INTERNATIONAL ENERGY AGENCY

Energy Policies of IEA Countries

The United Kingdom 2002 Review

OECD

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The International Energy Agency (IEA) is an autonomous body which was established in November 1974 within the framework of the Organisation for Economic Co-operation and Development (OECD) to implement an international energy programme.

It carries out a comprehensive programme of energy co-operation among twenty-six* of the OECD's thirty Member countries. The basic aims of the IEA are:

- to maintain and improve systems for coping with oil supply disruptions;
- to promote rational energy policies in a global context through co-operative relations with non-member countries, industry and international organisations;
- to operate a permanent information system on the international oil market;
- to improve the world's energy supply and demand structure by developing alternative energy sources and increasing the efficiency of energy use;
- to assist in the integration of environmental and energy policies.

** IEA Member countries: Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States. The European Commission also takes part in the work of the IEA.*

ORGANISATION FOR ECONOMIC CO-OPERATION AND DEVELOPMENT

Pursuant to Article 1 of the Convention signed in Paris on 14th December 1960, and which came into force on 30th September 1961, the Organisation for Economic Co-operation and Development (OECD) shall promote policies designed:

- to achieve the highest sustainable economic growth and employment and a rising standard of living in Member countries, while maintaining financial stability, and thus to contribute to the development of the world economy;
- to contribute to sound economic expansion in Member as well as non-member countries in the process of economic development; and
- to contribute to the expansion of world trade on a multilateral, non-discriminatory basis in accordance with international obligations.

The original Member countries of the OECD are Austria, Belgium, Canada, Denmark, France, Germany, Greece, Iceland, Ireland, Italy, Luxembourg, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom and the United States. The following countries became Members subsequently through accession at the dates indicated hereafter: Japan (28th April 1964), Finland (28th January 1969), Australia (7th June 1971), New Zealand (29th May 1973), Mexico (18th May 1994), the Czech Republic (21st December 1995), Hungary (7th May 1996), Poland (22nd November 1996), the Republic of Korea (12th December 1996) and Slovakia (28th September 2000). The Commission of the European Communities takes part in the work of the OECD (Article 13 of the OECD Convention).

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1

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

SUMMARY

Over the past four years, the United Kingdom (UK) has continued its process of liberalising its energy industries. Since 1998, all natural gas consumers have been free to choose their supplier, and since 1999, all electricity consumers have enjoyed the same right. Both markets have become highly competitive. Some 15 million domestic gas and electricity customers have switched suppliers since the markets were opened. Currently, about 67,000 gas customers and 100,000 electricity consumers switch suppliers every week. Residential customers have enjoyed reductions in their gas bills of 25% in real terms since 1990.

The British natural gas and electricity supply industries have gone through a phase of intense restructuring in these last years. The overwhelming majority of these acquisitions, mergers and de-mergers were the result of commercial considerations, as the industries are almost exclusively privately owned. The only exception to this is BNFL Magnox Generation, a state-owned company that retains the magnox nuclear power plants.

Today the UK has eight major gas suppliers, including Centrica, which developed from the trading arm of British Gas, the former public gas monopoly. England and Wales have 38 major power producers, as well as seven large and many smaller companies supplying electricity. The restructuring also has resulted in closer integration of the gas and electricity markets, as gas suppliers increasingly also sell electricity and other services such as water, telecommunication services and financial services. In recognition of this trend, the separate regulatory authorities for electricity and gas were merged in 2000 to form Ofgem.

The decisive breakthrough towards a fully competitive electricity generation market was achieved through the introduction of the New Electricity Trading Arrangements (NETA) in March 2001. NETA replaced the Electricity Pool, the mandatory electricity trading mechanism, that had been at the core of the power market in England and Wales for ten years following the first reforms in 1990/91. NETA is a very flexible, voluntary mechanism for electricity trading. It has led to a decline in electricity wholesale prices of 20-25%.

Liberalisation of the gas and electricity markets was highly successful and is now nearly complete. Industry restructuring continues, based on private-sector decisions: at the end of April 2002, Lattice, the UK's gas transportation company, and National Grid Company which runs the electricity transmission grid, announced their intention to merge.

A few areas need to be addressed nevertheless. The electricity markets in Scotland and Northern Ireland are not as competitive as the market in England and Wales. In Scotland, competition still only occurs in the form of third party access to the networks of two vertically integrated companies, ScottishPower and Scottish & Southern Energy. In Northern Ireland, the market has been opened only partially. But the situation is set to improve as NETA is to be extended to Scotland by April 2004.

In the gas market, capacity auctions at the St. Fergus (Scotland) beach entry point into the UK's onshore pipeline system run by the monopoly operator Transco have fetched very high bid prices in recent years. This has revealed bottlenecks at the St. Fergus terminal itself and further afield in the pipeline network. But so far the high prices have not directly resulted in Transco increasing its capacity. The government and Ofgem must review this situation and adjust the regulatory regime in order to give Transco and potential private investors stronger incentives for new pipeline construction and the removal of bottlenecks.

This is important because the operation and construction of offshore infrastructure might otherwise decline. That could dampen the prospects for importing natural gas from Norway. Ultimately, that could have a crucial, negative impact on the exploitation of the declining North Sea hydrocarbons reserves.

The North Sea part of the UK continental shelf is now a mature province, characterised by a large number of small discoveries and undeveloped finds close to existing pipeline infrastructure. The existing infrastructure has a limited remaining lifetime and increasing spare capacity as the large old fields have become depleted. If this infrastructure is not now used to develop and exploit the large number of small new fields, these fields may never be developed. The UK gas industry, meanwhile, estimates that the UK will become a net gas importer again as of 2005. To make optimal use of the remaining resources, the government should fine-tune the fiscal regime for upstream hydrocarbons. It should improve regulation and address the bottlenecks in Transco's system to ensure optimal conditions for the marketing of the remaining gas.

The UK has two targets relating to greenhouse gas emissions. It is subject to a binding international target under the 1997 Kyoto Protocol and the European Union's burden-sharing agreement. This requires a 12.5% reduction in greenhouse gas emissions (six gases) compared with 1990 levels by 2008-2012. In addition, the country has a national target of cutting its carbon dioxide emissions by 20% below 1990 levels by 2010. Largely as a consequence of energy market reform and the resulting "dash for gas" in power generation (the massive construction of gas-fired power plants replacing coal generation), the UK is in the fortunate position of probably being able to meet the Kyoto target. However, meeting the national target will require extra efforts.

To address the potential emissions gap, the government published a new Climate Change Programme in November 2000. This programme contains a large number of additional measures including a Climate Change Levy and a domestic Emissions

Trading Scheme. The programme could cut greenhouse gas emissions by 23% below 1990 levels by 2010. Carbon dioxide emissions could be reduced by an estimated 19% in the same period, close to the national target.

The Climate Change Levy has a number of questionable design features. The most important such features are that it is based on the energy content of fuels, and that it applies to the business and public sectors, but not to the residential sector. However, the government has a strong commitment to reducing the problem of fuel poverty that affects low-income households in old, poorly insulated buildings. This commitment provides a justification for exempting the residential sector from the tax, in particular since there are energy efficiency programmes in place for the fuel-poor. In addition, the government is implementing a Renewables Obligation that will raise the contribution of renewable sources of energy to England and Wales' electricity supply to 10% by 2010. It expects a voluntary green certificates market to emerge on the basis of this obligation.

To a large degree these measures address the same issues, but their combined application could lead to excessive internalisation of external cost in some areas and insufficient internalisation in others. This could increase the cost of compliance with the government's greenhouse gas objectives. The government should look again at whether the levy is really achieving the government's original objectives and, in particular, should consider including residential consumers into its scope. In future, it should focus on fewer but more forceful greenhouse gas emissions abatement schemes.

As of June 2001 the prime minister's Performance and Innovation Unit (PIU) carried out a review of the strategic energy policy issues affecting the UK in the future. Both the PIU review and a recent report by the House of Lords note that electricity output from nuclear power is expected to decline in the coming years if no measures are taken. The report of the House of Lords recommends that the UK maintain its present ability to produce no less than 20% of domestic electricity demand from nuclear.

RECOMMENDATIONS

The Government of the United Kingdom should:

Energy Market and Energy Policy

- ☐ In an ever-changing world, reaffirm its general energy policy objectives, i.e. to ensure secure, diverse, sustainable supplies of energy at competitive prices for the future.

- ☐ Stabilise to a greater degree the structure of governmental organisations and the definition of the remit of government and the market.

- ☐ Under this stable equilibrium, align the various energy policy institutions with the government's energy policy, eliminate overlap and strengthen co-ordination.

- ☐ Avoid, where possible, using energy policy measures to pursue social and other policy objectives. If this is unavoidable, clearly delineate the trade-offs and costs of such measures.

Environment, Energy Efficiency and Renewables

- ☐ For the industrial and power generation sectors, consider again using either emissions trading or carbon taxation. Consider introducing carbon taxation for households.

- ☐ Consider again modifying the Climate Change Levy to reflect the carbon content of fuels.

- ☐ Consider again eliminating restrictive definitions limiting the eligibility of industries for voluntary climate change agreements, as well as incentives and possibilities for free-riding.

- ☐ Pursue its involvement in the residential/commercial sector to promote energy efficiency while avoiding duplication. Reinforce the energy efficiency measures targeted at the commercial sector, in particular offices.

- ☐ Consider again extending voluntary agreements to cover all larger industries, and consider including small and medium-sized industries.

- ☐ Review carefully the practical potential of energy efficiency policies to curb energy consumption. Clarify the costs of specific policy measures.

- ☐ Continue the systematic monitoring and evaluation of energy efficiency programmes and use the results to enhance the quality of new and existing measures and programmes.

- ☐ Enhance the efforts to curb the energy consumption and CO_2 emissions from the transport sector. To achieve this, the government should implement its 10-year Transport Plan swiftly and according to schedule, with an emphasis on reducing greenhouse gas emissions and improving energy efficiency.

- ☐ Implement the reforms relating to renewables effectively and efficiently as anticipated, and closely monitor the results.

- ☐ Review regularly the complex system of support mechanisms for renewables and streamline it into a simpler system as soon as an opportunity to do so appears.

- ☐ Pursue the current attempts to bundle intermittent generators into more predictable units. In doing so, the government and the regulator should take utmost care that whatever bundling is chosen does not result in cross-subsidies.

Fossil Fuels

Upstream Hydrocarbons

- ☐ In view of the ageing infrastructure and the limited window of opportunity, revise the upstream taxation system to ensure an optimal exploitation of the North Sea resources.

- ☐ Standardise offshore regulation and make it more transparent.

- ☐ Encourage exploration in new promising frontier areas to maintain the UK's position as a net exporter of hydrocarbons as long as possible.

- ☐ For the gas from the UK North Sea to be developed, organise the interface with the regulated downstream sector in such a way as to avoid non-economic constraints on the marketing of the gas.

Natural Gas

- ☐ Implement soon an incentive scheme for Transco to invest in upgrading its infrastructure and eliminating bottlenecks in a timely manner. This may call for the regulator to define which individual pipeline projects are needed to "de-bottleneck" the infrastructure.

- ☐ Consider placing the security of supply obligation on the gas suppliers, not on Transco.

- ☐ Continue to leave as many parts of the gas industry as possible open to competition. Continue to concentrate the regulation of prices and conditions on the monopoly part of the industry.

Electricity

- ☐ Continue to allow the electricity market to settle into the smooth and fully competitive operation of NETA by refraining from intervention.

- ☐ Encourage full participation of the demand side in the balancing market (load shedding).

- ☐ Seek consistency in the regulation of the gas and electricity networks.

- ☐ Provide incentives for the transmission owner to build over the long term the infrastructure needed to secure supply.

Nuclear

- Take a more proactive attitude in the design and implementation of a comprehensive national policy for the decommissioning of nuclear power plants and fuel cycle facilities, and for the disposal of radioactive waste.
- In order to ensure the safe operation of existing nuclear facilities, continue to monitor the availability of adequate infrastructure, equipment and manpower.
- Clarify how it intends to keep the nuclear option open.

Energy R&D

- Clarify the priority among technology areas and revise the R&D programmes accordingly.
- Clarify the roles of the government and industry in specific technology areas to facilitate the deployment of technologies.

2

ORGANISATION OF THE REVIEW

REVIEW TEAM

An IEA team visited the UK in January 2002 to review the country's energy policies. This report was drafted on the basis of information received during, prior to and after the visit, including the government's official response to the IEA's 2001 policy questionnaire and the views expressed by various parties during the visit. The team greatly appreciated the openness and co-operation shown by everyone it met.

The members of the team were:

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ORGANISATIONS VISITED

The Department of Trade and Industry (DTI)
The Performance and Innovation Unit (PIU)
The Department for Environment, Food and Rural Affairs (DEFRA)
The Department for Transport, Local Government and the Regions (DTLR)

The Office of Gas and Electricity Markets (OFGEM)
The Carbon Trust
The Energy Saving Trust

British Petroleum plc (BP)
Centrica plc
The Lattice Group
The National Grid Group plc
PowerGen plc

The Association for the Conservation of Energy (ACE)
The British Nuclear Industry Forum (BNIF)
The British Wind Energy Association
The Electricity Association (EA)
The Green Alliance
The Oil and Gas Environmental Consortium
The UK Offshore Operators Association (UKOOA)

3

ENERGY MARKET AND ENERGY POLICY

ENERGY MARKET

The United Kingdom of Great Britain and Northern Ireland, or abbreviated United Kingdom (UK), comprises England, Scotland, Wales and Northern Ireland. The country is the world's fourth-largest economy. In the year 2000, the UK enjoyed its ninth consecutive year of positive economic growth, and experienced the lowest inflation for over 30 years. Employment rose to a record high, with unemployment falling to its lowest level since the 1970s. The service sector has become increasingly prominent in recent decades, accounting for some 70% of gross value-added in the UK during 1999. Manufacturing activities contributed a further 19%, with the difference made up by other production industries (5%), construction (5%) and agriculture, hunting, forestry and fishing (1%). International trade plays a key role in the UK economy, with exports accounting for 27% of GDP during 2000.

The UK joined the European Union (EU) in 1973 (confirmed by referendum in 1975), but has no plans to join the common European currency, the euro, in the immediate future. Some 52% of UK goods and services exports went to the EU, and around 18% to the United States. The EU supplied 52% of goods and services imports to the UK, with a further 16% coming from the United States.

In 1998, devolution legislation was introduced to establish the Scottish Parliament, the National Assembly for Wales and the Northern Ireland Assembly. These bodies are generally referred to as the devolved administrations. Devolution gives these Parliaments jurisdiction over a range of issues such as education, health, transport, environment and agriculture. In the devolution process, the UK government reserved most aspects of energy policy, although some energy issues were devolved, e.g. renewable energy to the Scottish Executive. The departments responsible for energy policy maintain regular contact with the devolved administrations over issues of importance to them (e.g. oil and gas for Scotland). The UK remains a single market.

The UK government retains overall responsibility for energy policy in the UK, for climate change policy, including methods to meet the UK's Kyoto target, and for reserved policies such as taxation. But the UK government and the devolved administrations are co-operating intensely to develop together an overall strategy for climate change policies. Local government is responsible for implementing policies at a local level through their responsibilities, for example as planning and waste authorities, and as housing and local transport providers.

The UK is a country of 242,900 square kilometres on two major and many smaller islands off the north-west of the European Continent. Most of the UK's land surface is in commercial use. In 2002, around 47% of the UK's territory was made up of intensively managed agricultural ecosystems. Thirty per cent of the land was less intensively managed or semi-natural. Woodlands accounted for 12%; urban and built-up areas made up most of the remaining 11%. The proportion of land used for agriculture has declined over the past 20 years, whilst woodland, urban and semi-natural areas are increasing.

The country's climate is maritime: variably cool, moist, temperate and with a moderate annual temperature and limited ranges. Average annual precipitation rates range from less that one metre to over three metres. Space heating is needed in buildings throughout the winter months and the use of air-conditioning in the summer months is increasing. Temperature records for Central England indicate a warming of the UK climate of about 0.7°C since the 17th century, of which about 0.5°C has occurred during the 20th century. The warming has been greater in winter than in summer. In England, four of the five warmest years in a 340-year record have been in the 1990s, and 1999 was the warmest year ever. Modelling[1] suggests that average temperatures in the UK could rise by a further 3°C by 2100. Winters and autumns are expected to become wetter, and spring and summer rainfall patterns to change. The climate-induced rise in sea level, together with natural vertical land movements, could be 41 centimetres in the east of England and 21 centimetres in the west of Scotland by the 2050s. Gradual changes in climate and sea level will also be accompanied by changes in the frequency of extreme weather events, such as severe floods.

The UK's population was 59.5 million in 1999. Of this, 49.8 million live in England, 5.1 million in Scotland, 2.9 million in Wales and 1.7 million in Northern Ireland. Population growth by about 5% is projected by 2021, and is expected to coincide with a long-term trend towards urbanisation. In England, for example, land in urban uses is projected to reach 12% of the land area by 2016 compared with 10.6% in 1991, with relatively high rates of urbanisation in the south-east and north-west of England. Some areas are sparsely populated, however, including the Highlands of Scotland, parts of Wales and part of the north-east of England. Population density in 1999 was 245 persons per square kilometre for the UK as a whole, with 381 in England, 141 in Wales, 125 in Northern Ireland and 66 in Scotland.

Energy Demand

The UK's total final consumption (TFC) of energy was 161.5 million tonnes of oil equivalent (Mtoe) in 2000. Oil and gas shared the bulk of this with 45.6% and 34%, respectively. The share of oil in TFC was slightly lower than in 1990 (47.3%) and

1. Department for Environment, Food and Rural Affairs (DEFRA): *3NC. The UK's Third National Communication under the United Nations Framework Convention on Climate Change*. London, October 2001.

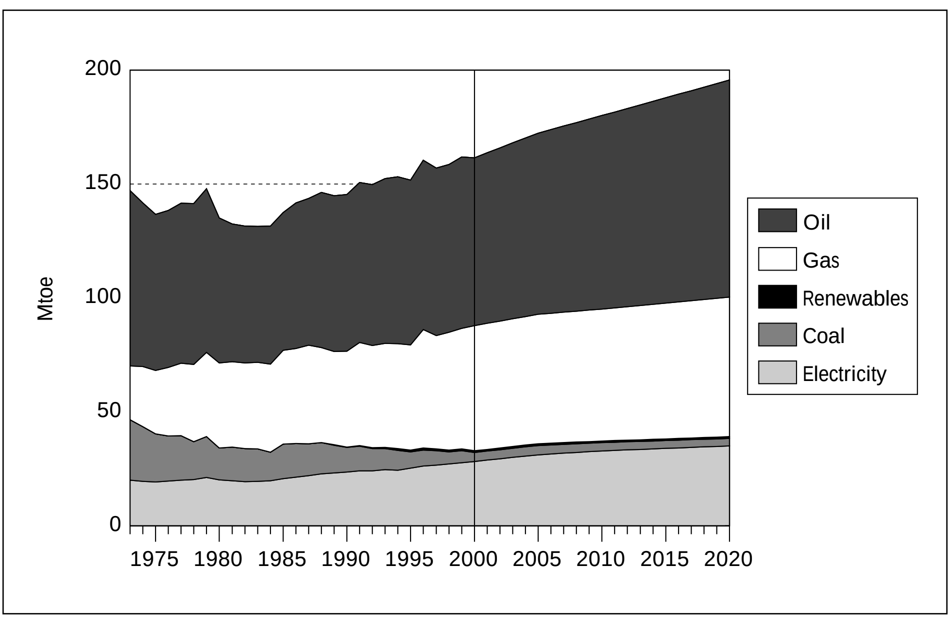
significantly lower than in 1973 (52.3%). The share of natural gas was up from 28.9% in 1990, and more than double 16.1% in 1973. Electricity ranked third with 17.5% in 2000 (16.2% in 1990 and 13.6% in 1973).

The most striking feature of energy consumption in the UK over the last three decades was the rise in natural gas use, and the decline in coal use, from 18% of TFC in 1973 to 2.4% in 2000. In the last 20 years industrial gas consumption grew by 21%, most of this in the last five years. Household users' gas consumption grew by 50%, and services gas consumption has more than doubled.

Oil demand fell after the oil crises but has been growing again since the late 1980s. Transport fuels increased their share of overall oil demand from 41% in 1980 to 63% in 2000, contrasting with a pronounced decline in the share of fuel oils among energy uses. The latter represents a move away from fuel oil towards natural gas as the preferred source of energy by electricity generators and by industry. Figures 1 and 2 show the development of TFC by source and by sector over the last three decades.

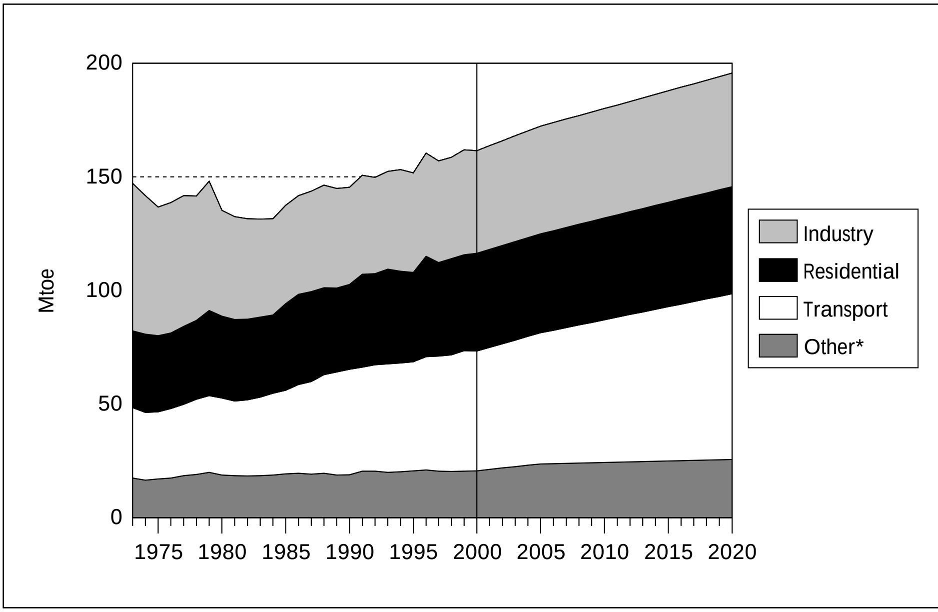
Figure 2 shows that transport is the sector where the bulk of TFC growth has occurred. There has been a rapid growth in total passenger and goods transport in the UK in recent decades. Transport is now the biggest energy user, accounting for 33% of final energy use in 2000. Households account for 29%, industry 23%,

Figure 1
Total Final Consumption by Source, 1973 to 2020



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001, and country submission.

Figure 2
Total Final Consumption by Sector, 1973 to 2020



* includes commercial, public service and agricultural sectors.

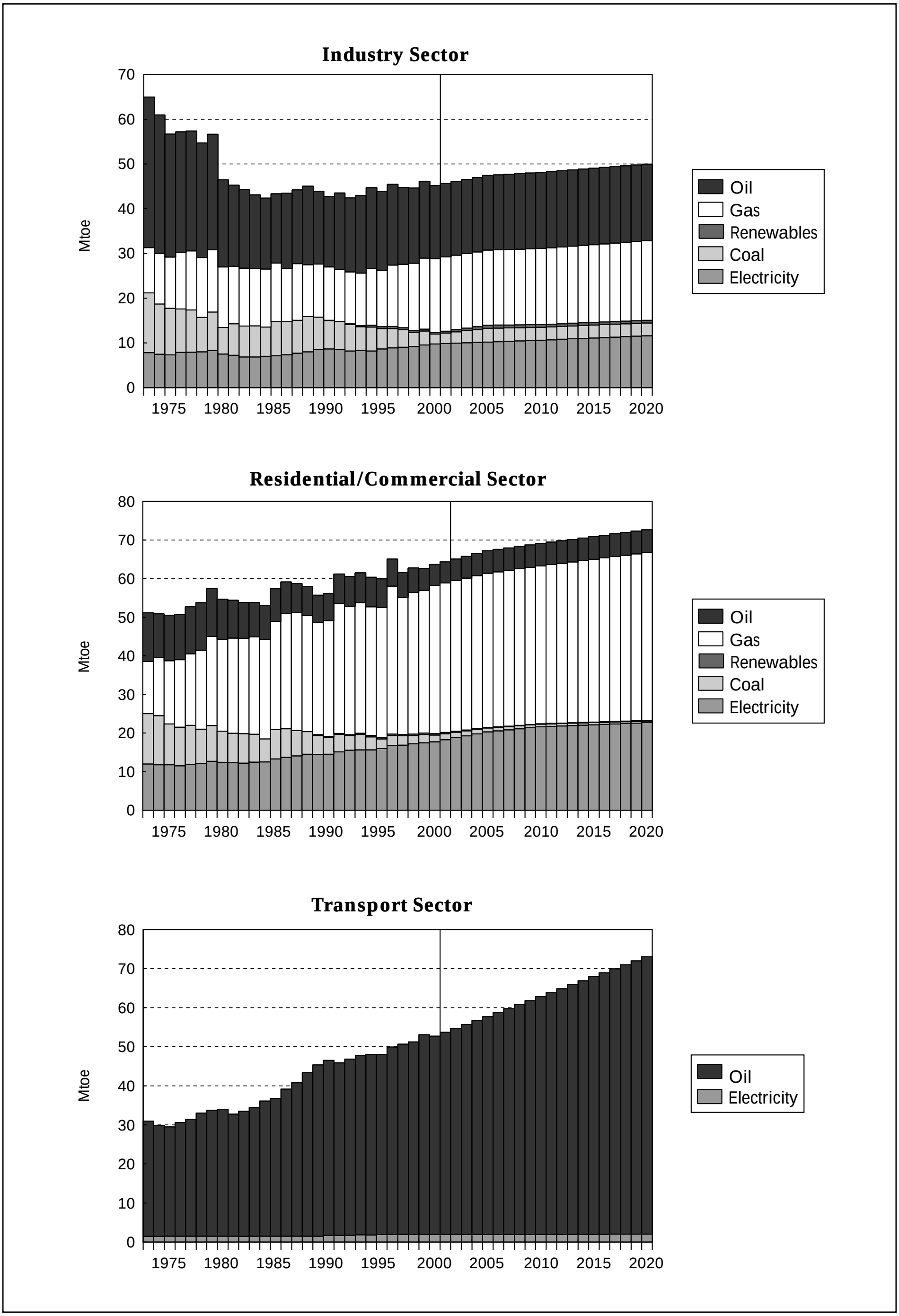
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001, and country submission.

and services and agriculture 14%. Industry had actually reduced its energy consumption in absolute terms between 1973 and 1990, and since then its energy use has seen only minor growth.

Transport is also the third-largest source of greenhouse gas emissions and, more importantly, it is the fastest growing source. The number of miles per year travelled by the average resident in Great Britain has increased by nearly a half since the early 1970s. Average journey lengths have increased by a quarter since the middle of the 1980s, the greatest change being in the length of commuting journeys. A quarter of car trips are less than two miles long, and over a quarter of households now have access to two or more cars. Road freight traffic has increased by 68% between 1980 and 2000.

If the growth of transport demand continues unabated, car traffic could grow by 20% over the next two decades, and commercial traffic by about 22%. The growth in road traffic has been accompanied by limited improvements in vehicle fuel efficiency, especially for passenger cars, since the middle of the 1980s. Although there have been substantial improvements in engine efficiency during the past decade, these have been largely offset by the effects of greater vehicle weight as a result of increased size, better safety standards and the provision of additional features such as air-conditioning.

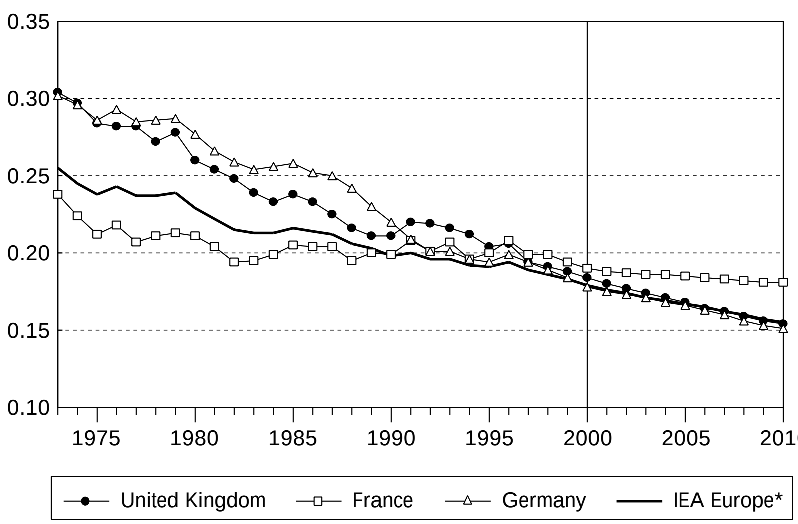
Figure 3
Final Consumption by Sector and by Source, 1973 to 2020



Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001, and country submission.

Figure 4 shows the UK's energy intensity (total primary energy supply, TPES, per unit of GDP) in comparison with other European countries. The energy intensity of the UK economy has been declining for some time. The energy ratio – calculated by dividing temperature-corrected primary energy consumption by GDP at constant prices – has been falling steadily, at just under 1.5% a year since 1950. It was half its 1950 level in 1999. The downward trend can be explained by a combination of factors: improved energy efficiency; fuel switching; a decline in the relative importance of energy-intensive industries; and the fact that some uses, such as space heating, do not increase in line with output.

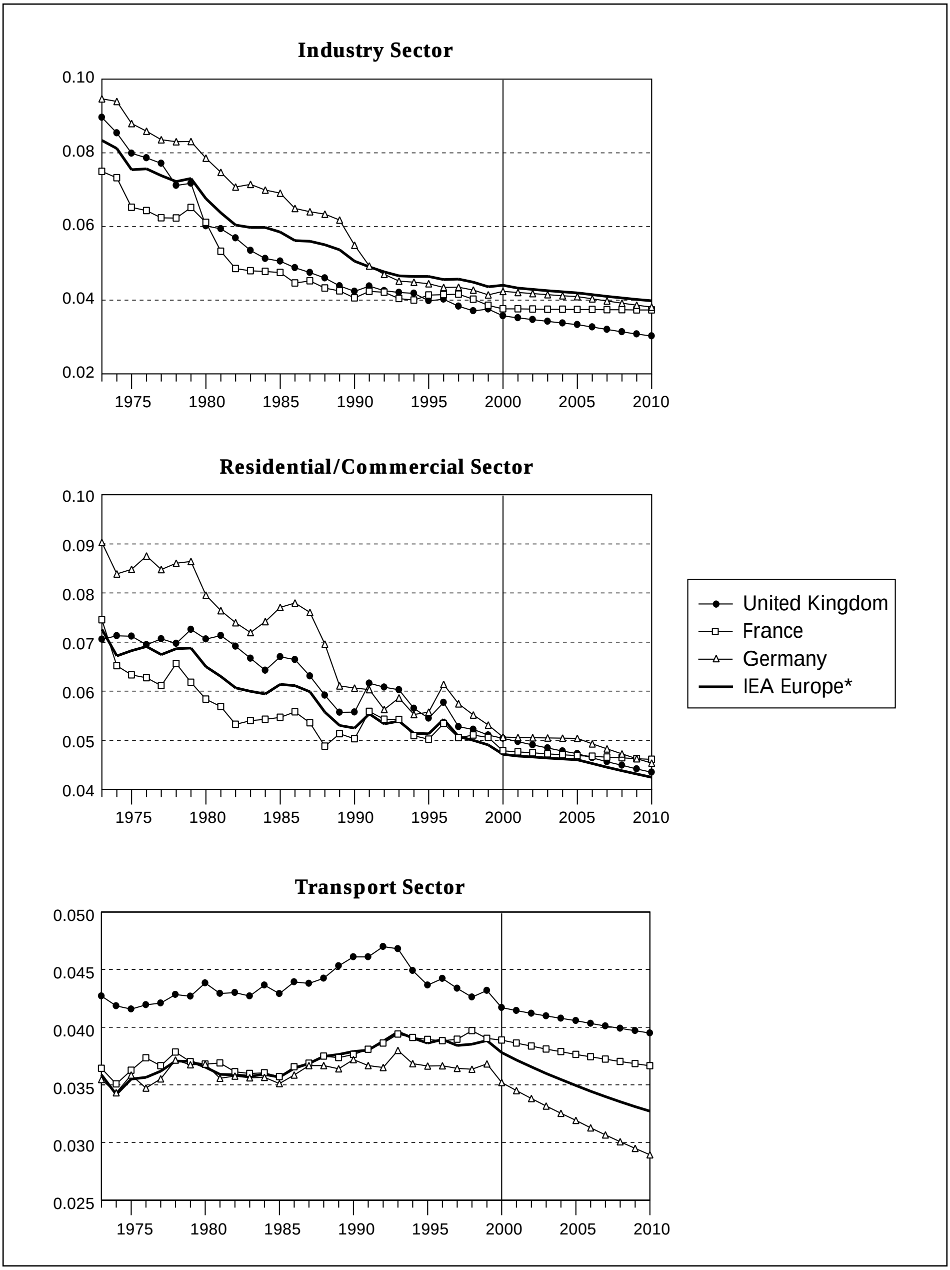
Figure 4
Energy Intensity in the United Kingdom and in Other Selected IEA Countries, 1973 to 2010
(toe per thousand US$ at 1995 prices and purchasing power parities)



* excluding Norway from 2001 to 2010.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001; *National Accounts of OECD Countries*, OECD Paris, 2001; and country submissions.

Figure 5
Energy Intensity by Sector in the United Kingdom and in Other Selected IEA Countries, 1973 to 2010
(toe per thousand US$ at 1995 prices and purchasing power parities)



* excluding Norway from 2000 to 2001.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001; *National Accounts of OECD Countries*, OECD Paris, 2001; and country submissions.

In 2000, the Department of Trade and Industry published new demand projections up to 2020[2]. These demand projections also form the basis of the UK's Third National Communication under the Framework Convention on Climate Change, submitted in October 2001. These projections represent an update of the government's projections of future UK energy demand and energy-related emissions of carbon dioxide last published in 1995. The document contains six scenarios based on three GDP assumptions and two energy price assumptions. These cover the key exogenous variables in the model.

The report's two central scenarios estimate economic growth of 2.5% per annum up to 2005 and 2.25% thereafter. Even under the report's high oil price scenario, oil prices are not expected to remain at the levels of over US$ 30/bbl reached in 2000 when supplies tightened in the face of strong demand. The report's high price scenario sees a gradual return to a sustainable high of US$ 20/bbl (1999 prices) by 2005, with prices remaining at this level thereafter. In its low price scenario, oil prices drop to US$ 10/bbl by 2005, remaining constant thereafter, as plentiful supplies meet growth in demand.

Final energy demand, in the central scenarios, is projected to grow at around 1% a year to 2010. Within this, growth is strongest (at 1.7% to 1.9% a year from 2000 to 2010) in the transport sector. However, this growth could be moderated somewhat by technological improvement, particularly through the voluntary agreement reached between the European Commission and vehicle manufacturers to improve fuel efficiency in order to reduce carbon emissions from new cars. Residential and services sector energy demand also shows continued growth, 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.

In the central scenarios, primary energy demand is projected to grow by around 0.7% to 0.8% a year to 2010. Overall, this growth in demand is lower than forecast in the 1995 projections. It implies that the primary energy intensity (ratio of primary energy demand to GDP) will fall by around 1.6% a year between 2000 and 2010 in the central low scenario, compared with about 1.3% actual per year between 1990 and 1999. In the central scenarios, total primary energy demand in 2010 is expected to reach 247.4 Mtoe (central – low oil price) to 242.8 Mtoe (central – high oil price). This is in line with the corresponding IEA figure of 244.1 Mtoe TPES. In 2020, the figures are 258.6 Mtoe and 251.3 Mtoe, respectively.

Longer-term energy demand and supply scenarios have recently been prepared by the UK government under its Performance and Innovation Unit (PIU) review of energy policy[3]. These scenarios, extending to 2050, are described in the box.

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2. Department of Trade and Industry (DTI): *Energy Paper 68: Energy Projections for the UK.* London, November 2000.
3. The PIU review is described below, in a separate section in this chapter.

