Options for a Low Carbon Future - Phase 2

A report produced for The Department of Trade and Industry

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Executive Summary

INTRODUCTION

The need to reduce greenhouse gas (GHG) emissions arising from the production, distribution and use of energy is an important consideration for UK climate change and energy policies. Indeed the Royal Commission on Environmental Pollution's report – "Energy – the Changing Climate" (RCEP, 2000) proposed that UK carbon dioxide emissions should be reduced 60% from present day levels by 2050. The first phase of this study – Options for a Low Carbon Future – was commissioned by DTI and DEFRA to advise on the technical options and costs of moving to a low carbon dioxide emission energy system as part of the wider Interdepartmental Analysts Group study into Long term Reductions in greenhouse Gas emissions in the UK (IAG, 2002). The study concentrated exclusively on measures that could be undertaken in the UK and did not cover other options such as the use of the Kyoto Protocol's Flexibility Mechanisms or the import of low/zero carbon energy sources such as biomass, hydrogen or electricity. The work was completed at the end of 2001 (FES, 2002), and the results, which were an input to the Cabinet Office Performance and Innovation Unit's review of UK energy policy, are available at
http://www.etsu.com/en_env/html/climate_change.html.

This earlier study showed that it was technically possible for the UK to abate carbon dioxide emissions by at least 70% by 2050. It also highlighted five key results concerning the options for attaining this level of abatement and their costs:

- There is a diversity of technology options for reducing CO_2 emissions from both energy supply and the main energy consuming sectors of transport, industry, domestic and services.
- The implementation of energy efficiency technologies and measures is central, but not sufficient on its own, to achieving the abatement targets irrespective of which supply side technologies are used.
- Natural gas is attractive economically and has low CO_2 emissions compared to other fossil fuels, and therefore is likely to take a growing share of primary energy supplies.
- Abatement costs are highly uncertain, but the effects on the UK's economic growth prospects are likely to be small, and may even be positive if other benefits such as increased security of supply, other environmental benefits and new business opportunities were to be taken into account.
- Innovation and technical progress are central to the attainment of a low carbon economy while continuing to provide energy related services at costs that are not far removed from current levels.

This second phase of the study has made a more detailed assessment of some critical factors affecting the abatement of emissions from the energy sector and the associated costs. Once again it has only considered measures that can be implemented within the

UK, and only estimates the resource costs of abatement without examining how these might be distributed. It has yielded these additional key results:

- Annual abatement costs never exceeded 2% of GDP, and in the majority of scenario cases were less than 0.5% of GDP. Moreover, the share of energy costs in GDP declines in most scenarios (including abatement scenarios) reflecting expected structural changes towards a lower energy intensity economy and investment in more energy efficient technologies. As a consequence the estimated effects on economic growth of carbon abatement were generally small (i.e. annual GDP growth reduced by about 0.01 percentage points over a 50 year period)[1].
- Abatement costs are particularly sensitive to the level of improvement in energy efficiency, successful innovation in both the development and manufacture of energy technologies and possible limitations to the deployment of key technologies.
- Abatement measures increase the energy costs of all sectors of the economy. By 2050 total energy costs are about 20% higher than they would otherwise have been for the domestic, service and industry sectors and are over 50% higher for transport.
- Reductions in carbon dioxide emissions are achieved through a roughly equal combination of end user energy efficiency and switching to less carbon intensive primary energy sources (i.e. natural gas, nuclear power and renewable energy).
- Growth in carbon dioxide emissions from road transport will be limited by anticipated improvements in the fuel efficiency of diesel and gasoline fuelled vehicles. However, more substantial reductions require the deployment of more costly options such as hydrogen technologies, which is delayed until other, more cost effective, measures have been taken in other sectors.
- The preferred source of hydrogen is natural gas with carbon capture, but when gas supplies are limited gasification of biomass is used. Hydrogen was never produced from electricity under the cost assumptions used.
- There are important uncertainties over the mechanism for making the transition to a hydrogen energy system and the infrastructure costs this will entail.
- Technological innovation is a key element for making a successful transition to a low carbon energy system. Long-term technology forecasting involves too much uncertainty to identify specific technologies, but it is clear that five families of technologies could make major contributions, namely end-use energy efficiency, renewable energy, carbon capture and storage, hydrogen and nuclear power. All of these options should be maintained at this stage.
- It is possible that certain of the above families of technologies (e.g. nuclear power, carbon sequestration) may be excluded through considerations of safety, public acceptance, etc. Moreover past experience shows that strong measures will be needed to support enhanced take up of energy efficiency. Excluding more than one of these technology groups, or failure to capture the potential for energy efficiency, could greatly increase the cost of abatement.
- Progressive action is needed from now onwards to put the UK on an achievable and cost effective trajectory to a carbon dioxide abatement target of around 60% by 2050. Delaying action does little to encourage the development of low carbon technologies or facilitate the transition processes essential to moving to a low

[1] The energy system covered in MARKAL produced 130MtC in 2000 compared to the 155MtC from the full energy system. This is because the model did not include some energy conversion processes (e.g. refineries) and end-uses (e.g. agriculture). Consequently these results represent a small under-estimate of the costs of abatement if the abatement costs of the sectors omitted are similar to those in the model.

carbon system. Moreover the aggregate emission reduction to 2050, which is the important factor affecting climate change, would be much less with delayed action.

APPROACH TO THE STUDY

Investigations of future trends, whatever the subject area, are fraught with uncertainty, particularly over a timeframe of 50 years. This is no less true for the energy sector, which is subject to a range of economic and social drivers, which could evolve in different ways. This can be illustrated by three examples. Firstly, overall economic growth will affect the wealth of all the population and thereby personal demand for energy services such as warmth, mobility, entertainment, etc. Secondly, the changing balance of business activities between energy intensive manufacturing, and less intensive light engineering and services will change both the level and nature of commercial energy use. Thirdly, energy demand will change with social preferences affecting decisions on where we live, how and to what extent we travel, what leisure activities we follow, etc.

This study has adopted a scenario based approach to examine a range of possible future development paths and their implications for energy prices, energy demands and related carbon dioxide abatement costs and technology changes. The three scenarios developed for the first phase of the study were retained for this work. Their titles and conceptual themes were:

- Baseline (BL) – in which the current values of society remain unchanged and policy intervention in support of environmental objectives is pursued in a similar way to now (GDP growth 2.25% per year).
- World Markets (WM) – based on individual consumerist values, a high degree of globalisation and scant regard for the global environment (GDP growth 3% per year).
- Global Sustainability (GS) – based on the predominance of social and ecological values, strong collective environmental action and globalisation of governance systems (GDP growth 2.25% per year).

The three scenarios were essentially global in the sense that it was implicitly assumed that the world would be following the same development path as the UK. They were developed to investigate three quite different combinations of the economic and social drivers outlined above. As part of the scenarios, fuel prices were specified by DTI, to take account of the different demands for energy services that are envisaged. For example gas and oil prices were higher in WM on account of higher world demands for energy services and the importance of these fuels for transport and power/heat production respectively.

The “bottom up” estimates of future energy consumption and carbon dioxide emissions for each scenario were developed through a systems approach using the IEA’s MARKAL model. This linear programme model provided cost optimised solutions for the UK energy system to 2050, taking account of the costs, performance and emissions of alternative supply and demand technologies. The study did not consider the impact on technology deployment of other energy related policy issues such as security of supply and industrial competitiveness[2], or the barriers that may affect the implementation of some energy technologies.

A common technology database was used throughout. In compiling this data it was recognised that the parameters characterising the technologies will change with time through such factors as economies of production, innovation, learning by doing, etc. Accordingly the assembly of the database was guided by two underlying principles:

- The costs and performance data were set to be representative of commercially deployed technologies enjoying the benefits of volume production (i.e. not first of a kind costs).
- Technologies with low deployment prospects in the UK were still assumed to gain the benefits of volume of production if they had significant global potential (e.g. PV).

Overall energy savings, and hence reductions in carbon dioxide emissions, come from a combination of energy efficiency improvements by suppliers and end users combined with structural changes (e.g. reductions in energy intensive industry, change in the utilisation of transport modes, increased share of service sector activities in total GDP). Energy intensity (i.e. the ratio of energy consumption to GDP) measures how effectively energy is used within an economy. Structural change is included in the scenarios and therefore some change of energy intensity occurs external to the MARKAL model's optimisation of the energy system. This has been estimated as an annual reduction of energy intensity of 1.4%, 1.9% and 1.6% for the BL, WM and GS scenarios respectively. For comparison the UK's energy intensity fell by 2.1% on average over the last 30 years.

KEY RESULTS

They key results from this second phase of the study have been headlined above. As with all scenario studies, the results are *not* forecasts, they are an exploration of what technology can in principle deliver, and of what the costs and effects on emissions might be. Which technologies emerge and are deployed and what the actual costs will be, will turn on many factors including the policies that are implemented, the social acceptability of particular energy technologies, the extent to which householders and industry invest in energy efficiency and, not least, our capacity for discovery and innovation.

The following sections examine the key results in more detail.

Abatement costs are sensitive to key factors in the UK energy system

Phase 1 of the study indicated that the cost of abatement to the UK, although significant in absolute terms, was generally small in relation to (a) the overall costs of energy supply, and (b) the level of GDP. This has been reinforced by the additional scenarios examined herein, in which annual abatement costs in the majority of cases did not exceed 0.5% of GDP, and the impact was to reduce average economic growth by about 0.01 percentage points per year. However, the results also highlighted the sensitivity of abatement costs to certain key factors in the UK energy system:

[2] A separate assessment of the impact on industry competitiveness has been made by DTI using results from this study, and is presented in Annex F.

Energy efficiency – The abatement costs are less than they otherwise would have been because the model deploys all cost effective and low cost energy efficiency technologies and measures. However, experience shows that it is difficult to attain such levels of efficiency improvement. When the rate of improvement in energy intensity was limited to the average rate for the last decade (i.e. 1.6% per year between 1990 and 2000) the total discounted cost of abatement over the 50 year period in the BL scenario increased four fold (i.e. £41bn to £164bn)[3].

Technical Innovation – An important feature of the technology cost and performance data used in the study is that technical progress is expected to deliver considerable improvements to both existing and emerging technologies. This innovation, both in the development of devices and in their manufacture, is expected to be a global process, with all nations motivated to move to lower carbon energy systems. The importance of this innovation in limiting abatement costs is illustrated by an assessment with the BL scenario in which technology parameters were frozen at 2010 levels. This increased total discounted abatement costs from £41bn to £168bn.

Technology Exclusion – The transition to a low carbon energy system will inevitably involve the deployment of a range of new or revised technologies and systems; some of which may encounter barriers linked to such factors as social acceptance or compliance with international regulations. Two such technologies are nuclear power and carbon sequestration. Phase 1 of the study investigated the implication of one or other of these technologies not being deployed, and found that while this did not prevent the attainment of abatement targets it did cause an increase in costs. The current study has shown that the 60% abatement target can also be attained without both technologies, but this resulted in a much larger increase in total discounted abatement costs from £41bn to £138bn. (These estimates ignore the valuation of the risks and liabilities associated with these technologies, as they do for the other technologies.)

Carbon abatement impacts on all sectors of the UK economy

The costs associated with reducing carbon emissions are distributed across all sectors of the economy. This occurs through increased prices for low to zero carbon energy sources including electricity, hydrogen and other alternative transport fuels such as biodiesel and methanol.

The distribution of costs between sectors in 2050 for a set of modelling runs based on the BL scenario is summarised in Table E1. There is no impact on sector energy costs in 2020 because cost effective energy efficiency measures are sufficient to attain the required emission reduction. However, significant additional costs are incurred in all sectors to attain the 60% reduction in carbon emissions in 2050. The transport sector has a particularly large increase in costs because of the deployment of a large proportion of hydrogen fuelled transport technologies by this stage.

[3] A discount rate of 3.5% was used to estimate the present value total abatement costs quoted here.

Table E1 Percentage Increase in Annual Sector Energy Costs due to Carbon Emission Constraints

Sector	BL 60% Constraint in 2050
	2050
Domestic % Change in average cost per household	20%
Services % Change in total annual cost	23%
Transport % Change in average cost per km of travel	54%
Industry % Change in total annual cost	22%

The cost impact of carbon constraints on industry will not be distributed evenly across manufacturing sectors because some are more energy intensive than others. Also the implications of higher energy costs are greater for sectors that produce internationally traded goods since they may lose cost competitiveness if their rivals do not incur similar increases. Sectors experiencing the greatest increases in production costs (> 2% of total costs) would be industrial gases, inorganic chemicals, brick manufacture, cement/plaster, and to a lesser extent (~ 1% of total costs) metals, paper, chemicals and minerals industries. Of these sectors metals, paper, chemicals, and minerals (ceramics) face the most intense international price competition.

Carbon abatement is distributed across all sectors of the UK economy

Carbon dioxide emissions can be reduced by improving the efficiency of energy conversion processes such as power generation, by increasing end use energy efficiency and by switching to lower carbon primary energy sources. This study found that end use energy efficiency and fuel switching made roughly equal contributions to abatement. Energy conversion efficiency (i.e. the ratio of Final Energy demand to Primary Energy supply) actually declined because of an increase in demand for processed fuels such as electricity and hydrogen, which emit zero carbon dioxide at the point of use, and the deployment of carbon capture, which also involves an efficiency loss.

The reduction in the carbon intensity of primary energy sources was achieved by reducing coal use (NB this happened without emissions constraints), and by the replacement of a substantial proportion of petroleum based transport fuels with hydrogen. The improvement in end use energy efficiency occurred in all sectors, but was strongest in domestic and transport.

Certain technology groups are key to a low carbon future

The “bottom up” modelling approach used in this study draws on a detailed database of current and prospective technologies for the supply, conversion, transmission and use of energy. This database has been compiled from a range of sources and has been subject to peer review by government departments, industry and academia. Nonetheless it is a forecast for the performance of technologies extending 50 years into the future with the attendant uncertainties. Therefore alone it does not form the basis for picking individual winners and losers.

However, the model results do point to key "families" of technologies that are consistently important for attaining a low carbon future across the range of scenarios investigated. These are energy efficiency, renewable energy, carbon sequestration, nuclear power and hydrogen. It is too soon to pick from this list and all five should be maintained as options at this stage.

Hydrogen technologies are central to abating emissions from road transport

Growth in carbon dioxide emissions from road transport will be limited by anticipated improvements in the fuel efficiency of diesel and gasoline vehicles. However, more substantial reductions require the deployment of costly hydrogen technologies, and are therefore delayed until other, more cost effective, abatement measures have been taken in other sectors.

The preferred route for producing hydrogen is with "shift" reactors fuelled with natural gas, and fitted with carbon capture facilities. When natural gas supplies were limited hydrogen was produced by gasification of biomass. Hydrogen was never produced from electricity on the basis of the cost assumptions made.

The cost of deploying hydrogen in transport includes the provision of a transmission and distribution infrastructure as well as production and end-use technologies. There is considerable uncertainty over these infrastructure costs, since this might be done at relatively low cost by adapting parts of the existing natural gas network or could require an entirely new system, which would be substantially more expensive. This will have a significant influence over the size and timing of hydrogen deployment, but nevertheless, given the expected cost reductions, hydrogen currently appears the most promising option for attaining substantial emissions reductions from transport.

The revolutionary change to hydrogen as a fuel for road transport requires measures to encourage the demonstration and deployment of the chain of production, transmission and end-use technologies needed to support this on increasingly large scales. In this respect, differential excise duties on transport fuels could be a powerful instrument for promoting limited early deployment. Examples would include projects involving depot refuelling of centralised fleets of vehicles such as buses, taxis or urban delivery vans.

Different paths to a low carbon future have implications for costs and technology development

Different trajectories to a 60% reduction (Figure E1) in carbon dioxide emissions by 2050 yield different overall costs. In most of the modelling assessments emission limits were set for 2030 and 2050 (e.g. 30% in 2030 and 60% in 2050) but the model was left free to determine emissions at intervening times. As a result it delayed action in order to optimise costs because low carbon technologies are expected to become cheaper with time. Consequently a linear reduction from 2000 to 2050 (i.e. 10% in 2010, 20% in 2020, etc.) is a more costly option because this initiates action earlier with more expensive technologies. However, the cumulative abatement from the linear trajectory is almost twice that of the lower pathway.

Another approach would be to delay action but then aim for higher levels of abatement in later years to achieve the same cumulative reduction in emissions (Figure E1). First consideration would suggest that this was the ideal combination; delaying action to minimise costs by using future less expensive and more advanced technologies, but finally achieving the same result. However, the level of abatement needed is very high (80 to 90%) in the last decade of the period if this is to be achieved, which forces the deployment of very high cost options. As a result the costs are higher, even when discounted to the present.

While this report has tended to focus on specific abatement targets for 2050 these should only by regarded as milestones to a low carbon energy system. From the view-point of climate change the key action is to reduce cumulative greenhouse gas emissions, thereby stabilising their atmospheric concentration. This has been recognised by the Kyoto targets for 2008-2012 and the UK government's aspirational target of a 20% reduction in carbon dioxide emissions in 2010. Consequently, while the above results indicate that the low cost option for achieving a particular abatement target by 2050 would be to delay action, this would not meet the true objectives of climate change strategy. Cumulatively less carbon dioxide abatement would be achieved by delaying action into the future even if the 2050 target was attained.

Also the practicality of delaying action should be questioned on two counts. Firstly, although the MARKAL model considers constraints on the deployment of the major low carbon technologies there is no explicit feedback between the rate of deployment and costs. While it may be possible to speed up the deployment of an individual technology without substantial cost increases, it is doubtful that substantial changes in a large number of technologies and their associated infrastructure could be achieved over a more compressed timescale without higher costs. Secondly, the technology costs and performance values used in the analysis are based on the assumption of a global move to a low carbon energy system. If the UK was to delay action it would be attempting to be a "free rider", assuming the development of the necessary technologies and devices would be done elsewhere. This may not happen if other countries take the same view, in which case, even if technically feasible, abatement cost would be substantially higher in later years, as shown by the results of the limited innovation scenario (Section 6). Moreover, the UK would be foregoing the opportunity to take a leading position in an area offering considerable future business opportunities.

The more important conclusion from the above results is that the most cost effective approach for attaining an appreciable cumulative reduction in carbon dioxide emissions, combined with achieving a defined abatement target in 2050, is to take progressive action from now. This is also consistent with encouraging the necessary technological developments and economic and social changes needed to facilitate a low carbon future.

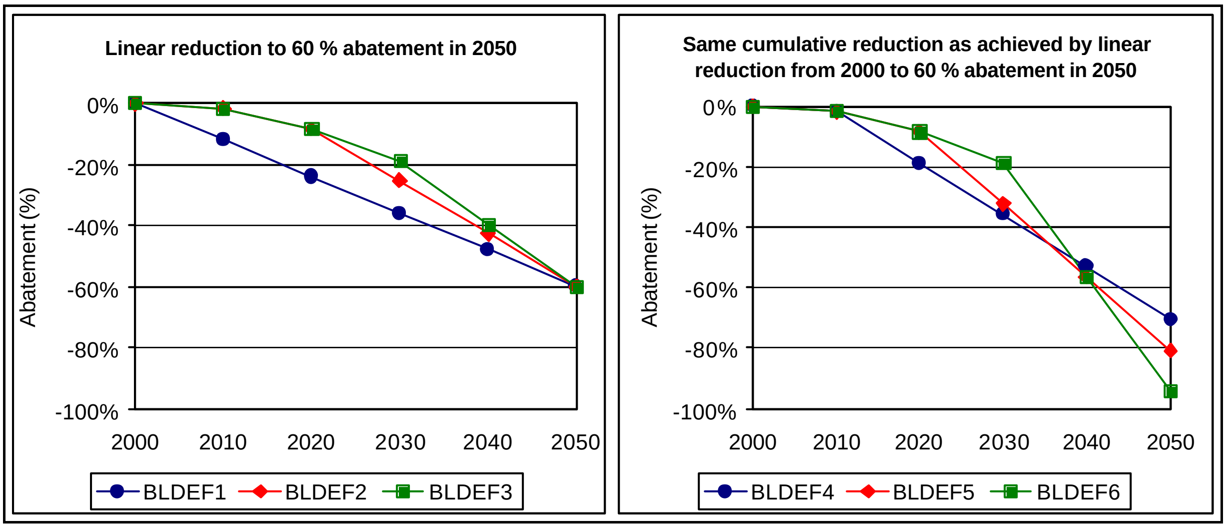

Figure E1 Alternative Emissions Trajectories to a Low Carbon Future

Contents

1 Introduction

The need to reduce greenhouse gas (GHG) emissions arising from the production, distribution and use of energy is an important consideration for the UK's climate change and energy policies. Indeed a long term target for carbon dioxide abatement, of reducing emissions by 60% from current levels by 2050, was proposed in the Royal Commission on Environmental Pollution's report – "Energy – the Changing Climate" (RCEP, 2000). The first phase of this study – Options for a Low Carbon Future – was commissioned by DTI and DEFRA, as part of the Interdepartmental Analysts Group study into Long-term Reductions in Greenhouse Gas Emissions in the UK (IAG, 2002), to advise on the technical options and costs of moving to a low carbon dioxide emission energy system. The study concentrated exclusively on measures that could be undertaken in the UK; it did not cover other options such as the use of the Kyoto Protocol's Flexibility Mechanisms or the import of low/zero carbon energy sources such as biomass, hydrogen or electricity. The work was completed at the end of 2001 (FES, 2002), and the results, which were also an input to the Cabinet Office Performance and Innovation Unit's review of UK energy policy, are available at http://www.etsu.com/en_env/html/climate_change.html.

The earlier study developed a range of "bottom-up" estimates of carbon dioxide emissions from the UK energy sector up to 2050, and investigated options for reducing these emissions by 45%, 60% and 70% relative to 2000 levels. Such projections of future trends are inherently uncertain, consequently a scenario approach was adopted, which explored three alternative visions of the key themes that may shape the future UK economy and the resultant demands for energy services. This enabled the study to assess the sensitivity of the results to a reasonably wide range of future developments and to gauge how robust the most promising technology options were to future uncertainties.

Five key results came from this earlier work:

- There is a diversity of technology options for reducing CO_2 emissions from both energy supply and the main energy consuming sectors of transport, industry, domestic and services.
- The implementation of energy efficiency technologies and measures is central, but not sufficient on its own, to achieving the abatement targets irrespective of which supply side technologies are used.
- Natural gas is attractive economically and has low CO_2 emissions compared to other fossil fuels, and therefore is likely to take a growing share of primary energy supplies.
- Abatement costs are highly uncertain, but the effects on the UK's economic growth prospects are likely to be small, and may even be positive if other benefits such as increased security of supply, other environmental benefits and new business opportunities are taken into account.
- Innovation and technical progress are central to the attainment of a low carbon economy while continuing to provide energy related services at costs that are not far removed from current levels.

The initial study also identified several areas that merited further investigation because of their potential importance in determining technology deployment and CO_2 abatement costs. These areas included:

- limiting the implementation of energy efficiency to less than its maximum cost effective potential;
- limiting the share of primary energy supplied by natural gas to reflect concerns over security of supply;
- further sensitivity tests on technology costs and performance to assess the impact of moving away from "best practice" values;
- further investigations into the effect of infrastructure costs on the deployment of embedded generation and transport technologies;
- further investigation of the implications of cost differentials between primary fuels;
- impact of fuel taxation levels on the choice of fuels and technologies in transport.

This second phase of work on Long Term Low Carbon Options was commissioned by DTI, with input from other government departments. It has made a more detailed analysis of the issues listed above, and also examined issues relating to the phasing of emission reduction and the role of specific technologies. The results have helped inform the Energy White Paper.

The report is structured as follows:

- Chapter 2 gives a recap on the overall approach to the work, including brief details of the MARKAL energy system model, the energy supply and demand scenarios and the technology database.
- Chapter 3 examines the implications of a low carbon future in terms of implementation cost, economic growth and impacts on energy users.
- Chapter 4 looks at the distribution of carbon abatement actions between economic sectors.
- Chapter 5 looks at the impact of a low carbon future on the primary energy mix, the sensitivity of technology choices to energy price differentials and the importance of new infrastructure requirements.
- Chapter 6 examines the importance of technology and innovation in supporting a low carbon future.
- Chapter 7 considers the impact of alternative ways of phasing the transition to a low carbon future on costs and the choice of technologies.

2 Approach

The framework for this analysis was the MARKAL energy system model developed in the first phase of the - *Options for a Low Carbon Future* study. Systems models are designed to calculate the cost-optimal mix of energy technologies needed under different scenario assumptions regarding the demand for energy services, primary energy prices and limits on energy related emissions. They also estimate the cost of the energy system for each time step and over the full period of investigation, and therefore provide estimates of the cost associated with changes to the system, for example to abate carbon dioxide emissions. The advantages of such models are that they:

- Cover a wide range of technologies in the energy system and allow some feedback between the energy supply and demand sides;
- Provide a framework to evaluate technologies on the basis of cost assumptions, check the consistency of results and explore sensitivities to key data and assumptions;
- Have the flexibility to represent a wide range of energy systems with the possibility of easy extension to meet additional requirements;
- Are able to look across a timeframe (in this case to 2050), thus providing information on the phasing of technology deployment, energy supply and use and carbon emissions;
- Enable emissions constraints to be applied, with the energy system adjusting to meet these at least cost[4];
- Allow comprehensive analysis of the costs associated with changes to the energy system including total discounted cost, annual costs and average and marginal costs of abatement.

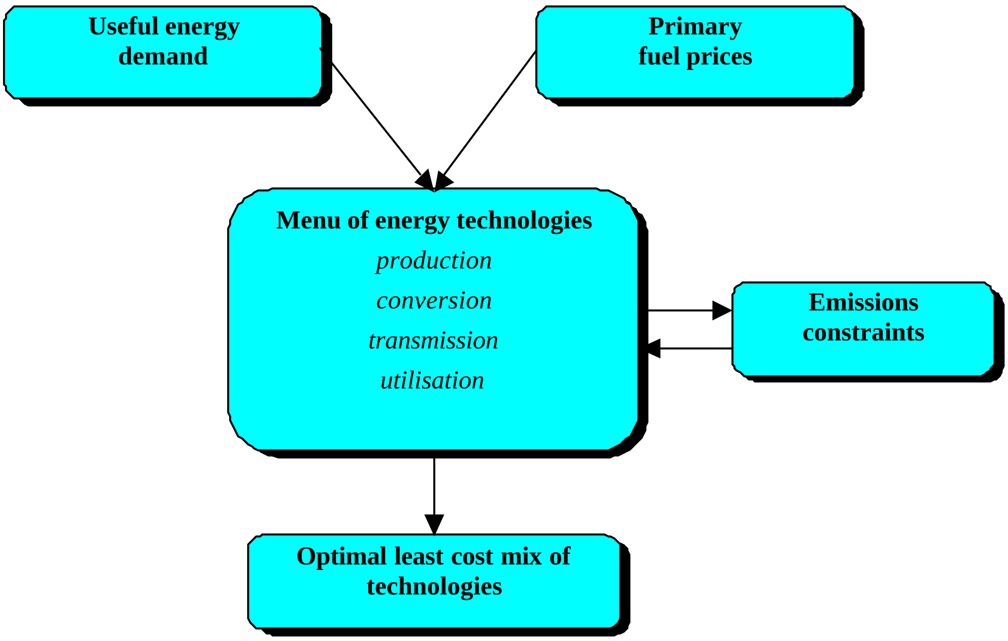

Figure 1 Schematic representation of the key features of the MARKAL Model

[4] In this study the model only considered abatement of carbon dioxide emissions and not the other gases covered by the Kyoto Protocol.

Data input to MARKAL consists of both *scenario* assumptions and *technology* information (Figure 1). The scenario assumptions consists of primary energy prices, demands for energy services and any emissions constraints; the technology information concerns data on the costs (capital and operating) and performance (efficiencies, availability etc) of each technology in the model.

2.1 SCENARIO ASSUMPTIONS

Investigations of future trends, whatever the subject area, are fraught with uncertainty, particularly over a timeframe of 50 years. This is no less true for the energy sector, which is subject to a range of economic and social drivers, which could evolve in different ways. This can be illustrated by three examples. Firstly overall economic growth will affect the wealth of all the population and thereby personal demand for energy services such as warmth, mobility, entertainment, etc. Secondly the changing balance of business activities between energy intensive manufacturing, light engineering and services will change both the level and nature of commercial energy use. Thirdly energy demand will change with social preferences affecting decisions on where we live, how and to what extent we travel, what leisure activities we follow, etc.

This study has maintained the scenario based approach of the first phase to examine a range of possible future development paths and their implications for energy prices, energy demands and related carbon dioxide abatement costs and technology changes. The three scenarios used for the first phase of the study were retained for this work. Their titles and conceptual themes were:

- Baseline (BL) – in which the current values of society remain unchanged and policy intervention in support of environmental objectives is pursued in a similar way to now (GDP growth 2.25% per year).
- World Markets (WM) – based on individual consumerist values, a high degree of globalisation and scant regard for the global environment (GDP growth 3% per year).
- Global Sustainability (GS) – based on the predominance of social and ecological values, strong collective environmental action and globalisation of governance systems (GDP growth 2.25% per year).

