	37.3	31 - 43
Coal to electrical energy ratio MJ/MJ	2.303	2.64 – 2.05	2.679	3.18 – 2.32
Capital cost Euro/kW_e	1157	+/-30%[7]	1418[8]	+/-30%
CO2eq emissions g/kWhe	728	646 - 833	127	110 -151
CO2 captured g/kWhe	-	-	720	

Process layout and key streams are summarised in the following simplified flowsheet

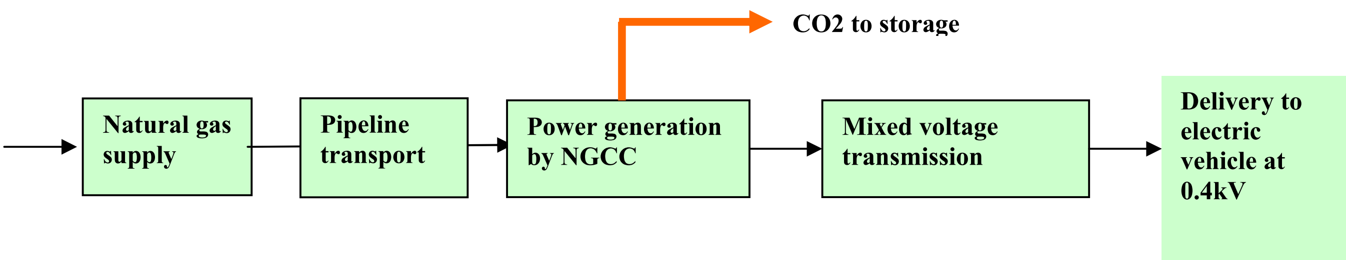
[7] All capital costs +/- 30% are at a P5 – P95 level of accuracy.
[8] Includes the capital costs of CO2 disposal

Fig I - 1 Simplified IGCC flowsheet showing overall energy balance and CO2 emissions



I.i.ii Natural gas to electricity

Natural extracted and processed in a remote location and transported by high-pressure pipeline over a distance of 4,000km to the Netherlands, and then by national distribution pipelines to a coastal generating site. Power is generated by state-of-the-art NGCC comprising gas turbines, heat recovery steam generators and steam turbines. Carbon capture is by solvent scrubbing process, drying and compression for pipeline disposal. Electricity is distributed via a high, medium and low voltage transmission system and delivers to the customer at 0.4kV.



I.i.ii.i Natural gas supply

Shell data indicate that the efficiency of gas extraction and processing ranges between 96-99% with a best estimate of 98% and average greenhouse gas emissions of ca. 3

gCO_2eq/MJ of natural gas produced. Energy efficiency and greenhouse gas emissions arising from extraction and processing are summarised in Table I – 3.

Table I- 3 Estimated energy efficiency and emissions form natural gas extraction and processing

	Best estimate Energy expended MJ/MJ	Range of estimates	Best estimate CO2 eq. emitted g/MJ	Range of estimates
Primary energy and emissions	0.02	0.01-0.04	2.9	0.6 – 4.0

Gas transport over long distances by pipeline requires that gas is re-compressed at regular intervals to compensate for pressure loss. Gas is compressed at a series of compressor stations use pipeline gas as fuel. Gas turbines drive the compressors with overall efficiency 27.8%. The gas flow therefore decreases along the line so that the average specific energy tends to increase with distance. The actual energy consumption is also a function of the line size, pressure, number of compressor stations and load factor. A figure of $0.3MJ_{ex}$/t.km is typical of existing pipelines operating at around 8MPa, and has been used in this study. The distance selected is typical of the Near/Middle East (4000 km), a likely source of marginal gas for Europe. Methane losses associated with long-distance pipeline transport are based on data from a joint study by Gazprom and Ruhrgas[9], which suggests 1% loss per 6000 km - a figure of 0.016% per 100km has been used. 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 similar to that of a long-distance pipeline, with recompression stations and therefore energy consumption along the way. The recompression stations are driven by electricity, generated by gas turbines using the gas itself as fuel. An average distance of 100 km within the Netherlands for an average energy consumption of 0.27 MJ/(t.km), which is typical of European networks. Overall efficiency (compression energy expended /fuel energy consumed) is estimated at 30%. Gas losses are reportedly very small -a figure of 0.0001 MJex/MJ has been used based upon measurements on the Ruhrgas system. Estimated energy demand and GHG emissions used in this study are summarised in Table I – 4.

Table I - 4 Estimated energy demand and total GHG emission (CO2eq) for the pipeline supply of natural gas

	Energy expended MJ/MJ NG transported	Range P20 – P80	GHG emissions CO2 eq./MJ NG transported	Range P20 – P80
4000km pipeline supply	0.094	0.079-0.104	7.84	7.1-8.4
Trunk distribution	0.0021	-	0.162	-

[9] 'GM Well-to-Wheel Analysis of Energy Use and Greenhouse Gas Emissions of Advanced Fuel/Vehicle Systems- A European Study' LBST September 2002, page75

I.i.ii.ii Electricity production and carbon capture

Electricity generation by NGCC is a widely practised technology. Data used in this study has been taken from IEA PH3-44[10], which assessed the impact of post-combustion capture of CO2 from an 800 MW power plant located in the Netherlands. IEA PH3-44 based current combined cycle plants on the GE 9FA gas turbine, which is typical of the large gas turbines being produced by the main manufacturers. More advanced and efficient gas turbines are being and are expected to be commercial within the timeframe of this study. The study postulated that, because of the strong market pull for higher efficiency power plants significant efficiency improvements could be expected by 2020 and projected improvements of ca. 6% on the current efficiency levels ca 56%[11].

Post-combustion scrubbing processes typically based on MEA[12] have been commercially demonstrated in plants that produce CO2 for enhanced oil recovery, chemicals production and the food industry. Plants have operated for 20 years with outputs of over 1,000 tpd. CO2 for a 750MW plant is typically 7,000 tpd and significant scale-up is needed. Post-combustion solvent scrubbing processes are expected to improve between now and 2020. Improvements are expected to be in a combination of design optimisation and solvent improvements. IEA PH3-44 projects capital cost of future capture and compression plant to be 60-70% of current levels and energy requirements to be reduced by ca 30%.

In this study, the best estimate of process efficiency and cost has been assumed to be the average of current technology and that projected for 2020.

Table I – 5 Estimated energy efficiency, emissions and costs for a 800MWe NGCC with and without carbon capture

	NGCC plant without capture	Range P20 – P80	NGCC plant with capture	Range P20 – P80
Overall efficiency %	58.3	56 – 61	52.5	50 - 55
NG to electrical energy ratio MJ/MJ	1.715	1.63 – 1.8	1.911	1.81 – 2.01
Capital cost Euro/kW$_e$	440	+/-30%[13]	767[14]	+/-30%
CO2eq emissions g/kWhe	352	329 -363	63	55 - 67
CO2 captured g/kWhe	-	-	328	

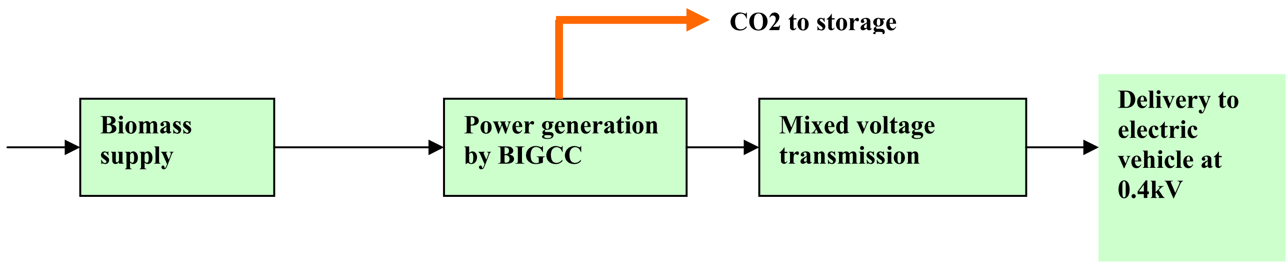
[10] IEA PH3-44 Improvement in power generation with post-combustion capture of CO2 November 2004.
[11] Based on net electrical power output and the fuel lower heating value.
[12] Monoethanolamine
[13] All capital costs +/- 30% are at a P5 – P95 level of accuracy.
[14] Includes the capital costs of CO2 disposal

I.i.iii Biomass to Electricity

Biomass is already utilised on a large scale to generate electricity in the Netherlands in co-fired plants. In 2000, approximately 1.6 TWh (5.8 PJ) or 1.5 % of the total electricity demand was supplied by biomass residues and waste streams[15]. Currently, however, biomass from domestic plantations is used on a very small scale. Under a scenario driven by reduction of greenhouse gases, Junginger et al. estimate that biomass could be expanded to 152 PJ_{th} (ca 15 TWh_e if all diverted to electricity generation), of which 34% would be from "clean sources" (farmed wood, verge grass, wood pruning and agricultural residues). Biomass could therefore make a significant contribution to incremental electricity demand.

In this study, we assume "clean sources" of domestic biomass are available to supply a small number of medium sized (200MW_{th}) BIGCC power generation plants located centrally within the biomass collection area. Electricity is distributed via a high, medium and low voltage transmission system and delivers to the customer at 0.4kV.

Wherever possible, best estimate data are taken from previous IEAGHG studies. Range data are assessed from a number of other recent studies, including the JEC study, which reflect the variability of biomass supply and performance of conversion technology.



I.i.iii.i Biomass supply

The potential for short rotation coppice (SRC) crops depends on yield, costs (including subsidies) and land availability. Junginger et al. estimate that under a minimum CO_2 scenario, the Netherlands could provide 1 million tonne cultivated biomass dry matter per annum, based on 100,000 hectare (ha) and an average yield of 10 tonnes (dry)/ha. If a plant is located centrally within an area with a 4%[16] woodland coverage, biomass would need to be collected over an area of 8,000 km^2, representing an average transport distance of ca. 35 km.

Estimates of energy demand and emissions depend on the intensity of the process and inputs such as fertilisers, pesticides and diesel for harvesting, chipping and transport and

[15] M. Junginger et al., 'Renewable energy in the Netherlands', Energy Policy, **32** , 2004
[16] For comparison, the UK has currently 10% of its land covered with trees, predominantly in Scotland and Wales. 4% is judged a reasonable figure for a highly populated country like the Netherlands.

show wide variability. N_2O is major is a major potential source of greenhouse gas and arises from fertiliser manufacture and associated land emissions; the latter is strongly depend on soil type and cultivation practice. Estimates vary widely reflecting a range of different land productivity and management practices. The JEC study calculated individual inputs separately and estimated a primary energy demand of 0.346 MJ/MJ biomass and emissions of 8.8 g CO_2 eq./MJ biomass. Indirect energy expenditure and emissions (primarily fertiliser production and land emissions) represent a significant component of these figures. A similar detailed study by Bauen[17] estimated the energy input to SRC production to be in the range 0.004 and 0.065 MJ/MJ biomass dry and GHG emissions in the range 0.92 – 13.1g CO_2 eq./MJ biomass. In this study, we use JEC data as a best estimate and Bauen's data as a measure of variability. Biomass is transported in dedicated trucks and trailers over a distance of 35km (one way). Diesel consumption is estimated at 0.97 MJ/t km and variability based on a trucking distance of 25 – 45km.

Table I - 6 Estimated energy expenditure and GHG emissions for SRC wood chips supply to a central power plant

	Energy expended MJ/MJ biomass	Range	GHG emissions CO_2 eq./MJ biomass	Range
Wood farming and chipping	0.0346	0.004 – 0.065	8.8	5.2 – 10.7
Wood chips to central processing	0.0044	0.003 - 0.006	0.33	0.25 – 0.32

Estimated supply costs of domestic biomass vary widely depending on yield and management practices. IEA GHG report PH2/10 looked, in some detail, at biomass supply from dedicated plantations at a number of specific locations in Spain. Plantation sizes were comparable with the assumptions made in this study. Supply costs were estimated in the range 49-72 Euro/ tonne dry matter or 2.7 – 3.9 Euro /GJ delivered to the central facility[18]. A similar study for the UK[19] estimated the delivered cost of SRC biomass supply to be in the range 2.1 – 5 Euro/GJ. Costs of cultivated energy crops in the Netherlands are approximately 4 US$/GJ and thinnings 3 US$/GJ[20] (Faaij 1997), and biomass imported from Sweden on a large scale is expected to cost 7 US$/GJ (1998)[21].

In this study a best estimate price for SRC biomass supply is 3.3 Euro/GJ with a range of 2.1 – 7 Euro /GJ. However, these estimates are well below the estimates used in the JEC study (8.7 Euro/GJ), which were developed from a 'bottom-up' analysis. The final biomass pathway costs will reflect this difference.

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[17] Bauen 2000 or GM Well to Wheels Analysis of Energy Use and Greenhouse Gas Emissions of Advanced Fuel/Vehicle Systems

[18] Original data was developed in 1997 and costs have been brought to a 2003 basis using an escalation factor of 1.16

[19] A. Bauen and J. Woods, 2003, 'Technology status review and carbon abatement potential of renewable transport fuels in the UK, Report to the DTI New And Renewable Energy programme'

[20] A. Faaij, 1997, 'Energy from biomass and waste' , PhD Thesis University of Utrecht, 1997

[21] A. Faaij et. al., 1998, 'Exploration of land potential for the production of biomass for energy in the Netherlands', Biomass and Bioenergy, **14**

Biomass residues offer a potentially large source of biomass: Junginger estimates ca. $40PJ_{th}$ for the Netherlands. Energy expenditure and GHG emissions tend to be lower for this source because fertilisers and pesticides (with their associated indirect energy demand and emissions) are not required and land emissions would not be increased. In this study, it is assumed that lower emissions from residues are captured in the wide range of estimates.

I.i.iii.ii Biomass electricity production and carbon capture

Air-blown biomass gasification has been used for many years as a source for low heating value fuels. Integration with a combined cycle gas turbine requires that the gas be cleaned to meet the strict requirements of the turbine, but provides higher efficiencies than in conventional power plants. BIGCC is currently only at the demonstration stage, at a scale of operation typically of $10MW_e$ or less (e.g. the $10MW_e$ at Varnamo, Sweden). Within the timeframe of this study, it is assumed that plants of $200MW_{th}$ (ca. $80MW_e$) will be a commercial reality.

