Analysis of UKSHEC Hydrogen Visions in the UK MARKAL Energy System Model

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Authors: Nazmiye Balta-Ozkan, Ramachandran Kannan, Neil Strachan
Institution: Policy Studies Institute

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1 Introduction

Analysis of the possible roles of hydrogen in the UK energy system and how this might evolve continues to be of considerable interest to policy makers as well as to the interdisciplinary scientific community (including engineers, social scientists and economists). As such a hydrogen system does not yet exist, a number of hydrogen visions and pathways to reach them from present day have been put forward based on a literature review, a stakeholder workshop, and scoping interviews (see Eames and McDowall (2006)).

The objective of this paper is to provide insights on the development of a foreseeable hydrogen economy in the UK energy system. This analysis is carried out using the UK MARKAL energy system model developed in 2006 (Strachan et al, 2006). The UK MARKAL model has provided substantive analytical input to the policy making process, notably the 2007 Energy White Paper. To analyse the hydrogen visions of UKSHEC[1], the model has been further updated with the inclusion of detailed hydrogen pathways using up-to-date data available in the literature.

A review of other approaches as well as MARKAL to analyze the development of a hydrogen economy in the UK has been presented by Joffe and Strachan (2007). In their review, Joffe and Strachan point out that any analysis of the possible pathways for hydrogen development is bound to face a set of challenges that are inherent to hydrogen economy. In particular, any quantitative tool needs to be coherent and sophisticated enough to take into account resource competition, the spatial nature of hydrogen infrastructure development and a great level of technical detail in representing the various hydrogen pathways. As discussed extensively by Joffe et al (2007), the first and the latter issues are MARKAL's strengths, while methods to represent spatial aspects of hydrogen can only be approximated in a standard MARKAL model.

This paper is organized as follows. Section 2 gives an overview of the UK MARKAL modelling framework. Section 3 presents how hydrogen pathways are depicted in the model. Section 4 discusses an overview of UKSHEC hydrogen visions and how they are modelled in MARKAL. Section 5 presents indicative model outputs, and the final section is devoted to conclusions.

2 The UK MARKAL energy systems model

MARKAL (acronym for MARKet ALlocation) is a widely applied bottom-up, dynamic, linear programming (LP) optimisation model. It was developed in the late 1970s at Brookhaven National Laboratory and has been continually supported by the International Energy Agency (IEA) via the Energy Technology and Systems Analysis Program (ETSAP). It has being used by around 100 active teams in over 30 countries.

MARKAL portrays the entire energy system from imports and domestic production of fuel resources, through fuel processing and supply, explicit representation of infrastructures, conversion to secondary energy carriers (including electricity, heat

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[1] This paper is also one of the outputs of UKSHEC. UKSHEC, the UK Sustainable Hydrogen Energy Consortium, is one of the Supergen consortia funded by the UK's Engineering and Physical Sciences Research Council, to whom gratitude is expressed for support of this research.

and hydrogen), end-use technologies and energy service demands in the industrial, commercial, residential, transport and agricultural sectors. A highly simplified reference energy system – focusing on the electricity component of the full model – illustrates how these components are linked to each other as in Figure 1.

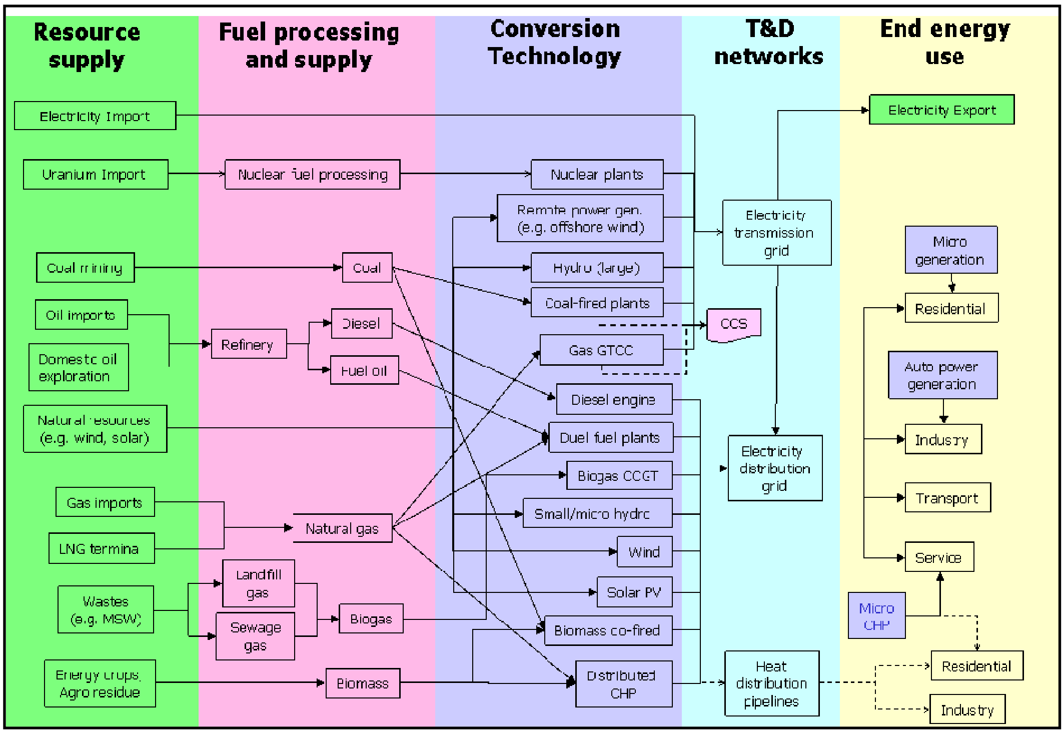

Figure 1 Highly aggregated example of the UK MARKAL Reference Energy System (RES)

As a perfect foresight optimization model, MARKAL minimizes the total system cost by choosing the investment and operation levels of all the interconnected system elements. The participants of this system are assumed to have perfect inter-temporal knowledge of future policy and economic developments. Hence, under a range of input assumptions, which are key to the model outputs, MARKAL delivers an economy-wide solution of cost-optimal energy market development.

The construction of the UK model entails definition of the specific characteristics of the UK energy system, including resource supplies, energy conversion technologies, end-use demands, and the technologies used to satisfy these demands. In particular, the current model is developed based on the previous model used in the Energy White Paper 2003 (DTI, 2003), and supplemented by stakeholder workshops and a wide range of peer reviewed data sources[2]. Inputs into the model include base levels for global energy price curves (DTI, 2006), and detailed energy service demands in units of useful energy. These energy services demands were calibrated to final energy consumption projections that were published by the government (DTI 2006). A full description of the UK MARKAL model is given in Strachan et al (2006).

In order to replicate the physical, regulatory and policy aspects of the whole UK energy system in MARKAL, some hundreds of constraints are introduced to the model. These are designed such that the optimization of the model database of technological pathways occurs under a realistic engineering and economic framework of the deployment of new infrastructures, fuels and technologies.

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[2] Three stakeholder workshops on road transportation technologies, electricity generation technologies and hydrogen were held. For further details on model calibration and validation, please see Strachan et al (2006).

The model is calibrated in its base year (2000) to within 1% of actual resource supplies, energy consumption, electricity output and installed technology capacity. The principal calibration source is DUKES (2006). In addition, considerable attention is given to near-term (2005-2020) convergence of sectoral energy demands and carbon emissions with the econometric outputs of the government energy model (DTI 2006). The model solves in 5-year time steps for an optimal evolution of energy pathways and technology deployment and use.

In order to analyze the UKSHEC hydrogen visions, the UK MARKAL model has been extensively restructured with detailed representation of hydrogen pathways. The next section presents how hydrogen pathways are depicted in the model.

3 Overview of UK MARKAL depiction of hydrogen

The updated UK MARKAL model has a representation of hydrogen that covers a range of technologies and resources in production, distribution and end-use. The structure of the hydrogen module is illustrated in Figure 2. Implicit in the model (although not shown in Figure 2) is the dynamic nature of the hydrogen chains with costs reflecting new vintages of technologies or global learning rates.

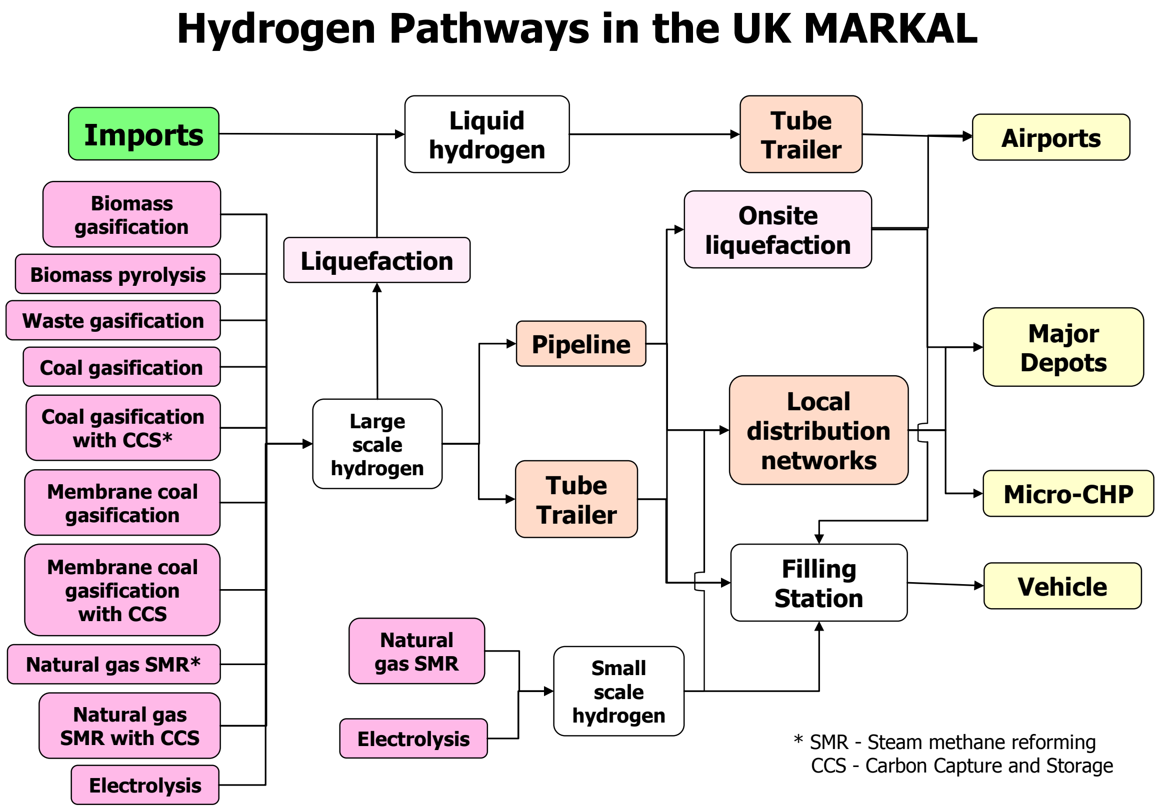

Figure 2 Structure of the hydrogen module in the UK MARKAL model

3.1 Hydrogen production

As presented in Figure 2, the updated UK MARKAL model has a very detailed presentation of hydrogen production technologies, which are reviewed in detail in the UKSHEC Working Paper No.25 (Hawkins and Joffe, 2006). Major categories of hydrogen production technologies are steam methane reforming (SMR), gasification of coal, biomass and municipal wastes, and electrolysis. These production technologies are represented in two scales of production as follows:

- **Large-scale production** from SMR of natural gas, electrolysis, gasification of coal, biomass or municipal waste. CCS is included as an option for the large-scale SMR and coal/gas gasification technologies.
- **Small-scale production** from SMR of natural gas and electrolysis.

In addition to the above, on-site liquefaction (by transport modal size) and imported liquid hydrogen options are included.

3.2 Hydrogen infrastructure

Whether hydrogen is imported or produced at a large-scale, the model structure assumes it first is delivered to centrally located hydrogen distribution terminals and then transported to potential end-users. Two main hydrogen transmission options via pipeline or road trailer (either liquid or compressed form) have been included. The pipelines transmission is connected to end-use specific distribution networks based on hydrogen flow rate and distribution distance, which have a key role on the distribution costs of hydrogen (see Table 1). The network types are determined by requirements on the demand side, as each type of transport would require a filling station at different capacities at different spatial proximity. For example, while air and rail transport would require few large fuelling hubs – which might be close to resource or import sites – due to their large scales, cars would need filling stations throughout the country with lower flow demands to each station. On the other hand, buses would use relatively small depots when travelling in short distances as they are mostly based in urban areas. Heavy good vehicles, though, would need few truck services located on major road networks with high flow demands.

Hence, the UK MARKAL model has been updated to develop a hydrogen distribution system that takes into account distance and flow rate relationship as well as characteristics of the end use options. Following Yang and Ogden (2007), four hydrogen distribution networks are assumed to take place based on distance and flow rate. Yang and Ogden (2007) argue that a distribution distance of 50 km versus 300 km, and a flow rate of 15t/day versus 100t/day significantly affect the costs. Hence, in the UK model, each transport mode is assigned to a quadrant in a 2 x 2 matrix, formed by these two axes for all the distribution networks. Table 1 presents each transport mode in one of these quadrants. In addition, hydrogen distribution for stationary micro-generation technologies for end-use sectors is similarly treated, with low flow rates and long distances required to meet distributed buildings applications.

Table 1 UK hydrogen distribution network by mode

		Distribution Distance	
		Short (50 km)	**Long (300 km)**
Flow rate	**High (100 t/day)**	Air, rail, ship	Heavy goods vehicles (HGV)
	Low (15 t/day)	Bus, Two-wheeler	Car, light goods vehicles (LGV), micro-generation

However, these different types of transport also require hydrogen in different forms, e.g. gaseous versus liquid. While air transport requires only liquid hydrogen, the other transport types may take hydrogen in liquid or compressed form with the exception of two-wheelers and rail transport. Hence, for several types of road transport – namely, buses, cars, HGVs and LGVs and air transport – on-site hydrogen liquefaction technologies are introduced, in addition to the centrally produced and distributed liquid hydrogen chain. These on-site liquefaction technologies can take gaseous hydrogen either centrally produced and distributed via pipelines or tube trailers, or locally produced gaseous hydrogen.

As the small scale hydrogen production is assumed to take place at a site close to demand points, there are no hydrogen distribution or transmission costs associated with them. Instead the distribution is via the electricity or natural gas infrastructures, and incurs the efficiency losses and costs associated with those infrastructures implicitly.

3.3 Hydrogen end-use technologies

Technologies to use hydrogen in the transport sector are represented in considerable detail. These are available for air transport, rail and several modes of road transport viz. buses, cars, LGVs, HGVs, and two-wheelers. In road transport fuel cell vehicles use gaseous hydrogen, whereas vehicles with internal combustion engine require liquid hydrogen, and these both are enabled in the model. Vehicle technologies are successively vintaged to represent the development over time of the characteristics of new vehicles.

Similarly, in service, residential and industrial sectors, a range of hydrogen-driven fuel cell technologies are included for stationary power generation and/or micro-generation (both CHP and electricity only)

3.4 Technologies and data sources

Within the UK MARKAL model, the hydrogen module is one part of the larger model of the energy system. The hydrogen-specific technology data that is included in the model is presented in Appendix I, within various tables. However, crosscutting infrastructures[3] and technologies are not included in the Appendix. Consolidated data is given for transport technologies due to the sheer number of vintaged technologies in the transport module. Detailed explanation for these data is given in Strachan et al (2006).

An important aspect of the technological representation within MARKAL is how costs and performance of technologies change with time, especially those that are immature, such as hydrogen and fuel cell technologies. In order to represent the changes in the technology over time, the model has used technology vintages. This means that the technology is represented by several database entries, each applying to the installation of that technology in a particular year. Use of this approach enables representation of the gradual turnover of the technology stock as the technology matured.

Further detail on the hydrogen structure within the UK MARKAL model and its comparison to the approaches taken by the U.S. and Netherlands MARKAL modelling teams is given in Joffe et al (2007).

Finally, while the best data and projections from literature have been used, clearly the future development of immature technologies is, to some extent, uncertain. It is therefore very important to undertake sensitivity analyses for these parameters, in order to ascertain the degree to which this affects the overall results.

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[3] e.g., natural gas pipelines can deliver gas to power plants, residential boilers, distributed hydrogen production sites etc.

4 Hydrogen transition scenarios

Eames and McDowall (2006) define a set of transition visions on what future hydrogen economies might look like through literature review, a stakeholder workshop, and scoping interviews. These visions describe both an end point and an indicative pathway to achieve this vision from today. By acknowledging the role of institutions on the development of hydrogen technologies at different levels, they identify four sets of visions in a 2 x 2 matrix defined by two axes as shown in Figure 3. The two key axes they identify from the literature are

1. The degree to which innovation is shaped by a normative or guiding vision, or might evolve without a coherent 'action plan'.
2. The extent to which innovation can be driven by existing actors and institutions, or whether new ones will be required.

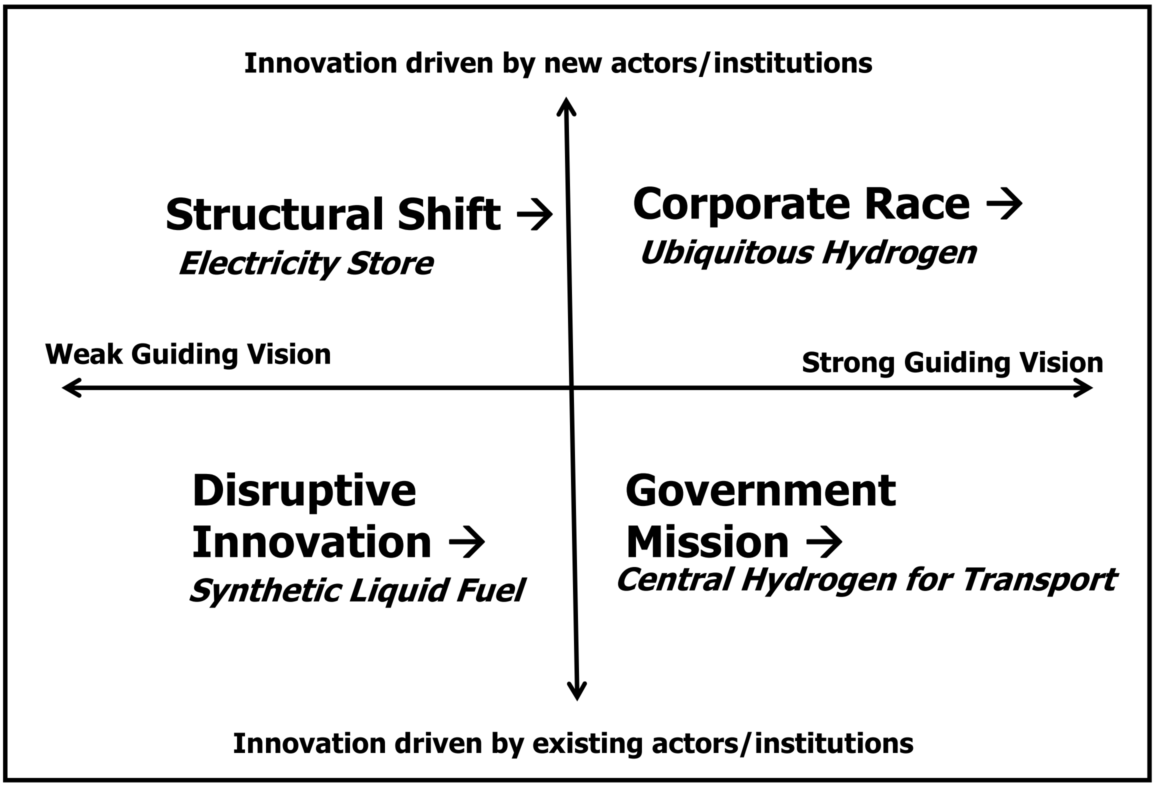

Figure 3 UKSHEC Transition Scenarios (Eames and McDowall 2006)

The first of these scenarios is called *electricity store* which is defined by a 'weak guiding vision' and 'innovation driven by existing actors and institutions'. Even though this scenario does not have a guiding vision specifically for hydrogen, its development is driven by policies that give strong incentives to renewable electricity and micro-generation, due to concerns about climate change and energy security. In particular, the intermittency issue of the renewable energy opens room for the development of hydrogen as a storage medium to buffer the electricity system. With the widespread use of hydrogen for distributed energy storage, hydrogen becomes viable as a transport fuel as well. Hence, under this scenario hydrogen plays a dual role, a buffer for the electricity system as well as a fuel for road transport.