The three scenarios were essentially global in the sense that it was implicitly assumed that the world would be following the same development path as the UK. They were developed to investigate three quite different combinations of the economic and social drivers outlined above. As part of the scenarios, fuel prices were specified by DTI, to take account of the different demands for energy services that they envisaged. For example gas and oil prices were higher in WM on account of higher world demands for energy services and the importance of these fuels for transport and power/heat production respectively (See Section 2.1.2).

In this second phase of the study further sensitivities were developed to examine factors such as reduced uptake of energy efficiency, alternate costs and availability of particular fuels and technologies and different abatement targets and trajectories. Most of the sensitivities have been assessed around or against the Baseline (BL) scenario, but where appropriate work has also covered the other scenarios to provide a broader range of results.

2.1.1 Demand for energy services

Energy services or useful energy is a measure of the demand for a service the provision of which involves energy consumption (e.g. light, warmth, mobility). Useful energy demands can be met by a variety of competing fuels, burned in different devices with different efficiency. For example, useful energy demand for space heating reflects the desired level of comfort and the area to be heated. This demand could be met by electric heating or gas boilers, but alternatively it could be ameliorated by insulation measures designed to reduce the heat supply required. The evolution of these useful energy demands for each of the main end-use sectors is shown in the tables below relative to their levels in 2000.

Table 1 Index of Useful Energy Demands for Each Scenario

Baseline Scenario

	Domestic	Industry	Service	Transport
2000	100	100	100	100
2010	118	103	116	118
2020	133	107	127	135
2030	145	110	135	148
2040	151	114	142	158
2050	154	117	149	165

World Markets Scenario

	Domestic	Industry	Service	Transport
2000	100	100	100	100
2010	128	104	119	122
2020	150	108	132	145
2030	168	111	142	165
2040	180	115	154	183
2050	184	119	166	198

Global Sustainability Scenario

	Domestic	Industry	Service	Transport
2000	100	100	100	100
2010	117	104	114	112
2020	131	108	120	122
2030	140	112	127	127
2040	145	116	133	130
2050	145	120	138	129

In line with the underlying concepts of the scenarios WM involves a greater increase in demand than BL across all sectors. In contrast GS, despite having the same overall GDP growth rate as BL, has a slower increase in demand for energy services. This reflects a greater readiness to adopt sustainable patterns of behaviour by commercial organisations, government and private individuals. Population growth and the increase in number of households are other key drivers for useful energy demands. All three scenarios assume modest growth in population (~7-10%) but a greater expansion in the number of households (~17-35%) by 2050. This is reflected in some slowing of transport and domestic demand growth. A fuller description of the derivation of the scenario for useful energy demand projections is given in Annex A of the report covering Phase 1 of the study (FES, 2002).

Overall energy savings and hence reductions in carbon dioxide emissions come from a combination of energy efficiency improvements by suppliers and end users combined with structural changes (e.g. reductions in energy intensive industry, change in the utilisation of transport modes, increased share of service sector activities in total GDP). Such structural change has been included in the scenario assumptions.

Energy intensity (i.e. the ratio of energy consumption to GDP) measures how effectively energy is used within an economy. The combination of population and social trends combined with structural change, outlined above will cause a change of energy intensity external to the MARKAL model's optimisation of the energy system. This has been estimated as an annual reduction of energy intensity of 1.4%, 1.9% and 1.6% for the BL, WM and GS scenarios respectively. For comparison the UK's energy intensity fell by 2.1% on average over the last 30 years.

2.1.2 Energy Prices

The main exogenous assumptions about energy prices required for the analysis are the primary or landed prices for oil, natural gas and coal. These were specified by DTI, taking account of the long run supply position and demand variations between scenarios and are shown in the following tables.

It is certainly possible to conceive of a wider range of fossil fuel prices than those projected for the scenarios. Furthermore, the price scenarios do not take account of the potentially appreciable changes in demand (e.g. for natural gas) caused by constraints on carbon dioxide emissions. Sensitivities have been further investigated through separate assessments of the implications of limits on natural gas supplies (Section 3) and other fossil fuel price differentials (Section 5).

MARKAL did not model the production of refined fuels from crude oil or the preparation of natural gas and coal for distribution to end users. Instead established relationships between "beach prices" and delivered prices were used to calculate final user prices for each scenario, which were included in the model. These are presented in Annex A.

Another factor affecting delivered energy prices is taxation and duty. Here, the base assumption was that the current rates of duty and VAT would apply throughout the modelling period. One important exception was alternative road transport fuels, where it was assumed that they would incur their current level of duty (frequently zero at present) until they exceeded 3% of the market. Further production above the 3% level attracted the same duties and VAT as gasoline and diesel (i.e. on a unit of energy basis) on the assumption that tax revenues would need to be broadly maintained[5]. Alternatives to these assumptions were investigated as part of this work (Section 6).

Table 2 Primary Energy Prices used in the Study ($ 2000)

Baseline Scenario

	Oil ($ per barrel)	Gas ($/toe)	Coal ($/tonne)
2000	28	120	36
2010	20	120	36
2020	20	135	36
2030	25	160	36
2040	25	180	36
2050	25	180	36

World Markets Scenario

	Oil ($ per barrel)	Gas ($/toe)	Coal ($/tonne)
2000	28	120	36
2010	24	145	36
2020	28	170	36
2030	35	210	36
2040	35	210	36
2050	35	210	36

Global Sustainability Scenario

	Oil ($ per barrel)	Gas ($/toe)	Coal ($/tonne)
2000	28	120	36
2010	15	130	36
2020	15	150	36
2030	15	180	36
2040	15	190	36
2050	15	200	36

2.2 TECHNOLOGY CHARACTERISATION

The choice of technologies to be included in a systems analysis study is crucial because this effectively sets limits on the range of options available. This study aimed to cover a broad range of current and prospective technologies relevant to the 2050 time horizon and the potential for major constraints on CO_2 emissions. Technologies were specified for the following areas:

[5] Below the 3% threshold, the duty incurred by alternative fuels was CNG 9p/k g , biodiesel 25.82 p/litre, while hydrogen, methanol, ethanol, electricity did not incur any duty. Above the 3% threshold all fuels were taxed at the same duties as ultra-low sulphur petrol and diesel (45.82 p/litre) on a unit of energy basis. This equates to about £11.6/GJ,

- Electricity generation (centralised and decentralised)
- Production of alternative fuels for transport
- Hydrogen production and distribution
- Passenger car transport
- Freight transport (road and rail)
- Public transport (road, rail and air)
- Domestic sector
- Commercial and Services Sector
- Industry sector

To ensure consistency in the selection of the technologies, and in their representation in the model, each of the areas was specified through a “route map” showing the linkages between supply and end-use technologies. These route maps are presented in Annex C of the report on Phase 1 of the project (FES, 2002).

Individual technologies are represented in the MARKAL model through a data set covering capital and operating costs, efficiency, availability and operating lifetime. Clearly these parameters will change with time through economies of production, innovation, learning by doing, etc., and it is important to consider this evolution in the study. A broad range of data sources was used (see Bibliography to the report on Phase 1 of the study) to establish a database on all the technologies. These data were assessed and adjusted to produce an internally consistent database by comparison of both the individual performance parameters and their overall production/end-use costs. Gaps in data time series were filled by interpolation, drawing on published engineering assessments of future developments, and available studies of the projected effects of innovation on costs. The underlying principles guiding this process were:

- Technologies were assumed to be developed globally and to benefit from advances in design, engineering and production stemming from such broad involvement, although the implications of more limited innovation have been explored (Section 6).
- The costs and performance data were set to be representative of commercially deployed technologies enjoying the benefits of volume production (i.e. not first of a kind costs).
- Technologies with low deployment prospects in the UK were still assumed to gain the benefits of volume of production if they had significant global potential (e.g. PV).
- Those development costs incurred in the UK were not considered explicitly within the analysis, but were assumed to be included in technology costs.
- “Best practice” costs (i.e. costs that assume plant are built on time and according to cost projections) were used throughout the database

This established a reference database, common to all three scenarios, which was reviewed by DTI, DEFRA and the PIU team, and subject to further checking through preliminary runs of the model (see Annex D of the report on Phase 1 of the project). Clearly, forecasting technology performance over a 50 year period is uncertain and highly judgemental. By following this process the aim was to develop a data set that avoided the high optimism of the protagonists of particular technologies and the pessimistic assessments made by supporters of rival options. Moreover, whilst all such projections are associated with considerable uncertainty, the projected cost differentials between technologies are often rather smaller.

Discount rates of 15% were applied to supply side investments when estimating the annualised value of capital costs, following the standard practice of industry, which is to make some allowance for risks and cost escalation by using higher discount rates than those used, for example, by the public sector. For energy efficiency, discount rates of 25% were used, both to allow for risks and for the observed fact that consumers are often sceptical about estimates of (or ‘discount’) the efficiency gains claimed for new technologies.

During this second phase of the work the assumptions relating to two key technology areas were subject to further review by two workshops on electricity supply and hydrogen production and distribution (see Annexes C and D of this report). These discussions identified some key technology issues, which were examined further in this work or other studies supported by DTI.

- Recent developments have established new designs for cleaner coal technology, both with and without carbon dioxide separation, that are substantially more cost effective than those included in the original data base.
- Retrofitting existing coal plant with supercritical boilers offers a potentially cost effective means for continued use of coal for power generation.
- New nuclear plant designs offer lower costs with series ordering than those used in the model.
- The impact of generation intermittency requires specific investigation, particularly for wind energy.
- The assumptions for hydrogen transmission and distribution costs in the model were considered optimistic.
- Fuel duty levels are a key instrument for promoting the transition to alternative, low carbon, fuels in road transport.

3 Economic Implications of a Low Carbon Future

3.1 INTRODUCTION

The results of the earlier work showed that the costs of achieving a low carbon economy, while large in absolute terms, were a relatively small proportion of Gross Domestic Product (GDP) (i.e. for a given year annual costs were always less than 1% of GDP in that year). As a result, the economic implications were estimated to be quite modest, with an average annual loss of GDP of 0.01 to 0.02 percentage points for a 60% reduction in CO_2 emissions by 2050[6]. This equates to an overall loss of 0.5% of GDP by 2050 or 2.5 month loss of growth.[7]

However, it was noted that the core assumptions used for this analysis reflected significant cost reductions and improvement in performance as a result of world-wide technical advances, 'learning by doing' and economies of scale. Moreover, no additional price increase or limit on supply was considered, which may be triggered by the significant increase in demand for natural gas resulting from the measures taken to reduce CO_2 emissions.

The analysis undertaken in the second phase of the project has examined a range of alternative scenario assumptions in a wide range of areas, which could be expected to lead to higher costs and more significant impacts on the UK economy than those seen in the earlier results. Key areas in which different assumptions have been explored include:

- Restrictions to the availability and cost-effectiveness of energy efficiency;
- Limits on the availability of natural gas;
- Reduced innovation;
- Increased costs or non- availability of key technologies;
- Increased costs of infrastructure to support new technologies and fuels.

It should be stressed that while the analysis has focussed on alternative, more pessimistic, assumptions it would have been possible to have constructed scenarios that reduced costs. However, for the purposes of this analysis it was the upside risks that were of most interest.

It should also be noted that the energy system represented in MARKAL produced 132MtC in 2000 compared to the 155MtC attributable to the full energy system. The difference arises because MARKAL does not include some areas of energy conversion and consumption, the most important of which are refinery operations, solid fuel production, own consumption by the oil and gas industries, agriculture, construction and water transport. Consequently the results presented below are a slight underestimate of the costs of abateing carbon dioxide emissions from the full energy

[6] For example an original GDP growth rate of 2.25% per annum would be reduced to an average 2.24% due to carbon dioxide abatement measures.
[7] These values are consistent with the results presented in the IPCC Third Assessment Report which suggests that the best estimates for the global GDP impacts of stabilising CO_2 emissions at 550 ppm (broadly consistent with the UK achieveing a 60% reduction in emissions by 2050) lie in the range 0.1% to 1.8%, depending on scenario.

system. If the costs of abatement are similar for these additional areas then the costs presented below are about 85% of the total abatements costs for the energy sector.

3.2 ABATEMENT COSTS

A number of measures have been used to examine the costs of achieving a low carbon economy. These have included:

- Increase in the annual energy system costs (i.e. over and above the system cost without CO_2 emissions abatement) in each decade between 2000 and 2050 (i.e. the Annual Abatement Cost);
- Increase in total energy system cost to 2050 discounted back to 2000 (i.e. the Total Abatement Cost);
- The marginal cost of emission reduction in 2030 and 2050 (i.e. the Marginal Abatement Cost)[8].

In line with the objectives of the study these measures only consider the costs to the UK of reducing emissions. They do not cover the benefits of reduced climate change or indirect benefits such as improved security of supply, other environmental benefits, health improvements, etc.

Table 3 shows the annual abatement cost profiles to 2050 for the additional scenarios examined in phase 2 of the study. This shows that in the majority of the abatement scenarios, investment takes place in the period 2030 to 2050, when the CO_2 emission constraints are applied. The exceptions to this are those scenarios for which the constraints on technology options require early deployment of particular technologies in order to achieve the abatement targets in 2050. Under the original 60% reduction scenarios annual costs in 2050 are in the range £7bn to £13bn. With the new results this range has widened to £7bn to £42bn, although for most runs the annual costs in 2050 are less than £20bn. Assumptions that gave rise to much higher costs were those involving very limited uptake of energy efficiency measures, a combination of limited energy efficiency and no carbon sequestration or a lack of innovation (cost and performance improvement) in supply-side technologies[9].

Expressed relative to GDP the annual abatements costs in 2050 range from a low of around 0.3% to a level approaching 2% of GDP. Corresponding values for 2030 range from zero to about 0.4%. (NB for the BL scenarios with an average GDP growth of 2.25% per year).

[8] The marginal cost of abatement is the cost of abating the last tonne of carbon which achieves the specified emissions reduction.
[9] These individual results and trends are examined in more detail in later sections of the report.

Table 3 Annual abatement costs for the various scenario combinations (£Bn per year)

Theme	Scenario[10]	2020	2030	2040	2050
Original Results	BL60	0	1	5	10
	WM60	0.1	2	6	13
	GS60	0	0.3	2	7
Limited Energy Efficiency	BL60EE1	0	3	5	12
	WM60EE1	0	3	8	18
	GS60EE1	0	1	3	9
	BL60EE2	0	3	8	20
	BL60EE3	0.1	8	17	38
Limited Gas Supplies	BL60PE1	0	0	4	10
	WM60PE1	0	1	5	15
	GS60PE1	0	0	1	7
	BL60PE2	0	1	4	10
	WM60PE2	0	1	5	14
	GS60PE2	0	0.1	2	7
Technology Sensitivities	BL60INNOV	0.1	6	19	42
	BL60NUC1	0	6	4	9
	BL60NUC2	0.1	1	5	10
	BL60EE1NS	0	3	12	42
Infrastructure Sensitivities	BL60HYD	0	1	5	13
	BL60WIND	0	1	5	10
Alternative Emission Paths	BLDEF1	1	3	6	10
	BLDEF2	0	1	4	10
	BLDEF2	0	0.1	3	10

Total discounted abatement costs over the period to 2050 have been calculated at both a 3.5% and a 6% discount rate. At the 3.5% discount rate, the total discounted Abatement Costs for the core scenarios covered in phase 1 of the project (i.e. 60% reduction in emissions by 2050) lay between £22bn and £56bn. With the broader set of assumptions being investigated in the current work, the range of costs has broadened to £17bn and £170bn, with most of the runs having costs between £30bn and £60bn (Figure 2). Again the scenario variants giving the highest costs were those involving very limited uptake of energy efficiency measures, a combination of limited energy efficiency and no carbon sequestration or a lack of innovation (cost and performance improvement) in supply-side technologies.

[10] A full listing and specification of the scenario/model assessments undertaken in this study is given in Annex A.

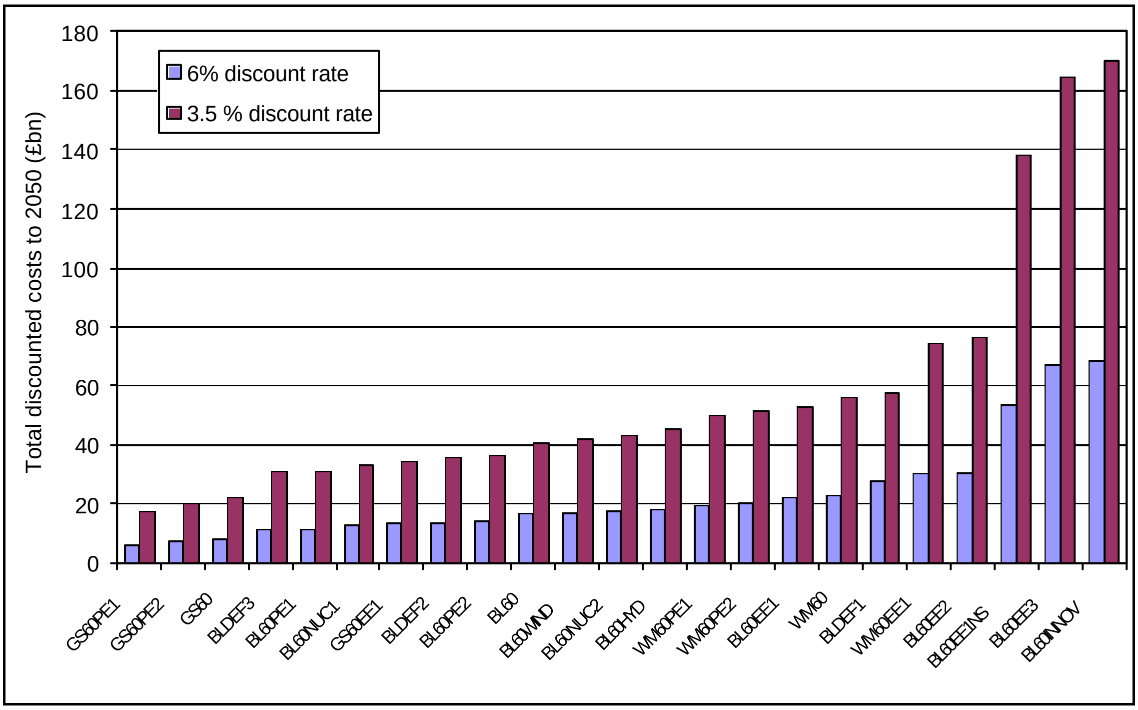

Figure 2 Total cumulative abatement costs to 2030 and 2050, discounted back to 2000 (£bn)

The marginal costs of abatement in 2030 and 2050 have also been calculated for each of the scenario variants and these are shown in Figure 3. Previously, the marginal abatement costs in 2050 varied between £329 and £538/tC. This has extended to £329 to £5840, with most of the runs having marginal costs of less than £900/tC. In contrast, marginal costs in 2030 are much lower, typically between £25 and £150/tC, although under the reduced energy efficiency runs costs can be as high as £400/tC.

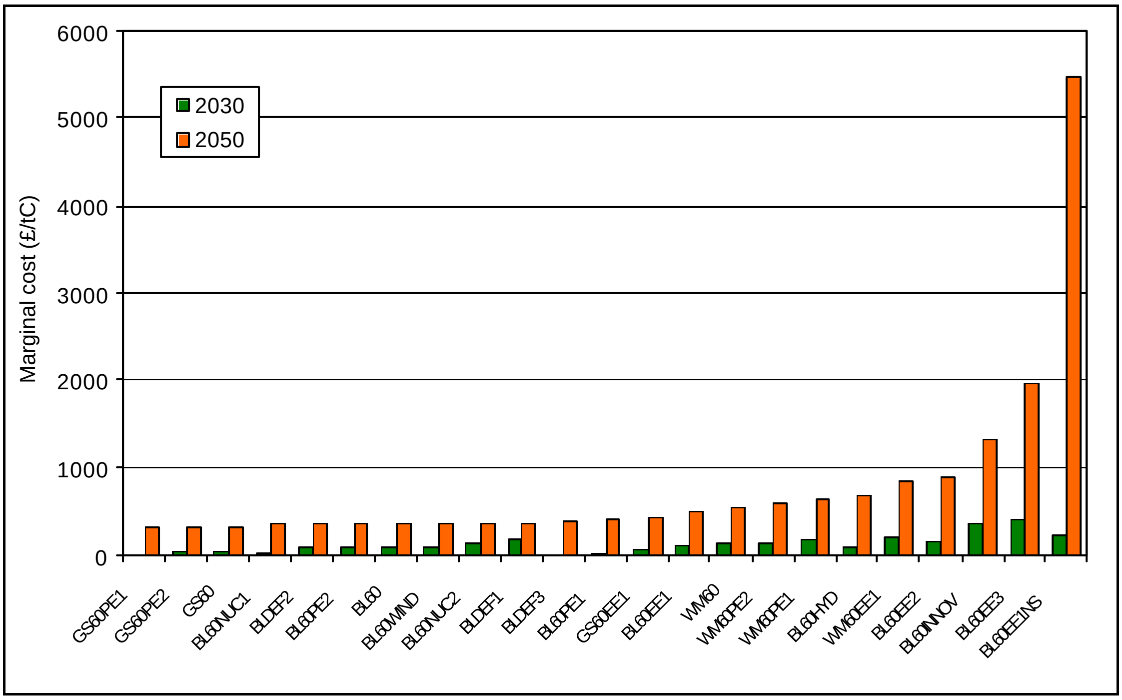

Figure 3 Marginal costs of abatement in 2030 and 2050 (£/tC)

3.3 SENSITIVITY OF ABATEMENT COSTS TO OIL AND GAS PRICES

The impact of assumptions regarding the level of fossil fuel prices have been explored with the range of scenario prices (Table 2) and in sensitivity assessments using alternative fossil fuel price projections (Section 5.2). In addition assessments have been made of the relative impact on total abatement costs when the price of both crude oil and natural gas are assumed to be lower than those initially assumed in each scenario. It has been found that when oil and gas prices are lower the total abatement costs increase as low carbon technologies become relatively more expensive. The size of the increase in total abatement cost is, however, small relative to the overall abatement cost in each scenario.

To illustrate the impact of lower gas and oil prices on abatement costs reductions of 20% and 50% in oil and gas prices compared with those in Table 2 were examined. Under the BL scenario a reduction of 20% in prices implied an increased abatement cost of around £1bn/yr, or 0.04% of GDP in 2050. This represented an increase of around 10% in total abatement costs. The impact under the World Markets scenario of a 20% lower price assumption was broadly similar. A reduction of 50% in oil and gas prices increased abatement costs by around 0.09% of GDP in 2050 and total abatement costs by about 20% in each scenario.

3.4 IMPACT ON GDP

An alternative way of considering the costs of CO_2 abatement, and to place them in an overall national economic perspective, is to consider their impact on (a) energy costs as a share of GDP and (b) the rate of GDP growth. The method of calculating the effects of changes in costs on economic growth is outlined in the box below.

At present energy costs account for about 4% of GDP. Results for the BL scenario without emission constraints show this falling to about 3.8% in 2020 and 2.3% in 2050. This reduction is due in part to the trend for reducing energy intensity, linked to structural change in the UK economy, assumed in the demand scenarios (e.g. 1.4% per year in the BL scenario). In addition, the MARKAL model deploys improved energy efficiency technologies. With the BL scenario and a 60% constraint on carbon dioxide emissions the share of energy costs in GDP stays at 3.8% in 2020 but only falls to 3.0% in 2050. Nonetheless, the trend remains for energy to take a declining and small share of overall economic activity.

Taken overall the new estimates of the affect of carbon dioxide abatement on economic growth confirm the earlier findings that the impact of moving to a low carbon economy is small. For most scenario variants the reduction in average annual GDP growth is about 0.01 percentage points or less (Figure 4). This equates to a total loss of GDP in 2050 of 0.9% or 5 months growth.

Calculating GDP impacts

The calculation of GDP impacts is based on elementary investment theories of growth. In practice, economic models that take into account the effects of policies on taxation, revenues, investment, employment, the returns to investment, trade and a variety of other factors are needed to arrive at more satisfactory estimates. However, the following is useful for ‘ball park’ estimates and, if anything, may lead to an overstatement of the effects of CO_2 abatement on growth.

Denoting the long-term rate of economic growth per period in a given scenario by *g* then by definition the change in income (Y) between periods $t + 1$ and t is:

$$\boldsymbol{Y_{t+1} = Y_t + g.Y_t} \qquad (1)$$

Under an abatement scenario, in which CO_2 emissions are reduced relative to the reference case, $\boldsymbol{Y_t}$ will be lower than it would otherwise have been because of the extra expenditures (C) on energy (assuming costs rise). Hence $\boldsymbol{Y_{t+1}}$ will also be lower for two reasons, as can be seen from the second two terms on the right hand side of (1): the initial income will be lower, and fewer resources will be put into growth. Similarly, if the costs of reducing the emissions rise further, from say $\boldsymbol{C_t}$ to $\boldsymbol{C_{t+1}}$ in year $\boldsymbol{t}+1$, then $\boldsymbol{Y_{t+1}}$ will also be diminished. Hence the increase in output between the two periods will be given by

$$\boldsymbol{Y_{t+1} = Y_t + g.Y_t - (C_{t+1} - C_t)} \qquad (2)$$

The difference in $\boldsymbol{Y_{t+1}}$ between (2) and (1) gives the effects on GDP of imposing carbon constraints. The MARKAL results for annual abatement costs in the energy sector (C) have been used to solve this relationship recursively using 10-year increments.

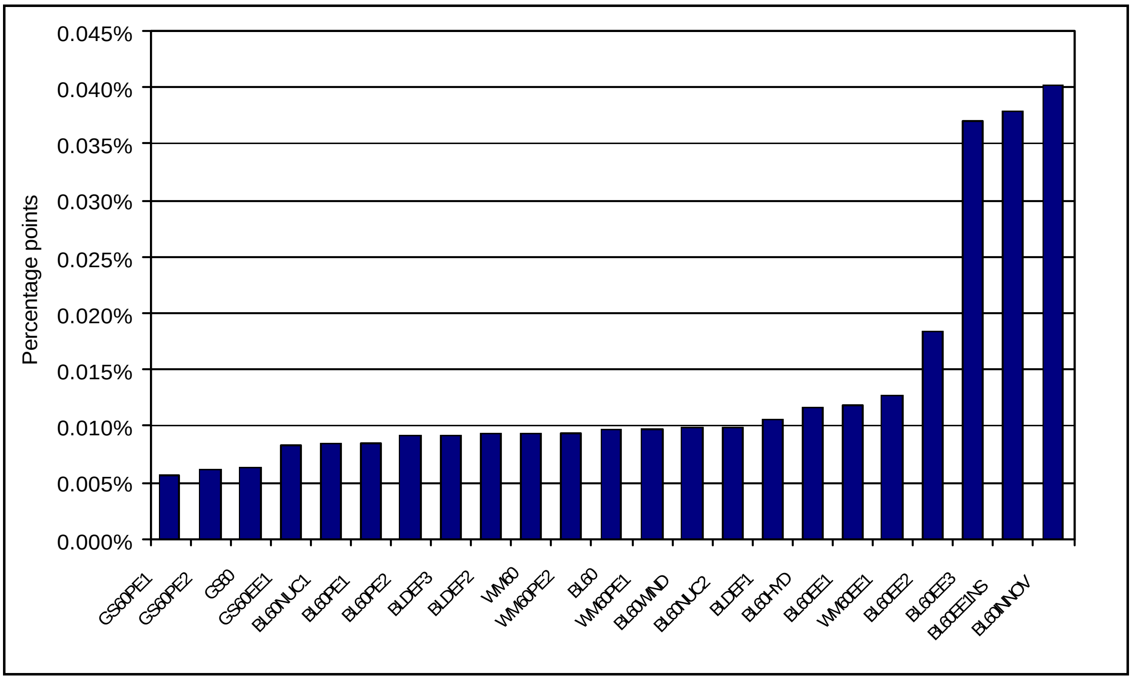

Figure 4 Reduction in average annual GDP growth over the 50 years to 2050

3.5 SECTOR IMPACTS

The costs associated with meeting carbon emissions constraints are distributed across all sectors of the economy. This occurs through increased prices for low to zero carbon energy sources including electricity, hydrogen and alternative transport fuels such as biodiesel and methanol[11]. The model allows sectors to respond to these price increases by investing in additional cost-effective fuel switching and energy efficiency in both supply and demand.