Product gas from the Varnamo air-blown gasifier typically contains 50% nitrogen [22], which is a processing disadvantage when removing CO_2. As in the case of IGCC, pre-combustion de-carbonisation is likely to be the more attractive option for carbon removal. This requires oxygen-blown gasification and CO shift to maximise CO_2 content of the product gas from the gasifier. CO_2 is captured using a physical solvent process, dried and compressed to 110bara.

Data used in this report are taken from case studies cited in IEA GHG PH 2/10 and PH 3/11and from the analysis of Audus et al.[23]. Since the engineering definition of the individual plants is limited, costs are estimated in both cases are certainly no better than +/-30%.

Table I– 7 Estimated energy efficiency, emissions and costs for a 200MWth BIGCC with and without carbon capture

	BIGCC plant without capture	**Range[24] P20 – P80**	**BIGCC plant with capture**	**Range P20- P80**
Overall efficiency %	40	37 - 43	32	29 - 35
Biomass to electrical energy ratio MJ/MJ	2.50	2.70 – 2.33	3.125	2.86 – 3.45
Capital cost Euro/kW_e	1769	+/-30%[25]	3323[26]	+/-30%
Net CO2eq emissions g/kWh	4	-	(970)[27]	(887) - (1071)

[22] PH3/11 page 108 -product gas composition at Varnamo
[23] H. Audus and P. Freund, 2004, ' Climate change mitigation by biomass gasification combined with CO_2 capture and storage'. Proceedings of 6th International Conference on Greenhouse Gas Control Technology.
[24] Assumed to be the same as IGCC derived by Bessan et al.
[25] All capital costs are +/-30% at P5 – P95 level of accuracy
[26] Includes the capital costs of CO_2 transport and storage
[27] Capture results in a net negative emissions

Process layout and key streams are summarised in the following simplified flowsheet:

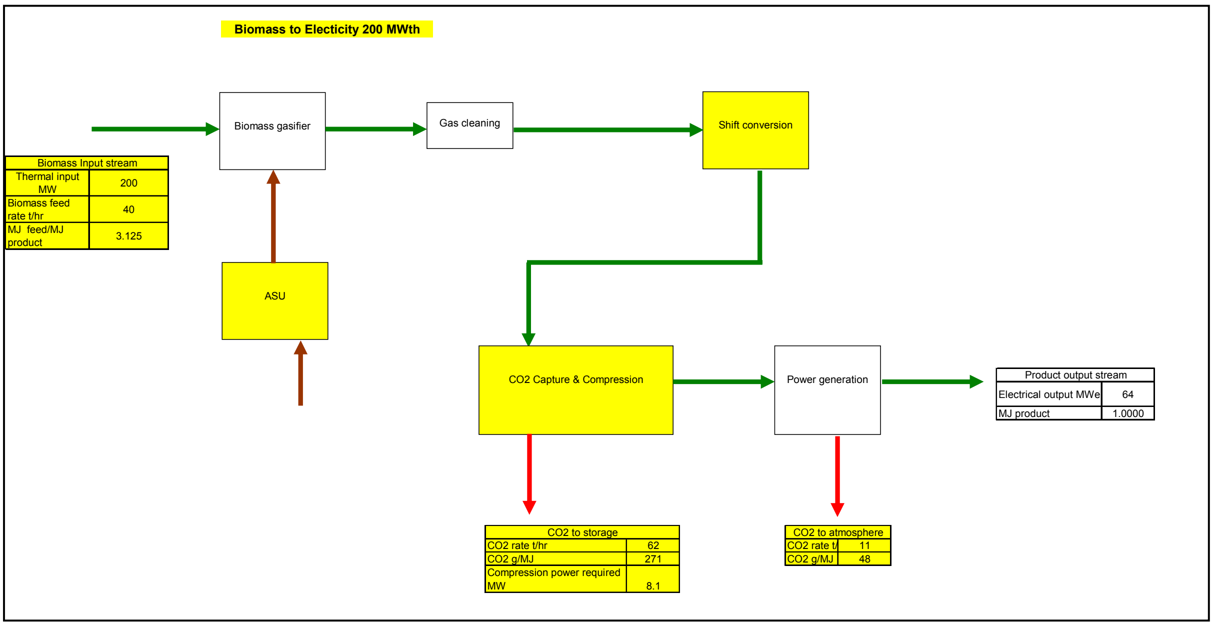


Fig I- 2 Simplified BIGCC flowsheet showing overall energy balance and CO2 emissions

I.i.iv Electricity Distribution

Electricity distribution from the power station to the customer, which requires final distribution to the 0.4kV level, results in losses throughout the transmission system. For calculation, it is assumed that losses from electric power distribution in the Netherlands are the same as those in Germany[28]. Distribution losses produce no greenhouse gas emissions.

Table I- 8 Estimated distribution losses in electricity transmission system

	Distribution losses MJ/MJ
High and medium voltage transmission (110 – 10kV)	0.017
Low voltage transmission (0.4kV)	0.012

I.i.v Well to Tank analysis

Full fuel cycle estimates of energy expenditure, GHG emissions and supply costs for coal and biomass pathways based on the methodology described in section 2.2 are summarised in Tables I– 9,10,11,12,13,14. The data are single point estimates using the best estimates provided in the previous sections for each individual step in the supply chain.

[28] Well to Wheels analysis of future automotive fuels and powertrains in the European context WELL TO TANK Report Version 1', 2003, Tank to Wheels Appendix 1

Table I - 9 Full fuel cycle energy expenditure, GHG emissions and supply cost for electricity from coal without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq/MJf	Cumulative electricity supply costs Euro/GJ	
					5% discount rate	10% discount rate
Hard coal provision EU mix	0.094	2.370	**0.223**	**36.3**	**1.5**	**1.50**
Coal to electricity	1.303	1.029	**1.341**	**208.1**	**9.23**	**11.6**
Power transmission to 0.4kV	0.029	1.000	**0.029**	**0.0**	**17.9**	**20.3**
Full fuel chain			**1.593**	**244.4**	**17.9**	**20.27**

Table I - 10 Full fuel cycle energy expenditure, GHG emissions and supply cost for electricity from coal with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq./MJf	Cumulative electricity supply costs Euro/GJ	
					5% discount rate	10% discount rate
Hard coal provision EU mix	0.094	2.7570	**0.259**	**42.3**	**1.5**	**1.5**
Coal to electricity	1.679	1.0292	**1.728**	**36.3**	**11.5**	**14.1**
Power transmission to 0.4kV	0.029	1.0000	**0.029**	**0.0**	**20.1**	**22.7**
Full fuel chain			**2.016**	**78.6**	**20.1**	**22.7**

Table I - 11 Full fuel cycle energy expenditure, GHG emissions and supply cost for electricity from pipeline natural gas without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq/MJf	Cumulative electricity supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.9351	**0.046**	**5.6**	**-**	**-**
4000 km pipeline transportation	0.094	1.7687	**0.166**	**14.0**	**-**	**-**
Trunk distribution – 100km	0.002	1.7650	**0.004**	**0.3**	**3.0**	**3.0**
Power generation 800MWe by NGCC	0.715	1.0292	**0.736**	**100.5**	**7.3**	**8.1**
Power transmission to 0.4kV	0.029	1.0000	**0.029**	**0.0**	**15.9**	**16.7**
Full fuel chain			**0.981**	**120.5**	**15.9**	**16.7**

Table I - 12 Full fuel cycle energy expenditure, GHG emissions and supply cost for electricity from pipeline natural gas with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq/MJf	Cumulative electricity supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	2.156	**0.052**	**6.3**	**-**	**-**
4000 km pipeline transportation	0.094	1.970	**0.185**	**15.6**	**-**	**-**
Trunk distribution – 100km	0.002	1.966	**0.004**	**0.3**	**3.0**	**3.0**
Power generation 800MWe by NGCC	0.911	1.029	**0.937**	**18.1**	**9.6**	**11.1**
Power transmission to 0.4kV	0.029	1.000	**0.029**	**0.0**	**18.2**	**19.7**
Full fuel chain			**1.207**	**40.3**	**18.2**	**19.7**

Table I - 13 Full fuel cycle energy expenditure, GHG emissions and supply cost for electricity from biomass without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq/MJf	Cumulative electricity supply costs Euro/GJ	
					5% discount rate	10% discount rate
Wood farming and chipping	0.035	2.573	**0.089**	**22.6**	**3.4**	**3.4**
Truck for dry product (round trip considered)	0.006	2.573	**0.015**	**1.1**		
Power generation 30MWe by IGCC	1.500	1.029	**1.544**	**1.1**	**19.5**	**22.8**
Power transmission to 0.4kV	0.029	1.000	**0.029**	**0.0**	**28.1**	**31.5**
Full fuel chain			**1.676**	**24.7**	**28.1**	**31.5**

Table I - 14 Full fuel cycle energy expenditure, GHG emissions and supply cost for electricity from biomass with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq/MJf	Cumulative electricity supply costs Euro/GJ	
					5% discount rate	10% discount rate
Wood farming and chipping	0.035	3.216	**0.11**	**28.2**	**3.4**	**3.4**
Truck for dry product (round trip considered)	0.006	3.216	**0.02**	**1.37**		
Power generation 30MWe by IGCC	2.125	1.029	**2.19**	**-277.4**	**32.3**	**38.5**
Power transmission to 0.4kV	0.029	1.000	**0.03**	**0.00**	**40.9**	**47.1**
Full fuel chain			**2.346**	**-247.8**	**40.9**	**47.1**

I.i.vi Electric vehicle

The JEC study considered a battery power vehicle only in the context of a hybrid operating in a ZEV mode i.e. only powered by its on-board battery. This study includes a stand-alone battery powered vehicle based upon the fuel cell hybrid in the JEC study. All the JEC joint study data are based upon a range of 600km. Even with anticipated improvements in battery technology, this range cannot be achieved with a realistic vehicle overall mass. This study assumes a target range of 350km for an electric vehicle. Lithium ion batteries are specified based on the target performance for 2020 of the US Battery Consortium (150Whr/kg and 300W/kg) to meet a range of 350km and deliver a maximum instantaneous power of 80kW.

Table I-15 provides a summary of the mass and cost implications of a battery-powered drive train. Costs of all of the non-conventional power trains are difficult to assess. The only hard costs are those available for development vehicles and these will be orders of magnitude greater than costs expected in mass production. Cost estimates used in this report are taken from three principal sources (Ricardo [29], MIT [30], JEC study) that reflect differing perceptions of future costs by reputable organisations involved in road transport research and development. Data from these sources have been used to provide a best estimate of incremental cost and an estimate of the range of costs.

[29]' Carbon to Hydrogen roadmaps for passenger cars – A study for the Department for Transport and the Department of Trade and Industry', Ricardo Consulting Engineers, November 2002.
[30] M A Weisss et. al., 'On the road 2020 - A life cycle analysis of new automobile technologies', MIT Engineering laboratory October 2000.

Table I - 15 Electric vehicle component mass and associated costs

Vehicle component	Mass kg	Cost	Cost Range P5 – P95
Reference vehicle - stripped[31]	**968**	**€ 15,735**	**-**
Battery - 58 kW Li-ion	390	€ 15,175	12,860 – 17,500
Electric motor and electronics	73	€ 1,710	1,392 – 2,025
Enlarged vehicle	50	-	-
Electric Vehicle	1480	€ 32,620	30,200 – 35,125

The vehicle has been simulated on the NEDC[32] using the ADVISOR model by IFP. Model parameters were consistent with all simulations in the JEC study[33]. Predicted vehicle performance is summarised in Table I– 16.

Table I- 16 Electric vehicle simulated performance on NEDC

		EV	*Target*
Min time lag for 0-50 km/h	s	3.3	*<4*
Min. time lag for 0-100 km/h	s	10.8	*<13*
Min. time lag for 80-120 km/h in 4th gear	s	8.8	*<13*
Gradeability at 1 km/h	%	>100	*>30*
Top speed	km/h	180	*>180*
Min "max acceleration"	m/s^2	4.8	*>4.5*
Range	km	"	*>350*
Performance from ADVISOR simulation			**P20 – P80**
Energy consumption	MJ/100km	46[34]	40.5 – 52.5

In the WTW analysis, a battery charging efficiency of 90% (range 85% – 95%) has been assumed.

I.ii LNG to CNG

Most of the natural gas entering EU is imported through pipelines. LNG represents only a small fraction of supply. It will be, however, a possible complementary source over the next decade as supplies open up from major gas fields in Africa and the Middle East.

LNG is an expensive option for the supply of natural gas, and the drive within the industry is to capture the economies of scale with increasing size of plant. Typical plants

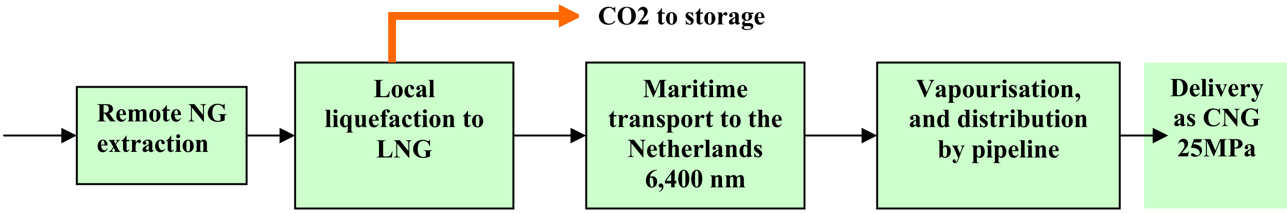
[31] Based on a reference vehicle representative of a 2002 5-door sedan similar to a 1.6 litre VW Golf, with a conventional port injection spark ignition powertrain. For the battery vehicle the reference vehicle mass is corrected for engine, gearbox, three-way catalyst and fuel tank (including 90% fuel) to provide its stripped vehicle mass. Reference vehicle cost is € 18,600.

[32] NEDC Northern European Drive Cycle

[33] Stephane His (IFP) private communication

[34] The vehicle energy consumption is 53 MJ/100 km – the figure shown in the table includes braking energy recovery.

are in the range 2-4 million tonnes LNG per year (MTPA), with designs being promoted for capacities up to 10 MTPA. Air Products have recently described a single train design for an 8 MTPA plant[35], which corresponds to an annual energy production of ca. 400 PJ per year. The annual demand for 1 million cars is ca. 30PJ per year. For the purposes of this study, it is assumed that CNG for road transport is imported into the Netherlands and the balance of production is exported to other customers.



