LONG-TERM REDUCTIONS IN GREENHOUSE GAS EMISSIONS IN THE UK

Report of an Inter-departmental Analysts Group (IAG)

February 2002

LONG-TERM REDUCTIONS IN GREENHOUSE GAS EMISSIONS IN THE UK

EXECUTIVE SUMMARY

Background

1 In June 2000 the Royal Commission on Environmental Pollution (RCEP) published an important report on the long-term challenges for UK energy and environmental policy posed by climate change. It makes 87 recommendations, to which the Government will respond in due course. Amongst its key recommendations is that the Government should now adopt a strategy which puts the UK on a path to reducing carbon dioxide emissions by some 60% from current levels by about 2050. This would be in line with a global agreement based on contraction and convergence which set an upper limit for the carbon dioxide concentration in the atmosphere of some 550 parts per million (ppm) and a convergence date of 2050. However, contraction and convergence is only one of a number of potential models which could help achieve the objectives that we are striving to fulfil.

Group's remit

2 In order to help inform the Government's response to this recommendation, and also thereby a number of the RCEP's other proposals, an inter-departmental analysts group (IAG) was set up whose remit was to consider:

- the scale of emission reduction implied by the RCEP's recommended 60% cut (taking account of potential future energy demands and energy mix);

- the options that might be available to fill this gap, and their associated costs;

- the implications for policy now if the prospect of meeting such a target at minimum or low cost is to be maintained.

3 Subsequently, a review of long-term energy policy, to be undertaken by the Performance and Innovation Unit (PIU), was announced. This had a broader remit than the IAG. We have therefore seen our role as helping inform the PIU's review with economic analysis of the implications and challenges in moving to a low carbon economy. The group has therefore deliberately not made recommendations on the long term objectives for energy policy, which falls to the PIU, nor on the

environmental science, covered by the RCEP, which is the responsibility of DEFRA.

Carbon gap

4 The rate of carbon intensity improvement (ratio of carbon emissions to GDP) required to meet a 60% CO_2 reduction target by 2050 would average 4.3% a year after 2010 (allowing for GDP growth of 2.25% a year). To put this in perspective it is:

- greater than the improvement expected over the period 2000-2010 (around 2.8% a year) which includes the impact of the Climate Change Programme (CCP);

- greater than the historic trend (around 3% a year 1970-2000).

5 UK emissions of CO_2 in 1997 amounted to 154MtC. Depending on the assumption made for a baseline projection of CO_2, by 2050 such emissions could amount to between 103 and 167MtC. So the projected gap against a 60% reduction target in 2050 ranges from 41-105MtC.

6 It should not be assumed that all sectors (domestic, industry, services and transport) be required to make a 60% reduction, since some sectors may be able to achieve such a reduction at lower cost than others. In practice, therefore, cost effectiveness and other considerations will mean that contributions will be likely to differ across sectors. But it is still useful to understand what a 60% reduction by sector would mean.

7 Transport has the greatest gap of any individual sector between historic performance and that required to reduce CO_2 by 60%. The rate of reduction required in industry to achieve a 60% reduction is broadly in line with the past trend. It is lower than the average requirement post 2010 reflecting that the CCP to 2010 includes significant reduction from industry. Significantly greater reductions in carbon intensity than delivered to date would be required of both the domestic and services sectors. The scope for further fuel switching in final demands may be limited, so energy efficiency improvement would have to increase by 2% (domestic) or 3% (services) a year more than we already have in the baseline.

8 The easiest reductions in non-CO_2 emissions have been made, and by 2020 non-CO_2 gases are only 14% of the GHG total. So we do not expect a greater than 60% reduction in non-CO_2 emissions could substantially and cost-effectively reduce the burden on CO_2 itself.

9 Emissions of non-CO_2 greenhouse gases have fallen by about a quarter since 1997 and are expected to be about a third below their 1997 level by 2020. If hypothetically the projected rate of decrease continued to 2050 emissions of these gases will have fallen by about 45%, and would then be equivalent to about 11% of total UK emissions in 1997. Therefore, although in the context of a 60% reduction in CO_2, additional measures might be introduced for non-CO_2 gases to give a balanced reduction effort, there is unlikely to be sufficient margin for further action on non-CO_2 gases to make a big difference to the need to reduce CO_2.

10 Similarly, whilst action to increase uptake by UK terrestrial carbon sinks could offset a few per cent of 1997 CO_2 emissions by 2050 it is very unlikely that sequestration by forestry and agriculture could be increased to offset a large fraction of a 60% cut, especially as the time to 2050 is long enough for sink enhancement measures taken early on to be approaching saturation. Forestry and agriculture could of course make larger contributions via biomass renewable energy schemes. Nonetheless, forestry and agricultural options offer some scope for increasing sequestration through no-regrets or low-regrets measures.

International issues

11 The Kyoto mechanisms will provide the right framework for cost-effective emissions reductions only if price signals work and are allowed to work. This means that the UK should look to work towards a future emissions trading scheme (both domestically and internationally) with minimal artificial constraints and the simplest possible rules. This will implicitly require that the schemes in the shorter term – consistent with sound carbon accounting – be seen as a success.

12 Key attention will need to be paid to the longer-term role of the developing countries, and to the nature and stringency of targets in the developed world. These will be the crucial determinants of what happens to the mechanisms.

13 In the long term, if developing countries are themselves taking on emission targets of similar stringency to others (as exemplified by the contraction and convergence methodology) then the UK cannot rely on there being substantial sources of cheap emission savings to buy in from others and supplement domestic action.

14 Even when the price signal works, the mechanisms provide only part of the required policy framework. They will not necessarily eliminate other market failures that may be holding back emissions-reducing technologies, and do not preclude the use of other policy tools.

15 In the same way that the RCEP path to 550 ppm implies a 60% reduction in the UK's current CO_2 emissions, it is possible to estimate the implied reductions for other developed countries. Key points from this are that:

- the US would need to reduce emissions by around 80%, and the EU by around 53% on 1998 levels;

- in terms of scale of reduction, in percentage terms the UK reduction is mid-table in both EU and G8 rankings;

- during the period from 1990 to 1998 the UK has improved its performance relative to the EU and G8.

16 At the international level, the UK will almost certainly not be looking to buy units of assigned amount (AAUs) in the first commitment period. But it may well be looking to sell or bank excess AAUs and we will be seeking to ensure in the relevant EU negotiations that any member states which over achieve their target have autonomy over any surplus they accrue.

17 Looking further ahead, the expected tightening of targets, coupled with a rising emissions baseline, could make it less likely that the UK will be in a position to sell – and we may then look to rely on purchases of AAUs from elsewhere. But this is not an inevitability and, as noted above, such substantial sources will not necessarily be available. It depends on the targets and emissions baselines of other countries relative to the UK. If the UK is among the leaders in developing low and no carbon technologies, it could develop a comparative advantage in emission reduction.

Costs of meeting the target - evidence from the literature

18 We have considered literature on the costs of moving to a lower carbon economy, including both top-down and bottom-up approaches. Each has uses in illustrating the scale of the challenge and each also has different weaknesses. The uncertainties in looking 20-50 years ahead are, of course, huge.

19 Top-down macro economic models tend to overstate costs of meeting climate change targets because, among other reasons, they take insufficient account of the potential for no-regret measures or large technical advances. Equally most top-down models ignore the benefits of climate change mitigation and present a gross economic cost estimate.

20 Technologically disaggregated (so called "bottom-up") models can take these benefits into account but may understate the costs of overcoming economic barriers.

21 The Working Group III of the Intergovernmental Panel on Climate Change (IPCC) has assessed the international work on both analytical approaches. DTI, DEFRA and the PIU have also commissioned work using the MARKAL model, a report of which will be available shortly. Modelling work tends to show that costs can be reduced if rules are flexible and a wide range of options is considered. In particular, measures such as trading can significantly reduce costs of achieving a target.

22 Estimated costs - such as those summarised in the report of Working Group III, IPCC - can look large, amounting to hundreds of billions or even trillions of dollars, depending on the assumptions made and time period considered. But this can also be looked at in terms of the percentage impact on GDP or GDP growth rates, taking into account that economic growth over the period might be between 2% and 3% per annum.

23 Macro models assessed by IPCC suggest that the cost in 2050 leading to stabilisation at 550ppm might be between 0.2% and 1.5% of GDP in 2050 (with GDP having tripled by then). There will be GDP losses in earlier years building up to these levels. Estimated costs would increase substantially for stabilisation levels below 550ppm.

24 However these global economic costs are viewed emission reductions may not be easy to achieve. There may be very substantial distributional implications. The modelling work reported above generally

assumes international action to meet targets. Costs for one country by itself may be very different. But with full trading estimated marginal costs of meeting Kyoto are found by IPCC to be typically $70/tC (range $50 to $140/tC) assuming US engagement. Costs could be much less without the US, although this will depend on the amount of so-called "hot air" that comes onto the market, on whether any alternative emissions reduction scheme introduced by the US is sufficiently compatible with Kyoto to allow partial engagement and on the degree to which sinks measures offset emissions reductions internationally.

25 It should be borne in mind that, while there will be abatement costs associated with emissions reductions, the wide-ranging impacts of climate change means that there will also be costs associated with inaction. Recent work by DEFRA indicates that a point estimate of £70/tC, together with a sensitivity range of £35-£140/tC, would be appropriate illustrative values to use for the estimated damage costs associated with current carbon dioxide emissions.

Where is the potential in the UK?

Energy efficiency

26 Within our baseline projections there is substantial improvement in energy efficiency. Savings of around a further 25MtC might be possible by 2050 at a cost reaching, at worst, £20-35/tC. In practice, actual costs could be much less. Past experience suggests that raising the take-up of energy efficiency measures is not easy but, even at these worst case levels, energy efficiency measures are likely to be competitive with other abatement options.

Renewables and other low carbon options

27 The practicable resource from renewables options by 2025 is large. Allowing for technological advance, but before additional systems costs around half to two-thirds of projected electricity demand could be met by renewables with electricity costing under 5p/kWh. Delivery will be substantially reliant on wind (on and offshore) and, to a lesser extent, energy crops. The key issues for renewables include the achievement of technological advances to bring costs down and the management and cost of the security attached to intermittent sources of generation.

28 Onshore wind has a large potential with generation of 50TWh/year by 2025 costing around 2-2.5p/kWh. This could remain competitive even if the additional system costs of intermittent supply, an area requiring further work, rise towards 0.4p/kWh (a level of penalty which may not be reached until intermittent sources make up well over 20% of generation). This generation cost estimate is more optimistic than the Energy Technology Support Unit (ETSU) work. Alongside this, there are planning issues concerning the location of wind farms.

29 Offshore wind could offer the greatest potential for renewable generation. Little has been developed in the UK so far, but advances in installation methods and demonstration plants could prove the technology, reduce costs and increase deployment. By 2020-25, the cost could be down to 2-3p/kWh and 100TWh/year (over one-quarter of the UK's generation needs) could be provided. Again, further systems costs will need to be factored in.

30 Municipal solid waste and landfill gas could be competitive (cost around 1.5-2.7p/kWh), but the scale of resource is likely to be relatively small – around 3-4% of total generation.

31 Energy crops and other woody biomass could be a significant resource at around 10% of generation. But this is at a slightly higher cost than wind (and also above generation from gas), at around 3-4.5p/kWh.

32 Carbon capture and storage has potential – with intensive capital investment - to save significant amounts of carbon. Capture applied to a new CCGT plant with transport over 300 km and storage in geological aquifers might add 0.5-1p/kWh to the cost of gas-fired generation. There are technical uncertainties and concerns over public acceptability. Issues associated with this technology which need resolving include engineering risks associated with transmission, probability of sudden or gradual release, associated environmental risks and the legal status of disposal in sub-sea strata, given the provisions of the London and Ospar conventions.

33 Tidal stream has modest technical potential but might be available at a cost of around 3.4-6p/kWh. Other options such as active solar and wave power are unlikely to be available at an economically acceptable cost.

34 Nuclear currently provides the bulk of carbon-free electricity generation in the UK and just over 20% of all generation. If low construction costs for the new technologies were confirmed (which might

require series construction and high availabilities) then it is possible to see new nuclear generation competing with other generation at reasonable levels of carbon value at costs of 2.6-4p/kWh.

35 There are, however, issues other than generation cost. Uncertainties over waste management are also material from the perspective of public acceptability as well as cost. There are also issues of public perception and acceptability on safety and the environment. The long-term nature of the capital investment with significant planning/exploratory work in a liberalised market is also an issue. DEFRA has recently started a consultation process on waste management.

36 There are therefore a number of carbon-free generation options with costs which have the potential to move to being competitive with gas.

37 Individual transport measures such as hybrid vehicles, biofuels and Intelligent Speed Adaptation look costly when measured in terms of £/tC. But the benefits of action often go wider to include a reduction in congestion or regulated air pollutants. There is scope for energy efficiency gain and behavioural change but the most significant abatement opportunities arise from fuel switching measures such as fuel cells. There is also no sign at present of any substitute for kerosene in aviation, a sector where demand is growing rapidly.

Costs

38 Achieving a 60% reduction in emissions is technically feasible but extremely challenging. Total costs need not be excessive, though distributional effects may be significant. A combination of substantial (non-transport) energy efficiency improvement and a move to carbon-free electricity generation would help to deliver a significant proportion of the emission reductions required. But emissions savings from other sources, such as the transport sector, would need to be achieved as well.

39 In terms of overall costs to the economy, moving to a carbon-free generation system by 2050 could cost between -0.1% and +0.2% of GDP (with GDP having grown threefold by then). This figure was estimated by looking at the costs of a system with an increased share of renewables and varying the proportions of nuclear and gas-fired generation with carbon sequestration. The costs were compared with those for gas-fired

generation at a range of costs. The impact on electricity prices could vary from around a 20% increase, if low carbon options turn out to be relatively expensive, to a position where prices could fall as a result of cheap on and offshore wind resources and high gas generation costs.

40 MARKAL modelling results indicate that the cost of moving to a 45% reduction in emissions by 2050 could be between £85 and £150/tC. For a 60% reduction the average cost increases to around £200 and for 70% to between £270 under Global Sustainability (GS) and £360 under World Markets (WM). The marginal cost involved in moving from 60% to 70% reduction increases significantly to about £440 under the GS scenario and to nearly £1100 under the WM scenario. The cost of abatement is estimated to have an impact of between 0.01 and 0.02 percentage points on a long-term GDP growth rate of 2.25%. This would still represent a non-recoverable decrease in living standards, although the model does not take account of the benefits of emissions mitigation or any opportunities to the UK economy which might arise from the technological developments implied.

41 Overall impacts on GDP then depend on the success in delivering low cost energy efficiency improvements. There is undoubted potential but achieving it, as demonstrated by past experience, is difficult. It will also depend on the extent to which transport demand growth is constrained and/or technology develops to allow a low cost switch to low carbon transport fuels. This is highly uncertain and more work is needed on the relationship between generalised costs, infrastructure provision and modal shifts.

General conclusions

42 A key theme of the preceding analysis is uncertainty. We do not know how baseline emissions will change. We do not know how the costs and potential of currently available technologies will develop.

43 In these circumstances a prime consideration must be to create the right framework which will reward the best, most cost-effective technologies and encourage their development. This means a policy that is not about picking winners, but which allows the market to provide appropriate incentives. But at the same time, while we see price signals as fundamental, this is not to exclude other policy actions. A range of measures such as information campaigns, target setting and minimum standards may have a role.

44 We have made use of projected resource cost curves, but these are inevitably constrained by what we (think we) know now, and by our past experience of cost reductions for new technologies. Economic instruments (carbon internalisation, trading) have a role here – they provide a signal which helps to incentivise innovation. There are key questions to be addressed about how to achieve the kind of cost reductions projected for a number of low-carbon technologies.

LONG-TERM REDUCTIONS IN GREENHOUSE GAS EMISSIONS IN THE UK: Report of an Inter-departmental Analysts Group (IAG)

1. INTRODUCTION

1.1 In June 2000, the Royal Commission on Environmental Pollution (RCEP) published an important report[1] on the long-term challenges for UK energy and environmental policy posed by climate change. It makes 87 recommendations, to which the Government will have to respond in due course. Amongst its key recommendations is the following:

> *(Recommendation 5), The Government should now adopt a strategy which puts the UK on a path to reducing carbon dioxide emissions by some 60% from current[2] levels by about 2050. This would be in line with a global agreement based on contraction and convergence which set an upper limit for the carbon dioxide concentration in the atmosphere of some 550 ppm[3] and a convergence date of 2050.*

1.2 The Government has recognised that action now will lay the foundation for the more fundamental changes that will be needed in years to come.[4] Its 20% goal for a reduction of CO_2 emissions by 2010 provides a signal of the direction in which policy is moving, but it has not committed to any further figure for longer-term reduction. Nor has the Government agreed the contraction and convergence approach.

1.3 In order to help inform the Government's response to this recommendation, and also thereby a number of the RCEP's other proposals, an inter-departmental analysts group (IAG) was established (membership at Annex A). Our remit was to consider:

- the scale of emission reduction implied by the RCEP's recommended 60% cut (taking account of potential future energy demands and energy mix);

- the options that might be available to fill this gap, and their associated costs;

---

[1] Energy – the Changing Climate, RCEP, June 2000, Cm 4749
[2] For "current" the RCEP report uses 1997 levels of emissions.
[3] There is no international agreement on stabilisation levels. Even at 550ppm work by the Hadley centre indicates that temperature increases will still occur but at half the level than if no action is taken.
[4] Climate Change: the UK Programme, DETR, November 2000, Cm 4913

- the implications for policy now if the prospect of meeting such a target at minimum or low cost is to be maintained.

1.4 Subsequently, a review of energy policy, to be undertaken by the Performance and Innovation Unit (PIU), was announced. This has a broader remit than the IAG. We have seen our role as to help inform the PIU, largely in its consideration of environmental issues. This report is therefore focused on the challenge concerned with the adoption of the RCEP target.

1.5 Our work concentrates on the 60% target and does not consider the adoption of contraction and convergence as a principle in international negotiations.

Costs of inaction

1.6 It should be borne in mind that while there will be abatement costs associated with emissions reductions, the wide-ranging impacts of climate change means that there will also be costs associated with inaction. Recent work by DEFRA[5] indicates that a point estimate of £70/tC, together with a sensitivity range of £35-£140/tC, would be appropriate illustrative values to use for the estimated damage costs associated with carbon dioxide emitted in 2000. Since the value of damages associated with carbon emissions increases over time, the point estimate for future emissions increases by £1/tC per year after 2000. Socially contingent impacts of climate change have not been included in this estimate. It is stressed that the uncertainty associated with climate change is very large and these values should only be considered as illustrative of possible costs.

Uncertainties

1.7 It is important to be clear from the outset that any consideration of prospects over a 50 year timescale must be very uncertain. Our projections and technology assessments will inevitably turn out to be inaccurate. But this does not invalidate the exercise. Policy actions now, or decisions to postpone policy action, ought to be informed by best

[5] Estimating the Social Cost of Carbon Emissions: Government Economic Service Working Paper 140 available at:
http://www.hm-treasury.gov.uk

possible assessment of potential costs and benefits. And the uncertainty attached to those assessments should itself be factored in to consideration of the appropriate policy response.

1.8 There is a range of uncertainties attached to the various costings. We have drawn from a range of sources. Despite our best efforts to put figures on as common a basis as possible, there will inevitably be some inconsistencies. We would not want to claim robustness for precise comparisons, particularly of point estimates. We think, nevertheless, that it is possible to make some comparisons and draw broad conclusions. Our use of ranges for many of the cost assessments helps in that regard.

2. GREENHOUSE GAS EMISSION PROJECTIONS TO 2050

Key messages: The rate of carbon intensity improvement required to hit a 60% CO_2 reduction target by 2050 (4.3% a year after 2010) is:

- ***greater than the historic trend (3.0% a year 1970-2000).***
- ***greater than the improvement expected over the period 2000-2010 (2.8% a year) which includes the impact of the CCP;***

Depending on the assumptions made for a "business as usual" baseline projection of CO_2, the projected gap against a 60% reduction target in 2050 ranges from 41-105MtC.

To achieve a 60% CO_2 reduction target, emissions reductions would be required across sectors. Ideally, more would be achieved where it is relatively cheap and less where costs are relatively high.

Looking across sectors, the greatest gap between historic performance and that required to reduce CO_2 by 60% is in the transport sector.

The easiest reductions in non-CO_2 emissions have been made, and by 2020 non-CO_2 gases are only 14% of the GHG total. So we do not expect a greater than 60% reduction in non-CO_2 gases to substantially and cost-effectively reduce the burden on CO_2.

2.1 We have taken as our remit that we are considering the implications, including cost, of the RCEP's recommendation of a 60% reduction in CO_2 emissions by 2050. Identifying what might be involved requires that we establish a baseline projection – a view of what might happen to emissions in the absence of further policy action.

2.2 We cannot predict 50 years ahead but that does not negate the requirement for us to at least consider this baselines issue. If the Government is being asked to consider reducing CO_2 emissions by 60% it needs to establish the implications of that commitment as best as it is able. The Government's Climate Change Programme (CCP)[6] makes clear that the kind of emission reduction required in the future will be of a different order to that achieved in the past, or even projected to be achieved in the UK to 2010. We have attempted a rather more precise quantification or specification of the nature of that task.

[6] Climate Change The UK Programme, DETR Published November 2000.

Carbon dioxide or greenhouse gas basket?

2.3 There is immediately an issue to be resolved about the nature of the RCEP's recommendation. It is very clearly focused on CO_2. For the Kyoto protocol, targets for 2008-12 relate to a basket of six gases[7]. Whilst CO_2 is the most substantial of the greenhouse gases (for the UK, in 2000 CO_2 accounts for around 84% of the total), it seems odd to frame the overall target on only one of the contributory gases. Ideally, it makes sense to look at the overall basket of greenhouse gases and consider which can be reduced most cost-effectively.

2.4 In our analysis much of the focus is on CO_2. But we also consider in paragraphs 2.24-2.28 how UK emissions of the six gas basket might move and whether greater or lesser reductions in non-CO_2 emissions might reduce or increase the burden on CO_2.

Establishing a baseline

2.5 An econometric approach to forecasting over so long a period would make no sense. Our approach to establishing a baseline projection for CO_2 has been as follows:

(i) our starting point has been the Government's emission projections contained in Energy Paper 68 (EP68)[8], published in November 2000;

(ii) EP68 provides projections to 2010[9], but excludes the full impact of the Climate Change Programme (CCP). We have included separate allowance for the impact of the CCP to 2010;

(iii) we have "projected" beyond 2010 on the basis of a range of simple assumptions for continued carbon intensity improvement, but also including the impact of the closure of

[7] Carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride.
[8] Energy Paper 68 Energy Projections for the UK available at: http://www2.dti.gov.uk/energy/energy_projections.htm
[9] EP68 provides projections to 2020 and it is equally possible to use them as the basis to 2020, with divergence allowed beyond that point. A limited set of projections is included in Annex B. They are not our preferred baseline because the CCP is aimed at 2010 (or at least at the Kyoto period 2008-12), and because allowing divergence from 2010 is probably a better reflection of the uncertainties.

existing nuclear generation plant and constraints to reflect limits on fuel switching potential.

2.6 Emerging from (i) –(iii) we have a range of baseline projections of CO_2 to 2050 (Table 2.1 below). We extend this initial range of baselines later. What we produce in this way is inevitably broad-brush, but we hope it gives a reasonable indication against which to begin consideration of the “gap” to a 60% reduction target.

Scale of the carbon gap on baseline projections of CO_2

2.7 The RCEP recommendation of a 60% reduction in CO_2 on *current* levels seems to view the level of emissions in 1997 as current. UK CO_2 emissions in 1997 amounted to 155 Million tonnes of Carbon (MtC), so achieving a 60% cut would mean emissions no higher than 62 MtC in 2050[10]. It is against that target that we assess various baseline projections. Against 1990 levels, which would be consistent with international negotiations, a 60% cut would mean emissions no higher than 65 MtC in 2050).

2.8 A business as usual baseline itself can be constructed in various ways. We have primarily made use of the CO_2 projections to 2010 within EP68, considered the difference made for allowance for the CCP, and projected forward beyond that on various bases, and with resulting carbon gaps by 2050, as in Table 2.1 below. These initial projections are based on extrapolation of total UK carbon emissions to GDP ratios and illustrate the wide range of potential business as usual projections to 2050.

[10] The emissions figures have recently been revised as a result of adjustments to the numbers resulting from land use change. On this basis emissions in 2050 should be no higher than 60MtC. At the margin and given the uncertainties the implications for our work are minor.

Table 2.1 A range of baseline CO_2 projections to 2050 illustrating the size of gap to 60% reduction target

Basis for projection	Assumed % p.a. carbon/GDP intensity change (post 2010/20)	Carbon projection (MtC) in 2050	Gap to 60% reduction target (MtC)
EP68 TO 2010 AND THEN:			
Historic (1970-2000) p.a. carbon intensity change	-3.0	103	41
Historic (1970-2000) p.a. carbon intensity change, less dash for gas in ESI, less impact of fuel switching in final demand, including nuclear closures.	-2.1	145	83
EP68 (2000-2010) projected p.a. carbon intensity change (including fuel switching in ESI, CCP and nuclear closures)	-2.8	110	48
EP68 (2000-2010) projected p.a. carbon intensity change (including fuel switching in ESI, excluding CCP, including nuclear closures)	-1.8	162	100
EP68 (2000-2020) projected p.a. carbon intensity change (less fuel switching in ESI, excluding CCP, including nuclear closures)	-1.7	167	105

2.9 Allowing for the impact the CCP is projected to have had on carbon emissions by 2010, the annual required rate of carbon intensity improvement after that date in order to reach the 60% reduction target is 4.3%. None of our baseline projections comes close to this requirement. Reaching such a target - especially allowing for the fact that some factors that have produced emission reductions in the past are not available looking forward (or not available to the same extent) - is a significantly bigger task than anything achieved to date. The rate of carbon intensity improvement required to reach a 60% reduction target by 2050 is:

- significantly greater than the historic trend (3% a year 1970-2000);

- significantly greater than the recent historic trend ignoring the impact of the dash for gas (2% a year 1990-2000);

- greater than the improvement expected over the period 2000-2010 which includes the impact of the CCP (2.8% a year).

Scenarios

2.10 To help deal with inherent uncertainties associated with the longer term, we have included the development of scenarios to complement our baseline projections. Energy and emission scenarios are used extensively in long-term policy work to stimulate debate about the future. Notably, the emissions scenarios developed by IPCC provide four qualitative storylines which explore alternative directions in which social, economic and technical changes may evolve over coming decades. Closely linked to these scenarios, and developed by SPRU and the DTI, are the Foresight scenarios. These have also been used by the PIU.

2.11 The point of scenario development is to provide a range of "views of the world". They do not have to be considered equally likely. But they can be helpful in a planning context – for example, to consider potential policy developments which may be consistent with a range of future outcomes.

2.12 Generally an emissions scenario represents a complete set of assumptions regarding the possible state of the future. These include assumptions about the socio-economic situation, future climatic effects and the impact of technological change on the environment. Our use of scenarios is rather different. The immediate task we set our group was to identify the potential gap in CO_2 emissions against a baseline scenario (in order to explore potential policy implications). The projections we produce are therefore influenced by the views within the Foresight scenarios, but not wholly determined by them. We did not want, for example, to adopt a full "environmentally sustainable" future as a baseline - where international climate change targets are met. That would assume away the very problem that we are interested in looking at – i.e. the policy actions necessary to deliver that outcome.

2.13 We were interested in building a bridge between our projections and the scenario approach, without developing our own scenarios from scratch (which would require a level of resource we did not have). For this purpose we have made use of Foresight Environmental Futures scenarios[11]. The four scenarios are described briefly as:

> **World Markets: -** based on individual consumerist values, a high degree of globalisation and scant regard for the environment.
>
> **Global Sustainability:** -based on predominance of social and ecological values, strong collective environmental action and globalisation of governance systems.
>
> **Provincial Enterprise:** -based on individualistic consumerist values, reinforced governance systems at national and sub-national level.
>
> **Local Stewardship: -** based on communitarian and strong conservation values, diverse political systems and economic regionalisation.

2.14 We have taken some of the key assumptions from these scenarios (including rates of growth of GDP, and population and household numbers) and projected forward from our 2010[12] base on those different assumptions. This does not explicitly consider[13] (as in the PIU work) the extent to which different rates of technological change might be associated with each scenario, but that can be considered further in the context of considering how the "gap" is filled. Two baselines have been selected from those illustrated in Table 2.1 to compare with these scenarios. They are (a) the historic (1970-2000) carbon intensity change, less dash for gas, fuel switching and including nuclear closures and (b) the estimated EP68 (2000-2010) carbon intensity change, less dash for gas, fuel switching and including the CCP and nuclear closures. More details of the baseline and scenario assumptions are provided in Annex B.

2.15 In addition to each of these two baseline projections, the scenario approach gives us another set of four projections of CO_2 emissions beyond 2010[14] based on the carbon intensity assumptions and limited

---

[11] The Foresight scenarios were developed in co-operation with SPRU. They are closely aligned to the IPCC emission SRES scenarios, most recently updated in 2000.

[12] We have selected 2000-2010 representing a reasonable near-term period for which there has been extensive econometric modelling (EP68) and for which the Climate Change Programme provides detailed sector analysis of the effects of measures.

[13] Our scenarios do include some basic assumptions which reflect a de-coupling of economic growth and transport growth, and improvements in emissions associated with the vehicle stock. The key assumptions and limited allowance for technology development in the transport sector to vary across the scenarios are described in annex B.

[14] An alternative projection base of 2020 was also examined. (Annex B).

socio-economic conditions associated with each of the different scenarios. Thus we have:

- two baseline projections that allow for future CO_2 emissions to move similarly to some estimate of the past trend (A), or an alternative projected trend (B);

- two sets of four scenario constructed projections which adjust those baselines to allow, for example, for a lower rate of GDP growth and lower rate of household growth as might be observed in a “provincial enterprise” world; or for a higher rate of GDP growth and higher population growth as might be observed in a “world markets” world.

2.16 Our approach is not the same as providing a full range of CO_2 projections based on fully different scenarios (because the fully different scenarios probably imply different rates of technology improvement, of environmental behaviour and of willingness and capacity to introduce policy measures to reduce emissions that we have not allowed for). But we are left with a set of projections of CO_2 emissions which imply a different scale of gap to a 60% reduction target – gaps which would have to be filled by other actions.

<u>Scale of the carbon gap on baseline projections of CO_2 augmented for quantifiable variations attached to scenarios</u>

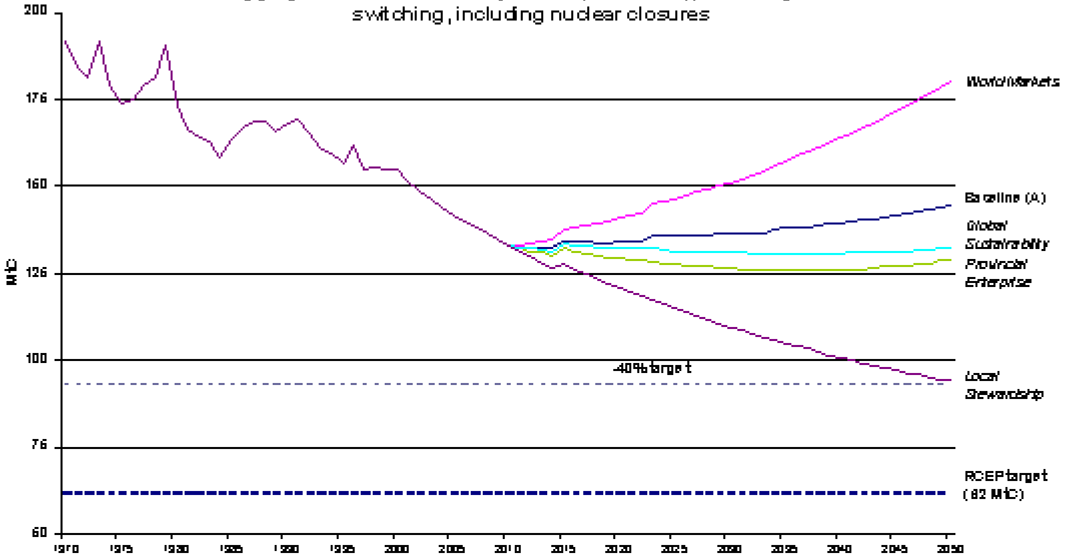
2.17 Where do our baselines sit against the kind of worlds envisaged in the scenarios? This is illustrated in Figures 2.1 and 2.2 below. In both graphs the 60% target is indicated. A line representing a 40% reduction is also shown – this has no formal basis from the RCEP report or as a Government target, and is purely illustrative of an intermediate step towards 60%.

2.18 In Figure 2.1 CO_2 emissions are projected on different bases according to scenario, but in all cases on the basis that carbon intensity improvement by sector beyond 2010 continues from the rate of improvement observed over the period 1970-2000 (but excluding – on the basis that once achieved these cannot be repeated - the impact of the dash for gas in generation and the switch out of coal in final demands). (Baseline (A))

2.19 In Figure 2.2 CO_2 emissions are projected on different bases according to scenario, but in all cases on the basis that carbon intensity improvement beyond 2010 continues at the rate of improvement by sector expected for the period 2000-2010 (which incorporates the CCP)[15]. (Baseline (B) This is on average a higher rate of carbon intensity improvement by sector than in Figure 2.1 – hence in all scenarios the gap to the 60% target is lower.

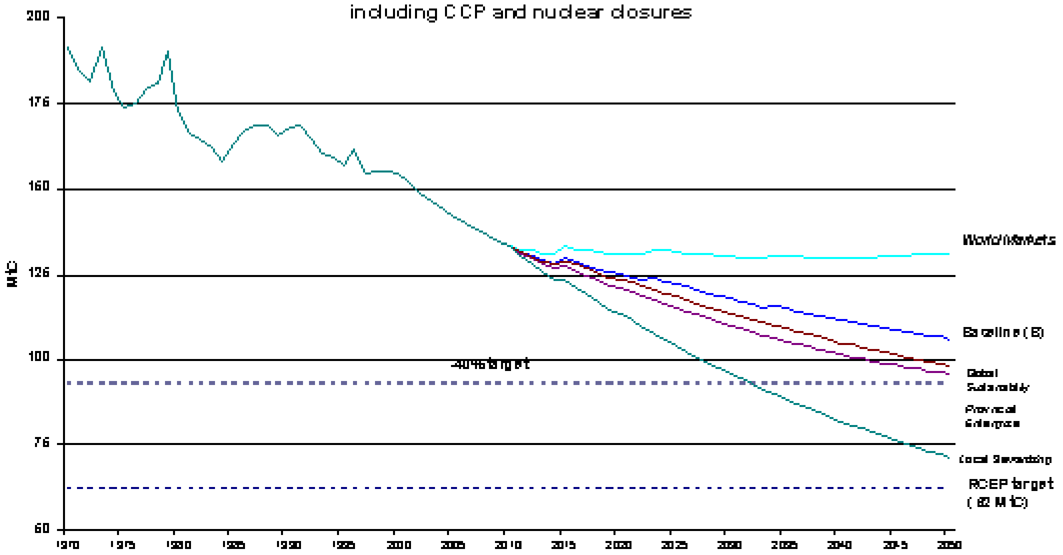
2.20 The scale of the gap to the 60% reduction target in 2050 is summarised in Table 2.2 below. It might be considered that an assumption of continued improvement in carbon intensity at the higher rate projected for the UK in the period 2000-2010 (reflecting the CCP) is more relevant to the global sustainability and local stewardship scenarios; and that improvement at the same rate as observed from 1970-2000 has more in common with world markets or provincial enterprise. In Table 2.2 these correspond to the highlighted figures in bold.

Figure 2.1 Baseline (A) and scenario (A) CO_2 emission projections based on aggregated sectoral intensity trends (1970-2000), excluding DFG and fuel switching, including nuclear closures



[15] Baseline and scenarios projections at this point are aggregated from sector projections. This has been necessary to reflect sectoral differences in scenarios, see scenario sector assumptions annex B, and an allowance for non-sectoral emissions included. These projections are more detailed in construction and differences between the baseline projections by this method and the aggregate emissions projections shown in Table 2.1are small.

Figure 2.2 Baseline (B) and scenario (B) CO_2 emission projections based on aggregated sectoral intensity trends (2000-2010) excluding DFG, fuel switching, including CCP and nuclear closures



Note: The aggregated emissions projections represent end user emissions from the industry, services, domestic and transport sectors and include non-sectoral emissions such as land use change (LUC), military emissions, marine bunkers, etc. Non-sectoral emissions represent approximately 6% of total emissions in 2050 in baseline (A) and 8% in Baseline (B). The most recent land use change (LUC) estimates have been included in the projections and the impact of LUC is assumed to be 2.5MtC in 2010, and projected forward at a constant level of 1.6MtC from 2020 to 2050.

Table 2.2: Size of gap in 2050 relative to RCEP target (62MtC) by scenario, CO_2 only and sector carbon intensity assumption (A) or (B)

Baseline	**World Markets**	**Global Sustainability**	**Provincial Enterprise**	**Local Stewardship**
Falls short by between 44 and 83 MtC	Falls short by between 69 and **118** MtC	Falls short by between **36** and 70 MtC	Falls short by between 34 and **67** MtC	Falls short by between **9** and 32 MtC

<u>Carbon intensity change by sector</u>

2.21 In considering the implications of hitting a 60% reduction target, it may be useful to examine historic rates of improvement by sector of final demand. Overall, as previously estimated, carbon intensity must improve by 4.3% post 2010. Table 2.3 below compares the rates of improvement observed over the period 1970-2000 with the rate of improvement required post 2010 (assuming the CCP delivers as expected) to meet a 60% cut by 2050 in each sector. In practice, cost effectiveness and other considerations will imply that contributions will differ across sectors.

2.22 Significant indicators from this are that:

(i) the greatest gap between historic performance and that required to reduce CO_2 by 60% is in the transport sector;

(ii) the rate of reduction required in industry is broadly in line with the past trend. It is lower than the average requirement post 2010 reflecting that the CCP to 2010 includes significant reduction from industry;

(iii) Significantly greater reductions in carbon intensity than delivered to date would be required of both the domestic and services sectors. Excluding decarbonisation of electricity, or further fuel switching in final demands (for which scope may be limited), energy efficiency improvement would have to increase by 2% (domestic) or 3% (services) a year more than we already have in the baseline.

Table 2.3: Historic (1970-2000) carbon/energy intensity improvements and requirements to meet 60% CO_2 reduction in 2050

<u>Domestic sector</u>			
Historic rate of carbon intensity improvement (% pa)	4.3	Rate of carbon intensity improvement post 2010 required to meet 60% reduction in 2050	4.8
of which: energy intensity[16]	*2.6*		
carbon to energy	*1.7*		
Historic rate of carbon intensity improvement excluding dash for gas and major fuel switching	3.0		
of which: energy intensity	*2.6*		
carbon to energy	*0.4*		
<u>Transport sector</u>			
Historic rate of carbon intensity improvement (% pa)	1.2	Rate of carbon intensity improvement post 2010 required to meet 60% reduction in 2050	4.9
of which: energy intensity[17]	*1.1*		
carbon to energy	*0.2*		
Historic rate of Carbon intensity improvement excluding dash for gas and major fuel switching	1.1		
of which: energy intensity	*1.1*		
carbon to energy	*0.1*		
<u>Industry sector</u>			
Historic rate of carbon intensity improvement (% pa)	3.7	Rate of carbon intensity improvement post 2010 required to meet 60% reduction in 2050	3.5
of which: energy intensity[18]	*2.8*		
carbon to energy	*0.9*		
Historic rate of carbon intensity improvement excluding dash for gas and major fuel switching	3.0		
of which: energy intensity	*2.8*		
carbon to energy	*0.2*		
<u>Service sector</u>			
Historic rate of carbon intensity improvement (% pa)	2.7	Rate of carbon intensity improvement post 2010 required to meet 60% reduction in 2050	4.9
of which: energy intensity[19]	*1.6*		
carbon to energy	*1.1*		
Historic rate of carbon intensity improvement excluding dash for gas and major fuel switching	1.8		
of which: energy intensity	*1.6*		
carbon to energy	*0.2*		

[16] Energy per unit GDP per household
[17] Energy per unit GDP per household
[18] Energy per unit GDP
[19] Energy per unit GDP

International aviation contribution to emissions

2.23 At present only emissions from domestic flights are included – in line with the format of the international targets. But if the UK were assigned a share of international emissions this would make achieving a 60% reduction more difficult. Projections of growth in UK international aviation made on the same assumptions across scenario and baseline as those made for domestic aviation (see annex B) suggest that in 2050 an additional 14MtC would be added to the baseline projection based on the historic rate of carbon intensity improvement and an additional 21MtC on the baseline projection based on the carbon intensity improvement expected between 2000-2010.

Allowing for non CO_2 greenhouse gases

2.24 In 2000 non-CO_2 greenhouse gases accounted for 16% of the basket of UK emissions. Those gases have been reducing faster than CO_2. Available projections, summarised in Table 2.4, suggest that will continue to be the case in the period to 2020.

Table 2.4: Non-CO_2 greenhouse gases

	Non CO_2 (MtC)	Change since 1990 (%)	Change since 2000 (%)	Non CO_2 as % total GHGs
1990	44			21
1997	39	-12		20
2000	29	-34		16
2020	26	-41	- 10	14

2.25 As we saw above, the RCEP's recommended 60% cut relates to CO_2. Whether it would be easier (less costly) to achieve a 60% reduction in the greenhouse gas basket depends on the balance between the marginal cost of achieving further CO_2 reduction as against further non-CO_2 reduction – whether it is possible to reduce by 60% on non-CO_2 at lower marginal cost than for CO_2.

2.26 But the base year also matters. For CO_2 the RCEP seem to view the 60% target as against a *current 1997* level. But since a very substantial reduction in non-CO_2 has been achieved over the past decade the precise base year for non-CO_2 could make a significant difference:

- a 60% reduction on 1990 non-CO_2 is equivalent to 26 MtC non-CO_2, which is 8MtC more than the non-CO_2 reduction currently projected (on business as usual) to 2020;

- a 60% reduction on 1997 non-CO_2 is equivalent to 23MtC non-CO_2, which is 10MtC more than the non-CO_2 reduction currently projected (on business as usual) to 2020;

- a 60% reduction on 2000 non-CO_2 is equivalent to 17MtC non-CO_2, which is 14MtC more than the non-CO_2 reduction currently projected (on business as usual) to 2020.

2.27 So in order to reduce the burden on CO_2 reduction more than 8-14MtC cuts in non-CO_2 would have to be found, beyond reductions already expected to 2020. Achieving cuts of that order may not be easy. By 2020 approaching half of non-CO_2 emissions will be from agriculture, principally methane and nitrous oxide:

- research is being conducted on techniques of cattle farming with lower methane emissions, but significant improvements are not considered available in the foreseeable future, reflecting lack of technical development and implications for animal welfare and food safety;

- no additional measures, beyond a business as usual improvement, for improving the efficiency with which nitrogen is used by crops and livestock have been identified in the CCP.

2.28 There may be some relatively cost-effective further reductions available. Catalytic destruction of N_2O on all plant could reduce emissions by 0.6MtC compared with the latest business as usual projections (0.7MtC in 2010). No further plant closures are assumed. Measures aimed at CO_2 in the transport sector could also reduce nitrous oxide. But although DEFRA is planning further work to assess policy options for reducing non-CO_2 emissions, in general we do not expect that greater than 60% reductions in non-CO_2 can cost-effectively and significantly reduce the burden on required CO_2 reductions.

Energy demand projections

2.29 The IAG analysis has been directed towards projections of carbon emissions to inform the response to the RCEP recommendation of a 60% reduction in carbon by 2050. However, it is also necessary to consider the equivalent final energy demand of the baseline and scenario projections - firstly as this is a significant determinant of carbon emissions and secondly as it provides the basis for the MARKAL analysis of the low carbon options which will be reported separately. The projected energy demands have been estimated independently on different bases, although to the same set of scenario assumptions. These are reported in Annex B.

2.30 The levels of energy demand in the industrial, service and domestic sectors projected to 2050 are fairly consistent under each approach[20]. Differences in transport sector demand are apparent and reflect a significant difference in the assumption of transport sector growth. The approach adopted for IAG by DEFRA assumes constrained transport growth to 2050, implied by the NRTF[21] model projections while the IAG(A) assumptions incorporate continuation of past rates of growth. The IAG(A) demand projections are plausible in terms of implied kilometres per household without saturation of car ownership, but do not explicitly incorporate the increased impact of congestion in constraining growth. On the other hand the NRTF forecast assumes no new road build after 2010 and reflects substantial modal switches and falling rail prices in real terms. It is probably safe to assume that actual transport final energy demand growth lies somewhere between the two projections (i.e. between a growth rate of 0.3 and 1.3 per cent per annum) which would mean transport final energy demand representing somewhere between 35 and 50 percent of baseline total final energy demand in 2050 and contributing between 42 and 59 MtC of carbon. This assumes that transport fuel has about the same fossil carbon intensity as at present and that there is no major switch to low carbon fuels such as hydrogen or electricity from renewables.