The *ubiquitous hydrogen* scenario is defined by a 'strong guiding vision' and 'innovation driven by existing actors and institutions'. Due to failure of governments to take action on climate change, the existing actors and institutions, which are global automotive companies and regional / local governments, drive innovation through championing demonstration projects. In particular, innovation arises out of the research and development activities of the global companies who are in a strategic race to enable a low carbon energy system. These activities are facilitated by demonstration projects of the regional and local governments. Even though hydrogen penetrates rapidly in transport sector due to improvements in on-board storage and fuel cell technologies, increasing natural gas prices facilitates use of gas grid to supply hydrogen. Eventually, this integrated hydrogen grid allows for both centralized and decentralized hydrogen production where the latter is used for domestic and commercial heat and power generation.

The *central hydrogen for transport* scenario is defined by 'strong guiding vision' and 'innovation driven by new actors / institutions'. Hence, national governments play a key role by forming new institutions as a response to the threat of climate change. While these institutions might be industry partnerships or regulations, they deliver innovation for the development of hydrogen economy. Under this scenario, hydrogen production takes place centrally and then it is distributed by a network. This network allows for delivery of both gaseous and liquid hydrogen as appropriate.

The *synthetic liquid fuel* scenarios is characterised by 'weak guiding vision' and 'innovation driven by new actors / institutions'. This scenario assumes that due to difficulties in its storage and distribution, hydrogen may not become a dominant transport fuel. Instead, innovation in the electronics sector and niches outside of transport and energy systems brings in growth of new markets for portable power and synthetic liquid fuels. Hence, hydrogen is packaged in the form of a synthetic liquid hydrocarbon, such as methanol.

4.1 Modelling of UKSHEC hydrogen visions in MARKAL

In order to characterize the four UKSHEC visions in MARKAL, a corresponding set four core modelling scenarios have been developed. A number of assumptions have been made, some of which are generic to all, and some of which are scenario specific. In all the scenarios, it is assumed that hydrogen economy will be realized in a low carbon society. Hence, an economy-wide 60% CO_2 emissions reduction target by 2050 from the year 2000 levels is included in all these scenarios. In particular, this constraint imposes half of this reduction be achieved by 2030 and the remaining half by a linear trend from 2030 to 2050. This equates to the long term CO_2 target outlined in RCEP (2000) and codified in the Energy White Paper (DTI 2003). In presenting the results, this CO_2 constrained model run is called *reference case*, while the business as usual case without any CO_2 cap is called *base case*. In the base case, all existing UK energy and environmental policies, including fiscal instruments such as the climate change levy, and regulatory instruments such as the power and transport renewable obligations, are included.

The implications of these scenarios from energy, environment and economic aspects are analyzed using the UK MARKAL model. A brief description of how the UKSHEC vision scenarios are characterized in MARKAL modelling framework is provided below for each scenario.

4.1.1 Central hydrogen for transport

This scenario assumes a hydrogen dominated transport fuel. In 2000, the transport sector energy demand constitutes one-third of the UK total final energy consumption.

In the reference case, during the modelling horizon, from 2000 until 2050, fuel use in transport sector varies between 22% and 31% of the final energy demand. However, for technical and socio-economical reasons[4], it may not be possible to move the entire transport fleet to hydrogen. Hence, for this scenario, it is assumed that 20% of the UK's final energy demand would be met from hydrogen and used in transport sector. This scenario is implemented from the reference case via an additional constraint. The constraint is linearly imposed from 2030, similarly to when carbon cap is imposed, so as to reach the 20% final energy share by 2050. By imposing this constraint from 2030 onwards, the carbon cap effectively contributes to the price signal for hydrogen take-up. In order to caveat the model inputs assumptions, additional sensitivities are carried out with high and low levels of resource and technology costs (see section 4.2).

4.1.2 Ubiquitous hydrogen

The ubiquitous hydrogen scenario assumes a dual role for hydrogen, a fuel for road transport, as well as an energy carrier for domestic and commercial heat and power generation. Hence, it would be reasonable to assume that the share of hydrogen in total UK final energy consumption would be higher than the above case. Consequently, a constraint is introduced into the model to deliver 50% of total UK final energy from hydrogen. This constraint is similarly imposed on the reference case, in a linear form from 2030 to 2050.

4.1.3 Synthetic liquid fuel

The synthetic liquid fuel vision is envisaged via use of methanol in the transport sector. Thus, methanol based production, distribution and transport technologies were included in the model. A parametric study was carried out to estimate plausible level of methanol use in transport sector. As noted, in the reference case, fuel use in transport sector varies between 22% and 31% of the final energy demand. The proportional energy use for car, bus, LGV, HGV and two wheeler fleets is about 83 - 90% of the transport sector fuel demand. Potentially, methanol can be used in these fleets. Thus, a foreseeable synthetic liquid fuel economy is envisaged as a maximum of 20% methanol in the final energy demand. This constraint, as before, is implemented on the reference scenario linearly from 2030 onwards. The modelling methodology is similar to the central hydrogen scenario, but methanol is imposed in the system instead of hydrogen. Nonetheless, there is no restriction in the model to choose hydrogen, if it is cost-effective to do so. In this scenario, four sensitivity analyses are performed with different shares of methanol in total final energy viz. 10%, 15%, and 30%. Then, additional sensitivity analyses are also carried out for high and low fuel costs. However, due to inadequate methanol technology data, no technology specific sensitivities are performed.

4.1.4 Electricity store

Under the electricity store vision, hydrogen plays a major role as a buffer for the electricity system. In the standard MARKAL energy system model, energy service demands are represented in six annual time slices viz. two diurnal (Day: 6.30am – 23.30pm & Night: 23.30pm – 6.30am) and three seasons (Winter, Summer & Intermediate). If any demand technologies chooses to use electricity, then the model algorithm calculates the electric demand capacity for each of the six time periods by aggregating the variable demand in each period. It means that total day- and night-time electricity demands (GWh) are averaged to calculate the capacity demand (GW)

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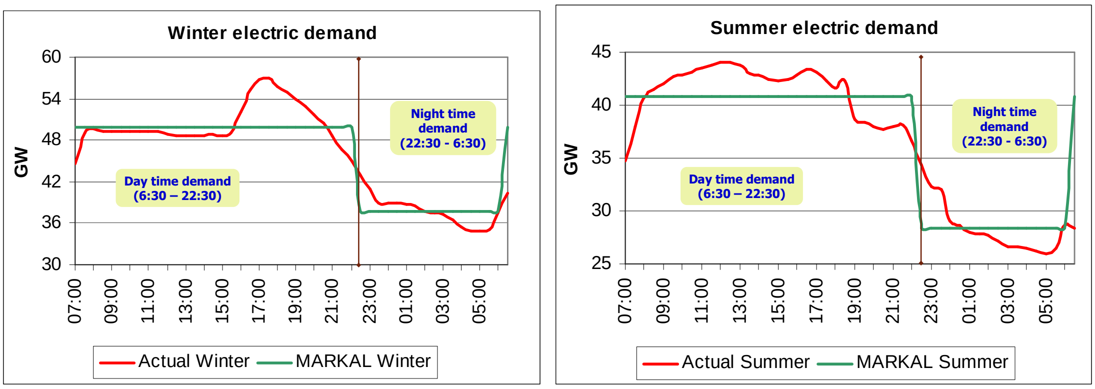
[4] For example the use of hydrogen in very rural or island regions

of day and night respectively in only two diurnal demands. However, UK electricity demand varies seasonally and diurnally, with the daily variation being quite significant (see Figure 4). Typically, peak demand occurs in evening and lasts for less than two hours depending on weekdays, weekends/bank holidays. The shoulder load occurs in the morning and lasts for five to six hours. Thus, the current simplified diurnal representation in MARKAL underestimates (and some times overestimates) the actual load demands.

Figure 4 shows the actual electric demand in a typical summer and winter day with their representation in the current standard MARKAL. It can be seen that MARKAL only approximates the demand profile, although it provides a closer fit for total electricity demand i.e. area under the two lines are similar. Thus the current model is not accurate enough to study the electricity storage vision.



Source: *National Grid, 2006*

Figure 4 Typical winter & summer electric demand in standard MARKAL

In order to take this vision further, updates are being made in the UK model structure to improve the approximation of load demand in standard MARKAL, through a flexible-time period (i.e. temporal MARKAL). This work is being developed as part of the DfT Horizons project (Strachan et al., 2007) The updated model will have five diurnal time periods and an extension to twelve monthly seasons. Figure 5 shows the revised representation of load profile in temporal MARKAL in a typical winter and summer day.

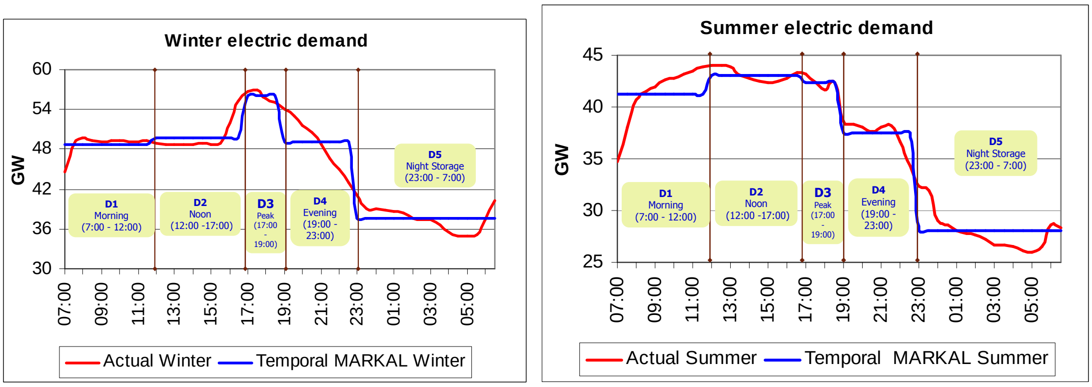


Figure 5 Typical winter & summer electric demand in temporal MARKAL

The five-step diurnal periods enhance the representation of peak and shoulder demands more efficiently and thereby enables detailed modelling of energy storage (including hydrogen). The main advantages of having greater detail on seasonal representations in temporal MARKAL is to model large intermittence renewable energy sources, and to hence fully investigate the potential use of hydrogen as an electricity storage medium. This would enable a truly optimal use of the electric power capacity, as well as the development of renewable resources, energy infrastructures (including remote grids), and hydrogen as a fully integrated process in the energy supply chain. However this work is ongoing and due to limitations of the temporal scale of the current MARKAL model, the electricity store scenario will be analyzed as part of the ongoing UK MARKAL modelling programme.

4.2 Uncertainty and Parametric Analysis

As a what-if analysis tool, MARKAL output results are strongly driven by input data assumptions. Hence, it offers a systematic framework to explore these uncertainties. That is why it is important to carry out extensive sensitivity analysis to explore thresholds and tipping points between alternate energy technology pathways. This becomes more important for the analysis of possible hydrogen pathways as there are major uncertainties around the funding and timing of fuel infrastructure provision, the requirement and opportunities of hydrogen storage, the total productive capacity from alternate feed-stocks at various cost levels, and the safety (and public perceptions of safety) of hydrogen supply and use, as well as development and diffusion of cost-competitive hydrogen end use technologies (Joffe et al 2007). Additionally, the relative cost of other fuels would also have an impact on the penetration of hydrogen in the UK economy.

However the strength of an integrated approach like MARKAL is its ability to look at equally plausible assumptions, and investigate trade-offs that might be due to data assumptions. Hence, a parametric sensitivity analysis on the cost of hydrogen technologies has been carried out. Appendix II shows the range of variation that hydrogen supply and distribution technologies might evolve around based on the literature review. When there is more uncertainty around a technology or more room for future development, then it is assumed that its cost might vary by 40%. If, however, the technology is more mature and there are no major innovations expected, then it is allowed to vary by 10%. The model is run for both + (the so-called *high technology cost*) and – (the so-called *low technology cost*) variation of these technologies at these rates.

Similarly, the cost of fossil fuels might have an effect on the development and penetration of hydrogen technologies. Hence, a sensitivity analysis on the costs of fuel is carried out. For the range of costs of fuels, possible high and low fuel costs published by DTI (2006) are used. Appendix III presents high and low range of fossil fuel prices.

Thus in the investigation of the main UKSHEC scenarios (detailed below in section 5), the results are compared with these equally plausible set of assumptions on technology and fuel costs. Section 5.5 then synthesizes the key findings and uncertainties from this initial modelling exercise in the characterisation of the long-term evolution of hydrogen as a major component of the UK energy system.

5 UK MARKAL model key results

This section details the model outputs defined in the previous section.

- **Base case**: UK MARKAL (with expanded treatment of hydrogen infrastructure) run under a business-as-usual case.

- **Reference case**: UK MARKAL (with expanded treatment of hydrogen infrastructure) run with an economy-wide CO_2 constraint applied at 30% below 2000 level in 2030 and declining linearly to 60% below 2000 levels in 2050.
- **Transport case**: Same as the reference case, with an additional constraint to deliver 20% of final energy from hydrogen by 2050 to be used in transport sector.
- **Ubiquitous case**: Same as the reference case, with an additional constraint to deliver 50% of final energy from hydrogen by 2050.
- **Synthetic liquid fuel case**: Same as the reference case, with an additional constraint to deliver 20% of final energy from methanol by 2050.

In presenting the results, the model outputs from the three UKSHEC hydrogen scenarios are discussed with respect to the base and/or reference case. As MARKAL generates a large number of outputs, model results focus on the following key set of parameters.

- Primary and final energy demand,
- Sectoral and end-use sectoral[5] CO_2 emissions,
- Hydrogen production and use,
- Fuel use in transport fleet,
- Electricity generation mix,
- Total system cost,
- Price[6] of CO_2.

The model outputs for these parameters are presented for each scenario in time series graphs from 2000 to 2050. The discussion of each scenario results is followed by a synthesis section where the results are compared and main results are highlighted. To compare the scenario results or to identify their sensitivity to technology and/or fuel cost assumptions, the model outputs for the year 2050 are used.

5.1 Base and Reference cases

As shown in Figure 6 and Figure 7, in the base case, coal use increases largely due to increased electricity generation. Natural gas' overall share holds steady at around 40% largely due to direct use in the residential, service and industrial sectors. Oil use shows a relative decline due to greater efficiency in the transport sector and latter movement to hydrogen in some modes. Nuclear energy drops out of the UK energy mix. In the reference case, primary energy demand is reduced by 20% compared to the base case where major decarbonisation occurring in power sector via carbon capture and storage (CCS). Coal is restricted to electricity generation using the UK's finite carbon storage potential. The natural gas retains its primary energy share around the same percentages due to relatively low emissions and high efficiency. Nuclear remains at low levels, even though it starts to grow after 2030, and constitutes 5% overall primary energy share by 2050. The share of renewable energy sources

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[5] In the end-use sectoral emission, emissions from power sector and hydrogen production are allocated to four end-use demand sectors based on their use.

[6] The average cost of CO_2 is calculated from the model outputs for each scenario, based on the differences in system cost and amount of emission reductions from the base case

and imported electricity also increase in this case. Lastly, there emerges demand for imported liquid hydrogen due to carbon implications of domestic hydrogen production options. Even though not presented in the graphs, conservation measures are also taken up at end use levels and reduce the demand for final energy thereby the primary energy demand.