The PIU Review Energy Scenarios

Scenario: World Markets (WM)

A world defined by an emphasis on private consumption with a highly developed and integrated world trading system.
– GDP growth averages 3%
– Sustainable development is marginalised
– Light regulation with a declining role for government in economic management
– Strong growth in international trade, energy markets dominated by fossil fuels
– Energy prices remain low in the short term, low priority for energy efficiency

Result: Final energy demand is higher by 40% in 2050 compared with 2000 in WM.

Scenario: Provincial Enterprise (PE)

A world of private consumption values coupled with policy-making reflecting local, regional and national concerns and priorities.
– GDP growth averages 1.5%
– Sustainability disappears as a political objective, renewables not developed, energy efficiency limited by available capital and the low priority of environmental investment
– UK independence in economic and foreign policy prioritised
– Use of existing sources of energy including indigenous coal and nuclear power
– Energy prices for consumers higher than in the world markets scenario

Result: Final energy demand is higher by 23% in 2050 compared with 2000 in PE.

Scenario: Global Sustainability (GS)

Social and ecological values are more pronounced and there is greater effectiveness of global institutions, including stronger collective action in dealing with environmental problems.
– GDP growth averages 2%
– Adoption of more sustainable technologies and behaviour, energy prices high owing to environmental policy, large global markets for renewable energy
– Greater co-operation and management within the international system
– Strong technological innovation
– New dwellings built to high environmental standards

Result: Final energy demand is lower by 20% in 2050 compared with 2000 in GS.

…/…

Scenario: Local Stewardship (LS)

Stronger local and regional governance allow social and ecological values to be demonstrated to a greater degree.

– GDP growth averages 1%
– Social values encourage co-operative self-reliance and resource conservation, high energy prices for all sectors particularly transport, willingness to invest in local renewable energy technologies
– Decision-making power, including regulation, is devolved
– Widespread adoption of energy efficiency measures
– Trend towards smaller households reversed

Result: Final energy demand is lower by 37% in 2050 compared with 2000 in LS.

Source: DTI.

Energy Production and Supply

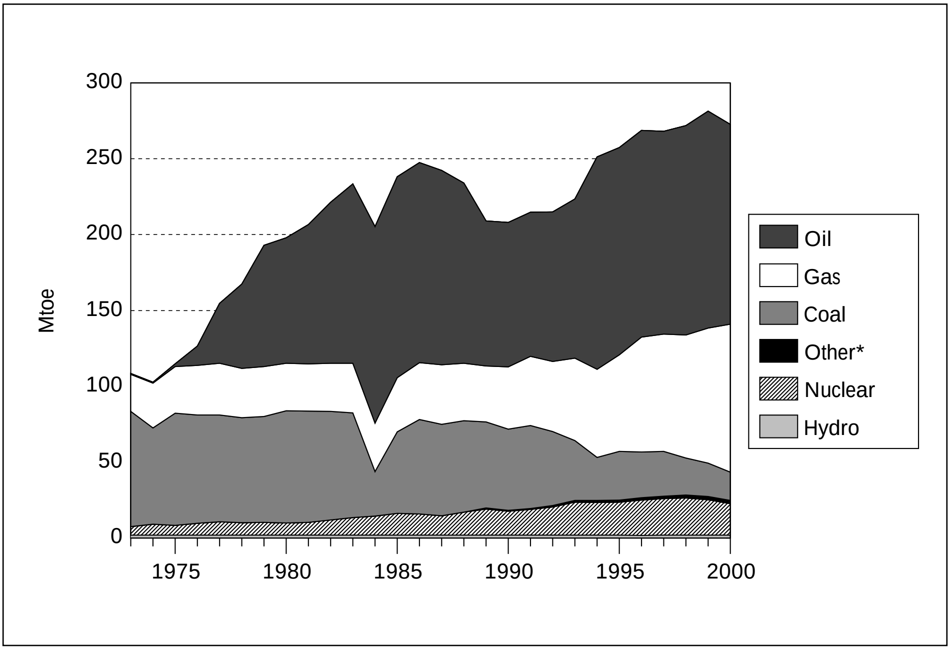
Figures 6 and 7 show the UK's energy production and total primary energy supply (TPES) by source. Figure 6 shows that the UK is, and has been for a long time, a major energy producer, especially of coal and natural gas. The UK produces approximately half of Europe's oil. In 2000, the UK's energy production was 272.7 million tonnes of oil equivalent (Mtoe). Total energy production in 2000 was 2.5 times the level of 1973, primarily owing to the growth in oil and gas production.

Overall energy production declined in 2000 from record levels in 1999. Oil production decreased by 8% from its 1999 record level. Only six new oil fields started producing during the year 2000 and these accounted for only 1.5% of production. Natural gas production hit record levels in 2000, climbing 9.5 % over 1999, and maintaining a series of annual production increases that began in 1989.

The general trend in the coal industry has been one of decline. Coal production in 2000 was a quarter of the level in 1980 and only a third of the level in 1990. This decline in coal production and the increase in gas production are clearly visible in the graph. The dip in the production in 1984/85 is a reflection of the year-long coal miners' strike that preceded the reform and privatisation of the UK coal industry.

Figure 7 shows how the supply of coal and oil declined over time, whereas the supply of natural gas and nuclear power increased. Overall, TPES was 232.6 Mtoe in 2000. In 1973, oil accounted for 50.5% of TPES, coal for 34.6%.

Figure 6
Energy Production by Source, 1973 to 2000

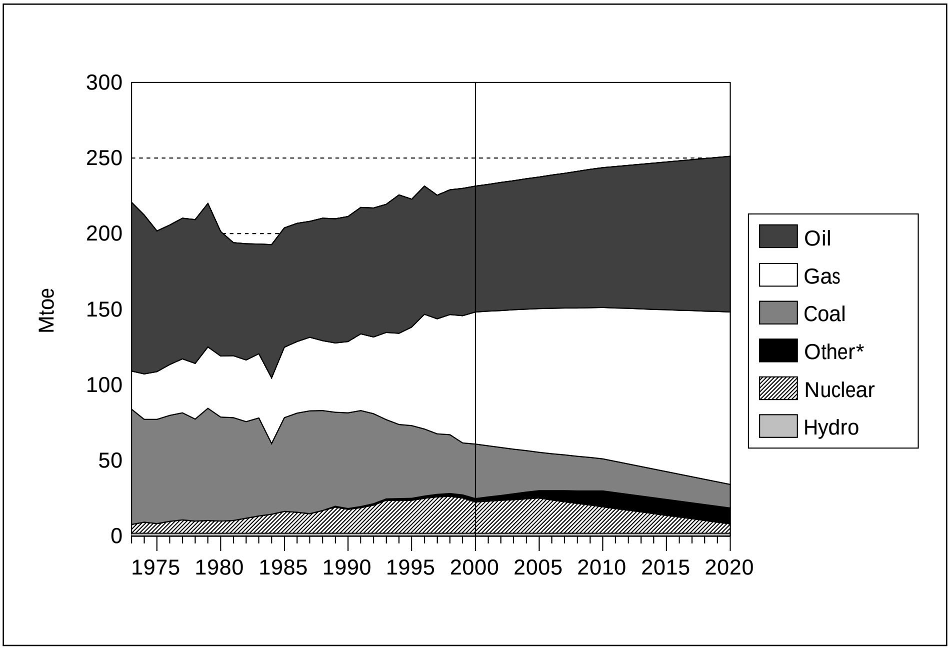


* includes solar, wind, combustible renewables and wastes.
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001, and country submission.

In 2000, oil had declined to 35.7% and coal to 15.5%. In the same time period, gas increased from 11.4% to 37.6%, and primary nuclear power rose from 3.3% to 9.5%. The growth in gas use and supply since 1991 can largely be attributed to electricity generation. This was caused by the privatisation and liberalisation of the electricity market, as well as by a number of accompanying factors such as the reform of the coal industry and the advent of the combined-cycle gas turbine (CCGT). Electricity generation now accounts for nearly 30% of natural gas consumption. Figure 7 also shows that the shortfall from the coal miners' strike was essentially compensated for by fuel oil.

The UK's energy industries contribute significantly to the country's wealth. In 2001, they were responsible for 4% of GDP, 8% of total investment, 24% of industrial investment, and 3% of business expenditure on research and development (R&D). In addition, they employed 165,000 people (amounting to 4% of industrial employment) and indirectly employed an estimated 360,000 people in the support of oil and gas production from the UK continental shelf (2000 figure). Before 1986, the contribution of the energy industries to UK GDP was more than twice as high as it is today, i.e. around 10%, because of higher oil prices.

Figure 7
Total Primary Energy Supply, 1973 to 2020



* includes solar, wind, combustible renewables and wastes.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001, and country submission.

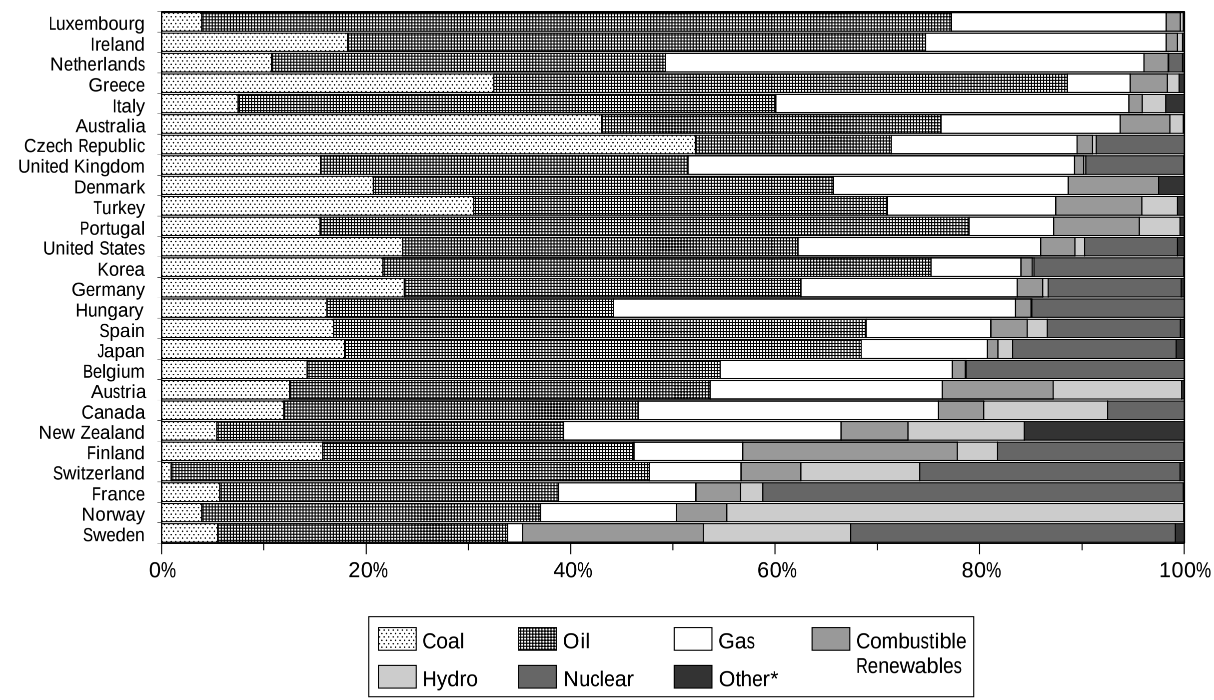
The UK is self-sufficient in energy and has been a net energy exporter since 1980. In 2000, the UK's total net energy exports amounted to 42.8 Mtoe. These exports generated a trade surplus in fuels of £6.5 billion in 2000. Net oil and gas exports taken together were even higher at 49.3 Mtoe and 9.3 Mtoe, respectively. Net coal imports of 14.6 Mtoe and net electricity imports of 1.2 Mtoe accounted for the balance. The UK exports its natural gas via the interconnector from Bacton to Zeebrugge in Belgium and via the interconnector from Scotland to the Irish Republic, and imports electricity from France through a 2-GW direct current cable.

The UK exports nearly all of its oil to the EU (Denmark, Finland, France, Germany, Greece, Ireland, Italy, the Netherlands, Portugal, Spain and Sweden), as well as to Canada, Norway and the US. EU countries took about 41 million tonnes out of total exports of 71 million tonnes of oil in 2000, the US alone took 26 million tonnes.

Oil and gas production are both expected to decline in the next few years. The largest oil and gas fields were discovered in the early phases of exploration and were brought on stream first. As these old fields peak and head into decline, their place has to be taken by an increasing number of smaller fields, which can sustain overall production only for a limited period of time. The UK government and significant parts of the oil industry believe that UK oil production passed its peak in 1999, and

Figure 8

Total Primary Energy Supply in IEA Countries, 2000



* includes solar, wind and ambient heat production.

Source: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001.

that production is set to fall by about 60% over the next ten years. The UK will likely rely increasingly on imports and revert to being a net importer of gas within the next five years. But there are also dissenting views that hold that the Atlantic Margin area to the west of Britain offers the prospect of sufficiently large reserves to significantly extend the period during which the country will remain a net exporter of oil and gas. Since deep water and strong currents make this environment harsh and costly to work in, exploration and development may require a supportive tax regime. So far, exploration in this area has been disappointing.

The PIU review predicts that by 2020 and on current policies, nearly half of the UK's energy needs will be met by gas, with coal accounting for just over 6%, renewables 4% and nuclear power 3%. The balance will be met by oil. The review also foresees that the UK will be importing 15% of its gas by 2006, by which time it may be a net importer of oil as well.

ENERGY POLICY

Energy Policy Institutions

The main responsibility for the development of national policies regarding all forms of energy supply in Great Britain falls on the Department of Trade and Industry (DTI). Important constitutional changes were introduced in 1999, establishing the Scottish Parliament, the National Assembly for Wales and the Northern Ireland Assembly. These devolved administrations have a right to be consulted on energy matters, and are themselves responsible for some energy-related matters such as energy efficiency policies and programmes and planning matters. The Northern Ireland Assembly is responsible for all energy matters in the province.

DTI's responsibilities include the government's relations with the UK Atomic Energy Agency (UKAEA), British Nuclear Fuels plc (BNFL, which also owns Magnox Electric plc), the Coal Authority, and the government interest in the development of the oil and gas resources of the UK.

DTI also contributes to the development of environmental and energy efficiency policies. The main responsibility for environmental and energy efficiency policy rests with the Department for Environment, Food and Rural Affairs (DEFRA). In May 2002, the Department for Transport (DfT) replaced the Department for Transport, Local Government and the Regions (DTLR), which previously was responsible for transport policy and hence for a large number of policy initiatives addressing the use of energy in transport and greenhouse gas emissions from transport. DEFRA and DTLR had been created in June 2001 out of the former Department of the Environment, Transport and the Regions (DETR) and the Ministry of Agriculture, Fisheries and Food (MAFF). Also in May 2002, responsibility for local government and the English regions was transferred to the newly created Office of the Deputy Prime Minister. DfT has the lead in delivering the £180 billion *10 Year Plan: Transport 2010*, which is a key part of the government's Climate Change Programme.

The Gas and Electricity Markets Authority (GEMA) and its executive arm, the Office of Gas and Electricity markets (Ofgem) were created under the Utilities Act 2000 and replace the former separate gas and electricity regulators (Ofgas and Offer respectively). The chairman of GEMA is chief executive of Ofgem, which oversees day-to-day regulation. The merging of the two former regulators reflected the convergence of the two markets – most suppliers offer both fuels (and in some cases other services as well) and, increasingly, electricity is generated from gas. The primary duty of GEMA is to protect the interests of consumers, whereas the main concern of Ofgas and Offer had been to ensure that the industry could finance itself properly. Ofgem is a governmental organisation but enjoys significant independence from the day-to-day business of the executive.

Energy Policy Objectives

Overall Policy Objectives

The government's overall energy policy remains "to ensure secure, diverse, 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 UK government is subject to a binding international target under the 1997 Kyoto Protocol and the EU's internal burden-sharing agreement of 17 June 1998 requiring a 12.5% reduction of greenhouse gas emissions (six gases) compared with 1990 levels by 2010. The government also is responsible for meeting the national target of cutting the UK's carbon dioxide emissions by 20% below 1990 levels by 2010.

Fuel Poverty

Among the most important policy initiatives in UK energy policy is the Fuel Poverty Strategy that the government launched on 21 November 2001[4]. The phenomenon of fuel poverty in the UK is the result of a combination of multiple factors. The UK housing stock is the oldest in Europe, and especially older residential buildings and

4. Department of Environment, Food and Rural Affairs (DEFRA), Department of Trade and Industry (DTI): *The UK Fuel Poverty Strategy*. London, November 2001.

houses are poorly insulated as well as difficult to insulate. Low-income households spend a comparatively large part of their budget on space heating in any case, but in addition they are drawn to the low-rent, poorly insulated end of the housing market, which is more expensive to heat than the average housing stock.

Hence, fuel poverty stems from many factors, including the state of the housing stock, available income (including social security benefits) and its distribution, as well as energy prices. The government has defined a fuel-poor household as "one that cannot afford to keep adequately warm at reasonable cost", i.e. one that needs to spend more than 10% of its income on all fuel use and to heat its home to an adequate standard of warmth. Adequate standards of warmth are defined as 21°C in the living room and 18°C in the other occupied rooms, in accordance with the temperatures recommended by the World Health Organization. Taking into account the above definition, the number of fuel-poor households in England in 2000 was 3.9 million if housing benefits were not included as part of income, and 2.8 million if they were. In 1998, the same numbers were 4.5 million and 3.3 million, respectively, on the same basis. In 1996, the number of fuel-poor households in the UK was estimated to have been around 5.5 million on the first basis.

Households inhabited by the elderly, by children and by the chronically sick or disabled are particularly vulnerable to fuel poverty. In 2000, this vulnerable group was estimated at 2.2 million to 2.4 million households if housing benefits were included as part of income, and 3.1 million to 3.3 million if they were not.

The government has set out in its 2001 Fuel Poverty Strategy document how it – and, in particular, DTI, DEFRA and the devolved administrations – intends to reduce fuel poverty in the UK. The document sets a target to seek an end to fuel poverty for vulnerable households by 2010. Fuel poverty in other, less vulnerable households will be tackled once progress is made on the priority group. The specific interim targets are:

- England: by 2004, the government aims to have assisted 800,000 vulnerable households through the Home Energy Efficiency Scheme (HEES)[5] now marketed as the Warm Front Team (WFT) and to reduce the number of non-decent social sector homes by one-third.

- Scotland: by 2006, the government aims to ensure that all pensioner households and tenants in the social rented sector live in centrally heated and well-insulated homes.

- Wales: by March 2004, the government aims to have assisted 38,000 likely fuel-poor households through the Home Energy Efficiency Scheme for Wales.

- Northern Ireland: by 2006, the government aims to have assisted at least 40,000 households in fuel poverty through the new Warm Homes Scheme and partnership programmes.

5. See Chapter 4.

PIU Review

On 25 June 2001, the government announced that the Performance and Innovation Unit (PIU), attached to the Cabinet Office, was to carry out a review of the strategic energy policy issues for Great Britain. The review was set within the context of meeting the challenge of global warming, while ensuring secure, diverse and reliable energy supplies at competitive prices. The main aim of the review was to set out the objectives of future energy policy and to develop a strategy that ensures that current policy commitments are consistent with longer-term economic, environmental and social goals. The review considered the role of coal, gas, oil and renewables in the UK's future energy balance as well as of combined heat and power (CHP), and the enhancement of energy efficiency. The review also considered what, if any, role the nuclear industry should play in meeting the environmental and security of supply objectives.

The project's findings are expected to greatly influence the government's future policy on security and diversity of energy supply and on climate change. The PIU Review Team reported to the prime minister at the end of 2001, and the PIU review was published in February 2002.

The PIU project stated three main energy policy challenges and attempts to develop ways of addressing these. The government also underlined that competitive markets will continue to be central to energy policy. The three challenges are:

- Managing potential conflict between energy and environmental objectives. Meeting the long-term targets for emissions reductions, whilst ensuring that future projections for energy demand are met, is thought to require fundamental changes in energy and fuel markets, the management of energy demand, the development of new technologies, and infrastructure and policy.

- Ensuring continued security and diversity of energy supplies over the long term, including appropriate investment incentives to maintain sufficient spare capacity in order to be able to cope with supply shocks, especially within the regulatory regimes for the energy utilities.

- Managing potentially conflicting policy goals for energy prices. Whereas higher energy prices could be a potent instrument for advancing environmental objectives, they are in potential conflict with fuel poverty[6] and industrial competitiveness objectives.

The PIU review stated that security and diversity of energy supply were once more central issues for several reasons. It cited the Californian experience of electricity blackouts in 2000 and 2001, the concerns resulting from the 11 September 2002 terrorist attacks in the USA, and the UK's future need to import gas possibly across long pipelines and from trading partners that seem to offer less security. The PIU review rejected the idea that self-sufficiency is necessary for security of supply as well as the notion that the government should determine the future fuel mix in the electricity supply industry.

6. See below.

The review suggested risk management along the following lines to safeguard security:

- Making maximum use of competitive markets. A key conclusion of the review was that the liberalisation of EU gas and electricity markets is important for energy security. Liberalisation would add flexibility and depth to European energy markets, increasing substantially the resilience of the energy system.

- Creating a more resilient and flexible energy system. The review considered various options for enhancing the resilience of the UK energy system, including increased gas storage; greater use of liquefied natural gas (LNG); and greater ability to use coal than would otherwise be the case. In the first instance, these are matters for market participants to address. The role of government should be to monitor the actions of market participants; to remove any barriers due to policies, and to intervene directly, as a last resort, where there is clear evidence of market failure and where the benefits of intervention are likely to outweigh the costs.

- Using international action to address global threats to energy security. The UK will become more dependent on imports of gas and oil. The report highlighted that there is little risk of a lack of gas internationally, with plentiful supplies and 70% of the world supplies accessible from Europe. But the report identified several potential concerns, namely the low level of investment in the exporting countries; the low level of investment in the transit countries; and facility failure abroad. The report stated that these risks were outside the direct control of UK purchasers or the UK government, and that they should be monitored. The report also suggested developing strong links with trading partners to ensure that the benefits associated with trade were mutually recognised and delivered.

With respect to issues like *grid reliability* and power plant investment related to the Californian experience, the report stated that the organisation and regulation of the UK power market were unlikely to give rise to the same problems. It said that present levels of capacity in UK electricity and gas networks and in electricity generation were healthy, and that the processes of privatisation and liberalisation seemed to have succeeded well. Even so, the report recommended monitoring the signals and incentives given by the regulatory structures and ensuring that the anticipation of public intervention does not lead the private sector to hold back on its own investment plans.

Recognising the fact that the energy system is the source of 80% of UK greenhouse gases and 95% of CO_2, the PIU review developed greenhouse gas emissions scenarios for 2020 and 2050. Scenarios for 2050 that the report assessed as "credible" suggest the possibility of CO_2 emissions reductions of 60%. However, this presupposes large changes in the energy system and in society. In particular, this would require substantial improvements in the energy efficiency of the transport system, and in the domestic and business sector. The report assessed these improvements as feasible. But even if they could be achieved, and even if the electricity system was to produce no carbon whatsoever, a 60% cut in CO_2 emissions could only be met if very large reductions in the use of fossil fuels in transport were made.

The Royal Commission on Environmental Pollution (RCEP) had proposed that the UK should adopt a strategy to reduce CO_2 emissions by 60% from current levels by 2050. The PIU report stated that it would be unwise for the UK to adopt this target unilaterally and in advance of international negotiations. Yet it anticipated that future, legally binding, international targets would become more stringent beyond 2012, and suggested a precautionary approach by which the UK should create a range of options for a low carbon future to be delivered, as and when the time comes. A centrepiece of any such long-term carbon-reducing policy should be the use of market-based instruments to put a price on carbon emissions and to help determine the most cost-effective opportunities. According to the report, this need not happen immediately, but decisions about long-term approaches were needed soon, since early commitment would start to influence decisions in many markets. The report said a central aim should be to enable the UK to participate in international carbon trading.

The review put forward a programme to accelerate the UK's *energy efficiency* improvements. At its centre was the suggestion of a challenging new target to improve domestic consumers' energy efficiency by 20% between 2002 and 2010, and by a further 20% between 2010 and 2020. This would approximately double the existing rate of improvement. The gains in terms of energy savings in a year could reach about 0.25% of GDP by 2020, over and above the cost of the investment needed to unlock these savings.

Combined heat and power (CHP) was seen as a low-cost option for carbon abatement, but not zero carbon. In the long term, it would benefit from policies that put a price on carbon. The report suggested that current market and institutional barriers to CHP should be removed.

The PIU review endorsed the *Renewables* Obligation[7], which the government is currently implementing, and noted that further efforts were needed to bring down the cost of new renewables and to establish new options. To this end, it proposed an expanded renewables target, calling for 20% of electricity supplied in 2020 to come from renewable sources of energy. The review estimated that meeting the whole of this 20% target could produce domestic electricity prices in 2020 around 5-6% higher than otherwise. The longer-term assurance that an extended target would be given to the industry could, however, help to bring down the costs of supporting renewables over the next decade. The review did not come to a conclusion about how the 2020 target should be met. This was deferred until the evaluation of the Renewables Obligation in 2006/07. It noted, however, that achieving the existing renewables target of 10% of electricity by 2010 was by no means guaranteed. According to the review, the renewables industry faces three institutional barriers that must be removed if it is to succeed. These are:

7. The Renewables Obligation is described in greater detail in Chapter 4.

- An excessive discount which, following the introduction of the New Electricity Trading Arrangements (NETA)[8], is currently imposed on the prices paid to small and intermittent generators.

- The way in which local distribution networks are organised and financed.

- The planning (plant siting) system which at present fails to place local concerns within a wider framework of national and regional need. In many parts of the energy industries, investors found that their projects had difficulty in gaining planning permission.

Another important result of the PIU review was the recommendation that measures be taken to keep the *nuclear* option open. The report stated that nuclear power offers a zero-carbon source of electricity on a scale which, for each plant, is larger than that of any other option. If existing approaches to both low-carbon electricity generation and energy security prove difficult to pursue cheaply, then the case for using nuclear would be strengthened.

The report stated that nuclear power was likely to remain more expensive than fossil-fuelled generation, although current development work could produce a new generation of reactors in 15–20 years that are more competitive than those available today. It then went on to say that, nuclear being a mature technology within a well-established global industry, there was no current case for further government support and that the decision to build new nuclear was a matter for the private sector. But private-sector decisions in favour of new nuclear have so far been exceedingly rare. Finland may soon become the first and so far only country with a liberalised electricity market where a new nuclear station is built[9].

But, given that the government sets the framework within which commercial choices are made, the report proposed that the government could, as with renewables, make it more likely that a private-sector scheme would succeed. Noting the UK nuclear industry's current suggestion of a 10 GW investment programme, the report stated that smaller and more flexible programmes would be preferred. If the UK does not support nuclear power today, the option would still be open in later years, since the nuclear industry is an international one, using designs that have been developed to meet circumstances in many countries. The desire for new options points to the need to develop new, low-waste, modular designs of nuclear reactors, and the UK was encouraged to continue to participate in international research aimed at this.

The report underlined that the nuclear skill base needs to be kept up-to-date. In particular the government should ensure that the regulators are adequately staffed to assess any new investment proposals. Action is also required to allow a shorter

8. For an introduction to NETA, see Chapter 6. For a discussion of intermittent renewables within NETA, see Chapter 4.
9. The Finnish Parliament voted in favour of a 5th nuclear plant on 24 May 2002.

lead time to commissioning, should new nuclear power be chosen in future. Finally, within a new framework for encouraging a low-carbon economy, the report recommended that any new methods to value carbon in the market correctly reflect that additional nuclear output is carbon-free.

The main focus of public concern about nuclear power is on the unsolved problem of long-term nuclear waste disposal, coupled with perceptions about the vulnerability of nuclear power plants to accidents and attack. Any move by government to advance the use of nuclear power as a means of providing a low-carbon and "indigenous" source of electricity would need to win widespread public acceptance. That acceptance is more likely to be won if progress can be made in dealing with the problem of waste.

The report noted that *coal* has a continuing role to play in the energy mix in the intermediate term. For the longer term, it recommended that CO_2 capture and sequestration be analysed as an option well suited to UK circumstances, since the UK has potential repositories in the continental shelf, and the carbon could be used to get more oil from existing wells. The government was called upon to reduce the current large uncertainties surrounding costs, safety, environmental impacts and public and investor acceptability.

The report stated that *transport* is likely to remain primarily oil-based until at least 2020. Access to oil supplies was not a current concern, but the economy's dependence on transport, coupled with increased imports as UK oil production declines, reinforced the need to improve the energy efficiency of oil-driven vehicles. The review also stated a need to develop alternative fuels, notably including fuel cells based on hydrogen and liquid biofuels, which are combustible renewable sources of energy. International efforts were needed to develop these technologies. It suggested limiting the projected growth in aviation energy use and CO_2 emissions through taxation.

To address the cluster of issues set out in the review, the report suggested that in the long term the government should bring together the three interlinked themes of energy policy, climate change policy and transport policy under one department of state. In the shorter term, the government should consider locating responsibility for energy efficiency and combined heat and power (CHP) policy with other aspects of energy policy. As an immediate response to the challenge, the government should set up a Sustainable Energy Policy Unit. The different responsibilities of the DTI and the regulators, most notably Ofgem, should continue. The DTI and DEFRA should do more to set out their priorities in guidance to Ofgem, so that Ofgem can further consider the impacts of its proposals for non-economic objectives. Ministers should take responsibility for intervention in markets if economic objectives conflict with environmental and social goals.

To achieve the goals of the review – to enable the UK to put itself on the path to a low-carbon economy, while maintaining competitively priced and secure energy – the report listed two main tasks that the government should undertake within the next five years:

- Move towards a clear rationale for the balance of policy instruments – taxes, permits and regulation – to create powerful incentives for long-term carbon reduction.

- Take immediate action to assist innovation and to create new options, and also to manage risk.

The report acknowledges the importance of the roles of the international community and international developments in these matters. In order to make progress, the PIU suggested as the next step a national public debate. During the review, proposals were made to the PIU for an extensive process of public involvement. There was insufficient time for this, but it is considered a central part of the implementation of the findings of the review. The government has announced that it will issue an energy white paper towards the end of 2002, following a process of public consultation.

Security of Supply

The issue of security of supply was also addressed by the European Union Committee of the House of Lords in reaction to the EU green paper on security of supply[10]. The report[11] of this committee was published in February 2002.

It concludes that liberalisation of energy markets will help promote energy security, but also that markets on their own cannot cope with the geopolitical problems that are the main source of security concerns. For this reason, there continues to be a role for governments and regulators. Energy security needs to be redefined for liberalised energy markets. Risk management should be at its core rather than central planning or self-sufficiency. The focus of energy policy should be on understanding, reducing and mitigating risks, and should use diversity, flexibility and availability of backup as the main tools to achieve this. In the past, energy security was seen as the product of central planning and control, with the government taking ultimate responsibility for building sufficient capacity to meet demand. Import dependence was seen as inherently risky and energy policy focused on self-sufficiency, neglecting the fact that domestic sources could also be disrupted, by strikes, accident or terrorist action, for example. Also, self-sufficiency could be enormously expensive.

Diversity should apply to fuels, the sources of those fuels, and to transit routes, to avoid over-dependence on any particular source. Flexibility is necessary to ensure that the system can respond quickly to any disruption. Backup should be provided through the existence of stocks and alternative sources which can be expanded in

10. Commission of the European Communities: *Towards a European strategy for the security of energy supply,* 5619/01 COM(2000)769 final, Brussels, 2001.
11. House of Lords: *Energy Supply: How Secure Are We?* European Union - Fourteenth Report, HL 82, London, 12 February 2002.

an emergency. The report qualifies diversity and flexibility as characteristic of competitive markets. No fundamental incompatibility between energy market competition and security is found, but the government has to set the framework within which the market operates.

The House of Lords committee does not perceive the need to attribute significant new powers in the area of energy security to the European Commission (EC), or any need for an energy chapter in the EU's treaties. Instead, it recommends that the Commission's priorities be to complete a liberalised single market in energy, to facilitate energy interconnections between member States, to promote equivalent standards of emergency preparedness and to encourage stable investment conditions in producer countries.

The report contains recommendations with respect to individual energy sector issues and fuels. With respect to *nuclear* energy, it states that the UK's existing nuclear power stations will go progressively out of service in the years up to 2025. The effect will be to increase the dependence on gas in electricity generation from the current 40% to around 60% in 2010 and 80% by 2025, the balance being provided by coal and renewables. Without action, there is a risk that the nuclear power generation option will be lost by default. The report recommends that the government maintain the UK's present ability to produce no less than 20% of domestic electricity demand from nuclear, and that the EU should aim at least to retain its present proportion of nuclear power generation. Both the UK government and the EU should examine what is necessary to achieve this. The report identifies three main issues that must be resolved: the perceived safety of nuclear plant; the problem of nuclear waste disposal; and the economic viability of nuclear power generation. Generating electricity through nuclear power is currently much more expensive than through natural gas and coal. It recommends that the government proceed as a matter of urgency to agree a method of dealing with nuclear waste and an appropriate planning policy.

In the *natural gas* market, the report expresses concern that Europe and the UK are becoming increasingly dependent on external sources for the supply of gas. It expresses concern that many member States depend on one or two major gas trunk lines and that there is much variation in the levels of planning for gas storage. With storage equal to about 4% of annual consumption, the UK has relatively little indigenous storage compared with 25% in Germany and 22% in France. It is recommended that there should be a mandatory storage capacity obligation on companies supplying gas to UK customers.

Also, EU member States should be required to have comparable standards of emergency preparedness in relation to gas emergencies. In order to promote security of supply through greater market liquidity, the report recommends full market liberalisation, rather than large long-term contracts, to help create the conditions for the substantial investments needed in producing countries. The EC should continue to encourage gas interconnections and inter-operability between member States to create a larger, effective market.

The report highlights capacity constraints in the UK gas transportation grid (National Transmission System, NTS) and its entry points. Capacity at the two main gas terminals at St. Fergus and Bacton is allocated through capacity auctions, and the prices in these auctions have recently been high and volatile without causing capacity expansion. The report discusses this issue – it is also discussed in detail in Chapter 5 of this report. The House of Lords' report states that gas producers and suppliers are not likely to assume the commercial risk of contracting long-term supplies into the UK without reasonable predictability in the price and in the long-term availability of adequate entry capacity into the UK gas grid. It notes that this issue should be addressed by an incentives regime that would contribute to long-term security of supply and would address constraints on the network as a result of too much gas being landed and too little capacity being available to transport it. Also, new gas terminals should not simply be located next to St. Fergus and Bacton. Rather, the government should determine what means it has to ensure that new terminals are located so as to increase the diversity and flexibility of the infrastructure.

Coal is seen as a key element of energy diversity and flexibility. The committee recommends that Europe avoid handicapping coal unnecessarily in view of its contribution to energy security, and focus support for coal on the development of clean coal technologies, not on unprofitable coal mines.

The contribution of *renewables* is acknowledged, but the report cautions that it would be risky and premature to assume that renewables on their own would be able to provide the answer to the environmental and security challenges facing the energy sector, or that they should be the primary recourse.

As with gas, *electricity* security could be improved by facilitating trade and interconnection in electricity. It is recommended that EU member States and the Commission keep the electricity regulatory system under review to ensure that it promotes security of supply.

Energy Taxes

Overview

Apart from the introduction of the Climate Change Levy, the last four years have witnessed a number of small adjustments to energy product taxation. VAT on domestic gas and electricity was reduced from 8% to 5% in September 1997. As far as upstream taxation is concerned, the gas levy on Southern Basin gas was reduced to zero in April 1998. The Fossil Fuel Levy that is used to fund renewable energy under the Non-Fossil Fuel Obligation (NFFO) is now at 0.3% on all electricity bills.