The distribution of costs between sectors in 2020 and 2050 for a set of modelling runs based on the BL scenario is summarised in Table 4. Results show that for model runs constrained to reduce carbon emissions by 60% in 2050 (and by 30% in 2030) there is no impact on sector energy costs in 2020. This is because the model only needs to deploy cost effective energy efficiency measures to attain the required emission reduction up to 2020 to be on track to achieve the above emissions constraints. (NB The model is free to determine the level of emission reduction in 2020 on its way to a 30% reduction in 2030.) However, significant additional costs are incurred in all sectors to attain the 60% reduction in carbon emissions in 2050. The transport sector has a particularly large increase in costs because the model deploys a large proportion of hydrogen fuelled transport technologies by this stage. (NB costs for transport cover road and rail transport).

Table 4 Percentage Increase in Annual Sector Energy Costs due to Carbon Emission Constraints[12]

Sector	BL 60% Constraint in 2050		BL 20% Constraint in 2020	BL 30% Constraint in 2020
	2020	2050	2020	2020
Domestic % Change in average cost per household	0	20%	5%	6%
Services % Change in total annual cost	0	23%	13%	26%
Transport % Change in average cost per km of travel	0	54%	0	0
Industry % Change in total annual cost	0	22%	7%	22%

[11] It is possible that the price of natural gas will also rise because of its attractiveness as a low carbon intensity primary energy source. This has not been considered in the model runs reported here, but was investigated indirectly in the model runs with limited natural gas supplies.

[12] In the model runs used for this analysis Markal was prevented from deploying additional energy efficiency when the emissions constraints were applied. Consequently these estimates represent an upper limit to the sector costs for the BL scenario.

In the model runs in which firm emission reductions of 20% and 30% were applied for 2020 the services and industry sectors experienced substantial cost increases, with more modest increases in the domestic sector. As would be expected these rises were greater for the 30% carbon constraint. Transport avoids significant cost changes in 2020 and 2030 because carbon abatement, over and above that attained by cost effective improvements to the fuel efficiency of diesel and gasoline vehicles (Section 4.4.) requires radical changes in fuel and vehicle technology. Because of the high cost of such changes the model takes action in other areas first.

The cost impact of carbon constraints on industry is not distributed evenly across manufacturing sectors because some are more energy intensive than others. Also the implications of higher energy costs are greater for sectors that produce internationally traded goods since they may lose cost competitiveness if their rivals do not incur similar increases. These issues have been examined in a separate study by DTI using MARKAL energy costs (this is presented in Annex F). This showed that the sectors experiencing the greatest increases in production costs (> 2% of total costs) would be industrial gases, inorganic chemicals, brick manufacture, cement/plaster, and to a lesser extent (~ 1% of total costs) metals, paper, chemicals and minerals industries. Of these sectors metals, paper, chemicals, and minerals (ceramics) face the most intense international price competition.

3.6 IMPACT ON TAX REVENUE OF SWITCHING BETWEEN TRANSPORT FUELS

It has been reported earlier that the model introduces major changes in the mix of road transport fuels in order to reduce carbon dioxide emissions. These changes may impact on the tax revenue derived from the transport sector in two ways:

- Fuel switching is generally accompanied by the deployment of more fuel efficient vehicle technologies, thus reducing the amount of fuel consumed.
- Some alternative transport fuels (e.g. CNG and biodiesel) are currently taxed at lower rates than diesel and gasoline, and these rates were maintained for the first 3% of the market after which they attracted tax at the gasoline/diesel rate.
- Other alternative fuels (e.g. hydrogen and methanol), which currently have negligible utilisation, were allowed to each take 3% of the market before attracting tax at the gasoline/diesel rate.

The impact of these factors on tax revenue is shown in Table 5, which examines the percentage changes in revenue and energy consumption resulting from various levels of emission constraint. The impact on tax revenue increased with the level of emission constraint, and also occurred sooner with the more severe emission reduction. Most of the reduction in revenue was linked to a cut in energy consumption. Most of the balance was accounted for by hydrogen and methanol each being permitted to take up to 3% of the market before attracting tax.

Similar losses of revenue were noted with the GS and WM scenarios.

Table 5 Percentage Changes in Tax Revenue and Energy Consumption in the Transport Sector Resulting from Various Levels of Emission Constraint

Scenario	2000	2010	2020	2030	2040	2050
Tax Revenue						
BL-45%	0	0	0	0	0	-16
BL-60%	0	0	0	0	-25	-33
BL-70%	0	0	0	-15	-35	-34
Energy Consumption						
BL-45%	0	0	0	0	0	-12
BL-60%	0	0	0	0	-20	-25
BL-70%	0	0	0	-12	-27	-27

4 Distribution of carbon abatement actions between sectors

4.1 INTRODUCTION

This section examines the distribution of carbon abatement actions between sectors under different low carbon scenarios. Future carbon abatement can be achieved in three main ways:

- Improving the efficiency of energy supply;
- Improving energy efficiency in end-use sectors;
- Switching to low or zero carbon fuels so reducing the carbon intensity of energy supply and use.

The following sub-sections discuss the relative importance of each of these abatement alternatives, including the role of energy efficiency in each of the end-use sectors. It also examines how the overall energy intensity of the economy may change under a low carbon future.

4.2 CONTRIBUTION OF ABATEMENT OPTIONS TO EMISSIONS REDUCTIONS

Within a future scenario for the demand for energy services up to 2050 the development of carbon emissions will be determined by how a number of factors change over the period. These include:

- Useful energy demand (driven by GDP, population growth, etc);
- Efficiency of energy supply;
- Efficiency of energy use;
- Carbon intensity of energy supply and use.

Figure 5 shows how each one of these factors is projected to change under the BL scenario and under a number of different abatement scenarios resulting in 45%, 60% and 70% reductions in carbon emissions in 2050 compared to 2000.

Under the BL scenario, useful energy demand is projected to increase by 47% and in the absence of any changes to the other factors, CO_2 emissions would therefore also increase by 47%. However, even under this BL scenario, a number of changes take place that offset the tendency for rising useful energy demand to increase CO_2 emissions. The overall efficiency of energy supply improves by 16%, the efficiency of energy use improves by 36% and the carbon intensity of energy supply and use decreases by 2%. These are measures that are cost effective and do not need carbon dioxide abatement actions to stimulate their deployment. The net effect of the increasing useful energy demand, offset by these other factors, is that CO_2 emissions are projected to decline by 22% by 2050.

Under the abatement scenarios, the change in useful energy demands remains constant (there is no feed back between useful energy demands and prices in MARKAL), but the effect of the other factors changes. Perhaps surprisingly at first sight, the efficiency of energy supply actually decreases as the abatement scenario becomes more severe. The overall efficiency of energy supply worsens by 1% between 2000 and 2050 under the 60% abatement scenario and by 11% under the 70% abatement scenario. The reasons for this are that the improvements in the conversion efficiency of individual supply-side technologies are more than offset by the increasing use of secondary fuels, such as hydrogen and efficiency losses due to the use of carbon capture technologies. These changes are discussed in more detail in the next section.

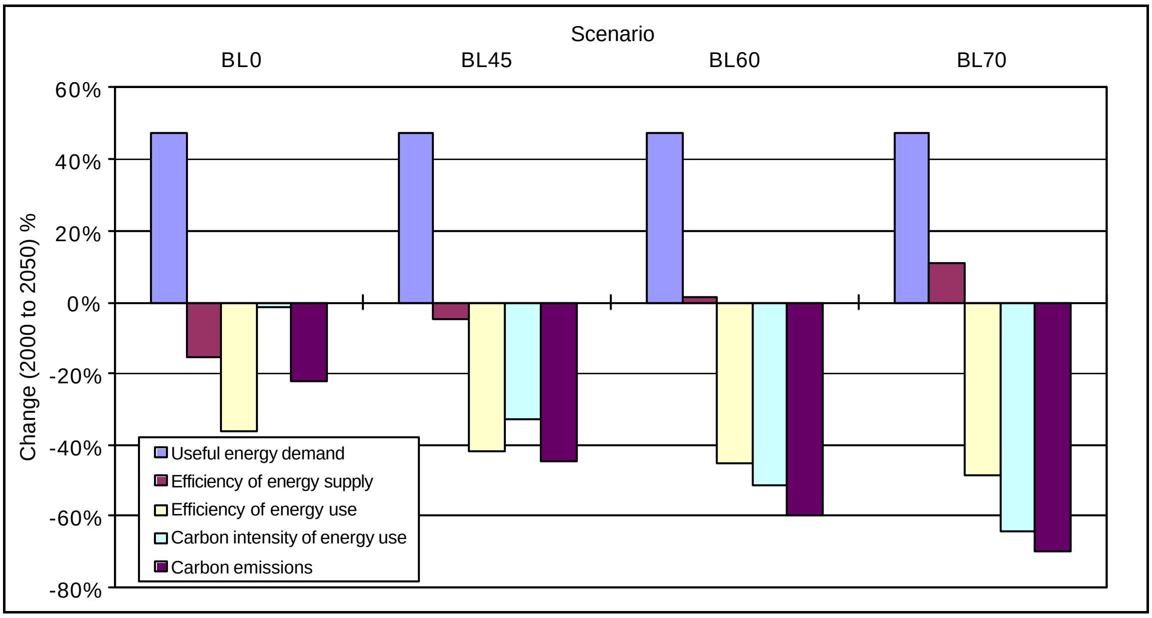

Figure 5 Contributions to the change in carbon emissions over the period 2000 to 2050

One obvious facet of these results is the large improvements in end-use energy efficiency being shown over the next 50 years, even in the absence of specific abatement targets. Comparing the projected improvements in energy efficiency, with those that have occurred historically, is not easy as there is no ready measure of true end-use 'energy efficiency' that can be taken from past energy statistics. However, it is possible to compare past and projected trends in energy intensity[13] - which incorporate both changes in energy efficiency and changes in the structure of the economy. This is done in Figure 6, which shows that on average final energy intensity (excluding energy used for international air travel as this is not included in the MARKAL results) improved at an annual average rate of 2.1%. This compares to the projected improvements in final energy intensity of 2.3% per year under the unconstrained BL scenario, rising to 2.6% under the 60% abatement scenario.

It is generally acknowledged that energy efficiency measures face a number of barriers to their uptake, even when shown to be cost-effective, and so two additional scenarios were developed to consider lower improvements in final energy intensity. These considered future intensity improvements of 2.1% (the thirty year historical average) and 1.6% (the ten year historical average).

The results of these scenarios are discussed in the Section 4.3 and 4.4 below.

[13] The ratio of total primary energy consumption to GDP.

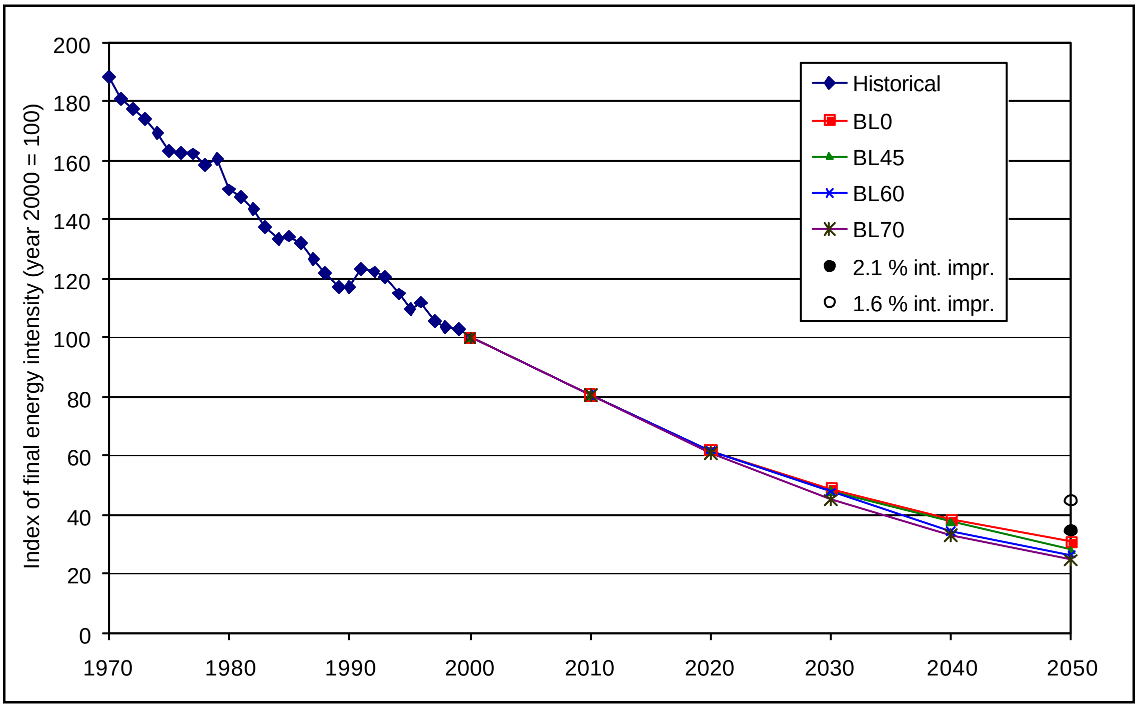

Figure 6 Historical (actual) and projected (model results) final energy intensities (excluding international air transport)

4.3 SUPPLY-SIDE ENERGY EFFICIENCY

The overall efficiency of energy supply, as measured by the ratio of final energy use to primary energy supply, increases between 2000 and 2050 under the unconstrained BL scenario due to improvements in the efficiencies of key technologies. However, under many of the abatement scenarios conversion efficiency falls as these improvements are offset by the increasing use of secondary fuels (e.g. hydrogen) and by the deployment of CO_2 capture and storage technology with its associated efficiency penalty.

Under all scenarios the efficiency of electricity generation improves significantly. Figure 7 shows the improvement in the efficiency of electricity generation from fossil fuels. Under the unconstrained BL scenario, the average efficiency increases from just less than 40% in 2000 to 75% by 2050, largely as the result of technological advances in CCGT technology including, in the long term, the advent of new configurations utilising fuel cells. Similar improvements in efficiency are also seen under the BL 45% abatement scenario. However, under the 60% and 70% abatement scenarios, the average efficiency of fossil fuel electricity generation only reaches 66% by 2050 as a result of the deployment of CO_2 capture and storage technology which has an efficiency penalty of around 8-10%.

With more stringent abatement scenarios, the improvements in the efficiency of individual conversion technologies are offset by a greater proportion of secondary fuels such as hydrogen and electricity in the final energy fuel mix. These fuels consume energy in their production and therefore as their share increases so too does the trend to reduce the overall efficiency of energy supply. Figure 8 illustrates that between 2000 and 2050 under the unconstrained BL scenario, the share of hydrogen and electricity in final energy consumption shows a modest increase from 19% to 25%. However, under the BL 60% and 70% abatement scenarios the proportion of these fuels in 2050 increases substantially to 42% and 53% respectively. Since the efficiency of hydrogen production (with carbon capture) is similar to that of fossil generated electricity in 2050, the increasing penetration of both these fuels puts a downward pressure on the overall efficiency of energy supply.

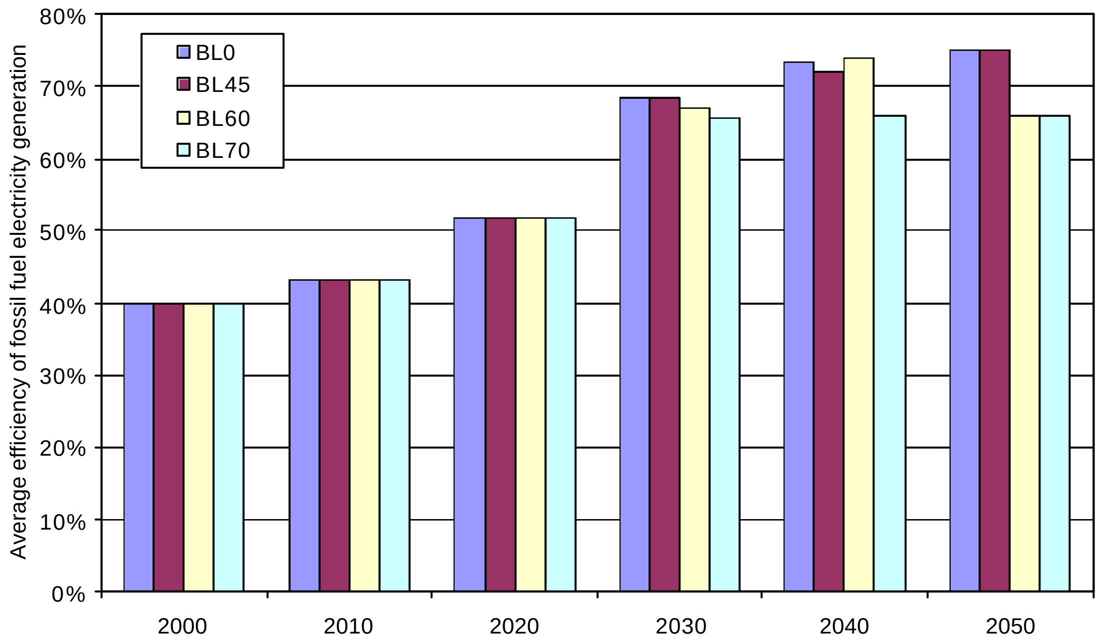

Figure 7 Average efficiency of electricity generation from fossil fuels

If efficiency improvements in energy use are constrained further, as in the scenarios when final energy intensity improvements are limited in line with historical trends, then the efficiency of the supply side decreases further as even more use is made of secondary fuels. However, as these secondary fuels are largely carbon free, the carbon intensity of energy use falls significantly so that the same level of CO_2 emissions reductions are achieved. Figure 9 shows the contribution of the various factors under the reduced energy efficiency scenarios compared to the core BL -60% reduction scenario.

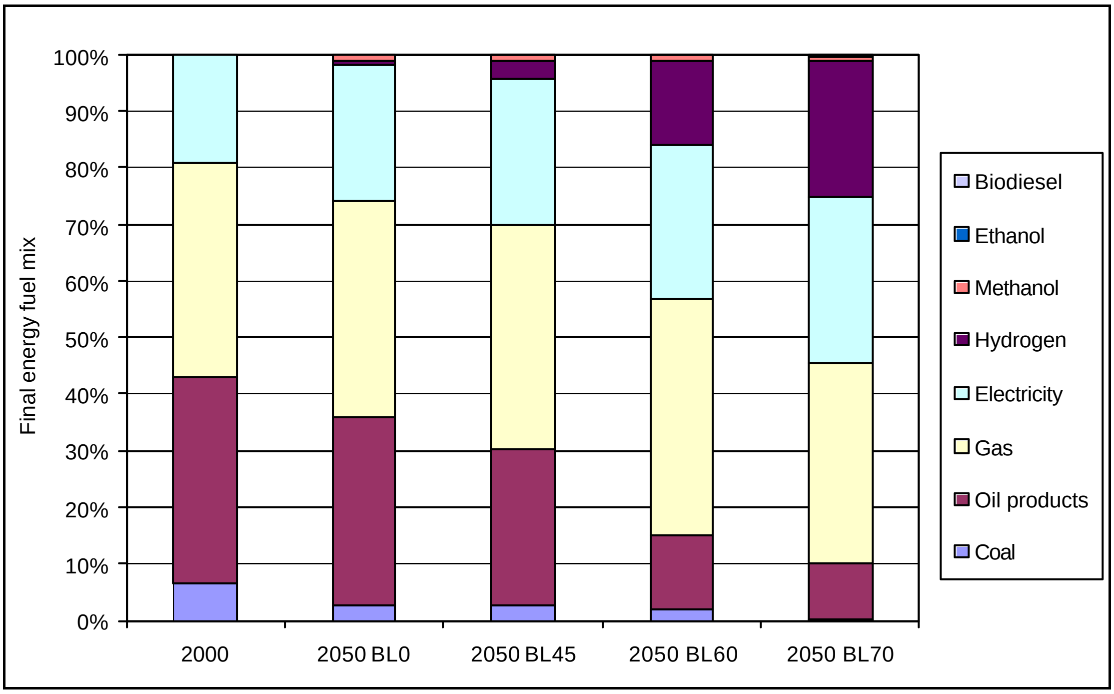

Figure 8 Final energy fuel mix

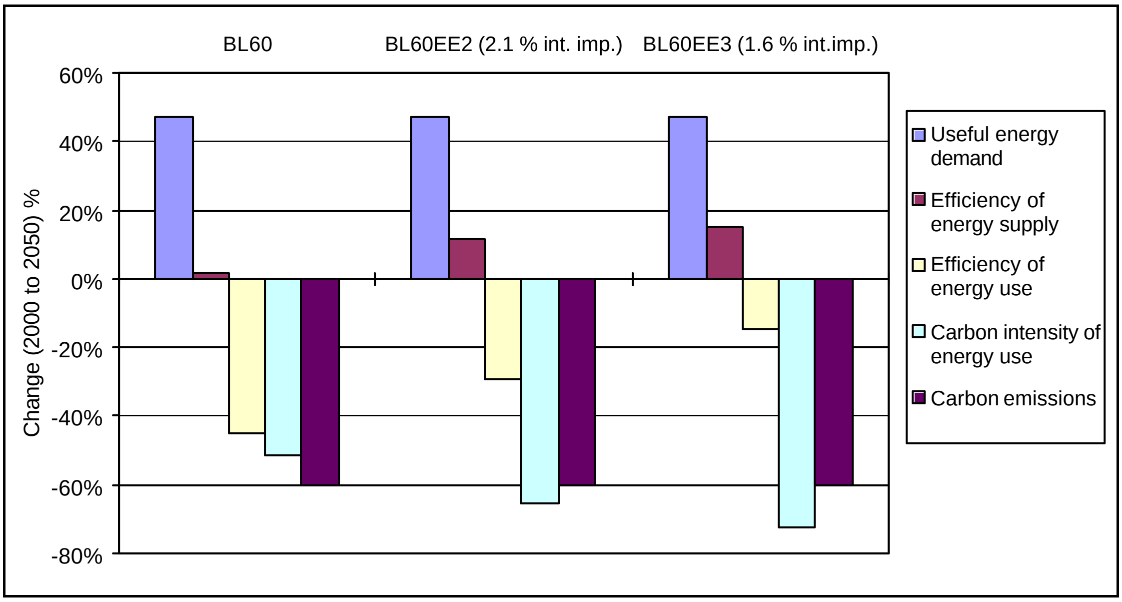

Figure 9 Effect of limiting end-use energy efficiency on the contributions to the change in carbon emissions over the period 2000 to 2050

The figure shows that, for the most severe limit on the rate of end use efficiency improvement, energy supply actually increases carbon dioxide emissions by 15% over the period 2000 to 2050 due to a deterioration in conversion efficiency. Also this limit constrains the reduction in emissions attributable to end use efficiency to only 14%. To compensate the carbon intensity of energy supply and use decreases by 72% under this scenario, through a combination of renewables, nuclear power and carbon sequestration.

4.4 DEMAND-SIDE ENERGY EFFICIENCY

Section 4.2 briefly described the important role that improvements in end-use energy efficiency have in reducing carbon emissions and Section 4.3 examined some of the knock-on effects on the supply sector if the improvements in end-use energy efficiency are limited. This section explores the improvements in end-use energy efficiency in more detail, discussing the contribution in different sectors and the impacts on costs of placing limits on this efficiency improvement[14].

Under the unconstrained BL scenario, energy efficiency is projected to improve by 36% over the period 2000 to 2050. Figure 10 shows how this improvement varies between sectors. The service sector shows the smallest improvement at 21%, while the largest improvement of 44% comes from the domestic sector.[15] As the targets for abatement are increased so the scenarios show increasing improvements in energy efficiency in all sectors. Under the 60% abatement scenario the improvements are 50% for domestic, 39% for industry, 27% for services and 53% for transport.

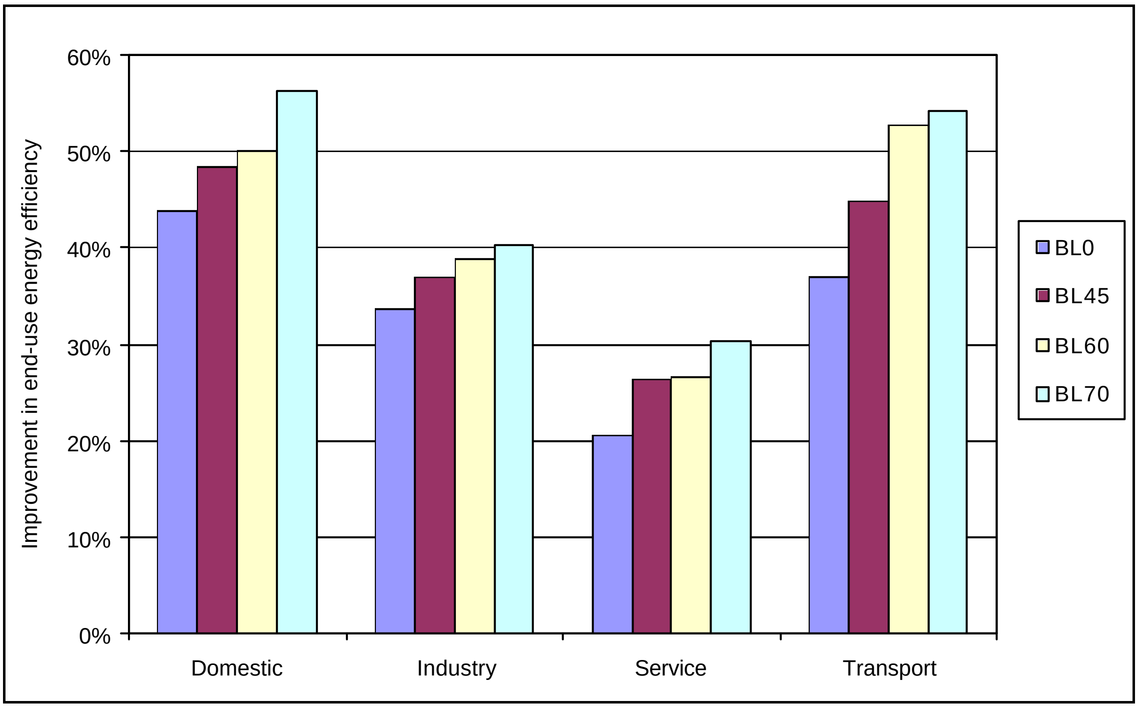

Figure 10 Efficiency improvements by sector over the period 2000 to 2050

[14] In this section improvements in demand-side energy efficiency are calculated by examining changes in the ratio of final energy demand to useful energy demand in each sector.
[15] The improvements in energy efficiency for each sector are in line with those calculated by DEFRA in a number of working papers submitted to the PIU as part of the Energy Review.

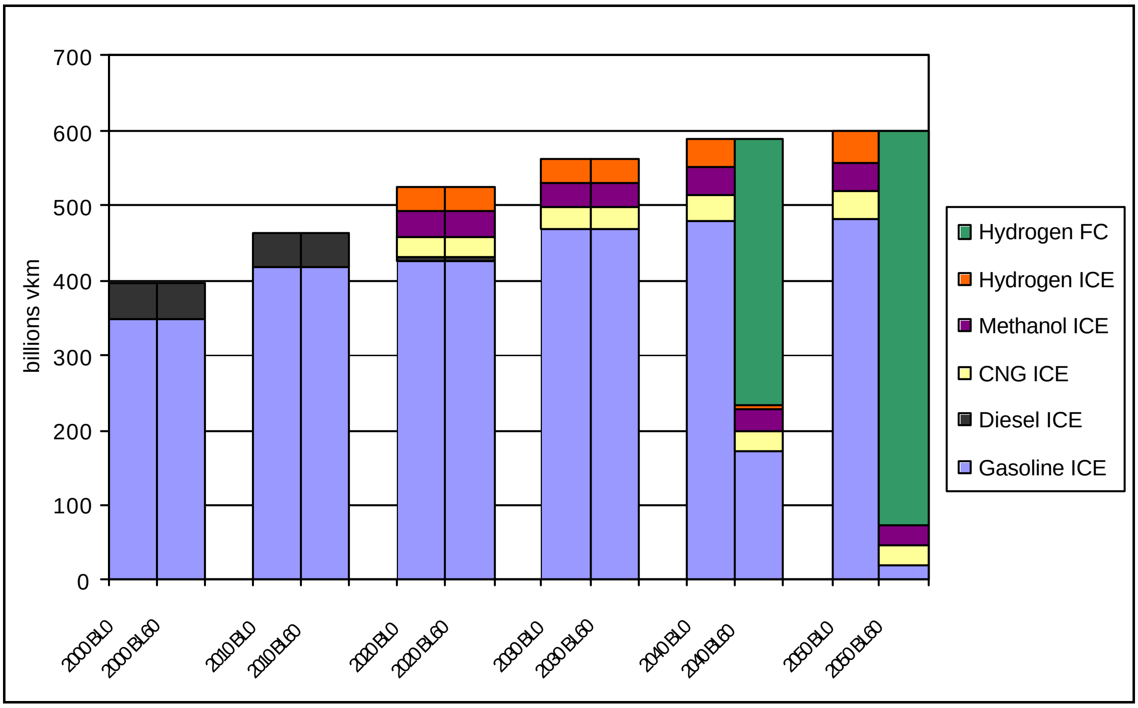

Figure 11 Car usage by technology and fuel type

The significant improvements in the transport sector are at odds with recent historical trends. Even without emissions constraints efficiency is expected to improve by 37%, and is achieved by improvements in conventional gasoline and diesel fuelled cars, the adoption of hybrid heavy goods vehicles, electrification of the rail system and more fuel-efficient aircraft. The additional improvement with emissions constraints is made possible by fuel switching and the use of fuel cell technologies.