---

[20] Full details of the IAG(DEFRA) Energy Demand Analysis are to be found in the 4 DEFRA sectoral papers on the PIU website:
http://www.cabinet-office.gov.uk/innovation/2001/energy/submissionshome.shtml.
A description of the general methodology and a summary of the results is in Annex B: Appendix 7.
[21] National Road Transport Forecast provided by DTLR and based on the Ten Year Transport Plan to 2010, with additional assumptions of saturation of car ownership, road congestion and no new road build.

3. THE INTERNATIONAL CONTEXT

Key messages:

The Kyoto mechanisms will provide the right framework for cost-effective emissions reductions only if the price signal works and is allowed to work. This means that we should look to work towards a future emissions trading scheme (both domestically and internationally) with minimal artificial constraints and the simplest possible rules consistent with sound accounting. This will implicitly require that the schemes in the shorter-term be seen as a success.

Key attention will need to be paid to the longer-term role of the developing countries, and to the nature and stringency of targets in the developed world. These will be the crucial determinants of what happens to the mechanisms. Issues attached to JI and CDM currently add substantial complexity. On a 2050 timescale, however, these should be transitional issues.

In the long term, if developing countries are themselves taking on emission targets of similar stringency to others (as exemplified by the contraction and convergence methodology) then we cannot rely on there being substantial sources of cheap emission savings to buy in from others and supplement domestic action.

The UK is mid-ranked in terms of scale of emissions reduction required to 2050 and may become a buyer in the latter part of the period. An RIIA study for DEFRA suggests, however, that the UK could produce emissions savings at a lower cost than some other developed countries.

Even when the price signal works, the mechanisms provide only part of the required policy framework. They will not necessarily eliminate market failures that may be holding back emissions-reducing technologies, and do not preclude the use of other policy tools.

Introduction

3.1 It is not the role of the IAG to provide a detailed assessment of the position of other countries relative to current or potential targets, nor to consider the rules governing use of the mechanisms that were agreed in Marrakesh in November 2001. The RCEP itself assumes that the UK would move to a 60% reduction within a global framework and that trading would be available. In considering whether the UK should commit to a 60% (or otherwise stretching) long-term reduction target, we should clearly therefore pay some attention to:

- the likelihood of others moving similarly. The UK accounts for a small proportion of global emissions (2% of world CO_2 emissions in 1995, falling to perhaps 1.6% by 2010). If there are costs to achieving such targets then there is little point in environmental terms in the UK acting alone – unless there are other (non greenhouse gas) benefits which exceed costs;

- whether the UK has a comparative advantage in being in the lead in emissions reduction. There is limited information on this. Work for DEFRA by Dames and Moore[22] suggests that marginal costs of emissions reduction in the UK could be less than the Annex B country average under certain circumstances.

Progress towards Kyoto targets

3.2 Whilst some member states are yet to produce the national climate change programmes that would be expected to start to move them towards Kyoto, the latest European Commission assessment[23] suggests that:

- the majority of EU member states are far away from their target paths to Kyoto;

- by 2010, on policies and measures adopted to date, at best stabilisation of emissions at 1990 levels will be achieved; and additional policies and measures identified by member states take that to -5%. This compares with the EU's Kyoto obligation to an 8% reduction by the 2008-12 period;

- But contributions from member states are very uneven. Most fall well short of a Kyoto target path. To the extent that the EU, allowing for implementation of planned measures by member states, is on course for its Kyoto

[22] 'The implications for the UK of an International Carbon Emissions Trading Scheme' by Dames and Moore published in October 1999
[23] COM (2001) 708 final, Report under Council Decision 1999/296/EC for a monitoring mechanism of Community greenhouse gas emissions.

target then this is principally due to potential over-achievement in Germany and the UK.

3.3 Looking beyond the EU, and before allowing for potential use of the Kyoto mechanisms (which many countries such as Japan will rely on heavily to meet their Kyoto commitments), a number of other countries look likely to be well short of Kyoto targets. This includes the US, of course, which has announced its withdrawal from the Kyoto Protocol.

What is implied by contraction and convergence?

3.4 The RCEP recommends that the Government should press for a future global climate agreement on a contraction and convergence approach[24], allowing also for emissions trading. It selects one path for achieving stabilisation of CO_2 concentrations in the atmosphere at 550ppm that implies a convergence date of 2050. Many other paths to stabilisation at this level could be taken. The Government is keen to establish a dialogue on possible approaches to future target setting. However, contraction and convergence is only one of a number of potential models, some of which may be more attractive to developing countries and still promote the objectives that we are striving to fulfil. Other possible approaches, for example, include setting dynamic targets linked to GDP, or setting limits on the basis of countries' historical emissions (the "Brazilian Proposal"). The Government believes that it would be premature to rule out any options at this stage and plans to engage constructively in future debates.

3.5 In the same way that the RCEP path to 550 ppm implies a 60% reduction in the UK's current CO_2 emissions in 1997, it is possible to estimate[25] the implied reductions for other developed countries. These are summarised in the chart below, which is based on 1998 data. Key points from this are that:

- the US would need to reduce emissions by around 80%, and the EU on average by around 53%;

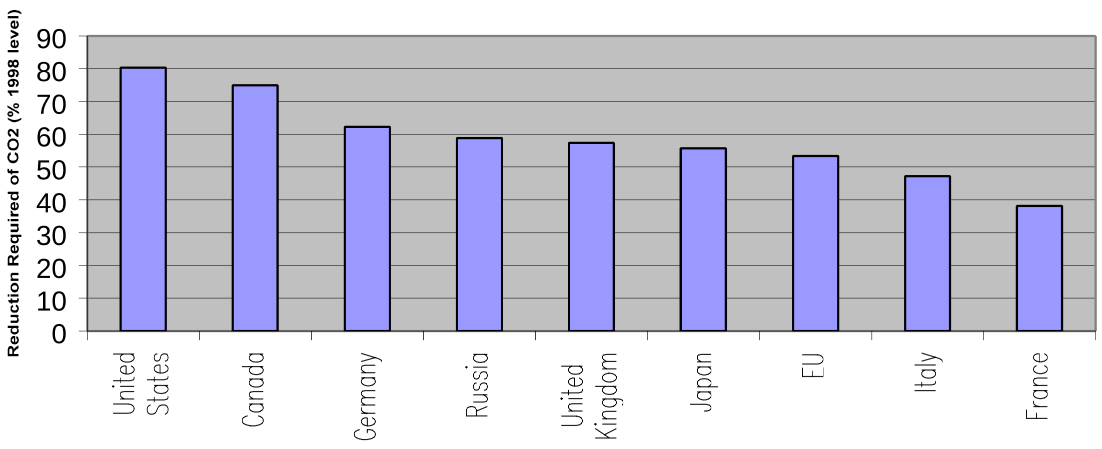
[24] A contraction and convergence approach means that over the coming decades each country's emission allocation would gradually shift from its current level towards a level set on a uniform per capita basis. By this means "grandfather rights" would gradually be removed. The allocations of developed countries would fall, year by year, while those of developing countries would rise, until all had an entitlement to emit an equal quantity of greenhouse gases per head *(convergence)*. From then on the entitlements of all countries would decline at the same rate *(contraction)*.

[25] All these estimates are from a base year of emissions in 1998.

- in terms of scale of reduction, in percentage terms the UK reduction is mid-table in both EU[26] and G8 rankings;

- during the period from 1990 to 1998 the UK has improved its performance relative to the EU and G8.

Figure 3.1: Reductions Required of CO_2 in 2050 Under 550ppm Scenario (1998 base Year)



3.6 The impact of such large-scale reductions in emissions on a country's relative international competitiveness partly depends on the availability and cost of measures to achieve their target. We do not comment on this issue. However, it is worth noting that, providing use of the Kyoto Mechanisms (International Emissions Trading, Joint Implementation and the Clean Development Mechanism) is supplemental to domestic action, Parties can use the mechanisms to help fulfil their commitments at minimum cost.

Costs and benefits of being in the lead

3.7 Although the UK accounts for a small proportion of global emissions, the Government has made clear in the CCP that it expects the UK to take a leading role in the fight against climate change.

3.8 Even ignoring the carbon benefits, many of the measures in the CCP are designed to deliver wider environmental, social and economic benefits. But as we move beyond Kyoto it seems likely that we will increasingly have to look to measures that impose real costs. Even in

[26] On 1998 data the UK (57% reduction) has more to do than Portugal (27%), Sweden (35%), France (38%), Spain (39%), Italy (47%), Austria (48%) and Greece (50%); less than Ireland (62%), Germany (62%), Denmark (63%), Netherlands (64%), Finland (66%), Belgium (67%), Luxembourg (76%).

those circumstances there may be arguments for moving faster than others, depending on:

- the potential of early mover advantage;

- the extent to which use of the Kyoto flexible mechanisms gives a value to over-achievement of targets. Such value will depend on the price of carbon if surplus units are sold and the EU rules governing the achievement of its collective target. On the latter point, there is a danger that the Commission will seek to establish rules that require Member States that have surplus Assigned Amount Units to subsidise those have failed to meet their target. This is unacceptable because it removes the incentive to go beyond the legal commitment and the UK will therefore seek to ensure that over-achievers are not penalised for their diligence and are free to dispose or bank any surplus as they deem most appropriate.

<u>Long-term implications of the Kyoto mechanisms</u>

3.9 One of the key innovations of the Kyoto Protocol in 1997 is the role it gives to market mechanisms in achieving emissions reductions. These market mechanisms are:

- **International Emissions Trading:** The basic idea is simple: the effect on the global environment is the same wherever the emissions come from, so it is better to reduce emissions where the cost is lowest. Emissions trading therefore allows businesses to reduce their emissions of greenhouse gases in the most economically efficient way. An overall emissions reduction target covering a group of emitters is set and then individual businesses decide how to achieve their own target. Participants can either make 'in house' emission reductions (and can sell any reductions surplus to their requirements on the market) or they can buy tradable emission allowances as a way of meeting their targets.

- **Joint Implementation (JI):** JI involves two Annex 1[27] countries with targets under Kyoto. Under the emerging rules, Country A could invest in a project in Country B that reduced the emissions of Country

[27] Annex 1 to the UN Framework Convention lists developed countries, whose emissions limitation or reduction commitments are listed in Annex B of the Kyoto Protocol.

B by x tonnes. Country B would then transfer x tonnes of its assigned amount (its permitted emissions under Kyoto) to Country A.

- **The Clean Development Mechanism:** The CDM allows project developers to undertake emission reduction projects in developing countries. These are only eligible for registration as CDM projects if they are additional – i.e. the emission reductions would not have occurred in the absence of the CDM. The projects generate emission reduction credits that can be used by developed countries to meet their Kyoto targets.

3.10 The rules governing the use of these mechanisms were agreed at the 7th Conference of Parties in Marrakesh in November 2001. In this report, our interest is in the potential long-term use of the mechanisms. But, in considering that, it is worth summarising some of the salient features of the agreed rules which provide a good basis on which to proceed.

- for the first commitment period there is a need to build confidence in the new system and also to signal that domestic action in the industrialised countries will be of primary importance. There is also some residual hostility to the use of market solutions amongst a number of countries, especially developing countries;

- use of the mechanisms shall be supplemental to domestic action, which shall constitute a significant element of each Party's effort to meet its target. Parties shall report on how use of the mechanisms is supplemental to domestic action;

- concerns have also been expressed about the possible impact of "hot air"[28] on international emissions trading. There is potential for the excess units in the Former Soviet Union (FSU) to flood the emissions trading market and significantly depress for the price of carbon, allowing other countries to achieve their targets with substantially reduced effort (and resulting in less investment through the CDM – a major concern to many developing countries). However, this depends on whether Russia restricts supply of its surplus units;

[28] "Hot air" is the generic term given to excess of units of Assigned Amount arising from the collapse of economies in the Former Soviet Union (FSU). The size of these economies is now much smaller than it was in the 1990 base year against which targets are set – and emissions levels have dropped as a direct corollary.

- the arrangements for facilitating, promoting and enforcing Parties' compliance with their commitments under the Kyoto Protocol. It was agreed to establish a compliance committee, which advises on, facilitates and promotes compliance and determine breaches by developed countries with emissions targets. Among the consequences that can be imposed on a Party for failing to meet its obligations under the Protocol are: (a) a requirement to prepare a compliance action plan, (b) suspension of eligibility to participate in one or more of the mechanisms, and (c) the imposition of a restoration rate of 1.3 (which means that a country that exceeded its emission limit during the first commitment period between 2008-2012 would have to make up the shortfall, plus 30%, in the following target period). In accordance with the Bonn Agreement in July 2001, the decision on whether the consequences of the system will be legally or, merely, politically binding has been left over for decision by the Parties to the Protocol at their first meeting;

- The rules for the project-based mechanisms (JI and the CDM) were agreed. Annex 1 countries must refrain from using credits generated from nuclear facilities to meet their commitments; sinks projects under the CDM are limited afforestation and reforestation; and there is a cap on the amount of CDM sinks credits that Annex 1 Parties can use. More generally, transaction costs for projects could be as high as $100,000s and are certainly likely to be in the order of $10,000s, which could deter all but the largest emissions reduction projects. However, there was agreement to the development of simplified procedures for small-scale CDM projects to lower transaction costs and make such projects economically viable.

3.11 A key influence is likely to be the need for increasingly stringent emissions caps to be met. Given the scale of these reductions, and the likely costs of meeting them, there will be considerable pressure to find least-cost approaches. Economic theory – and evidence from trading schemes in other policy areas – suggests that emissions trading is likely to be one of the best ways of achieving this. On the basis of those pressures, and potentially of helpful experience of emissions trading in the period to 2012, it is likely that there will be fewer and fewer voices calling for restrictions on the use of the mechanisms. It may well be the case that increasing reductions in emissions are otherwise unattainable. There is also provision in the text to review the operation of the project-based mechanisms by the end of the first commitment period at the latest.

Hopefully, such opportunities will be used to reflect on experience and seek to improve and streamline procedures.

3.12 Arguably the main uncertainty in assessing the future impact of the mechanisms is the question of developing country targets. Once the CDM process beds in, and transactions costs are reduced, emissions reduction projects in the developing world could be expected to provide an increasingly significant source of credits to be used in compliance with caps. That is certainly the result delivered by general equilibrium models of international emissions trading. (For example, the Dames and Moore project shows CDM sales from China increasing from 190MtC in 2010 (less than half the sales from the FSU) to over 900MtC in 2030 in one fairly central scenario).

3.13 But the role of the CDM in the longer term is crucially dependent on the wider role of the developing countries in the Kyoto process. With projections showing developing country emissions overtaking those from the developed world in the next quarter of a century, there will be an increasing imperative to limit the growth in these emissions and eventually to reduce them. This is a highly political issue and efforts to encourage developing countries to take on further commitments in future will be adversely influenced by the US's stance on Kyoto and failure to take on a binding target (we are, at the time of writing, unaware of the outcome of the US climate change review).

3.14 An RIIA report[29] surveys 10 studies that have attempted to assess potential CDM activity. It finds prices ranging from £5 to £26/tC, with annual quantities of carbon ranging from 103Mt to 844Mt. Taking an average, RIIA calculates 409Mt trading at an average of £17/tC, which is certainly significantly below the marginal cost of many of the options within the UK examined later.

3.15 The size of the CDM and the availability of hot air will inevitably affect the trading price of carbon, and the availability of hot air will influence the size of the CDM.

- an illustration of the potential effect of constraining the extent to which emissions reductions in developing countries can be counted is provided by the Dames & Moore study. In a scenario where the developed world is required to keep emissions at the levels set out in the Kyoto Protocol, this shows

[29] The paper by Christiaan Vrolijkcan be found at: http://www.riia.org/Research/eep/quantky.pdf

CDM contributing sales of over 1000MtC into global trading by 2030 (compared with just 150MtC from the FSU). This leads to a price of around £36/tC. With more expensive CDM (in terms of high transactions costs which do not decline over time), sales are only about 750MtC and the price of permits increases to £60/tC. And with no CDM sales allowed, the price of permits increases to around £140/tC;

- another key pressure will be the rate at which "hot air" is used up. On the assumption that the economies of the FSU pick up again in due course, there will come a point when "business as usual" emissions exceed targets. We can also reasonably expect the FSU countries to have tougher targets in future commitment periods. (In the Dames & Moore project, this does not happen until sometime between 2020 and 2030.) This will have a bearing on the price of carbon and availability of surplus units of assigned amount (AAU)[30] in subsequent commitment periods.

3.16 Of course, the fact that Annex 1 countries can bank AAUs between commitment periods could spread the effects of hot air over time depending on how Russia (and other much less significant sellers of hot air) act. This will be influenced by the view they take of the advantages of present sales versus future uncertainty (i.e. their discount rate) and the demand for carbon in the market (i.e. the price any AAUs sold might realise). The FSU countries might not sell all their excess units in the first Kyoto commitment period (if they think that the price in the market is going to increase significantly over time). The key influences governing the price of carbon will vary depending on the volume and availability of hot air which will be influenced by:

a) levels of economic growth and the relationship between growth and emissions;

b) how many (and which) holders of hot air meet the eligibility requirements to participate in the mechanisms;

[30] The assigned amount represents the emissions allocations of a party for a commitment period measured in AAUs, each equivalent to a tonne of carbon dioxide. A Party would have excess AAUs if its emissions during a commitment period were less than its assigned amount, allowing for international emissions trading, project-based transfers and acquisitions under the provisions of Articles 6 and 12 of the Kyoto protocol and sinks activities. The detailed rules are set out in the Marrakesh accords agreed at the seventh meeting of the Parties to the UN Framework Convention on Climate Change (November 2001) and can be found on the UN-FCCC website.

c) whether Russia (acting alone or in conjunction with others) seeks to dominate the carbon market by restricting the supply of hot air and thereby drive up the price. However:-

- Russia's market power is checked by the CDM which provides buyers with an alternative means of securing non-domestic emissions reduction if the price of hot air rises steeply;

- rather than collude, sellers of hot air could, in the absence of the US, compete to gain a share of the much smaller market. This could result in price undercutting, reducing revenues still further.

d) expectations about the future – if the prospects are good for the US re-joining Kyoto, tougher targets in future commitment periods and the extension of targets beyond Annex B countries[31], the future price of carbon could rise and may make banking more attractive. Conversely, buoyant expectations about the pace of technological development could depress the future price;

e) the discount rate used by Russia and other sellers of hot air. Discounting allows the comparison of economic costs and benefits at different points in time. The higher the discount rate the more weight is placed on current costs and benefits than those that occur in the future. Informal contacts suggest that Russia would like to benefit from sales revenue as early as possible to finance investment in the energy sector.

Sinks

3.17 Following the Bonn agreement and the Marrakesh Accords, parties may choose to use forest management up to an individual cap, and the mitigation effect of agricultural activities over and above the 1990 level towards meeting their Kyoto targets. They must also account for carbon uptakes during the first commitment period due to new forests planted since 1990, less any deforestation, though deforestation need not be counted if existing forests are taking up sufficient carbon to compensate[32].

[31] Annex B countries comprise those countries which have made a commitment to reduce greenhouse gas emissions
[32] This provision for compensation applies up to a limit of 9 MtC/yr.

3.18 Under the CDM, afforestation and reforestation projects will be eligible during the first commitment period, up to a cap set at 1% of base year emissions. The Subsidiary Body for Scientific and Technological Advice will prepare recommendations on modalities and procedures for decision at COP9 in November 2003. The limitations and need for further work reflect serious concerns about their permanence, scientific uncertainty, baseline setting and socio-environmental impacts.

3.19 Sink allowances are unlikely to amount to more than about 2-3% of developed country emissions in 1997 and will probably be less than 3% of total CO_2. They should, as experience is gained and difficulties are resolved, make a significant contribution to the effort needed to meet current commitments, although still small compared with the emissions reduction needed to stabilise atmospheric concentrations. Using IPCC data the Royal Society has estimated that, on optimistic assumptions, sinks enhancement by 2050 could account for no more than about 25% of the emissions reduction required for stabilisation, with limited potential thereafter due to saturation.

Implications for the UK

3.20 At the international level, the standing of the UK in the first commitment period will be influenced by our performance relative to our Kyoto target. The CCP suggests an emissions reduction for all greenhouse gases of 23% on 1990 levels by 2010, compared with the target of 12.5%. If this were achieved, it would leave the UK with around 22MtC per annum to sell or bank in the Kyoto commitment period.

3.21 The Dames & Moore project confirms the UK's role as a potential seller between 2008 and 2012. This is determined in the model by the UK's marginal cost of abatement being less than the average across Annex B countries as a whole. It should be noted, however, that this study assumed the participation of the USA in the Kyoto process. Since the USA was seen to be a major buyer of permits its non-participation could have significant implications. The project also considers the implications of some of the constraints on the UK's position in 2010. Relative to a base case of Annex B trading only, with no restrictions but no CDM, the report finds that:

- the existence of the CDM with relatively high transactions costs would reduce sales by 5%;

- the existence of the CDM with relatively low transactions costs would reduce sales by 50%;

- the absence of Russian hot air would increase sales by 75% (although this is of course not on the cards, Russia may restrict supply of credits to bolster the price).

3.22 Looking further ahead, the UK's position is likely to switch from that of being a seller to that of being a buyer. In the majority of scenarios where it is assumed that the Kyoto targets are maintained indefinitely into the future, the UK starts as a moderate seller in 2010, becomes a moderate buyer in 2020 and then a significant buyer in 2030.

3.23 In order to deal with the expected increasing stringency of targets, the Dames & Moore project considers a 1 percentage point per annum emissions reductions across Annex B countries from 2010 onwards. No targets are imposed on the developing countries, but CDM is not included. In this scenario, the FSU and Eastern Europe are the only sources of supply and the price of allowances rises steeply over time.

Conclusions

3.24 The mechanisms provide a framework that will lead to least cost emissions abatement activities being undertaken, and which should allow bigger emissions reductions sooner than would otherwise have been the case.

3.25 The way in which the mechanisms provide these benefits is by putting a price on greenhouse gas emissions. Restrictions and constraints on the mechanisms can limit their effectiveness in levering in emissions reductions. However, given the aims of the Convention and the Kyoto Protocol, there is of course a need to balance market efficiency and environmental integrity where the project-based mechanisms are concerned.

3.26 It is unrealistic to expect the balance between these two competing considerations to be perfect at this stage as the rules represent a compromise between 180 countries and were developed in the light of little practical experience and empirical data on which to draw. It should be possible to streamline the rules in the future the light of experience. At the international level, the UK will almost certainly not be looking to buy in the first commitment period. But it may well be looking to sell or to bank excess AAUs (subject to a successful outcome on the development of the rules on this issue within the EC). Looking further ahead, the expected tightening of targets, coupled with a rising emissions baseline, will make it less likely that the UK will be in a position to sell – and we may indeed look to rely on purchases of AAUs from elsewhere. But this is not an inevitability. It depends on the targets and emissions baselines of other countries relative to the UK and if the UK is among the leaders in developing low and no carbon technologies, it could develop a comparative advantage in emission reduction.

4. OVERVIEW OF COST ISSUES

Key messages:

Top-down macro economic models tend to overstate costs of meeting climate change targets because, among other reasons, they take insufficient account of the potential for no-regret measure or large technical advances. Additionally most top-down models ignore the benefits of climate change mitigation and present a gross economic cost estimate.

Technologically disaggregated (so called "bottom-up") models can take these benefits into account but may understate the costs of overcoming economic barriers. The Working Group III of the Intergovernmental Panel on Climate Change (IPCC) has assessed the international work on both analytical approaches. DTI, DEFRA and the PIU have also commissioned work using the MARKAL model, a report of which will be available shortly.

Modelling work tends to show that costs can be reduced if rules are flexible and a wide range of options is considered. In particular, measures such as trading can significantly reduce costs of achieving a target.

Economic analysis for IPCC suggests that the cost of stabilisation might mean an average GDP loss of 1% in 2020, rising to 1.5% in 2050 and then declining by 2100 to 1.3%. Most scenarios show the cost to GDP is under 3% (and some even find a positive impact - reflecting assumptions made about positive feedback on technology development and transfer). Expressed in terms of impact on average annual rate of GDP growth, the impact is a reduction of up to –0.06% a year, but averaging only –0.003% a year. Projected costs do, however, increase significantly for stabilisation levels below 550ppm.

Whilst some features of aggregate models may tend to lead to under-estimation of costs such as assumed efficiency in market operation; or particular assumptions which allow for availability of excess AAUs, the use of which might in practice be restricted, on balance there are clear grounds to expect much of the available modelling to overstate costs.

The wider inclusion of the six greenhouse gases, rather than just CO_2 can significantly reduce costs (some models suggest by up to 50% but the exact amount depends on the target level and timing).

Emissions trading may reduce costs to Annex 1 countries by 60–90 %. However, models also show that there is little gain in economic terms from restricting trading to the EU. In short, the wider the base of trading the more costs can be reduced.

Summary of general economic modelling work

4.1 During the late 1990's a great deal of economic research was devoted to estimating the costs of meeting the Kyoto targets. There has also been some work aimed at examining the implications of longer-term emission stabilisation targets. Perhaps the most authoritative review is that conducted by Working Group III of the IPCC on mitigation[33]. This quotes results from an earlier review by the Energy Modelling Forum (EMF)[34], but in summary it concludes that in respect of Kyoto targets:

- in the absence of emissions trading the majority of studies show a cost to GDP in 2010 of 0.2-2.0%;

- with emissions trading that cost is halved (0.1-1.1%);

- carbon leakage (associated with the relocation of carbon-intensive sectors) outside Annex I countries might amount to 5-20% of emissions.

4.2 The cost of stabilisation becomes increasingly speculative. It finds:

- an average GDP loss of 1% in 2020, rising to 1.5% in 2050 and then declining by 2100 to 1.3%;

- most scenarios show the cost to GDP is under 3% (and some even find a positive impact - reflecting assumptions made about positive feedback on technology development and transfer);

[33] Report of Working Group III of Intergovernmental Panel on Climate Change, Mitigation, 2001.
[34] The EMF study finds that the costs of meeting Kyoto target for OECD-Europe vary by study. The GDP loss in 2010 in a "no emissions trading" world ranges from 0.31-1.50%. If Annex I trading is allowed this cost declines to 0.13-0.81%, and to 0.03-0.54% if global trading is allowed.

- expressed in terms of impact on average annual rate of GDP growth, the impact is a reduction of up to –0.06% a year, but averaging only –0.003% a year;

- projected costs increase significantly for stabilisation levels below 550ppm.

4.3 Expressed in monetary terms such impacts can look large:

- GDP losses for OECD countries in hitting Kyoto targets in 2010 amounting to about $100 billion to $350 billion (1990 prices, without international trading);

- total accumulated gross costs of stabilisation at 550 ppm by 2100 ranging from $1,000 billion to $9,000 billion depending on mitigation path and trading assumptions.

4.4 It is clear that estimates of cost vary widely and are dependent on the structure of the model used, definitions, data availability, the treatment of uncertainty and crucially the starting and behavioural assumptions (including interaction with domestic measures).

Do models overstate costs?

4.5 Much of the cost modelling work has been top-down in nature – based on estimated relationships between changes in relative prices and the use of different fuels. This may over-state costs for a variety of reasons:

- since the instrument of carbon reduction is generally taken to be a carbon tax, a key parameter in these models is energy's price elasticity of demand. Evidence for this is provided by the responses to the oil price rises of the 1970s and the reductions of the mid-1980s. But there are reasons to think that the response to these price movements is unlikely to be the same as the response to a planned programme aimed at carbon reduction[35], and that response to a planned programme would be greater (and less costly). Such arguments rest on a planned

[35] Barker, T., Ekins, P. & Johnstone, N. 1995a 'Introduction' in Barker, T., Ekins, P. & Johnstone, N. Eds. 1995b Global Warming and Energy Demand, Routledge, London/New York, pp.1-16

programme over time being understood and viewed as permanent. That gives, for example, a greater stimulus to long-term development of low carbon technologies, and allows the capital stock to be replaced gradually rather than induce premature scrapping.;

- insufficient attention to no-regret (already cost-effective) measures. Top-down models generally start from a basis that actors within an economy are acting efficiently, implying all zero or negative net direct cost opportunities are being exploited. Bottom-up approaches suggest many such opportunities exist. Much of this relates to energy efficiency potential. While it can be argued that such bottom-up assessments ignore a number of real costs, a part of this non-take up does seem to be associated with market failures. There is some scope, therefore, for measures which induce increased take-up to reduce carbon at nil cost;

- neglects the impact of greenhouse gas mitigation on other environmental externalities. Many carbon-reducing measures will have other benefits (for example, reduced NOx, SOx, particulates). Of course, there may be some uninternalised costs (such as visual intrusion attached to wind farms), but in general the expectation is that wider environmental benefits exceed wider environmental costs;

- insufficient regard to possibilities of technical progress. Where technical progress is incorporated this is generally a reflection of past trends, including observed change in carbon/energy intensity in respect of past price movement. The possibility of faster progress, or leaps in technology, incentivised by the appropriate internalisation of carbon, or carbon reducing programme, is difficult to allow for.

4.6 Work by Repetto and Austin[36] reviewed the results of 16 US models (162 different predictions). Worst case results indicated that a 30% reduction in US emissions by 2020 would cost around 3% of GDP; best case indicated an increase in GDP of 2.5%. Much of the overall variation (5.5 percentage points – pp) could be explained by variation in type of model and assumption as follows:

[36] Repetto, Robert, and Duncan Austin. 1997. The Costs of Climate Protection: A Guide for the Perplexed. Washington, D.C.: World Resources Institute.

- computable general equilibrium models gave lower costs than macroeconomic models (1.7pp);

- inclusion of averted non-climate damages such as air pollution effects (0.7pp);

- allowance for trading (0.7pp);

- availability of a constant cost backstop technology (0.5pp);

- inclusion of averted climate change damages in the model (0.2pp);

- whether the model allows for product substitution (0.1pp).

4.7 Overall, this indicates that model methodology is a big influence on results. Worst case assumptions will generate costs; best case assumptions can generate net benefits.

4.8 It is of course possible to argue about the most appropriate basis for the modelling. One of the most significant sensitivities indicated in the Repetto and Austin work is attached to the use of a general equilibrium model. Such models allow, for example, for the effects of revenue recycling – the use made of the revenue generated by a carbon tax. Current tax systems are non-optimal, providing scope for use of revenues to reduce distortionary taxes. Such use (double-dividend) can greatly reduce estimated costs of emission reduction.

4.9 However, it is equally possible to argue that if such tax distortions exist, then they should be reduced in any case and this need not be ascribed to the introduction of a carbon tax. The existence of (sometimes long-standing) distortions in tax structures is also indicative that we cannot simply assume that revenues from a carbon tax would in practice be used to reduce such distortions.

4.10 There is no simple summary of such arguments. We cannot point to a single best estimate of the cost, from previous macroeconomic modelling work, of hitting Kyoto targets or of stabilisation. But despite the range of results, and associated uncertainties, we can draw a number of conclusions of policy interest:

- looked at in terms of percentage impact on GDP or GDP growth rates (and seen in the context of economic growth which might be between 2% and 3% per annum) estimated costs can generally be viewed in percentage terms as small;

- while some features of aggregate models may tend to lead to under-estimation of costs (such as assumed efficiency in market operation or particular assumptions which allow for availability of excess AAUs, the use of which might in practice be restricted), on balance there are clear grounds to expect much of the available modelling to overstate costs;

- if rules are flexible and more options are considered to control emissions, then costs are lower;

- the wider inclusion of the six greenhouse gases, rather than just CO_2 can significantly reduce costs (some models suggest by up to 50% but the exact amount depends on the target level and timing);

- emissions trading may reduce costs to "Annex 1" countries by 60–90 %. However, models also show that there is little gain in economic terms from restricting trading to the EU. In short the wider the base of trading the more costs can be reduced.

4.11 Even if economic costs may in the end be fairly small does not, of course, mean that emission reduction is easy to achieve. There may be very substantial distributional implications. It should also be remembered that the modelling work reported above is generally reflective of international action to meet targets. Costs of domestic action in individual countries may be very different.

5. OPTIONS FOR REDUCING CARBON EMISSIONS IN THE UK

Key messages:

There is a wide range of often divergent views on the costs and potential of different technologies.

There is substantial scope for cost-effective energy efficiency to be taken up. There may be a variety of information failures or hidden costs which prevent or slow down the rate of uptake.

There is very large potential for renewables but the main issues are how much can technically be developed and at what cost. Onshore and offshore wind offer the most potential and could be more than competitive with gas-fired generation. Other new technologies may have niche roles but cannot be relied on to make a cost-effective contribution.

Carbon capture and storage has significant potential, though at some cost, and would have to overcome concerns about environmental and security issues and legal issues regarding sub-sea storage.

The scope of new nuclear build will depend primarily on the ability of new plant designs to reduce the current generation cost.

Reducing transport emissions will require a combination of measures to reduce traffic demand, improve the efficiency of vehicles and introduce low carbon fuels.

Introduction

5.1 The macroeconomic modelling approach to cost consideration has been examined in chapter 4. In this chapter we pursue an alternative bottom-up approach. This proceeds by assessing the potential and costs of a range of possible technologies (including energy efficiency options). Chapter 6 then attempts to pull together packages of options, aimed at emissions reduction, to give indications of overall costs.

5.2 As against the macroeconomic approach, this has advantages and disadvantages. It allows us to make best use of data and expert views specific to particular options and at a level of detail not addressed in the more macro approach. If there is potential for the future to look radically different to the past – step changes in the development of low carbon technologies, for example, rather than the continuation of past gradual change – then this may be very important.

5.3 But it can also appear a very judgemental approach. There is a wide range of views on the potential of different technologies and the bottom-up approach will inevitably be limited to options or technologies that we know about now. The macroeconomic approach gets round this because it does not speculate on individual technologies. It merely predicts on the basis that the future will change at rates similar to those previously observed.

5.4 The packages we produce should therefore be viewed as illustrative only. They are not predictions, but are included simply to explore the implications of particular assumptions.

5.5 We address the following options in turn (with more detailed descriptions contained in Annex C):

- Energy efficiency improvement;
- Electricity generation options;
- Transport options;
- Other.

Energy efficiency improvement

5.6 Bottom-up consideration of the potential for energy efficiency improvement always indicates that the technical and economic potential is large. Pulling together estimates from a variety of sources it is possible (Annex C) to estimate an economic potential in 2010 (beyond the amount expected to be delivered by the CCP) of almost 20 MtC.

5.7 We have not found it straightforward to assess this evidence on a similar basis to other options. For most of the options we are concerned with – such as renewables and carbon sequestration – there are clear resource costs attached to these technologies. There may be scope for some renewables to become cost-competitive with other forms of generation, but the basic picture is that with these options there are definitely in the short/medium term cost penalties attached. We can see in the market what it costs to produce electricity from renewable sources and that can be compared with alternatives (gas-fired generation at the margin).

5.8 With energy efficiency, however, bottom-up assessments suggest that there is substantial scope for greater energy efficiency, and that a great deal of this is cost-effective in its own right (before we consider adding in anything for the value of emissions saved).

5.9 If there is all this cost-effective potential, the obvious question to ask is why is it not being taken up. There are two competing explanations:

i. that a variety of market failures and barriers prevent or slow down such uptake. At one extreme this would be consistent with a view that in making investment decisions economic agents (in households and/or business) actually do not operate rationally. A PIU Scoping Note[37] contains a summary of the arguments;

ii. that the potential identified is not actually cost-effective – that economic agents are operating quite rationally in their decisions, but that these are affected by a variety of (hidden) costs not easily picked up in the bottom-up assessment. These might include costs of acquiring and considering information on options; costs attached to the risks that such options will not perform as expected; opportunity costs attached to the time and resources put into pursuing energy efficiency options when there may be other investments to pursue; costs attached to the disruption to the household or business of work to install energy efficiency measures.

5.10 This matters because the implications for policy might be very different. If we accept the first view, then this argues, firstly, for policy actions to reduce or remove the identified market failures. If that is difficult, or fails to generate much response, then it would be possible to go on to argue that this supports strong action to regulate energy efficiency and require that certain measures are taken up (after all they are cost-effective).

[37] This note is available at: http://www.cabinet-office.gov.uk/innovation/2001/energy/energyscopeenergy.shtml

5.11 But on the second view there are actually costs of energy efficiency measures. Some of these may be costs to GDP (for example, costs to a business of acquiring information and of management time); some may be welfare costs, for example personal time or household inconvenience. This would suggest that it is very important that these costs be assessed, with energy efficiency options pursued only to the point that that they produce carbon savings at a cost lower than other options.

5.12 In reality, the “truth” will not be wholly in line with either i or ii. Both will have some validity. Which looks the better explanation? We have not found empirical material to convincingly make the case for either. But the balance of the available material points us to think that the position is closer to i than to ii. The arguments for existence of a variety of market failures in consideration of energy efficiency investments look compelling. It is much more of a struggle to make a convincing argument that hidden costs, attached to things like management time or the risks attached to having contractors working in the home, are actually very significant set against the apparent financial returns to many energy efficiency investments.

Cost of energy efficiency measures

5.13 We have attempted to get a better handle on the potential range of costs attached to improving energy efficiency beyond “business as usual”. For the domestic, industry and commercial sectors the paper at Annex D provides our detailed assessment. But in brief:

- we start with estimates of cost curves for carbon abatement, derived from bottom-up assessments in each sector;

- we examine the amount of carbon saving that (according to the abatement curve, and applying assumed take-up factors representative of what is actually observed), would be induced by carbon internalisation set at varying levels;

- the average and marginal costs per tonne of carbon saved are similarly derived from these abatement curves.

5.14 There are two substantial issues attached to this:

- the bottom-up derived carbon abatement curves show large amounts of carbon savings apparently available at nil cost. There is an argument about whether this is realistic. We therefore provide estimates of costs on two bases: first, in line with the abatement curves, i.e. accepting that this nil cost potential exists. And second, to consider the sensitivity of costs to a worst case assumption that economic actors are actually operating at an efficient point (that they are currently taking measures up to the point where the marginal cost of taking action equals the marginal benefit);

- the carbon abatement curve is static – it reflects opportunities available now. In practice, as time moves on new opportunities will become available. We therefore consider a further sensitivity whereby new energy efficiency technologies are assumed to replenish cost-effective measures as they are taken up. This clearly increases the potential long-run carbon savings. Although full replenishment is quite a strong assumption, it is interesting to note that bottom-up assessments of cost-effective potential conducted over recent decades have typically shown potential energy saving of around 20%. Assessments today, despite take-up in the intervening years, show similar potential to that existing 10 or more years ago.

5.15 The results of this analysis are shown below on the basis that replenishment of opportunities is assumed. Our estimates of cost per tonne of carbon saved range from a negative (savings) figure – where an optimistic view of availability of cost-effective options is taken – to a positive (cost) figure, where it is assumed that taking further measures always incurs net costs.

Table 5.1 Cost and potential of energy efficiency measures

	Marginal cost £/tC	Carbon saving (above baseline), 2050, MtC
Industry	-80 to +35	Up to 7
Services	-250 to +25	Up to 8
Domestic	-100 to +20	Up to 11

5.16 The key message from this is that there is a substantial potential for energy efficiency to contribute further carbon savings beyond our baseline projection. Savings of up to 26MtC from the study's baseline projection might be possible by 2050 at a cost reaching, at worst, £20-35/tC. In practice, actual costs could be much less. But even at these worst case levels energy efficiency measures are likely to be competitive with other abatement options. If this conclusion is accepted, the key issue is not whether energy efficiency should be pursued as a priority within a carbon saving programme – but how. Past experience, however, suggests that raising the take-up of energy efficiency measures is not easy.

Electricity generation options

Renewables

5.17 Potentially there are sufficient identifiable renewable resources to meet all the UK's expected electricity demand in 2050. The key questions are how much can and will be developed and at what cost.

5.18 Our starting point in making this assessment has been work by ETSU for the DTI[38], summarised in Tables 5.2 and 5.3 below (detailed assessments by individual technology are in Annex C). These show estimates of potential for electricity generation by 2025, if the technologies continue to develop, and on the basis that barriers to development are successfully removed. We have concentrated on potential to 2025 rather than 2050 because to estimate 50 years ahead would become almost entirely speculative. The tables are based on discount rates of 8% and 15%. The lower figure is currently likely to be more realistic for most projects and technologies.

[38] New and Renewable Energy: Prospects in the UK for the 21st Century, Supporting Analysis, ETSU, March 1999.

Table 5.2 Maximum practicable resource in 2025 (8% discount rate)

	Electricity generated (TWh/year) at price under:			
	2.5p/kWh	3p/kWh	5p/kWh	7p/kWh
Agricultural and forestry residues	1	3	19	19
Energy crops (SRC)	0	5	33	33
Landfill gas	2	7	7	7
Municipal Solid Waste	3	4	6	7
PV	0	0	0	0.5
Tidal	<1	1	1.4	2
Wave	0	0	33	33
Onshore wind	10	45	57	57
Offshore wind	35	98	100	100
TOTAL	51	163	257	258

Table 5.3 Maximum practicable resource in 2025 (15% discount rate)

	Electricity generated (TWh/year) at price under:			
	2.5p/kWh	3p/kWh	5p/kWh	7p/kWh
Agricultural and forestry residues[39]	0	0	14	18
Energy crops (SRC)	0	0	33	33
Landfill gas	1	2	8	8
Municipal Solid Waste	0	1	2	4
PV	0	0	0	0
Tidal	0	0	1	1.4
Wave	0	0	0	33
Onshore wind	0	0	57	57
Offshore wind	0	0	98	100
TOTAL	1	3	213	254

[39] Data for sawmill co-products and forest products, which may constitute significant resources, are not available.

5.19 The ETSU resource cost curves from which these figures are drawn represent one view only, and it is possible to regard some of these assessments as too pessimistic (we return to this below). But there are some key points which we think would be widely accepted:

- the practicable resource, by 2025, is large. At a price of electricity under 5p/kWh it amounts to around half to two-thirds of projected electricity demand;

- delivery of significant renewables generation at reasonable cost (under 5p/kWh) will be substantially reliant on wind (on and offshore) and, to a lesser extent, energy crops.

5.20 Our own assessment would categorise the key renewables technologies under the headings of already proven, proven by 2025 and those with long-term potential by 2050.

5.21 Already proven technologies include:

<u>Onshore wind</u> - this has a large potential – generation of 50TWh/year by 2025, at a competitive cost around 2-2.5p/kWh. In cost terms this is more optimistic than the ETSU work.

<u>Municipal solid waste and landfill gas</u> can be competitive (cost around 1.5-2.7p/kWh), but the scale of resource is relatively small – around 3-4% of total generation.

5.22 Technologies proven by 2025 include:

<u>Offshore wind</u> offers great potential. Little has been developed in the UK so far, but advances in installation methods and demonstration plants could prove the technology, reduce costs and increase deployment. By 2020-25, cost could decline to 2-3p/kWh and 100TWh/year (over one-quarter of the UK's generation needs) could be provided.

<u>Energy crops</u> A significant resource, around 10% of generation, is possible. But this is at a slightly higher cost than wind (and also above generation from gas), at around 3-4.5p/kWh.

5.23 Technologies with long-term potential by 2050 include:

Wave power The UK has one of the best wave power resources available. It is clear that wave power devices can be made to work; but it is not yet demonstrated that they can do so at economically attractive prices. Further innovation will be required to achieve true commercial competitiveness.

Photovoltaics is currently and for the foreseeable future too expensive for significant electricity generation applications, but it has potential by 2050.

Other technologies may have niche roles, but are too speculative for us to include as definite cost-effective contributors to electricity supply by 2050 (tidal) or the resource is too small to make a substantial further contribution (agricultural and forestry wastes, landfill gas, hydro).

Other options

Capture and storage

5.24 Carbon capture and storage has potential – with intensive capital investment - to avoid the release of significant amounts of carbon. Capture applied to a new CCGT plant with transport over 300 km and storage in geological aquifers might add between 0.5p and 1p/kWh to the cost of gas generation. Issues associated with this technology which need resolving include engineering risks associated with transmission, probability of sudden or gradual release, associated environmental risks and the legal status of disposal in sub-sea strata, given the provisions of the London and Ospar conventions. The cost of carbon sequestration from coal-fired plant will be somewhat higher (there is a greater efficiency decrease in coal-fired plant because more CO_2 per kWh has to be captured).

Existing nuclear plant – life extensions

5.25 Life extensions to existing plants, so long as the plant continues to contribute to electricity supply to the high safety and environmental standards that are required, might be cost-effective as means of contributing to intermediate Carbon reduction targets (beyond the Kyoto period, but not 2050). However, most of the closures are expected in the next two decades, and even the last of the existing stations, Sizewell B, is currently expected to close around 2035. By 2050, even with some life extensions, we can expect to see all existing stations closed.

New nuclear build

5.26 There are some public concerns about safety relating to new nuclear build. Based on current costs new nuclear build on current technology is probably not cost-effective as a source of carbon saving. However, looking towards 2050, cost reductions with new designs are possible. Based on assessment of the literature and industry views, a price range of 2.6 p/kWh to 4.0 p/kWh is suggested.

Fusion

5.27 The RCEP report briefly addressed fusion but noted that it is still at the research stage and that a commercial-scale demonstration plant is unlikely before 2050. It therefore concluded that, even if the technical viability of fusion could be established, it would not be prudent to base energy policies on the assumption that it will become competitive with other non-carbon energy sources in the future.

5.28 We have also looked at options such as active solar, geothermal power and photoconversion. They are generally either technically not proven or likely to prove too expensive compared with other low carbon options. A more detailed analysis of these options is contained in annex C.