The 2002 budget introduces important changes to upstream hydrocarbons taxation. These are designed to put in place a stable regime for the future that will secure the government a share of revenue on North Sea producers' profits which it considers adequate for the exploitation of a national resource. Effective Budget Day (17 April 2002), the new tax regime introduces a 10% supplementary charge on North Sea profits. Simultaneously, the government intends to promote long-term investment in the North Sea. Therefore, the new charge is counterbalanced by a 100% first year capital allowance for capital expenditure, rather than the 25% allowance available previously. This allowance also applied from Budget Day; therefore, most capital investment in the North Sea qualifies for an immediate 100% allowance against general corporation tax. Eventually, the government intends, subject to consultation on the appropriate timing, to abolish North Sea Royalty, which applies only to older fields.

In 2001, a Climate Change Levy was introduced on the use of energy in industry, commerce, agriculture, and the public sector, in support of the UK's climate change objectives. This levy is described in detail in Chapter 4 on energy and the environment.

Vehicle Excise Duty (VED)

Cars registered on or after 1 March 2001 are subject to graduated Vehicle Excise Duty (VED, an annual tax on road vehicles) based upon CO_2 emissions. Vehicles powered solely by electricity are exempt from VED and new gas-powered vehicles benefit from a small discount of £5 to £10. Diesel cars with lower carbon dioxide emission rates than similar petrol cars pay a small supplement to compensate for the fact that diesel cars may emit higher levels of particulates and other local air pollutants such as NO_x. It is these pollutants that pose the greatest challenge in terms of meeting the UK's air quality standards. Budget 2002 announced the introduction of a new low-carbon VED rate for cars that emit less than 120 g/km of CO_2. This increases the VED differential between the least and most polluting cars to up to £100 per year. Under Budget 2002 the new low rate of VED for cars producing less than 120 g/km CO_2 is £60/year for cars using alternative fuel, £70/year for cars using petrol and £80/year for cars using diesel.

On average in 2001, US$ 1 = £0.694.

Table 1

Vehicle Excise Duties

(private/light goods vehicles registered on or after 1 March 2001)

		Diesel Car TC 49*	*Petrol Car TC* 48*	*Alternative Fuel Car TC* 59*
Bands	CO_2 emissions (g/km)	12 months rate £	12 months rate £	12 months rate £
Band A	Up to 150	110.00	100.00	90.00
Band B	151 - 165	130.00	120.00	110.00
Band C	166 - 185	150.00	140.00	130.00
Band D	Over 185	160.00	155.00	150.00

*TC = taxation class.

Source: DTI.

The government also developed proposals for a comprehensive reform of lorry VED, to reflect better the environmental and track costs of different lorries. The proposals were welcomed by the road haulage industry. As a consequence, the government's 2001 budget introduced a new system of lorry VED that came into effect on 1 December 2001. These rates reduce the total burden that lorry VED imposes on the haulage industry, while at the same time improving the environmental signals that haulers face by encouraging the use of lorries that cause less road damage and pollution. As a result of these reforms, UK lorry VED rates are among the lowest in Europe for the cleanest and least-damaging lorries.

Additionally, heavy goods vehicles fitted with certain emissions reduction technologies, e.g. particulate traps, or converted to natural gas, have for some time benefited from lower VED rates under the Reduced Pollution Certificate scheme. However, the government wants to go further in improving the environmental signals from the VED system and therefore plans to offer reduced VED rates for lorries meeting the new Euro IV standard from around 2004. The government also issued new motorcycle VED rates, reformed the company car tax and fuel scale charges for fuel provided for private use, and developed proposals for lorry road-user charging.

CRITIQUE

Both the objectives and the implementation of UK energy policies are sound in principle. The UK government's general energy policy objectives are consistent with the *Shared Goals* of the IEA (see Annex B). It bases its energy policies on market mechanisms. The government has a pragmatic approach to energy policy measures and is prepared to tackle future challenges early on.

Like other IEA countries, the most fundamental task that the UK government is facing in energy policy is to reconcile the conflict between energy policy objectives, in particular the striving for low energy prices from competition, and the need for higher prices to address environmental and security of supply concerns. The solution to this conflict is internalisation of external costs. The government has taken numerous measures to ensure that this internalisation takes place[12]. Many of these measures are equally based on market mechanisms, which suggests that they do not compromise the economic efficiency of the UK energy market.

Over the past decades, government policy has shifted several times, which may well reflect the conflicting objectives referred to above. This has led to episodes of renewed, short-term government intervention within a general context of liberalisation. An example is the "stricter consents policy" for new gas-fired power plants, essentially a moratorium on the construction of new gas plants that was applied between 1998 and 2001 following public criticism that the rules of the

12. See Chapter 4.

electricity pool were biased against coal. That the pool rules were not optimal and required reform had become clear after the first few years of operation. That natural gas was the preferred power plant fuel in the liberalised market was evident – so strong was this preference that the expression "dash for gas" was soon coined for the UK experience after liberalisation.

Yet, whether the moratorium was really necessary is debatable. Reform to address the underlying problems was pursued at the time and might well have been sufficient in its own right to eliminate any inefficiencies and biases in the rules of power market trading. The coal industry shrank predominantly because of government reform to eliminate subsidies and privatise the economically viable mines. It is also important to note that the "dash for gas" increased the diversity of the UK's overall energy market and electricity supply. Before liberalisation, the UK electricity market depended on coal for almost two-thirds (gross electricity output 1990) of supply. Only nuclear power provided a significant counterweight with some 20%. Even in 2000, almost one-third of gross power generation was still based on coal, but the market was more balanced with about 40% of gas and 23% of nuclear. This fact was often overlooked, as power companies' plans for new capacity construction centred almost exclusively on gas. But the UK's starting position was lacking in diversity[13], and the "dash for gas" provided a corrective. It should also be noted that the decline of the very high share of coal contributed decisively to the fact that the UK managed to reduce its CO_2 emissions while at the same time enjoying almost a decade of economic expansion. This put the UK in a position where it can be confident to reach its Kyoto greenhouse gas emissions target, and where its stricter national target is within reach[14]. It also contributed to reduced air pollution.

The above discussion suggests that, whereas the general policy approach is laudable, more stability in the delineation of the remit of the market and government policy might be beneficial. This is particularly true at present, as the government is introducing or stepping up a number of policy programmes that are designed to further social, regional and environmental policy objectives combined with general energy policy. This includes the Fuel Poverty Strategy, the Climate Change Levy, the Renewables Obligation and other policies to promote renewables.

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13. The implications of the "dash for gas" for security of supply are complex. On the one hand, shifting to gas from coal may have contributed to faster exploitation of the gas resource, and thus advanced the moment in time when the UK has to import gas. If imports are seen as *per se* inferior in security, then this might be interpreted as a decline in supply security. On the other hand, the energy security report of the House of Lords points out that domestic supply does not necessarily mean secure supply, and domestic coal supply did certainly not mean secure coal supply, as illustrated by the supply record of the British coal industry before and during the coal miners' strike in 1984/85. Moreover, the discussion in the critique section in Chapter 5 on fossil fuels illustrates that the gas that was used in the "dash for gas" was to a large extent associated gas. Hence, it was the use of this gas that allowed the extraction of the oil associated with it. This may well have contributed to enhanced security of supply in the oil market.

14. See Chapter 4.

In principle, addressing fuel poverty through special energy pricing gives rise to distortions. In the context of the fuel poverty programme, energy suppliers are encouraged to help the fuel-poor, but this occurs only in the form of voluntary initiatives by the energy supply industry to alleviate fuel poverty in the short to medium term. A range of company programmes have emerged, including special tariffs for pensioners (an easily differentiated group, but not all fuel-poor), energy efficiency advice and simple energy efficiency measures such as low-energy lighting. Others include debt advice, benefits checks, help with simple bank accounts, and links with visiting health workers to promote referral of needy clients to programmes (government and other) which can help. The main thrust of the government's Fuel Poverty Strategy is to improve housing energy efficiency as the long-term answer to the problem.

The number of programmes targeting the energy-environment-security cluster of issues is likely to increase further in the future. In order to avoid surprises and pressure for government intervention later on in the process, the government should make sure that the public is amply informed and fully understands the degree to which energy prices will have to rise as a consequence. The PIU review states that the next step in this area must be a broad public debate. This debate should be used to convey and discuss this information. It should be conducted with the same transparency and inclusiveness as was the consultation process for developing the PIU review. The government has announced that it will issue an energy white paper towards the end of 2002, based on the findings of the PIU review and following a process of public consultation.

Taking into account the PIU review, UK energy policy was undergoing at least two major reviews at the time of the IEA's 2002 review visit. Simultaneously, a review of the performance and achievements of the Department of Trade and Industry is under way.

At the time of the last in-depth IEA review in 1998, no fewer than eight major energy policy areas were under review by the government, including the issues of energy sources for power generation, the operation of the electricity pool, the Non-Fossil Fuel Obligation, as well as many others. Separate reviews of ministries and authorities, often resulting in restructuring (e.g. the merging of Offer and Ofgas into Ofgem and the reorganisation of DETR into DEFRA and DTLR), went on in parallel. Further review and reorganisation may lie ahead, as responsibility for "rural affairs" in the Department for Environment, Food and Rural Affairs, and "the regions" in the Department for Transport, Local Government and the Regions might be merged since there is no real cleft in these policy areas. Moreover, the PIU review already suggests further restructuring, proposing that energy policy, climate change policy and transport policy be brought together in one department of state – which would conceivably mean merging or remerging at least the energy-relevant parts of DTI, DEFRA and DTLR.

Reviewing energy policy and energy policy institutions regularly is a sound strategy. However, in the UK this strategy has been taken very far, and any acceleration in the process of review and restructuring could actually prove counter-productive. The results from the PIU review show that the easy times of economic expansion and simultaneous environmental improvement that the UK went through during the 1990s will soon end or have already ended, essentially because the massive substitution of gas for coal will be finished. In the long run, meeting both the objective of prosperity and that of improved environmental performance will, this is clearly demonstrated by the PIU review, require hard choices on a massive scale. These choices have real effects on the distribution of wealth, and not everybody will be made better off. When they will have to be taken, it will not matter much how the government departments that must defend and impose them are structured. The public will care more about effective explanation of the rationale of policy measures and about their effective design.

What will be much more important will be to have a strong, motivated team that is able to develop the solutions least painful to society, convince the public of the well-foundedness of these solutions and implement them in a predictable, even-handed manner. It is not certain that nearly uninterrupted institutional and policy review will help build and/or preserve such a strong and motivated team. Frequent reviews certainly open the possibility to be responsive to criticisms expressed in the media – and to be seen to be responsive – but all major policy changes require time to work through the system and generate the benefits they are designed to deliver.

RECOMMENDATIONS

The Government of the United Kingdom should:

- ☐ In an ever-changing world, reaffirm its general energy policy objectives, i.e. to ensure secure, diverse, sustainable supplies of energy at competitive prices for the future.

- ☐ Stabilise to a greater degree the structure of governmental organisations and the definition of the remit of government and the market.

- ☐ Under this stable equilibrium, align the various energy policy institutions with the government's energy policy, eliminate overlap and strengthen co-ordination.

- ☐ Avoid, where possible, using energy policy measures to pursue social and other policy objectives. If this is unavoidable, clearly delineate the trade-offs and costs of such measures.

4

ENVIRONMENT, ENERGY EFFICIENCY AND RENEWABLES

CLIMATE CHANGE

Climate Change Commitments

The UK has two different targets relating to future greenhouse gas emissions. Under the 1997 Kyoto Protocol and the EU's legally binding internal burden-sharing agreement of 17 June 1998, the UK is committed to reducing greenhouse gas emissions by 12.5% below 1990 levels by 2008-2012.

But the government believes that the UK can and should go further, and that there will be benefits for the UK from taking early action to cut emissions. The government has therefore set a domestic goal to go beyond the Kyoto commitment and cut the UK's emissions of carbon dioxide by 20% below 1990 levels by 2010. The "Rio commitment" to bring the UK's greenhouse gas emissions back to 1990 levels by the year 2000 has already been met.

Trends in Greenhouse Gas Emissions

The UK is among a small number of OECD countries to have reduced its greenhouse gas emissions over the last decade. The UK's greenhouse gas emissions have fallen despite the strong economic growth the UK has enjoyed during the period. The reduction is largely a side effect to the restructuring of the energy supply sector, and especially the 30% decline in coal-based electricity generation and its replacement by gas-based generation between 1990 and 2000. But it is also the result of the promotion of greater energy efficiency, the introduction of pollution control measures in the industrial sector, and of policies to reduce methane emissions.

The UK's total greenhouse gas emissions were about 14.5% below 1990 levels in 1999. Over the same period, carbon dioxide emissions fell by 9%; methane emissions by 28%; and nitrous oxide emissions by 36%. Between 1995, the year the UK decided to use as the base for fluorinated gases, and 1999, hydrofluorocarbon (HFC) emissions fell by 60%; perfluorocarbon (PFC) emissions fell by 36%; and sulphur hexafluoride (SF_6) emissions increased by 18%.

Table 2 details UK greenhouse gas emissions at their respective baselines, their estimated development between the baseline and the year 2000, and projections to 2020. These projections for CO_2 and other greenhouse gases are contained in the

UK's Third National Communication under the United Nations Framework Convention on Climate Change[15]. They suggest that the UK is broadly on course to meet its Kyoto commitment for the period 2008-2012. The projections include the effect of several major climate change policies, notably the Climate Change Levy, the 10% renewables target and the fuel duty escalator to 1999.

The domestic goal to reduce emissions of CO_2 alone by 20% is more challenging. The projections suggest that under 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. 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 will resume an upward path. In 2020 CO_2 emissions are projected to be 4% to 7% above the level projected for 2010.

Table 2
Projections of UK Greenhouse Gas Emissions
(million tonnes of carbon)

Gas	*Baseline*	*2000*	*2010*	*2020*
Carbon dioxide	168.0	154.3	153.8	160.7
Methane	21.1	14.3	11.6	10.1
Nitrous oxide	17.9	11.2	11.5	12.0
Hydrofluorocarbons	4.1	2.5	2.9	3.0
Perfluorocarbons	0.3	0.2	0.1	0.1
Sulphur hexafluoride	0.3	0.4	0.3	0.3
Total greenhouse gas emissions	211.7	182.9	180.2	186.2
Change from 1990 (6 gas basket)		–13.6%	–14.9%	–12.1%
Change from 1990 (CO_2 only)		–8.2%	–8.4%	–4.4%

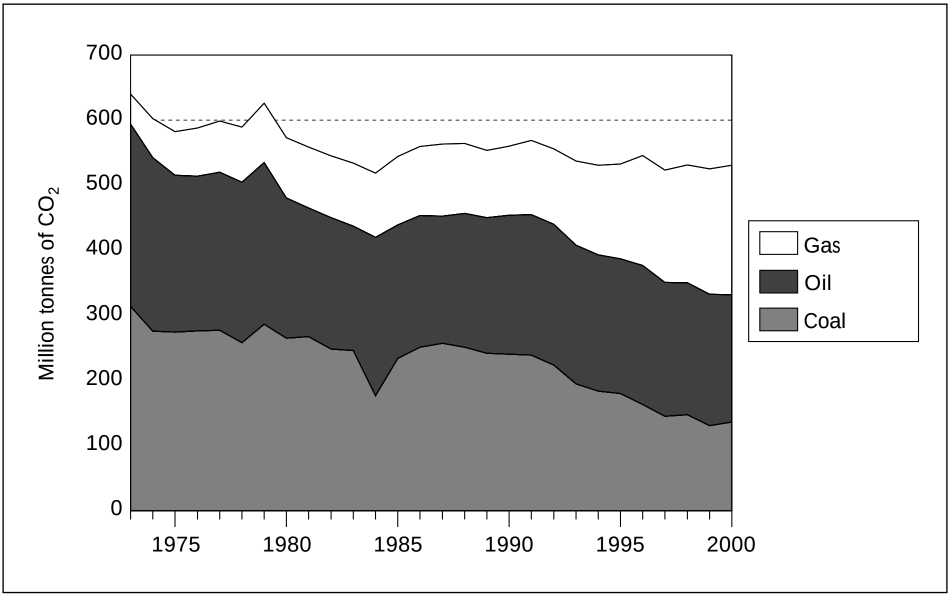
Note: 1990 has been used as the baseline year for carbon dioxide, methane and nitrous oxide. 1995 has been used as the baseline year for hydrofluorocarbons, perfluorocarbons and sulphur hexafluoride.

Source: Department for Environment, Food and Rural Affairs (DEFRA): *Climate Change – The UK Programme*, London, November 2000.

Despite the current favourable picture, additional efforts are needed and emissions are expected to increase in the future. The government and the devolved administrations are introducing policies to address the environmental, economic and social effects of these trends, within the overall framework of sustainable development.

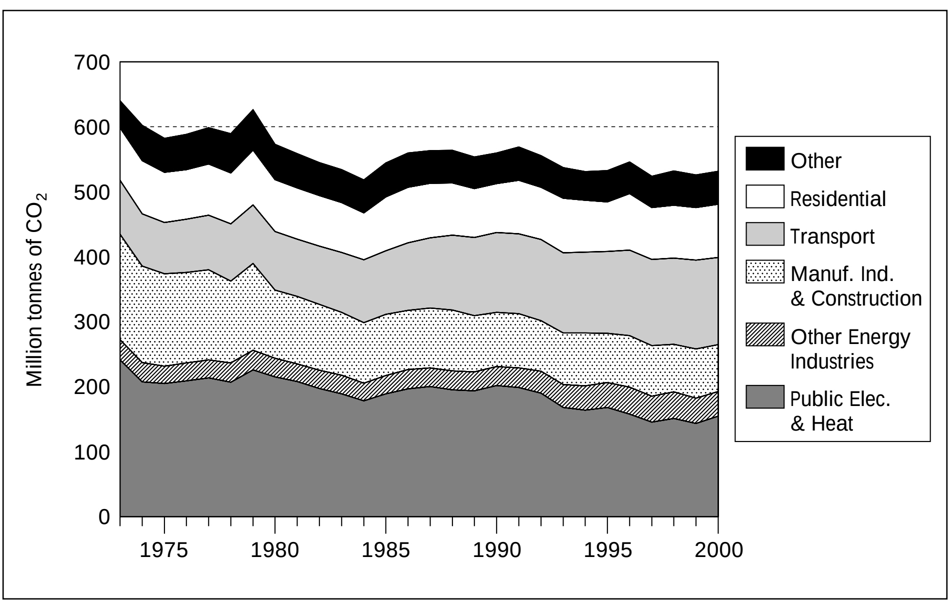
15. Department for Environment, Food and Rural Affairs (DEFRA): *3NC. Op. cit.*

Figure 9
Carbon Dioxide Emissions by Fuel*, 1973 to 2000



* estimated using the IPPC Sectoral Approach.
Source: *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2001.

Figure 10
Carbon Dioxide Emissions by Sector*, 1973 to 2000



* estimated using the IPPC Sectoral Approach.
Source: *CO_2 Emissions from Fuel Combustion*, IEA/OECD Paris, 2001.

Abatement Programmes

The Climate Change Programme is the UK's central policy document setting out how the country intends to address the challenge of climate change and meet its twofold target. It was published on 17 November 2000. The Climate Change Programme aims to:

- Deliver the UK's legally binding target under the Kyoto Protocol. These measures could cut greenhouse gas emissions by an estimated 23% below 1990 levels by 2010. This means that carbon dioxide emissions alone could be reduced by an estimated 19% below 1990 levels by 2010. Together with policies whose impact has not been quantified, the measures could also achieve the domestic goal.

- Set out a package of cost-effective, flexible policies and measures in which all sectors of the UK's economy play their part. The package aims to safeguard and enhance the UK's competitiveness and deliver wider benefits through lower energy costs for businesses and people, as well as through less fuel poverty, improved air quality, reduced risk to health, and new business and export opportunities.

- Respond to the need for action to cut emissions in the longer term (beyond 2010) by putting in place policies that give clear signals about the changes that will be required.

The individual actions taken under the Climate Change Programme comprise the following:

Business Sector

- A climate change levy (described in detail below) that includes challenging improvement targets for energy-intensive sectors through voluntary climate change agreements, and additional support for energy efficiency measures in the business sector.

- A UK-wide emissions trading scheme, with government support of £215 million over five years, to provide financial incentive for companies to take on binding emissions reductions targets.

- Establishment of the Carbon Trust, an organisation that is to recycle around £100 million of climate change levy receipts over three years to accelerate the take-up of cost-effective, low-carbon technologies and other measures by businesses and levy payers.

- A scheme of enhanced capital allowances to support investments by business in qualifying energy efficiency technologies.

- Exemption of "good-quality" combined production of heat and power, and of renewable sources of energy from the climate change levy.

- Energy labels, standards and other product-related measures designed to improve the energy efficiency of lighting, appliances and other key traded goods.

- Negotiated agreements with the energy-intensive sectors with challenging improvement targets.

- Integrated pollution prevention and control.

Power Generation

- The renewables obligation, which requires electricity suppliers to increase the proportion of electricity provided by renewables to 10% by 2010, subject to the cost to consumers being acceptable.

- A target of at least doubling the UK's combined heat and power (CHP) capacity by 2010.

Transport Sector

- European-level voluntary agreements with car manufacturers to cut engine emissions and to improve the average fuel efficiency of new cars by at least 25% by 2008-2009, backed up by changes to vehicle excise duty and the reform of company car taxation.

- A new 10-Year Transport Plan, foreseeing £180 billion of investment and public spending on transport over the next ten years to cut congestion and reduce pollution.

Residential Sector

- A new Energy Efficiency Commitment (successor to the Energy Efficiency Standards of Performance), through which electricity and gas suppliers help their domestic customers, particularly the elderly and those on low incomes, to save energy and cut their fuel bills.

- The new Home Energy Efficiency Strategy (HEES) in England, similar schemes for Wales and Northern Ireland and, in Scotland, the Warm Deal and the Central Heating Programme, and the promotion of new community heating and upgrading of existing systems. This includes new funding.

- An Affordable Warmth Programme developed in conjunction with Transco to facilitate the installation of efficient gas central heating systems and insulation in a million homes.

- The promotion of new community heating and upgrading of existing systems; and more efficient lighting, heating and other appliances.

- Improved energy efficiency requirements in building regulations.

Table 3
Summary of the UK's Climate Change Programme
(emission projections and additional measures)

	Measure	*Saving (MtC)*	*Change from 1990*
Projected emissions in 2010	Includes ongoing impact of measures introduced before 1997, as well as: – climate change levy per year – fuel duty escalator to 1999 per year – delivery of 10% renewable energy target per year	 2 1-2.5 2.5	
All greenhouse gases			**–15%**
Carbon dioxide			**–8.5%**
Additional measures			
Business	Climate change agreements	2.5	
Business	Energy efficiency measures under the levy package/Carbon Trust	0.5	
Business	Emissions trading scheme	At least 2	
Business and domestic	Reform of building regulations	1.3	
Transport	EU-level voluntary agreements on CO_2 from cars, backed up by changes to company car taxation and vehicle excise duty	4	
Transport	Ten-Year Plan	1.6	
Transport	Additional savings from sustainable distribution in Scotland and Wales	0.1	
Domestic	Domestic energy efficiency	2.6-3.7	
Domestic	Action to encourage replacement of community heating systems	0.9	
Domestic	New HEES (heating energy efficiency standards)	0.2	
Domestic	Appliance standards and labelling	0.2-0.4	
Agriculture, forestry and land use change	Afforestation	0.6	
Public sector	New central government, schools and National Health Service targets	0.5	
Scottish Executive	Building regulations, central estate and NHSiS targets	0.1	
Reduction from additional measures		**17.75**	
All greenhouse gases			**–23%**
Carbon dioxide			**–19%**
Examples of additional action not quantified at this stage	– further action by devolved administrations – housing expenditure by local authorities – improved management of traffic speed – further action by local authorities – carbon offset schemes – public awareness campaigns		Additional carbon savings

Source: DEFRA.

Other Sectors

- Continuing emission cuts and increasing sinks in agriculture and forestry through better countryside management; reduced fertilizer use; protecting and enhancing forests; better energy efficiency and encouraging biomass energy use.

- Ensuring that the public sector takes a leading role through new targets for improving energy management of public buildings, as well as through energy efficiency targets for local authorities, schools and hospitals and through green travel plans.

Table 3 summarises the main elements of the UK's Climate Change Programme and, where possible, provides an estimate of emission cuts in million tonnes of carbon that each policy is expected to deliver.

Three of the market-based measures for climate change abatement, i.e. the Climate Change Levy, the Climate Change Agreements built on it, and the Emissions Trading Scheme, are discussed below in greater detail. The measures relating to the promotion of energy efficiency and renewables are set out in greater detail in the following sections.

Climate Change Levy

In November 1998, a report on the role of economic instruments and the use of energy in industry, entitled *Economic Instruments and the Business Use of Energy*, was presented by the Energy Task Force, a team of senior civil servants appointed by the Chancellor of the Exchequer and led by Lord Marshall. This report contained a recommendation to address climate change and the need to limit carbon emissions through a climate change levy. Following this recommendation, the Chancellor of the Exchequer announced in March 1999 the introduction of a climate change levy on business energy use, to be implemented as of April 2001.

The Climate Change Levy is a tax on energy use in industry, commerce, agriculture and the public sector. Legislation to implement the levy is contained in the Finance Act 2000. The levy was introduced on 1 April 2001 and applies to gas, electricity, liquefied petroleum gas (LPG) and coal. Electricity generated from "new" forms of renewable energy, such as solar and wind power, and by "good quality" combined heat and power plants is exempted. The full rates of the levy are 0.43p/kWh for electricity, 0.15p/kWh for gas, 1.17p/kilogram for coal, and 0.96p/kilogram for LPG. Fuel oils do not attract the levy as they are already subject to hydrocarbon oil duty. The levy is added to energy bills before VAT is applied.

Residential energy users, charities and very small businesses (using domestic amounts of energy) are exempt from paying the levy. There are also further exemptions in transport, in production of taxable commodities and hydrocarbon oils, in "good quality" combined heat and power plants, and in non-fuel uses. Energy-intensive businesses can reduce their levy payments by participating in voluntary Climate Change Agreements. Companies can obtain a rate reduction of up to 80% if they enter into Climate Change Agreements. The reduction is 50% for horticultural producers. The levy package, including the Climate Change Agreements, is likely to save approximately 5 million tonnes of carbon per year by 2010.

The revenues generated from the levy are recycled back to businesses via a 0.3 percentage point cut in the main rate of employers' National Insurance Contributions and additional support for energy efficiency measures. The government calculates that there will be no net gain to the public finances from this reform. The levy package as a whole will be broadly neutral for the manufacturing and service sectors of the economy. The revenues also provide money for improving business energy efficiency. The sum of £50 million was available under the levy package in 2001-2002 to support the provision of energy efficiency advice, promoting the take-up of low-carbon technologies and the promotion of renewable energy projects. A further £70 million in 2001-2002 was allocated to finance a system of 100% first-year enhanced capital allowances (ECAs) against tax for firms making energy-saving investments. This was increased by £20 million in the 2002-2003 budget, although this includes support for both energy-saving technologies and low-emission vehicles and fuel infrastructure. The scheme is worth around £200 million in the period 2001-2003, depending on take-up.

Climate Change Agreements

The Climate Change Agreements between energy-intensive sectors of industry and the secretary of state are a new policy mechanism for achieving environmental objectives. In return for agreeing and meeting stringent targets to reduce energy consumption or emissions, these sectors are entitled to an 80% reduction in the Climate Change Levy. Eligible are all users that operate processes subject to regulation under the Integrated Pollution Prevention and Control (IPPC) directive, as implemented by the Pollution Prevention and Control (England and Wales) Regulations 2000 (or sites operating processes that would be subject to such regulation but for the fact that they fall beneath the relevant threshold, except for combustion plants).

The rationale for this eligibility criterion is that the processes in question are subject to a regulatory requirement to use energy efficiently. This requirement does not apply to other non-domestic energy users. The levy discount is designed to maintain the competitiveness of the energy-intensive sectors while providing an incentive at the margin to improve efficiency further. The eligible sectors cover all the main energy-intensive sectors of industry which are subject to international competition.

Currently there are 44 "umbrella" agreements with 39 sector associations. Some of these sector associations have a number of agreements to cover specific industry sub-sectors. Around 5,000 "underlying agreements" have been concluded with participating companies. The agreements cover around 13,000 individual facilities, and more sites are joining.

Facilities that are covered by a Climate Change Agreement are entitled to pay the reduced rate of Climate Change Levy until the end of March 2003. Before the end of this period, sectors will be assessed on the information that they have provided. Company energy efficiency data will be supplied through sector organisations and will permit actual energy savings to be compared against milestone targets. In this process, companies will be required to report the performance of their facilities to the relevant sector association. The sector associations will in turn report performance to the Department for Environment, Food and Rural Affairs (DEFRA). Also, throughout the course of the agreements, the data are subject to independent audit by auditors acting on behalf of the secretary of state. DEFRA undertook an informal progress review in January and February 2002 to ensure that robust sector data processing systems were in place.

The sector performance will be tested against the sector target adjusted for exits and entrants, emissions trading and, where applicable, product mix and/or throughput. If the sector (or sub-sector) has failed to meet this adjusted target, the individual facilities will be assessed. If the target has not been met, the relevant facilities will not be required to leave the agreement. They can remain within the agreement, but they will not be eligible for the levy discount for the next two-year certification period. If the facilities catch up with projected energy savings targets at the next review stage, then they can be re-certified and will, once again, pay the levy at the reduced rate. In isolated cases where regulatory or planning requirements imposed by the government have prevented the facilities from meeting their targets, the facilities will still need to demonstrate that they have made satisfactory progress.

Companies that have entered into Climate Change Agreements will be able to use the Emissions Trading Scheme (see below) to help them meet their emission targets. Emissions trading is expected to be the principal mechanism for dealing with fluctuations in performance within each target period. The agreements will therefore have an important role to play in establishing emissions trading in the UK as the agreements cover around 60% of the energy used by manufacturing industry.

Facilities are also subject to audit requirements by other environmental, tax and trading regimes, e.g. by DEFRA for Combined Heat and Power Quality Assurance, by the Environment Agency for Integrated Pollution Prevention and Control (IPPC), by HM Customs and Excise for payment of the levy, and the Emissions Trading Agency for trading. It is the government's intention to co-ordinate these regimes to avoid duplication of effort by both operators and auditors and to minimise the need for data collection, recording and inspection.

Emissions Trading Scheme

The UK Emissions Trading Scheme is a new policy initiative which forms part of the UK Climate Change Programme. It is a voluntary scheme, designed to allow UK companies to gain experience with carbon emissions trading before it starts on a wider geographical scale. The scheme complements the Climate Change Levy as a means for businesses to contribute to emissions reductions. It has been estimated that the Emissions Trading Scheme could significantly cut the cost to UK companies of complying with the Kyoto Protocol.

The framework for the Emissions Trading Scheme was launched on 14 August 2001. The scheme started in April 2002, three years ahead of the planned EU emissions trading scheme. As all emissions trading schemes, it consists of setting an overall target covering a group of participant organisations, and then letting those participants decide in a flexible way how to achieve their own target.

The government has agreed to provide a financial incentive for organisations taking on voluntary emissions reduction targets for a five-year period, 2002-2006. The government made £215 million available, equivalent to £30 million per year after tax. Participating organisations are required to make absolute reductions in emissions against a 1998-2000 baseline. The targets and the level of incentive payment were set through a competitive bidding process. Each participant was able to bid in absolute levels of emissions reduction at prices set through an auction. The government aimed to obtain the maximum level of reductions for the incentive money. Organisations successfully bidding in the auction have to deliver five equal incremental annual emissions reductions to qualify for their incentive payments. Companies that already have emission or energy targets set through the Climate Change Agreements will be able to use the trading scheme either to help meet their target or to sell any over-achievement if they can do better than their target.

Organisations will be able to undertake emissions reduction projects and sell the resulting credits into the scheme. These credits can then be used by other participants to meet their targets. A project must be in addition to emissions reductions that would have been delivered under business as usual. The Emissions Trading Scheme is open to most businesses and other organisations that are responsible for greenhouse gas emissions in the UK, although some emission sources are not eligible. These include emissions already covered by a Climate Change Agreement and those from electricity generation for usage off-site. Each participant must measure and report their initial (baseline) emissions and their annual emissions according to the government's reporting guidelines. All reported emissions are subject to independent third-party verification.

Organisations that receive the financial incentive operate under the "cap and trade" version of the scheme. They receive emission targets covering each annual compliance period. Emission allowances are allocated to them equal to this target each year, provided they have been in compliance in the previous year. Participants must demonstrate to the government at the end of each year that they have sufficient allowances to cover their emissions. Companies entering the scheme through the Climate Change Agreements operate under the "baseline and credit" version of the scheme. They do not receive allowances up front but can only receive credits after the emissions reductions have been verified. At the end of each year in which they have targets (i.e. every second year starting from 2002) they receive allowances if they have performed better than their target. If they have not achieved their target, they can buy additional allowances.

All allowance holdings are recorded on a computerised registry. Unused allowances can be banked for future use or sold. There will be no restriction on banking up to 2007. Participants with absolute emission targets will also be able to bank any over-achievement of their own target into the Kyoto Protocol commitment period starting in 2008. The time schedule for the start-up of the Emissions Trading Scheme was as follows:

- August 2001: Framework document and reporting guidelines published.

- August 2001 to December 2001: Pre-registration period to prepare bids for financial incentive.

- January 2002: Registration and auction to allocate incentive money.

- April 2002: Start of scheme.

Friday 1 February 2002 marked the end of the official pre-registration period for the UK Emissions Trading Scheme. On 4 February 2002, the government announced that 46 organisations across a range of sectors had successfully completed the first stage of entry for the UK Emissions Trading Scheme. These included Barclays, British Airways, BP, Caterpillar, Dalkia, General Domestic Appliances, Ineos Fluor, Rolls-Royce, Sainsbury's, Somerfield, Shell, TotalFinaElf and Whitbread Hotels. The auction determining five-year carbon dioxide emission targets and levels of incentive payment commenced on 11 March. Thirty-four companies successfully bid as direct participants, pledging over 4 million tonnes of emissions reductions over the five years of the scheme. This is over 5% of the planned reduction in the UK's annual emissions by 2010. Although details of individual trades are confidential for commercial reasons, the government considers the level of trading in this new market to date as very encouraging.

The Carbon Trust

The Carbon Trust was established in April 2001 as a non-profit organisation with the aim of accelerating the take-up of cost-effective, low-carbon technologies and other measures by business and the public sector. The Energy Savings Trust, set up in 1992, is responsible for implementing energy efficiency programmes in the residential sector (see next section). The Carbon Trust was set up as a separate organisation to reflect that the needs of the domestic and business sectors are often very different. In areas of common interest, both trusts have a joint programme of work.

The aim of the Carbon Trust is to help the UK move towards a sustainable, low-carbon economy whilst maintaining business competitiveness. In the short term, the organisation will concentrate on helping business save energy and money. In the longer term, it will develop the UK's capacity to meet the problems of climate change, considering not only commercial and technological factors but also wider socio-economic factors that hinder the move towards a low-carbon economy.

The trust's first year's funding is up to £50 million, from Climate Change Levy receipts and from the government's Energy Efficiency Best Practice Programme

(EEBPP). The trust will soon take over the EEBPP, which is the UK's main energy efficiency information, advice and research programme for organisations in the public and private sectors. The Carbon Trust will also manage and promote the government's Enhanced Capital Allowance (ECA) scheme for energy-saving technologies that has been operational since April 2001 (See next section for more detail on EEBPP and ECA).

Other Environmental Effects

Air Quality

Following the adoption of new EU air quality limits under the First Daughter Directive (1999/30/EC) of the Air Quality Framework Directive (96/62/EC), and public consultation in 1999, new national air quality objectives for 2005 to 2008 were placed in regulations in 2000. A further round of consultations on revised national air quality objectives for 2003-2010 began in autumn 2001. The objectives for sulphur dioxide, oxides of nitrogen and airborne particulates will be relevant to the continuing regulation of fossil fuel combustion in all sectors.

Acid Deposition

The final adoption of agreed revisions to the EU Large Combustion Plants Directive (88/609/EC) and the new National Emissions Ceilings Directive was approved by the European Parliament and the Environment Council on 23 October 2001. The UK government is considering the national implementation of these directives, in particular the option of using a national plan for reducing emissions of sulphur dioxide and oxides of nitrogen from existing (pre-1987) plants. The ceiling agreed for UK sulphur dioxide emissions from all sources by 2010, 585 kilotonnes, represents a reduction of about 85% from 1990 emissions.