I.ii.i Supply pathway definition

Natural gas is liquefied in remote locations using world-scale liquefaction plant. It is transported in liquefied form via maritime tanker over a distance of 6,400 nautical miles to Rotterdam. At the import terminal LNG is regasified and fed to the high-pressure natural gas distribution system. Gas is transported over a distance of 100km within the high-pressure network and a further 450km within the low-pressure local network that supplies filling stations

I.ii.ii Gas extraction and processing

Shell data indicate that the efficiency of gas extraction and processing ranges between 96-99% with a best estimate of 98% and average greenhouse gas emissions of ca. 3 gCO_2eq/MJ of natural gas produced.

Table I- 17 Estimated energy efficiency and emissions form natural gas extraction and processing

	Best estimate Energy expended MJ/MJ	Range of estimates	Best estimate CO2 eq. emitted g/MJ	Range of estimates
Primary energy and emissions	0.02	0.01-0.04	2.9	0.6 – 4.0

I.ii.iii Liquefaction

The industry standards for the next generation of large-scale LNG plants will have higher energy efficiency, lower greenhouse gas emissions and costs will improve on current operating practice. BP's benchmarking study[36] set targets of 25% reduction in expected production cost per tonne LNG and a 50% reduction of greenhouse gas emissions compared with BP's Atlantic LNG1 plant. The study showed that these targets could be

[35] 'Reducing capital cost in today's competitive environment the AP-X™ process', LNG 14, Doha March 2004

[36] 'Big Green Train – benchmarking next generation LNG plant designs', LNG 14, 2004

met. These data, which were derived from four leading technology vendors, are used in this study. Best estimate of efficiency (based on internal consumption of NG) is 5.5% with a range of 5.1- 6%. Based on BP philosophy, no venting or flaring is allowed except in emergency. No fugitive losses are therefore included in these estimates. The joint JEC study [37] includes 0.17 % fugitive methane losses and 0.25 % flare losses as a measure of current practice. In this study, best estimates include 50% of these emissions reflecting the trend to reduce fugitive emissions. Maximum estimates include all emissions; minimum estimates are based on zero fugitive emissions. The LNG process requires pre-separation of any water and CO_2 in the feed gas to prevent freezing. Emission data therefore include an allowance for the 2% CO_2 within the feed gas.

All new LNG processes are based upon an all-electric design, which utilizes an island power plant configuration that is powered by gas turbines operating in combined cycle. The electricity generated from the power plant is provided to the LNG plant's electrical grid. The power is then supplied to large electric motors that drive the mixed refrigerant compressors. This design improves operability, availability, environmental performance, and provides cost benefits. Plant capacities of 8 MTPA LNG per year are quite possible with this technology. Apart from any fugitive emissions and CO_2 separated from the feed, all greenhouse gases are emitted from the power plant. CO_2 capture from gas turbine exhausts has been studied in IEA PH3-14[38] at a scale that is comparable with the power requirements of an 8 MTPA LNG plant, based on GE frame 9FA gas turbines. Data provided in IEA PH3-14 have been used to estimate CO_2 emissions and LNG production costs with CO_2 capture on the basis that, with capture, the power plant efficiency reduces from 56% to 47%. LNG plant investment costs are based on reported figures for Air Products 8 MTPA plant with an up-rated gas turbine to compensate for efficiency loss. CO_2 capture and compression costs are 193 $US (2000) /kWe and 44.3 $US (2000) /kWe, respectively.

Table I - 18 Estimated energy demand and total GHG emission (CO2eq) from an 8MTPA LNG plant

	Best estimate Energy expended MJ/MJ	Range	Best estimate CO2 eq. emitted g/MJ	Range
Primary energy and emissions w/o capture	0.057	0.05 – 0.06	4.0	3.3 – 5.3
Primary energy and emissions with capture	0.069	0.06 – 0.08	0.7	0.05 – 1.1

[37]Well to Wheels analysis of future automotive fuels and powertrains in the European context WELL TO TANK Report Version 1', Tank to Wheels, Appendix 1, 2003, page 19
[38] 'Leading options for the capture of CO2 from power stations', PH3- 14 February 2000

Table I - 19 Estimated investment costs[39] for an 8MTA LNG plant

	Costs without capture Million Euro	Costs with capture Million Euro
LNG plant investment costs	1207	1235
LNG investment costs - Euro/MTA	151	154
CO2 capture	-	136
CO2 compression and disposal	-	19

I.ii.iv Distribution

LNG is transported by ship over a distance of 6,400 nautical miles, discharged at the import terminal, regasified and fed to the high-pressure natural gas distribution system. Gas is transported over a distance of 100 km within the high-pressure network and a further 450km within the low-pressure local network that supplies filling stations. Modern LNG tankers have a typical capacity of 135,000 m^3 LNG, which is equivalent to ca. 57,000 tonnes. A ship of this capacity would make about 12 round-trips per year and deliver ca. 33PJ per annum of LNG, and meet the annual demand of a fleet of 1 million CNG vehicles.

Vaporisation losses are typically 0.15% per day[40]. The evaporated LNG is used as fuel. The balance in fuel demand is provided by heavy fuel oil (HFO). The average fuel consumption of an LNG tanker is estimated at 0.178 MJ/t.km fully laden and 0.141MJ/tkm unloaded[41]. Assuming full combustion, energy demand and GHG emissions have been estimated

Table I - 20 Estimated energy demand and total GHG emission (CO2eq) from marine transport of LNG

	Energy expended MJ/MJ LNG transported	**Range P5 – P95**	**GHG emissions CO2 eq./MJ LNG transported**	**Range P5 – P95**
NG to ship's fuel	0.0428	0.038-0.048	2.35	2.2-2.7
HFO to ship's fuel	0.0352	0.032-0.039	2.83	2.6–3.1
Primary energy and emissions	0.081	0.075-0.088	5.0	4.9-5.9

LNG delivered to the Netherlands is transferred from ship to a storage terminal with a storage capacity of ca. 160,000 m^3 LNG and vaporised at 40 barg using seawater heat exchangers to minimise CO_2 emissions. Gas is fed continuously into a high-pressure

[39] Excluding contingencies and owners costs

[40] Mitsubishi Heavy Industries 2000, MHI completes last LNG carrier for Qatar project; Sea-Japan, Japan Ship Exporter's Association (JSEA), Tokyo;

[41] 'GM Well-to-Wheel Analysis of Energy Use and Greenhouse Gas Emissions of Advanced Fuel/Vehicle Systems- A European Study' LBST September 2002, page 88

main and distributed via the existing distribution system to retail outlets. Boil-off during unloading and from storage is compressed and injected into the high pressure main. Nominal pipeline distances relevant to the Netherlands have been assumed. At the retail outlet, gas is compressed from a suction pressure of 0.4 MPa and dispensed to a vehicle at a delivery pressure of 25 MPa. Retail site costs have been estimated assuming investment in 2 dispensers, which are capable of supplying the average annual demand per converted site. Retail stations could purchase gas at lower (0.2MPa) and higher (2MPa) supply pressure, and these provide an estimate of the upper and lower bound for energy expended and emissions.

Table I- 21 Estimated primary energy demand and total GHG emission (CO2eq) for the distribution of natural gas for CNG dispensing.

<table>
<tr><th></th><th>Energy expended MJ/MJ NG supplied</th><th>Range</th><th>GHG emissions CO2 eq./MJ NG supplied</th><th>Range</th></tr>
<tr><td>LNG storage and vaporisation</td><td>0.001</td><td></td><td>0.047</td><td></td></tr>
<tr><td>NG trunk and local distribution</td><td>0.002</td><td></td><td>0.16</td><td></td></tr>
<tr><td rowspan="2">CNG compression and dispensing</td><td rowspan="2">0.063</td><td rowspan="2">0.04-0.78</td><td>2.8</td><td>1.8-3.4</td></tr>
<tr><td>.6</td><td>0.4 – 0.7</td></tr>
</table>

I.ii.v Well to tank analysis

Full fuel cycle estimates of energy expenditure, GHG emissions and supply costs for the LNG to CNG pathway are summarised in Tables I – 22,23. The data are single point estimates using the best estimates provided in the previous sections for each individual step in the supply chain.

Table I - 22 Full fuel cycle energy expenditure, GHG emissions and supply cost for LNG production without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.116	**0.027**	**3.3**	**1.0**	**1.0**
NG liquefaction	0.057	1.056	**0.060**	**4.7**	**1.5**	**1.6**
LNG terminal (loading)	0.011	1.045	**0.012**	**0.7**		
LNG shipping	0.081	1.002	**0.081**	**5.5**	**2.2**	**2.6**
LNG terminal (unloading)	0.003	1.002	**0.003**	**0.2**	**2.2**	**2.6**
LNG vaporization and compression	0.001	1.002	**0.001**	**0.0**	**2.8**	**3.5**
NG trunk distribution	0.002	1.000	**0.002**	**0.2**	**3.4**	**4.4**
CNG compression and dispensing	0.063	1.000	**0.063**	**2.8**	**5.5**	**6.6**
Full fuel chain			**0.25**	**17.3**	**5.5**	**6.6**

Table I- 23 Full fuel cycle energy expenditure, GHG emissions and supply cost for LNG production with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO_2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.128	**0.027**	**3.7**	**1.0**	**1.0**
NG liquefaction	0.069	1.056	**0.072**	**1.3**	**1.5**	**1.7**
LNG terminal (loading)	0.011	1.045	**0.012**	**0.7**		
LNG shipping	0.081	1.002	**0.081**	**5.5**	**2.3**	**2.8**
LNG terminal (unloading)	0.003	1.002	**0.003**	**0.2**	**2.3**	**2.8**
LNG vaporization and compression	0.001	1.002	**0.001**	**0.0**	**2.9**	**3.6**
NG trunk distribution	0.002	1.000	**0.002**	**0.2**	**3.5**	**4.5**
CNG compression and dispensing	0.063	1.000	**0.063**	**0.6**	**5.5**	**6.7**
Full fuel chain			**0.262**	**12.1**	**5.5**	**6.7**

I.ii.vi CNG vehicles

The study assumes a vehicle with a dedicated CNG engine, with and without hybridization. For the non-hybrid case, the engine size is increased above that of the reference gasoline engine in order to meet the minimum acceleration criteria. This results in 9% higher fuel consumption, which cancels out a 9% gain in fuel efficiency from the increase in the compression ratio from 9.5 to 12.5 made possible by the high octane rating of natural gas.

For a hybrid vehicle, a parallel configuration has been simulated. This combines a CNG PISI engine and an electric motor with battery as torque generators. The availability of the electric motor allows the acceleration criteria to be met and the CNG engine can be reduced in size. Fuel consumption is estimated on the basis that the battery state of charge at the energy of the cycle returns to its initial state. As a result, a 14 kW electric motor is adequate. A 6kWh Li-ion 42 V battery provided a 20km ZEV range. Generally, all configurations benefit from hybridization (15% efficiency gain for gasoline and 18%for diesel), but in this case reducing the size of the gas engine back to the common value of 1.6 l makes this a particularly attractive change for CNG fuel as the efficiency improves to 24%.

Uncertainty remains as to what extent the additional cost for a natural gas vehicle will be reduced with mass production. The inherently more expensive high-pressure gas tank implies that a certain additional cost for a natural gas vehicle will remain in spite of mass production advantages. In a report by the Alternative Fuels Contact Group[42], the Natural Gas Topic group estimated the additional vehicle of a dedicated natural gas vehicle to be 1200-2000 € above that of an equivalent gasoline powered vehicle. In this study the estimated costs range between 1060 and 1900 € above that of the reference 2010 gasoline vehicle. Vehicle data used in this study are shown in Tables I – 24,25

Table I-24 Energy consumption and GHG emissions from a dedicated CNG vehicle and CNG hybrid vehicle

	Energy consumption MJ/100km	Range P20 – P80	GHG emissions CO2eq/km	Range P20 – P80
Dedicated CNG vehicle	193.2	180-201	110.8	103-115
CNG Hybrid	146.8	134-160	84.7	78-93

[42] 'Market Development of Alternative Fuels', Report of the Alternative Fuels Contact Group, December 2003

Table I - 25 CNG vehicle retail price estimates

Vehicle component	Cost Euro	Cost Range[43] P5 – P95
Reference vehicle - stripped[44]	**16,165**	**-**
Dedicated CNG		
Engine and transmission	2,550	
CNG tank (26 kg capacity) and fittings	1,365	900 – 1,830
EURO IV compliance, Turbo and "Stop & Go" system	680	
Total cost	**20,760**	**20,320 – 21,230**
CNG Hybrid		
Engine and transmission	2,040	
CNG tank (21 kg capacity) and fittings	1,053	700 – 1,400
EURO IV compliance	300	
Electric induction motor & controller	300	210 - 378
Battery	2042	1,500 – 2,580
Total cost	**21,980**	**21,400 – 22,700**

I.iii Hydrogen

Hydrogen can readily be produced in industrial scale from fossil energy resources, such as natural gas through reforming, or coal through gasification. The key factors in all these processes are cost of the energy input and the efficiency of energy conversion. Hydrogen production from biomass gasification could offer the most efficient pathway from renewable resources. All of these pathways offer the potential for carbon dioxide capture and storage from a large-scale facility.

