Policies for a Low Carbon UK Energy System

Findings of a Study for the IPPR

Dennis Anderson, August 7, 2007

Abstract

This paper was written at the request of the Institute for Public Policy Research. Its purposes are to provide an independent assessment of the policies required for achieving a low carbon energy system in the UK, and to estimate the costs. The *directions* of such policies in the UK have been set out in the recent Energy White Paper. The principles on which they are based are clearly stated and, as with those outlined in the Stern Report, have three elements: carbon pricing, direct support for innovation, and reforming regulatory standards and procedures to facilitate the uptake of low carbon and energy efficient technologies and practices.

But it is fair to say that the *magnitudes* of the incentives required, with the partial exception of the 'banding' of the Renewables Obligation, fall substantially short—in some cases by factors of 5 to 10—of what will be needed if the UK is to meet both its near and long-term targets of achieving a low carbon energy system by 2050. Through an analysis of the costs of low carbon technologies relative to those of the fossil fuels they would displace the paper estimates the magnitudes of the incentives required and, following the Stern Report, the overall cost of carbon abatement in relation to the level and growth of economic output. It also makes proposals as to how the incentives might be financed without—in my view, unnecessary—recourse to the public revenue.

The question has been raised by the IPPR and the WWF, what if the carbon abatement targets need to be more ambitious? The Government's target of 60% abatement by 2050 stemmed from the report of the Royal Commission on Environmental Pollution in 2000. But as the Stern Review and the Fourth Assessment Report of the IPCC have found, the probabilities of dangerous threshold effects occurring in the climate system are now thought to be much higher than they were seven years ago, and may require more stringent climate change policies. As will be shown below (and not surprisingly) this would raise the costs of abatement and the magnitudes of the incentives required.

Acknowledgements

I wish to thank Matthew Lockwood of the Institute for Public Policy Research for initiating the study and the generosity of the Esmee Fairbairn Foundation in supporting it. Matthew put searching questions to me throughout the work and made numerous suggestions and comments to guide and improve the analysis. Keith Allott of the World Wildlife Foundation was likewise searching in the questions he asked, and it was a pleasure to interact with Neil Strachan of the Policy Studies Institute who was conducting a parallel analysis for the WWF. The responsibility for the contents of this paper (and the spreadsheet which is to accompany it) lies solely with me: it is a background paper for the work of the IPPR and WWF, who will be publishing their own analyses separately.

Contents

1. Introduction and Summary

1.1 Questions

The Government's Energy White Paper announced a set of policies that would put it on the path toward reducing carbon emissions from energy production and use by 60% by 2050. Following the *Stern Review* the policies have three components:

1. *Carbon pricing*. The intention is to seek a recovery of the carbon price under the EU's Emission Trading Scheme (ETS), which has recently collapsed nearly to zero, and to extend the ETS to more sectors of economic activity, including road transport and aviation.

2. *Direct support for innovation*. This has several aspects: an extension of the Renewables Obligation for electricity generation, with a 'banding' of the Obligation such that technologies in an earlier phase of development would receive a greater incentive; a Renewable Transport Fuels Obligation together with duty allowances on biofuels; and a number of R&D and demonstration programmes.

3. *Regulatory reforms and standards*—to facilitate the use of low carbon technologies, and the development and adoption of a large number of practices for improving energy efficiency.

Hence the direction of the policies is clear, and both the EWP and a large number of supporting papers, including the Department for Transport's paper on *Innovation Strategy* in May 2007, provide well-informed reviews of the technological options for carbon abatement. They provide good reasons for thinking that high levels of abatement—up to 100% for electricity generation and close to this for road transport and the heating markets—are technologically feasible in the long-term.

The main issues ahead now relate less to the direction of the policies than to the scale of support required. It is for instance no longer necessary to argue the case for carbon pricing, which has been accepted by the Government for some years. There is still the question of what *form* it would best take, for example a carbon tax or a marketable permit scheme. However, Governments in the EU have decided to follow the marketable permit approach, which in theory is a good option; in the interests of continuity in policies, it will only be necessary to revisit the economist's ideal of a carbon tax if the EU-ETS fails or proves to be administratively too costly and inefficient.

The main question is—what level will the carbon price need to be if it is to encourage investment on a sufficient scale to meet the targets? The carbon price under the EU-ETS peaked at approximately €35/tCO_2 (£85/tC) before its recent collapse, which stemmed from the allocations of the carbon permits or 'caps' being too generous. The following analysis estimates that the caps will need to be set such that the carbon price will (a) move to the upper end of the €40-80/ tCO_2 range (£100-200/tC) in the period 2008-2020, and (b) be extended to all hydrocarbon fuels, if it is to have the desired effect.

Similarly, the case for supporting innovation directly has been accepted by the UK Government for sometime, going back to the non-fossil fuel obligation (NFFO) of the 1990s, notwithstanding the objections of some economists to the levels of intervention such support requires. In fact, the case has long-been accepted by all governments throughout the OECD, not least a large number of State Governments in the US, and it has proved to be by far the most influential instrument for developing the broad range of technologies that are now available for addressing climate change—nuclear power, carbon capture and storage, and the full range of renewable energy technologies. But, in the UK, are the *magnitudes* of the incentives to support innovation directly sufficient? The following analysis suggests that they are in a few cases only. For the majority of situations—in transport in particular—they fall a very long way short of what is required, sometimes by an order of magnitude. The analysis endeavours to provide quantitative estimates of what the incentives for innovation will need to be.

There is a further question of whether the UK target of 60% abatement by 2050, relative to 1990 levels, is sufficient. This target stemmed from the findings of the Royal Commission on Environmental Pollution (2000) and was adopted as an ‘aspiration’ in the 2003 Energy White Paper. However, as the Stern Review and the Fourth Assessment Report of the IPCC have shown, the probabilities of irreversible threshold effects are greater than was thought when the RCEP report was published, and rise rapidly for global average temperature increases in and above the range 2-3 $^{\circ}$C. Such a range is now within that calculated for stabilisation levels of 450 ppm of CO_2-equivalent, as shown in the following table, which is compiled from the Stern Review:

Expected global average increase in temperature at 450 and 550 ppm:

Stabilisation Level: PPM of CO_2-equivalent	**Lower 5% limit**	**Mean**	**Upper 5% limit**
450	1.0	2.5	3.5
550	1.5	3.5	4.5

Source: Stern Review (2006)

With current accumulations already being 430 ppm and rising at 2.5 ppm per year, it is thus not unreasonable to ask, as the IPPR and WWF have done, what would be the implications of yet tighter targets? The IPPR have proposed a long-term target of 90% abatement by 2050.

1.2 Findings

For the 60% targets it is estimated below that the costs of abatement would rise to around 0.8% of GDP over the next 20 years and to 1.2 ± 0.5% of GDP in the long-term. For the more demanding IPPR-WWF trajectory they are roughly twice these levels; and they would also require more urgency in policies and yet stronger incentives in the near-term.

Most studies have concluded that a broad portfolio of options will need to be developed—the full range of renewable energy technologies, carbon capture and storage, nuclear power, low carbon energy carriers such as hydrogen for transport and heat, low carbon vehicles and a broad range of measures to improve energy efficiency in industry, commerce and homes. This study is no exception.

The IPPR and WWF wished in addition to consider the implications of nuclear power being phased out. This would, after allowing for possibilities of cost escalation, probably increase the costs of abatement somewhat, by about 0.2 % of GDP in the medium term, somewhat less in the longer term when the alternatives are more developed. But more importantly, there would need to be a much greater effort to develop the alternatives, principally renewable energy and carbon capture and storage, and to greatly increase the rate of improvement of energy efficiency.

Turning to the incentives required a summary is provided in the conclusions in Part 6. The main points are:

Carbon pricing: There is a heavy focus on electricity in current policies. As economists have widely argued, carbon pricing needs to be extended to all sectors, to include transport fuels and the gas markets for heat, with a medium term aim of setting the EU-ETS caps such that the carbon price will be at the upper end of the range £100-200/tonneC.

Innovation policies: For *electricity generation* the proposals to band the ROCs are a step forward, but leave RD&D activities in the UK seriously under-funded. The government have either the option of calling on the public revenue to fund the gap, which is bound to conflict with the many other demands on this resource, or to look for alternative funding mechanisms. For *renewable energy* technologies still in the RD&D stage a logical step would be to create a 'pre-ROC' band of grant finance to be funded by a portion of the revenues from buy-outs to RD&D, with the balance, as at present, being recycled to the suppliers of renewable energy. For *carbon capture and storage*, for which the proposed demonstration programme is distinctly un-ambitious, relying on a £65m grant for a single project, a better option would be to introduce a feed-in tariff premium of ~ 3 p/kWh, to be phased out once the demonstration phase is over and as the EU-ETS takes root; this would have the advantages of engaging industry more widely in the task of CCS development, of raising substantially more finance, and of avoiding over-dependence on the public revenue.

For *transport* the incentives for change are lamentably weak and short-termist. The current RFTO and the fuel duty allowance will only be in effect for the next 3-4 years, and there is no structure or 'banding' in the incentives to favour second generation biofuels, which are much the more promising of the biofuel options from both an economic and an environmental perspective.

A larger issue concerns the dangers of biofuel production and imports raising world food prices and accelerating deforestation and land degradation in developing countries. This is an especially important issue for the UK given its long-standing commitment to international development, and that it will almost certainly become an importer of biofuels. Yet there is an opportunity for producing biofuels in ways that would have the opposite and highly beneficial effects. This is through the production of lingo-cellulosic (second generation) biofuels via the restoration of degraded lands, forests and watersheds in developing regions. As discussed in Part 5, the potential is appreciable. The practices are well-known to foresters and agronomists and people knowledgeable about rural development. As a first step in the UK, indeed in the OECD countries more generally, there needs to be a 'meeting of minds' between those responsible for transport and biofuel policies, and the development community, on an approach to be followed.

In addition to the development of low carbon fuels, there is a need to develop a set of incentives to support the development and emergence of low carbon/high-fuel-efficiency vehicles. Private RD&D in these options, which include hybrid and hydrogen vehicles, the former using more advanced battery technologies, is already considerable, and the options are emerging. The UK vehicle duty incentive of £400 for the "most polluting vehicles" is too small. It would be far more effective if it were increased substantially with the revenues being recycled to support lower duties or tax credits on low-carbon/high-fuel-efficiency efficiency vehicles. The *net incentive* for the latter needs to be 5-10 times greater than it now is. An alternative though less cost-efficient approach might be to set increasingly tight carbon emission standards on vehicles; the imputed price of such incentives, however, would be similar.

In the *heating markets*, as in the transport markets, innovation policies are in a much earlier phase of development than for electricity. The Energy White Paper expresses the intention to extend carbon pricing to these markets, but conveys no sense of urgency on this matter. The RD&D programmes on low carbon buildings, for example, decentralised combined heat and power (dCHP) and the use of hydrogen from low carbon energy sources as an energy carrier are all small in relation to the size of the market, whilst there are no other incentives in place, such as the Obligations' policies for electricity and transport fuels, for the commercialisation and uptake of low carbon heat forms once they have passed through the demonstration phase. The 'virtual utility' is another option for introducing low carbon energy forms into the heating markets; this would draw on developments in metering and information technologies for the management of demands and distributed energy forms in the distribution networks for gas and electricity.

Part 2 of the paper provides a summary of the carbon abatement trajectories considered in the paper, Part 3 a brief assessment of technologies and costs, Part 4 an estimate of the impact of turning to the low carbon technologies on economic output, Part 5 a review of policies and Part 6 a summary of policy recommendations. In Part 5 there are estimates of what the scales of the policies will need to be if the Government's targets are to be met. As noted, a move to a more demanding trajectory, of the sort put forward by the IPPR and WWF, would argue for a further intensification of the incentives, toward both carbon pricing and direct support for innovation.

1.3 Limitations

The task of including aviation and heavy duty vehicles in the analysis proved to be too daunting for the present study. Its recommendations for these cases are thus confined to the blindingly obvious point as to the importance of including their fuels in the EU-ETS (or in whatever carbon pricing arrangement eventually is used).

Another area requiring far more attention than has been given to it below is that of energy efficiency. The income elasticities of demand are declining for electricity, road transport and heat, partly as a consequence of energy markets maturing and partly with energy efficiency, though the elasticity remains high for road transport fuels. For aviation, the elasticity is very high (about 1.7) and over the past 25 years shows no obvious signs of declining with market maturity or with the benefits of well-documented gains in the fuel efficiency in aeroplanes. But, overall, we are in need of empirical studies on the effects on the demands for energy of (a) technical progress in energy efficiency, (b) incomes, (c) the prices of energy, and (d) the prices of energy using devices. Engineering studies, for example those that underpinned the reports of the RCEP (2000), the Energy White Papers (2003 and 2006), the IEA (2006) and a study by the Vattenfall Corporation (2006) suggest that the scope for reducing energy demands and emissions through energy efficiency is greater than the present analysis assumes. If so, this would lead to a 'trend break' in the elasticity assumptions. I have no reason to doubt that this is possible, though did not have the empirical evidence to go beyond making an exploratory calculation, which is reported in Part 4.

1.4 Calculating the Costs of Abatement

The method used is the same as that reported in Chapter 9 of the Stern Review.[1] The idea is to calculate probability distributions of the costs of abatement using statistical (Monte Carlo) methods to combine the probability distributions of (a) the costs of the various technologies and fuels, and (b) the possible portfolios of technologies. For each portfolio the first step is to estimate the cost differences between

- The costs of using the low carbon alternatives and
- The costs of the fossil fuels they displace

A broad range of portfolios is considered, while respecting the constraints faced by each technology: the land that might be practically available for biomass, for example, the amount of intermittent generation that a grid can absorb in the absence of storage technologies (such as the 'hydrogen option'), the low initial market base of several technologies, the rate of build of nuclear power and coal plant with CCS, and so forth. It is also necessary to allow for the supporting infrastructure requirements, as with electricity and gas grids, and for the turnover of capital stock.

The cost assumptions are set out in Parts 3 and 4.[2] The capital and fixed annual maintenance costs are expressed as probability distributions with a 5-95% probability range of ± 25% on average. The assumed rates of decline of costs with innovation vary with technology, but on average correspond to a 12% decline with each doubling of the

[1] See also my background paper which is on the Treasury website: Anderson, D 'Costs and finance of carbon abatement in the energy sector.' Available from www.sternreview.org.uk.
[2] The spreadsheet used for the calculations is also to be made available on the IPCC website.

cumulative volume of investment. The costs of energy conversion and use from fossil fuels are likewise projected to decline with technical progress. Oil and gas prices are taken to vary over a wide range, from $20-80 per barrel for oil, with the upper end of the range widening to over $100 per barrel in later years, and £2-6/Gigajoule for gas.

Although the approach is not without its limitations, it does have two merits. *First*, it is a statistically more satisfactory way of handling the appreciable uncertainties as to the future costs and portfolios of the technologies that might emerge. *Second*, equally important, the method is simple and transparent, and the assumptions and results can easily be easily checked by the reader. For the technologies listed in Table 6 (Part 4) below for example, it is easy for the reader to question the assumptions on unit costs and whether the error margins reported in the text are reasonable. Nor is it difficult to consider alternative unit costs and portfolios of options that might emerge, such that the reader may form his or her own assessment of the overall costs of a transition to a low carbon system.

2. Targets and Technology Choices

The emissions trajectory without carbon abatement assumes that the shares in energy output of technologies for supplying electricity, heat and transport fuels will be the same as those existing in 2005. Call this the base case. The following are cases are then considered when alternatives to fossil fuels are introduced:

1. The costs of carbon abatement corresponding to a long-term reduction of emissions of approximately 60% relative to the emissions that would otherwise arise (in the base case). This turns out to be very close to the Government's target set out in the Energy White Paper. Without carbon abatement, the emissions rise with the growth of incomes and energy consumption from a level of 152 MtC/year in 2005 to over 200 MtC/year. With abatement they remain stable next 10 years, decline to 135 MtC/year and then decline by half again to 65 MtC/yr by 2050.

   This case is a good point of departure since it has been well-researched by the Royal Commission on Environmental Pollution (in 2000), and for the Government's White Papers in 2003 and 2007. It is also close to—but slightly less ambitious than—the case considered for the world economy in the Stern Report. The calculations are made:

   (a) with nuclear power included

   (b) with nuclear power gradually being phased out.

   The intention is to assess the cost and technological implications of the UK not resuscitating its nuclear power programme.

2. The costs of carbon abatement corresponding to a more demanding trajectory put forward by the IPPR and WWF. This is considered to be more consistent with a UK contribution to a global stabilisation goal 450 ppm (as opposed to being within the range 450-550 ppm in the Stern Report). Again, the calculations are made:

   (c) with nuclear power included and

   (d) with nuclear power gradually being phased out.

The emissions trajectories and the differences between them are summarised in Table 1:

Table 1: Carbon Emission Assumptions With and Without Abatement. Million tonnes C per year

Year	Emissions without abatement	Emissions with ~ 60% abatement = **A**	IPPR-WWF trajectory **= R**	Difference: **D = A-R**
2005	152	152	152	0
2015	177	150	141	9
2025	192	135	93	42
2050	207	65	34	31

The IPPR and WWF are also concerned about the UK's contribution to water vapour emissions from aircraft. Aviation currently accounts for roughly 7-8 % of primary energy consumption and a similar percentage of carbon emissions, a figure that will probably rise over the next 40-50 years. However, the effects of water vapour may raise the CO_2 equivalent rate of emissions by a factor of 2.5 (though there is a wide error margin to estimates of this effect), raising their effective contribution to around 20%. The difficulty they pose is that, in contrast to carbon emissions, there is no technology available for abating the greenhouse effects of water vapour emissions, such that, even if a carbon-neutral fuel such as bio-kerosene were to totally displace kerosene, the contribution to greenhouse gas emissions would still be around 15%. To look into this, further runs were as follows:

3. The 60% and IPPR-WWF emission trajectories with water vapour from aircraft included. The assumptions are summarised in Table 2:

Table 2: Carbon Emission Assumptions plus Emissions from Water Vapour from Aircraft With and Without Abatement. Million tonnes C per year

Year	Emissions without abatement, including water vapour	Emissions with ~ 60% abatement = **A**	IPPR-WWF trajectory **= R**	Difference: **D = A - R**
2005	171	171	171	0
2015	200	150	141	50
2025	216	135	93	81
2050	235	165	34	89

The IPPR policy assumption is that the stabilisation trajectories are the same as those calculated when water vapour is ignored, but of course the required level of abatement is greater. As will be seen this requires greater abatement in other sectors such as the heat markets to make up the 'headroom' lost to aviation, which raises costs. It will also require considerable improvements in energy efficiency. As the 60% government target applies to carbon emissions only, it is not adjusted here for water vapour emissions such that the incremental effects, first of moving to a more demanding carbon abatement trajectory, and then of including water vapour emissions from aircraft can be assessed.

3. General Approach to Estimating the Costs

The approach is similar to that used for the Stern Review, but adapted to UK conditions. In brief it is as follows.