Integrated Pollution Prevention and Control (IPPC)

To comply with the EC Directive on Integrated Pollution Prevention and Control (96/61/EC) the UK government passed the Pollution Prevention and Control (England and Wales) Regulations 2000 (SI 2000 No.1973) which came into force on 1 August 2000. These were made under the Pollution Prevention and Control Act 1999.

IPPC applies an integrated environmental approach to the regulation of around 7,000 mainly large and industrial installations across many sectors ranging from small textile units to large power plants. Emissions to air, water (including discharge to sewer) and land, plus a range of other environmental effects, must be considered together. IPPC aims to conserve energy, prevent emissions and waste production and, where that is not practicable, reduce them to acceptable levels.

IPPC also takes an integrated approach, from assuming the initial task of granting permission for a facility to operate, all the way through to restoring sites when industrial activities cease.

Under the Pollution Prevention and Control Regulations 2000, new or substantially changed installations will have to apply for an IPPC permit before they can start operating. Existing installations can continue to operate under the conditions of their current Integrated Pollution Prevention and Control (IPPC) permit until a new IPPC permit is granted in accordance with the transitional timetable between now and 2007. In relation to power plants, any "combustion activities" using appliances of more than 50 MW have an IPPC phase-in date of between 1 January and 31 March 2006.

ENERGY EFFICIENCY

In June 2001, the energy efficiency responsibilities of the Department for Environment,Transport and the Regions (DETR) were taken on by the newly formed Department for Environment, Food and Rural Affairs (DEFRA). The devolved administrations (the Scottish Executive, the National Assembly of Wales) are themselves responsible for some energy-related matters such as energy efficiency policies and programmes. The Department of Trade and Industry (DTI) also contributes to the development of energy efficiency policies. Energy efficiency forms a major part of the UK's Climate Change Programme of November 2000. Also, according to the Performance and Innovation Unit (PIU) Report of February 2002: "The current, apparently cost-effective, potential for energy efficiency is approximately 30% of final energy demand. The potential financial benefits in reduced costs to consumers (net of taxes) are £12 billion annually, and the potential carbon reductions are 40 million tonnes of carbon per year."

Residential / Commercial Sector

Energy use in the residential/commercial sector contributed about 40 million tonnes of carbon (26%) to the UK's total carbon dioxide emissions in 2000. Space and water heating together use more than 80% of the sector's energy. Light and appliances are responsible for only 11% of energy use.

In recent years, the government has adopted a number of energy efficiency measures, including the tightening every few years of the minimum legal requirements for the energy performance of new buildings that have been in force since 1965. The last Building (Amendment) Regulations Part L, which form an important part of the Climate Change Programme, came into effect on 1 April 2002. New dwellings will be required to meet improved standards of insulation and heating and new standards for lighting. For buildings other than dwellings, similar improvements are required, including the provision of energy meters, and testing and commissioning. Carbon savings of 1.3 million tonnes per year by 2010 are envisaged from these changes.

The government published in 2001 a new version of its Standard Assessment Procedure (SAP), which was introduced in July 1995 as the government's standard for home energy rating. The new version updates the calculation tables and incorporates additional features such as an extended scale (to encourage even higher standards) and a carbon index to be used for the new building regulations mentioned above.

The new Home Energy Efficiency Strategy (New HEES), a radical reshaping of a former scheme, was launched in June 2000 to offer packages of home insulation and heating improvements, including central heating systems, to those households most vulnerable to cold-related ill health. The scheme provides grants up to £2,500 tailored to the property type and the needs of the household. The government has allocated over £600 million to HEES up to 2004. From June 2000 to March 2002, HEES has helped over 350,000 householders with over 30,000 receiving new central heating systems. A full-scale evaluation on the health benefits achieved by the New HEES should be completed at the end of 2003.

In accordance with the Warm Homes and Energy Conservation Act of November 2000, the government launched the UK Fuel Poverty Strategy as a major initiative in November 2001. In all parts of the UK, the government and devolved administrations are committed to eradicating fuel poverty. By 2000, the UK had around 4 million fuel-poor households, which are defined as those that need to spend more than 10% of their income to keep adequately warm. The devolved administrations also have devised their own separate approaches to tackle fuel poverty.

The *Market Transformation Programme* is a policy research, development and support programme funded by DEFRA to improve the availability, adoption and use of domestic appliances and traded goods in the commercial sector which use less energy and do less harm to the environment. To date, the programme has established sector reviews in ten major sectors, covering 27 product types, representing 75% of UK electricity consumption. It is also seeking to develop and implement practical policy measures, such as mandatory energy labels, minimum energy efficiency standards and voluntary agreements negotiated with manufacturers within the framework of the European Commission. DEFRA monitors the product sales changes resulting from this programme.

Industry

Major improvements in energy productivity in the industry sector have been achieved since 1970, mainly by the shift in UK economic activity away from heavy industry. Increases in energy prices in the 1970s and 1980s played a major role. It is estimated that the technical energy efficiency potential by industrial sector is more than 30% above business as usual and the economic potential energy efficiency about 20%. Important initiatives were launched in 2001 to promote energy efficiency in industry.

As noted in the preceding section, the Carbon Trust was established in April 2001 to reduce the greenhouse gas emissions of businesses. Simultaneously, the Climate Change Levy was introduced on energy use in the non-domestic sector (industry, commerce, agriculture and the public sector). The Climate Change Agreements between energy-intensive industries and DEFRA are another new mechanism for achieving environmental and energy efficiency objectives in industry.

Introduced on 1 April 2001, the *Enhanced Capital Allowances* (ECAs) scheme provide 100% first-year capital allowances for approved energy-saving investments for businesses. The technologies and criteria will be reviewed annually and the Energy Technology Product list updated monthly. Companies can take this investment into account in calculating their corporation or income tax bills. The Carbon Trust will soon take over the management and promotion of this government scheme, which is worth an estimated £70 million in 2001-2002 and £130 million in 2002-2003, depending on take-up.

Both gas and electricity suppliers have a statutory responsibility to provide energy advice to consumers. From 1 April 2002 to 31 March 2005, the *Energy Efficiency Commitment* (EEC) to be enforced by Ofgem will place an obligation on such suppliers to help their domestic customers, particularly the elderly and those on low incomes, to save energy and cut their fuel bills. The government estimates that the average annual financial benefit for low-income consumers would build up to around £14 a year by 2005 and for all consumers around £10 a year by 2005. The proposed overall target for the EEC is energy savings of around 64 TWh, with 50% of the energy savings coming from customers receiving benefits or tax credit. The EEC will cut greenhouse gas emissions by around 0.4 million tonnes of carbon a year by 2005.

In addition to these programmes, a number of already established schemes continue to operate. These encompass the *Energy Efficiency Best Practice Programme* (EEBBP) which was launched in 1989 and is the UK's main energy efficiency information, advice and research programme aimed at commercial and industrial (including business transport) services, the public sector and all types of housing. It has helped many organisations save up to 20% on their energy bills. It also maintains the biggest library of independent information on energy efficiency in the country.

The *Energy Efficiency Advice Centres* (EEACs) around the country in partnership with local and national bodies give free, impartial and locally relevant advice to help householders improve the energy efficiency and comfort of their homes. To date, there are 52 such centres that have advised 900,000 customers to save energy and money.

Combined Heat and Power (CHP)

In 2000, CHP capacity reached almost 4,700 MW on 1,556 sites and was expected to be 5,000 MW by the end of 2001. While just under 50% of the CHP installations in the UK are small plants, with an electrical capacity of less than 100 kW, schemes larger than 10 MW account for over 80% of the total CHP installed electrical capacity. In 2000, 6% of the total electricity generated in the UK came from CHP schemes. The government has set a target of 10,000 MW of CHP capacity by 2010 as an important part of the Climate Change Programme. It has introduced a number of measures to promote CHP power plants.

The *CHP Quality Assurance* (CHPQA) programme certifies the energy efficiency and environmental performance of CHP schemes; it exempts "good quality" CHP from the Climate Change Levy. Over 1,200 CHP schemes have registered for CHPQA, nearly 900 of which have been certified. Good quality CHP is eligible for Enhanced Capital Allowances on investment in energy-saving technologies, and is exempt from business rates of the electricity-generating plant and machinery in CHP schemes.

Recent high gas prices and low electricity prices (which have fallen partially as a result of the implementation of the New Electricity Trading Arrangements) have created commercial difficulties for CHP. A draft government CHP Strategy addressing the market conditions affecting CHP and outlining the contribution of existing and possible new measures has been issued for public consultation in early 2002. Other new developments to encourage greater use of CHP include:

- The new £50 million *UK-wide Community Energy Programme* which aims to promote community heating through grants to install new schemes and refurbish obsolete infrastructure and equipment. This is intended to benefit 100,000 people on low incomes, while contributing to reductions in greenhouse gas emissions.

- The Revision of *Planning Policy Guidance Note 3: Housing,* June 2000, which provides some leverage for local planning authorities to encourage developers to explore the feasibility of energy-efficient options, including newly built CHP/ district heating.

- That power station developers who are seeking consent under the Electricity Act 1989 and the Energy Act must now demonstrate that they have explored the opportunity for CHP and sought to identify heat loads for the waste heat.

Public Sector

The public sector, including central and local governments, schools, hospitals and universities, accounts for less than 5% of the UK's total greenhouse gas emissions. However, it has a responsibility to lead by example in reducing greenhouse gas emissions and energy consumption. A number of energy consumption targets have been set for the public sector:

- The government set a target for reducing consumption in its own buildings by 20% of 1990/91 levels. By March 2000, savings of 17% had been made, equivalent to just over 0.3 million tonnes of carbon. It has also set a target of reducing CO_2 emissions from its estate by 1% a year against 1999/2000 levels and expects to introduce a new energy savings target in due course, based on the results of a current exercise to benchmark its estate.

- The UK Climate Change Programme gave a commitment to benchmark schools and improve their energy management over a five-year period. It is expected this will lead to 10% energy savings, equivalent to a reduction of 0.16 million tonnes of carbon over the next nine years.

- For the bodies of the National Health Service, the government has set a mandatory target to reduce energy consumption by 15% (equivalent to 0.15 million tonnes of carbon) of 2000 levels by 2010.

- For local authorities, the Home Energy Conservation Act (HECA) 1995 requires all UK local authorities with housing responsibilities to submit to the secretary of state an energy conservation report identifying practicable and cost-effective energy conservation measures. Significant improvement was defined as 30% (34% in Northern Ireland) over ten years from an agreed baseline of either April 1996 or 1997. In the first four years to March 2000, local authorities reported an overall energy efficiency improvement in the residential sector of just over 6%.

Transport

Transport has been the biggest energy user in the UK for the past 12 years, partly because of the large increase in the distance travelled (by both passengers and freight) and in the number of cars. It accounted for 34% of final energy use in 2000 and is expected to increase sharply. Between 1968 and 1998, passenger and freight transport almost doubled, a rise closely linked to economic growth. Total road traffic, measured in vehicle kilometres, is forecast to grow by 22% between 2000 and 2010.

Emissions from the transport sector of carbon dioxide (CO_2) currently represent a quarter of the UK's total emissions, and are forecast to increase by 2010 as traffic grows. The government's White Paper on the future of transport, *A New Deal for Transport: Better for Everyone, July 1998*, recognised that the environmental impacts of the growth in road traffic may be a threat to sustainable development and emphasises the need to reduce those impacts. Recently, the government amended two measures: the VED (vehicle excise duty) and the company car tax :

- In March 2001, graduated VED was introduced. New cars with the highest emissions will pay up to 55% more than the lowest polluters. The 2001 government budget also cut VED rates for existing vehicles. Rates have been cut by £55 for cars below 1,500 cc. This was extended from the 1,200 cc announced previously. About 5.4 million owners will benefit from this measure which will be backdated to November 2000. There is also an additional £10 reduction for alternatively fuelled vehicles. The 2002 budget also introduced changes to the vehicle excise duty.

- From April 2002, the existing system of company car tax, based on 35% of the car's price, subject to business mileage and age-related discounts, will be abolished. The new system will apply to all company cars, including second company cars. Company cars first registered after January 1998 are to be taxed on a percentage of their list price according to one of 21 carbon dioxide emission bands, measured in grams per kilometre (g/km). The reform will remove the perverse incentive in the current system to reduce the tax due by driving unnecessary, extra business miles and it will provide a significant incentive to company car drivers to choose more fuel-efficient vehicles.

It is estimated that the CO_2-based reforms to VED and company car taxation, along with the European-level voluntary agreements with car manufacturers, will result in savings of around 4 million tonnes of carbon a year by 2010.

The most important initiative designed by the Department for Environment, Transport and the Regions for delivering the aims of the 1998 White Paper is the 10 Year Plan[16], which is a key part of the government's Climate Change Programme. It is expected to deliver savings in CO_2 emissions equivalent to about 1.6 million tonnes of carbon a year by 2010. The plan aims to tackle congestion and pollution by improving all types of transport, including rail, road, public transport and private transport. It envisages the necessary level of investments, total private and public expenditure, to be £180 billion over the next ten years. The breakdown is as follows: public investment, £64.7 billion; private investment, £56.3 billion; public resource/revenue, £58.6 billion. The plan sets the strategic framework, and individual projects and programmes are to flow from decisions taken by a variety of agencies, the private sector, and through Regional Transport Strategies and Local Transport Plans, as well as public and private partnerships.

All modes of transport will benefit from this massive new investment. Spending on railways will total £60 billion, spending on roads, local and national, will total £59 billion, and local transport spending will also be increased substantially to a ten-year total of £59 billion.

Monitoring and Assessment

The UK government has long recognised the value of regular monitoring and assessment of energy efficiency programmes to ensure that the value of tax payers' money is maintained. The PIU report, based on assessments of most of the energy efficiency programmes and measures, is a striking example of this government concern. To get money from the Treasury, the government authorities in charge of implementing the various energy efficiency programmes have to report to it on the progress achieved.

Under the Climate Change Programme, the new programmes dealing mainly with energy efficiency will generally have to report progress regularly against interim

16. DETR: *Transport 2010: The 10 Year Plan*, London, July 2000.

targets towards the UK's Kyoto target (and the UK government's own 20% carbon reduction target for 2010). Some of the programmes involving tax discounts (e.g. the Climate Change Levy) will be subject to close scrutiny by the tax authorities.

Energy efficiency policies are also assessed by some independent non-profit organisations, such as the Green Alliance or the Association for the Conservation of Energy, which formulate recommendations to improve their effectiveness.

RENEWABLES

Renewable energy sources accounted for some 2.6 Mtoe or 1.1% of the UK's TPES in 2000. Most of this is from combustible renewables and wastes (2.1 Mtoe). The remainder comprises hydro-electricity (0.4 Mtoe) and other renewables such as wind energy. Table 4 shows the use of renewable energy resources between 1990 and 2000 in greater detail.

Table 4

Renewable Energy in the UK

(thousand tonnes of oil equivalent)

	1990	*1998*	*1999*	*2000*
Active solar heating	6.4	9.4	10.0	10.5
Onshore wind	0.8	75.4	73.1	81.3
Hydro	447.7	440.0	460.9	439.1
Landfill gas	79.8	402.4	572.0	731.2
Sewage sludge digestion	138.2	180.6	188.8	161.3
Wood	174.1	641.1	571.9	502.8
Straw (for heat)	71.7	71.7	71.7	71.7
Municipal solid waste	160.0	574.0	579.6	636.2
Other biofuels	24.0	197.3	240.9	362.7
Total	**1,102.7**	**2,592.7**	**2,769.8**	**2,996.8**

Source: Department of Trade and Industry.

According to the data set out in the table, "biofuels", or combustible renewables, accounted for 82% of renewable energy resources, with most of the remainder from large-scale hydro-power (15%). Wind power contributed 2.5%. Of the nearly 3 million tonnes of oil equivalent of primary energy use accounted for by renewables, 2.2 million tonnes was used to generate electricity and 0.8 million tonnes to generate heat. Renewable energy use grew by 8% in 2000 and doubled over the last 7 years. Renewables-based electricity accounted for 1.5% of electricity generated in the UK in 2000.

Whereas biofuels already contribute a sizeable share to the supply of renewables in the UK, there is a large technical potential for wind energy that has so far remained largely unexploited. According to government studies, the UK has one of the windiest coastlines in Europe, and offshore wind energy has the technical potential of supplying 100% of UK electricity demand. The country has one existing offshore wind farm, the Blythe project. Currently 18 offshore wind projects are under consideration, based on the support mechanisms set out in the following paragraphs. The box details the assessment from the government's PIU review relating to the potential of renewables between now and 2050.

Conclusions from the PIU Report on the Potential of Renewables in the UK

There is good evidence that onshore wind is likely to become amongst the cheapest of *all* generating technologies within 20 years, less than 2 p/kWh on average in good wind speed locations. Though developments are less certain in offshore wind, where world experience is limited, engineering assessment of offshore technology issues suggests that offshore wind is likely to become broadly competitive with conventional "baseload" stations by 2020, at 2 to 3 p/kWh.

There is equally robust evidence that photovoltaics (PV) is likely to continue to experience sustained and substantial cost reductions over the next 20 years. But although PV will become cost-competitive in many applications in sunnier climates, it will still be some way from being generally cost-competitive in the UK – 10 to 16 p/kWh – even taking into account the value of being a decentralised source of power. However, PV is widely expected to continue to secure cost reductions after 2020 and extrapolation beyond 2020 suggests PV could become cost-competitive with retail electricity in the UK by around 2025.

Advanced combustion technologies for energy crops also have considerable potential for cost reduction, with capital costs projected to fall by around 50% once demonstration plants such as "ABRE" in Yorkshire move into commercial deployment. Reductions in crop production and processing will also be required if energy crops are to become cost-competitive. This makes cost reductions in biomass more difficult to assess. Best estimates lie in the range 2.5–4 p/kWh.

More uncertainty surrounds wave and tidal technologies, with many competing devices currently at an early stage of development. As yet it is not clear which technologies will "win", and all face technical hurdles. Parametric estimates of potential costs suggest that costs will be of the order of 4 to 8 p/kWh for early devices, but it is not yet clear when this might be achieved. The UK is currently at the forefront of wave and tidal power; continued development could be secured at modest short-term cost.

The Renewables Obligation (RO)

The UK government believes that renewable sources of energy must be an essential ingredient of its Climate Change Programme and that they are set to make an increasingly important contribution to the provision of secure, diverse, competitive and sustainable energy supplies.

In the last ten years, the main instrument for the support of renewables was the so-called Non-Fossil Fuel Obligation (NFFO). Since privatisation of the electricity supply industry in 1990, public electricity suppliers have been obliged to secure a specified capacity from specified renewables through competitive bidding procedures for government support under the NFFO. Under the five rounds of the NFFO carried out to date, renewable technologies were separated into different technology categories, and competitive bidding rounds were organised for each category separately. This mechanism was successful in bringing down the cost of the support for renewables in each technology tranche, but less so in boosting the overall use of renewables in the energy market.

Recognising this, the government published a consultation paper in March 1999 seeking views on the kinds of support mechanisms which might be used in future to promote the development of renewables. The responses collected from interested parties offered a range of differing views, with no strong preference for any single format. There was however considerable support for an obligation on electricity suppliers to supply a specified proportion of electricity from renewable energy sources.

After further discussion with interested parties and extensive consideration within government, the government concluded that it should move away from the existing Non-Fossil Fuel Obligation arrangements and adopt a supply obligation. Subsequently, the details of the new Renewables Obligation (RO) were designed, and it was adopted under the Utilities Act 2000. The RO is also an integral part of the UK's Climate Change Programme. The Renewables Obligation will require licensed electricity suppliers to buy specified proportions of their purchases from renewable energy sources. It will stay in force until 2026 at least.

The most important feature of the Renewables Obligation is the target of raising the contribution of renewables to England and Wales's electricity supply to 10% by 2010. It is expected that in 2010, electricity sales will be about 324.3 TWh. According to the RO target, 10% of this, or 32.4 TWh, are to be renewables-based, subject to the cost to consumers being acceptable. The 10% renewables target for electricity is estimated to save an additional 2.6 to 3.0 million tonnes of carbon.

Scotland is expected to adopt a similar provision when a draft order is approved by the Scottish Parliament. Northern Ireland intends to match this target and may ultimately join the British scheme. Its contribution will count towards the EU indicative target.

Should the cost of supplying electricity produced from renewables become prohibitively high, suppliers can choose the buy-out option as an alternative to supplying what would be the more expensive renewable–generated electricity. It is proposed that the buy-out price will be set at a level of 3.0 p/kWh; and that buy-out receipts will be recycled to suppliers in proportion to the extent that they meet the targets set out in the RO, as evidenced by the redemption of Renewables Obligation Certificates. This increases the likelihood of meeting the 2010 target by providing a financial investment incentive for supply companies, whilst placing a limit on the overall additional cost to electricity consumers.

The DTI issued a draft Renewables Obligation Order in August 2001, to be placed on all electricity suppliers in England and Wales to supply a proportion of their electricity from renewable energy sources, and the Cabinet Office recently announced the distribution of financial support. The draft Renewables Obligation Order provides the detailed statutory arrangements of the order. The obligation will operate under the provision of Section 62 of the Utilities Act 2000. State aid clearance of the scheme has been completed, and with parliamentary approval now secured, its entry into force is imminent. The total cost to consumers of the RO was estimated at £780 million per annum by 2010, amounting to 10% of total electricity sales. There is a corresponding obligation for Scotland.

Under the draft Renewables Obligation Order, licensed electricity suppliers must ensure that a specified proportion of supplies is from renewable sources. It is intended that the proportion of supplies required to be from renewable sources in any one year will be based on the amount of electricity supplied by the licensed supplier in the previous year. If the supplier is not able to supply all or part of those supplies from renewable energy sources, it may instead purchase green certificates to show that another supplier has provided those supplies. If it is unable to buy green certificates, it may buy out its obligation by making a payment to Ofgem, the Office of Gas and Electricity Markets. There may be some exceptions – for example for new entrants to the supply market in their first year – but the intention is to place an equal obligation on all suppliers, corresponding to the volume of electricity that they supply.

Based on the draft Renewables Obligation Order of August 2001, the features of the definitive RO are to contain the following provisions:

- The suppliers on whom the obligation falls.

- The proportion of their supplies that must be from renewable energy sources in each year specified by the obligation.

- The sources of renewable energy which will be eligible to be counted in the obligation, including how electricity generated using fossil fuels will be treated. Eligible supplies can include a wide range of renewable sources of energy. Eligibility is restricted to UK renewables only, imports are not eligible. All new hydro-electric developments, all biomass, and the non-fossil fraction of advanced waste technologies (pyrolysis, gasification, anaerobic digestion) are eligible. Incineration of mixed waste, and existing hydro-electric schemes with an installed capacity exceeding 20 MW are not eligible, since large-scale hydro has long been established in the market and is in a position to compete in the open market with fossil energy. Co-firing and combined heat and power supplied from generating plants that consume both fossil fuels and renewable sources will be eligible under the new Renewables Obligation for a number of years as a transitional measure. Electricity from combined heat and power stations will be eligible if powered from renewable sources.

- The evidence of compliance that must be provided to Ofgem or its agents who will administer the scheme. Generators prove their compliance through Renewables Obligation Certificates (ROCs) that are tradable from generators to suppliers and between suppliers. Suppliers may bank within limits, but not borrow, the ROCs.

- Ofgem is to report annually the extent of compliance and the additional cost to electricity consumers using information from suppliers on the cost of securing renewables supplies and the cost of alternative supplies. The reports are to be published.

- The arrangements for the trading of green certificates as an alternative means of meeting the obligation. The Utilities Act makes it possible for suppliers to fulfil their obligation through the purchase of green certificates. Ofgem is responsible for certification. Green certificates will be issued in respect of each metered unit of electricity generated from eligible renewables.

  Suppliers' need for green certificates to fulfil the obligation will create a demand for the certificates. The government therefore believes that a market in green certificates will develop, in which suppliers trade with each other and with intermediaries. Prices are expected to vary according to the balance of supply and demand. Spot, forward and derivatives markets in green certificates may also emerge, enabling generators and suppliers to hedge their risks. The trade in green certificates can remain entirely separate from trade in the electricity. The electricity generated using renewables would simply be traded in the same way as electricity from non-renewable sources. However as long as electricity from renewable sources remains more costly than fossil generation, green certificates will command a positive price in the market. The price for renewables and therefore green certificates would be the higher the greater the production cost of renewables. If renewables were to become cheaper to produce than fossil generation, the value of green certificates could fall to zero.

- The arrangements for suppliers to be able to buy out their obligation or part of it as an alternative to supplying electricity generated from renewables or buying green certificates. These arrangements aim to protect consumers from an uncontrollable rise in the cost of RO if there are serious delays in the development of the industry. The new provisions allow electricity suppliers to buy out all or part of their obligation in any particular year as an alternative to supplying renewables-generated electricity or purchasing green certificates.

  The total cost of renewables-generated electricity needed to meet the obligation will reflect the underlying cost of regular electricity supplies plus the buy-out price. For example, suppliers who do not meet their RO in any particular year will have supplied their customers with non-renewable power purchased at a price of, say, 2.3 p/kWh and paid Ofgem the buy-out price of, say, 3 p/kWh. Consequently, in this example, the buy-out price will set a cap of 5.3 p/kWh on the price suppliers are likely to be willing to pay for electricity from renewables, which will itself provide an upper limit to the impact of the RO on consumer prices.

The government intends to recycle receipts from suppliers who choose to buy out their obligation back to them, on a basis to be set out in the order. The recycling mechanism is to provide further commercial incentives for electricity suppliers to meet the obligation through supply of renewable energy or purchase of green certificates rather than through buying out their obligation. Receipts might be recycled on the basis of suppliers' shares of the electricity supply market or on the basis of their renewable electricity supply under the obligation. In this way, revenue from non-compliant suppliers may be fed back to compliant suppliers.

- The price of the buy-out option. The buy-out price has been set at an initial minimum level of 3.0 pence for every kilowatt-hour by which the supplier fails to satisfy the obligation, indexed to inflation through the retail price index (RPI). This price might be increased by an amending order. It will be set following consultation and on advice from Ofgem, and it is expected that the same buy-out price will be used throughout Great Britain, even if a separate obligation is made for Scotland.

Under the Renewables Obligation, suppliers will be able to meet their requirements by any or a combination of the following means:

- Physically supplying power from renewables-generating stations.

- Purchasing green certificates independently of the power that gave rise to their issue.

- Paying the buy-out price to Ofgem.

Suppliers will be able to obtain electricity from renewables-generating stations that:

- They own.

- Are owned by generators with whom they have contracted individually.

- Are owned by generators with whom they have contracted collectively with other suppliers.

- Are owned by generators with whom they have contracted through intermediaries.

Transitional arrangements are being put in place to ensure that projects begun under the last NFFO rounds can be developed successfully. Eligible supplies under the RO are to include power from projects concluded under the first two rounds of the NFFO and the corresponding small hydro projects in Scotland. Arrangements for rounds three, four and five of the NFFO and the corresponding Scottish arrangements will be put in place to ensure that already contracted, commercially viable projects continue to attract and retain project finance.

The Utilities Act provides for secondary legislation to be developed to facilitate this process. The bill includes powers to continue the operation of the current sections 32 and 33 of the Electricity Act 1989 (relating to the NFFO and the Fossil Fuel Levy) and these measures may be amended to adjust to the new arrangements as necessary.

The government expects that further obligations may be imposed in respect of additional supplies from renewable sources in 2010 and beyond. Any further RO is expected to amend or extend the existing RO.

Other Incentives for Renewable Energy

As renewable energy policy is considered a particularly important part of the UK's Climate Change Programme, helping the UK move beyond its Kyoto target towards the government's domestic goal of a 20% cut in carbon dioxide emissions by 2010, it benefits from several other support policies beyond the RO:

- Renewables benefit from exemption from the Climate Change Levy. The levy and exemption rules were introduced from April 2001. This exemption concerns both electricity generated from renewable energy sources (with the exception of large-scale hydro) and renewables used as energy sources in their own right, e.g. for heat production. In order to qualify for the exemption, a supplier has to contract with a generator or generators of eligible renewable energy to purchase such electricity and to supply it to non-domestic consumers, and both supplier and generators have to agree to an independent audit by the authorities. The government has estimated that the exemption of renewables from the Climate Change Levy translates into an annual forgone tax revenue of £160 million between 2001 and 2010.

- The UK government has also announced a package of further measures to stimulate renewable energy costing over £260 million over the period 2001-2004.

- £89 million towards capital grants to help develop power generation projects using offshore wind and energy crops and small-scale biomass heating projects, through DTI and New Opportunities Fund support. Following consultations, detailed guidelines are to be announced shortly.

- Planting grants for energy crops (short rotation coppice and miscanthus) of £12 million. This is an England-only scheme managed by DEFRA.

- An initial pledge of £10 million to kick-start a major photovoltaic programme. The fuller plan for this programme remains under consideration.

- A further £100 million to bring on stream new-generation renewable energy technologies. Allocations from this fund are expected shortly in the light of recommendations from the Performance and Innovation Unit of the Cabinet Office.

- An expanded renewable energy research and development and technology transfer programme of £55.5 million to provide a technology push, and assistance in overcoming non-technical barriers to deployment. Reorganisation of this research and development programme is in progress.

- Development of a proactive strategic approach to planning in the regions and the introduction of regional targets for renewables based on renewable energy resource assessments.

CRITIQUE

Climate Change

Over the past decade, the UK has enjoyed both sustained economic growth and falling greenhouse gas emissions, a favourable position few IEA Member countries find themselves in. As a result, it seems that the country will meet its legally binding Kyoto target of reducing the emissions of six greenhouse gases by 12.5% below 1990 levels in the time period 2008-2012. At the same time, it appears that reaching the more ambitious national objective of reducing carbon dioxide emissions by 20% over the same time period requires extra efforts, although this target is also definitely within reach. Both targets are demanding and the progress that has been made so far is impressive.

But the task should not be underestimated. A recent study[17] concluded that special circumstances that cannot be repeated in future accounted for 60% of the reduction in energy-related CO_2 emissions in the UK between 1990 and 1999. These special circumstances include:

- The liberalisation and privatisation of the electricity and gas markets.

- The reduced political and financial support for the UK coal industry, which was privatised in 1994.

- Technological advancement, especially the combined-cycle gas turbine (CCGT).

- The impact of the EU Large Combustion Plant Directive on permitted SO_2 emissions and hence fuel choice.

17. Eichhammer, W., Boede, U., Gagelmann, F., Jochem, E., Kling, N., Schleich, J., Schlomann, B., Chesshire, J., Ziesing, H.-J.: *Greenhouse Gas Reductions in Germany and the UK – Coincidence or Policy Induced?*, Research report No. 201 41 133, German Federal Environment Agency (Umweltbundesamt), Berlin, June 2001.

- The abolition in 1990 of EU-wide limitations on gas use in power generation that had been imposed in 1975.

All of these factors strongly favoured substitution of natural gas for coal, especially in the power industry. As the UK had a comparatively high share of coal to begin with – a condition that is not necessarily met elsewhere – this substitution produced large environmental, and notably climate change-related, benefits. The share of coal in the country's TPES nearly halved from 30% in 1990 to 14.8% in 1999 (15.5% in 2000), as did the share of coal in power generation, from 65.3% in 1990 to 30.5% in 1999 (33.4% in 2000). The option of substitution is now largely exploited and is not available any more in future, or only to a very much lesser degree.

The UK government is aware of these issues and has developed a wide range of measures to fill the looming gap. Among them are policies that also target other objectives (fuel poverty, energy efficiency, renewables and security of supply). According to the government's estimates, the numerous measures set out in the Climate Change Programme of November 2000 will ensure that even the more demanding national target is met. This is equally a very encouraging result.

However, the climate policy measures were introduced in a pragmatic manner over the last years to create and make use of a political momentum, and as a result there is room for improvement. The Climate Change Levy is based on the energy content of fuels. It addresses only business and the public sector. In order to allow the most effective substitution away from carbon-rich fuels throughout the economy, other energy users, including residential customers, should be included. However, the government has a strong commitment to reduce the problem of fuel poverty that affects low-income households in old, insufficiently insulated buildings. This provides valid justification for exempting the residential sector from the tax, particularly since the government is simultaneously pursuing energy efficiency programmes for the fuel-poor. Over time, when the fuel poverty programmes have reduced this problem sufficiently, the government should reconsider applying the Climate Change Levy to the residential sector, too.

Energy-intensive industries can obtain a discount on the levy in exchange for commitments under voluntary agreements. In principle, this is a highly effective way of creating incentives for emissions reductions. However, the definition of eligible industries appears to be somewhat restrictive, as it is based on administrative decisions as to which industries do and do not qualify for such agreements. The voluntary agreements also appear to allow a certain degree of free-riding by paying for energy efficiency gains that would have been achieved without them. While free-riding is always difficult to avoid, greater care should be taken to limit its impact.

The government is putting an emissions trading scheme into practice that is intended to complement the Climate Change Levy. It offers incentives for companies to participate in emissions trading to gain early experience on the national level using a limited scheme before a mandatory, international scheme might apply. There is merit in measures that allow the UK's domestic industry to get acquainted with emissions trading in this manner.

But eventually emissions trading and carbon taxes are two mechanisms that aim at achieving the same objective: internalisation of the external cost of climate change into energy prices by means of market-based policy instruments. As international developments progress, the government should give priority to one of them, and align its other policy instruments accordingly to guarantee a cost-efficient response to the threat of climate change. Since the government's own cost estimates show that the emissions trading scheme has the potential to significantly reduce the cost to UK companies of complying with the Kyoto Protocol, there might be merit in placing the emissions trading scheme at the centre of climate change abatement policy. This perhaps could be done once the scheme has gone beyond the state of experimentation, at least for the business sector. In designing the concrete rules for the emissions trading system, the government should ensure that the emissions trading rules of the domestic scheme remain compatible with the other such systems that are being developed in the EU and beyond.

Energy Efficiency

The government's commitment to comply fully with the UK Climate Change Programme has highlighted the need to strengthen the energy efficiency policies and measures in all the energy sectors. Various energy efficiency measures and schemes have been or are being designed and implemented depending upon the targets, or sectors targeted. These include both mandatory and voluntary approaches, but with a particular emphasis on voluntary ones.

All these very ambitious programmes must be well co-ordinated if they are to be efficient and effective. At present, energy efficiency activities are divided among many organisations, ranging from energy suppliers (electricity and gas companies) to energy-intensive industries, to government bodies (DEFRA, DETR, DTI, Ofgem), to local governments. The multitude of players could be preventing the activities from working as effectively as possible to achieve their goals and perhaps the government needs to streamline and co-ordinate its programmes in order to avoid overlap and duplication.

According to the PIU report, the estimated potential for currently saving energy in the residential/domestic sector amounts to 17.4 Mtoe/year or 37.2% of its final energy demand. The government has already been active in this field: it has launched important initiatives and created new organisations, such as the Energy Efficiency Commitment, the new Home Energy Efficiency Scheme (HEES), the Community Energy Programme, new building regulations, the Fuel Poverty Scheme, the Energy Savings Trust, etc. This is commendable.

However, there could be some duplication of efforts between programmes addressing the same targets. This is the case, for example, in the promotion of energy efficiency measures in households of low-income people, a matter being tackled by the UK-wide Community Energy Programme, the new HEES and the UK Fuel Poverty Strategy.

Three major initiatives are being implemented to promote energy efficiency in industry: the Climate Change Levy, the Carbon Trust and the Enhanced Capital Allowances (ECAs) schemes. There are also other schemes, such as the Energy Efficiency Best Practice Programme (EEBPP). An 80% discount from the Climate Change Levy is granted to energy-intensive industries that engage in voluntary agreements. This voluntary approach is very well received by industry. However, it should be noted that investments in energy efficiency are potentially economic, especially if large efficiency gains are expected, and may not need government financial support. It is necessary to ascertain whether energy efficiency programmes have brought about energy efficiency gains that would have been achieved without them. This would avoid free-riding.

Despite the already strong economic disincentives (excise duties), growth of road transport consumption continues to be robust. Past IEA experience has shown that efforts to stabilise or reduce transport energy use and CO_2 emissions have been largely unsuccessful. If growth continues, there will be an additional burden on other sectors to reduce greenhouse gas emissions. However, other sectors, in particular industry and power generation, have already made significant efforts towards energy efficiency and emissions reductions, and further cuts may be costly. Therefore, transport will now have to be addressed with high priority.