Hydrogen can be consumed in ICE or fuel cell powertrains. While ICE powertrains represent a smaller technological development step, they do not offer the potentially high efficiencies and zero toxic emissions of a fuel cell. ICE engines, however, could well be an enabling technology on the pathway to establishing a hydrogen infrastructure. In this study, which is based on a significant market penetration of alternatively fuelled vehicles, it is assumed that fuel cell powertrains have become the technology of choice. Based on an average energy consumption of ca 1 MJ/100km[45], a fleet of 1 million fuel cell vehicles implies a hydrogen demand of 15 PJ pa. This would be increased to 27 PJ pa for ICE

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[43] Lower bound figure taken from MA Weiss et al. 'On the road 2020 - A life cycle analysis of new automobile technologies', MIT Engineering laboratory October 2000

[44] Reference vehicle stripped of gasoline powertrain and tank

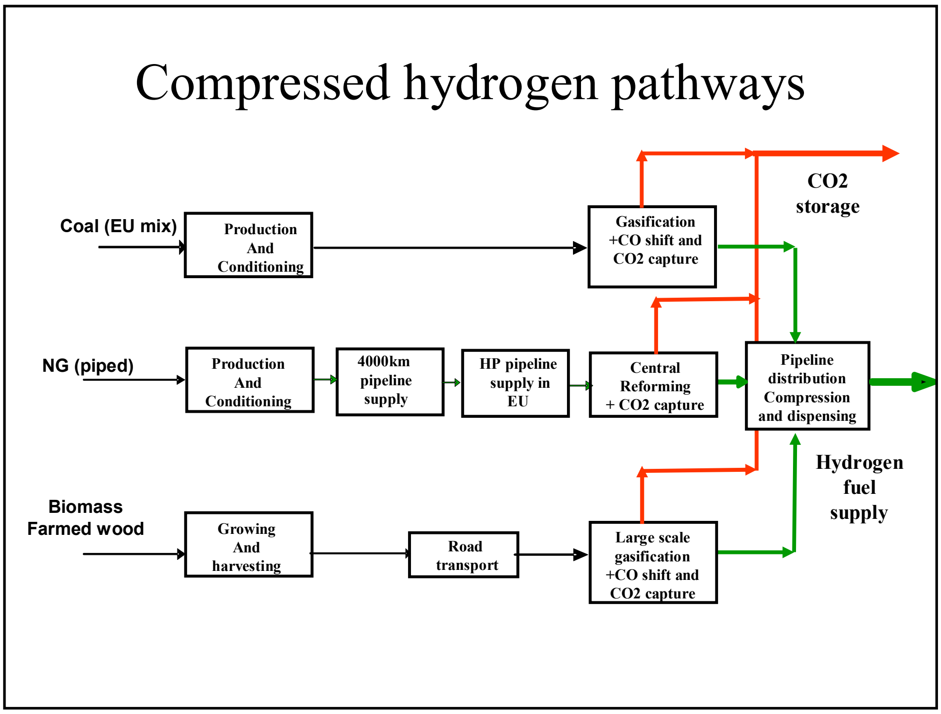
[45] 'Well to Wheels analysis of future automotive fuels and powertrains in the European context WELL TO TANK Report Version 1', Tank to Wheels report Appendix 1, 2003

engines powered by hydrogen. The following hydrogen pathway scenarios are based on the manufacture and distribution of this quantity of hydrogen from coal, natural gas and biomass primary energy sources.

I.iii.i Supply pathways

The basic stages in the supply of hydrogen from the three primary energy sources are represented in the following figure.

Fig. I – 3 Integrated hydrogen supply pathways



The availability of coal and natural gas are such that either source could produce sufficient hydrogen for transport use: resource demand for 1 million fuel cell vehicles is approximately 8% and 1.5%, respectively of the Netherlands' current demand. Hydrogen would be produced centrally from a small number of large-scale plants to benefit from economies of scale in both manufacture and CO_2 capture. Biomass supplies are more limited. A recent study estimates that the total energy supply of cultivated biomass (poplar, miscanthus and other short rotation cultivation (SRC) crops) at ca. 12 PJ[46], based on maximum renewable electricity implementation (as discussed in Appendix I.i.ii.i). If any of this were available for transport use, small plants would operate in parallel with either coal of gas, and the hydrogen produced distributed through a common infrastructure. In all cases it is assumed that market penetration has reached a sufficiently high level to make hydrogen supply by pipeline economic.

[46] 'Renewable electricity in the Netherlands', M. Junginger et al. Energy Policy, **32** 2004

I.iii.ii Natural gas

I.iii.ii.i Supply

Natural extracted and processed in a remote location and transported by high-pressure pipeline over a distance of 4,000km to the Netherlands. Energy efficiency and greenhouse gas emissions arising from extraction and processing are those presented in Table I – 3 and those for pipeline transmission and distribution are shown in Table I-4.

I.iii.ii.ii Production

Steam reforming natural gas is a well-established technology. IEA GHG have assessed the impact of carbon capture on hydrogen production from coal and natural gas in report IEA PH2-2[47]. The basic parameters of this study were that 99.9% hydrogen is produced at 60 barg at a production capacity equivalent to 834 MW_{th}. Assuming 90%load factor, a plant of this capacity would produce 23 PJ per year which is sufficient to fuel 1 million fuel cell vehicles. The required hydrogen purity specification for such vehicles is uncertain[48], with auto manufacturers calling for higher purity than that quoted above. Certainly CO, which poisons fuel cell catalysts, would need to be reduced to ppm levels. In the absence of any fuel specification, this study uses data provided in PH2/2. Higher purity would require an additional purification step and result in a small additional production cost.

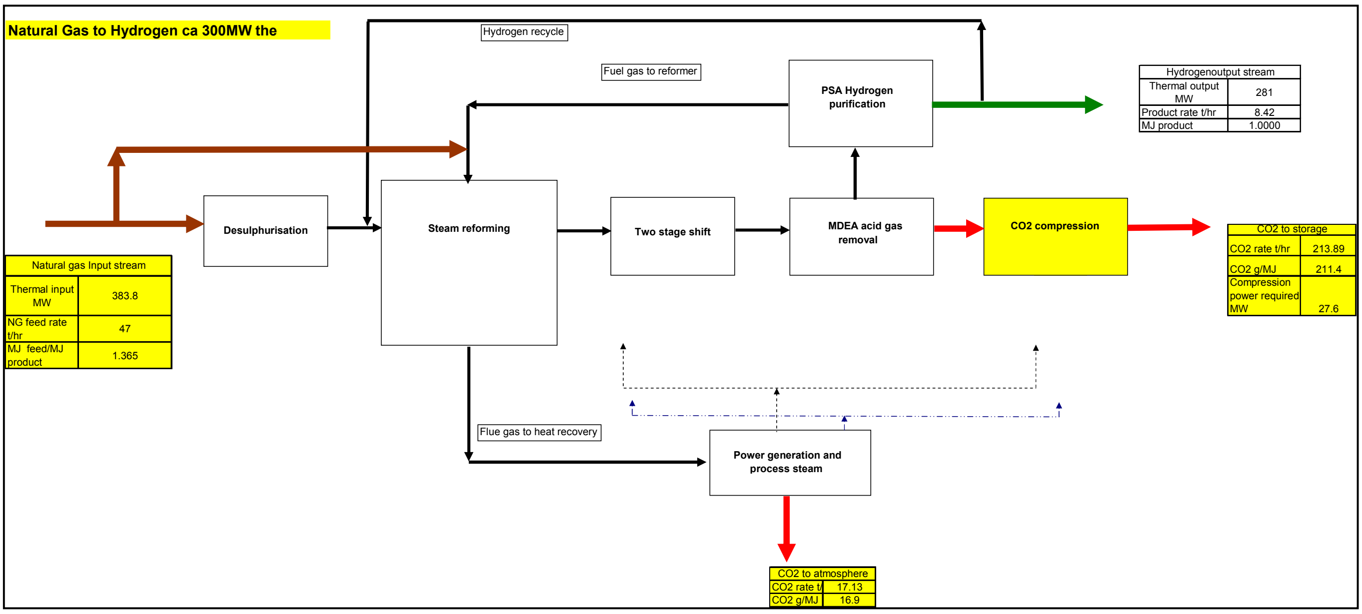
A simplified flowsheet incorporating carbon capture is summarised in Figure I - 4. The production capacity is too large for single stream operation and the plant is divided into three equal parallel trains The plant is self sufficient in all utilities, which, in practice means that the plant must also produce electric power to drive its machines, including a hydrogen compressor. In order to capture all the carbon within the process, almost all natural gas is processed through the plant and the carbon content transformed into CO_2 and removed in an MDEA unit. CO_2 is dried and compressed to 110 bar. 85 % of the produced CO_2 is captured

Table I- 26 Estimated energy efficiency, emissions and costs for a steam reforming plant producing 835 MWth hydrogen

	Reforming plant without capture	Range P20 – P80	Reforming plant with capture	Range P20 – P80
Overall efficiency %	75.9	72-74%	73.1	72-74%
NG to hydrogen energy ratio MJ/MJ	1.3178	1.302 – 1.334	1.3678	1.350 – 1.386
Capital cost Euro/kWth Hydrogen	369	+/-30%[49]	630	+/-30%
CO2eq emissions g/MJ	74.1	73-75	11.8	11-12
CO2eq captured g/MJ	-	-	65.1	

[47] 'Decarbonisation of fossil fuels' IEA GHG Report Number PH2/2 March 1996
[48] David Hart private communication
[49] All capital costs are +/-30% at P5 – P95 level of accuracy

Figure I– 4 Simplified flowsheet of hydrogen production from natural gas by steam reforming



I.iii.iii Coal

I.iii.iii.i Supply

All assumptions and data are the same as those in section I.i.i.i

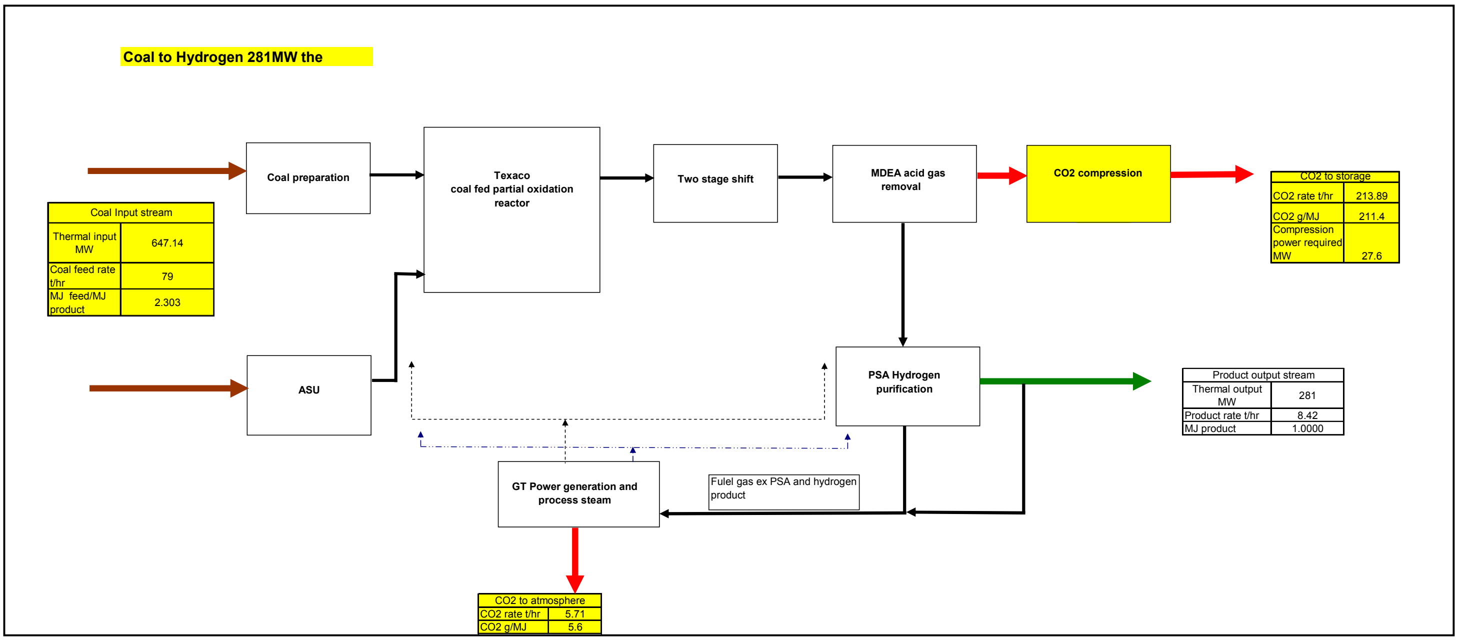
I.iii.iii.ii Production

The basic process of the coal gasifier is the well-established Texaco coal/water slurry fed to a 70 bara gasifier in which coal is partially oxidised in oxygen from an air separation unit. The process gas from the gasifier is scrubbed to remove soot, reheated and fed to a two-stage shift reactor. Acid gases, H_2S and CO_2, are removed from the process stream in a two-stage MDEA regenerative system. Hydrogen is purified in a conventional PSA unit. For carbon capture, the CO_2 stream is dried and compressed to 110bara. A frame 5 gas turbine generates power in combined cycle mode using fuel gas from the PSA supplemented with a small amount of hydrogen. Additional power for compression requires additional fuel gas, which is obtained by increasing gasifier capacity by 17%. CO_2 capture efficiency for this process is ca 97%.

Table I –27 Estimated energy efficiency, emissions and costs for a coal gasification plant producing 835 MW_{th} hydrogen

	Gasification plant without capture	Range P20 – P80	Gasification plant with capture	Range P20 – P80
Overall efficiency %	50.8	50-52	43.4	42-45
Coal to hydrogen energy ratio MJ/MJ	1.967	1.919 – 2.015	2.303	2.238 - 2.368
Capital cost Euro/kWth Hydrogen	1212	+/-30%[50]	1695	+/-30%
CO2 eq emissions g/MJ	183	174-193	5.7	5.4-6.0
CO2 captured g/MJ			208	198-219

Figure I– 5 Simplified flowsheet of hydrogen production from coal gasification



I.iii.iv Biomass

As already discussed, biomass is a limited resource and is unlikely to supply more than a small fraction of a transport fuel. As in the case of electricity generation, biomass is included primarily as renewable source with a low net emission of CO2. Combined with capture, biomass pathways could provide net removal from the atmosphere of CO_2. Unlike the other options investigated, however, biomass plant capacity is limited by the supply, because of infrastructure constraints (land availability, water and road access,

[50] All capital costs are +/-30% at P5 – P95 level of accuracy

etc). As in the electricity case, a hydrogen plant based on 200MW_{th} feedstock is sited centrally within the biomass collection area.