Energy markets: These are divided into three main sectors: electricity, heat (mainly those now supplied by gas), and transport. The growth of these markets is determined by the growth of incomes times the income elasticity of demand. Econometric studies (Dargay and Gately, 1995 and Judson et al. 1990) have found that income elasticities are declining over time with the growth of incomes. With the important exception of aviation, historical data on the UK fit this pattern (see Annex 3). The most likely explanation is a combination of improvements in energy efficiency, the decline of heavy industry and market maturation. The following are the assumptions:

Table 3: Income Elasticities of Energy Demand

	Up to 2025	2025-50	Range factors [a/]
Electricity	0.40	0.20	-0.2 to + 0.1
Gas/heat	0.20	0.10	- 0.2 to + 0.1
Transport--surface	0.60	0.30	- 0.4 to + 0.2
Transport--air	1.7	0.7	- 0.4 to + 0.2

a/ These are added to the estimates shown in the two columns. E.g. the elasticities for electricity range from 0.2 to 0.5 up to 2025 and 0.0 to 0.3 for the period 2025-50. Any changes in the elasticities in the first period are assumed to apply in the second period.

It is conceivable, with improvements in energy efficiency, that the elasticities may become lower than this, for example with the development of the hybrid and plug-in hybrid vehicles.[3] The Monte Carlo calculations make some allowance for this by applying asymmetric ranges to the above, as indicated in the last column. In Part 4 some exploratory calculations are also made with yet lower elasticities.

Moving to a low carbon economy will very likely entail an increase in energy prices, which would reduce demands somewhat. In the absence of reliable estimates of price elasticities this effect is ignored on the grounds that, first, it is likely to be small, and second that this will act to understate the costs of abatement.

Technological Options and Unit Costs: A range of low-carbon technological options is identified for each market along with estimates of unit costs for three points in time: 2015, 2025 and 2050. The list of options is familiar:

- Coal for the generation of electricity and hydrogen with carbon capture and storage;
- Nuclear power. At the request of IPPR and WWF, the case where nuclear is phased out is also included to assess what the costs and implications for the UK would be;

[3] Indeed it is not inconceivable that, with improvements in energy efficiency, the income elasticities of demand as usually estimated may become negative in the long-term. See Annex 3 for a further discussion.

- A full range of renewable energy options;
- Decentralised forms of electricity and combined heat and power, the latter using fuel cells or micro-generators fuelled by hydrogen from carbon neutral sources (coal with CCS and electrolytic hydrogen);
- First and second generation biofuels for road transport.[4] Bio-kerosene is also considered a possibility for reducing carbon emissions from aviation.
- Hydrogen fuelled vehicles using the internal combustion engine in the medium term and fuel cell vehicles in the longer term (2025 onwards). The estimated incremental costs of hydrogen vehicles are averaged out over the vehicles' lifetimes and divided by fuel consumption to provide an estimate of the costs per unit of energy consumed. Allowances are made for the higher fuel efficiency of these vehicles based on the report by CONCAWE on the subject and data provided to the Stern Review.

The list of options is in fact much longer. The above selection follows Pacala and Socolow (2004) by concentrating on technologies that are already available, have been shown to 'work' and are capable of being developed further. However, the possibilities of new technologies emerging should not be overlooked, even if there is not sufficient experience available on which to estimate of costs. Developments in organic photovoltaic technologies, new and lower cost methods of storing electricity or hydrogen, photo-electrolysis, the harnessing the energy in wave and tidal streams, plug-in hybrid vehicles with the electricity coming from carbon-neutral resources—these are just a few of many possibilities that may be sources of technological surprises. There are already substantial research programmes in these areas in laboratories around the world, in industry, national research centres and the universities. In addition, there is the ongoing research in energy efficiency which could reduce demands by more than expected. If, as is to be hoped, such possibilities do emerge and are taken up, they will not only widen the options available but will lower costs. Improved storage technologies in particular would do much to open the markets for intermittent renewable energy. In this sense, I believe, the approach followed here biases the cost estimates upwards.

Costs of the 'Marker' Technologies and Fuels: These are the technologies and fuels that would be replaced by the low carbon technologies:

- coal and gas for electricity generation, including the costs of transmission and distribution in the case of decentralised sources of electricity and combined heat and power;
- gas for heat, including the costs of transmission and distribution; and
- oil fuels for transport, including refining and distribution.

[4] "First generation biofuels are manufactured from agricultural commodities that are also used for food and animal feed such as the use of starch from corn or sugar from cane to produce ethanol … and vegetable oils to produce biodiesel. … Second generation biofuels are those that utilise lignocellulose feedstocks such as from forestry, energy crops, residues and wastes, as well as improved oil crops and marine resources." Royal Society Report on biofuels (forthcoming).

The estimates of unit costs per unit of energy supplied are summarised in Part 4 (see Table 6). Adjustments for the costs of intermittency in the case of renewable energy are included. In the case of electricity, the analysis also includes the costs of providing capacity sufficient to meet the requirement of peak demand and the extra fuel costs of meeting loads above base load, that is to say, of coping with load variation (Annex 2).

Uncertainties in Unit Costs: The key components of costs are provided as probability distributions (only the means are shown in Table 6).[5] For fossil fuels the main uncertainties are in the prices: the price of oil has fluctuated between \$25 and \$80 per barrel in recent years, and of central gas supplies between £2 and £6 per gigajoule. The possibilities ahead are represented by a truncated normal distribution, fanning out in the case of oil from a range of \$25/barrel to over \$100/per barrel.

Capital costs for all technologies, including the marker technologies, are also highly uncertain. For power generation from coal and gas, they are given a range of ± 15% (± two standard deviations); and for the low carbon options a range of ± 25-30% depending on the case. The same ranges are applied to the fixed annual maintenance costs of plant and equipment. For transport, the incremental costs include an estimate of the extra costs of manufacturing vehicles capable of using hydrogen as a fuel.

Average Costs of Carbon Abatement: The total costs are the differences, for each technology, between the unit costs of the technology and the unit costs of its marker, times the amount of energy it supplies. The differences are then added up over all technologies to obtain the total costs of abatement. The average costs are the resulting estimates divided by the amounts of carbon abatement. These are also represented by probability distributions derived from the probability distributions of costs.

It is necessary to make allowances for the longevity and the turnover of the capital stock. For 2015, the estimates are based on the investments represented by the period 2005-15; and for 2025, on the sum of investments in the periods 2005-15 and 2015-25, since most of the investments in the former period will still be in operation in 2025. For 2050, most of the capital stock will be renewed and the estimates are based on the incremental costs of investments in 2050.

Portfolios of Options: Aside from uncertainties in energy demands and the unit costs of the low carbon technologies relative to their markers, there are appreciable uncertainties as to what the future 'mix' or portfolio of technologies will be. Aside from the effects of (highly uncertain) relative prices on technology choice, it is hard to be precise over the constraints facing each technology—the acceptability and rate of build of nuclear power for example, the land available for biofuels, the availability of onshore sites for wind farms, the rate of development of carbon capture and storage, the limits that the absence of storage technologies would impose on renewable energy at high levels of market penetration, and so forth.

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[5] The spreadsheet will be made available on the IPPR website.

The IEA's MARKAL model estimates portfolios using an optimisation (LP) routine. Energy demands, fuel prices, technologies, costs and constraints are specified in impressive detail and the energy system is optimised to minimise costs for any particular set of assumptions. The results are checked for technological feasibility and alternative assumptions are explored. Since the optimal mix so calculated often changes kaleidoscopically with assumptions on costs and constraints it is necessary to make a large number of runs to estimate the distribution of possibilities. Some MARKAL runs have been undertaken by Neil Strachan and colleagues at the Policy Studies Institute for the present study.

The approach followed below is based on the statistical method of Monte Carlo analysis, and is the same as the approach used for the Stern Report. First, the input assumptions on costs and prices are specified as probability distributions, as discussed above. Estimates of future demand elasticities, and of the rate of uptake and use of each technology are similarly specified as probability distributions (in the present case, rectangular distributions were used to define the ranges of these quantities), bearing in mind the likely constraints on the rates of uptake and use. The Monte Carlo method then considers a random set or 'trial' of the possible values of the input variables and estimates the costs; the calculation is then repeated for a large number of such sets or 'trials', with the frequency of any input value used for the trials being determined by its probability of occurrence. [6] The outputs are probability distributions of the variables of interest, such as the total and incremental costs of abatement, and the costs of the low carbon technologies relative to their markers.

Figures 1 and 2 show one of the 20,000 portfolios so examined.[7] They show the contributions to carbon abatement of each key technology. The contribution of nuclear power is shown in absolute terms (rather than relative to its contribution in the base year, as with the other technologies) in order to highlight the ground that would need to be made up by the other technologies if it were phased out. The contribution of energy efficiency is an illustrative calculation to show the effects of a downward shift in the income elasticities of energy demand (roughly a 0.2 shift in the average value); it is probably an understatement since the main effects of energy efficiency improvements are embodied in the declining elasticity estimates discussed above (Table 3).

There is no formal optimisation in the model, though the portfolios and their ranges are chosen in light of their relative costs. Thus solar is given a very low but rising market share, carbon capture and storage, biofuels and onshore then offshore wind higher shares. The 60% abatement case is not dissimilar to those of several other studies, including those of the Royal Commission on Environmental Pollution (2000) and the background studies for the Energy White Paper (2003), except that the hydrogen option is added and there is more emphasis on CCS and micro CHP. Pollution abatement in electricity is given most weight in the initial years since there are more options for carbon abatement in this sector and the incremental costs of abatement are less; transport and heating markets assume higher weights in later years.

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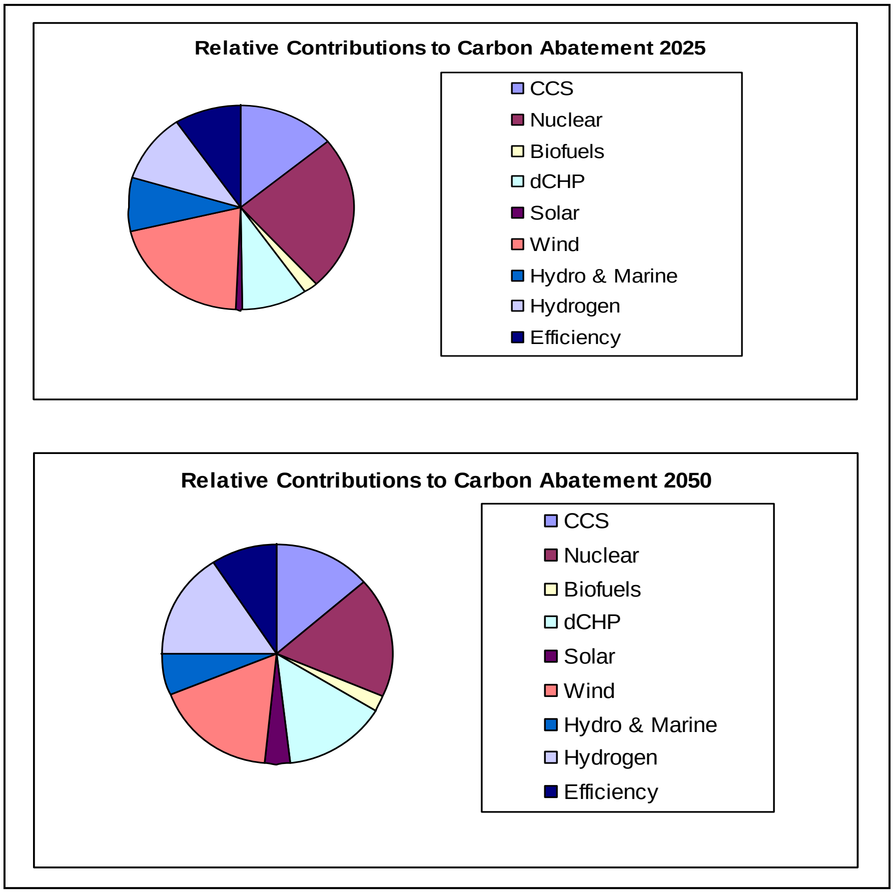
[6] For this study, there were 20,000 trials.
[7] The spreadsheet can be made available on request.

Figures 1 and 2: Contributions to Carbon Abatement of a Particular Portfolio (corresponding to 85% abatement as in IPPR proposal)



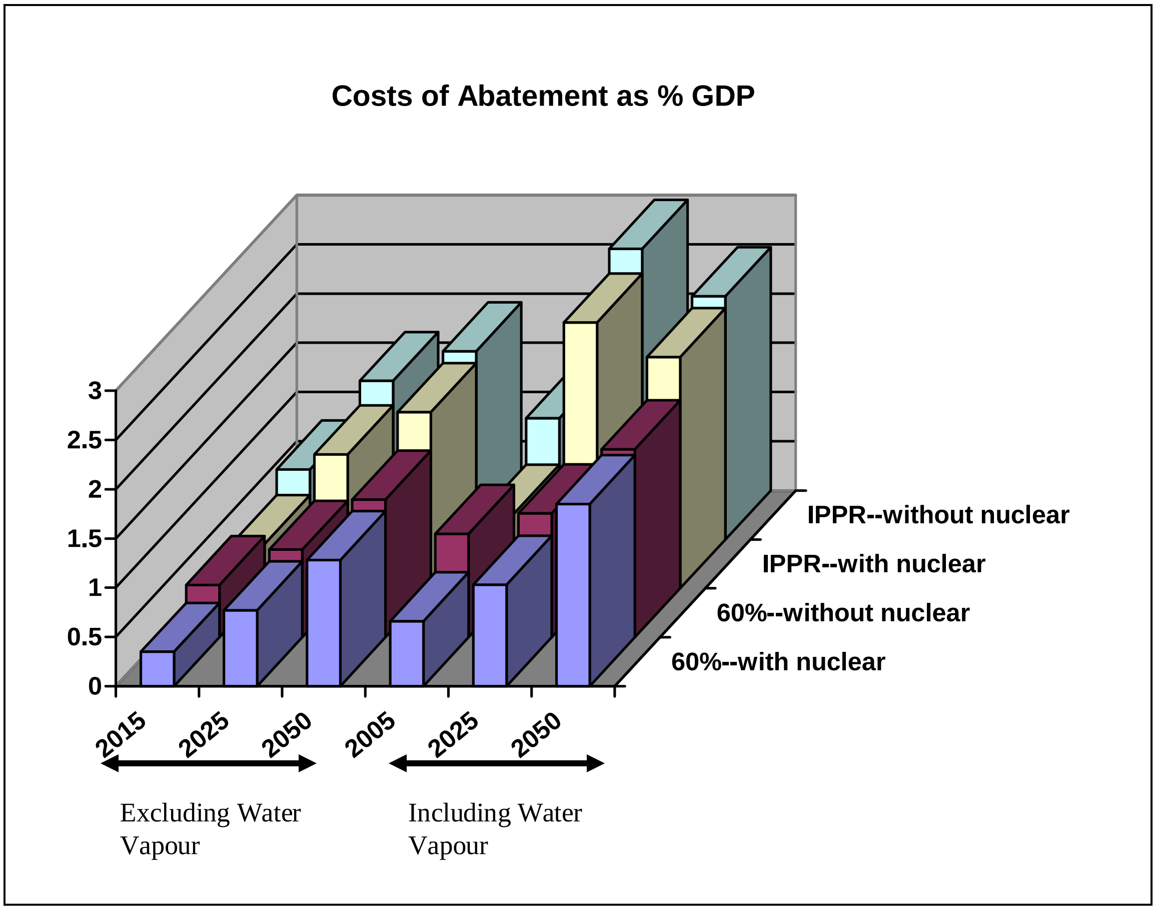
A further breakdown of the portfolios with nuclear power phased out is provided in Annex 7.

4. Costs of Abatement

4.1 Costs a % of GDP

The costs of abatement as a percentage of GDP are shown in Figure 3 (Annex 5 tabulates the results). The estimates of cost corresponding to the government's targets are shown in the lower left hand corner: nuclear power is included, and water vapour emissions from aircraft are excluded. The figure then shows the costs of moving to the more demanding abatement trajectory proposed by the IPPC and WWF, first including then excluding nuclear power and water vapour emissions from aviation. The results only show the calculations based on the mean values of the cost and other parameters; probability distributions will be considered shortly.

Figure 3:



See table 2 for details

The effects of a more demanding abatement target. Moving to a more demanding abatement target will raise costs appreciably over the next 20 years. For the 60% target costs rise from around 0.35 % of GDP in 2015 to 0.8 % in 2025 to 1.3 % by 2050, similar to the estimates made for the Stern Report, and within the range of previous studies for the UK. The costs are slightly higher if nuclear power is phased out.

The more demanding trajectories of the IPCC-WWF point to a doubling of costs over the next 20 years. They rise to roughly 0.7-1.2 % of GDP by 2015, to 1.6-3.0 % by 2025 and 1.9-2.5 % by 2050 depending whether water vapour emissions from aircraft are included. The reason is that with a more demanding abatement target there is a reduction of what Pacala and Socolow (2007) call ‘headroom’, the quantity of greenhouse gas emissions that is still permitted by the end of the target period, such that the abatement efforts have to be far more ambitious early on when the costs of many technologies are still high.

The policy implications are clear, which is that the policy signals in the form of price incentives for the low carbon options will have to be strengthened greatly relative to those that would be required for the 60% aspiration, which by comparison looks almost benign.

Nuclear Power: The phase-out of nuclear power reduces would probably raise costs somewhat in all cases, particularly over the next 20 years or so, since it is a mature technology. However, the frequency distribution of its costs overlaps that of the other technologies. The other technologies, by contrast, are still high on their learning curves, and have not been developed to the extent where scale economies in manufacture and use have become significant; this is the case for instance with carbon capture and storage, dCHP, the offshore wind and marine resource, and second generation biofuels. As they mature the incremental cost of phasing-out nuclear power declines and becomes statistically insignificant.

Against this, nuclear power diversifies supplies, and its phasing out, as shown in section 2 (see Figures 1 and 2) would leave a large—roughly a 25%—gap to be filled by the other technologies, principally by coal with CCS and a growing share of renewable energy, mainly the offshore resource of wind and marine energy. There is no reason from an engineering perspective why such a gap could not be filled in this way, but the strains and risks this will place on the alternatives need to be recognised.

Probability distributions of costs as a % GDP: These are shown in Figures 3 and 4 for the cases of 60% abatement and the IPPR target respectively. For the Government’s targets the estimated range is from around 0.7 to 1.6 % of GDP by 2050, with a mean of approximately 1.2 % of GDP[8]. For several reasons this range is somewhat narrower than we calculated for the Stern Report when looking at the global economy:

- The income elasticity of demand for energy is lower for a mature economy such as the UK than for developing regions, and is declining over time with market saturation and the effects of energy efficiency. The only exception is air transport. Hence incomes are growing relative to energy which reduces the costs as a percentage of GDP.