Transport 2010: The *10 Year Plan* is a basic part of the Climate Change Programme. It aims to tackle congestion and pollution from all modes of transport -- road and rail, public and private -- in ways that increase choice. Massive investments are carefully planned. These measures favour a shift away from road transport, and, although not targeted exclusively at emissions reduction, should also help improve the environment. The adopted 10-year plan should be implemented as soon as possible.

As mentioned above, a wide range of assessments is available, aimed at improving the effectiveness of the energy efficiency measures and programmes. This is commendable, but it is unclear to what extent the results of such assessments have been used to amend, strengthen and sometimes even cancel energy efficiency programmes. There is certainly scope to improve existing programmes and benefit from past experience to design better ones.

Renewables

The past record of policies directed at renewable energies in the UK is a mixed one. On the one hand, the country implemented the Non-Fossil Fuel Obligation (NFFO), a support scheme with market-based features and notably a competitive bidding mechanism for support, at the time of electricity liberalisation in 1990/91. On the other hand, this scheme was based on technology tranches that were predefined by the government. This feature, which is now seen as one of the main weaknesses of the scheme, was excessively rigid and may have prevented greater penetration of renewables in the market place. On the one hand, the UK has one of the best technical wind resources in Europe, theoretically capable of meeting 100% of the country's electricity demand. But the UK lags far behind other European countries with a less advantageous wind resource in terms of wind capacity build-up.

The current government appears determined to make up for delays of the past in the development of renewables. It has an ambitious renewables target of 10% of power generation by 2010. It is putting in place the programmes and tools that will help it reach the target, the most important being the Climate Change Levy, the emissions trading scheme, the Renewables Obligation, and the market for green certificates, as well as various other support programmes. In total, the UK government has committed itself to support of £1 billion per year up to 2010 for the development of renewables. This is impressive.

The new Renewables Obligation overcomes several of the weaknesses of the Non-Fossil Fuel Obligation. In particular, the government lets the market decide which renewable energy technology is the most advantageous instead of picking the winners itself. The transitional schemes that are being put in place to ensure that the projects under the past rounds of the NFFO go ahead allow the government to benefit from past efforts and build on them.

The government has also become more discerning about the renewables technologies it supports. It has decided to move away from waste incineration for power generation and towards cleaner technologies such as waste gasification. This has clear environmental benefits and is commended.

However, the government is superimposing numerous different layers of promotion measures for renewables, whereas the implementation of fewer but perhaps more stringent measures might have led to the same results at less cost and friction. Among the new measures to support renewables are the exemption from the Climate Change Levy, to some degree the emissions trading scheme, the Renewables Obligation, the green certificates and numerous other, smaller programmes and initiatives, including regional targets. To be sure, there are reasons for this plethora of measures. The green certificates are a more "voluntary" form of trading than the Renewables Obligation Certificates, and the buy-out option is meant to operate as a safety net in case the RO and the green certificates system become altogether too expensive. But this superimposition of measures can create considerable administrative costs and also places non-negligible information and transaction costs on market participants. Eventually, the government may have to simplify the system to allow it to function properly.

Moreover, the EU is also embarking upon setting up a support scheme for renewables based on certificates trading. Whereas it may be seen as advantageous by the UK government to put its scheme in early and thus influence the debate through the *de facto* existence of such a scheme, it is likely that eventually both systems have to be made compatible with each other. That will in all likelihood mean that in future the government will need to reconsider some of the basic design choices of the UK system. The government should take care to avoid a situation in which the system would be amended more or less constantly and would never be allowed to settle into a normal mode of operation, as this would certainly push up the cost of the desired expansion of renewable energy use.

It is also highly important to ensure that the full cost of renewables is correctly taken into account when the system is designed and implemented. This applies in particular to wind energy. The UK has a very promising wind resource, and this should be exploited to a greater extent than is currently the case. However, wind energy is not only in most cases still more expensive than conventional electricity generation on a per-kWh basis, it is also intermittent. This intermittency imposes an extra cost on wind generation, above and beyond the regular per-kWh cost. The UK's long coastline and geographical location imply that in most cases, the wind is blowing somewhere in the UK and wind generation is possible in some location. Ofgem is currently trying to design a market mechanism that would allow wind generators located in different areas to "bundle" their generation. The bundled wind generators could then bid into NETA as if their generation was not intermittent. This is seen as important as NETA exposes intermittency more starkly than the pool did, and places a higher implicit value on predictability, as generation that is scheduled but does not occur results in purchases from an expensive balancing mechanism[18].

This is a valuable initiative. But it seems unlikely that Ofgem can find a pricing mechanism that can make the underlying cost disadvantage of intermittent generation disappear – unless some of the cost is placed elsewhere by way of internal subsidy. It may be possible that a wind turbine in Cornwall and another one in Scotland taken together can generate 95% of the time, because if the wind does not blow in Cornwall it may blow in Scotland. However, it remains a basic fact that both generators use the transmission system in a different manner, with the corresponding network cost, and that switching from one supplier to another may make re-dispatch necessary. It may be possible that the extra cost of intermittency can be reduced through such bundling, but it is unlikely to disappear. The government and the regulator should take utmost care that whatever bundling mechanism they design does not result in cross-subsidies.

RECOMMENDATIONS

The Government of the United Kingdom should:

- For the industrial and power generation sectors, consider again the use of either emissions trading or carbon taxation. Consider introducing carbon taxation for households.

- Consider again modifying the Climate Change Levy to reflect the carbon content of fuels.

- Consider again eliminating restrictive definitions limiting the eligibility of industries for voluntary climate change agreements, as well as incentives and possibilities for free-riding.

18. See Chapter 6 on electricity.

- Pursue its involvement in the residential/commercial sector to promote energy efficiency while avoiding duplication. Reinforce the energy efficiency measures targeted at the commercial sector, in particular offices.

- Consider again extending voluntary agreements to cover all larger industries, and consider including small and medium-sized industries.

- Review carefully the practical potential of energy efficiency policies to curb energy consumption. Clarify the costs of specific policy measures.

- Continue the systematic monitoring and evaluation of energy efficiency programmes and use the results to enhance the quality of new and existing measures and programmes.

- Enhance the efforts to curb the energy consumption and CO_2 emissions from the transport sector. To achieve this, the government should implement its 10-year Transport Plan swiftly and according to schedule, with an emphasis on reducing greenhouse gas emissions and improving energy efficiency.

- Implement the reforms relating to renewables effectively and efficiently as anticipated, and closely monitor the results.

- Review regularly the complex system of support mechanisms for renewables and streamline it into a simpler system as soon as an opportunity to do so appears.

- Pursue the current attempts to bundle intermittent generators into more predictable units. In doing so, the government and the regulator should take utmost care that whatever bundling is chosen does not result in cross-subsidies.

5

FOSSIL FUELS

COAL

Overview

The UK's coal requirements in 2000 were met by 31 million tonnes of local production, plus 23 million tonnes of imports and a stock draw of about 5 million tonnes.

Very little UK coal is exported, usually less than 1 million tonnes per year[19]. In recent years, imports have been around 20 million tonnes per year, somewhat higher than before. In 2000 and 2001 steam coal imports were especially high. Of the 20 million tonnes imported, around 9 million tonnes are for the iron and steel sector, as the UK does not produce the coking coal required by this sector. The remainder was steam coal. Major sources of imports include Australia, Colombia, Poland, South Africa and the United States.

Of the slightly more than 31 million tonnes of coal mined in the UK in 2000, about 17.5 million tonnes came from deep mines and 13.5 million tonnes from opencast mines. The general trend has been one of decline – coal production in 2000 was a quarter of the level in 1980 (approximately 120 million tonnes) and only a third of the level in 1990 (92 million tonnes). Coal production was 16% lower in 2000 than in 1999 with deep-mined production falling by 17.5%, while opencast production fell by 12%.

The UK coal industry has been in private ownership since 1994. There are 16 major deep mines left in operation. Eleven are owned by UK Coal, the largest operator, which has approximately 60% of market share. Until 25 May 2001, UK Coal was called RJB Mining. One mine each is owned by Betws, Blenkinsopp, Flack & Sons, Tower and Mining Scotland (Longannet mine, the last in Scotland, though this is no longer in operation). In addition there were 14 smaller deep mines in operation as at 30 June 2000. There were 48 opencast sites in production at 30 June 2000. In addition, one site was under development, one was being restored and 8 were in care and maintenance.

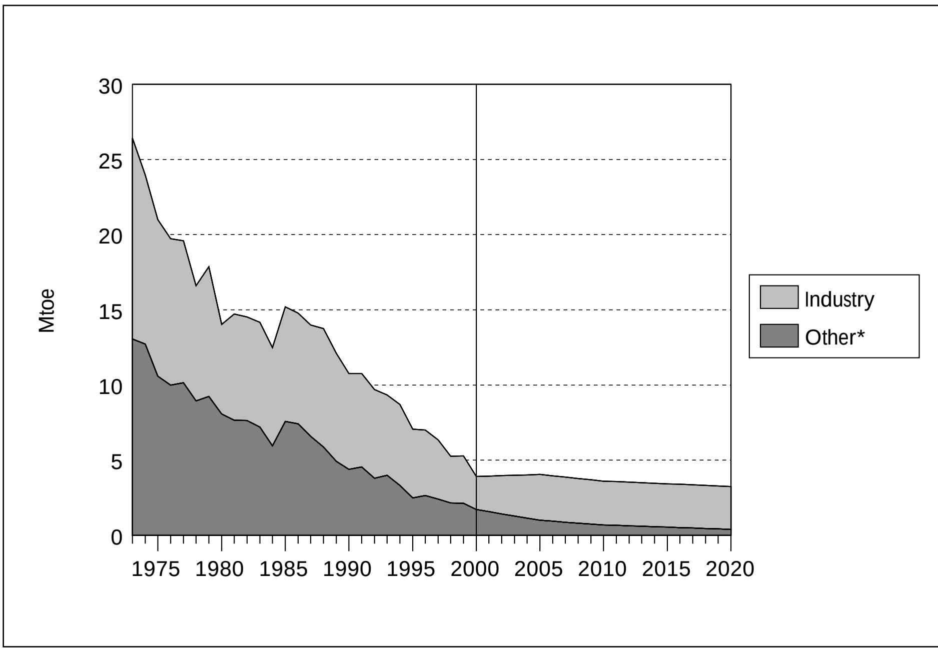
Prices for internationally traded coal delivered to UK ports hit a low of around £17/tonne in mid-2000, but have risen strongly since then and have now almost reached £30/tonne, although it is unlikely that these latest prices will be sustained. Because of their location close to power stations, UK coal producers are generally able to command prices up to around £5/tonne higher.

19. Mostly to Ireland, Norway and elsewhere in Europe.

Around 75% of the UK coal demand is from the electricity sector (indeed about 33% of electricity generated in 2000 came from coal). UK coal consumption has been declining in recent years as electricity generators switch to gas. Demand last year rose to 58.9 million tonnes because of problems at some nuclear and gas power stations and periods of higher gas prices. Demand is expected to fall in future as more new gas stations are built.

The UK coal industry currently employs approximately 12,000 people, of whom about 75% (9,000) are employed in deep mines and 25% (3,000) in opencast. The general employment trend has also been downward – employment stood at approximately 300,000 in 1980 and 60,000 in 1990.

Figure 11
Final Consumption of Coal by Sector, 1973 to 2020



* includes residential, commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001, and country submission.

State Aid

In principle the UK government's coal policy is based on the view that it is for the coal industry to find its own place in a competitive energy market. However, owing to low world coal prices and the lifting of the stricter gas consents policy for new power plants (see Chapter 6) the UK introduced a coal aid scheme. The Coal Operating Aid Scheme, announced on 17 April 2000, was designed to assist those production units with a viable future without aid to overcome short-term market

Table 5

IEA Secretariat Estimates of Total Producer Subsidy Equivalent (PSE) for Coal Production in Selected IEA Countries

Year		*1991*	*1992*	*1993*	*1994*	*1995*	*1996*	*1997*	*1998*	*1999*	*2000p*
France	Production (in Mtce)	10.07	9.45	8.30	7.46	7.80	7.07	5.73	4.43	4.13	3.16
	Aid per tce (in FRF)	222	225	288	269	75	81	434	581	564	691
	Aid per tce (in USD)	39.42	42.51	50.79	48.41	14.95	15.73	74.41	98.69	91.76	97.15
Germany	Production (in Mtce)	67.57	66.86	59.29	53.15	54.45	48.94	47.06	41.62	40.02	34.00
	Aid per tce (in DEM)	170	184	192	242	224	220.34	217	211	216.9	244.5
	Aid per tce (in USD)	102.40	117.93	115.93	149.20	156.15	146.41	124.94	119.83	118.2	115.4
Japan	Production (in Mtce)	6.34	5.98	5.68	5.46	4.93	5.10	3.37	2.91	2.80	
	Aid per tce (in JPY)	17,289	15,649	17,192	17,184	16,878	15,553	16,849	13,772	15,107	n.a.
	Aid per tce (in USD)	128.54	123.52	154.60	168.14	179.36	142.95	139.24	105.62	134.29	n.a.
Spain	Production (in Mtce)	11.60	12.39	12.33	12.39	11.94	11.95	12.07	11.00	10.34	10.38
	Aid per tce (in PTA)	6,354	6,073	6,133	10,370	11,593	11,058	11,591	12,624	11,376	12,652
	Aid per tce (in USD)	61.16	59.32	48.22	77.39	92.97	87.28	79.18	85.83	72.92	70.32
Turkey	Production (in Mtce)	2.69	2.47	2.46	2.34	1.88	1.97	1.94	1.64	1.47	1.67
	Aid per tce (in '000 TRL)	637	1,713	1,760	2,106	6,487	8,031	12,371	27,212	63,976	138,078
	Aid per tce (in USD)	151.61	248.32	160.02	70.66	141.95	98.79	81.60	104.54	155.8	220.95
UK	Production (in Mtce)	78.11	69.75	56.41	41.23	46.97	43.10	41.70	35.42	32.06	27.5
	Aid per tce (in GBP)	14.45	15.51	3.45	5.03	2.76	2.67	4.30	0.00	0.00	2.15
	Aid per tce (in USD)	25.49	27.21	5.18	7.71	4.35	4.16	7.03	0.00	0.00	3.25

p : Preliminary data, subject to revision.

Note: Mtce is million tonnes of coal equivalent.

problems, and to prevent a sudden and sharp decline in the size of the coal industry. Aid was granted to both deep mine and opencast units to cover losses incurred in the production of coal for electricity generation or industrial usage. Units qualifying for aid had to demonstrate, among other things, digression of production costs, and a viable future without aid until at least mid-2004. The UK Coal Operating Aid Scheme contained specific clauses that prevented grants from causing the delivered prices for UK coal to be lower than those for coal of a similar quality from third countries.

Aid was granted in three tranches; 17 April to 31 December 2000, 1 January to 31 December 2001, and 1 January to 23 July 2002, when the European Coal and Steel Community (ECSC) Treaty expired. The scheme had an overall cap of £170 million, although HMG did not anticipate spending this amount. Further, no single coal production undertaking was eligible for more than £75 million.

To date, aid has been paid to 17 production units: £ 87,539,600 of aid was approved and paid in respect of the 2000 tranche; £ 54,673,750 has been approved and paid in respect of the 2001 tranche, although other 2001 applications are still being processed. Table 5 contains an IEA estimate of the total producer subsidy equivalent in the UK in 2000.

UPSTREAM HYDROCARBONS

Industry Overview

The UK is the largest petroleum producer and exporter in the EU. The country is also the largest producer and an important exporter of natural gas in the EU. In 2000, the UK produced 131.7 Mtoe of oil and 97.6 Mtoe of natural gas. Oil production was 57% above the UK's domestic oil TPES in 2000, gas production 11%.

The oil and gas industry is 100% privately owned. It represented about 12% of UK industrial capital investment, and 2% of total capital investment in 2000. Oil and gas production makes a contribution to the UK's balance of payments that was estimated to have risen from around £4 billion in 1999 to some £6 billion in 2000.

Several hundred companies are active in the North Sea. Most of the international oil majors have a share of UK North Sea production. The second and third-largest publicly traded energy companies in the world[20], Royal Dutch/Shell and BP, respectively, are based in the UK[21]. The largest upstream producers are ENI-AGIP, Amerada Hess, BG, BHP, BP, Centrica, Chevron/Texaco, Conoco, Enterprise, ExxonMobil, Kerr McGee, Marathon, Phillips, Premier, Ranger, Royal Dutch/Shell, Talisman, TotalFinaElf, Veba, and Statoil. The International Petroleum Exchange (IPE), the second-largest energy futures exchange in the world, is located in London.

20. In terms of market value.
21. Royal Dutch/Shell is also based in the Netherlands.

The current situation is the result of recent structural changes in the hydrocarbons industry. As a reaction to the then low oil price, the UK upstream oil industry embarked upon reorganisation in 1998, beginning with a merger between BP, already one of the world's largest petroleum companies, and Amoco. In April 1999, the merged BP Amoco, now simply called BP, announced its intention to take over the American company Atlantic Richfield (Arco). This merger was completed in April 2000. The merged company is the world's third-largest publicly traded oil and gas company.

There are also numerous smaller independent British oil companies operating in the North Sea. These companies were hard hit by the oil price decline of 1998. As a result, the five major independents at the time, Enterprise, Lasmo, Premier, British-Borneo, and Cairn, attempted to consolidate in the same manner as the oil majors. Enterprise, the largest British independent (164,907 barrels of oil equivalent per day in 2000) unsuccessfully attempted to take over the second-largest, Lasmo, in the spring of 1999. In 2000, the Italian oil and gas company ENI began to acquire British independents, British-Borneo in March 2000, and Lasmo in February 2001. The remaining two independents are either heavily focused outside the UK (Premier), or very small (Cairn).

Exploration and Production

The UK continental shelf (UKCS) consists of three different provinces, the UK part of the North Sea, the area west of the Shetland Islands, and another area west of the Hebrides (deep water prospects). Almost all of the proven oil reserves are located in the North Sea, and most of the country's production comes from basins east of Scotland in the central North Sea. The northern North Sea (east of the Shetland Islands) also holds considerable reserves. In the North Atlantic Ocean, in the west of the Shetland Islands, smaller deposits are located. Table 6 shows the UK's remaining oil and gas resources as estimated at 31 December 2000.

Table 6

Oil and Gas Reserves on the UK Continental Shelf*, 2000

	Oil reserves, million tonnes	*Gas reserves, billion cubic metres*
Proven reserves	3,200	2,255
Probable	380	460
Possible	480	430
Cumulative production to 2000	2,570	1,518
Total remaining (proven)	630	735

* onshore and offshore.

Source: Department of Trade and Industry (DTI): *Development of UK Oil and Gas Resources 2001*. London, 2001.

The North Sea is considered a mature area. This is reflected in the ratio between proven, probable and possible reserves in Table 6. A comparison with the US yields the following: both the US and the UK have a reserves-production ratio in the order of 10 years. However, the ratio of proven gas reserves to as yet undiscovered gas resources in the US is 5,000 bcm to 15,000 bcm[22]. Adding the probable and possible gas reserves figures in the table, in the UK the ratio is 2,255 bcm to 890 bcm. Hence, a ten-year reserves-production ratio is not an indication of declining reserves, but rather a function of economic optimisation of exploration and production spending, as the potential of undiscovered gas reserves seems to be comfortably large in the US. In the UK in contrast, the ratio seems to indicate that the gas reserve potential has largely been explored and that a decline of production may not be compensated by additional exploration efforts.

Currently, the number of fields under development or in production in the UK is still increasing. At the end of 2000 it was 264, up from previous years. In the same year, development and production consent was given for 11 new field developments and 12 other developments. Fourteen authorisations for the construction and use of 141 additional submarine pipelines were issued. Two fields ceased production, the Bladen and Blenheim fields. Oil production from six offshore fields commenced in 2000: the Bittern, Cook, Guillemot West, Guillemot North West, Shearwater and Keith fields. In 2001, the British Oil and Gas Directorate approved four new offshore oil fields for development: the Halley, Hannay, Kestrel and Otter fields. The Angus field was approved for redevelopment. High levels of production were maintained in 2000, with 126 million tonnes of oil and natural gas liquids, and 115 billion cubic metres of gas produced. Combined production was 1% lower than in the historical high of 1999.

North Sea oil and gas reserves were first discovered in the 1960s. The North Sea did not emerge immediately as a key oil-producing area, but North Sea production grew after the first oil crisis in 1973, and continued to expand as major discoveries were made throughout the 1980s and into the 1990s. Most of the UK's oil and gas reserves and production are located off the coast of Scotland, and most hydrocarbons-related business activities centre around the Scottish city of Aberdeen. Although the region is a relatively high-cost area, its high-quality crude oil, political stability and proximity to consumer markets have allowed it to play a major role in world oil and gas markets. Unit costs for UK oil fields averaged just above $15 per barrel in 2000, though fields that started production in the 1990s have lower costs[23]. Europe's largest onshore oilfield is Wytch Farm in east-central

22. IEA: *World Energy Outlook*. Paris, 2001, p. 182.
23. Many of the world's major crude oil prices are linked to the price of the North Sea's Brent crude oil. Brent crude is a blend of North Sea crude oils and does not come exclusively from the Brent field. Because Brent crude is traded on the International Petroleum Exchange in London, fluctuations in the market are reflected in the price of Brent. Therefore, all other crude oils linked to Brent can be priced according to the latest market conditions. Brent production is forecast to fall precipitously from its current 450,000 barrels/day by 2005.

England. Estimated reserves in this field are 500 million barrels. Other smaller onshore fields are located in east-central England.

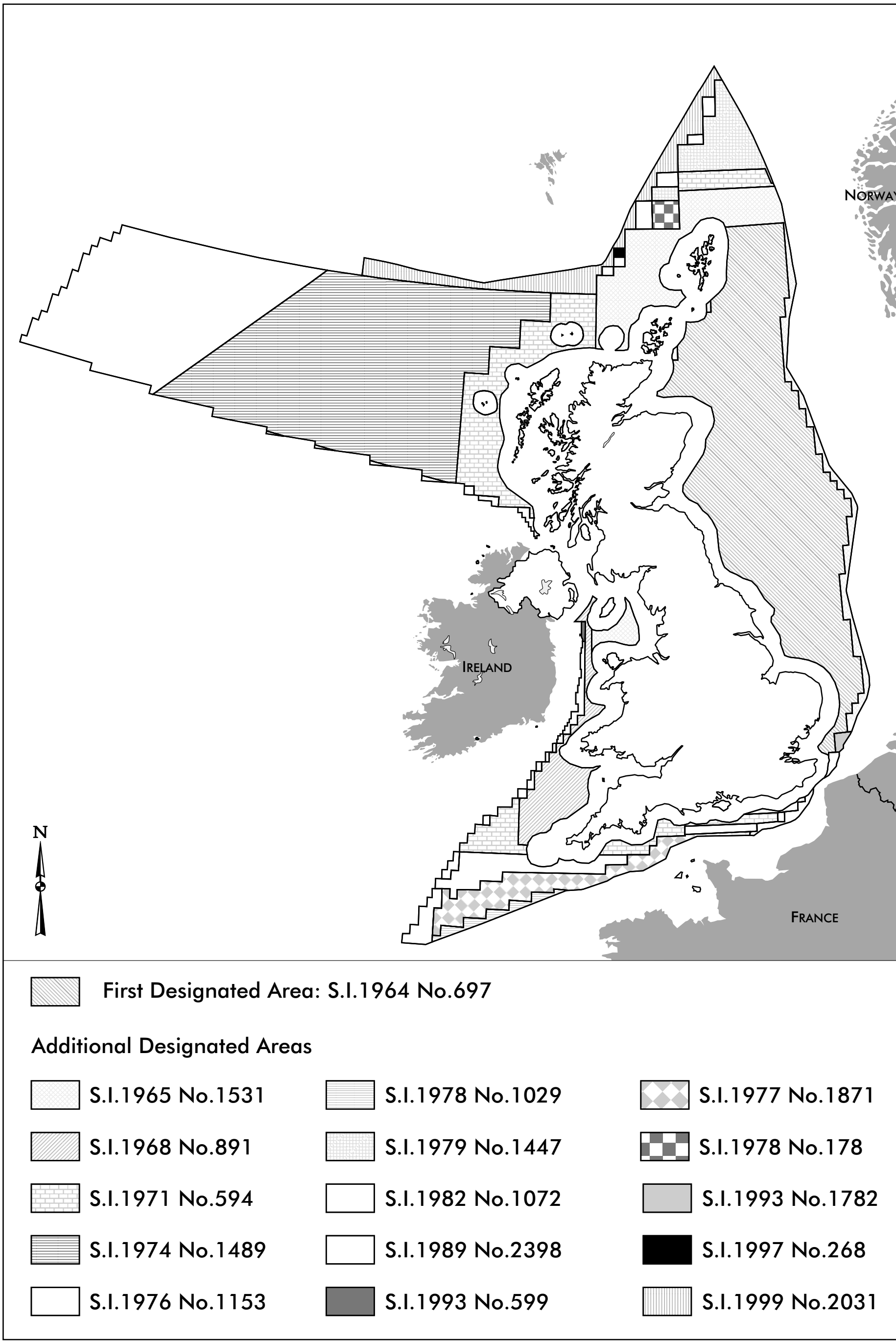
The UK's natural gas reserves are for the most part located in non-associated gas fields off the English coast in the Southern Gas Basin, adjacent to the Dutch North Sea sector. The UK shares the declining Frigg field with Norway (39.18% to the UK), which is expected to be shut down in 2002, and has a small share of the Statfjord field (14.53%). There are a few small fields onshore. The Irish Sea contains the large Morecambe and Hamilton fields. Morecambe alone accounts for up to 20% of British natural gas production. The largest gas project that came online (in March 2002) in the British North Sea is the TotalFinaElf-operated Elgin/Franklin field, which might prove to be the last big North Sea production platform. It is the world's largest high-pressure, high-temperature development.

A key offshore gathering pipeline is the Scottish Area Gas Evacuation (SAGE) system to the St. Fergus Terminal, which handles gas produced from a number of North Sea fields, including Britannia, the Beryl and Brae areas. Another key offshore gathering pipeline in the central/northern North Sea is the Central Area Transmission System (CATS) that also goes to the central North Sea, and takes gas from several fields, including Everest, Judy and Jade. Another is the Far North Liquids and Associated Gas System (FLAGS) that takes gas from the northern North Sea, including the Brent, Magnus, Cormorant, Ninian and Hutton fields. BP produces oil and gas and brings ashore 40% of the UK's total production through the Forties Pipeline System to Grangemouth, Scotland.

The domestic UK oil and gas industry is expected to decline as reserves become depleted in the coming decade. The size of new finds as well as of fields that are expected to be developed is getting smaller. Fields developed are predominantly satellite fields. The decline of the existing fields is unlikely to be compensated for by likely new discoveries. The North Sea part of the UK continental shelf is already a mature province. Only a few frontier areas appear to hold the possibility of further discoveries of large oil and gas fields. The new provinces in the deep water west of the Hebrides have so far had little exploration success. BP believes that the area west of Shetland holds the largest potential for new large discoveries. So far, these areas were disappointing. In June 2001, however, a new discovery was made. The Buzzard field is located 100 km north-east of Aberdeen, in an area that was considered mature and of limited potential. Estimates for this field published in June 2002 are in the range of 1 billion barrels of oil or more. This is the largest North Sea oil discovery in the last 25 years. Whether this find signals further large potential in the North Sea is highly uncertain, but it does show that there may be more reserves than anticipated.

The UK government is encouraging industry to continue to explore and develop oil and gas fields on the UKCS. The 9th round of onshore petroleum licensing was announced in January 2000, and licences awarded in July 2000. The 19th round of offshore petroleum licensing was announced in November 2000 and successful applicants were announced in May 2001. The government expects that exploration

Figure 12
Hydrocarbons Licence Area and Production Facilities



Source: DTI.

of the zone between Shetland and the Faeroes could give a significant boost to the long-term future of the UKCS. The 19th round was the first to be considered under regulations to apply the EU Habitats Directive to offshore oil and gas activities. Close to 1,000 licences have so far been awarded. At the beginning of January 2002, the energy minister announced that the 20th licensing round for the UK sector of the North Sea would open up almost 300 blocks offshore for competitive bids. The blocks were located in the northern, southern and central North Sea. The closing date for applications was 16 April 2002.

The number of wells drilled as well as investment reached a low in 1999. This might result from a combination of oil price levels and the fact that the North Sea is a mature province. Trends indicate that exploration activity has picked up since, but it remains lower than in 1998. Twenty-six exploration wells were drilled offshore in 2000, compared with 16 in 1999. Thirty-three appraisal wells were drilled in 2000, compared with 20 in 1999. Six significant discoveries were announced in 2000. Drilling intentions appear to have improved according to the latest DTI survey of operators' intentions which took place in early 2001. This shows operators as expecting to drill 112 exploration and appraisal wells in the course of 2001–2003, compared with 92 in the previous survey covering the period 2000–2002.

Trade and Transportation

The UK is self-sufficient in oil, but oil imports still take place. As it generally contains lower levels of contaminants such as sulphur, UK crude oil can command a higher price than other crude oils on the international market. It is also higher in quality. Most high-quality crude oil is exported, while cheaper, lower-quality (mainly from the Middle East) crude oils are imported for refining, in particular for the manufacture of various petroleum products, such as bitumen and lubricating oils.

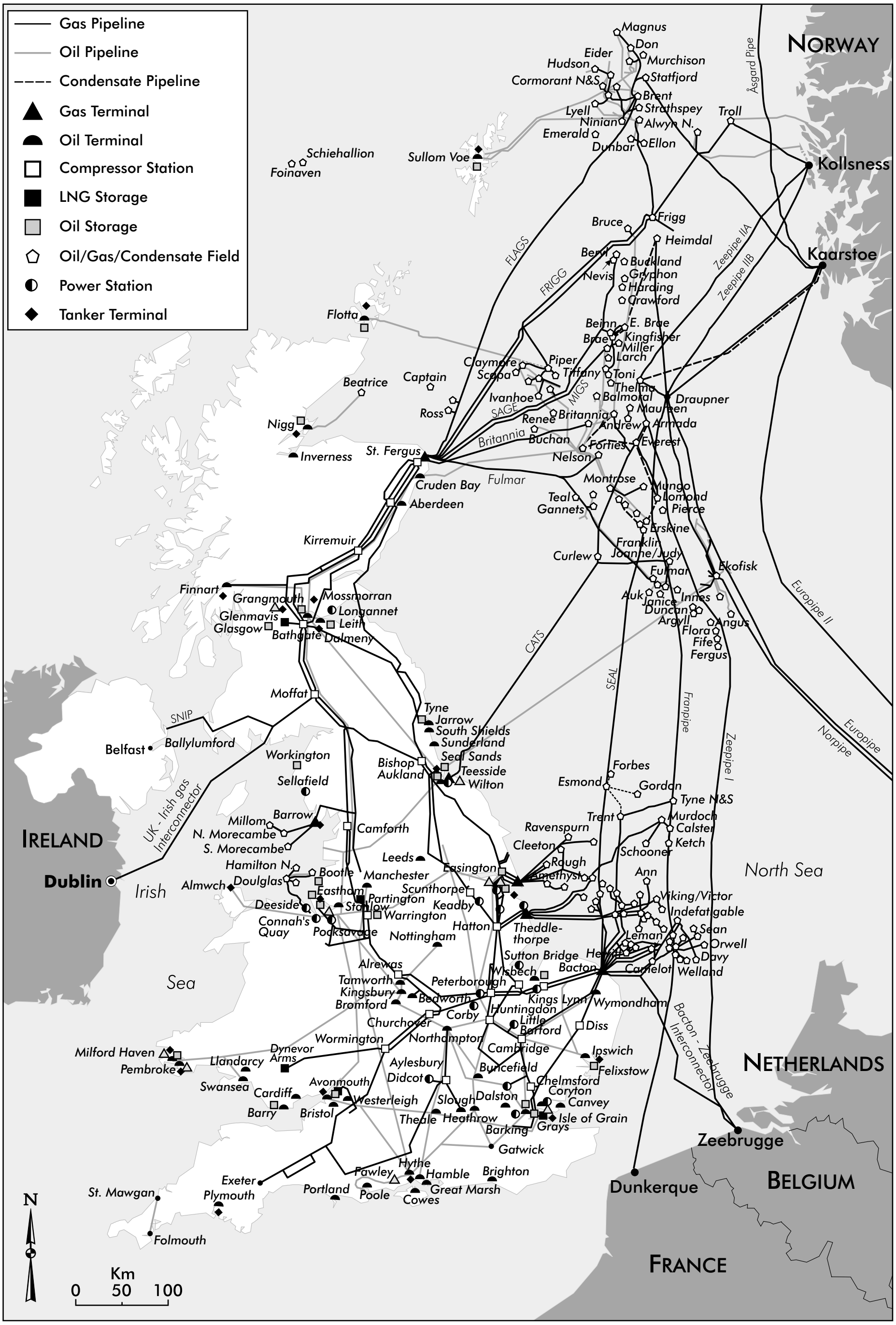
Three-quarters of the UK's primary oil production in 2000 was exported, and imported crude oil accounted for 61% of UK requirements. Total oil imports in 2000 were more than 20% higher than in 1999. While the level of net exports fell in 2000, exports were still 70% higher than imports. While exports in 2000 continued at around the same level as in 1999, refiners needed to import increased volumes of crude oil to make up for the reduction in indigenous production. Unless substantial new finds are made in the so-far unexplored areas, the UK will become a net importer of oil and gas in the coming decade. Figure 13 shows the UK's main oil and gas pipelines.

Government Intervention in the Upstream Market

In the UK, petroleum companies operate in the private sector on a commercial basis. Government intervention is restricted to regulation. The Oil and Gas Directorate of the Department of Trade and Industry has the main responsibility for oil and gas regulation. Its overall objective is to "maximise the economic benefit to

Figure 13

Oil and Gas Pipelines in the UK, 2001



Source: DTI.

the UK of its oil and gas resources, taking into account the environmental impact of hydrocarbon development and the need to ensure secure, diverse and sustainable supplies of energy at competitive prices." To achieve this, the Oil and Gas Directorate aims to:

- Promote exploration for oil and gas resources over the maximum extent of the UK continental shelf by means of an appropriate licensing regime which pays due regard to the environment and to the interests of other land and sea users.

- Regulate and promote oil and gas developments which are technically, economically and environmentally sound.

- Promote open and competitive markets and strong companies in UK and EU policy formulation and in international discussions.

- Collect, analyse and disseminate data relating to the UK's hydrocarbon reserves.

The main forum for co-operation between government and industry relating to hydrocarbon exploration and production policies is PILOT. PILOT is the successor to the British Oil and Gas Industry Task Force, which was set up in 1998 to bring together government departments and oil and gas industry representatives to discuss the future of the industry, and in particular its decline. Both the government and industry are interested in collaborating to prolong the active life of the UK continental shelf. Part of this involves shifting focus from small numbers of very large fields to larger numbers of smaller fields. PILOT pursues a programme of work aimed at securing improvements in the international competitiveness of the UK industry and continued exploration and development activity on the UKCS. In recent years policy developments have concentrated on:

- Stimulating increased investment on the UKCS, particularly of previously unexploited acreage.

- Increasing the transparency of the licence award system.

- Using Internet and e-commerce to facilitate communication between industry and government and reduce the regulatory burden on business.

- Improving the competitiveness of the UK supply chain.

- Developing more widely based forums for discussing offshore environmental issues with interested parties.

- Reviewing through public consultation the voluntary industry Code of Practice governing third party access to offshore infrastructure (upstream pipelines and processing facilities).

PILOT is seen as successful both by the government and the industry. Among PILOT's concrete tasks is to develop engineering methods for the economically viable and ecologically sensitive recovery of previously unattractive fields. Part of the initiative is to ease the trading of licences to allow the concentration of licences according to strategies, to provide skills required for optimum development, and to provide opportunities to more specialised niche players.