As an example, Figure 11 shows contribution of different fuels and technologies to car use under the BL and BL -60% reduction scenarios. It should be stressed that these results should only be regarded as illustrative since not all car technology options were included in the model. In particular diesel hybrid technology was not covered. The small market shares taken by CNG, methanol and hydrogen/ICE vehicles is linked to the low to zero fuel duty applied to the first 3% of the market taken by these technologies. This illustrates the strong influence that fuel duty can exert on the choice of vehicles (Section 6.1.5).

Under the BL scenario without emission constraints, conventional fuels (mostly gasoline) dominate over the entire period to 2050, with only a small contribution from alternative fuels (determined by the fuel tax structure). However, under the 60% reduction scenario, there is a significant penetration of hydrogen from 2040 onwards, which brings efficiency benefits over gasoline even when used in an internal combustion engine (ICE) powered vehicle, but, more significantly, facilitates the use of fuel cells which are inherently more efficient than any ICE[16].

The imposition of limits on improvements in the energy efficiency of the demand sectors has significant implications for the costs of the abatement scenarios (Figure 12).

[16] Under the two scenarios, total car usage is the same since there is no feedback between useful energy demands and prices in MARKAL.

Limiting energy efficiency such that the overall improvement in final energy intensity is 2.1% per year (the 30 year historical average) increases the cost of achieving a 60% abatement target by a factor of almost two compared to the core run. For the scenario with an annual 1.6% improvement in final energy intensity (the 10 year historical average), costs are increased by a factor of four.

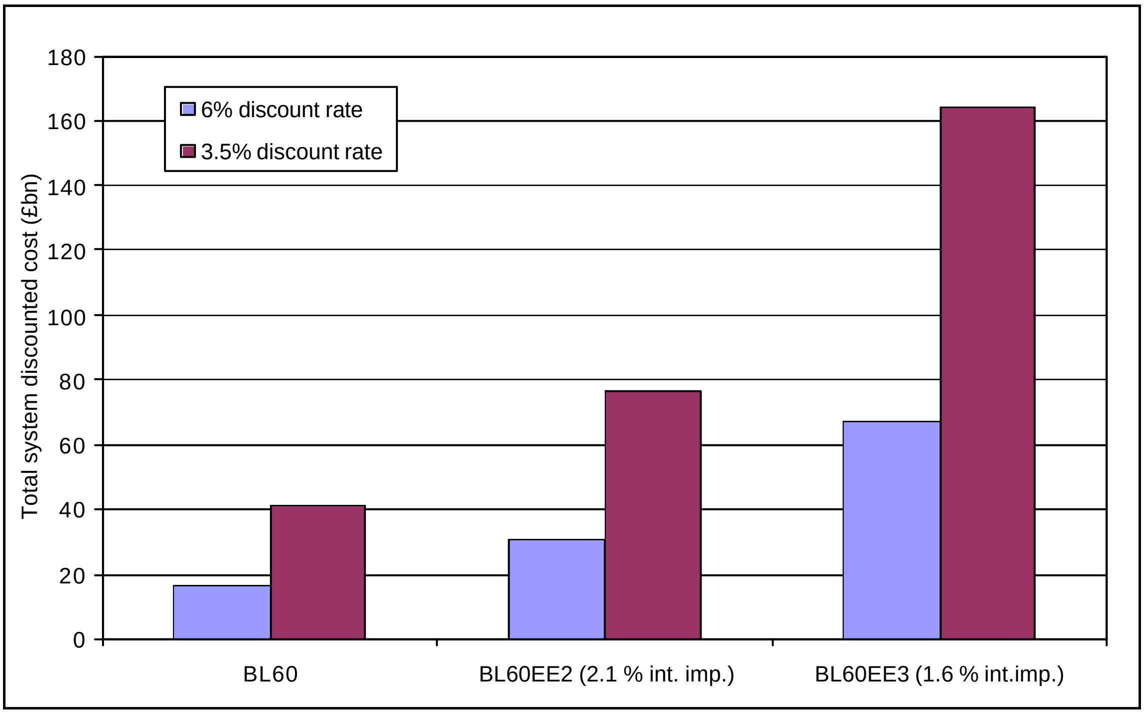

Figure 12 Effect on total discounted abatement costs of limiting energy efficiency for the 60% abatement scenario

5 Fuel costs, availability and infrastructure requirements

The modelling results indicated some significant changes in the UK's energy system over the period to 2050. These changes were driven by a range of factors, of which the most influential was the imposed emission constraints, although expected progressions in technology costs and primary energy availability were also important. Scenario variations in the demand for energy services and primary energy prices had less influence on the mix of fuels and technologies deployed, but did affect the timing of their deployment. This section discusses some key findings relating to:

- Primary energy mix
- Sensitivity to primary energy prices
- Implications of new energy infrastructure

5.1 PRIMARY ENERGY MIX

The trend in the energy mix was the similar in most respects across all scenarios with no emission constraint and is illustrated for the BL scenario in Figure 13.

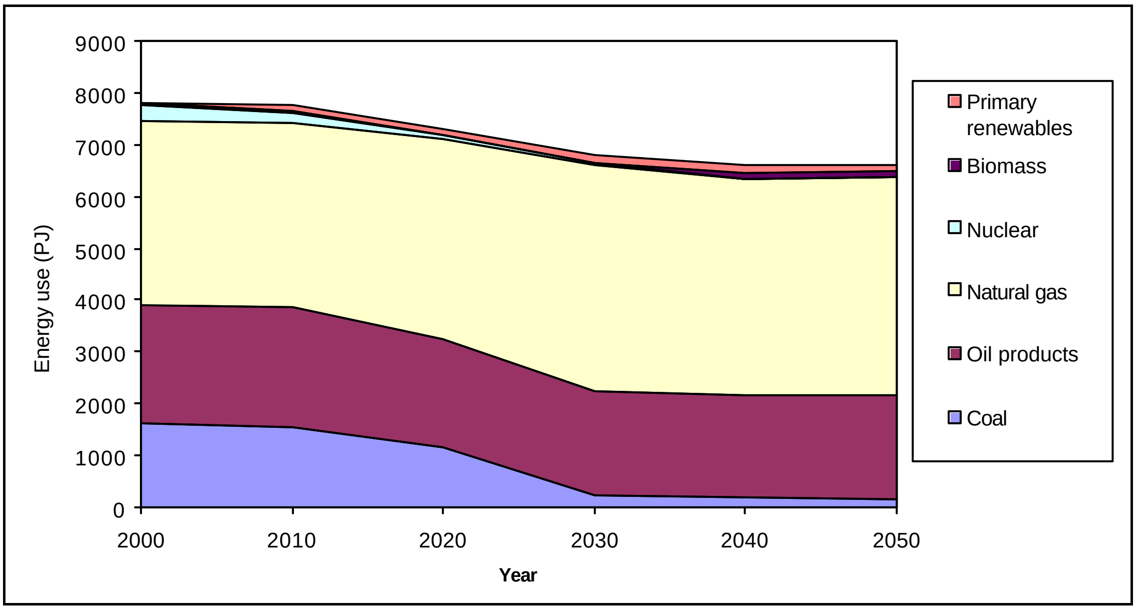

Figure 13 Variation of the primary energy mix in the BL scenario 2000 to 2050

Coal consumption declined steadily with the retirement of existing coal power stations, which were decommissioned by 2030 and their replacement by gas-fired plant. The small amount of remaining coal consumption by 2050 was in industry and the domestic sectors. Nuclear energy also declined in the absence of emission constraints as existing plant were retired before 2040 once again to be replaced with gas fired capacity. Consumption of oil products also declined in the domestic, services and industry sectors, but this was partially offset in the BL and GS scenarios by growth in transport. Transport related oil consumption fell in the WM due to a major switch to compressed natural gas in passenger cars, which was driven by the higher price of gasoline in this scenario combined with the better fuel efficiency of CNG cars.

Significantly the range of fossil fuel prices covered by the scenarios were not sufficient to affect the trend to use mainly gas-fired plant for electricity production. Indeed, across all scenarios natural gas accounted for between 60-80% of total primary energy consumption by 2050, compared to just over 40% in 2000.

Application of constraints on carbon dioxide emissions had little effect on coal consumption, which was phased out at the same rate (Figure 14). However, natural gas consumption was reduced through the construction of new nuclear capacity after 2020, and a steady expansion of renewable energy resources. Nonetheless gas still accounted for a larger share of primary energy supplies in 2050 (about 45-55%) than it did in 2000. Oil consumption was also reduced, principally through large scale switching to hydrogen in road transport. This only occurred after 2030 in most scenarios, but happened a decade earlier in the WM scenario with carbon constraints of 60 and 70% in 2050.

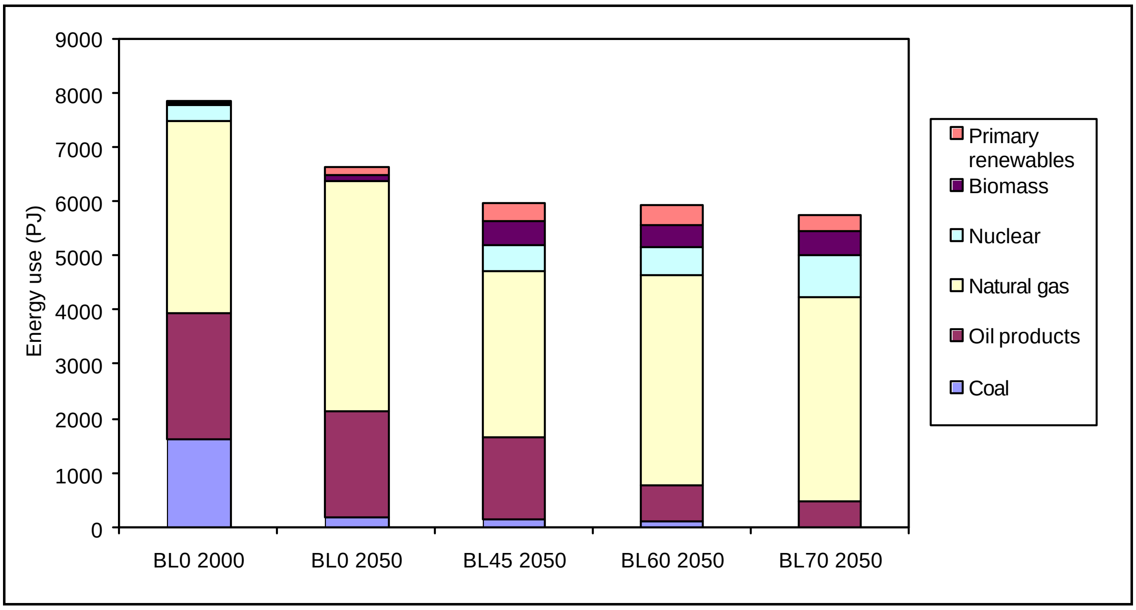

Figure 14 Changes in primary energy mix driven by carbon dioxide emissions constraints 2050

The large share of natural gas in primary energy supply, both with and without carbon emissions constraints, was particularly notable in these results. It could be argued that such a high demand, especially if repeated on a global scale, could put pressure on supplies and led to price rises that were higher than those covered by the scenarios. To investigate the implications, additional analyses were undertaken with the BL scenario in which natural gas supplies were limited to the year 2000 level of supply. Without constraints on carbon emissions this lead to the construction of new nuclear capacity after 2020 and an increase in electricity generation from biomass and wind energy. With a 60% constraint on carbon emissions by 2050 electricity generation from nuclear power and renewable energy sources was further increased such that natural gas was not used for power generation after 2040. This reserved natural gas for direct use in the domestic, industry and services sectors, and for the production of hydrogen for use in road transport.

Surprisingly the effect of limiting natural gas supplies was to reduce the cost of carbon abatement. This occurred because the limit on gas affected the unconstrained model runs, increasing the overall cost of the energy system, but reducing carbon emissions compared to the original unconstrained cases. Consequently the increase in costs caused directly by reducing emissions by 60 and 70% were actually less than those obtained from the original analysis without a limit on natural gas. This is because some of the costs linked with using less gas are taken in the unconstrained model run before the emission constraints are applied.

5.2 SENSITIVITY TO PRIMARY ENERGY PRICES

Fossil fuel prices will influence the choice of technologies for electricity generation both with and without constraints on carbon emissions. However, the range of prices covered by the scenarios was not sufficient to have a significant effect on the choice of technology, which was dominated by the high efficiency and low capital cost of gas turbine combined cycle (GTCC) technology. Of the fossil fuels only natural gas and coal are used for power generation, therefore a wider range of natural gas prices was investigated while holding the coal price at the original value. Table 5 shows the effect of the alternative gas prices on the cost of electricity from new GTCC technology. With the exception of Option 2 the gas price changes are not radical compared with the original prices and the impact on generation costs is correspondingly modest.

Table 5 Impact of Alternative Natural Gas Prices on the cost of electricity from GTCC

	Original BL Prices	Option 1	Option 2	Option 3
Gas Price 2020(p/therm)	25.5	28.0	18.0	31.3
Gas Price 2040 (p/therm)	33.0	34.7	18.0	38.0
Electricity 2020 (p/kWh)	1.95	2.08	1.56	2.25
Electricity 2040 (p/kWh)	2.10	2.18	1.42	2.33

Since coal prices, and the costs of non-fossil technologies, have not been changed in any of these sensitivity cases, the main effect is to move the cost of GTCC technology relative to alternative generation options. Table 6 presents a ranking of generation cost for ESI technologies in 2020.

For Option 1, of the original technologies included in the model, only one tranche of on-shore wind energy (0.4GW) moves above GTCC compared to the original BL prices. Since 5GW of wind energy are deployed in order to meet the 10% renewables target in 2010, much of which is not cost competitive with GTCC, this small change in the ranking will have no effect on GTCC deployment of 66GW. New GTCC moves up the cost ranking in Option 2 and goes down the ranking in Option 3 compared to the original BL case. However, the moves are not major, and because they only involve renewable energy technologies that are already deployed to attain the 10% target, this will not affect the size of the GTCC deployment.

Similar results were obtained for 2040 with the alternative gas prices having little effect on the position of new GTCC in the ranking of generation costs.

GTCC with carbon dioxide capture is only deployed in the BL scenario with a 70% constraint on emissions in 2050. This is mainly because the model prefers to build new nuclear capacity first to reduce emissions. This is consistent with the ranking of generation costs since new nuclear plant (3.0 p/kWh) is marginally cost competitive against GTCC with carbon capture (3.1 p/kWh) with the original BL scenario gas price. This position stays the same for Options 1 and 3. However, with the low gas price of Option 2, GTCC with carbon capture (2.4 p/kWh) becomes competitive against nuclear and greater and earlier deployment would be expected.

The reason for the decline in coal fired power production is clear from the table, with electricity from new IGCC plant costing considerably more than from GTCC plant. However, a workshop with industry representatives (see Annex C for full report of the workshop) identified refurbishing existing coal plant with high efficiency super-critical boilers as an alternative option. Additionally some more advanced IGCC designs have been proposed that considerably reduce capital costs compared to the data used in the model (Jacobs Consultancy, 2002 and Progressive Energy, 2002). Costs for these technologies are included in the table (shaded boxes), and show refurbished coal plant achieving cost competitiveness with GTCC at the higher gas price of Option 3. Similarly the advanced IGCC designs with carbon dioxide separation facilities approach cost competitiveness with GTCC with capture facilities at the higher gas price.

Overall these results serve to illustrate the strength of the competitive position of natural gas fuelled GTCC plant for power generation. They also highlight the importance of technology developments to the future of coal for power generation.

Table 5 Effect of Natural Gas Price on the position of GTCC on the electricity price merit oder in 2020

Original Baseline	(p/kWh)	Option 1	(p/kWh)	Option 2	(p/kWh)	Option 3	(p/kWh)
Wind On-shore 1	1.9	Wind On-shore 1	1.9	**New GTCC**	1.6	Wind On-shore 1	1.9
Wind On-shore 2	1.9	Wind On-shore 2	1.9	Wind On-shore 1	1.9	Wind On-shore 2	1.9
New GTCC	2.0	Wind On-shore 3	2.0	Wind On-shore 2	1.9	Wind On-shore 3	2.0
Wind On-shore 3	2.0	**New GTCC**	2.1	Wind On-shore 3	2.0	Wind On-shore 4	2.1
Wind On-shore 4	2.1	Wind On-shore 4	2.1	Wind On-shore 4	2.1	Retrofit Supercritical boilers to coal	2.2
Retrofit Supercritical boilers to coal	2.2	Retrofit Supercritical boilers to coal	2.2	Retrofit Supercritical boilers to coal	2.2	Wind On-shore 5	2.2
Wind On-shore 5	2.2	Wind On-shore 5	2.15	Wind On-shore 5	2.2	**New GTCC**	2.3
Wind On-shore 6	2.3	Wind On-shore 6	2.25	Wind On-shore 6	2.3	Wind On-shore 6	2.3
Wind On-shore 7	2.4	Wind On-shore 7	2.42	Wind On-shore 7	2.4	Wind On-shore 7	2.4
Alternative IGCC	2.6	Alternative IGCC	2.6	**New GTCC/CO2 Sep**	2.6	Alternative IGCC	2.6
Wind On-shore 8	2.6	Wind On-shore 8	2.9	Alternative IGCC	2.6	Wind On-shore 8	2.9
Wave -Shoreline 1	2.9	Wave -Shoreline 1	2.9	Wind On-shore 8	2.9	Wave -Shoreline 1	2.9
New Nuclear	2.9	New Nuclear	2.9	Wave -Shoreline 1	2.9	New Nuclear	2.9
Wind On-shore 9	2.9	Wind On-shore 9	3.0	New Nuclear	2.9	Wind On-shore 9	3.0
New GTCC/CO2 Sep	3.0	Wave –Shoreline Tranche 1	3.2	Wind On-shore 9	3.0	Wave –Shoreline Tranche 1	3.2
Wave –Shoreline Tranche 1	3.2	Wave – Shoreline Tranche 2	3.3	Wave –Shoreline Tranche 1	3.2	Wave – Shoreline Tranche 2	3.3
Wave – Shoreline Tranche 2	3.3	New IGCC	3.3	Wave – Shoreline Tranche 2	3.3	New IGCC	3.3
New IGCC	3.3	**New GTCC/CO2 Sep**	3.4	New IGCC	3.3	Energy Crops	3.4
Energy Crops	3.4	Energy Crops	3.4	Energy Crops	3.4	**New GTCC/CO2 Sep**	3.6
Alternative New IGCC/CO2 Sep	3.5	Alternative New IGCC/CO2 Sep	3.6	Alternative New IGCC/CO2 Sep	3.6	Alternative New IGCC/CO2 Sep	3.6
Retrofit Super Crit/CO2 Sep	3.6	Retrofit Super Crit/CO2 Sep	3.9	Retrofit Super Crit/CO2 Sep	3.9	Retrofit Super Crit/CO2 Sep	3.9
New IGCC/CO2 Sep	3.9	New IGCC/CO2 Sep	5.4	New IGCC/CO2 Sep	5.4	New IGCC/CO2 Sep	5.4

1. Shaded boxes indicate technologies not in the MARKAL model

5.3 INFRASTRUCTURE

The MARKAL model's results have indicated some significant changes in the mix of energy sources to be used in the future, particularly under carbon dioxide emissions constraints. These changes will require accompanying changes to the transmission and distribution infrastructures. Two trends that have particularly important implications for infrastructure investment are the use of hydrogen as a transport fuel and the deployment of a larger proportion of intermittent renewable energy sources for electricity generation. This section examines the implications of these changes for the cost of abatement and selection of future technologies.

5.3.1 Hydrogen

Hydrogen is deployed in all three scenarios when carbon dioxide emissions are constrained. It is mainly used as a road transport fuel to replace oil based fuels, and achieves an appreciable level of deployment after 2030, particularly with the most severe constraint on carbon dioxide emissions. Hydrogen was usually produced from natural gas with carbon dioxide capture and storage, and was assumed to be distributed using parts of the natural gas network that had been progressively updated to be able to handle hydrogen. This represented an optimistic case with low infrastructure costs of £1.4/GJ.

A more pessimistic option would be one in which a new infrastructure needed to be established to distribute hydrogen to final users. Estimates for this have been developed for road transport in Annex E, which gave an infrastructure cost of £5.8/GJ in 2020 falling to £5.5/GJ in 2050.

The impact of this higher infrastructure cost, with the BL scenario constrained to reduce emissions by 60%, was to increase the marginal abatement cost in 2050 from £351/tC to £680/tC. However, the impact on the total discounted abatement cost was much less, increasing by £6bn to £46bn (3.5% discount rate). This increase in costs was limited because the model delayed the deployment of hydrogen from 2030 to 2040 and used a third less hydrogen than with the lower distribution cost. These changes resulted in higher emissions from the transport sector that were balanced by further energy efficiency, mainly in the domestic sector, combined with the virtual phase out of coal consumption by manufacturing industry.

Overall this indicates that infrastructure cost may have a significant influence on the timing and size of the deployment of hydrogen technologies, but that they are still a key element for large-scale reductions in carbon dioxide emissions in the long term.

5.3.2 Intermittent Electricity Generation Sources

The deployment of large quantities of intermittent electricity generation, such as that from wind and wave energy, can bring additional costs to the electricity system. A recent report by ILEX for the DTI (ILEX, 2002), has estimated these costs for a range of deployment levels and locations. The most significant element of these extra costs was the additional conventional capacity needed to back-up the intermittent sources for balancing operations and longer-term system security.

Within the MARKAL model, the intermittent nature of some sources of electricity generation (wind, wave, PV) is reflected in their average availability and the extent to which they can contribute to system security. It is this latter factor that should equate to the additional back up capacity costs identified by ILEX. MARKAL allows intermittent sources to contribute to capacity at peak demand, but this contribution is assumed to be less than for equivalent conventional generation. For instance, in the case of wind, a scaling factor of 0.43 has been applied to the installed capacity to obtain the average contribution at peak. The ILEX report concludes that the extent to which wind power can contribute to capacity at peak is not constant, but rather declines as the penetration of wind increases. For a small level of penetration the ILEX results show that the capacity value of wind is significant since 2 GW of wind generation displaces about 1.5 GW of conventional plant. In other words only 0.5 GW of conventional plant back up is needed giving 2GW of wind a scaling factor of 0.75. However, as the capacity of wind generation increases the marginal contribution declines: 20 GW of wind capacity displaces only about 4.5 GW of conventional generation (scaling factor of 0.225).

To examine the implications of the ILEX results for the deployment of wind generation and system costs, a sensitivity assessment was undertaken in which the scaling factor was made a function of wind capacity in MARKAL. Since it is not possible to introduce such a relationship directly into the model, this was done in an iterative manner until a stable solution was found. The results for the deployment of wind generation are shown in Figure 15.

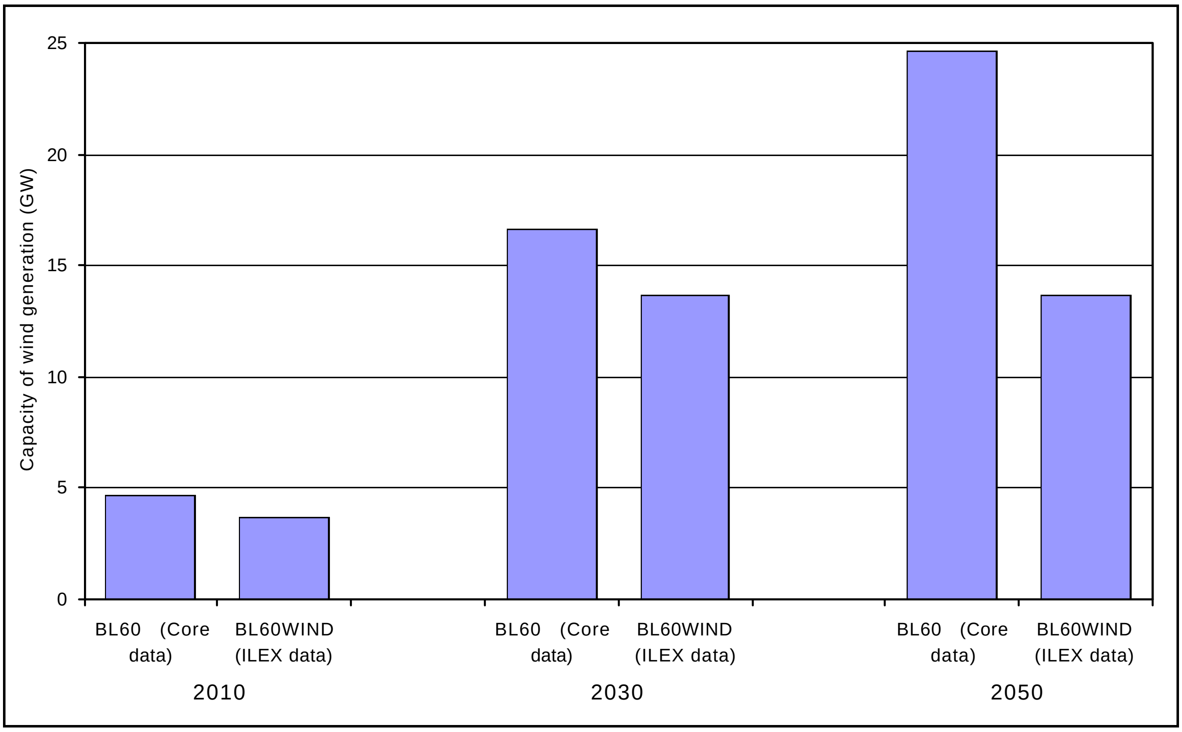

Figure 15 Effect on wind deployment of assumptions on its contribution at peak demand

Overall, wind capacity in 2050 is reduced from 25 GW to 14 GW. This sizeable reduction is not surprising when it is remembered that there are large numbers of electricity generating technologies with very similar costs and so even quite small increases in costs can lead to another technology becoming the preferred option. In this case it is a combination of GTCC with CO_2 capture and nuclear that is built instead.

Despite the significant impact on wind capacity, the implications for system costs are much smaller. The cost of the 60% reduction scenario discounted at 3.5% increases from £41bn to £42bn, an increase of 1.5%.

6 The Importance of Technology in Supporting a Low Carbon Future

Technological development is central to a transition to a low carbon future. It has the potential to provide alternative low to zero carbon energy sources, more efficient energy conversion plant, transmission and distribution systems with lower losses and more energy efficient end use devices. It also can reduce the cost of these options by a combination of technological improvement, learning by doing and economies of scale and volume production.

The technology data used in the MARKAL model were assembled from sources that took account of these trends through various methods including time series analysis, learning curve assessments and expert judgement. Additionally key data on power generation and hydrogen technologies were reviewed in workshops involving specialists drawn from industry and academia (see Annexes C and D). Nonetheless quantitative technology forecasting is an uncertain process, which needs to be backed up by sensitivity analyses to evaluate the implications of variations around the central values. This section examines the role of key technology groups in supporting a low carbon future, and how this role is affected by variations in technology assumptions.

6.1.1 Innovation

Innovation itself is a key assumption underpinning the MARKAL technology database. Generally technologies become less costly and more efficient with time as they benefit from innovation. The rate of innovation implicit in the database assumes a global development effort. However, if only a limited number of countries including the UK took a lead on carbon reduction the rate of innovation would be slower in many cases because it would be more dependent on fewer resources, and would benefit from reduced economies of scale because of the smaller market. Similarly, even with global resources, innovation may prove to be more difficult than anticipated at this stage, so technologies could be more expensive and less efficient in the long term than currently expected.

To measure the importance of innovation additional model assessments were undertaken in which technology costs and performance values were frozen at their 2010 values across the full period to 2050. This effectively represented a zero innovation case, which may be highly pessimistic, but serves to scope the impact of innovation on abatement costs. Results are presented in Figure 16, which shows that this had a major effect on the marginal cost of abatement in 2050. The total discounted system cost also increased from £41bn to £170bn for the case of 60% abatement.

These large cost increases occurred for two reasons. Firstly energy demand was higher due to the deployment of less efficient production and end use devices. Secondly the technologies deployed to reduce carbon emissions were more costly.