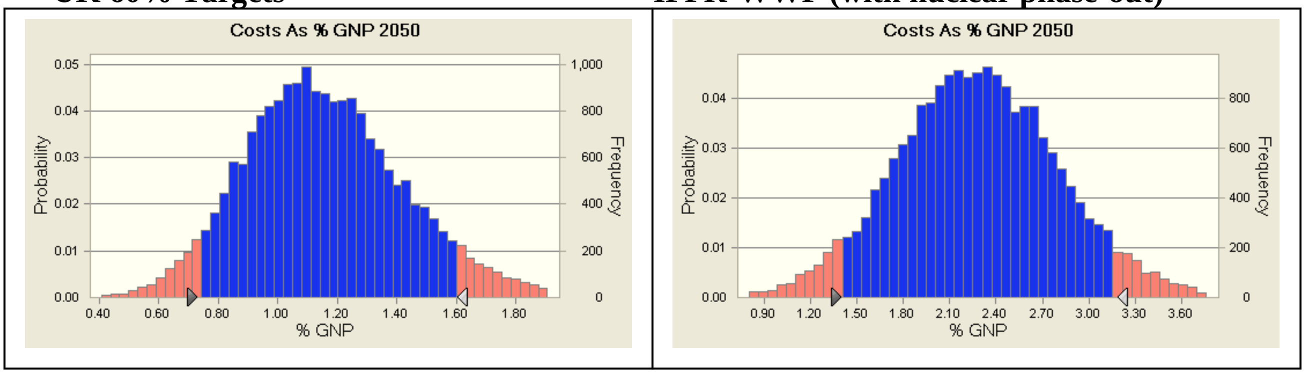
[8] The means of the probability distributions turn out to be lower than the estimates based on the mean values of the input parameters. This is because of asymmetries in some distributions and non-linearites in some terms (e.g. the effects of price elasticities on growth rates). The mean of a term like $\exp(x)$ for example, where x is a random variable with a mean $\bar{x}$, is different to $\exp(\bar{x})$.

- The portfolio of options is wider for most other regions, particularly for the US and developing countries. The incident solar energy per unit area is 2 to 2.5 times greater and is highest when it is most in demand; the land available for biomass and onshore wind is also more plentiful. The UK, in contrast, is already having to develop its more costly (though also more plentiful) offshore resource.

For the IPPR-WWF proposals, the costs are about 2.3 ± 1% of GDP.

Figure 3: Costs of Abatement as a % GDP by 2050: UK Government Targets and IPPR-WWF Proposals*

UK 60% Targets | **IPPR-WWF (with nuclear phase-out)**



* The UK Targets exclude but the IPPR-WWF proposals include water vapour emissions from aircraft

4.2 The Costs of Slippage

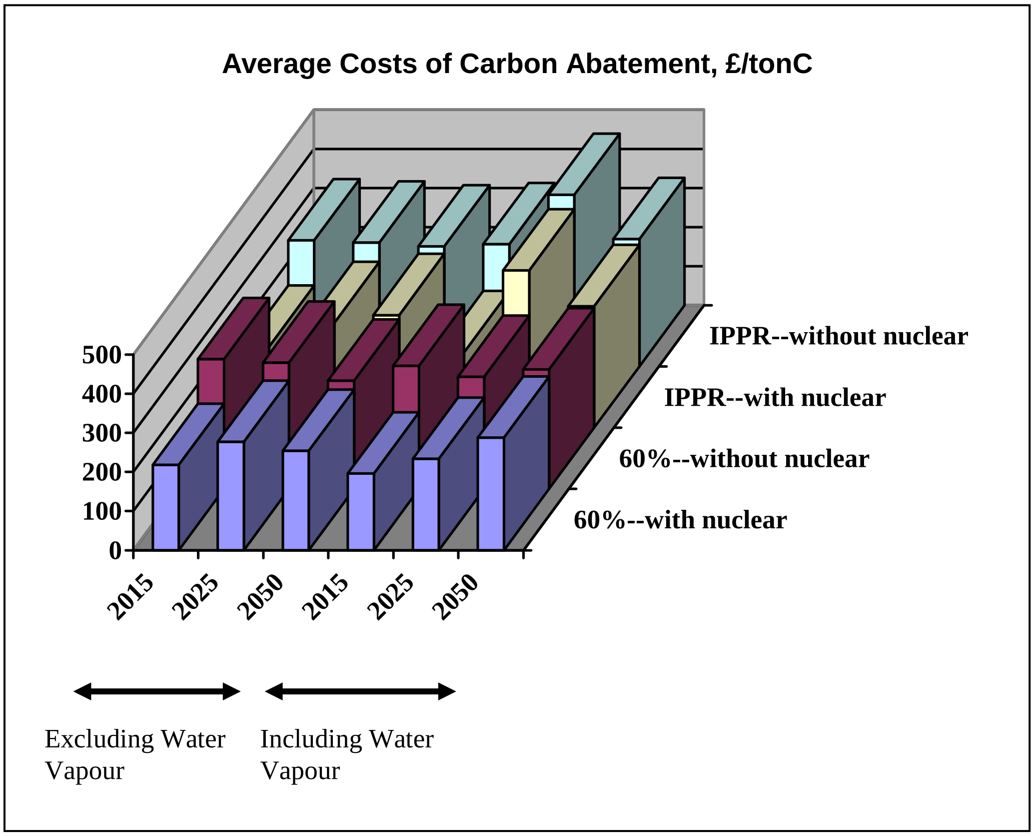
As the Stern Review argued, the longer policies are delayed, the greater will be the costs of mitigating climate change. Headroom will be lost as emissions accumulate, and policies will need to become more and more stringent. The Government's long term target is to reduce carbon emissions from 150 MtC/year today to 65 MtC/year by 2050, leading to cumulative emissions of around 5.4 GtC over the period. A simple arithmetic calculation shows that a decade's delay would require the Government's target to be reset to 45 MtC/year by 2050, or to 75% of 1990 levels, if the cumulative emissions by then were to be the same, raising the long term costs by a third, to 1.5 ± 0.7 %.

4.3 Average Costs per tonne of Carbon Abated

These are shown in Figure 4, first for meeting the Government's targets (in the lower left-hand set of results) and then for the IPPR-WWF proposals. Again the incremental effects of phasing out nuclear power and of including water vapour emissions from aircraft are also shown. The estimates underlying the Figure are provided in Annex 5.

The disparities in costs per tonne of carbon abated are much less than those of the disparities in total costs discussed above. Whilst the IPPR-WWF proposals imply much higher costs, they are also associated with much higher levels of carbon abatement, such that the effects per tonne of carbon abatement are much less pronounced. In other words the higher costs are rewarded by higher levels of abatement. In fact, within the error margins of the analysis, the differences in average costs are quite small.

Figure 4:



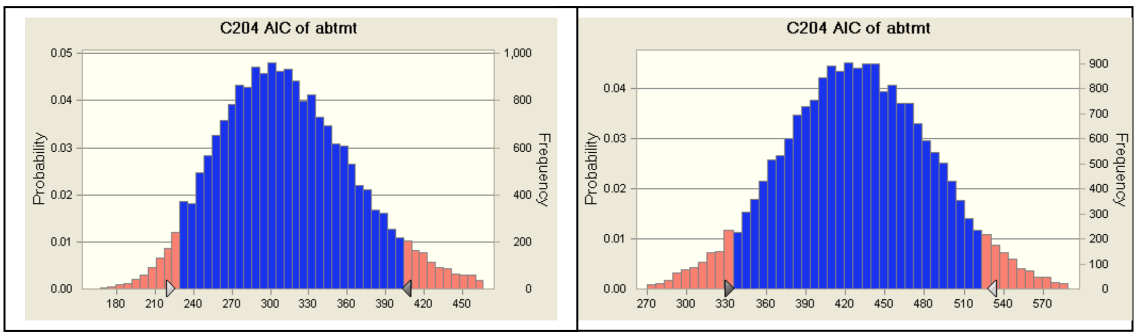
The costs in the early years of the policy are similar to those estimated for the Stern Review, about £200-300/tonC if nuclear power is included, but $250-450/tonC if it is phased out. But in contrast to the Stern Review, the costs do not decline over time. There are two reasons for this. The *first* is that the range of options for the UK is more limited as compared with other countries and the constraints on the lower cost options begin to bite sooner. As noted earlier, the incident solar energy in the UK is a factor of 2-2.5 times less than in most developing regions and much of the US, and it is also least available when heat and electricity are most in demand, such that its 'capacity credit' is low; hence the UK is relatively disadvantaged in using the technology that perhaps promises the best prospects for technical progress and cost reductions. The main exception may be micro-generation and micro CHP, which is a modular technology with significant prospects for further progress and for cost reductions through batch production. The availability of land for onshore wind and biomass is also less in the UK than in other countries. *Second*, whilst a closer look at the costs of abatement does indicate that there will be reductions in the costs of abatement in electricity generation—the costs of the offshore resource and of CCS for example should decline—in mature economies it will soon become necessary to begin abatement in sectors where it will be more costly, namely in the transport and heat markets.

By 2050 the differentials in average costs between the four cases narrow to the point of insignificance. The main reason is that the less mature options today—offshore wind and marine energy, dCHP, coal for power generation and hydrogen production—all have time to ‘catch up’ with the more mature option of nuclear power.

The probability distributions of the average incremental costs are shown in Figure 5 for two cases, for the year 2025, one relating to the Government’s targets, the other the targets proposed by the IPPR/WWF.

Figure 5: Probability Distributions of Costs Per Tonne of Carbon Abated for 2025

UK Government Targets **IPPR-WWF Proposals**



4.4 Variations in Average Costs between Sectors

The average costs per ton of abatement vary unevenly between sectors and over time. In *electricity*, there is a general tendency for the costs to decline over time with innovation, whether or not nuclear power is phased out (though they are lower when nuclear is kept in). The average initial costs are in the range £175 to £300 per ton of carbon, falling to the £140-180/tC in the long term. In the *heating markets* the costs are initially much higher, around £900/tC, reflecting the considerable difficulties of finding a low carbon alternative for natural gas in homes and industry; however these too decline by about half over the long term, for example with the assumed wider adoption of micro-CHP. In *transport*, the costs are initially comparable to those of abatement in the electricity sector, about £350/tC, on account of the availability of biofuels. But as the land constraint on the supply of biofuels begins to bite it becomes necessary to turn to higher cost options such as the hydrogen car using an internal combustion engine or a fuel cell. (Electric vehicles are another possibility, but have not been included in the present analysis.) Further details are provided in Table 4.

It is emphasised that these calculations do not explicitly include the cost advantages of energy efficiency. For reasons explained in Section 2, these advantages are reflected in the income elasticity of demand assumptions; and they are appreciable, especially in the heating and transport markets, for example with economies in use, innovations such as the plug-in hybrid vehicle, heat pumps, home insulation and so forth.

Table 4: Variations in Average Costs (£/tC) over Time and Between Sectors*

Year	Electricity		Heating	Trans port	Overall	
	With nuclear	With nuclear phased-out			With nuclear	With nuclear phased-out
2015	175	300	910	340	210	325
2025	160	225	510	810	270	320
2050	140	180	440	410	290	310

*IPPR-WWF Scenarios without water vapour. Estimates rounded.

Such calculations perhaps help to explain why current policies so far are mainly focussed on the 'easier' options of abatement in electricity supply (and base-load supply at that), biofuels in the transport markets, and of course energy efficiency. But for high levels of abatement to be achieved, it will be necessary to go beyond these policies and face the difficulties of higher levels of abatement in the transport and heating markets. This is evident if we compare the carbon emissions of the three sectors today (numbers rounded); electricity currently accounts for 40% of emissions, which would leave the UK with a 20% shortfall in its long-term targets even if electricity supply were 100% carbon neutral:

	Million tonnes C/year (2005)
Electricity	60
Heating (mainly gas)	40
Transport	50

Average costs may decline over time with innovation as the easier options are taken up, rise significantly when it becomes necessary to address constraints, for example on the availability of land for biofuels and onshore wind, and fall again, though from a higher level as these constraints are addressed.

4.5 Marginal Costs

The corresponding marginal costs are shown in table 5 for the abatement trajectories put forward by the IPPR and WWF. They were estimated by expanding the portfolios to reduce emissions by a unit amounts at each point in time.

Table 5: Overall Marginal and Average Costs of Abatement Compared, £/tonC

	With Nuclear Power		With Nuclear Power Phased-Out	
	Average Costs	Marginal Costs	Average Costs	Marginal Costs
2015	210	175	325	300
2025	270	260	320	310
2050	290	425	310	425

There is a general tendency for marginal costs to rise over time, as other studies have found. This again is linked to the need to move to the higher cost abatement options in transport and heating markets as the abatement requirements increase.

It should be added that the estimates of average and marginal costs relate to the expansion of a *portfolio* of options--*not* to the expansion of a single technology--on the grounds that uncertainties and risks require governments and industry to develop portfolios as opposed to one or just a few options. For this reason the marginal costs estimated here tend to be lower than those of studies based on deterministic analysis, which focus on the marginal technology in the energy system. The marginal costs of the portfolio decline at first, and pull down average costs, with scale economies and learning by doing (which is reminiscent of the electricity industry up to around the 1960s, when economists were concerned about declining marginal costs being below average costs and leading to losses). However, as the 'easier' options are taken up, marginal costs tend to rise--particularly when it becomes necessary to seek higher levels of carbon abatement in the transport and heating markets, and pull up average costs with them. Needless to say, the estimates have wide probability distributions owing to uncertainties as to the costs of the technologies, the prices of the fossil fuels they are displacing, and the portfolio of options considered.

4.6 Marginal Cost Curves and their Limitations

The costs of the low carbon technologies relative to their marker vary appreciably between technologies, as shown in Table 6. Many studies assign to each technology an estimate of its abatement potential, and then rank the technologies in ascending order of costs to derive a marginal-cost-of-abatement curve for each point in time.[9] Such curves are a good way of synthesising information, but they can be misleading if used as a basis for policy:

- Firstly, they are biased towards the *status quo*. The mature technologies with large sunk costs (such as nuclear power) by definition are first in the ranking, while innovative technologies still in their early phases of development use, such as carbon capture and storage, low carbon vehicles, decentralised CHP, and renewable energy, are low in the ranking. Technologies of considerable long-term promise are often unwittingly excluded by policies on these grounds.

- Second, marginal cost curves present a static picture, and exclude the possibility that costs change endogenously with investment. Once again, this leads to a bias against technologies in their early phases of development, when the influence of investment on innovation and costs is greatest. Allowing for the positive externalities of innovation—the reductions in unit costs times the prospective levels of use—may completely alter the rankings and perceptions of costs, as discussed shortly.

[9] In contrast to the estimates given at particular points in time such as those in Table 5, marginal cost curves are written as a function of the level of abatement.

- Third, there is the different point that available evidence on current and prospective costs shows appreciable error margins, such that the rankings associated with such curves are much hazier than they may seem. As discussed in the Stern Review, the need to minimise risks and increase the chances of policies succeeding requires a portfolio of initially low and higher costs options to be developed.

Marginal costs may also vary in more complex ways than the traditional analysis assumes. They initially rise with the level of abatement, decline with 'learning-by-doing' and scale economies as the level of abatement is increased (the more we abate pollution, the better we become at it), rise again as constraints and difficulties are encountered (such as the land constraint on biofuels), decline again as these are resolved (for example with the shift to substitutes for biofuels), and rise yet again at very high levels of abatement as further difficulties are encountered.

Table 6: Relative Costs of Low Carbon and Fossil Fuel Technologies

Low Carbon Technology	Marker Technology	Cost unit	Cost of Marker	Cost of Low Crbn Technlgy	Net cost, % Marker
Medium term estimates					
………..………………………. **Electricity Markets** …………………………...					
Electricity from gas with CCS	NGCC or coal	p/kWh	3.2	5.2	62
Electricity from coal with CCS	NGCC or coal	p/kWh	3.2	5.2	63
Nuclear power	NGCC or coal	p/kWh	3.2	3.9	20
Electricity from energy crops	NGCC or coal	p/kWh	3.2	6.3	97
Electricity from organic wastes	NGCC or coal	p/kWh	3.2	6.9	115
Onshore wind	NGCC or coal	p/kWh	3.2	4.4	38
Offshore wind	NGCC or coal	p/kWh	3.2	8.2	156
PV for distributed generation	Grid electrcty	p/kWh	8.0	42.1	426
dCHP using H from NG or coal with CCS	Grid electrcty	p/kWh	8.0	24.2	202
……………………………………. **Gas Markets** …………………………………..					
Hydrogen from NG or coal (CCS)--industry	NG	£/GJ	4.0	7.7	93
Hydrogen from NG or coal (CCS)--distributed	NG	£/GJ	6.0	15.5	158
Electrolytic hydrogen--industry	NG	£/GJ	4.0	19.7	392
Electrolytic hydrogen--distributed	NG	£/GJ	6.0	27.1	352
Biomass for heat--distributed	NG	£/GJ	6.0	9.5	58
Low-C Electricity for heat	NG	£/GJ	5.0	21.5	330
……………………….. **Transport Markets** …………………………..					
Bioethanol	Petrol	p/litre	29.5	45.0	53
Biodiesel	Diesel	p/litre	29.5	50.0	70
Hydrogen ICE vehicle--fossil H (+ CCS)	Petrol	p/litre	29.5	141.0	378
Long term estimates (over 20 years):					
……….………………………. **Electricity Markets** …………………………...					
Electricity from gas with CCS	NGCC or coal	p/kWh	2.6	4.8	81
Electricity from coal with CCS	NGCC or coal	p/kWh	2.6	4.8	82
Nuclear power	NGCC or coal	p/kWh	2.6	3.5	32
Electricity from energy crops	NGCC or coal	p/kWh	2.6	4.8	82
Electricity from organic wastes	NGCC or coal	p/kWh	2.6	4.1	57
Onshore wind	NGCC or coal	p/kWh	2.6	3.9	46
Offshore wind	NGCC or coal	p/kWh	2.6	6.0	126
PV for distributed generation	Grid electrcty	p/kWh	8.0	24.0	200
dCHP--H from NG or coal with CCS	Grid electrcty	p/kWh	8.0	8.8	10
…….……………………… **Gas Markets** …………………………………..					
Hydrogen from NG or coal (CCS)--industry	NG	£/GJ	4.00	6.3	58
Hydrogen from NG or coal (CCS)--distributed	NG	£/GJ	6.00	13.1	119
Electrolytic hydrogen--industry	NG	£/GJ	4.00	14.1	253
Electrolytic hydrogen--distributed	NG	£/GJ	6.00	20.5	242
Biomass for heat--distributed	NG	£/GJ	6.00	7.0	16
Low-C Electricity for heat	NG	£/GJ	5.00	19.8	297
……………………….. **Transport Markets** …………………………..					
Bioethanol	Petrol	p/litre	29.5	60.0	104
Biodiesel	Diesel	p/litre	29.5	50.0	70
FC Hydrogen vehicle--fossil H (+ CCS)	Petrol	p/litre	29.5	132.8	350
FC Hydrogen vehicle--electrolytic H	Petrol	p/litre	29.5	155.8	428

4.7 Effects of Energy Efficiency on Costs

The uncertainties as to the effects of energy efficiency on future levels of energy demand are appreciable. Estimates range from a 20% or more decline in demand from present levels, to a continued increase, albeit at a declining rate. The first column of the following table summarises the expected demands under the average elasticity assumptions in this study (see Table 3 above), the second the demands associated with the lower elasticity assumptions of the study (also shown in Table 3), and the third the demands implied by a number of engineering studies.[10]

Table 7: Primary Energy Demands, EJ/year

	Average elasticity assumptions	Lower elasticity assumptions [a/]	Elasticities implied by Engineering Studies
2005	9.6	9.6	9.6
2015	10.8	10.1	9.7
2025	11.3	10.2	9.5
2005	12.3	9.9	8.9

a/ Corresponding to the lower end of the ranges shown in the last column of Table 3a.