Under the UK offshore regulatory regime, the use of infrastructure by third parties is not regulated, but has to be negotiated by the players within a legal and voluntary framework. In the event of disputes, owners of third-party fields can appeal to the secretary of state for access to infrastructure. General competition rules also apply. A voluntary Code of Practice, which was introduced in 1996 and has recently been reviewed through a DTI consultation, provides guidance for infrastructure access negotiations. The consultation found industry views divided on the effectiveness and need for revision of the code. DTI has proposed a number of limited but worthwhile changes for industry to consider and agree. Implementation of the upstream part of the European Gas Directive{98/30/EC) introduced a requirement on the owners of onshore gas terminals to publish annually, from 10 August 2001, their main commercial conditions for access.

The UK upstream fiscal regime has undergone numerous changes in the last three decades. A special royalty and tax system applied to petroleum exploitation since 1975, encompassing royalty, Petroleum Revenue Tax (PRT), and Corporation Tax (CT). Since, the system has been changed many times, generally increasing the tax burden when oil prices have risen. However, since 1983 burden for new developments has been reduced. In its current shape, there are two different systems for new and for old fields. For fields approved before end-March 1982, the following tax elements apply:

- The royalty, paid at a rate of 12.5% of the value of production.
- The Petroleum Revenue Tax, paid at a rate of 50%.
- The Corporation Tax, currently at a rate of 30%[24].

For fields developed in the time period April 1982 to 16 March 1993, the royalty is not paid[25]. For new fields developed since March 1993, neither royalty nor PRT are paid. The effective marginal tax rate for new fields is therefore 30%.

As part of the 2002 budget, the government introduced a 10% charge on profits from North Sea operations, counterbalanced by a 100% first year capital allowance for capital expenditure, rather than the 25% allowance available previously. Eventually, the government also intends, subject to consultation on the appropriate timing, to abolish North Sea Royalty, which applies only to older fields.

24. Marginal rate = r + p (l-r) + t[l–r–p(l-r)] = 69.375%, with r = royalty, p = petroleum revenue tax, t = corporate tax, 1 = 1.
25. Marginal rate = p + t(l-p) = 65%.

DOWNSTREAM OIL

Industry Overview

The main integrated oil downstream companies in the UK (i.e. refiners, distributors and retailers) are Esso, BP, Shell, TotalFinaElf, Texaco, Conoco, Murco Petroleum and Petroplus (excludes gasoline). The other main retailers are Kuwait Petroleum, CPL Petroleum Ltd, Tesco, Sainsbury's, Safeway, Asda and Morrisons.

Industry mergers and other structural change have affected the UK downstream oil market in the last two years. In February 2000, Elf and TotalFina merged to become TotalFinaElf following regulatory clearance from the European Commission. Chevron and Texaco merged in 2001. During 2000, Texaco had acquired 80 Shell petrol stations along with the latter's 50% equity interest in Plymouth distribution terminal.

In December 2000, Petroplus bought the jointly owned Phillips Petroleum-Huntsman (formerly ICI) refinery at Port Clarence at Teesside in north-east England. The refinery is the UK's smallest major oil refinery, with a capacity of around 100,000 barrels/day and is a major producer of ultra-low sulphur diesel. Petroplus also bought Phillips Petroleum Products, Phillips' UK distribution and marketing business. Thus Petroplus acquired an 8% share of the UK diesel market, largely through bulk commercial diesel sales. Petroplus already operates a storage facility in the UK, on the site of the former Gulf Refinery at Milford Haven, in south-west Wales.

Including Petroplus's refinery, there are currently nine principal refineries and three smaller refining units in the UK. The largest refinery is ExxonMobil's (Esso's) 311,240-bbl/d Fawley refinery in Southampton, one of the largest in Europe and accessible to marine tankers. It also has a pipeline to the onshore Wytch Farm field. The 100,000-bbl/d Port Clarence Phillips-Imperial Petroleum refinery at North Tees is connected by pipeline to the Phillips Consortium Ekofisk Oil Terminal at Seal Sands, giving it a direct feed from the North Sea. The Grangemouth refinery is also directly connected to the North Sea through the Forties Pipeline System.

The UK's total crude oil refining capacity is approximately 1.77 million barrels per day, slightly more than the country's consumption. At the end of 2000, UK distillation capacity was 89 million tonnes, only slightly higher than at the end of 1999. Similarly, total UK reforming capacity at the end of 2000 was 13 million tonnes, and cracking and conversion capacity was 36 million tonnes, both virtually the same as at the end of 1999.

Every year since 1974, with the exception of 1984 owing to the effects of industrial action in the coal-mining sector, the UK has been a net exporter of oil products. However, the UK also imports refined products because British refineries produce an excess of some grades and products and insufficient quantities of others for local demand. Oil product imports in 2000 were comprised mainly of aviation turbine fuel, gas oil/diesel oil and gasoline (mainly low-sulphur). The main sources of the

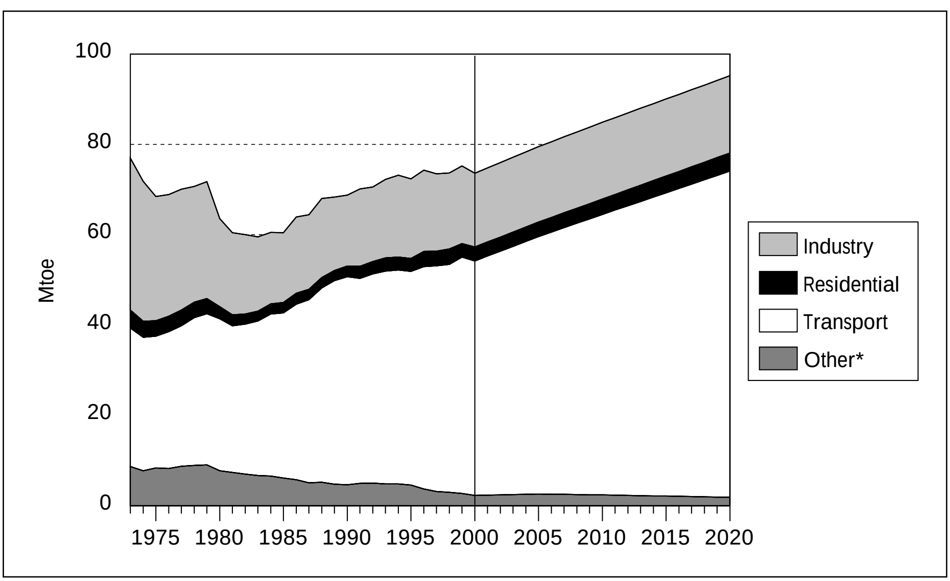
UK's imports of petroleum products were France, the Netherlands and Norway. UK exports mainly consisted of gasoline, gas oil/diesel oil and fuel oil. The major export market was the US, with UK exports to that market totalling 3 million tonnes in 2000. This represented 14% of total UK petroleum product exports and 5% of the total volume of US imports of petroleum products that year, most in the form of gasoline. Other major UK export markets were Ireland, Italy, France, the Netherlands, Germany and Spain. Net exports of petroleum products in 2000 were 6.5 million tonnes, lower than the 1999 level of 7.8 million tonnes.

Petroleum products represented 46% of the UK's final energy consumption in 2000. Fuel oil use has declined by 30% since 1998, as industrial and home-heating demand has dropped in favour of gas.

The UK petrol retail market is highly competitive. The largest players are Esso (ExxonMobil), BP, Shell, TotalFinaElf, Texaco and Conoco, which together account for 58% of gasoline sales. But over the last years, there has been intense retail price competition from hypermarkets with their high-throughput sites. The market share of hypermarkets consequently has grown very quickly. By 2000, hypermarkets had captured 26% of the retail petrol market and 9% of the retail diesel market. This is leading to a shake-out of the smaller, largely independent, players in the

Figure 14

Final Consumption of Oil by Sector, 1973 to 2020



* includes commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001, and country submission.

market. At the end of 2000, there was a total of 13,043 petrol retail outlets in the UK, a reduction of 673 or 5% from 1999. In 1990, there was a total of 19,465 petrol retail outlets in the UK. Hence the number of petrol stations declined by 33% over the past decade.

However, the growth of the market share of hypermarkets is beginning to slow. In 2000, their share of the petrol and diesel market increased by only 1%, compared with 1999. In response to the competition from hypermarkets, oil companies began to invest in new convenience store formats to maximise income from sites. Some retailers make up to 40% of their total site income from shop revenue. Some oil companies have chosen to operate a small number of stations jointly with their hypermarket competitors. Alliances include Esso/Tesco, BP/Safeway and Shell/Sainsbury's.

Government Intervention in the Downstream Sector

Over the past 10 years, UK competition authorities have conducted a number of inquiries into the UK petrol market under the Competition Act 1998 and the Fair Trading Act 1973. These have concluded that the market is highly competitive. The Office of Fair Trading (OFT) continues to monitor the market to ensure that anti-competitive behaviour does not occur. An inquiry into petrol and diesel pricing in the Highlands and Islands of Scotland in 2000 arrived at the same conclusion.

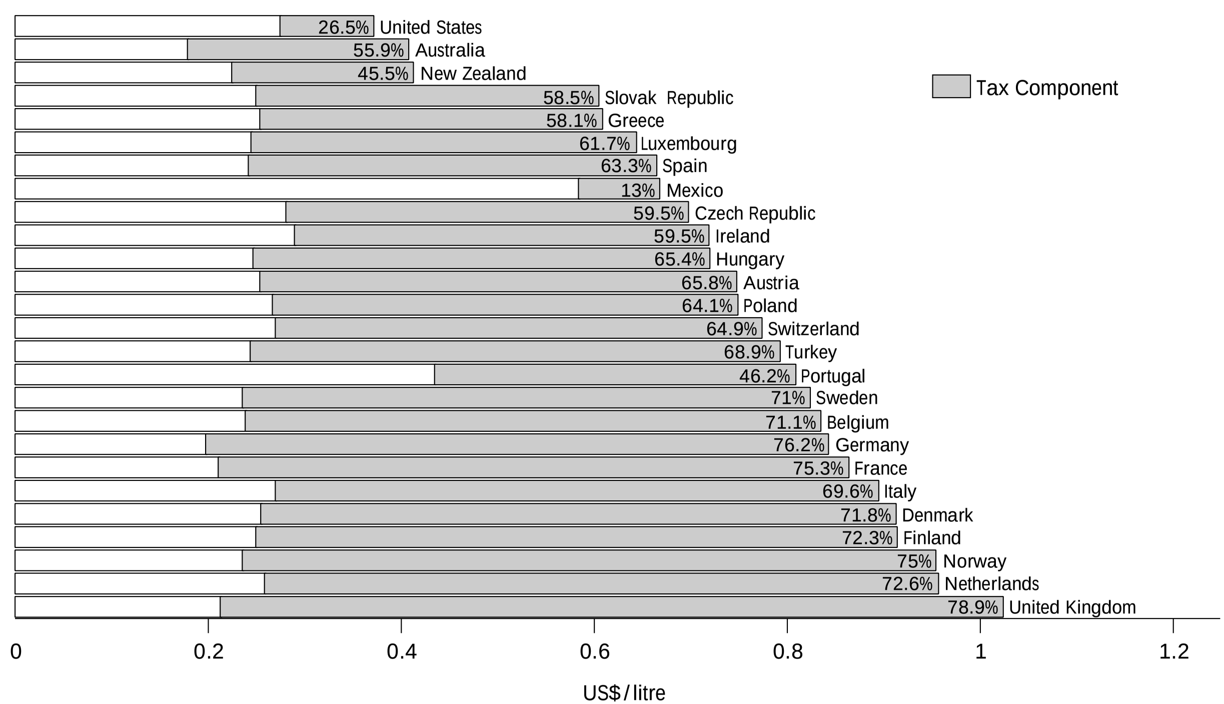
The UK has high taxes on petroleum products, which are among the highest priced in the IEA. High fuel prices caused protests and blockades in September 2000, when crude oil prices were high[26]. Following the September 2000 fuel supply crisis, the OFT received a number of complaints from independent fuel retailers and distributors about two-tier wholesale petrol and diesel pricing by the major oil companies. The independent retailers claimed that major oil refiners were selling motor fuel to them at a price that reflected international petroleum prices (that had risen along with crude oil prices), but were subsidising the fuel sold through their own branded networks and in some cases making losses on these sales. The OFT carried out an inquiry into two-tier wholesale petrol and diesel pricing and reported its findings in November 2000. It concluded that the price movements were due to increased world oil prices and public pressure on retail prices rather than anti-competitive behaviour. The OFT carried out further reviews of two-tier pricing in January and April 2001 and came to the same conclusion.

In the 2001 budget, the government froze duties on petrol, diesel and other road fuels and non-road fuels in cash terms. The following duty changes and announcements were also made, mainly to support cleaner fuels:

26. See section on Emergency Preparedness below.

Figure 15

OECD Unleaded Gasoline Prices and Taxes, Fourth Quarter 2001

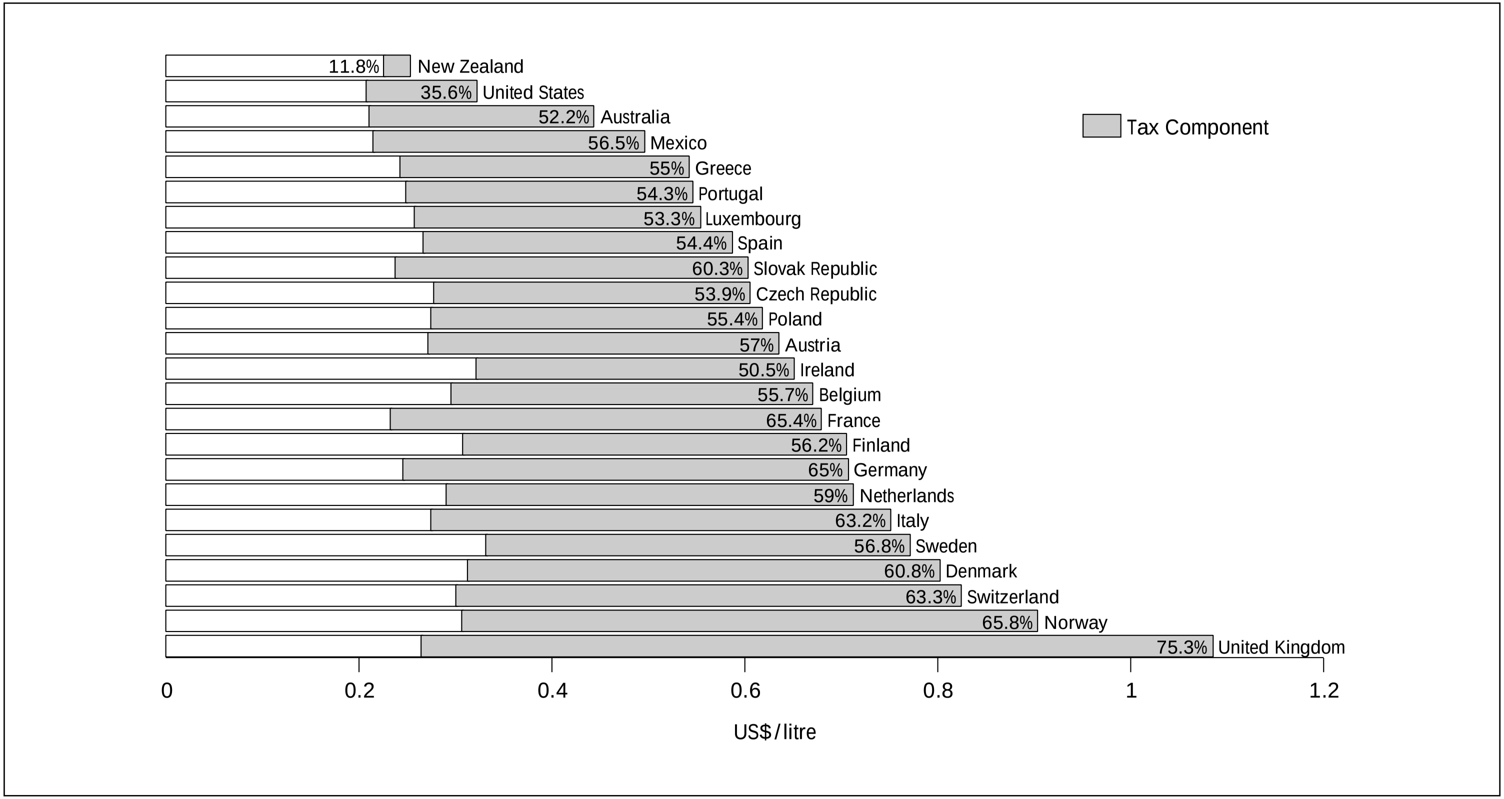


Note: Data not available for Canada and Japan.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2002.

Figure 16

OECD Automotive Diesel Prices and Taxes, Fourth Quarter 2001



Note: Data not available for Canada, Hungary, Japan and Turkey.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2002.

- Ultra-low sulphur petrol (ULSP) duty was cut by 2 pence per litre (p/l) following oil companies making this fuel widely available across the UK.

- Ultra-low sulphur diesel (ULSD) duty was cut by 3 p/l to maintain the existing balance between duty rates on the main forms.

- The higher duty rate for higher octane unleaded petrol was abolished and duty was linked to the sulphur and aromatics content of the fuel to bring it into line with the ULSP duty rate.

- A new duty rate for bio-diesel set at 20 p/l below the ULSD rate was to be introduced in 2002.

- The duty on road fuel gases was cut to 9 pence per kg and duty on this fuel was not to be increased in real terms until 2004 at the earliest.

European clean fuel and environmental legislation continues to have a major competitive impact on the profitability of UK refineries. The UK government implemented directive 98/70/EC into UK law through the Motor Fuel (Composition and Content) Regulations in 1999. The Sulphur Content of Liquid Fuels Directive (1999/32/EC) was implemented in the UK by regulations that came into force on 27 June 2000. The European Commission's draft directive on petrol and diesel quality was expected to impose a total annual cost to UK refiners of approximately £117 million.

EMERGENCY PREPAREDNESS

The Energy Act 1976 provides the legislative basis for action by the UK to implement its obligations under the IEA's International Energy Program (IEP) or, in the event of national emergency, to control the production, supply, acquisition and use of oil and oil products.

The powers under the Energy Act can be enacted with minimal delay. In the event of disruption or threatened disruption, the UK government would likely seek an Order in Council under section 3 of the act so as to obtain the full range of powers to make orders and give directions for emergency purposes under sections 1 and 2 of the act. Orders made under section 1 can be brought into force with immediate effect, even before they are laid before Parliament.

The UK government's approach to both oil stocking and emergency planning focuses on encouraging and supporting industry-led arrangements and favouring market mechanisms. In preparation for crises, the UK places greater emphasis on information availability, industry co-operation and flexibility rather than detailed planning within the industry. However, such detailed plans do exist for certain emergency measures. These are regularly reviewed and revised by the UK government in liaison with the overall industry body, the United Kingdom Petroleum Industry Association (UKPIA).

Consistent with IEA Governing Board Decision of 1995, if an oil crisis arose, the UK would expect stockdraw, demand restraint and complementary measures to form the first stage of any international action and other measures to be introduced as and when appropriate. Although the UK is a net exporter of oil and is therefore not obliged to hold stocks under the IEP, it is obliged to hold stocks equivalent to 67.5 days of the previous year's consumption in accordance with EU directives.

In September 2000 there were supply disruptions in the UK due to widespread protests occurring in reaction to high fuel prices. These protests had large public support. Fuel blockades were set up at a number of UK oil refineries and distribution terminals. These protests, which lasted for almost a week, resulted in severe oil products shortages occurring very quickly. The government responded to this situation by invoking emergency legislation under the Energy Act 1976, which, among other things, activated a priority users scheme and identified key petrol stations and fuel depots.

As a result of the disruptions, a task force was established involving ministers, the oil industry, the police, the trade unions and road haulers to develop a series of practical arrangements involving all the key parties aimed at maintaining the continuity of oil supply. This work resulted in a Memorandum of Understanding (MoU) signed by a number of parties, including the oil companies, police and trade unions.

Two key elements of the MoU commit the relevant parties to joint early warning systems and co-ordinated contingency plans as well as to joint crisis management systems. As such, the new procedures put in place represent a refinement of the existing plans and an enhancement of the information gathering and dissemination necessary during any fuel emergency. There were sporadic fuel protests in the first half of 2001 but the impact on fuel supplies was minimal.

NATURAL GAS

Overview

UK gas supply was run as a state-owned monopoly until 1986, when British Gas, the monopoly supplier, was privatised. In 1988, following recommendations from the Monopolies and Mergers Commission (MMC), British Gas was restricted from buying more than 90% of the UK's North Sea gas. As a consequence of this "gas release programme", the first competitive gas contract was concluded in 1991. Independent gas suppliers entered the firm market for bulk supplies as of this date.

But the gas release programme was not really effective until after further investigations by the Monopolies and Mergers Commission and the Office of Fair Trading in 1993. Following this, British Gas was obliged to make gas available to the market. Although other companies had been able to buy new gas before that date, it was not sufficient to make competition work. The government decided in 1993 that full competition for all gas customers should be implemented by 1998. In 1995 the Gas Act was adopted. This act obliged British Gas to separate its business into one company for pipelines and storage (Transco) and one for gas supply and shipping (British Gas Trading) in 1996. Between 1996 and 1998, retail competition was phased in, in three steps.

In 1997, British Gas decided to split off its gas sales, trading, services and retail business in a new company called Centrica plc. The supply business (including British Gas Trading, British Gas Services, the Retail Energy Centres) and gas production from the Morecambe gas field are now part of Centrica plc. Transco, as well as British Gas's exploration and production part and the international downstream business, remained with British Gas, which was renamed BG plc. Centrica markets gas in the UK under the brand name "British Gas", whilst BG plc (now BG Group plc) markets this brand outside the UK.

In October 2000, BG plc split once more, again for commercial reasons. Transco became part of a separate holding company called Lattice Group plc. Transco still owns and operates the national and the regional grids as a monopoly network; LNG facilities within the transmission/distribution system were retained by Transco LNG, which is also part of the Lattice Group. The storage business was transferred to BG Group plc, which also kept exploration and production and the international downstream business. Its main storage facilities are Rough, a partially depleted offshore gas field, and Hornsea (an onshore salt cavern). In July 2001, the Houston-based company Dynegy purchased BG Storage comprising of just the Rough and Hornsea facilities from BG Group plc, acquiring Rough and Hornsea, plus their associated facilities, and the natural gas processing terminal at Easington, which handles Rough gas. Other salt cavities are owned by independent operators.

Following a period of mergers and acquisitions, there are today eight major gas suppliers including Centrica. At the end of 2000, suppliers other than Centrica had captured 20% to 30% of the market in many regions of the UK. Among most suppliers there is a trend towards "multi-utility" bundling, i.e. they diversify into other energy markets, especially electricity, and even into telephone and financial services. Centrica acquired numerous other companies, including electricity supply, financial services, telecoms, insurance and motoring services. In 2001, Centrica had 13.5 million gas customers and 5 million electricity customers, and had become a major player in electricity trading.

Transportation and Trade

As already noted in the preceding section, the UK is a net exporter of gas, mainly via the interconnector to Continental Europe. However, net exports of natural gas, although growing rapidly, were not large in absolute terms, amounting to only 9.5% of total production in 2000. In total, the UK exported 9.3 Mtoe of natural gas in 2000. Exports of natural gas exceeded imports for the first time in 1997 but grew rapidly (by 46% in 1998, then by over two and a half times in 1999, and by 73% in 2000). The volume of exports was five and a half times the volume of gas imports in 2000. Imports added only about 2% to UK production. As the decline of UK gas production is currently anticipated, the gas industry estimates that by 2005, the UK would have to import gas regularly, and would need seasonal top-up deliveries even earlier.

Figure 13 above shows the gas pipeline network in the UK onshore and offshore, including the interconnections between the UK and surrounding countries. One of the most important developments in recent years was the opening of the UK-European Continent natural gas interconnector in October 1998. This interconnector has terminals in Bacton in England and in Zeebrugge in Belgium and is the first natural gas pipeline linking the UK to the European Continent. The interconnector can be operated both ways. The capacity from Bacton to Zeebrugge is 20 bcm/year, the capacity from Zeebrugge to Bacton at present, i.e. without extra compression, is 8.5 bcm/year. Currently a volume of about 10 bcm/year is exported to Continental Europe under long-term contracts as well as short-term and spot transactions. The UK has been a net importer of seasonal gas every winter since the interconnector opened, with the exception of 1999. The amount imported is determined by a combination of temperature, production and storage availability in the UK and the cost of European gas. In 1999, and again in 2000, there was an increase in imports brought about by inflows through the Bacton-Zeebrugge interconnector, although the UK remained a net exporter through this interconnector in 1999 and 2000.

The opening of the interconnector has created arbitrage opportunities for gas traders, and these have led to greater variation in the wholesale price of gas in the UK. Gas prices in the UK were influenced by the higher prices in Continental Europe. Given the greater size of the Continental European market, it is likely that the price pattern of Continental European gas, which at present is predominantly pegged to fuel oil prices, will prevail. Until full gas-to-gas competition becomes the dominant feature of continental gas trades, gas prices in the UK may remain at a higher level than they would have otherwise been.

There is currently one pipeline linking Britain and Ireland, the Irish Interconnector, allowing Ireland to import gas from sources east of Scotland. Exports to the Republic of Ireland began in 1995. Northern Ireland is connected via the Scotland-Northern Ireland Pipeline (SNIP). A second interconnector with the Irish

Republic is now under construction and is expected to be operational from October 2002. It follows a similar route to that of the first but also includes a spur to the Isle of Man. Some gas is exported directly from the offshore Markham field to the Netherlands via offshore pipelines. Exports to mainland Europe from the UK's share of the Markham field began in 1992 with a volume increase in 1997.

The UK was the first country to receive LNG from Algeria in the 1960s. However, the original landing terminal at Canvey Island has been decommissioned. Its size is minor by today's standards. Building new terminals on the coast might run into opposition. Lattice,Transco's parent company, is considering upgrading their LNG facility on the Isle of Grain to receive imports. But the large infrastructure in the southern North Sea, developed on the large gas fields now heading depletion, might offer interesting opportunities. As the UK moves to become a net importer again, there has been interest in LNG, with existing brownfield coastal sites a possibility.

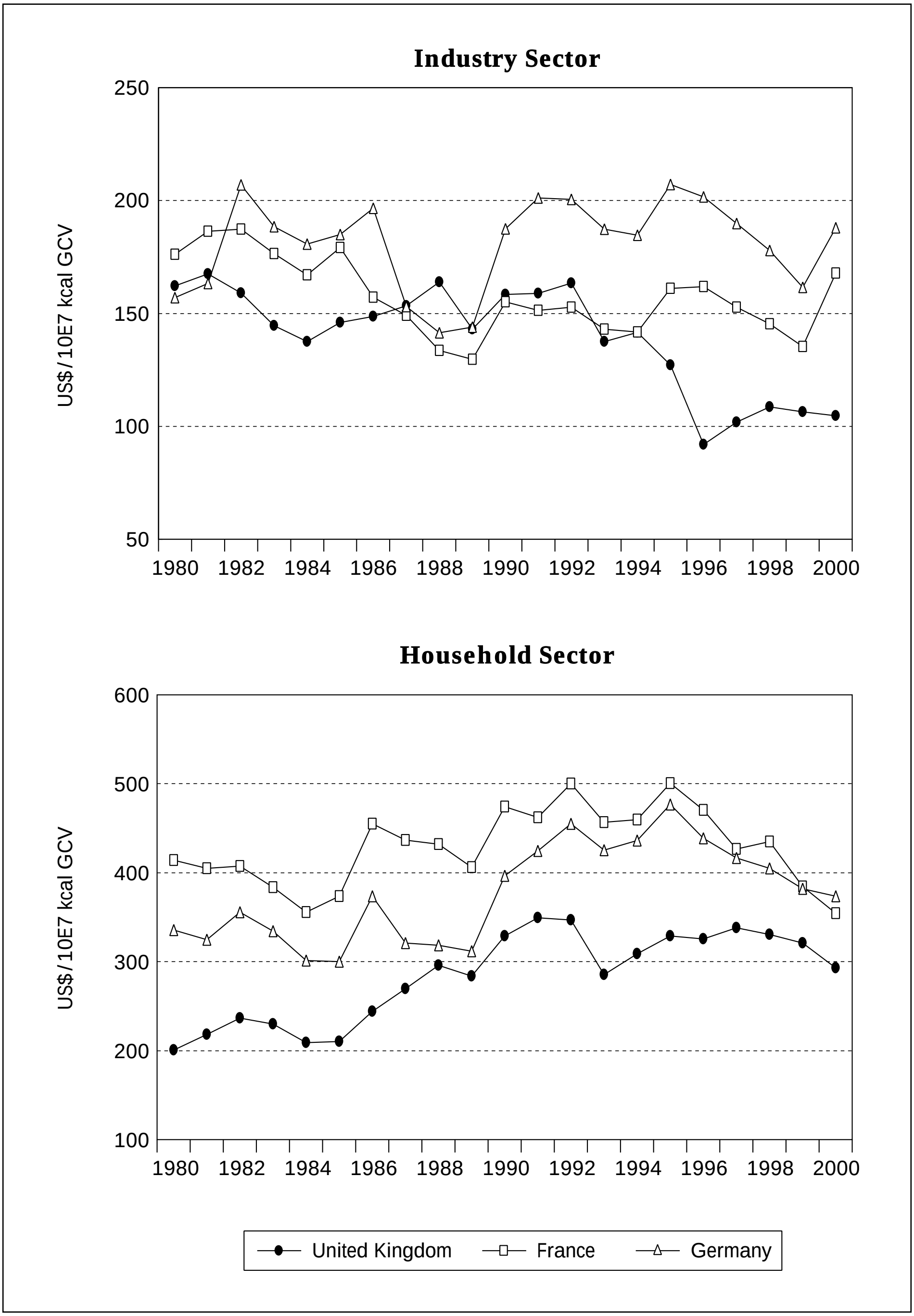
Despite the above pipeline projects, the UK will remain a much smaller natural gas exporter than North Sea neighbour Norway, and may soon begin to import Norwegian gas again. Norway supplied up to a quarter of British demand in the 1980s, but from the late 1980s these imports dwindled as the Frigg field that supplied the gas was depleted.

The UK is now co-operating with Norway to improve the exploitation of the North Sea by making technical and economic regulation more consistent. In this context, cross-border connections between the UK and the Norwegian sectors of the North Sea are being increased. The first significant connection is the new Vesterled gas pipeline, which was scheduled to begin operations on 1 October 2001. Vesterled connects the existing Frigg pipeline with the Heimdale platform, which is already connected by pipeline to the Sleipner gas fields, and from there to other areas of the Norwegian North Sea. This provides a link allowing Norwegian gas to enter the terminal in St. Fergus.

In July 2001, BP announced a 15-year contract to buy 56.5 billion cubic feet (bcf) or 1.6 billion cubic metres (bcm) of natural gas per year from Statoil through the Vesterled pipeline. However, Statoil indicated that it would not export large volumes of gas through Vesterled unless Britain changed its pricing system for bringing gas onshore from North Sea fields. Statoil believes that the UK's system of auctioning entry capacity, or access rights to the national pipeline system[27], produced volatile, very high prices.

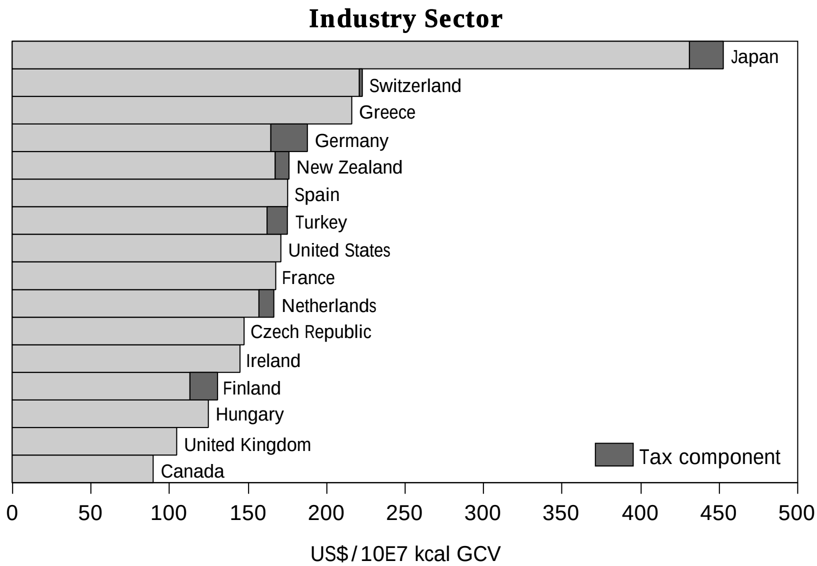
27. See section on regulation below.

Figure 17
Natural Gas Prices in the United Kingdom and in Other Selected IEA Countries, 1980 to 2000

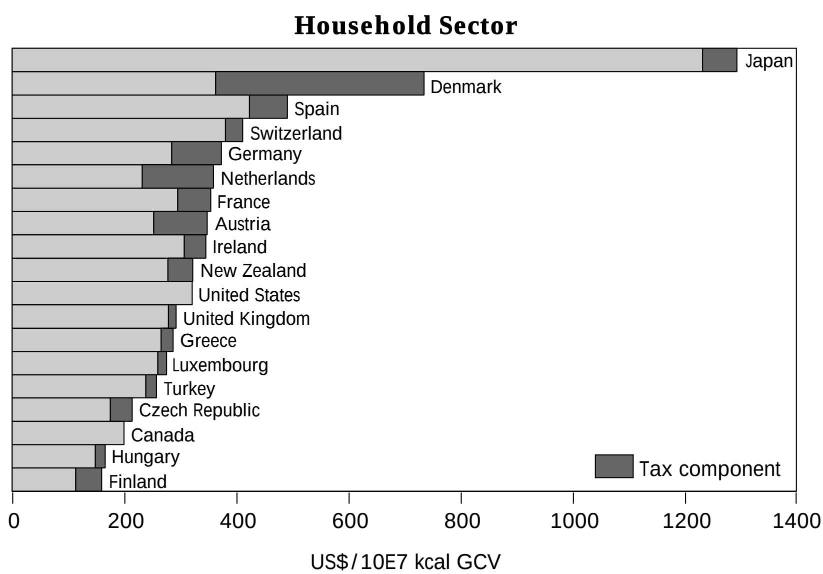


Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2001.

Figure 18
Natural Gas Prices in IEA Countries, 2000



Note: Tax information is not available for Canada and the United States. Data not available for Australia, Austria, Belgium, Denmark, Italy, Korea, Luxembourg, Norway, Portugal and Sweden.



Note: Tax information is not available for Canada and the United States. Data not available for Australia, Belgium, Italy, Korea, Norway, Portugal and Sweden.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2001.

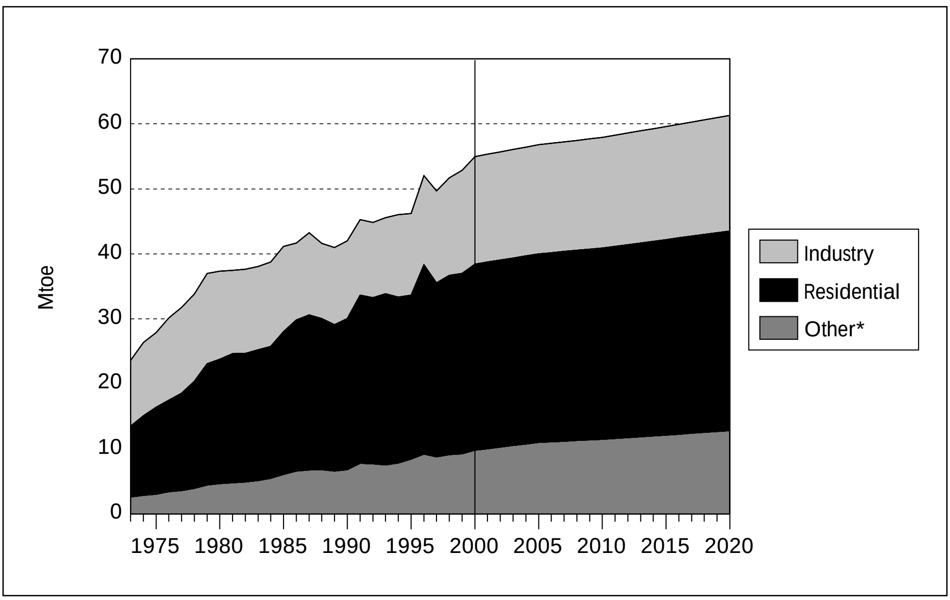
Natural Gas Demand

The share of natural gas in the UK's TPES was 37.6% in 2000, up from 22.2% in 1990 and 11.4% in 1973. The increase of gas use occurred to a large degree in power generation, where the share of gas-based output grew from 1.1% in 1990 to 39.4% in 2000. The government estimates that it could rise to 56% in 2010 and 74% in 2020.