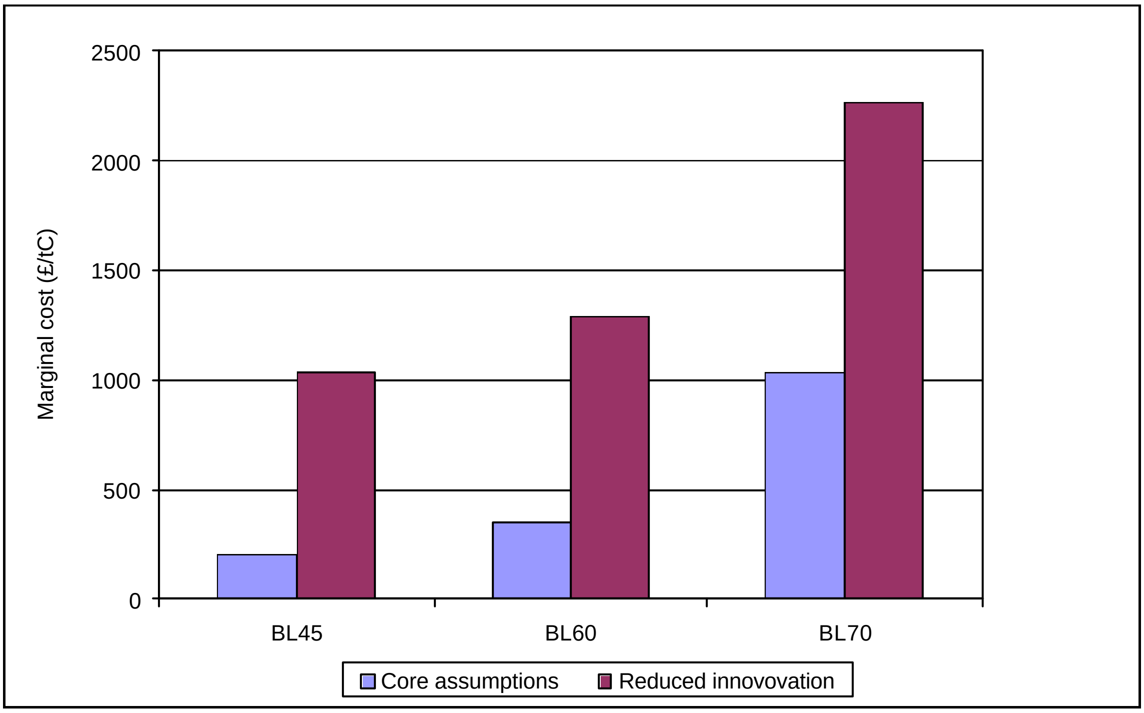

Figure 16 Impact of reduced innovation on marginal carbon dioxide abatement costs in 2050

6.1.2 Nuclear Power

Nuclear power is deployed by the model to reduce carbon emissions from power generation in most of the abatement scenarios. The cost and performance data for nuclear plant used in the model were based on information gathered in previous work for DEFRA and by the Energy Review (Cabinet Office, 2002)[17]. However, there is considerable debate over the future cost of electricity from new designs of nuclear plant that are expected to benefit from international series ordering (see Annex C). Thus while the data used in the core modelling studies yielded a generation cost of 3.0p/kWh industry estimates give costs of less than 2.0p/kWh[18].

This uncertainty was investigated with additional model assessments using the BL scenario in which nuclear costs were adjusted to give generation costs of 2.5 and 3.5 p/kWh. This cost range had no effect on deployment without carbon emissions constraints. Nuclear generation was still phased out with the retirement of existing stations in favour of more cost effective GTCC plant. However, with a 60% emission constraint in 2050 nuclear power increased its share of electricity generation with the lower cost level, while its share was substantially reduced at the higher cost level (Figure 17).

Notwithstanding these substantial changes to the electricity generation mix, the overall effect of this range of nuclear power costs on the total discounted cost of abatement was small. Thus the lower nuclear cost reduced the total abatement cost from £41bn to £33bn while the higher nuclear cost increased the abatement cost to £43bn. The reason for this small effect is that other generation technologies, particularly GTCC with

[17] This included costs for fuel services and decommissioning
[18] 2020 costs using a 15% discount rate

carbon capture and offshore wind energy and wave energy are expected to have only slightly higher costs by 2030 and beyond.

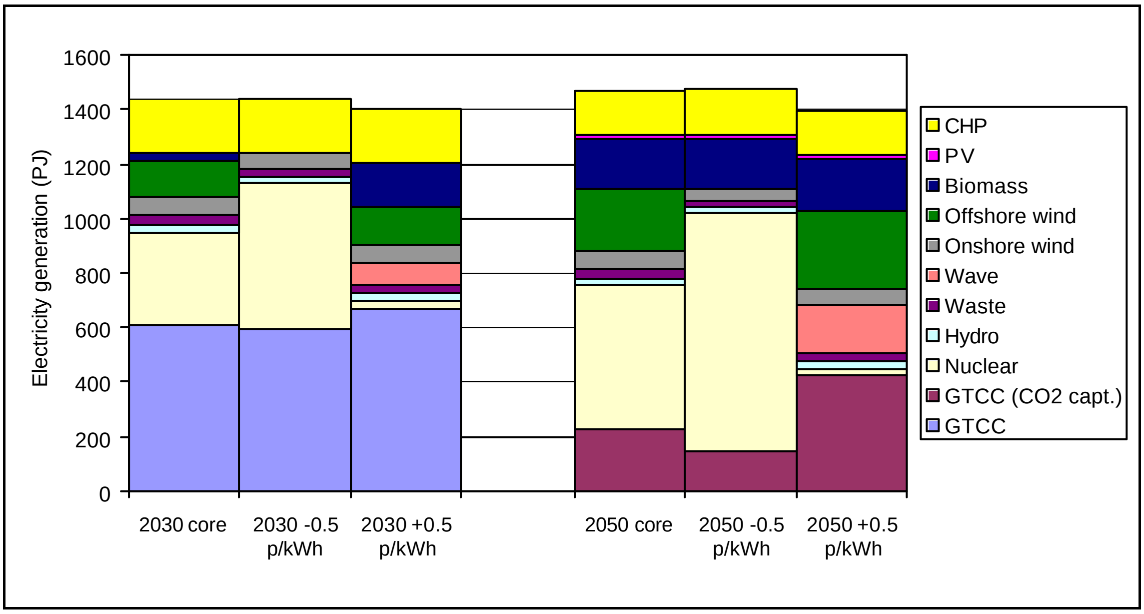

Figure 17 Impact of alternative nuclear power generation costs on the mix of fuels used for electricity generation (2030 and 2050)

6.1.3 Technology Exclusion

Both nuclear power and carbon dioxide capture and storage are deployed on a large scale after 2030 to attain all three emissions abatement targets (i.e. 45%, 60% and 70% in 2050). Even when carbon dioxide capture is not used in power generation it is applied for the production of hydrogen from natural gas. However, the future deployment of both technologies is likely to face opposition. In the case of nuclear this is due to safety concerns and the lack of a publicly accepted method for waste disposal. In the case of carbon dioxide capture there are uncertainties over the legality of sub sea storage and concerns over long term leakage to the atmosphere. Consequently MARKAL was used to investigate the feasibility and cost of attaining the carbon emissions target without these technologies.

In the previous phase of work (FES, 2002) it was found that either nuclear power or carbon capture could be excluded from the UK's energy system while still attaining the abatement target, but the cost of abatement increased. In the Global Sustainability scenario a 'no nuclear' constraint only had an effect with the maximum 70% reduction when costs increased by four fold from £6bn to £24bn. However, with the same scenario, preclusion of CO_2 sequestration increased abatement costs with both the 60% and 70% targets, by 90% and over 600% to £11bn and £43bn[19] respectively. The greater impact of excluding carbon capture was because this deprived the transport sector of hydrogen from natural gas, which had to be replaced by diverting biomass from electricity to hydrogen production.

[19] GS scenario abatement costs are less than for the BL and WM scenarios because GS already invokes a greater improvement in energy intensity through structural changes as part of its sustainability theme.

The current work has investigated the combined exclusion of nuclear power and carbon capture from the BL scenario with a 60% emission constraint. Here again it proved possible to attain the emission reduction target, mainly through the deployment of additional energy efficiency measures and a large switch to renewable energy for power generation from 2030. The effect of these changes was to increase the total discounted abatement cost from £41bn to £138bn; or almost 250%. This considerable increase arose because the model needed to use some high cost renewable energy sources such as photovoltaics to meet the electricity demand.

6.1.4 Renewable energy

Renewable energy technologies were deployed in all three scenarios, mainly for electricity production. However, without carbon dioxide constraints the share of electricity generation increased only slightly after reaching the 10% in 2010, which was set in the model to be in line with government targets. This pattern changed under carbon constraints with the share of generation from renewables increasing from 2020 onwards to reach 25 to 35% of production by 2050 (Table 6). The only case in which higher deployment of renewables technologies occurred was with the exclusion of nuclear and carbon sequestration technologies, when the model required almost 70% renewable electricity production to attain a 60% emission reduction in 2050.

Table 6 Renewable Energy Electricity Production (TWh)

Scenario	2010	2020	2030	2040	2050
BL	34	32	32	47	47
BL-60%	34	33	83	123	152
WM	35	33	36	81	80
WM-60%	35	33	110	166	131
GS	33	32	32	48	79
GS-60%	33	32	81	148	144

The main renewables technologies deployed were on- and offshore wind, biomass, waste combustion and existing hydro-electric facilities. Under the high demand conditions in the WM scenario, and with the highest emission constraint in the other scenarios, there was also some deployment of wave energy and PV.

Outside of electricity generation there was little use of renewable energy sources except when natural gas supplies were limited in which case biomass was gasified to provide an alternative supply of hydrogen.

Additional modelling studies were undertaken to evaluate the costs of achieving a target of generating 20% of electricity from renewable energy by 2020 against a background of 20% and 30% reductions in carbon emissions by the same time. Results shown in Figure 16 indicate a significant additional cost of achieving 20% abatement combined with 20% of electricity generation from renewable energy sources. In contrast only a modest additional cost was involved in attaining 30% abatement combined with a 20% renewable electricity target. This result is indicative of the relative costs of renewable electricity for carbon abatement compared to other options. When the abatement target is 20% there are more cost effective options available, but when the target is increased to 30% renewable energy is amongst the most cost effective of the additional measures required.

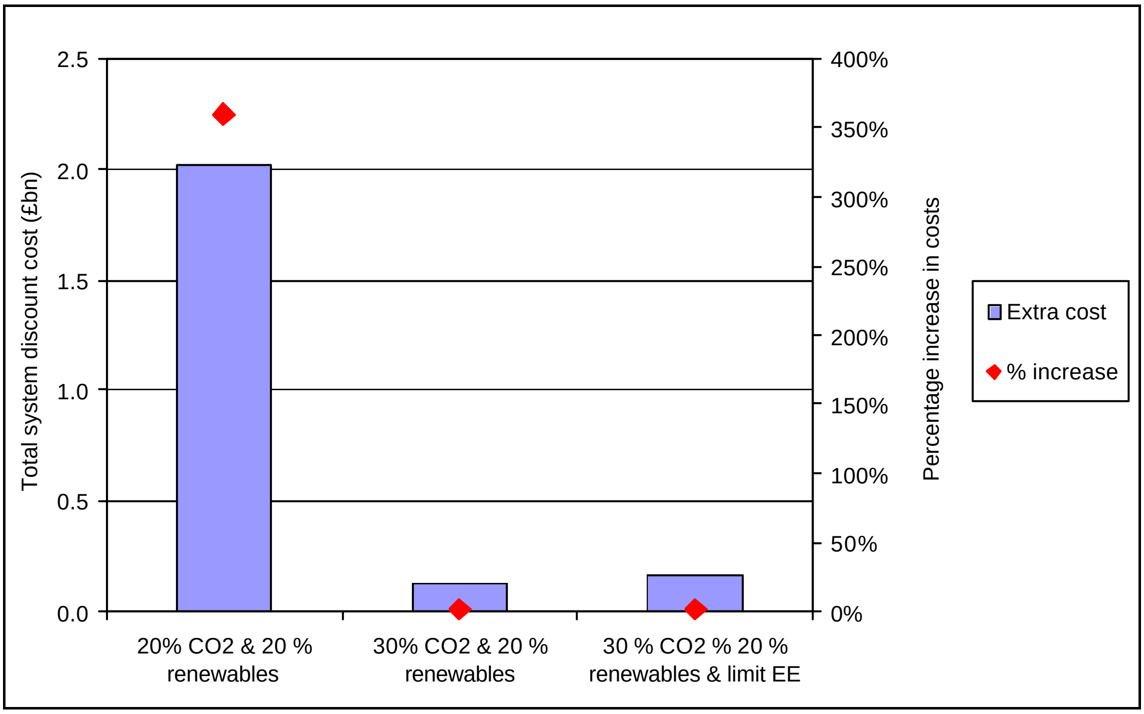

Figure 18 Additional cost of attaining a 20% renewable electricity target by 2020

6.1.5 Transport Technologies

Section 4.4 reported that an appreciable improvement in energy efficiency was projected for the transport sector, even without emissions constraints, because of anticipated improvements in vehicle efficiencies. However, due to increasing demand this was only sufficient to prevent further growth in transport related carbon dioxide emissions. Going beyond this to attain net reductions in emissions has a high cost. This was because, unlike other sectors, substantial additional abatement requires a change of fuel, at the minimum adaptation of the existing fuel distribution system and new end use technologies that can operate with the new fuel.

For passenger cars the main abatement option was switching to hydrogen fuel. This could be used in vehicles equipped with internal combustion engine propulsion systems. However, the preferred option was to use fuel cell powered vehicles, which because of their superior fuel efficiency, reduced fuel consumption and hence running costs. At the lowest carbon emission limit of 45% heavy goods vehicles stayed with diesel fuel, but attained greater fuel efficiency by adopting hybrid technology. However, at the higher constraints this hybrid technology was replaced with hydrogen vehicles in 2050. For light goods vehicles (LGVs) the preferred technology continued to be based on the diesel engine, even under emission constraints. However, in the scenarios with significant CO_2 reductions, biodiesel displaced some use of traditional diesel in LGVs and this switch would have been greater but for exogenous assumptions that limited its availability.

Other notable changes were full electrification of the rail network and a switch to electric buses in urban applications. Hydrogen powered aircraft were included in the model, but this high cost abatement option was only deployed in the World Markets scenario with a 70% abatement target, and then only in 2050.

6.1.6 Influence of Transport Fuel Tax

Current road fuel duty and VAT accounts for over 70% of vehicle fuel costs. Therefore the duty applied can be influential in the choice of transport fuels and vehicles. In most of this study it was assumed that, where duty was applied, current rates would be maintained to 2050. With new alternative fuels such as hydrogen and methanol, these were made available duty free until their utilisation exceeded 3% of the market, when additional consumption attracted the same duty as gasoline and diesel (i.e. per unit of energy).

Without constraints on carbon dioxide emissions these assumptions resulted in methanol and hydrogen penetrating the market up to their 3% duty free limits. With emissions constraints methanol generally was still used up to the 3% limit, but larger quantities of hydrogen were used as discussed above.

To further explore the influence of duty on the size and timing of transport fuel and technology deployment two further options for applying duty to alternative fuels were studied. It should be stressed that these are only scenarios involving changes to the taxes on future low carbon fuels and that they do not commit the Government to any policy on the taxation of such fuels.

Option A

New fuels were allowed to take a 1% market share before attracting duty. Additional hydrogen then took the current CNG duty and methanol and ethanol took the current biodiesel rate to 2050.

Option B

New fuels were allowed to take 1% market share before attracting duty. Additional consumption then attracted 50% of the duty applied to traditional fuels for 10 years, and thereafter the full rate.

Results from these additional options are shown in Figures 19 and 20, where they are compared to the results with the original assumptions on duty (i.e. core results). Without emission constraints the lower duty of Option A encouraged a large switch to hydrogen with both passenger cars and HGVs by 2030. Interestingly, because of the lower hydrogen price the fuel was used in ICE powered cars rather than the more efficient fuel cell vehicles. This is because, at the lower fuel costs, the higher capital cost of fuel cell vehicles outweighs the fuel savings. In contrast, with the higher duty of Option B, deployment of alternative fuels was limited to the 1% duty free market shares.

This pattern of behaviour was maintained with a 60% constraint on carbon dioxide emissions (Figure 20). The lower duty of Option A encourages deployment of hydrogen by 2030 while this was delayed until 2040 with Option B. The greater total energy consumption by transport in 2050 with Option A is again due to the deployment of less fuel-efficient ICE powered vehicles. When hydrogen is deployed in Option B and in the original “core” assessment the higher fuel cost encourages the use of fuel cell vehicles.

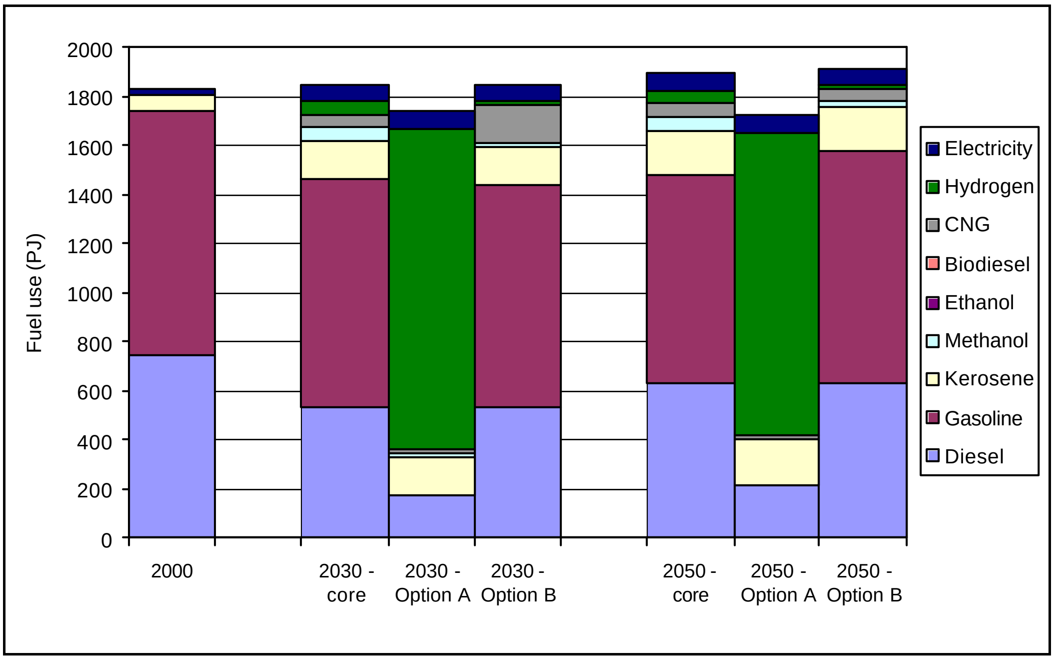

Figure 19 Influence of fuel duty assumptions on the use of alternative transport fuels in the absence of a carbon dioxide emissions constraint

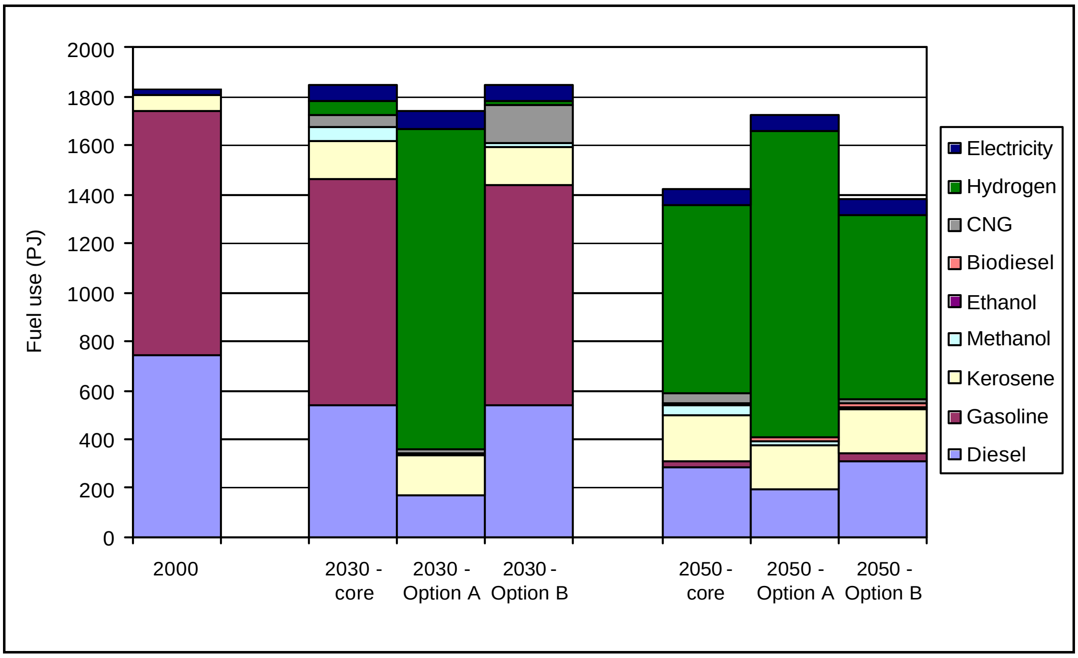

Figure 20 Influence of fuel duty assumptions on the use of alternative transport fuels with a 60% constraint on carbon dioxide emissions

Overall these results illustrate that fuel duties are a powerful instrument for influencing the size and timing of deployment of alternative transport fuels. Moreover, duty may have a strong influence on the choice of vehicle technologies by affecting the economic balance between higher capital cost-higher fuel efficiency vehicles and those with lower capital costs-lower fuel efficiency.

7 Impact of Different Paths to a Low Carbon Future

A number of scenario variants have been developed to examine the impact on costs of different paths to a low carbon future. All are based on the BL scenario.

7.1 POST-KYOTO SCENARIOS

Two 'post-Kyoto' emission abatement scenarios were investigated to examine the effects of imposing emissions targets from 2020, rather than from 2030 as in the original abatement scenarios. These consisted of:

- 20% reduction in 2020 increasing linearly to a 60% reduction in 2050 (BL60PK1)
- 30% reduction in 2020 increasing linearly to a 60% reduction in 2050 (BL60PK2)

Scenario	2020	2030	2040	2050
BL60	None	-30%	-45%	-60%
BL60PK1	-20%	-33%	-47%	-60%
BL60PK2	-30%	-40%	-50%	-60%

The total discounted costs of the post-Kyoto scenarios are compared in Figure 21 with the original BL-60% abatement scenario, which has a 30% reduction in 2030 increasing linearly to a 60% reduction in 2050. This shows that under BL60PK1 (20% reduction target in 2020 increasing to 60% in 2050), costs are only slightly higher than under the original BL-60% abatement scenario (£45bn as against £41bn). However, under the BL60PK2 scenario (30% reduction target in 2020 rising to 60% abatement in 2050), costs are substantially higher at £68bn.

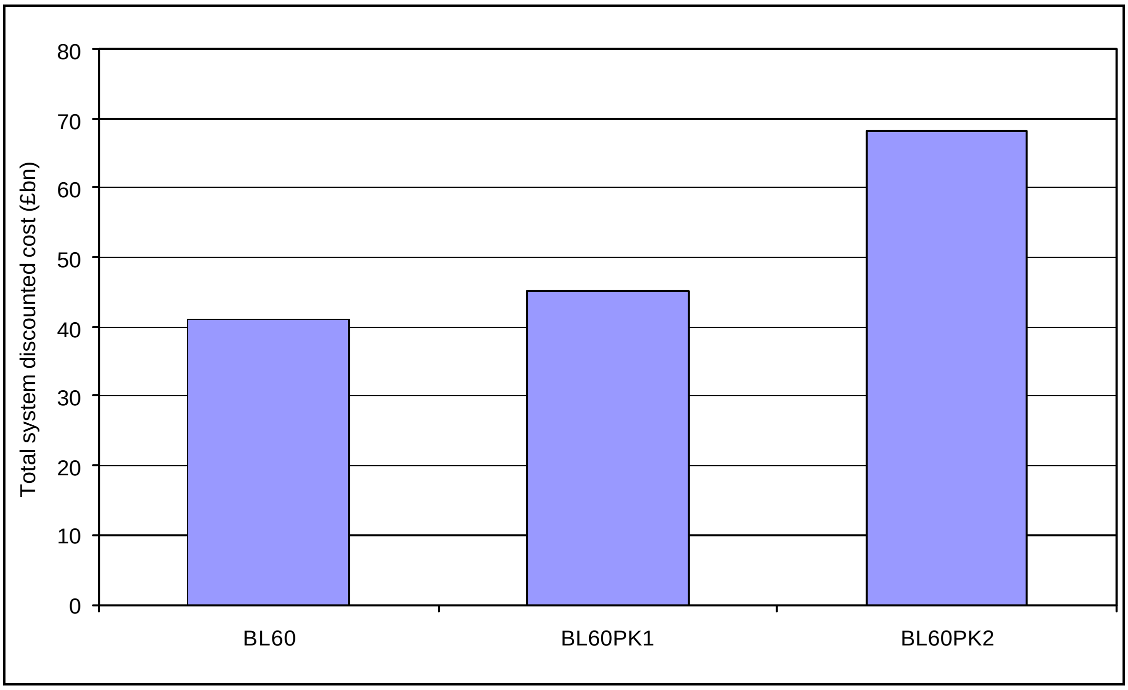

Figure 21 Costs of abatement under the post-Kyoto scenarios (3.5% Discount Rate)

7.2 IMPACT OF DELAYING ACTION

The second set of scenarios were designed to look at a range of abatement paths, some involving linear reduction paths and others delaying action to reduce emissions, but achieving the same overall level of emissions abatement over the 50 year period. These scenarios are described below and shown schematically in Figure 22.

1. Smooth (linear) reduction from 2000 to 2050 (BLDEF1).

2. BL original to 2020 and then smooth linear reduction to 60% in 2050 (BLDEF2).

3. BL original to 2030 and then smooth linear reduction to 60% in 2050 (BLDEF3).

4. BL original to 2010 and then smooth linear reduction to achieve same cumulative reduction as in Scenario 1 by 2050 (BLDEF4).

5. BL original to 2020 and then smooth linear reduction to achieve same cumulative reduction as in Scenario 1 by 2050 (BLDEF5).

6. BL original to 2030 and then smooth linear reduction to achieve same cumulative reduction as in Scenario 1 by 2050 (BLDEF6).

(NB The latter three options will require greater reductions than the 60% level in 2050 with implications for overall costs.)

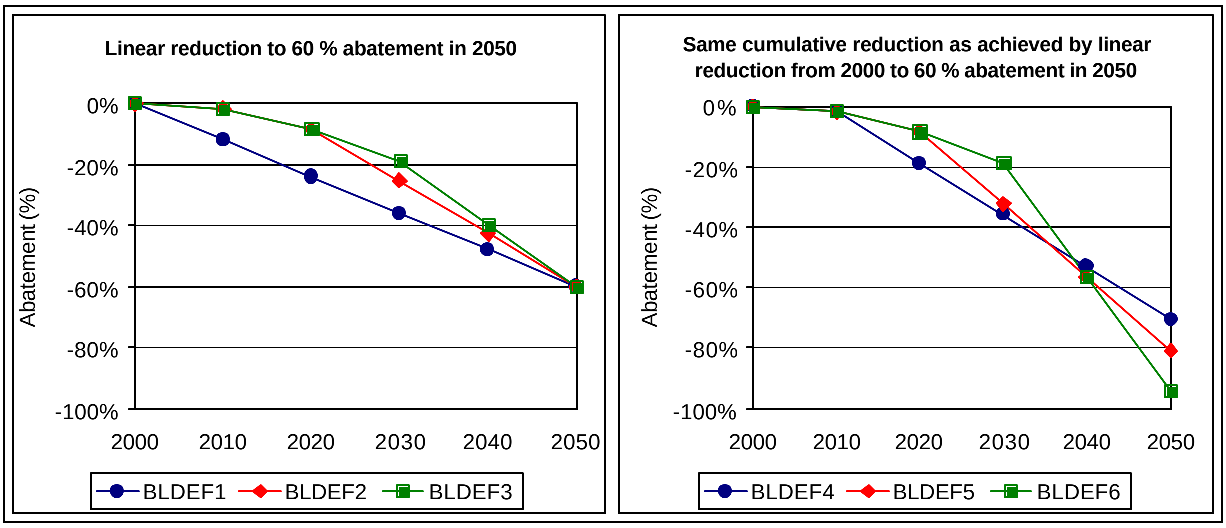

Figure 22 Emission abatement profiles

The first set of scenarios, with linear abatement paths were designed to look at the trade-off between starting abatement earlier and so incurring costs sooner, with starting later but having to reduce emissions more quickly, possibly incurring higher costs once the process has begun. In each case these emissions projections were fixed in the MARKAL model.

The results show that the discounted costs are highest in the scenario under which abatement starts earliest (BLDEF1) and are least when abatement is delayed the most (£58bn as against £31bn). However, the cumulative abatement to 2050 when starting abatement in 2000 is nearly twice that for the scenario in which abatement starts in 2030. Correcting for the extent of abatement by looking at costs per tonne shows that, on both an average and marginal basis, costs in 2050 are somewhat higher for the scenario in which abatement is delayed the most. Thus, judged on a cost per tonne basis, the additional costs associated with acting sooner are more than offset by the extra cumulative abatement. This is true irrespective of discount rate.

