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Summary

1. This paper presents the results of an exercise to update the Government's projections of future UK energy demand and energy-related emissions of carbon dioxide (CO_2) last published in Energy Paper 65 in 1995. It builds on work issued as a working paper in March 2000.[1] In general terms, the main aims of the projections are to:

- monitor the general development and direction of energy markets since 1995, for example, as a background against which to view the Government's key energy policy objective of ensuring secure, diverse and sustainable supplies of energy at competitive prices;
- contribute to policy development and monitoring of how the UK is meeting its international commitments to reduce emissions of greenhouse gases and sulphur and its domestic goal to reduce emissions of CO_2; and
- inform debate on future commitments, in particular for the period beyond the current Kyoto commitment period of 2008-2012.

2. The paper does not rely on a single forecast. Rather, its projections provide a view of the possible future levels and composition of energy demand based on a set of different scenarios of growth in the economy and of world fossil fuel prices. Six core scenarios are considered. This approach provides a range of energy and emissions projections, comparable with Energy Paper 65. It also recognises that uncertainties are inherent in projecting the future path of energy demand, although even the range of scenarios covered cannot cover all the uncertainties which apply.

The Projections

3. The projections are based on an analysis of historical trends in energy use and its relationship to factors such as economic growth and fuel prices. They also reflect the impact of existing Government and devolved administrations policies on energy and the environment. For example:

- the baseline allows for continuation of at least the existing level of effort to encourage energy efficiency through the Energy Efficiency Best Practice Programme, Home Energy Efficiency Scheme and Energy Saving Trust
- allowance is made for announced policy measures including the climate change levy and the obligation, subject to the price increase to consumers being acceptable, to achieve 10% of electricity generation from renewables by 2010.

The projections do not include measures which are listed as additional to the baseline in the Government's Climate Change Programme (CCP).[2] Development of the

1 Energy Projections for the UK, Working Paper, March 2000, EPTAC Directorate, DTI.
2 Climate Change: UK Programme, November 2000, DETR. Within this, see in particular Section 2, Chapter 9.

projections, in establishing the trend in emissions on announced policies and measures, has helped inform the further measures in that programme.

Developments since Energy Paper 65

4. Other developments in energy markets are also reflected. In particular:

- there has been a general lowering of expectations for future fossil fuel prices. More recently, however, the oil price has risen to levels above $30 a barrel, and there have been knock-on effects to energy prices more widely. Sensitivity to the higher current oil price is explored
- a new energy policy framework was set out in the October 1998 White Paper "Review of Energy Sources for Power Generation". This established a stricter consents policy for gas-fired power stations, but made clear that the policy would be lifted once the programme of reforms of the electricity market set out in the White Paper was substantially complete
- further sulphur emission limits have been implemented and new ones proposed.

Final Energy Demand

5. Final energy demand is projected, in our central scenarios, to grow at around 1% a year to 2010.

6. Within this, growth is strongest (at 1.7-1.9% a year from 2000 to 2010) in the transport sector – though it is possible that this could be moderated somewhat by technological improvement (particularly through the voluntary agreement to improve fuel efficiency, reached between the European Commission and vehicle manufacturers, to reduce carbon emissions from new cars). Domestic and services sector demands also show continued strong growth, at approaching 1% and 1.1% a year respectively. The structural shift in the economy away from heavier industry and towards services and commerce is projected to continue, with final industrial energy demand showing relatively low growth.

Primary Energy Demand

7. Primary energy demand is projected, on our central scenarios, to grow by around 0.7-0.8% a year to 2010. Overall, this growth in demand is lower than previously projected in EP65. It implies that the primary energy ratio (ratio of primary energy demand to GDP) will fall (by around 1.6% a year between 2000 and 2010 in the CL scenario, compared to about 1.3% a year between 1990 and 1999).

Carbon Dioxide Emissions

8. The short-term forecast trend in CO_2 expected in EP65 has been largely borne out by events. Energy demand growth has been relatively subdued and there has been a strong shift towards use of gas. The UK is well placed to meet and exceed its Rio target of returning CO_2 emissions to 1990 levels by 2000.

9. The new projections for CO_2, combined with separate projections of other greenhouse gases, suggest that, with allowance for the impact of policies that have already been announced, the UK is broadly on course to meet its Kyoto commitment for the period 2008-12. The domestic goal to reduce emissions of CO_2 alone by 20% is more challenging. The projections suggest that on existing policies, prior to consideration of new measures within the Climate Change Programme, CO_2 emissions will be around 19 million tonnes of carbon above the domestic goal in 2010.

10. The reduction in CO_2 from now to about 2005 to 2010 reflects mainly a reduction in emissions from the power generation sector. It is associated with a continued shift into generation from gas. Emissions from other sectors generally increase – most strongly from road transport and the domestic sector. Beyond around 2005 to 2010 growth from these sectors, combined with reducing scope for reductions in emissions from generation, mean that overall CO_2 emissions for the UK resume an upward path. In 2020 CO_2 emissions are projected to be 4-7% above the level projected for 2010.

CHAPTER 1

Introduction

1.1 As set out in its October 1998 White Paper,[1] the Government's central energy policy objective is to ensure secure, diverse and sustainable supplies of energy at competitive prices. Competitive markets and companies are the key to achieving this objective. But the Government also has a substantial contribution to make. The Government:

- sets the framework – by providing the appropriate legal structure for competitive energy markets and the economic development of energy resources consistent with safety and environmental protection
- provides for regulation in the consumer interest – to oversee the transition to competition and to supervise remaining monopoly activities
- monitors the wider public interest. The Government has a responsibility to ensure that energy plays a proper role in sustainable development. The Government has international commitments in relation to greenhouse gases and other emissions and a domestic goal to reduce CO_2.

Because of these factors the Government needs to consider the possible level and nature of future energy demands and related environmental effects.

1.2 This paper presents the results of work to update and revise projections of future UK energy demand and energy-related emissions which were published in 1995 as Energy Paper 65.[2] Finalisation of the projections has benefited from comments received on an earlier version of the analysis issued in March 2000 as a Working Paper. In terms of structure, this paper follows that Working Paper very closely. The projections themselves have undergone some amendment, to reflect comments received (of which there is a summary at Annex I), recent policy announcements and availability of new data.

1.3 In environmental terms, these new projections are issued against the background of:

- the Government's international commitment, under its share of the EU's reduction target under the Kyoto Protocol, to reduce our emissions of a basket of 6 greenhouse gases to 12½% below 1990 levels over the period 2008-2012
- the domestic goal of a 20% reduction in CO_2 emissions by 2010
- the likelihood of progressively tighter international targets beyond 2010.

1 Conclusions of The Review of Energy Sources for Power Generation and Government response to fourth and fifth Reports of the Trade and Industry Committee, Cmd 4071, TSO, October 1998.

2 Energy Projections for the UK. Energy Use and Energy-Related Emissions of Carbon Dioxide in the UK, 1995-2020, Energy Paper Number 65, HMSO, March 1995.

In October 1998 the Government published a consultation paper[3] considering a wide range of policy options that could be used to deliver emission reductions and providing a first assessment of the cost, benefits and practicality of these measures. A draft programme of measures was then issued for consultation[4] and a finalised programme has now been published.[5] The projections in this paper have helped to inform consideration of those measures.

1.4 The analytical models on which the projections are based have been developed from Energy Paper 65, published in 1995. The level of detail that lies behind the projections continues to expand. Nevertheless, considerable uncertainty attaches to projections of this kind. The further into the future we look, the greater those uncertainties. The approach taken here, therefore, is to consider a range of possible scenarios for the main determinants of energy demand. No attempt is made to produce a single most likely outcome. It is to be hoped that the approach will encompass the likely range of possible outturns and help to indicate where the biggest uncertainties lie. But further consideration of the sensitivities is contained in Chapter 8.

3 UK Climate Change Programme - a consultation paper, October 1998, DETR.
4 Climate Change: Draft UK Programme, March 2000, DETR.
5 Climate Change: UK Programme, November 2000, DETR.

CHAPTER 2

The Modelling Process

2.1 The energy scenarios described in this paper are based on a set of interconnected economic models of consumption in the electricity supply industry and twelve other sectors. Assumptions about fossil fuel prices, economic growth and other relevant factors are used in the models to investigate possible scenarios for UK energy demand and supply. The general structure of the modelling system is discussed below.

The Energy Demand Model

2.2 The energy demand model used for this paper is based on the model in Energy Paper 65 which comprised some 130 econometric equations of which approximately 60 were fuel share equations, 20 were stock equations and the remaining 50 were energy demand equations. The equations used have been revised and refined to reflect developments in econometric analysis.[1] The structure of the model, however, remains essentially similar to that used in EP65.

2.3 Energy demand is disaggregated into the following sectors of final user. The sectors are:

1. Services
2. Domestic
3. Iron and Steel
4. Transport
5. Non-Ferrous metals
6. Engineering with Vehicles
7. Mineral Products
8. Chemicals
9. Food, Drink and Tobacco
10. Textiles, Leather and Clothing
11. Paper and Packaging
12. Construction and Other Industries
13. Agriculture[2]

The projections in this paper have been aggregated to four main sectors – domestic, transport, services and industry.

1 The econometric revisions, where appropriate, include reestimation of equation coefficients over longer sample periods, revision of assumptions of a stochastic rather than a deterministic trend element and inclusion of error correction models where cointegration could be established.

2 Allowance is also made for energy use and emissions from agriculture, though this sector – accounting for less than around 1 per cent of total energy use – is not modelled in great detail.

2.4 The level of disaggregation within the model facilitates comparison with technology based models (often described as "bottom up" models). Further, the specification and estimation of the econometric equations in this paper takes account of bottom up data supplied for buildings by the Building Research Establishment (BRE) and for manufacturing industry by the Energy Technology Support Unit (ETSU).

2.5 The disaggregation used in the model permits sectoral trends to be identified and incorporated into the scenarios. Where possible, each of the final user sectors has been further disaggregated by type of energy use.

2.6 Representation of each of the final user sectors consists of a number of econometric equations that attempt to explain past energy demand as a function of other variables such as prices and income or output levels. These equations therefore implicitly incorporate historic trends in efficiency. Where reliable information exists, stock data has been incorporated into the equations (e.g. stock of cars). To the extent that Government policies, particularly in the area of energy efficiency, have affected these trends the models incorporate these effects. By implication, the equations assume a continuation of the level of Government support for energy efficiency achieved in recent years.

Combined Heat and Power

2.7 The latest version of the Science Policy Research Unit's (SPRU) boiler and combined heat and power (CHP) model is used in the service, other industry and iron and steel sectors as a shares model to divide total boiler and CHP fuel requirements into the three different fossil fuels (coal, gas and oil). These shares are then applied to projections of total fossil fuel demand in each sector, obtained from econometric equations linking output and fuel prices to demand.

Energy Efficiency and Energy Intensity

2.8 The rate of energy efficiency change within each final-use sector is an important component of the change in delivered energy and therefore in emissions.

2.9 Energy efficiency and energy intensity are different concepts. Energy efficiency is the technical efficiency with which a demand for useful energy can be met. If less delivered energy is used to meet a given level of useful energy demand over time, then energy efficiency is said to have increased. Energy intensity relates to the amount of energy used per unit of output produced in a sector or the economy as a whole. Therefore, changes in energy efficiency contribute to changes in energy intensity, but the latter is also affected by structural change in the economy.

2.10 In many situations energy efficiency and energy intensity will move together, but this is not always the case. For example, GDP may be static, but because of a shift from low energy use sectors into higher energy use sectors, energy use increases and energy intensity rises, even though energy efficiency in each sector is unchanged.

Energy Efficiency in the Demand Equations

2.11 Despite the level of disaggregation used in this paper, energy efficiency changes cannot entirely be distinguished from energy intensity changes. Even at the level of disaggregation employed, the models do not generally identify energy demand at a technology or process specific level. Because of this the rest of this paper uses the term energy efficiency to cover both concepts, except where its use would be misleading.

2.12 The econometric equations used for calculating energy demand allow directly for changes in energy efficiency in two ways. First, the demand for energy tends to rise less rapidly than economic activity for any given level of energy prices. This implies increases in energy efficiency as GDP grows. This partly reflects the application of new energy efficient technologies, partly the tendency for growth to be concentrated in industries with low energy intensities, e.g. the service sector, and partly the tendency of domestic consumers to spend a declining share of their income on fuel as they get richer.

2.13 Second, the demand for energy rises less rapidly for any given level of activity if energy prices rise faster than general inflation. This is due to capital or labour being substituted for energy (e.g. through more insulation or more energy managers) or to research and development expenditures being diverted to energy saving technologies and products. It also arises because with higher energy prices, consumers may desire lower heating and lighting standards and consumption patterns will tend to switch to products that require less energy to manufacture and/or use.

2.14 The choice of whether or not to invest in energy saving technology is affected by the discount rate used for the appraisal. The models used here have been estimated using historical data and therefore implicitly reflect the discount rates or appraisal methods which individuals or companies actually use rather than a theoretical assumption about optimal behaviour.

2.15 Although the econometric estimation of these energy efficiency changes is based on past trends and relationships, there are areas, particularly in the domestic and service sectors, where future trends seem likely to diverge from those of the past. In particular, saturation levels – discussed further below – have been built into the modelling.

2.16 Improvements to energy efficiency in space heating have historically been outweighed by the effect of consumers choosing higher comfort levels, but as central heating starts to approach saturation levels it is reasonable to assume that the increase in the associated energy consumption will become less rapid. Stock variables, such as the number of homes with central heating, are used in the space heating equations to embody the saturation effects mentioned above. The model also includes the greater uptake of energy efficiency measures, such as double glazing and loft insulation, that will stem from higher real incomes.

2.17 Domestic sector use of electricity has risen rapidly as the ownership of electricity-intensive appliances such as freezers and tumble dryers has spread. As most households now own these electricity-intensive appliances the market for these products is approaching saturation. The future growth in the demand for energy associated with these products is likely to be less than in the past. However, growth in the demand for domestic electricity is expected from the recent developments in the area of electronic home entertainment, especially the advent of digital television. The model estimates electricity consumption in these domestic appliances using saturation curves and average appliance consumption assumptions.

2.18 Apart from the major electrical appliances there are a large number of minor electrical appliances. The demand associated with these appliances is captured via a separate demand equation. The minor electrical appliance equation is specified in such a way that a 1 per cent increase in income has a smaller impact on energy demand the higher the existing level of income.

2.19 Of course, whilst demand for some appliances may be reaching saturation levels, new appliances may enter the market. It can be viewed as an advantage of the top-down econometric approach that it does not attempt to model, in depth, the take-up of each and every appliance – rather its more aggregative approach is more akin to assuming that the level and rate of penetration of new appliances will resemble that observed in the past. The risk attached to this is that some particularly sensitive innovation, such that the path of energy demand shows a break with the past, is missed. Inevitably, judgements on these issues have to be made. For these projections, making some allowance for comment received in respect of the Working Paper, we have assumed a rapid increase in take-up of set-top boxes for digital TV.

2.20 Service sector energy demand would appear, on the basis of growth in the last 20 years, to have significant output elasticities well above unity. It seems unlikely that such high elasticities will be sustained in the long-run. Saturation levels are incorporated in the modelling.

MODELLING THE ELECTRICITY SUPPLY INDUSTRY

2.21 As in EP65, all of the UK's major coal power stations are modelled individually. Each station has its own plant characteristics, such as remaining lifetime, thermal efficiency, emissions abatement, etc. A linear programming (LP) model is used to allocate generation to these stations in order to meet electricity demand in such a way as to minimise the overall system cost, subject to meeting fuel, emissions and other constraints placed upon them (e.g. load factor restrictions).

2.22 A number of minor changes have been made to modelling this sector since EP65. In particular, the latest model structure allows for more detailed modelling of renewables plants, in order to improve simulation properties.

Basic Modelling Procedure

2.23 The basic approach is that the LP is given a choice of plants, both existing, those under construction and future possible types, from which it can choose to meet the projected electricity demand. For example, several types of CCGT are included in the list of plants, reflecting differences in performance (efficiency, etc).

2.24 Given appropriate assumptions on future plant margins, the LP needs to decide which types of new plant build will satisfy the growth in electricity demand. To do this, cost and performance data is required for each type of plant which can be built in the future. Once the level of electricity demand – mostly via the final demand equations – is estimated, the LP then chooses, in a least cost fashion, the means of meeting demand. A least cost solution is generated, subject to any constraints placed upon plant performance or emissions abatement either at individual plants or at a national level.

Electricity Prices

2.25 Given generation of the least cost solution, electricity prices are calculated, which, after the addition of various mark-ups to reflect transmission and distribution costs, the fossil fuel levy, VAT and normal profits, can be transformed into prices to final consumers for each final demand sector. These prices are then fed back into the energy demand models, which recalculate electricity demand and the process continues until a pre-specified degree of convergence is attained.

Emissions Modelling

2.26 With the ESI model constructed in this way, emissions can be estimated on a plant-by-plant basis. This considerably improves the modelling of emissions and responses to various emissions abatement policies.

CHAPTER 3

Energy Price, Industry Share and GDP Assumptions

3.1 In order to develop a projection of energy demand, a number of assumptions about the state of the world in the future must be made. These assumptions about the variables which drive the model (the exogenous variables) have a significant impact on the final projections. Every care is taken to ensure that they are plausible. However, the inherent uncertainty about the future means that the results are inevitably subject to large uncertainties, particularly at the end of the projection horizon.[1] To allow for this uncertainty this paper analyses a number of scenarios that have different underlying assumptions. In this way it is possible to build up a picture of the range of possible outcomes in the energy sector, without relying on the outcome of one central forecast. It also allows the sensitivity of the model to the underlying assumptions to be examined.

3.2 As in EP65, six core scenarios are examined based on three GDP assumptions and two energy price assumptions. These cover the key exogenous variables in the model. There are a large number of other assumptions which can be varied if required by policy makers to analyse their impact on energy demand and supply. Sensitivity to some of these is considered in Chapter 8. However, in the interest of brevity and clarity the paper focuses on the two central core scenarios with less detailed reporting of the full six core scenarios. Table 3.1 below presents the notation used to summarise these six scenarios.

Table 3.1 Scenarios

GDP Growth	Energy Prices	Abbreviation
Low	Low	LL
Low	High	LH
Central	Low	CL
Central	High	CH
High	Low	HL
High	High	HH

1 There are also uncertainties attached to the estimation of parameter values within the modelling process. This is considered further in Chapter 8.

GDP Growth and Economic Structure

3.3 GDP growth has been, and continues to be, one of the key drivers of energy demand growth. Given its importance we assume three different growth paths for GDP and real personal disposable income (RPDI). In the long-term, GDP growth across the three different scenarios is based on analysis accompanying the Government's 'Pre-Budget Report' (PBR) forecasts,[2] confirmed in the March 2000 Budget.

3.4 The long-term annual rates of growth vary between each scenario. The central scenario incorporates a baseline estimate of the long run potential of the UK economy. Over the period to 2005, in line with the analysis and conclusions of the 1999 Pre-Budget Report, this has been set at 2.5% per annum. Post 2005, the central growth rate reverts to 2.25% pa as a cautious interpretation of the possible outturn. To allow for the inherent uncertainty in making estimates of future growth, over the long-term the low and high GDP scenarios are roughly one standard deviation below and above the central scenario respectively. This leads to an increasingly wide band of GDP outcomes as the forecast period increases. It reflects a view that the effect of economic shocks persist and that there will be increasing uncertainty about the level of GDP as the forecast period moves further into the future.

3.5 This provides a rather stylised and smoothed view of the GDP path in the future, but does ensure energy demand does not dip or blip, due to assumed recessions or booms in the economy.[3]

Table 3.2 Possible Low, Central and High GDP Growth Rate Scenarios

% pa

	2001–2005	2006–2020
Low	2.00	1.75
Central	2.50	2.25
High	3.00	2.75

3.6 These GDP growth paths then have to be allocated to each of the sub-sectors that comprise the model. This is particularly important due to the very different energy intensities in the service, domestic and industrial sectors and within the industrial sectors themselves. The assumptions about how the GDP growth is allocated must be consistent with assumptions of growth in overall GDP and energy prices under our six scenarios. There are thus six separate industrial share projections, one to match each combination of GDP and energy price scenario.