Figure 19 shows that other sectors also increased their gas demand. Of the total increase in natural gas consumption between 1990 and 1999, 27 bcm/year is attributable to the use of gas for power generation and CHP. About 3 bcm/year is attributable to an increase in own use by the petroleum industry, another 3 bcm/year to increased industrial gas consumption, 5 bcm/year increase in the services sector (including government services) and 4 bcm/year in residential and commercial. In 1999 the residential sector was still the largest consumer of gas with 32.5 bcm/year, second was power generation and CHP with 28.6 bcm/year. For 2000, the difference is likely to become smaller.

Figure 19

Final Consumption of Natural Gas by Sector, 1973 to 2020



* includes commercial, public service and agricultural sectors.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001; and country submission.

The penetration rate of gas in households in the UK is very high, comparable only to the penetration rate in the Netherlands and much higher than in any other OECD country. Similarly, the UK and the Netherlands stand out with regard to their absolute use and share of power generation based on gas.

Regulation

The sector is regulated by Ofgem. Ofgem was created as the joint regulator for electricity and gas in 2000 through the Utilities Act by merging Ofgas, the former gas regulator, with Offer, the former electricity regulator. Before 2000, there had already been *de facto* joint regulation of both markets to a degree, because both regulatory organisations had had the same director. Ofgem is the body responsible for ongoing regulation of the non-competitive parts of the gas and power industry. This comprises essentially regulation of prices and access conditions on the major monopoly network activities, gas transportation and distribution, electricity transmission and electricity distribution[28].

The UK's monopoly gas transportation company Transco is regulated under a price cap regime, which has formed the basis of network regulation in the UK from the early days of liberalisation. The asset base for the price cap is renegotiated every 5 years. The second renegotiation was to be implemented as of 1 April 2002.

Transco is responsible for security of supply. As a condition of its Gas Transporter Licence it must design and operate its system to meet a 1 in 20 (years) peak consumption day. Additionally, under the terms of the Gas Safety (Management) Regulations, it must also ensure that demand for a 1 in 50 (years) winter is met if shippers have not already booked sufficient storage capacity. The Gas Safety (Management) Regulations are administered by the Health and Safety Executive (HSE). This means that Transco is subject to two regulators: Ofgem for economic regulation and the HSE for matters of reliability of gas supply and safety.

The price structure for gas transportation is as follows. To use Transco's pipeline system, also often referred to as the National Transmission System (NTS), gas shippers have to pay an entry fee and an exit fee respectively, depending on location, plus a fee that is independent of location. Once gas is on the NTS it can be traded at the National Balancing Point (NBP), a notional point at the centre of the system, without quantitative restrictions relating to its entry or exit point. This way the NTS serves as a market place for gas. The gas is then traded through bilateral deals over the counter (OTC) market, and various other platforms including an independent gas financial exchange (IPE). It is traded largely for balancing purposes on the On-the-day Commodity Market (OCM) and independent exchange, and partly owned by the National Grid Company. At the end of April 2002, Lattice and the National Grid Company announced their intention to merge. Ofgem has proposed reforming price controls on Transco's pipeline usage fees.

At present, entry capacity is auctioned for duration of half a year. In the recent past, some of the auctions have shown high bid prices. The auction of capacity in St. Fergus especially drew high bidding for entry capacity, reflecting not necessarily

28. See also the section The Utilities Act 2000 in Chapter 6.

a bottleneck at the terminals but rather bottlenecks further afield in the transport capacity to the main consumption areas of gas in the South of the UK. The auction offers access to all gas shippers, both those that operate under long-term contracts and those that carry out spot transactions. This has caused difficulty for many of those with long-term contracts to honour their contracts, which put additional upward pressure on entry capacity prices. On the supply side at the beach, about 85% of the gas volumes are traded under contracts; about 30% are contracts within the same conglomerate.

The upstream sector has expressed concern about the short-term capacity auctions, high bid prices and bottlenecks, and has stressed that it needs a longer-term planning horizon for its offshore investment decisions. Onshore gas regulation and its impact on operational and investment performance of the onshore gas infrastructure can have severe impacts on offshore economics (operations and investment performance). The offshore industry favours long-term capacity commitments, necessary for reliable planning for offshore investment. To address this problem, industry working groups are developing a new scheme for auctioning capacity for a longer duration. This may be in place by October 2002 for capacity starting in 2004.

CRITIQUE

Coal

It was a positive step for the UK to terminate coal subsidies in July 2002 (end of the European Coal and Steel Community) and to let the size of the coal industry be determined on competitive grounds.

Depending on relative prices between coal and gas, power generation based on coal may play a larger role than envisaged today. Given the plenty and widely spread coal reserves, the development of zero-emission power plants should be considered as an option for a secure, de-carbonised power generation.

To promote that option, a road map needs to be drawn for R&D on the necessary development steps, on the division of work between State and industry as well as on the role of the UK in the international efforts in that area.

Upstream Hydrocarbons

The most important issue facing the UK's upstream oil sector is how to best address the decline of the oil and gas resources on the UK continental shelf. In particular, the government must devise policies that encourage the best use of the remaining reserves and the existing infrastructure.

The North Sea part of the UK continental shelf is now a mature province, characterised by a large number of small discoveries and undeveloped finds close to existing pipeline infrastructure. In the 1990s all oil finds were below 20 million tonnes and all gas finds below 20 bcm, with only two or three exceptions. As a consequence, the existing pipeline infrastructure has limited remaining useful lifetime and increasing spare capacity as fields become depleted. The industry should use the remaining lifetime of this infrastructure to tie in the larger number of smaller, specialised fields. Otherwise, because of the cost of installing new offshore infrastructure later, smaller hydrocarbon accumulations may be lost.

The first imperative is to adapt an upstream fiscal regime that allows companies to make the best possible use of this window of opportunity. Most importantly, the government would be well advised not to collect royalties on small reservoirs and satellite fields. Royalty payments are a form of depletion premium, reflecting the opportunity costs of future depletion – i.e. they compensate for the fact that a resource extracted today is no longer available for extraction later on. However, a depletion premium is not required for these small reservoirs – there will not be any future depletion if the resource is not used now. Therefore, it seems logical to abstain from taking royalties and to tax the development of such reservoirs like any normal economic activity, i.e. merely through general corporate income tax. This would provide an incentive to develop small fields as long as they earn the standard profit rate.

The UK government has clearly taken these issues into account. For fields that received approval after March 1993, no Royalty or Petroleum Revenue Taxes are paid. Only corporate tax is due, which is unique worldwide. Under this system, UK citizens do not benefit from their resources by taking a rent in the form of a royalty, but rather through the creation of the extra employment and technical innovation that accompanies the development and extraction of the resource.

However, this approach is only partially reflected by the present tax system. Satellite fields that are part of an older licence are still subject to Royalty and Petroleum Revenue Tax (PRT). Enhanced oil or gas recovery projects in older licences are also subject to the old tax regime. In view of the ageing infrastructure and the limited window of opportunity, the government should fine-tune the upstream tax regime to encourage hydrocarbon developments and ensure optimal exploitation of the North Sea resources.

Next, it is necessary to increase the efficiency of offshore regulation. Further development in the North Sea depends on the use of intelligent, tailor–made technology to tie the small fields into the existing infrastructure. There are principal differences between offshore and onshore infrastructure. Offshore infrastructure often has multiple ownership, but also a plethora of technical elements that can hardly be covered *ex ante* by a regulator, e.g. management of pressure, quality and timing, as well as very non-linear economics. More transparency and higher standardisation could help to speed up decisions and development.

A similar consideration might apply to the use of existing infrastructure for the capture of carbon dioxide. As carbon sequestration increasingly emerges as a potentially cost-effective method of carbon abatement in the long run (after 2020), the still-existing oil and gas infrastructure provides a window of opportunity to use depleted fields for carbon injection. The capture of CO_2 in exhausted fields of the North Sea may well be too valuable an option to preclude it simply by letting the infrastructure break down between now and then, which might be the default option if the development of small fields is not fostered.

The government also should consider taking steps to accelerate UKCS exploration outside the North Sea, which so far has not been very successful. While exploration success cannot be forced, its likelihood might be able to be enhanced by suitable incentives. The government should consider such incentives if finding additional hydrocarbons in new exploration areas has potential synergies with the existing industry and market infrastructure. Such synergies may exist in production and skills in the offshore industry.

Import needs for gas depend on the role of gas in power generation (driven by cost considerations and environmental concerns). The alternative to importing more gas might be to replace gas where it can most easily be replaced, i.e. in power generation. This would imply increased imports of coal, which would not cause problems given the competitiveness of the international coal trade. It would however require investment into new coal-based power generation capacity and/ or eventually upgrading of existing power capacity that might have a negative impact on the environment, unless the additional CO_2 inevitably associated with a switch back to coal could be sequestered.

The past development of the UK's oil and gas resources was driven by two factors. One was the large potential of the UK sector of the North Sea and the other was the need to exploit it in a way that made optimal use of the infrastructure needed for offshore development of reserves, e.g. by tying in satellite fields at the right time. In the 1990s, the activity shifted to the central part of the North Sea and to more associated gas fields/gas-condensate fields. A part of them were high temperature/high pressure fields.

As the UK government has a policy to avoid flaring, and as there were difficulties to re-inject the gas, the associated gas from these fields had to find a market in order for the fields to be developed. The marketing of associated gas was largely fostered by the opening of the gas market and by the increased use of gas in power generation in the UK.

Given the development of the UKCS offshore pipeline infrastructure and its increase of idle capacity, transport competition is developing offshore. The upstream hydrocarbons industry is now a very competitive sector. Innovative schemes like PILOT help to ensure easy transfer of licences to those companies willing to develop smaller fields by innovative technology. The PILOT initiative is an interesting and successful approach to make the UK shelf attractive for a multitude of players, including small niche players.

Natural Gas

The liberalisation of the downstream gas industry took a long time to complete, but it is now very successful. Competition in the UK has progressed well in advance of EU requirements. The retail market has been fully open to competition since 1998, i.e. all households are eligible to choose their supplier. The complete opening of the gas market to all consumers successfully created competition, as is shown by the number of companies which are active in the market, including the market to serve final consumers, and by the large number of customers who have used the possibility to switch their supplier. The liberalisation of the onshore gas sector in the 1990s led to increased gas supply and reduced prices and helped gas replace coal as a source for electricity generation. This liberalisation was driven by associated gas from the central UKCS seeking an outlet, and by the liberalisation of the power sector which resulted in the "dash for gas". The building of new combined-cycle gas turbines (CCGTs) during the 1990s was favoured by the prices in the UK power pool that allowed newly constructed CCGTs to recover their full costs. As a result, a total capacity of 18,500 MW of gas-fired power generation capacity, predominantly CCGTs, had been added by 1999.

The development of new gas-fired power generation capacity was brought to temporary stop with the implementation of the "stricter consents" policy imposed in 1998 and lifted in 2001. The removal of the government's stricter consents policy was a positive step. The successful penetration of the power generation market by gas now continues with positive economic and environmental effects.

A potential scenario of lower electricity prices combined with higher gas prices could impair the development of gas-fired power. The New Electricity Trading Arrangements (NETA)[29] have been in force since March 2001, but have been anticipated by the electricity market already a year ahead. Over the last year, this has resulted in electricity spot prices substantially lower than the former pool prices. Present spot price levels would not allow recovering the full costs of a CCGT. It should be noted, however, that present low NETA power prices might not reflect the prices of long-term bilateral agreements, and the long-term bilateral gas prices might also be independent of the gas prices reported for the NTS.

Gas prices, meanwhile, have been driven up by higher fuel oil prices, and the decline of gas production from the North Sea might exacerbate the situation by pushing gas prices further upward. The use of gas in power generation might be reduced as a result of cost optimisation in power generation insofar as environmental restrictions on the use of coal allow this.

Under the present prices scenario, imported new gas, e.g. from Norway or possibly through a new LNG terminal, might not be economically attractive. Imports via the existing interconnector might be more obvious, as they would not need new

29. See Chapter 6.

infrastructure and could respond to the development of prices. The interconnector would offer substantial opportunities to close the gap opening between North Sea production and the projected demand. In a first step, existing contractual delivery obligations could be bought back, then the reverse flow capacity of 8.5 bcm/year could be used, which could be increased to 20 bcm/year by adding compression at Zeebrugge. Such imports from the Continent could result in higher UK gas prices – in fact, the interconnector has already caused some price increases as it has opened an outlet for UK gas in the continental gas market, where the gas fetches higher prices. If gas prices rose beyond a certain level, the combination of high gas prices and low power prices could not only put the construction of new CCGTs to a halt, but also lead to a different place of gas in the merit order, more in intermediate load. This could reinstate coal into baseload, which might jeopardise the CO_2 reduction goal.

With respect to the UK's gas transportation network, the capacity auctions have recently revealed bottlenecks at the entry point in St. Fergus. These effectively reflect capacity constraints in the north-south direction on the national gas grid. But the high bids did not result in corresponding investment by Transco. This suggests that the auctions might not yield the right, or sufficiently strong incentives for Transco to invest in new capacity construction.

This issue is very important and needs to be addressed. It has implications for the optimal development of the onshore gas transportation infrastructure, and a potential impact on the level playing field in the competitive gas market and the further development of the offshore infrastructure (and thus eventually on the development of the remaining UK gas reserves). The capacity restrictions at St. Fergus appear to have already become an obstacle to the timely development of further gas production in the central part of the UK North Sea.

An incentive scheme for Transco to invest in "de-bottlenecking" in a timely manner should be implemented soon. Obviously the investment performance of Transco is decisive for securing the development of the offshore sector as well as for enabling flexible gas trading and security of supply to the final customer. A private monopoly that is subject to a price cap and a regulated asset base does not necessarily have the incentive for capacity expansion. As far as rewards for new investment are concerned, shareholders cannot expect more than the capped price plus some possible efficiency gains. But they have to face regulatory risk, in particular the possibility that the regulator might not accept new investment as part of the regulated asset base. It is questionable whether the management should take a risk to invest without a guarantee by the government or the regulator to include the new investment into the asset base. But even if this occurs, there is not much of a commercial incentive to build an efficient enlargement that effectively exploits economies of scale. This seems to be a generic issue of private independent system operators (ISOs) with a regulated asset base.

On the other hand, it is doubtful that the government can impose an investment obligation on a private company to de-bottleneck crucial pipelines. While private gas pipelines have been built, these seem to have been restricted to dedicated pipelines linking gas terminals with specific large gas users like chemical plants. It is unclear whether private pipelines could be built to de-bottleneck the Transco system and thereby contest its monopoly. The regulator may have a role in identifying specific bottlenecks and inviting tenders from private companies to build the necessary specified pipelines. For the sake of diversity of supply, the government might also wish to foster an alternative import infrastructure such as LNG.

Another problem that needs to be addressed in relation to the NTS is that Transco is subject to two regulators. Ofgem carries out the commercial regulation of Transco, but the HSE regulator defines the obligation to supply all firm customers even under extreme conditions (1 in 50 winter). This raises two issues. First, Transco is a transmission company, and it is questionable whether the obligation to supply should be placed on it instead of on the suppliers. Second, Ofgem does not accept the supply obligation as a component of Transco's cost. That means one regulator is setting the obligation for Transco while the other one is not allowing it to recover the incurred costs. It is unclear how the cost of the 1 in 50 winter obligation for the transport system can be passed on to the users without cross-subsidies. This creates market distortions that should be eliminated as soon as possible. Otherwise, Ofgem should continue to leave as many parts of the gas industry as possible to competition. It should also continue to concentrate the regulation of prices and conditions on the monopoly part of it.

RECOMMENDATIONS

The Government of the United Kingdom should:

Upstream Hydrocarbons

- In view of the ageing infrastructure and the limited window of opportunity, revise the upstream taxation system to ensure an optimal exploitation of the North Sea resources.

- Standardise offshore regulation and make it more transparent.

- Encourage exploration in new promising frontier areas to maintain the UK's position as a net exporter of hydrocarbons as long as possible.

- For the gas from the UK North Sea to be developed, organise the interface with the regulated downstream sector in such a way as to avoid non-economic constraints on the marketing of the gas.

Natural Gas

- Implement soon an incentive scheme for Transco to invest in upgrading its infrastructure and eliminating bottlenecks in a timely manner. This may call for the regulator to define which individual pipeline projects are needed to "de-bottleneck" the infrastructure.
- Consider placing the security of supply obligation on the gas suppliers, not on Transco.
- Continue to leave as many parts of the gas industry as possible open to competition. Continue to concentrate the regulation of prices and conditions on the monopoly part of the industry.

6

ELECTRICITY

INDUSTRY OVERVIEW

The UK electricity supply industry comprises three distinct regions, England and Wales, Scotland, and Northern Ireland. All three changed fundamentally during and after the liberalisation introduced in 1990/91. In England and Wales, the Central Electricity Generating Board was split up into separate entities for generation, transmission and distribution, and supply. The resulting companies were the two generators, National Power and PowerGen, the National Grid Company (NGC), and twelve regional electricity supply companies (RECs). Coal and oil-fired generation plants in England and Wales were divided between two generators, National Power and PowerGen. All of these companies were privatised.

After unsuccessful attempts to privatise the country's nuclear power plants as part of the generators, nuclear power stations were bundled in a company called Nuclear Electric that was retained by the State. Following a review of nuclear power in 1995, the British nuclear industry was restructured once more in 1996. The UK's advanced gas-cooled nuclear reactors (AGRs) and its two pressurised water reactors (PWRs) were formed into a new company, British Energy, which also took over the Scottish nuclear plant. It was privatised in 1996. The older magnox reactors were kept in government ownership in the newly created BNFL Magnox Generation.

For ten years after the introduction of the first reforms, the pool, a mandatory electricity trading mechanism, was at the core of the power market in England and Wales. The pool allowed nationwide trade of electricity. This mechanism, the first of its kind, was soon criticised as restrictive and flawed. Following a government review in 1997, it was replaced by a new, entirely voluntary scheme, the New Electricity Trading Arrangements (NETA) in March 2001. The NETA were phased in on the legal basis of the Utilities Act 2000, which also abolished the authorised exclusive supply areas and contained an obligation to separate supply from distribution.

The generation market in England and Wales remained very concentrated at first but following further reform and adaptation have now developed into a market with many diverse generating companies, including merchant generators often owning only one plant. In England and Wales, there are now 38 companies regarded as major power producers. The largest are: British Energy (19% market share), PowerGen (13%), AES (10%), Innogy (10%), Electricité de France (LE Group, 9%), TXU Europe (6%), Edison Mission Energy (6%), and BNFL (3%). The smaller generators together account for 17%, and the remaining 6% of power generation in the England and Wales market are imported from Scotland.

The Scottish electricity industry had an integrated structure prior to privatisation. This structure remains broadly as it was in 1997. Two companies, ScottishPower and Scottish and Southern Energy, the latter formed as a result of merger between Scottish Hydro Electric and Southern Electric, cover electricity generation, transmission, distribution and supply. British Energy, which also has nuclear power plants in Scotland, is the third main company operating in Scotland. It has contracted the full output of its nuclear plants to the other two companies until 2005. There are at present 10 suppliers licensed to supply electricity in Scotland.

Competition in electricity supply was introduced at the same time as in England and Wales. Competition can occur in the form of third party access. At present, the Scottish wholesale electricity price is indexed to that in England and Wales on the basis of a regulated price. Under the provisions of the Utilities Act 2000, both vertically integrated companies have had to create subsidiaries to ensure that transmission and distribution are in a separate company from those dealing with generation and supply.

Following lengthy consultation on future trading arrangements in Scotland, the electricity and gas regulator Ofgem and the industry agreed that NETA should be extended to Scotland to allow Scottish companies to participate in a larger British market. Scotland will become a part of the British Electricity Trading and Transmission Arrangements, BETTA, which is expected to be introduced in April 2004, with a common set of rules for trading and transmission access.

The electricity supply industry in Northern Ireland is very small, with only 4 main power stations, and was isolated from other networks until March 1995. Northern Ireland Electricity (NIE) ran the entire industry in Northern Ireland until 1998. At that time, NIE was made responsible for the wires businesses (transmission and distribution), but retained a power supply arm of its own. The four major power stations were turned into independent generating companies. Two coal-fired stations were bought by Nigen, a 50:50 venture between US's AES and Belgium's Tractebel, but are now wholly owned by AES. A large oil-fired station was sold to a British Gas subsidiary with permission for conversion to gas firing and since 1997 has been running on gas. The remaining plant was bought by the station's management team.

NIE was established as a power wholesale company. A series of power purchase agreements was struck between NIE's Power Procurement Business and the generating companies. Generating companies were required to sell their entire output to the Power Procurement Business of NIE, which then sold electricity on to licensed suppliers, including NIE's own supply business. Until July 1999 all suppliers had to buy their power from NIE's Power Procurement Business. Since 1999, the market is gradually opened to competition, broadly in line with the EU electricity directive.

Generating plant ownership has seen numerous changes since 1991, as a result of forced and voluntary divestment of plant, significant entry of new generators and changes in business strategies. Generation has changed from a highly concentrated market with a few players to a market with many diverse generating companies. Today there are 42 companies in the British electricity market regarded as major power producers, compared with seven in 1990.

In 1991 there were 14 public electricity suppliers (PESs) in Great Britain (England, Wales and Scotland). They were the successors of old area and Scottish boards. In the decade that has passed since, electricity supply has gone through consolidation – the previous PESs have formed seven major supply groups following take-overs and mergers. British Gas Trading, the trading arm of Centrica, has also become an important electricity supplier. The former public electricity suppliers on the other hand have become major players in the gas market. Among the seven large suppliers, four major retailers cover two-thirds of the British market: Innogy, British Gas Trading, TXU Europe, and Scottish and Southern Energy.

Chronology of Major Events in UK Power Market Liberalisation

25 February 1988	White Paper: Privatising Electricity: the government's proposals for the privatisation of the electricity supply industry in England and Wales.
27 July 1989	The Electricity Act 1989 that liberalises the UK electricity market receives Royal Assent.
July-November 1989	Nuclear power stations withdrawn from privatisation.
30-31 March 1990	"Vesting Day": the electricity pool opens for trading, the regional electricity companies, National Power, PowerGen, Nuclear Electric, National Grid Company, Hydro Electric, ScottishPower and Scottish Nuclear begin operating. The Office of Electricity Regulation assumes full responsibilities.
11 December 1990	Regional electricity companies (RECs) floated on the stock exchange.
12 March 1991	60% of National Power and PowerGen floated.
6 March 1995	Second tranche (40%) of National Power and PowerGen floated.
31 March 1995	The government's "golden share" in the RECs ends.
17 July 1995	First successful take-over bid for a REC by Southern Company (USA) for South Western Electricity. Take-over completed 18 September 1995. Between this date and the end of 2001, more than two dozen successful take-overs and acquisitions occur in the UK. In addition, UK companies are involved in or affected by a host of further take-overs, acquisitions and mergers in the US.
September-October 1995	PowerGen bids for the REC Midlands Electricity, National Power for Southern Electric. Both bids are referred to the Monopolies and Mergers Commission. The government blocks both bids on 24 April 1996.
11 December 1995	National Grid Group floated.

31 March 1996	"Vesting Day": British Energy begins operating. Nuclear Electric plc changes its name to Magnox Electric plc and begins operating.
15 July 1996	British Energy floated.
3 December 1996	The government sells almost all residual shareholdings in British Energy, ScottishPower, Hydro Electric, National Grid, Northern Ireland Electricity, National Power and PowerGen.
23 October 1997	The government announces plans to review the Electricity Pool.
3 December 1997	The government calls review into energy sources for power stations following concerns being raised over security and diversity of energy supplies, in particular increasing dependence on gas and the role of coal. New gas-fired CHP projects continue to be approved but further ordinary gas-fired power capacity is largely put on hold pending outcome of the review.
30 January 1998- 30 January 1999	The government's shareholding in Magnox Electric is transferred to British Nuclear Fuels plc (BNFL). Magnox Electric becomes a wholly-owned subsidiary of BNFL as BNFL Magnox Generation.
25 March 1998	The government publishes the Green Paper *A fair deal for consumers: modernising the framework for utility regulation*.
July 1998	PowerGen takes over the REC East Midlands Electricity from Dominion Resources.
25 June 1998	The government publicly consults on findings of review of serious distortions in electricity market and proposes agenda for market reform and temporary stricter consents policy on new gas-fired power stations.
8 October 1998	The government publishes the White Paper *Conclusions of the Review of Energy Sources for Power Generation* confirming that, following consultation, the reform programme for electricity market will be stepped up and the stricter consents policy introduced. New gas-fired CHP projects continue to be approved but some 5 GW of new ordinary gas-fired capacity is put on hold.
September- December 1998	Scottish Hydro Electric and Southern Electric merge to form Scottish and Southern Energy.
November- December 1998	Electricité de France purchases London Electricity from Entergy.

November 1998-June 1999	Midlands Electricity spins off its supply business and sells it to National Power. Similar transactions by other companies follow.
1 January 1999	The Office of Electricity Regulation and the Office of Gas Supply merge to form Ofgem, the Office of Gas and Electricity Markets.
May 1999	Full supply competition: all 26 million electricity customers in Great Britain are free to choose their suppliers (but not in Northern Ireland).
November 1999-October 2000	National Power splits into two independent businesses – Innogy, its UK energy business that markets power under the brand name npower, and International Power. The UK branch sells two power plants.
December 1999	London Electricity and Eastern Electricity set up a joint venture to operate their distribution networks. The new operator, 24seven, is launched on 3 April 2000.
20 January 2000	Utilities Bill presented to Parliament.
28 July 2000	The Utilities Act 2000 receives royal assent.
9 August 2000	The government redeems its golden share in National Power at the request of the company.
15 August 2000	Elexon Ltd takes over the responsibility for the Electricity Pool and the introduction of the Balancing and Settlement Code under the New Electricity Trading Arrangements.
15 November 2000	The government announces the lifting of the stricter consents policy and simultaneously approves six major power stations. Developers bringing forward proposals for central government clearance will have to show they have seriously explored opportunities to use CHP. Guidance on that requirement issued on 23 March 2001.
22 December 2000	The government redeems its golden share in PowerGen at the request of the company. The government still holds golden shares in National Grid, British Energy, Northern Ireland Electricity, ScottishPower and Scottish and Southern Energy.
27 March 2001	The Electricity Pool is replaced by the New Electricity Trading Arrangements (NETA).
9 April 2001	E.ON (Germany) bids for PowerGen, subject to regulatory approvals (expected in 2002).
October 2001	The Utilities Act 2000 comes into force.
2001	During the year, the electricity companies separate their distribution and supply businesses, as required under the Utilities Act 2000.

Once the supply businesses were sold off, consolidation also was taking place in electricity distribution. There are now nine distribution companies. Recent years have also seen a trend to vertical (re-)integration of generation and supply. Generators losing their market shares, as a result of growing competition in the generation market and divestment of capacity required by the regulator, have been prompted to diversify into the supply business. The box above contains a brief list of the most important milestones in UK electricity market reform to date.

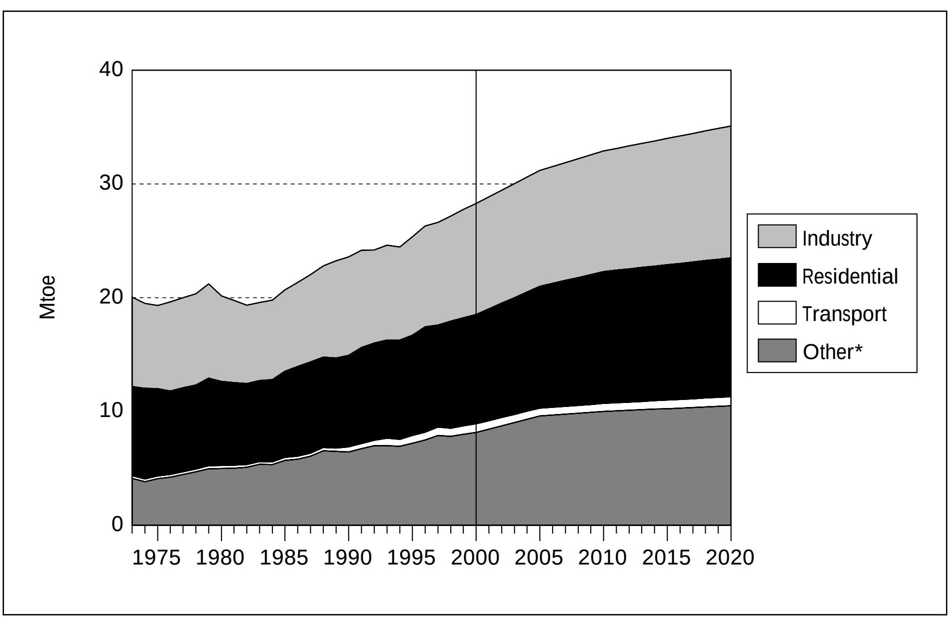
ELECTRICITY DEMAND

Figure 20 shows electricity demand by sector in the UK. As in most other IEA countries, electricity accounts for an increasing share in total final consumption, which currently stands at 17.5%.

According to government figures, UK electricity demand grew at an average rate of 1.9% p.a. between 1998 and 2000. During this period, electricity imports fluctuated between 3.4% and 3.7% of total UK supply whereas exports were negligible (less than 0.1% of total supply). The government anticipates that demand developments and the expected closure of some 36 GW of power plant capacity will result in a need of between 25 and 50 GW of new capacity by 2020.

Figure 20

Electricity Consumption by Sector, 1973 to 2020



* includes commercial, public service and agricultural sectors.

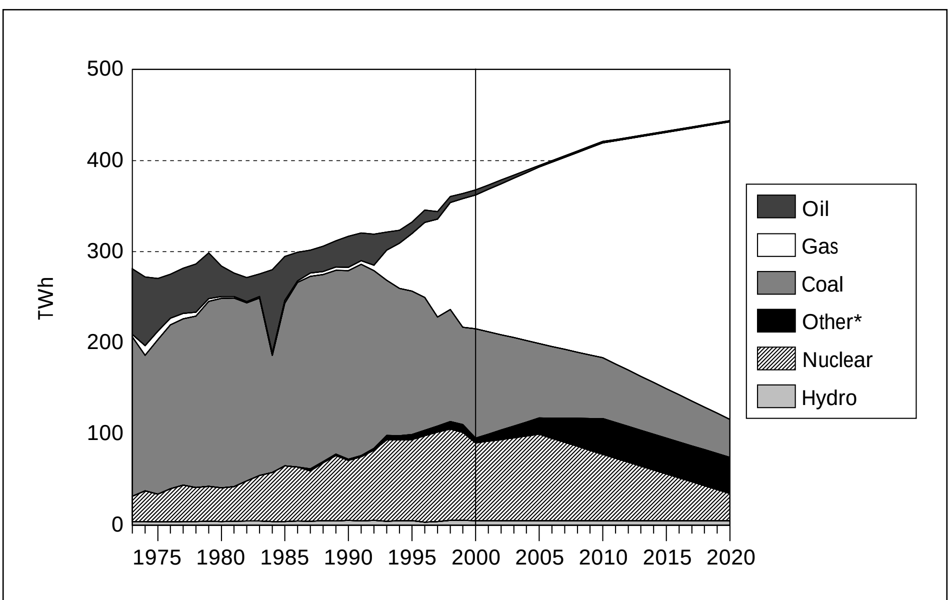
Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2001; and country submission.

Generation

Figure 21 details electricity generation by source in the UK since 1973. The graph clearly illustrates the "dash for gas" that followed the introduction of competition into the power industry in 1990/91. Between 1990 and 2000, total electricity generation increased from 317 TWh to 378 TWh. In the same time period, gas-based generation rose from 3.5 TWh or 1.1% to 145.5 TWh or almost 40% of total generation. Much of this increase is due to the high growth rate of combined-cycle gas turbine (CCGT) generation. CCGT output rose more than 400-fold in absolute terms since 1990. Four new CCGT power plants came on stream during 2000 alone.

For the most part the increase in gas-based generation occurred at the expense of coal. The output share of coal declined from 207 TWh or 65.3% to about 120 TWh or about one-third. Very recently, i.e. between 1999 and 2001, the use of coal in UK electricity generation has increased by about 24% (in Mtoe). This was the consequence of a significant rise in the wholesale price of natural gas, which made some gas-fired generation more expensive, and of a 10.5% fall in nuclear power output between 1999 and 2000. This decline in nuclear generation during 2000 was largely caused by a higher than usual level of maintenance and repair outages. Oil was also affected by the "dash for gas", declining from 34.2 TWh (10.8%) to 5.5 TWh (1.5%).

Figure 21
Electricity Generation by Source, 1973 to 2020



* includes geothermal, solar, wind, combustible renewables and wastes.

Sources: *Energy Balances of OECD Countries*, IEA/OECD Paris, 2000; and country submission.

Other energy inputs remained unaffected by the "dash for gas". Nuclear generation remained broadly stable at about 85 TWh or 23%. Hydro-power (5.2 TWh or 1.4%), combustible renewables (4.4 TWh or 1.2%) and solar, wind, and other renewables (1.1 TWh or 0.3%) also continued their long-term trends and accounted for the remainder in 2000.

Following accusations that the pool rules were skewed against coal, leading to reduced diversity of UK energy supply, the government introduced a "stricter gas consents policy" in October 1998. This was essentially a moratorium on the approval of any new gas-fired power stations pending the implementation of measures to deliver a more competitive market. By 2000 the government decided that with the introduction of NETA, enough progress had been made in reforming the electricity market to allow the moratorium to be lifted. The moratorium was rescinded in November 2000.

Projections of energy demand and supply prepared by the Department of Trade and Industry (EP 68, DTI, November 2000)) suggest that nuclear generation could represent about 17% to 18% of total UK generation in 2010 (about 66 TWh), and about 7% of total generation by 2020. The projections assume no new plant construction. Neither British Energy nor BNFL have any plans to build new nuclear power plants in the UK.

The projections also take into account that while plant lifetimes are dependent on safety and economic factors, there is potential for lifetime extension. British Energy has announced that it anticipates obtaining lifetime extensions for some of its AGR stations. Taking that into account, the first plant closure date is currently expected to be in 2008 and the last in 2023. It is conceivable that the PWR station, licensed for 40 years, could operate beyond its currently published lifetime of 2035 and perhaps beyond 2050.