Electricity network

5.29 It seems generally expected that the next few decades will see a considerable expansion of embedded generation. Intermittent generation from wind and, in the longer term, solar sources will also grow. Greater emphasis on carbon reduction will add to these developments.

5.30 It is uncertain exactly how the network will respond. It will almost certainly look very different in 2050 compared with now. A number of different technical developments are possible. The costs of such developments are currently unclear. We are not in a position to judge what the requirements of a 60% carbon reduction target would add to such costs. Work is under way at NGC to consider possible developments.

5.31 There seems, however, to be a general expectation that the Government's target for 10% of electricity generation from renewables by 2010 could be incorporated without significant implications for the network, although such implications are not ruled out as large increases in wind power in Scotland might require additional grid capacity for export. Beyond that up to around 20% of intermittent generation can be accommodated before technical and managerial change is required. The degree of fluctuation attached to such a level of intermittency is similar to that attached to current demand fluctuation.

5.32 As the market penetration of intermittent forms of generation increases some increase in costs is probably inevitable. Greater back-up generation or storage is required, that is increased start-ups/shutdowns of conventional plant.

5.33 It has previously been suggested that the costs of increased spinning reserve might amount to around 0.1p/kWh for 10% intermittent penetration. This estimate is, however, some years old. Wind predictability estimation has improved. NGC has itself confirmed that increased embedded generation to 2010 is not a problem and that sufficient fast response and reserve services are available for the entire 2010 renewables target to be met from wind.

5.34 For the purposes of considering the costs of increased renewables generation to 2025/2050 we have allowed for a cost of up to 0.4p/kWh for a 40% level of intermittent generation. This is, however, an area where more analysis is required, such as that being undertaken by NGC.

Transport

5.35 Substantially reducing carbon emissions from transport will require a combination of measures to reduce traffic demand, enhance the transport infrastructure across all modes, improve the energy efficiency of vehicles and encourage the introduction of low carbon fuels. Many measures primarily aimed at reducing traffic growth and congestion and improving public transport (e.g. congestion charging, local transport plans, rail and bus investment) should have a considerable impact on carbon emissions from road transport, but it is not possible at present to provide quantifiable long term estimates of the carbon saving beyond 2010.

5.36 Hybrid vehicles offer around twice the energy efficiency of conventional vehicles. There are models on the UK market now. They currently cost significantly more but the cost disadvantage is likely to decline as the market grows.

5.37 Fuel cell vehicles offer a longer-term prospect, offering substantive carbon reductions, especially if the hydrogen is produced from renewable sources. But considerable research and development needs to be undertaken worldwide to make fuel cells commercially viable, and there is no consensus yet about the best way of introducing this technology to the market. Ultimately fuel cell technology looks a likely market development. We are not able meaningfully to suggest costs at this stage. But as the Government's recent consultation on "Powering Future Vehicles[40]" makes clear, hybrid electric vehicles and fuel cells are identified as having long-term carbon reduction potential and being likely to move towards commercial viability.

[40] "Powering Future Vehicles": Draft Government Strategy. DTLR, DTI, HMT and DEFRA, December 2001

6. COST OF REDUCING CARBON EMISSIONS IN THE UK

Key messages:

Some low carbon (renewables) options could be competitive with electricity generation from gas even in the absence of allowance for carbon savings. New nuclear build and carbon sequestration may operate at a cost penalty to gas but have significant potential to produce carbon savings.

Energy efficiency improvements and structural change could produce between 22 and 26MtC additional (beyond baseline savings by 2050). Even allowing for a high take up of renewables and the assumption of a carbon-free electricity generation system still leaves a gap of 23MtC to the RCEP target. Much of the remaining gap will need to be filled by the transport sector. If the additional emissions from international aviation were to be included the gap would further increase potentially to around 40MtC.

In terms of overall costs to the economy, moving to a carbon-free generation system by 2050 could cost between -0.1% and +0.2% of GDP (with GDP having grown threefold by then). The impact on electricity prices could vary from around a 20% increase, if low carbon options turn out to be relatively expensive, to a position where prices could fall as a result of cheap on and offshore wind resources and high gas generation costs.

Modelling work using the MARKAL model suggests that the overall cost of abatement for a 60% reduction is estimated at up to 0.01 percentage points and up to 0.02 percentage points for a 70% reduction against a long term GDP growth rate of 2.25%.

Introduction

6.1 The previous chapter considered specific “options” for reducing CO_2 emissions. In this chapter we begin to consider how these might combine towards filling the “gap” to a 60% reduction target; and we move on to consider associated costs.

6.2 Our previous work has considered a variety of bases for a baseline projection. Depending on assumptions it is possible to construct very different baselines for 2050. Our initial projections show a gap as against a 60% reduction target ranging from 41 to 105MtC. Consideration of different "scenarios" for the type of world we live in further widens that range.

6.3 For our work in this chapter we start from a particular selected baseline – a projection of CO_2 emissions on the basis that carbon intensity change post-2010 continues at the historic (1970-2000) rate, excluding the unrepeatable fuel switching of the dash for gas, and allowing for nuclear generation plant closure. For illustrative purposes this seems to us a reasonable baseline to choose[41]. It gives CO_2 emissions in 2050 of 145 MtC, a gap to the RCEP target of 83MtC.

Sector contribution to baseline emissions projection to 2050

6.4 Figure 6.1 illustrates the sector contributions to this baseline projection to 2050, based on assumptions of continuation of intensity change equivalent to historic rates (1970-2000), by sector, after allowance for non-repeatable events such as the dash for gas and major fuel switching. This is the baseline (A) of Chapter 2 shown in Figure 2.1[42].

6.5 The sector contributions illustrated in Figure 6.1 (and given in Table 6.1 below) indicate reductions in emissions between 2000 and 2010 in all sectors due to measures included in the CCP. The industrial and domestic sectors continue a reduction in emissions post 2010, while transport and service sector projections to 2050 indicate the increasing proportion of total emissions contributed by the transport sector and to a lesser degree increased contribution from the service sector.

[41] Our purpose is to illustrate the potential for "filling the gap". It should be noted that the potential contribution of various "options" has to be considered against the chosen baseline. If we chose a different baseline then the scope of further options would also change. If, for example, more energy efficiency improvement were included in the baseline assumption, then the scope for additional energy efficiency improvement to be attained by further measures ought to fall.

[42] This baseline also incorporates an assumption of economic growth of 2.25% p.a. to 2050; a slight increase in population to 2030 and then a levelling off, resulting in a slight increase in household growth; and a continuation of trends away from heavy energy intensive industry to the service sector. Energy demand growth in the transport sector has been assumed to be at a slightly lower rate than in the past and energy efficiency improvements in transport are implied at past rates. Domestic air travel is assumed to grow faster than GDP, as has been the case in the past.

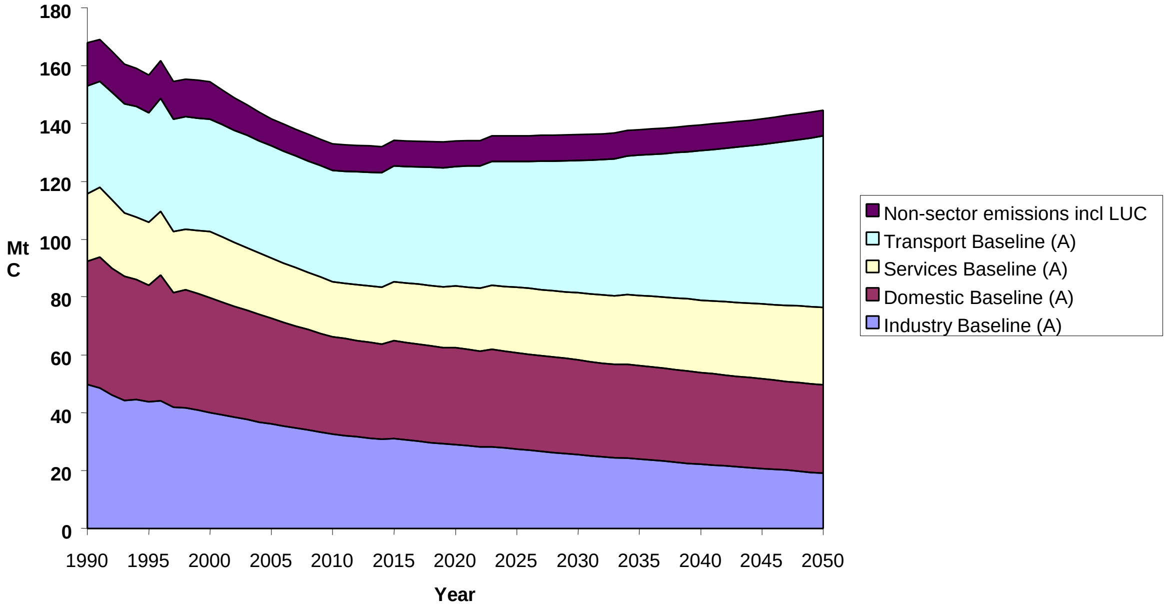
Table 6.1 Sector contributions to total baseline CO_2 emissions projections in 2050 (MtC)

	2000	**2010**	**2050**
Industry	40	33	19
Domestic	40	34	30
Services	23	19	27
Transport	39	39	59
Non-sectoral	13	9	9
Total	155	133	145

6.6 The contribution of the transport sector to total emissions in 2050 is significant. An assumption of continuation of past trends in growth in transport includes assumptions of past rates of energy efficiency improvement, but excludes the potential impact of road congestion, saturation of car ownership, increases in price of fuel and increased switching to alternative form of transport (modal switching), all of which could reduce energy demand. Improvements in technology e.g. fuel cells based on hydrogen from renewable sources; advanced ICE and hybrid duel fuel vehicles also provide opportunities to lower transport sector emissions.

6.7 An alternative approach, IAG(DEFRA), to the estimation of transport emissions (see paragraph 2.30) includes an increased impact of congestion, saturation of car ownership and assumes no new road build beyond 2010, reductions in rail fares which promote modal shift and fuel switching (to less gasoline and more biodiesel) and the (limited) introduction of fuel cells (non-hydrogen). That analysis suggests that transport emissions in 2050 may be as low as 39 MtC, some 20MtC below the IAG (baseline A) projection.

Figure 6.1 Historic and projected emissions by sector (baseline A) 1990 - 2050, including impact of nuclear closures, CCP and non-sector emissions



Bridging the gap to a 60% reduction

6.8 Starting from the IAG (baseline A) projection to 2050, based on historic rates of intensity change (1970-2000), bridging the gap to the RCEP target of 62MtC appears difficult but not technically impossible. A combination of:

- full achievement of all identified additional[43] energy efficiency potential in the domestic, service and industrial sectors;

- the continued penetration of renewables to reach 40% of generation;

- the additional carbon reduction achievable if all generation were carbon-free by 2050;

would provide overall emissions reductions of 60MtC. The calculation is illustrated in Figure 6.2 and Table 6.2 below.

6.9 A residual gap, if all these were achieved, of some 23MtC would remain. The main source for filling that gap would have to be transport. The IAG(DEFRA) baseline projection provides one illustration of how that gap might be filled allowing for congestion which acts to constrain

[43] Additional cost-effective energy efficiency potential identified by the DEFRA contributed papers above the energy efficiency improvement incorporated within Baseline (A). Differences in sectoral detail between the IAG(A) and DEFRA BAU baselines are ascribed to different degrees of structural change.

demand growth, no new road build beyond 2010 and reductions in rail fares. But if technical developments could deliver a greater switch to low carbon fuels, then these emissions reductions could potentially be achievable with less constraint on transport demand.

Figure 6.2 Bridging the gap to a 60% reduction in CO_2 emissions by 2050

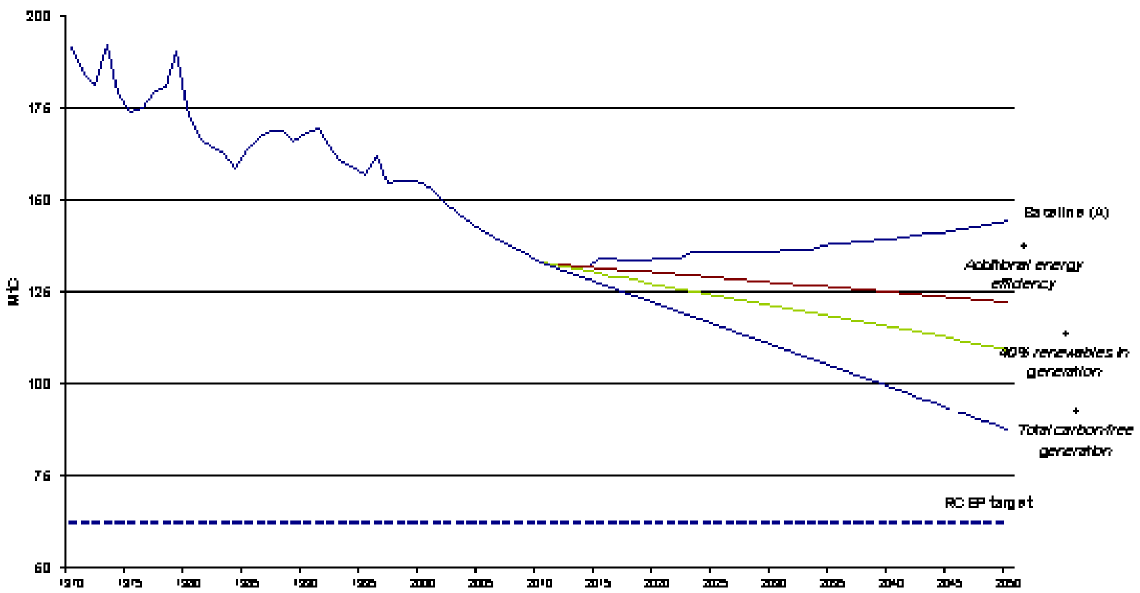


Table 6.2 Potential additional reduction from baseline (A)

	Potential reduction in emissions MtC	Cumulative sum of additional potential reduction	Projected emissions to 2050 from 145 MtC (baseline A projection)
Energy efficiency potential above baseline A	22-26	25 (approx.)	120
Renewables contribution to a 40% limit of generation	13	38	107
To total carbon-free generation	22	60	85

6.10 It is, of course, easier to specify the kinds of options that might contribute to closing the gap to a 60% reduction than to achieve that in practice. Aside from difficulties attached to raising energy efficiency performance:

- it is unlikely that UK electricity will be carbon-free by 2050. The above simply illustrates that measures other than carbon-free electricity will also be needed;

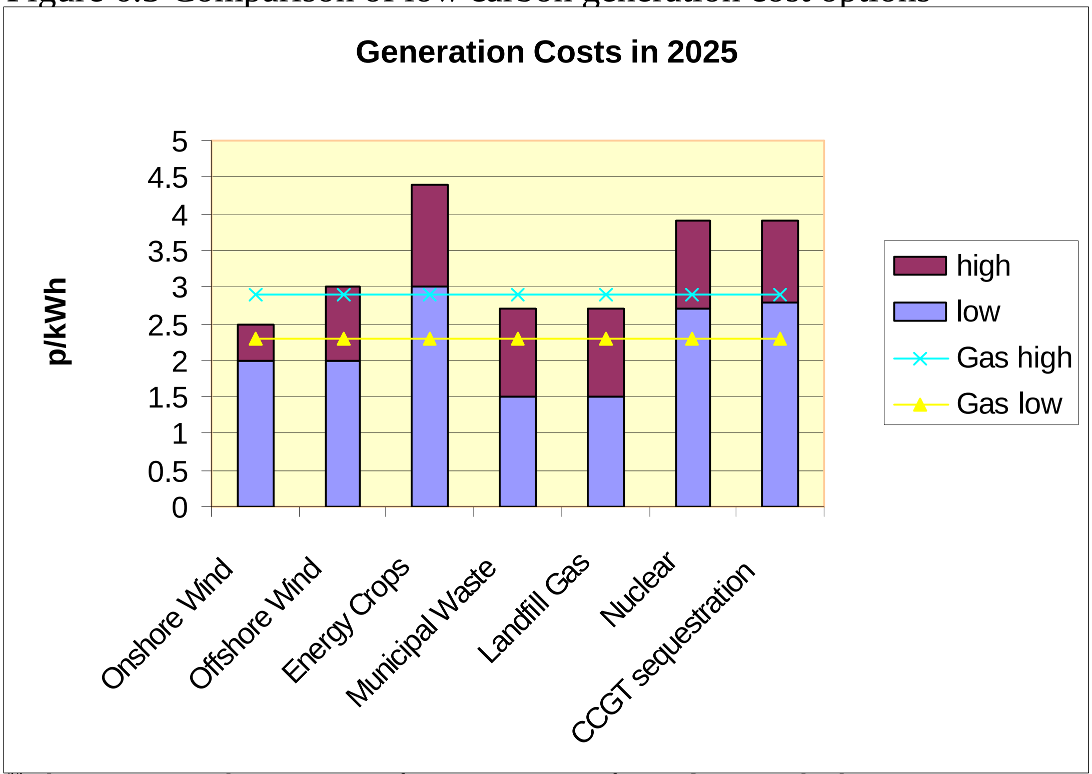
- international aviation emissions, to the extent assigned to the UK, could add significantly to the scale of difficulty.

Costs of generation

6.11 Drawing on the assessments from the previous chapter (and Annex C), Figure 6.3 below summarises our projected ranges of electricity generation costs in 2025 for the main technologies we think have (a) potential to become broadly cost-effective (including allowance for carbon saved); and (b) potential to contribute significant carbon savings.

6.12 The cost comparisons are drawn against a cost range for generation from gas of 2.3-2.9p/kWh.[44]

Figure 6.3 Comparison of low carbon generation cost options



[44] This compares with a current cost for gas generation of around 1.8-2.0p/kWh. A gas generation cost reaching 2.9p/kWh by 2025 would represent annual real growth from current levels of 1.7% a year. Note that sequestration will always be more expensive than gas generation by a factor estimated to be between 0.5p and 1p/kWh. The cost of sequestration from coal-fired stations could be somewhat higher.

6.13 On the basis of Figure 6.3 it is possible that some low carbon technologies could become cost competitive with gas, even in the absence of allowance for carbon gains. Others could become competitive if they operate towards the more optimistic view of their potential on cost, or through internalisation of carbon. In terms of potential to contribute significant carbon savings, on and offshore wind are most promising in this regard.

Cost per tonne of carbon saved

6.14 Tables 6.3 and 6.4 below summarise our estimates , in ranges, for cost per tonne of carbon saved by different technologies. This is not confined to generation options. It includes energy efficiency by sector. None of the specific transport technology options that we have considered are shown. These have high estimated costs when measured in terms of cost per tonne of carbon saved (above £250/tC), but these often produce significant other environmental benefits such as improved air quality and reduced congestion, which have not been taken into account here. So a high £/tC does not necessarily indicate that these policies would not be cost effective overall.

Table 6.3 Estimated costs and potential in 2025

	Cost (£/tC)		**MtC**
	L	**H**	**Potential**
Energy crops	10	210	1
Municipal waste	-140	40	1
Landfill gas	-140	40	1
Onshore wind	-90	20	4
CCGT sequestration	70	100	5
Nuclear	-20	160	6
Offshore wind	-90	70	7

Table 6.4 Estimated costs and potential in 2050

	Cost (£/tC)		**MtC**
	L	**H**	**Potential**
Municipal waste	-80	210	1
Landfill gas	-80	60	1
Energy crops	10	180	3
Onshore wind	-90	20	6
Energy efficiency - industry	-80	35	7
Energy efficiency - services	-250	20	8
Offshore wind	-90	70	10
Energy efficiency - domestic	-100	20	11
CCGT sequestration	50	100	25
Nuclear	-30	170	25

6.15 The cost ranges shown reflect:

- for the electricity generation options, the low cost/tC figure reflects a low cost for the specific technology against a high gas generation cost; a high cost/tC figure reflects a high cost for the specific technology against a low gas generation cost;

- for the energy efficiency options, the low cost/tC figure reflects an assumption that bottom-up assessments correctly identify significant potential which is cost-effective in its own right; a high cost figure makes a worst-case assumption that there are hidden cost such that all further potential entails positive marginal costs.

6.16 The results suggest that there is a range of options combining low cost with limited potential and higher cost options with greater potential carbon savings. New nuclear build and carbon sequestration may offer the greatest absolute potential at a reasonable cost, compared with a number of transport options. Energy efficiency in individual sectors offers good potential at a probable lower cost. The costs for certain renewables options do not include those associated with their intermittent nature or the impact on quality of supply, e.g. on and offshore wind.

Summary cost analysis

6.17 Based on the generation cost estimates in table 6.4 we have estimated a cost of moving to a carbon-free generation system of between -0.1% and +0.2% of GDP in 2025. This calculation depends very heavily on the assumptions made about the cost and potential capacity of new renewables options and the cost of the alternative means of generation, assumed to be gas. These costs include an estimate for network/balancing costs associated with embedded generation/intermittency. Compared with a cost of gas-fired generation of 2.3p/kWh, the impact on final industrial electricity prices would be between 1% and 4% if zero carbon options cost at the low end of our estimates or up to 23% at the high end. The impact on domestic electricity prices would be around just over half this level. Clearly if gas generation costs were as high as 2.9p/kWh and zero carbon options came in at the lower end of the range, there is scope for reductions in electricity prices compared with what they would otherwise have been. These might be in excess of 10% for industry and 5% for domestic consumers compared with the level of prices consistent with gas-fired generation.

6.18 We have also considered a worst case scenario where all electricity generation is carbon-free but at a cost of 4p compared with gas at 2.3p/kWh. This would mean a cost per tonne of carbon of around £170. The total cost to the economy in 2050 would be £6.8bn. This is based on an additional cost of 1.7p/kWh multiplied by an estimated level of generation of 400TWh. It would represent about 0.27% of GDP in 2050, assuming that the economy grows at 2.25% over the period. The impact on the GDP growth rate over the whole period would be around 0.005 percentage points.

6.19 The DTI, DEFRA and the PIU commissioned AEA Technology and Imperial College to use the MARKAL model to develop a range of "bottom-up" estimates of carbon dioxide emissions from the UK energy sector up to 2050, and to identify the technical possibilities for the abatement of these emissions. Three levels of abatement by 2050 were considered: a 60% reduction relative to emission levels in 2000 – approximating to the level considered by the RCEP – plus 45% and 70% reductions.

6.20 The MARKAL modelling results indicate that the cost of moving to a 45% reduction in emissions by 2050 could be between £85 and £150 per tonne of carbon. For a 60% reduction the average cost increases to around £200 and for 70% to between £270 under Global Sustainability and £360 under World Markets (scenarios described in Annex B). The marginal cost involved in moving from a 60% to a 70% reduction increases significantly to about £440 under the GS scenario and to nearly £1100 under the WM scenario. The cost of abatement for a 60% reduction is estimated at up to 0.01 percentage points and up to 0.02 percentage points for a 70% reduction against a long term GDP growth rate of 2.25%. This would still represent a non-recoverable decrease in living standards, although the model does not take account of the benefits of emissions mitigation or any opportunities to the UK economy which might arise from the technological developments implied. The conclusions of the project are described in annex E.

7 GENERAL CONCLUSIONS

Key messages:

The future is uncertain. We cannot know, today, what the most cost-effective means of meeting a carbon reduction target 50 years ahead will be. There are many examples from the energy sector and elsewhere of Government efforts to establish particular technologies as "winners", which have failed and actually led to large costs. We are most likely to meet a substantial carbon reduction target at least cost if we give a value to carbon, via emissions trading or the appropriate internalisation of carbon, and let the market respond.

While economic instruments are likely to be an important component of a policy package, energy supply and demand is characterised by a number of market failures. There are a number of barriers such as lack of information, inertia and uncertainty to the adoption of low carbon measures. There will be a role for a mix of instruments, including regulation, to achieve carbon reduction at least cost and drawing in sectors across the economy. A range of measures is likely to be required, targeted to specific market failures or barriers.

A 60% reduction target is technically achievable but it is a major challenge. It is unlikely to be reached without a substantial enhancement of policy measures and the development of low cost technologies. On the supply and demand sides the costs could be quite large. But with such technology development there is scope for considerable cost reduction. The right policy framework can encourage technology innovation and development.

Letting the market decide

7.1 A key theme of the preceding analysis is uncertainty. We do not know how baseline emissions will change. We do not know how the costs and potential of currently available technologies will develop. We expect the costs of a number of developing lower carbon technologies to reduce, but we do not know how far. We do not know what new technologies might develop.

7.2 In these circumstances a prime consideration must be to create the right framework which will reward the best, most cost-effective technologies and encourage their development. This means a policy that is not primarily about picking winners, but which allows the market to provide appropriate incentives. That means using the market to promote the achievement of regulated standards or targets (as with the renewables obligation or the energy efficiency commitment). Given our objective is carbon reduction it means moving towards a structure, whether by emissions trading or the appropriate internalisation of carbon, and with coverage that, subject to the constraints which will inevitably arise from other policy considerations, is a wide as possible.

7.3 The fact that we see price signals as fundamental is not to exclude other policy actions. Other measures such as information campaigns, target setting and minimum standards will have a role. But some role for price signals is inevitable and in some areas they will be key.

Innovation

7.4 Much of our analysis has been too static in nature. We have made use of projected resource cost curves, but these are inevitably constrained by what we (think we) know now, and by our past experience of cost reductions for new technologies. And we do not know what new products and processes may emerge.

7.5 Economic instruments (carbon internalisation, trading) have a role here – they provide a signal which helps to incentivise innovation. But more than this may be required. In specific areas there may be a role for further Government support to encourage or fund RD&D. Economic instruments will be strongest where the signal is clear and strong – the potential innovator must be convinced that there is long-term Government commitment, and therefore that the reward will be long-standing. But markets may still reflect too much "short-termism".

Energy efficiency

7.6 Energy efficiency improvement is constrained by a range of barriers but the potential is large. While improving price signals (to reflect carbon) will help, it is not sufficient. Market transformation is required incorporating a range of policies (standards, pricing signals, information) which build and reinforce each other.

7.7 Product regulation is likely to be particularly effective in markets involving large numbers of small users, such as housing and consumer products.

7.8 The role of process/emission regulation for large business users is less clear-cut. There is evidence that energy demand in business is price inelastic. But pricing signals through emissions trading may nevertheless expand the market for energy efficiency improvement – attracting the attention of business in a way not achieved to date.

Inter-departmental analysts group – membership

Adrian Gault, DTI (Chairman)
Stephen Green, DTI (Secretary)
Chris Bryant, DTI
Terry Carrington, DTI
Mark Hutton, DTI
Margaret Maier, DTI
Duncan Millard, DTI
Peter Roscoe, DTI
Ian Coates, DEFRA (until April 2001)
Hunter Danskin, DEFRA
Kathryn Deyes, DEFRA (until September 2001)
Gabrielle Edwards, DEFRA (until June 2001)
Rhian Hawkins, DEFRA (from April 2001)
Jim Penman, DEFRA
Stuart Anson, DTLR
Liz Cox, DTLR
Ashley Bennett, HMT
Michael Dawson, HMT
Andrew Holder, HMT (until April 2001)
Nick Eyre, PIU
Robert Gross, PIU
Catherine Mitchell, PIU

We have also benefited from the considerable contribution of a number of others on particular topics, even if they have not been regular attendees at group meetings. These include John Collingwood, Heather Haydock and Peter Taylor from AEAT and Professor Paul Ekins from the Policy Studies Institute and the University of Keele.

Estimating scale of the carbon reduction required

SUMMARY – The size of the Gap.

B1 The development of a range of business as usual baselines, and scenario projections of long term carbon emissions, within the Foresight scenario framework[45], provides an illustration of the absolute size of the gap between the recommended RCEP emissions target to be reached by 2050. The scenario approach provides a range of "expected" carbon emission levels in 2050 on the basis of several key assumptions associated with, for example, GDP, population and sector growth. This paper does not consider the introduction of radical technological changes (although some limited assumptions are made within the scenario sector assumptions), but looks at what "could happen" if things were to continue according to past trends and four alternative future scenarios. The approach has deliberately been kept simple and transparent so that the projections and the estimation of scale of the task required to meet such a target recommended by the RCEP will inform the work of the IAG rather than implying the projections are the *results* of the group. The scenario projections are therefore "baseline scenario" projections.

B2 The size of the gap between the recommended RCEP target of emissions 60% below 1997 UK levels and a "business as usual" baseline scenario[46], is estimated to be 83MtC[47]. In the most unfavourable baseline scenario, e.g. a world based on individual consumerist values, a high degree of globalisation and scant regard for the environment the gap could be as much as 118MtC. In a world based on strong collective environmental action the gap could be lower, at 70MtC. Only in a world characterised by communitarian and strong conservation values, with diverse political and economic regionalisation does this analysis suggest the gap may be as low as 32MtC. This is partly as a result of the low economic growth (as measured by GDP) associated with this scenario together with high energy prices, sharp increases in transport costs, use of alternative modes of travel, e.g. walking and cycling and greater environmental awareness.

---

[45] Appendix 1

[46] Based on historic rates of carbon intensity improvements in the various sectors, adjusted for non-repeatable carbon reducing impacts e.g. the dash for gas.

[47] Other baseline scenario projections, using less optimistic assumptions suggest the size of the gap could be as high as 100MtC. See Table B.5

B3 These estimates of the size of the gap are based on carbon intensity (carbon per unit of GDP) rates of change experienced in the past (1970-2000) net of non-repeatable events, such as the dash for gas in the power industry and switching from high carbon fossil fuels to lower carbon fuels in the domestic sector. Based on an alternative assumption of say a series of environmental policy measures devised to achieve higher carbon intensity improvements than experienced in the past and similar to those measures included in the Climate Change Programme, launched in November 2000, for example, (conditional on these anticipated reductions in carbon emissions being achieved and maintained throughout the next fifty years) the gap may still be 44MtC above the RCEP target of 62MtC by 2050 in this baseline scenario. This also assumes that technological developments, structural change and energy efficiency improvements continue at a similar rate as in the past.

B4 Table B.1 illustrates the size of gap between projected UK emissions in 2050 relative to the recommended RCEP target estimated by the baseline business as usual projection and the four alternative futures[48] scenarios. The lower limit in each case illustrates an *optimistic* scenario of sustained low carbon policies over the long term, the upper limit illustrates a continuation of past trends, excluding trends considered non-repeatable such as fuel switching in the domestic sector and the dash for gas in the power generation sector.

Table B.1 Size of the gap under the baseline and four alternative scenarios

Target	**Baseline MtC**	**World Markets MtC**	**Global Sustainability MtC**	**Provincial Enterprise MtC**	**Local Stewardship MtC**
RCEP	44 to 83	69 to 118	36 to 70	34 to 67	9 to 32

INTRODUCTION

B5 The IAG have taken as their remit the consideration of the implications of the RCEP's recommendation of a 60% reduction in CO_2 emissions by 2050. To estimate the scale of the task it is necessary to establish a baseline CO_2 projection - a view of what might happen to CO_2 emissions in the absence of further policy action. Projecting 50 years ahead is difficult and there will be considerable uncertainty associated with any estimate so far into the future. Econometric models are valuable in the medium to longer term but projecting beyond 2010 to 2050

[48] The four Foresight scenarios have been developed to illustrate four "possible states of the world" they are not all equally probable.

becomes difficult as for example, technologies are expected to change, new processes and systems are introduced and the detailed econometric relationships built on past relationships are no longer valid in this time frame.

B6 The approach adopted in this study has been to develop a range of baseline projections of carbon emissions, which are simple and transparent. The starting point has been the Government's energy and emissions projections to 2010 contained in Energy Paper 68 (EP68) published in November 2000. Projections beyond 2010 are based on a range of simple assumptions for continued carbon intensity[49] change based on historic rates of change or assumed rates of future change. To help illustrate the inherent uncertainties in projecting over this time scale four alternative scenario projections have been developed to represent four possible "future states" of the world. The four scenarios are based on the Foresight Future scenarios developed by the DTI. The Foresight scenarios are also being used by the PIU. In this way it is possible to estimate the size of the gap between the projections of carbon dioxide emissions estimated in 2050 and RCEP's recommended target of a reduction of 60% emissions from 1997[50] levels.

Establishing a baseline.

B7 The baseline projections to 2050 have been established using an initial period from 2000-2010 and a longer period from 2010 to 2050. This initial period was developed from the energy and emissions projections contained in Energy Paper 68 (EP68) and based on the two central GDP growth scenarios. These projections relate to the period during which policy measures introduced in the CCP to reduce emissions and improve energy efficiency are estimated to take effect. The EP 68 baseline projection was then adjusted to include effects of the CCP measures that were not included in the original EP68 modelling. The 2000-2010 projection, including the CCP effects forms the initial "stem baseline projection" to 2010[51]. The longer term baseline projections, from 2010 to 2050, are formed on basic assumptions of future rates of

[49] Defined as carbon per unit of GDP.
[50] The RCEP recommendation of a 60% reduction in emissions from current levels does not specify the final level or year upon which it is based – it has been assumed that it refers to the level in year 1997 which is the latest year quoted in the report. The 1997 level of UK emissions at 156MtC (basis used in EP68) thus implies an RCEP target of 62MtC.
[51] An alternative approach was explored which took the econometrically modelled projection to 2020, however this included the period beyond 2010 for which the CCP effects were not sufficiently known and it was decided to adopt the earlier stem period to 2010 as the baseline, while also reporting the results of using a 2020 base for illustrative purposes.

carbon intensity change by sector, i.e. domestic, services, industry and transport, including non-sectoral and land use change emissions.

B8 Two variants of the baseline projections were formed to 2050. In the first the assumption is of a continuation of the historic sectoral carbon intensity rates of change trends from 1970 to 2000.The carbon intensity rates of change by sector were adjusted to remove past effects considered non-repeatable, for example, the effect on carbon intensity rates of change of the "dash for gas" (DFG) and to allow for limits on future opportunities for fuel switching (from high carbon fossil fuels to lower carbon fossil fuels). The carbon intensity rates of change and the energy intensity rates are shown in Appendix 2 Table 6. The second baseline scenario assumes the continuation of *estimated* trends of carbon intensity change between 2000-2010 under the period of the CCP and based on EP68 projections. This has the advantage of examining two possible scenario variants, the historic trends representing perhaps what may also be termed the *pessimistic* scenario i.e. a projection of a continuation of trends in carbon intensity change where little or no policy was directed at reducing carbon emissions (1970–2000) and a projection of the 2000-2010 trends representing perhaps the *optimistic* scenario where a concerted effort is being made to reduce carbon emissions over a ten year period with e.g. the CCP and with a view towards the Kyoto target (2008-2012) and the UK domestic target of a 20% reduction on emissions by 2010, a rate of change, which if maintained over a forty year period, would represent a considerable commitment to carbon reduction by 2050.

B9 The baseline projections also include the impact of nuclear closures on emissions with the assumption that capacity is replaced by gas-fired generation. The baseline includes the four sectors listed above plus an element of non-sector emissions.

Scenario approach.

B10 To illustrate the considerable uncertainty associated with projecting carbon emissions over the next fifty years the baseline scenario idea was extended to include the introduction of more radical ideas of what the world may look like in 2050. The time available for the IAG study did not allow for the original development of some new scenarios so it was decided to adopt the four Foresight Futures scenarios developed by SPRU and the DTI. These are briefly described below.

The Foresight Environmental Futures scenarios

B11 The Foresight Environmental Futures scenarios have been developed by the DTI in co-operation with SPRU and are closely aligned to the IPCC emission scenarios published in 2000 in the Special Report on Emissions Scenarios (SRES). The SRES Emissions scenarios[52] provide four qualitative storylines or "families" A1, A2, B1 and B2. These families, while more complex, are reflected closely in the four Foresight scenarios referred to as World Markets, Provincial Enterprise, Global Sustainability and Local Stewardship respectively (and illustrated in Appendix 1). The four Foresight scenarios are not intended to predict the future, rather explore alternative directions in which social, economic and technological changes may evolve.

B12 They are described briefly as follows:

World Markets: - based on individual consumerist values, a high degree of globalisation and scant regard for the environment;

Global Sustainability: - based on predominance of social and ecological values, strong collective environmental action and globalisation of governance systems;

Provincial Enterprise: - based on individualistic consumerist values, reinforced governance systems at national and sub-national level;

Local Stewardship: - based on communitarian and strong conservation values, reinforced diverse political and economic regionalisation.

B13 The key indicators assumed for each scenario are based on developmental work by SPRU[53], which provided the framework for studies within the UK Climate Impact Programme to provide coherent and different pictures of the future[54]. The key scenario indicators available were limited to assumptions on economic and population growth, and household growth.

B14 Some of the key assumptions used in the SPRU study were inconsistent with current ONS long term population projections and there was some doubt about economic growth assumptions associated with some scenarios but the decision was taken in cooperation with PIU and

[52] Emission Scenarios: A special Report of IPCC Working Group III, 2000
[53] Environmental Futures Scoping Study, Final Report Nov 1998, University of Sussex.
[54] Socio-economic scenarios for climate change impact assessment. Feb 2001. UKCIP.

DEFRA that, although revised population projections were needed, the essential characteristics of the original Foresight scenarios would be maintained. The key assumptions agreed are given in Table B.2 below and have been applied from a base of 2010, estimated from EP68. The assumptions within each scenario are also variable with respect to the assumed rates of carbon intensity change, as before in the baseline, i.e. the variants are the past rate of carbon improvement 1970-2000 or the estimated rate 2000-2010 adjusted for CCP, DFG and fuel switching as appropriate.

Table B.2 Long Term Projections Scenario Assumptions

	EP68 Baseline	World Markets	Provincial Enterprise	Global Sustainability	Local Stewardship
UK GDP growth p.a.	2.25%	3.00%	1.75%	2.25%	1.25%
Population in 2050 (million)	65	66	64	63	62
Household size in 2050	2.17	2.00	2.40	2.20	2.60
Implied household numbers growth p.a.	0.30%	0.54%	0.00%	0.18%	-0.27%

<u>Additional scenario assumptions</u>

B15 In addition to the key assumptions on growth of GDP, population and number of households additional assumptions have been made to reflect, in a limited sense, the socio-economic implications of the different scenarios. Behavioural changes in the domestic and transport sectors are captured in the household formation and growth assumptions and between transport and economic growth assumptions. Technological change assumptions in the transport sector determine transport vehicle emission rates. Structural and technological change in the service and industry sectors is determined across scenarios in the value added contribution to GDP and relative weight of each sector. These basic assumptions reflect the de-coupling of transport demand from economic growth and allow for improvements in the emissions associated with the vehicle stock across scenarios. The rates of industrial and services sector growth associated with each scenario are also allowed to vary across scenario to reflect structural and technical change. Additional basic assumptions have been made for nuclear and coal in power generation across scenarios. These have been limited to the closure or continuation of existing nuclear plant and coal use being maintained at 2020 levels projected in EP 68.

B16 The assumptions underpinning the scenarios are shown in Appendix 3. Obviously judgements are involved here. Different detailed assumptions could be made, and almost certainly would be if others were to attempt such an exercise. But these are only scenarios and we hope that in this context - as a set - they cover a range of possibilities that can command broad acceptance.

B17 Generally an emissions scenario approach includes a complete set of assumptions regarding the possible state of the future. These would include assumptions about the full socio-economic situation, future climate change effects and the impact of technological change on the environment. This study requires a more limited approach to scenario prescription. The immediate task of the IAG was to identify the potential gap in CO_2 emissions against a business as usual scenario in order to explore potential policy implications. Adopting all the assumptions associated with say, the Global sustainability scenario, would require that the effects of policies designed to build an environmentally sustainable future were "built-in" in order that international climate change targets were met. This would leave little room to identify those policy actions, which the group hoped to identify as being necessary to meet the gap. The gap would have been assumed away! This represents a departure from other scenario approaches, such as the PIU approach, but we believe is a necessary one. One small concession to this approach has been in respect of nuclear closures. The baseline, and world markets scenarios assume nuclear closures as scheduled whereas the other three scenarios assume existing nuclear plant life has been prolonged. The impact of these assumptions is minimal. (See sensitivities below in section 5). The IAG approach also has the advantage that building "business as usual" baseline and scenario projections enables the calculation of consistent final energy demand projections which are then available to provide the basic demand projections input required to conduct a linear optimisation analysis (e.g. MARKAL) which seeks to identify possible technologies needed to meet the gap between the various emissions targets. The available technologies, the technology costs, learning curves and fossil and other fuel costs are then assumed consistent with the baseline and scenario "storylines".

Forecast base and forecast horizons.

B18 Econometric models work best in the medium term and scenarios best with the longer-term horizon. It was therefore decided that this analysis utilised the medium term projections obtained from the DTI UK energy and emissions model for the medium term. This conveniently covered the period 2000 to 2010 and beyond to 2020. This provided an option to take as a forecast base either the year 2010 or 2020, both following on from the EP 68 econometric projections and allow for scenario divergence from the points 2010 or 2020. The EP68 projections could be adjusted easily to allow for the impact of CCP to 2010 from the published programme, however, beyond 2010 estimates of the continuing impact of CCP were unavailable and required to be estimated. We have adopted as the base set of scenario projections those, which begin at 2010, although those starting from 2020, allowing for estimated CCP effects have also been made and are given as comparisons in this paper. A full set of 2020-based results is available on request.

Climate Change Programme impact in medium term (2010 to 2020)

B19 The impact of CCP measures beyond the programme's 10 year horizon was provided by DEFRA on the basis that the percentage change from the carbon emissions baseline of a 17.75MtC reduction in 2010 is applied to the 2020 emission figure. This assumes an 11.5% reduction from the 160.7MtC estimate of 2020 emissions in EP68 (i.e. 18.5 MtC). This was only a proxy figure which at the political level balances a likely ongoing imperative for action against a probable rising trend in emissions, and at the technical level depends on the rate at which new energy saving potential becomes available compared to the rate at which measures are taken up. This assumption has been adopted in all the calculations relating to "CCP effect to 2020".

Structural and technological change in industry and service sectors

B20 Technological and structural change in the industrial and service sectors is demonstrated by their contribution to economic growth. The historical trend away from heavy to less energy intensive industry are assumed to represent "technological" change and are reflected in assumptions of carbon intensity change and structural change is reflected in the economic contribution from each sector. The assumptions relating the industrial/service split of the baseline and within each scenario are outlined briefly below and shown in Appendix 3 .

Baseline assumption: current shift to services continues, with the assumption that the services-industry mix in additional value added will be 75% to 25%, for an overall GDP growth rate of 2.25% p.a.

World Markets scenario assumption: the relative decline of industry accelerates rapidly: the service-industry mix standing at 85% to 15%, with an overall GDP growth rate of 3% p.a.

Provincial Enterprise scenario assumption: the relative decline of industry is halted, implying balanced growth at 50% to 50%.

Global Sustainability scenario assumption: the split is assumed at 80% to 20% with moderate relative decline.

Local Stewardship scenario assumption: relative decline is halted; the industry services split in value added is 50% to 50%.

Renewables assumption in electricity supply Industry

B21 The assumption of growth in renewables in the electricity sector under the optimistic scenario projections is of a continuation of growth assumed in EP68 and represents a growth to 40 % generating capacity saving 11.1 MtC in 2050.

Energy efficiency improvement

B22 Within the scope of this analysis and the degree of sector disaggregation available the rates of improvement in energy intensity per annum by sector assumed within the baseline are given in Table B.3 below. Energy efficiency improvement trends have been included within the baseline and scenario projections to the extent that they reflect a continuation of past energy efficiency improvement trends and are reflected in the assumptions of sector emissions growth in the transport, industry, service and domestic sectors.

Additional energy efficiency

B23 There is considerable literature on the potential energy efficiency improvement still available within these sectors, especially the domestic sector. DEFRA have contributed papers on energy efficiency improvement potential to the IAG[55]. IAG (DEFRA) have assumed baseline rates of energy efficiency broadly in line with historic rates and are thus reflected in the levels of energy efficiency rates by sector included within our baseline and scenario projections (Baseline A). The IAG(DEFRA) papers suggest that, if the additional potential energy efficiency improvements were achieved, this would amount to some additional savings in carbon emissions of between 22-26MtC in 2050 above their baseline. Consideration of the differences between the IAG and DEFRA baseline emissions projections suggests that they can be ascribed to different assumptions concerning structural change, i.e. the additional energy efficiency contribution applies to either baseline, within reasonable margins of error.

Table B.3 Implied energy intensities by sector[56] in baselines

	Energy intensities assumed in baseline (% p. a. change)		
	Baseline A (1970-2000)	**Baseline B (2000-2010)**	**Baseline B (2000-2020)**
Aggregate	-1.83	-2.40	-2.25
Domestic	-2.60	-3.41	-2.89
Services	-1.57	-2.53	-2.21
Transport	-1.09	-2.05	-1.94
Industry	-2.80	-2.62	-1.89

Baseline A represents assumed energy intensity improvement at historic 1970-2000 rates, excluding DFG and fuel switching

Baseline B represents assumed energy intensity change of 2000-2010 or (2000-2020) rates, including CCP but excluding DFG and fuel switching effects

[55] The DEFRA summary paper is included at annex D and the remaining five papers are available on the PIU website.

[56] Aggregate defined as aggregate energy per unit of GDP. Domestic and transport sectors are sector energy per unit of GDP per household. Industry and services are sector energy per unit of output.