2 *Pre-Budget Report*, November 1999.

3 Although the typical path followed by GDP is cyclical our assumption is that, in the long-term, GDP follows a smooth trend growth path.

3.7 The industrial and service sector share projections were based on analysis by Oxford Economic Forecasting (OEF) using the 1998 version of their UK industry model. This breaks down UK industry and services into 27 sectors, with more limited detail on a further 43 sub-sectors, and is based on an input-output matrix of the interactions between these sectors.

3.8 The main OEF model is not currently used to forecast beyond 2010. To project beyond 2010, OEF assumed that industries will have adjusted to their long run growth paths by 2010 and will continue on these paths (although some cases have had their growth rate adjusted downwards where the extrapolation of rapid growth looks implausible over such a long period). This may appear a strong assumption, but it is consistent with a scenario approach that produces projections on the basis of a continuation of current trends and patterns.

3.9 The central projections produced by OEF include a set of judgements regarding the likely growth paths of the various industries which is used to adjust the OEF model output, as is normal in economic forecasting. These judgements are made by industry experts about the *world level* prospects for the various sectors.

3.10 The different GDP growth paths are assumed to be generated in the main by differences in the growth of international trade. This will affect domestic GDP both through aggregate demand and by changes in consumption demand, investment and productivity that can potentially shift the aggregate supply curve. The manufacturing sector, being the most 'open' to international trade, will benefit most from high export growth and lose most from low growth. Those parts of the service sector that depend on manufacturing will also be affected but the prospects for non-marketed services are similar across all growth scenarios.

3.11 Under the varying long-term energy price projections the high temperature energy intensive sectors, i.e. non-ferrous metals, iron and steel and chemicals, have lower growth for higher energy prices. Because overall GDP growth remains the same this means that the non-energy intensive sectors such as food and drink, and most of the service sector, must grow faster. Nevertheless, the effects of energy price variation seem relatively small. For example, the chemicals industry is projected to grow by 30% between 1995 and 2010 under the Central Low scenario as against 26% in the Central High. Table 3.3 shows the level of output assumed for 2010 in each sector under the CL and CH scenarios. All sectors are equal to 100 in 1995.

Table 3.3 Output by Sector in 2010

1995=100

Sector	CL	CH
Services	153.0	153.0
Iron and Steel	105.3	101.7
Non-Ferrous Metals	119.2	117.4
Engineering with Vehicles	151.6	147.9
Mineral Products	115.0	113.9
Chemicals	129.5	125.7
Food, Drink and Tobacco	118.7	121.7
Textiles, Leather and Clothing	81.9	81.1
Paper and Packaging	138.3	137.3
Construction with Other Industries	129.2	129.8

Energy Price Assumptions

3.12 Energy price assumptions play a pivotal role in the demand models. In the main scenarios two states of the world are assumed, one characterised by high energy prices, the other characterised by low energy prices.

3.13 The price of crude oil is the main exogenous price variable, because gas and coal prices are assumed to be influenced, at least in part, by the oil price (this reflects the nature of the markets for these fuels). The future path taken by oil prices is impossible to forecast, so the approach taken is to identify a set of plausible scenarios for the factors that determine prices. This gives a range of price outcomes. We believe there is a low *a priori* probability that prices will move outside this range for a sustained period,[4] in the context that the projections here are very much concerned with the long-term.

3.14 The high price scenario reflects the strong demand balanced by the tight supply which has taken current oil prices to over US$30/bbl (all monetary values are in 1999 prices unless otherwise stated) in 2000. But we do not expect them to remain at that level for the rest of the projection period. The high price scenario sees a gradual return to a sustainable high of US$20/bbl (1999 prices) by 2005 and remaining at this level thereafter (see Table 3.4). In the low price scenario demand growth is met by plentiful supply and oil prices drop to US$10/bbl by 2005, remaining constant thereafter.

3.15 The oil price has, of course, been on an upward trend since February 1999 and has been above our long-term high assumption of $20 a barrel for around a year. A downturn is expected with futures markets showing an oil price back close to our long-term high assumption in the second half of 2001. This price is inherently uncertain, however, and sensitivity of emissions to the oil price remaining very high for longer than in our central scenarios is considered in Chapter 8.

4 This does not mean that the price will not move outside the range for some periods. Indeed, the oil price is currently above our modelling range for the longer-term.

Table 3.4 Crude Oil Price Assumptions

1999 prices

	Low $US/bbl	High $US/bbl
1999	18.0	18.0
2000	24.0	27.0
2005	10.0	20.0
2010	10.0	20.0
2015	10.0	20.0
2020	10.0	20.0

3.16 Building on these assumptions, the final consumer prices for each energy using sector are then determined by adding the appropriate rate of duty and tax, if any, and assumed margins for wholesale, distribution and retail costs. Table 3.5 contains the High and Low Transport price assumptions, while Table 3.6 presents the High and Low price assumptions for gas oil, HSFO and LSFO. (Prices for 2000 are based on first half year statistics).

Table 3.5 Road and Air Transport Petroleum Price Assumptions

1999 prices

	Jet Kerosene		4 Star/LRP		Unleaded		DERV	
	Low p/litre	High p/litre	Low p/litre	High p/litre	Low p/litre	High p/litre	Low p/litre	High p/litre
1999	11.0	11.0	77.8	77.8	70.6	70.6	73.1	73.1
2000	16.0	16.0	84.9	84.9	78.8	78.8	79.4	79.4
2005	7.1	12.6	74.6	80.5	68.2	74.2	69.1	74.9
2010	7.1	12.6	74.6	80.5	68.2	74.2	69.1	74.9
2015	7.1	12.6	74.6	80.5	68.2	74.2	69.1	74.9
2020	7.1	12.6	74.6	80.5	68.2	74.2	69.1	74.9

Table 3.6 Water Transport and Other Petroleum Price Assumptions

1999 prices

	Water Gas Oil		Industry Fuel oil		Domestic Petroleum		Service Petroleum	
	Low p/litre	High p/litre	Low p/litre	High p/litre	Low p/litre	High p/litre	Low p/litre	High p/litre
1999	12.6	12.6	9.0	9.0	12.8	12.8	11.2	11.2
2000	18.5	18.5	12.0	12.0	14.3	15.6	12.2	13.3
2005	11.0	16.0	7.0	10.2	10.4	15.5	8.8	13.0
2010	11.0	16.0	7.0	10.2	10.4	15.5	8.8	13.0
2015	11.0	16.0	7.0	10.2	10.4	15.5	8.8	13.0
2020	11.0	16.0	7.0	10.2	10.4	15.5	8.8	13.0

3.17 Table 3.7 below, presents the underlying ARA (Amsterdam-Rotterdam-Antwerp) coal price assumptions. The international coal price has moved up quite sharply over the past year, but has not reached the levels of the mid-1990s. In the future, prices seem more likely to fall than to rise from current levels and the high and low scenarios reflect this.

Table 3.7 ARA Coal Price Assumptions

1999 prices

	Low $US/tonne	High $US/tonne
1999	28.8	28.8
2000	31.8	37.1
2005	26.5	42.4
2010	26.5	42.4
2015	26.5	42.4
2020	26.5	42.4

3.18 Table 3.8 presents what these ARA prices imply for delivered coal prices to industry and the service sector – excluding the climate change levy – and the domestic sector for the Low and High energy price scenarios. Again an assumed exchange rate, margin for transport and wholesale and retail costs are used to derive these consumer prices.

Table 3.8 Delivered Coal Price Assumptions

1999 prices

	Industry		Service		Domestic	
	Low p/therm	High p/therm	Low p/therm	High p/therm	Low p/therm	High p/therm
1999	11.8	11.8	16.6	16.6	55.4	55.4
2000	12.5	13.8	17.3	18.6	56.1	57.4
2005	11.1	14.9	15.9	19.6	54.7	58.4
2010	11.1	14.9	15.9	19.6	54.7	58.4
2015	11.1	14.9	15.9	19.6	54.7	58.4
2020	11.1	14.9	15.9	19.6	54.7	58.4

3.19 The delivered gas price assumptions are based on an underlying gas price (the beach price) of 14p/therm in 1999 (1999 prices). The Low energy price scenario sees prices remaining at approximately 11p/therm to 2010 and thereafter. The High energy price scenario assumes prices rise to 23.4p/therm in 2010 and holding at that level thereafter.

3.20 The domestic gas price is then derived by projecting a market share for British Gas (Centrica) and its assumed competitors based on assumptions about the differing gas costs and non-gas costs for each. Costs are eventually assumed to converge and hence market shares stabilise. The industrial and service sector prices are determined by assuming the shares of each sector on Tariff, Firm or Interruptible contracts, and combining these with projections of the prices under each of these contracts. The resulting prices excluding any climate change levy are presented in Table 3.9.

Table 3.9 Delivered Gas Price Assumptions

1999 prices

	Industry		Services		Domestic			
					400 Therms pa		800 Therms pa	
	Low p/therm	High p/therm	Low p/therm	High p/therm	Low p/therm	High p/therm	Low p/therm	High p/therm
1999	15.2	17.4	20.7	22.6	48.7	53.0	44.5	48.4
2000	12.3	16.6	17.8	21.5	44.9	51.2	41.0	46.7
2005	12.3	22.1	17.6	26.5	44.3	58.8	40.5	53.7
2010	12.3	24.3	17.6	28.5	44.2	62.0	40.4	56.6
2015	12.3	24.3	17.6	28.5	44.2	62.0	40.4	56.6
2020	12.3	24.3	17.6	28.5	44.2	62.0	40.4	56.6

CHAPTER 4

Projections of Final Energy Demand

- **Strong energy demand growth in the domestic, transport and service sectors**
- **Strongest growth in transport sector**
- **Lower energy demand growth to 2010 in the industry sector than previously projected**
- **The share of DERV fuel in the transport sector is expected to flatten off**
- **Increase in the share of aviation fuel in the transport sector**
- **The share of gas in the domestic sector is now projected to be lower**

4.1 This chapter summarises the projections for the main final user sectors and compares these with previous projections published in Energy Paper 65 (EP65). Charts 4.1 and 4.2 below illustrate the projected change in demand share of the four sectors in 2010 compared with 1995. The projected demand share is similar for both the central high and central low price scenarios.

Chart 4.1: Actual 1995 Final Energy Demand by Sector

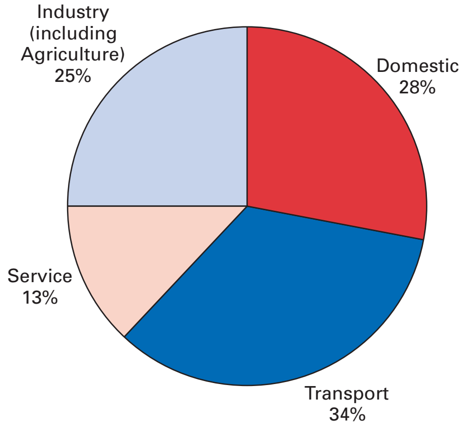
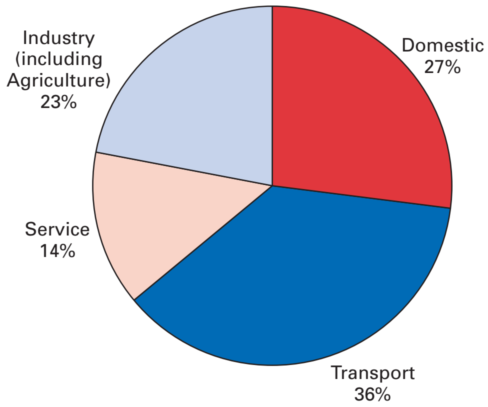


Chart 4.2: Projected 2010 Final Energy Demand by Sector



NB: Agriculture is included with Industry and contributed less than 1% to current and projected energy demand

THE DOMESTIC SECTOR

Table 4.1 Final Energy Demand, Domestic Sector

CL				Mtoe		% pa growth
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	45.4	45.4	46.1	46.6	0.2	0.3
EP68	42.7	45.8	47.9	49.5	1.0	0.8
CH				**Mtoe**		**% pa growth**
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	44.9	44.6	45.1	45.4	0.1	0.2
EP68	42.7	45.1	46.1	47.0	0.6	0.4

4.2 Under both the Central Low and Central High scenarios energy demand grows much faster in our current projection than in EP65.[1] In general, it now appears that too little weight was given in EP65 to the underlying trends, which point towards continued increases in energy use per household and growth in household numbers including the effects of greater numbers of people living alone. On the other hand, there are also indications that external temperatures are increasing and this will offset some of the increased energy demand. Our core scenarios include an increase in external temperatures in line with Met Office projections. In this context, it is worth remembering that about 80% of domestic fuel is used for space and water heating. The sensitivities of core scenario assumptions in temperature and number of households are examined in Chapter 8.

1 In this chapter values for EP65 are projections. 1995 values for EP68 are actuals as reported in Digest of UK Energy Statistics 2000.

Table 4.2 Fuel Mix, Domestic Sector

CL				%
	1995	2000	2005	2010
Electricity	21	21	23	24
Gas	66	69	69	68
Oil	7	7	7	7
Solid Fuel	6	3	1	1

CH				%
	1995	2000	2005	2010
Electricity	21	21	23	24
Gas	66	68	68	67
Oil	7	8	7	8
Solid Fuel	6	3	2	1

4.3 If we compare with EP65, the main difference is that the share of oil as a domestic fuel for space and water heating is now expected to be much more significant than was previously thought. This reflects recalculation of the equations based on a longer data set and econometric revision. The share of gas is now projected to be lower.

Table 4.3 Fuel Mix, Domestic Sector, EP65

CL (EP65)				%
	1995	2000	2005	2010
Electricity	19	19	20	20
Gas	66	71	73	75
Oil	6	3	2	2
Solid Fuel	9	7	5	3

THE TRANSPORT SECTOR

4.4 Compared with EP65, the growth in transport energy use is very similar – just under 2% per annum in CL, a little lower in CH.

Table 4.4 Final Energy Demand, Transport Sector

CL				Mtoe		% pa growth
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	52.9	57.5	62.7	69.0	1.8	1.8
EP68	50.2	55.0	61.1	66.6	1.9	1.9

CH				Mtoe		% pa growth
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	52.4	55.9	59.7	64.8	1.4	1.5
EP68	50.2	55.0	59.6	64.9	1.7	1.7

4.5 Despite the impact of measures such as previous annual real terms increases in the rate of road fuel duty, changes to other assumptions (such as underlying oil prices and the assumed increase in real personal incomes and total final expenditure: key variables in transport sector modelling) tend to make for a steady rate of growth in the baseline. This will be moderated by measures in the transport sector, most importantly the Voluntary Agreements to improve fuel efficiency discussed in paragraphs 4.9 and 4.10 below.

Table 4.5 Fuel Mix, Transport Sector

CL				%
	1995	2000	2005	2010
Motor Spirit	49	43	39	38
DERV	29	33	35	35
Aviation Fuel	17	20	22	24
Other	5	4	4	3

CH				%
	1995	2000	2005	2010
Motor Spirit	49	43	40	39
DERV	29	33	35	35
Aviation Fuel	17	20	21	23
Other	5	4	4	3

4.6 In both scenarios the share of DERV in road fuel is expected to flatten off post 2005. This contrasts with EP65 where the DERV share was expected to continue to increase over the forecast period. The most significant feature of the transport sector projections is the increase in the share of aviation fuel under both price scenarios. Recent increases in aviation demand have been adding around 0.5 million tonnes of oil equivalent per annum to overall transport use. This includes international as well as domestic aviation. The fuel mix in the EP65 CL scenario is reproduced below for comparison.

Table 4.6 Fuel Mix, Transport Sector, EP65

CL (EP65)				%
	1995	2000	2005	2010
MSP	53	48	42	39
DERV	26	30	34	36
Aviation Fuel	16	18	20	22
Other	5	4	4	3

An Alternate Price Response

The long run price elasticity of road fuel demand in our current model has been estimated at -0.23. Because of the uncertainty surrounding this estimate and the importance of this figure for projecting the carbon savings resulting from application of the fuel duty strategy to date, we have considered the implications for future carbon emissions if the EP65 elasticity of -0.4 were to be imposed on the model.

Table 4.7 Road Transport CO_2 Emissions

						Million Tonnes of Carbon
	1995	2000	2005	2010	2015	2020
Unrestricted Elasticity	30.2	32.0	35.0	37.6	40.1	42.6
Restricted Elasticity	30.2	31.5	33.6	36.5	39.0	41.4

The Government has said that the appropriate level of fuel duties will in future be decided on a Budget by Budget basis. The above results in terms of emissions from road transport are derived under the assumption that fuel duty is maintained at the current level in real terms. Underlying fuel prices are our low scenario and the GDP growth assumption is the central path. The implication is that, in 2010, carbon emissions would be 1.1 million tonnes lower if the price elasticity of road fuel demand was -0.4 rather than the -0.23 estimated within the model.

4.7 Road transport emissions have become a very significant share of total emissions, are projected to be a fast growing sector in terms of GHG emissions and affect local air quality. A number of policy measures have recently been announced to increase the incentives to manufacture, buy and drive low emissions vehicles and reduce the environmental impact of road transport. These measures are not included in the baseline but two of them are discussed below. Nor do these projections incorporate the potential impact of the Government's 10 Year Plan for transport in which there is allowance in the Climate Change Programme.

4.8 The projections do not allow for announcements in the 2000 Pre-Budget Report. It was announced that fuel duty would be frozen in cash terms in Budget 2001. Consideration is to be given to increasing the current 1 pence per litre differential between Ultra Low Sulphur Petrol and standard unleaded by a further 2 pence per litre. The duty rate on Ultra Low Sulphur Diesel would then be reduced by 3 pence per litre. These measures can be expected to produce a small increase in demand for road fuels. The Government believes that any increase in carbon dioxide emissions from the road transport sector as a result of these changes will be minimal. Currently, oil prices are very high. In the longer term, Ultra Low Sulphur Petrol will allow manufacturers to introduce Gasoline Direct Injection technology, which is significantly more fuel efficient than standard petrol technology. This will therefore help support the delivery of the EU Voluntary Agreements on fuel efficiency.

Voluntary Agreements To Improve Fuel Efficiency

4.9 The European Commission have reached an agreement with the European Automobile Manufacturers Association (ACEA) which requires car manufacturers to reduce the average CO_2 emissions from new passenger cars produced in the EU to 140 grams of CO_2 per kilometre by 2008, a cut of about 25% on the current average. They will also be required to meet an intermediate target in the range of 165-170 grams by 2003. This agreement forms part of a wider strategy to reduce CO_2 emissions from new cars which was adopted by the Council of Ministers in June 1996. The Commission has also reached agreements with the Japanese Automobile Manufacturers Association and the Korean Automobile Manufacturers Association, which produce similar savings from their sections of the fleet to those agreed with ACEA.

Table 4.8 Effect of the VA on Base Case Projection

	2010
MtC (range)	-2.6 to -5.9
MtC (mid point)	-4.0

4.10 The impact of these agreements has not been included within our baseline scenarios. Instead, we have drawn on analysis undertaken by the Department of the Environment, Transport and the Regions,[2] in order to produce an estimate of the potential impact on baseline road traffic emissions by 2010, assuming the agreements deliver. This analysis points to a potential reduction in 2010 baseline road traffic emissions of between 2.6 and 5.9 MtC, giving a central estimate of 4 MtC. The

2 This work was undertaken to inform *Tackling Congestion and Pollution*, the Government's first report under the Road Traffic Reduction (National Targets) Act, published in January 2000. Copies of the report can be obtained from the Department of the Environment, Transport and the Regions, Transport Strategy Division, Zone 1/18, Great Minster House, 76 Marsham Street, London SW1 4DR, Tel: 020 7944 5192

range attached to this estimate reflects differences between our model and the DETR National Road Traffic Forecasting model used to produce it. The impact could be expected to rise over time, potentially beyond 2010, as the fuel efficiency improvements in new cars required under the agreements spread throughout the fleet.