I.iii.iv.i Biomass supply

All assumptions and data are the same as those in section I.i.iii.i

I.iii.iv.ii Biomass gasification

As noted in section I.i.iii.ii , air-blown gasification has been widely used to produce a low heating value fuel gas. Air-blown gasifiers, however, yield a product gas relatively low in hydrogen (10-12% by volume), which pose processing difficulties for hydrogen separation. Alternative approaches, principally oxygen-blown or indirectly heated gasifiers, are being developed but all of these are at the development stage and data are based on small demonstration plants. Indirectly heated gasifiers based on the BCL/FERCO concept, which is being demonstrated at a 40 MW_{th} scale in Burlington Vermont, and appears to offer the potential for lower hydrogen cost[51] than oxygen-blown gasifier. The system is called indirectly heated because the heat necessary for endothermic gasification is supplied by hot sand circulating between the char combustor and the gasification vessel in a configuration similar to a fluid bed catalytic cracker using in conventional refining processes. The gas is cleaned using available conventional technology, by applying gas cooling, low temperature filtration, and water scrubbing at 100 – 250 °C. After gas clean up, product gas is further cooled so that it can be compressed (ca 35 bara) to drive pressure loss through reactors and the final hydrogen purification stage. Following compression, the gas is steam reformed in a conventional steam reformer heated by process fuel gas and finally passed through two-stage shift to produce a concentrated H_2 and CO_2 stream. Finally, hydrogen is purified by PSA unit and compressed to 65 bara for export. Estimates of plant performance and cost based on flowsheet models have been widely reported. The overall energy efficiency figures for a standalone plant vary from 52-59%[52], assuming electricity generated from biomass on site. In this study, the higher efficiency figure has been used reflecting process developments that are expected in the scenario time frame. Electricity is generated by BIGCC at an efficiency of 40% (see section I.i.iii.ii)

For the case with capture, the process modifications are similar to coal gasification. CO_2 is separated following the two-stage shift using a physical solvent process, such as Selexol, dried by molecular sieves and compressed to 110 bara. It has been assumed that CO2 capture and storage is well established for power generation and large industrial processes and a CO_2 gathering infrastructure exists within 25 km of the plant. Additional electrical power is required for CO_2 compression and CO_2 recovery. It is assumed that

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[51] Update of Hydrogen from Biomass – Determination of the delivered cost of Hydrogen P. Spath et al., NREL report April 2000

[52] C. Hamelinck et. al. 'Future prospects for production of methanol and hydrogen from biomass' September 2001

electricity is generated by BIGCC with carbon capture on site with an efficiency of 32% (see section I.i.iii.ii). As a result, overall process efficiency is reduced. Data derived for this study are summarised in Table I - 28.

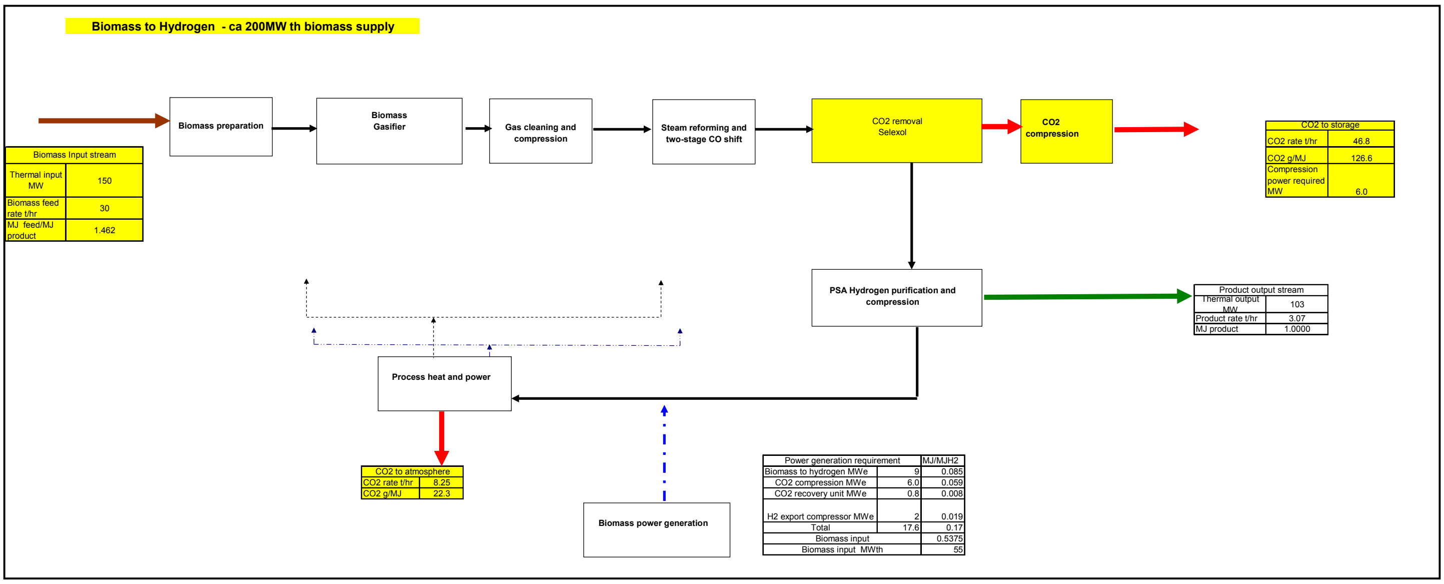
Capital cost data is derived from Hamelinck 2001, scaled for a 150 MWth (biomass) plant. Overall, with biomass supply to power generation, the total biomass demand is ca. 200 MW_{th} and supply constraints are as discussed in section I.i.iii.i. Biomass is assumed to be supplied at a best estimate cost 3.3 Euro/GJ with a range of 2.1 – 7 Euro /GJ (ref. section I.i.iii.i). BIGCC electricity costs, with and without capture and storage, are those estimated in this study. CO2 disposal costs are based on an average figure of 1.45 Euro/tonne, which is comparable with the other hydrogen pathways considered in this report.

Table I- 28 Estimated energy efficiency, emissions and costs for a Biomass gasification based on a supply of 200MW_{th} feedstock

	Gasification plant without capture	Range	Gasification plant with capture	Range
Overall efficiency %	58.4	56 - 61	52.2	49 - 52
Biomass to hydrogen energy ratio MJ biomass/MJ H2 produced	1.714	1.64 – 1.79	1.986	1.91 – 2.06
Capital cost Euro/kWth Hydrogen	1320	+/-30%[53]	1572	+/-30%
CO2eq emissions g/MJ	2.8	2-4	(164)	(170) – (157)

Figure I – 6 Simplified flowsheet of hydrogen production from biomass gasification

[53] All capital costs are +/-30% at P5 – P95 level of accuracy



I.iii.v Hydrogen distribution and dispensing

It is assumed that a hydrogen supply infrastructure in the Netherlands would start with selected geographically concentrated pilot zones around major cities. This would avoid long periods of loss-making dispersed re-fuelling stations with marginal turnover. Concentration of the limited vehicle output in the hydrogen start-up phase to selected areas would provide higher vehicle densities thus providing better utilisation rate of new hydrogen dispensers. In a second phase, the pilot zones could be expanded to provide a larger market base, with a profitable infrastructure and interconnected through corridors. In a third step, the network could be densified as demand increased.

The price for hydrogen at the re-fuelling point essentially depends on the consumption level. Retail fuel prices are expected to fall rapidly with market development, with significant reductions up to 2% market share due to economies of scale, somewhat more savings up to a 10% market share, and remaining essentially independent of market share above that[54]. The market scenario assumed in this report corresponds to a market penetration of ca. 15 % – i.e. above the level at which the hydrogen price is dependent on market penetration.

In the early stages of market build-up, the small quantities of hydrogen required would be distributed in high-pressure cylinders or, more likely, as a cryogenic liquid. In this study, it assumed that market development reached the point at which pipeline distribution from a large central plant is economic. A pipeline network will have been established to supply a developing market, which has been established around the larger cities in the highly urbanised areas of South Holland, North Holland and Utrecht. It is assumed that hydrogen is supplied from the process plant at a pressure of ca. 6MPa and supplied to the

[54] 'Market development of Alternative Fuels' – Report of the Alternative Fuels Study Group, December 2003

retail outlets at ca. 2MPa. A pressure loss 4MPa is available to overcome losses through the distribution network and associated control valve. A hypothetical network comprising 16 main pipelines feeding major cities, with each main line supporting 6 branch lines along developing supply corridors has been assumed. The network has been sized and costed using the IEA Greenhouse Gas Programme pipeline model[55]. The network is used for the centralised production of hydrogen from large-scale coal gasification and natural gas reforming. For small-scale de-centralised biomass plants, it is assumed that they are located within 25 km of the an established hydrogen infrastructure described above and can be connected to a spur line which is included as part of the plant capital. Hydrogen is distributed at the cost of large volume supply.

In addition, hydrogen dispensing is deployed at existing filling stations in proportion to market penetration. Thus, ca. 600 hydrogen-refuelling outlets would service 1 million alternative fuel vehicles, each providing an average customer base of ca. 1600 vehicles. Costs and emissions have been estimated upon the basis of each station providing 2 high utilisation hydrogen dispensers.

At the retail outlet hydrogen, supplied at 2MPa is boosted to 88Mpa for dispensing to on-board vehicle storage at 70MPa[56]. Assuming a polytropic compression efficiency of 75% and an electric drive efficiency of 90%, the electrical energy expended in compression is 0.0704 MJ/MJ compressed H_2. If this energy is supplied by 0.4kV supply at the retails outlet at the average generation efficiency, primary energy expenditure is 0.222 MJ/MJ compressed H_2. Hydrogen loss during compression is assumed to be2%. Range estimates are based on supply pressures of 1.5 and 3 MPa respectively.

Table I - 29 Estimated primary energy demand and total GHG emission (CO2eq) for the distribution of hydrogen for compressed hydrogen dispensing.

	Energy expended MJ/MJ H2 supplied	**Range P20 – P80**	**GHG emissions CO2 eq./MJ H2 supplied**	**Range P20 – P80**
Hydrogen distribution to 2MPa	Hydrogen distributed without additional boosting			
Hydrogen compression to 88Mpa and dispensing	0.0704	0.065 – 0.077	8.9	8.2 – 9.8
			2	1.9 – 2.1

[55] IEAEnergy Distribution and CO2 Capture Cost Estimation Model A model description can be found in ‘Pipeline Transmission of CO2 and Energy Transmission Study' Woodhill Report No. 2164brt8001c – February 2001
[56] See LBST_GM study 2003

I.iii.vi Well to Tank analysis

Full fuel cycle estimates of energy expenditure, GHG emissions and supply costs for the hydrogen from coal, natural gas and biomass pathways are summarised, respectively, in Tables I- 30 - I – 35 inclusive. The data are single point estimates using the best estimates provided in the previous sections for each individual step in the supply chain.

Table I – 30 Full fuel cycle energy expenditure, GHG emissions and supply cost for hydrogen production from coal without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
Hard coal provision EU mix	0.094	2.006	**0.189**	**30.8**	**1.5**	**1.5**
Coal to hydrogen with capture	0.967	1.020	**0.986**	**186.6**	**8.3**	**10.6**
Gaseous hydrogen transport by pipeline from central plant	0.000	1.020	**0.000**	**0.00**	**10.4**	**13.5**
Hydrogen compression and dispensing	0.222	1.000	**0.222**	**8.94**	**15.2**	**18.8**
Full fuel chain			**1.3969**	**226.3**		**18.8**

Table I -31 Full fuel cycle energy expenditure, GHG emissions and supply cost for hydrogen production from coal with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
Hard coal provision EU mix	0.094	2.349	**0.221**	**36.0**	**1.5**	**1.5**
Coal to hydrogen with capture	1.303	1.020	**1.329**	**5.8**	**12.0**	**15.2**
Gaseous hydrogen transport by pipeline from central plant	0.000	1.020	**0.000**	**0.00**	**14.0**	**18.0**
Hydrogen compression and dispensing	0.222	1.000	**0.222**	**1.8**	**19.2**	**23.7**
Full fuel chain			**1.772**	**43.7**	**19.2**	**23.7**

Table I - 32 Full fuel cycle energy expenditure, GHG emissions and supply cost for hydrogen production from pipeline natural gas without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJ main products	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.474	**0.035**	**4.30**	**-**	**-**
NG transportation - average quality 4000km	0.094	1.347	**0.127**	**10.6**	**-**	**-**
NG trunk distribution 100km	0.002	1.344	**0.003**	**0.2**	**3.0**	**3.0**
NG steam reforming central plant ca 300MW	0.318	1.020	**0.324**	**75.6**	**5.2**	**5.9**
Gaseous hydrogen transport by pipeline from central plant	0.000	1.020	**0.000**	**0.0**	**7.3**	**8.7**
Hydrogen compression and dispensing	0.222	1.000	**0.222**	**8.9**	**12.1**	**14.1**
Full fuel chain			**0.711**	**99.7**	**12.1**	**14.1**

Table I -33 Full fuel cycle energy expenditure, GHG emissions and supply cost for hydrogen production from pipeline natural gas with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.530	**0.037**	**4.46**	**-**	**-**
NG transportation - average quality 4000km	0.094	1.398	**0.132**	**11.0**	**-**	**-**
NG trunk distribution 100km	0.002	1.395	**0.003**	**0.2**	**3.0**	**3.0**
NG steam reforming central plant ca 300MW	0.368	1.020	**0.375**	**12.1**	**6.3**	**7.3**
Gaseous hydrogen transport by pipeline from central plant	0.000	1.020	**0.000**	**0.0**	**8.4**	**10.1**
Hydrogen compression and dispensing	0.222	1.000	**0.222**	**1.8**	**13.5**	**15.9**
Full fuel chain			**0.768**	**29.6**	**13.5**	**15.9**

Table I - 34 Full fuel cycle energy expenditure, GHG emissions and supply cost for hydrogen production from biomass without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
Wood farming and chipping	0.035	1.748	**0.060**	**15.3**	**-**	**-**
Truck for dry product (round trip considered)	0.006	1.748	**0.010**	**0.7**	**3.4**	**3.4**
Hydrogen generation	0.713	1.020	**0.728**	**1.9**	**14.1**	**16.4**
Gaseous hydrogen transport by pipeline from central plant	0.000	1.020	**0.000**	**0.0**	**16.1**	**19.3**
Hydrogen compression and dispensing	0.222	1.000	**0.222**	**8.9**	**20.9**	**24.7**
Full fuel chain			**1.020**	**26.9**	**20.9**	**24.7**

Table I – 35 Full fuel cycle energy expenditure, GHG emissions and supply cost for hydrogen production from biomass with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
Wood farming and chipping	0.035	2.026	**0.070**	**17.8**	**-**	**-**
Biomass transport	0.006	2.026	**0.011**	**0.9**	**3.4**	**3.4**
Gasification (BCL) 200MWth	0.986	1.020	**1.006**	**-172.3**	**20.2**	**23.0**
Gaseous hydrogen transport by pipeline from central plant	0.000	1.020	**0.000**	**0.0**	**22.3**	**25.8**
Hydrogen compression and dispensing	0.222	1.000	**0.222**	**1.8**	**27.4**	**31.6**
Full fuel chain			**1.309**	**-151.8**	**27.4**	**31.6**

I.iii.vii Hydrogen powered vehicles

Two different propulsion systems are presently being developed for the use of hydrogen in road transport. These are the internal combustion engine (ICE) powered by the thermal energy released from hydrogen combustion, and fuel cell systems driven by electricity produced in a chemical reaction of hydrogen with oxygen.