Table 8 summarises the effects of these lower elasticity assumptions on emissions and costs. The carbon equivalent of water vapour emissions is included, and the carbon abatement trajectory is that proposed by the IPPR and WWF:

Table 8: Effects of Energy Efficiency on Emissions and Costs

	Average elasticity assumptions	Lower elasticity assumptions [a/]	Elasticities implied by Engineering Studies
Emissions without abatement (from supply side technologies), MtC/year:			
2005	171	171	171
2015	200	185	174
2025	216	189	172
2050	235	184	158
Cost of abatement as % GDP			
2015	1.2	0.9	0.7
2025	2.9	1.9	1.3
2050	2.5	1.8	1.4

Improvements in energy efficiency would greatly reduce the onus placed on low carbon energy supply technologies to abate emissions, as many other studies have found (see the upper rows). The effects on costs, however, are less clear, and the estimates in the above table come with the health warning that I have not been able to estimate the costs of improving energy efficiency in this study, only the costs of supplying energy.

4.8 Cost Minimisation Models and the Dynamic Process of Innovation

The use of cost-minimisation models such as MARKAL presents similar problems. These models have the merit of representing the energy system in considerable detail, and also

[10]Some studies point to yet lower demands than indicated here For example the Royal Commission on Environmental Pollution (2000), the IEA (2006) and the background papers for the Energy White Paper in 2003 (DTI Economics Paper no 4, June 2003).

extend to the analysis of options for reducing energy demand. The transactions costs and the costs of developing the infrastructure associated with the development of new technologies can also be factored in. Lastly, sensitivity studies and Monte Carlo methods may also be used to explore the effects of uncertainties as to the costs of and constraints facing each technology. The key problem, however, is how to allow for endogenous technical change. Consider, for instance, a time-stream of investments in a particular technology. The total costs C is the present value of the costs of investments in periods 1, 2, 3, etc, say X_1, X_2 … times their unit discounted unit costs, say c_1, c_2…, such that:

$$C = c_1 \cdot X_1 + c_2 \cdot X_2 + ...$$

If there is extra investment in period 1, the assumption (in MC curves, as well as in MARKAL) is that the change in costs is:

$$\Delta C = c_1 \cdot \Delta X_1$$

But if future costs are influenced by what we do in the present period, say through R&D, demonstration and 'learning-by-doing', the actual change in costs is equal to the change in costs in the present periods, less the reduction in costs in future periods times the prospective levels of use:

$$\Delta C = c_1 \cdot \Delta X_1 - \Delta c_2 \cdot X_2 - c_2 \cdot \Delta X_2 + \ldots.$$

In words: the change in costs equals the change in costs in the first period, minus the reduction in costs of future investments (- Δc_2) times the volume of projected use, allowing for the extra volume of use (+ ΔX_2) brought about by the reduction in future costs.[11]

The second term on the right hand side (the direct benefits of reducing future costs) is obvious enough, but the third term merits more comment. It says that when the costs of a technology are reduced relative to those of others, this will lead to an increase in its level of use, depending on the change in the relative costs and the price elasticity of substitution. When the relative costs (and thus prices) are far apart, the substitution effect may be trivially small; but when they are close, it can be very large. In turn, an increase in the level of use will lead to further R&D and opportunities for further innovations, scale economies, further reductions in costs and further substitution.

Depending on the rate of innovation and substitution elasticities, the upshot may be a threshold effect, which in the present case is a cumulative dynamic process beginning

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[11] More formally, $-\Delta c_2 = \frac{\partial c_2}{\partial X_1} \cdot \Delta X_1$ and $-\Delta X_2 = \frac{\partial X_2}{\partial c_2} \cdot \frac{\partial c_2}{\partial X_1} \cdot \Delta X_1$ such that the sum of the two terms is $\frac{\partial c_2}{\partial X_1} \left\{ X_2 + c_2 \cdot \frac{\partial X_2}{\partial c_2} \right\} \Delta X_1$

with discovery and innovation, investment in demonstration activities, cost reductions, investment in applications induced by cost reductions, and further discoveries, innovations and cost reductions as experience accumulates, and so on, leading to patterns of supply and use that are fundamentally different to those of the initial situation (Anderson and Winne, 2007). The examples of technologies failing are too numerous and familiar to labour the point that such threshold effects often never take place; incumbent technologies may reduce costs through innovation and scale economies too, and ward off the challenge from the 'upstarts', as arguably happened to nuclear power with coal and gas for power generation in the period 1960-present. But the history of the energy industry is also replete with positive examples: the emergence of coal as a fuel for homes, industry, electricity generation and transport in the industrial revolution, its replacement by oil as a fuel for transport in the twentieth century, and its continuing replacement by gas as a fuel for homes, industry and electricity generation. Numerous further examples are to be found in the uses of energy for light, heat, refrigeration, and motive power. Responses to past environmental problems from energy use, by bringing about orders-of-magnitude reductions in the levels of local pollution, provide yet further examples.

Such possibilities are too important to be neglected in the analysis of technological options, costs and policies. Methods of modelling them are still in the research phase.[12] As an interim device the users of cost minimisation models such as MARKAL often 'constrain in' certain technologies thought to be of long term promise, and make exogenous adjustments to the input cost data to allow for the effects of innovation on costs. The same approach is also used to ensure that a portfolio of options is considered in the analysis.

4.9 Investment Portfolios

The approach followed in the present study of specifying a range of portfolios and estimating probability distributions of outcomes and costs does not overcome the limitations of using marginal cost curves or cost-minimisation models discussed above, but it does have the merits of spanning a wide range of possibilities. Uncertainties with respect to the rates of innovation and other factors on costs are included in the probability distributions fed into the analysis, and the contribution of each technology is limited to a technologically feasible range. The estimated range of costs of the approach is similar to that found in many other studies.[13]

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[12] See the meta analysis of Terry Barker and Jonathan Koehler for Chapter 10 of the Stern Review. IIASA and the research group at Cambridge are undertaking research in this area.

[13] See Stern Report, chapters 9 and 10.

5. Implications for UK Policies

5.1 Principles

The principles of climate change policy have been stated in a large number of studies, and accepted for some years by governments throughout the OECD. They have three components:

1. Carbon Pricing

2. Direct support for innovation in the form of:

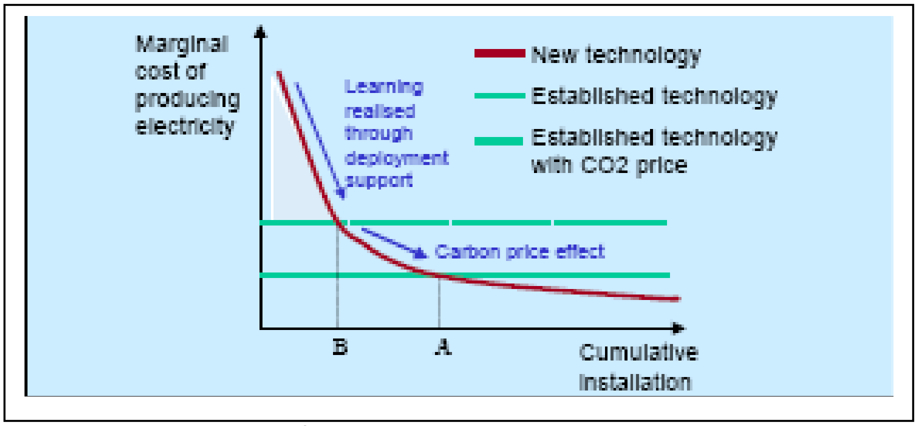
    - Tax or other incentives for private R&D combined with finance for public R&D in public research institutions and universities;
    - Tax incentives and/or grant finance for demonstration projects;
    - Public procurement of innovative technologies—solar roofs and micro-generators for public buildings, fuel cells for the defence and aerospace industries and for demonstrator buses, and so forth;
    - Regulatory incentives and standards for low carbon technologies (low carbon vehicles for example, and efficiency standards in buildings and for a large number of appliances);
    - Price support mechanisms, again for innovative technologies in their early phases of development—feed-in tariffs in several EU countries, the Renewables Obligation in the UK (also the former NFFO programme) and more recently the RTFO;
    - Tax credits for investment in or the use of innovative technologies.

3. Addressing market 'barriers'—shortcomings in the patent system, labelling on the performance and efficiency of appliances, congestion pricing to reduce the social costs of congestion, and various other.

The Stern Review (Part IV, chapters 14-17) provides a review of the literature, so it is unnecessary to develop the rationale further here other than to make one practical point. This is that, although there is no disagreement over the long-term importance of carbon pricing, in practice the sorts of approaches listed under 2 and 3 have so far been, by a large margin, much the more important in the development of low carbon technologies. There is not a single low carbon technology of the many listed earlier (p 12-13 and table 6) that does not owe its emergence to these categories of policy. Carbon pricing will (it is to be hoped) assume a more important role in future; it is especially well-suited, as the Stern Review showed[14], as an incentive for the adoption of the mature low carbon options, with direct support for innovation assuming greater responsibility in earlier phases of a technology's development. Figure 6, taken from the Stern Review summarises the argument very well:

[14] See especially section 16.4 and Figure 16.6

Figure 6: Interaction between carbon pricing and deployment support



Source: Prepared by Chris Taylor for the Stern Review (Figure 16.4)

It is necessary to make this point since there are still disagreements in the economics profession, apparent also in the tensions between Treasury economists and the departments responsible for energy and the environment, as to the desirability of direct support for innovation, or what the Stern team called 'deployment support'. In theory and in practice, however, direct support for innovation is needed to take low carbon options to a stage where carbon pricing can have its effect. The theoretical argument has two aspects. *First*, it is an attempt to recognise the positive externalities of innovation discussed in Part 4 above, which are overlooked by the traditional economic analysis of pollution abatement. *Second*, in the presence of appreciable uncertainties and risks, it recognises the importance of having a diverse portfolio of options, including higher cost options that may easily be excluded in a deterministic analysis. The practical argument is that it has proved possible, in all OECD countries, to win political and public acceptance of direct support for innovation and addressing market 'barriers' to the uptake of new low carbon technologies and energy efficiency.

When stated in terms of their imputed costs per ton of carbon emissions avoided, such incentives have been substantial. For example:[15]

- The UK Renewables Obligation has a buy-out price of 3p/kWh, but a value of around 4.5p/kWh once the revenues recycled from buy-out payments are included. The buy-out price (taking this as an indication of the minimum the government thought necessary to stimulate investment) is equivalent to a carbon price incentive of £100/ton on generation from coal and £270/ton on generation from natural gas, which has twice the calorific value of coal and a smaller carbon fraction per unit of energy produced.
- The plan to 'band' the Obligation announced in the Energy White Paper (2007) may result in some lessening of the incentive for new investments in mature technologies (such as onshore wind)[16], but appreciable increases for others such as offshore wind, decentralised forms of CHP, and solar. This is fully consistent

[15] The following is taken from my paper for the Stern Review.
[16] The incentives provided to existing investments will be grandfathered.

with the idea of offering greater incentives for technologies in their earlier phases of development and use.

- The 30p/litre fuel duty allowance for bioethanol in the UK is equivalent to £150-300/ton of carbon saved depending on the crop and transformation pathway, neglecting greenhouse gas emissions from the fertilisers used in its production and from its transport. This is to be increased by 15p/litre under the Renewable Transport Fuel Obligation, providing an overall incentive of £225-450/tonC.
- To keep the nuclear option open the UK Non-Fossil Fuel Obligation (NFFO) in the 1990s injected approximately £8 billion into the nuclear power industry. On an annualised basis over the remaining lifetimes of the nuclear plants (which had already been subsidised out of electricity tariffs during construction) this amounted to approximately 2p/kWh, or £180/tonC relative to gas-fired generation, the 'fuel of choice' in the 1990s. In addition, Sizewell B went ahead, with an imputed value of carbon of ≈ £250/ton (Pearson and Pena, 1999).

In Europe[17], the incentives for low carbon technologies are of similar orders. Germany's feed-in tariffs for biomass are 8.5-10 €cents/kWh, and for wind 6-9 €cents/kWh, guaranteed for 20 years, with the higher incentive applying to offshore wind projects. In Holland they are 7.8 and 9.7 €cents/kWh for onshore and offshore wind respectively, and in Austria 4-12 €cents/kWh for heat and electricity from biomass, depending on the primary source of fuel. The Scandinavian countries provide a similarly wide range of incentives for biofuels for heat and power and for wind energy, and include a carbon tax in Sweden. Spain's incentives consist of high feed-in tariffs plus 'bonus prices' totalling about 9 €cents/kWh for biomass and wind, and 10-30 €cents/kWh for solar.

The *net* incentives provided for low carbon technologies in European countries, assuming a cost of generation from fossil fuels of 4 €cents/kWh, thus average about 4 €cents/kWh (2.8p/kWh) for wind, are somewhat higher for biomass and much higher for solar. For wind and biomass they are equivalent to carbon taxes of about £100/ton carbon if coal is the marker and £250/ton if gas is the marker, but are appreciably higher for technologies in their earlier phases of development. The same can be said of incentives for solar energy in Japan. Incentives for wind, biofuels and solar energy in the US vary greatly between States. There is a Federal tax incentive of $0.5 per gallon for bioethanol (equivalent to £85/tonC[18]) and up to $1.0 per gallon for biodiesel from waste oils (£170/tonC); both wind and solar energy also receive substantial incentives in the form of capital grants, tax credits and higher prices under the influence of the Renewables Portfolio Standards in effect in twenty States.

5.2 Carbon Pricing

The rationale for incentives of the orders just outlined can easily be seen in the costs of the technologies listed in table 6 above. There is not a single low carbon technology for

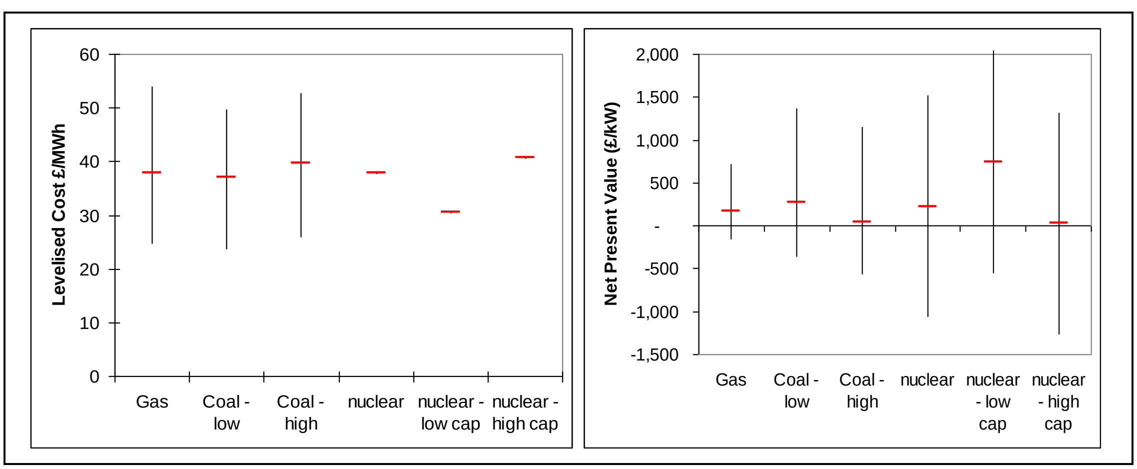
[17] See the "Review of Renewable Energy Development in Europe and the US" by Stenzel, Foxon and Gross. ICCEPT (2003), on which the figures in this paragraph are based.
[18] Here and elsewhere a ppp exchange rate of $1.6/£ is used.

supplying energy for which the *expected* costs are lower than those of the fossil fuel or 'marker' technologies. Higher prices for oil and gas would change the picture somewhat (this table assumes \$50/barrel and £4/GJ), as would assumptions at the optimistic ends of the ranges of costs discussed earlier for the various technologies. The probability distributions for three cases—nuclear power, offshore wind and electricity generation from coal with carbon capture and storage—are shown in Annex 6. Of these, only nuclear power has a small chance (barely 10%) of being profitable without the benefit of carbon pricing or price support or subsidy (including support for liabilities and waste disposal in the case of nuclear power).

The introduction of a carbon price of £100/tonC would tilt the balance somewhat for the more mature options, as shown in table 9 below, but even then they would be working with small margins. For example, \$100/tonC would raise the expected cost of gas-fired power plant by 0.6p/kWh, though by coal by 2.7p/kWh. Gas would thus become the marker technology, and at prices of around £100/tonC would still be able to undermine the emergence of low carbon options, notwithstanding the higher gas prices in recent yearss.

Furthermore, this is to understate the difficulties facing low carbon technologies, as shown in recent reports by Gross, Heptonstall and Blyth (2007) for the UKERC and in the background paper by Blyth. Private sector investors base their investment decisions not on the basis of average or 'levelised' costs, but on the rate of return or net present value of investment. Blyth compares two sets of calculations: one showing the range of the relative levelised costs of gas, coal and nuclear stations under alternative assumptions of carbon prices and prices of coal and gas; the other the net present values of the investments under the same assumptions. The results are shown in the left and right hand sides respectively of Figure 7 below, taken from Blyth's paper:

Figure 7: Levelised costs (left hand chart) and net present values (right hand chart) under alternative fuel and carbon price assumptions.



Source: Blyth (2006). The range of fuel and carbon price assumptions was taken from the UK *Energy Review* (2006). His carbon price assumptions were 0/tCO_2, £10/tCO_2, £17/tCO_2, and £25/tCO_2.