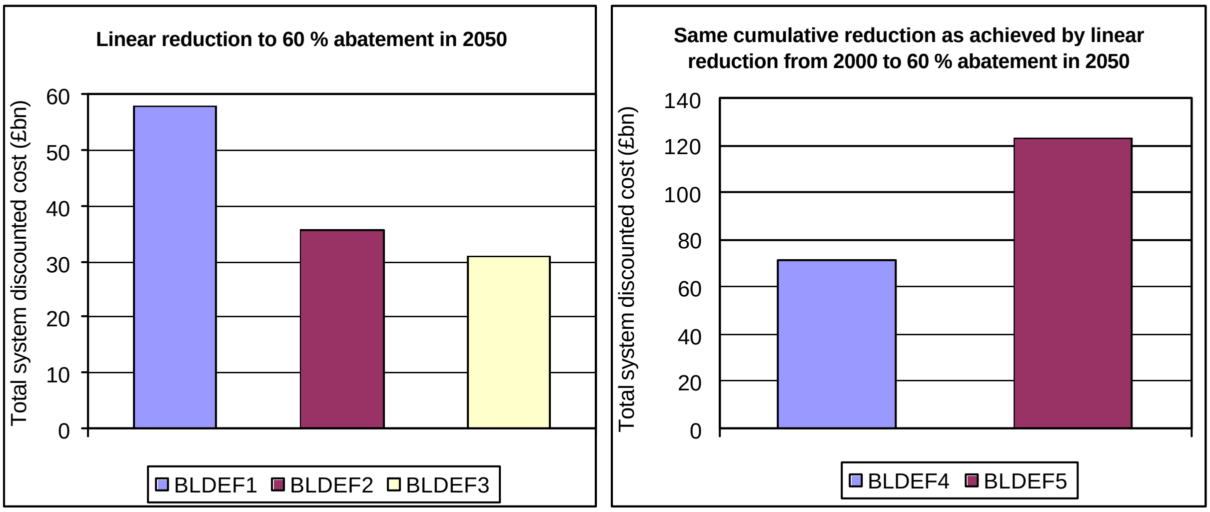

Figure 23 Total discounted abatement cost for different emission reduction profiles

If action to reduce emissions is delayed, but the same cumulative reduction is achieved as under a linear reduction from 2000 to 2050, then costs increase progressively. The cost of the linear reduction scenario (BLDEF1) is £58bn. Achieving the same cumulative reduction to 2050 but starting in 2010 (BLDEF4) costs£72bn and starting in 2020(BLDEF5) costs £123bn. If action was delayed until 2030 (BLDEF6), then such enormous reductions were required in 2050 that they were impossible with the technology options available.

7.3 IMPLICATIONS OF DIFFERENT ABATEMENT PATHS

While this report has tended to focus on specific abatement targets for 2050 these should only by regarded as milestones to a low carbon energy system. From the view-point of climate change the key action is to reduce cumulative greenhouse gas emissions, thereby stabilising their atmospheric concentration. This has been recognised by the Kyoto targets for 2008-2012 and the UK government's aspirational target for a 20% reduction in carbon dioxide emissions in 2010. Consequently, while the above results indicate that the low cost option for achieving a particular abatement target by 2050 would be to delay action for a decade or two, this would not meet the true objectives of climate change strategy. Cumulatively less carbon dioxide abatement would be achieved by delaying action into the future even if the 2050 target was attained.

Also the practicality of delaying action should be questioned on two counts. First, although the MARKAL model considers constraints on the deployment of the major low carbon technologies there is no explicit feedback between the rate of deployment and costs. While it may be possible to speed up the deployment of an individual technology without substantial cost increases, it is doubtful whether substantial changes in a large number of technologies and their associated infrastructure could be achieved over a more compressed timescale without higher costs. Secondly the technology costs and performance values used in the analysis are based on the assumption of a global move to a low carbon energy system. If the UK was to delay action it would be attempting to be a "free rider", assuming the development of the necessary technologies and devices would be done elsewhere. This may not happen if other countries take the same view, in which case, even if technically feasible, abatement cost would be substantially higher in later years, as shown by the results of the limited innovation scenario (Section 6). Moreover, the UK would be foregoing the opportunity to take a leading position in an area offering considerable future business opportunities.

The more important conclusion from the above results is that the most cost effective approach for attaining an appreciable cumulative reduction in carbon dioxide emissions, combined with achieving a defined abatement target in 2050, is to take progressive action from now. This is also consistent with encouraging the necessary technology developments and economic and social changes needed to facilitate a low carbon future.

8 References

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Annexes

CONTENTS

Annex A

End User Energy Prices used in the Scenarios

END user Energy Prices used in MARKAL

End-user energy prices for the Baseline scenario

		2000	2010	2020	2030	2040	2050
Jet Kerosene	(p/litre)	16.49	12.57	12.57	15.31	15.31	15.31
DERV	(p/litre)	80.80	75.78	75.78	78.72	78.72	78.72
Unleaded petrol	(p/litre)	80.09	74.95	74.95	77.96	77.96	77.96
Fuel Oil (industrial)	(p/litre)	12.38	10.22	10.22	11.81	11.81	11.81
Fuel oil (ESI)	(p/therm)	34.7	28.3	28.3	32.3	32.3	32.3
Petroleum (services)	(p/litre)	15.5	13.1	13.1	15.2	15.2	15.2
Petroleum (domestic)	(p/litre)	16.3	13.8	13.8	16.0	16.0	16.0
Gas oil (ESI)	(p/therm)	46.1	39.7	39.7	43.7	43.7	43.7
Gas (industrial)	(p/therm)	21.5	21.5	24.0	28.2	31.5	31.5
Gas (domestic)	(p/therm)	50.0	50.0	52.5	56.7	60.0	60.0
Gas (services)	(p/therm)	27.5	27.5	30.0	34.2	37.5	37.5
Gas (ESI)	(p/therm)	23.0	23.0	25.5	29.7	33.0	33.0
Coal (Industrial)	(p/therm)	14.4	14.4	14.4	14.4	14.4	14.4
Coal (domestic)	(p/therm)	57.2	57.2	57.2	57.2	57.2	57.2
Coal (services)	(p/therm)	19.5	19.5	19.5	19.5	19.5	19.5
Coal (ESI)	£/tonne	30.5	30.5	30.5	30.5	30.5	30.5

End-user energy prices for the World Markets scenario

		2000	2010	2020	2030	2040	2050
Jet Kerosene	(p/litre)	16.49	14.75	16.14	20.74	20.74	20.74
DERV	(p/litre)	80.80	78.11	80.45	84.53	84.53	84.53
Unleaded petrol	(p/litre)	80.09	77.35	79.75	83.93	83.93	83.93
Fuel Oil (industrial)	(p/litre)	12.38	11.49	12.76	14.96	14.96	14.96
Fuel Oil (ESI)	(p/therm)	34.7	31.5	34.7	40.3	40.3	40.3
Petroleum (services)	(p/litre)	15.5	14.7	16.4	19.3	19.3	19.3
Petroleum (domestic)	(p/litre)	16.3	15.5	17.4	20.4	20.4	20.4
Gas oil (ESI)	(p/therm)	46.1	42.9	46.1	51.7	51.7	51.7
Gas (industrial)	(p/therm)	21.5	25.7	29.8	36.5	36.5	36.5
Gas (domestic)	(p/therm)	50.0	54.2	58.3	65.0	65.0	65.0
Gas (services)	(p/therm)	27.5	31.7	35.8	42.5	42.5	42.5
Gas (ESI)	(p/therm)	23.0	27.2	31.3	38.0	38.0	38.0
Coal (Industrial)	(p/therm)	14.4	14.4	14.4	14.4	14.4	14.4
Coal (domestic)	(p/therm)	57.2	57.2	57.2	57.2	57.2	57.2
Coal (services)	(p/therm)	19.5	19.5	19.5	19.5	19.5	19.5
Coal (ESI)	£/tonne	30.5	30.5	30.5	30.5	30.5	30.5

End-user energy prices for the Global Sustainability scenario

		2000	2010	2020	2030	2040	2050
Jet Kerosene	(p/litre)	16.49	9.83	9.83	9.83	9.83	9.83
DERV	(p/litre)	80.80	72.84	72.84	72.84	72.84	72.84
Unleaded petrol	(p/litre)	80.09	71.93	71.93	71.93	71.93	71.93
Fuel Oil (industrial)	(p/litre)	12.38	8.85	8.85	8.85	8.85	8.85
Fuel Oil (ESI)	(p/therm)	34.7	24.3	24.3	24.3	24.3	24.3
Petroleum (services)	(p/litre)	15.5	11.0	11.0	11.0	11.0	11.0
Petroleum (domestic)	(p/litre)	16.3	11.5	11.5	11.5	11.5	11.5
Gas oil (ESI)	(p/therm)	46.1	35.7	35.7	35.7	35.7	35.7
Gas (industrial)	(p/therm)	21.5	23.2	26.5	31.5	33.2	34.8
Gas (domestic)	(p/therm)	50.0	51.7	55.0	60.0	61.7	63.3
Gas (services)	(p/therm)	27.5	29.2	32.5	37.5	39.2	40.8
Gas (ESI)	(p/therm)	23.0	24.7	28.0	33.0	34.7	36.3
Coal (Industrial)	(p/therm)	14.4	14.4	14.4	14.4	14.4	14.4
Coal (domestic)	(p/therm)	57.2	57.2	57.2	57.2	57.2	57.2
Coal (services)	(p/therm)	19.5	19.5	19.5	19.5	19.5	19.5
Coal (ESI)	£/tonne	30.5	30.5	30.5	30.5	30.5	30.5

Annex B

Full Listing and Description of Model Runs

Description of Model Runs

Name	Scenario	Emission constraint 2030	Emission constraint 2050	Sensitivity
Core runs				
BL0	Baseline	None	None	
BL45	Baseline	20%	45%	
BL60	Baseline	30%	60%	
BL70	Baseline	40%	70%	
WM0	World Markets	None	None	
WM45	World Markets	20%	45%	
WM60	World Markets	30%	60%	
WM70	World Markets	40%	70%	
GS0	Global Sustainability	None	None	
GS45	Global Sustainability	20%	45%	
GS60	Global Sustainability	30%	60%	
GS70	Global Sustainability	40%	70%	
Limited energy efficiency				
BL0EE1	Baseline	None	None	Limited cost-effective potential for energy efficiency. Cost-effective potential limited to give a 2.1% improvement (30 year historical average) under the unconstrained scenarios. Further energy efficiency available when carbon reductions applied, but at positive costs.
BL45EE1	Baseline	20%	45%	
BL60EE1	Baseline	30%	60%	
BL70EE1	Baseline	40%	70%	
WM0EE1	World Markets	None	None	
WM45EE1	World Markets	20%	45%	
WM60EE1	World Markets	30%	60%	
WM70EE1	World Markets	40%	70%	

Name	Scenario	Emission constraint 2030	Emission constraint 2050	Sensitivity
GS0EE1	Global Sustainability	None	None	
GS45EE1	Global Sustainability	20%	45%	
GS60EE1	Global Sustainability	30%	60%	
GS70EE1	Global Sustainability	40%	70%	
BL60EE2	Baseline	30%	60%	Limited absolute potential for energy efficiency. Absolute potential limited to give a 2.1% improvement (30 year historical average) under the all scenarios. No further energy efficiency available, even when carbon constraints applied.
BL0EE3	Baseline	None	None	Limited absolute potential for energy efficiency. Absolute potential limited to give a 1.6% improvement (10 year historical average) under the all scenarios. No further energy efficiency available, even when carbon constraints applied.
BL60EE3	Baseline	30%	60%	
Limited gas supplies				
BL0PE1	Baseline	None	None	Proportion of natural gas in primary energy mix limited to current levels.
BL45PE1	Baseline	20%	45%	
BL60PE1	Baseline	30%	60%	
BL70PE1	Baseline	40%	70%	
WM0PE1	World Markets	None	None	
WM60PE1	World Markets	30%	60%	
GS0PE1	Global Sustainability	None	None	
GS60PE1	Global Sustainability	30%	60%	
BL0PE2	Baseline	None	None	Proportion of natural gas in primary energy mix limited to 10% increase above current levels.
BL45PE2	Baseline	20%	45%	
BL60PE2	Baseline	30%	60%	

Name	Scenario	Emission constraint 2030	Emission constraint 2050	Sensitivity
BL70PE2	Baseline	40%	70%	
WM0PE2	World Markets	None	None	
WM60PE2	World Markets	30%	60%	
GS0PE2	Global Sustainability	None	None	
GS60PE2	Global Sustainability	30%	60%	
Reduced innovation				
BL0INNOV	Baseline	None	None	Costs & performance of technologies frozen at 2010 levels to 2050. Exclude all technologies that are developed after 2010
BL45INNOV	Baseline	20%	45%	
BL60INNOV	Baseline	30%	60%	
BL70INNOV	Baseline	40%	70%	
Nuclear costs				
BL0NUC1	Baseline	None	None	Generation costs of nuclear power decreased by 0.5 p/kWh
BL60NUC1	Baseline	30%	60%	
BL60NUC2	Baseline	30%	60%	Generation costs of nuclear power increased by 0.5 p/kWh
Discount rates				
BL0D10	Baseline	None	None	Discount rate of 10% applied to all supply-side technologies
BL60D10	Baseline	30%	60%	
WM0D10	World Markets	None	None	
WM60D10	World Markets	30%	60%	

		Emission Constraint		Sensitivity
Name	**Scenario**	**2020**	**2050**	
Transport fuel tax				
BL0TX1	Baseline	None	None	New transport fuels penetrate market at current duty to 1%, thereafter hydrogen duty set at CNG rate & methanol & ethanol at biodiesel rate
BL60TX1	Baseline	30%	60%	
BL0TX2	Baseline	None	None	New transport fuels penetrate the market at current duty to 1% thereafter, new fuels attract duty at 50% rate of the traditional fuel rate for a period of 10 years & thereafter the same rate as traditional fuels
BL60TX2	Baseline	30%	60%	
Technology exclusion				
BL0EE1NS	Baseline	None	None	As BL0EE1 & BL60EE1, but with the exclusion of all nuclear & carbon sequestration technologies.
BL60EE1NS	Baseline	30%	60%	
BL60EE2NS	Baseline			As BL0EE1 & BL60EE1, but with the exclusion of all nuclear & carbon sequestration technologies.
Infrastructure				
BL0HYD	Baseline	None	None	Higher costs for hydrogen infrastructure
BL60HYD	Baseline	30%	60%	
BL0WIND	Baseline	None	None	Alternate assumptions for intermittent electricity generating technologies
BL60WIND	Baseline	30%	60%	

Renewables

BLWP1	Baseline	20% reduction of carbon emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010.
BLWP2	Baseline	30% reduction of carbon emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010.
BLWP3	Baseline	20% reduction of emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010 & 20% target in 2020.
BLWP4	Baseline	30% reduction of emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010 & 20% target in 2020.
BLWP5	Baseline	20% reduction of carbon emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010. Limit on energy efficiency as in BL60EE2.
BLWP6	Baseline	30% reduction of carbon emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% target for renewables in 2010 and 20% target in 2020. Limit on energy efficiency as in BL60EE2.
BLWPA	Baseline	20% reduction of emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010 & 30% target in 2020.
BLWPB	Baseline	30% reduction of emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010 & 30% target in 2020.
BLWPC	Baseline	30% reduction of emissions in 2020, then linear abatement to reach 60% reduction in 2050. 10% renewables target in 2010 & 30% target in 2020. Limit on energy efficiency as in BL60EE2.

Alternative emission paths		
BL60PK1	Baseline	20% reduction of carbon emissions in 2020, then linear abatement to reach 60% reduction in 2050
BL60PK2	Baseline	30% reduction of carbon emissions in 2020, then linear abatement to reach 60% reduction in 2050
BLDEF1	Baseline	Linear abatement of carbon emissions from 2000 to reach 60% reduction in 2050
BLDEF2	Baseline	Unconstrained emissions to 2020 then a linear abatement to 60% reduction in 2050
BLDEF3	Baseline	Unconstrained emissions to 2030 then a linear abatement to 60% reduction in 2050
BLDEF4	Baseline	Unconstrained emissions to 2010 then a linear reduction to achieve same cumulative reduction in carbon emissions as under BLDEF1
BLDEF5	Baseline	Unconstrained emissions to 2020 then a linear reduction to achieve same cumulative reduction in carbon emissions as under BLDEF1
BLDEF6	Baseline	Unconstrained emissions to 2030 then a linear reduction to achieve same cumulative reduction in carbon emissions as under BLDEF1

Annex C

Workshop to Review Data on Low Carbon Power Generation Technologies – Note of Main Conclusions

Introduction

This workshop was held at the DTI's Conference Centre on Friday, 21st June 2002. Its objectives were:

- To present results from an energy system modelling study, undertaken by AEA Technology and Imperial College, into long-term low carbon energy options.
- To seek comment and review of the electricity technology data used in the study.
- To identify areas meriting further sensitivity studies as part of the on-going modelling work.

The agenda for the workshop and list of delegates is appended to this note. The conclusions are reported for each of the workshop sessions, which considered fossil, nuclear and renewable energy electricity generation technologies.

Presentation of modelling results

1. No value is assigned to the carbon dioxide that is separated and disposed of in some modelling runs. This was considered correct because the technology is not taken up until after 2030 when opportunities for use in Enhanced Oil Recovery (EoR) in the North Sea will have passed. However, offshore platforms will have been decommissioned by 2030-2040 and therefore the study was optimistic in assuming there would be no costs associated with erecting new offshore disposal facilities.
2. It was suggested that the opportunity for disposing of carbon dioxide through EoR should be included since this would put a value on the CO_2 and use existing platforms before they are decommissioned. The problem is that the model does not need to deploy CO_2 separation and disposal before 2030. There is a separate requirement to examine the timeframe available to exploit EoR.
3. Generation technology capital costs should be amortised over a fixed period not the lifetime of the plant. 15 years was considered realistic.
4. The 15% discount rate was considered a little high and 10 to 12% was suggested as a realistic commercial rate.
5. Sensitivity studies have been undertaken to assess the effect of amortisation period and discount rate on some of the main technologies. Results listed below show that a discount rate reduction from 15 to 10% has the greatest impact with amortisation period becoming more significant at the lower discount rate. However, these changes had little effect on the relative order of production costs from the technologies, which suggests that the influence on technology choice within the MARKAL model will be small. The lower discount rate will affect abatement costs, and this will be taken into account in future modelling work.

Technology	Costs with 15% discount rate and amortisation over plant life	Costs with 15% discount rate and amortisation over 15 years	Costs with 10% discount rate and amortisation over plant life	Costs with 10% discount rate and amortisation over 15 years
GTCC 2000	2.05	2.10	1.89	1.97
IGCC 2000	4.34	4.61	3.60	3.96
New Nuclear 2010	3.70	4.06	2.86	3.37
Energy Crops 2000	4.32	4.50	3.64	3.87
Wind on-shore 2000	2.47	2.61	1.92	2.10
Wind off-shore 2020	3.91	4.14	3.05	3.33

[N.B the results in the table are based on the original data presented to the workshop and are for comparative purposes only.]

6. If capital costs are amortised over plant life it is unfair to assign 25 years to fossil plant and 40 years to nuclear. With refurbishment fossil plant can go on much longer than 25 years, and it was suggested new nuclear designs could last 60 years.
7. Natural gas prices were expected to increase more than the range covered by the scenario prices because of the large increase in demand. It was explained that one sensitivity study was investigating the effect of limiting the use of natural gas to 45% and 55% of year 2000 Primary Energy demands; another is looking at the impact of different coal, oil and gas prices on power generation costs from the technologies in the data base.
8. Points of clarification:
   - Model limits other air pollutants to the Large Combustion Plant Directive limits.
   - Carbon dioxide disposal costs cover pipeline transport and pressurisation, and are constant over the modelling period.
   - No international trading of carbon or electricity is included.
   - All costs are in year 2000 prices.
   - Future technology costs and performance assume international development and are on the optimistic side.
   - Model looks at capacity and not plant size.
   - CCL taxes are considered in estimating energy demands.
9. Regarding the ESI route map, it was suggested that Super Critical Pulverised Coal plant be included as well as IGCC. Also efficiency improvements and the possibility of carbon capture should be covered for existing coal plant.
10. Generators would favour retrofitting super-critical boilers to existing coal plant, taking advantage of existing infrastructure.
11. Energy crops should be considered separately from forestry waste since they have a greater cost. The energy crop price was assumed to be £1.39/GJ in 2000 falling to £1.01/GJ in 2040, which was acknowledged to be at the optimistic end of the range.

12. The possibility of co-firing existing coal plant with energy crops was discussed. Opinions were mixed with doubts raised over its viability and the financial and operational risks involved.
13. The representation of renewables and CHP in embedded generation was unclear.

Fossil power generation technologies

1. GTCC capital costs are too low. It was suggested that these should be almost flat over the 2000 to 2050 period at about £400/kW in 2000 falling to £380/kW in 2020. This anticipates costs being held fairly steady as plant gets more complex to achieve higher efficiencies. However, the PIU work suggests £400/kW is moving too high.
2. It was suggested that a survey be made of present GTCC plant costs (e.g. Power UK survey) to establish a baseline. The price reductions assumed in the database seemed reasonable and could then be applied to the baseline to estimate future costs.
3. The GTCC with 75% efficiency for 2040 would require a complex triple cycle plant with fuel cells up stream of the gas turbine. The capital cost would be higher than £400/kW for such plant.
4. With GTCC plus CO_2 capture the capital cost of the separation unit should fall with time. Costs should come down by a factor of 2 over 10 years and possibly more in the longer term.
5. The efficiency penalty of CO_2 capture should also come down with time. For GTCC suggested a reduction from 9 percentage points off efficiency in 2000 falling to 6 points off in 2020.
6. Operating costs in database for GTCC with CO_2 separation plant seem about right and consistent with IEA GHG Programme data.
7. Should examine the option to refit existing coal plant with super-critical boilers. This would cost about £300 to 400/kW and increase generation efficiency to 43% (same as current IGCC).
8. Should examine the option of CO_2 capture on refitted coal plant. Again cost should come down by about 33% over the next 10 years and the impact on generation efficiency should come down as for IGCC.
9. New super-critical pulverised coal plant would cost about £900/kW at present. New IGCC would cost about £1100/kW. However, there is more potential for cost reduction with IGCC in the future, and the 2020 and 2040 costs for IGCC are about right. Can only expect a small fall in PF/Super critical capital cost.
10. Costs for IGCC plus CO_2 separation are in line with an USA study.
11. Availability of all fossil fuel plant should be set at 90%.

Nuclear generation technologies

1. Discount rates and amortisation periods are influential in the costs of nuclear technology. Need to examine these effects in sensitivity studies, but must apply comparable treatment to all generation technologies (see analysis above).
2. Nuclear technologies need to be separated out into three options:
    - Existing plant
    - Near Term Deployment
    - Generation 4

3. Capital cost for near term (2010) build £1000/kW.
4. Capital cost for Gen 4 in 2020 £700/kW, with possibility of further cost reductions post 2020.
5. These costs have some uncertainty because they depend on series ordering and “learning curve” effects.
6. New nuclear plant should have availability above 90% over their full operating life of 40 to 60 years.
7. All the above costs are overnight costs neglecting interest during construction.
8. Should the nuclear build rate be as high as 1GW per year?
9. The possibility of rewarding technologies that can load follow was raised. This is not possible in MARKAL but the model incorporates a crude load curve, which affects the take-up of technologies.

Renewable energy generation technologies

1. The cost of energy crops was questioned and it was suggested that this should be divided into tranches to reflect location and production costs. The model has 3 tranches of energy crops of 32, 50 and 160PJ with prices in 2020 of £1.13, £1.43 and £1.80/GJ respectively.
2. IEA GHG programme offered to send a report that examines energy crop costs.
3. Energy crop generation costs are based on small scale IGCC. Therefore capital cost should be set 10% above coal IGCC to reflect lower economy of scale.
4. Energy crop conversion efficiency was also considered too high and should be reduced to 37% in 2000 and 40% in 2020.
5. Tidal stream costs and potentials should be taken from the report to DTI by Binnie, Black and Veitch.
6. Tidal stream capacity is too low. It needs to be over 10 GW.
7. Capture efficiency of lower tranches of tidal stream should be 30% rather than 21.9%.
8. The load factor (actually availability) of wave energy was questioned. This was estimated from a reliability model that examined the trade-off between capital sunk in spares, increased operating costs for extra maintenance teams and generation costs. No alternative values were offered.
9. Both on and offshore wind resource were considered too small. Currently the model uses all but one of the offshore wind tranches so it may be prudent to include more. However, it could also be argued that on-shore wind is too large if a pessimistic view is taken on planning constraints.
10. Offshore wind should be available from 2010 as it is being deployed now.
11. On-shore wind load factors (availability) seem too high at 50 and 47%.
12. PV cost reduction seems very high in comparison to wind. This raised the question of comparability if target costs are used for some technologies and best estimates for others. This is somewhat academic since little PV is deployed.

Main implications of suggested changes

Tables 1 to 3 attached compare the generation costs of the original technology database with the changes suggested by the workshop. Main observations are:

1. GTCC stays as the cheapest new build option up to 2020, but the differential is less.

2. The costs suggested by BNFL have nuclear becoming the lowest cost option after 2020.
3. Retrofitting supercritical boilers to existing coal plant appears economically attractive.
4. New IGCC still looks a high cost option, but it should be noted that information received from Progressive Energy and Jacobs Consulting after the workshop has indicated the potential for substantially lower cost designs. (See main report)
5. Co-firing of energy crops in a coal PF or GTCC plant is a lower cost option than using a dedicated plant.
6. Supercritical PF with CO_2 capture is price competitive with GTCC with CO_2 capture.
7. Costs suggested by BNFL have nuclear as the lowest cost low/zero carbon generation option from 2010 rather than 2020 with the original database.