Graduated VED and Company Car Taxation

4.11 The 1999 Budget announced further measures that would increase incentives to own and operate low emission vehicles. The rate of VED for smaller cars (engines up to 1100cc) was reduced, and plans were outlined to introduce Graduated Vehicle Excise Duty (VED) for new cars to relate VED to CO_2 emissions. In addition, the tax charges for company cars will also be graduated according to CO_2 emissions and the incentives to drive unnecessary extra business miles in order to cross mileage thresholds and thereby reduce tax charges will be removed.

4.12 These measures will help reduce CO_2 emissions and make the achievement of the efficiency target of the voluntary agreement in the UK more likely by increasing the demand for cleaner vehicles.

THE SERVICE SECTOR

4.13 The growth in energy demand in the services sector is expected to be slightly higher in these forecasts than in EP65. This seems consistent with recent experience. The service sector continues to expand quite rapidly. It appears that EP65 significantly under forecast year 2000 energy demand – partly because growth in the economy generally has been greater than assumed in EP65.

Table 4.9 Final Energy Demand, Service Sector

CL				Mtoe		% pa growth
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	19.7	20.9	22.2	23.4	1.2	1.1
EP68	20.0	22.8	23.8	24.4	1.3	0.7

CH				Mtoe		% pa growth
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	19.7	20.7	21.9	23.2	1.1	1.1
EP68	20.0	22.7	23.5	24.3	1.3	0.7

4.14 As can be seen, the pattern of fuel demand is little affected by change in fuel price between the central scenarios. Service sector energy use is dominated by the provision of building services, especially space heating, cooling and hot water provision. Lighting is the biggest single source of electricity demand. Demand has not been a strong function of energy price historically and this is reflected in the econometric relationships. But the response to permanent and pre-announced future price changes,

Table 4.10 Fuel Mix, Service Sector

CL				%
	1995	2000	2005	2010
Electricity	33	37	40	40
Gas	50	50	50	50
Oil	15	11	9	9
Solid Fuel	2	2	1	1

CH				%
	1995	2000	2005	2010
Electricity	33	37	39	39
Gas	50	50	51	52
Oil	15	11	9	8
Solid Fuel	2	2	1	1

such as those brought about by the climate change levy, might differ from the response expected from past behaviour. Given that the incentives to improve energy efficiency brought about by the levy will be reinforced by energy efficiency measures such as specialist advice and investment incentives, the effects of the levy package could well be greater than those estimated by econometric means using past data and relationships.

4.15 The fuel mix for the CL EP65 scenario was:

Table 4.11 Fuel Mix, Service Sector, EP65

CL (EP65)				%
	1995	2000	2005	2010
Electricity	36	40	40	39
Gas	42	47	50	52
Oil	19	13	10	9
Solid Fuel	3	1	1	1

4.16 EP65 underestimated the prevalence of gas in 1995 as compared to oil.

THE INDUSTRY SECTOR

4.17 The Industry sector comprises the manufacturing sectors included as “Other Industry”, “Iron & Steel” and Agriculture. The current projections are for lower energy growth in this sector. Despite lower energy prices, changes in the structure of “other industry” has caused it to become less energy-intensive. The climate change levy – even excluding the potential impact of negotiated agreements, which we have not allowed for – also acts to reduce demand post 2001.

4.18 Although 1995 energy use was higher than envisaged by EP65, the growth to 2010 is projected to be much lower.

Table 4.12 Final Energy Demand, Industry Sector[3]

CL				Mtoe		% pa growth
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	38.1	42.1	45.2	45.9	1.2	0.9
EP68	39.2	39.2	40.6	41.5	0.4	0.5

CH				Mtoe		% pa growth
	1995	2000	2005	2010	1995-2010	2000-2010
EP65	38.1	40.1	42.9	43.9	0.9	0.9
EP68	39.2	40.2	40.0	40.5	0.2	0.1

4.19 The fuel mix breakdown (Table 4.13) shows that the share of electricity remains steady and that gas will see some further increase in its share at the expense of the other fossil fuels.

Table 4.13 Fuel Mix, Industry Sector

CL				%
	1995	2000	2005	2010
Electricity	25	25	24	25
Gas	36	41	40	41
Oil	20	16	17	16
Solid Fuel	17	15	16	15
Coke Oven Gas	2	1	1	1
Renewables	0	2	2	2

CH				%
	1995	2000	2005	2010
Electricity	25	25	26	26
Gas	36	41	42	42
Oil	20	16	15	15
Solid Fuel	17	15	14	14
Coke Oven Gas	2	1	1	1
Renewables	0	2	2	2

4.20 When this is compared with the EP65 fuel mix (Table 4.14), it can be seen that the latter has a smoother shift towards gas. The low level of gas prices in the mid to late 1990s were clearly unanticipated in EP65 so that the share of gas in the mix and the speed of uptake was underestimated.

4.21 Combined heat and power systems are used in industry, commercial buildings, hospitals and other public services to generate substantial quantities of electricity both for on-site use and for export to local distribution systems or the grid. These systems produce

3 EP68 1995 figure is based on DUKES 1998, rather than DUKES 2000, and includes the Iron & Steel sector's use of fuel for transformation, also agriculture.

4 As defined by the CHP Q A Programme – see www.chpqa.com

Table 4.14 Fuel Mix, Industry Sector, EP65

CL (EP65)				%
	1995	2000	2005	2010
Electricity	19	22	22	25
Gas	29	31	32	36
Oil	19	17	16	14
Solid Fuel	34	32	31	26

usable heat and power simultaneously with an overall efficiency greater than that possible if they were produced separately. CHP is also used in conjunction with community heating. The Government aims to have at least $10GW_e$ of installed capacity by 2010. This will make a substantial contribution to emission reductions.

4.22 Currently available data indicates that the installed CHP capacity has expanded from $3.4GW_e$ in 1995 to around $4.6GW_e$ in 2000. The baseline projection for 2010, taking into account the exemption of "Good Quality"[4] CHP from the Climate Change Levy, is $7.6GW_e$. This value excludes the impact of other measures in the Climate Change Programme and the further developments noted in the paragraphs below. These measures, both individually and through their interactions, are expected to increase build considerably above this baseline figure.

4.23 The Government's Climate Change Programme announced several measures to encourage the expansion of CHP. These included:

- the provision of enhanced capital allowances for Good Quality CHP
- the exemption from business rates for Good Quality CHP
- the provision for climate change agreements, giving an 80% Climate Change Levy discount, where CHP will be an important means for industries to deliver the agreed emission reductions and
- Government encouragement for the modernisation of outdated community heating systems, in conjunction with CHP where possible.

In addition to the specific measures above, CHP is also likely to be helped by changes in other areas. The government has announced that once the stricter consents policy is lifted, developers will be expected to show that they have explored opportunities to use CHP. The terms of distribution network connection for embedded generation are currently being reviewed by DTI and OFGEM. CHP technology itself is developing. There is the prospect, for example, of individual household CHP being introduced in the first half of the decade. The effects of all these developments on the future path for CHP capacity are being further considered by DTI and DETR. A consultation draft "UK CHP Strategy" discussing these and other initiatives will be published shortly.

CHAPTER 5

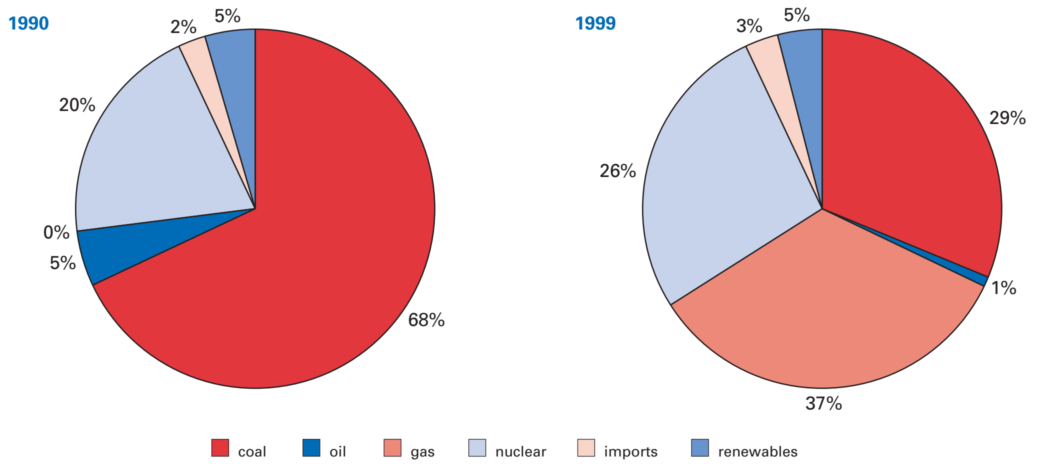
The Electricity Supply Industry[1]

- **The future pattern of generation is influenced significantly by fuel price relativities**
- **Coal-fired generation remains at relatively high levels in the high energy price cases, but declines significantly in the low energy price cases**
- **Nuclear output continues to account for a significant part of generation through to 2010**
- **Renewable plants account for 10% of generation in 2010 in accordance with government intentions; oil-fired generation is effectively zero**

BACKGROUND

5.1 The pattern of generation within the UK electricity supply industry has undergone a dramatic shift since 1990. Chart 5.1 shows the shares of generation accounted for by the various types of plant in 1990 and 1999.

Chart 5.1: Shares of Electricity Generation by Fuel, %



NB: Basis of data is electricity supply (gross) as in Table 5.5 of the year 2000 edition of the *Digest of UK Energy Statistics*. Note that the data for imports includes pumped storage output.

5.2 Coal's share of generation fell particularly rapidly after 1992 to around 29% in 1999. Coal's share of generation has increased in the early months of 2000 mainly as a result of significant reductions in the output of nuclear plants and lower imports of

1 Note that the ESI is defined here as including those companies whose main business is to supply electricity together with those 'industrial' generators using renewables as a source of power. There are numerous other companies who also generate electricity, but whose main business is not electricity supply. Some additional generating plants (usually in CHP form) are being built by these companies. Such plants are modelled as part of the industrial sector.

electricity from France. The increase in coal-fired generation is not expected to persist and in all cases examined, at least some reduction in coal generation is expected. The share of gas in generation was virtually zero in 1990, but rose rapidly after 1992 to reach 37% in 1999. There has also been steady growth in nuclear output, with nuclear's share of generation rising from 20% in 1990 to 26% in 1999. Other notable recent developments include the virtual disappearance of oil in generation as a result of high fuel oil prices, partly brought about by real increases in fuel oil duty.

5.3 The causes of these changes in the generation mix are already well documented. Privatisation of the generation part of the industry was accompanied by significant technological advances in electricity generation, particularly in the field of combined cycles. Such technological progress, together with a steady decline in gas prices for industrial users and low combined cycle hardware costs, encouraged a swift increase in the uptake of such plant.

5.4 The combined cycle gas turbine (CCGT) stations built in the UK in the early 1990s benefited from high efficiencies relative to existing coal plants. The early generation of CCGTs operated at an efficiency of around 45%.[2] The efficiency of more recent vintages of CCGT has increased significantly, with the latest UK plants exceeding 50%. Existing coal plants, partly as a result of programmed station upgrading, have been operating at around 36% efficiency. A trend towards lower gas input prices (though not necessarily lower than coal prices on a common unit of energy basis) reinforced the operating cost advantage of CCGTs over coal, added to by the lower sulphur and other emissions from CCGTs. CCGTs have, therefore, been highly competitive against existing coal plant, notwithstanding improvements in the technical efficiency of existing coal generating plants and significant reductions in both internationally traded and UK produced coal prices. Thus, in general, new CCGT plant has operated essentially at baseload displacing existing coal-fired generation.

5.5 At least some of the build of CCGTs was no doubt due to a desire on the part of the regional electricity companies (RECs) to diversify their sources of electricity, or in some cases, simply to establish a foothold in the electricity generation market. But at issue for most of the 1990s has been the degree to which the large scale construction of CCGTs has been caused by uncompetitive electricity generation and wholesale markets. Wholesale electricity prices appeared to remain above, sometimes well above, the long run marginal cost of new generation.

5.6 The Government announced a 'Review of Energy Sources for Power Generation' in December 1997 and at the same time deferred decisions on consents and clearances needed for the construction of gas-fired power stations. The main conclusions of the Review were confirmed in the White Paper published in October 1998.

2 Based on gross calorific values. The *Digest of UK Energy Statistics* reports that average CCGT efficiency in 1999 was 46.4%.

5.7 The White Paper's main points were that there did indeed appear to be distortion in the electricity market, in two areas:

- distortions in the wholesale electricity pool which have affected competition between different fuels encouraging new plant to enter the market and
- inadequate competition in coal-fired generation, leading to higher than necessary wholesale electricity prices also encouraging entry of new plants.

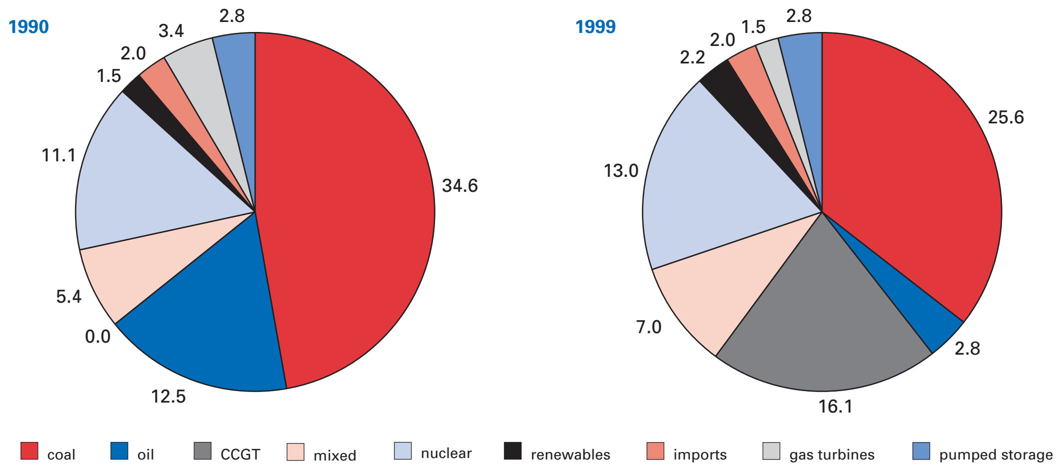
5.8 While reforms to address these distortions were put in place the Government announced a stricter approach to consents for power stations as part of which new natural gas-fired capacity would normally be seen as inconsistent with wider energy policy. The restrictions on new plant consents will be lifted once the programme of reforms set out in the White Paper is substantially complete. In the long run, which is the main focus of the work reported here, a competitive electricity generation and wholesale market can be assumed.

MAIN ASSUMPTIONS

Plant Closures and Plant Construction

5.9 In the near term the amounts of coal, oil and gas-fired capacity on the system are virtually fixed. Closure of some of the remaining older, less efficient plants or sets are possible, though not on a scale sufficient to alter the short-term outlook significantly. Some of the CCGTs which are already under construction will be generating by the end of the year 2000, although the length of the commissioning process makes it likely that these stations will not achieve their expected maximum output until at least 2001.

Chart 5.2: Power Station Capacity, GW[3]



NB: 1999 figures extracted from Table 5.7 of the *Digest of United Kingdom Energy Statistics*, 2000

3 Comprises the capacity of the major power producers and renewables capacity in other sectors.

5.10 At present, a significant number of CCGT projects await consent. However, it is far from certain that all those projects would actually proceed if given consent. Following relaxation of the stricter consents policy, we could expect at least some projects to be re-evaluated in the light of new market conditions. When considering oil-fired capacity, it appears that some plant is being kept open despite very low loadings, perhaps because there is a desire by generators to maintain an alternative to coal and gas-fired generation. In the longer term, the profile of plant closures will be determined mainly by the age of the plant concerned – as a proxy for the effects of wear and tear on plant equipment and the economic potential for plant refurbishment.[4] New capacity will therefore be required to meet both closure of existing plants and the projected growth in electricity demand.

5.11 Chart 5.2 shows the breakdown of plant capacity in 1990 and 1999. Pure coal-fired capacity has fallen by around 9GW, although 2GW of this is due to Didcot having converted to dual-firing capability (coal and gas) during the period. CCGT capacity has grown from zero in 1990 to 16GW at the end of 1999.

5.12 In view of the discussion above it is difficult to be at all certain about the remaining lifetimes of existing coal and other plants. The approach taken in the projections has been to use the power station model to offer guidance as to whether it would be economic to maintain existing plant on the system. Thus the composition of generating capacity will vary according to the background economic assumptions. For example, coal-fired capacity is more likely to survive over a longer period in the high energy price scenario – in which coal prices are more favourable relative to gas prices – than in the low energy price case. Experience in other parts of the world and evidence from the UK suggests that there could be some coal plants which in an engineering sense could physically be able to remain in operation until 2020 or so, perhaps longer if plant re-powering were to be carried out.

5.13 Amongst the various other assumptions made, an important one for CO_2 purposes relates to prospective nuclear capacity. On balance, the longevity of any given nuclear plant is likely to be determined more by technical than economic factors. The extent and cost of work required to maintain safe operation, the first priority, is likely to vary considerably from station to station, and over time. For the main ESI projections we

4 It is worth noting also the potential impact of forthcoming European Legislation. The remaining operating lives of unabated coal and oil plants will now be influenced by the agreement, as part of a revision to the existing Large Combustion Plant Directive, that such plants will operate for no more than 20,000 hours beyond 1st January 2008. Clearly the operation of such plants will also need to be consistent with the UK's current emission limits, such as those determined by the Environment Agency. There will also be potential pressures on the electricity generating sector as a result of the UK's commitment, under the National Emissions Ceiling Directive, to reduce sulphur dioxide emissions to a maximum of 585 kilotonnes in 2010. These issues are also discussed in Chapter 7 and paragraphs 5.19 to 5.23 below.

employ a single view of future nuclear capacity and output. Illustrative sensitivities on the output from nuclear plants are discussed in Chapter 8. The main assumptions on nuclear electricity are believed to be broadly in line with industry views. The recent announcement by BNFL concerning the lifetimes of Magnox plants establishes a framework for considering prospects for this particular type of plant. The assumptions for nuclear capacity in this report are consistent with BNFL's announcement.

5.14 The Government is committed to ensuring that the contribution from renewables increases over time. Existing NFFO and equivalent orders made to date, plus supply from existing large hydro, mean that electricity supply from renewable plants is broadly on track to reach 5% of total generation by 2003. Following the recent policy announcement on renewables, which provides for a new supply obligation, the share of generation accounted for by renewables is assumed to be 10% in 2010 and is maintained at that level beyond. The Government is consulting on the acceptability of the price increases needed to achieve a 10% target and has also said that the obligation mechanism will contain a price cap which will act to limit the cost to consumers should an expansion of renewables prove more expensive than currently thought. At this stage there is little indication of the likely composition of the additional renewables generation required although it seems likely that a sizeable contribution from wind power will be needed.

5.15 In line with current policy new renewables are modelled as being exempt from the climate change levy.

Assumed Consent Policy

5.16 The impending removal of restrictions on consents should allow sufficient time for new plant to be built in order to operate for the whole of 2005.

New Electricity Trading Arrangements

5.17 The Government's reform of the electricity market will ensure a level playing field between fuels, but it seems probable on most scenarios that coal use in generation will continue to decline in the longer term. The projections have been constrained such that coal provides at least a 10% share of electricity generation in 2010. This constraint reflects a likely desire by the generators to retain some hedging opportunities against risk – in relation to price movements or indeed Government policy.

Plant Costs and Performance

5.18 The modelling work described here embodies assessments of future plant costs and efficiency. It is possible that future plant costs and performance, in part influenced by current research and development activity, could be different to those assumed here. For example, the construction of new nuclear power stations does not currently appear economically competitive, but various research and development initiatives are underway world-wide and it is possible that more competitive reactor design technologies may emerge. Such developments will be kept under review, alongside technological improvement in other areas of generation. It is unlikely, however, that such cost and efficiency improvements would significantly affect the outlook for 2010.