All major car manufacturers have built prototype hydrogen vehicles, and about 250 are being assessed worldwide at present.

PISI internal combustion engines can be adapted to burn hydrogen directly. Such engines can be also be used in a hybrid configuration. The main addition to the vehicle is a complex and expensive tank to hold high pressure or liquid hydrogen. Advanced combustion concepts are being explored for hydrogen engines, as for gasoline, diesel and CNG. However, in the 2010+ timeframe the maximum efficiency of hydrogen ICEs is expected to be very close to the best 2010 gasoline engines since they employ similar combustion processes and engine thermodynamics. The hydrogen ICE also uses a turbo-charged 1.3 l format.

High energy efficiency is expected for fuel cell vehicles, superior to ICE vehicles, particularly in part-load operation typical of passenger cars in urban traffic, buses, short-range utility services and delivery vans. In full load operation, fuel cell and internal combustion engine efficiencies come closer together. With present technology, 37% has been achieved with fuel cell vehicles in the New European Drive Cycle (NEDC) used for all certifications in Europe. This compares to efficiencies of close to 20% for gasoline and around 24% for diesel engines under the same conditions. All types of engines are expected to improve in efficiency in future. Values up to 50% are expected from the automotive industry for fuel cell drive trains.

Fuel cell technology is, however, still at a relatively early stage, whereas the technology of a hydrogen ICE is similar to that adapted for CNG. It may be expected that commercial production would be earlier than for fuel cell vehicles. Therefore, an early market introduction of hydrogen in the automotive sector could be facilitated by a faster parallel build-up of vehicles with hydrogen powered internal combustion engines, provided the appropriate hydrogen infrastructure is available. Bi-fuelled gasoline/hydrogen vehicles would also allow a smooth market introduction, based on a more limited hydrogen-refuelling infrastructure in the initial phase.

Since fuel cells are assumed 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.

The fuel cell system fed from on-board stored H_2 clearly has no CO_2 emissions. Nevertheless, the possibility to re-store electric energy in batteries during recuperative braking may noticeably influence the energy efficiency and hence the WTW GHG emissions. In the study, a 75kW electric motor is assumed. The fuel cell efficiency map used in the JEC study is based on information from three sources (GM, Daimler-Chrysler and the European FUERO Project).

Nevertheless, it has to be mentioned that the uncertainty in the simulation results is quite large for these fuel cell configurations (mainly concerned with the evaluation of the cold start over-consumption).

Cost estimates are particularly uncertain for all hydrogen vehicles. There is strong competition between the manufacturers, most of which have large research effort in developing either ICE (principally BMW) or fuel cell technology. Hydrogen storage tanks are under development. Daimler Chrysler and Hyundai are currently using storage pressures of 33 MPa. Research effort is being directed to pressures of 70MPa, which allow 7kg of hydrogen to be stored in a ca. 220 litre tank. The estimated cost of high-pressure storage tanks in mass production is somewhat speculative. Ricardo estimate the cost of 7kg compressed hydrogen storage tank at £366 (ca. €550) or €79/kg, whereas the JEC study estimated €635 per kg hydrogen stored on the vehicle, clearly a wide range of views. MIT figures, also obtained after discussion with the auto industry, suggest $650 for on-board storage of 4 kg hydrogen (€163/kg). In this study, we have assumed that costs estimates are normally distributed with Ricardo and JEC data representing the P5 and P95 points (mean value €315/kg). A standard figure of 200€ has been included to cover the cost of regulators, high-pressure pipe work, new gauges and gas filters and hydrogen shut-off valve. The fuel cell "engine" represents a similar level of uncertainty. The cost for a complete 80kW fuel cell power unit is estimated to be in the range $4,800-$8,400.

Table I -36 Energy consumption and GHG emissions from a dedicated CNG

	Energy consumption MJ/100km	Range P20 – P80	GHG emissions CO2 eq/km	Range P20 – P80
Hydrogen ICE	167.5	163-180	0.5	0-1
Hydrogen ICE hybrid	148.5	137-161	0.5	0-1
Fuel Cell - direct hydrogen	94.0	82-106	0	0
Fuel cell - direct hydrogen hybrid	83.7	73-94	0	0

Table I-37 Hydrogen ICE vehicle retail price estimates

Vehicle component	Cost Euro	Cost Range P5 – P95
Reference vehicle - stripped[57]	**16,165**	**-**
Dedicated Hydrogen PISI		
Engine and transmission	2,310	
Compressed Hydrogen tank (9kg capacity) and fittings	3040	905 - 5175
Turbo and "Stop & Go" system	380	
Total cost	**21,900**	**19,785 – 23,950**
Dedicated Hydrogen PISI Hybrid		
Engine and transmission	2,310	
Compressed Hydrogen tank (7.5kg capacity) and fittings	2,550	920 – 4,150
Turbo	180	
Electric induction motor & controller	378	
Battery	2042	1,500 – 2,580
Total cost	**23,630**	**21,780 – 25,560**

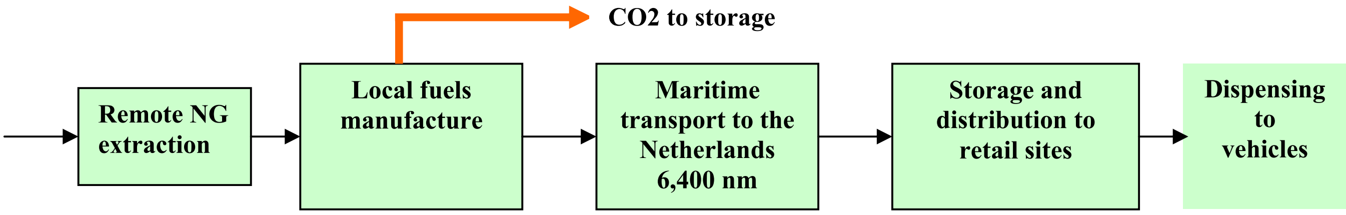
Table I - 38 Hydrogen Fuel cell vehicle retail price estimates

Vehicle component	Cost Euro	Cost Range P5 – P95
Reference vehicle - stripped[58]	**15,735**	**-**
Direct PEM Fuel cell		
Fuel cell engine – 80kW	6,600	4,800 – 8,400
Electric induction motor (75kW) & controller	1709	1390 - 2025
Compressed Hydrogen tank (4.7kg capacity) and fittings	1,636	570 - 2700
Total cost	**25,680**	**23,400 – 27,500**
Direct PEM Fuel cell Hybrid		
Fuel cell engine – 80kW	6,600	4,800 – 8,400
Electric induction motor (75kW) & controller	1,709	1390 - 2025
Compressed Hydrogen tank (4.2kg capacity) and fittings	1,472	530 - 2415
Battery	2042	1,500 – 2,580
Total cost	**27,560**	**25,550 – 29,700**

[57] Includes cost of a three-way catalyst

I.iv Remote natural gas to synthetic diesel fuels

Alternative pathways to the monetization of remote natural gas involve conversion to fuels that are more easily transported to markets. This study examines synthetic diesel fuels produced by the Fischer Tropsch process and DiMethyl ether produced by the dehydration of Methanol. The latter fuel, while gaseous under normal conditions, can be easily liquefied, transported and stored under conditions similar to liquefied petroleum gas (LPG). The LPG infrastructure would require relatively low cost modification to seals etc.



I.iv.i Fischer Tropsch diesel production

Zero sulphur paraffinic hydrocarbons can be synthesised over a wide boiling range by the Fischer Tropsch process from a synthesis gas comprising H_2 and CO in a ratio of approximately 2:1. A number of processes exist. Shell has had a 12,000 bbl/day gas-to-liquids plant operating in Bintulu for several years and has announced plans for construction of second generation plants with improved efficiency and an order of magnitude greater capacity. Sasol has a 34,000 bbl/day plant based on its Slurry Phase Distillate process under construction in Qatar. The facility named ORYX GTL, is due to start up late 2005, and will produce ca. 9,000 bbl/day of naphtha and 25,000 bbl/day diesel from ca. 330 million cubic feet per day of lean natural gas from the Ras Laffan North Field. These data imply an efficiency of ca. 54% (carbon efficiency 67%). Shell[59] expects that state-of-the-art for plants to be designed in the next few years will have a typical overall efficiency of 61-63% (carbon efficiency 80%) depending on configuration and product slate. The higher efficiencies are generally achieved with less product upgrading. The product yield, which can be adjusted within the process and through conventional product upgrading, is a mix of paraffinic hydrocarbons including specialist waxes and base oils, distillate fuels and light hydrocarbons.

In this study, it is assumed that the process operates in the maximum-diesel mode with 75% diesel fraction and 25% lower boiling range products – similar to Sasol's ORYX plant. Products are treated independently and produced with the same overall energy efficiency. It is assumed that the co-product is absorbed in the local kerosene and naphtha markets thereby displacing production from crude oil. Energy efficiency and emissions are estimated per MJ of FT diesel product corrected for energy and emission saving from displacement of products from crude oil refining and production.

[59] Private communication F Van Dijk Shell GTL Global Development

Naphtha is a commodity, which is traded globally. Historical naphtha prices have averaged ca. 20 -30% above the crude oil price but this differential has almost disappeared over recent years because of reduced demand from the petrochemicals industry and a booming supply of field condensates. In this study it is assumed that, over the timeframe of this study, this supply demand situation will persist as gas supplies increase. Local naphtha prices are based on netback values at 10% premium over crude, with range -10% (crude parity) to +30%

Previous work by IEG GHG (report PH3/15) examined the impact of carbon capture and storage on both Sasol's SPD process and Shell's first generation process. Although, Shell's process has been developed further, efficiency and cost data used in that study are comparable with data in the public domain for Sasol's Oryx plant. In this study, it is assumed that future stand-alone plants will have efficiencies in the range of 55 - 61%. Energy efficiency penalties for carbon capture and storage are based on de-carbonisation of fuel gas as derived in PH3/15 and assumed to apply over this efficiency range.

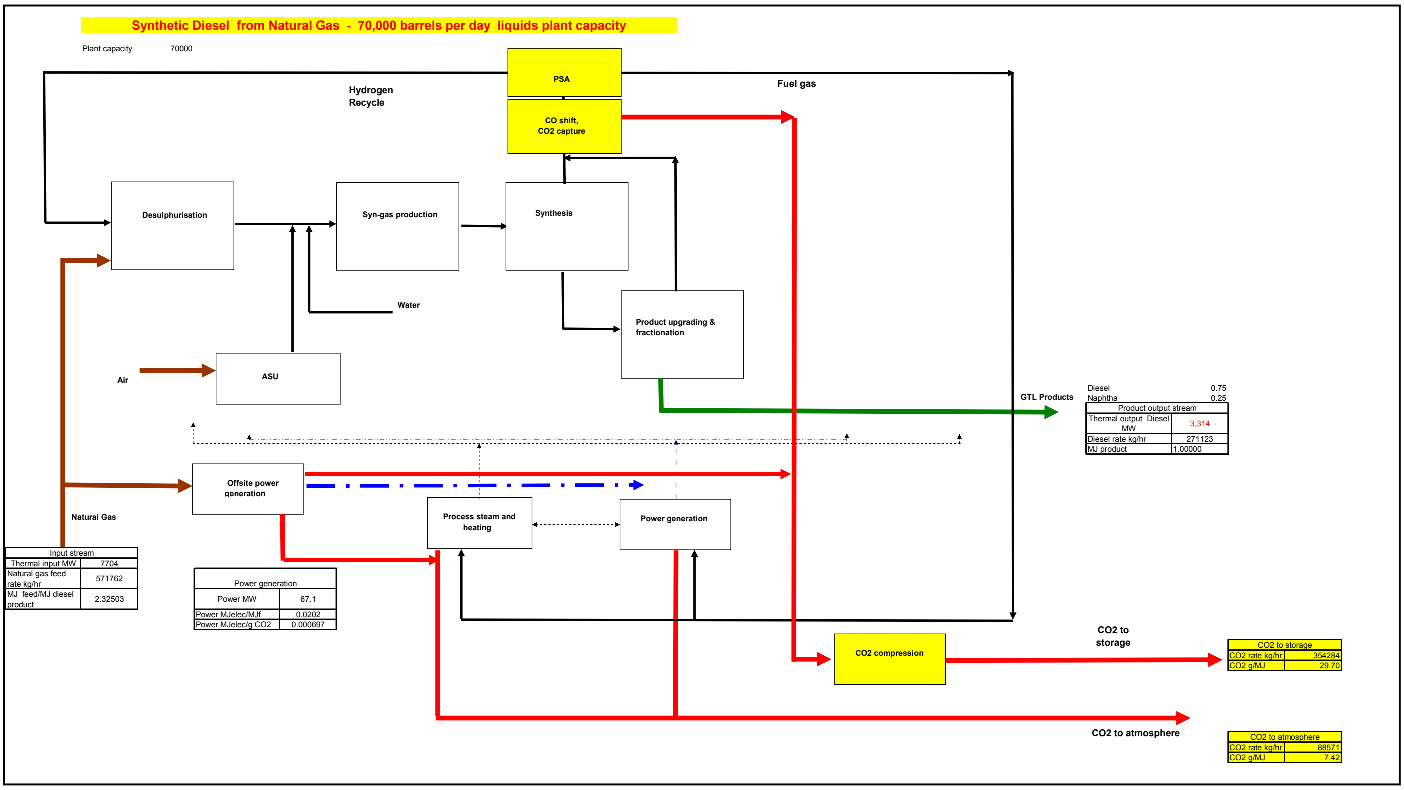
For the scenario timeframe it is assumed that plants of 70-75,0000 bpd capacity have been constructed[60] and that this represents state-of-the–art plant design. Cost data have been estimated using data provided in PH3/15 and rebased to match published data for Sasol Oryx total installation costs. A simplified flowsheet incorporating carbon capture is summarised in Figure I -7. Estimated data used in this study are summarised in Table I - 39

[60] Shell define future world-scale plants being those in excess of 100,000 bpd distillate product.