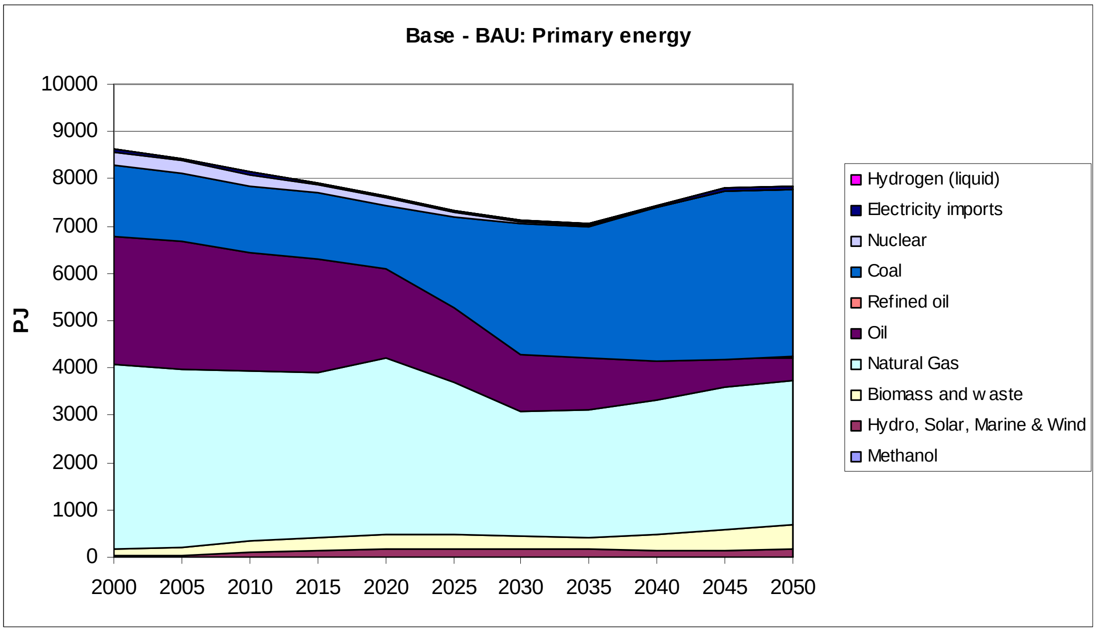

Figure 6 Primary energy use – base case

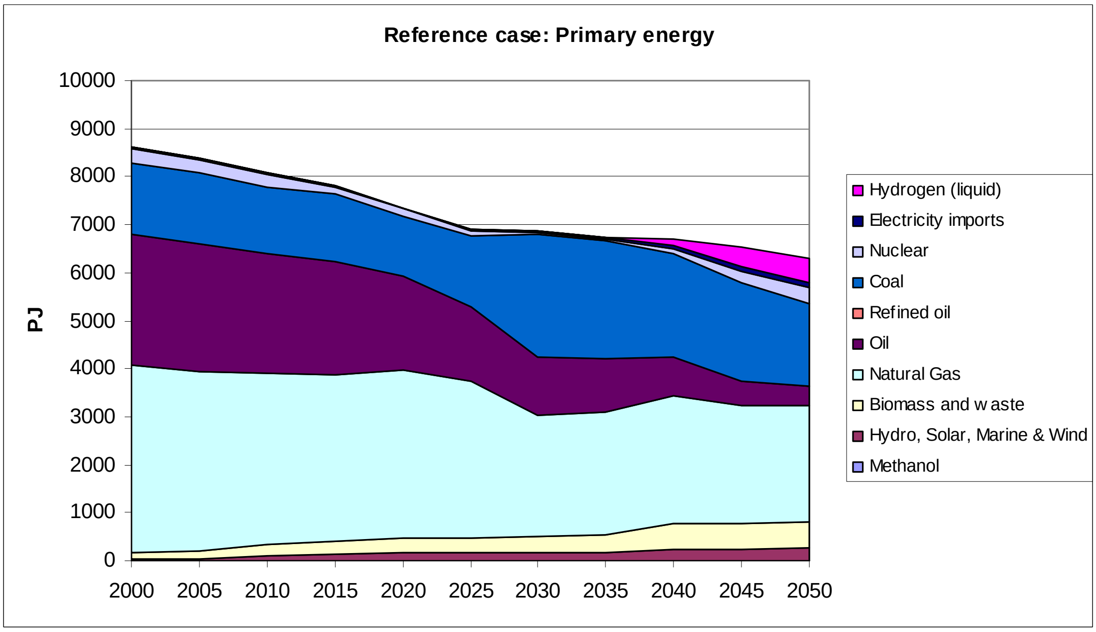

Figure 7 Primary energy use – reference case

Even though primary energy demand is significantly reduced in reference case, final energy demand levels are not reduced to the same level as presented in Figure 8 and Figure 9 (only a 3% reduction from the base case). This is because power generation is moving from coal to nuclear and more renewables due to the carbon cap. In the base case, major final energy sources are electricity, gas, petrol and diesel. About 2020, hydrogen starts to penetrate in transport sector and constitutes around 15% of the final energy demand by 2050 in both base and reference cases. The reason for hydrogen penetrating around the same levels in both runs is due to cost and efficiency assumptions of hydrogen end use technologies which are implicitly driven by research and development expenditures. The sectoral final energy demand levels stay steady, with only slight reductions in the transport, services and residential sectors in the reference case. The reductions in final energy demands of services and residential sectors are due to uptake of conservation measures at the end use levels. In transport sector, though, more efficient electricity driven rail engines are selected at the expense of diesel driven ones, hence reducing sectoral final energy demand. Demand for manufactured fuels, which are derived from coal and used in industrial sector, is also replaced by fuel oil in the reference case.

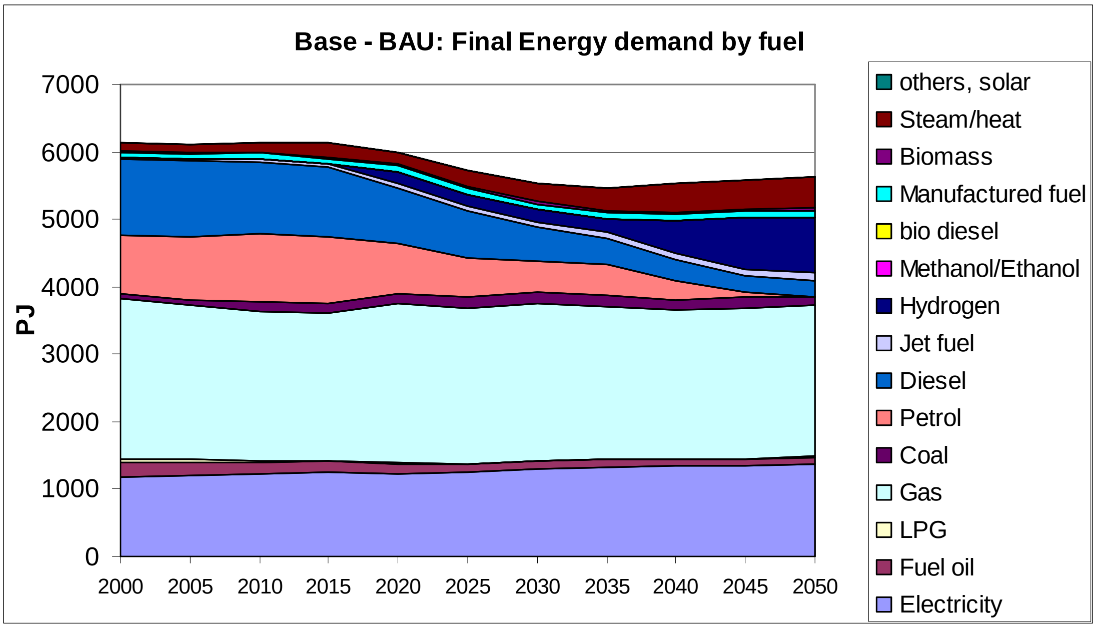

Figure 8 Final energy demand –base case

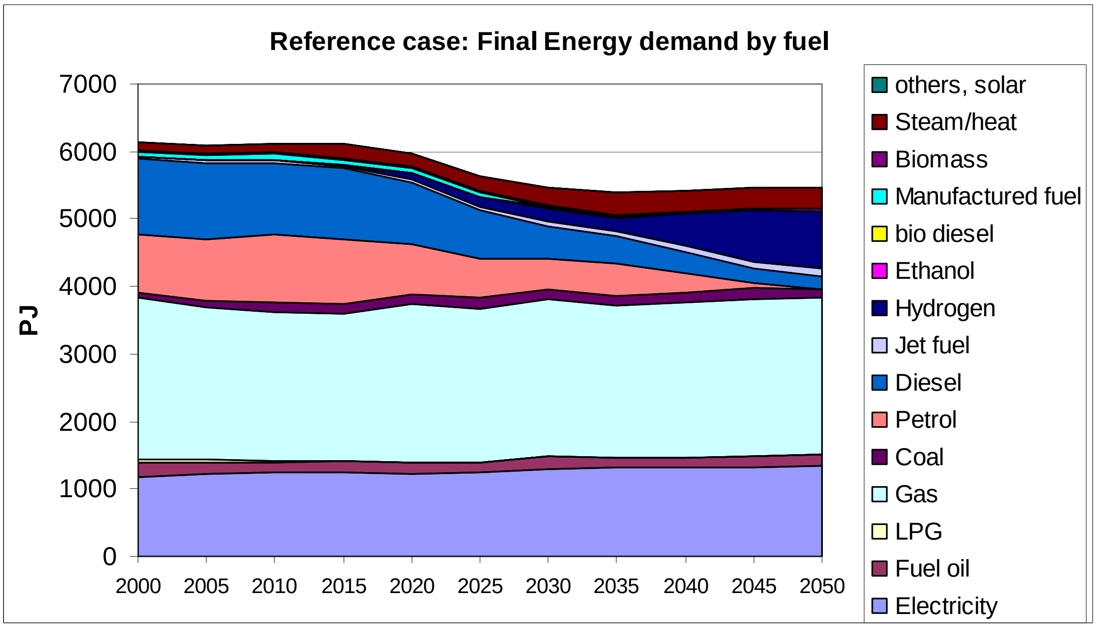

Figure 9 Final energy demand –reference case

In the base case and reference case, hydrogen is used solely in transport sector. Also, there is no change in the pattern of take-up of hydrogen vehicles between base and reference cases. Firstly, HGVs begin to use hydrogen from 2020 and then gradually it penetrates into buses, LGVs, and cars. By 2050, about 70% of transport final energy demand is met from hydrogen. Figure 10 shows the fuel use in major modes of transport fleet in the reference case. Due to technical and socio-economical reasons the model is constrained to retain 10% of car fleet as diesel, which is kept in all the scenarios for consistency.

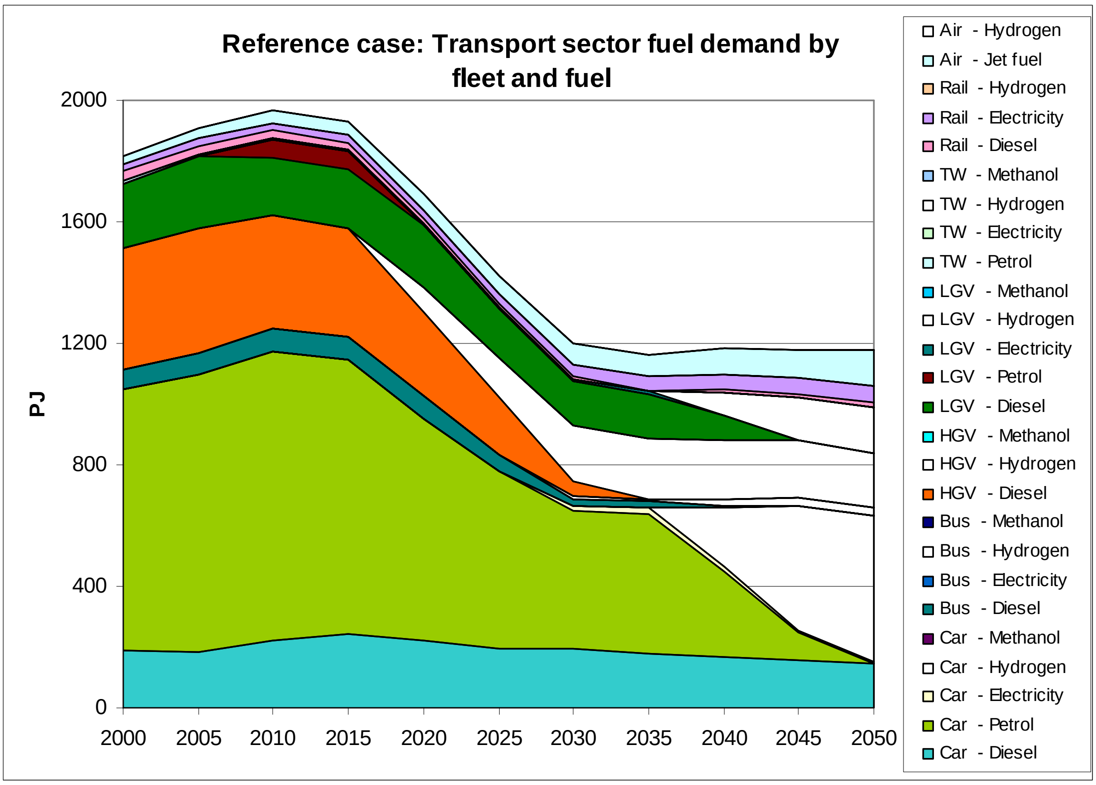

Figure 10 Fuel demand for selected transport fleets – reference case

On the supply side, there are differences in the source of hydrogen between base and reference cases. In the base case, hydrogen is initially produced from gas (steam methane reforming) and then predominantly from coal (membrane gasification). Once the carbon constraint is in place, from 2030, in reference case the hydrogen is produced by CCS-based coal/gas technologies rather than conventional coal/gas based technologies. However, when the limit for carbon storage is reached, then hydrogen is produced from electricity via electrolysis. This shift increases the demand for electricity and the electricity is produced from nuclear. As the carbon cap tightened, large amount of hydrogen is imported (about 50% by 2050) because imported hydrogen price declines due to higher learning rates for renewable technologies. Figure 11 shows the hydrogen production in base and reference cases.

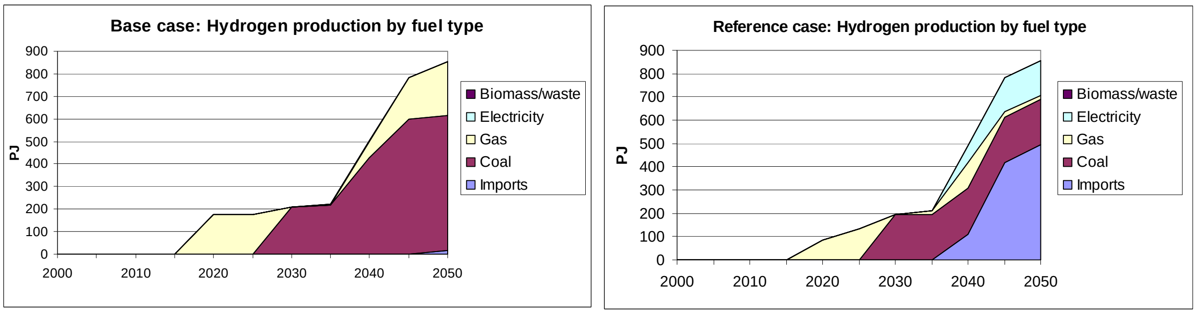

Figure 11 Sources of hydrogen production in base and reference cases

With reference to the base case, undiscounted energy system cost in 2050 is increased by 1.4% which is about £ 4.6 billion. Average cost of CO_2 is about £ 14 per tonne CO_2 and marginal cost is over 50 £/t-CO_2 the evolution of which are illustrated in Figure 12.

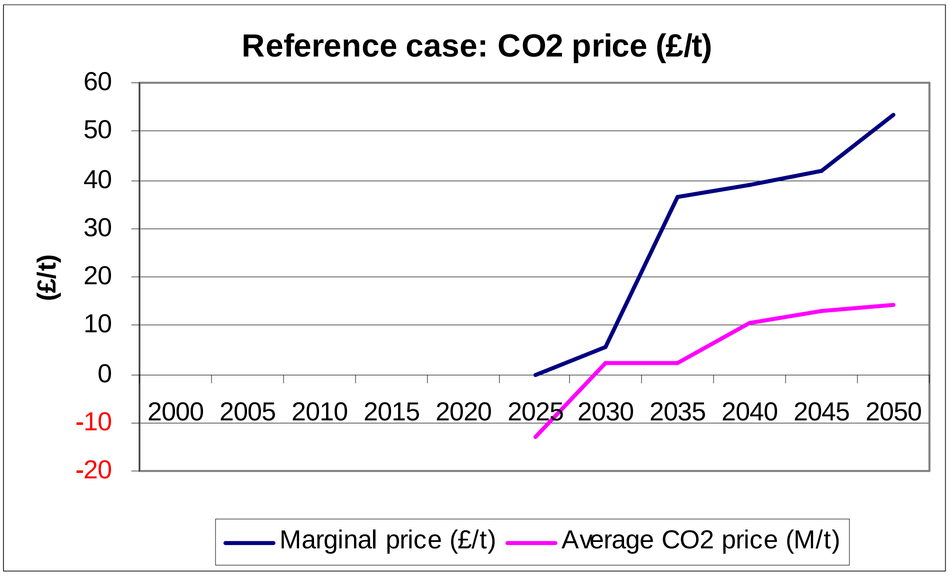

Figure 12 Marginal and average CO_2 prices - reference case

5.2 Central Hydrogen for Transport

As described in Section 4.1.1, in this scenario, 20% of the final energy demand is delivered from hydrogen and used in transport sector. In the reference case, hydrogen is already penetrated into transport sector up to 15% of final energy demand by 2050. Hence, this scenario is very similar to the reference case.

As presented in Figure 13, this additional 5% hydrogen production does alter the total primary energy demand with slight changes in its composition. Mainly, demand for natural gas increases (8% by 2050), while that for coal, oil and renewable/nuclear-based electricity go down by 4%, 5% and 17%, respectively compared to the reference case. The hydrogen production moves to gas based CCS from the coal based CCS in the reference case (see Figure 15). Additionally, imported hydrogen increases by 10%.

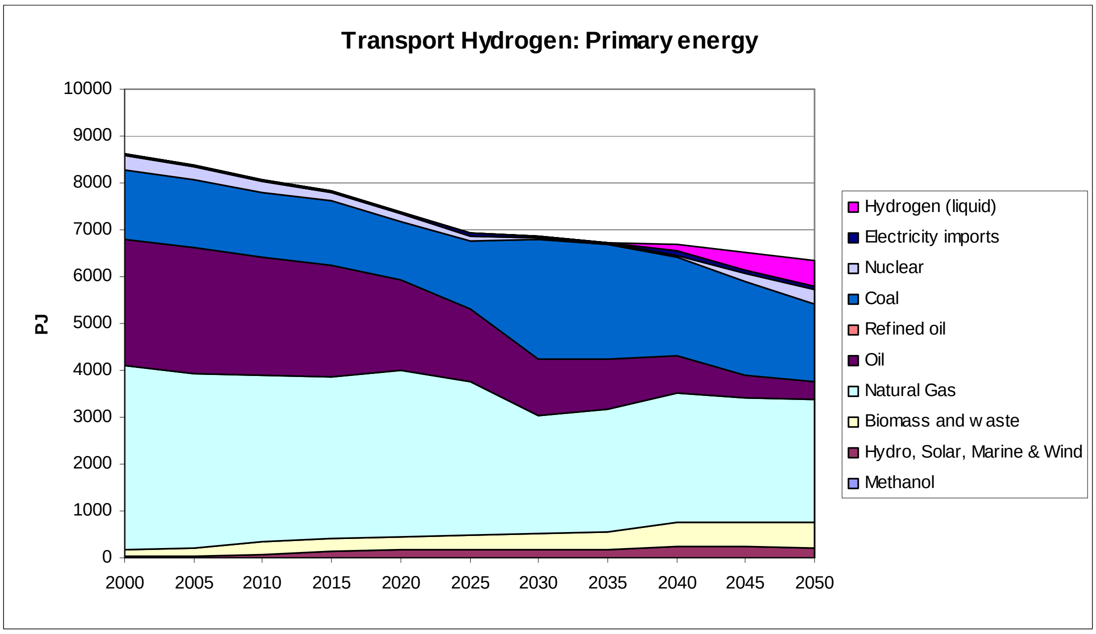

Figure 13 Primary energy use – transport hydrogen scenario

As can be seen in Figure 14, total final energy demand is very similar to the reference case. But the fuel mix is changed marginally. For example, diesel demand declines by 8% because transport sector switches further to hydrogen. Then demand for natural gas declines by 11%, even though more of it is used in hydrogen production. As a result, more district heating is used with that heat produced from cogeneration plants. At the sectoral level, final energy demand increases 1% by 2050 in transport sector, while a reverse trend is observed in the services and residential sectors. The increase in transport sector fuel results from the hydrogen constraint. As can be seen in the reference case, almost all HGV, LGV and car fleets switch to hydrogen. In addition to these, in this scenario rail transport also moves to hydrogen. Because of the 20% hydrogen constraint, the LGV fleet use 10% more hydrogen by not moving to advanced vehicle technologies. Otherwise the 20% hydrogen cannot be used within the transport sector more cost-effectively. Due to high cost of hydrogen-driven aircraft, hydrogen does not penetrate to air transport.