Table B.4 Assumed transport sector energy intensity variants by scenario

	Transport Sector energy intensity by scenario (% p.a. change)			**Energy Intensity Index (1995 = 100)**		
	Baseline A (1970-2000)	**Baseline B (2000-2010)**	**Baseline B (2000- 2020)**	**2000**	**2010**	**2020**
World Markets	-.81	.15	.16	99.7	101.4	102.8
Provincial Enterprise	-.72	.14	.14	99.7	101.4	102.8
Global Sustainability	-1.08	.20	.22	99.7	101.4	102.8
Local Stewardship	-1.08	.20	.22	99.7	101.4	102.8

RESULTS

The scale of the effort required based on aggregate projections.

B24 The scale of the effort required to meet the recommended target of a 60% reduction in CO_2 emissions by 2050 is illustrated in Tables B.5 and Table B.6 below. These tables present the simple projections of the aggregate UK emissions by carbon intensity trends. Table B.5 illustrates the carbon intensity changes required to reach the targets from either a 2010 or 2020 base and B.5 the projected carbon levels (MtC) in 2050 based on assumptions of historic trends based on 1970 to 2000 carbon intensity trends under a number of conditions, such as, the impact of fuel switching, dash for gas, nuclear plant closure assumptions, results are given for scenario divergence from either 2010 or 2020.

B25 The scale of the effort is shown in a carbon intensity improvement rate required to meet the target. The rate of change of energy intensity is assumed to remain constant at the historic rate.

Table B.5 Carbon intensity[57] improvements required to reach reduction targets

Scenario assumptions	**Required p.a. carbon intensity % improvement**	**Target carbon level (MtC) in 2050**
Required p.a. carbon intensity % p.a. change (post 2010) **to meet RCEP** target, including nuclear closures	-4.28	62
Required p.a. carbon intensity % p.a. change (post 2020) **to meet RCEP** target, including nuclear closures	-5.03	62
Required p.a. carbon intensity % p.a. change (post 2010) **to meet –40% target**, including nuclear closures.	-3.20	93
Required p.a. carbon intensity % p.a. change (post 2020) **to meet –40% target,** including nuclear closures.	-3.61	93

[57] Defined as carbon per unit GDP

Table B.6 Scenario projections to 2050 based on aggregate emissions and various assumptions of adjusted carbon intensity improvement achieved or expected

Scenario assumptions	**Assumed carbon intensity[58] % p.a. improvement**	**Carbon level (MtC) in 2050**
Historic p.a. carbon intensity change **2010 base**	-2.99	102.7
Historic p.a. carbon intensity change **2020 base**	-2.99	113.9
Historic p.a. carbon intensity change, less dash for gas in ESI, less impact of fuel switching in final demand, including nuclear closures **2010 base**	-2.10	145.4
Historic p.a. carbon intensity change, less dash for gas in ESI, less impact of fuel switching in final demand, including nuclear closures **2020 base**	-2.10	148.1
EP68 (2000-2010) projected p.a. carbon intensity change (less fuel switching in ESI, **including CCP** and nuclear closures) **2010 base**	-2.81	110.2
EP68 (2000-2020) projected p.a. carbon intensity change (less fuel switching in ESI, **including CCP** and nuclear closures) **2020 base**	-2.58	128.6
EP68 (2000-2010) projected p.a. carbon intensity change (less fuel switching in ESI, **excluding CCP** including nuclear closures) **2010 base**	-1.79	162.4
EP68 (2000-2020) projected p.a. carbon intensity change (less fuel switching in ESI, **excluding CCP** including nuclear closures) **2020 base**	-1.70	166.8

[58] Defined as carbon per unit GDP

The size of the gap based on aggregated sector analysis

B26 The results are presented below for the size of the gap based on scenario divergence at 2010 and 2020 (termed “2010 (or 2020) base”). Tables B.7 and B.8 present the size of the gap relative to the recommended RCEP target and a “progressive” target of –40% of 1990 carbon emissions levels from the two bases. These figures are based on individual sector projections for domestic, transport, industry and services including a projected non-sector emissions element. The non-sector estimates include estimates of LUC emissions. More detailed results are shown in appendix 5 which show the individual sector contributions to emissions by baseline and scenarios.

Table B.7 Size of the gap based on aggregated sector projections and base year 2010

Target	**Baseline MtC**	**World Markets MtC**	**Global Sustainability MtC**	**Provincial Enterprise MtC**	**Local Stewardship MtC**
RCEP	44 to 83	69 to118	36 to 70	34 to 67	9 to 32
-40%	13 to 52	39 to 87	5 to 39	3 to 36	-22 to 1

Table B.8 Size of the gap based on aggregated sector projections and base year 2020

Target	**Baseline MtC**	**World Markets MtC**	**Global Sustainability MtC**	**Provincial Enterprise MtC**	**Local Stewardship MtC**
RCEP	63 to 77	85 to107	57 to 72	49 to 68	30 to 41
-40%	33 to 46	54 to 76	26 to 42	18 to 37	-1 to 11

B27 In Table B.7 the higher figure of each range represents what may be viewed as the *pessimistic* projection based on the 1970-2000 carbon and energy intensity change rates, net of non-repeatable fuel switching, dash for gas effects removed, and including planned nuclear closures and LUC[59] emission estimates. The lower figure of each range represents what may be view as the *optimistic* projections based on the 2000-2010 carbon and energy intensity change rates projected by EP68 adjusted for the CCP and fuel switching. Table B.8 is similar but is but based on a 2020 scenario divergence and 2000-2020 EP68 projected carbon and energy intensity change rates adjusted for CCP “effects” to 2020.

[59] Based on latest LUC figures from National Emissions and Technology Centre (NETCEN) (March 2001)

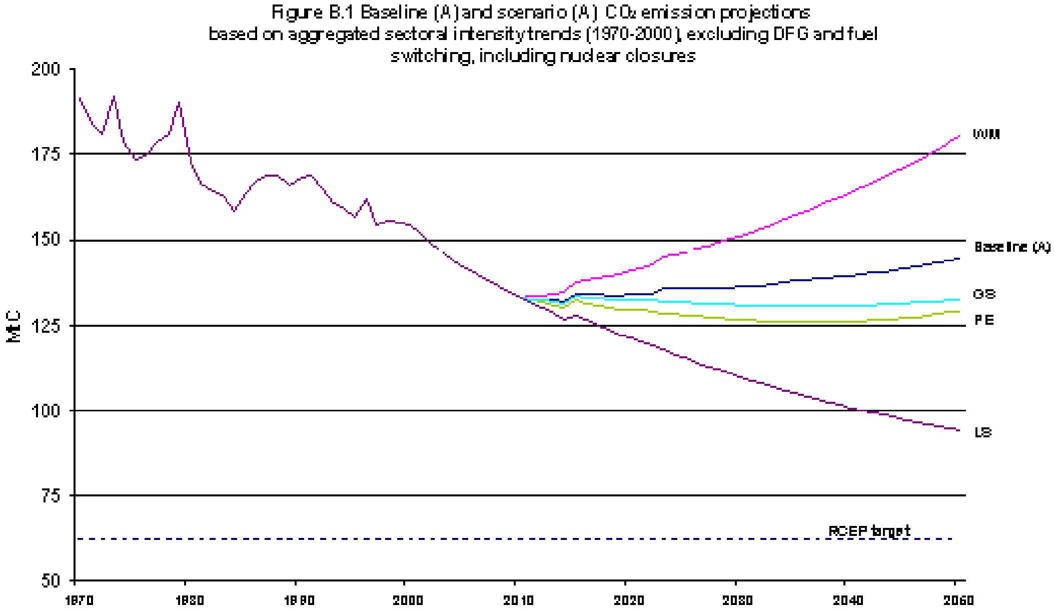
B28 The size of the gap in each scenario at the upper end of the range is sensitive to inter alia higher population growth, lower household occupancy, higher GDP growth, assumed behavioural changes and temperature effects. The impact of these and other assumptions has been explored in the section on sensitivities at the end of this paper.

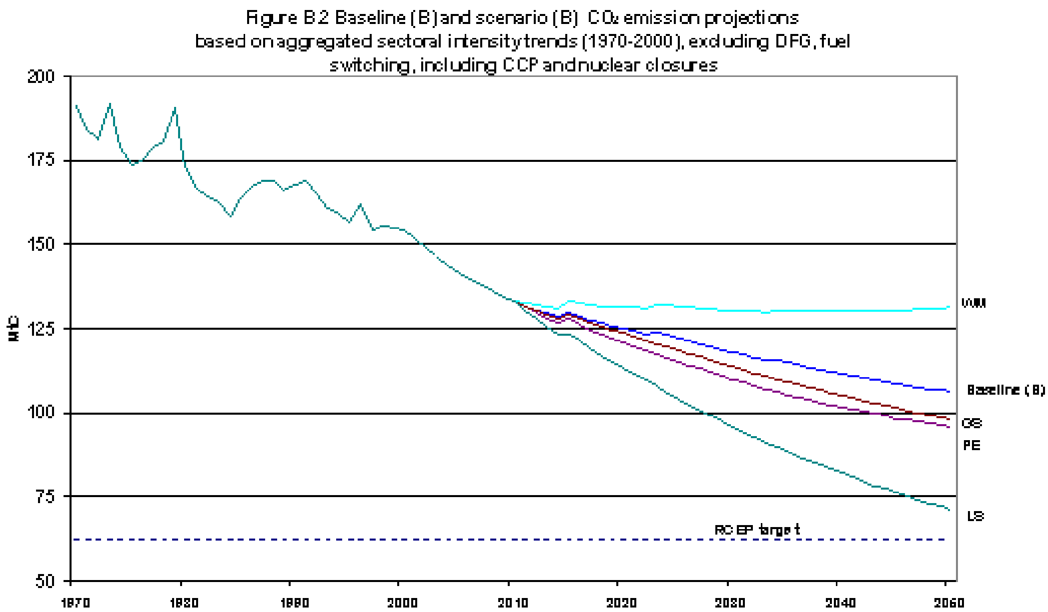
The projected scenarios

B29 The projections are illustrated graphically in Figures B.1 and B.2 below. Figure B.1 represents the baseline and scenario projections based on historic (1970-2000) sectoral carbon and energy intensity trends excluding fuel switching and the dash for gas effects, including allowance for nuclear closure assumptions. Figure B.2 represents the baseline and scenario projections based on sectoral carbon and energy intensity trends estimated by EP68 in the medium term (2000- 2010) including adjusting for the CCP, fuel switching and nuclear closures. Baseline and scenario projections by sector are illustrated in appendix 4.

B30 Only the Local Stewardship (LS) scenario meets the -40% target by 2050 and none of the scenarios meet the RCEP target at 2050 on either the assumption of past rates of carbon intensity improvement assumptions, or the improvement anticipated in the medium term under the CCP *optimistic* projection assumptions. Only the LS even approaches the RCEP target in the *optimistic* scenario.

B31 The assumptions underpinning the scenarios are shown in appendix 3. Obviously judgements are involved here. Different detailed assumptions could be made, and almost certainly would be if others were to attempt such an exercise. But these are only scenarios and we hope that in this context - as a set – they cover a range of possibilities that can command broad acceptance.





Note: The aggregated emissions projections represent end user emissions from the industry, services, domestic and transport sectors and include non-sectoral emissions such as land use change (LUC), military emissions, marine bunkers, etc. Non-sector emissions represent approximately 6% of total emissions in 2050 in baseline (A) and 8% in Baseline (B). The most recent land use change (LUC) estimates have been included in the projections and the impact of LUC is assumed to be 2.5MtC in 2010, and projected forward at a constant level of 1.6MtC from 2020 to 2050.

Sectoral emissions projections by scenario

B32 Projections at the sectoral level are illustrated graphically in appendix 4. At the sectoral level all the domestic scenario projections indicate a downward trend under both optimistic and pessimistic assumptions with the exception of WM. In the transport sector, which has been projected on a sub-sector basis of aviation, household motoring and commercial/freight (for assumptions by scenario see appendix 3) trends in emissions are upwards in the WM, B/L and GS scenarios under pessimistic assumptions, level in PE and downwards in LS. In the optimistic assumption scenarios (carbon intensity change is maintained at projected medium term (2000-2010) levels which include the CCP) only WM is upwards, all others are downwards. However, transport sector continues to contribute a significant proportion of overall emissions (40% in 2050). No assumptions have been included in the transport sector projections for carbon free or low carbon fuels. At past intensity rates (1970-2000) three transport scenarios indicate a raising trend in emissions. The service sector also exhibits a raising trend in emissions to 2050 if pessimistic (1970-2000 intensity) rates are assumed.

Variability of scenario outcomes

B33 The scenario assumptions represent one set of assumptions and there are certainly other assumptions about the future fifty years ahead that are equally valid, however, these projections provide a simple range of possible outcomes. Plausibility of the projections and saturation effects have been examined in the sectoral emissions and energy demand growth implied over the next fifty years.

B34 Sensitivities to some of the key assumptions of population, household formation, and GDP growth are examined below. Technological developments are beyond the scope of this analysis and are examined as part of the MARKAL study commissioned by the IAG, DEFRA and PIU.

International aviation: impact on emissions

B35 The assumption throughout this paper has been that only the domestic element of aviation emissions contributes to the UK total emissions. If the UK international aviation emissions were to rise at the same rates assumed for domestic (see appendix 3) the contributions from aviation would be increased by the ranges given in Table B.8.

Estimates of international aviation projections

Table B.9 Estimates of international aviation projections

International aviation projection	Baseline MtC	World Markets MtC	Global Sustainability MtC	Provincial Enterprise MtC	Local Stewardship MtC
2010 base	21 to 14	37 to 28	12 to 8	20 to 14	9 to 5
2020 base	18 to 15	28 to 24	13 to 10	18 to 15	11 to 7

B36 Growth assumptions in international aviation are assumed to be the same as those for domestic aviation.

Size of the gap (including international aviation)

B37 The impact of including international aviation in the UK emissions baseline scenario projections is illustrated in Table B.10. The task of meeting the RCEP is much harder in all scenarios.

Table B. 10 Size of the gap (including international aviation)

Size of gap including international aviation projection	Baseline MtC	World Markets MtC	Global Sustainability MtC	Provincial Enterprise MtC	Local Stewardship MtC
2010 base	65 to 96	107 to 147	48 to 78	54 to 81	18 to 37
2020 base	82 to 92	112 to 131	70 to 82	67 to 83	41 to 49

B38 First figure based on *optimistic* assumptions the second based on *pessimistic* assumptions and scenario assumptions in international aviation projections consistent with the scenario assumptions for the domestic aviation sub-sector.

Sensitivities

B39 In the following section we examine the sensitivities to key assumptions of the projections and their impact in terms of million tonnes of carbon in 2050. The estimates referring to the transport and aggregate projections are based on the scenario projections excluding international aviation, i.e. domestic aviation included.

Sensitivity to GDP growth assumptions

B40 The scenario assumptions for economic growth provide the most significant key drivers of energy demand growth and emissions in each scenario. The GDP growth assumed for the scenarios World Markets, Provincial Enterprise, Global Sustainability and Local Stewardship are 3.0%, 1.75%, 2.25% and 1.25% respectively. The average impact of one percentage point change in GDP for each scenario, in terms of carbon emissions is 34MtC, 33MtC, 24MtC, and 20MtC respectively, compared with an average impact on the baseline projection of 31MtC.

Sensitivity to future population and household size assumptions

B41 The population in the baseline assumes UK population to be increasing slightly to 2020/30 and declining slightly thereafter to 2050 resulting in a level population in 2050 of some 65 million. In the world markets scenario it is slightly higher at 66 million, and lower in provincial enterprise, global sustainability and local stewardship scenarios at 64, 63 and 62 million respectively.

B42 Energy demand from the domestic and transport sectors has traditionally been driven by population size, number of households and disposable income. These are key drivers of demand and determination of these indicators has a significant impact on the final emissions projection. It is estimated that the sensitivity of baseline emission projections to assumptions of UK population in 2050 are approximately that a 10% increase in population results in a similar order of increase in emissions from the domestic sector and a 7% increase from the transport sector. This result is similar across all four scenarios.

B43 Family formation or household size represents a behavioural feature of the scenarios and reflects the socio-economic “storyline” of each scenario, e.g. world markets assumes households in 2050 comprise, on average two persons, provincial enterprise: 2.4 persons; global sustainability: 2.2 and local stewardship: 2.6 persons. The sensitivity of the emissions projections to household size assumptions varies with the size of the population and the scenario and is asymmetric, but for example the magnitude of the sensitivity is illustrated with the world markets scenario and suggests thus if the WM household size were 1.5 (some 25% smaller) the emission projection in 2050 could increase from between 14-16% (depending on carbon intensity change assumptions). This effect represents a 33% increase in emissions from the domestic sector and 22% increase from the transport sector. A similar *increase* in household size in this scenario results in an overall reduction in projected emissions in 2050 of around 10%, a 20% reduction in emissions from the domestic sector and 14% reduction in emission from the transport sector. These estimates are on 1970-2000 carbon intensity change basis. Sensitivities to household size in other scenarios will differ slightly depending on the transport dependency assumptions of the individual scenario.

Electricity generation sensitivity

<u>Sensitivity on impact of nuclear plant closures in electrical power generation</u>

B44 The impact on carbon emissions of final nuclear plant closures according to their proposed dates for closure is estimated at an additional 1.6MtC in 2023 and another 0.8MtC in 2034.

<u>Sensitivity on impact of phasing out of coal plant generation by 2020</u>

B45 As a sensitivity we examine a case where there is no coal-fired generation by 2020. The likely impact would be the saving of just over 5MtC in 2020.

<u>Gas price sensitivity (2010-2020) and impact on carbon emissions</u>

B46 The relative prices of the major fossil fuels, and principally those of gas and coal influence the carbon impact of the fuel mix in traditional electricity generation. It is possible to estimate gas price sensitivity in traditional power generation through econometric modelling. The impact beyond 2020, however, is more difficult to estimate. The following example illustrates a near term sensitivity.

B47 Taking the projected gas price to a level comparable with the IEA World Energy Outlook 2000 scenario projection in a low fossil fuel price scenario (such as is described by the CL scenario of EP68) results in increase coal burn in existing plants. In a high fossil fuel price scenario (i.e. CH in EP68) such an increase in gas prices could make it economic to build new "clean" coal plants. This difference in impact is because in the high price scenario coal is more competitive against gas than in the low price scenario where coal is relatively less competitive. The impact on carbon emissions, in the CH case, of taking the projected gas price to a level comparable with the IEA World Energy Outlook 2000 scenario projection is an additional 5MtC. In the CL case it would result in a 1.9MtC increase in carbon emissions from the electricity generation industry in 2020. It is worth noting that the World Energy Outlook 2000 fossil fuel scenario assumes a lower price advantage for coal over gas in 2020 than the EP68 CH scenario and therefore the additional 5MtC should be viewed as an upper limit. The UK sulphur limit is unlikely to be exceeded in either case as the plants built under the CH case will be "clean" coal plants, while in the CL case, the increase in coal burn is insufficient to breach the current SO_2 limit.

Land use change estimates

B48 Estimates of land use change (LUC) provided by DEFRA[60] at the start of this analysis indicated that currently these represented approximately 4% of total UK emissions. The data is based on land use surveys, most recently 1990, and was consistent with the UK Greenhouse Gas Emissions Inventory[61]. However, the LUC inventory time series and projections were revised in March 2001 and the new estimates have been used for the analysis. Emissions projections from land use change beyond 2020 have been held at an illustrative 1.6MtC per year on the assumption that the lagged effect of the earlier trends to more intensive agriculture and urbanisation will have stabilised. This does not take account of any further measures to reduce or reverse these emissions.

[60] Climate Change The UK Programme, DETR Nov 2000. Since this analysis was undertaken the DETR have roughly halved the UK emissions estimates from LUC in their latest inventory following advice from the Centre for Ecology and Hydrology (formerly ITE). The new estimates will be included in subsequent analysis.
[61] UK Greenhouse Gas Inventory, 1990 to 1999, April 2001, NETCEN.

Climate change

B49 The full climatic impact of the Foresight scenarios is beyond the scope of this analysis, as it requires the use of climate change models. However, work prepared for UKCIP by Climatic Research Unit at University of East Anglia and the Hadley Centre at the Meteorological Office has been published in a report[62] and describes how the UK climate may change during the next 100 years. This work was based on high or low greenhouse gas emission scenarios unrelated to the present Foresight scenarios. The results indicated a further rise from the present observed warming of recent decades leading to rises in temperature of between 2 and 3 degrees centigrade by 2100.

Temperature sensitivity

B50 Increases in external temperature and associated altered weather patterns will impact on the domestic and service sectors through the direct consumption of fuel required by space heating or air conditioning the home or office. An increase of temperature of between 1 and 1.5 degrees centigrade by 2050 is estimated, on the basis of current econometric relationships, to reduce demand in the domestic and service sectors and hence reduce carbon emissions by between 2.5 and 3.8 MtC in 2050. This effect is likely to be offset by increased emissions due to the use of air conditioning equipment in the summer months, unless non-energy consuming solutions were found to cool buildings.

Energy demand projections

B51 The IAG analysis has been directed towards projections of carbon emissions to inform the response to the RCEP recommendation of a 60% reduction in carbon by 2050. However, it is also necessary to consider the equivalent energy demand of the baseline and scenario projections as this provides the basis for the MARKAL analysis of the low carbon options which will be reported separately. The projected energy demands have been estimated by the IAG and DEFRA independently (by different approaches although to the same set of scenario assumptions) and these are illustrated in Appendix 6. The level of energy demand in the industrial, service and domestic sectors projected to 2050 are fairly consistent by both approaches. Differences in transport sector demand are

[62] Climate Change Scenarios for the United Kingdom. UKCIP. September 1998.

apparent and reflect a significant difference in the assumption of transport sector growth. DEFRA assume constrained transport growth to 2050, implied by the NRTF[63] model projections while the IAG assumptions imply the continuation of past rates of growth.

B52 It is clear that while the IAG demand projections remain plausible in terms of implied kilometres per household travelled without saturation of car ownership, this assumption fails to appreciate the impact of congestion. It is probably safe to assume that actual transport sector energy demand growth lies somewhere between the two projections (i.e. between a growth rate 0.3% and 1.3% per annum) and transport energy demand representing somewhere between 35% and 50% of baseline total final energy demand in 2050. Transport energy demand is expected to grow at 1.8 percent per annum between 2000-2010 and to represent 36% of total final energy demand in 2010.[64]

Appendix 1 - Foresight scenarios
Appendix 2 - Intensity change rates- 2010 base
Appendix 3 - Full IAG scenario assumptions
Appendix 4 - Baseline and scenario projections by sector (graphs)
Appendix 5 - Baseline and scenario projections by sector
Appendix 6 - Final energy demand projections
Appendix 7 - Energy Efficiency: DEFRA Projections Methodology

[63] National Road transport forecast provided by DTLR and based on the Ten Year Transport Plan, with additional assumptions of congestion saturation and no new road build.
[64] Energy Paper 68. Energy Projections for the UK, DTI

THE FORESIGHT SCENARIOS FRAMEWORK

We have adopted a similar approach to define four contextual scenarios according to the scheme in Figure 1 below. The scenarios are:

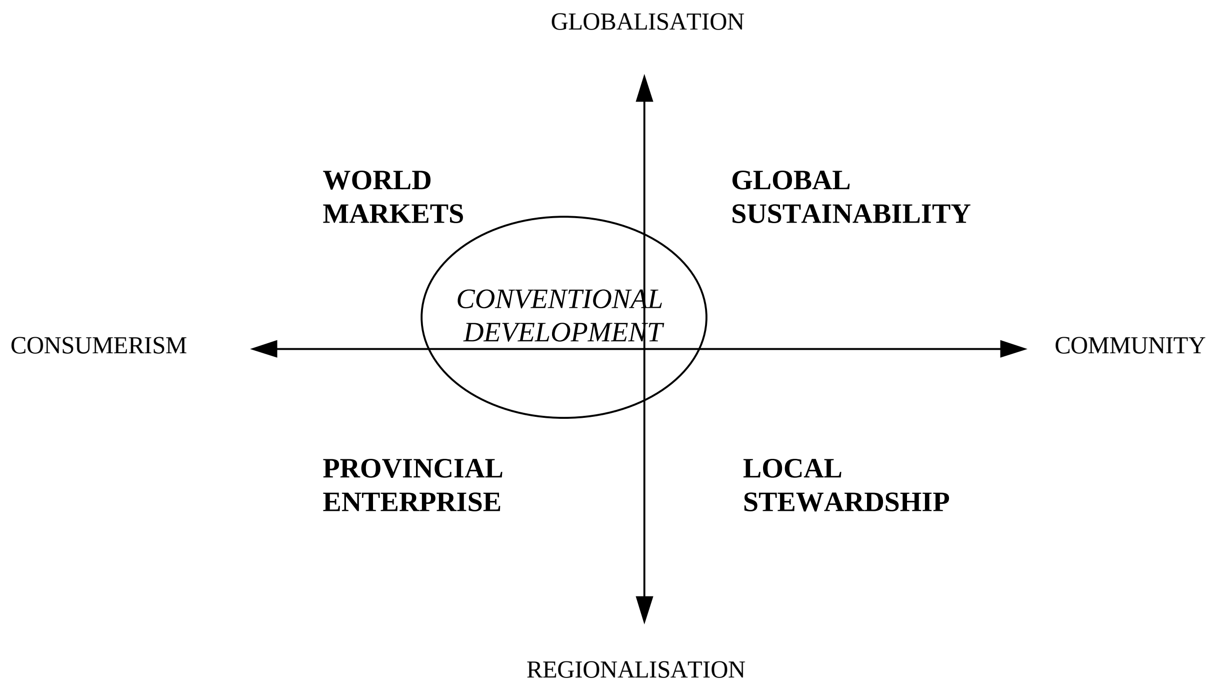
WORLD MARKETS (top left), a world defined by an emphasis on private consumption and a highly developed and integrated world trading system;

GLOBAL SUSTAINABILITY (top right), a world in which social and ecological values are more pronounced and in which the greater effectiveness of global institutions is manifested through stronger collective action in dealing with environmental problems;

PROVINCIAL ENTERPRISE (bottom left), a world of private consumption values coupled with a capacity for lower level policy-making systems to assert local, regional and national concerns and priorities;

LOCAL STEWARDSHIP (bottom right), a world where stronger local and regional governments allow social and ecological values to be demonstrated to a greater degree through the preservation of environments at the local level.

Figure 1: Four contextual UK futures scenarios



Intensity changes, by sector (Tables 1-5) and aggregate energy and emissions (Table 6)

Baseline scenario with nuclear closures from 2010 base, CCP fully apportioned to energy intensity change

Table 1: Domestic sector intensities

	Energy intensity (E per GDP per HH)	**Carbon intensity (C per E)**	**CO_2 level 2050 (MtC)**
Past, including dash for gas (DFG)	-2.60	-1.67	18.1
Past, excluding DFG and fuel switching	-2.60	-0.36	30.4
Medium term 2000-2010 excl. CCP, excl. DFG	-2.42	-0.50	30.9
Medium term 2000-2010 incl. CCP, excl. DFG	-3.41	-0.50	20.9
Medium term 2000-2020 excl. CCP, excl. DFG	-2.38	-0.43	32.2
Medium term 2000-2020 incl. CCP, excl. DFG	-2.89	-0.43	26.4
Required to meet RCEP target, historic EI	-2.60	-2.17	14.8
Required to meet RCEP target, projected CCP EI	-3.41	-1.36	14.8

Table 2: Transport sector intensities, aggregate treatment

	Energy intensity (E per GDP per HH)	**Carbon intensity (C per E)**	**CO_2 level 2050 (MtC)**
Past, including dash for gas (DFG)	-1.09	-0.16	64.3
Past, excluding DFG and fuel switching	-1.09	-0.05	67.2
Medium term 2000-2010 excl. CCP, excl. DFG	-1.25	-0.42	54.5
Medium term 2000-2010 incl. CCP, excl. DFG	-2.05	-0.42	39.9
Medium term 2000-2020 excl. CCP, excl. DFG	-1.32	-0.39	53.6
Medium term 2000-2020 incl. CCP, excl. DFG	-1.94	-0.39	41.9
Required to meet RCEP target, historic EI	-1.09	-3.84	14.6
Required to meet RCEP target, projected CCP EI	-2.61	-2.32	14.6

Table 3: Implied transport sub sector intensities

	Energy intensity (E per quoted unit)	Carbon intensity (C per E)	Aggregate CO_2 level 2050 (MtC)
Aviation: past, 1970-2000 (bpkm)	-0.89	-0.05	59.3**
Motoring: past, 1970-2000 (bvkm)	-1.24	-0.05	
Commercial: past, 1970-2000 (bvkm)	+0.83	-0.05	
Aviation: medium term, 2000-2010 excl. CCP	-0.18	-0.42	39.0**
Motoring: medium term, 2000-2010 incl. CCP	-1.94	-0.42	
Commercial: medium term 2000-2010 incl. CCP	-0.07	-0.42	
Required to meet RCEP target, historic EI	*-0.41**	-3.49	14.6
Required to meet RCEP target, projected CCP EI	*-1.02**	-1.76	14.6

* indicate implied aggregate transport energy intensities (energy per weighted transport service) in 2010-2050

** indicate aggregate transport emissions with sub sector energy intensity changes either at the historic or projected rates, and include domestic aviation emissions only

Table 4: Industry sector intensities

	Energy intensity (E per output)	Carbon intensity (C per E)	CO_2 level 2050 (MtC)
Past, including dash for gas (DFG)	-2.80	-0.90	14.6
Past, excluding DFG, fuel switching	-2.80	-0.21	19.3
Medium term 2000-2010 excl. CCP, excl. DFG	-1.33	-0.25	34.0
Medium term 2000-2010 incl. CCP, excl. DFG	-2.62	-0.25	20.4
Medium term 2000-2020 excl. CCP, excl. DFG	-1.23	-0.24	35.5
Medium term 2000-2020 incl. CCP, excl. DFG	-1.89	-0.24	27.3
Required to meet RCEP target, historic EI	-2.80	-0.71	15.8
Required to meet RCEP target, projected CCP EI	-2.62	-0.89	15.8

Table 5: Service sector intensities

	Energy intensity (E per output)	Carbon intensity (C per E)	CO_2 level 2050 (MtC)
Past, including dash for gas (DFG)	-1.57	-1.10	19.2
Past, excluding DFG, fuel switching	-1.57	-0.25	26.8
Medium term 2000-2010 excl. CCP excl. DFG	-1.87	-0.45	22.1
Medium term 2000-2010 incl. CCP excl. DFG	-2.53	-0.45	17.1
Medium term 2000-2020 excl. CCP excl. DFG	-1.87	-0.41	22.4
Medium term 2000-2020 incl. CCP excl. DFG	-2.21	-0.41	19.6
Required to meet RCEP target, historic EI	-1.57	-3.35	7.9
Required to meet RCEP target, projected CCP EI	-2.53	-2.39	7.9

Table 6: Aggregate intensities

	Energy intensity (E per GDP)	Carbon intensity (C per E)	CO_2 level 2050 (MtC)
Past, including dash for gas (DFG)	-1.83	-1.16	102.7
Past, excluding DFG, fuel switching	-1.83	-0.27	145.4
Medium term 2000-2010 excl. CCP excl. DFG	-1.38	-0.41	164.2
Medium term 2000-2010 incl. CCP excl. DFG	-2.40	-0.41	110.2
Medium term 2000-2020 excl. CCP excl. DFG	-1.37	-0.33	166.8
Medium term 2000-2020 incl. CCP excl. DFG	-2.25	-0.33	128.6
Required to meet RCEP target, historic EI	-1.83	-2.45	62.0
Required to meet RCEP target, projected CCP EI	-2.40	-1.88	62.0

Assumptions:

1) CCP fully apportioned to energy intensity change, i.e. reduction of emissions by the CCP achieved fully by an intermediate reduction in energy demand (extreme case)
2) Baseline includes nuclear closures as planned, reflected in intensity to target
3) RCEP target based on an "equal pain" principle of equiproportionate reductions across the four sectors
4) Carbon intensity change needed to meet target projected on the basis of maintenance of the historical rate of energy intensity change
5) Non-sector emissions (inc. military, exports, marine bunkers and other) constant at 7.3 MtC after 2020 for sectoral analysis
6) Land use changes assumed constant at 1.6 MtC after 2020 (new DEFRA assumptions)
7) RCEP target is effective 62.5% cut per sector
8) Transport sub sectors assume individual energy intensities but an overall carbon intensity, which changes to meet the target

BASELINE AND SCENARIO ASSUMPTIONS

Table 3.1 Long Term Projections Scenario Assumptions (disaggregated transport sector basis)

		EP68 Baseline	World Markets	Provincial Enterprise	Global Sustainability	Local Stewardship
UK GDP growth p.a.		2.25%	3.00%	1.75%	2.25%	1.25%
Population (million)		65	66	64	63.00	62
Household size		2.17	2.00	2.40	2.20	2.60
Implied household numbers growth p.a.[1]		0.30%	0.54%	0.00%	0.18%	-0.27%
Service sector output growth p.a.		2.49%	3.25%	1.75%	2.36%	1.25%
Industry sector growth p.a.		1.56%	1.60%	1.75%	1.80%	1.25%
Nuclear		Closures continue as planned	Closures continue as planned	Closures continue as planned	Closures continue as planned	Closures continue as planned
Coal usage in electricity generation		Continues as of 2020	Continues as of 2020	Continues as of 2020	Continues as of 2020	Continues as of 2020
Transport[2]	Freight link to economic growth	Ratio = 0.75 in line with BAU growth	Ratio = 0.825 higher growth	Ratio = 0.9 higher growth	Ratio = 0.675 slower growth	Ratio = 0.6 slower growth
	Technology development	Ratio = 1 in line with BAU	Ratio = 1.2 less polluting vehicles	Ratio = 0.8 more polluting vehicles	Ratio = 1.2 less polluting vehicles	Ratio = 1.2 less polluting vehicles
	Air travel link to economic growth	Ratio = 1.5 faster than GDP growth	Ratio = 2.0 faster than GDP growth	Ratio = 1.5 faster than GDP growth	Ratio = 1 in line with GDP growth	Ratio = 0.0 no additional growth
	Car traffic link to household numbers	Ratio = 2.5 faster than HH growth	Ratio = 2.5 faster than HH growth	Ratio = 2.5 faster than HH growth	Ratio = 2.5 faster than HH growth	Ratio = 2.5 faster than HH growth
	Implied transport energy demand growth p.a.[3]	1.51%	2.44%	1.47%	0.75%	-0.24%

Notes

[1] Implied growth from 2010 base
[2] 2010 DERV *car* share of 15% assumed
[3] Assumes 2010-2050 growth based on historic energy intensity changes and demand assumptions

Appendix 4 Baseline and scenario projections by sector

Industry sector

Fig A4.1 Projected Industry Sector CO_2 Emission Scenarios
based on 1970-2000 sectoral carbon intensity trends, excluding DFG and fuel switching, including nuclear closures

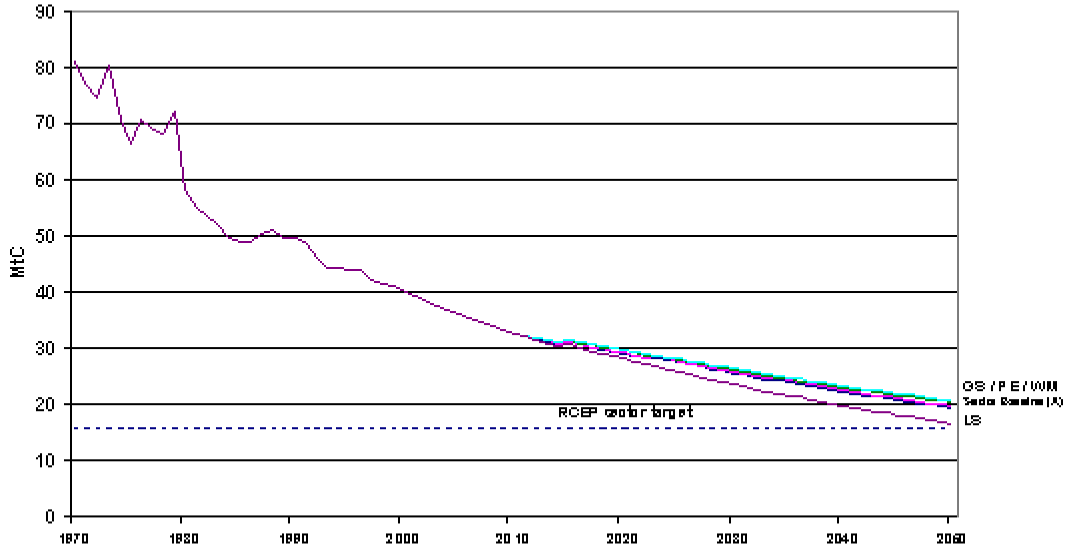
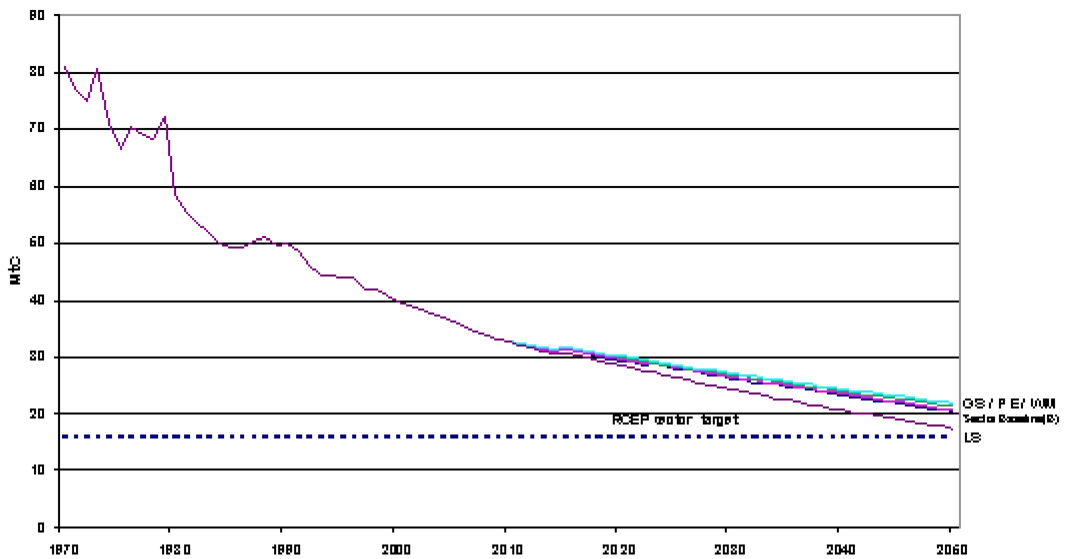


Fig A4.2 Projected Industry Sector CO2 Emission Scenarios
based on 2000-2010 sectoral carbon intensity trend including CCP, excluding DFG and including nuclear closures



Domestic sector

Fig A4.3 Projected Domestic Sector CO_2 Emission Scenarios
based on 1970-2000 sectoral carbon intensity trends, excluding DFG and fuel switching, including nuclear closures

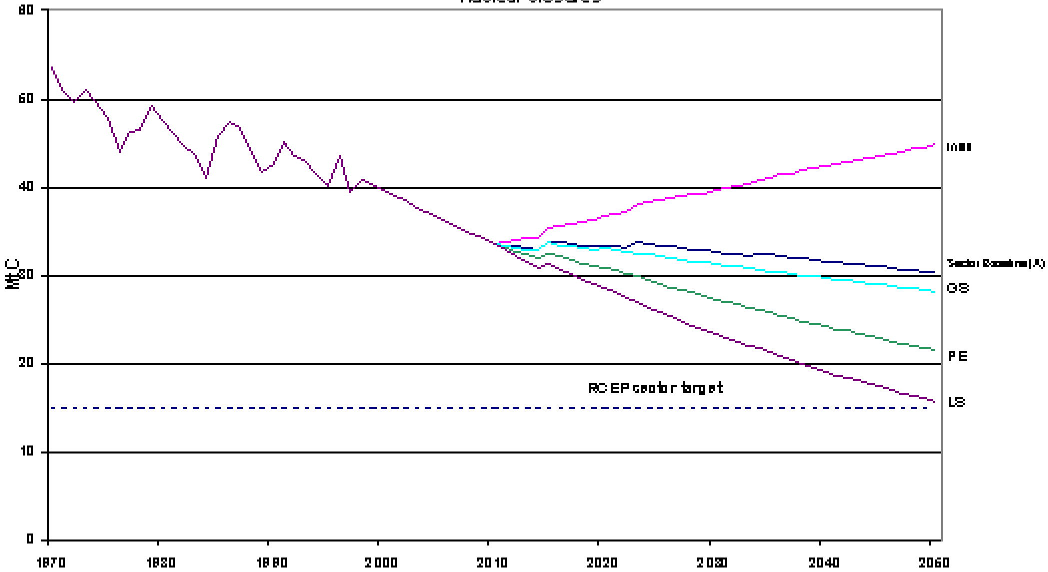


Fig A4.4 Projected Domestic Sector CO_2 Emission Scenarios
based on 2000-2010 sectoral carbon intensity trend including CCP, excluding DFG and including nuclear closures

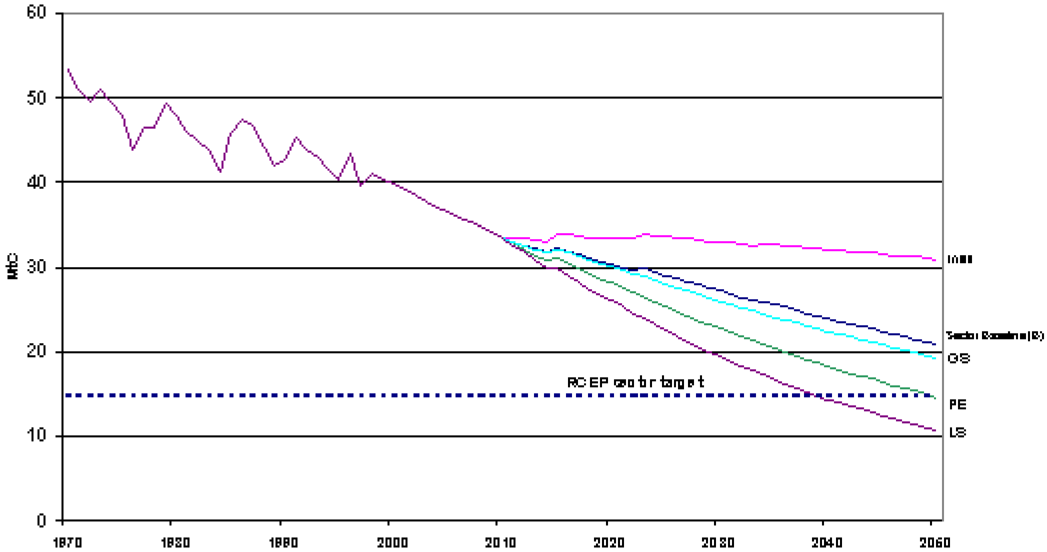


Fig A4.5 Projected Service Sector CO_2 Emission Scenarios
based on 1970-2000 sectoral carbon intensity trends, excluding DFG and fuel switching, including nuclear closures

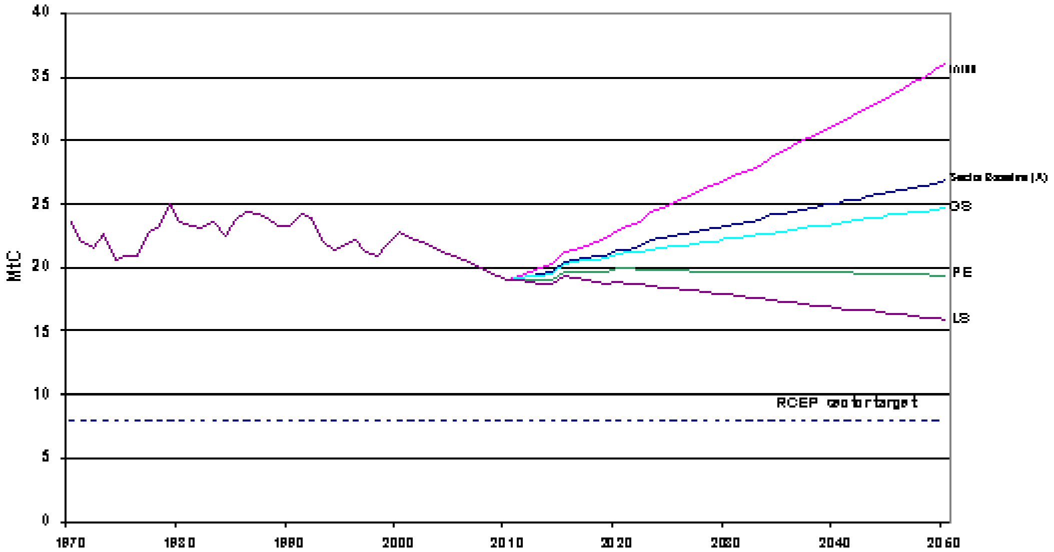


Fig A4.6 Projected Service Sector CO_2 Emission Scenarios
based on 2000-2010 sectoral carbon intensity trend including CCP, excluding DFG and including nuclear closures