EMISSIONS ABATEMENT ASSUMPTIONS

FGD Plant

5.19 In England and Wales, it is assumed that FGD equipment is fitted and operating at least until 2010 at Drax, Ratcliffe and West Burton in all scenarios. The same basic assumption is made with respect to the Longannet power station in Scotland, which is assumed to have at least some sea water based scrubbing equipment fitted. In Northern Ireland, the prospects are less clear at Kilroot, where there seem to be a number of potential options. Until the situation becomes clearer and purely for working purposes, it is assumed that Kilroot continues operation in its current form. The environmental authorities in both Scotland and Northern Ireland are working with companies on longer term emission limits.

5.20 The operation or otherwise in 2010 of other coal-fired stations with FGD is dependent in some cases on the prevailing energy price scenario and in others on decisions by the Environment Agency, principally in the light of European legislation. The Environment Agency's (EA) March 1999 proposals, and subsequent December 1999 decisions, on sulphur controls for the period up to 2005 provide some incentives for the construction of further FGD. It seems likely that these incentives are encouraging further FGD build.

5.21 It is further assumed that FGD equipment is operated as effectively as possible subject to the modelled loading on the plant concerned. In line with the emphasis in the White Paper, and reflecting the EA's recent decisions, it is assumed that in the early years of this century, FGD plants are run in preference to unabated plants within a company's portfolio. In the longer term, emissions from, and therefore the operation of, unabated coal plants will partly be determined by EA guidance, based on the principles of IPPC, as well as other influences.

Low-NO_x Burners

5.22 In line with company plans virtually all major coal plants are assumed to have been fitted with low NO_x burners by 2000.

Environment Agency Emission Limits

5.23 Under EA plant authorisations ESI plant operators are required to pursue a programme of improvements to the environmental performance of their existing plants. In the period during which these projections were being prepared the EA issued a consultation document on future emission controls in the industry. Subsequently, in December 1999, the EA issued its decision document. The overall limit for 2005 remains at the level (365kt SO_2) previously indicated and this limit has been imposed in the modelling process.

MODELLING RESULTS

5.24 Electricity demand is projected to rise steadily throughout the projections period requiring substantial additions to generating capacity. In the CL case, electricity supply to the grid[5] is estimated to grow by around 1¼% per annum between 2000 and 2010. In the CH case, growth is lower at around 0.8% per annum. This compares with a projected growth of about 0.9% per annum over the period 1999/00 to 2006/07 reported in the year 2000 Seven Year Statement (SYS) issued by the National Grid Company (NGC).[6]

5.25 Perhaps the most important influence on the projections is the relative price of coal and gas in the energy price cases. Compared with the low energy price assumptions, gas prices in the high energy price case rise by more than coal prices. This means that coal is more competitive with high energy prices than it is with low energy prices.

5.26 In scenario CH, coal-fired capacity continues to decline over the period to 2010 – on average coal's competitive position deteriorates through time as more efficient gas stations come on stream to meet growth in electricity demand. But a number of coal plants are able to compete effectively and achieve respectable annual load factors. By 2015, however, even the most recently constructed coal plant will then be over 40 years old.

5.27 CCGT capacity rises to around 18GW by the end of 2000, increasing **in the CH case** by a further 6GW by 2005 and another 8GW by 2010. The relatively slow growth in CCGT capacity beyond 2000 partly reflects the increase in renewables capacity. There are two other features worthy of note. Nuclear capacity declines steadily after 2005 while there is an apparent need for gas turbine peaking plant to be built, with about 1GW being built between now and 2010. Total GT capacity is flat over this period, due to closures of existing oil based GT capacity.

5.28 **In the CL scenario**, coal capacity falls more quickly between 2000 and 2010 than in CH. In this case even the best coal plants face difficulty in competing against CCGTs. It is unlikely that numerous coal plants could remain on the system while running at low load factors. The view taken here is that the general wear and tear on plant

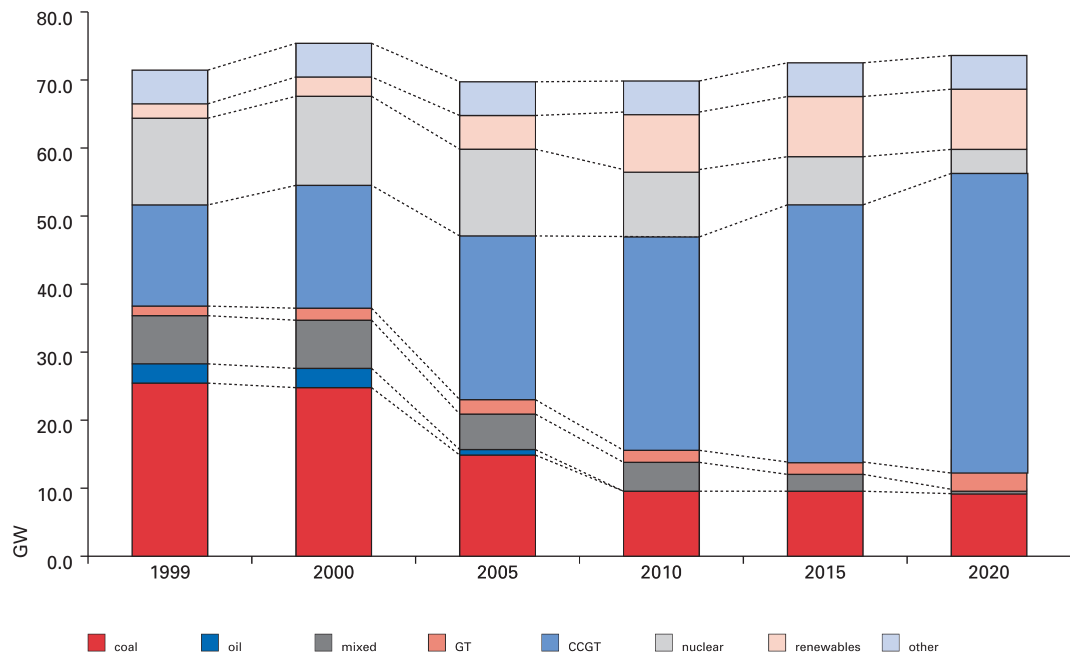
5 The data includes the output of the major power producers and those 'industrial' generators using renewable sources of energy. The figures also include imports of electricity from France and pumped storage output. All data is on a gross supply basis (see the memo to Chart 5.1, Section 5.1).

6 The SYS covers the England and Wales system only.

resulting from intermittent operation and anticipation of further market openings by new entrants would lead to more CCGT build.

5.29 Capacity and fuel use projections vary somewhat according to scenario. Gas commands a much higher share of capacity and generation than other fuels in the low energy price cases, whereas coal is better placed in the high price cases. This result is not particularly sensitive to the economic growth assumption. Chart 5.3 shows the evolution through time of plant capacity by plant type in the CH case. Further details are given in Annex G.

Chart 5.3: UK Generating Capacity, GW, CH[7]

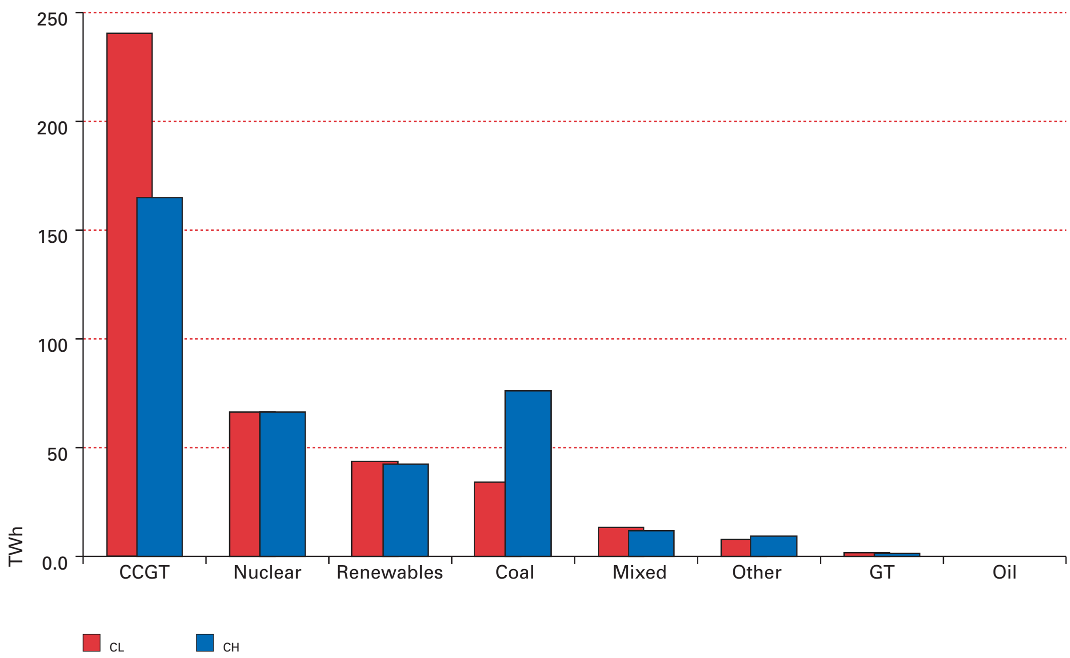


5.30 Pure coal-fired capacity – as opposed to coal plant with mixed firing capability – is just over 4GW lower in 2010 in CL than in CH. There is a large difference in the amount of **generation** in these two cases. The table in Annex D shows generation by fuel type for the CL and CH cases. Chart 5.4 below shows a comparison of CL and CH generation patterns for 2010 only. The relativity between coal and gas generation costs are such that in CH, coal plants can operate at low-medium (typically unabated plant) to medium high (typically FGD plant) load factors. Generation from coal combustion in 2010 is 45TWh lower in CL than in CH, while gas-fired generation is around 63TWh higher in CL than in CH. The assumptions

7 This chart follows the conventions used in the *Digest of United Kingdom Energy Statistics*, Table 5.7. One implication of this treatment is that there is a small amount of normal coal firing capacity included within the mixed-fired total. Such plants have the in-built capability of firing on at least one alternative fuel. In the projection for 2010, the amount of normally coal firing capacity within the mixed firing category is around 3GW. The 'other' category is composed of the capacity of pumped storage plants and the French/UK interconnector.

underlying the low energy price cases suggest that there would be very significant competitive pressures on all coal stations, including those with FGD. The projected amounts of FGD capacity are shown in Annex G.

Chart 5.4: UK Power Station Output in 2010, TWh, CL and CH[8]



5.31 Oil-fired generation is projected to be very low – some oil capacity is assumed to be retained in the short-term only, mainly for diversity reasons. Renewables capacity and output is very similar in CH and in CL, reflecting the obligation that they contribute an assumed 10% share of generation.

5.32 In the projections there are indications of a continuing role for coal for some time, particularly in the high energy price scenario. There is little indication, however, that the construction of new coal plants is an economic option given the assumptions employed. The uncertainties do, however, increase the longer ahead we look.

The Demand for Fuels

5.33 Fuel use by type of fuel in CL and CH are shown in Tables 5.1 and 5.2 below. Units are million tonnes of oil equivalent, as in DUKES Table 5.2. In CL, gas forms 52% of total fuel inputs in 2010, coal 12%, nuclear 22% and renewables 13%.

5.34 In CH, gas forms 38% of total fuel inputs in 2010, coal 25%, nuclear 22% and renewables 14%.

8 This chart follows the conventions used in the *Digest of United Kingdom Energy Statistics*, Table 5.7. One implication of this treatment is that a small amount of generation from normally coal firing capacity is included within the mixed-fired total. Such plants have the in-built capability of firing on at least one alternative fuel. In the projection for 2010, the amount of generation from normal coal firing capacity which is included within the mixed firing category is between 7 and 8TWh in the CL and CH cases. Generation by fuel is shown in Annex D.

Table 5.1 Projected ESI Fuel Use, CL

CL:	Mtoe					
	1999	2000	2005	2010	2015	2020
Coal	24.2	25.1	12.7	9.0	7.2	5.9
Oil	0.8	0.7	0.5	0.4	0.4	0.4
Gas	24.2	25.5	34.3	39.8	46.4	50.7
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	1.8	1.8	4.6	9.8	9.8	9.8
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	74.9	74.8	75.0	76.3	74.4	73.9

Table 5.2 Projected ESI Fuel Use, CH

CH:	Mtoe					
	1999	2000	2005	2010	2015	2020
Coal	24.2	25.0	22.6	19.5	17.3	11.4
Oil	0.8	0.8	0.7	0.6	0.6	0.4
Gas	24.2	24.9	24.9	29.2	35.9	42.8
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	1.8	1.8	4.6	10.5	10.4	10.4
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	74.9	74.1	75.8	77.0	74.7	72.2

DISCUSSION OF PROJECTIONS FOR INDIVIDUAL FUELS

Coal

5.35 Within the framework of a generally more competitive electricity market, and in the context of a level playing field between fuels, there is little to suggest that large scale construction of new coal-burning plants would be an economic option. The assumed level of gas prices (even in the high energy price cases) and ever increasing efficiency of gas turbine based plant make the large scale construction of new coal plants unlikely. In the high price scenario, however, existing coal plant may be able to displace some older CCGTs from baseload operation, particularly at times of year when gas prices are higher.

5.36 Coal burn in the long run is supported by the continued operation of existing coal plants. But there is considerable variation as between the low and high energy price scenarios. Coal is better placed to compete in a high energy price scenario. A risk to these projections is the possibility of further tightening of the existing emission limits – this could endanger the survival rate of existing coal plants in the early years of the century and/or lower the scale of output at surviving plants. The projections already assume that unabated coal plants are limited to 20,000 hours of operation post January 1st 2008. On the energy price assumptions employed in this analysis, prospects for the construction of new coal plants look remote.[9] It would seem from the evidence available that although integrated gasification combined cycle (IGCC)[10] plants may hold significant long-term potential, it is more likely that supercritical coal plant[11] would stand the best chance of being built – at least over the next 10 years.

Gas

5.37 In general the demand for gas rises steadily throughout the projections period in most scenarios, the rate of growth depending on the growth in electricity demand and the extent to which other fuels manage to maintain market share or make some inroads in terms of new plant construction. In the period 2000-2005, gas use in power stations rises significantly (by 35%) in the CL case. The increase in demand for gas arises from the build up of output from those gas stations which are already in the process of commissioning, or which will be commissioning before 2005, even where construction has yet to start. In the CH case, the relative prices of coal and gas are sufficiently favourable to coal to mean that gas-fired stations cannot compete as effectively as in CL with coal stations.

Oil

5.38 Oil demand is projected to remain very low over the whole projections period due to its uncompetitive price.

Orimulsion

5.39 Orimulsion is an emulsified heavy oil, produced in Venezuela. There are many other sources of heavy oils and the term Orimulsion is used here to denote all such oils. Orimulsion burn in EP65 was projected to be quite significant – the fuel oil plant Pembroke was assumed to be modified to accept the fuel. National Power subsequently withdrew its application to modify Pembroke and, while the proposal to modify Kilroot in Northern Ireland to accept Orimulsion is still under consideration, overall prospects for this fuel now look rather less good than thought at the time of the EP65 projections. Orimulsion is not projected to be used in power stations or final user sectors. It is possible however, that if market conditions were to prove attractive and various environmental concerns could be alleviated, the use of such fuels could form an important contribution to generation.

9 The energy price sensitivity analysis presented in Chapter 8 shows that alternative assumptions – even more favourable to coal than those employed in the main cases does not lead to new coal plants being more economic than new gas plants.

10 IGCC plants gasify the fuel input, which, in principle could be one of a wide range of fuels, such as coal, oil or wastes, to produce a fuel suitable for use in a combined cycle gas turbine.

11 Technological development has increasingly allowed new vintages of coal plants to operate at very high temperatures and pressures leading to higher efficiencies. This is often termed supercritical operation.

Nuclear

5.40 Given present economic assumptions, modelling suggests that no new nuclear plants will be built over the projections period. Generation from nuclear plants decline post 2000 as plants gradually retire from the system. By 2010, nuclear generation still forms a relatively high proportion of total generation – around 17 to 18% in the two central cases, compared with 23% or so in 2000. Nuclear generation falls to 7% of the total by 2020. There is further discussion of the sensitivity of emissions to nuclear retirement dates in Chapter 8.

5.41 Nuclear capacity is projected to be about 10GW in 2010, compared with a projection of 7GW in EP65.

Renewables

5.42 Renewables fuel use and capacity increase significantly in the longer term, reflecting policy measures to achieve an assumed 10% of electricity generation from renewables. Renewable fuel inputs in the low energy price cases are roughly comparable to the use of coal in 2010.

Electricity Prices

5.43 For a number of years, electricity prices to most consumer groups have fallen in real terms. The new electricity trading arrangements will have an important influence on the path of underlying **wholesale** electricity prices in the early years of the century. It is projected that in real terms, especially in the low energy price cases, underlying wholesale prices will continue to fall over the main projection period as a result of further improvements in technology, combined with continuing low levels of energy prices. In terms of **final consumer prices**, the introduction of the Climate Change Levy in 2001 will most likely result in increases to final consumer prices in the affected sectors.

Changes Compared With the Energy Projections Working Paper

5.44 Real world events have not significantly changed the projections. In terms of assumptions, the main changes compared with the Energy Projections Working Paper are:

- short-term energy prices revised up, particularly oil prices;
- longer term coal prices revised down, in both energy price cases;
- short-term nuclear output reduced;
- assumed electricity imports reduced in the long-term; and
- coal plants without FGD are restricted to a maximum of 20,000 hours of operation beyond 1st January 2008.

5.45 Broadly speaking, the projections are similar to those in the Working Paper. The greater use of coal in the high energy price cases remains and indeed is reinforced by the change to long-term coal price assumptions. Gas demand grows quickly in the low energy price cases and is higher than in the Working Paper projections, mainly due to a higher projected growth in electricity demand.

Comparison with EP65 results for 2010

5.46 The basic trends in the ESI during the second half of the 1990s accorded quite well with the projections in EP65. For the future, total power station capacity is a little lower than in EP65. One reason for this is that peak demands are now thought likely to be rather lower than in EP65. Total fuel use is a little higher in 2010 than in EP65 – total electricity demand is higher in EP68.

5.47 CCGT capacity in 2000 is very much in line with the EP65 projection, but in the longer term, CCGT capacity is now projected to be significantly higher than in EP65, partly because the cap placed upon gas use in EP65 has been replaced by the less stringent constraint which is discussed in paragraph 5.17.

CHAPTER 6

Primary Energy Demand

- **The energy ratio is projected to fall by around 1.6% per annum between 2000 and 2010 – a little more than in recent years**
- **Primary demand in 2010 is projected to be lower than in EP65**

PROJECTIONS OF PRIMARY ENERGY DEMAND

6.1 The projected primary energy demand for each scenario is shown in Table 6.1. Historic data are extracted from DUKES 2000, Table 1.9.

Table 6.1 Primary Energy Demand Projections, Mtoe

	1990	1995	2000	2005	2010	2015	2020
LL	214.9	218.7	229.5	237.7	243.4	246.3	250.8
LH	214.9	218.7	227.7	233.6	238.9	241.2	243.6
CL	214.9	218.7	229.8	239.9	247.4	252.2	258.6
CH	214.9	218.7	227.9	235.6	242.8	247.0	251.3
HL	214.9	218.7	229.9	241.8	251.3	257.8	266.2
HH	214.9	218.7	228.1	237.7	246.5	252.3	258.4

6.2 When viewing the shorter term outlook, it is important to bear in mind that the 'heating season' in both 1990 and 1995 was mild by historic standards. Indeed, most years in the 1990s have been mild by historical standards. This feature was repeated in the early months of 2000.

6.3 Between 1995 and 2010, primary energy demand increases by around 0.8% pa in CL, 0.7% pa in CH. The variation in primary demand – as between the energy price variants of the same growth case – is relatively small. The difference between the lowest and highest demand in 2010 is about 5%. The difference increases to 9% by 2020. Between 2000 and 2010, primary energy demand increases a little more slowly – by around 0.7% pa in CL, 0.6% pa in CH.