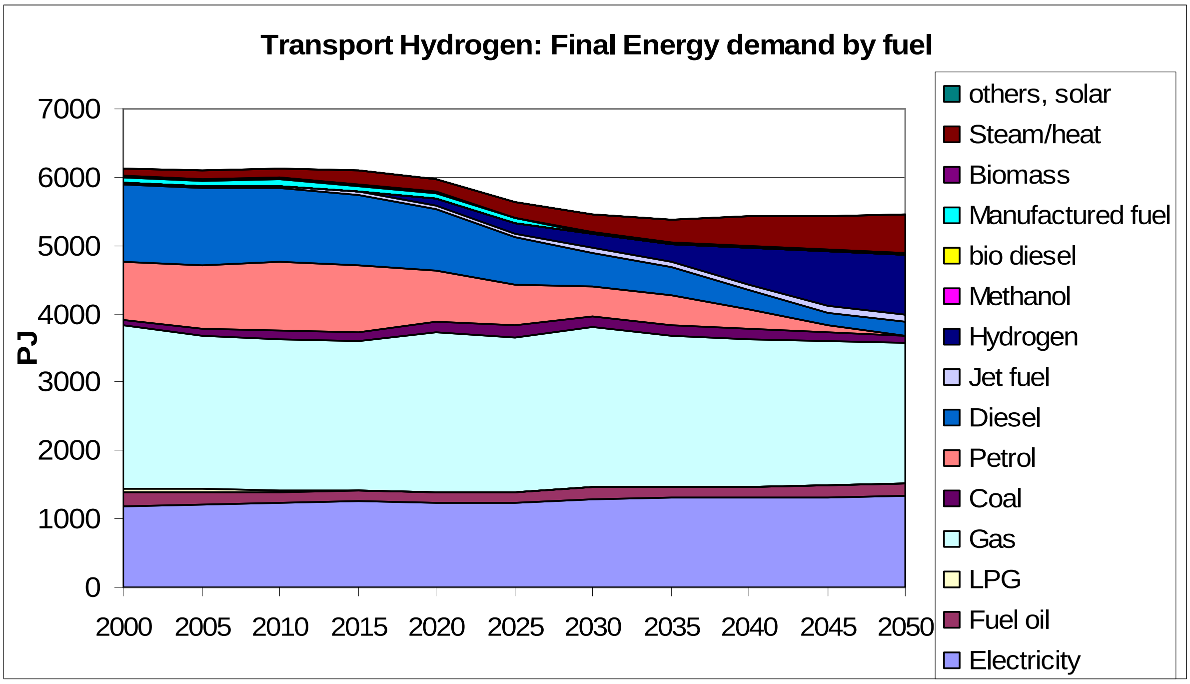

Figure 14 Final energy demand – transport hydrogen scenario

As mentioned earlier, in addition to imported hydrogen (55% production share), hydrogen is produced from coal, electricity and natural gas. Under the low technology cost assumption sensitivity, imported hydrogen is reduced to 47% and the rest is produced from biomass and wastes. However, in the high technology cost assumption, imported hydrogen is increased to 70% and the remaining 30% is produced from natural gas. As a result, demand for electricity declines and so does primary energy demand.

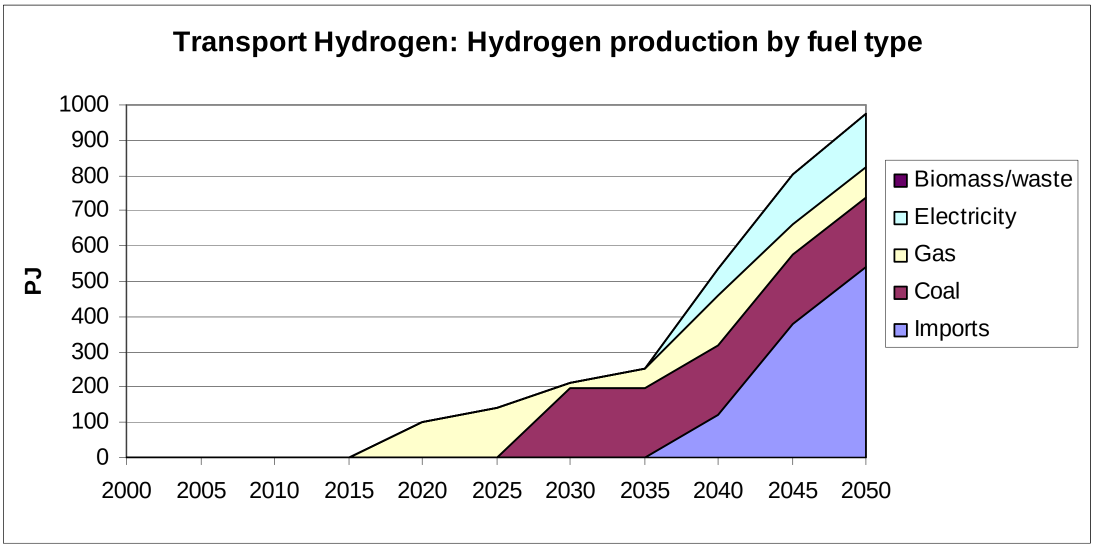

Figure 15 Source of hydrogen production - transport hydrogen scenario

Figure 16 shows the power generation mix in this scenario. Total electricity demand declines slightly (0.8%) as rail transport moves from electricity to hydrogen. In 2050, compared to the reference case, gas-based electricity generation is more than doubled. This is resulted from the use of district heating in service and residential sector thereby the gas used in these two sectors is available for power generation. However, the nuclear-based power generation, imported electricity and renewable electricity are reduced by between 4% and 30%. With high technology cost assumption, nuclear based electricity declines to one third of that in the reference case. This is because electricity is not used for hydrogen production.

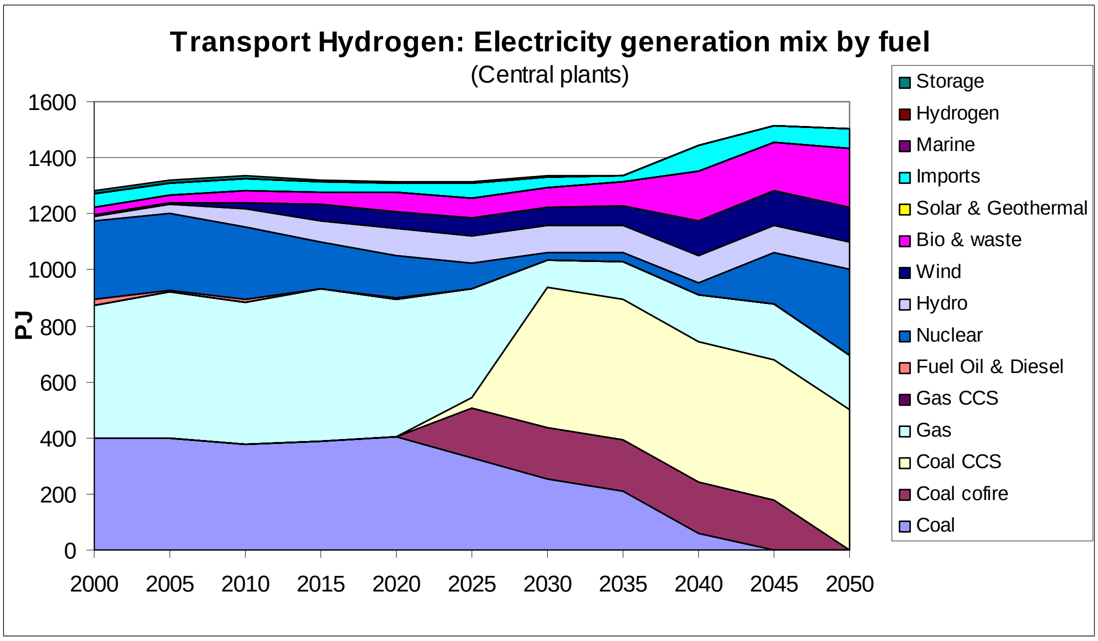

Figure 16 Electricity generation mix – transport hydrogen scenario

Figure 17 shows the end-use sectoral emissions. Compared to the reference case, service and residential sector emissions decline slightly because these two sectors switch from direct use of gas to district heating. However, the transport sector emissions increase marginally from the increased use of hydrogen, which is produced from natural gas.

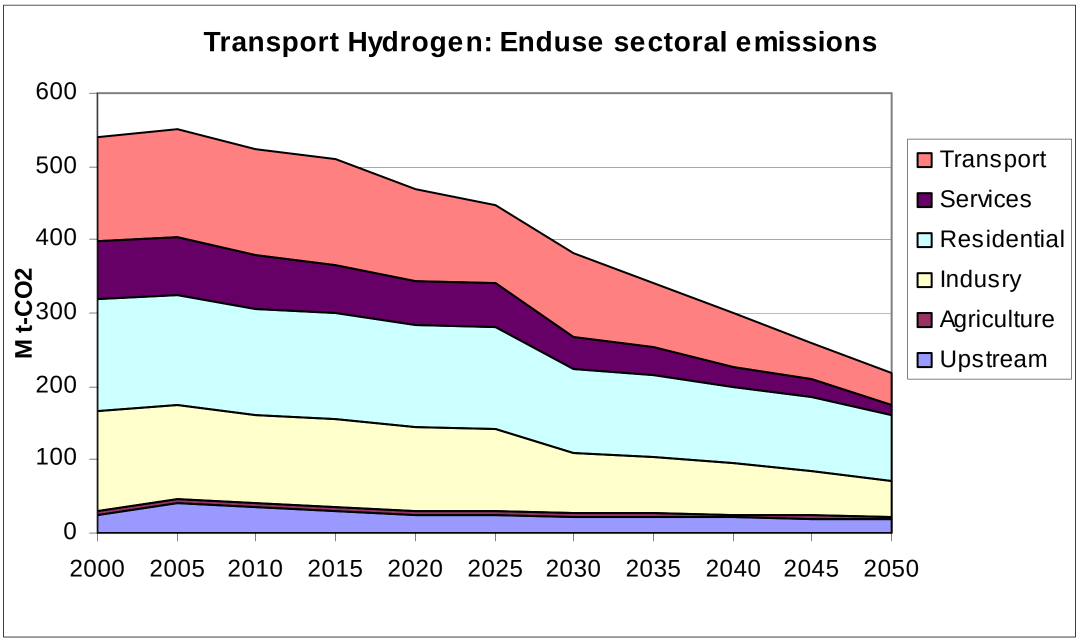

Figure 17 End-use sectoral CO_2 emissions - transport hydrogen scenario

The composition of fuel demand for transport fleet is very similar to the reference case. The only difference is observed in rail transport. In this scenario, use of diesel in rail transport is phased out and replaced by hydrogen as illustrated in Figure 18.

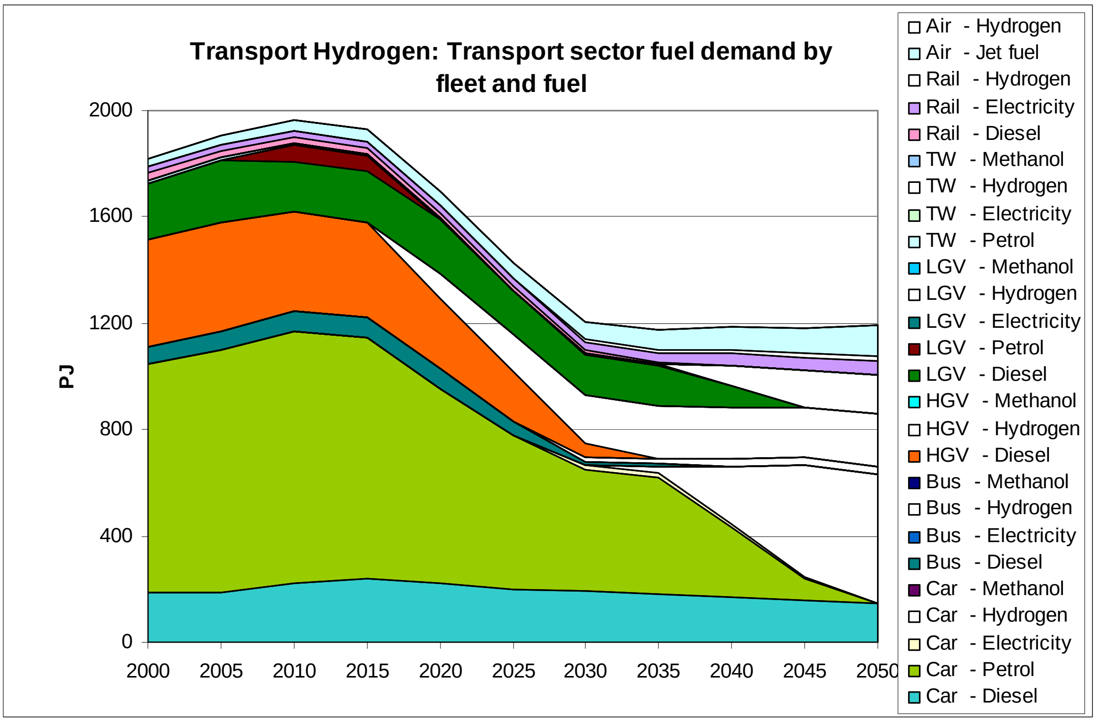

Figure 18 Transport sector fuel demand by fleet - transport hydrogen scenario

The undiscounted energy system cost is increased by 2% from the base case which is about £ 6.3 billion. Comparing this cost with the reference case, the incremental cost is about £ 1.7 billion and the total system cost is about £ 326 billions by 2050. The marginal cost of CO_2 increased to 61 £/t-CO_2 compared to the reference case marginal of 54 £/t-CO_2. Similarly the average cost of CO_2 is increased to 20 £/t-CO_2 compared to the reference case price of 14 £/t-CO_2. Figure 19 shows the evolution of marginal and average cost of CO_2.

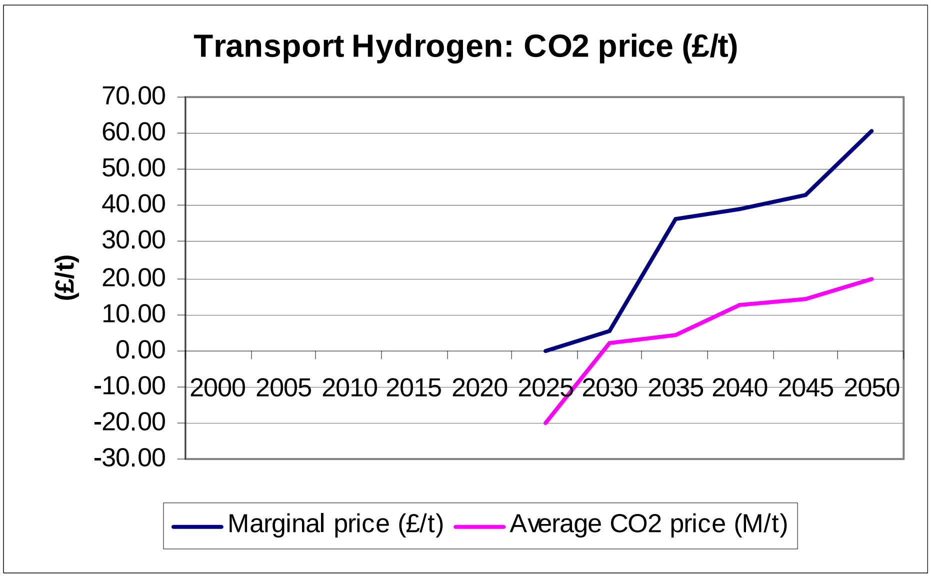

Figure 19 Price of CO_2 - transport hydrogen scenario

5.3 Ubiquitous hydrogen

This scenario assumes a dual role for hydrogen; as a transport fuel as well as an energy carrier for heat and power generation. Hence, the model is updated with a constraint to deliver 50% of final energy from hydrogen by 2050. On the supply side, this constraint translates into 2489PJ of hydrogen production. Due to losses in transmission and distribution (which is 1%), 2470PJ is used in transport and stationary applications. Of this, 39% is used in transport and the rest for heat and power generation. In transport sector, 966PJ of hydrogen meets 78% of transport energy demand.

Compared to the reference case, under this scenario UK primary energy demand increases by 14% in 2050. While demand for oil and coal go down, demand for natural gas, nuclear and imported hydrogen increases. The increase in primary energy use is associated with hydrogen related thermodynamic losses which is explained in the subsequent discussions.

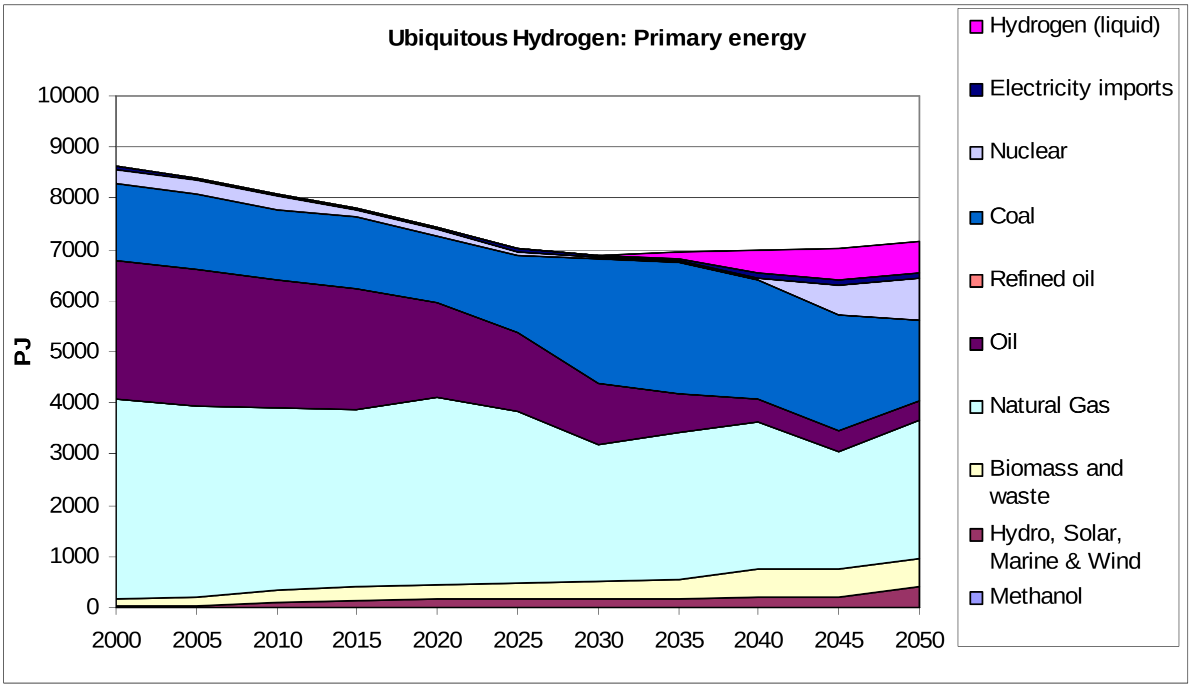

Figure 20 Primary energy use - ubiquitous hydrogen scenario

Overall final energy demand decreases by 5%. Service and residential sectors energy demands go down by 8% and 14% respectively compared to the reference case. The reduction in residential sector is mainly due to uptake of conservation measures at end use devices (179PJ versus 424PJ at sectoral level). Compared to the reference case, further energy saving potentials, which have higher investment costs, are realized in space heating (170PJ versus 415PJ), hence reducing residential sector final energy demand. The uptake of conservation options in service sector is also higher than in the reference sector (117PJ versus 162PJ in total), due to improvement potentials in lighting. However, these efficiency improvements are limited in service sector, and instead hydrogen-driven micro generation technologies are taken up. Even though in the reference case, service sector uses 135PJ of heat, in this scenario it is almost tripled, 356PJ by 2050. Heat generated from hydrogen-driven micro generation technologies also contributes to lower residential sector final energy demands, but this is quite limited (6.6PJ of heat demand in reference case versus to 9.1PJ in ubiquitous scenario by 2050). The use of more heat produced from these hydrogen-driven technologies result in lower demand for gas and electricity in service sector, as well as in total. Overall, total gas and electricity demand in the final energy is declined by 19% and 8% respectively by 2050, compared to the reference case. As Figure 21 reveals, demand for diesel and jet fuel are also reduced due to penetration of hydrogen in rail and air transport.