The contrast between the two charts is striking. Changes in carbon and fuel prices have large effects on the levelised costs of coal and gas, but of course no effect on the costs of nuclear power (or of any other non-carbon technology). But shifts in prices arising from changes in fossil fuel and carbon prices have a large effect on electricity prices because the short-run marginal costs of fossil fuel plant determine the short-run marginal costs of supply and hence prices; this reduces the exposure of the fossil fuels to price risks but increases the exposure of the low carbon technologies. When levelised costs are compared, the non-carbon technologies look less risky; but when the NPVs are compared it is the non-carbon technologies that look more risky.[19]

Table 9: Effects of a £100/tonC and £200/tonC Carbon Price on Relative Costs

Low Carbon Technology	Marker Technology	Cost unit	Cost of Marker £100/tC	Cost of Marker £200/tC	Cost of Low Cbn Technlgy	Net cost, % Marker £100/tC	Net cost, % Marker £200/tC
Medium term estimates							
………...………………………. **Electricity Markets** …………………………...							
Electricity from gas with CCS	NGCC or coal	p/kWh	4.6	5.6	5.2	12	-8
Electricity from coal with CCS	NGCC or coal	p/kWh	4.6	5.6	5.2	13	-8
Nuclear power	NGCC or coal	p/kWh	4.6	5.6	3.9	-16	-32
Electricity from energy crops	NGCC or coal	p/kWh	4.6	5.6	6.4	38	14
Electricity from organic wastes	NGCC or coal	p/kWh	4.6	5.6	6.9	50	22
Onshore wind	NGCC or coal	p/kWh	4.6	5.6	4.4	-4	-22
Offshore wind	NGCC or coal	p/kWh	4.6	5.6	8.2	78	45
PV for distributed generation	Grid electrcty	p/kWh	9.7	11.4	42.1	333	269
dCHP using H from NG or coal with CCS	Grid electrcty	p/kWh	9.7	11.4	24.2	149	112
……………………………………. **Gas Markets** ……………………………………..							
Hydrogen from NG or coal (CCS)--industry	NG	£/GJ	5.4	6.9	7.7	42	12
Hydrogen from NG or coal (CCS)--distrbtd	NG	£/GJ	7.4	8.9	15.5	108	75
Electrolytic hydrogen--industry	NG	£/GJ	5.4	6.9	19.7	262	186
Electrolytic hydrogen--distributed	NG	£/GJ	7.4	8.9	27.1	264	205
Biomass for heat--distributed	NG	£/GJ	7.4	8.9	9.7	29	10
Now low-C electricity heat							
……………………….. **Transport Markets** …………………………..							
Bioethanol	Petrol	p/litre	36.8	44.2	45.0	22	2
Biodiesel	Diesel	p/litre	36.8	44.2	50.0	36	13
Hydrogen ICE vehicle--fossil H (+ CCS)	Petrol	p/litre	36.8	44.2	54.2	47	23
ditto--including incrtl cap cost of H vehicle	Petrol	p/litre	36.8	44.2	141.0	283	219
Long term estimates (over 20 years):							
…………………………………… **Electricity Markets** …………………………...							
Electricity from gas with CCS	NGCC or coal	p/kWh	4.2	5.1	4.8	15	-6
Electricity from coal with CCS	NGCC or coal	p/kWh	4.2	5.1	4.8	15	-6
Nuclear power	NGCC or coal	p/kWh	4.2	5.1	3.5	-16	-32
Electricity from energy crops	NGCC or coal	p/kWh	4.2	5.1	4.9	17	-3
Electricity from organic wastes	NGCC or coal	p/kWh	4.2	5.1	4.1	-1	-19
Onshore wind	NGCC or coal	p/kWh	4.2	5.1	3.9	-7	-24
Offshore wind	NGCC or coal	p/kWh	4.2	5.1	6.0	43	17
PV for distributed generation	Grid electrcty	p/kWh	9.7	11.4	24.0	148	111

[19] The report by Gross et al argues that the incentives should be derived from analyses of their estimated effects on the rate of return to investment.

dCHP--H from NG or coal with CCS	Grid electrcty	p/kWh	9.7	11.4	8.8	-9	-23
……….……………………… **Gas Markets** …………………………………..							
Hydrogen from NG or coal (CCS)--industry	NG	£/GJ	5.44	6.88	6.3	16	-8
Hydrogen from NG or coal (CCS)--distributed	NG	£/GJ	7.44	8.88	13.1	76	48
Electrolytic hydrogen--industry	NG	£/GJ	5.44	6.88	14.1	159	105
Electrolytic hydrogen--distributed	NG	£/GJ	7.44	8.88	20.5	175	131
Biomass for heat--distributed	NG	£/GJ	7.44	8.88	9.7	29	10
New low-C electricity heat							
……………………….. **Transport Markets** …………………………..							
Bioethanol	Petrol	p/litre	36.8	44.2	60.0	63	36
Biodiesel	Diesel	p/litre	36.8	44.2	50.0	36	13
FC Hydrogen vehicle--fossil H (+ CCS)	Petrol	p/litre	36.8	44.2	132.8	261	201
FC Hydrogen vehicle--electrolytic H	Petrol	p/litre	36.8	44.2	155.8	323	253

A carbon price of £200/tonC would have a larger effect, but many options would still be left out, as indicated in the last column of table 9. This is consistent with the experiences of the UK with the Renewables Obligation, of several countries in the EU with feed-in tariffs, and of many countries with biofuel policies. As discussed above, the incentives provided in generally exceed this level, except those for the mature options such as nuclear power and onshore wind.

Policies will thus need to aim for carbon prices in the range £100-200/tonC (€40-80/tonneCO_2) for the mature options, and add to these further incentives (a) for innovation, and (b) to diversify the portfolio. Furthermore, carbon pricing needs to be extended to all hydro-carbon fuels.

This would be an immense step forward from carbon pricing policies so far. Theoretically most efficient option is a carbon tax with revenue recycling. This was first mooted in the EU over 15 years ago, but rejected, though it remains the ideal option. The UK's Climate Change Levy could have been the beginnings of a carbon tax system at the national level, but it was applied to energy consumption not carbon emissions, and has had little or no effect on substitution and technology development. Instead, much reliance is now being placed on the EU-ETS, which for 2005-07 had a peak value of ~ €35/ tonneCO_2. However, it has recently collapsed to €0.13/tonne CO_2, and it is restricted to particular installations and excludes transport. A failure to set the caps negotiated in the next round of the EU-ETS will mean that national targets and aspirations are unlikely to be met unless some alternative such as a carbon tax is introduced.

5.3 Electricity Markets

Electricity so far has been the main focus of attention in the UK, as in other countries. Initiatives in transport and the gas and heating markets have barely begun, aside from some demonstrator projects in transport and efficiency in the use of heat.

(a) Electricity from Renewable Energy

Several European countries have preferred to support renewable energy through feed-in tariffs, with Holland considering the alternative of adding a feed-in premium to the market price of electricity, tailored to each technology according to its stage of development.[20] Such policies would also work well in the UK. But the White Paper has opted instead for a degree of continuity with past policies, and has proposed to 'band' the Renewables Obligation and progressively extend the RO targets. The key proposals are:

- To make the Obligation a moving target, always keeping ahead of the amount of renewable energy actually generated up to 20% of supply. Effectively this will obviate the dangers of a collapse of ROC prices and guarantee the market for the next 15 years, by which time the costs of several of the more successful technologies should have fallen to the point where continued support could be provided by carbon pricing alone.

- A buy-out price for each ROC worth £34.30/MWh, indexed to the RPI. (One ROC = 1 MWh of electricity from a renewable resource.)

- Recycling the revenues from buy-out payments to suppliers in proportion to the amount of renewable energy they supply. As in the past, this will continue to raise the effective price of the ROC by an amount equal to the cash payments from the buy-outs divided by the obligations actually met. (E.g. 20% of suppliers buying out would lead to an increase in the ROC price by 1/0.8 or by 25 %.)

- To award ROCs according to the level of development of a technology:

    - 0.25 ROCs for sewage and landfill gas and co-firing plant from non-energy crop biomass
    - 1.0 ROCs for onshore wind, hydro electricity, co-firing of energy crops and energy from waste for CHP
    - 1.5 ROCs for post-demonstration technologies: offshore wind and dedicated 'regular' biomass
    - 2.0 ROCs for emerging technologies such as wave, tidal stream, solar photovoltaics, tidal stream, biomass with CHP, geothermal and other.

Assuming the ROC price is around £40/MWh or above such incentives should be sufficient to make the established and post-demonstration technologies profitable, including offshore wind, though the emerging technologies will probably need further support in their demonstration phases. (See cost estimates in Table 9.) Quantitatively, the incentives provided by this new arrangement will be similar in magnitude to the incentives provided by feed-in tariffs in several other countries in Europe.

It is possible that the ROCs in conjunction with carbon pricing would also make the long-discussed possibility of the Severn Barrage marginally viable. The estimates of capital and operating costs in the report by S. J. Taylor (2002) of Robert McAlpine point to a cost of around 9p/kWh (assuming a 10% discount rate), which is about 6p/kWh above

[20] The Carbon Trust has suggested a similar approach.

the wholesale electricity price.[21] The project is under review by the Sustainable Development Commission.

(b) Ofgem's Objections to the Renewables Obligation

Ofgem wrote to oppose the continuation of the Renwables Obligation, whether banded or not. It is necessary to weigh their argument since it is often made by economists unsympathetic to the idea of any form of policy other than carbon pricing, supplemented by R&D. It highlights the dilemma facing governments wishing to retain the benefits of market liberalisation while trying to transform the energy system to a low carbon one.

In their response to the Government's consultation on the Energy White Paper, "Reform of the Renewables Obligation 2006", Ofgem supported the idea of carbon pricing through emissions trading, citing the EU-ETS, but objected to the current RO and the proposals to extend and band it beyond 2015, arguing that:[22]

(i) The level of support is far too generous for some technologies since the "cost to consumers of carbon abatement through the RO is in the range £184-481 per tonne of carbon (depending on the fuel), with a figure of £400/tC if the grid average is used…..To set these numbers in context the costs of other policies are estimated at £66/tC for the UK ETS, £18-40/tC for the Climate Change Levy and for the Energy Efficiency Commitment the range is from negative to £66/tC. Under the EU ETS, the equivalent volume of reduction could have been secured for between around £12/tC and £70/tC."

(ii) They did not feel qualified to administer a banded RO; and

(iii) A banded RO would expose them to lobbying and make it difficult to regulate the electricity industry in a technology-neutral way in the interests of consumers.

Support for innovation is clearly seen by Ofgem as an encumbrance on the ideals of market liberalisation, which perhaps explains why they are also opposed to an extension of the RO targets to beyond 2015—and further why they have viewed with equanimity the decline of RD&D in the electricity industry over the past twenty years. The government are right, however, to have rejected Ofgem's arguments, on three grounds:

First, the RO is not a substitute for carbon pricing, as Ofgem assume, but a complement, intended to support the emergence and development of new sources of electricity generation. As the Stern Review has shown (Chapter 16) we need both policies not one. It is also simply untrue that an "equivalent volume of reduction" could have been achieved for £12-70/tC: in fact the EU-ETS and the UK CCL are already in place and have so far accomplished little or nothing. Ofgem's argument seriously underestimates the costs and difficulties of transforming the electricity system to a low carbon one.

[21] A carbon price of €40-80/tonneCO_2 would translate into 2-3 p/kWh. Assuming a ROC price of 4p/kWh the total incentive under the proposals would amount to about 6-7p/kWh.

[22] www.ofgem.gov.uk Ref 11/07. Contact john.costyn@ofgem.gov.uk

Second, low carbon technologies are in different stages of development: research and demonstration projects in nuclear power were undertaken more than 50 years ago; offshore wind and solar technologies are in their infancy, as is the use of coal with carbon capture and storage; and new systems and possibly new energy carriers such as hydrogen will need to be developed on a commercial scale. Climate change mitigation is requiring a level of intervention that was unanticipated when markets were liberalised nearly two decades ago, notwithstanding the accomplishments of liberalisation. The dilemma is that the emergence of low carbon technologies will be dependent on some form of differentiated support.

Third, there is the issue posed by uncertainty and risk. If climate change policies are to succeed, it will become necessary to develop a portfolio of options, and this too will require some form of differentiated support.

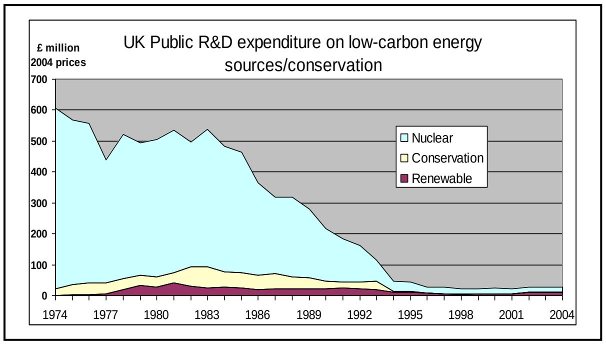
(c) RD&D in the Emerging Renewable Energy Technologies, Energy Carriers and Storage

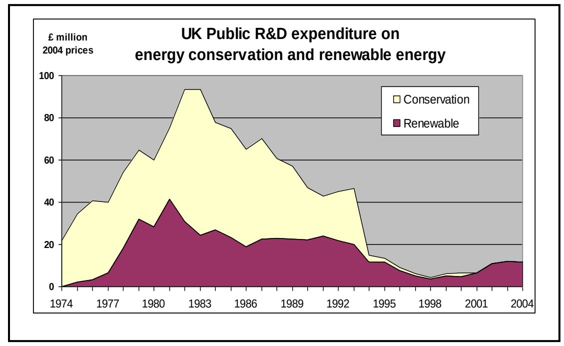
The importance of a substantial RD&D programme to take technologies to the point where they can benefit from banded ROC policies is accepted in the Energy White Paper. There is a full statement of the options requiring more RD&D, which include (see especially table 6.1 of the EWP):

- Offshore wind
- Bioenergy for heat and transport, including the development of second generation biofuels
- Wave and tidal stream devices
- Micro-generation for heat and power: solar PVs, solar heating, small wind turbines, micro CHP, heat pumps, small-scale fuel cells
- Hydrogen production for fuel cells for large and small scale stationary applications and transport, and as a storage medium for intermittent forms of renewable energy. This would include RD&D on hydrogen production from fossil fuels with CCS, electrolysis and photo-electrolysis.
- New generations of solar PV
- Battery technologies for electric and hybrid vehicles
- Demand management and efficient end-use technologies, including ‘smart metering’

The RD&D agenda is rich and promising, and the main issues ahead relate less to its range and content than to the scale of the effort required. The UK’s RD&D effort fell nearly 10-fold following the collapse of oil prices in the 1980s and market liberalisation shortly afterwards. Moreover, the decline was not confined to nuclear energy, but was across the board, as can be seen in the right hand chart in Figure 8. Across other countries in the OECD R&D expenditures fell by half. As a pragmatic first step, the Stern Review argued for a doubling of the RD&D effort, but if the UK is to pull its weight and draw on its scientific expertise it will have to increase it by much more.

Figure 8: UK Public R&D expenditures on Low Carbon Energy and Energy Conservation Technologies: 1974-2004





Source: IEA spreadsheet supplied to Stern Review 2006

The newly announced Energy Technologies Institute (£600million over 10 years), recent increases in the Research Council's energy programmes, and various other initiatives discussed in the White Paper are welcome developments, but still fall short of what is needed in view of the scale of the challenge of developing a low carbon energy system. How is an expansion to be financed?

Further increases in public expenditures are one possibility. However, these will inevitably be limited by the already heavy pressures on the public revenue, and it will be necessary to look for alternative source of finance.

Another possibility would be to recycle revenues out of the Climate Change Levy or out of the buy-out payments of the Renewables Obligation. The case for the latter is two-fold:

- The principle of recycling the revenues from RO buy-outs to innovation is already accepted and practiced. The intention is to continue with it under the banded RO, including the finance of the upper bands for post-demonstration and emerging technologies, which will receive 1.5 and 2 ROCs respectively. It would be a logical step, therefore, fully consistent with the aims of the RO, to add a further component to the recycling policy in support of RD&D in technologies in their 'pre-ROC' phase. It would not take the form of a ROC payment based on MWh output; instead, it would be a source of grant finance.

- It is an elastic source of revenues, and will rise rapidly with the share of renewable energy in electricity output. For example 15% of electricity output by 2015 will amount to roughly 60 million MWh. Assuming roughly 20% of suppliers buy-out (since the intention is to keep the Obligation ahead of the market) and a ROC price of £35/MWh the revenues from buy-outs would amount to £420 million per year, roughly three times the amount generated by buy-outs

> in 2004.[23] This is over 20 times current RD&D expenditures on low carbon technologies, which for renewable energy and conservation are less than £20 million per year (see figure 7). A relatively small adjustment to the policy of recycling the revenues, therefore, could yield immense benefits for energy RD&D programmes—and would probably relieve pressures on public RD&D budgets elsewhere.

The resources for an appreciable increase in RD&D expenditures are therefore available if the Government is willing to consider alternative financial mechanisms.

(d) Coal with Carbon Capture and Storage

There is a welcome commitment to the development of coal fired power stations with CCS in the Energy White Paper. The bidding details for a demonstration programme are currently being worked out. In parallel the Government is working with the EU to "work toward a series of up to 12 CCS demonstration projects by 2015". Several such projects are indeed needed since there is a range of options to be demonstrated involving both pre- and post-combustion technologies and much exploratory work to be done to identify and test the integrity of carbon sinks.

The post-combustion options are the least disruptive, and a good way of demonstrating the carbon capture and storage aspects of the technology, but they are basically an 'end-of-pipe' technology. The development of pre-combustion options involving coal gasification and hydrogen production, on the other hand, would enable the 'hydrogen economy option' to be opened up, with hydrogen being used for electricity generation, the heating markets (e.g. in fuel cells for CHP) and for transport.

It will also be necessary, as the demonstration programme proceeds, to develop incentives for a series of first generation of CCS plant, i.e. for 'post-demonstration' policies to be in place. Otherwise the private returns will be marginal and risky; the carbon price will need to reach a steady level of ~ £200/tC (€80/tC) to provide a satisfactory return to investment (see table 9). Two options are:

- A tightening of the caps in the National Allocation Plans (NAPs) in the next round of the EU-ETS such that an assured carbon in the range €40-80/tC is realised, preferably at the higher end of this range;
- A feed-in tariff premium of ~ 3p/kWh to be applied over a development and demonstration phase of approximately 5-10 years, to be phased out and superseded by the incentives provided by carbon pricing. It would be grandfathered over the lifetimes of those CCS demonstration projects remaining in operation.

The latter, as we have seen with the experience of feed-in tariffs in Europe, would offer a stable and durable incentive until the carbon market is developed and has won the

[23] The buy-out payments were £136million in 2004. Ofgem (2006) *Renewables Obligation: Third Annual Report*. Report no. 35/06. The buy-out percentage in that year was 30%.

confidence of industry. If applied it would almost immediately engage industry in both the demonstration and the deployment of new approaches such as pre-combustion technologies and hydrogen production.

(e) Nuclear Power

The Energy White Paper expresses the Government's commitment to allow private investment in new generations of nuclear plant to proceed. It shows (as does the present study) that phasing nuclear power out would put an immense strain on the development of the offshore wind industry and carbon capture and storage if the UK is to meet its targets. The key components of policy are:

- Reliance on the EU-ETS to raise the costs of generation from coal and gas such that nuclear power will benefit from carbon pricing. Their central estimate is that a carbon price of €36/tCO_2 (£90/tonne) would give nuclear power a satisfactory rate; this is probably on the low side (see section 5.2 and Figure 7 above).
- A requirement that private investors would have to meet their "full decommissioning and full share of wastes management costs". The financing arrangements for this would have to be in place "before proposals for new nuclear power stations could proceed."
- Various measures to reduce planning and regulatory risks.

The estimate of €36/tCO_2 is similar to that that would be implied by the present analysis (see Table 9). It is only a "central estimate" however. Once the possibilities of cost escalation and price risks are taken into account it is likely that a higher carbon price than this will be needed if the programme is to succeed.

5.4 Gas and Heat

The White Paper emphasises the improvement of energy efficiency in the gas and heating markets. In addition it is recognised that low carbon energy supply options will be needed. The EWP provides a long list of options and a summary of policy measures to support them:

- Distributed heat and power: micro CHP, larger scale CHP, solar water heating, biomass, heat pumps… The emergence of distributed energy would, as the Paper says, mark a considerable change from the present system of centralised supplies of heat and power, and will require changes in energy market regulation to accommodate it. Among other measures, the Government proposes to provide:
  - "more flexible market and licensing arrangements … to be implemented by end 2008;
  - "more clarity on the terms offered by energy suppliers to reward micro-generators for the excess electricity they produce and export; and
  - "making it easier to connect to and use the distribution network."

- A low carbon building demonstrator programme, which includes £86m for micro-generation and CHP, plus further incentives by Renewables Obligation Certificates, exemptions from the Climate Change Levy
- Low carbon electricity for heat and power. This source of supply would also benefit of course from carbon pricing and the Renewables Obligation.

Beyond the possibilities for energy efficiency, carbon abatement in the heating markets will be technically difficult to achieve, and will require all the above measures and more.