Primary Demand By Fuel

6.4 The composition of primary demand by fuel is shown in Table 6.2.

Table 6.2 Projected Primary Energy Demand by Fuel, Mtoe

CL	1990	1995	2000	2005	2010	2015	2020
coal	66.9	48.9	35.1	21.7	17.4	15.4	13.8
petroleum	78.3	75.7	73.6	79.9	85.9	91.4	97.1
natural gas	51.2	69.2	96.8	109.7	115.9	124.0	129.9
nuclear	16.3	21.2	20.5	22.0	16.9	10.3	6.9
renewables	1.2	2.1	2.9	5.6	10.8	10.7	10.8
imports	1.0	1.4	1.1	0.9	0.4	0.3	0.3
Total	**214.9**	**218.7**	**229.8**	**239.9**	**247.4**	**252.2**	**258.6**

CH	1990	1995	2000	2005	2010	2015	2020
coal	66.9	48.9	35.0	31.5	27.8	25.2	19.1
petroleum	78.3	75.7	73.8	77.9	83.8	89.0	94.3
natural gas	51.2	69.2	94.7	97.7	102.4	110.7	119.4
nuclear	16.3	21.2	20.5	22.0	16.9	10.3	6.9
renewables	1.2	2.1	2.9	5.7	11.5	11.4	11.4
imports	1.0	1.4	1.1	0.9	0.4	0.3	0.3
Total	**214.9**	**218.7**	**227.9**	**235.6**	**242.8**	**247.0**	**251.3**

6.5 Gas demand is higher in the CL scenario (and in the low cases generally) than in the CH scenario. The reverse is true for coal.

Primary Energy Ratio

6.6 Primary energy demand is projected, on our central scenarios, to grow by around 0.6-0.7% a year from 2000 to 2010. Overall, this growth in demand is lower than previously projected in EP65. It implies that the primary energy ratio (ratio of primary energy demand to GDP) will fall by around 1.6% a year between 2000 and 2010 in the CL scenario. This compares with a reduction of just over 1% a year than during the 1990s. This is consistent with the impact of policy measures such as the climate change levy, the aim of increasing the share of renewables in electricity generation to 10%, the increasing efficiency of generation in general and the need to restrain sulphur dioxide emissions.

Comparison With EP65

6.7 The EP68 projections of primary demand are generally lower than in EP65. For example, primary demand in the CL case for 2010 is now estimated at 247 Mtoe, compared with an estimate of 257 Mtoe in EP65. This is a reduction of around 4%. Similarly, projected demand for coal, oil and gas are all lower compared with EP65. In contrast use of renewables is projected considerably higher than in EP65, in line with the assumed level of the new obligation. In the CH scenario, overall demand is some 2½% lower than in EP65. Coal and gas demand in CH are both around 8 Mtoe lower than in EP65 in 2010.

6.8 Across all of the scenarios considered, the low and high ranges of the projection for 2010 are 239 Mtoe and 251 Mtoe respectively. This compares with the EP65 range of 237 Mtoe and 266 Mtoe. The reductions in primary demand would seem to be consistent with the introduction of policies as described above and occur despite the lower level of energy prices assumed.

CHAPTER 7

CO_2 and SO_2 Emission Projections

- **These projections show a significant reduction in CO_2 emissions between 1990 and 2010**
- **Much of the forecast reduction in emissions occurs in the electricity supply industry – coal use declines significantly in the low energy price cases, by much less so in the high energy price cases**
- **Emissions arising from road transport, services and the domestic sector are projected to be higher in 2010 than in 1990, but lower in industrial sectors**
- **Excluding power generation, emissions in most other sectors are either lower or little changed from EP65 levels**

BACKGROUND

7.1 The short-term forecast trend in CO_2 expected in EP65 has been largely borne out by events. Since 1995, primary energy demand has grown slowly. It is notable that the use of those fuels with relatively high carbon contents – coal and oil – has declined, while the use of gas and to a much lesser degree, renewable and nuclear energy has increased. The increase in gas use has occurred most obviously in power generation, but a significant increase has also taken place in other sectors. Some of the growth has been at the expense of other more carbon-intensive fuels, although there appears to have been new growth in the domestic and service sectors. This growth has been encouraged by favourable overall trends in the price of gas relative to other fuels.

7.2 UK CO_2 emissions in 1998 on an IPCC basis[1] were 7½% below the level of 1990. Provisional estimates for CO_2 emissions in 1999 suggest that further reductions in CO_2 have been achieved. Energy use data so far for the year 2000 suggests that emissions for the year as a whole will increase compared with 1999. Depressed output from nuclear plants has required increased generation from coal plants with a corresponding increase in the use of coal. The assessment made in compiling this report is that in overall terms emissions in the current year are most likely to be a temporary blip and emissions are expected to fall through to 2005.

1 i.e. consistent with the 1996 Revised Guidelines for Greenhouse Gas Inventories, published by the Intergovernmental Panel on Climate Change (IPCC). This is the methodology used for reporting emissions to the United Nations Framework Convention on Climate Change. The 7½% figure includes emissions from land use change. Excluding this category of emission, the fall was about 7%.

7.3 The evolution of emissions by sector between 1990 and 1998 has varied from a decrease of about 25% in power station emissions to an increase of some 6% in road transport emissions. There was also an increase in emissions from refineries, of about 13%.

7.4 The EP65 projections were not primarily intended to be used to assess the short-term outlook for emissions but they seem to have been broadly correct in their expectation of the nature and scale of emission reductions by the year 2000. A particularly significant factor here is that much of the expected uptake of gas in power stations was correctly anticipated in EP65.

7.5 From other evidence available it appears that, in the short-term, domestic, industrial and road transport emissions were overestimated in EP65 and service sector emissions underestimated. In industry the projections appear to have overestimated coal and oil use but underestimated gas use. In the residential sector overall energy demand appears to have been estimated well, with coal use overestimated, but oil use underestimated.

7.6 With hindsight the long run energy price assumptions used in EP65 now look too high. Amongst other factors, lower fossil fuel prices and reductions in gas based plant costs have tended to reduce electricity costs below EP65 levels.

7.7 External temperatures during the 1990s have been warmer than average and this paper assumes the trend to continue, as described briefly in Chapter 4, paragraph 4.2. More details are given in Chapter 8, paragraph 8.14.

EP68 CO_2 PROJECTIONS

Overall CO_2 Totals[2]

7.8 Table 7.1 below, shows projected CO_2 emissions in each of the six main scenarios, including the effects of policies which have been incorporated in the baseline.[3] Taking the average of the two central cases, a reduction in CO_2 emissions of around 7½% is expected between 1990 and 2000. The strong downward trend evident between 1990 and 1995 is expected to reduce a little, with the decrease between 1995 and 2000 around a quarter of that in the previous five years. This slowing in the rate of

2 The methodology for constructing emission totals can change somewhat from year to year. The emission projections contained within this working paper are based on the methodology at the time of writing.

3 Annex F sets out those policies which have been included. As Annex F makes clear, a number of other measures, or potential measures, including measures set out in the DETR's Climate Change Programme, are not included. It should be noted also that the data and projections in this chapter exclude emissions arising from land use change and forestry. See Annex E for summary projections including emissions from land use change and forestry.

reduction is somewhat affected by the temporary increase in emissions in the year 2000, discussed in section 7.2. Without this effect, the reduction in emissions between 1995 and 2000 would probably be around half that of the reduction between 1990 and 1995. Projected levels vary somewhat according to specific scenario, but in each case, emissions are expected to increase beyond 2005. Emissions are expected to remain below 1990 levels in all scenarios at least until 2015, while in 2020 emissions are below 1990 levels in all but the high economic growth cases.

Table 7.1 UK CO_2 Emission Projections (MtC)[4]

	1990	1995	2000	2005	2010	2015	2020
LL	159.3	149.6	147.6	143.4	144.7	148.7	151.9
LH	159.3	149.6	146.4	145.2	146.0	149.6	149.9
CL	159.3	149.6	147.8	144.9	147.5	152.9	157.3
CH	159.3	149.6	146.7	146.6	148.7	153.6	155.2
HL	159.3	149.6	147.9	146.2	150.2	156.7	162.5
HH	159.3	149.6	146.8	148.0	151.2	157.2	160.0

7.9 The projected level of emissions in any given scenario is determined by two key components. One is the overall level of energy demand, the other is the carbon intensity of demand. The fact that the high energy price cases tend to produce lower overall energy demands but higher carbon intensities means that there can be relatively little difference between the overall emissions projection for the energy price variants within a given economic growth scenario.

7.10 In 2005, 2010 and 2015, higher power station emissions in the high energy price cases are not fully offset by lower energy demand overall. In 2020, emissions are projected to be lower in the high price variant than in the low price variant. Although coal use in power stations is significantly higher in the high energy price cases, this is offset by the lower levels of energy demand which are expected in these cases.

7.11 Table 7.2 shows the projected percentage change in emissions from 1990.

7.12 In broad terms, emissions tend to fall somewhat between 2000 and 2005, but then increase beyond 2005. This contrasts with the projections in the Working Paper. Without the temporary increase in 2000, emissions would have appeared on a rising trend beyond 2000, much as in the Working Paper estimates.

4 Excluding emissions from land use change and forestry, which are not covered by DTI modelling.

Table 7.2 Percentage Changes in CO_2 Emissions from 1990

	1990	1995	2000	2005	2010	2015	2020
LL	0.0	-6.1	-7.4	-10.0	-9.2	-6.7	-4.7
LH	0.0	-6.1	-8.1	-8.9	-8.3	-6.1	-5.9
CL	0.0	-6.1	-7.2	-9.1	-7.4	-4.1	-1.3
CH	0.0	-6.1	-8.0	-8.0	-6.7	-3.6	-2.6
HL	0.0	-6.1	-7.1	-8.3	-5.7	-1.7	2.0
HH	0.0	-6.1	-7.9	-7.1	-5.1	-1.3	0.4

7.13 Direct comparison with the EP65 projections is made difficult by numerous changes to the emissions inventory methodology during the intervening years. Table 7.3 shows changes in projected emissions from the EP65 scenarios. In the longer term, the revised energy projections show an underlying significant reduction in CO_2 emissions in all six scenarios compared with the equivalent cases in EP65. On a short-term horizon however, projected emissions are quite close to the EP65 projections.

7.14 With regard to the longer term changes from EP65 projections it should be emphasised that the background economic and policy assumptions have changed considerably.[5]

Table 7.3 Absolute Changes in CO_2 Emissions from EP65

Total CO_2 Differences From EP65 (MtC):

	1990	1995	2000	2005	2010	2015	2020
LL	0.0	0.0	0.2	-14.0	-10.8	-16.1	-20.0
LH	0.0	0.0	1.9	-8.8	-7.7	-15.1	-23.3
CL	0.0	0.0	-2.5	-17.8	-14.7	-21.3	-27.3
CH	0.0	0.0	-2.3	-13.1	-12.3	-21.6	-32.8
HL	0.0	0.0	-4.2	-19.7	-17.0	-24.6	-31.0
HH	0.0	0.0	-4.2	-15.5	-13.9	-25.4	-37.6

7.15 For 2010, now the main year of interest as far as UK emission targets are concerned, emissions are projected to be around 12-15MtC below EP65 levels in the two central growth cases. Across all scenarios the reductions in emissions are typically lowest in the low growth cases and highest in the high growth cases.

5 Particularly obvious and significant policy changes include the climate change levy, generation of 10% of electricity supply from renewables, tighter emission controls on power stations by the Environment Agency than anticipated in EP65 (the changes announced in March 1996 and more recently), the agreement reached on the EC National Emissions Ceilings Directive (reducing the UK's overall maximum sulphur dioxide emission to 585kt by 2010), plus significant real increases in the level of duty on fuel oil. For a more detailed list of policies and measures included in the baseline see Annex F.

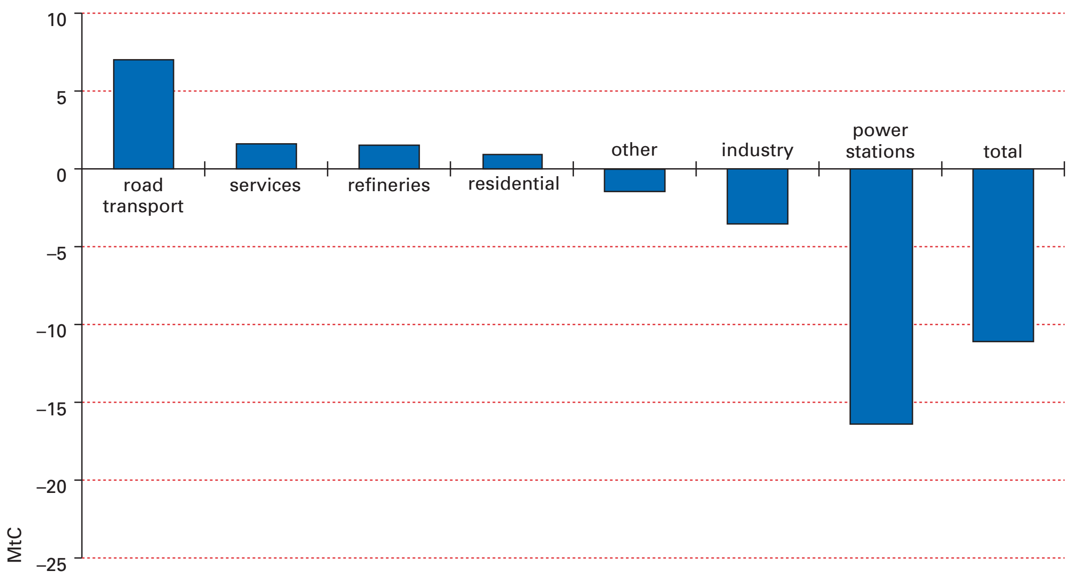
7.16 In the longer term emissions are significantly lower than in EP65 across all cases. The effect of policy changes since the publication of EP65 is a continuing influence over the latter years of these projections but it is likely that the more distant the time horizon the more the reductions in projected emissions are related to changes in the background **economic** assumptions. One of the main superficial differences between the latest projections and those in EP65 is that, whereas in EP65 IGCC plants were built to form part of generating capacity, this is not a feature of the latest projections. The lack of any build of new coal plants is largely due in the CL case to the absence of a cap on gas use such as that imposed in EP65. In the CH case, it is related to changes in assumed plant costs and relative fuel prices.

7.17 It is difficult be precise about how much of the change in emissions is due to various factors, but according to internal estimates, it is thought that policy change may account for between 50 and 75% of the change in 2010.

Projected Sectoral Trends

7.18 Changes in sectoral emissions between 1990 and 2010 are particularly striking as shown in Chart 7.1 (for the CH case). Emissions from power stations in 2010 are projected to be 17MtC lower than in 1990. In contrast, emissions in the residential, refinery, service and road transport sectors are projected to be higher in 2010 than in 1990. In other sectors, which includes waste treatment and disposal, off-road and other transport emissions, there is a small reduction from 1990 levels. A more detailed discussion of the projected emission levels in each sector follows.

Chart 7.1: Projected Emissions by Sector in 2010 compared with 1990, CH, MtC



Sectoral Analysis

7.19 The tables below show a summary of the emission projections for the CL and CH cases.[6]

Table 7.4 Emission Projections, CL, MtC

	1990	1995	2000	2005	2010	2015	2020
Power Stations	54.1	44.1	40.5	33.5	33.5	35.9	37.1
Refineries	5.1	5.9	5.1	6.1	6.4	6.6	6.6
Residential	21.5	21.7	22.5	22.7	23.1	23.7	24.3
Services	8.4	8.8	9.6	9.5	9.6	9.7	9.9
Industry	35.2	34.3	33.9	33.5	32.7	32.4	32.2
Road Transport	29.8	30.2	32.0	35.0	37.6	40.1	42.6
Off-road	1.6	1.5	1.3	1.3	1.4	1.4	1.4
Other transport	3.6	3.2	3.1	3.1	3.1	3.1	3.2
Total	**159.3**	**149.6**	**147.8**	**144.9**	**147.5**	**152.9**	**157.3**

Table 7.5 Emission Projections, CH, MtC

	1990	1995	2000	2005	2010	2015	2020
Power Stations	54.1	44.1	40.0	38.0	37.6	39.4	37.8
Refineries	5.1	5.9	5.1	6.0	6.3	6.5	6.5
Residential	21.5	21.7	22.0	21.9	22.0	22.6	23.1
Services	8.4	8.8	9.6	9.5	9.8	10.0	10.2
Industry	35.2	34.3	33.7	32.5	31.8	31.6	31.5
Road Transport	29.8	30.2	32.0	34.5	36.9	39.4	41.8
Off-road	1.6	1.5	1.3	1.2	1.2	1.2	1.2
Other transport	3.6	3.2	3.1	3.0	3.0	3.0	3.1
Total	**159.3**	**149.6**	**146.7**	**146.6**	**148.7**	**153.6**	**155.2**

7.20 In **power stations** the established trend towards lower emissions is continued through to at least 2005 in all cases. There is projected to be a continued shift out of coal-fired generation into gas, although the pace of change varies considerably by case. The need for new plant construction is reinforced from 2005 onwards by a reduction in capacity and output from nuclear plant. Although new renewables will provide some extra non-fossil fired capacity, the projected reduction in nuclear generation from 2005 to 2020 adds around 5.5MtC to annual emissions in 2020, based on the extra generation which would be required from new gas plants. In the

6 The model covers all UK CO_2 emissions from IPCC source categories except emissions from land use change. It can be used to aggregate emissions by sector, by end user, by fuel or by IPCC inventory category. Annexes A to C show emissions aggregated in these different ways. Land use change emissions are summarised in Annex E.

low price scenarios the trend towards gas is such that the majority of coal plants are unable to operate competitively against CCGTs and the prospective low load factor operation is likely to be associated with plant closures. In the high price scenarios coal-fired generation is much more competitive – one of the key issues is then how long coal plants could continue to operate without requiring major refurbishment.

7.21 Judging from world experience it is clear that, in the right circumstances, conventional steam cycle power stations can have very long lifetimes sometimes even without major expenditure to refurbish equipment. Evidence for the UK also suggests that power station operators feel there is potential for long lifetimes at some plants. Much depends on the environmental policy background.

7.22 Other than the power station assumptions previously described these business as usual projections make no assumptions about future policy action by the Environment Agency. On the basis that much of the coal-fired generation in 2010 is likely to be sourced from plants with FGD fitted there would seem to be relatively little cause for concern. Given the UK's commitment to reduce SO_2 emissions to at most 12% of their 1980 level, some further policy action may be required. Given the power station sector's likely future contribution towards reductions in sulphur dioxide and to diversity, there may be more of a case for reductions in emissions in other sectors. Further pressures from continental Europe for yet further reductions in overall SO_2 and NO_x emissions should not be ruled out, but these should clearly not be included in baseline projections. However, pressures in this direction, probably ultimately leading to further gas use, are one of the more substantial risks to these projections.

7.23 In the **domestic** sector there is only a modest increase in emissions through to 2010. This slow growth reflects the offsetting effects of growth in household numbers and assumed increase in external temperatures. Domestic sector emissions also grew slowly during the 1990s.

7.24 In the **services** sector emissions are projected to grow slowly, with something of a pause between 2000 and 2005, in part brought about by the effects of the climate change levy. It is notable that energy demand growth in this sector has slowed in recent years. Overall energy use in the sector changed little between 1997 and 1999. The projections reflect this slowing of demand growth.

7.25 In the **industry** sector emissions are projected to decline slowly, as they have since 1990. Over time, assumed increases in industrial production are offset by reductions in energy intensity and as the switch to gas from coal and oil continues. The modelling work underlying this report suggests that a core of coal and oil use will remain and that coal and oil demand will not fall as rapidly post 2000 as it has since 1990. Emissions arising from offshore activity are also estimated to fall through time.

7.26 **Road transport** emissions increase throughout the forecast period. Projected emissions are somewhat below those in EP65. One cause of this has been the past policy of raising road fuel duty by 6% a year in real terms, to reach levels rather higher than assumed in EP65. This policy has now been discontinued and the projections assume that real road fuel duties remain constant at their current levels. The freeze, in cash terms, announced in the 2000 Pre-Budget Report for Budget 2001 will very marginally increase projected future emissions.