As expected in this scenario, 50% of hydrogen is not seen in the final energy demand graph (Figure 21) because hydrogen used in micro/on-site generation technologies are presented as electricity and/or heat rather than hydrogen. In the model, final energy is defined as energy used in the final demand technologies. However, micro-generating technologies are not defined as demand technologies because they produce electricity and heat and which is further used in end-use demand technologies. For example, heat produced from micro-generation is used in radiators for space heating. Thus, heat is presented as heat though it is produced from hydrogen. Similarly, hydrogen-based electricity accounted for 44% of the total final electricity presented in the final energy (As Figure 24 presents, 552PJ of electricity is produced by hydrogen-based micro-generation applications by 2050, by when total final electricity demand is 1241PJ). Thus, 44% of the electricity in Figure 21 should be interpreted as hydrogen.

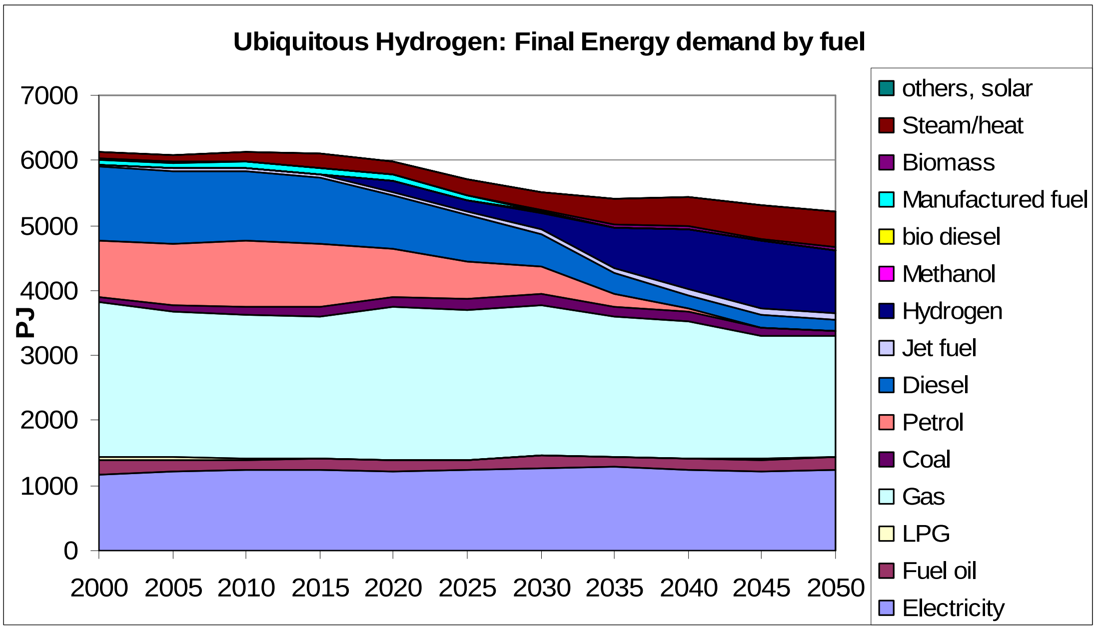

Figure 21 Final energy use - ubiquitous hydrogen scenario

An increased level of primary energy demand in this scenario is due to use of electricity in hydrogen production as presented in Figure 22 and Figure 23. Compared to the reference case, hydrogen production is tripled by 2050 (from 855 PJ to 2489 PJ) under this scenario, 60% of which is produced by electrolysis. While 25% of hydrogen is imported, another significant amount is produced from natural gas, which has very limited application in the reference case.

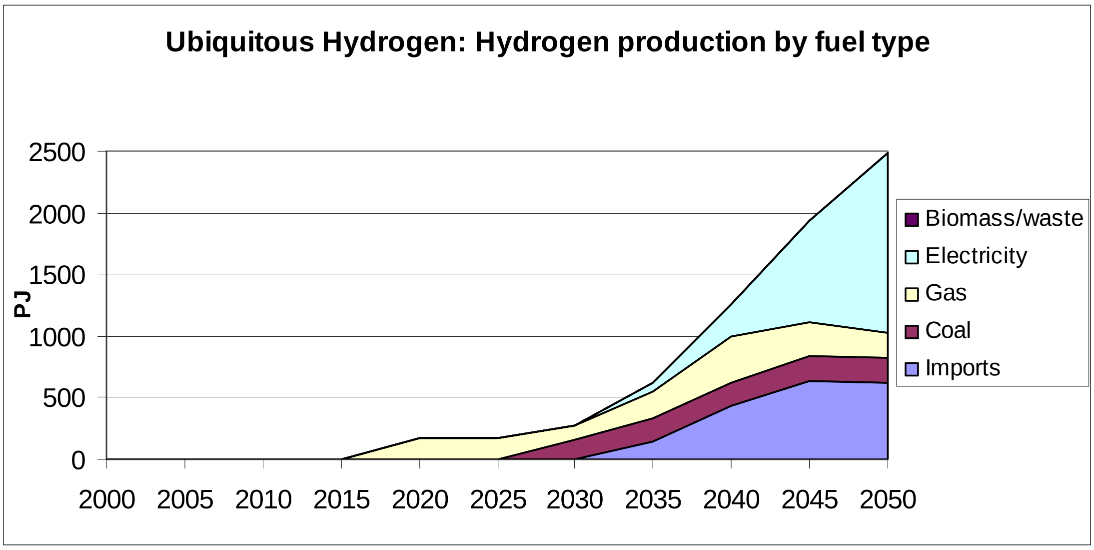

Figure 22 Source of hydrogen production – ubiquitous hydrogen scenario

Figure 23 confirms the burden this high level of hydrogen production places on power generation sector. Under this scenario, electricity generation from central plants increases by 34% by 2050 compared to the reference case in order to allow the energy system to produce hydrogen. This higher electricity generation is made possible mainly by nuclear power.

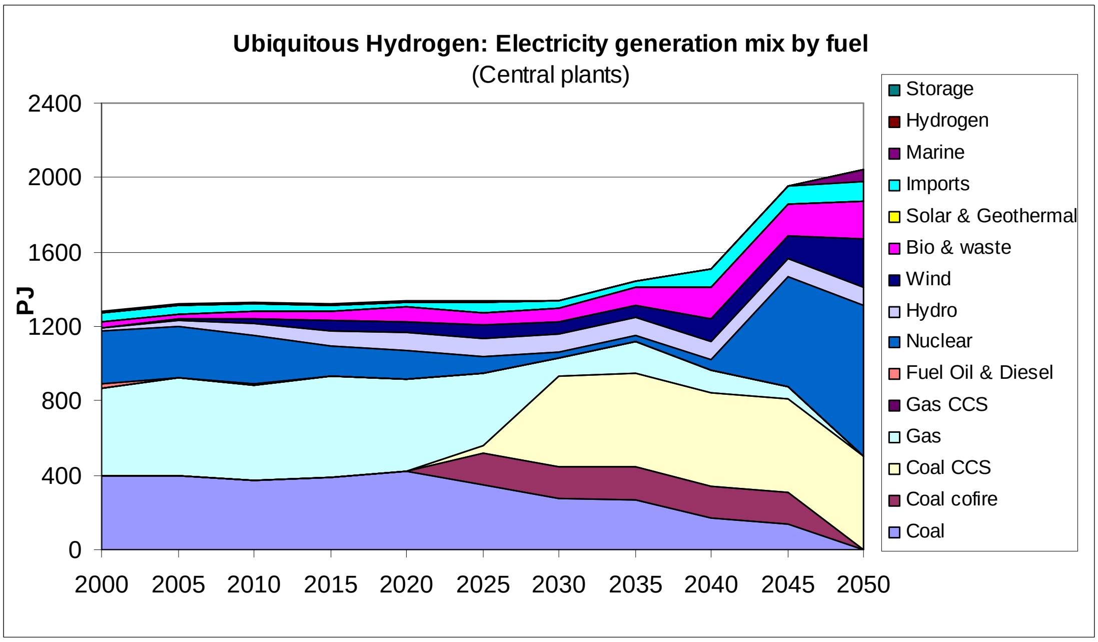

Figure 23 Electricity generation mix - ubiquitous hydrogen scenario

In addition to these central plants, a substantial amount of micro-generation and CHP applications take place as well. Even though in the reference case these applications do not take place, as Figure 24 illustrates, starting from 2040 hydrogen becomes a major energy carrier for heat and power generation. By 2050, 570 PJ of electricity is produced on-site, which rises total electricity generation to 2600 PJ, 70% more than the reference case.

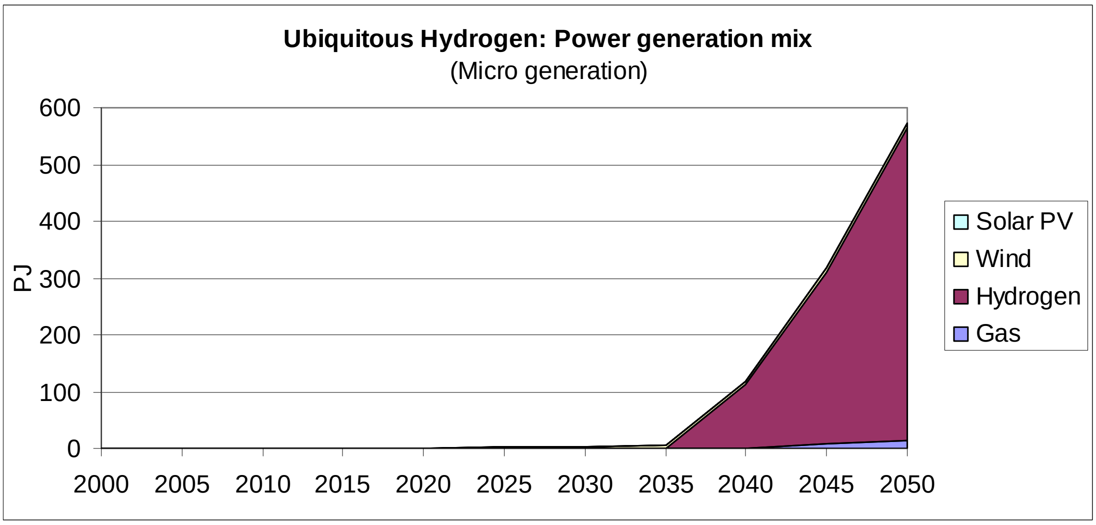

Figure 24 Micro generation mix - ubiquitous hydrogen scenario

Hydrogen firstly penetrates into the energy system as a transport fuel from 2020 onwards. By 2040, it becomes an energy carrier for heat and power generation in services sector as Figure 25 demonstrates. Later, it finds applications in heat and power generation in industrial sector.

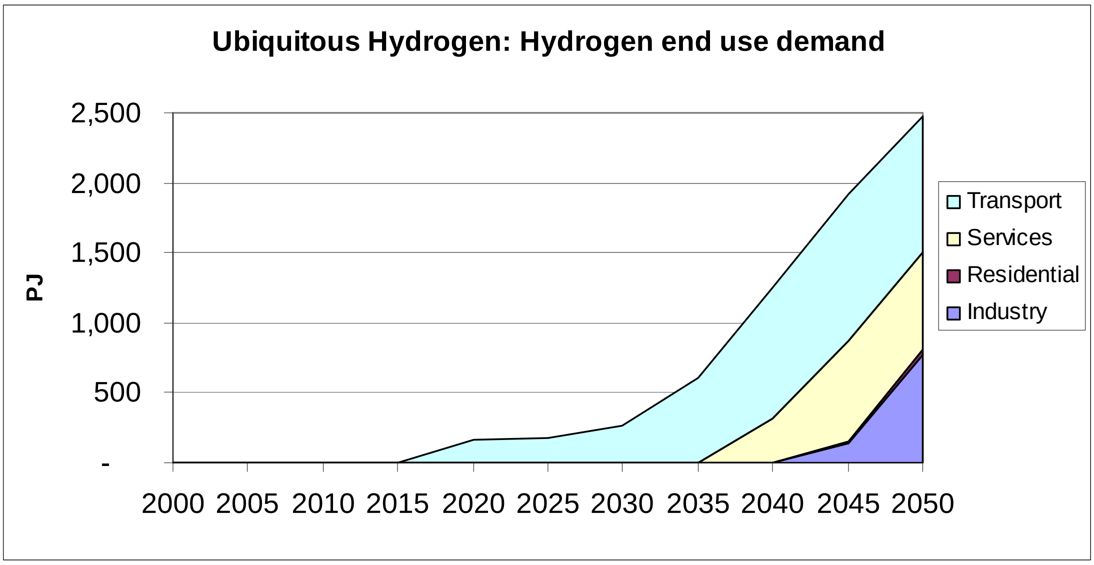

Figure 25 Sectoral use of hydrogen - ubiquitous hydrogen scenario

This initial result and sensitivity indicate that an extremely large scale deployment of hydrogen appears to be thermodynamically inefficient. This is because hydrogen is initially produced from electricity via electrolysis and then electricity (with some heat) is reproduced from the hydrogen via micro-generation. In other words, this represents thermodynamic losses in electricity-hydrogen-electricity processes. This resulted in higher primary energy demand. However, it is difficult to conclude that production and use of hydrogen is always thermodynamically inefficient. It might be partly because of the modelling limitation as the current model is not detailed enough to use hydrogen as a medium of storage. If the intermittence renewable is used for hydrogen production then hydrogen could be a potential source of buffer storage.

The use of hydrogen in transport sector is similar to the reference case, yet still with some differences. In sectoral final energy demand, the transport sector uses 5% more energy than in the reference case. This is because hydrogen demand for rail transport is higher than electricity use in rail sector, which is partially due to less mature technologies in hydrogen based rail engines. A similar trend is also seen in air crafts between jet fuel and hydrogen. Overall, 78% of transport hydrogen energy demand is met from hydrogen, compared to 71% in the reference case.

At a more detailed level, as in the reference case, hydrogen penetrates firstly to IC engine-based HGV fleet by 2020, then to fuel cell based vehicles, as shown in Figure 26. However, in this scenario, hydrogen penetrates into cars and LGV fleet earlier (2030 and 2035, compared to 2040 in the reference case) and at a wider scale. By 2025, hydrogen-based fuel cells find applications in rail transport as well. By 2050, hydrogen penetrates further to air transport. In the reference case the early entry of hydrogen-based IC engines in HGV fleet is phased out by fuel cells which are more efficient with higher capital costs. In this scenario, though, these higher capital costs prevent penetration of hydrogen-based fuel cells into all HGV fleet. Hence, HGV fleet runs on both IC engines and fuel cells. Consequently, overall road transport uses more hydrogen than the reference case due to trade-offs between capital costs, fuel efficiency and costs. By spending less on road transport, there is room for use of hydrogen by rail engine and air crafts which are very expensive technologies. Additionally, hydrogen gets a wide range of use in service and industrial sectors for stationary power generation. The costs of hydrogen production at small scale, which avoids the investments to a distribution network, might be another factor contributing to wide range use of hydrogen in power generation[7].

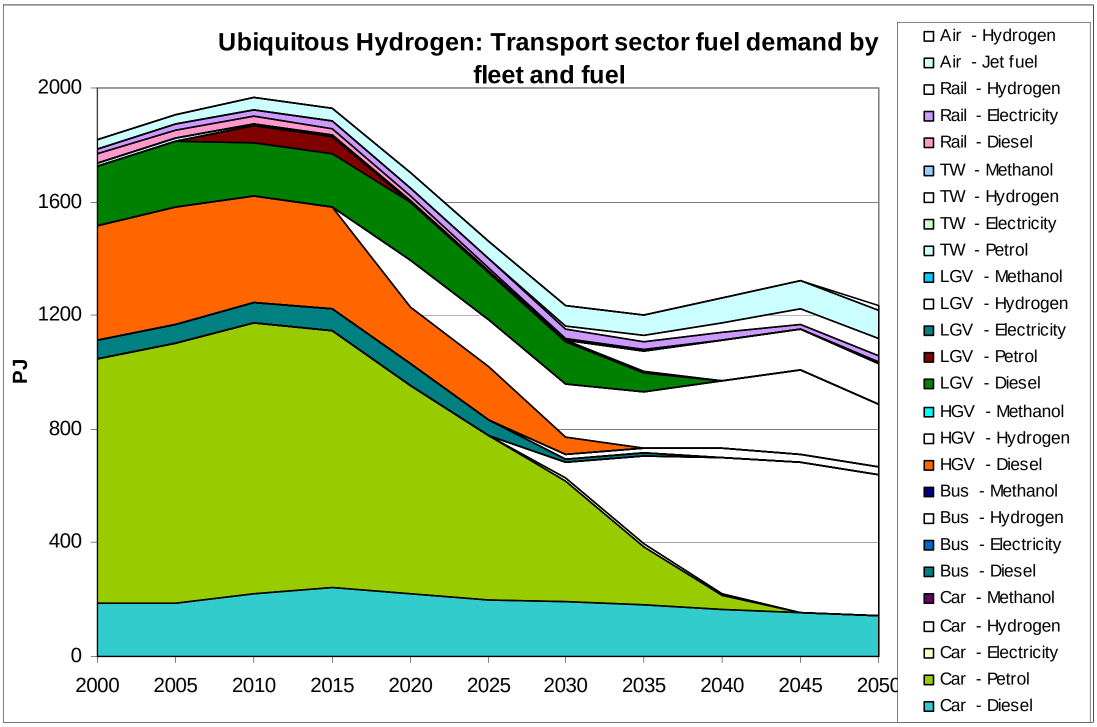

Figure 26 Transport sector fuel demand by fleet - ubiquitous hydrogen scenario

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[7] As the current structure of the model does not allow for explicit accounting of hydrogen generated from small scale or large scale production facilities and where it is used, it is not possible to draw conclusions on this.

However, sensitivity runs with high and low technology costs reiterate this finding. Hence, when the costs of hydrogen increases, hydrogen would be employed in the more efficient applications with advanced technologies like air crafts rather than in low grade applications like generation of power and heat in industrial or service sectors. The levels of technology costs also alter the uptake of hydrogen technologies in road transport. Under low technology cost assumptions, fuel cell cars are widely taken up despite their higher capital cost, whereas high technology costs force the model to select IC engines as in the central hydrogen for transport scenario.

Under this scenario, the undiscounted energy system cost is increased by 11% in 2050 from the base case, which is about £ 35.3 billion. The incremental cost with respect to the reference case is about 9% or £30 billion. Under a high technology cost assumption, this incremental cost doubled, 18% or £ 52 billion. Figure 27 shows how the marginal cost of CO_2 price evolves over the modelling horizon.