Table I – 39 Estimated energy efficiency, emissions and costs for a synthetic diesel based on a 70,000bpd plant

	Synthetic diesel production without capture	Range P20 – P80	Synthetic diesel production with capture	Range P20 – P80
Overall efficiency %	58	55 - 61	55	53.6 – 59.9
Net primary energy expended MJ/MJ diesel product	0.925[61]	0.82 – 1.05	0.975	0.86 – 1.1
Capital cost Euro/kW_{th} GTL product	384	+/-30%[62]	437	+/-30%
CO2eq emissions g/MJ diesel	33.5	27 - 40	5.35	4.4 – 6.6

Fig. I – 7 Simplified flowsheet for synthetic diesel showing overall energy balance and CO2 emissions



I.iv.ii Synthetic diesel shipping

Synthetic diesel is pumped to storage prior to being transported to The Netherlands in product carriers powered by heavy fuel oil. Best estimates of energy and emissions assume 50kt product carriers sailing a distance of 6400 nautical miles with an average

[61] Corrected for naphtha production
[62] All capital costs are +/-30% at P5 – P95 level of accuracy

speed of 16 knots and an average fuel consumption for the round trip is 0.124MJ/t.km. Uncertainty estimates take into account different product carrier capacities, distance and speed.

Assuming full combustion, primary energy demand and GHG emissions have been estimated as follows:

Table I – 40 Estimated energy demand and total GHG emission (CO2eq) from marine transport of synthetic diesel

	Energy expended MJ/MJ diesel transported	Range P5 – P95	GHG emissions CO2 eq./MJ diesel transported	Range P5 – P95
Primary energy and emissions	0.0363	0.03 – 0.04	2.91	2.6 – 3.2

I.iv.iii Synthetic diesel distribution

Synthetic diesel is distributed from the import terminal to regional depots by rail over an average distance of 150km, and thence by road tanker to filling stations over a further distance of 150km. Energy, in the form of electricity for pumping and rail transport and diesel for road transport, are expended in the distribution process.

Table I - 41 Estimated energy demand and total GHG emission (CO2eq) from the distribution of synthetic diesel to filling stations

	Energy expended MJ/MJ diesel transported	Range	GHG emissions CO2 eq./MJ diesel transported	Range
Primary energy and emissions	0.018	-	0.92	-

I.iv.iv DiMethyl ether (DME)

DME has been shown to have excellent properties as diesel fuel giving emission levels better than the Californian ULEV standards. Today, DME is manufactured predominantly as an aerosol propellant to substitute for CFCs. Total world production is around 150,000 tonnes per day and is made by the dehydration of methanol, and is therefore inherently more expensive than methanol. Use as an alternative fuel, supplying a market of some 1 million vehicles, would imply annual demand of 28 PJ or 1 million tonnes per year, which would require significant expansion of manufacturing capacity.

In large-scale manufacture, DME can be produced directly from synthesis gas, using multifunctional catalysts that permit the methanol, shift and DME reactions to take place simultaneously. DME can then be manufactured at a scale comparable with that of methanol (10,000 tonnes per day)[63] and at lower cost. Haldor Topsoe have developed such catalysts and demonstrated their performance and stability in laboratory pilot plants.

[63] World-scale plants have typically been 2,500 tonnes per day; plants of this scale are likely to be typical in the study timeframe.

No manufacturing plants have, however, been built. The process is, however, very similar to methanol manufacture, a well-established technology. Investment costs are lower; typically, 8%[64] less for a plant producing fuel grade DME[65].

In this study, a 10,000 tonnes of methanol eq. per day[66] world-scale plant, producing fuel grade DME, has been assumed. This corresponds to approximately 7,500 tonnes per day of DME. In order to achieve maximum conversion of synthesis gas to DME, the ratio $(H_2-CO_2)/(CO+CO_2)$ should be in the range 2.1-2.2. With auto-thermal reforming the ratio is below 2, and is adjusted by hydrogen recycle or intermediate removal of CO_2. Although hydrogen recycle is preferred in modern plants employing state-of-the-art auto-thermal reactors, an intermediate CO_2 removal step is best suited to carbon capture[67]. Carbon efficiency in the reactor section has an optimum of around 98% and very little CO_2 escapes in the fuel purge gas stream (see reference in footnote 64). As a result, more than 93% of CO_2 emissions are available as a pure stream that requires only drying and compression to 110 bara. The remaining emissions are at low concentration (ca 5%) in low-pressure boiler and gas turbine exhaust streams and relatively expensive to capture.

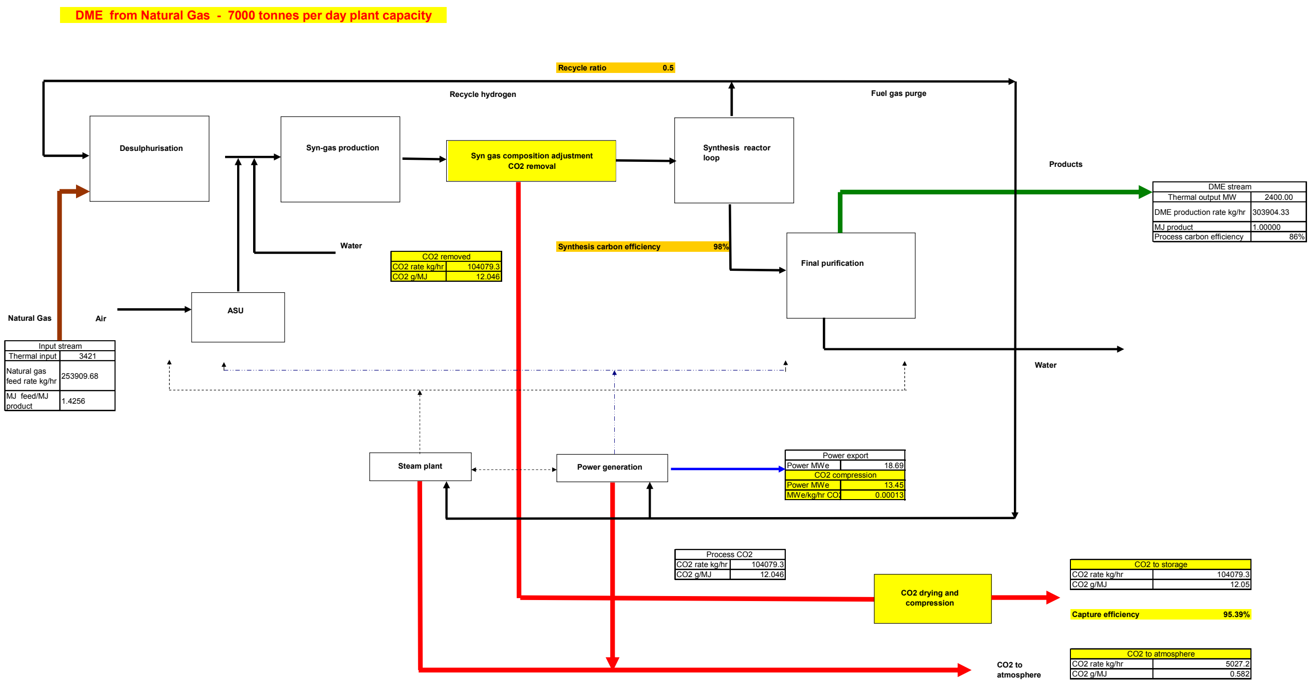
A simplified flowsheet incorporating carbon capture is summarised in Figure I – 8. Data are based on comparable process information published by Haldor Topsoe (see reference in footnote 64). Cost data are based on a lump sum turn-key cost of 250 million US $(1999) for a 2,500 tonne per day methanol plant, which is currently the industry standard capacity[68]. Upper and lower bounds reflect an overall 5% spread in process efficiency, which represents the range in performance of different generations of methanol plants (see footnote 68). Costs include product storage and loading facilities

Table I - 42 Estimated energy efficiency, emissions and costs for a 10,000tpd methanol eq. DME plant

	DME production without capture	Range P20 – P80	DME production with capture	Range P20 – P80
Overall efficiency %	71.5	69 - 74	71	68.5 – 73.5
Natural gas to DME energy ratio MJ/MJ DME product	1.40	1.36 – 1.45	1.409	1.4 – 1.5
Capital cost Euro/kW_{th} DME product	317	+/-30%[69]	333	+/-30%
CO2eq emissions g/MJ DME	11.4	10 - 13	0.4	0.3 – 0.5

[64] ‘ Large Scale Manufacture of Dimethyl Ether - a New Alternative Diesel Fuel from Natural Gas’, SAE 950063 J. Hansen et al. February 1995
[65] DME containing small quantities of water and Methanol - can be produced for lower investment cost in product purification.
[66] Methanol eq.=Methanol+2*DME [moles]
[67] Private communication H Holm Larsen
[68] ‘Recent Advances in Autothermal Reforming Technology – Reducing Production Cost to Prosper in a Depressed Market World’, J Haugaard et al., Methanex Conference 1999.
[69] All capital costs are +/-30% at P5 – P95 level of accuracy

Fig I - 8 Simplified flowsheet for DME showing overall energy balance and CO2 emissions



I.iv.v DME shipping

DME can be easily liquefied, transported and stored under conditions similar to liquefied petroleum gas (LPG). DME is pumped to storage prior to being transported to the Netherlands in product carriers powered by heavy fuel oil. While LPG vessels are available in several sizes and types, refrigerated vessels, which are available in 35,000, 56,000 and 78,000 m^3 capacity, would be of commercial interest for fuel grade DME. Fuel grade DME has a specific gravity of ca 0.75 at its nominal boiling point –25 Deg C. Modern LPG vessels are designed for an average specific gravity of 0.73, resulting in a small ullage space. DME best estimates of energy and emissions assume nominal 56,000 m^3 (41kt payload DME) product carriers sailing a distance of 6400 nautical miles with an average speed of 16 knots and an average fuel consumption for the round trip of 0.163MJ/t.km. Uncertainty estimates take into account different product carrier capacities, distance and speed. Assuming full combustion, primary energy demand and GHG emissions have been estimated as follows:

Table I - 43 Estimated energy demand and total GHG emission (CO2eq) from marine transport of DME

	Energy expended MJ/MJ DME transported	Range P5- P95	GHG emissions CO2 eq./MJ DME transported	Range P5- P95
Primary energy and emissions	0.074	0.066 – 0.08	5.9	5.3 – 6.9

I.iv.vi DME distribution and dispensing

DME is distributed from the import terminal by road tanker to filling stations over a distance of 250km. Energy, in the form of electricity for pumping and diesel fuel for transport, is expended in the distribution process.

Table I - 44 Estimated energy demand and total GHG emission (CO2eq) from the distribution of synthetic diesel to filling stations

	Energy expended MJ/MJ DME transported	Range	GHG emissions CO2 eq./MJ DME transported	Range
Primary energy and emissions	0.024	-	1.48	-

I.iv.vii Well to Tank analysis

Full fuel cycle estimates of energy expenditure, GHG emissions and supply costs for the synthetic diesel and DME pathways from remote natural gas are summarised, respectively, in Tables I– 45, 1-48, inclusive. The data are single point estimates using the best estimates provided in the previous sections for each individual step in the supply chain.

Table I - 45 Full fuel cycle energy expenditure, GHG emissions and supply cost for synthetic diesel production from remote natural gas without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.941	0.046	5.66	1.00	1.00
Gas converted locally to liquid fuel using GTL process	0.925	1.000	0.925	31.21	3.05	4.04
Synthetic diesel remote handling and loading	0.002	1.000	0.002	0.09		
Synthetic diesel sea transport	0.036	1.000	0.036	2.91	3.73	4.89
Synthetic diesel reception and storage	0.002	1.000	0.002	0.38	3.77	4.95
Synthetic diesel distribution and dispensing	0.018	1.000	0.018	1.00	5.87	7.08
Full fuel chain			1.030	41.2	5.9	7.1

Table I - 46 Full fuel cycle energy expenditure, GHG emissions and supply cost for synthetic diesel production from remote natural gas with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.813	**0.043**	**5.29**	**1.0**	**1.0**
Gas converted locally to liquid fuel using GTL process	0.798	1.000	**0.798**	**1.61**	**3.5**	**4.7**
Synthetic diesel remote handling and loading	0.002	1.000	**0.002**	**0.09**		
Synthetic diesel sea transport	0.036	1.000	**0.036**	**2.91**	**4.2**	**5.5**
Synthetic diesel reception and storage	0.002	1.000	**0.002**	**0.38**	**4.3**	**5.6**
Synthetic diesel distribution and dispensing	0.018	1.000	**0.018**	**1.00**	**6.4**	**7.7**
Full fuel chain			**0.9**	**11.28**	**6.4**	**7.7**

Table I - 47 Full fuel cycle energy expenditure, GHG emissions and supply cost for DME production from remote natural gas without capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	10% discount rate
NG extraction and processing	0.024	1.402	**0.033**	**4.09**	**1.0**	**1.0**
DME synthesis	0.402	1.000	**0.402**	**11.38**	**2.7**	**3.3**
DME loading terminal	0.002	1.000	**0.002**	**0.13**		
Transport by ship 6400 nm	0.074	1.000	**0.074**	**5.92**	**4.1**	**5.1**
DME Depot	0.004	1.000	**0.004**	**0.58**		
DME distribution and dispensing	0.024	1.000	**0.024**	**1.48**	**6.5**	**7.6**
Full fuel chain			**0.539**	**23.6**	**6.5**	**7.6**

Table I - 48 Full fuel cycle energy expenditure, GHG emissions and supply cost for DME production from remote natural gas with capture and storage

Process step description	Net primary energy expended per MJ of main products of the process MJex/MJ	Energy multiplier	Net primary energy expended per MJ final fuel MJex/MJf	CO2 eq/MJf	Cumulative fuel chain supply costs Euro/GJ	
					5% discount rate	5% discount rate
NG extraction and processing	0.024	1.409	**0.033**	**0.034**	**1.0**	**1.0**
DME synthesis	0.409	1.000	**0.402**	**0.409**	**2.8**	**3.4**
DME loading terminal	0.002	1.000	**0.002**	**0.002**		
Transport by ship 6400 nm	0.074	1.000	**0.074**	**0.074**	**4.2**	**5.2**
DME Depot	0.004	1.000	**0.004**	**0.004**		
DME distribution and dispensing	0.024	1.000	**0.024**	**0.024**	**6.6**	**7.8**
Full fuel chain			**0.546**	**12.6**	**6.6**	**7.8**

I.iv.viii Diesel powered vehicles- costs and performance

As for all vehicles, the study utilises unmodified data from the JEC study. Data are summarized in the following paragraphs and Tables.