Table 1 Cost of Electricity Production from Fossil Fuelled Plant Based on the Fuel Prices Listed Below (15% Discount Rate)

Capital Discounted over the life of the plant
Discount Rate 15%

Values in shaded boxes are those proposed at the workshop

	2000	2020	2040		2000	2020	2040
Gas (p/therm)	**23.00**	**25.50**	**33.00**	**p/kWh**	**0.78**	**0.87**	**1.13**
Coal (£/tonne)	**33.00**	**33.00**	**33.00**	**p/kWh**	**0.47**	**0.47**	**0.47**
Biomass (£/GJ)	**1.39**	**1.13**	**1.01**	**p/kWh**	**0.50**	**0.41**	**0.36**

	Max Capacity GW	Cap Cost £/kW	Ops Fix £/kW	Ops Var p/kWh	Efficiency %	Load Factor %	Plant Life yrs	Fuel p/kWh	Electricity p/kWh
Existing GTCC		0	12.0	0.05	39.8%	90%		0.78	2.17
New GTCC 2000		270	9.4	0.00	56.2%	90%	25	0.78	2.05
New GTCC 2020		260	9.1	0.00	65.6%	90%	25	0.87	1.95
New GTCC 2040		250	8.8	0.00	75.0%	90%	25	1.13	2.10
New GTCC 2000		400	13.9	0.00	56.2%	90%	25	0.78	2.36
New GTCC 2020		380	13.3	0.00	65.6%	90%	25	0.87	2.24
New GTCC 2040		380	13.3	0.00	65.6%	90%	25	1.13	2.63
New GTCC/CO_2 Sep 2000		514	19.0	0.48	47.2%	90%	25	0.78	3.39
New GTCC/CO_2 Sep 2020		483	26.2	0.41	56.6%	90%	25	0.87	3.23
New GTCC/CO_2 Sep 2040		450	16.6	0.34	66.0%	90%	25	1.13	3.14
New GTCC/CO_2 Sep 2000		644	23.8	0.48	47.2%	90%	25	0.78	3.71
New GTCC/CO_2 Sep 2020		502	27.3	0.41	59.6%	90%	25	0.87	3.20
Existing Coal (Small)		0	14.0	0.07	31.9%	80%	25	0.47	1.73
Existing Coal (Exist LCP no FGD)		0	14.0	0.07	35.5%	80%	25	0.47	1.58
Existing Coal (Exist LCP with FGD)		0	21.0	0.10	34.6%	80%	10	0.47	1.75
Retrofit Supercritical boilers to coal 2010		400	21.0	0.10	43.0%	90%	25	0.47	2.24
Retrofit Supercritical boilers to coal 2020		300	21.0	0.10	43.0%	90%	25	0.47	2.04
Retrofit Super Crit/CO_2 Sep 2000		960	50.4	0.24	30.0%	90%	25	0.47	4.32
Retrofit Super Crit/CO_2 Sep 2020		580	30.5	0.15	35.0%	90%	25	0.47	3.00

Table 1 Cost of Electricity Production from Fossil Fuelled Plant Based on the Fuel Prices Listed Below (15% Discount Rate) (Continued)

Capital Discounted over the life of the plant
Discount Rate 15%

Values in shaded boxes are those proposed at the workshop

	Max Capacity GW	Cap Cost £/kW	Ops Fix £/kW	Ops Var p/kWh	Efficiency %	Load Factor %	Plant Life yrs	Fuel p/kWh	Electricity p/kWh
New IGCC 2000		1232	52.0	0.00	43.0%	85.0%	25	0.47	4.34
New IGCC 2020		966	52.0	0.00	49.0%	87.5%	25	0.47	3.58
New IGCC 2040		700	52.0	0.00	55.0%	90.0%	25	0.47	2.88
New IGCC 2000		1100	52.0	0.00	43.0%	90.0%	25	0.47	3.90
New IGCC/CO_2 Sep 2000		1685	72.9	0.86	35.5%	85.0%	25	0.47	6.65
New IGCC/CO_2 Sep 2020		1336.5	72.9	0.74	42.3%	87.5%	25	0.47	5.49
New IGCC/CO_2 Sep 2040		988.3	72.9	0.62	49.0%	90.0%	25	0.47	4.43
New IGCC/CO_2 Sep 2000		1553	72.9	0.86	35.5%	90.0%	25	0.47	6.14
New IGCC/CO_2 Sep 2020		1151.3	72.9	0.64	44.0%	90.0%	25	0.47	4.88
Gas/FC/CO_2 2040		825	43.0	0.77	48.0%	90.0%	25	0.47	3.90

Table 2 Cost of Electricity Production from Nuclear Plant (15% Discount Rate)

Capital Discounted over the life of the plant
Discount Rate 15%
Values in shaded boxes are those proposed at the workshop

	Max Capacity	Cap Cost	Ops Fix	Ops Var	Load Factor	Plant Life	Fuel	Electricity
	GW	£/kW	£/kW	p/kWh	%	yrs	p/kWh	p/kWh
Existing Nuclear		0	80	0.00	75.0%	40	0.00	1.22
New Nuclear 2010		1300	80	0.00	85.0%	40	0.00	3.70
New Nuclear 2020		1100	60	0.00	85.0%	40	0.00	3.03

Alternative Nuclear Data 40 Year Plant Life

AP1000 2010		1000	N/S	0.70	90.0%	40	0.00	2.61
Gen 4 2020		751	N/S	0.65	95.0%	40	0.00	2.01

Nuclear 25 Year Plant Life

Existing Nuclear		0	80.0	N/S	75.0%	25	0.00	1.22
New Nuclear 2010		1300	80.0	N/S	85.0%	25	0.00	3.78
New Nuclear 2020		1100	60.0	N/S	85.0%	25	0.00	3.09

Nuclear 60 Year Plant Life

Existing Nuclear		0	80.00	N/S	90.0%	60	0.00	1.01
New Nuclear 2010		1300	80.00	N/S	90.0%	60	0.00	3.49
New Nuclear 2020		1100	60.00	N/S	90.0%	60	0.00	2.85

Table 3 Cost of Electricity Production from Energy Crops based on the Energy Prices Listed Below (15% Discount Rate)

Capital Discounted over the life of the plant
Discount Rate 15%

Values in shaded boxes are those proposed at the workshop

	2000	2020	2040		2000	2020	2040
Biomass (£/GJ)	**1.39**	**1.13**	**1.01**	**p/kWh**	**0.50**	**0.41**	**0.36**

	Max Capacity	Cap Cost	Ops Fix	Ops Var	Efficiency	Load Factor	Plant Life	Fuel	Electricity
	GW	£/kW	£/kW	p/kWh	%	%	yrs	p/kWh	p/kWh
Energy Crops 2000		1200	42.0	0.05	44.0%	85.0%	20	0.50	4.32
Energy Crops 2020		940	37.0	0.03	46.9%	85.0%	20	0.41	3.41
Energy Crops 2030		700	30.0	0.00	50.0%	85.0%	25	0.36	2.59
Energy Crops 2000		1210	42.4	0.05	37.0%	90.0%	25	0.50	4.31
Energy Crops 2020		1063	41.8	0.03	40.0%	90.0%	25	0.41	3.66
Energy Crops 2030		770	33.0	0.00	43.0%	90.0%	25	0.36	2.78
Energy Crops co-firing PF		18	0	0.01	34.6%	90.0%	15	1.5	1.54
Energy Crops co-firing in GTCC		228	0	0.2	56.2%	90.0%	15	1.5	2.08
Energy Crops in dedicated GTCC		1686	0	1.4	56.2%	90.0%	15	1.5	5.71

Workshop attendance list

Name	Organisation
George Marsh	AEAT
Heather Haydock	AEAT
Peter Taylor	AEAT
Nick Otter	Alstom Power
Richard Mayson	BNFL
John Haddon	BNIF
Tony Espie	BP
Stuart Woodings	British Energy
John Witton	Cranfield University
David Milborrow	DM Energy
Adrian Gault	DTI
Margaret Maier	DTI
Peter Bainbridge	DTI
Stephen Green	DTI
Richard Brook	Energy Power Resources
Paul Freund	IEA GHG
Rob Gross	Imperial College
Peter Fraenkel	Marine Current Turbines
Andrew Timms	Mitsui Babcock
Gordon MacKerron	NERA
Lewis Dale	NGC
Andy Read	PowerGen
Mike Parker	SPRU/Energy Advisory Panel

Annex D

Workshop on Infrastructure for transmission and distribution of hydrogen

There were six main points:

1. *A hydrogen future is technologically feasible and would not be economically disruptive.* This is one of the central conclusions of the modelling effort and of the analysis of the cost and engineering data. In this respect, the conclusions of the study so far were fully supported by the participants from industry and other organisations of the workshops.

2. *There are many routes or pathways to an economy in which hydrogen can become the energy vector for transport and as a fuel for industry, electricity generation and CHP.* The modelling effort had concentrated on the alternatives of centralised production from fossil fuels (coal and gas) and electrolysis using nuclear power and renewable energy. The existing gas infrastructure would gradually be upgraded to become hydrogen compatible. *This was considered to be a technically plausible pathway. If anything, however, it* <u>*understated*</u> *the options ahead:*

    - The decentralised production of hydrogen using low-cost off-peak electricity and renewable energy sources might favour electrolytic methods in the longer term, in contrast to centralised production using natural gas or coal with carbon sequestration. Biomass wastes are another possibility for small scale, more localised production.

    - In the near term, liquefaction of hydrogen for distribution and use (e.g. in transport) might be a better option than transmission and distribution via pipelines when levels of use are comparatively small. The latter option would become more attractive when markets become large.

3. *The costs of hydrogen production are if anything likely to be overstated in the analysis, and in this respect the conclusions have not been overstated:*

    - The efficiencies of hydrogen production from coal and gas are generally higher than assumed. Figures of 70-80% were quoted, as compared with the 45-50% figures for coal-based and 65-70% for gas-based hydrogen assumed in the analysis.

    - Availabilities were higher in practice—95-97% as compared with 90% assumed in the analysis.

    - The unit capital costs of coal based hydrogen production plant (£600-£700/kW) were also thought to be too high.

    - The use of off peak electricity would make electrolysis more attractive.

    - The development of long-term storage systems for hydrogen could also be a transforming event, making electrolytic hydrogen more attractive.

    In sum, some participants said costs would probably be in the range £3-5/GJ, much lower than the £6-7/GJ for gas-based and £11-13/GJ for coal-based hydrogen assumed in the analysis. (Joan Ogden's survey for the *Annual Review of Energy and the Environment* in 1999, vol. 24, 222-79 suggests prospective costs of \$5/GJ for gas based and \$10/GJ for coal based hydrogen. For advanced electrolysis using off peak electricity, she comes out at \$5/GJ and on the basis of the average costs of electricity at \$12/GJ.) A discussion of discount rates showed that this did not explain the disparities between the estimates in the study and those of the participants from industry.

Overall, some recognition of the possibility of better availabilities and efficiencies and lower costs in the production of hydrogen would be defensible.

4. *The costs of hydrogen transmission and distribution, on the other hand, may have been understated.* We had assumed that the transition to hydrogen transmission and distribution via gas networks would be around 20% more expensive than for natural gas. This was on the basis of discussions with members of the Hynet (EU) network. On the other hand, no one was able to come up with a better assumption. It was felt that the initial fixed costs would be large, on account of the need to cover a wide network of hydrogen filling stations. In addition, there would be quite large initial costs in setting up each station. We are to obtain further estimates from Shell and Air Products on this.

5. *Early and not marginal and gradual action, drawn out over long periods would be necessary to sustain industry's involvement.* There were several points here:

- Industry is already making a significant commitment. Assurances that hydrogen would be the 'fuel of the future' in the long-term, which are useful for setting visions and defining the 'end game', would need to be complemented by decisive policies to make the investments viable in the nearer term. Related to this:

  - If we are to have a viable industry in 20 years time, this will take significant investments in the next few years, and will entail significant costs.

  - The 'granularity' of the study, being based on 10 year steps, did not permit it to look at these transition costs in the detail required, and by being focussed on the longer term might understate the transition costs—e.g. for the reasons given in 4 above.

Thus some follow up work is needed to look at the costs of transition and the structure of the supporting policies in more detail. This is beyond the scope of the present study, though one run with a more rapid introduction of hydrogen in the first three decades would help take the analysis further. This could be coupled with changes in the cost assumptions noted in 3 and 4.

6. *World markets, and the policies of many countries besides the UK—especially in Europe, the US and Japan—are unanimously agreed to be the main drivers for innovation and cost reductions, as assumed in the study.* This of course has implications for UK national and international policies, a discussion of which was outside the scope of the study and the workshop, except insofar as they affect the cost assumptions discussed earlier.

Workshop attendance list

Name	Organisation
George Marsh	AEAT
Peter Taylor	AEAT
Dina Shah	Air Products
Nigel Cox	Alstom
Bob Wheadon	Association of Manufacturers of Power Generation Systems
John Hollis	BMW Group
Jon Maddy	BOC
Kenneth Fergusson	Combustion Engineering Association
Colin Garland	DfT
Brian Morris	DTI
David Crockford	DTI
Peter Brunt	DTI
Stephen Green	DTI
Gary Smith	Ford Motor Company
Geoff Day	Freight Transport Association
Tim Helweg-Larsen	Global Commons Institute
Ausilio Bauen	Imperial College
David Hart	Imperial College
Dennis Anderson	Imperial College
Rob Gross	Imperial College
Tim Foxon	Imperial College
Malcolm Fergusson	Institute for European Environmental Policy
Stephen Scott	Jacobs Consultancy
Brian Smith	Mitsui Babcock Energy
Simon Rowley	OST
Malcolm Watson	PIA
David Hanstock	Progressive Energy
Jim Skea	PSI
Phil Rugen	Shell Global Solutions
Frank Gerschwiler	SMMT
J N von Glahn	Solar Hydrogen Energy Group
John Speight	University of Birmingham

Annex E

Estimation of the cost for the distribution of hydrogen to road transport users

REFUELLING

1. Fuel capacity for a single hydrogen car is likely to be set to achieve a range of about 350km. With a fuel efficiency of about 1.2 MJ/km this infers a capacity of 420 MJ or 3.5 kgms.

2. With an assumed car utilisation of 16682 km/yr this infers a minimum of 48 refuels per car per year.

3. With total hydrogen car utilisation of 30bvkm in 2020 increasing to about 600bvkm in 2050 the number of cars to be refuelled will rise from about 2m to 36m.

4. So the number of refuels will be 263,000/day in 2020 rising to 4.7m/day in 2050.

5. If the refuelling rate is 1 kg/min then the time per refuel will be about 7 minutes (allowing x2 time for coupling up etc.). Therefore if refuelling is done over a 20h day the total number of refuelling facilities required will be a minimum of 1538 in 2020 rising to 27,485 in 2050.

6. ICCEPT gives a cost of $25,000 for one refuelling facility dispensing 8.3 kg/h. Assuming linear scale up a facility dispensing 30 kg/h would cost about £60,000 (assuming £1=$1.5). Therefore the capital cost in 2020 would be £92.3m rising to £1649m by 2050.

7. Refuelling facilities are, however, only likely to have a load factor of about 40%, therefore the capital cost is more likely to be £231M in 2020 rising to £4122m in 2050.

8. Let us assume that the refuelling facilities have an operating life of 10 years and capital is charged at 15%.

9. Operating costs of a filling station are maintenance and staff. Take maintenance to be 10% of capital costs. Let us assume a station can be operated by one person paid at £6/h. Therefore staff costs are £120 for a 20h day and £43800 per 365 day year.

10. Assuming 1200 hydrogen filling stations in 2020 rising to 12,000 in 2050, total operating costs are £52.6M in 2020 rising to £526M in 2050.

DISTRIBUTION TO FILLING STATIONS

1. Total amount of hydrogen needed for car transport is 54PJ (450kt) in 2020 rising to 885PJ (7380kt) in 2050.

2. Assuming the total number of filling stations in the UK is 12,000 and this stays constant over the modelling period. The average station will handle 615 tonnes of hydrogen per year or 1685/day in 2050. In 2020 it is assumed 10% of filling stations handle hydrogen with an average through put of 375t/yr or 1027g/day.

3. ICCEPT states that tube trailers can carry up to 460 kg therefore one filling station would require 3-4 deliveries per day. Therefore let us assume filling stations are supplied by Tube Trailers from central production plant or pipeline nodes.

4. ICCEPT gives transport costs of \$0.64/kg for 32km transport increasing to \$1.39/kg for 161 km.

TRANSMISSION FROM PRODUCTION PLANT

1. The production plant unit size assumed in the MARKAL database was 30,000kW which equates to 851472 GJ/yr or 7100t/yr.
2. Such a plant would produce 50kt of CO_2 per year. This is not sufficient to attain economies of scale in carbon capture and transportation. Therefore lets consider a plant 20 times this size.
3. At the above production unit size we will need 64 units in 2020 rising to 1040 units in 2050. With 20 units per plant this is approximately 3 plant in 2020 increasing to 52 in 2050.
4. Taking the surface area of Great Britain to be 23m hectares the average area to be supplied by one production plant is 442308 hectares by 2050. This equates to a distribution radius from each plant of 37.5 km.
5. Therefore it seems reasonable for hydrogen to be distributed from each centre of production by Tube Trailer. In 2020 the distribution will be from the three production plants to concentrated areas of utilisation. In 2050 it will be national distribution.
6. Let us assume that the average transport distance both in 2020 and 2050 is 32 km. Clearly most filling stations will be closer to the plant, but this value makes a crude allowance for the roads not going directly and straight to filling stations.
7. Using the tube trailer transport costs given above the cost of transport over 32 km would be £0.41/kg (\$0.64/kg) or £3.4/GJ.

CARBON DIOXIDE TRANSPORT AND STORAGE

1. The costs of capture transport and storage from large centralised plant has already been included in the cost of hydrogen production. For transport and storage this was £12.5/t CO_2, which equates to about £1.7/GJ of hydrogen.
2. However, for the present scenario we have smaller production units each generating about 1Mt of CO_2 per year. We need to include some additional transport costs for collecting this CO_2 to feed into a larger transmission pipeline.
3. Let us assume a pipeline node is centred on one production plant, and collects the CO_2 from a further nine such plants with an average distance from plant to pipeline node of 100 kms.
4. This gives an extra CO_2 transport cost of £0.41/GJ of hydrogen.

SUMMARY

1. The cost of dispensing hydrogen at filling stations is estimated to be £2/GJ in 2020 falling to £1.7/GJ in 2050. This includes a small economy of scale in staff costs to operate the filling stations.

2. The cost of transport to the filling stations has been estimated from above as £3.4/GJ.
3. The additional cost for carbon dioxide disposal is £0.41/GJ of hydrogen.
4. Therefore total distribution costs for transport applications is £5.8/GJ in 2020 falling to £5.5/GJ in 2050.

	2000	**2010**	**2020**	**2030**	**2040**	**2050**
REFUELLING COST						
Cost £/GJ			2.0	2.0	1.7	1.7
DISTRIBUTION						
Cost per GJ			3.4	3.4	3.4	3.4
EXTRA CO_2 DISPOSAL COST			0.41	0.41	0.41	0.41
TOTAL £/GJ			5.8	5.8	5.5	5.5

Annex F

Impact on Industry Competitiveness of Delivering Carbon Reductions

IMPACT ON INDUSTRY COMPETITIVENESS OF DELIVERING CARBON REDUCTIONS

Summary

This paper reports work undertaken by the Department of Trade and Industry to consider which industrial sectors are likely to be most affected by cost increases attached to reducing emissions of carbon dioxide.

Its starts from estimates of electricity price increases derived from long term (up to 2050) MARKAL modelling, though much of the focus here is the estimated impact to 2020. The implications of these price changes for production costs by sector are estimated. This assessment is then further informed by consideration of the international tradability of the various sectors – it might be expected that those sectors with the greatest production cost increase and which are significantly traded would face the greatest difficulties in passing cost increases on without damaging market share. For those sectors most affected impacts on profitability are also assessed as well as regional effects.

For gas, the MARKAL modelling work does not adjust prices in the event of increased demand. It therefore, does not forecast cost increases. It may be that in an internationally constrained carbon world, demand for gas – particularly in the EU – will rise by more than otherwise. But if that happens, the international price can be expected to rise – the impact will not be confined to the UK. The MARKAL work for the UK also suggests that the UK demand for gas, where the UK is on a course to a 60% CO_2 cut, need not rise above the base case level (without a CO_2 constraint) provided energy efficiency measures deliver.

It is important to note that this work does not address site-by-site effects, as the analysis at this stage looks only at the sector level. Within broad industry sectors there may be certain industries whose costs increase by much more than indicated here and in a number of cases, a greater impact on specific manufacturing processes and plants. So while the analysis allows broad judgments to be made about the implications, generally, for industry competitiveness, further work would be needed to examine in more detail the costs to specific industries/companies in the event of imposing carbon reduction targets.

The overall assessment provided here is, however, worst case. It does not allow for any greater improvement in energy efficiency than assumed in the base case. To the extent that enhanced energy efficiency measures can successfully reduce energy use this will also reduce energy costs. Also as the calculations are based on the UK taking low carbon measures in isolation, they represent the worst case in terms of the relative position of the UK against our international competitors.

MARKAL is one tool for assessing costs of the UK energy system. But we have also, separately, considered the costs of potential measures to address a 15-25MtC "carbon gap" in 2020. These projections remain highly uncertain, but in that work we have built up the potential impact on gas and electricity prices in a rather different way to that used in MARKAL – to reflect assumed measures including EU emissions trading and support for growth in renewables. These different approaches have provided a useful check on each other. From MARKAL we have electricity price increases to industry of 17% by 2020; in our assessment based on potential measures we have a range of 10-15% increase for electricity

and 15-30% for gas. Depending on the choice of measures, and details of their implementation, such estimates could change significantly.

Even with price increases of this order, UK energy prices would remain below levels of the past couple of decades. Nevertheless, to maintain competitiveness they indicate the importance of energy efficiency measures and of other countries following a UK lead to take measures to reduce emissions.

Because of the difficulties in disaggregating energy use down to detailed sectoral level there is a case for further scenario based work to better establish the impact of carbon reductions at a sectoral level in the UK and the impact on industry competitiveness.

Key points

- MARKAL modelling work has considered carbon reductions of 20% and 30% by 2020, and 60% for 2050. This work has been used to estimate energy cost implications. In practice, the work has indicated that most of the implications to 2020 are for electricity. The cost increases identified represent electricity price increases of 17% and 36% in 2020 (for 20% and 30% CO_2 reductions, respectively) and 32% in 2050.
- the sectors where production costs increase most – by greater than 2% for a 30% CO_2 reduction - are industrial gases, inorganic chemicals, brick manufacture and the cement, lime and plaster sectors. There is little international trade in these sectors apart from the inorganics sector.
- outside of those sectors, the greatest production cost increases – around 1% for a 30% CO_2 reduction - are in the metals, paper, chemicals and minerals industries.
- the parts of the chemicals sector most affected are the manufacture of basic chemicals (especially industrial gases and inorganics) and fibres.
- in all cases, the assessment reflects current cost structures. It does not allow for any behavioural reaction (for example, to adjust relative inputs to production) in response to energy price increase. Nor do the increased production costs take any account of energy efficiency gains beyond business as usual. They can therefore be considered as relatively conservative assumptions.
- the Gross Operating Surplus (GOS) as a percentage of turnover decreased for the sectors most affected by increased costs. The iron and steel sector is most affected.
- the paper, chemicals and metals sectors have products that are highly traded. Products from the minerals sector are traded to a lesser extent, though a relatively high proportion of trade in ceramics is with countries that have not ratified, or are outside, the Kyoto Protocol.
- non-ratification of the Kyoto Protocol by the US would put parts of the chemicals and metals sectors at a competitive disadvantage. This is a result of the high volume of trade which these sectors have with the US.
- these sectors are relatively highly located in regions/countries that are in receipt of European Structural Funds and/or are Assisted Areas.

1. Background

The work presented here examines the impact on industry competitiveness of achieving a range of carbon reductions. The carbon reductions analysed were: 20% and 30% by 2020 and 60% by 2050.

2. Methodology

The estimates of the costs to industry of delivering carbon reductions were derived as follows:

1. An estimate was made of the possible increase in electricity costs for manufacturing industries for 2020 and 2050. This was done using the MARKAL model, which was run to estimate the cost per unit of electricity supplied. Predicting electricity prices for 20 and 50 years ahead is clearly difficult and depends on a number of factors, particularly the relative movements of the costs of fossil fuels used for generation and new low carbon generation technologies.
2. Electricity prices were estimated when there were no carbon constraints and carbon constraints of 20% and 30% for 2020 and 60% for 2050.
3. Future electricity costs were calculated for each sector for each of the carbon reduction scenarios. This assumes that electricity use per unit of output remains as it is now, i.e. there is no allowance for any energy efficiency gains. The percentage increase in expenditure on energy was then calculated for each sector assuming that the price of other fuels remained unchanged. The increase in production costs was also calculated.
4. Having identified those sectors that would be most affected by an increase in electricity costs it was important to assess the extent to which they trade their products. Trade figures were broken down into imports and exports from and to countries throughout the world. Trade patterns were analysed according to whether or not countries had ratified the Kyoto Protocol.
5. Using trade figures it is possible to estimate the import penetration (the share of the UK market taken by imports) and the value of the importance of exports to UK manufacturing (export intensity). Together, these figures give an indication of the extent to which an industry sector could be penalised were its costs to increase relative to its competitors. Price elasticity was also considered and the effect on output assessed.
6. The effect of increased costs on the sectors' Gross Operating Surplus was estimated.
7. Finally, the location of those sectors predicted to be most affected was determined. This gave an indication of the importance of these industries to the local economy.

3. Results of analysis

3.1 Impact on energy prices

Table 1 includes details of energy consumption for a range of industry sectors. These data were obtained from the Office for National Statistics. Using the MARKAL model it was possible to estimate the future electricity prices when carbon constraints were imposed.

Table 1. Energy intensity and impact on production costs

Sector	[1]Total production costs (£million)	Current Expenditure on energy as % of total production costs	% Increase in production costs for different levels of carbon reduction		
			2020 20%	2020 30%	2050 60%
FOOD PRODUCTS & BEVERAGES	43,675	1.7	0.2	0.4	0.3
TOBACCO PRODUCTS	1,306	0.7	0.1	0.2	0.2
TEXTILES	5,439	2.8	0.3	0.6	0.5
WEARING APPAREL & FUR	3,428	0.7	0.1	0.2	0.1
LEATHER & ARTICLES; FOOTWEAR	1,112	1.2	0.1	0.3	0.2
WOOD & PRODUCTS EX FURNITURE	3,919	2.3	0.2	0.5	0.4
PAPER & PAPER PRODUCTS	7,751	3.6	0.4	0.8	0.7
PRINTING, PUBLISHING & REPRODUCTION	17,995	1.1	0.1	0.3	0.3
CHEMICALS & CHEMICAL PRODUCTS	33,033	2.8	0.3	0.6	0.5
241 Basic chemicals	13,956	4.9	0.5	1.1	0.9
2411-14 Basic chemicals except fertilisers	8,973	6.2	0.6	1.3	1.1
2411 Industrial gases	556	18.2	3.0	6.5	5.6
2412 Dyes & pigments*	1,009	2.9	0.2	0.6	0.5
2413 Inorganic*	1,203	10.7	1.1	2.3	2.0
2414 Organic*	6,320	4.5	0.5	1.0	0.8
2415 Fertilisers & nitrogenous compounds	871	2.8	0.3	0.7	0.6
2416-17 Plastics in primary form, synthetic rubber	4,112	2.6	0.3	0.7	0.6
242 Pesticides & other agro-chemical products	1,102	0.8	0.1	0.2	0.2
243 Paints, varnishes, printing inks, mastics	2,379	1.0	0.1	0.3	0.2
244 Pharmaceuticals, medicinal chemicals etc	7,278	1.1	0.1	0.3	0.3
245 Soap, cleaning preps, perfumes, cosmetics	4,003	0.8	0.1	0.2	0.2
246 Other chemical products	3,484	1.3	0.2	0.3	0.3
247 Man-made fibres	832	4.4	0.4	0.9	0.8
RUBBER & PLASTIC PRODUCTS	12,221	2.7	0.4	0.8	0.7
251 Rubber products	2,077	2.9	0.3	0.7	0.6
252 Plastic products	10,144	2.6	0.4	0.8	0.7
OTHER NON-METALLIC MINERAL PRODUCTS	6,959	6.0	0.5	1.0	0.9
261 Glass & glass products	1,619	8.1	0.8	1.6	1.4
262-3 Ceramic products	977	6.3	0.5	1.1	0.9
264 Bricks	282	22.7	1.2	2.4	2.1
265 Cement, Lime & Plaster	488	14.6	1.1	2.3	2.0
266-8 Articles of concrete	3,591	2.6	0.3	0.5	0.5
BASIC METALS	11,313	4.8	0.6	1.2	1.1
271-3 Basic iron & steel & first processing	5,974	4.6	0.5	1.0	0.9
274 Basic precious & non-ferrous metals	4,272	4.4	0.6	1.3	1.1
2742 Aluminium	2,246	5.7	0.5	1.2	1.1
275 Casting of metals	1,067	7.9	1.0	2.2	1.9
FABRICATED METAL PRODS EXCEPT MACHNIERY	14,360	2.2	0.3	0.5	0.5
MACHINERY & EQUIPMENT	21,661	1.1	0.1	0.3	0.2
OFFICE, ACCOUNTING & COMPUTER MACHINERY	13,788	0.2	0.0	0.1	0.1
ELECTRICAL MACHINERY & APPARATUS	9,723	1.1	0.1	0.3	0.3
RADIO, TV, COMMUNICATION EQUIPMENT	19,531	0.6	0.1	0.2	0.2
MEDICAL PRECISION INSTRUMENTS	6,864	0.9	0.1	0.3	0.2
MOTOR VEHICLES, TRAILERS ETC	32,256	0.7	0.1	0.2	0.2
OTHER TRANSPORT EQUIPMENT	13,565	1.0	0.1	0.2	0.2

* Electricity costs are assumed to constitute 60% of total energy costs.
[1] Production costs include costs of goods, materials and services, which represents the value of all goods and services purchased during the year.

Initially, only electricity prices are considered, as the bulk of the energy cost implications within MARKAL are for electricity. It is assumed that gas and coal prices will reflect international prices and price increases for these fuels will affect all countries. There is, however, further assessment of gas price impacts in section 3.2 below. [20]

Table 2 shows the electricity prices and the percentage increase, relative to the unconstrained prices, for the years 2020 and 2050.

Table 2. Estimated Electricity Prices for 2020 and 2050 for different carbon constraints (no energy efficiency improvement above base case)

	No constraint		**20% CO2**	**30% CO2**	**60% CO2**
	2020	2050	2020	2020	2050
Electricity prices (£/GJ)	12.1	12.7	14.2	16.5	16.7
% Increase to 2050	-	31.5	-	-	-
% Increase to 2020 20% 30%	 17 36	-	-	-	-

The MARKAL model focuses on assessing costs of technologies for electricity supply and does not predict individual industry demand-side measures to reduce energy usage. Therefore, the electricity prices predicted for the different scenarios presented here are a reflection of the costs associated with bringing forward the lower carbon energy supply technologies. In reality, it would be expected that industry would partially respond to these price rises by improving energy efficiency. In this respect, it is likely, therefore, that the costs to industry to achieve the different carbon reduction targets are worst-case estimates.

3.2 Sector energy costs

Using these estimated electricity prices it is possible to calculate the added cost to industry's energy bills. These are also shown in Table 1.

The sectors whose production costs are most affected include parts of the chemical industry (industrial gases, inorganic and organic chemicals, and man-made fibres), the minerals industry, paper industry and the metals industry. In some of these cases production costs, for a 20% reduction in CO_2, increase by more than 1% in 2020. Of particular note is the industrial gases sector, whose costs are estimated to rise by 3% in 2020. Such increases could have a significant impact on the sector's profitability depending on the margins at which it operates. Production cost increases for brick manufacture and the cement, lime and plaster[21] sector are also relatively high.