An omission from this section of the Energy White Paper is that it doesn't discuss the possibilities of producing and distributing hydrogen as a low carbon energy carrier for CHP.

Another possibility is the emergence of what is termed the 'virtual utility', which would draw on developments in metering and information technologies for the management of demands and distributed energy forms in the distribution networks for gas and electricity. If they were to emerge, such utilities could have considerable influence on the rate of uptake of distributed energy and energy efficiency.

Policies to reduce emissions from the supply and use of heat are at an earlier stage than those for electricity. The Government intends to "look at the full range of policy options, including the range of existing policy mechanisms such as the EU ETS." Two options that clearly need weighing are the extension of carbon pricing to the gas markets, which would be another stimulus to distributed energy forms, and reforms to the current regulatory arrangements to facilitate the emergence of the virtual utility.

5.5 Transport

UK policies for emissions abatement in transport as they stand will not 'deliver' the level of abatement sought by the Government. The policies are less developed and less ambitious than those for electricity. The Energy White Paper estimates that the combination of measures currently in place or under review would produce yearly savings of 2.0 to 5.5 MtC by 2020, or roughly 1.3 to 3.7 percent of the UK's carbon emissions by then assuming no further growth of emissions from today's levels.[24] Yet in surface transport alone emissions could easily rise by 10 MtC per year under current trends from today's levels of 45 MtC, since under current policies the demands for fuels for both surface transport and aviation continue to rise with—and are unlikely to offset the effects of—income growth (see Annex 3 table A-3.4).

To put the problem in perspective, Table 10 provides some calculations of (a) the likely (b.a.u.) trajectory of UK carbon emissions in the absence of climate change policies; (b) the targets set by the Government; (c) the required level of abatement to meet the targets (a - b); and (d) an estimated breakdown of (c) under the policies in place.

[24] The projected 'baseline emissions' for 2020 are 150 MtC/year, the same as the levels in 2005 (Energy White Paper, table B1, p 328)

Table 10: Estimates of the Contributions of the Energy Markets to Carbon Abatement under Current UK Targets and Policies

	2005	2015	2025	2050
(a) Emissions Trajectory (b.a.u.), MtC/year	152	175	185	200
(b) Government's targets, MtC/year	--	150	135	65
(c) Required abatement	--	25	50	135
(d) Estimated breakdown of required abatement, MtC/year:				
• Electricity		22	38	79
• Gas-heating		1	8	18
• Transport		1	5	36
(d) Breakdown of required abatement as % sector emissions without abatement:				
• Electricity		32	51	100
• Gas-heating		3	19	43
• Transport		1	7	47

Source: calculations from the spreadsheet developed for the present study, which is to be made available on the IPPR website. The table shows the mean values of a range of possibilities considered.

Despite the uncertainties in such estimates, the pattern is clear: current policies are heavily focussed on electricity, and policies for transport are not carrying their weight. This pattern will need to change appreciably as electricity supply becomes decarbonised since even 100% decarbonisation of electricity will leave the UK a short of its long-term targets.

This conclusion is tacitly accepted in the EWP, and also in the supporting study on low carbon transport by the DfT, both of which provide a survey of the options available and proposals to take the analysis further in discussions with the EU on carbon pricing and other matters, and through a study to be led by Julia King and Sir Nicolas Stern. In addition the UKERC is to undertake a technology and policy assessment of options in transport, with encouragement from DfT.

(a) Policies Discussed in the Energy White Paper and the DfT's Low Carbon Transport Innovation Strategy

The EWP, along with the DfT's *Low Carbon Transport Innovation Strategy* published in May 2007 cannot be faulted for their recognition of the options available for reducing emissions from transport. The near-term options identified in the DfT's strategy have been well-informed by a study the DfT commissioned from E4Tech (2006). They include:

- Incremental improvements to petrol and diesel engine vehicles
- Hybrid petrol-electric or diesel-electric vehicles,
- First generation biofuels (bioethanol made from sugar or starch crops and biodiesel made from oil crops and wastes)

Over a longer timescale high levels of de-carbonisation of road transport are seen to be technological feasible by turning to:

- Plug-in hybrids which can be re-charged from the electricity grid
- Electric vehicles, "which may expand independently or evolve from plug-in hybrids"
- Second generation biofuels, manufactured from a wide range of biomass sources
- Hydrogen fuelled vehicles based on the internal combustion engine or fuel cells.

Drawing on the Stern Review, the reports also recognise the key elements of the policies required. There are commitments to carbon pricing in transport and to policies to support innovation directly. There is "a dialogue with our EU and international trading partners ... [to] provide a *carbon price signal* to all major transport modes"; an intention to see aviation included in the ETS; and there are proposals to utilise "*other market based or regulatory approaches* to encourage the deployment of lower carbon transport technologies … including taxation incentives, measures to support lower carbon public procurement [and] minimum standards regulations …" [Emphases in original.]

However, questions have to be raised about the scale and durability of the actual incentives currently in place. The principal measures are:

- An incentive for low carbon vehicles through a graduated vehicle excise duty regime. The 2007 budget raised this to £300 for 2007 and to £400 for 2008 "for the most polluting cars"
- An initial fund of £20m for a public procurement programme to reduce "the barriers faced by companies in moving from prototype demonstrations of lower carbon technologies to full commercialization."
- Support for biofuels through the development of the Renewable Transport Fuel Obligation (RTFO) over the period 2008/9 to 2010/11. It is estimated that this will deliver 1 MtC of emissions savings.
- A preferential tax for biofuels—bioethanol and biodiesel—relative to gasoline and diesel, with a 20p/litre reduction in the duty levied until 2009/10, "which alongside the RFTO will mean a 35p/litre incentive for that year."
- Investment in the development of new vehicle technologies through a £5 million grant to the Energy Technologies Institute, to provide "a new Innovation Platform for UK automotive R&D."
- £5m per year of funding to "support … industry-led low carbon vehicle R&D, [plus] £0.5m per annum of grants for the trialing and demonstration of infrastructure for alternative fuels."
- "Up to £200 million per year" earmarked "from the Transport Innovation Fund to support packages of measures that combine demand management such as road pricing with modal shift, smarter travel choices and better bus services."

In relation to the scale of the problem to be addressed, these measures are tinkering at the edges. They are for instance a very small fraction of the Government's commitments to renewable energy, nuclear power and carbon capture and storage, which also fall short. The RFTO is also very short-term and unbanded, in contrast to the RO which now extends to 15 years and is banded.

(b) Biofuels for Transport

The main policies in place are to support the use of biofuels, for which an incentive of 35p/litre is to be provided by the RTFO and the fuel duty allowance. A comparison of their costs with those of petroleum fuels shows that such an incentive should be sufficient to encourage substitution. The pre-tax costs of petroleum fuels are about 30p/litre (with oil at $50/barrel), whereas the costs of biofuels produced in the UK are in the range 30-60p/litre, depending on crop. For ethanol from sugarcane in Brazil the costs are yet lower, being at or below the low end of this range.[25] The costs of second generation biofuels such as ethanol from lingo-cellulosic materials are higher, around 50-70p/litre, though with technical progress production costs are estimated to fall to about half this range.

There is, however, a flaw in such estimates, which is that they do not allow for the effects on the prices of agricultural lands and food, most of all in developing regions. Already in the US there is evidence that biofuel production acting to raise the prices of wheat and corn, with the effects being transmitted to food prices in developing countries[26]; the FAO have likewise warned that whilst "biofuels like ethanol can greatly help reduce global warming and create jobs for the rural poor … the benefits may be offset by higher food prices for the hungry."[27]

The problem is that biofuels are land intensive. The total biomass yield in energy units is typically 180 GJ per hectare. On this basis 10% of the land under forests and crops in the UK, and allowing for a conversion efficiency of about 20%, could conceivably yield about 300 PJ; an estimate for the forthcoming Royal Society study is about half this amount, equivalent to 23 million barrels of oil per year, or 4% of UK consumption of oil fuels. The inclusion of energy production from organic wastes could perhaps raise this contribution to the 5-10% range, which is similar to the estimates of the DfT report. This is significant, but the industrial countries have already had ample warning of the ecological dangers of an aggressive pursuit of biofuels and of exporting the adverse effects on food prices to developing countries.

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[25] Forthcoming report on biofuels by the Royal Society, drawing on evidence submitted by industry and academics to the Society.

[26] See C. Ford Runge and Benjamin Senauer (2007) "How biofuels could starve the poor." Foreign Affairs, May-June.

[27] FAO (June, 2007) Food Outlook Report No 1, which comments that "global expenditures on imported foodstuffs look set to surpass US$ 400 billion in 2007, almost 5 percent above the record of the previous year. The bulk of the increase can be levelled against rising prices of imported coarse grains and vegetable oils – the commodity groups which feature most heavily in bio-fuel production."

A further danger is of biofuels being produced in ways that would much-diminish their climate change benefits. Table 11 shows one set of estimates of the greenhouse gas intensities of alternative biofuels, allowing for ‘life cycle’ emissions arising in various stages of production and distribution. Estimates vary between studies and also between regions—the use of fertilisers, the effects of micro-climates on N_2O emissions, fuels used in processing, transport distances, and so forth. But the uncertainties are not such as to obscure the two main points: (a) First generation biofuels from cereals, beet and rapeseed are likely to reduce greenhouse gas emissions, though the estimated contribution varies over a wide range (averaging about 50%) depending on crop, cropping practice and processing technologies. (b) Second generation biofuels using lignocellulosic materials are likely to show a two-fold or more improvement in average abatement potential when compared to first generation biofuels.

Table 11: Greenhouse Gas Emissions from Petroleum fuels and Biofuels: kg of CO_2 equivalent per GJ of energy

Petrol and Diesel	90-100
Biofuels based on:	
• Cereals	60-80
• Beet	30-95
• Rapeseed	20-40
• Ligno-cellulose	5-40

Source: Taken from a chart by Jeremy Woods, who comments that these ranges are rough estimates and can be wider.

Yet there is an outstanding international opportunity for producing biofuels in ways that would greatly contribute to economic development and, indirectly to food production in developing countries. This is through the wider adoption of agro-forestry practices in developing countries and the restoration of degraded agricultural lands, woodlands and watersheds. It is estimated that that degraded agricultural lands, woodlands and watersheds amount to nearly 2000 million ha, 500 million ha in Africa alone.[28] Taking an average yield of 50GJ/ha, the restoration and afforestation of even one-half of such lands would produce 50 EJ per year. This about 30% of the world’s demands for transport fuels. Since most of the fuels from this source would be lingo-cellulosic, the net savings on emissions would be approximately 0.8 Gigatons, or close to one of the ‘wedges’ in the in the influential analysis of Pacala and Socolow (2004) on the technological options for carbon abatement,[29] and equivalent to the carbon savings of 500 GW of new nuclear capacity (50 times the UK’s current installations) or new coal plant with carbon capture and storage.

Thus there is an opportunity to produce biofuels in ways that would help to restore degraded lands and watersheds, improve micro-climates, increase the rate of carbon

[28] Presentation of Jeremy Woods, drawing on Lal (2002, 2006) and UNEP (2006). Lands under crops and permanent pasture are about 1,500 and 3,300 million hectares respectively.
[29] See also the Stern Review’s summary of the Pacala-Socolow analysis in chapter 8.

sequestration in the form of a higher standing stock of biomass, and improve yields in agriculture[30], an immense 'win-win' opportunity at the international level.

The strategies of the UK and the EU for harnessing biofuels for transport therefore need to be re-assessed with this possibility in view, and reviewed with the national and international development organizations. There are useful contributions to carbon abatement to be made from first generation and, especially second generation biofuels using dedicated crops. But if this route is pursued to excess, there is a danger that it would inflict much collateral damage to the environment and to programmes to address world poverty. A policy to combine biofuel production in association with the restoration of degraded lands in developing regions would have completely the opposite effect.

(c) Hybrid, Electric and Hydrogen Vehicles

The technological possibilities have been reviewed in a report by E4Tech[31], and summarized by both the EWP and the strategy paper of the DfT. Hence it is only necessary to recall the main points and then turn to the two main policy questions: what sorts of incentives are needed to encourage further innovation in and use of (a) the low carbon vehicle technologies? and (b) low carbon fuels?

The E4Tech study lists the key vehicle technologies as:

- Battery-electric vehicles for niche markets, including urban journeys. Although these have a limited range, typically 50 km, depending on the quantity of battery storage built into the car, most urban journeys are one quarter of this distance, with ample time for recharging in between.
- Hybrid-electric vehicles, to replace conventional gasoline and diesel vehicles. E4Tech provide a description of the five main concepts, ranging from the partial hybrid, in which the electric engine is a high efficiency booster to the internal combustion engine, to the full 'plug-in' hybrid in which the main driver is the electric motor with regenerative breaking and the internal combustion engine is essentially a battery charger, though it can also supply torque to the transmission.
- Fuel-cell vehicles, with the potential to replace all conventional vehicles

The key low carbon fuels are:

- Low carbon electricity for battery and plug-in hybrid vehicles.
- Biofuels
- Hydrogen for the fuel cell vehicle. Hydrogen can also be used in an internal combustion engine.

[30] Agro-forestry practices have long been shown to improve yields by the improving the quality of soils, micro-climates and the availability of surface and ground water resources. Anderson (1989)
[31] "UK Carbon Reduction Potential from Technologies in the Transport Sector", A report for the Department for Transport and the Energy Review Team, May 10, 2007. http://www.dti.gov.uk/files/file31647.pdf

E4Tech comment that the "hybrid vehicle technology [is] a very credible medium term option and has already been commercialized despite the extra cost and constraint related to the added electrical equipment. A large spectrum of technological options is being investigated and associated performances vary from a few percent to about 50% lower CO_2 emission rates compare with conventional gasoline fuelled ICE vehicles when measured for urban cycles. The plug-in hybrid option potential allows even much greater emissions reductions" particularly if the electricity is generated from low carbon technologies and/or lingo-cellulosic biofuels are used. The technology, as the vehicle manufacturers often note, is a natural stepping stone to the fuel-cell electric vehicle in which the fuel cell is in essence a replacement for an ICE-electric generator assembly in the hybrid vehicle.

(d) The Incremental Costs of Policies for Low Carbon Vehicles

Overall therefore the technologies for a low carbon transport system are emerging, and there is the opportunity for the Government to embark on a more ambitious policy of carbon abatement in the transport sector. To meet its long-term targets the UK will need to scale-up the incentives with respect to both carbon pricing and support for innovation.

1. ***Carbon Pricing***. A carbon price in the range of £100-200/tC (€40-80/tC) would increase the price of petroleum fuels in the UK by approximately 7½ to 15 p/litre—the latter figure being only half the incentive as that provided by the current fuel duty allowance and the RFTO together. By itself this would be barely sufficient to encourage substitution to biofuels (see table 9), with some exceptions such as ethanol imported from Brazil. This is, however, assuming an oil price of $50/barrel, and the net incentive for substitution is of course very sensitive to oil prices. An oil price of $70/barrel for example would raise the ex-refinery costs of oil fuels by approximately 12 p/litre (depending on the refiners' margins), raising the net incentive for moving to biofuels to a range of ≈ 20-30p/litre. This would provide a significant incentive for substitution *if* oil prices were expected to remain at such levels.

The carbon price penalty would also need to be applied to biofuels in proportion to the CO_2 equivalent emissions arising in their production. This would diminish the incentives for some categories of biofuels—sugar beet, cereals and rapeseed in particular, which have high levels of CO_2 equivalent emissions varying from 20 to 80% of those of the petroleum fuels they would displace (Table 9).

Ligno-cellulosic fuels, on the other hand, would have a much lower penalty, and as discussed above are more promising longer-term option, both from an economic and an environmental perspective. Hence a rigorously applied carbon pricing regime would work directly in favour of the latter—a highly desirable and rewarding feature of pricing carbon directly.

2. ***Innovation policies***. Even at £200/tonne carbon pricing alone would not be sufficient to effect the transformation required. It would be barely sufficient to encourage the long-term production of first generation biofuels, once an allowance is made for the greenhouse gases emitted in their production and distribution, while the second generation biofuels are still in the development phase. Table 12 shows a recent comparison of costs and prices of biofuels, taken from an analysis of Jeremy Woods; estimates of the costs of hydrogen fuels are also shown:

Table 12: Relative Prices and Costs of Petroleum Fuels and Biofuels, p/litre

	2007	**Estimate, c2030**
Petroleum Fuels:		
• Market Prices at $50/barrel (f.o.b.)	22-30	
• Market Prices at $70/barrel (f.o.b.)	45-60	
Biofuels. Basis:		
• Sugar cane	15-32	15-22
• Corn	37-50	22-28
• Beet	37-50	25-38
• Wheat	44-60	28-40
• Lignocelluloses	50-70	10-38
Hydrogen fuels, including costs of distribution, *excluding* incremental vehicle costs:		
• From coal with CCS	55	25
• Electrolytic from low carbon sources	--	45 [b/]
Hydrogen fuels, including costs of distribution, *including* incremental vehicle costs:		
• From coal with CCS	140 [a/]	130 [b/]
• Electrolytic from low carbon sources	--	160 [b/]

Sources and basis of estimates: The estimates for biofuels are from a presentation by Jeremy Woods at a Royal Society Workshop on International Biofuels Opportunities, 24 April 2007. I have converted his estimates of US cents/litre to pence/litre using a purchasing power parity rate of $1.6/£.

The costs of hydrogen fuels are estimated in the spreadsheet used for this study, to be made available on the IPPR website. See Annex 7 for the basis of the estimates.

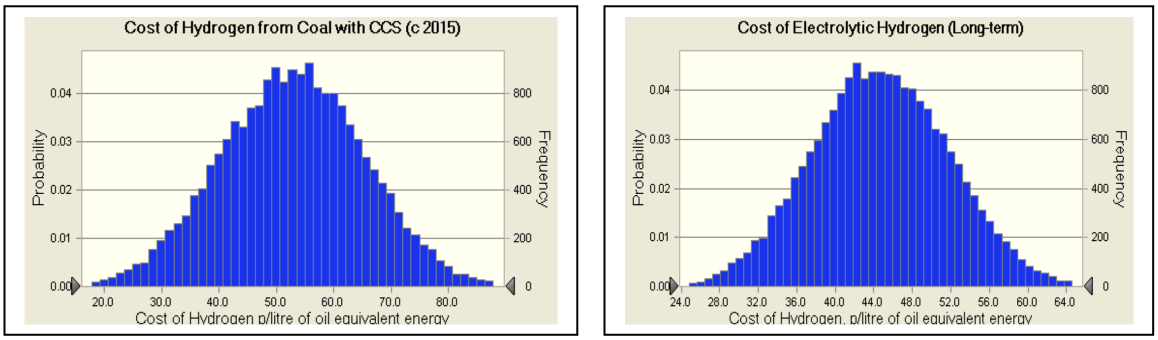
a/ Using an internal combustion engine
b/ Fuel-cell vehicle. These figures include an adjustment for the superior fuel efficiency of the fuel cell vehicle (see Annex 7).

Consider biofuels first. As can be seen, ethanol based on sugar cane (mainly imported from Brazil) can already compete at current oil prices. Biofuels based on corn, beet and wheat (and also rapeseed, not shown) would also become marginally attractive under an incentive of £200/tonne (roughly 15p/litre), though only if the greenhouse gas emissions associated with their production are ignored.