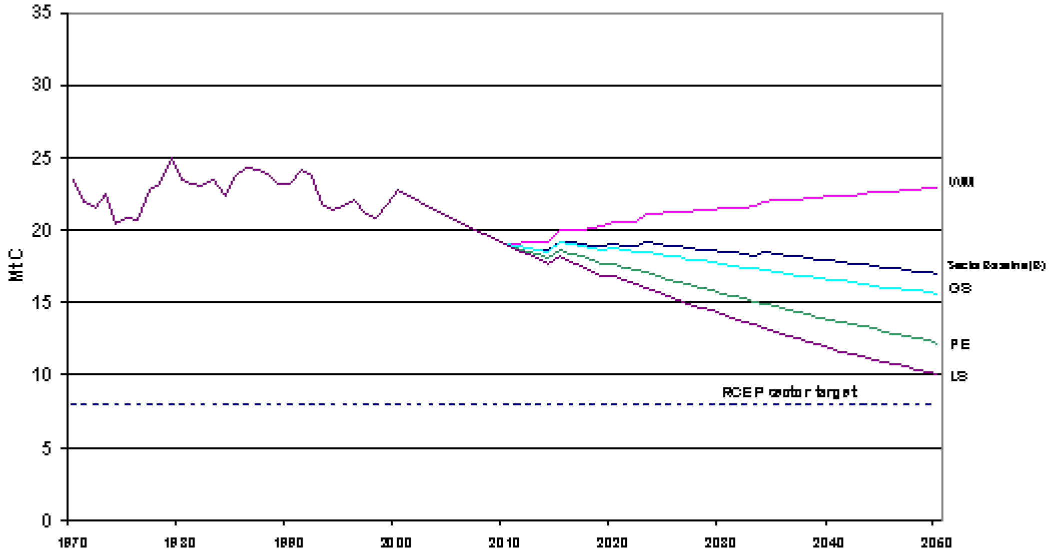


Fig A4.7 Projected Transport Sector CO_2 Emission Scenarios
based on 1970-2000 sectoral carbon intensity trends, excluding DFG

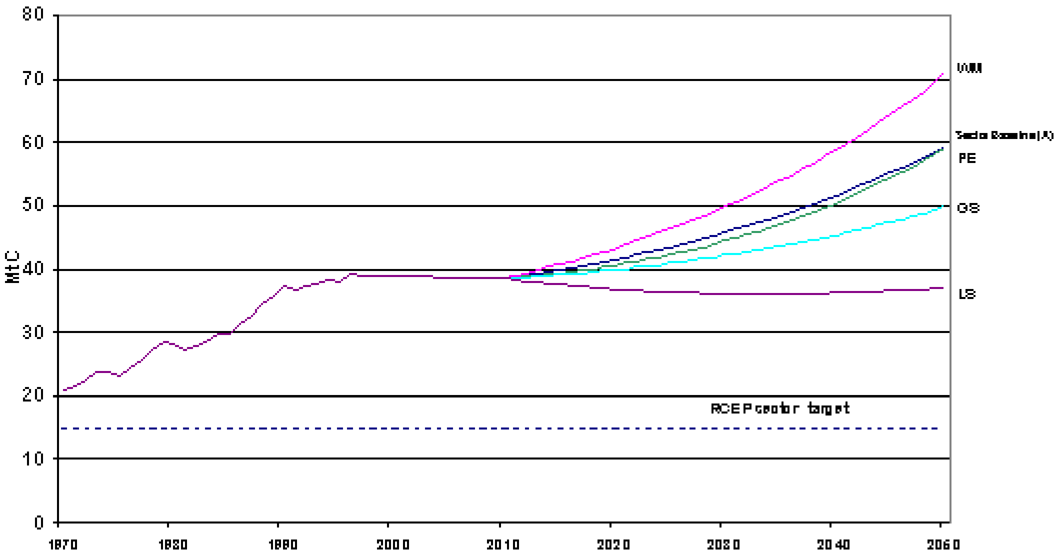
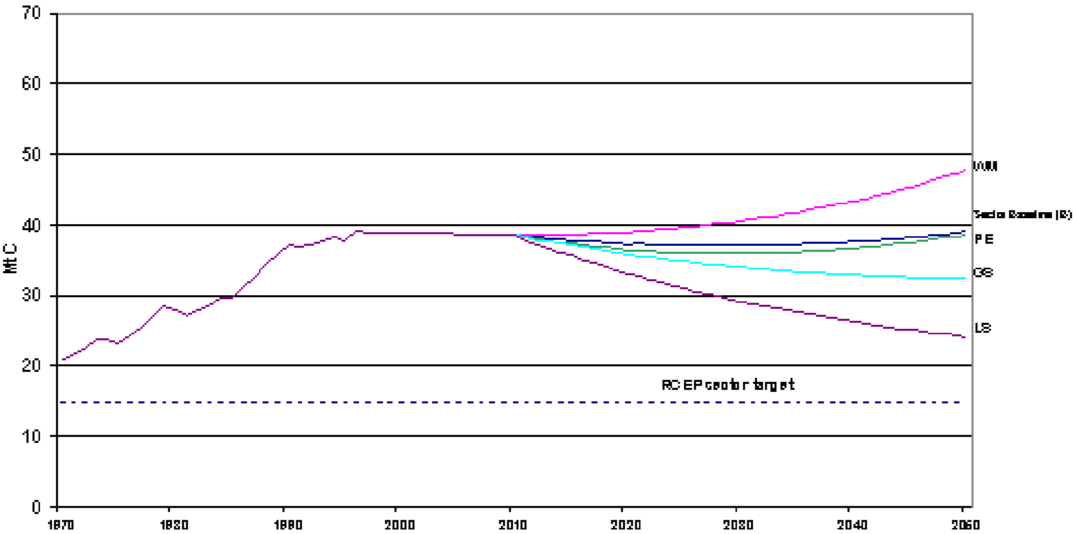


Fig A4.8 Projected Transport Sector CO_2 Emission Scenarios
based on 2000-2010 sectoral carbon intensity trend including CCP, excluding DFG



PROJECTIONS EMISSIONS 2010 BASE (MtC)
Historic 1970-2000 rate of intensity change exc. DFG and fuel switching, including nuclear closures

Baseline (A)

	2000	2010	2030	2050	Growth %
Industry	40.1	32.7	25.5	19.3	-1.45
Domestic	39.8	33.6	32.7	30.4	-0.54
Services	22.8	19.1	23.2	26.8	0.32
Transport	38.9	38.5	45.8	59.3	0.85
Subtotal	141.5	123.8	127.3	135.7	-0.08
LUC	7.0	2.5	1.6	1.6	-2.93
NSE	6.0	6.7	7.3	7.3	0.39
Total	154.5	132.9	136.1	144.6	-0.13

World Markets (A)

	2000	2010	2030	2050	Growth %
Industry	40.1	32.7	25.7	19.6	-1.42
Domestic	39.8	33.6	39.7	44.9	0.24
Services	22.8	19.1	26.9	36.0	0.92
Transport	38.9	38.5	49.8	71.0	1.21
Subtotal	141.5	123.8	142.2	171.4	0.38
LUC	7.0	2.5	1.6	1.6	-2.93
NSE	6.0	6.7	7.3	7.3	0.39
Total	154.5	132.9	151.1	180.3	0.31

Global Sustainability(A)

	2000	2010	2030	2050	Growth %
Industry	40.1	32.7	26.4	20.7	-1.32
Domestic	39.8	33.6	31.4	28.2	-0.68
Services	22.8	19.1	22.2	24.7	0.16
Transport	38.9	38.5	42.1	49.8	0.50
Subtotal	141.5	123.8	122.0	123.4	-0.27
LUC	7.0	2.5	1.6	1.6	-2.93
NSE	6.0	6.7	7.3	7.3	0.39
Total	154.5	132.9	130.9	132.3	-0.31

Provincial Enterprise(A)

	2000	2010	2030	2050	Growth %
Industry	40.1	32.7	26.1	20.2	-1.36
Domestic	39.8	33.6	27.4	21.5	-1.22
Services	22.8	19.1	19.7	19.4	-0.32
Transport	38.9	38.5	44.4	59.1	0.84
Subtotal	141.5	123.8	117.6	120.2	-0.33
LUC	7.0	2.5	1.6	1.6	-2.93
NSE	6.0	6.7	7.3	7.3	0.39
Total	154.5	132.9	126.5	129.1	-0.36

Local Stewardship(A)

	2000	2010	2030	2050	Growth %
Industry	40.1	32.7	23.6	16.5	-1.75
Domestic	39.8	33.6	23.4	15.7	-1.84
Services	22.8	19.1	17.8	15.9	-0.72
Transport	38.9	38.5	36.0	37.1	-0.09
Subtotal	141.5	123.8	100.9	85.2	-1.01
LUC	7.0	2.5	1.6	1.6	-2.93
NSE	6.0	6.7	7.3	7.3	0.39
Total	154.5	132.9	109.8	94.1	-0.99

FINAL ENERGY DEMAND

IAG A, IAG B and IAG(DEFRA) Projected Energy Demand to 2050

(IAG A and B projections are from EP68 2010 base, A: based on historic rate of carbon intensity change excluding DFG and excl. fuel switching, B: based on 2000-2010 estimated rate of carbon change, including CCP and excluding fuel switching)

Baselines (A); (B) and DEFRA – Energy Demand (Mtoe)

		2000	2010	2030	2050	% p.a. growth (2000-2050)
Industry	IAG A	40.4	36.1	28.1	21.9	-1.22
	IAG B	40.4	36.1	29.2	23.7	-1.06
	IAG(DEFRA)	35.6	-	-	29.4	-0.38
Domestic	IAG A	45.5	41.8	41.4	40.9	-0.21
	IAG B	45.5	41.8	35.1	29.6	-0.86
	IAG(DEFRA)	45.8	-	-	42.6	-0.14
Services	IAG A	22.8	22.3	26.8	32.1	0.69
	IAG B	22.8	22.3	22.2	22.1	-0.06
	IAG(DEFRA)	21.8	-	-	25.3	0.30
Transport	IAG A	55.0	57.3	74.5	104.5	1.29
	IAG B	55.0	57.3	62.1	81.9	0.80
	IAG(DEFRA[1])	43.5	-	-	50.0	0.24
Subtotal	IAG A	163.7	157.5	170.8	199.4	0.40
	IAG B	163.7	157.5	148.6	157.3	-0.08
	IAG(DEFRA)	146.7	-	-	147.3	0.00

World Markets – Energy Demand (Mtoe)

		2000	2010	2030	2050	% p.a. growth (2000-2050)
Industry	IAG A	40.4	36.1	28.3	22.3	-1.18
	IAG B	40.4	36.1	29.5	24.1	-1.03
	IAG(DEFRA)	35.6	-	-	29.0	-0.41
Domestic	IAG A	45.5	41.8	50.4	60.8	0.58
	IAG B	45.5	41.8	42.9	44.0	-0.07
	IAG(DEFRA)	45.8	-	-	53.9	0.33
Services	IAG A	22.8	22.3	31.1	43.3	1.29
	IAG B	22.8	22.3	25.8	29.9	0.54
	IAG(DEFRA)	21.8	-	-	29.6	0.61
Transport	IAG A	55.0	57.3	87.5	150.1	2.03
	IAG B	55.0	57.3	75.1	132.8	1.78
	IAG(DEFRA[1])	43.5	-	-	60.7	0.64
Subtotal	IAG A	163.7	157.5	197.3	276.5	1.05
	IAG B	163.7	157.5	173.3	230.8	0.69
	IAG(DEFRA)	146.7	-	-	173.2	0.33

Global Sustainability – Energy Demand (Mtoe)

		2000	2010	2030	2050	% p.a. growth (2000-2050)
Industry	IAG A	40.4	36.1	29.5	24.1	-1.03
	IAG B	40.4	36.1	30.7	26.1	-0.87
	IAG(DEFRA)	35.6	-	-	25.0	-0.70
Domestic	IAG A	45.5	41.8	40.4	39.1	-0.30
	IAG B	45.5	41.8	34.3	28.2	-0.95
	IAG(DEFRA)	45.8	-	-	36.8	-0.44
Services	IAG A	22.8	22.3	26.1	30.5	0.58
	IAG B	22.8	22.3	21.6	21.0	-0.16
	IAG(DEFRA)	21.8	-	-	21.2	-0.06
Transport	IAG A	55.0	57.3	64.6	77.3	0.68
	IAG B	55.0	57.3	52.5	54.2	-0.03
	IAG(DEFRA[1])	43.5	-		37.1	-0.38
Subtotal	IAG A	163.7	157.5	160.6	171.0	0.09
	IAG B	163.7	157.5	139.1	129.5	-0.47
	IAG(DEFRA)	146.7	-	-	120.1	-0.42

Provincial Enterprise – Energy Demand (Mtoe)

		2000	2010	2030	2050	% p.a. growth (2000-2050)
Industry	IAG A	40.4	36.1	29.2	23.6	-1.07
	IAG B	40.4	36.1	30.4	25.6	-0.91
	IAG(DEFRA)	35.6	-	-	30.5	-0.31
Domestic	IAG A	45.5	41.8	35.3	29.8	-0.84
	IAG B	45.5	41.8	29.9	21.5	-1.49
	IAG(DEFRA)	45.8	-	-	39.1	-0.32
Services	IAG A	22.8	22.3	23.1	23.9	0.09
	IAG B	22.8	22.3	19.1	16.4	-0.66
	IAG(DEFRA)	21.8	-	-	24.9	0.27
Transport	IAG A	55.0	57.3	72.5	102.7	1.26
	IAG B	55.0	57.3	60.4	79.4	0.74
	IAG(DEFRA[1])	43.5	-	-	68.7	0.88
Subtotal	IAG A	163.7	157.5	160.1	180.0	0.19
	IAG B	163.7	157.5	139.8	142.9	-0.27
	IAG(DEFRA)	146.7	-	-	163.2	0.20

Local Stewardship – Energy Demand (Mtoe)

		2000	2010	2030	2050	% p.a. growth (2000-2050)
Industry	IAG A	40.4	36.1	26.4	19.3	-1.47
	IAG B	40.4	36.1	27.5	20.9	-1.31
	IAG(DEFRA)	35.6	-	-	25.7	-0.65
Domestic	IAG A	45.5	41.8	30.1	21.7	-1.47
	IAG B	45.5	41.8	25.5	15.6	-2.12
	IAG(DEFRA)	45.8	-	-	26.9	-1.06
Services	IAG A	22.8	22.3	20.9	19.6	-0.30
	IAG B	22.8	22.3	17.3	13.4	-1.06
	IAG(DEFRA)	21.8	-	-	20.0	-0.17
Transport	IAG A	55.0	57.3	52.4	52.0	-0.11
	IAG B	55.0	57.3	43.1	36.0	-0.84
	IAG(DEFRA)	43.5	-	-	28.5	-0.93
Subtotal	IAG A	163.7	157.5	129.8	112.6	-0.75
	IAG B	163.7	157.5	113.4	85.9	-1.28
	IAG(DEFRA)	146.7	-	-	101.1	-0.77

Energy Efficiency: DEFRA Projections Methodology

Introduction:

A series of six working papers was prepared by DEFRA for the Inter-departmental Analysts Group over the period March to October 2001. Together with this introductory note, they cover the economy as four sectors (domestic, industry, services and transport), and present a general method for cost estimation. The titles[65] are as follows:

1. (this introductory paper)
2. Energy Efficiency: DEFRA paper on Low Carbon Options for the Domestic Sector
3. Energy Efficiency: DEFRA paper on Scope for Demand Side Measures in Industry
4. Energy Efficiency: DEFRA paper on Energy Projections for the Service Sector
5. Energy Efficiency: DEFRA paper on Transport Energy Efficiency
6. Energy Efficiency: DEFRA paper on Additional Savings and Associated Costs (Annex D above)

Aim: to estimate the scope for energy intensity reduction, and the corresponding costs, for five scenarios, in 2050.

Steps:

1. Estimate energy demand for the four reference Foresight scenarios, together with the "BAU" (current trends) case, and the contributions to energy intensity trends of energy efficiency and structural changes (different in each scenario).
2. Identify demand-side options for further reductions in energy intensity under each scenario.
3. Estimate relative costs of demand-side energy technologies, within the context of each reference scenario, and the additional energy intensity reduction options envisaged.

[65] The four sectoral papers are available on the PIU website

Projections methodology

BAU projections

Energy demand is estimated for several different end uses or "energy services" in each of the four main sectors. Energy services are regarded as the fundamental drivers. At the most basic level, examples include a workspace or dwelling at a comfortable temperature, an adequately lit space, appropriate computing power. For some services, it is possible to quantify the level of service and calculate directly to a corresponding energy consumption figure, using assumptions on technical factors along the way, e.g. from an average whole-house temperature, using heat losses from the building and heating system efficiencies, to delivered energy (preferably split by fuel) for space heating. For others, particularly process use in business, in practice we may have to use something closer to the energy use, possibly even the actual use itself.

Projecting the demand for a particular energy service is probably best done by linking it to a consuming unit, e.g. a dwelling or household, an employee, a square metre of floor space. The level of service per unit, or service intensity, may remain constant over time (e.g. lighting levels in offices) or may rise with increasing income (e.g. average indoor temperatures in housing).

The final element in this approach is the number of "units", e.g. households, employees, floor area, and how this number varies with GDP and the other socio-economic variables which define a scenario. The product of the service intensity and the number of units gives the level of total energy service.

All of this can represented by the identity:

$$E = E/ES \; * \; ES/U * U,$$

where E = energy, ES = energy service, and U = number of "units". Then E/ES represents an efficiency factor while ES/U gives a measure of energy service intensity.

Future values of E relative to today's can then be calculated by giving values to the relative change in each of the variables on the right hand side of the equation. For example, if the efficiency improves by 50%, the service intensity increases by 20% and the number of units increases by

60%, the respective factors are 0.5, 1.2 and 1.6 and the energy demand is 0.96 times today's value.

This approach to projecting energy demand

- involves a relatively small number of factors;

- separates technical ones from socio-economic ones;

- focuses attention on a few key energy services which represent the development of the economy under different scenarios;

- is reasonably transparent.

For each energy service, the relative importance of each factor is easily seen. Particular values can be discussed and the sensitivities readily calculated. If necessary, more detailed underlying models can be constructed to check particular values. In particular, likely limits on future growth of some service intensities, e.g. whole-house temperatures, time per individual spent travelling, can be built into the equations in a way which is impossible with conventional econometric modelling.

ES/U and U are socio-economic factors while E/ES is a technical one. Conventional energy efficiency improvements, i.e. via technical measures, would be represented by reductions in E/ES. However, energy demand could also be reduced via demand-side reductions represented by a fall in the energy service intensity, ES/U: for example, a drop in average whole house temperature.

There is an argument which says that this last change represents a move to a different scenario, on the basis that a scenario could effectively be defined by the values of a full set of energy services. DTI have chosen to use a more basic definition of a scenario, i.e. using only the Foresight variables - GDP, population, number of households, industry/services balance, traffic growth. DEFRA has followed the latter approach for the present to try to link DTI's projections as closely as possible to our projections for each scenario. This then allows us to include further demand-side reductions from changes in the levels of energy service intensities, and other structural factors. We can envisage the final results as being new, low-carbon paths for the UK economy within the international backdrop defined by each of the Foresight scenarios.

This approach forms the basis for the four DEFRA sector papers listed above.

Additional demand-side reductions and corresponding costs

An underlying aim in this section is to treat demand- and supply-side measures in the same way, as far as possible. That should ensure that comparisons are fair, that the same cost definitions are used – and it may have the added bonus that apparently intractable problems on one side are illuminated, and possibly solved, by using "standard" techniques from the other.

For example, we have unit costs and potential for energy efficiency measures for the present, but not for the more distant future: and this is in the form of carbon-saving supply curves, showing how the potential varies with rising unit cost. For renewables, we classify them as short-, medium- and long-term according to the time when their unit cost for a sizeable amount of potential drops to within an acceptable range of the conventional alternative (usually CCGT-generated electricity around 2-3 p/kWh); the difference, usually about 5p/kWh, is taken as the relevant unit cost.

In fact, we could construct an analogous renewables supply curve for the present, with the three broad categories at their current unit costs; this would show the current best, i.e. onshore wind, around 3p/kWh or £40/tC, and photovoltaic cells (PV) somewhere around 40p/kWh, or over £3000/tC. However, the same curve 40-50 years hence could well show PV down at the low end, alongside residual high-cost wind with other, perhaps as yet uninvented, technologies occupying the high-cost end: fusion might or might not be on the horizon.

This illustrates several points:

- installation costs can fall over time – but only if someone carries on with the development;

- this development has a cost; does this appear anywhere in our calculations?;

- as markets develop, new technologies are likely to be developed, initially at very high costs – even if we cannot identify them today.

These points will apply equally to energy efficiency measures. So we might expect a similar supply in the future to that of today, with (some of) today's high cost energy efficiency measures then at low cost.

However, there will be a “normal” or “natural” rate for today’s high cost measures to move to the low cost end of the supply curve, corresponding to the BAU rate of energy efficiency improvement (or rate at which particular renewables become less costly). So our interest is in how this normal rate can be increased, and at what cost, since this would correspond to the extra energy efficiency savings which we are looking for. It is clear from these arguments that there is no single figure for either the amount or the cost: rather there is a sliding scale, with successive tranches becoming available at ever higher costs – as for renewables.

One of the reasons for this “generalised”, rather abstract, approach to extra energy efficiency savings is that we do not always have specific technologies in mind, particularly for the myriad business process uses in the future. But we are confident that such technologies will become available in time, and will gradually drop in cost, as a result both of the usual continuing improvements in existing technologies (the learning curve effect) and of more formal R&D programmes. Heating, lighting and cooling in buildings is a partial exception to this rule, and may be able to offer clues to solving the more general problem.

There are other general issues which we have not yet had time to analyse fully. These include:

- other demand-side savings, e.g. from socio-economic measures;

- the nature of the costs for extra savings (renewables, sequestration, energy efficiency etc) – capital, total implementation, programme, welfare;

- how much the availability of low-carbon electricity under some scenarios might influence the balance of energy sources in each sector (e.g. switch from gas central heating to electric heat pumps).

Summary of projections

The table which follows below presents a summary of the energy demand and carbon emissions estimates for each of the five scenarios, based on the results described in the four DEFRA sector papers. All of these projections are broadly compatible with the DTI’s baseline carbon intensity projections, but have been constructed separately in a bottom-up fashion, in terms of demand for fossil fuels and electricity. Energy efficiency improvements are included explicitly. No attempt has been made to take into account the likely changes in electricity generation under each of the scenarios, nor have possible system effects (e.g. switch to electric heating if cheap low-carbon electricity is available) yet been investigated. However, estimates for CHP generation are included since they already have a significant effect on the emissions from the industry (and to a lesser extent the services) sector.

In addition to the five scenarios, there is an additional column labelled ‘extra energy efficiency’. This presents demand and emissions estimates corresponding to what we currently regard as the most rapid, credible implementation of demand-side efficiency measures, taking into account all of the results presented in the five other DEFRA papers. These figures relate specifically to the BAU growth rates, and would scale accordingly for other growth scenarios.

Projections for Energy Consumption and Carbon Emissions in the Domestic, Industry and Service Sectors
for a Business As Usual baseline scenario, and for extra energy efficiency

			Business As Usual			Extra EE	**WM**	**PE**	**GS**	**LS**
Energy consumption (excluding transport)		***2000***	***2010***	***2020***	***2050***	***2050***	***2050***	***2050***	***2050***	***2050***
Mtoe	Domestic Elec	10	10	11	11	9	14	10	9	7
	Domestic FF	37	36	34	31	19	40	30	28	20
	Industry Elec	10	11	12	13	10	13	14	12	11
	Industry FF	26	24	23	16	12	15	17	12	15
	Services Elec	8	9	10	11	7	12	10	9	8
	Services FF	14	13	13	14	10	17	15	12	12
	Total Elec	28	30	32	35	27	40	33	30	25
	Total FF	77	73	70	62	41	72	61	53	47
	Grand Total	105	103	102	**97**	**68**	**112**	**94**	**83**	**72**

Carbon emissions (excluding transport)		***2000***	***2010***	***2020***	***2050***	***2050***	***2050***	***2050***	***2050***	***2050***
MtC	Domestic Elec	14	14	14	15	12	19	13	12	9
	Domestic FF	28	25	23	21	13	27	20	19	14
	Industry Elec	14	14	14	16	12	17	17	14	13
	Industry FF	20	17	15	11	8	10	11	8	10
	Services Elec	12	12	13	14	9	16	13	11	10
	Services FF	10	9	9	10	7	12	10	8	8
	Total Elec	40	39	41	45	33	52	43	37	32
	Total FF	58	50	47	41	28	48	41	35	31
	Process emissions	4	3	3	3	3	3	3	3	3
	Grand Total	103	93	91	**89**	**63**	**104**	**87**	**76**	**66**

		kgC/GJ								
Assumptions:	Electricity emission factors ESI	35.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0	32.0
	CHP	35.0	25.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
	CHP fraction of generation Industry	18%	26%	30%	23%	47%	19%	15%	33%	33%
	Services	6%	8%	10%	11%	23%	6%	6%	15%	15%
	Fossil fuel emission factor Weighted	18.0	16.5	16.0	16.0	16.0	16.0	16.0	16.0	16.0

Annex C

Description and assessment of options

Energy efficiency

C1 The group has had difficulty in attempting to assess scope for energy efficiency gains on a similar basis to its consideration of other options. This is linked to the number of technologies involved, the evolution of new technologies and alternative interpretations of unrealised but apparently cost effective potential. We start by considering the potential for current known options.

C2 We employ the following definitions:

- *Technical potential.* All commercially available energy efficiency technologies.

- *Economic potential.* A sub-set of the technical potential that passes a cost-effectiveness condition. In this paper we use a payback time of less than five years in the domestic sector and less than four years in the business sectors.

- *Economic potential to 2010.* That part of the economic potential that can be realised short-term, taking account of capacity and capital constraints.

C3 In assessing the potential for energy savings our starting point is a work in progress paper by the PIU. To this we have added an allowance for development of micro-CHP in the domestic sector, based on the assessment in Box 1 below. On this basis, estimates of potential are shown in Table C1 below.

Table C1: Energy efficiency savings potential MtC

	Technical	Economic
Domestic sector[66]		
Loft insulation	1.4	1.4
Cavity wall insulation	2.6	2.6
Hot water cylinder insulation	0.3	0.3
Condensing boilers	5.3	5.3
Energy efficient lighting	1.1	1.1
Energy efficient appliances	3.6	3.6
Controls	0.4	0.4
Micro CHP	4.5	0.2
Solid wall insulation	2.8	-
Double glazing (+low emissivity)	1.7	-
Draught proofing	0.3	-
Solar water heating	1.6	-
Ground source heat pump	5.3	-
High performance glazing	1.2	-
Sub-total	*32.1*	*14.7*
Commercial and service sector[67]		
Various costed measures	6.1	3.4
Office equipment	0.2	0.1
CHP[68]	0.9	0.9
Energy management	1.0	0.8
Sub-total	*8.2*	*5.1*
Industrial sector[69]		
Metals	3.2	2.2
Minerals and ceramics	1.8	1.3
Chemicals	1.9	1.1
Food and drink	0.8	0.7
Paper and textiles	2.4	1.4
Engineering and other	3.3	1.9
Sub-total	*13.2*	*8.6*
TOTAL	**53.4**	**28.6**
Climate Change Programme already scores:		
Domestic sector[70]		- *4.5 – 6.0*
Commercial and service sector[71]		- *0.4*
Industrial sector[72]		- *4.5*
TOTAL after CCP		**17.7 – 19.2**

66 Domestic sector savings based on combination of sources, including BRE, ACE, EST and ECU, with judgement applied to provide estimates shown
67 Source: background paper prepared for the RCEP, Fisher, Blyth, Collings, Boyle, Wilder, Henderson and Grubb, Prospects for energy saving and reducing demand for energy in the UK.
68 Moss and Shorrock, BRE, have estimated a range of CHP savings in buildings from 0.9-3.4MtC.
69 Source: background paper prepared for the RCEP, Fisher, Blyth, Collings, Boyle, Wilder, Henderson and Grubb, Prospects for energy saving and reducing demand for energy in the UK.
70 Estimated impact of EEC, new HEES, appliance standards and labelling, new building regulations, improvements to community heating.
71 Estimated impact of new building regulations
72 Estimated impact of climate change agreements, energy efficiency measures under Carbon Trust and emissions trading scheme.

Box 1 Micro or domestic CHP

At least three UK firms are working towards the launch of micro CHP units in the UK. They may come to the market within the next couple of years.

It seems that most units would deliver 1-3kW of electricity and 5-9kW of heat. They would mainly run during the 2,000-3,000 hours a year that households require heat, and not therefore aim to provide a household's total electricity needs. When they are running, however, some may produce more electricity than required, making some available for export.

Market potential

Gas fired central heating boilers are fitted in around 17m properties. About 1 million are replaced each year, and 175,000 new homes are built. In practice the economic market is rather smaller. The more optimistic company view is that sales could reach 200,000 a year by 2005 and 1m a year in the following five years.

Cost

The cost premium over a conventional gas boiler is currently of the order of £600. With volume production this should fall. One company has adopted a target of no more than £400 additional cost for a 1kWe/7kWt unit. The reduction in primary energy use is of the order of 30% (relative to the new building regulations and the current generation fuel mix).

Emission savings

Based on a saving of 0.3tC a year per unit, and sales of 500,000 units a year from 2005 then carbon savings would reach 0.75MtC/year in 2010. Sales at a more realistic level of 100,000 a year over that period would provide carbon savings of 0.15MtC/year in 2010. If in the long-term 10m installations were achieved, carbon savings could reach 3MtC/year.

Barriers

To achieve potential:

(i) arrangements have to be in place for the domestic consumer to obtain a fair price on electricity exported back to the grid.

(ii) Currently, the cost of establishing a connection to the low-voltage network is around three times the cost of the appliance, and a simple low cost connection is required.
(iii) Equipment leasing via energy services may be the most practical approach to developing the market.

(iv) The technical installation/maintenance/repair skill-base needs to be developed.

C4 Although there is disagreement across sources on the detail, broad messages from Table C1 can be summarised:

- in the domestic sector, currently available technology can reduce carbon emissions by at least 50%. This does not allow for any comfort effect, but over the longer-run any such effect should be fairly small. A cost-effective potential of almost 15MtC represents around 30% of total domestic emissions;

- not all the economic potential identified above could be achieved within the next decade. The EST, for example, identifies potential 5.8MtC savings by 2010, above business as usual, based on its assessment of reasonable installation rates (see box next page);

- the CCP itself has identified savings of 4.5-6MtC by 2010 from the domestic sector. The scope to achieve more than that by 2010 therefore looks small;

- in the commercial and services sector, a cost effective potential around 5.1MtC represents around 24% of total sector emissions;

- not all that potential could be achieved within the next decade. The background paper from which the technical potential estimates are drawn also indicates around 2.3MtC economic potential by 2010;

- relatively little of this potential – perhaps 0.4MtC – is directly targeted by the CCP, although the climate change levy will also have an impact at the margin;

- in the industrial sector the figures relate to the potential for 2010. The technical potential represents around 30% of total industrial emissions;

- the economic potential of 8.6MtC represents around 20% of sectoral emissions;

- but a relatively large part of this potential has been targeted by the CCP, especially by the climate change agreements. The scope to produce much greater saving by 2010, at least, looks very limited.

Box 2. Energy Savings Trust estimates of potential savings from energy efficiency to the year 2010

The EST has identified a programme of home energy efficiency measures to reduce annual emissions by 5.8MtC by 2010 over and above reductions that would occur without policy changes.

	Technical potential[73] MtC	Economic potential MtC	Investment cost per household £
Cavity wall insulation	2.3	1.1	450
Double glazing	0.3	0.1	170
Low E glazing	0.6	0.3	35
Loft insulation	0.3	0.2	200
Tank/pipe insulation	0.4	0.2	35
Condensing boilers	3.0	0.8	300
Controls	0.7	0.2	300
Residential CHP	0.2	0.1	300
CFL	0.7	0.6	9
Appliances	2.8	1.7	<70
New build standards	0.5	0.5	250
TOTAL	11.7	5.8	

The EST's estimates of achievable potential take account of the existing state of the housing stock and appliance market, and the realistic eventual take-up of each measure.

All measures are estimated by the EST to be cost-effective: energy savings over the life of the measure more than offset the initial investment cost. The initial investment cost per household is shown in the final column above. This represents investment rising to £1billion annually.

[73] Calculated from EST figures on assumption that all households missing these measures are reached.

Box 3. Potential energy efficiency savings in the domestic and services sector beyond 2010 – more speculative sources

Heat pumps. Early signs of application in areas without gas. Used for heating and cooling. If air conditioning begins to take off, heat pumps may be a more attractive option on environmental grounds. But little data exist on potential.

Appliances. Number of household appliances on stand-by is becoming a challenge. Minimum standards may be required to address such energy use.

Triple glazing and smart windows. Smart windows are able to dynamically change their solar-optical properties in response to changing performance requirements. Some devices might respond directly to environmental conditions such as light level or temperature. Others can be directly controlled in response to occupant preferences for heating or cooling. Benefits may be greatest in commercial buildings but there is also scope for application for housing.

Longer term: potential to 2050

C5 Overall, the above analysis suggests an economic potential for energy efficiency savings beyond 2010 (i.e. not already claimed by the Climate Change Programme) of a little under 20MtC.

C6 But such estimates do not take into account that energy efficiency potential is dynamic rather than static. By 2010, some new processes in industry will offer the prospect of further energy efficiency improvements in the future, particularly when plant is built or replaced. RD&D over the next decade will also "replenish" the potential.

Renewables

C7 For electricity generation a wide range of renewables options exist. Their production potential, as far as it is currently understood, is summarised in table C2 below.

C8 The data indicate that some options have in theory limitless potential. For example the theoretical capacity offered by offshore wind could alone meet the UK's future electricity needs – the potential output at around 4,000TWh is 10 times the UK's electricity production in 1999. Even considering the practical resource (less than the overall potential to allow for distance from shore, difficulties of development in high wind speed areas off the outer Hebrides etc, but achievable if grid connections are in place and planning issues overcome) offshore wind could provide around 100TWh of electricity a year. On the other extreme some options such as municipal waste currently appear to have limited resource potential, regardless of the scope for significant technical advancement.

C9 Another factor to consider is whether the options offer a long-term potential. In the medium term, landfill gas and incineration of municipal solid waste have potential for growth, consistent with the Government's Waste Strategy. But landfill gas probably has very little potential looking to 2050 and beyond. Similarly the potential for generation from the incineration of municipal waste could be constrained in the longer term if the absolute amount of waste produced starts to fall or recycling increases substantially.

Table C2: Resource potential for electricity generation options – based on ETSU data

	Current (1999)[1]	Theoretical max	Practical max	Current max	
	Capacity (GW)/ Electricity generated (TWh)	**Capacity (GW)/ Electricity generated (TWh)**	**Capacity (GW)/ Electricity generated (TWh)**	**Capacity (GW)/ Electricity generated (TWh)**	**Lifetime emissions g CO_2/kWh[2]**
Onshore wind	0.36/0.9	110/318	19	2.75/8	9
Offshore Wind	0.004	1088/approx. 4,000	100		9
Energy crops	0.010	3 – 4 GW per 1 mill ha. Max 74 (all UK agricultural land)			14
Municipal Waste	0.16 (DNC)/1.4	13.5			364
Landfill gas	0.3 (DNC)/1.7		5	5	49
Solar PV	0.0012 (DNC)/ 0.001	266 of which BIPV 37		BIPV 0.17	59 -71
Large Hydro	1.4 (DNC) 5.1	13 (all hydro) 40		Potential for additional 1GW, but unlikely	32
Small Hydro	0.06 (DNC) 0.2		0.3 – 0.55	0.04 – 0.1	5
Tidal		Tidal stream 36 TWh Barrage 50TWh			
Wave		Elec. gen. Shore 2 Nearshore 100 Offshore 600	Elec. gen. Shore 0.4 Nearshore 2.1 Offshore 50		

1. Data from 2000 Digest of UK Energy Statistics table 7.4, expect for offshore wind, energy crops. DNC is declared net capacity
2. Estimates from ETSU, except PV which are from Government – Industry PV group report, gas generation taken as 100,000tc/TWh

Onshore wind

Technical description and market status

C10 Wind turbines are commercially available up to 2MW. Most new installed grid-connected machines are 600kW, which are more cost effective. A 600kW turbine operating in a wind farm produces around 1,600 MWh per year, assuming a wind speed of 7 m/s with the turbine 45 m above ground level. Turbines are designed for a 25 year lifetime, although few so far have operated for more than 15 years. Better design has improved operating availability (the time the plant can be used, irrespective of wind) to around 97–99%.

C11 By the end of 2000 there was around 360MW of wind power in the UK (9,000MW in the EU and 16,000MW world-wide). These capacities represent significant global growth since 1997 when EU capacity was 4,400MW and worldwide 7,500MW. UK growth has been slower by comparison; the 1997 figure was 313MW. The UK is now the 7th largest wind generating country.

Resource potential

C12 The UK has one of the best wind resources in Europe. Clearly not all that land can be used as it includes towns, lakes, woods and other constrained areas such as National Parks. Removing these areas and applying limiting assumptions[74] ETSU have calculated an accessible resource of nearly 110GW, capable of producing 318TWh/year.

C13 Further planning limitations, such as minimum distance apart for wind farms, and minimum and maximum farm size, reduces the usable land further. Allowing for these factors, ETSU estimate “base case” capacity of 19GW by 2025, capable of producing around 19% of the UK’s electricity requirements.

C14 But ETSU also suggest that network limitations will come into play long before such levels are reached. Without network reinforcement it is estimated that the resource would be limited to 2750MW, providing around 8TWh/year (or 2-3% of UK electricity).

---

[74] Maximum turbine density of 9 MW/km^2, buffer zones ranging from 100m around roads to 6km around airports and ignoring land with a gradient in excess of 10%.

C15 From other work, however, it seems that network reinforcement may prove less of a problem than this. The rate at which capacity can actually be built may represent a more significant limitation.

Costs

C16 The cost of wind-generated electricity has decreased significantly over the past few years. For example under NFFO-3 launched in 1995, 31 wind projects were accepted with capacity greater than 1.6MW at an average price of 4.3p/kWh. By NFFO-5 launched in late 1998 the average price for the 33 accepted projects over 1MW had fallen to 2.88p/kWh. Costs have fallen for three main reasons. (i) the capital cost of turbines has fallen despite average sizes increasing (ii) increased expertise and experience and (iii) perceived project risk has decreased providing lower cost finance for project developers.

C17 Cost per tonne carbon saved: Looking towards 2025, onshore wind prices ranging from 2p/kWh to 2.5p/kWh would lead to a carbon cost of -£30 to +£20 against a gas price of 2.3p/kWh or -£90 to -£40 compared with a gas price of 2.9p/kWh.

Offshore wind

Technical description and market status

C18 Little offshore development has so far taken place worldwide. At present Denmark has 40MW of offshore plant installed with plans to develop 750MW by 2008 and 4,000MW by 2030. Holland plans to have 1,500 MW installed by 2020, but so far only has four 500MW turbines in an in-land lake. By the end of 2000 the UK had 4MW of installed offshore wind capacity.

C19 Offshore windfarms need demonstration and assessment before they can be considered commercially proven. By 2010 medium-sized wind farms will be developed in the UK, with assessment and R&D supported by the DTI R&D programme. At the same time parallel developments will be under way in other, mainly European, countries.

Resource potential

C20 The UK has enormous potential for offshore wind. At the optimal turbine height of 60m above sea level, almost all of the UK's offshore wind has speed between 7 and 9 m/s. The only real limitations are practical water depths, the use of maritime areas for other activities, environmental impact and limitations of the onshore electrical network. An ‘accessible resource’ estimate shows[75] the potential UK offshore capacity is estimated at 1,088GW (total UK capacity at end 1999 was around 75GW).

C21 Further constraints are needed to turn the theoretical maximum estimate into an estimate of practical resource estimate.[76] These restrictions produced an estimated offshore wind resource capable of producing 100TWh per year (approximately 30% of current UK demand) of which nearly half could be produced less than 10km from the shore. Relaxation of network and planning constraints (although an allowance for the latter is included in the derivation of the practical resource) would be necessary to achieve this potential.

Costs

C22 Increased foundation costs required for offshore wind means that the minimum cost-effective capacity for a single turbine is about 1MW (wind turbines for onshore use are commercially available up to 2MW). Anticipated costs have decreased significantly over the past few years, most notably costs of large turbines whose costs are now at a level projected (in 1994) not to be achieved until 2025. These cost reductions mean it is now viable to use onshore developed turbine technology for offshore applications and therefore bring forward off shore development. Likewise the performance improvement of onshore wind plant has reduced O&M costs and similar costs for near shore offshore plants could now be expected.

C23 There is considerable scope for future cost reduction if the technology becomes more widely deployed, although this will need demonstration farms to verify initial costs, performance, outputs and materials. However, with successful demonstration there is scope for cost savings through purpose-built offshore turbines and economies of scale

[75] Derived by limiting water to 30km from shore and 40m deep and discounting sea bed with either gradient greater than 5 degrees, shipping lanes, military zones, pipelines or other constraints such as fishing grounds or wildlife reserves.
[76] Assumes that only 5% of potential sites will be developed (as a result of seabed composition or planning constraints – a higher figure would of course increase potential); capacity reduced by 50% for sites less than 10kn from shore, for reasons of public acceptability; reduced capacity of sites with wind speed over 9m/s by 95% to account for development barriers presented by hostile environment; finally other sites with average wind speed 8–9 m/s had capacities reduced by 5%.

by establishing larger farms. ETSU suggest that cost could fall to 60% of 1996 levels by 2010 and 56% by 2025.

C24 Cost per tonne carbon saved: Based on current costs of around 5.5p/kWh for offshore wind and 2p/kWh for gas the carbon cost is around £350/tC. However, looking towards 2025 offshore wind prices should fall, and we use a range from 2.0 p/kWh to 3.0 p/kWh. These prices imply a carbon cost of -£30 to +£70 against a gas price of 2.3 p/kWh or -£90 to +£10 compared with a gas price of 2.9p/kWh.

Energy crops

Technical description and market status

C25 Energy crops are plants grown specifically for use as a fuel. The rationale for growing dedicated energy crops is that the resource that can be realised from other forms of biomass (such as agriculture and forestry residues and forestry products) is not sufficient to meet the perceived needs for this form of energy. Dedicated crops have the further advantage that they can be grown close to the point of use or conversion.

C26 There are two categories of energy crop - perennials such as trees and grasses, and annuals such as oilseeds, cereals and sugar bearing plants. Perennial crops require lower energy inputs, in the form of fertilisers and other agrochemicals and so maximise the net non-fossil energy output (and so minimise the cost of greenhouse gas abatement). Oil seed is attractive however in that the technology is simple, and available.

C27 Crops are turned into electrical power via direct combustion or gasification. The electrical efficiency of a gasification process is much higher than a combustion process at the same scale. Thus a 30MWe state of the art combustion plant will return 31% whereas a gasification plant will be capable of 42%. There have, however, been technical difficulties with plants at 8-10MWe and downtime could significantly reduce efficiency in these plants. Specific capital costs should be similar so the cost of electricity will be reduced and the available resource increased. There has also been a great deal of interest in pyrolysis from power plant project developers in the UK. This stems from a combination of factors - chiefly that when the biomass is converted to liquid product it can be easily stored and transported.

C28 There is a growing interest in small scale, distributed power plant, using biomass. In the UK, the applications are typically CHP in rural areas with an electrical output below 250kWe. There is also some limited interest from environmentally conscious housing developments or farmers seeking to add value to their energy crops.

C29 Energy crop fuel chains, in the form of short rotation coppice, are commercially deployed in Sweden and in the demonstration phase in the UK. Around 1500 hectares of short rotation willow coppice has been planted to provide fuel for the ARBRE project in Yorkshire (a European Commission THERMIE project). This will demonstrate the technology (producing 8MWe from a fluidised bed atmospheric gasifier and employing CCGT), opening the way for future replication at a larger scale. The UK has three demonstrations of distributed power systems in Northern Ireland. Grasses, though promising, are still in the development stage.

Resource potential

C30 There are currently 18.5million ha used for agriculture in the UK, but not all could be used for energy crops. The maximum potential is largely dependent on agricultural policy (specifically CAP reform – energy crops cannot currently provide the grower with the same returns as subsidised food production) and competition for land from different crops, though improvements in crop yield would also help. Availability of land is not considered to be a barrier as 1 million hectares would be capable of generating 3-4,000MWe, but in practice a more reasonable target for 2010 would be 1,000MWe.

Costs

C31 Development of energy crops has been slow. This reflects the infant nature of the industry and the complexity of creating a fuel supply of a novel crop and then using it in conversion plant that has not been proven commercially. Because of the relatively low density of biomass fuels, transport costs are high. It is generally feasible to produce the fuel for a 30MW power station within a 15-20 mile radius of the plant. The cost of establishing the crop is high with insufficient volume to drive cost reduction in the specialised agricultural equipment required.

C32 Supporting analysis by ETSU, published March 1999, showed a possible evolution of costs from ARBRE at 8.65p/kWh, to first commercial deployment 6.8p/kWh, mature technology 4.5p/kWh and "future" 2025, 3.7p/kWh.