The study assumes the reference vehicle powered by a 1.9 l turbo-charged engine (74 kW). The higher diesel engine mass requires structural reinforcements that increase the total vehicle mass by about 70 kg compared to the reference gasoline vehicle. Much of the benefits expected from gasoline engines are already accounted for in current diesel engines and 2010 vehicles only incorporate minor technology improvements. As a result, diesel efficiency only improves 6% over current levels in the study timeframe. It is assumed that, in order to meet particulate emissions, a particulate filter (PF) will be required for conventional and synthetic diesel fuels, but not for DME. The PF option carries a fuel penalty of about 4%.

Because of its low viscosity and lubricity, DME requires a purpose-built fuel injection system to avoid high leakage rates and to minimise wear on all moving parts. DME vehicles also need to be provided with an “LPG-type” steel tank. These changes are expected to increase the cost of a DME fuelled vehicle over a conventionally fuelled vehicle meeting EURO IV emission levels. The JEC study estimated this cost to be € 675. Alternative assessments suggest that by 2010 the cost of vehicles meeting Euro IV requirements should be similar; with the additional fuelling system costs offsetting the cost of additional exhaust treatment. In this study, it is assumed that the incremental manufacturing cost for a DME fuelled vehicle will be within the range 0 – € 675.

Table I - 49 Energy consumption and GHG emissions from a synthetic diesel and DME fuels

	Energy consumption MJ/100km	Range P20 – P80	GHG emissions CO2eq/km	Range P20 – P80
Synthetic diesel with PF	179.7	172 - 187	129	124 - 134
Synthetic diesel hybrid with PF	147.8	136 - 159	106.4	98 - 115
DME	172.4	165 - 180	117.9	113 - 123
DME hybrid	141.1	130 - 152	96.8	89 - 104

Table I- 50 Vehicle retail price estimates

Vehicle component	Cost Euro	Cost Range P5 – P95
Baseline vehicle cost	**20,300**	**-**
Synthetic diesel with PF		
PF - EURO IV compliance	700	
"Stop & Go" system	200	
Total cost	**21,200**	**21,000 – 21,400**
Synthetic diesel hybrid with PF		
PF - EURO IV compliance	700	
Electric induction motor & controller	378	
Battery	2042	1,500 – 2,520
Total cost	**23,420**	**22,850 - 24,050**
DME DICI		
Fuel tank – net increase	1040	825 - 1500
DME DICI		
Fuel tank – net increase	1040	825 - 1500
DME DICI		
Fuel tank – net increase	1163	825 - 1500
"Stop & Go" system	200	
Total cost	**21,540**	**21,190 – 21,900**
DME DICI hybrid		
Fuel tank – net increase	1010	725 - 1350
Electric induction motor & controller	378	
Battery	2042	1,500 – 2,520
Total cost	**23,610**	**23,060 – 24,230**

Appendix II – Pathway Economic Assessment

See attached Excel spreadsheets

Appendix III IEA Assessment Criteria

Technical and Financial Assessment Criteria

This Appendix contains a general list of technical and financial factors likely to be required for appraisal studies. It is intended to ensure that studies for the IEA Greenhouse Gas R&D programme are conducted using a consistent set of technical and financial conventions.

Technical/Financial Factor (notes)	Assessment Convention
1. <u>Development Status</u> ***(It is well documented that the cost of technology decreases and its performance improves as experience is gained.)***	***For commercially available technology current 'state-of-the-art' cost and performance figures will be assumed.*** ***Where technology has only reached the demonstration stage or earlier stages of development, 1st (commercial) generation costs and performance will be assumed and compared with 'state-of-the-art' current figures. The cost vs. installed capacity relationship assumed should be presented in the results.***
2. <u>Plant Size</u> ***(Significant economics of scale can apply up to the size at which increases can only be obtained by using plant modules and/or the cost of working capital due to extended construction periods outweighs benefits of scale.)***	***The net power output after deducting ancillary power requirements will be 750 MW. There will be cases (e.g. gas turbines which have fixed sizes) where it is not possible or advisable to match the required net power output. In such cases the power output will be agreed with IEA GHG.***
3. <u>Location</u> ***(The standard site for IEAGHG studies is on the NE coast of The Netherlands; this appears to give costs, which are in the middle of the range for OECD member countries.)***	***A green field site with no special civil works implications will be assumed. Unless otherwise specified, the plant will be assumed to be on the NE coast of The Netherlands. Adequate plant and facilities to make the plant self sufficient in site services will be included in the investment costs.*** ***Alternative and/or multiple sites will be specified for some studies.***
4. <u>Currency</u> ***(Converting US$ costs to a local currency equivalent involves more than using the current exchange rate; members of the IEA***	***The results of the studies will be expressed in US $ applicable to a specific year. Data obtained in other currencies will be converted at rates to be agreed.***

Technical/Financial Factor (notes)	Assessment Convention
GHG programme will need to take their own views on appropriate rates.)	
5. <u>Design and Construction Period</u> ***(Project finances can be sensitive to the time required to erect the plant.)***	***Coal fired power generation plant: 3 years.*** ***Natural gas fired combined cycle plant: 2 years.*** ***CO_2 capture plant and 'chemical plants' in general: 2 years.*** ***Underground CO_2 storage: 2 years*** ***Ocean storage: 4 years (assuming a long pipeline to the disposal point)*** ***Modular renewable technologies such as wind turbines: 1 year*** ***Typical `S' curves of expenditure during construction will be used, viz:*** ***Coal-fired Natural gas fired*** ***Year Power Plant % Power Plant %*** ***`Chemical' Plant %*** ***1 20 40 40*** ***2 45 60 60*** ***3 35***
6. <u>Plant Life</u> ***(Design life to be used as a basis for economic appraisal. A financial assessment convention; actual life is frequently extended.)***	***Twenty-five years. Where for technical reasons this is regarded as excessive, provision will be made for the cost of any major maintenance/refurbishment or a shorter life will be assumed.***
7. <u>Load Factor</u> ***(Achieved output as a percentage of rated/nameplate capacity. Appropriate to the ranking of technical options; in practice, because of system limitations, many power plants achieve***	***For coal, other solids, and liquid processing plants; 1st. year: 60% of rated capacity; subsequent years: 85% of rated capacity. For natural gas fuelled plants (and other plants solely processing gases) 90% of rated capacity for all operating years.***

Technical/Financial Factor (notes)	Assessment Convention
considerably less output.)	*Renewable technologies on a case-by-case basis.* *Allowance should be made for sufficient installed duplicate/spare capacity to meet required load factor taking into account maintenance requirements and reliability. No allowance for decline as plant ages.*
8. <u>Cost of Debt</u> *(Note that money is required during design, construction and commissioning i.e. before any returns on sales are achieved.)*	*For simplicity, all capital requirements will be treated as debt at the same discount rate used to derive capital charges. No allowance for grants, cheap loans etc. (More complex financial modelling might be considered for certain studies.)* *Specific capital cost figures should be presented without including an allowance for funds used during construction (i.e. independent of discount rate).*
9. <u>Capital charges; inflation</u> *(In the event of the reduction in carbon emissions being achieved at a significantly later date than the expenditure, the investment costs should be projected forwards.)*	*Discounted cash flow calculations will be expressed at a discount rate of 10% and, to illustrate sensitivity, at 5%; the resulting capital charge rate will be quoted. All annual expenditures will be assumed to be incurred at the end of the year.* *Inflation assumptions will not be made. No allowance will be made for escalation of fuel, labour, or other costs relative to each other.*
10. <u>Contingencies</u> *(A contingency is added to the capital cost to allow for unforeseen set-backs, cost under-estimates, programme overruns etc.)*	*A contingency will be added to the capital cost to give a 50% probability of a cost over-run or under-run. In the absence of a more detailed assessment, the default value for the contingency should be 10% of the installed plant cost (overnight construction).*

Technical/Financial Factor (notes)	Assessment Convention
	All plant should be assumed to be built on a turnkey basis, ie; the cost of risk should be built into the contractor's fees.
11. <u>Fees and other owners costs</u> ***(The contractor's fees for design and build will form part of the basic plant cost estimate; additional fees and costs covered here include:- process/patent fees, fees for agents or consultants, legal and planning costs, land purchase, surveys and general site preparation etc. Start-up costs are not included here as they are calculated separately)***	***A total of 7% of the installed plant cost (overnight construction, excluding contingency) will be included to cover these owners costs.*** ***A separate statement of the cost should be made where any proprietary technology or other technology license fee exceeds 2% of the plant cost.***
12. <u>Commissioning and Working Capital</u> ***(Commissioning is defined as the period between the construction period [item 3] and the start of the 1st year of operation [item 4]. Working capital includes raw materials in store, catalysts, chemicals etc.)***	***A 3 month commissioning period will be allowed for all plant. Sufficient storage for 30 days operation at rated capacity will be allowed for raw materials, products, and consumables (except for natural gas and other gaseous fuels in which case provision should be made for an alternative supply of fuel). No allowance will be made for receipts from sales in this period.***
13. <u>Decommissioning</u> ***(Costs associated with final shut down of the plant, long term provisions and 'making good' the Site).***	***This will be included to facilitate comparison with technologies where decommissioning can be a significant proportion of project cost.***
14. <u>Taxation and Insurance</u> ***(The treatment of these items will differ markedly from country to country. Therefore, a simple treatment is used which can be readily adapted to suit the circumstances of individual members.)***	***Allow 1% per year of the installed plant cost (overnight construction, excluding contingency and fees) to cover specific services e.g. local rates. Taxation on profits will not be included in the assessments.*** ***Allow 1% per year of the installed plant cost (overnight construction excluding contingency and fees) to cover***

Technical/Financial Factor (notes)	Assessment Convention
	insurance.
15. <u>Maintenance</u> ***(To include labour, materials and contract maintenance costs)***	***Routine and breakdown maintenance will be allowed for at: 4% per year of installed plant cost (overnight construction excluding contingency and fees) for solids handling plant and at 2% per year for plants handling gases and liquids and services plant.***
16. <u>Labour</u> ***(Agreed conventions are required for the treatment of operating, supervising, maintenance and other labour elements; including administrative, other general overheads and items such as social security payments.)***	***The cost of maintenance labour is assumed to be covered by item 15.*** ***Operating labour only will be identified and assumed to work in a 5 shift pattern. If not estimated in detail, an allowance of 20% of the operating labour direct costs will be included to cover supervision. A further 30% of direct labour costs will be included to cover administration and general overheads. (ie; total cost = (direct operating labour cost x 1.2) x 1.3)***
17. <u>Fuels and Raw Materials</u> ***(Where a range of fossil fuels could be used, coal and natural gas will normally be specified as they span the range of H:C ratios for fossil fuels.)***	***'Typical' bituminous coal and natural gas are used as a standards. Their specifications are given on the last page of this document.*** ***Where appropriate the analysis of alternative fossil fuels fuel will be supplied.*** ***The cost of coal delivered to site is to be assumed to be US$1.5/GJ (LHV basis).*** ***The cost of natural gas delivered by pipeline to site is to be assumed to be US$3/GJ (LHV basis).***

Technical/Financial Factor (notes)	Assessment Convention
18. Water.	***The use of sea water cooling will be assumed for the site in the Netherlands and other coastal sites. Direct cooling will be used for the steam turbine condenser and large compressor intercoolers and an indirect cooling system will be used for other process coolers. Unless otherwise stated, any inland sites will be assumed to use closed circuit cooling water systems.*** ***Sea-water cooling conditions are: Average inlet temperature 12C; maximum temperature rise 7C; salinity 22grams/litre.***
19. Effluent/Emissions and Solids Disposal ***(a) Sulphur, ash, oils and tars, NO_x, SO_x etc (other than CO_2)***	***The plant will be assumed to have effluent abatement and treatment facilities sufficient to meet achievable reductions, eg*** ***Particulate matter < 25 mg/Nm^3*** ***NO_x < 200 mg/Nm^3*** ***SO_2 < 200 mg/Nm^3*** ***Where disposal of waste is required the cost of appropriate plant and methods will be included in the assessments. The cost of ash disposal, value of by-products e.g. sulphur, etc., will be treated on a case-by-case basis.***
(b) CO_2 processing.	***Unless otherwise specified, minimum CO_2 capture level is to be 80%; and the preferred level 85%.*** ***Unless otherwise specified, CO_2 is to be compressed to 110 bar before injection into the transfer pipeline.*** ***Note will be taken of possible emissions arising from CO_2***

Technical/Financial Factor (notes)	Assessment Convention
	processing, eg, amine scrubbing.
20. <u>Site Conditions</u>	***Ambient air temperature: 9C*** ***Ambient air relative humidity: 60%*** ***Ambient air pressure: 1.013 bar***
21. <u>Heat Content</u>	***Lower Heating Value will be used in all efficiency calculations***

FUEL SPECIFICATIONS

1. Natural gas specification

Component	**volume %**
Methane	83.9
Ethane	9.2
Propane	3.3
Butane +	1.4
CO_2	1.8
Nitrogen	0.4
Sulphur (as H_2S)	4 mg/Nm^3
Gross CV	53.76 MJ/kg
Net CV	48.51MJ/kg

The gas specification is based on a pipeline quality gas from the southern part of the Norwegian off-shore reserves.

2. Coal specification

Proximate analysis:	**weight %**
coal (dry, ash-free)	78.3
ash	12.2
moisture	9.5
Ultimate analysis:	
Carbon	82.5
Hydrogen	5.6
Oxygen	9.0
Nitrogen	1.8
Sulphur	1.1
Chlorine	0.03
Ash analysis:	
SiO_2	50.0
Al_2O_3	30.0
TiO_2	2.0
Fe_2O_3	9.7
CaO	3.9
MgO	0.4
Na_2O	0.1
K_2O	0.1

P_2O_5	1.7
SO_3	1.7
Gross CV	27.06 MJ/kg
Net CV	25.87 MJ/kg
Hardgrove Index	45
Ash fusion point (reducing atmosphere)	1350 C

The coal specification is based on an open-cut coal from Eastern Australia