Policy Implications

7.27 Emissions are expected to fall significantly between 1990 and 2010, reflecting the scale of action already taken by the UK to meet the challenge of climate change. Taking into account the trends in emissions of other greenhouse gases,[7] and summarised in the climate change programme, the UK looks to be on course to meet the Kyoto target. However, given the legally binding nature of the UK's commitments, consideration needs to be given to the non-central cases and of other risks to the projections. The climate change programme also sets out how the Government intends to move towards the 20% goal to reduce CO_2. Clearly there is significant uncertainty about how emissions will actually evolve through time and as an aid to understanding how emissions might react to different real world events, various sensitivities are considered further in Chapter 8.

7.28 In order to achieve the Government's domestic goal of a 20% reduction below 1990 levels in CO_2 emissions by 2010, significant policy action not identified in this paper would be required. Based on the average of the two central economic growth cases, a further reduction of around 19MtC would be needed.

7.29 It is also the case that CO_2 emissions are shown on an upward trend beyond 2005. Projected continued growth in final energy demands combined with reduced scope for a switch to lower carbon fuels in generation means that overall emissions rise. Against this background, meeting more demanding post Kyoto targets is likely to be more difficult, depending also on the trends in emissions of other gases.

7.30 The projections in the main body of this report do not include emissions from land use change, which are described in the new climate change programme. Table E.1 in Annex E shows the CL and CH scenarios with the current central land use change emissions projection included.

Comparison With EP65 Sectoral Projections

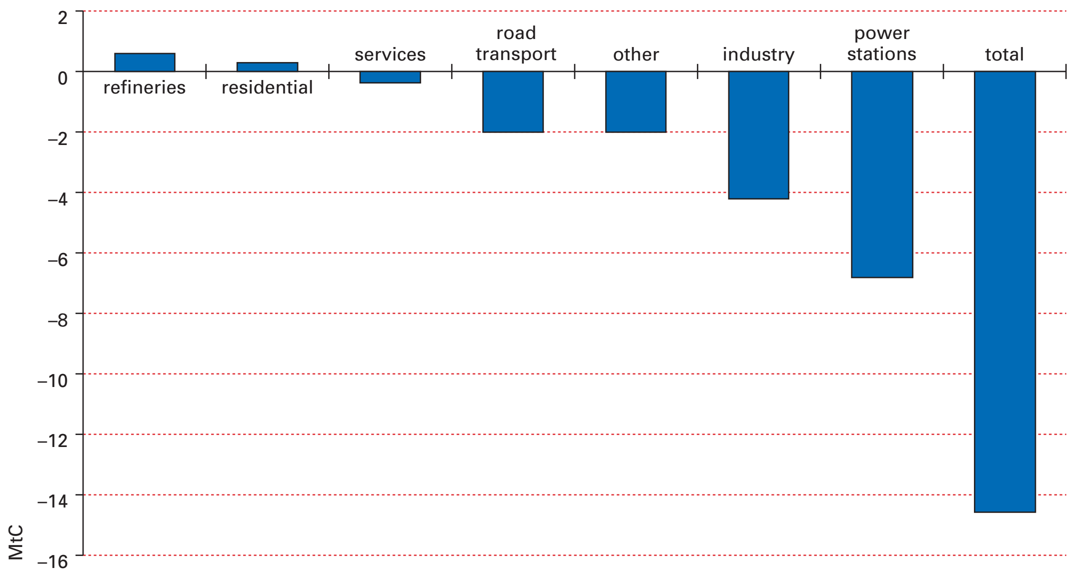
7.31 The chart below shows a comparison of the EP68 CL sectoral emissions in 2010 against the equivalent EP65 projection. The notable features of this comparison are that emissions are expected to be similar or lower in all sectors. Only in the refinery

7 Set out in more detail in *"Projections of non-CO_2 Greenhouse Gas Emissions for the UK and Constituent Countries"*, November 2000, WS Atkins Consultants Limited.

and residential sectors is there an increase in emissions compared with EP65 levels. The difference in power station emissions is particularly marked – caused mainly by lower coal/oil use projections. Industrial emissions are also lower, in part reflecting an assumed lower level of offshore activity.

7.32 A similar pattern of differences is evident for the other scenarios.

Chart 7.2: Projected Emissions in 2010 compared with EP65, CL, MtC



Comparison with the Working Paper sectoral projections

7.33 Compared with the CL projections for 2010 in the Working Paper, emissions in power stations are higher by around 2.5MtC while industrial emissions are lower by just under 4MtC. Overall emissions are reduced by around 2MtC. Power station emissions are higher due to higher projected electricity demand. Industrial emissions are lower mainly due to lower estimated emissions from offshore activity.

PROJECTED SO_2 EMISSIONS

Background

7.34 It is important to ensure that the CO_2 projections take account of policies and measures which act on other types of emission. Thus far it has been policy towards SO_2 emissions which has had most impact on CO_2 projections. EP65 for example, postulated emission limits for power stations which were in the process of being set by (what is now) the Environment Agency.

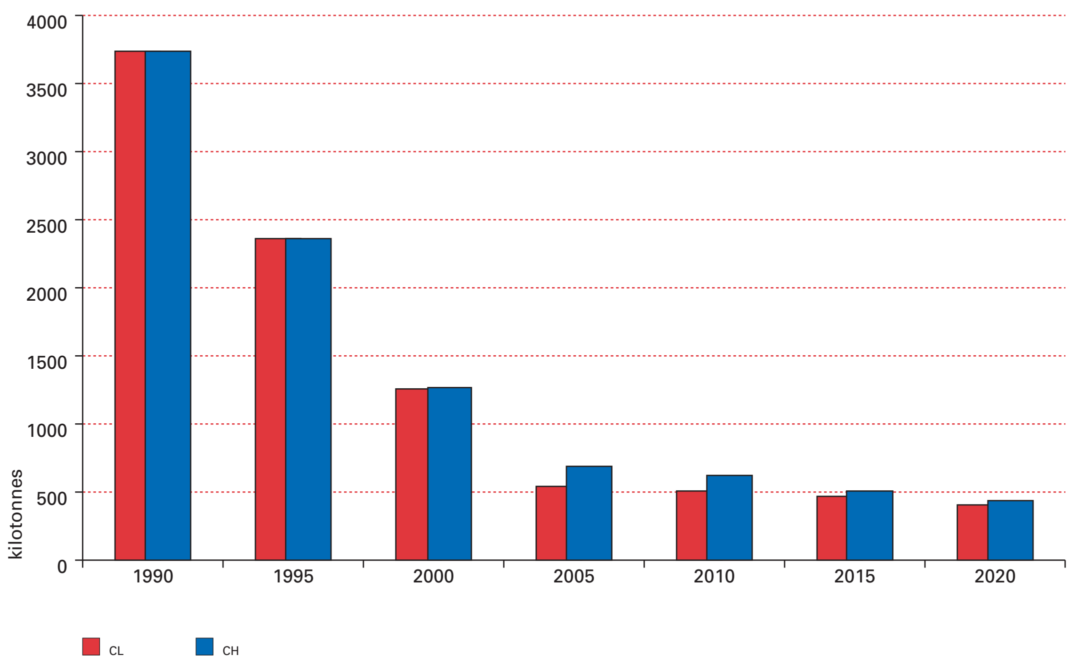
7.35 The main assumptions relating to future power station emissions are set out in Chapter 5.

7.36 There are some other developments which will affect the future level of SO_2 emissions. Potentially of most importance is the agreed restriction of the sulphur content of liquid fuels to 1% maximum by January 2003. The current UK average sulphur content of fuel oil, for example, is just over 2% so that to comply with the latest requirements the fuel oil sulphur content must more than halve. It is assumed that this is achieved. In the field of road transport fuels an EC Directive has recently been adopted which changes the quality of petrol and diesel fuels in two stages – 2000 and 2005. This will have the effect of reducing the 2005 sulphur content of diesel to around one tenth of its current maximum permissible level.

7.37 The projections embodied in EP65 forced economy – wide SO_2 emissions to comply with the UK's agreed limits under the Second Sulphur Protocol. These limits were initially superseded by agreements reached in the UNECE forum, limiting UK SO_2 emissions to 625kt in 2010. Subsequently, agreement has been reached in discussions of the EC National Emissions Ceilings Directive that UK SO_2 emissions should be restricted to no more than 585kt in 2010. Reflecting these international commitments, it is assumed that measures are taken to ensure that this target is met. The future impact of IPPC on emissions from industrial plants is uncertain. Although for working purposes we assume that such controls do not themselves reduce emissions to the 585kt limit, it is possible to take a more optimistic view of the effectiveness of IPPC.

7.38 The latest projections[8] are shown in the chart below, covering the CL and CH cases. Results for other cases do not differ markedly from these assessments.

Chart 7.3: UK SO_2 Emissions, kilotonnes of SO_2 1990-2020



8 Emissions are reported on a UNECE/CORINAIR basis.

7.39 Emissions in both cases fall rapidly to 2000 and 2005, mainly as a result of reduced use of coal in power stations and, in 2005, of the installation of some additional FGD capacity. Thereafter, emissions continue to drift downwards as the economy becomes more gas intensive. In the CL case emissions reach a level in 2010 which is somewhat below the maximum permitted. Emissions of SO_2 are higher in CH than in CL because coal use in power stations is higher than in CL and more of it is consumed in unabated plants.

7.40 Tables 7.6 and 7.7 below show a broad sectoral breakdown for both CL and CH. The gradual shift into gas and out of coal and oil products takes place in many sectors. Also notable, though not shown separately, are reductions in emissions arising from fuel combustion in refineries, where the reduction in sulphur content of fuel oil and uptake of gas in new CHP plants, produces a significant decline by 2010. In the road transport sector, emissions fall sharply to 2005, influenced by the Directive on road fuel quality. Industrial emissions will also be influenced by likely action to reduce process emissions in refineries.

7.41 Compared with EP65, SO_2 emissions are expected to be much lower for the same reasons as CO_2 is expected to be lower – more use of gas, less use of coal and (particularly fuel) oil. Policy change has had a significant influence on the SO_2 projections.

Table 7.6 SO_2 by Sector, CL, kilotonnes of SO_2

	1990	1995	2000	2005	2010	2015	2020
Power Stations	2723	1591	725	191	148	81	60
Industrial	701	543	383	291	291	293	291
Domestic	108	67	27	16	11	9	7
Commercial	90	60	47	24	20	18	15
Transport	102	91	51	17	17	17	17
Other	12	7	5	4	4	4	4
Total	**3736**	**2356**	**1238**	**543**	**491**	**422**	**395**

Table 7.7 SO_2 by Sector, CH, kilotonnes of SO_2

	1990	1995	2000	2005	2010	2015	2020
Power Stations	2723	1591	718	279	237	175	97
Industrial	701	543	386	286	285	286	285
Domestic	108	67	31	20	15	12	10
Commercial	90	60	47	24	20	18	15
Transport	102	91	51	17	16	16	14
Other	12	7	5	4	4	4	4
Total	**3736**	**2356**	**1238**	**629**	**577**	**511**	**425**

CHAPTER 8

Sensitivity Analysis on CO_2 Emissions

- **A forecast interval of ±6% in projected CO_2 emissions in 2010 is suggested by a simple model approach**
- **Reforms in the transport sector (primarily the Voluntary Agreement) are estimated to result in reduction of emissions in the range -2.6 to -5.9 MtC**
- **A less rapid rise in the number of households is estimated to result in a 0.6 MtC reduction in emissions by 2010**
- **A return to long-term average temperature is estimated to result in an increase in emissions of 2 MtC in 2010**
- **Were current high (particularly oil) energy prices to persist into 2005 it is estimated that fuel switching and lower demand would result in 0.7 MtC reduction in emissions in 2010**

8.1 Considerable uncertainties attach to energy and emission projections of this kind. We allow for some of this by presenting results on a range of scenarios for the level of energy prices and economic growth. But that does not cater for all the potential sensitivities. This chapter explores the impact on projected carbon emission levels of uncertainties in the estimation of model parameters and changes in key assumptions.

PARAMETER UNCERTAINTY

8.2 The complex structure of the energy demand model has made impracticable a detailed analysis of the additional uncertainty introduced into the projections by the uncertainty in the values of parameters fitted to historical data. This may be possible in future using Monte Carlo analysis or its equivalent. For the present, in order to get a first estimate of the potential uncertainties involved, we have explored an alternative approach using a simplified model of energy consumption which postulates aggregate energy demand as a function of price, income and temperature. The suggestion is that consideration of the parameter uncertainty in a simplified model may give some indication of the potential uncertainty (and thence in overall carbon emissions) in the wider model.

8.3 The simple model contains only energy demand, price, GDP and temperature as independent variables and inevitably entails econometric compromises. Nevertheless, with only a few parameters to fit, the uncertainty associated with the fitting process can be calculated from standard output statistics. This suggests a standard error for the projections indicating a forecast interval of the order of ±6% at two standard deviations in 2010. We assume (without formal justification) that this uncertainty is representative of the uncertainty arising from the parameter fitting process in the main model.

8.4 Comparing the CH and CL scenarios suggests a rather narrow range in the projections based on uncertainties in GDP, fuel price and temperature assumptions. But were an uncertainty interval of say ±6% to be applied to the projections core scenarios, this would indicate a level of uncertainty in the CO_2 emission projections as in Charts 8.1 and 8.2 below. On either scenario, ±6% corresponds approximately to ±9MtC in 2010.

Chart 8.1: Upper and Lower Probable Limits due to Parameter Uncertainty, CL

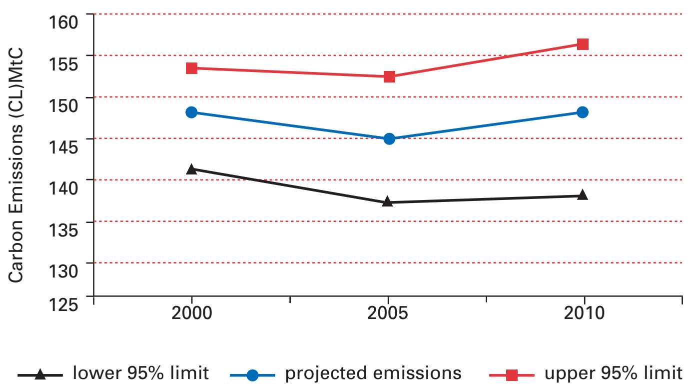
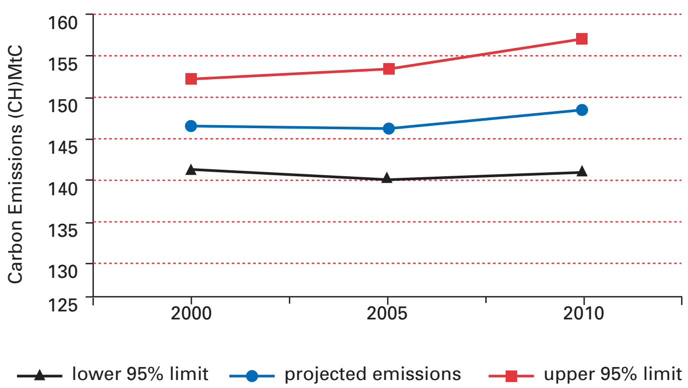


Chart 8.2: Upper and Lower Probable Limits due to Parameter Uncertainty, CH



SENSITIVITIES OF KEY ASSUMPTIONS

8.5 A summary of the effects on carbon emissions of changes in some key assumptions is shown in Table 8.1 below. Each of these effects is estimated on the basis that other assumptions remain as in the core scenarios. The effects should not be considered in any way cumulative.

Table 8.1 Summary of Possible Effects on Carbon Emissions of Key Assumptions in 2010

Key Assumptions	Alternative	Emissions in 2010 (MtC)
Voluntary Agreement on CO_2 emissions new cars and reforms to VED and company cars		-4.0
Number of households	Lower Growth in number of households	-0.6
Lifetime of Nuclear Plant	Low Output	+2.0
	High Output	-0.7
Renewables reach 10% of generation	Renewables 8%	+0.8
	Renewables 12%	-0.8
Road Fuel Price Elasticity	Imposition of -0.4 elasticity	-1.1
French Interconnector	Low Imports	+0.5
	High Imports	-1.1
Temperature	Level Trend	+2.0

Voluntary Agreements to Improve Fuel efficiency

8.6 The effect of the Voluntary Agreement (VA) reached between the European Commission and the European Automobile Manufacturers Association (ACEA) and its Japanese and Korean counterparts (JAMA and KAMA) which requires car manufacturers to reduce average CO_2 emissions from new passenger cars is discussed in Chapter 4, sections 4.9 and 4.10. In the UK, achievement of the agreed targets should be helped by proposed changes to Vehicle Excise Duty and company car taxation. If achieved this should result in emission savings of between 2.6 and 5.9 MtC in 2010, with a mid-point value of around 4.0 MtC.

Number of households

8.7 In the core scenarios we have assumed that household numbers grow by approximately 8%. If the growth in household numbers were less rapid we would expect total emissions to be reduced. If annual growth in household numbers were reduced by 25,000 a year then CO_2 emissions would be reduced by 0.3 MtC in the transport sector, 0.2 MtC in the domestic sector and power station emissions reduced by 0.1 MtC. The total effect is 0.6 MtC.

Nuclear Plant lifetime

8.8 The baseline projections embody a steady rundown in nuclear output in the post 2000 period as existing stations reach the end of their lives. There is, of course, great uncertainty about the lifetimes of existing plant and hence about future output levels. Plant lives will depend on the economics of continued operation which in turn will be affected by actions required of their owners to ensure safe operation. To analyse the sensitivity of CO_2 emissions to different nuclear assumptions, two alternative output levels in 2010 have been examined. The baseline output assumption for 2010 is 66 TWh. The low and high sensitivities examined here are 45 TWh and 74 TWh respectively.

8.9 If, instead of a baseline output of 66 TWh, the low case sensitivity were assumed, CO_2 emissions would be some 2 MtC higher than in the baseline. Emissions on a high output case sensitivity would be some 0.7 MtC lower than in the baseline.

Renewables

8.10 In the core scenario projections, it is assumed that generation from renewables forms 10% of the total in 2010. If, instead, renewables were to form a lower percentage of the total, emissions would be higher, unless the difference were made up from nuclear generation. If, for example, renewables' share were 8%, emissions would be 0.8 MtC higher than in the baseline.

Road Fuel Price Elasticity

8.11 The long run price elasticity of road fuel demand in our current model has been estimated at -0.23. There is uncertainty surrounding this estimate. Indeed, the literature on the subject provides a very wide range of estimates. Were a higher elasticity of -0.4 (the same as in EP65) to be imposed on the model then future CO_2 emissions would be reduced.

Table 8.2 Road Transport CO_2 Emissions

Million Tonnes of Carbon

	1995	2000	2005	2010	2015	2020
Unrestricted Elasticity	30.2	32.0	35.0	37.6	40.1	42.6
Restricted Elasticity	30.2	31.5	33.6	36.5	39.0	41.4

8.12 The Government has said that the appropriate level of fuel duties will in future be set on a Budget by Budget basis. The above results in terms of emissions from road transport are derived under the assumption that fuel duty is maintained at the current level in real terms. Underlying fuel prices are our low scenario and the GDP growth assumption is the central path. The implication is that, in 2010, carbon emissions would be 1.1 million tonnes lower if the price elasticity of road fuel demand was -0.4 rather than the -0.23 estimated within the model.

French Interconnector

8.13 Imports of electricity from France have historically accounted for about 5% of electricity available through the UK public distribution system. Imports through the interconnector between England and France have generally been around the highest possible level, given the capacity of the link. The continued size and duration of this flow is, however, open to some doubt, particularly given the growth in demand in Europe for clean electricity, the impact of liberalisation within Europe and increasing electricity demand within France itself. The base assumption within the core scenarios incorporates a reduction in the scale of imports of around 65% by 2010 from current levels. Uncertainty however is high and estimates of the impact on carbon emissions of alternative import assumptions have been made. The impact on emissions of such variations is illustrated in Table 8.3 below. (The figures presented are different to those in the Working Paper, reflecting the new, lower baseline estimate of imports of electricity from France).