C33 Resource cost curves, allowing for a maximum practical resource, suggested that in 2025 around 33TWh of electricity could be generated by SRC at a cost of up to about 4.0p/kWh (at 8% discount rate) or 5.0p/kWh (at 15% discount rate).

C34 Cost per tonne carbon saved: Looking towards 2025 with assumed development leading to energy crop produced electricity ranging from 3p/kWh to 4.4p/kWh implies a carbon cost of £70 to £210 against a gas price of 2.3p/kWh or £10 to £150 compared with a gas price of 2.9p/kWh.

Hydro

Technical description and market status

C35 Hydropower is now the foremost electricity-producing renewable energy technology in terms of installed capacity and energy yield, both in Europe and the world. The technology is commercially developed and commercially competitive. UK installed capacity is around 1,265MWe (large scale) and 95MWe (small scale) with output of 3,955GWh (large scale) and 333GWh (small scale). Micro-hydro should be commercially competitive with alternative fuels (e.g. diesel) in non-grid connected markets.

Resource potential

C36 The total hydropower resource for the UK is estimated at 40TWh/year or 13GW of installed capacity. This is based on mean annual rainfall figures, land area and elevation data. Allowing for geographical and environmental constraints on potential sites will indicate a much reduced accessible resource. In Scotland there may be an unexploited accessible large-scale resource of 1GW or 3TWh/year. But this would require reservoir storage and its development is likely to be limited by environmental constraints. Remaining UK small hydro resource which might be commercially attractive is small – between 40 and 110MW (under 5p/kWh unit generation cost at 15% and 8% discount rate over 15 years respectively).

C37 Environmental constraints prevent development of the remaining resource in the UK in sensitive areas. Since the good quality, most commercially attractive resource has been virtually completely developed, the domestic market is limited.

Solar PV

Technical description and market status

C38 Photovoltaic (PV) materials generate direct current electrical power when exposed to light. PV cells can be formed from either silicon wafers or from thin-films of either vacuum deposited silicon or other semiconductor materials such as cadmium telluride (CdTe) or copper indium diselenide (CIS). For most commercial uses some form of energy storage and associated controller are required and this can be replaced or supplemented by a DC to AC inverter to match with the mains network or AC loads.

C39 Crystalline silicon modules have proved to be both reliable and low-maintenance items with a service life of at least 25 years. However, the crystal growth and wafer cutting processes are costly and inefficient - wastage can be up to half of the feedstock - and so considerable cost savings can be made by utilising silicon in sheet form. There are about six different methods of growing silicon crystals in sheet form currently under pilot production. There has been increasing investment in a group of PV technology developments that aim to avoid the need for semiconductor silicon feedstock and dependence on the electronics industry. These devices are based on thin-films of semiconductor materials that have the advantages of lower material and production costs. Some are now well-established products, particularly in consumer goods such as watches and calculators, and other more recent devices are at the pilot plant phase. Although costs are lower, efficiency and reliability are not as high as crystalline devices. Ongoing investment is tackling these issues.

C40 At the systems level, network-connected PV technology is developing rapidly in Central Europe, the USA and Japan where there are national subsidy schemes in place mainly for domestic systems. Some European countries have demonstrated large-scale power plants up to 3MW. More recently, large systems have also been installed on motorway verges, combining the benefits of electricity generation with a sound barrier function alongside residential areas. However, large-scale centralised generation of electricity for the grid by means of PV is unlikely to be economically attractive in the UK, at least for the foreseeable future. Developing country applications and building-integrated products are likely to be the most significant in terms of growth.

Resource potential

C41 The use of PV developed initially as a remote electrical power supply - firstly in space applications and then telecommunications and signalling. Installed capacity of PV in the UK is approximately 1MW but has shown about a 50% growth in the last 5 years as large (Building Integrated) BIPV demonstration projects have been installed

C42 The maximum practicable resource for PV is calculated as the electricity generated by the application of PV to all available domestic and non-domestic buildings. This gives a maximum of 266TWh/year in 2025[77]. A substantial proportion of this resource will be relatively high cost due to low levels of received sunlight, e.g. for north-facing surfaces.

C43 For building integrated PV an ETSU study has calculated potential in 2010 as 7.2TWh/year and market potential at 32.5GWh/year; with potential extrapolation to 37TWh/year and 170GWh/year respectively by 2025 (possibly more if environmental drivers are strong).

Costs

C44 At present, PV generation costs are high relative to alternative central generation options. PV equipment costs have reduced in the last few years, related to a steady increase in the size of the market. However, whilst PV is already cost effective in some remote applications, supported by a growing global manufacturing base, cost reductions are needed to realise market volume.

C45 International module prices are largely beyond the influence of UK players as manufacturing plants are set up to service an international market. There is potential for UK PV companies to achieve incremental cost reduction targets utilising the UK R&D base and expertise in mass production, as well as developing BIPV systems and components that will form an increasing segment of the UK market from 2010. Current manufacturing methods are high precision and labour intensive.

[77] Based on a series of assumptions made by ETSU on solar radiation, building rate, PV and inverter efficiency, property numbers etc.

Significant cost reductions will need the development of capital intensive, high volume technology. In addition the costs of metering required by current regulation for grid connection will need to be addressed.

C46 Cost per tonne carbon saved: ETSU published figures indicate no PV resource at under 7p/kWh by 2010. By 2025, at an 8% discount rate, up to 0.5TWh electricity might be generated at between 6 and 7p/kWh. As such PV is currently and for the foreseeable future too expensive for significant electricity generation applications.

Agricultural and forestry residues

Technical description and market status

C47 Agricultural and forestry residues fall into two main groups – dry combustible materials such as forestry residues, straw and poultry litter; and wet materials like green agricultural crop wastes (e.g. root vegetable tops) and farm slurry. The first group can be combusted (or converted by other thermal processes like gasification or pyrolysis) to produce heat and/or power. The second group can be used to produce methane-rich biogas through the process of anaerobic digestion. A third class of material which merits consideration with agricultural and forestry residues is sawmill co-product –that is, bark fragments, wood offcuts and sawdust from wood processing. Such material is a major source of biomass energy in Nordic countries but UK data are not currently available to the IAG.

C48 Mature technology for forestry residue fuel chains exists in the Nordic countries and North America. Conditions in the UK are significantly different however, and the technology is in the demonstration phase. Mature technology for forestry residue fuel chains exists in the Nordic countries and North America. Conditions in the UK are significantly different however, and the technology is in the demonstration phase. Nevertheless forestry residues have already proved to be a valuable and readily available source of biomass to make up initial shortfalls in planned availability of SRC in experimental plants.

C49 Straw and poultry litter fuel chains are based on current agricultural practice and fully commercial. One plant, in Ely, Cambridgeshire has been generating for some months. A number of plants using poultry litter conversion technology are either operational or in construction.

C50 The pyrolysis of woody biomass for energy is currently in the development phase (although small units have been built for the commercial production of chemicals). Treatment of farm slurries by anaerobic digestion leads to the production of biogas, which can then be used for heating or the generation of electrical power. Farm digesters have in many cases proved difficult to manage, – maintaining the right blend of feedstock can be difficult and unless these are managed effectively the risk of fugitive GHG emissions is high. There are also biosecurity issues surrounding the import of foodstuffs to maintain the right blend. In NFFO4 six projects, in the range 0.5-1.4Mwe, were granted licences to generate electricity from digested slurries. More generally the initial cost of investing in a digestion system appears to be a barrier.

Resource potential

C51 In all cases, plant size will be limited by the availability of sufficient resource within economic transport distance.

C52 The amount of forest residues available from UK woodland is limited by harvesting cycles and, under current management practices, the need to protect fertility and structure of soils on some forest sites. Moreover, the area of woodland in the UK (2.8 million hectares) is small compared to most of the countries where use of forestry residues is an established technology. There is potential to use agricultural by-products as well as forest material alongside purpose-grown energy crops. The total accessible resource available from farm slurries is estimated to be of the order of 2.9TWh/year.

Costs

C53 ETSU resource cost curves show maximum practicable resource availability of 19TWh/year by 2025 at under 5p/kWh (8% discount rate) or 18TWh/year at under 6p/kWh (15% discount rate).

Landfill Gas

Technical description and market status

C54 Under the anaerobic conditions of landfill sites, organic waste breaks down, leading to the formation of landfill gas – primarily a mixture of CO_2 and methane, with a number of trace components. Exploitation of landfill gas for electricity production is adapted from an established and proven reciprocating engine technology. Gas turbines are also used in some applications.

C55 Over 300Mwe is deployed in the UK, with a further 400MWe under NFFO contract.

Resource potential

C56 Energy recovery from landfill gas is only possible for those sites sufficiently large to sustain substantial gas generation (often taken to be around 200,000 tonnes of waste in place). This suggests current maximum potential of 5TWh/year electricity in England and Wales.

C57 The number of schemes using landfill gas in the UK is expected to rise as EU directives to control methane emissions to the atmosphere are implemented. However, in the longer term, from 2015-2025, the landfill directive will effectively prevent the deposition of biodegradable wastes – it will divert such wastes away from landfill, and reduce potential for methane generation.

Costs

C58 Costs have been based on data available within the landfill gas industry and reflect a growing trend to buying in a complete package from a landfill gas project developer. Costs are expected to fall by around 10% by 2005, reflecting increased sales volumes. It is also likely that gas collection costs will have to be borne as part of the environmental control costs of landfill operation.

C59 ETSU resource cost curves show availability of 7.5TWh/year by 2025 at under 3p/kWh (8% discount rate) or 4p/kWh (15% discount rate).

C60 Cost per tonne carbon saved: Looking towards 2025 it may be possible to produce electricity ranging from 1.5p/kWh to 2.7 p/kWh implying a carbon cost of -£80 to +£40 against a gas price of 2.3p/kWh or -£140 to -£20 compared with a gas price of 2.9p/kWh.

Municipal Solid Waste

Technical description and market status

C61 The UK currently produces around 27 million tonnes of municipal waste annually. Using such wastes to produce energy can reduce the environmental problems of disposal, whilst displacing fossil fuels from generation. Excluding landfill gas (covered separately), the energy content of the waste may be recovered via combustion or anaerobic digestion.

C62 Mass burn technology for recovering energy from municipal and general industrial wastes is well established. UK installed capacity, in 1997, was 143Mwe. By the end of 1998 combustion capacity was about 2.3 million tonnes.

Resource potential

C63 Assuming all MSW was used to generate electricity the potential is around 13.5TWh/year. Currently over 80% of household and commercial waste is disposed of to landfill, which will remain the major disposal route for some time. Longer term, regulatory pressures on landfill should act to favour energy recovery from MSW.

Costs

C64 ETSU resource cost curves show availability of between 4 and 6.5TWh/year by 2025 (for 15% and 8% discount rates respectively).

C65 Cost per tonne carbon saved: Looking towards 2025 it may be possible, as with landfill gas, to produce electricity ranging from 1.5p/kWh to 2.7 p/kWh implying a carbon cost of -£80 to £40 against a gas price of 2.3 p/kWh or -£140 to -£20 compared with a gas price of 2.9p/kWh.

Tidal stream

Technical description and market status

C66 Tidal stream is the name given to high velocity tidal currents created by the movement of the tides and frequently enhanced by topographical features. A tidal stream energy converter would extract and convert the mechanical energy in the current into useful form. It could be expected to capture power from both the ebb and flood tides. It is envisaged that tidal stream generators would be installed in arrays, with the individual generators connected to an offshore ring circuit, with a single cable to transmit power to shore.

C67 A number of device concepts have been proposed. There is no consensus on the best approach, and no certainty that it has yet been identified. No meaningful scale systems have yet been constructed and there is no significant operating experience. Long term performance and reliability remains to be demonstrated. Whilst work with prototype designs is going forward, commercial scale demonstrations are not likely until post 2010.

Resource potential

C68 Studies have shown the UK resource to be between 31 and 58TWh/year. Allowing for the location of this resource – tending to be at the extreme ends of the country where demand for power is small – perhaps 10TWh/year might be capable of exploitation (in the region of 3% of UK electricity demand). That could only be increased if designs could be found and proven for use in either shallower or deeper waters than currently look most promising.

Costs

C69 It is clear that tidal stream devices can be made to work; but it is not yet demonstrated that they can do so at economically attractive prices. One of the more advanced designs is that proposed by Marine Current Turbines Ltd, to be demonstrated near Lynmouth in North Devon. Independent studies on the MCT concept indicate that it might produce energy at between 3.4p and 6p/kWh (5% and 15% discount rates respectively). This would be substantially below previous estimates and approaching a cost that would be viable within the Renewables Obligation.

C70 A cost of 3.4p implies a carbon cost of £110 against a gas price of 2.3 p/kWh or £50 compared with a gas price of 2.9p/kWh. At 6p/kWh the cost range is from £310 to £370/tC.

Wave

Technical description and market status

C71 There are many potential methods for extracting energy from waves and converting it to useful form (e.g. oscillating water/air columns, hinged rafts or gyroscopic/hydraulic devices, with the energy then converted to electrical power using a generator. Direct drive generators with the motion of the wave directly converted to electrical power are also being contemplated.

C72 Deployment could be on the shoreline or in deeper waters offshore, though the shoreline resource is limited (few sites meet the requirements of useful energy capture). The engineering challenge is greater offshore – and prototypes are likely to progress first near shore (or onshore), but the energy potential and cost effectiveness should be rather greater.

C73 A number of device concepts have been proposed. There is no consensus on the best approach, and no certainty that it has yet been identified. Three projects have been awarded contracts under the Third Scottish Renewables Order. The first of these – the LIMPET device, a 500kW shoreline Oscillating Water Column deployed by Wavegen (Inverness) on Islay – is now operating. In general, shoreline wave energy conversion is technically developed, but not fully commercially proven and still some way from being competitive. Offshore wave energy is mainly in the research and development phase. Commercial scale demonstrations are not likely until after 2010.

Resource potential

C74 The UK has one of the best wave power resources available.

Costs

C75 It is clear that wave power devices can be made to work; but it is not yet demonstrated that they can do so at economically attractive prices. Further innovation will be required to achieve true commercial competitiveness.

Active solar

C76 Active solar systems collect, store and distribute the sun's thermal energy (heat) which can then be used to heat water and air for domestic and industrial purposes. The technology is mature and proven. There are few R&D opportunities to reduce costs or improve performance.

C77 The main barrier to the increased exploitation in the UK of the domestic and non-domestic water heating systems is the economic justification for its application. There may also be a lack of awareness and a perception that solar energy does not work in the UK.

C78 Current domestic systems cost are around £2,500 upwards for a professionally installed retrofit system. The energy saved by such a system is typically between 1000kWh and 1500kWh for a water run-off in the region of 150 litres per day (typically that used by a household of around 4-5 people). If an investment calculation is made, it is more likely to be based on simple payback methods (0% test discount rate) than on discount rate calculations. The payback period of the system will depend on the fuel that it is displacing. Where the fuel is natural gas, the simple payback would be in the region of several decades. For the displacement of electricity, the simple payback reduces to around 20 years. A decrease in the water used (e.g. smaller households) could well increase the simple payback further, whereas an increase in the water used would reduce the payback time.

C79 If an active solar system is displacing peak-rate electricity at 7.5p/kWh (the highest energy cost will give the most attractive payback - actual electricity prices are probably lower than this at the moment), 1,500kWh per year is worth £112.50, giving a simple payback of 22 years. If such a system is displacing natural gas (the worst case) with a price per unit of 2p/kWh, the annual savings are £30, the simple payback is 84 years. Clearly, more rigorous discounted cash flows would substantially worsen these figures.

C80 DIY systems may cost between £1,500 and £2,000. These give the simple paybacks of between 13 and 18 years for displacing peak rate electricity and between 50 and 67 years for natural gas (same price of energy assumptions as above). Again, discounted cash flow analyses will make this worse.

Passive solar

C81 Passive solar design (PSD) is a process of building design that utilises solar energy to provide some of the space heating and lighting required in buildings and to assist natural ventilation. PSD differs from other renewable energy producing technologies in that it has the direct effect of substituting conventional energy in buildings.

C82 PSD is not a power generating technology. It need cost little or nothing to apply or it can involve more expensive and complex design and special features or components. Consequently there are no hard and fast rules on the general cost of applying PSD and the benefits.

C83 The growth of PSD is currently restricted by developers who do not perceive commercial advantages in the use of the technology. There is nowadays a demand for high levels of environmental comfort in buildings and a wide belief that this can be achieved only through highly controlled active systems of ventilation and air conditioning. The general public is largely unaware of the benefits of PSD and this ignorance is a constraining factor on the growth of the technology.

Geothermal

C84 Geothermal aquifers exploit heat from the earth's crust through naturally occurring ground waters in deep porous rocks. The exploitation of these aquifers as a source of energy requires a production borehole to extract the water and an injection hole to dispose of the cooled water. An alternative single hole configuration can be used where, instead of using an injection well, the used water is simply discharged to the sea or some other convenient sink. Because of the poor thermal conductivity of rock and low-fluid recharge rates, heat is usually extracted at a greater rate than it is replenished from the surrounding rock mass. Geothermal aquifers are, therefore, not 'renewable' resources in the strict sense of the word, but are usually grouped along with renewables.

C85 In the UK heat from aquifers and ground source heat pumps needs to be commercially competitive with fossil fuels and off peak electricity. The geothermal aquifer resource within the Wessex Basin under the Bournemouth area appears to be the most attractive for possible future exploitation, but the commercial risks of speculative drilling remain high. At 3.5p/kWh_{th} or more, the cost of heat from the aquifer resource is still significantly higher than heat from conventional industrial boilers (approximately 1.44 p/kWh$_{th}$).

Photoconversion

C86 Photoconversion is a generic term describing the capturing of light energy by a chemical, biological or electrochemical system which is then harnessed as a fuel, chemical or electricity. It is sometimes referred to as artificial photosynthesis. When the sunlight is absorbed by such a photoconverter, a transient 'excited' or energy rich storage state is produced. It is this captured energy which is subsequently harnessed and utilised.

C87 The longer-term targets for the technology would be to be competitive with other means of electricity production and/or produce competitive fuels. Early applications involving consumer products would have different targets relating to the specific host product. ETSU concluded that since there is no obvious progress towards a commercial future, this group of technologies should at best continue to be kept under observation.

Carbon capture and storage

Technical description and market status

C88 Carbon dioxide Capture and Storage (CS) is essentially a process whereby CO_2 is removed from the fossil fuel used to generate electricity (either pre or post combustion) and stored in natural underground reservoirs, preventing it reaching the atmosphere. It can achieve an 80% reduction in CO_2 emissions to the atmosphere. Carbon dioxide storage will only be an effective way of avoiding climate change if the CO_2 can be stored for several hundreds or thousands of years. The most promising storage options are depleted and producing oil and gas reservoirs (where CO_2 injection for enhanced oil recovery (EOR) is possible), deep saline reservoirs and unminable coal beds. However the legal status of disposal in sub-sea strata is questionable, given the provisions of the London and OSPAR conventions. Direct injection into the deep ocean below about 1000 metre depth can generally be discounted.

C89 Capture and storage technologies are best suited to large-scale sources of CO_2 such as power stations (coal or gas), which account for about one-third of global CO_2 emissions. However, the large capital costs involved in adapting existing generation plant to CS and the resulting loss in efficiency, mean the technology is best applied to new plant, where it can be incorporated into initial construction. Certain industrial processes such as oil refining, as well as cement and iron and steel manufacture already produce concentrated streams of CO_2. These could be captured at little cost. Indeed the oil industry is investigating heavily into developing the technology and could apply it earlier than power generation.

C90 In addition, if hydrogen became established as a major fuel for cars, aeroplanes and heat and power generation, centralised, large-scale production of hydrogen from fossil fuels would be possible from pre-combustion capture of CO_2 emissions. This would avoid CO_2 emissions whilst providing lower cost hydrogen than through other routes.

C91 All the individual components of the technology exist and are commercially proven and could be deployed. There are examples of use in the US, Canada and Norway. These projects are being closely monitored and should lead to a wider understanding of the permanence of the storage. There appears to have been no systematic probabilistic analysis of risks and environmental consequences, or systematic assessment of the available data on slow release.

Resource potential

C92 DTI energy projections have gas-fired generation increasing by an average of 117 TWh (average of CL and CH) between 2005 and 2020. Assuming all this extra gas generation was new build and that all this new build was fitted with CS technology, the resulting reduction in CO_2 in 2020 compared with a no CS baseline would be around 10 MtC. This assumes no application of the technology occurs prior to 2005. A more cautious estimate, assuming no application of the technology prior to 2015, would suggest 3MtC estimated carbon reduction in 2020.

C93 CS linked to EOR can provide revenue that will partially offset the costs of capture and storage. But in general, since CS involves large capital costs its application can be considered as cost effective only in comparison with other measures designed to reduce carbon emissions.

C94 CS can be used on any fossil fuel generating plant, but there are significant benefits in applying the technology to new plants (spreads capital cost over longer life; less efficiency reduction). CS could be used with viable clean coal generation to further reduce emissions for coal-fired generation. There is vast storage potential in the UK alone. Storage estimates for offshore UK are: Deep aquifers, 8563 Mt CO_2; Oil fields, 2617 Mt CO_2; Gas fields, 4878 Mt CO_2; onshore deep aquifer capacity of 245 Mt CO_2. Any decision on CS would need to be preceded by resolution of the legal issues plus a convincing assessment of associated engineering and environmental risks.

Costs

C95 Cost per tonne carbon saved: Current estimates based on a 700MW CCGT plant indicate the cost of electricity through capture and storage will increase by around 0.7p/kWh leading to a carbon cost of around £70/tC. Future widescale application of the technology could reduce the cost, but this has not been quantified. However, taking a range of 0.5p to 1.0 p/kWh for the extra cost of capture and storage on top of the assumed gas price produces a range of carbon costs of £50 to £100. The cost of carbon sequestration from coal-fired plant will be somewhat higher (there is a greater efficiency decrease in coal-fired plant because more CO_2 per kWh has to be captured).

Nuclear generation plant life extensions

C96 Nuclear generation plant currently contributes nearly 25% of UK electricity supply. Nuclear output is likely to decline, however, from around 2005 as the existing stations reach the end of their lives and begin to close. Our baseline carbon projections allow for a reduction in nuclear output of around 70% by 2020. The last of the existing stations, Sizewell B, is likely to close around 2035. Overall, these closures will add, assuming their replacement by gas-fired generation, around 9MtC to annual UK emissions.

C97 It is possible that life extensions to existing plant could ameliorate this run-down in generation. As a means of saving carbon, such life extensions might be cost-effective. They could contribute to the meeting of intermediate targets for carbon reduction between 2020 and 2040. However, by 2050 we can expect to see all existing stations closed. On that timetable, life extensions to existing plants are not material.

New nuclear build

Technical description and market status

C98 Nuclear generated electricity currently accounts for around 25% of total UK electricity. However, on current assumptions it is likely that by 2020 the UK will be left with perhaps three operating nuclear stations and by 2030 only one (Sizewell B). A low-carbon future will require a move away from fossil fuels and one option is to consider new nuclear build, either the existing generation II plants (e.g. Pressurised Water Reactors (PWR) or the Generation III plants (e.g. Advanced Boiling Water Reactors (ABWR), Advanced Light Water Reactors (ALWR) and High Temperature Reactors (HTR) currently being developed. At this stage there is far too much uncertainty about Generation IV plants (which are still at the drawing board stage) to consider them as an option. That situation may change in time.

C99 Nuclear electricity generation is, of course, widely employed across the world, although in the UK, as in the rest of the EU (except potentially Finland) there are currently no plans to build any new plants. Current utilisation consists of mainly Generation II plants, although some new Generation III plants are being built in Asia.

C100 Outside the EU new nuclear plants are being developed and built (18 plants are under construction in 2000), with UK companies such as BNFL involved in the developments. New plants are being designed such as the Westinghouse AP600 and AP1000. The AP600 has received design certification from the US Nuclear Regulatory Commission. Westinghouse claims the AP600 has a commercial advantage of over 0.8p/kWh over other nuclear plant designs. Another evolutionary plant type is the Pebble Bed Modular Reactor (PBMR) which is a form of HTR. The key element of the design is flexibility. It is designed as a small (around 100MW) modular station, that gives it a shorter construction time and potentially low generating costs (claimed to be less than 2p/kWh). It is claimed that its design characteristics eliminate the potential for accidents leading to off-site consequences and it is highly proliferation resistant. A feasibility study is currently underway to determine whether to proceed with a demonstration plant in South Africa.

Resource potential

C101 The potential market is large. In theory, with generally abundant supplies of nuclear fuel, all UK electricity could be produced from nuclear power (although such a scenario is difficult to consider from a security and diversity of supply angle). It is not the size of the market that causes a barrier for nuclear electricity. Rather, public acceptability of the technology, long lead times, high capital costs, waste management issues, uncertainty about back-end costs and, at present, lack of political readiness (in most OECD countries) to promote nuclear as an option, are the main barriers to new nuclear construction.

Costs

C102 From a solely economic point of view the key question for nuclear relates to costs. These particularly relate (since fuel costs are relatively low) to the large capital costs for construction, the large decommissioning costs, and the uncertainties attached to waste management costs.

C103 The case for nuclear energy as a potential means of reducing carbon emissions was considered in the 1995 White Paper "The Prospects for Nuclear Power in the UK". It concluded that based on assumed lifetime cost of a Sizewell C type plant of 3.5–5.75 p/kWh (1990 prices) that the additional cost per tonne of carbon abated – over and above the cost of CCGT- was in the order of £100 - £250. Compared with the then estimated carbon costs of £15-£70 per tonne for 2005–2010 it concluded that "new nuclear build is currently too expensive to be considered for CO_2 policy purposes alone".

C104 For traditional PWR technology designs that assessment continues to look broadly correct. But it has to be looked at more closely for the new designs. Companies developing new designs such as the AP1000 and the PBMR have put forward estimates showing that in series construction (which avoids the substantial first of kind costs) these stations can be built to full safety requirements, including full decommissioning costs, to produce electricity at around 2p/kWh. However, compared to the costs of stations that have actually been built such as the Westing. 412 or the GE ABWR which produce electricity at around 3.8p/kWh the new designs cost look low and will continue to be disbelieved outside the industry until fuller cost breakdowns are provided or actual plants built.

C105 This is not to say that cost reductions for nuclear build are not possible. British Energy, for example, have provided estimates to indicate how costs might be reduced from 3.9p/kWh (within the range contained in the 1995 Nuclear Review White Paper) to 2.6p/kWh. However, this relies on a combination of series production, amortisation over 40 years, a reduced rate of return, and faster construction. The combination can be considered optimistic.

C106 Assuming current nuclear technology and investment criteria likely to be acceptable in a liberalised market, Pena-Torres and Pearson[78] have estimated costs for new build to lie in a range 3.8-6.4p/kWh. They estimate a required value for carbon to make nuclear break-even with CCGT ranges from £150/tC (10% discount rate; gas price 25p/therm) to £395/tC (15% discount rate; gas price 12p/therm).

C107 Assessment by Hesketh and Paulson[79] suggests that the generation cost of the AP600 could be equivalent to a CCGT (at a 15% discount rate; gas price 25p/therm). This is probably an optimistic estimate. At a lower gas price (12p/therm) the break-even carbon tax ranges from £20/tC (10% discount rate) to £85/tC (15% discount rate). The AP600 has yet to be constructed anywhere in the world (and is not licensed in the UK). In approximate terms, for each 10% escalation in the capital cost, generation cost would rise around 7% and about £20/tC is added to the break-even carbon tax.

C108 Costs are far from the only issue. Uncertainties over waste management – from the public acceptability perspective as well as cost – are also material. There are issues of public perception on safety and the environment. But if low construction costs for the new more radical technologies were confirmed (which might require series construction and high availabilities) then it is possible to see new nuclear generation competing with other generation at reasonable levels of carbon tax. Were the economics to be proven, and with diversity arguments also, it is possible that there would be more impetus to address other issues. But the long-term nature of the capital investment in nuclear power means no development, or even significant planning/exploratory work is likely in the UK without a greater degree of certainty about government policy towards new nuclear power stations.

[78] Energy Policy 28, 2000
[79] Nuclear Energy 39, no 5, October 2000

C109 Cost per tonne carbon saved: Based on current costs of 3.8-6.4p/kWh and 2 p/kWh for gas, Pena-Torres and Pearson estimate the carbon cost ranges from £150 to £395/tC. There are arguments to suggest that the industry might do better than that, but the general point that traditional PWR designs do not look likely to be attractive on economic grounds, with reasonable allowance for carbon, looks broadly confirmed.

C110 Looking towards 2050, cost reductions with new designs are possible. Assuming a price range of 2.6 p/kWh to 4.0 p/kWh, the implied carbon cost is £30 to £170 against a gas price of 2.3 p/kWh or -£30 to £110 compared to a gas price of 2.9p/kWh. This encompasses the range estimated by Hesketh and Paulson.

Nuclear fusion

C111 Fusion has been under development throughout the world for nearly 50 years. It offers the prospect of a safe, long-term energy source that makes no contribution to global warming. Despite many scientific and technical advances, the production of fusion power is still currently focused 50 years into the future, which takes it outside most models for future energy sources.

C112 An inter-departmental review of fusion research concluded that the economic and science and technology arguments for fusion research, when combined, were sufficiently attractive to argue for continued involvement of the UK at around the current level in the international fusion research programme.

C113 The Royal Commission report briefly addressed fusion but noted that it is still at the research stage and that a commercial-scale demonstration plant is unlikely before 2050. It therefore concluded that, even if the technical viability of fusion could be established, it would not be prudent to base energy policies on the assumption that it will become competitive with other non-carbon energy sources in the future.

Transport options

C114 Transport emissions have grown steadily over the past 30 years and are forecast to continue growing through to 2050. Much of the growth is demand-driven through increased car and lorry use and international air travel etc. As such, supply side improvements and increasing engine efficiency have been to date either outweighed by increased demand, greater traffic congestion, and consumer desire for larger, higher specification vehicles. Safety and other environmental (particularly air quality) requirements for new vehicles have also have a detrimental impact on fuel efficiency.

C115 However, there are technological developments on going which are significantly improving engine and fuel efficiency. Motor manufacturers are committed to reducing the average CO_2 emissions from new cars by 25% on 1995 levels across Europe by 2008/9, primarily through the introduction of a wide range of fuel saving technologies already developed (e.g. direct injection engines, variable transmission systems, lightweight materials). There is also a range of emerging vehicle technologies which can further improve the energy efficiency of vehicles over the longer term (such as hybrid electric and fuel cell technology)

C116 Besides improvements to the energy efficiency of vehicles, reducing traffic growth and congestion – key policy drivers in their own right – should provide significant carbon savings over the longer term. This could involve the introduction of new transport technologies aimed at relieving traffic congestion and improving the efficiency of the road network (e.g. telematics and intelligent highway management systems). Likewise, the efficiency of goods distribution can still be significantly improved through better logistic management and use of advanced ICT technology.

C117 The encouragement of cross-modal shifts away from the car to more sustainable alternatives (e.g. public transport, walking, cycling), as part of an integrated transport policy will also be central to reducing traffic congestion and carbon emissions from the transport sector, and this will require a comprehensive package of measures at a national, regional and local level, as outlined in the 1998 Integrated Transport White Paper. No robust estimates of the long term (post-2020) potential for cross-modal shift and their subsequent impact on carbon emissions, are available, but modelling by DEFRA last year for the Government's Ten Year Plan for transport – which aims to boost long-term investment in transport – suggested that an additional 1.6MtC carbon saving can be expected by 2010 as a result of the implementation of the Plan.

C118 Given the wide range of potential measures in the transport sector which could reduce carbon emissions, it is not possible at present to provide a comprehensive assessment of different long term options for this paper, especially as many of the measures will be introduced primarily to meet other policy objectives (e.g. reducing traffic growth or congestion). The paper consequently only provides a snapshot of some potential long term technological measures primarily aimed at reducing greenhouse gas emissions in the transport sector: hybrid electric and fuel cell vehicles; liquid biofuels; intelligent speed adaptation; and technological measures in the aviation sector. The assessment of alternative fuels assumes that the infrastructure necessary for their delivery to end users would be put in place.

Hybrid electric vehicles

Description, market status and costs

C119 Simply speaking, vehicles with hybrid electric powertrains are powered by conventional internal combustion engines in combination with electric motors. But there is no one distinct ‘hybrid electric vehicle’ concept, rather there is a wide range of potential hybrid electric powertrain configurations, with varying energy efficiency benefits.

C120 Some of the first generation of hybrid electric cars are now commercially available in the UK (e.g. Toyota Prius and Honda Insight), and further models by other manufacturers are likely to be introduced by 2003. These models are essentially concept cars, and generally have a limited production run: around 900 hybrid electric cars have been sold to date in the UK since the introduction of the Prius and Insight.

C121 The CO_2 reduction from hybrid electric cars varies depending on the type of hybrid configuration and the vehicle’s use. The Toyota Prius - a family hatchback - has a sophisticated engine management system which controls a small petrol engine and electric motor in parallel to ensure continual optimal powertrain efficiency and allow regenerative braking. It reduces CO_2 emissions by around a third relative to a similar sized conventional car on the European type approval test cycle – with potentially greater savings when operated in heavily congested traffic. Conversely, the Honda Insight is a two-seat coupe, which is primarily powered by a petrol engine with only a small electric motor for additional power and torque. Most of the CO_2 savings from the Insight actually come from other energy saving technologies (e.g. lightweight materials and aerodynamic style), not the hybrid electric powertrain.

C122 Hybrid electric cars are not yet cost-effective relative to conventional vehicles – the high cost of the battery is one key factor - but are being introduced by companies seeking to establish environmental and technological leadership and prestige. The Prius is currently about £3,000 more expensive than vehicles of the same size (about £16,500) and Toyota is subsidising the cost of the vehicle so the actual production costs are likely to be significantly higher than this. However, cost comparisons are more favourable if fuel savings over the lifetime of the vehicle are included.

C123 Besides cars, hybrid electric vehicle technology could be eventually employed in light vans, small trucks and urban buses. Their use in these markets could provides useful air quality benefits, as well as carbon savings, given the vehicle could potentially run on electricity in congested pollution hotspots. There are already several demonstration projects involving hybrid electric buses worldwide.

C124 It is clear at the moment that major commitments are now being made to hybrid electric technologies by many car manufacturers, with the desire for environmental and technological leadership being a key motive. Over the next decade, it is likely that some more cost effective hybrid electric technologies – e.g. electronic alternators - will be introduced by manufacturers into new more conventional car models as standard, as means of meeting their voluntary agreement commitments.

C125 But the outlook for any new technology depends not only on its own cost and value, but also on the capabilities of competing technologies that can meet market and policy needs. Both types of determinants are subject to various influences that can change the outlook as a result of decisions by manufacturers, consumers, and policy makers.

C126 The long-term future of hybrid electric vehicles is uncertain. There is room for debate among experts as to whether hybrid vehicles will be a long-term technology improving the efficiency of the internal combustion engine or whether they are just an interim step towards fuel cells. Some believe that they are both a long-term technology and an interim step. Their attraction is that they use the existing refuelling infrastructure and are similar to what the general public is used to. Other experts believe that hybrid electric vehicles will help fuel cell vehicles emerge, the two technologies will coexist, and then the hybrid technology will end but only in the long term.

C127 Cost per tonne of carbon saved*:* Assuming an average life of a Toyota Prius of 10 years and an annual mileage of 12,000 miles a cost of carbon has been calculated. This has assumed that a Toyota Prius costs £3000 more than the average vehicle of the same size. This also assumes that the Prius has CO_2 emissions of 114 g/km while the average car of the same size has CO_2 emissions of 140 g/km (the voluntary agreement target). Using a 6% discount rate this gives an estimate of approximately £1670/tC. Against the current average CO_2 emissions of new cars (around 180g/km), this estimate is around £660/tC. This is a rough estimate of the cost per unit of carbon saved, and must be treated as such. If the additional costs of hybridisation were £6,000, the cost per tonne of CO_2 saved would range from £1520 to £3860/tC relative to new car emissions of 180g and 140g respectively.

Transport fuel cells

C128 Fuel cell vehicles have always been considered a potential long-term development requiring substantive research and development. But over the last decade, technological breakthroughs and increasing worldwide political pressure to reduce the environmental impact of road transport and the first generation of fuel cell cars may be on sale from 2004 onwards.

C129 A key driver for the development of fuel cell vehicles worldwide has been the Californian zero emission mandate. This mandate was primarily introduced for air quality reasons, and fuel cell vehicles powered directly by hydrogen have the major advantage of only producing water at their point of use. As a climate change abatement measure, the promotion of fuel cell vehicles depends crucially on the inherent energy efficiency of a fuel cell powertrain relative to an internal combustion engine and how the hydrogen is generated in the longer term.

C130 It is widely acknowledged that a fuel cell is much more energy efficient than the current generation of internal combustion engines – the efficiency of fuel cell used in a vehicle on a typical drive cycle is around 50% compared to 15% for a conventional petrol engine. But the comparative energy efficiency advantage of the fuel cell may narrow in the longer term, as hybrid electric powertrain technology in particular improves the efficiency of the internal combustion engine. A key uncertainty is the extent to which both the energy efficiency fuel cell and hybrid electric vehicle technology can be improved over time through continuous research and development.

C131 The lifecycle carbon saving from fuel cell vehicles is also very much dependent on the fuel used as a feedstock of the fuel cell. Hydrogen produced from renewable sources of energy will have near zero emissions on a lifecycle basis, and this would be the ultimate long-term goal for fuel cell vehicles from a climate change perspective. But hydrogen from renewable sources is not yet available at a commercial scale, and may require substantive further research and development in the longer term.

C132 The most obvious way of producing hydrogen on a large scale from renewable sources would be through electrolysis using renewable electricity, although there is obviously an issue whether the UK will have the capacity to produce sufficient renewable electricity to cover both a large proportion of the electricity supply and transport sectors.

C133 In the short-to-medium term, most of the hydrogen used for fuel cell vehicles is likely to be derived from natural gas, which is a relatively inefficient way of producing hydrogen. Furthermore, a breakthrough in hydrogen storage technology and the development of infrastructure is needed before hydrogen use can be widespread. Consequently, depot-based fleets such as buses are likely to be the first users of fuel cell vehicles directly using hydrogen.

C134 In the meantime, many vehicle manufacturers are developing non-hydrogen fuel cells, especially for passenger cars, based on fuels that are hydrogen carriers such as purified petrol and methanol. These fuels differ widely in the lifecycle CO_2 emissions generated and scenarios with different development paths should be considered. But there is no stakeholder consensus yet about the best way forward, at either a global, European or national level, given the considerable research and development still required to produce hydrogen 'on board' the vehicle economically.

C135 There are in particular large uncertainties attached to the cost and projected uptake of fuel cell vehicles, as available research is limited, but work is ongoing to refine them. It is clear that fuel cell vehicles – especially cars – need to have eventually a comparable production cost relative to conventional vehicles, and manufacturers are striving to reduce the cost of producing the fuel cell stack, but it is difficult to know when this will occur. This makes it difficult at present to evaluate whether the promotion of fuel cell vehicles will be a long-term cost effective climate change abatement measure.

Biofuels

C136 Biodiesel and ethanol are two potential liquid biofuels which can be readily used in existing vehicles, particularly as conventional fuel extenders. But both biofuels can be only niche road fuels if produced from domestic biomass, due to continuing land constraints in the UK, particularly from other products and uses.

Biodiesel

C137 Biodiesel - a substitute for diesel - is produced from vegetable oils through the simple process of esterification. In northern Europe, biodiesel would normally be produced from oilseed rape. Biodiesel produced from this source currently provides only modest lifecycle carbon savings when compared with dedicated energy crops, due to the intensive nature of oilseed rape cultivation (e.g. extensive agricultural machinery use, high fertiliser and pesticide application). It is also expensive to produce (up to three times the underlying production cost of diesel), as rapeseed oil is a valuable food commodity, and will require significant subsidy for the considerable future, making it a relatively poor carbon saving measure from a cost effectiveness perspective.

C138 The longer term prospect for biodiesel produced from oilseed rape is also difficult to determine: there are no estimates for the potential carbon savings post-2010, although it is possible to envisage, with higher yields and lower agricultural inputs, that biodiesel could provide a 60% carbon saving relative to mineral diesel by 2020.

C139 But even with this carbon saving, it is not clear that biodiesel from rapeseed oil would be cost effective, with a cost per tonne of carbon saved of £320-£520/tC. This range reflects recent variation in the price of rapeseed oil, with the upper end seeming more likely in the near future. But a key longer-term uncertainty for rapeseed oil prices lies in the development of CAP, especially given European enlargement, trade liberalisation and the encouragement of more sustainable agricultural practices.

C140 It is also feasible that biodiesel – or the vegetable oil feedstock- could be imported into the UK in significant quantities from low cost oil-producing countries, given the transportation of biodiesel is relatively straightforward. Key low cost producer countries could include central and eastern Europe (rapeseed oil), the Americas (soyabean oil), and South East Asia (palm oil). Low cost oil would improve the cost effectiveness of biodiesel, and imported biodiesel from a UK GHG inventory perspective would have near zero carbon emissions, as most carbon would be released during cultivation, although from a policy perspective, complete lifecycle analysis is more appropriate.

C141 Biodiesel can also be produced domestically from waste vegetable oils – a low cost feedstock with carbon savings of potentially up to 90%, making biodiesel produced from this feedstock relatively cost effective: at £100-£250/tC saved, with considerable scope to reduce production costs through efficiency improvements to the collection of waste oil. But, due to the limited potential feedstock, biodiesel produced from waste vegetable oils can be only a niche road fuel, accounting for around 1% of the present DERV market and saving around 0.1 MtC per annum.

Ethanol

C142 Ethanol is added to petrol as an oxygenate in many countries worldwide, where it has been produced normally from grains like corn (USA and Canada) or sugar cane (Brazil). In northern Europe, wheat would be the main arable crop for ethanol using traditional production processes, but ethanol from this source provides few lifecycle carbon savings, given the intensive nature of wheat cultivation and high energy input required for ethanol production.

C143 More promising is the production of ethanol from ligno-cellulose biomass, such as forestry products, agricultural and forestry residues, energy crops and municipal solid waste. This involves more advanced ethanol production processes, involving more powerful enzymes to breakdown the cellulose to fermentable sugars and using the lignin residue as feedstock for an integrated CHP plant to power the ethanol production. Ethanol produced from this feedstock could potentially have lifecycle carbon savings of around 80% relative to petrol, and the widespread adoption of a 5% ethanol/petrol blend would deliver a 0.8MtC target. But the production technology is still at the research and development stage, and worldwide there are no large scale ligno-cellulosic-to-ethanol production plants operating on a commercial basis, making any assessment of the long-term role for this biofuel difficult.

C144 Initial estimates from DTLR of the production cost for the first generation of commercial plants, using US Department of Energy research data, suggests that ethanol produced from ligno-cellulosic biomass could be relatively cost effective at around £200-£280 per tonne of carbon, with further cost savings possible with later generations of production plant. But further research needs to be conducted, to develop more robust estimates of the carbon savings and cost effectiveness of this form of ethanol in a UK context. A key issue which needs to be resolved is whether it is more cost effective to use ligno-cellulosic biomass feedstocks for electricity generation or ethanol production.

Intelligent Speed Adaptation

C145 Potentially significant carbon savings from road transport can be realised through reducing vehicle speeds, especially on motorways. There is a range of potential ways of achieving this, but one long term technological option is Intelligent Speed Adaptation (ISA), a system designed to limit or advise on the speed of a road vehicle. The system is currently operational only in Formula One racing, but a pilot programme is under way in Sweden, primarily to improve road safety, but it should also generate useful carbon savings High costs and doubts over public acceptability are two large obstacles.

Aviation

C146 Although technical improvements provide significant scope for energy efficiency improvements in aircraft, the growth in passenger numbers/miles means that the IPCC expect aviation fuel use to grow by 3% a year to 2015. The IPCC has not been able to identify practical alternatives to kerosene for commercial jet use in the next few decades. So, technology is not keeping pace with demand.

C147 While developments like larger planes would cut fuel use per passenger km, they would mean greater fuel use at take-off which could have implications for the UK (as a world air-travel hub) if take-off emissions are allocated to country of departure. The issue of allocation of aviation emissions is on the whole undecided.

C148 The International Civil Aviation Organisation is carrying out work on air transport’s contribution to climate change. However, the work has a long time scale and a report may be three years away.

Embedded generation

C149 Embedded generation is any plant that is used for generating electricity that is connected to the regional electricity distribution networks. The majority of new renewables and CHP plant will tend to be small and require connection to regional distribution networks. But there are concerns that an accelerated rate of connection of such plant will be extremely difficult to achieve. The existing technical and commercial rules governing the operation of the ESI have been developed in the context of power generation by large, remote, National Grid connected coal, nuclear and gas fired plant.

C150 An OFGEM/DTI Embedded Generation Working Group delivered a report on the issues in January 2001. It identifies the following key factors currently tending to constrain the expansion of embedded generation:

i. restrictions on network capacity in rural areas;

ii. fault level restrictions in urban areas which limit connection of generators such as CHP;

iii. design standards which prevent the variable nature of loads, generation and network capability being fully recognised;

iv. “deep” connection charges levied on embedded generators for the full reinforcement costs which result from their connection. These provide strong locational signals, but represent a financial barrier to new plants. If major reinforcement is triggered, there is no mechanism for sharing the costs with subsequent connectees;

v. DNOs have no further revenue streams from embedded plant because such plant pay no distribution “Use of System” (DUoS) charges;

vi. there is a lack of published information on the best locations for embedded generation.