Such an incentive would be far too weak for biofuels derived from lignocelluloses: in the long-term the carbon price incentive would be sufficient to ensure continued production and use, but with cost differentials of 20-40 p/litre it is clear that some additional incentive to encourage innovation will be required. An obvious solution would be to ‘band’ the RFTO, and perhaps also the biofuel duty allowance, to provide a greater incentive for lignocellulosic biofuels. As carbon pricing is being phased-in the RFTO could be phased out for first generation biofuels but retained for second generation biofuels—and also hydrogen derive from carbon-neutral technologies. These possibilities are discussed further below.

Turning to the costs of hydrogen, there are two features that are of interest for policy. The *first* is that the estimated costs in energy units (£/GJ or p/litre of oil-equivalent energy), when the hydrogen is derived from coal gasification with carbon capture and storage, are comparable to those of first generation biofuels—being equal to the costs of petroleum fuel at about $70/barrel and 25p/litre higher at $50 per barrel (Table 10). These estimates allow for the distribution as well as the production of the hydrogen fuels (see Annex 7). Over the long-term, the costs may fall somewhat below those of petroleum fuels. The probability distributions are however very wide (see Figure 9).

Figure 9: Cost of Hydrogen from Coal with CCS (near term) and Electrolysis (long-term)



The *first* point then is that vehicle *fuel costs*, if there were to be a transition to hydrogen as a fuel, will be similar to those experienced today. The same point applies to the use of biofuels based on lignocelluloses (Table 10).

The *second* point is that the main additions to costs are those of developing the new vehicle technologies, whether it is the hydrogen vehicle using an internal combustion engine or a fuel-cell. Estimates vary in the range £3,000-5000 per vehicle (passenger car) in the medium term to £1,000-2,000 in the long-term for a hydrogen vehicle using an internal combustion engine. For fuel cell passenger-car vehicles, the added costs are estimated to be £4,000-6,000 in the medium term and £1,500-2,000 in the long-term (see Annex 7). It is evident that substantial incentives in support of innovation in the markets for low carbon vehicle will be needed if these vehicles are to be developed and used.

The same conclusion applies to the development and use of hybrid and other low carbon vehicle technologies. The Government has recognized this in its graduated vehicle excise duties. In 2008 "the most polluting cars" are to be taxed at £400/car. The problem is that this incentive is much too low to encourage substitution. The premium price of hybrid cars is in the range £2,500-3,600 according to the E4Tech report. We are in need of a statistical and engineering analysis of costs in the UK context, on the lines provided by the CONCAWE studies to arrive at a more precise estimate of the incentives required. But the over-riding conclusion is that the incentives will need to be substantially increased.

6. Conclusions and a List of Recommendations

Many studies have shown that the technological options for mitigating climate change are (a) available and (b) capable of being developed much further. They are well summarized in the recent UK Energy White Paper (2007), the Energy Review (2002), the Energy White Paper of 2003, a report by the International Energy Agency (2006), the Stern Review (2006), Vattenfall (2007), the World Energy Assessment by the UNDP and World Energy Council (2000) and several academic studies, of which that by Pacala and Socolow (2004) has been especially influential. The technologies include the full range of renewable energy forms, the use of fossil fuels with carbon capture and storage, nuclear power, new energy carriers such as hydrogen, and a very large number of options for improving energy efficiency.

With some exceptions (the possibilities for improving energy efficiency being the most commonly cited examples) the costs of turning to low carbon technologies are higher than those of the fossil fuels they would displace, even on the assumption of high fossil fuel prices. The disparities, however, are not such as to make the costs of turning to these technologies prohibitive. In fact, as the Stern Review and the preceding analysis have shown, the effects on economic output would be small over a long time period:

- For the UK Government's target of 60% carbon abatement relative to 1990 levels by 2050 it is estimated below that the annual costs would rise steadily to around 0.8% of GDP over the next 20 years, to 1.2 ± 0.5% of GDP in the long-term.

- For the more demanding IPPR-WWF trajectory of 90% abatement by 2050 they are roughly twice these levels, with a much greater commitment in the near and medium term than is required by the Government's own target.

These estimates are consistent with those of many other studies, using different methods of approach based on economic modeling, and are similar to those of a parallel study to this report headed by Neil Strachan of the Policy Studies Institute, which will be reported on separately.

Nevertheless, the disparities in costs between the low carbon technologies and fossil fuels are such as to require appreciable economic incentives for investments in the former. With the partial exception of the newly banded Renewables Obligation for electricity generation, however, the incentives in place or under review *fall seriously short of what is required if the Government is to meet its targets—in the near-term, in the medium-term, and in the long-term*—let alone the more demanding trajectory that the IPPR and WWF have reasonably proposed is necessary.[32]

[32] An identical conclusion was reached at a recent Engineering Forum for Energy hosted by the Institute for Energy and Technology on behalf of the UK's leading engineering institutions. See the report by Georgia Nakou in the IET's Journal, Vol. 2 no. 7, July 2007, p 18-19. ' "More carrots and stronger sticks" was one of the key messages'.

Enough is now known about the costs of the technological options, and of the factors that bear on the returns to investments in them, to make an approximate assessment of the incentives required, and of how they might be financed. This is what has been attempted above, *not*, it is emphasized, with the immodest ambition of providing definitive answers, but of indicating how much further policies will need to go if the Government's (and possibly yet more stringent) targets are to be met.

In summary, the recommendations are as follows:

1. *Carbon Pricing*. A comparison of costs shows that there is not a single low carbon technology for supplying energy for which the *expected* costs are lower than those of the fossil fuel or 'marker' technologies it would displace, aside from some 'niche market' applications not discussed in this report. Higher prices for oil and would change the picture for some technologies, as would assumptions at the optimistic ends of the ranges of costs considered in this report. *Overall, however, policies will need to aim for carbon prices at the upper end of the range £100-200/tonC (€40-80/tonneCO_2) if substitution to low carbon technologies and practices is to be encouraged*. A carbon price of £100/tonC for example would add only 0.6 p/kWh to the price of gas-fired generation (which would become the marker technology under carbon pricing), and 7 p/litre of petrol and diesel fuels; in neither case this would this be sufficient to encourage substitution on the scale required.

The recent collapse of the carbon price under the EU-ETS from a peak of €35/tonC to nearly zero shows that the 'caps' under the National Allocation Plans will need to be tightened appreciably in the next round of negotiations. In addition, the scope of the ETS needs to be extended. The Government rightly plans to pursue carbon pricing through the EU-ETS, and seeks to have the ETS extended to more fuels, including petroleum fuels for road transport and aviation. There also needs to be a commitment to extend the ETS to gas markets for heat in industry and homes.

2. *Importance of Incentives for Innovation*. In addition to carbon pricing, there needs to be further incentives (a) for innovation for technologies in their earlier phases of development, and (b) to diversify the portfolio. For many years, such incentives have enabled governments to exercise considerable discretion over the directions of national policies; they have been by far the most important influence to date on the emergence and development of low carbon technologies. There is not a single low carbon energy supply technology in existence today, other than natural gas, that does not owe its emergence to incentives for innovation. The economic case for such incentives rests on the positive externalities of innovation, as discussed in Part 4 above. But there is also a political-economic case, which is that Governments in all OECD countries have been able:

(a) To win political and public support for innovation policies, and

(b) To find means of financing the policies without relying extensively on direct recourse to the public revenue.

The Energy White Paper is therefore right to emphasise the importance of innovation policies. The rest of the following recommendations are concerned with the details of innovation policy in the UK. The tension between these kinds of interventions and the ideals of energy market liberalisation is self-evident, and has led to objections to the Renewables Obligation in the case of electricity supply from no less an authority than Ofgem. But it is difficult to see what the alternatives are if a low carbon energy system is to be achieved.

3. *Electricity markets: the Renewables Obligation*. The RO is to become a moving target, always keeping ahead of the amount of renewable energy generated up to 20% of supply. It is also to be 'banded' so as to provide a greater incentive for investments in renewable energy technologies in an earlier phase of development. These are big steps forward. The main issue relates not to those technologies sufficiently developed to benefit from the 'bands', such as offshore wind and perhaps the Severn Barrage, but to technologies still in a developmental and demonstration (RD&D) stage. They will continue to depend on the grants available from Treasury allocations, which on account of the many pressures on the public revenue are bound to fall short, as in the past, of what is needed. But is this dependence necessary?

An obvious solution would be to create a *'pre-ROC' band of grant finance* out of the revenues recycled from the buy-out payments of the RO. These revenues are recycled to the suppliers of renewable energy to further encourage investment and innovation. They are an elastic source of funding: they are currently about £140 million per year, and will probably rise to over £400 million per year in the next few years. The latter is 20 times current public expenditures on energy R&D, which have declined precipitously over the past 20 years. A relatively modest adjustment to the policy of recycling the revenues would permit an appreciable increase in energy RD&D programmes—and would also relieve pressures on public RD&D budgets elsewhere. The policy would also be logical application of the RO, which is intended to support innovation.

4. *Carbon Capture and Storage*. The Government is to provide grant finance to support a commercial scale (over 300MW) carbon capture and storage project. However, there are several CCS concepts that need to be demonstrated involving pre- and post-combustion and the production and use of hydrogen. A dozen other projects are being developed elsewhere in the EU and others in the US. There is much interest by industry in the development of the technologies. The reliance by the UK on single-project-grant-finance brings with it the dangers of micro-management and of stifling industry interest in the development and use of the technology.

A better approach would be to introduce an incentive such as a feed-in tariff premium of approximately 3p/kWh for industry to engage in the demonstration of the technologies. It would be phased out once the demonstration phase is over and superseded by the incentives provided by carbon pricing.

4. *Gas and Heating Markets*. Policies to stimulate investment in low carbon fuels in the gas and heating markets are less well developed than those for electricity. They lack

- The incentives of a carbon price
- A counterpart to the RO programmes in electricity and transport to support innovation directly.

There are a number of initiatives to support RD&D, but these too are mild.

The main emphasis in the EWP is on the improvement of energy efficiency, the use of low carbon electricity for heat, and the finance of demonstration programmes in low carbon buildings and distributed energy. There are also to be a number of regulatory reforms to provide "more clarity on the terms offered by energy suppliers to reward micro-generators for the excess electricity they produce and export … [and to make it] easier to connect to and use the distribution network."

There are several ways by which these policies could be strengthened, which would also act to develop links with the electricity and transport sectors:

- The extension of the EU-ETS to gas for heat in industry and for use in homes would be a big step forward, acting to encourage efficiency and provide an extra incentive for the use of low carbon electricity for heat and CHP. As to direct support for innovation three further possibilities are:

- To include micro-CHP in the higher bands of the RO. Analyses of long-term costs consistently find such decentralised energy forms to be amongst the most promising of the long-term low carbon technologies. The EWP has rightly placed much emphasis on them, but has not found a way of moving *beyond* the demonstration programmes it proposes.

- A demonstration programme for the use of hydrogen as an energy carrier and storage medium. This could be done in association with the demonstration programmes for CCS, since at least one of the main pre-combustion technologies will involve the production of hydrogen. Engineering studies have shown for sometime that the production of hydrogen from coal would be a low cost pathway to open up the 'hydrogen economy'. It is estimated that the current gas networks would be able to accommodate up to a 20%/80% hydrogen/natural gas mix. If this is the case, the natural gas infrastructure could gradually be converted to becoming suitable for hydrogen transmission and distribution as it is being renewed over the next 50 years.

- To provide incentives for the possible emergence of 'virtual utilities' for the management of decentralized energy forms, both for electricity and heat.

These would also be stepping stones to the integration of the electricity and gas/heating markets. It is likely that, the more decarbonised the energy system becomes, the more connected the electricity and heating markets will need to be both for centralised and decentralised energy supplies. Indeed, energy market integration may go further than this, since both electricity and the gas markets (the latter in the form of hydrogen) will eventually become, again in a low carbon energy system, the main suppliers of transport fuels.

5. *Transport.* For road transport low carbon vehicles and fuels are emerging, and from a technological viewpoint there is no reason why very high levels of carbon abatement cannot be achieved. The Energy White Paper recognizes this and provides an informed review of options, but there is a lack of urgency in the policies put forward, and they will not lead to the level of carbon abatement sought by Government. Emissions from transport today are around 45 MtC/year, and in surface transport alone could easily grow by 10 MtC/year by 2020. In contrast the EWP estimates that the savings from measures currently in place would be 2-5 ½ MtC per year, barely enough to offset one half of the increase of emissions in the next 15 years. Emissions are thus likely to rise with income growth under current policies. Incentives of the following orders are needed if transport is to contribute effectively to meeting the UK's targets:

(i) *Carbon Pricing and petroleum fuels*. The UK is rightly seeking to see carbon pricing extended to road transport, and also to aviation. It will take a carbon price of around £200/tonC (€80/tonCO_2 equivalent) to make a significant difference in the choice of fuels. This would raise the price of petroleum fuels by approximately 15p/litre, which is about half the incentive currently provided by the RFTO and the fuel duty allowance on biofuels in current policies.

(ii) *Carbon pricing and biofuels*. Some biofuels—and first generation biofuels in particular—are associated with significant greenhouse gas emissions in their production and should not qualify for 100% exemption from the carbon price (see Part 5).

(iii) *The RFTO and the fuel duty allowances on low carbon fuels*. As with the RO for electricity generation these allowances need to be extended and banded. They currently only apply until 2010-12, which is not a sufficient incentive to support long-term investments in bio-refinery capacity and the development of second generation biofuels. The RFTO and duty allowances could be phased out for first generation biofuels once carbon pricing takes root, as they are a mature technology, but retained for the production and use of second generation biofuels.

(iv) *Hydrogen.* The intention should be declared to extend the RFTO to the use of hydrogen as a vehicle fuel, perhaps as a higher band in the Obligation, once hydrogen vehicles and hydrogen production from coal as part of the CCS projects have passed through their demonstration phase.

(v) *Development assistance and the sustainable production of lingo-cellulosic biofuels*. The current incentives for first generation biofuels pose the dangers of exporting environmental problems to developing regions and of putting pressures on food prices in low income regions; indeed there is evidence from the US of this happening already. The tragedy would be that there is an economically and environmentally attractive alternative, which is to base biofuel production in developing regions on the reclamation of degraded lands and watersheds. Again, lingo-celluloses would be the basis, for example through agro-forestry and afforestation programmes. This would actually benefit the environment and agriculture over very large areas. The approach could be stimulated by use of the CDM, the Clean Energy Investment Framework of the multi-lateral development banks, and the bilateral aid agencies.

The strategies of the UK and the EU for harnessing biofuels for transport therefore need to be re-assessed with this possibility in view, and reviewed with the national and international development organizations.

(vi) *Incentives for low-carbon vehicles*. The introduction of vehicle excise duties for low polluting vehicles has opened up a new and potentially important incentive for innovation. Looking at the extra costs of hybrid and plug-in hybrid vehicles, however, and at the prospective costs of the hydrogen-fuel cell vehicles, the incentive needs to be increased substantially. We are in need of a statistical analysis of the costs to estimate the precise incentive required more reliably. But it will probably need to be in the range 5-10 times higher than the current duties, which are to be £400/vehicle in 2008. Such incentives could be introduced in a revenue-neutral way by taxing conventional high-fuel consumption cars more and offering tax credits on the low carbon options.

(vii) *R&D, demonstration and procurement programmes*. Once again, the scale of what is proposed seems small in relation to the problem in hand. The question was raised above whether the £5m per year grant to the ETI will be sufficient to support a “new innovation platform for low carbon vehicles”, even when it is weighed along with the £5.5 m per year of funding to support R&D into low carbon vehicle and fuels. As with the RO for electricity there is an opportunity to expand such funding *if* there is a willingness to recycle revenues from the RTFO to these ends. The RTFO is ideally seen as an incentive for innovation; it would be a logical step to allocate a portion of the revenues from the buy-out payments to the development of options that have passed through their demonstration phase.

It has proved to be beyond the scope of the present study to cover other possibilities for achieving a low carbon transport system. Probably the most important is congestion pricing, to which there is a substantial commitment in the EWP and the strategy paper of DfT. This is a ‘win-win’ option, which has long been recognized to be a source of economic and environmental improvement by reducing the externalities of congestion. The calculations over 10 years ago by Maddison, Pearce and others (1996), and in the World Development Report of the World Bank (1992), both showed that external benefits of such policies are exceptionally large.

There is also a need for an econometric analysis of the scope for carbon abatement through energy efficiency. Current analyses of the options, for example those of the IEA (2006), the background studies for the Energy White Paper and a number of earlier government studies are based on engineering-economic analysis of options; they suggest that the scope for carbon abatement through energy efficiency is much greater than is implied by the income elasticities in the energy statistics. It is the econometric studies that are lacking, since they fail to distinguish between the contributions of technical progress in energy efficiency from those of income growth and prices. This shortcoming has been known for many years (see Grubb et al, 1993). A simple exploratory calculation presented in Part 4 this report served to show how important a clarification will be to improve our understanding of costs and policies.

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Annex 1: Cost Adjustments to Allow for Load Variation in Electricity Supply

The unit cost estimates for electricity generation are average costs assuming plant generate continuously at the full available capacity. Hence adjustments are needed to provide for load variations, including the need for standby capacity at peak, and, in the case of intermittency generation for the extra backup capacity requirements they require. Adjustments are already included for the added costs of intermittency, following the methods outlined in my working paper for the UKERC (Anderson, 2006). This leaves us with the need to allow for load variations.

There are two approaches. One is the long-familiar one of using load duration curves and simulating the operation of the system; such an approach is used by the MARKAL model, results from which have also been consulted and compared with those of this study. For the purposes of this study, however, a simpler approach has sufficed. This is to begin with the average costs assuming that plants are operating their expected available capacity (= average plant factor times installed capacity for intermittent plant) and then to add the extra capacity and energy costs of meeting the load fluctuations as follows.

The formula used for estimating the extra capacity costs is:

$$\Delta C = \left((1+m)\cdot \hat{D} - E/8760\right)\cdot \Delta s \cdot (C_l - C_f)$$

Where m is the capacity margin for uncertainties in demand and plant availability (m is typically 20%), $\hat{D}$ is the expected peak demand, E the energy output and $E/8760$ is the equivalent continuous power output of plant i, and C_l and C_f are the annuities on the capital costs of the plant operating over the peak and intermediate load periods in low-carbon and thermal systems respectively; Δs is the difference in the share of low carbon technologies in system output when a low carbon system is compared with a thermal one.

For a thermal-system the plant usually brought into operation during off-base load periods is usually a mix of coal and gas fired plant that has been moved down the merit order and gas turbines for peaking. Assuming capital costs in the range £400-600/ kW and taking an average of £500/kW this gives an annuity of approximately £55/kW/yr (10%, 30 year lifetime) with an annual fixed maintenance cost of ≈ £35/kW/yr. C_f ≈ £90/kW/yr is used as a basis. For a low carbon system, the system will be much more capital intensive since it will include require coal with CCS taking up much of the variability demand, plus the contributions of intermittent generators when operating in above-average wind conditions, and probably gas turbines for peak. Taking £1000/kW plus annual fixed maintenance costs of £70/kW/yr as a basis, gives C_l ≈ £175/kW/yr and $(C_l - C_f)$ ≈ £85/kW/yr.