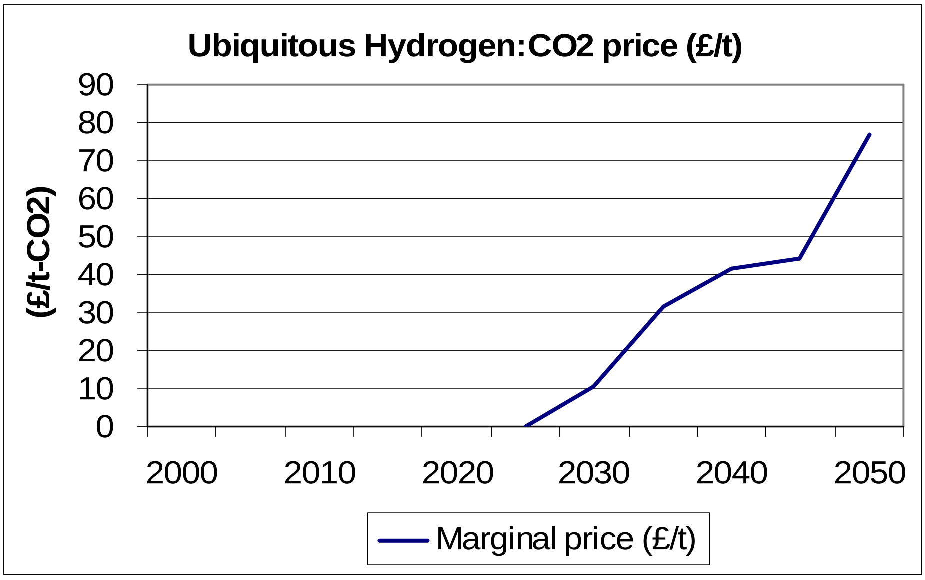

Figure 27 Price of CO_2 - ubiquitous hydrogen scenario

5.4 Synthetic liquid fuel

In addition to the update of hydrogen infrastructures depiction, new methanol-based supply and demand technologies are now included. After these additions, the model outputs from the base and reference cases do slightly change. In the base case, for an intermediate period methanol-based vehicles are taken up, e.g. IC engines based car (2020-2040) & LGV (2020-2050). However, take-up of hydrogen vehicles is reduced. In other words, a proportion of some transport modes switch from hydrogen to methanol. Methanol is predominately produced from natural gas based steam methane reforming and from hydrogen. Hydrogen is produced from coal.

As discussed earlier, a parametric study is carried out in order to identify plausible levels of methanol penetration in the overall economy. Based on this, a foreseeable synthetic liquid fuel economy is envisaged as one where a maximum of 20% of the final energy demand is delivered from methanol[8].

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[8] This also ensures comparability to the 20% hydrogen lower constraint imposed in the transport scenario.

In this scenario, firstly LGV vehicles switch to methanol, then cars and HGVs as shown in Figure 28. However, buses and two-wheelers do not switch to methanol, a trend that is observed in the sensitivity runs as well. In this scenario, compared to the reference case, transport fleet heavily runs on methanol. About 77% of overall transport fuel is methanol.

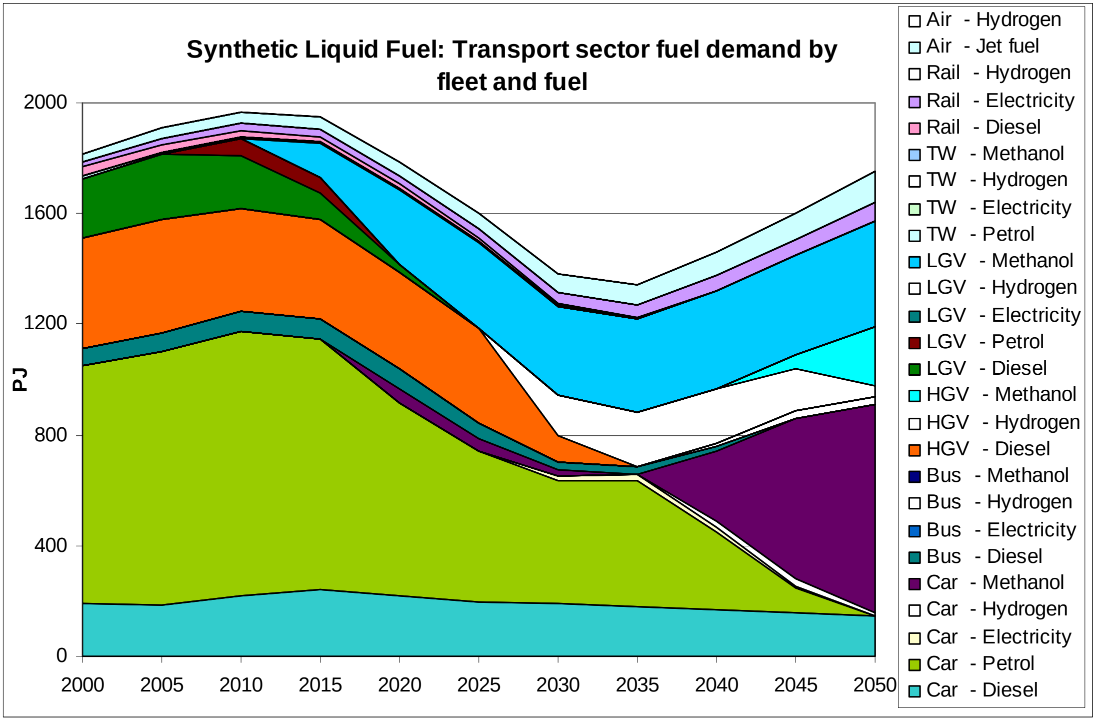

Figure 28 Penetration of methanol in transport fleet

As shown in Figure 29, methanol is produced from gas (42%), hydrogen (20%) and imported (33%). On the other hand, hydrogen is produced from coal (with CCS) and electricity (Figure 30).

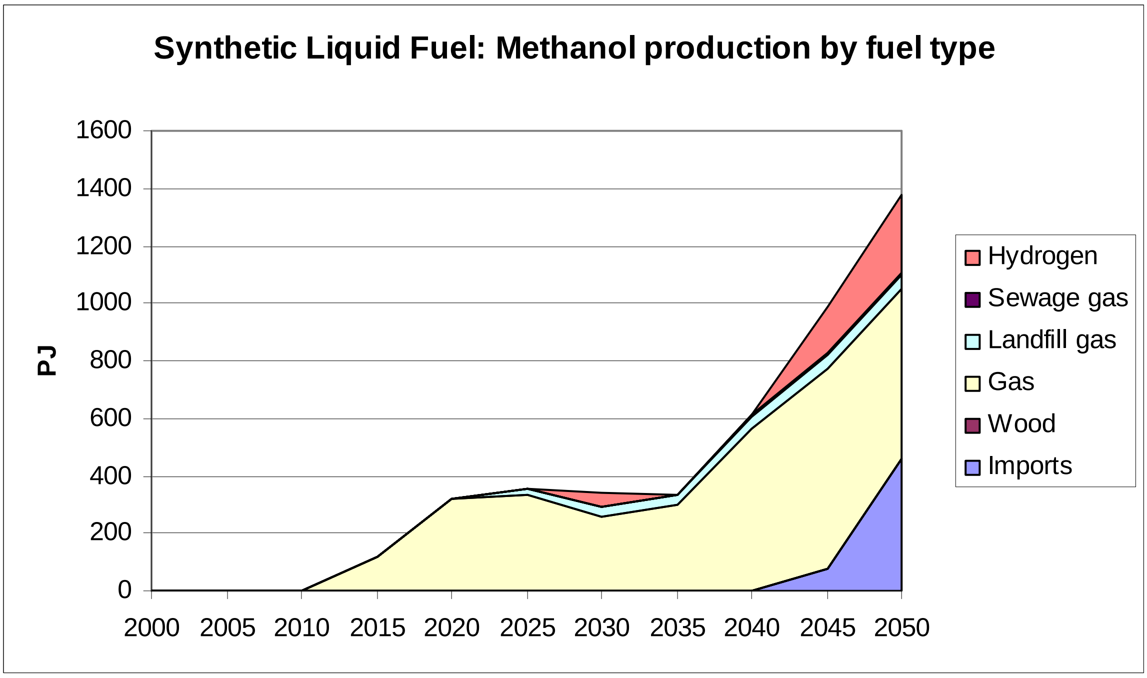

Figure 29 Methanol production sources - synthetic liquid fuel scenario

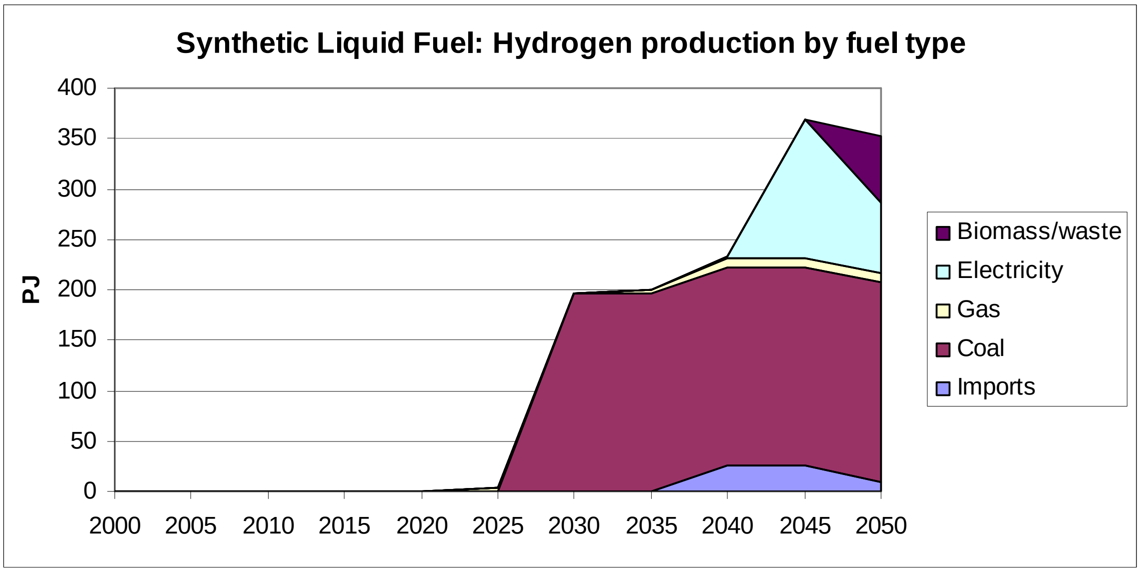

Figure 30 Hydrogen production - synthetic liquid fuel scenario

Hydrogen production in this scenario is about 15% of that in the ubiquitous hydrogen scenario. However, nuclear-based power generation is on par with the ubiquitous hydrogen scenario due to switching of residential and service sectors from natural gas to electricity. As Figure 30 presents, in this scenario hydrogen is produced from more diversified resources. Due to storage limits, the same amount as in the previous scenarios is produced from coal CCS. But, use of electricity in residential and service sectors make hydrogen production from renewable resources viable for the first time.

As presented in Figure 31, electricity production from the central plants is highest in this scenario (2109PJ compared to 2041PJ in ubiquitous hydrogen scenario). In the residential sector, electric boilers are used for space and water heating (525PJ compared to 75PJ in reference case), even though more energy saving options than the reference case are taken up at end use device levels (329PJ compared to 179PJ). In the service sector, more electricity is used in district heating.

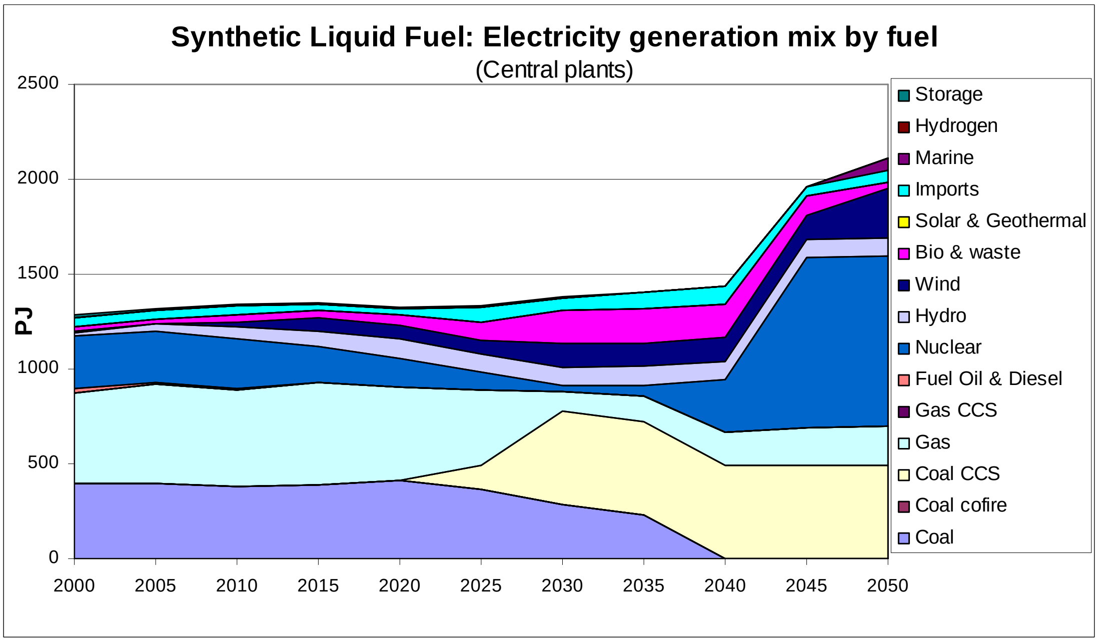

Figure 31 Electricity generation mix - synthetic liquid fuel scenario

Figure 32 presents emissions by sectors under this scenario as well as by end use sectors. When electricity and hydrogen emissions are accounted separately, emissions from the transport sector are substantially reduced. However, when these indirect emissions are included in the relevant end use sectors, then it becomes obvious that transport sector is hardly decarbonised. Instead, industrial, service and residential sectors are decarbonised though switching to electricity which is produced from nuclear.

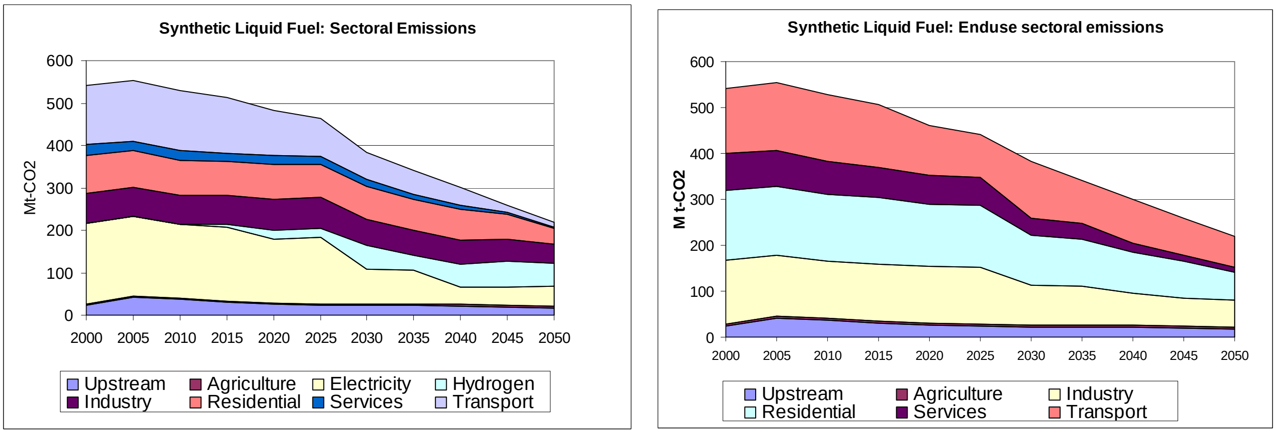

Figure 32 Emissions by sectors and end use sectors - synthetic liquid fuel scenario

The total system cost is about 7.4% higher than in the base case in 2050, (in absolute terms by £ 23.8 billion), i.e. substantially higher than the central transport hydrogen case (with 20% hydrogen). Compared to the reference case, the incremental cost is over £ 19 billion. The marginal cost of CO_2 is about 149 £/t-CO_2 and the average price is about 74 £/t-CO_2. The marginal cost is far higher than the one in the central and ubiquitous hydrogen scenarios driven by the use of methanol in less well suited transport modes.

5.5 Synthesis of scenario results

This section provides a synthesis of the above mentioned scenario results.

In a foreseeable hydrogen economy, imported zero-carbon hydrogen becomes one of the energy sources in the overall primary energy mix. From the base case to the (CO_2 constrained) reference and hydrogen scenarios, the primary energy demand declines because of the carbon constraint. This is mainly driven by phasing out of energy intensive coal-based power generation. However, compared to the reference, in all three hydrogen scenarios the primary energy demand increases due to thermodynamic losses in electricity-hydrogen-electricity conversions. Also the energy system is moving more towards gas due to its low carbon. Figure 33 shows the range of variation in key sources of primary fuel with respect to the reference case. The length of the red lines in each fuel bar indicates the variation among the three scenarios. The major variation occurs in natural gas, nuclear and imported hydrogen. This is driven by hydrogen production. The hydrogen is either imported or produced from nuclear-based electricity. Due to the carbon constraint, the demand for coal is always below the reference case. Similarly, the oil demand is also lower because the heavily oil dependent transport sector migrates to hydrogen fuel.

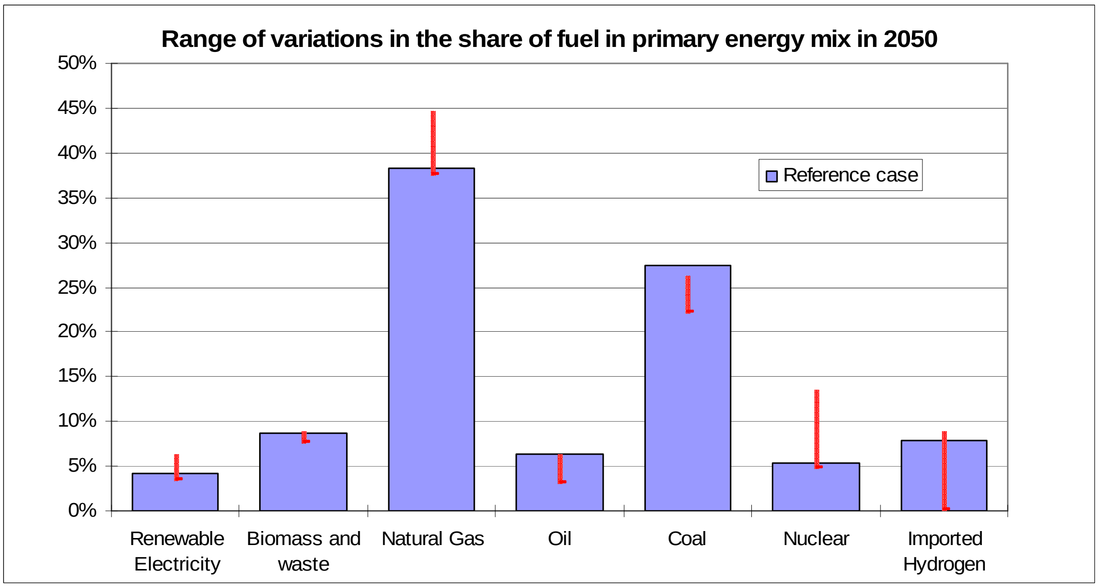

Figure 33 Changes in primary energy demand across the scenarios in 2050

Figure 34 shows the share of major fuels in the final energy demand. In all three scenarios, the share of gas demand declines from 43% of the final energy, down to 26% in the methanol case. This is because gas is used for methanol production. As a result, more heat is produced from cogeneration plants as well as a switch to electricity based space heating.