C151 The Group’s recommendations appear to be the key to developing a regulatory, commercial and technical framework within which embedded generation can develop. Its two key recommendations are:

(i) that OFGEM should review the structure of regulatory incentives on DNOs;

(ii) that implementation of longer-term recommendations should be overseen by a Government led co-ordination group.

C152 For some on the Embedded Generation Working Group, the current regulatory structure does not provide incentives for network operators to reward the services that embedded generation can give the network. A key first stage is therefore to move towards performance-based regulation.

C153 But while the group has recommendations which bear on the creation of appropriate pricing signals, it does not indicate the scale of costs (or benefits) that it sees attached to increased embedded generation. The main aim should be to provide an equitable regulatory and commercial framework within which transmission and distribution connected generation can compete fairly and which allows for future changes in the generation mix. That should allow for respective environmental costs and benefits. But the cost of connection and the cost of using the transmission and/or distribution system are all part of the overall cost to be considered.

Electricity storage

C154 Electricity storage offers some potential to reduce CO_2 emissions. The technical requirements of such a system result in emissions and losses during the charging process and further efficiency losses during discharge. The economic case depends on:

(i) using cheap base load electricity for charging and releasing the energy at times of higher prices. If this power is used, for example, to displace coal generation, the carbon saved is the difference between that emitted by coal plant and that emitted by base load plant during the charging process;

(ii) storing the output of intermittent generation, allowing release to be timed to most valuable periods;

(iii) further savings may be achievable by operating the plant as embedded, thereby saving perhaps 5% in transmission and distribution losses. This value is quite variable depending on location and technical arrangements. Extensive use of storage plant in this mode could result in considerable savings, especially if used in conjunction with CHP systems.

C155 A major use for storage is load levelling. During the winter months in the UK, there is a distinct peak in the power demand between about 4 and 9pm. In 2000, this peak amounted to about 4.7TWh, supplied by a mixture of coal plant and pumped storage. Had this all been coal plant, around 1MtC would have been produced.

C156 In principle, all of this could have been saved by a storage device that was charged by carbon free generation. In practice, charging the storage plant by use of base load generation would have produced around 200kt, giving a net saving of 800ktC. Levelling other peaks in the load curve during the year might raise this figure to about 1.3MtC. Larger storage plants may be able to achieve further CO_2 savings by use over extended periods of 10 hours or so to displace further coal plant, other less efficient plant or spinning reserve, but this would erode the economics somewhat.

C157 A recent review by Imperial College has identified six storage methods that have the potential to be used on a utility scale:

- Pumped storage – not considered further
- Regenerative fuel cells
- Compressed air energy storage, CAES
- The sodium/sulphur battery
- Hydrogen
- Superconducting magnetic energy storage, SMES

Regenerative fuel cells

C158 Innogy is currently developing a regenerative fuel cell technology – Regenesys – which offers the prospect of flexible electricity storage and release. This could be particularly valuable for the development of renewables and other non-controllable sources such as PV and domestic CHP. A 15MW plant at Little Barford is currently under construction. Regenesys has a modular design which suggests it could be applied in the range 5-500 MW. It is designed for a 20 year life and environmentally benign. If the Little Barford plant were to be completely discharged on a daily basis, it would displace some 44GWh generation per annum, amounting to about 9.8ktC if the displaced plant were all coal.

C159 Aside from storage, Regenesys offers prospects for other system services such as voltage control/reactive power, black start and distribution/transmission services. An independent assessment of Regenesys for DTI by Campbell Carr has concluded that the technology appears to have significant commercial prospects, particularly if capital costs can be reduced to levels anticipated by Innogy (the current cost is around £1000/kW – similar to pump storage – but Innogy anticipate a reduction to £500/kW).

Compressed air energy storage (CAES)

C160 CAES operates by compressing air into a large cavern and allowing it to expand through a turbine when the energy is required. Efficiency can be improved by burning fuel in the air stream before expansion. The extent to which any carbon may be saved will depend on the fuel burnt and the plant displaced during operation. There are CAES plants around the world with the capability to produce power ranging from 25MW (in Italy) to a planned 2.5GW plant in the USA which will discharge over several hours. Technically, CAES takes several seconds to start up and therefore cannot be used as spinning reserve. It is also geographically constrained. On both counts it is disadvantaged as compared to the Regenesys system.

C161 There is no CAES in the UK although it is certainly technically feasible with well-established technology. Investigations carried out by the CEGB in the 1960s and more recently located possible sites, particularly the Cheshire salt deposits, but none were further developed. Whilst the capital costs, estimated at around £350/kW (1997 prices), are considerably cheaper than pumped hydro, it appears that there is more profit to be made by storing natural gas in the caverns and playing the gas spot market. There is no apparent technical reason why CAES could not be used in the UK.

The sodium/sulphur battery

C162 The Na/S battery operates at around 350C and has a design that goes back to at least 1965. The temperature has to be maintained even when the battery is not in use to prevent the electrodes from solidifying. A 6MW unit has been operating in Japan since 1998 costing 1.25Myen/kW (1998 Yen, converted at £1=175Yen, equivalent to £7142/kW) for eight hours discharge. Efficiency is of the order of 90%. A more efficient, cheaper version is under development and projections for such units under mass production are for 0.2Myen/kW, (£1142/kW), competitive with pumped storage and the Regenesys system.

Superconducting magnetic energy storage (SMES)

C163 SMES systems operate by storing energy in the magnetic field of a superconducting coil. Whilst, theoretically, they have the potential to operate in the GW region, such a system would require a coil radius of maybe 800m. Not only is this infeasibly large, but any failure of the superconductor coolant can lead to explosion due to the extremely high currents used. The cost of a “small” 100MW system has been estimated at $6100/kW (1997$) for 20 hours storage, almost six times that for pumped hydro. Whilst a number of commercial and prototype micro scale products exist, it is difficult to see how anything other than the advent of room temperature superconductors and some method of reducing coil size would make the utility scale a viable proposition.

Annex D

Energy Efficiency: DEFRA Paper on Additional Savings and Associated Costs

D1 Because it is difficult to identify all the measures in industry even today, and impossible to do this for 2050 in all sectors, we are developing a generalised approach using cost supply curves for energy efficiency improvements. This paper outlines the approach, explains the model we are using, and draws some broad conclusions from the results. Data for the service and domestic sectors are also included. A full explanation of the work on energy efficiency undertaken by the IAG together with a paper on the methodology is contained at appendix A.

Summary

D2 At the root of this approach is the concept of a series of “Climate Change Programmes”, each lasting 10-20 years, and featuring a planned and gradually increasing carbon charge or obligation which is rebated or otherwise recycled via incentives to invest in efficiency measures.

D3 The higher effective price of energy improves the cost-effectiveness of all efficiency measures, bringing an additional tranche within the cost-effective framework at a stroke. This makes them more attractive to all investors.

D4 Over the period there is a larger improvement in the energy efficiency than would have occurred under Business As Usual. Over the same period, because of the higher demand for measures, we can expect additional R&D interest to result in an increase in the rate of new products entering the market, replenishing the cost-effective potential.

D5 Worst case cost increases for companies can be estimated by applying a rebated carbon charge to a company already investing to the cost-effective limit. Additional costs and carbon savings depend on the steepness of the cost-supply curve.

D6 Using (i) a standard cost supply curve for carbon/energy savings in the sector (based on today’s set of measures) and (ii) a model of measure uptake applied to the whole of the industrial sector, we can quantify the extra savings and costs for a given price increase, under best and worst case conditions.

D7 Long-term costs and savings are crucially dependent on the rate at which emerging technologies replenish the cost-effective measures as they are taken up. If technology renewal matches the rate of uptake, the additional investment costs should be minimal, but the cost of stimulating the technology needs to be considered. Replenishment rates are expected to be more rapid for energy using industrial, and other, processes than for buildings energy efficiency technologies.

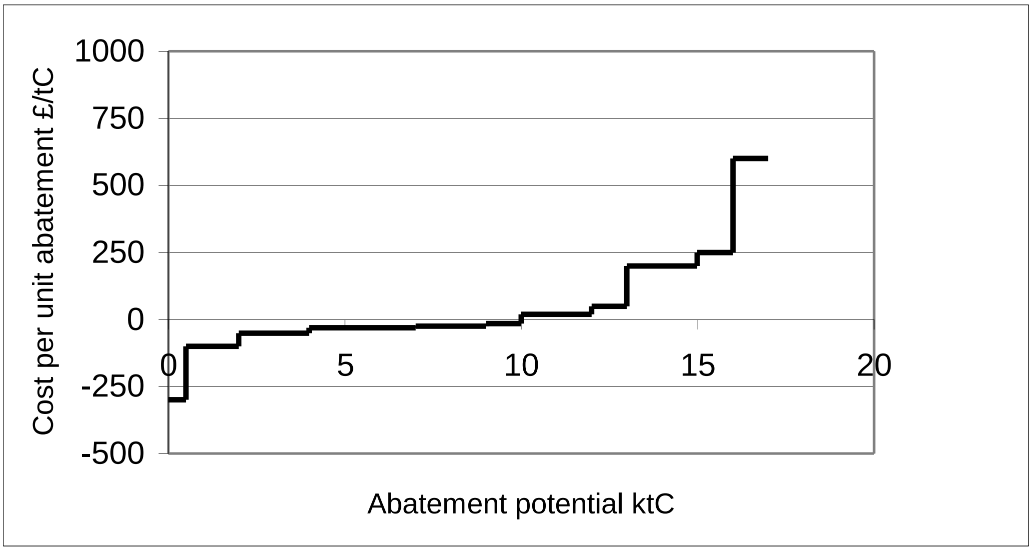
D8 The service sector presents a greater challenge than Industry and higher price increases would be needed to stimulate similar percentage carbon savings. Though the domestic sector should be more responsive in theory, the market is more conservative.

D9 Current indications are that it should be possible to double the 'business as usual' efficiency improvement of around 0.5% per year for Industry and Services, reducing carbon emissions in 2050 to around 20MtC and 15MtC respectively. Capital stock replacement rates are a limiting factor in all sectors, but particularly so for the Domestic sector, with initial estimates of 25-30MtC emissions.

Cost supply curves and cost-effectiveness criteria

D10 Cost supply curves for abatement of energy-related carbon emissions are used to bring together the abatement potential of all known measures, ordered according to their cost-effectiveness, as expressed by the annualised cost per unit of carbon saved. Typically they have the form shown in Figure 1, where each step represents a single technology or abatement procedure (e.g. replacement of boiler with more efficient version), and the costs comprise the capital cost (at a particular rate of return), plus all the fixed and variable costs. These include the energy cost savings, and any associated costs or benefits for the individual or organisation concerned (e.g. reduced labour costs). The lower part of the curve, to the left of the point at which it crosses the horizontal axis, represents the cost-effective potential. The portion of the curve to the right of the crossing point indicates the technical potential which is well enough developed for costs to be estimated, but which is not (or not yet) cost-effective at the chosen rate of return.

Figure 1 Typical Cost Supply Curve for Carbon Abatement



D11 Several points need to be taken into account:

- *The measures are ordered in terms of relative cost-effectiveness for the average user*. This does not necessarily imply that they will be taken up in this order. Investment opportunities generally arise at particular times. Implementation also takes time, and a portfolio of measures may be pursued together.

- *Not all energy users will have the same costs for any given measure*. Costs may vary due to many factors, e.g. building configuration, product mix, etc. In practice the cost for any particular measure has a distribution on the vertical axis, rather than a single level.

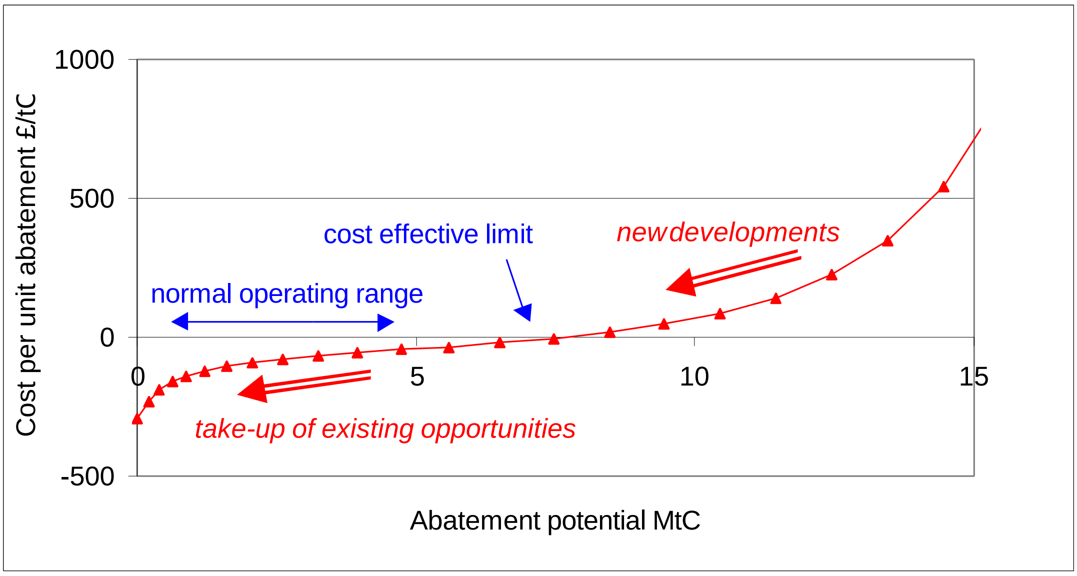
- *Not all energy users will have the same incentive or ability to invest in a particular measure*. Investment decisions on particular schemes are rarely made in isolation, and their relationship to other demands on resources will depend on individual circumstances, e.g. whether a company is expanding or contracting, or moving into a new area.

- *The continuing existence of a cost-effective potential has to be rationalised*. Part of it is due to the fraction of potential investors who are not currently ready to invest (since the costs do not allow for premature retirement of plant). A smaller fraction will be failing commercially. However it is also the case that many cost-effective investments just do not get made in practice, for a wide variety of well-documented reasons, including competition for capital, limited management resources, and barriers such as lack of information, lack of confidence in the market, etc. In some cases it can be appropriate to represent the barriers by hidden costs.

- *The whole shape of the cost supply curve is dynamic*. Cost-effective measures are gradually taken up, to a greater or lesser extent. They become standard practice, or obsolescent along with the processes they relate to. Increased uptake usually means lower unit costs, so the position of individual measures on the curve tends to move downwards to the left. This applies also to the technologies to the right hand side of the curve, some of which achieve full commercial viability, though others may be discarded or ousted by changes in the market. At the same time, R&D is introducing new technologies to replenish the potential supply of measures which are not yet cost-effective for the average user, but which will be developed to that stage by those best equipped to do so.

D12 Figure 2 illustrates these points for a generalised cost supply curve typical of the whole of UK manufacturing industry at the current time. Any steps are effectively smoothed out by the cost variations. Under a Business As Usual (BAU) scenario, the overall form of this curve may be expected to change very little. New abatement potential replaces that which is used up, and there is a dynamic equilibrium overall. This is consistent with the long-held view that the technical and economic potentials for energy efficiency have remained very similar over the last quarter of a century.

Figure 2. Dynamic Equilibrium Under Business As Usual Scenario



Effects of energy or carbon price increases and conditional charges

D13 The effect of increasing the price of energy or carbon emissions is to increase the cost saving for each tonne of carbon emitted, thereby making abatement measures more cost effective. In simple terms, this lowers the whole curve relative to the horizontal axis[80], and the cost-effective potential increases (i.e. the crossing point moves to the right). The extent to which there is increased uptake of energy efficiency (carbon abatement) measures will depend on the many factors mentioned above, and can be expressed in terms of price elasticities, both for short and longer terms.

D14 Energy or carbon charges can be used to mimic such price effects, though the overall economics – and the market signals that they convey – are more complex. Revenue from such schemes can be recycled by many different mechanisms, and their effectiveness as a stimulant to investment in abatement measures can be very powerful if conditions are attached. A conditionality can be used to force a change of investment priorities, as opposed to simply raising the effective rate of return on energy efficiency schemes. Revenue is thereby re-invested with a degree of focus which could not be achieved by price effects alone.

[80] Strictly speaking this needs to be considered fuel by fuel, since emission factors vary, and the cost of a tonne of carbon from electricity is several times as much as the cost of a tonne of carbon from natural gas. However, this does not affect the general argument, nor is it relevant if one is considering carbon charges or obligations. Note that around 95% of UK carbon emissions arise from energy consumption.

D15 The remainder of this note concentrates on the possible net costs or benefits that could arise from rebated conditional price increases, since they appear to be by far the most promising lever for achieving a higher fraction of the estimated cost-effective potential savings. A similarly effective (though theoretically distinct) mechanism is used in programmes such as Standards of Performance and the Energy Efficiency Commitment, in which a small levy (or notional levy) is fully dedicated to financing energy efficiency measures, once again achieving a much greater result than would result from a conventional price elasticity without targeted recycling of the revenues[81].

D16 Three questions emerging from such considerations are:
1. What additional cost burdens might one be imposing via such charges or obligations?

2. How far and how fast could one push this mechanism?

3. What could be done in order to enable more rapid progress?

Additional costs resulting from conditional energy or carbon charges

D17 If a conditional charge is applied, with full rebate, is there any net cost to the energy user? This is a complex question to answer for the general user, whose normal behaviour stops short of investment in all cost-effective energy efficiency measures, largely because there are other, more attractive or more pressing things to do. However, one can begin to quantify the possible additional cost by considering the extreme case of a company which is fully motivated by carbon abatement opportunities, and has no more cost-effective measures left to do when a carbon charge is introduced.

Single company already at the cost-effective limit

D18 This extreme case can be represented by the following sequence, in which energy efficiency schemes are assumed to require capital investment, and any non-energy benefits are ignored[82]:

---

[81] The Energy Efficiency Commitment, which involves a notional levy of ~1% of household energy bills, is expected to improve domestic energy consumption by ~1.5% over its three year duration, and carbon emissions by 1% after comfort increases are taken into account.
[82] Non-energy benefits can be incorporated straightforwardly and do not affect the conclusion. They are left out here to simplify the arguments.

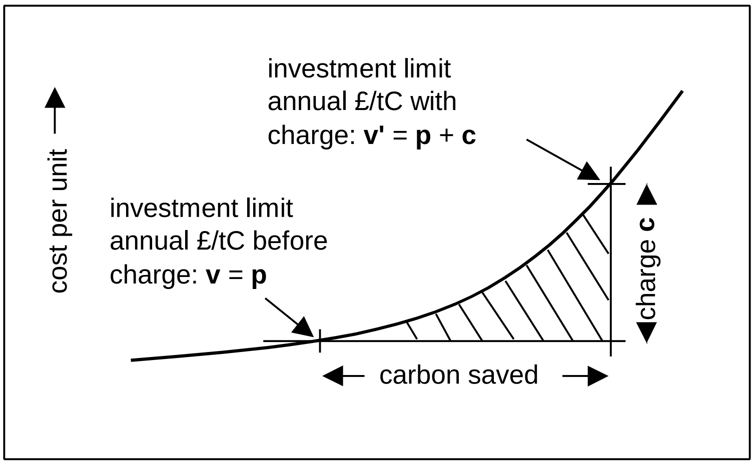
(i) The company has already invested up to the cost-effective limit, represented in Figure 3 by the investment criterion such that **v**, the annualised capital and operating costs per unit of carbon saved, exactly equals the energy price **p**. Under this condition, further investment at ratio **v** would have no effect on overall company costs.

(ii) An energy or carbon charge is applied, effectively raising the price of energy by an amount **c**. The company's energy bill rises by a factor (**p** + **c**)/**p**, and the exchequer benefits by the value of this increase.

(iii) The company invests up to a new cost-effective limit represented by the condition **v'** = **p** + **c** (i.e. once again further investment at this level has no effect on total costs, even though these are higher than before the charge was imposed).

(iv) Conditional on this investment up to the new limiting condition **v'**, the government allows a 100% rebate on the carbon charge[83].

Figure 3 Effect of Carbon Charge on Cost-Effective Limit for Investment



[83] Note that in this case there is not a simple proportionality between the rebated revenue and the investment required, nor is the argument dependent on such a relationship. All that is required of the company is that it adjusts its investment practice *as though the price of energy-related carbon emissions were at the higher level*. By virtue of this, the mechanism is fairer than a straight price-effect would be, since it does not penalise energy-intensive companies which have already exploited their energy-saving potential. Likewise, companies for which the charge would create substantial extra cost-effective potential are expected to make savings accordingly, as a condition of the rebate. For revenue recycling mechanisms, on the other hand (such as in the domestic Standards of Performance and the new Energy Efficiency Commitment programme), the actual investment is in direct proportion to the levy raised by the energy suppliers.

D19 Provided that the cost-supply curve between the points **v** and **v'** is smoothly continuous, it can be shown that there is an additional cost to the company[84], which is equal to the area of the roughly triangular shaded area shown in Figure 3. If the area were to be a perfect triangle, then:

Additional cost = **c**/2 ? (additional carbon abatement achieved)

D20 In other words, the additional annual cost per unit of abatement is simply **c**/2, so that a carbon charge which raised prices by £50/tonne, say, would result in additional annual costs of £25/tonne saved, times the amount of carbon saved (annually) by moving to the new cost-effective limit. The additional cost arises essentially because, once the rebate has been allowed, the effective price of energy consumption is restored to its original level, so that the extra cost savings do not fully cover the additional investment that has been agreed as a condition of the rebate.

D21 Several points emerge from this example:

- in practice, the cost supply curve is not linear, but becomes steeper towards the right, so the area under the curve will be less than that of a triangle, and the additional costs proportionally smaller;

- it also follows that this is a worst case as far as additional costs are concerned: companies not already invested to the cost-effective limit will have options open to them with higher rates of return, and their burden will be less;

- if the cost supply curve is very steep, so that the conditional charge opens up very little additional cost effective potential, little or no action is justified[85]. Costs will not be incurred, but no savings will be achieved;

- conversely, if the cost-supply is gently sloping, and the conditional charge opens up considerable additional potential, a modest charge can stimulate sizeable savings but at a net cost to the company. Typically this cost would be a substantial fraction of **c**/2 times the additional carbon savings, but this represents an

---

[84] Administrative costs are assumed to be zero, and wider welfare benefits or costs, e.g. from increased sales of energy efficient equipment, offset by lower profits for energy suppliers, are neglected in this example.

[85] The practicability of this mechanism relies on assessment and agreement of the cost-effective carbon abatement potential for the sector concerned. For some business sectors this may be hard to achieve.

upper limit which would only apply in this extreme case where then company invests to the hilt.

Distribution of companies operating to the left of the cost-effective limit

D22 The example above assumes that the company always invests to the cost-effective limit, as defined by the chosen rate of return[86], but this is not a realistic expectation for all of the reasons mentioned above. In fact, one has a spread of behaviours, with a broad distribution both for the uptake of nominally cost-effective measures, and for the propensity with which companies invest in efficiency measures. Although it can be difficult to determine the actual percentage uptake of a particular measure[87], there is plenty of evidence – e.g. from Energy Efficiency Best Practice Programme *Energy Consumption Guides* – to support the concept of a distribution of performance[88] within which leaders and laggards can be described. Under BAU this distribution moves forward in the direction of greater energy efficiency, as the leaders adopt increasingly better technologies and management practices, and the rest follow at a distance behind. In the short term, there is always scope for narrowing this distribution via cost-effective measures, and in the long term the crucial factor is the rate at which new technologies become commercially available.

D23 Given such a distribution, it can be argued that any additional investment – up to the cost-effective limit – should always yield positive benefits, so that the outcome of applying a fully rebated, conditional carbon charge will be to lower all companies' net costs rather than raise them. This net benefit means that the companies would be no worse off even with incomplete recycling, so there is some freedom of choice as to how the surplus revenue is used. However, this argument ignores the reasons – of timing, resource limitations, etc. – which restrain spontaneous moves towards higher efficiency.

D24 A counter-argument would claim that each company finds its own operating regime within the spectrum of investment opportunities, and the current situation reflects the competition between efficiency schemes and

[86] Moreover, the cost-effective 'limit' is an extreme criterion for investment schemes; typical schemes will span a range of payback times on the favourable side of this limit, so the competition is really with the average rate of return of schemes that *do* get implemented, not with the theoretical extreme.
[87] Low and zero-cost energy management 'housekeeping' measures are hard to define precisely, and applicability varies considerably for most technologies.
[88] Generally expressed in terms of energy consumption per unit of output.

other types of investment which may be intrinsically more attractive[89]. This situation could result in positive costs when a conditional charge is applied, since each company is being driven beyond its own equilibrium operating regime.

D25 These two cases represent lower and upper bounds, as far as estimation of additional costs is concerned, and the true picture is probably somewhere in between. Provided that the measure-induced shift in investment priorities results in a net benefit rather than a net cost, the fraction of the revenue that is rebated can be less than 100% without imposing additional costs on business as a whole (though there will be variations for individual companies). This appears to be the most likely situation, but supporting evidence is needed. A simple spreadsheet model, based on real cost supply curves and on approximate distributions for uptake of measures, and propensity to invest, has been constructed since an analytical solution would be very complicated to follow.

Generalised model

D26 Following up the ideas above, an Excel spreadsheet model was put together to represent the BAU situation for manufacturing industry, in which there is partial uptake of cost-effective measures, and a wide spread of investment behaviour amongst the companies in each sector.

Modelling partial uptake

D27 Any actual cost supply curve represents a snapshot in time. Each of the measures has achieved some degree of market penetration, generally with much higher fractions for those offering the highest rate of return. Expectations are that the uptake for the high-return measures will increase further in the future, and that the more promising of the less cost-effective measures will eventually become cheaper to implement.

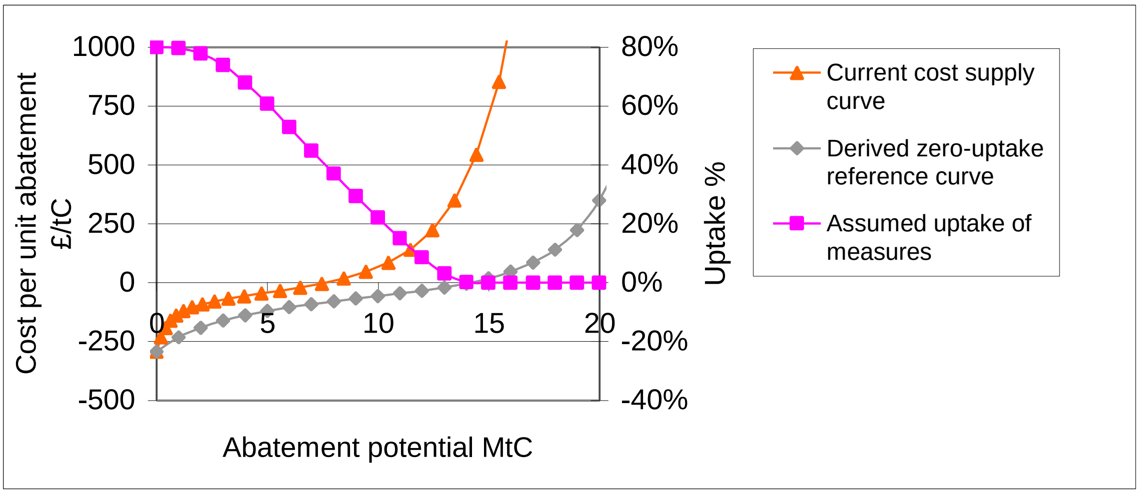
D28 The model represents the current uptake in terms of a function which estimates a percentage uptake for each measure, based on its current estimated rate of return. This implies the existence of an underlying reference potential for each measure, relative to which the uptake is expressed. These underlying potentials can be combined to produce a reference curve, which is the cost supply curve that would

[89] For example, an efficiency scheme might offer a guaranteed 30% return on investment, but it could be rejected in favour of new product development, estimated to yield a somewhat risky 25%, but for which the potential rewards are much greater in the long run.

pertain if all of the measures had zero uptake. Like the current cost supply curve, this reference is a snapshot – in this case of the total potential for all measures relevant to the current time.

D29 The actual cost supply curve used is illustrated in Figure 4, together with the assumed uptake function and the derived reference curve. The actual curve is based on an ETSU study, with an allowance for uptake since the data were collated[90], and the cost effective potential of approximately 7MtC is consistent with the Climate Change Programme documents.

Figure 4. Generalised Cost Curve for Industry and Assumed Uptake Function



D30 Note that the uptake curve in Figure 4 relates to the abatement potential for the underlying reference curve, not the current cost supply curve. The exponential uptake function includes the assumption that measures which are not cost-effective have negligible uptake, so the uptake curve reaches zero where the reference curve crosses the horizontal axis. The maximum uptake has arbitrarily been set a 80% to reflect observations that even the most cost-effective measures do not achieve full penetration, because of factors such as timing constraints and company restructuring. This, and the functional form assumed, affect the shape of the derived reference curve, but do not have a strong bearing on the broad cost estimates from the model (see comments below on sensitivity to assumptions and key parameters).

[90] 'Energy and Carbon Dioxide Savings Supply Curves for UK Manufacturing Industry', ETSU for DoE Global Atmosphere Division, October 1996, ref RYCA 18724001/Z/2

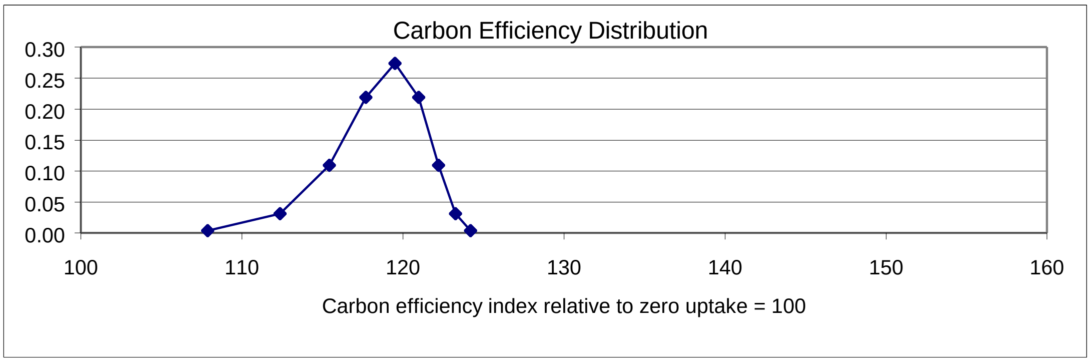
D31 Note also that this simple model ignores the improvement in cost-effectiveness that usually accompanies increased uptake; this can be quite significant for very large changes, and the effect will generally be to lower costs. Hence this approximation will tend to give a pessimistic view of costs and benefits due to increased uptake.

Modelling the distribution of investment behaviour

D32 Variations in propensity to invest in cost-effective measures are modelled by splitting the set of industrial companies into a bell-shaped distribution of nine unequal groups, each of which has a different scaling factor in the uptake function – i.e. a different sensitivity to the rate of return offered by each measure. In effect the overall model is a summation over each of these groups of companies, each of which has its own uptake function and share of the implied reference potential curve.

D33 For each group, the uptake function enables one to make an estimate of the carbon abatement relative to the zero-uptake condition. Taken together with the actual emissions for manufacturing industry[91], each group's current abatement can be expressed as a 'carbon efficiency index'[92]. The modelled distribution of carbon efficiency (which closely mirrors energy efficiency) is illustrated in Figure 5. Again, the exact shape of this distribution is model dependent, and it has been adjusted to be broadly consistent with the distribution widths observed in *Energy Consumption Guide* data.

Figure 5. Modelled Carbon Efficiency Distribution for Manufacturing Companies



[91] Currently around 34 MtC including the share of power station emissions but excluding non-energy process emissions.
[92] Defined here as 100 ? (share of total emissions + estimated abatement) ? (share of total emissions)

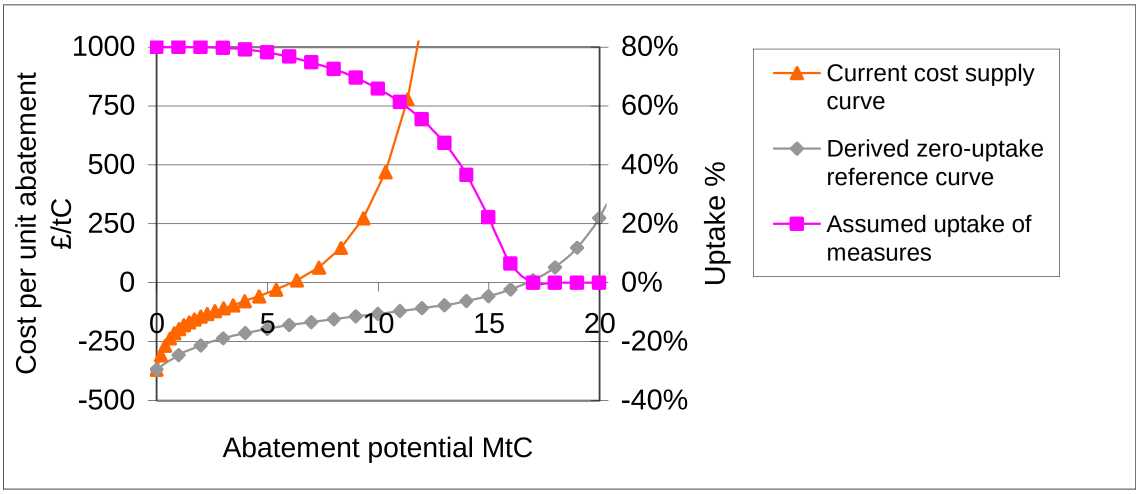
Modelling the effect of a carbon charge

D34 The effect of increasing the price of energy, or of applying a carbon charge, is, to a first approximation, to shift the horizontal axis of the cost supply curve by an amount equivalent to the price rise or charge.

Short-term effect

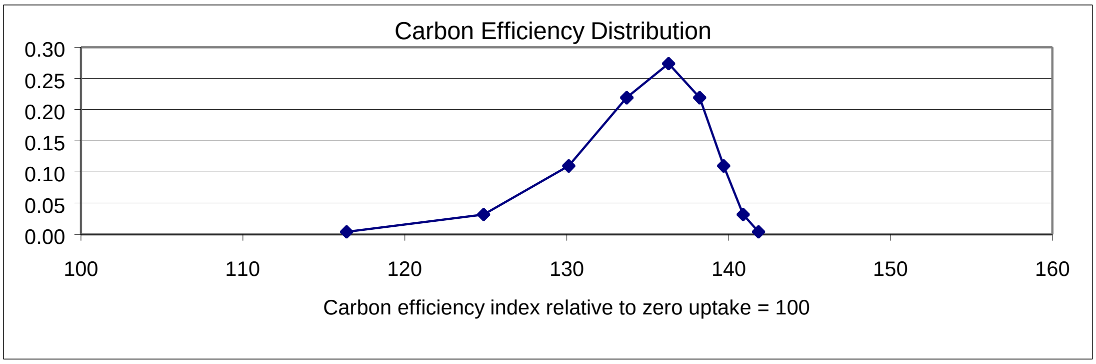
D35 This is illustrated in Figure 6 below for the example of a £75/tC carboncharge. In this case, the charge is applied instantaneously, such that there is no time for the cost curve to respond (via 'learning curve' effects, additional R&D, etc), and the additional uptake stimulated by the charge results in a directly equivalent diminution in the remaining potential. The derived reference curve is unchanged apart from the downward shift.

Figure 6. Generalised Cost Curve with Instantaneous £75/tC Emission Charge (no Replenishment of Cost-Effective Technologies)



D36 Under these circumstances, the efficiency distribution moves to the right, and there is a tendency for the width of the distribution to become restricted by the increasingly expensive options faced by those users at the leading edge.

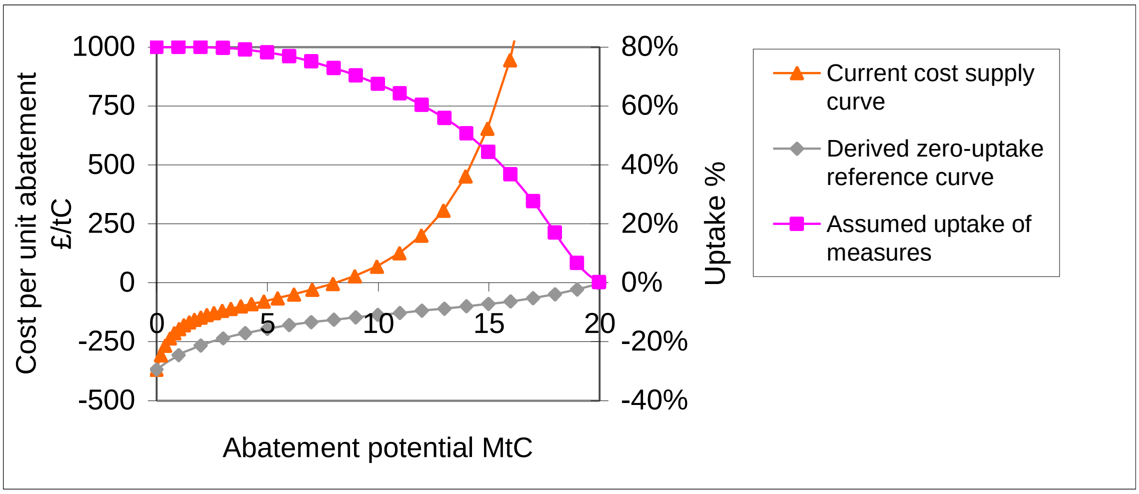
Figure 7. Carbon Efficiency Distribution with Instantaneous £75/tC Emission Charge (no Replenishment of Cost-Effective Technologies)



Long-term effect

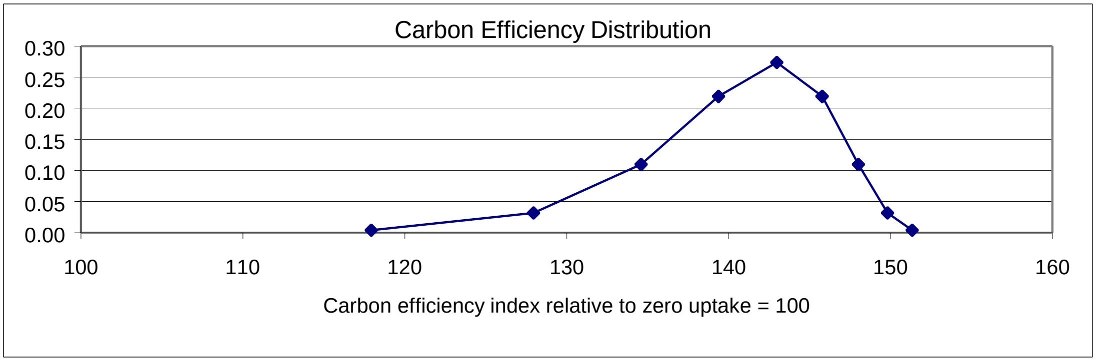
D37 If, however, the price rise or charge is applied at a rate such that the market can respond (or other measures contribute) so as to replenish the unused cost-effective potential, the uptake is no longer as restricted by lack of measures[93]. Uptake is increased, as in Figure 8, and the efficiency distribution of Figure 9 is both further to the right, and less constricted than in the instantaneous case above, where replenishment was not allowed to occur.

Figure 8. Generalised Cost Curve with £75/tC Emission Charge and Full Replenishment of Cost-Effective Technologies



[93] The coincidence of the cost-effective limit and the edge of the graph in Figure 8 has no significance, and the curves continue off-scale to the right of the chart.

Figure 9. Carbon Efficiency Distribution with £75/tC Emission Charge and Full Replenishment of Cost-Effective Technologies

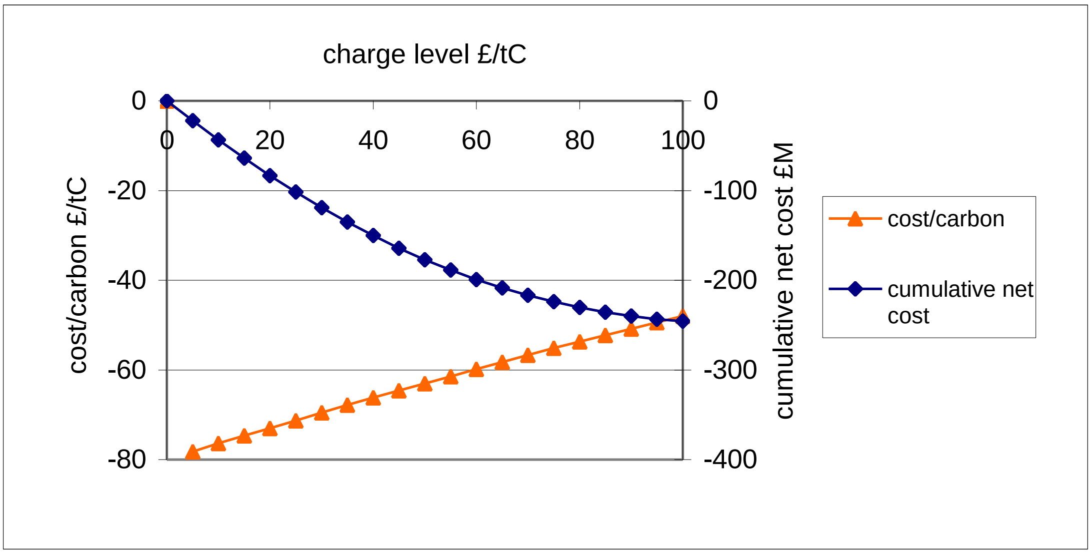


Net costs and charge recycling

Short term

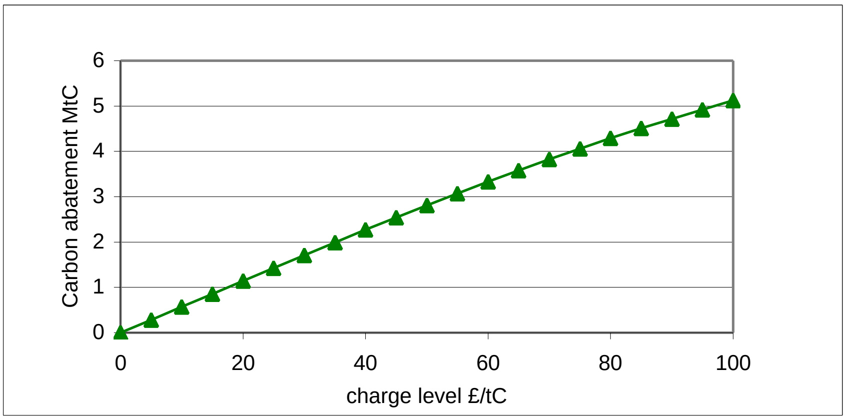
D38 It was shown above that, for a company investing at the cost-effective limit, in response to a conditional charge £**c** per tonne of carbon, which is fully rebated, the additional net cost to the company is approximately £**c**/2 per tonne of carbon saved. The equivalent result for the model described here depends on how one accounts for the actual behaviour, in which the operating point for each group of companies in the efficiency distribution falls short of the cost-effective limit. If one makes no allowance for any hidden costs or other barriers, then there is a large net benefit as shown in Figure 10. As the charge is raised, the net benefit per unit of carbon saved runs into diminishing returns as the remaining cost-effective potential is used up (this being a sudden increase, with no time for replenishment of the potential by emerging technologies). This is a 'best possible case' situation, in which the cost/carbon curve indicates that with no charge at all there is a net benefit of approximately £80/tC to be reaped. As the increasing charge is used to stimulate investment, the cumulative benefit becomes very considerable.

Figure 10. Net benefits from a fully rebated conditional carbon charge (best case: no allowance for competition for resources or hidden costs)



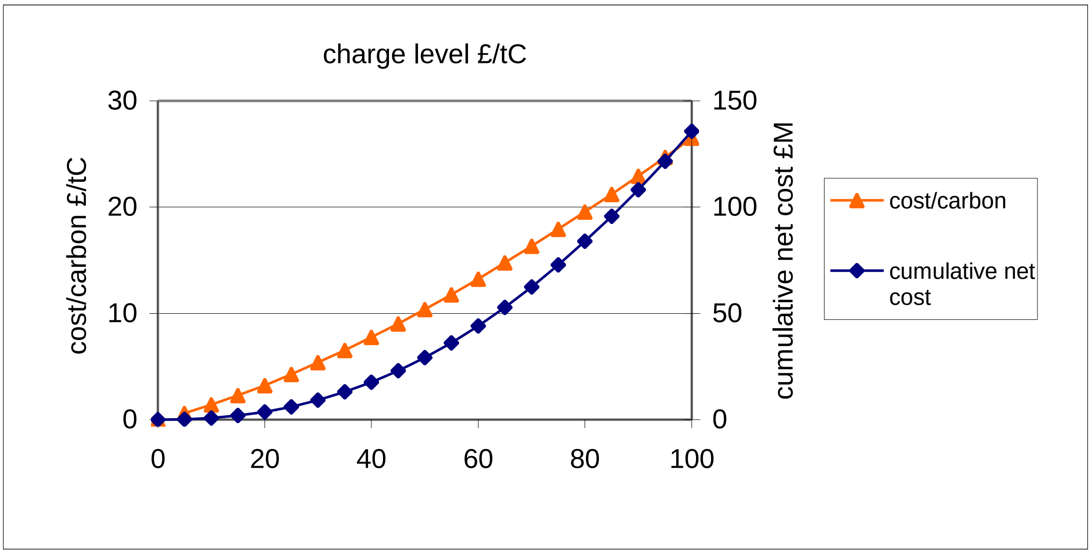
D39 The corresponding carbon abatement is shown in Figure 11 below.