Table 8.3 Impact on Carbon Emissions of French Interconnector

French Imports	2000	2005	2010	2015	2020
Low	0.4	0.4	0.5	0.4	0.3
High	0.0	-0.6	-1.1	-1.2	-1.3

External Temperature Effects

8.14 Modelling in the domestic and service sectors requires two variables which measure the effect on recorded energy demand of variations in external temperature. The variables are measured as 'heating degree days' and refer to the number of days that the recorded temperature falls 1 degree centigrade below a base level (15.5°C). The variables are constructed from detailed Met Office data to provide an overall data set for UK based on regional population distribution. Data from the Met Office suggests an upward trend in annual average temperatures and this is reflected in the heating degree data which indicates an average temperature in recent years of 0.8°C above the 1961-1990 average. The core scenario reflects this upward trend in line with Met Office predictions. An alternative assumption is that temperature projection to 2010 reflects no upward trend and remains at the recent average less one standard deviation. This alternative assumption is approximately equivalent to no change on the previous thirty-year average. This assumption is estimated to result in an approximate increase of 2.0MtC from CL base assumptions.

Recent Oil Price Developments

8.15 Recent developments in the crude oil market have resulted in prices tripling to over US$30 a barrel in the past eighteen months. The current high level of crude oil is reflected in the most recent product prices and has been incorporated into the core scenarios for current prices though also under the assumption that the oil price will revert to a more sustainable level relatively quickly. Futures markets show a much reduced price expected by 4Q 2001. Many analysts believe the current high price of oil to be unsustainable. However, to examine the sensitivity of results to different assumptions, an assumption of high price persistence over a longer period has been examined. The additional scenario assumes a high price of oil at $30 a barrel is maintained for several years, to 2005, then reducing over two years to the relatively high, but sustainable level of $20 a barrel. The prices assumed for gas and coal under this alternative scenario are shown in Table 8.4. Oil and gas prices are assumed to increase by more than coal prices. This scenario is estimated to result in an approximate decrease of 0.7MtC in 2010 from CH base assumptions.

Table 8.4 Alternative Crude Oil, Gas and Coal Price Assumptions

1999 Prices

	2000-2005	2007-2010
Crude Oil	US$30/bbl	US$20/bbl
Gas	26p/therm	23.43p/therm
Coal	US$44.5/tonne	US$42.24

8.16 The reduction in emissions in 2010 arises from a combination of fuel switching and lower energy demand in this high price scenario. Overall energy demand falls by about 0.6%. Oil and gas demand falls by 1.1% and 0.7% respectively. There is an increase of 0.5% in power station coal use, reflecting the fall in the relative price of coal. Power station emissions fall by 0.3MtC, transport and industrial emissions fall by 0.2MtC each, contributing to the total 0.7MtC reduction in emissions.

8.17 In this energy price sensitivity, the overall reduction in energy demand tends to outweigh the effects of fuel switching.[1]

1 Given the energy price assumptions used, there should be at least some switching into coal from oil or gas. The size of the switch is limited by the need to maintain SO_2 emissions below a ceiling of 585kt, as explained in Chapter 7, Paragraph 7.37.

ANNEX A
End User Emissions

A.1 The tables overleaf show the emissions projections on an end user basis. End user emissions are calculated by reallocating to end users those emissions produced in the course of combusting fuels in the process of making other fuels. The most obvious example of this is the reallocation of emissions produced by power stations when generating electricity. There are many such processes – probably the next most obvious process being the manufacture of oil products within refineries.

A.2 The end user sectors are those which do not use fuels to make other fuels. So, using the power station example, power station emissions need to be reallocated to the end users of electricity, in direct proportion to their use. In this way, the bulk of power station emissions would be reallocated to the domestic, industrial and commercial sectors, since these are the largest consumers of electricity. Along similar lines, much of refinery emissions would be reallocated to the transport sector, since this is the major user of oil products.

A.3 Naturally, since emissions are reallocated entirely from fuel producers to end users, the tabulation of emissions is rather different to those shown in Chapter 7, which show emissions on a 'source' basis. Further, since emissions are simply reallocated to other sectors, the overall total emission is the same as on a source basis.

A.4 Emissions are reported on an end user basis to show how the demand for energy services as a whole gives rise to emissions, including those at power stations and other energy transformation industries.

Table A.1 Total End User Emissions

LL	1990	1995	2000	2005	2010	2015	2020
domestic	42.6	40.2	40.0	38.1	38.4	39.5	40.2
commercial/public service	23.3	21.8	22.8	20.5	19.8	20.0	20.1
industry	48.2	42.5	38.6	35.9	35.3	35.7	35.8
agriculture	1.6	1.4	1.4	1.1	1.0	1.0	1.0
road transport	33.3	33.7	34.7	37.4	39.5	41.4	43.2
other transport	4.0	4.2	4.1	4.0	4.0	4.0	4.1
miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
military	1.6	1.2	1.0	1.0	1.0	1.0	1.0
exports	1.5	1.9	2.1	2.2	2.3	2.3	2.3
marine bunkers	0.2	0.2	0.2	0.2	0.2	0.2	0.2
other emissions	2.9	2.6	2.7	2.9	3.2	3.5	3.8
Total	**159.3**	**149.6**	**147.6**	**143.4**	**144.7**	**148.7**	**151.9**

LH	1990	1995	2000	2005	2010	2015	2020
domestic	42.6	40.2	39.4	39.1	39.1	40.2	39.8
commercial/public service	23.3	21.8	22.6	21.8	21.2	21.4	20.7
industry	48.2	42.5	38.4	36.0	35.2	35.4	34.7
agriculture	1.6	1.4	1.3	1.2	1.1	1.1	1.0
road transport	33.3	33.7	34.7	36.9	38.8	40.6	42.4
other transport	4.0	4.2	4.1	4.0	4.0	3.9	4.0
miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
military	1.6	1.2	1.0	1.0	1.0	1.0	1.0
exports	1.5	1.9	2.1	2.2	2.3	2.3	2.3
marine bunkers	0.2	0.2	0.2	0.2	0.2	0.2	0.2
other emissions	2.9	2.6	2.7	2.9	3.2	3.5	3.8
Total	**159.3**	**149.6**	**146.4**	**145.2**	**146.0**	**149.6**	**149.9**

CL	1990	1995	2000	2005	2010	2015	2020
domestic	42.6	40.2	40.1	38.1	38.4	39.5	40.2
commercial/public service	23.3	21.8	22.9	20.7	20.1	20.5	20.7
industry	48.2	42.5	38.8	36.7	36.8	37.8	38.6
agriculture	1.6	1.4	1.4	1.1	1.0	1.0	1.0
road transport	33.3	33.7	34.8	37.9	40.6	43.0	45.4
other transport	4.0	4.2	4.1	4.0	4.0	4.0	4.1
miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
military	1.6	1.2	1.0	1.0	1.0	1.0	1.0
exports	1.5	1.9	2.1	2.2	2.3	2.3	2.3
marine bunkers	0.2	0.2	0.2	0.2	0.2	0.2	0.2
other emissions	2.9	2.6	2.7	2.9	3.2	3.5	3.8
Total	**159.3**	**149.6**	**147.8**	**144.9**	**147.5**	**152.9**	**157.3**

Table A.1 Total, End User Emissions *(continued)*

CH	1990	1995	2000	2005	2010	2015	2020
domestic	42.6	40.2	39.4	39.1	39.1	40.1	39.7
commercial/public service	23.3	21.8	22.7	22.0	21.5	21.8	21.2
industry	48.2	42.5	38.5	36.7	36.6	37.5	37.4
agriculture	1.6	1.4	1.4	1.2	1.1	1.1	1.0
road transport	33.3	33.7	34.8	37.4	39.8	42.2	44.5
other transport	4.0	4.2	4.1	4.0	4.0	3.9	4.0
miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
military	1.6	1.2	1.0	1.0	1.0	1.0	1.0
exports	1.5	1.9	2.1	2.2	2.3	2.3	2.3
marine bunkers	0.2	0.2	0.2	0.2	0.2	0.2	0.2
other emissions	2.9	2.6	2.7	2.9	3.2	3.5	3.8
Total	**159.3**	**149.6**	**146.7**	**146.6**	**148.7**	**153.6**	**155.2**

HL	1990	1995	2000	2005	2010	2015	2020
domestic	42.6	40.2	40.1	38.1	38.4	39.4	40.2
commercial/public service	23.3	21.8	22.9	20.9	20.5	20.9	21.3
industry	48.2	42.5	38.8	37.3	38.0	39.7	41.2
agriculture	1.6	1.4	1.4	1.1	1.0	1.0	1.0
road transport	33.3	33.7	34.8	38.4	41.6	44.6	47.4
other transport	4.0	4.2	4.1	4.0	4.0	4.0	4.1
miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
military	1.6	1.2	1.0	1.0	1.0	1.0	1.0
exports	1.5	1.9	2.1	2.2	2.3	2.3	2.3
marine bunkers	0.2	0.2	0.2	0.2	0.2	0.2	0.2
other emissions	2.9	2.6	2.7	2.9	3.2	3.5	3.8
Total	**159.3**	**149.6**	**147.9**	**146.2**	**150.2**	**156.7**	**162.5**

HH	1990	1995	2000	2005	2010	2015	2020
domestic	42.6	40.2	39.4	39.1	39.0	40.0	39.7
commercial/public service	23.3	21.8	22.7	22.2	21.8	22.3	21.8
industry	48.2	42.5	38.6	37.4	37.7	39.2	39.6
agriculture	1.6	1.4	1.4	1.2	1.1	1.1	1.0
road transport	33.3	33.7	34.8	37.9	40.8	43.7	46.5
other transport	4.0	4.2	4.1	4.0	4.0	3.9	4.0
miscellaneous	0.0	0.0	0.0	0.0	0.0	0.0	0.0
military	1.6	1.2	1.0	1.0	1.0	1.0	1.0
exports	1.5	1.9	2.1	2.2	2.3	2.3	2.3
marine bunkers	0.2	0.2	0.2	0.2	0.2	0.2	0.2
other emissions	2.9	2.6	2.7	2.9	3.2	3.5	3.8
Total	**159.3**	**149.6**	**146.8**	**148.0**	**151.2**	**157.2**	**160.0**

ANNEX B
Emissions by Fuel

Table B.1 Emissions By Fuel, MtC

LL

Fuel category	1990	1995	2000	2005	2010	2015	2020
coal	61.3	42.7	29.2	15.3	11.3	9.5	7.9
motor spirit	20.8	18.8	17.8	17.7	18.7	20.3	21.6
derv	9.1	11.5	14.3	17.0	18.1	18.4	19.2
gasoil	7.3	6.5	5.9	5.8	5.6	5.4	5.3
fuel oil	11.8	7.7	4.4	4.3	4.3	4.2	4.1
burning oil	1.8	2.4	2.6	2.5	2.7	2.8	2.9
other petroleum	6.1	7.9	6.0	6.4	6.7	6.9	7.0
other gases	35.7	47.4	62.8	69.7	72.3	76.1	78.5
other emissions	5.4	4.7	4.7	4.8	5.1	5.2	5.4
Total	**159.3**	**149.6**	**147.6**	**143.4**	**144.7**	**148.7**	**151.9**

LH

Fuel category	1990	1995	2000	2005	2010	2015	2020
coal	61.3	42.7	29.1	25.3	21.7	19.3	13.4
motor spirit	20.8	18.8	17.8	17.4	18.3	19.9	21.1
derv	9.1	11.5	14.3	16.7	17.8	18.1	18.8
gasoil	7.3	6.5	6.0	5.4	5.2	5.0	4.9
fuel oil	11.8	7.7	4.5	4.4	4.4	4.3	4.0
burning oil	1.8	2.4	2.6	2.5	2.8	3.0	3.2
other petroleum	6.1	7.9	6.0	6.2	6.5	6.7	6.8
other gases	35.7	47.4	61.6	62.5	64.3	68.2	72.3
other emissions	5.4	4.7	4.7	4.8	5.1	5.2	5.4
Total	**159.3**	**149.6**	**146.4**	**145.2**	**146.0**	**149.6**	**149.9**

CL

Fuel category	1990	1995	2000	2005	2010	2015	2020
coal	61.3	42.7	29.3	15.4	11.5	9.6	8.1
motor spirit	20.8	18.8	17.8	18.3	19.4	21.0	22.6
derv	9.1	11.5	14.3	16.8	18.4	19.3	20.2
gasoil	7.3	6.5	5.9	5.8	5.6	5.5	5.4
fuel oil	11.8	7.7	4.4	4.4	4.4	4.3	4.3
burning oil	1.8	2.4	2.6	2.5	2.7	2.8	3.0
other petroleum	6.1	7.9	6.0	6.4	6.8	7.0	7.1
other gases	35.7	47.4	62.9	70.4	73.7	78.1	81.2
other emissions	5.4	4.7	4.7	4.8	5.1	5.2	5.4
Total	**159.3**	**149.6**	**147.8**	**144.9**	**147.5**	**152.9**	**157.3**

CH

Fuel category	1990	1995	2000	2005	2010	2015	2020
coal	61.3	42.7	29.2	25.4	21.8	19.4	13.6
motor spirit	20.8	18.8	17.8	18.0	19.0	20.6	22.1
derv	9.1	11.5	14.3	16.6	18.0	18.9	19.8
gasoil	7.3	6.5	6.0	5.4	5.3	5.1	5.0
fuel oil	11.8	7.7	4.5	4.4	4.4	4.4	4.2
burning oil	1.8	2.4	2.6	2.5	2.8	3.0	3.2
other petroleum	6.1	7.9	6.0	6.2	6.6	6.8	6.9
other gases	35.7	47.4	61.6	63.3	65.7	70.2	75.1
other emissions	5.4	4.7	4.7	4.8	5.1	5.2	5.4
Total	**159.3**	**149.6**	**146.7**	**146.6**	**148.7**	**153.6**	**155.2**

HL

Fuel category	1990	1995	2000	2005	2010	2015	2020
coal	61.3	42.7	29.3	15.5	11.9	9.8	8.4
motor spirit	20.8	18.8	17.8	19.0	20.6	22.2	23.8
derv	9.1	11.5	14.3	16.6	18.2	19.5	20.8
gasoil	7.3	6.5	5.9	5.8	5.7	5.6	5.6
fuel oil	11.8	7.7	4.4	4.4	4.5	4.5	4.4
burning oil	1.8	2.4	2.6	2.5	2.7	2.8	3.0
other petroleum	6.1	7.9	6.0	6.5	6.8	7.1	7.2
other gases	35.7	47.4	62.9	71.1	74.8	79.9	83.8
other emissions	5.4	4.7	4.7	4.8	5.1	5.2	5.4
Total	**159.3**	**149.6**	**147.9**	**146.2**	**150.2**	**156.7**	**162.5**

HH

Fuel category	1990	1995	2000	2005	2010	2015	2020
coal	61.3	42.7	29.2	25.4	21.9	19.6	13.8
motor spirit	20.8	18.8	17.8	18.7	20.2	21.8	23.3
derv	9.1	11.5	14.3	16.4	17.8	19.2	20.4
gasoil	7.3	6.5	6.0	5.4	5.3	5.2	5.1
fuel oil	11.8	7.7	4.5	4.4	4.5	4.5	4.3
burning oil	1.8	2.4	2.6	2.5	2.8	3.0	3.2
other petroleum	6.1	7.9	6.0	6.3	6.7	6.9	7.0
other gases	35.7	47.4	61.7	64.0	66.9	72.0	77.4
other emissions	5.4	4.7	4.7	4.8	5.1	5.2	5.4
Total	**159.3**	**149.6**	**146.8**	**148.0**	**151.2**	**157.2**	**160.0**

ANNEX C

IPCC Emissions

Table C.1 IPCC Emissions, LL, MtC

LL	1990	1995	2000	2005	2010	2015	2020
Total National Emissions	159.3	149.6	147.6	143.4	144.7	148.7	151.9
1 Energy (fuel combustion and fugitive)	155.3	146.1	144.5	140.1	141.2	145.0	147.8
A Fuel Combustion	152.2	143.6	142.5	139.1	140.5	144.6	147.6
1 Energy Industries	62.5	54.4	51.6	45.3	44.0	45.1	45.2
2 Manufacturing Industries & Construction	25.8	24.9	23.3	23.5	23.7	24.0	24.2
3 Transport	31.8	32.2	33.9	36.6	38.7	40.7	42.8
4 Other Sectors	30.6	31.1	32.7	32.8	33.1	33.8	34.5
5 Other	1.4	1.1	1.0	1.0	1.0	1.0	1.0
B Fugitive Emissions from Fuels	3.1	2.5	2.1	1.0	0.7	0.4	0.2
2 Industrial Processes	3.8	3.4	3.1	3.3	3.5	3.7	4.0
3 Solvent and Other Product Use	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4 Agriculture	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6 Waste	0.2	0.1	0.0	0.0	0.0	0.0	0.0
7 Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
memo items:							
International Bunkers	5.8	7.0	9.5	11.3	13.0	14.6	16.4
CO_2 emissions from biomass	1.1	1.4	2.1	3.0	4.9	4.5	4.4

Table C.2 IPCC Emissions, LH, MtC

LH	1990	1995	2000	2005	2010	2015	2020
Total National Emissions	159.3	149.6	146.4	145.2	146.0	149.6	149.9
1 Energy (fuel combustion and fugitive)	155.3	146.1	143.4	141.9	142.5	145.9	145.9
A Fuel Combustion	152.2	143.6	141.3	140.8	141.8	145.5	145.7
1 Energy Industries	62.5	54.4	51.0	49.5	48.2	49.1	46.5
2 Manufacturing Industries & Construction	25.8	24.9	23.2	22.5	22.6	22.8	22.8
3 Transport	31.8	32.2	33.9	36.0	37.9	39.8	41.9
4 Other Sectors	30.6	31.1	32.2	31.9	32.2	32.9	33.6
5 Other	1.4	1.1	1.0	1.0	1.0	1.0	1.0
B Fugitive Emissions from Fuels	3.1	2.5	2.1	1.1	0.7	0.4	0.2
2 Industrial Processes	3.8	3.4	3.1	3.3	3.5	3.7	4.0
3 Solvent and Other Product Use	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4 Agriculture	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6 Waste	0.2	0.1	0.0	0.0	0.0	0.0	0.0
7 Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
memo items:							
International Bunkers	5.8	7.0	9.5	10.7	12.5	13.9	15.6
CO_2 emissions from biomass	1.1	1.4	2.1	3.0	4.9	4.5	4.4

Table C.3 IPCC Emissions, CL, MtC

CL	1990	1995	2000	2005	2010	2015	2020
Total National Emissions	159.3	149.6	147.8	144.9	147.5	152.9	157.3
1 Energy (fuel combustion and fugitive)	155.3	146.1	144.8	141.5	144.0	149.0	153.2
A Fuel Combustion	152.2	143.6	142.7	140.5	143.3	148.6	152.9
1 Energy Industries	62.5	54.4	51.7	45.6	44.7	46.2	46.6
2 Manufacturing Industries & Construction	25.8	24.9	23.4	24.0	24.6	25.3	25.8
3 Transport	31.8	32.2	34.0	37.1	39.7	42.2	44.8
4 Other Sectors	30.6	31.1	32.7	32.9	33.3	34.0	34.8
5 Other	1.4	1.1	1.0	1.0	1.0	1.0	1.0
B Fugitive Emissions from Fuels	3.1	2.5	2.0	1.0	0.6	0.4	0.3
2 Industrial Processes	3.8	3.4	3.1	3.3	3.6	3.8	4.1
3 Solvent and Other Product Use	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4 Agriculture	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6 Waste	0.2	0.1	0.0	0.0	0.0	0.0	0.0
7 Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
memo items:							
International Bunkers	5.8	7.0	9.5	11.3	13.0	14.6	16.4
CO_2 emissions from biomass	1.1	1.4	2.1	3.0	4.9	4.5	4.5