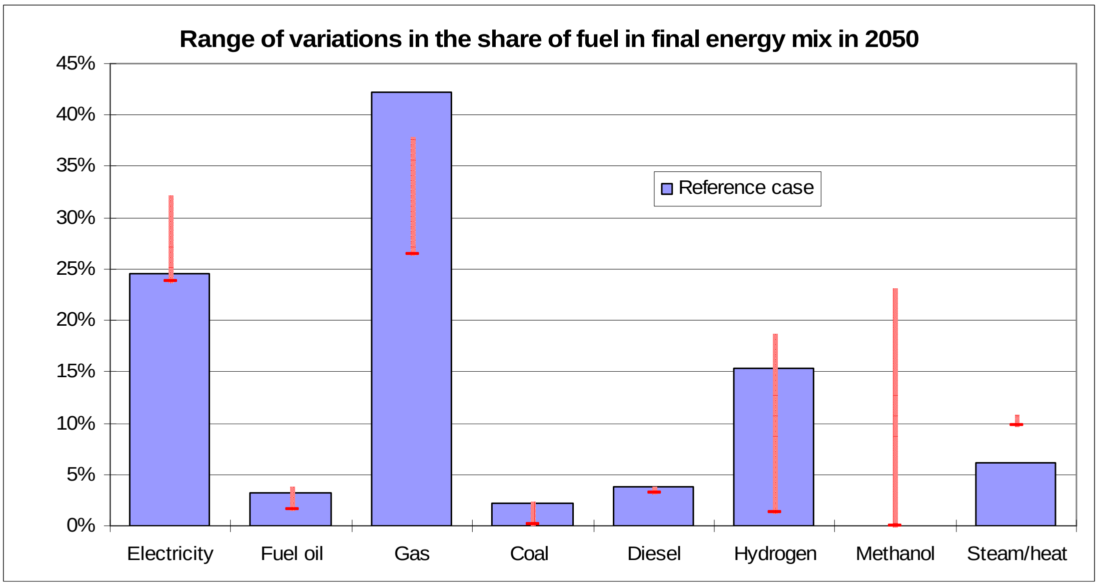

Figure 34 Changes in final energy demand across the scenarios in 2050

In the power generation mix, coal-based CCS, nuclear and biomass are the major sources of electricity generation. Electricity generation is generally increased because of hydrogen production from electrolysis. Figure 35 and Figure 36 show the range of variations in share of electricity sources. In the methanol case, the share of nuclear based electricity generation is increased to 42%.

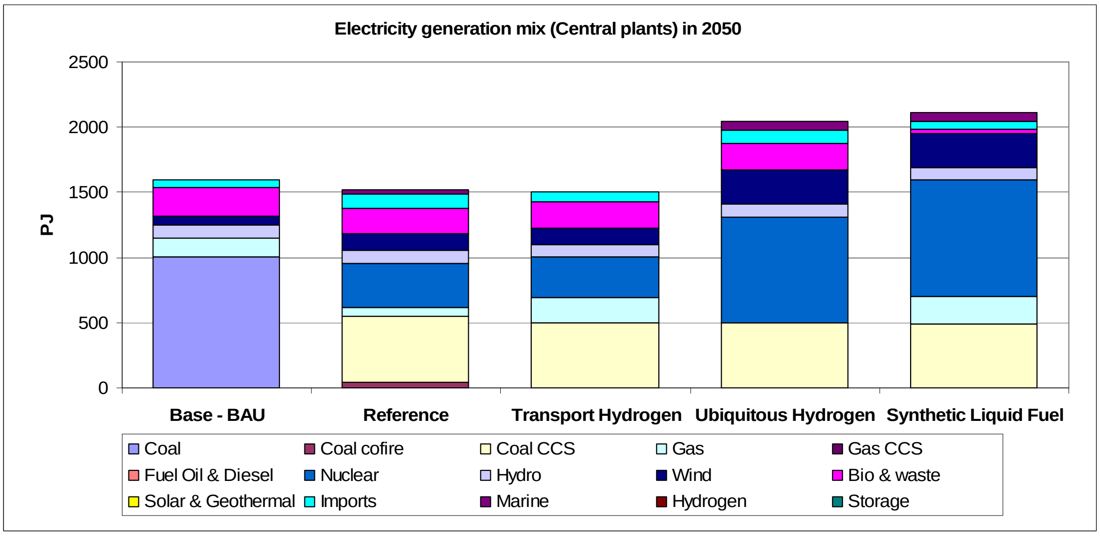

Figure 35 Electricity generation mix across the scenarios in 2050

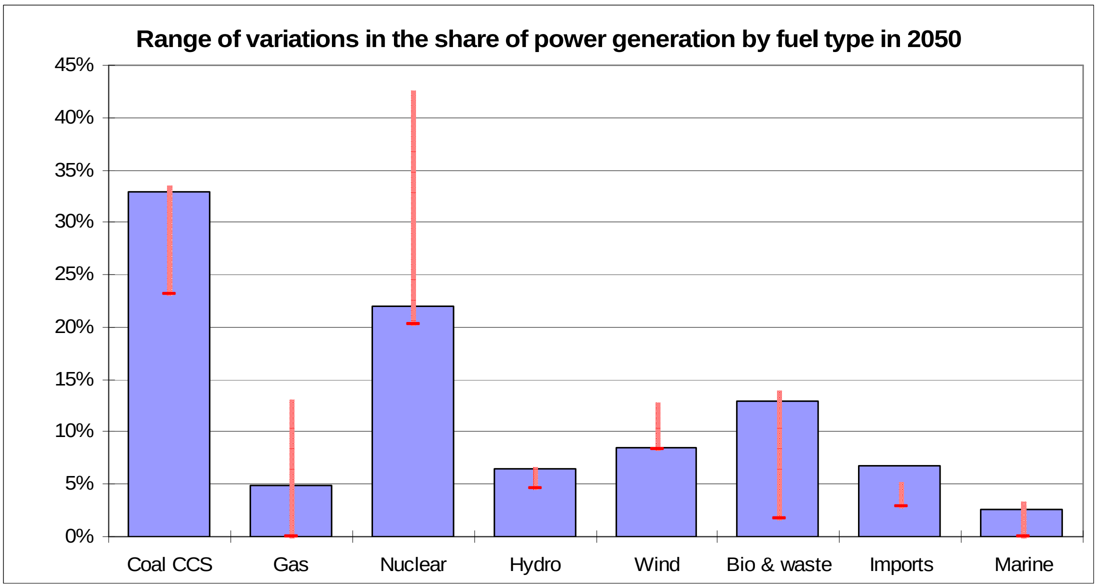

Figure 36 Share of electricity generation by fuel type across the scenarios in 2050

In all the scenarios, hydrogen firstly penetrates the transport sector. However, in the ubiquitous scenario, hydrogen finds a use in the service and industrial sectors for micro-power generation (see Figure 37). In the synthetic liquid fuel, methanol is used in transport sector and over 75% of transport fuel demand is met from methanol. Thus little hydrogen is used in the synthetic fuel scenario.

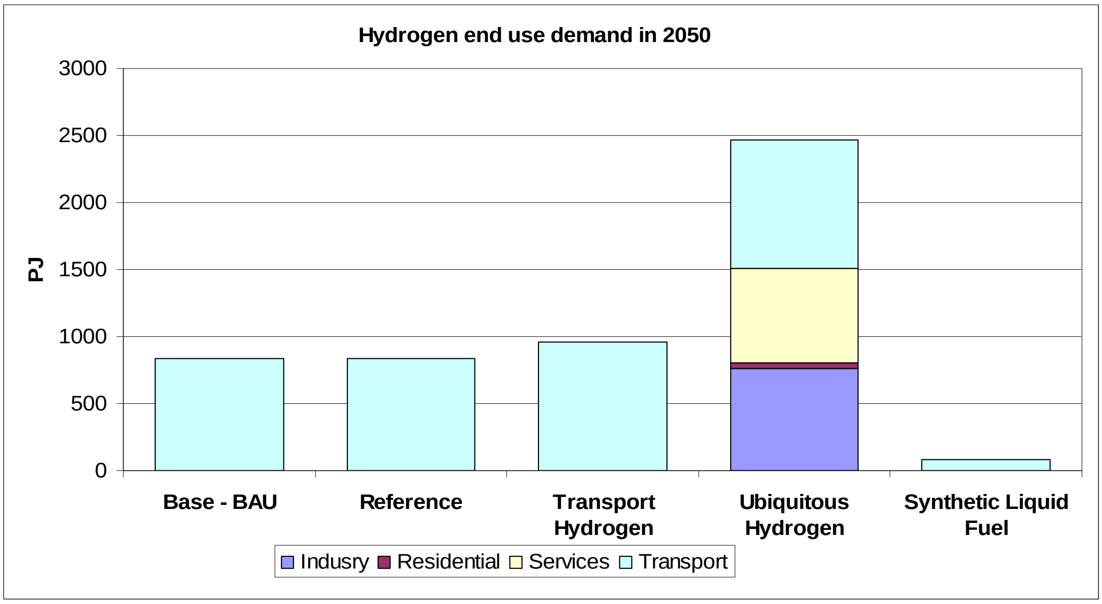

Figure 37 Hydrogen use by demand sectors across the scenarios in 2050

From the hydrogen production perspective (see Figure 38), imported hydrogen becomes a major source of hydrogen supply, with lesser shares from coal gasification (with CCS) and natural gas reforms. Electrolysis becomes a major source of hydrogen production using electricity generated from nuclear.

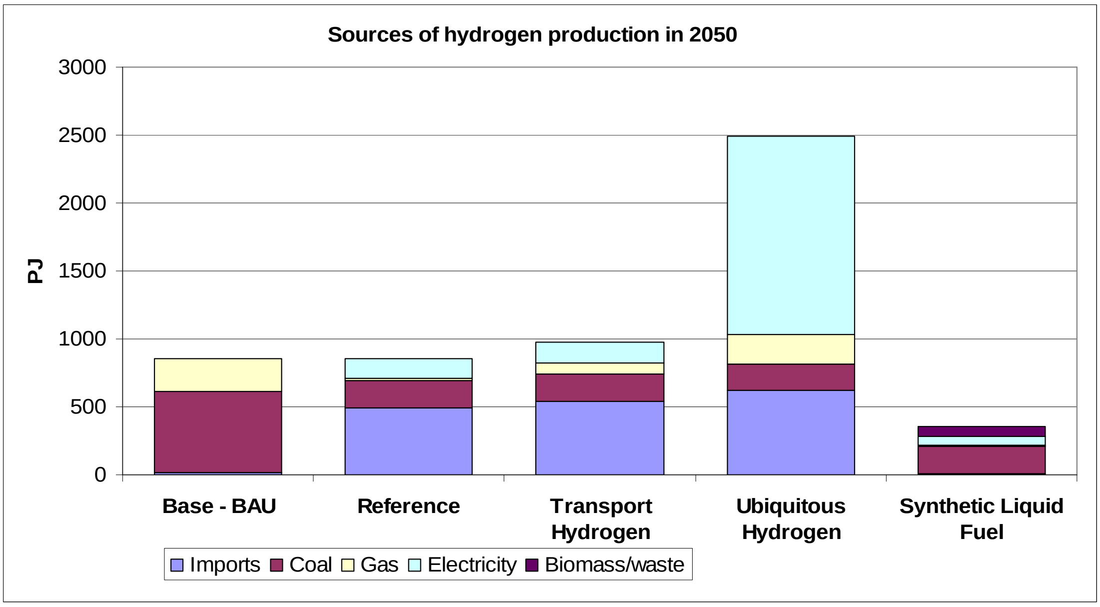

Figure 38 Sources of hydrogen production across the scenarios in 2050

In general, the transport sector is highly decarbonised through use of hydrogen. However, there are some structural changes in emissions. In the central hydrogen for transport scenario, the service sector moves to district cooling thereby leaving room for the use of gas in hydrogen production and power sector. The emissions generated from hydrogen production by gas increase transport sector emissions compared to those in the reference case. Similarly, more use of gas in electricity generation increases the power sector emissions, some of which are passed onto industry and residential sectors.

On the other hand, in the ubiquitous hydrogen scenario, hydrogen is used both in service and residential sectors through micro-generation. Thus, there is no significant change in end-use emissions relative to the reference case. However, emissions from power sector increase because of more gas based power generation.

In the synthetic liquid fuel (methanol) scenario, transport sector emissions are decreased by 50% compared to the reference case because of methanol use. Since methanol is produced from natural gas and hydrogen, which is also produced from coal or gas, the resulted emissions from methanol and hydrogen production is increased. Similarly, emissions from power sector increased due to more gas use. If the emissions from methanol and hydrogen production are allocated to transport sector then the transport sector end use emission is increased by 70%. All these trade-offs between end use and power sector emissions are demonstrated in Figure 39.

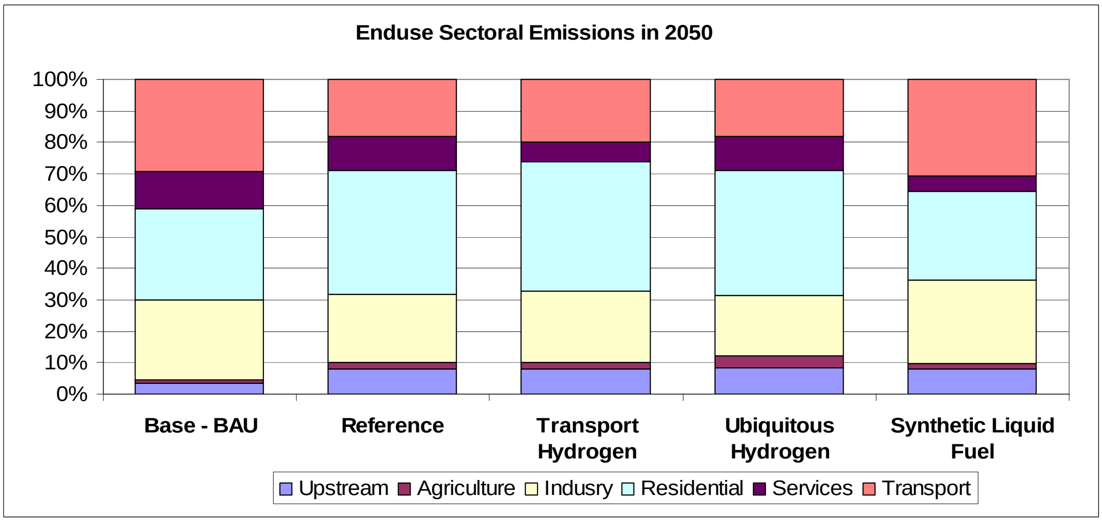

Figure 39 End use sectoral emissions across the scenarios in 2050

As expected, because of the carbon constraint, the overall system cost increases as the entire energy system moves to low carbon and energy efficient technologies. A major shift occurs in power sector which is highly decarbonised. By 2050, the undiscounted energy system cost increases about 1.4% which is around £4.6 billion. The total system cost includes all the cost of supply and end-use technologies (such as vehicle costs, etc) and relevant infrastructure (electric grid, gas pipeline, etc.). The marginal cost of CO_2 is about £ 54 per tonne of CO_2.

When moving from reference to hydrogen for transport scenario, the additional burden on the energy system is marginal as the reference case already deploys 70% hydrogen in transport sector. Thus the incremental cost is about £1.7 billion. This higher system cost results in higher marginal cost of CO2 which is 61 £/t-CO_2.

In the ubiquitous hydrogen scenario, which deploys a large amount of hydrogen (50% of the final energy demand), as can be expected, the system cost is increased by 11% or £ 35 billion from the reference case. The marginal cost of CO_2 also reaches to 77 £/t-CO_2 (see Figure 40).

In the synthetic fuel scenario, as explained before, a huge structural change occurs in entire energy system. Hence, the energy system cost increases by 5.9% from the reference case or incrementally by £19 billion by 2050, although the hydrogen produced is only about 15% of that produced in ubiquitous hydrogen scenario. Though methanol is deployed only in transport sector, the additional system cost is far higher than in the 20% hydrogen scenario. This could be due to immature methanol based demand technologies as hydrogen has a wide range of technologies with vintages. Because of this relatively higher energy system cost, the marginal cost of CO_2 is increased to 140 £/t-CO_2 which is the highest among all the scenarios. This could also be due to the presence of limited methanol technologies in the current model.

Hence, when the energy system moves to hydrogen, the cost of mitigation becomes higher so is the marginal cost. The marginal cost of CO_2 is presented in Figure 40.

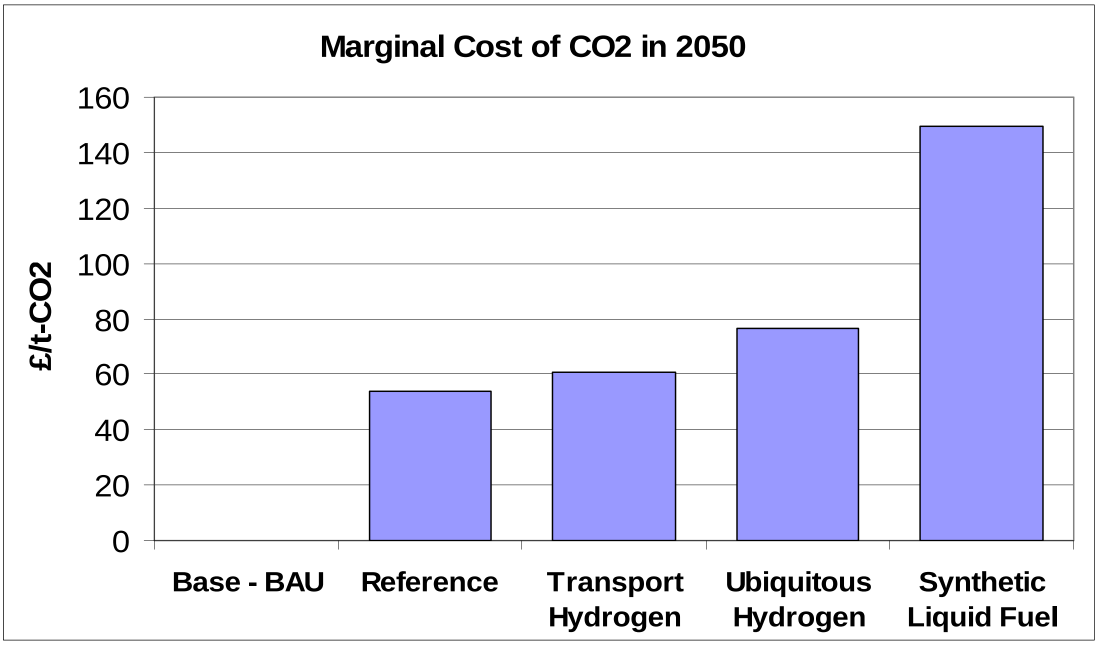

Figure 40 Marginal cost of CO_2 across the scenarios in 2050

5.6 Limitations of study

One of the main limitations of this study is due to treatment of temporal aspects in the current Markal model. This structure allows for analysis of 6 time slices, 2 diurnal (day and night), and 3 seasons, (summer, winter and intermediate). However, this structure does not allow for the analysis of UK electricity demand, which varies both seasonally and diurnally. Thus, this structure is very limited in capturing the full characteristics of the demand load as well as the availability of intermittent energy sources. This limitation certainly avoids the exploration of a possible role of hydrogen as an electricity buffer storage. Hence, the thermodynamic inefficiency that is revealed by the use of electricity in hydrogen production, then use of this hydrogen in electricity production can be a side effect due to this limitation.