Figure 11. Carbon abatement stimulated by conditional charge



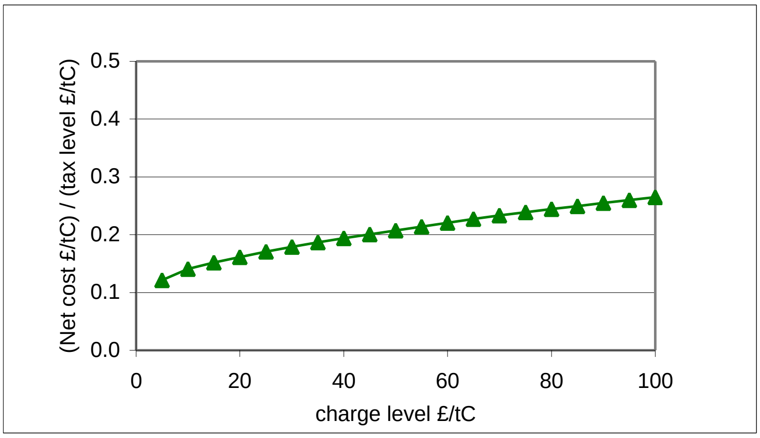
D40 An equivalent ‘worst case’ can be constructed by assuming that the current behaviour represents an equilibrium, such that there are no net benefits to be gained by increasing the priority of investment in carbon abatement measures. This is equivalent to applying a hidden cost per unit of carbon which exactly offsets the benefit of £80/tC observed in Figure 10 above, and the result is shown in Figure 12.

Figure 12. Net costs for a fully rebated conditional carbon charge (worst case: hidden costs nullify cost-effective savings at equilibrium)



D41 Now the cost per unit carbon savings is positive throughout, and reaches about £27/tC when the charge is raised to £100/tC (corresponding to carbon abatement of around 5 MtC as in Figure 11), i.e. the additional cost per unit of carbon is approximately £0.27**c** at this point, and is still rising gradually. Figure 13 shows the shape of this curve. As might be expected, this ratio is less than the limiting worst case of around £**c**/2 obtained in section 3.2 above, because of the breadth of the distributions of uptake and investment behaviour, both of which reduce the effective steepness of the cost supply curve which applies when the conditional charge is applied[94].

Figure 13. Worst Case Net Costs as Fraction of Charge Level



[94] If the uptake curve is replaced by a step function such that all cost-effective measures are taken up, and the behavioural distribution is collapsed to a single point, then this model does (as it should) reproduce the analytical result of £**c**/2 for incremental charges.

D42 Thus the model is able to give an estimate of the extent to which the additional costs for this generalised case relate to the result in section 3.1 above. In the best possible case, there are net benefits at all charge levels well beyond £100/tC. In the worst case, the cost per tonne of carbon rises steadily in relation to the charge level, reaching just over half of the limiting value of £**c**/2 by the stage at which t = £100/tC.

Long term

D43 In the BAU situation illustrated in Figure 2 above, it is assumed that emerging technologies replace the cost-effective measures at approximately the same rate as they are taken up. The cost-supply curve remains essentially unchanged, and there is no net cost as the overall carbon efficiency improves gradually with time. When a carbon charge is applied suddenly, the emerging potential has no time to respond, and there may be net costs as revealed in Figure 12. However, it is also possible to envisage a situation in which a steadily escalating charge is accompanied by a corresponding acceleration in the rate at which new cost-effective abatement technologies emerge, such that the cost-supply curve shape is still maintained, and there are therefore no net costs, even for the worst case where there are hidden costs as in Figure 12. This is equivalent to an accelerated version of BAU, where a dynamic equilibrium is maintained. The equivalent long term equilibrium for the 'best case' of Figure 10 would be that the net benefit of £80/tC would be maintained for all levels of charge and carbon abatement.

D44 Hence in the long term, the crucial factor is the rate at which emerging technologies become available, since this determines the extent of any net costs arising from rebated or recycled conditional charges.

<u>Technological development and renewal of abatement potential</u>

D45 A finely balanced equilibrium such as that described in the previous section 4.4.2 is of course only one possible situation in a whole range. At worst, it is assumed that relevant technological development will continue at least at the BAU rate. Except in a few specific cases – e.g. primary aluminium smelting – there are no signs yet of technical limits imposed by laws of physics. However, the BAU rate currently supports a rate of improvement in end-use industrial energy efficiency of around 0.5% per year, which is not adequate to ensure a 60% reduction in fossil fuel demand, particularly if the increasing electricity fraction is not matched by very substantial improvements in the carbon content of electricity.

D46 At best, the availability of cost-effective technologies might be increased so fast that it is not a limiting factor in practice. However, given that the cost of technology is only brought down to viable levels by using it widely, this is an unlikely situation for an advanced economy to encounter. There is a natural tendency in the mechanism for some sort of dynamic equilibrium to develop, whatever the rate of change.

D47 In very approximate terms, the rate of improvement in energy related carbon abatement would need to be roughly double the BAU rate for it to be consistent with a sustainable 60% reduction in fossil fuel use by 2050, and continuing improvements thereafter. The implication is that the rate of introduction of new carbon abatement potential needs to double also. It is hard to estimate the cost of such a change, particularly in an international context. Also difficult is to pinpoint areas of fundamental R&D to support with the aim of developing demand side measures for industry, since process improvements etc. come from such a wide range of disciplines.

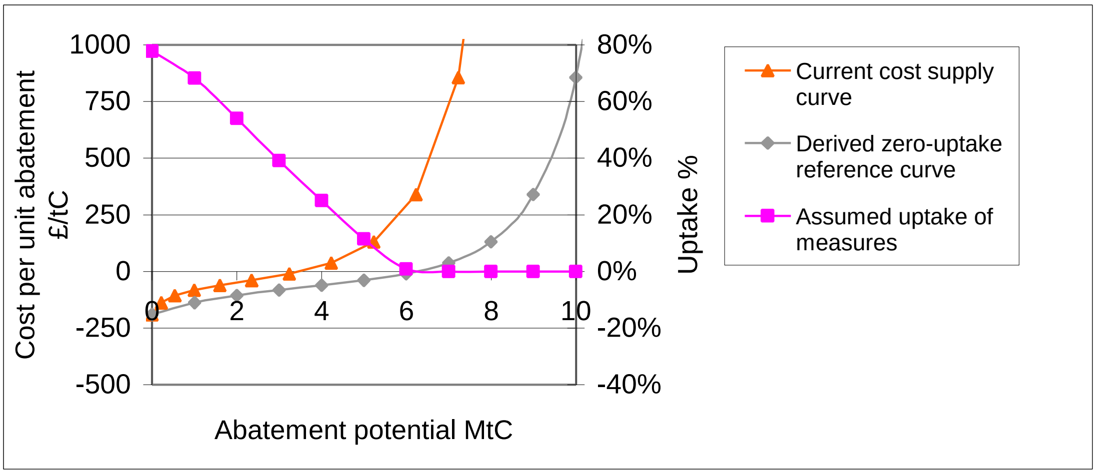
D48 Factors which are likely to be important include not only the general level of support for R&D in the relevant sectors, but also the currently typical gestation times of around 10 years for technological innovation, and plant replacement lifetimes of 15-20 years or more. It may be this last factor which presents the most costly barrier (as it does for domestic housing) and that premature retirement of industrial plant needs to be considered more seriously in the overall cost estimation.

D49 It is envisaged that a succession of such schemes could be continued effectively for at least two or three more decades, provided that they are announced well in advance. Since a sustained, elevated rate of carbon abatement implies a correspondingly higher rate of technological replenishment, the mechanisms governing investment rates (both in R&D and in plant and process renewal) may need to be addressed.

Role of CHP

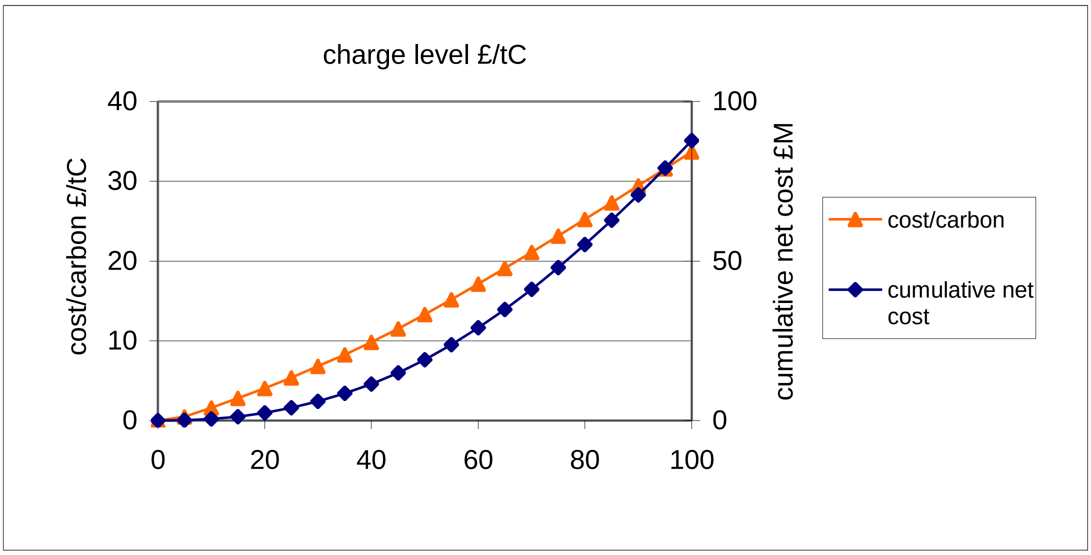
D50 About half of the current cost-effective carbon abatement potential for manufacturing industry is associated with CHP. Since CHP reduces carbon emissions but does not in itself reduce end-use energy consumption, it is also important to look at the energy efficiency measures separately from the CHP potential. The equivalent of Figure 4 with CHP excluded is shown in Figure 14.

Figure 14. Industry abatement potential curve with CHP excluded (cf. Figure 4)



D51 Applying a rebated carbon charge now yields only around half of the carbon savings (about 2.5 MtC for a charge level of £100/tC), as might be expected. The worst case additional costs per tonne of carbon are, however, essentially unchanged, as one can see by comparing Figure 15 with Figure 12 above.

Figure 15. Net costs for a fully rebated carbon charge: CHP excluded (cf. Figure 12) (worst case: hidden costs nullify cost-effective savings at equilibrium)



D52 Hence treating CHP as a special case and excluding it from the cost supply curve does not, in this instance, have any significant effect other than a simple scaling of the potential.

Sensitivity to assumptions and key parameter values

D53 The most important outputs from the model are:

- the amount of carbon abatement stimulated by a given charge level;

- the worst case additional cost per tonne of carbon, in relation to the charge level;

- the best case benefit per tonne of carbon, at low charge levels.

D54 Both of these are potentially sensitive to assumptions and parameter values, particularly those concerned with the uptake function, and the shape of the non-cost-effective part of the cost supply curve. The cost-effective part of the curve is taken as given. Sensitivities for the Industry cost supply curve model (including CHP) have been explored in a selective rather than exhaustive way, and the results are summarised in the table below.

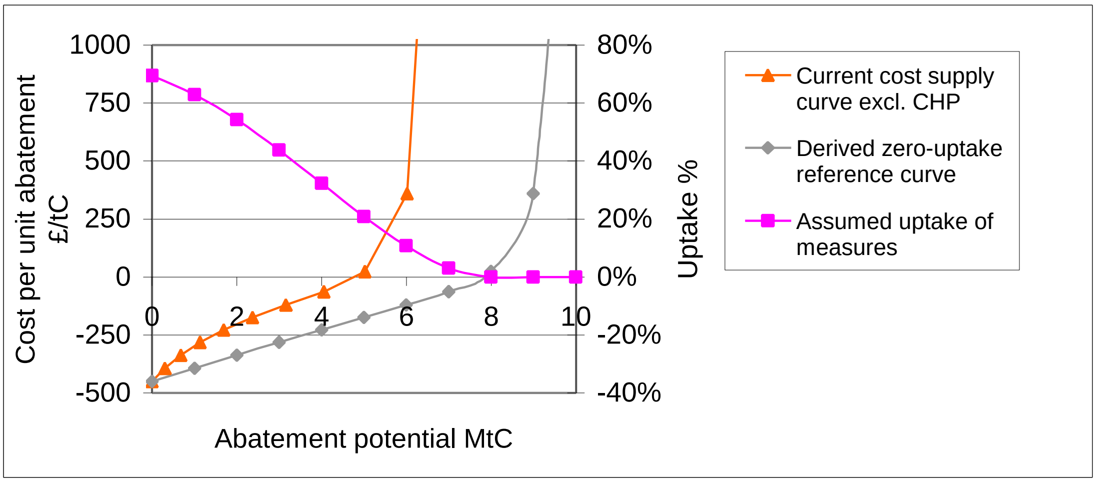
D55 Generally the effects are quite small in relation to other uncertainties – e.g. the wide range between the best and worst cases for hidden costs – and do not have a major effect on the main results.

Sensitivity Check	*Effect on carbon abatement*	*Effect on worst case cost per unit of carbon relative to charge level*	*Effect on best case benefit per unit of carbon*
Maximum uptake increased from 80% to 100%	Saving for charge of £100/tC increases from 5.0 MtC to 6.4 MtC	Cost/carbon @ charge of £100/tC falls from £28/tC to £22/tC	No change from low-charge benefit value of ~£80/tC
Investment sensitivity (scale factor for exponential) increased from 1.0 to 3.0	Saving for charge of £100/tC increases from 5.0 MtC to 6.0 MtC	Cost/carbon @ charge of £100/tC rises from £28/tC to £35/tC	Benefit reduced from £80/tC to £60/tC
Reduce the potential for all non-cost-effective technologies to ~50% of original values	Saving for charge of £100/tC reduces from 5.0 MtC to 4.4 MtC	Cost/carbon @ charge of £100/tC rises from £28/tC to £37/tC	No significant change
Halve the width of the behavioural distribution of carbon efficiency	No significant change	No significant change	No significant change

Services Sector

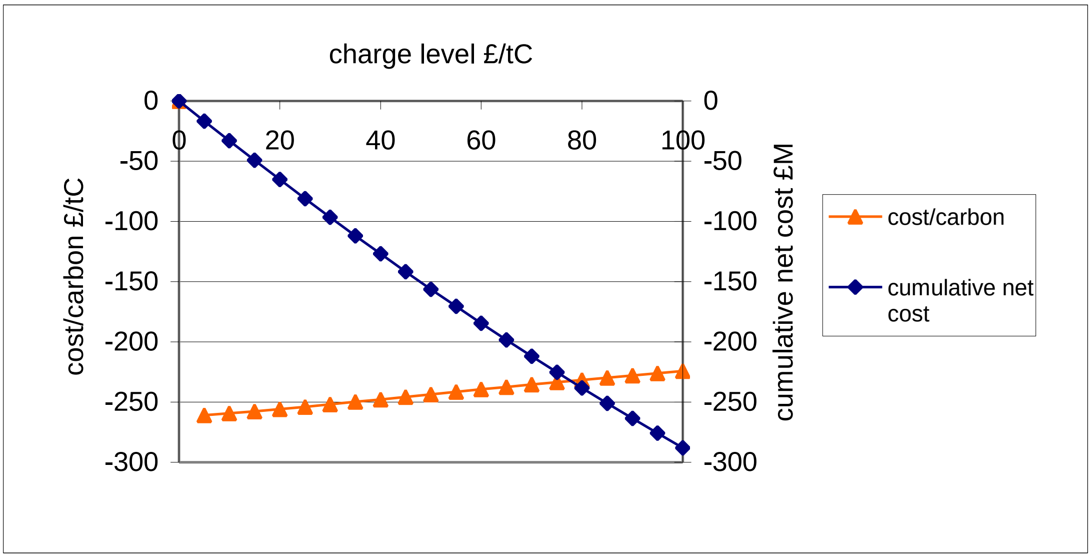
D56 Cost supply curves for the Services sector have been developed by the Building Research Establishment (BRE), and model curves[95] are shown in Figure 16, which is equivalent to Figure 14 for industry.

Figure 16. Services sector carbon abatement potential curve (with CHP excluded[96])



D57 Treating this in the same way as the industry model above yields the short-term response curves shown in Figures 17-20.

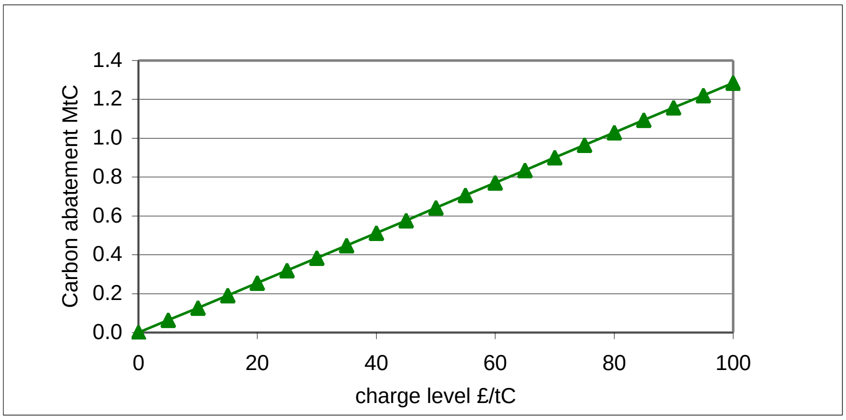
Figure 17. Services sector: net benefits from a fully rebated carbon charge (best case: no allowance for competition for resources or hidden costs)



[95] The "Current cost supply" curve approximates the potential and costs for a 25% rate of return, based on data provided by Christine Pout of BRE.
[96] The cost-effective potential for carbon abatement via CHP in the service sector requires further analysis, but is a much smaller fraction of the total potential than for industry.

D58 Comparing Figure 17 with the equivalent for industry (Figure 10) indicates that the estimated benefits per tonne of carbon for no-regrets measures in services are considerably larger than those for industry (starting at ~£250/tC rather than ~£80/tC). A consequence of this is that to account for sensible uptake levels, the propensity to invest in carbon abatement measures must be assumed to be much lower in the services sector than in industry. This is intuitively correct, since energy costs tend to be a much smaller fraction of total costs, and there are many other barriers such as landlord-tenant arrangements. The result is that the services sector is theoretically more difficult to influence with energy price signals such as the conditional rebated carbon charge, and Figure 18 shows a relatively modest effect, representing around 30% of total cost-effective potential for a charge level of £100/tC. This compares with about 60-70% for industry.

Figure 18. Services sector: carbon abatement stimulated by conditional charge



D59 Taking the worst case, with hidden costs[97] offsetting the no-regrets benefits, the additional cost burden per tonne of carbon as shown in Figure 19 is nevertheless similar to that for Industry at comparable charge levels, and this is confirmed by the fractional costs as shown in Figure 20. As in Industry, they appear to be significantly below the fully invested single company worst case value of 0.5 (see section 3.1).

[97] Following from the previous discussion, the hidden cost per tonne of carbon would have to be about three times as high for services as for industry. This feels improbable, and suggests the influence of barriers such as competition for capital and other resources, rather than true costs alone.

Figure 19. Services sector: net costs for a fully rebated conditional carbon charge (worst case: hidden costs nullify cost-effective savings at equilibrium)

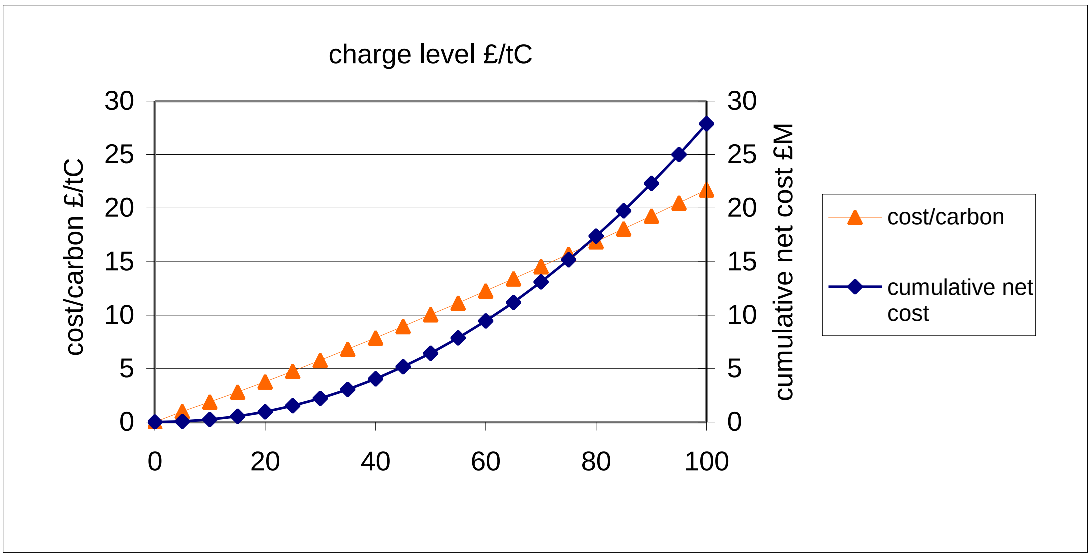
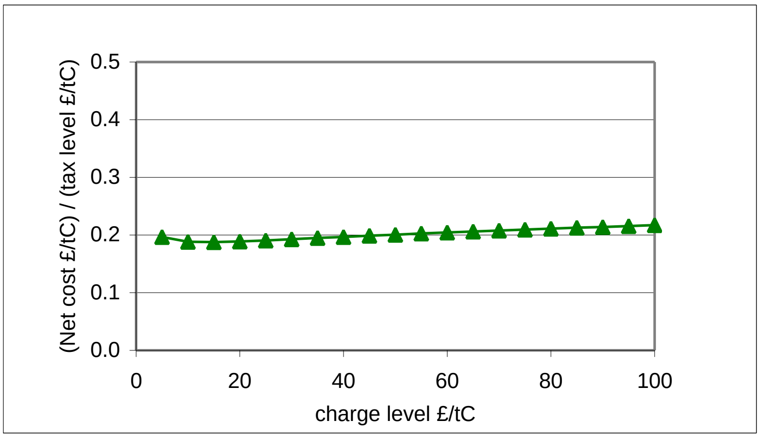


Figure 20. Services sector: worst case net costs as fraction of charge level



Domestic sector

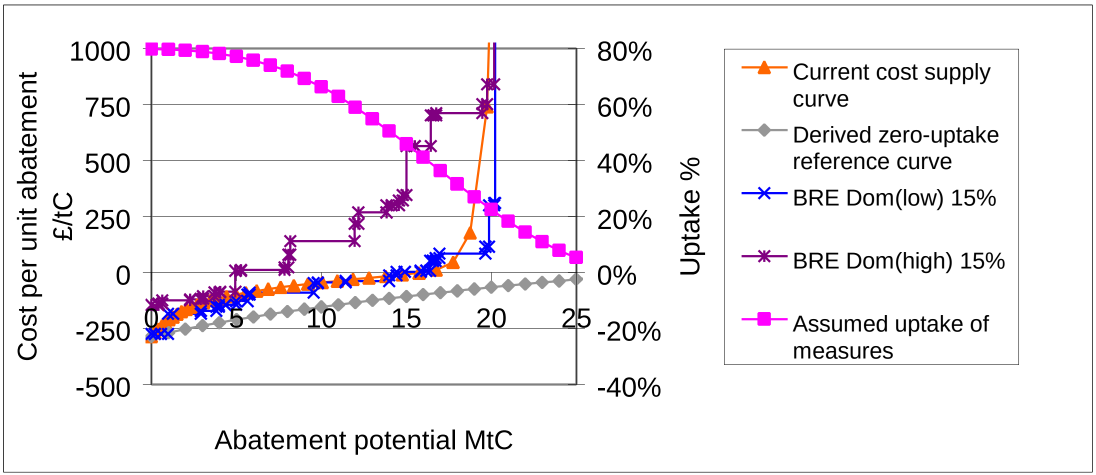
D60 BRE carbon abatement estimates for the domestic sector[98] are quoted for a range of costs per measure, and the extreme values are plotted as two cost supply curves in Figure 21 below. For the purpose of estimating costs associated with programmes to promote more rapid uptake of energy efficiency measures, the lower costs are most appropriate[99], and the model curve has been fitted accordingly[100].

---

[98] Provided by Les Shorrock, BRE. The data shown in Figure 21 are for a 15% discount rate.

[99] Comparison of estimated measure costs with those obtainable through energy efficiency schemes such as Standards of Performance and HEES suggests that the BRE lower costs can be achieved easily, or bettered, via bulk-purchase arrangements.

Figure 21. Domestic sector carbon abatement potential curves



D61 Comparison of these curves with the industry equivalent shows similar levels of benefit for the no-regrets measures, and a much shallower gradient than for the service sector. Best-case benefits are of the order of £100/tC (cf. £80 for industry and £250 for services). This would suggest that on simple economic arguments, the domestic sector should be more responsive to a conditional rebated charge than the service sector. Results from the model indicate that in terms of fraction of potential realised for a given level of charge, the domestic sector is very similar to industry. However, there is a major difference when it comes to estimating the rate at which the abatement measures are being supplemented by emerging technologies, and it is not obvious that one can regard BAU in the domestic sector as a steady state in which uptake of existing efficiency measures is balanced by new cost-effective potential. Radical improvements to building insulation can be envisaged, but they remain costly unless implemented widely, and the construction industry is very conservative.

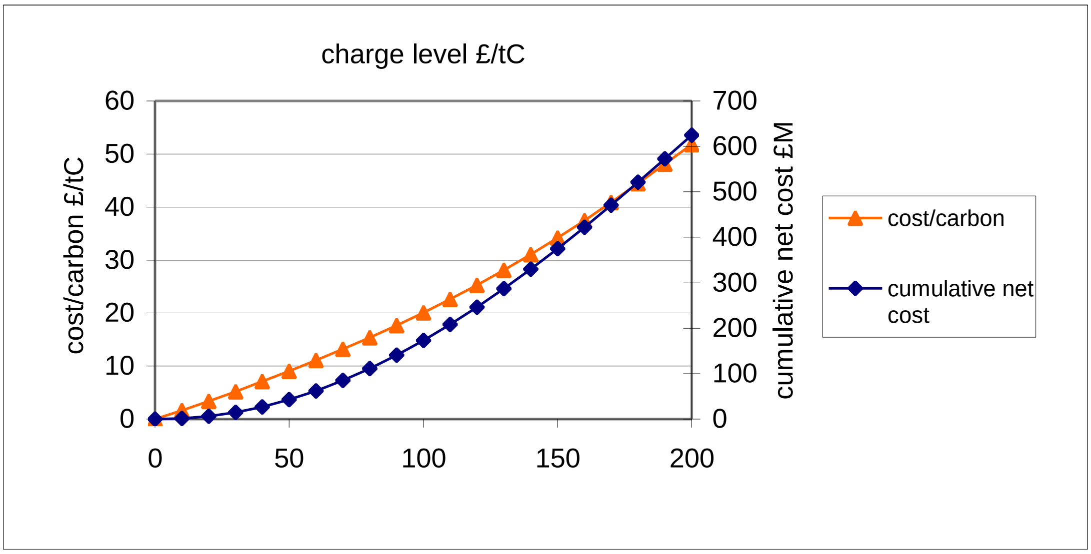
D62 The worst case would be one in which there is no replenishment of potential either in the short or the long term, and Figures 22-23 show what would happen if the charge level continued to rise to £200/tC, twice the illustrative value used for industry and services where more rapid technological response might be expected. Possible additional costs per tonne of carbon – assuming that hidden costs offset benefits – are similar

[100] It can be argued that the uptake limit for domestic measures should be closer to 100% rather than the 80% assumed for Industry and Services, since limitations to do with dwelling type have already been taken into account. However, raising the limit to 95%, say, does not significantly affect the cost estimates (though it does raise the realisable carbon savings). Moreover, there may be difficulties in accessing and implementing all of the potential, and the 80% limit is retained to allow for this. Given the level of detail in the BRE data, it would be possible to do a more accurate analysis of uptake, but this has not been practicable in the time available.

to those for services, and slightly lower than for industry. Figure 23 shows the effect of diminishing returns as the abatement potential becomes exhausted, in this case at around 12 MtC, or 25-30% of current emissions[101].

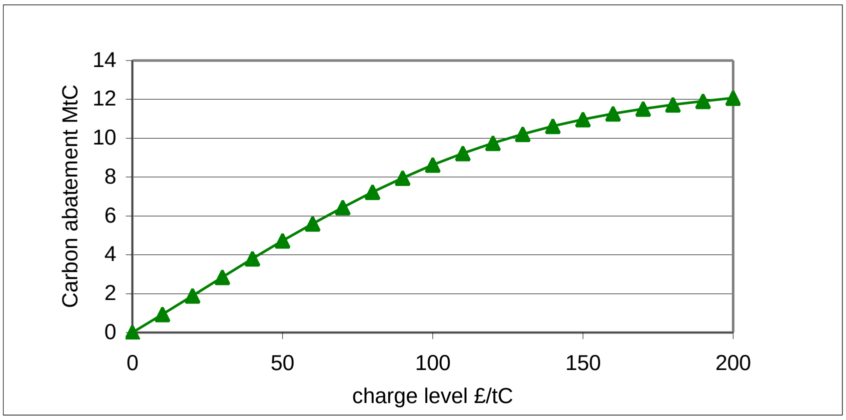
D63 In practice, it seems very unlikely that a prolonged programme to maximise the uptake of existing Domestic carbon abatement potential would not stimulate the introduction of additional measures, even to the extent of changing lifestyles to some extent. For this reason, the saturation seen in Figure 23 is not a real barrier if one is considering a timescale of 50 years or more; the DEFRA 2050 BAU projection for the Domestic sector is equivalent to a 42% improvement in energy efficiency, and an ultimate efficiency factor of 0.35 (for 2050 efficiency relative to 2000) is considered to be possible under the right scenario.

Figure 22. Domestic sector: net costs for a fully rebated conditional carbon charge up to £200/tC (worst case: hidden costs nullify cost-effective savings at equilibrium)



[101] Relaxing the 80% uptake limit in the model would increase the saturation level by up to another 3 MtC.

Figure 23. Domestic sector: carbon abatement stimulated by conditional charge (worst case, short term response, with no replenishment of abatement potential)



Conclusions

D64 Analysis based on the ETSU cost supply curve for carbon abatement in manufacturing industry has yielded estimates for the best case benefits and worst case additional costs that might result from the introduction of a conditional rebated carbon charge – a charge for which the revenue is rebated on condition that the user invests selectively in energy efficiency as though the energy price were increased by the amount of the charge.

D65 For the extreme case of a company which is already investing in all cost-effective abatement measures, the charge introduces an additional cost of the order of 50% of the product of the charge rate times the carbon saved. This should be a worst case limit.

D66 For a typical distribution of companies operating well below the cost-effective limit, there is a range of possible costs or benefits. The worst case, assuming that the benefits of 'no-regrets' measures are offset by hidden costs, leads to additional costs which increase progressively with the charge level, but for levels up to £100/tC are substantially lower than the worst case for the single company operating at the cost-effective limit. The spreadsheet model indicates worst case additional costs of around £20 to £35/tC in the short term, for a charge of £100/tC which stimulates savings of 5 MtC or about 14% of current emissions.

D67 The best case (assuming no hidden costs or transaction costs, and assuming that the barrier to investment is removed by the conditional charge) suggests average benefits of up to £80/tC, decreasing to around £50/tC after savings of 5 MtC.

D68 Long-term costs and savings are crucially dependent on the rate at which emerging technologies replenish the cost-effective measures as they are taken up. If technology renewal matches the rate of uptake, the additional costs of investment in carbon abatement should be minimal, but the cost of stimulating the technology needs to be considered.

D69 Similar analysis can be applied to the services and domestic sectors, and worst-case estimates of abatement costs are comparable, though different market behavioural characteristics need to be taken into account. In comparison with industry, the services sector is less responsive to energy price signals, since energy represents a very small fraction of total costs. The domestic market is affected by individual preferences and cultural factors. Stock turnover is very slow, and the building industry is very conservative.

D70 Current indications are that it should be possible to double the Industrial 'business as usual' efficiency improvement of around 0.5% per year, by means of a series of schemes involving conditional charges or obligations, spread over several decades. This might reduce carbon emissions by a further 30% by 2050, reducing projected emissions of about 25-30 MtC to around 20 MtC. Plant replacement cycle times, typically 15-20 years or more, are likely to be a barrier to progressing at an even faster rate, since premature retirement of plant would be costly. Similar rates of extra progress might be achieved in the service sector, reducing projected 2050 emissions to around 15 MtC. For the domestic sector the model has been used to estimate abatement and costs for the very restricted worst case in which no new technologies arise. In practice, development of new abatement measures will continue, and efficiency improvements to around 30-40% beyond BAU are considered possible, with emissions of 25-30 MtC.

Results of AEAT/Imperial College MARKAL project

E1 The DTI, DEFRA and the PIU commissioned AEA Technology and Imperial College to use the MARKAL model to develop a range of "bottom-up" estimates of carbon dioxide emissions from the UK energy sector up to 2050, and to identify the technical possibilities for the abatement of these emissions. Three levels of abatement by 2050 were considered: a 60% reduction relative to emission levels in 2000 – approximating to the level considered by the RCEP – as well as 45% and 70% reductions.

E2 The report reached the following conclusions:

(i) Final energy demand could remain fairly steady over the next 50 years, even with continued growth in the demand for energy services. This would require investment in cost effective energy efficiency in all the demand sectors, at a level that has not been attained in recent decades.

(ii) Demand for primary energy could fall due to the combination of increased demand side efficiency and improvements in the efficiency of the energy supply industries as they invest in more advanced technologies.

(iii) The adoption of cost effective energy efficiency technologies on both the supply and demand sides also yields benefits in terms of carbon dioxide emissions. Emissions fall between 2000 and 2050 by 11-33 %, which equates to a fall in emissions intensity (carbon emissions per unit of GDP) of between 2.7% and 3.1% per year. This compares with the average reduction over the last 30 years of 2.9% per year.

(iv) Reducing carbon dioxide emissions by 45% to 70% by 2050 requires the deployment of additional technologies, but the study has shown that there are sufficient options to achieve these levels of abatement, even with the high growth WM scenario.

(v) Natural gas is expected to take a growing share of energy supply, with coal falling to a low level and oil being essentially confined to transport applications. The share taken by gas increases further when seeking to reduce carbon emissions. In particular natural gas dominates electricity generation.

(vi) No new nuclear capacity is built in the reference scenarios, but new capacity is built when seeking to reduce carbon dioxide emissions by over 45%. However, there are other technologies available for power generation that are only marginally more costly (actually directly comparable within the uncertainty of the technology cost estimates).

(vii) Carbon dioxide sequestration and disposal could make a major contribution to reducing emissions from power generation with gas turbine combined cycle plant, and from hydrogen production, also from natural gas.

(viii) Coal-fired power plant has the potential for considerable improvements in both capital cost and conversion efficiency. However, these improvements will not be sufficient to make coal cost competitive without much larger increases in natural gas prices than expected in any of the scenarios.

(ix) Renewable energy sources slowly increase their share of power generation in the reference scenarios, mainly through the deployment of waste, on-shore wind and biomass technologies. When constraints are applied to carbon dioxide emissions their deployment increases with expanded biomass capacity together with deployment of offshore wind and wave energy.

(x) Hydrogen technologies are not deployed under reference conditions, but are needed after 2030 when seeking to reduce carbon dioxide emissions. They are mainly deployed in the road transport area with both passenger cars and HGVs. The hydrogen is derived from natural gas, but if carbon dioxide sequestration is not available, hydrogen is produced by gasification of biomass.

(xi) The costs of carbon dioxide abatement are appreciable in absolute terms but are small in comparison to the overall turnover of the energy sector, and are likely to have a negligible impact on economic growth. The cost of abatement is estimated to have an impact of up to 0.02 percentage points on a long term GDP growth rate of 2.25%.

E3 The full results of the project will be published separately.

Timing Issues

Key messages:

Delaying abatement action for a known short-term target increases the cost of meeting the target. Uncertainty favours early action, as "insurance" against future environmental states being worse than expected.

Learning by doing is best stimulated by early abatement. But investment in R&D can imply a postponement of action. So there is not a universal solution for all technologies.

Carbon taxes are a theoretically optimal emission reduction tool as they place a value on each unit of carbon emitted (trade in permits can act the same way). Inclusion of endogenous learning impacts increases the elasticity of response to a tax.

More work is needed on the full impact of induced technical change/learning on the optimal abatement path and abatement costs.

F1 Until recently most economic models (as discussed in chapter 4) have focused on the overall costs of addressing climate change in general and specifically the Kyoto targets. Modelling work has concentrated on presenting the benefits, in terms of lower costs, of flexibility be that through trading, CDM, the inclusion of all six greenhouse gases etc. At the same time modelling work has addressed issues concerning the structure of climate change abatement policies by considering the merits of taxes versus permits or trading versus joint implementation/CDM. However, it is only in the last few years that research has really started on the question of timing of action. As such there is a great deal of conflicting evidence and much more work to be done.

F2 An important factor on the cost of any emission reduction target is when work towards the target commences. However, timing considerations differ in relation to length to target and potentially type of target. For Kyoto, in this context a short term fixed emission limit target, there is clear evidence that delays in starting to meet the target will increase costs. For longer-term emission control commitments the arguments between immediate and delayed action are seemingly less clear-cut. In favour of delayed abatement are that:

- it prevents premature (and costly) early retirement of capital (e.g. generating plant);

- it allows for more technological progress so alternatives to fossil fuels become cheaper;

- time discounting, diminishing future abatement costs.

F3 The counter arguments, which promote early action, are that:

- it prevents further lock-in to carbon-intensive production and consumption;

- early investment in emissions reduction technology stimulates ‘learning by doing’ and is the best means to achieve cost reductions.;

- a cautious policy best in the face of future uncertainties;

- greater detrimental impact on climate change if action is postponed.

F4 Several arguments supporting early action are based around technological inertia. That is, if early action is not taken or deemed not to be needed the economy will not change. Deferring action encourages “technology lock-in” where producers of current products make small improvements rather than developing new low-carbon products, or carbon lock-in caused by the slow turnover of capital.

Balancing the short and long-term

F5 When does cost minimising investment and technology development have to stop and non-cost optimal measures start (e.g. premature retirement of plant)? In part an answer is a market solution, new technologies will become affordable and profitable; when the cost of running existing plant becomes too great. If a fixed date for an emission concentration target is assumed then earlier R&D has greater benefits than later R&D, so the marginal costs of investments in R&D decline over time.

F6 Assuming technology improvements reduce costs of future abatement, direct action can be delayed, but this does not mean that no action is required. No-regret options or low-cost long-term capital investments should be enacted; after-all they are (or are near) economically efficient. To ensure future costs decline, investment and R&D on energy supply and use are required now. For Government this implies providing a clear signal on long-term policy goals to allow industry to mix short-term (the "learning by doing" approach) and long-term investment as appropriate to ensure low-cost low carbon products and producers are available.

Learning

F7 Economic modelling work has only just begun to address the issue of uncertainty and learning in the context of climate change. Learning will have a greater impact the stronger the assumed relationship between periods. Early results show that including learning as an endogenous variable reduces the costs of emission abatement. This may all seem rather obvious. When learning by doing has been considered the results tend to indicate earlier abatement, especially if a strong learning effect is assumed (i.e. we learn a lot from doing). For learning via R&D the reverse is generally true, i.e. investment in R&D is required with abatement action postponed. So clearly there is not a universal solution for all technologies. There does not seem to be much in the literature on which is more important for greenhouse gas reduction – learning by doing or R&D.

F8 An important question is how learning or innovation can be encouraged. Companies choose to invest if they believe the cost of the investment will be more than compensated by future cost saving. For example, a carbon tax puts a price on emissions so a company may choose to invest in R&D to improve the efficiency of energy use, emit less and so pay less tax. The final decision to invest is taken on the expectation of gain on an investment. However, in the real world there are likely to be technology spillovers whereby other companies can imitate a new process derived from the R&D investment. Therefore, in a situation where companies believe they will not receive the full benefit (financial or competitive) of innovation (e.g. where patent protection is weak), there will be a tendency for the economy not to invest enough in R&D. This argument can be extended to the idea that Government has a central role in funding high “spillover” research that will not be economically attractive to any one single firm. This leaves the market to invest in specific application technologies where spillover risks are less. But clearly there are limits on the amount of learning investment the UK can and should undertake, especially in areas where significant development is happening elsewhere from which UK industry can learn.

F9 There is a view that a credible threat of "government/regulator" action can be sufficient to stimulate action/investment. However, some policies may limit the amount of abatement a company will undertake. Policies that enforce the use of best available technology or set performance standards leave little incentive to make additional cuts in emissions (other than if they were no cost).

F10 Some argue that because a tax puts a price on each unit of emissions it has the potential to create more innovation and more abatement than permits, which aim to limit the total amount of emissions. Under a permit system there may be less incentive to seek out additional means of reducing emissions (below the cap) as these emissions are free for grandfathering or already paid for under auction, so additional action cannot reduce current costs. With tight caps of the kind required for a 60% CO_2 reduction, and ability to sell emission savings to others, this argument does not seem highly relevant here.

F11 It has also been shown that the inclusion of learning lowers the optimal level of a carbon tax assuming it is set at the marginal cost of abatement, which is lowered through learning. It has also been shown that if learning is treated endogenously it increases the elasticity of response to a carbon tax. This means that, for a given tax, more abatement will occur than when learning is not internalised. But the treatment of learning and induced technical change is an emerging area of study and one that needs to be considered more fully in addressing optimal climate change mitigation pathways.

Uncertainty and risk

F12 Uncertainty (and the assessment of different outcomes from the expected) should lead to greater early abatement if the assessment concludes that future states could be worse particularly if large irreversible changes (such as suppression of the Gulf Stream) are a possibility. In this context learning and uncertainty are linked. If it is considered that learning about future climate states will show that the probability of a case worse than the expected case is greater than the probability of a better case, then learning will implies more action in the prior period. Since in theory there is an infinite range of possible bad climate states, but good states are bounded by proximity to current conditions, then early action is desirable to avoid the regret of not having done enough.

GLOSSARY

AAU	Assigned amount units
ABWR	Advanced Boiling Water Reactors
AC	Alternating current
ALWR	Advanced Light Water Reactors
ARBRE	Arable Biomass Renewable Energy project
BAU	Business as Usual
B/L	Baseline
BIPV	Building Integrated Photovoltaic
BNFL	British Nuclear Fuels plc
BRE	Building Research Establishment
CAES	Compressed air energy storage
CAP	Common Agricultural Policy
CCA	Climate Change Agreement
CCGT	Combined cycle gas turbine
CCL	Climate Change Levy
CCP	Climate Change Programme
CdTe	Cadmium telluride
CDM	Clean Development Mechanism
CEGB	Central Electricity Generating Board
CH	Central GDP growth - high fuel prices
CHP	Combined heat and power
CIS	Copper indium diselenide
CL	Central GDP growth - low fuel prices
CO_2	Carbon dioxide
CS	Carbon dioxide capture and storage
DC	Direct current
DEFRA	Department for Environment, Food and Rural Affairs
DERV	Diesel engine road vehicle
DFG	Dash for gas
DNO	Distribution Network Operator
DTI	Department of Trade and Industry
DTLR	Department for Transport, Local Government and Regions
EMF	Energy Modelling Forum
EOR	Enhanced oil recovery
EP68	Energy Paper 68
ESI	Electricity supply industry
EST	Energy Savings Trust
ETSU	Energy Technology Support Unit

EU	European Union
FSU	Former Soviet Union
GDP	Gross domestic product
GGE	Greenhouse gas emissions
GHG	Greenhouse gases
GS	Global Sustainability
GW	Gigawatt
GWh	Gigawatt hours
HTR	High Temperature Reactors
IAG	Inter-departmental Analysts Group
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
ISA	Intelligent Speed Adaptation
JI	Joint Implementation
ktC	Kilotonnes of carbon
kWh	Kilowatt hour
LS	Local Sustainability
LUC	Land use change
MCT	Marine Current Turbines
MSW	Municipal Solid Waste
MtC	Million tonnes of carbon
MW	Megawatt
NFFO	Non-fossil fuel obligation
NO_X	Nitrogen oxides
NRTF	National Road Traffic Forecast
OECD	Organisation for Economic Cooperation and Development
OFGEM	Office for Gas and Electricity Markets
ONS	Office for National Statistics
PBMR	Pebble Bed Modular Reactor
PE	Provincial Enterprise
PIU	Performance and Innovation Unit
PPM	Parts per million
PSD	Passive Solar Design
PV	Photovoltaic
PWR	Pressurised Water Reactor
R & D	Research and development
RCEP	Royal Commission on Environmental Pollution
RIIA	Royal Institute for International Affairs
SMES	Superconducting magnetic energy storage
SO_X	Sulphur oxides

SPRU	Science Policy Research Unit (University of Sussex)
SRC	Science Research Council
SRES	Special Report on Emissions Scenarios
tC	Tonnes of carbon
THERMIE	European Union Programme for promotion of non-nuclear technologies
TWh	Terawatt hour
WM	World Markets