Table C.4 IPCC Emissions, CH, MtC

CH	1990	1995	2000	2005	2010	2015	2020
Total National Emissions	159.3	149.6	146.7	146.6	148.7	153.6	155.2
1 Energy (fuel combustion and fugitive)	55.3	146.1	143.6	143.3	145.2	149.8	151.1
A Fuel Combustion	152.2	143.6	141.5	142.2	144.4	149.3	150.8
1 Energy Industries	62.5	54.4	51.2	49.9	48.9	50.1	47.8
2 Manufacturing Industries & Construction	25.8	24.9	23.2	22.9	23.3	23.9	24.4
3 Transport	31.8	32.2	34.0	36.4	38.9	41.3	43.8
4 Other Sectors	30.6	31.1	32.2	32.0	32.3	33.1	33.9
5 Other	1.4	1.1	1.0	1.0	1.0	1.0	1.0
B Fugitive Emissions from Fuels	3.1	2.5	2.1	1.1	0.7	0.5	0.3
2 Industrial Processes	3.8	3.4	3.1	3.3	3.6	3.8	4.1
3 Solvent and Other Product Use	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4 Agriculture	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6 Waste	0.2	0.1	0.0	0.0	0.0	0.0	0.0
7 Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
memo items:							
International Bunkers	5.8	7.0	9.5	10.7	12.5	13.9	15.6
CO_2 emissions from biomass	1.1	1.4	2.1	3.0	4.9	4.7	4.9

Table C.5 IPCC Emissions, HL, MtC

HL	1990	1995	2000	2005	2010	2015	2020
Total National Emissions	159.3	149.6	147.9	146.2	150.2	156.7	162.5
1 Energy (fuel combustion and fugitive)	155.3	146.1	144.9	142.8	146.6	152.8	158.3
A Fuel Combustion	152.2	143.6	142.8	141.8	145.9	152.3	158.0
1 Energy Industries	62.5	54.4	51.7	46.0	45.5	47.1	47.9
2 Manufacturing Industries & Construction	25.8	24.9	23.4	24.3	25.3	26.4	27.4
3 Transport	31.8	32.2	34.0	37.5	40.7	43.6	46.7
4 Other Sectors	30.6	31.1	32.7	33.0	33.4	34.2	35.1
5 Other	1.4	1.1	1.0	1.0	1.0	1.0	1.0
B Fugitive Emissions from Fuels	3.1	2.5	2.1	1.0	0.7	0.5	0.3
2 Industrial Processes	3.8	3.4	3.1	3.3	3.6	3.9	4.2
3 Solvent and Other Product Use	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4 Agriculture	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6 Waste	0.2	0.1	0.0	0.0	0.0	0.0	0.0
7 Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
memo items:							
International Bunkers	5.8	7.0	9.5	11.3	13.0	14.6	16.4
CO_2 emissions from biomass	1.1	1.4	2.1	3.0	4.9	4.6	4.5

Table C.6 IPCC Emissions, HH, MtC

HH	1990	1995	2000	2005	2010	2015	2020
Total National Emissions	159.3	149.6	146.8	148.0	151.2	157.2	160.0
1 Energy (fuel combustion and fugitive)	155.3	146.1	143.7	144.6	147.6	153.4	155.9
A Fuel Combustion	152.2	143.6	141.7	143.5	146.8	152.9	155.5
1 Energy Industries	62.5	54.4	51.2	50.3	49.6	51.1	49.2
2 Manufacturing Industries & Construction	25.8	24.9	23.3	23.3	24.0	24.8	25.6
3 Transport	31.8	32.2	34.0	36.9	39.9	42.7	45.7
4 Other Sectors	30.6	31.1	32.2	32.1	32.5	33.4	34.2
5 Other	1.4	1.1	1.0	1.0	1.0	1.0	1.0
B Fugitive Emissions from Fuels	3.1	2.5	2.1	1.1	0.8	0.5	0.3
2 Industrial Processes	3.8	3.4	3.1	3.3	3.6	3.8	4.1
3 Solvent and Other Product Use	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4 Agriculture	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6 Waste	0.2	0.1	0.0	0.0	0.0	0.0	0.0
7 Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
memo items:							
International Bunkers	5.8	7.0	9.5	10.7	12.5	13.9	15.6
CO_2 emissions from biomass	1.1	1.4	2.1	3.0	5.2	4.9	5.1

ANNEX D

Electricity Generation by Fuel Type

Table D.1 Electricity Generation by Fuel Type, TWh

CL	1990	1995	2000	2005	2010	2015	2020
coal	204	145	105	54	38	31	26
oil	15	9	1	0	0	0	0
gas	0	57	134	196	236	278	307
nuclear	59	81	80	86	66	40	27
renewables	5	6	11	22	43	43	43
imports	14	18	15	12	7	6	5
Total	297	315	345	370	390	399	408

CH	1990	1995	2000	2005	2010	2015	2020
coal	204	145	104	96	83	74	49
oil	15	9	1	0	0	0	0
gas	0	57	132	142	173	216	264
nuclear	59	81	80	86	66	40	27
renewables	5	6	11	22	41	41	41
imports	14	18	16	13	8	7	6
Total	297	315	343	360	371	378	387

ANNEX E

Emissions Including Land Use Change Effects

Table E.1 CO_2 Including Emissions From Land Use Change (MtC)

	1990	1995	2000	2005	2010	2015	2020
CL	159.3	149.6	147.8	144.9	147.5	152.9	157.3
CH	159.3	149.6	146.7	146.6	148.7	153.6	155.2
LUC central	8.7	7.1	7.0	6.0	5.7	5.2	4.4
Average of CL, CH, plus LUC	168.0	156.7	154.3	151.7	153.8	158.4	160.7

ANNEX F

Policy Assumptions in the Core Scenarios

F.1 The baseline energy projections have been set up to incorporate the effect of existing policies, or measures which are otherwise thought to be 'firm'. For example, existing policy would include the Energy Efficiency Best Practice Programme, Home Energy Efficiency Scheme and various activities undertaken by the Energy Saving Trust. Other measures in this category include VAT on domestic fuel at 5%, announced road transport fuel duty changes,[1] and announced changes to other fuel duties.

F.2 There are a small number of major policy announcements, which, although not completely finalised in detail, are considered to be firm enough to include in the baseline projections. These are listed below:

- the obligation for renewables to form 10% of electricity generation by 2010 subject to the price to consumers being acceptable
- the climate change levy, assumed to commence in April 2001. Within this, we allow for the estimated impact of the levy rates for 2001-02, which we assume are maintained in real terms in later years. We include the impact of the climate change levy exemption for new renewables, and for good quality CHP.
- UK sulphur dioxide emissions are restricted to a ceiling of 585kilotonnes in 2010, reflecting a UK commitment as part of the EC's National Emissions Ceilings Directive.

F.3 There are some other actual or potential measures for which some detail is available, but which are not yet sufficiently well developed to be included in the baseline. Amongst this group of measures are the climate change levy negotiated agreements, which are yet to be concluded; enhanced capital allowances for energy saving investments, on which consultation has recently been conducted; proposed introduction of graduated vehicle excise duty; and proposed company car taxation reform. The Climate Change Programme provides estimated impacts on carbon emissions for these.

F.4 A range of other potential measures considered in the Government's draft climate change programme are also not included in the baseline projections.

1 Though not announcements in 2000 pre-budget Report.

ANNEX G

ESI Capacity

Table G.1 ESI Capacity, GW

LL	1999	2000	2005	2010	2015	2020
Coal	20	19	6	0	0	0
Coal FGD	6	6	9	9	9	7
Oil	3	2	2	0	0	0
Mixed	7	7	6	4	2	0
GT	2	2	2	2	3	6
CCGT	16	18	27	37	41	46
Nuclear	13	13	12	10	7	4
Renewables	2	2	4	8	7	8
Other	5	5	5	5	5	5
Total	**73**	**74**	**73**	**74**	**75**	**75**

LH	1999	2000	2005	2010	2015	2020
Coal	20	19	6	1	1	0
Coal FGD	6	6	11	11	11	8
Oil	3	3	2	0	0	0
Mixed	7	7	6	5	3	0
GT	2	2	2	2	1	4
CCGT	16	18	23	31	35	45
Nuclear	13	13	12	10	7	4
Renewables	2	2	4	7	7	7
Other	5	5	5	5	5	5
Total	**73**	**74**	**71**	**71**	**71**	**72**

CL	1999	2000	2005	2010	2015	2020
Coal	20	19	6	0	0	0
Coal FGD	6	6	9	9	9	7
Oil	3	2	2	0	0	0
Mixed	7	7	6	4	2	0
GT	2	2	2	2	3	6
CCGT	16	18	28	38	42	48
Nuclear	13	13	12	10	7	4
Renewables	2	2	4	8	7	8
Other	5	5	5	5	5	5
Total	**73**	**74**	**74**	**75**	**76**	**78**

Table G.1 ESI Capacity, GW *(continued)*

CH	1999	2000	2005	2010	2015	2020
Coal	20	19	6	1	1	0
Coal FGD	6	6	11	11	11	8
Oil	3	3	2	0	0	0
Mixed	7	7	6	5	3	0
GT	2	2	2	2	2	4
CCGT	16	18	24	32	36	47
Nuclear	13	13	12	10	7	4
Renewables	2	2	4	7	7	7
Other	5	5	5	5	5	5
Total	**73**	**74**	**72**	**73**	**73**	**74**

HL	1999	2000	2005	2010	2015	2020
Coal	20	19	6	0	0	0
Coal FGD	6	6	9	9	9	7
Oil	3	2	2	0	0	0
Mixed	7	7	6	4	2	0
GT	2	2	2	2	3	6
CCGT	16	18	29	39	44	51
Nuclear	13	13	12	10	7	4
Renewables	2	2	4	8	8	8
Other	5	5	5	5	5	5
Total	**73**	**74**	**74**	**76**	**78**	**80**

HH	1999	2000	2005	2010	2015	2020
Coal	20	19	6	1	1	0
Coal FGD	6	6	11	11	11	8
Oil	3	3	2	0	0	0
Mixed	7	7	6	5	3	0
GT	2	2	2	2	2	4
CCGT	16	18	24	33	38	49
Nuclear	13	13	12	10	7	4
Renewables	2	2	4	7	7	7
Other	5	5	5	5	5	5
Total	**73**	**74**	**73**	**74**	**75**	**77**

ANNEX H

Primary Demand

Table H.1 Primary Demand, Mtoe

LL	1999	2000	2005	2010	2015	2020
Coal	36.7	34.9	21.4	17.0	14.8	13.0
Oil	73.4	73.5	79.2	84.3	89.0	93.9
Natural Gas	90.9	96.7	108.6	114.0	121.2	126.0
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	2.9	2.9	5.6	10.8	10.7	10.7
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	**227.8**	**229.5**	**237.7**	**243.4**	**246.3**	**250.8**

LH	1999	2000	2005	2010	2015	2020
Coal	36.7	34.9	31.3	27.5	24.7	18.4
Oil	73.4	73.7	77.2	82.3	86.7	91.3
Natural Gas	90.9	94.6	96.5	100.3	107.8	115.4
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	2.9	2.9	5.7	11.4	11.3	11.3
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	**227.8**	**227.7**	**233.6**	**238.9**	**241.2**	**243.6**

CL	1999	2000	2005	2010	2015	2020
Coal	36.7	35.1	21.7	17.4	15.4	13.8
Oil	73.4	73.6	79.9	85.9	91.4	97.1
Natural Gas	90.9	96.8	109.7	115.9	124.0	129.9
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	2.9	2.9	5.6	10.8	10.7	10.8
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	**227.8**	**229.8**	**239.9**	**247.4**	**252.2**	**258.6**

Table H.1 Primary Demand, Mtoe *(continued)*

CH	1999	2000	2005	2010	2015	2020
Coal	36.7	35.0	31.5	27.8	25.2	19.1
Oil	73.4	73.8	77.9	83.8	89.0	94.3
Natural Gas	90.9	94.7	97.7	102.4	110.7	119.4
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	2.9	2.9	5.7	11.5	11.4	11.4
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	**227.8**	**227.9**	**235.6**	**242.8**	**247.0**	**251.3**

HL	1999	2000	2005	2010	2015	2020
Coal	36.7	35.1	21.8	18.0	15.9	14.5
Oil	73.4	73.7	80.7	87.5	93.6	100.0
Natural Gas	90.9	96.8	110.7	117.5	126.7	133.6
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	2.9	2.9	5.6	10.9	10.9	10.9
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	**227.8**	**229.9**	**241.8**	**251.3**	**257.8**	**266.2**

HH	1999	2000	2005	2010	2015	2020
Coal	36.7	35.1	31.7	28.0	25.5	19.4
Oil	73.4	73.9	78.6	85.3	91.2	97.2
Natural Gas	90.9	94.7	98.8	104.2	113.5	123.1
Nuclear	22.7	20.5	22.0	16.9	10.3	6.9
Renewables	2.9	2.9	5.7	11.5	11.5	11.5
Imports	1.2	1.1	0.9	0.4	0.3	0.3
Total	**227.8**	**228.1**	**237.7**	**246.5**	**252.3**	**258.4**

ANNEX I

Main Comments on Working Paper

AREA	COMMENT	ASSESSMENT
Fuel Diversity	Projections abandon policy of security and diversity.	No. Projections indicate fairly diverse generation mix. Shannon-Weiner index (a common measure) in 2010 broadly unchanged from now (though it falls thereafter).
Coal Demand	ESI coal demand in 2000 too low.	Agree. Nuclear performance worse than expected. French electricity imports lower. But longer-run projections reflects cost fundamentals. Any single year may diverge from this for specific reasons (such as poor nuclear performance in 2000).
	Doubts that coal use will be so high.	Uncertain. Range of possible outcomes reflected in different scenarios.
Fuel Prices	Forecast gas prices too low. Not in line with IEA or WEFA.	We have range of assumptions, including real gas price increase in high energy price scenario. Even in this scenario, gas demand increases. It is possible that gas prices will increase more than assumed, but assumptions not out of line with a range of other forecasters.
	Oil price range too low.	Acknowledge 2000 price assumption was too low. But it is long-term position that matters. $20 a barrel long-term is above energy companies current assumption for planning purposes. Though a range of views, not out of line with other forecasters. Recent oil price developments explored as sensitivity in Chapter 8
NETA	NETA leads to electricity price fall that creates uncertainty for new investment in gas generation.	Already reflected. Fall in electricity price of 10-15% not inconsistent with continued gas build.
Renewables	Renewables reaching 10% generation very uncertain.	10% renewables is subject to the price increase to customers being acceptable. Sensitivity to figures around 10% examined in Working Paper. Further consultation document on renewables obligation has now been published.
Electricity Growth	Electricity growth at 1% a year less than historic experience and NGC forecast 1½ %.	Additional measures in baseline suggest growth could be lower than in past, though EP68 projection is higher than Working Paper.
Coal Generation	No current indications of coal generation plant closing. No technical reason why lives cannot be extended.	Acknowledge uncertainty. But outlook for 2010 more important than 2005 – even with refurbishment opportunities some closures very likely.
	Projection allows too little FGD to be fitted.	Further FGD plant construction seems very likely to proceed, although final outturn very uncertain.

AREA	COMMENT	ASSESSMENT
	Should be less FGD assumed.	Some FGD retrofits taking place. Gap to EA assumptions not large. Others say we have too little!
	Clean coal technology ignored.	Appears uncompetitive against combined cycle gas plant, given the energy price assumptions used.
Model Methodology	Modelling should reflect more scenarios – a greater range of possible outcomes. Probability/Monte-Carlo analysis should be used.	Worth exploring further in future exercises. But more scenarios not necessarily more illuminating – can make drawing implications complex. Single baseline scenario required for international monitoring of greenhouse gas emissions.
Nuclear Plant	Lifetimes nuclear plants uncertain.	Agreed. Sensitivity examined.
CHP	Why not assume 10GW CHP target achieved in baseline projection? What has been assumed for take off of fuel cells and micro CHP? Treatment of CHP marginalised. If not, should report amount of CHP.	Baseline projection in Working Paper approximately 7GW – see Chapter 4. Extrapolation of past trends. No further specific allowance. Hard to foresee. Address in further revisions. See above. Amount of CHP reported in Chapter 4.
Nuclear Generation	Nuclear generation 2010 over-stated. Recent outages/shut-downs.	Uncertain. Working Paper includes sensitivity to lower nuclear generation in 2010, but should not assume current poor performance permanent.
External Temperature	Should assume that outside temperature in future is above historic level.	This was already assumed in Working Paper. Sensitivity has been examined.
Refinery Demand	Oil projections too high-out of line with industry expectations of refinery throughout, UK product balances and refinery energy use. Projections may overstate transport and oil refining fuel demand and emissions.	Agree. Further exploration of issues has led to downward revision of refinery throughout assumptions. Treatment of EU Voluntary Agreement on cars may account for much of transport difference. Refining point accepted.

AREA	COMMENT	ASSESSMENT
Transport Demand	Impact of road fuel price on road fuel demand is low, but may be a little above level assumed. Hence, emissions from transport sector projected too high.	Working Paper estimate well within range of estimates in the literature. Sensitivity has been examined.
	Transport projection looks high.	Does not allow for impact of EU Voluntary Agreement on fuel efficiency of cars – this accounts for much of difference (impact of agreement is accounted for in CCP rather than baseline).
	Road congestion, alternative fuels and decoupling of goods vehicle traffic from economic growth will reduce road transport growth compared to projection.	Uncertain. Projections do not attempt to impose step changes attached to new technologies, costs of which, and success, very hard to predict.
	Insufficient allowance for new technologies in reducing road fuel emissions.	See above.
	Trend to more use of air conditioning in cars could add to energy demand.	Possible. But no data to examine (separate study currently underway). Overall impact probably small. For further consideration.
Domestic/Service Sector Demand	Air conditioning demand increasing.	Historic trend is included. Little data to suggest alternative treatment. For further consideration.
	Projection of increase domestic/commercial demand more realistic than previously. May still understate, particularly because of assumed increase outside temperature.	Agree uncertain. But accepting reality of global warming, and recent trend, assumptions reasonable. Sensitivity examined.
	Services demand growth underestimated.	No specific data evidence to back this up.
ESI	short-term growth of gas demand, attached to CCGT, may be higher than projected. Coal and oil in 2010 projected too high.	Uncertain, but specific evidence for view not presented. Ending of stricter consents policy already allowed for.
French Interconnector	Reduction in electricity imports from France may be greater than assumed, as France looks to other European markets.	Agreed. Sensitivity examined.
Refinery Emissions	Refinery emissions too high.	Agreed.

Glossary

ACEA	European Automobile Manufacturers Association
ARA	Amsterdam, Rotterdam, Antwerp
BRE	Building Research Establishment
CCGT	combined cycle gas turbine
CCP	Climate Change Programme
CH	central GDP growth – high fuel prices
CHP	combined heat and power
CL	central GDP growth – low fuel prices
CO_2	carbon dioxide
DERV	diesel engine road vehicle
DETR	Department of Environment, Transport and the Regions
DNC	declared net capacity
DTI	Department of Trade and Industry
DUKES	Digest of UK Energy Statistics
EA	Environment Agency
EC	European Community
EP65	Energy Paper 65
ESI	electricity supply industry
EU	European Union
ETSU	Energy Technology Support Unit
FGD	flue gas desulphurisation
GDP	gross domestic product
GW	gigawatts
HH	high GDP growth – high fuel prices
HL	high GDP growth – low fuel prices
HSFO	high sulphur fuel oil
IGCC	integrated gasification combined cycle
IPCC	intergovernmental panel on climate change
kt	kilotonnes
LCPD	Large Combustion Plant Directive
LH	low GDP growth – high fuel prices
LL	low GDP growth – low fuel prices
LP	linear programming
LSFO	low sulphur fuel oil
MtC	million tonnes of carbon
Mtoe	million tonnes of oil equivalent
NETA	New Electricity Trading Arrangements
NFFO	non-fossil fuel obligation
NO_x	nitrogen oxides
OEF	Oxford Economic Forecasting
RECs	Regional Electricity Companies

RPDI	real personal disposable income
SO_2	sulphur dioxide
SO_x	sulphur oxides
SPRU	Science Policy Research Unit (University of Sussex)
UNECE	United Nations Economic Commission for Europe
VA	voluntary agreement
VAT	value added tax
VED	Vehicle Excise Duty