Nonetheless, this issue will be addressed by improving the approximation of load demand in the UK Markal model. The work is underway as part of the DfT Horizons project (Strachan et al., 2007), which will have five diurnal time periods and an extension to twelve monthly seasons. Hence, not only will the peak and shoulder demands be represented more efficiently, but also will the modelling of energy storage be possible.

Another issue relates the need for addressing the spatial aspects of possible hydrogen development (Joffe et al 2007). The authors discuss the role of resource availability and concentration of demand on the build up of hydrogen network. It is most likely that a hydrogen system would develop where these two factors overlap or linked to the each other in an efficient manner. Hence, even though Markal does not allow for analysis of these spatial aspects explicitly, this issue is addressed by including all resource-infrastructure-demand options explicitly as competing technologies.

However, there is ongoing work to link MARKAL to a geographical information systems (GIS) framework (see Strachan et al, 2007).

The other important issue relates to the assumptions on the characterization of hydrogen technologies and uncertainty around them. Certainly, uncertainties in the evolution of a hydrogen infrastructure are profound. This study takes a step in addressing these issues by carrying out parametric analysis on technology costs and fuel prices. However, there is a need for further work in this area.

6 Conclusions and Future Work

This paper focuses on the analysis of the energy, environment and cost implications of the UKSHEC hydrogen visions including an exploration of their inherent uncertainties. For this purpose, an updated version of the UK MARKAL model that provided substantive analytical inputs to the Energy White Paper 2007 was developed. The updated model included a range of hydrogen production and end use technologies and relevant infrastructures. All plausible options of hydrogen infrastructure are depicted by taking into account distribution distance and flow rates of hydrogen; and hence the distribution network costs. Thus this model provides a systematic framework to analyze the development of hydrogen pathways in the UK energy system.

A set of hydrogen pathways and transition scenarios identified under UKSHEC visions are modelled. These visions define four different potential evolutions of a hydrogen economy in the UK energy system viz. i) Central hydrogen for transport; ii) Ubiquitous hydrogen – an economy wide use of hydrogen; iii) a synthetic liquid fuel, such as methanol; and iv) Hydrogen as an electricity storage medium to expand intermittency nature of renewable energy in the UK energy system. Except the electricity storage vision, the remaining three visions are modelled.

Energy, environment and economic implications of these three hydrogen visions are analysed and indicative results of key metrics, viz. primary and final energy mix, power generation mix, transport fuel use, sectoral emissions, hydrogen production and end-use pattern, average and marginal CO_2 prices and energy system costs are presented. Under given set of assumptions, the model points out a higher primary energy demand to produce hydrogen under all three hydrogen scenarios. In particular, a high level of hydrogen use economy wide can be met cost effectively by electrolysis, based on nuclear power. As hydrogen can be used either as transport fuel or an energy carrier for heat and power generation, high levels of deployment comes with thermodynamic losses from electricity-hydrogen-electricity conversion. Other than electrolysis, gas based reforming and imports are other hydrogen sources. The sensitivity analysis emphasise the role of technology costs on the uptake of these hydrogen production pathways.

On demand side, the cost of end-use technologies as well as the network costs appears to be the main factors in penetration of hydrogen. If hydrogen technologies would have higher costs, then the model indicates an optimum use of hydrogen in transport sector (including rail and air), rather than stationary power generation applications.

The sectoral emissions are very much linked to the deployment of hydrogen at sectoral level. When hydrogen is produced from natural gas, the residential and service sectors switch to district heating. Hence, sectoral emissions are closely linked to the pathways chosen for hydrogen production.

The overall system cost responds to the hydrogen pathways chosen as well as where it is being used. Even though it marginally increases in the hydrogen for transport scenario, it increases most in ubiquitous hydrogen scenario where 50% of final energy demand is to be delivered from hydrogen.

However, this initial analysis identifies some fundamental uncertainties for the introduction of a new energy infrastructure paradigm that need to be addressed in future work in a greater detail. In particular, these issues are:

- These indicative model outputs reveal that development of hydrogen system is very much dependent on cost of hydrogen production and distribution technologies. Hence there is a need for more parametric sensitivity analysis to increase the robustness of the modelling outputs.
- As discussed by Joffe et al (2007), a hydrogen network might be realized in areas of resource availability and where potential demand is sufficiently dense to justify these investments. This indicates the role of spatial aspects of the hydrogen system, such as the locations of resources and demands, as well as the infrastructure required to link the two. Even though these spatial aspects have been approximated by inclusion of these resource-infrastructure-demand options explicitly as competing technologies, there is ongoing work to link MARKAL to a geographical information systems (GIS) framework (see Strachan et al, 2007).
- One of the possible roles for hydrogen in the overall energy system is its emergence as a distributed storage medium to buffer intermittent renewable electricity supplies in the energy sector. However, this requires a more detailed temporal resolution than the one in current MARKAL model. The DfT research project that is mentioned in section 4.1.4 would address this issue.
- It appears to be cost-effective to produce hydrogen from electrolysis, via nuclear-based electricity generation. However, it may not be thermodynamically efficient because the primary energy use increased in all scenarios. This thermodynamic inefficiency issue is most probably driven by the limitations on analyzing the hydrogen as a distributed storage medium. Therefore the trade off between the uses of electricity for direct application versus via hydrogen should be studied in detail.
- Though up to date technology data are included in the model, when envisaging a large scale deployment of hydrogen, more advanced hydrogen technologies should to be included.

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Appendix I: UK MARKAL Model Hydrogen Technology Data

Technologies that explicitly define the hydrogen network system are listed below. They are presented in the following four groups: resource, process, transmission, and distribution technologies. End-use technologies are further broken out into electricity (and heat) conversion technology and transport technologies (by mode. Large-scale conversion technologies are poly-generation (electricity and hydrogen) plants that include CO_2 capture and are vintaged. Small scale conversion plants are micro-generation plants utilizing distributed hydrogen to produce electricity (and heat for CHP options) which can be distributed to the residential, commercial and residential energy carriers. Transport hydrogen technologies cover a wide range of modes and are vintaged every 10 years to reflect improvements in efficiencies, capital and operational costs. The main technology classes are: bus hydrogen ICEs, bus hydrogen FCVs, bus methanol FCVs, car hydrogen ICEs, car hydrogen FCVs, car methanol ICEs, car methanol FCVs, HGV hydrogen ICEs, HGV hydrogen FCVs, HGV methanol FCVs, LGV hydrogen ICEs, LGV hydrogen FCVs, LGV methanol ICEs, LGV methanol FCVs, air domestic hydrogen, air international hydrogen , rail (freight) hydrogen FCVs, rail (passenger) hydrogen FCVs, 2-wheel hydrogen FCVs, 2-wheel methanol FCVs. Further details for the complete technology dataset is given in Strachan et al (2006).

Table A. 1. Hydrogen resource technologies

No	Technology description	First year	Cost (£2000/GJ) (note 1p/kWhr = £2.78/GJ)
1	Imported liquid hydrogen	2000	23.33 falling to 15.41 by 2050 [9]

Table A. 2. Hydrogen process technologies

No	Technology description	Year	Efficiency (%)	Invest cost (£/GJ/yr)	Variable costs (£/GJ)	Lifetime (years)
3	Current coal gasification	2000	60%	11.44	0.71	30
4	Current coal gasification plus CO_2 sequestration	2000	50%	11.69	0.71	30
5	Future coal gasification	2015	70%	8.62	0.51	30
6	Future coal gasification plus CO_2 sequestration	2030	60%	8.62	0.51	30
7	Future membrane coal gasification	2030	70%	6.16	0.51	30
8	Future membrane coal gasification plus CO_2 sequestration	2030	65%	6.19	0.51	30
9	Current large SMR	2000	80%	4.05	1.37	30
10	Current large SMR with CO_2 sequestration	2000	65%	7.61	1.37	30
11	Future large SMR	2015	80%	5.85	0.71	30
12	Future large SMR with CO_2 sequestration	2015	75%	6.20	0.71	30
13	Current small SMR	2000	65%	46.07	1.37	20
14	Future small SMR	2015	70%	32.03	0.71	20
15	Electrolysis – small current	2000	75%	70.98		15
16	Electrolysis – small future	2020	85%	15.87		20
17	Electrolysis – large current	2000	60%	42.08		15
18	Electrolysis – large future	2020	75%	4.89		25
19	Biomass gasification to hydrogen - current	2000	50%	32.05	0.71	30
20	Biomass gasification to	2020	50%	19.23	0.71	30

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[9] Combination of solar electricity, electrolysis and liquefaction annualized over 30 years, plus operating liquefaction plant costs and second step for international LNG, includes learning economies of solar PV (commercial)

	hydrogen - future					
21	Biomass pyrolysis to hydrogen	2010	50%	11.20	0.71	25
22	Waste gasification - hydrogen	2000	65%	22.80	0.71	30
23	Liquefaction of hydrogen	2000	70%	18.37	0.78	30

Table A. 3. Hydrogen transmission technologies

No	Technology description	Year	Efficiency (%)	Invest cost (£/GJ/yr)	Variable costs (£/GJ)	Lifetime (years)
24	Hydrogen tube trailer	2000	89%			
25	Hydrogen pipeline	2000	98.7%	11.97		
26	Liquid HYDROGEN transmission	2000	98%			

Table A. 4. Hydrogen distribution technologies

No	Technology description	Year	Efficiency (%)	Invest cost (£/GJ/yr)	Variable costs (£/GJ)	Lifetime (years)
27	Hydrogen pipeline (SD,HF)	2000			1.57	
28	Hydrogen pipeline (SD,LF)	2000			4.70	
29	Hydrogen pipeline (LD,HF)	2000			3.13	
30	Hydrogen pipeline (LD,LF)	2000			16.84	
31	Hydrogen tube trailer (SD,HF)	2000			3.13	
32	Hydrogen tube trailer (SD,LF)	2000			3.52	
33	Hydrogen tube trailer (LD,HF)	2000			11.75	
34	Hydrogen tube trailer (LD,LF)	2000			12.13	
35	Liquid HYDROGEN by road (SD,HF)	2000			0.39	
36	Liquid HYDROGEN by road (SD,LF)	2000			0.39	
37	Liquid HYDROGEN by road (LD,HF)	2000			1.17	
38	Liquid HYDROGEN by road (LD,LF)	2000			1.17	
39	On-site liquefaction (SD,HF)	2000	70%	18.37	0.78	30
40	On-site liquefaction (SD,LF)	2000	70%	43.04	0.78	30
41	On-site liquefaction (LD,HF)	2000	70%	18.37	1.17	30
42	On-site liquefaction (LD,LF)	2000	70%	43.04	1.17	30

* As distribution technologies are defined to reflect the impacts of distribution distance and flow rates on the cost of these technologies, they are presented explicitly here where SD: short distance, LD: long distance, HF: high flow and LF: low flow. The costs follow Yang and Ogden (2006), and efficiency losses are accounted in the transmission technologies that were listed in the previous table.

Appendix II: Hydrogen technology data for sensitivity analysis

Parametric analysis is used due to variability of literature and expert judgement surrounding uncertainty of future costs. The capital and O&M costs are varied a base level of +/- 25% change, ranging from 10% to 40% change depending on uncertainty level.

- Production uncertainty
    - Biomass and electrolysis most uncertainty
    - Small scale production more uncertainty than large scale
    - Coal gasification the least uncertainty
    - In high cost case, not future vintages are not developed (i.e. no innovation)
- Transmission and distribution uncertainty
    - Liquefaction and liquid distribution the most uncertain
    - Gaseous hydrogen by road of medium uncertainty
    - Pipeline the least uncertainty

The variation used in hydrogen technology data sensitivity analysis is presented explicitly in Table A. 5, Table A. 6, and Table A. 7 below.

Table A. 5 The parametric ranges used in hydrogen production technology sensitivity

Technology description	Parametric Change	LOW PARAMETRIC CASE			CENTRAL CASE			HIGH PARAMETRIC case		
		Efficiency (%)	Invest cost (£/GJ/yr)	Variable costs (£/GJ)	Efficiency (%)	Invest cost (£/GJ/yr)	Variable costs (£/GJ)	Efficiency (%)	Invest cost (£/GJ/yr)	Variable costs (£/GJ)
Current coal gasification	+/- 10%	60%	10.30	0.64	60%	11.44	0.71	66%	12.58	0.78
Current coal gasification plus CO_2 sequestration	+/- 10%	50%	10.52	0.64	50%	11.69	0.71	50%	12.86	0.78
Future coal gasification	+/- 10%	70%	7.76	0.46	70%	8.62	0.51	N/A	N/A	N/A
Future coal gasification plus CO_2 sequestration	+/- 10%	60%	7.76	0.46	60%	8.62	0.51	N/A	N/A	N/A
Future membrane coal gasification	+/- 10%	70%	5.54	0.46	70%	6.16	0.51	N/A	N/A	N/A
Future membrane coal gasification plus CO_2 sequestration	+/- 10%	65%	5.57	0.46	65%	6.19	0.51	N/A	N/A	N/A
Current large SMR	+/- 10%	80%	3.65	1.23	80%	4.05	1.37	80%	4.46	1.51
Current large SMR with CO_2 sequestration	+/- 10%	65%	6.85	1.23	65%	7.61	1.37	65%	8.37	1.51
Future large SMR	+/- 10%	80%	5.27	0.64	80%	5.85	0.71	N/A	N/A	N/A
Future large SMR with CO_2 sequestration	+/- 10%	75%	5.58	0.64	75%	6.2	0.71	N/A	N/A	N/A
Current small SMR	+/- 25%	65%	34.55	1.03	65%	46.07	1.37	65%	57.59	1.71

Future small SMR	+/- 25%	70%	24.02	0.53	70%	32.03	0.71	N/A	N/A	N/A
Electrolysis – small current	+/- 40%	75%	42.59		75%	70.98		75%	99.37	
Electrolysis – small future	+/- 40%	85%	9.52		85%	15.87		N/A	N/A	N/A
Electrolysis – large current	+/- 40%	60%	25.25		60%	42.08		60%	58.91	
Electrolysis – large future	+/- 40%	75%	2.93		75%	4.89		N/A	N/A	N/A
Biomass gasification to hydrogen - current	+/- 40%	50%	19.23	0.43	50%	32.05	0.71	50%	44.87	0.99
Biomass gasification to hydrogen - future	+/- 40%	50%	11.54	0.43	50%	19.23	0.71	N/A	N/A	N/A
Biomass pyrolysis to hydrogen	+/- 40%	50%	6.72	0.43	50%	11.2	0.71	50%	15.68	0.99
Waste gasification - hydrogen	+/- 40%	65%	13.68	0.43	65%	22.8	0.71	65%	31.92	0.99
Liquefaction of hydrogen	+/- 40%	70%	11.02	0.47	70%	18.37	0.78	70%	25.72	1.09

Table A. 6 The parametric ranges used in hydrogen transmission technology sensitivity

Technology description	Parametric Change	LOW PARAMETRIC CASE			CENTRAL CASE			HIGH PARAMETRIC case		
		Efficiency (%)	Invest cost	Variable costs	Efficiency (%)	Invest cost	Variable costs	Efficiency (%)	Invest cost	Variable costs
			(£/GJ/yr)	(£/GJ)		(£/GJ/yr)	(£/GJ)		(£/GJ/yr)	(£/GJ)
Hydrogen tube trailer	+/- 25%	89%			89%			89%		
Hydrogen pipeline	+/- 10%	98.70%	10.77		98.70%	11.97		98.70%	13.17	
Liquid H2 transmission	+/- 25%	98%			98%			98%		

Table A. 7 The parametric ranges used in hydrogen distribution technology sensitivity

Technology description*	Parametric Change	Efficiency (%)	Invest cost	Variable costs	Efficiency (%)	Invest cost	Variable costs	Efficiency (%)	Invest cost	Variable costs
			(£/GJ/yr)	(£/GJ)		(£/GJ/yr)	(£/GJ)		(£/GJ/yr)	(£/GJ)
Hydrogen pipeline (SD,HF)	+/- 10%			1.41			1.57			1.73
Hydrogen pipeline (SD,LF)	+/- 10%			4.23			4.7			5.17
Hydrogen pipeline (LD,HF)	+/- 10%			2.82			3.13			3.44
Hydrogen pipeline (LD,LF)	+/- 10%			15.16			16.84			18.52
Hydrogen tube trailer (SD,HF)	+/- 25%			2.35			3.13			3.91

Hydrogen tube trailer (SD,LF)	+/- 25%			2.64			3.52			4.40
Hydrogen tube trailer (LD,HF)	+/- 25%			8.81			11.75			14.69
Hydrogen tube trailer (LD,LF)	+/- 25%			9.10			12.13			15.16
Liquid H2 by road (SD,HF)	+/- 25%			0.29			0.39			0.49
Liquid H2 by road (SD,LF)	+/- 25%			0.29			0.39			0.49
Liquid H2 by road (LD,HF)	+/- 25%			0.88			1.17			1.46
Liquid H2 by road (LD,LF)	+/- 25%			0.88			1.17			1.46
On-site liquefaction (SD,HF)	+/- 40%	70%	11.02	0.47	70%	18.37	0.78	70%	25.72	1.09
On-site liquefaction (SD,LF)	+/- 40%	70%	25.82	0.47	70%	43.04	0.78	70%	60.26	1.09
On-site liquefaction (LD,HF)	+/- 40%	70%	11.02	0.70	70%	18.37	1.17	70%	25.72	1.64
On-site liquefaction (LD,LF)	+/- 40%	70%	25.82	0.70	70%	43.04	1.17	70%	60.26	1.64

Appendix III: Fossil resource price

Table A. 8 below presents the ranges used in fossil fuel price sensitivity analysis.

Table A. 8. The parametric ranges used in fossil fuel price sensitivity

	Baseline (Central price assumption)			**High price**			**Low price**		
	Oil $/bbl	Gas p/therm	ARA Coal $/GJ	Oil $/bbl	Gas p/therm	ARA Coal $/GJ	Oil $/bbl	Gas p/therm	ARA Coal $/GJ
2005	55	41.0	2.4	55.0	41.0	33.6	55.0	41.0	2.4
2010	40	33.5	1.9	67.0	49.9	36.5	20.0	18.0	1.4
2015	43	35.0	1.9	69.5	51.4	36.5	20.0	19.5	1.2
2020	45	36.5	1.8	72.0	53.0	36.5	20.0	21.0	1.0
2025	48	38.1	1.9	77.0	56.0	39.1	22.5	22.5	1.1
2030	50	39.6	2.0	82.0	59.0	41.6	25.0	24.0	1.2
2035	53	41.1	2.1	82.0	59.0	41.6	27.5	25.5	1.3
2040	55	42.6	2.2	82.0	59.0	41.6	30.0	27.0	1.3
2045	55	42.6	2.2	82.0	59.0	41.6	32.5	28.5	1.4
2050	55	42.6	2.2	82.0	59.0	41.6	35.0	30.0	1.5

Source: DTI, 2006