[20] In order to reduce energy costs it is likely that industry would move towards fuels with lower carbon intensity. Coal and oil users would, therefore, shift to fuels with lower carbon intensities e.g. gas. This could have the effect of increasing gas prices, but it is assumed for the purposes of Table 1 that gas prices in the UK would move in line with world prices. If many countries adopt carbon constraints it is possible that gas prices will increase with demand, but UK industry should be no more disadvantaged than any other country's industry.

[21] The cement and lime industries are already seeking to reduce energy costs through the substitution of conventional fuels (coal) with waste materials. This currently forms the basis of their Agreements under the Climate Change Levy. Cost-savings through such measures are not factored into the MARKAL model and, consequently, the predicted increase in production costs of 2% is probably a worst-case scenario.

A number of points should be noted about these cost estimates. Firstly, although the sectors have largely been broken down into 3 digit codes there will be some averaging out of costs. Within a code there will be some industries with higher cost increases. We have illustrated this in the case of basic chemicals where estimates are shown broken down to the 4-digit level. This reveals the cost impact on the manufacture of industrial gases (5.6% in 2050, as against 0.9% for basic chemicals). At plant level, variation will clearly be even greater.

The second point to note is that in some cases, an increase in costs in one industry will have an impact on the input costs of other industries. The cost estimates here do not take this into account and will therefore represent underestimates of the impacts.

The EU emissions trading scheme is one of the policy instruments that will be used to deliver carbon reductions. This can be expected to increase the price of gas to industry in the EU. For the UK, dependent on the price of carbon in the traded market, we have estimated that the price increase might be of the order of 15%, but with a high case 30% increase, by 2020. As a worst-case, the upper bound of this range was used to re-calculate increased production costs for those sectors with significant trade outside of the EU (for choice of these sectors see section 3.4).

Table 3 shows production cost increases for these sectors. Inclusion of gas price effects increases production costs. Competitiveness impacts will depend on the impact of the EU emission trading scheme on costs of gas in other EU member states, and on the scale of carbon reduction measures taken outside the EU.

Table 3. Increase in production costs taking account of increased gas and electricity costs (20% carbon reduction target by 2020)

Sector	**% Increase in production costs for 2020**	
	Electricity only(MARKAL)	**Electricity (MARKAL) and gas**
Basic chemicals	0.5	0.8
Basic chemicals except fertilisers	0.6	1.0
Pharmaceuticals, medicinal chemicals etc	0.1	0.2
Paper and paper products	0.4	0.7
Basic iron and steel & first processing	0.5	0.9
Basic precious & non-ferrous metals	0.6	0.8

3.3 Historical energy usage by sector

To illustrate how energy costs have changed over time, energy costs as a percentage of Production Costs for 1979 to 2000 and estimates for 2020 and 2050 are given in Table 4 for some of those sectors predicted to experience greatest cost rises[22].

[22] Historic data from Energy Paper 64; Energy Use in UK Manufacturing Industry 1973 to 1993; 2000 data from Table 1. The projections for 2020 and 2050 add in the cost increases for electricity from the MARKAL work. A note of caution is added for these data as the sectors were defined by different codes during the periods 1979-1992 and 1992-present. This is a result of the 1980 SICs changing in 1992. It is not therefore possible to show similar data for industrial gases or inorganic chemicals. Nevertheless, the comparison of industries within the sector codes shown should be a reasonable approximation.

There has been a significant reduction in the share of energy costs in total production costs from 1979 to current levels. However, although the energy costs for each sector increase to 2020 and 2050 (a result of carbon constraints) the costs still remain (even in 2050) significantly below 1979 levels. Additionally, these increased energy costs take no account of improvements in energy efficiency. As energy costs become more significant it is likely that industry will be invest more in energy efficiency measures. There is considered to be a significant amount of cost-effective energy efficiency still available to industry. Achieving it, however, may still require overcoming significant barriers.

Table 4. Trends in Energy Costs

Year	**Energy costs as a % of Production Costs**			
	Iron & Steel	Non-Ferrous	Man-made fibres	Paper
1979	8.5	6.1	8.0	13.1
1984	7.9	6.2	8.2	10.2
1989	5.6	3.8	6.8	8.8
2000	4.6	4.4	4.4	3.6
2020*	5.1	5.5	4.8	4.0
2050*	5.6	5.5	5.2	4.3

* Data for 2020 and 2050 correspond to carbon reductions of 20% and 60%, respectively, and allow for estimates of electricity costs made using MARKAL.

3.4 Impact on trade

It is important to understand the impact of these increased costs on trade. Table 5 shows UK imports and exports, respectively, by sector. Import penetration and export intensity ratios provide an indication of the degree to which a product is traded. For UK manufacturing as a whole the average import penetration (the share of the home market taken by imports) is about 47% and the export intensity (the share of manufacturers' sales taken by exports) is 41%. The paper sector, metals sector (iron and steel, non-ferrous metals and aluminium) and parts of the chemicals sector have levels of trade above the average. The metals sector is a highly traded market - in particular the non-ferrous sector, which has import penetration and export intensity of 73% and 66%, respectively. The chemical sectors most affected by trade are basic chemicals, especially the organic and inorganic industries.

Because not all countries have signed-up to the Kyoto Protocol it is possible that UK industry could be disadvantaged if a significant amount of trade is with non-ratified countries. Tables 6 and 7 show the percentage of imports and exports, respectively, with ratified and non-ratified countries. The sectors for which data are shown are those showing some of the greatest increases in production costs. For all of these sectors, most trade is within the EU. However, for non-ferrous metals and aluminium there is a large proportion of trade with non-ratified countries, most notably the US. Up to 20% of all exports of basic chemicals are with non-ratified countries. Market share could also be affected through countries trading in third country markets with other non-ratified countries.

Table 5. Size of industry and extent of trade.

Sector	Employees	Output	Exports	Imports	Exports/ Output	Imports/ UK market
		£m	£m	£m	%	%
Food Products	429,000	61,594	9,011	13,510	15%	20%
Tobacco	6,000	8,655	1,201	241	14%	3%
Textiles	181,000	10,514	3,660	5,722	35%	45%
Apparel	141,000	5,757	2,779	5,171	48%	63%
Leather	38,000	2,036	1,089	2,564	53%	73%
Wood Products	83,000	4,928	291	2,294	6%	33%
Paper[1]	98,000	3,997	4,627	6,905	39%	49%
Printing	348,000	35,393	2,498	1,438	7%	4%
Dyes & Gas	13,000	2,447	1,047	728	43%	34%
Inorganic Chemicals	12,000	1,263	652	642	52%	51%
Organic Chemicals	22,000	5,191	4,593	4,217	88%	88%
Fertilisers &Nitrogenous compounds[1]	3,000	1,036	147	325	14%	27%
Plastics[1]	22,000	5,260	2,140	2,782	41%	47%
Agro Chemicals[1]	6,000	1,586	729	311	46%	27%
Paints, varnishes, printing inks, mastics[1]	26,000	3,470	794	553	23%	17%
Pharmaceuticals[1]	65,000	12,108	7,322	5,456	60%	53%
Soap, cleaning, perfumes, cosmetics[1]	43,000	6,301	2,205	1,586	35%	28%
Chemical Products[1]	33,000	5,220	3,814	3,181	73%	69%
Man-made fibre[1]	5,000	1,125	717	678	64%	62%
Rubber Products	47,000	3,693	1,517	1,655	41%	43%
Plastic Products	180,000	14,078	2,674	3,058	19%	21%
Glass Products[1]	36,000	2,857	616	849	22%	27%
Ceramic Goods[1]	46,000	1,883	679	628	36%	34%
Bricks[1]	12,000	625	25	18	4%	3%
Cement, lime & plaster[1]	5,000	952	223	149	23%	17%
Concrete	44,000	4,547	543	429	12%	10%
Iron & Steel[1]	62,000	7,970	3,351	3,116	42%	40%
Non-ferrous metal[1]	26,000	5,443	3,614	4,956	66%	73%
Aluminium	13,000	2,050	992	1,744	48%	62%
Casting of Metal	39,000	2,267	383	209	17%	10%
Metal Products	438,000	23,452	3,517	3,675	15%	16%
Machinery	393,000	31,429	17,902	14,984	57%	53%
Office & computer Machinery	48,000	12,559	12,279	12,875	98%	98%
Electrical machinery	179,000	12,140	6,447	6,918	53%	55%
TV & communication equipment	130,000	14,205	13,310	15,179	94%	94%
Precision instruments	156,000	9,869	6,139	5,944	62%	61%
Motor vehicles	223,000	31,970	16,191	21,785	51%	58%
Other transport equipment	155,000	14,181	8,527	6,238	60%	52%
Furniture & Toys	190,000	9,972	3,786	5,464	38%	47%
Miscellaneous Manufacturing	11,000	3,177	499	554	16%	17%

[1] These data are for 1997-2000. All other data are for 1996

Table 6. Percentage of UK imports from ratified and non-ratified countries

Sector	Percentage of total UK imports					
	E.U	**Other ratified countries**	**Non-ratified countries**	**Selected developing countries**	**Rest**	**Total**
Iron and steel	71	11	8	6	4	100
Non-ferrous metals	38	14	32	6	10	100
Aluminium	54	18	21	1	5	100
Basic chemicals (except fertilisers)	64	11	11	5	9	100
Plastics	81	6	9	3	3	100
Pharmaceuticals	68	9	14	1	7	100
Man-made fibres	69	5	11	7	8	100
Paper	68	6	17	6	4	100
Cement	82	6	4	6	2	100
Glass	67	13	11	7	4	100
Ceramics	63	5	10	9	11	100
Bricks	82	7	7	2	1	100

Table 7. Percentage of UK exports from ratified and non-ratified countries

Sector	Percentage of total UK exports					
	E.U	**Other ratified countries**	**Non-ratified countries**	**Selected developing countries**	**Rest**	**Total**
Iron and steel	61	7	14	7	11	100
Non-ferrous metals	60	10	17	8	5	100
Aluminium	69	6	12	7	6	100
Basic chemicals (except fertilisers)	59	6	20	5	11	100
Plastics	69	6	9	7	9	100
Pharmaceuticals	52	9	23	7	9	100
Man-made fibres	74	4	10	5	6	100
Paper	56	8	18	7	11	100
Cement	75	5	5	6	9	100
Glass	63	8	14	7	7	100
Ceramics	41	13	27	6	13	100
Bricks	74	8	6	4	8	100

3.5 Impact on price competitiveness

The international competitiveness of sectors whose costs increase most and whose products are highly traded may be reduced. Price elasticity gives a measure of the extent to which a product's demand is affected by price. They are only rule-of-thumb figures as other factors than price will have impacts on demand.

The impact that price elasticity can have on industrial output of the main sectors affected (i.e. higher energy costs and highly traded products) is shown in Table 8. The figures in the second column show the effect of a 1% increase in production costs on output, whilst the figures in parentheses have applied this elasticity to the projected increase in sectoral production costs. For example, in iron and steel the predicted 0.5% increase in production costs in 2020 results in a loss in output of 0.78% (i.e. £62million).

Table 8. Effect on industry output of a 1% increase in unit cost (based on 20% carbon reduction target by 2020)[23]

Sector	Impact on output (%)	Reduction in output (£m)
Paper	-1.88 (-0.75)	30
Man-made fibres	-1.19 (-0.48)	5
Inorganic Chemicals	-1.48 (-1.63)	20
Iron and Steel	-1.56 (-0.78)	62
Non-ferrous metals	-0.86 (-0.52)	28

3.6 Impact on sector revenue

Although the increases in production costs appear relatively small they can have a significant effect on profitability. Some sectors (and specific companies within sectors) operate with very small profit margins and a 1% increase in costs could have a major impact on the viability of the sector/company. This effect was analysed by estimating the impact of the increase in production costs on the sector's Gross Operating Surplus (GOS). This was done for 2020 (20% carbon reduction) and 2050 (60% carbon reduction).

The data used were taken from the Annual Business Inquiry Statistics. The change in GOS was calculated as a percentage of the sector's turnover. The Gross Operating Surplus (GOS) was used as an approximation to sector profits. The GOS was calculated by subtracting employment costs from gross value added.

The GOS also equates to the turnover with both employment costs and production costs removed. Therefore, a revised GOS was calculated for the increased production costs for the years 2020 and 2050 (as estimated earlier in the paper).

The estimates are shown in Table 9. Of most significance is the iron and steel industry, which shows a decrease in GOS/Turnover ratio of 10.8% and 19.3% in 2020 and 2050, respectively. The non-ferrous metals sector shows the next greatest reduction at 4.7% and 8.6% for 2020

[23] Based on a study by Carlin, Glyn and Van Reenen published in the Economic Journal 2000. Estimate for iron and steel sector made by DTI. David Humphry, "Unit costs and trade performance: some econometric results for the European steel industry" IES, DTI, September 2000.

and 2050, respectively. Without similar information for these sectors in other countries, it is difficult to determine the impact that this could have on their competitiveness or location decisions[24].

Table 9. Change in Gross Operating Surplus for increased costs

	Paper & Paper products	Industrial Gases	Inorganic Chemicals	Man-made-fibres	Iron & Steel	Non-ferrous metals
Gross Operating Surplus (£million)	1716	353	908	171	199	549
Total Production Costs (£million)	7751	556	1203	832	4346	4272
GVA	4075	587	357	320	1183	1208
Employment Costs (£million)	2359	234	295	149	984	659
Turnover (£million)	11826	1143	2406	1152	5529	5480
GOS/turnover (%)	14.51	30.88	37.74	14.84	3.60	10.02
Production Costs in 2020 (£million)	7782	573	1216	835	4368	4298
GOS/turnover (%) in 2020	14.25 (-1.8%)	29.40 (-4.8%)	37.1 (-2.6%)	14.55 (-2%)	3.21 (-10.8%)	9.55 (-4.7%)
Production Costs in 2050 (£million)	7805	587	1227	839	4385	4319
GOS/turnover (%) in 2050	14.05 (-3.2%)	28.17 (-8.8%)	36.74 (-2.6%)	14.27 (-3.8%)	2.89 (-19.3%)	9.16 (-8.6%)

Figures in parentheses show the percent reduction from current levels.

3.7 Regional effects of increased industry costs

The earlier work highlighted that the competitiveness of non-ferrous metals, iron and steel, man-made fibres, industrial gases and paper manufacture could be most affected.

Table 10 shows the location and number of employees in each region/country for these sectors, as well as total employment in each region/country. The percentage of employees in these sectors is also shown expressed as a percentage of total employment in each region/country[25]. Wales has the highest concentration – 2.3% of employment is in these

[24] Cost increases might be passed on to customers or absorbed. The latter is assumed in this analysis, and therefore GOS will decrease. This is the worst case scenario.
[25] The figures are for England, Scotland and Wales only. Employment in these sectors accounts for 0.68% of total employment across Great Britain

sectors, much of it in Iron and Steel. Much of Wales is classified as an Objective 1 and Tier 1 (see Annex II). The information in Table 10 is broken down further in Table A1 in Annex I, where the Local Authority is shown for each region/country. Although these sectors are located in 409 Local Authorities Table A1 only goes as far as showing those Local Authorities in which the selected sectors constitute greater than 1% of the total number of employees. This covers 18% of the total employed in these sectors and they are located in nearly 100 local authority areas, of which nearly two-thirds are in receipt of support under the European Structural Funds or are eligible for UK regional assistance.

Of the sectors shown it is the Iron and Steel and Paper sectors that have the greatest number of employees (33,213 and 95,690, respectively)[26]. Scope for localised impacts is indicated. For the Iron and Steel sector a number of the high employment Local Authorities are both Objective 1 or 2 and Tier 1 or 2 (Redcar and Cleveland; Neath Port Talbot; Blaenau Gwent; Rotherham).

It is important to remember that the analysis takes no account of structural changes in these sectors. Over the period of time analysed here it is likely that some sectors will experience significant changes in relative competitiveness through changes in demand, costs of competitors etc - impacts greater than associated with carbon constraints. Nevertheless, such impacts indicate the need to keep sectoral impacts, and policy responses, under careful review.

Table 10. Location of industry sector and number of employees by Region/Country

Region/country	2742	2743	2744	2745	21	2710	2411	2413	2470	Total	% of tota
Wales	2839	0	440	469	5900	11911	191	351	188	943228	**2.3**
North East	909	70	119	55	4022	4827	428	115	782	952847	**1.1**
Yorkshire and Humber	674	128	203	59	9497	9979	561	412	1089	2079440	**1.0**
North West	1936	85	1309	336	18236	1321	868	4578	217	2835344	**1.0**
East Midlands	1229	243	207	398	8946	674	146	361	256	1702806	**0.7**
West Midlands	1863	343	2210	2276	6033	2481	273	936	166	2377516	**0.7**
Scotland	773	29	7	130	9985	587	234	904	204	2238385	**0.5**
South East	1336	383	148	125	12823	831	1520	238	0	3672150	**0.4**
East	593	77	278	155	7937	41	92	763	156	2202355	**0.4**
South West	496	417	161	62	7285	175	14	199	498	2081602	**0.4**
London	304	25	105	108	5034	384	135	286	0	4052614	**0.1**
TOTAL	**12952**	**1800**	**5187**	**4173**	**95698**	**33211**	**4462**	**9143**	**3556**	**25138287**	**0.6**

Source: NOMIS

Sector definitions

2742 : Aluminium
2743 : Lead, zinc and tin
2744 : Copper
2745 : Other non-ferrous metals
21: Paper and paper products
2710: Iron and steel
2411: Industrial gases
2413: Inorganic chemicals
2470: Man-made fibres

[26] The data used here are for 2000 and use definitions slightly narrower than in the analysis on costs.

APPENDIX I

Table A1. Industry sectors by Local Authority, the number of employees and the status of the Local Authority

Region/country	Local Authority Area	2742	2743	2744	2745	21	2710	2411	2413	2470	Total	% of total	Objective	Tier
NE	Redcar and Cleveland	0	0	0	0	4	4011	92	2	719	40421	11.94	2	2
W	Neath Port Talbot	0	0	0	105	150	4189	109	0	47	40041	11.49	1	1
YH	North Lincolnshire	0	0	0	1	919	4342	80	1	0	66408	8.05	2	2
W	Newport	770	0	0	0	186	4306	67	252	0	71761	7.78	2	2
W	Blaenau Gwent	0	0	45	0	197	1204	1	24	0	21076	6.98	1	1
NW	Allerdale	393	0	0	0	597	705	0	1	0	32015	5.30	2	2
W	Flintshire	7	0	0	63	1863	1195	10	65	0	63938	5.01	-	2
SE	Swale	72	0	0	0	1189	590	2	13	0	38183	4.89	-	-
SE	Tonbridge and Malling	5	0	0	5	2387	0	0	2	0	49567	4.84	-	-
NW	Halton	90	0	0	0	307	0	20	1954	0	50407	4.70	2	2
NE	Wansbeck	670	0	0	0	1	0	0	0	0	16525	4.06	2	2
WM	Bridgnorth	601	0	0	7	85	27	0	0	0	18313	3.93	2	-
YH	Rotherham	323	14	0	6	94	2481	254	57	0	86333	3.74	1	1
W	Anglesey	545	0	0	0	1	0	0	0	0	15878	3.44	1	1
NW	West Lancashire	17	0	290	0	927	0	0	1	0	38676	3.19	2	2
NW	Blackburn with Darwen	39	0	205	0	1579	0	0	1	0	60313	3.02	2	2
SE	Gravesham	0	372	0	0	453	0	0	2	0	27440	3.01	-	-
EM	North East Derbyshire	88	0	0	162	445	0	0	0	0	24665	2.82	2	2
NW	Copeland	22	0	4	0	248	0	0	515	0	30264	2.61	2	2
NE	Tynedale	0	0	0	0	472	0	0	0	0	18966	2.49	2	2
S	Clackmannanshire	0	0	0	0	339	0	0	0	0	13877	2.44	2	2
NW	Hyndburn	0	0	0	0	529	0	1	157	0	28691	2.39	2	-
SW	Forest of Dean	3	0	81	0	462	0	0	0	0	23458	2.33	-	-
NW	Congleton	60	0	0	0	404	0	9	223	0	31452	2.21	-	-

Region/country	Local Authority Area	2742	2743	2744	2745	21	2710	2411	2413	2470	Total	% of total	Objective	Tier
NW	Barrow-in-Furness	0	0	0	0	416	0	0	0	0	18904	2.20	2	2
NW	Ellesmere Port and Neston	11	0	0	0	472	0	25	137	0	30130	2.14	2	2
WM	Redditch	214	0	45	152	391	52	4	1	0	40175	2.14	-	-
WM	Sandwell	63	6	376	72	629	794	0	725	0	125467	2.12	2	2
SW	West Somerset	4	0	0	0	226	0	0	0	0	10886	2.11	2	-
NW	Vale Royal	4	0	0	0	353	0	0	566	0	44826	2.06	-	-
EM	Corby	379	0	0	0	242	0	0	0	0	30589	2.03	-	-
SW	Tewkesbury	91	3	0	0	76	0	0	1	416	30292	1.94	-	-
E	Mid Bedfordshire	238	0	0	8	428	0	3	3	0	36371	1.87	-	-
NW	Burnley	0	0	0	0	570	0	0	81	8	35378	1.86	2	-
NW	Rochdale	42	0	90	1	882	306	0	23	0	72720	1.85	2	2
NW	Pendle	0	0	0	0	532	3	0	0	0	29941	1.79	2	-
EM	Charnwood	5	0	3	0	939	0	0	0	0	55923	1.69	-	-
YH	Sheffield	8	0	1	36	874	2895	0	19	0	227112	1.69	1	1
W	Bridgend	217	0	0	0	603	0	0	0	0	48660	1.69	1	1
SE	Chiltern	484	0	0	0	56	0	3	0	0	32238	1.68	-	-
NW	Rossendale	0	24	0	3	383	0	0	2	0	24681	1.67	2	-
S	Fife	0	0	0	0	1755	0	0	352	0	127480	1.65	2	2
W	Wrexham	181	0	0	0	636	0	0	0	0	49796	1.64	-	-
S	West Dunbartonshire	0	0	0	0	461	0	0	0	0	28630	1.61	2	2
SW	Mid Devon	0	0	8	0	242	0	0	0	82	20658	1.61	2	-
NE	Wear Valley	15	0	0	0	247	0	0	0	50	19737	1.58	2	2
EM	East Lindsey	3	0	0	0	559	0	0	0	0	35649	1.58	2	-
SE	Basingstoke and Deane	0	0	0	34	1094	14	55	3	0	76769	1.56	-	-
EM	High Peak	0	0	167	154	149	0	0	5	0	30395	1.56	2	-
NW	South Lakeland	181	0	0	0	497	0	0	0	0	44056	1.54	2	-
YH	North East Lincolnshire	0	0	0	0	82	0	107	0	797	65595	1.50	2	2

Region/country	Local Authority Area	2742	2743	2744	2745	21	2710	2411	2413	2470	Total	% of total	Objective	Tier
EM	Amber Valley	16	16	0	0	544	0	0	161	26	50960	1.50	-	-
WM	Herefordshire, County of	2	0	0	877	124	0	0	2	0	67313	1.49	2	-
W	Monmouthshire	0	0	0	0	473	0	0	0	0	32048	1.48	-	-
NW	Tameside	5	27	0	3	825	0	2	36	100	68338	1.46	2	2
E	Thurrock	0	0	0	1	438	0	0	334	0	53261	1.45	-	-
SE	Elmbridge	1	0	0	5	52	0	781	0	0	58740	1.43	-	-
EM	Wellingborough	0	0	0	55	414	0	0	0	0	33262	1.41	-	-
W	Torfaen	3	0	0	11	182	180	0	0	128	35862	1.41	1	1
W	Caerphilly	205	0	0	0	472	0	0	1	0	48291	1.40	1	1
WM	Walsall	54	208	468	38	313	369	0	0	1	104654	1.39	2	2
E	Forest Heath	0	0	0	0	318	4	0	4	0	23626	1.38	-	-
EM	Kettering	59	0	0	0	378	0	0	4	0	32077	1.37	-	-
NE	Gateshead	164	0	8	0	679	301	0	0	0	83849	1.37	2	2
NW	Knowsley	0	0	568	0	121	0	1	2	0	51389	1.35	1	1
S	Falkirk	88	0	2	4	197	0	4	427	0	53635	1.35	2	2
EM	Chesterfield	0	0	0	0	396	96	10	134	0	47260	1.35	2	2
EM	Mansfield	0	0	0	2	66	401	0	0	0	35155	1.33	2	2
E	Fenland	0	0	0	0	370	0	0	9	0	28495	1.33	-	-
W	Swansea	604	0	0	280	65	290	4	3	0	94289	1.32	1	1
NW	Salford	368	0	0	248	202	0	549	0	0	111293	1.23	2	2
L	Bexley	115	0	0	0	674	0	0	0	0	64697	1.22	-	-
E	East Cambridgeshire	0	0	0	1	223	0	0	0	0	18733	1.20	-	-
EM	Bolsover	159	0	4	0	8	0	0	0	21	16215	1.18	2	2
NW	Warrington	204	0	0	0	323	3	0	667	0	101590	1.18	-	-
NE	South Tyneside	8	0	0	19	480	0	0	10	0	44173	1.17	2	2
YH	Selby	0	0	0	0	298	0	1	4	0	25927	1.17	-	-
NW	Wigan	261	0	0	4	787	29	0	55	0	99967	1.14	2	2

Region/country	Local Authority Area	2742	2743	2744	2745	21	2710	2411	2413	2470	Total	% of total	Objective	Tier
S	North Ayrshire	4	0	0	3	446	11	0	0	0	41599	1.12	2	2
EM	Boston	0	0	0	0	295	1	0	0	0	27225	1.09	2	-
S	East Dunbartonshire	0	0	0	0	269	0	0	13	0	25993	1.08	2	2
NE	North Tyneside	0	0	111	36	495	0	0	0	0	59414	1.08	2	2
S	West Lothian	158	19	0	59	485	0	0	0	0	67683	1.07	2	2
WM	Staffordshire Moorlands	0	0	162	0	137	0	0	0	0	28150	1.06	-	-
SE	Medway Towns	245	0	0	2	470	119	2	12	0	80068	1.06	-	-
EM	Derbyshire Dales	130	186	0	0	6	0	0	11	0	31588	1.05	2	2
YH	Bradford	57	0	89	0	1769	75	0	0	65	195140	1.05	2	-
E	Great Yarmouth	0	0	0	0	325	0	1	0	0	30980	1.05	2	2
WM	Tamworth	105	9	45	0	170	0	0	0	0	31507	1.04	-	-
SE	Maidstone	2	0	0	7	671	0	0	0	0	65580	1.04	-	-
NW	Bolton	0	0	0	2	1024	0	0	4	79	107323	1.03	2	2
NE	Stockton on Tees	0	0	0	0	64	354	188	95	13	69415	1.03	2	2
S	Aberdeen City	0	0	0	0	1667	1	22	44	1	168690	1.03	-	-
NW	Lancaster	0	0	0	0	492	0	0	1	0	48566	1.02	2	2
E	Huntingdonshire	74	0	0	8	570	0	0	0	0	64270	1.01	-	-
SW	Stroud	0	0	2	2	389	0	0	0	0	38751	1.01	-	-
E	South Cambridgeshire	0	4	0	2	540	0	0	0	0	54019	1.01	-	-

E – East; **EM** – East Midlands; **L** - London; **NE** – North East; **NW** – North West; **S** – Scotland; **SE** – South East; **SW** – South West; **W** – Wales; **WM** – West Midlands; **YH** – Yorkshire and Humber.

APPENDIX II

European Structural Funds

Objective 1:

Eligible areas are those that have less than 75% of EU average GDP. It is the highest level of regional funding available from the EU. It is aimed at promoting the development and structural adjustment of the EU regions most lagging behind in development. In the UK areas that qualify are Merseyside, South Yorkshire, Cornwall and the Scilly Isles, and West Wales and the Valleys. In total the UK will receive over £3.9 billion of Objective 1 money between 2000-2006.

Objective 2:
Aims to support the economic and social conversion of areas facing structural difficulties. It is the second highest level of funding available from the EU. Areas qualify for Objective 2 under four strands - industrial, rural, urban and fisheries. This objective covers nearly fourteen million people in the UK. In addition, areas that had Objective 2 or 5b status in the previous programming period are eligible for transitional funding until 2005. Including transition, Objective 2 covers well over nineteen million people in the UK. In total, the UK will receive over £3.1 billion for UK Objective 2 and transitional Objective 2 areas for the period 2000 - 2006.

Assisted Areas of Great Britain

These are assigned by each Member State and their designation is done so within the European Commission's guidelines on regional aid (1998). These Assisted Areas became operational from 1 January 2000. Under the guidelines all Objective 1 designations will be Tier 1 although the same is not true for Objective 2 and Tier 2.