The extra energy costs over the peak and intermediate load periods are likely to decrease with the increasing shares of carbon-neutral generation on the system. Approximately 0.3 of the energy supplied is from non-base load plant. The formula used was:

$$-0.3E \cdot \Delta s \cdot F_f$$

Δs is now the rise in the share of low (≈ zero) running cost energy on the system and F_f the marginal running costs of the fossil fuels displaced.

Annex 2: Statistics on Energy Use in the Electricity, Heating and Transport Markets in the UK

Electricity Markets

The rate of growth of demand for electricity has been declining systematically for over four decades. In the 1960s it was 6.8% per year, By the 1970s and 1980s it had declined to 1.8% per year, by the 1990s 1.5% per year and today it is around 1.2% per year. A decline in the real costs and prices of electricity up to the 1960s helps to explain some of the expansion[33], but the main source of growth was the growth of demands from industry, commerce and domestic consumers (Table A-2.1) Income elasticities up to the 1960s were probably in the range 2.0-3.0, today they are around 0.5 and declining.

Table A-2.1: Statistics on UK Electricity Consumption, TWh/year

Year	Industry	Domestic	Other	Total
1960	45	34	21	**99**
1970	72	77	42	**192**
1980	79	86	58	**224**
1990	100	93	80	**274**
1999	110	110	101	**321**
2005	118	116	101	**345**

Source: Digest of UK Energy Statistics, 2000 and 2006.

The reasons for the changing elasticities merit econometric analysis. The traditional economic characterisation of energy demands is of the form:

$$D_t = kY_t^{\gamma} P_t^{-\beta} \qquad (1)$$

D, *Y* and *P* represent demand, income and price respectively, *k* is a constant and γ and β are elasticities. However, it is likely that technical improvements in energy efficiency exert a downward shift in demand independent of price and income effects such that the function is better characterised by the following, where λ is the rate of reduction of demand attributable to improvements in energy efficiency and α is re-defined income elasticity:

$$D_t = ke^{-\lambda t} Y_t^{\alpha} P_t^{-\beta} \qquad (2)$$

It is evident from a comparison of (1) and (2) that estimates of income elasticity in (1) combine an income effect with a technical progress effect, since if *g* is the rate of economic growth then:

$$\gamma = \lambda + \alpha \cdot g \qquad (3)$$

[33] As in other markets, we are short of estimates on price and income elasticities.

The shift term represented by α is itself a function of price variables requiring separate analysis—the costs of the hybrid car for instance, of home insulation, high efficiency lighting, and so forth. We are still in need of such an analysis.

Heating Markets

Heating markets up to the 1960s were dominated by coal, whereas today they are dominated by natural gas. The overall effect of the substitution has been to *reduce* the aggregate demand (in energy units) by roughly 20% for the energy supplied by the two fuels over the past 45 years, notwithstanding the growth of incomes and wealth in the period. Central electrical heating may account for some of the decline, as may the decline of heavy industries. But further factors include the greater efficiency of gas over coal as a source of heat in homes and industry, and gains in energy efficiency (loft insulation, the utilization of 'waste heat', central heating, double glazing, improvements in processes, etc). We are still in need of an empirical study to identify the various effects. The raw statistics are displayed in the following table:

Table A-2.2: Energy for Heating Markets: 1960-2005. Units of TWh/year

	Gas: total consumption	**Of which: gas for electricity**	**Coal for heat (excl. town gas & electricity)**	**Fuel oil and 'burning oil'**	**Gas - gas for electricity**	**Total Heating = Gas - gas for electricity + coal + fuel oil**
1960	80	0	696	228	80	932
1970	172	2	352	492	170	1014
1980	508	4	152	264	504	920
1990	597	6	96	168	591	855
1999	1065	313	48	72	752	872
2005	1056	354	24	40	702	766

Source: UK Digests of Energy Statistics (2000 and 2006). The coal statistics were converted using 8000kWh/ton of coal and 12,000kWh/ton oil. The main source of gas up to the early 1970s was town gas, which since then has been phased-out altogether.

The last column of the table nets out the use of gas for electricity production, and is approximately the total demand for heat from industrial, domestic and commercial consumers. This has declined at approximately 0.4% per year, despite a growth of real incomes of around 2% per year over the period such that the income elasticity was around -0.2, perhaps less.[34]

[34] Such estimates need to be adjusted econometrically for price effects, estimates of which are unfortunately not available so far as I know. In real terms prices have probably declined once one allows for the costs and inconvenience of using coal in homes and industry. In this case, the 'rebound effect' might lead us to the expectation that the demands should have risen. Add to this the effects of income growth; the income elasticity of the demands for the 'services' of heat—warmth in homes etc—are almost certainly significant. Perhaps, once an allowance is made for electrical heating, the primary demand for energy in heating markets may be found to have risen over the period. However, the hypothesis that energy efficiency has led to a decline in the demand for primary energy over the past 40-50 is worth exploring, as are a variety of alternative explanations.

It is necessary, however, to distinguish between household, commercial and domestic consumption since patterns of consumption have changed appreciably in all three cases. The following table provides data for the use of coal and gas:

Table A-2.3: The Use of Coal and Gas for Heat in Homes, Industry and Services: 1960-2005. TWh and %.

Year	Domestic			Industry			Services		
	G%	C%	Total	G%	C%	Total	G%	C%	Total
1960	9	81	**398**	8	92	**313**	25	75	**64**
1970	36	64	**283**	21	79	**202**	49	51	**47**
1980	77	23	**319**	73	27	**241**	82	18	**73**
1990	90	10	**332**	77	23	**212**	92	8	**87**
1999	94	6	**380**	89	11	**223**	98	2	**123**
2005	96	4	**395**	91	9	**163**	100	0	**163**

Source: UK Digests of Energy Statistics (2000 and 2006). Gas supplies in the years 1960 and 1970 include town gas, which had been phased-out completely by 1980.
G = Gas, C = Coal

The striking feature again is how rapidly gas replaced coal in the period. The overall use of heat dipped with the initial substitution in all three sectors. It has continued to decline in industry, rise very slowly in homes and increase quite rapidly in services.[35] The aggregated income elasticity of demand for gas as a source of heat, assuming industrial demands have bottomed out, is very low, around 0.2.

Transport Markets

Table A-2.4: UK Consumption ofFuels for Transport. Million tonnes per year

	Motor Spirit	Diesel	Subtotal: motor spirit and diesel	Aviation turbine fuel	Total
1960	7.9	2.6	**10.5**	0.8	**11.3**
1970	14.2	5.0	**19.2**	3.2	**22.4**
1980	19.2	5.9	**25.1**	4.7	**29.8**
1990	24.3	10.7	**35.0**	6.6	**41.6**
1999	21.5	15.2	**36.7**	9.7	**56.4**
2005	18.7	26.1	**44.8**	12.5	**67.3**

Source: Digest of UK Energy Statistics (2000 and 2006)

The growth rate for motor fuels is about 1.7% per year—about a third of the rate of growth in the very high growth period of the 1960s, when it was 6.2% per year nearly doubling every decade. The income elasticity is around 0.8 and declining. For aviation fuels the growth rate in the period 1990 to 2005 was about 4% per year an income

[35] Again the statistics need adjusting for the use of electricity for heat in homes, industry and commerce. I have also not been able to separate out burning oil use as between industry, commerce and homes, though looking at DUKES (statistics in chapter 3) it appears to have declined. These adjustments will have to be left to a later exercise.

elasticity of nearly 2.0, about the same as for the period 1970-1990. For aviation, the period of declining income elasticities of demand has not yet begun; the elasticity is ~ 2.0 for the period 1990-2005, about the same as for the period 1970-1990.

Annex 3: Calculating Emissions in the 'Without' Scenario

(a) With Nuclear Power

The scenario without abatement takes the case of no new investment in low carbon technologies beyond those in place in 2005, though it does allow for their replacement. In the case of electricity, the TWh generated and output shares were as follows:

	TWh	% Total
Coal	140	35
Gas	155	39
Low Carbon:	101	0
Of which:		
Coal-Carbon Capture and Storage	0	0
Nuclear	85	22
Biofuels	8	2
dCHP	0	0
Solar	~ 0	0
Wind (onshore and offshore)	3	1
Hydro and marine	5	2
Total	396	100

Let the initial outputs from coal, gas, and the sum of outputs from other low carbon technologies be denoted by C, G and N respectively, and the total output by T, with the subscripts 1 representing the initial year and 2 any other year. Since there are greenhouse gas emissions from the production of biofuels (e.g. from fertilisers and energy use in delivery), it is necessary to distinguish their outputs, B, from those of other low carbon technologies. Other technologies—coal and gas stations, wind, solar, nuclear and so forth—also have emissions in their construction but to a first approximation their aggregate value is assume to be the same in both the with and without scenarios; emissions in the transport of these fuels are assumed to be captured in the emissions calculated in the oil markets. Then:

$$C_1 + G_1 + B_1 + N_1 = T_1$$
$$C_2 + G_2 + B_2 + N_2 = T_2$$

In the without scenario $B_2 + N_2 = B_1 + N_1$ and it is necessary to raise the outputs from coal and gas to levels denoted by C_2^* and G_2^*. The scenario assumes their use remains in the same ratio to total output as in the initial year such that $C_2^* / T_2 = C_1 / T_1$ and $G_2^* / T_2 = G_1 / T_1$. Denoting the emissions per unit output by θ with subscripts c, g, and b representing coal, gas and biomass, total emissions, E, in the two cases are:

$$E_2 = \theta_f C_2 + \theta_g G_2 + \theta_b B_2$$
$$E_2^* = \theta_f C_2^* + \theta_g G_2^* + \theta_b B_2^*$$

For coal and gas the emissions co-efficients are roughly 0.31 and 0.125 MtC per TWh. For biomass, they are taken to be 0.21 times the fraction of emissions emitted attributable to harvesting and transport (about 0.1 if the fuel is combusted), giving a co-efficient of 0.021 MtC per TWh. From these relationships:

$$E_2^* = \frac{T_2}{T_1}\left\{\theta_f C_1 + \theta_g G_1\right\} + \theta_b B_1$$

The overall abatement is $E_2^* - E_2$. These savings are allocated across the individual technologies in accordance with their shares in the total output of low carbon technologies, with an adjustment for biofuels, what are given a weight of 0.9 (1.0 minus the emissions fraction).

The same approach was used for the other sectors.

(b) With nuclear power (or any other technology) being gradually phased out.

The approach is simply to calculate the energy required from the alternative low carbon sources to compensate for any reduction in the contribution of and to use this as a balancing item. This is apportioned among the rest of their low carbon technologies in any year in proportion to their relative contributions to total output.

Annex 4: Estimates Used for Figures 3 and 4 in the Text

Table A-4.1: Costs of Abatement as a % GDP for the UK 60% and IPPR-WWC Scenarios *

Case	2015	2025	2050
Excluding Water Vapour from Aviation:			
60% abatement			
• with nuclear power	0.35	0.77	1.28
• without nuclear power	0.53	0.89	1.40
IPPR-WWF			
• with nuclear power	0.45	1.36	1.79
• without nuclear power	0.71	1.61	1.91
Including Water Vapour from Aviation:			
60% abatement			
• with nuclear power	0.66	1.03	1.85
• without nuclear power	1.05	1.26	1.96
IPPR-WWF			
• with nuclear power	0.76	2.70	2.35
• without nuclear power	1.23	2.95	2.47

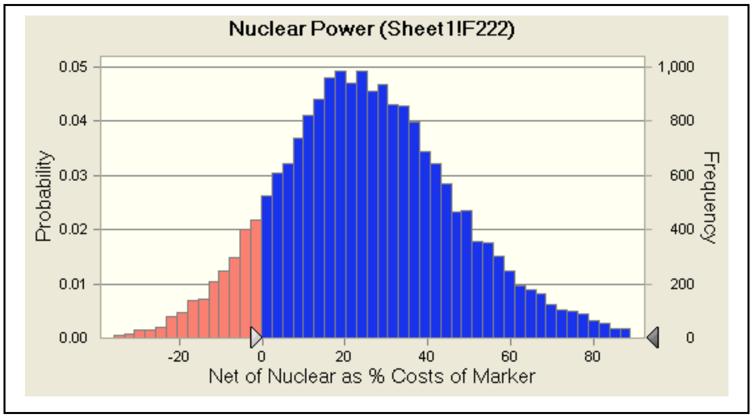
Table A-4.2: Average Incremental Costs of Abatement in £/Tonne C for the UK 60% and IPPR-WWC Scenarios *

Case	2015	2025	2050
Excluding Water Vapour from Aviation:			
60% abatement			
• with nuclear power	218	277	254
• without nuclear power	332	323	277
IPPR-WWF			
• with nuclear power	207	268	288
• without nuclear power	323	319	307
Including Water Vapour from Aviation:			
60% abatement			
• with nuclear power	196	234	288
• without nuclear power	315	287	306
IPPR-WWF			
• with nuclear power	193	402	311
• without nuclear power	313	439	326

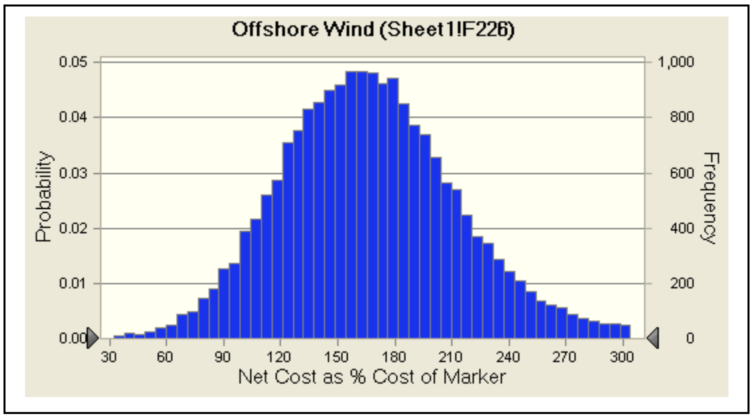
*The estimates to three significant figures in the table are not intended to indicate precision but to avoid rounding errors. The probability distributions are in fact very wide, as discussed in the text.

Annex 5: Probability Distributions of Costs of Selected Low Carbon Technologies Relative to their Marker Technologies

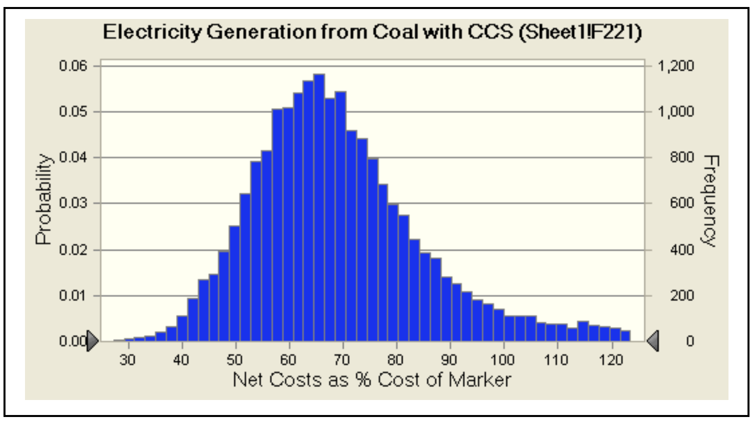
(a) Nuclear Power



(b) Carbon Capture and Storage



(c) Electricity Generation with Carbon Capture and Storage



Annex 6: Costs of Hydrogen and Hydrogen Vehicles

The estimates of the capital costs of the technologies for hydrogen production have drawn on the studies of the US National Academy of Sciences (…) and Ogden (…). These were combined with assumptions of fixed annual maintenance costs, plant lifetimes, coal and gas prices and operating efficiencies to arrive at an average cost of production. For distributed hydrogen, the costs of distribution were based on discussions with industry during the preparations of the background studies of the 2003 Energy White Paper, and assumed to be 50% greater than those for distributing natural gas. It is also assumed that, rather than building a hydrogen infrastructure from scratch, the optimum policy would be to gradually make the gas infrastructure suitable for hydrogen distribution as it is renewed over the next 50 years. Engineers estimate that the current infrastructure could accommodate a up to 20/80% hydrogen/methane mix without dangers of embrittlement. Capital costs were given an error margin of ± 25%. A 10% discount rate was used, and US data were converted to £ using a $1.6/£ purchasing power parity exchange rate. A summary of the costs is given in Table A-6.1:

Table A-6.1: Estimated costs of Hydrogen in £/GJ

	Near-term	Long-term
Central Hydrogen:		
• Based on Natural Gas with CCS	9	8
• Based on Coal with CCS	8	6
• Electrolytic, based on nuclear power	20	14
• Electrolytic, based on intermittent renewable energy	26	20
Distributed Hydrogen:		
• Based on Natural Gas with CCS	16	14
• Based on Coal with CCS	15	13
• Electrolytic, based on nuclear power	27	21
• Electrolytic, based on intermittent renewable energy	38	27

The costs of hydrogen vehicles for the near term are taken from the report by COCAWE (…). For the long-term the estimates were supplied to the Stern Review, based on study by AEA Technologies. The estimates are shown in Table A-6.2:

Table A-6.2: Incremental Costs of Hydrogen Vehicles

Source of hydrogen (with CCS in case of coal or gas)	Incremental Vehicle Cost. £	Range
Coal or gas: ICE vehicle--2010	3900	±20%
Coal or gas: FC vehicle--2025	5000	±20%
Electrolytic Hydrogen FC vehicle--2050	5000	±20%
Coal or gas: vehicle--2025	2250	±20%
Electrolytic Hydrogen ICE vehicle--2050	1400	±20%
Coal or gas: FC vehicle--2050	1700	±20%
Coal or gas: ICE vehicle--2050	1400	±20%

To arrive at the total incremental costs, the extra capital costs of the vehicle are amortised over the lifetime of the vehicle and divided by 15,000 km/year, the assumed average distance travelled (Table A-7.3). For fuel-cell vehicles, the petrol equivalent cost includes an adjustment for their greater efficiency. For an ICE the assumed efficiency is 0.18 GJ per 100 Km; for a fuel-cell vehicle it is 0.07 GJ/100km (see CONCAWE report).

Table A-6.3 Costs of Hydrogen Vehicles Including Extra Capital Cost of Vehicle Relative to a Conventional Petroleum Fuelled Vehicle

			Cost per km			Cost, p/ltre of oil fuel displaced		
Source of Hydrogen	Vehicle life, yrs	Fuel £/GJ	Fuel p/km	Inctl cap. cost p/km	Fuel + Inctl. cap. cost p/km	Equiv. petrol cost p/litre	Δ Capital Cost p/litre	Total, p/litre
Coal or gas: ICE vehicle--2010	10	15.5	2.6	4.2	6.9	54.2	86.7	141.0
Coal or gas: FC vehicle--2025	10	13.1	1.1	5.4	6.5	21.6	111.2	132.8
Electrolytic Hydrogen FC vehicle--2050	10	27.1	2.2	5.4	7.6	44.6	111.2	155.8
Coal or gas: vehicle--2025	10	13.1	2.2	2.4	4.7	45.9	50.0	95.9
Electrolytic Hydrogen ICE vehicle--2050	10	20.5	3.5	1.5	5.0	71.7	31.1	102.8
Coal or gas: FC vehicle--2050	10			1.8		21.6	37.8	59.4
Coal or gas: ICE vehicle--2050	10			1.5		45.9	31.1	77.0

Annex 7: Illustrative Portfolios With Nuclear Power Nuclear Power Phased-Out. IPPR-WWF Scenarios