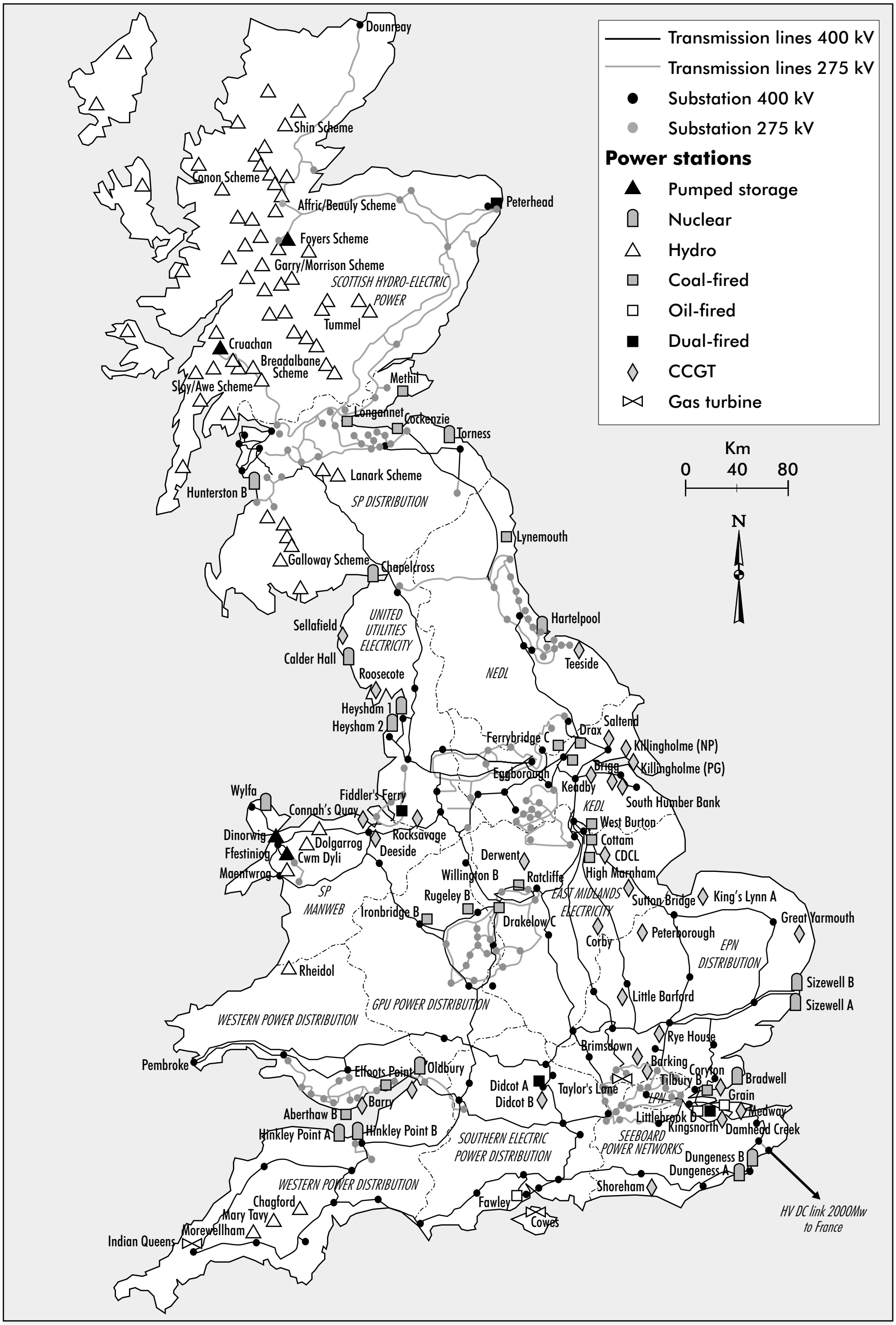
British Nuclear Fuels announced in May 2000 the lifetime strategy for its magnox stations, which produce about 7% of UK electricity generation. Under that strategy, the majority of stations would close by 2010 and magnox fuel reprocessing at the Sellafield plant would stop once all the fuel had been dealt with, around 2012. Two of its stations could be operated safely for a longer period, depending on the availability of alternative fuel options and/or fuel management facilities. BNFL concluded earlier this year that one such fuel option (magnox) was not commercially viable. Measures of diversity suggest that sources of fuel generation in the UK will be as diverse in 2010 as they have been in the recent past.

Transmission and Trade

Electricity transmission remains a monopoly in the hands of National Grid Group, the transmission network operator in England and Wales. National Grid has a central role in the industry. It has a statutory duty to develop and to maintain an efficient, co-ordinated and economic transmission system and to facilitate competition in supply and generation. National Grid must ensure that the system in England and Wales is balanced nationally and locally at all times, taking into account and resolving any constraints on the transmission network.

Figure 22

The Electricity Transmission System in the United Kingdom



Source: The Electricity Association.

The Scottish network, which is owned in the south by Scottish Power and in the north by Scottish and Southern Energy is connected to National Grid's transmission system in England and Wales via a 1,200 MW interconnector, which is currently being upgraded. The interconnector's capacity is shared by ScottishPower, Scottish and Southern Energy and British Nuclear Fuels (BNFL) under a formal agreement which allows the companies to sell or purchase electricity in England and Wales. The generation capacity in Scotland currently exceeds demand and companies export surplus output to England and Wales through the interconnector. The Northern Ireland system was isolated until 1995 but has been reconnected with the system of the Electricity Supply Board in the Republic of Ireland[30]. Figure 22 shows the transmission system in the UK.

The National Grid also owns and operates jointly with Electricité de France the 2-MW DC interconnector between the systems of England and France and owns jointly with ScottishPower and Scottish and Southern Energy the interconnector with Scotland. A number of other interconnectors are currently in the process of being upgraded or completed. In addition, there are (proposed) projects for interconnection with the Republic of Ireland, Norway and the Netherlands:

- The Anglo-Scottish Interconnector, which links the transmission networks of Scotland and England and Wales, is in the process of being upgraded from 1,200 MW to 2,200 MW.

- The Isle of Man Interconnector was commissioned in October 2000 and has a capacity of 40 MW.

- The North Sea Interconnector (NSI), which will have a capacity of 1,320 MW, will be constructed between north-east England and south-west Norway. It should be in operation by 2005/06, thereby enabling the UK to import cheaper peak electricity and Norway to reduce its dependence on hydro-power.

- BritNed, a joint venture between the National Grid and its Dutch equivalent, is currently investigating the technical and commercial feasibility of a subsea interconnector between Britain and the Netherlands. If given the go-ahead, the interconnector could enter service as early as 2004/05 and have a capacity of at least 1,000 MW. However, the project has yet to receive the necessary government approval.

- A feasibility study has recently been undertaken regarding the construction of a 500 MW interconnector between Wales and the Republic of Ireland. If construction proceeds, it could be completed by 2006.

- Northern Ireland's historic separation from mainland Britain's electricity market ended when construction of the 500-MW Moyle Interconnector, a new HV DC submarine cable linking Ulster to Scotland, was completed in December 2001.

30. The main north-south interconnector between Tandragee in Northern Ireland and Louth in the Irish Republic was first commissioned in 1970, but was destroyed by terrorists in 1975.

The Moyle Interconnector was formally opened in April 2002 and is expected to meet about 20% of future demand in Northern Ireland.

- The capacity of the principal interconnector between Northern Ireland and the Irish Republic was doubled from 300 MW to 600 MW in late 2001, around which time two separate "standby links" between north and south were also upgraded to full interconnector status.

Distribution and Supply

Distribution remains a monopoly business and, under the Utilities Act 2000, it has become a separately licensable activity. There are nine distribution companies operating 14 licensed distribution areas in Great Britain. Distribution companies hold separate licences for each area and are governed by the terms of their distribution licences. They are under a statutory duty to connect any customer requiring electricity within a defined area and to maintain that connection. The Utilities Act places statutory duties on Distribution Network Operators (DNOs) requiring them to facilitate competition in generation and supply, to develop and maintain an efficient, co-ordinated and economical system of distribution and to be non-discriminatory in all practices.

The provisions of the Utilities Act 2000 requiring separate companies to distribute and supply electricity came into force in October 2001. In England and Wales, only London Electricity, Seeboard, Manweb and Southern Electric continue to undertake both activities. Scottish and Southern Energy and ScottishPower each operate their own generation, transmission, distribution and supply companies in Scotland.

Any company holding an electricity supply licence can sell electricity to final customers. There is no longer a duty to supply, but supply licensees have a duty to offer terms on request. Suppliers may supply customers nationwide using other company's distribution networks and paying DNOs for the use of the system.

Retail Competition in the UK

The retail supply of electricity was opened to competition in the following three steps:

- **April 1990 – all customers consuming over 1 MW per site**
  There are 5,000 customer sites in this category and 81% of these had switched their supplier at end-2001.
- **April 1994 – all customers consuming 100 kW to 1 MW per site**
  This category contains 60,000 customers. Of these, 58% has found a new supplier at end-2001.
- **May 1999 – all customers consuming less than 100 kW**
  Of the 26 million customers in this category, 38% had switched supplier at end-2001.

Suppliers who are authorised to supply domestic customers are required by their licences to meet all reasonable demands for electricity made by domestic customers. This duty applied originally to the monopoly public electricity suppliers but was extended in 1998. Suppliers may meet this obligation through contracts with generators or by establishing their own generation. A number of the major generators are now active in the domestic supply market, and some have acquired one or more former Public Electricity Suppliers (PESs).

RECENT REFORM OF THE ELECTRICITY MARKET

The Starting Point for Reform

The system that was put in place by the UK government in 1990/91 was the first-ever market mechanism designed to function as a competitive electricity market. At the time of designing this system, it was not known with certainty whether it would work satisfactorily, and in most other countries there was still debate as to the feasibility in principle of competition in the electricity supply industry.

The market design reflected the state of knowledge, the existing technical systems in place for the dispatch of generating plant, and the fears surrounding the reforms at the time. After the first few years of operation of this system, it became clear that the power market was clearly functioning in the sense that supply covered demand without major problems – in fact the rules brought on a host of new capacity construction, almost exclusively CCGTs. However, the experience in the UK began to show that the combination of the Electricity Pool and the duopoly of dominant generators in the market led to higher prices than was justified by marginal cost. The pool itself was resistant to reform and insufficiently market-based. This was confirmed by experience in other countries that were able to draw on the UK's pioneering experience and design themselves systems that were both more liberal and more efficient.

The mandatory Electricity Pool in particular was seen as in need of reform. The Electricity Pool was the trading arrangement in England and Wales by which electricity suppliers and large industrial users purchased electricity from the electricity generators. It was established in 1990 at the time of privatisation, and continued until it was replaced on 27 March 2001 by the New Electricity Trading Arrangements (NETA). The pool operated under the Pooling and Settlement Agreement, a commercial arrangement between the generators and public suppliers of electricity.

The pool, which used computer software for the dispatch of power stations originally developed by the pre-privatisation Central Electricity Generating Board, was used to determine which generating sets were called on to satisfy demand. It also determined the price for wholesale electricity, the pool price. Under the pool system, generators bid prices at which their generating sets were available to run.

The pool price was set for each half-hour by the most expensive generator used during that period, and applied to all generators called to run. Those available, but not called to run, received a capacity payment which reflected the degree to which capacity was needed. The capacity price was calculated as the product of the probability that load had to be shed (Loss of Load Probability, LoLP) and the Value of Lost Load (VoLL), an estimate of the pecuniary equivalent of the damage from load shedding.

The pool attracted numerous criticisms. Long-standing criticisms of the pool include that its governance was not sufficiently open to electricity consumers, its operation was not transparent, it was a price-setting mechanism rather than a true market, it did not permit those buying power (i.e. suppliers) to influence the price.

Perhaps more important, the pool was criticised for allowing generators owning large amounts of mid-merit capacity to exercise control of the market. At the time, the three large power generators, PowerGen, National Power and Nuclear Electric, still had a combined market share in excess of 80% in the generation market. PowerGen and National Power, who dominated the ownership of own mid-merit coal-fired capacity, set the pool price 80% of the time or more. This opened vast possibilities for collusion and gaming to drive up the pool price. In recognition of these problems, the then electricity regulator asked PowerGen and National Power in December 1993 to divest 5,000 MW of mid-merit generating capacity. Between February 1994 and March 1996 the regulator also effectively installed a price cap on the pool price.

Another severe criticism of the pool was that it did not encourage the development of a full forward and futures market in electricity. In addition, the mechanisms that were available distorted the market by encouraging excessive new construction of gas-fired plant, displacing coal-fired plant by gas-fired plant beyond what one would expect in a normal market. In fact, generators and their customers wishing to hedge the risk of price volatility in the pool only had one instrument available, the so-called Contracts for Differences (CfDs). Under these contracts, generators would reimburse their customers if the pool price rose above the agreed price in future, whereas customers would reimburse generators if it fell below it. Physical forward trading was not allowed and standardised futures contracts did not develop.

Under the CfD arrangements, new entrant and nuclear generators soon discovered that it was advantageous for them to bid zero into the pool – i.e. announce that they would run whatever the price was. This would ensure that their plant was dispatched, but would not adversely affect their revenue, as they would be receiving the pool price for their generation anyway, corrected through the CfDs if necessary. Although there were restrictions relating to vertical integration between generation and supply at the time, the regional electricity supply companies (RECs) were allowed to generate up to 15% of their electricity needs themselves. This they did by building combined-cycle gas turbines trough their own subsidiaries and concluding CfDs with them, using the above mechanism. In this manner, the pool did not reveal any price information about these CCGT plants, and did not impose any competitive discipline. As competition in supply remained restricted over most of this time period, competition for ultimate consumers did not exert any strong disciplining influence either. These factors contributed to the speed of what became rapidly known throughout the world as the UK "dash for gas", although it was also caused by a genuine cost advantage of gas-fired generation at the time.

The shortcomings of the pool were significant enough to warrant an overhaul of the trading rules in the UK electricity market. Such an overhaul also was spurred by the lessons other countries had learnt from the flaws of the early UK system and the experience they had gained with systems that were not built around mandatory pools and that allowed much greater freedom and flexibility for generators and their customers.

Responding to the concerns, the minister for energy and industry announced in October 1997 a review of electricity trading arrangements, and asked the regulator to advise on a preferred model for trading electricity.

In December 1997 the government also announced that a review of fuel choices for electricity generation was to be carried out. The results of that review were published in the 1998 Energy White Paper *Conclusions of the Review of Energy Sources for Power Generation*. This White Paper committed the government to completing competition in electricity supply, reforming the wholesale electricity trading arrangements, and taking all available opportunities to encourage the divestment of mid-merit generation plant by National Power and PowerGen. All of these commitments were achieved. Competition in electricity supply was completed in early 1999, further major plant divestment was carried out by National Power and PowerGen in part in order to obtain approval for the purchase of former PES supply businesses, and the wholesale market was reformed with the introduction of NETA in 2001. The temporary "stricter gas consents policy", a moratorium on the approval of any new gas-fired power stations, was applied pending delivery of these objectives, i.e. between October 1998 and November 2000.

In July 1998, the regulator published proposals to replace the Electricity Pool with revised electricity trading arrangements. Subsequently a NETA Programme Development Office jointly established by the Department of Trade and Industry and the merged energy regulator Ofgem (Office of Gas and Electricity Markets) developed these proposals. Following an extensive consultation process undertaken by the NETA programme, a blueprint for NETA was published by DTI/Ofgem in October 1999.

Simultaneously, the government prepared a Utilities Bill to reform the regulation of the industry. This bill was presented to Parliament in January 2000 and received royal assent in July 2000.

The Utilities Act 2000

The Utilities Act 2000 amended both the Gas Acts 1986 and 1995, and the Electricity Act 1989. The Utilities Act introduced one last modification to the structure of the UK power industry by requiring separate companies to distribute and supply electricity. These provisions of the Utilities Act came into force in October 2001.

In addition to this modification of the industry structure, the Utilities Act also introduced changes to the regulatory structure for gas and electricity. The following changes were made:

- The Directors-General of Electricity and Gas Supply, the separate legal regulators for electricity and gas, were replaced with one regulatory authority: the Gas and Electricity Markets Authority. The authority, which came into existence in November 2000, is the governing body of the Office of Gas and Electricity Markets (Ofgem). It is headed by a chairman who is also the chief executive of Ofgem. In addition, the authority has a number of executive and non-executive directors, all of whom are appointed by the secretary of state. The authority and its executive office Ofgem are the bodies responsible for the oversight of the gas and electricity markets and for ongoing price regulation of the non-competitive parts of the gas and power industry. Unlike most European regulators, Ofgem is also a formal competition authority for the electricity and gas sectors.

- The existing duties of the regulator were revised to place a principal duty on the new authority to protect the interests of consumers, wherever appropriate by promoting effective competition. The legislation places other duties and objectives on the regulatory authority. The authority can impose financial penalties of up to 10% of a company’s turnover if a licensee breaches conditions of a licence or other requirements.

- The existing electricity trading arrangements were replaced with new ones. In England and Wales, the Electricity Pool has since been replaced with New Electricity Trading Arrangements (see below). Proposals have been made as to extending these arrangements to Scotland to create British Electricity Trading and Transmission Arrangements (BETTA).

- The Public Electricity Supply Licences (which also covered distribution activities) were replaced with separate licences for electricity supply and distribution. A person who holds a distribution licence can not hold a supply licence at the same time.

- The secretary of state can give statutory guidance to the authority on how the authority might assist in achieving the social and environmental objectives of government. The authority must have regard to the guidance, but it is not a power of direction, and it cannot over-ride the authority’s statutory duties.

- The Gas Consumers Council and the Electricity Consumers Committees were replaced with a single Gas and Electricity Consumers Council that has since taken the name Energy Watch.

The authority continues to review price controls on the major monopoly network activities, gas distribution, electricity transmission and electricity distribution. The authority monitors the wholesale electricity market and the behaviour of electricity licensees in it. It may take enforcement action against licensees for breach of licence conditions under the Electricity Act 1989. As a competition authority, it may also take action under the Competition Act 1998.

Licensees participating in the balancing mechanism have to comply with the Balancing and Settlement Code (BSC, see below). Following a modification procedure, modifications may be made to the BSC with the approval of the Gas and Electricity Markets Authority.

Implementation of new trading arrangements was made possible by Section 68 of the Utilities Act 2000, which received royal assent in July 2000. This inserted section 15A into the Electricity Act 1989 empowering the secretary of state to modify electricity licences during a period of two years. This he could do where he considered it necessary or expedient for the purpose of implementing or facilitating the operation of new arrangements relating to the trading of electricity. Following the exercise of this power the Electricity Pool was replaced with new electricity trading arrangements in March 2001.

The New Electricity Trading Arrangements (NETA)

The Electricity Pool in England and Wales was replaced by New Electricity Trading Arrangements (NETA) on 27 March 2001. The most important basic principle of the New Electricity Trading Arrangements is that those wishing to buy and sell electricity should be able to enter into any freely negotiated contracts to do so. Under the new trading arrangements, bulk electricity is traded on several power exchanges and through a variety of bilateral and multilateral contracts.

The purpose of NETA is not to impose ways in which electricity is to be bought and sold on these exchanges or in bilateral contracts, but to enable these transactions as close a possible to real time. This requires two essential functions.

The first function, imbalance settlement, is a mechanism for near real-time clearing and settlement of the unavoidable imbalances between contractual and physical positions of market participants. Instead of pricing and settling wholesale electricity purchases, as under the Electricity Pool, the NETA price and settle only the imbalances that occur. These occur because traders of electricity may buy more or less energy than they have sold, generators may generate more or less than they have sold, and the customers of suppliers may consume more or less energy than their supplier has purchased on their behalf. The prices and quantities of the wholesale transactions themselves are entirely in the hands of the contractual partners. As metered data for generation and wholesale demand are available on a half-hourly basis, imbalance volumes and imbalance prices are calculated on a half-hourly basis, and settled on a daily basis, approximately 28 days after the transaction. In another break with the formal pool, NETA were designed explicitly to encourage balancing on the part of generators and suppliers through the use of asymmetric dual cash-out prices. This means that the cost of “spilling” on to the system is determined differently from the cost of “topping up” – by contrast, the pool effectively only had a single cash-out price.

The second related function is load balancing. Its role is to provide a mechanism for adjusting the intended operating levels of generation and demand in real time. It is unlikely that the aggregate level of generation that generators intend to produce or actually produce precisely matches the aggregate level of demand that customers of suppliers intend to consume or actually consume at any given time. For a number of detailed technical reasons, including grid constraints, it can be necessary to be able to adjust the level of production or consumption of individual generators or demands away from the scheduled level (re-dispatch), e.g. to prevent localised overloading of the transmission system. Under NETA, the system operator will determine what actions need to be taken in the balancing mechanism in order to maintain the required national and local balances of generation and consumption.

The rules that govern load balancing and imbalance settlement are set out in the Balancing and Settlement Code (BSC). Licensed generators, distributors, public electricity suppliers and the National Grid are legally required to be parties to the Balancing and Settlement Code, whilst traders and others are free to become parties to the code or not. All regular transactions have to be notified to the system operator. "Gate closure" for notification is currently $3^1/_2$ hours before the start of the half-hour during which the electricity is effectively traded. This requirement notably includes generators and electricity suppliers. The latter may also indicate quantities and prices for re-dispatch.

To fulfil these functions, NETA comprise a series of bilateral markets. Unlike the pool, these are genuine two-sided markets, designed to encourage competition and liquidity and to remove distortions in the market. These markets are:

- The balancing mechanism operating from gate closure ($3^1/_2$ hours ahead of real time) up to real time, managed by the National Grid Company (NGC). As electricity cannot be stored, NGC needs to manage the grid system on a second-by-second basis and the balancing mechanism is the principal facility under NETA that allows it to do this. However, the vast majority of trading takes place in the forward markets rather than in the balancing mechanism.

- The settlement process to deal with the financial settlement of balancing mechanism trades and imbalance settlement.

- Screen-based over-the-counter (OTC) power exchanges to enable participants to refine their contract positions close to real time in the light of current information (e.g. on the weather). Five power exchanges have either set up or are in the process of being set up.

- A forward market where generators are able to contract with suppliers and large customers for the physical delivery of electricity. Such contracts can be struck close to the time of delivery or a year or more ahead.

- Associated derivatives markets to enable market participants to manage commercial risks.

In addition to these provisions of NETA, all licensed suppliers have a licence obligation to purchase sufficient power to satisfy the needs of their consumers such that the requirements of the Generation Security Code are met. It is therefore for suppliers to secure the services of adequate generating capacity – through bilateral contracts and/or participation in one of the wholesale electricity exchanges.

While the National Grid has a range of contracts to secure the successful operation of the transmission network in England and Wales, no capacity or availability payments are made to generators under the new electricity trading arrangements.

Outcomes of Recent Reforms

The Utilities Act 2000 required the separation of distribution and supply in England and Wales, and established separate licences for these activities, prohibiting any one entity from holding both. As a consequence, companies split their distribution and supply businesses, and most sold them off. In England and Wales, only London Electricity, TXU, Seeboard and Southern Electric continue to own companies that undertake both activities.

On the basis of the progress made thus far with the introduction of competition, the government expects that all ongoing price controls except for grid services can cease by April 2002.

In conjunction with the reforms under the Utilities Act 2000 and the plant divestments that have been carried out, NETA are beginning to deliver benefits, notably in the development of a more competitive wholesale market, which puts downward pressure on prices, and a flexible governance framework. Compared with the performance of the Electricity Pool during the last years of its existence, NETA have led to the following improvements:

- Electricity wholesale prices have fallen 20-25% as a consequence of NETA. In fact, bulk power prices began to fall in anticipation of its introduction as of Spring 2000.

- Market liquidity has improved, with a threefold increase in trades and a fivefold increase in the number of contracts concluded.

- Most electricity (93%) is traded bilaterally and 95% is traded on the forward markets and in power exchanges.

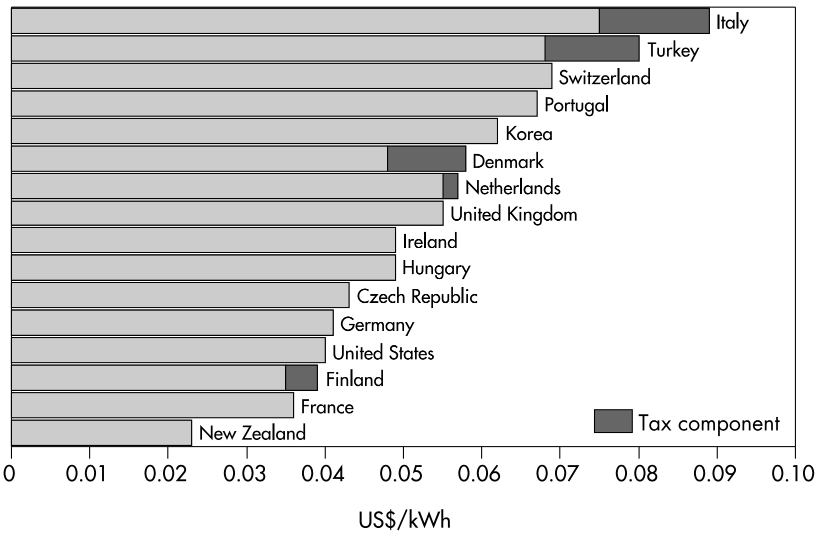
- The balancing mechanism trades very small volumes of about 3% of national demand. This proves that it is really used for balancing and not for selling regular bulk power at higher prices than in the regular markets.

- The National Grid Company has halved its daily balancing costs.

- Price volatility is decreasing and the spread of prices is narrowing.

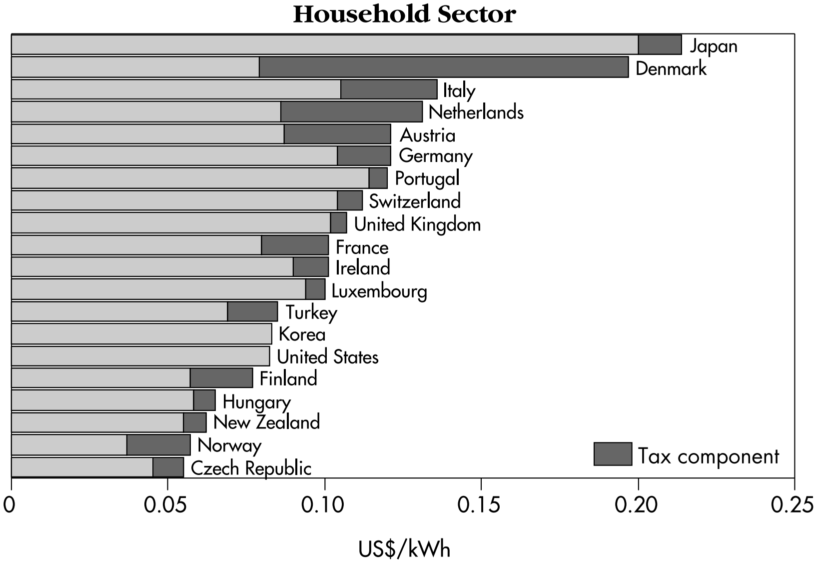
Figure 23
Electricity Prices in IEA Countries, 2000

Industry Sector



Note: Price excluding tax for the United States. Tax information not available for Korea. Data not available for Australia, Austria, Belgium, Canada, Greece, Japan, Luxembourg, Norway, Spain and Sweden.

Household Sector



Note: Price excluding tax for the United States. Tax information not available for Korea. Data not available for Australia, Belgium, Canada, Greece, Spain and Sweden.

Source: *Energy Prices and Taxes*, IEA/OECD Paris, 2001.

- Generators now optimise their generating units and power purchases themselves.

- Generators declare the availability of their generating units more reliably as they must otherwise buy from the more expensive balancing mechanism. This increases reliability for all market participants.

The government and Ofgem work to further improve the performance of NETA. Areas where further improvement is seen as necessary are better information flow in the over-the-counter (OTC) market, more participation of the demand side, and means to encourage the participation of smaller generators, especially those using renewable sources of energy.

More importantly still, NETA do not apply to Scotland. ScottishPower and Scottish and Southern Electricity are required to make available wholesale power to competing suppliers at a regulated price related to wholesale prices in England and Wales. Until 2005, these two companies are also required to buy the output of British Energy's two nuclear power stations in Scotland at prices related to wholesale electricity prices in England and Wales. The latter arrangement (known as the Nuclear Energy Agreement) is currently the subject of a legal dispute.

Under these arrangements, prices have not declined as rapidly in Scotland as they have in England and Wales. The government therefore intends to introduce legislation to extend NETA to Scotland during the 2002/03 parliamentary session. The combined system is known as the British Electricity Trading and Transmission Arrangements (BETTA) and involves the creation of a unified transmission system operator for the whole of Britain.

CRITIQUE

Being first is not always being best as mistakes can be made. Others can learn from these mistakes and undertake different reforms. This describes the early years of power industry reform in England and Wales. Much has been written about the flaws that characterised the early reforms. These are now generally accepted to have been:

- Too few competitors at the outset to generate effective competition.

- An overly restrictive trading mechanism at the core of the industry that did nothing to alleviate, and in fact exacerbated, the market control of the few players in the market.

- No demand side participation.

One of the most striking results of the early years of UK power liberalisation was that while there was enough competition to lead to significant reductions in UK power companies' costs, those cuts remained largely unmatched by reductions in prices. As a consequence, UK power utilities became a prized investment opportunity for global power investors, but the regulator had to intervene regularly to compensate for the lack of competition and ensure that the cost reductions were at least partly passed on to consumers.

It should be noted, however, that the UK's pioneering role in power market reform, including all its flaws, cannot be rated too highly, both in terms of the benefits it has created and the example it has set. The majority of UK customers are better off now than before the reforms (see below). The government received proceeds from privatisation in the order of £21 billion, and another £8 billion from corporation tax paid by the electricity companies since. Of all the countries that have since opted for power market reform, most if not all have implicitly or explicitly modelled their system on the UK experience – if only to avoid the flaws they perceived in it.

The recent reforms in England and Wales, and in particular the Utilities Act 2000 and the New Electricity Trading Arrangements, have now provided the decisive correction of the early flaws, and brought the England and Wales system back up to speed with the current state of knowledge of such reform. NETA were a decisive step forward from the Electricity Pool and towards a real market. It explicitly includes the demand side. The generation market is free and no longer dominated by one or two players with overwhelming market power. Market players have the choice of the market and market instruments, in particular direct bilateral contracts. They can equip themselves with the tools the market needs to function effectively. The establishment of several power exchanges shows that the market is responding to this challenge. Despite the fact that the NETA are still relatively recent, a long-term forward market is emerging. Liquidity in the forward market will improve the robustness of the signals for the need of future capacity.

The introduction of NETA and other reforms, notably including the divestment of generating capacity, have resulted in a more competitive electricity market. Throughout Britain, the number of generators has risen from 4 in 1990 to 42 today. This result is not entirely of the government's making. The industry has gone through vigorous self-restructuring in the past four years with a host of take-overs, spin-offs, mergers and acquisitions. There was vertical (re)integration between supply and generation companies, driven by companies' wish to manage risk more effectively. Supply businesses consolidated, driven by the wish to increase market share and reach the critical threshold of 5 million customers in order to cut costs and compete with British Gas Trading, the largest supply company. Others sought to focus on distribution activities and left the supply business. Distribution also consolidated, striving to improve efficiency.

About half of the electricity generated today is from new entrants. Prices reflect market conditions better than under the pool, much to the benefit of consumers, and generators and large demand sites are changing their behaviour and are responding to the new incentives given under NETA. It seems that the more liquid markets under NETA have reduced the possibility of players using market power, as illustrated by decreasing wholesale prices. These outcomes are highly encouraging.

It is fair to say that the introduction of competition was highly successful, especially given the recent improvements. Overall, since competition was first introduced in 1990, residential customers in England and Wales have seen their electricity bills fall by a cumulated £750 million. Their real electricity prices declined by 30% on average. Those who switched suppliers benefited from an additional 6% reduction. Industrial electricity prices are some 36% to 41% lower than in 1990. Standards of customer service and reliability have improved.

Security and reliability of electricity supply have benefited from the competitive market with £31 billion of new investment in gas and electricity networks since privatisation, a 30% reserve margin thanks to extensive generating capacity construction, and a more balanced supply portfolio than in 1990. Whereas coal accounted for 65% of generation in 1990, with nuclear at 21% and oil at 11%, coal was down to 33% in 2000, gas generation stood at 40% and nuclear at 23%. In addition to current installed capacity of 79.3 GW, an additional 16 GW of new generating capacity is under consideration.

In fact, the UK currently enjoys unprecedented levels of security and diversity of electricity supply. These results are encouraging and do not suggest any need for the government to deploy major activity to ensure security of supply. To be on the safe side, the government may find it useful to monitor the development of forward prices. In the longer run, and if the prevailing trend of fuel choice in the UK power industry continues, natural gas will increase its already significant share further. Should the share of gas-fired power generation grow beyond a certain threshold, say 60% or 70%, this might create problems on the interface of electricity and gas and reduce diversity below desired levels. The government would then have a role in ensuring diversity in the power industry.

While the power market in England and Wales has now developed into a successful and competitive business that generates significant benefits for consumers, the same cannot be said for Scotland and Northern Ireland, where competition is still limited by restrictive contractual arrangements, integrated industry structures and/or regulation. Given the small size of the Northern Irish system, this does not affect a large number of customers, although this should not be seen as a reason to defer reform indefinitely. However, the government should, as is indeed its intention, work towards integrating Scotland with the liberalised energy market in England and Wales. This will eventually contribute to a more efficient market, not least by improving the load factor of already-existing power plants.

More focus might also be given to consistency in the regulation of the gas and electricity networks. It is important that the regulatory regime give the transmission owner incentives over the long term to build the infrastructure needed relating to security of supply.

RECOMMENDATIONS

The Government of the United Kingdom should:

- ☐ Continue to allow the electricity market to settle into the smooth and fully competitive operation of NETA by refraining from intervention.

- ☐ Encourage full participation of the demand side in the balancing market (load shedding).

- ☐ Seek consistency in the regulation of the gas and electricity networks.

- ☐ Provide incentives for the transmission owner to build over the long term the infrastructure needed to secure supply.

7

NUCLEAR

OVERVIEW

Following deregulation of the electricity market, nuclear energy remains an important component of the British energy mix, supplying about 23% of the country's electricity and avoiding the emission of some 12 million tonnes of carbon per year. The nuclear power plants in operation, 33 units with a total capacity of 12.6 GW (Table 7), have shown good safety, technical and economic performance, increasing their electricity output by nearly 50% during the last decade. However, even at production costs below 2 p/kWh (~1.8 p/kWh), the competitiveness of nuclear is challenged by the current low prices under NETA.

Table 7
Nuclear Power Plants in Operation, 2001
(33 units - 12.59 GW)

	Capacity (MW net)	*Grid connection*	*Planned shut-down**
Magnox (BNFL)*			
Bradwell (2 units)	123 x 2	1962	2002
Calder Hall (4 units)	50 x 4	1956-1959	2006-2008
Chapel Cross (4 units)	50 x 4	1959	2008-2010
Dungeness A (2 units)	225 x 2	1965	2006
Oldbury (2 units)	217 x 2	1968	2008
Sizewell A (2 units)	210 x 2	1966	2006
Wylfa (2 units)	490 x 2	1971	2009
AGR (BE)			
Dungeness B (2 units)	555 x 2	1983-1985	2008
Hartlepool (2 units)	605 x 2	1983-1984	2009
Heysham 1 (2 units)	575 x 2	1983-1984	2009
Heysham 2 (2 units)	625 x 2	1988	2023
Hinkley Point B (2 units)	610 x 2	1976	2011
Hunterston B (2 units)	595 x 2	1976-1977	2011
Torness (2 units)	625 x 2	1988-1989	2023
PWR (BE)			
Sizewell B (1 unit)	1,188	1995	2035

* The magnox reactor Hinkley Point A was shut down in 2000.

Sources: BNFL, 2001, and DTI.

The British nuclear industry, which has developed over a period of more than forty years, is now a mature commercial sector directly employing some 30,000 people. The value of nuclear industry exports reached some £750 million in 1999. After the recent industry restructuring, the nuclear generating units of the country are owned and operated by two companies. British Energy plc operates 14 advanced gas-cooled reactors (AGRs) located on seven sites and one pressurised-water reactor (Sizewell B). British Nuclear Fuels Limited (BNFL), a state-owned company, operates the other 18 magnox-type nuclear power plants.

In the field of fuel cycle activities (Table 8), Urenco Ltd owns and operates a gas centrifuge plant (Capenhurst) supplying enrichment services. BNFL is not only owner/operator of the magnox plants but also provider of fuel cycle services including fuel fabrication and reprocessing. Nirex (the United Kingdom Nuclear Industry Radioactive Waste Executive), set up in 1982, is the company owned and operated by the nuclear industry responsible for implementing government policy on intermediate and low-level radioactive waste.

Table 8
Fuel Cycle Facilities, 2001

Activity	*Company*	*Location*	*Capacity*
Conversion	BNFL	Springfield	6 000 tU/year
Enrichment	Urenco	Capenhurst	2 000 tSW/year
Fuel fabrication			
LWR/UO2		Springfield	330 tHM/year
LWR/MOX	BNFL	Sellafield	120 tHM/year
AGR		Springfield	290 tHM/year
Magnox		Springfield	1300 tHM/year
Reprocessing			
LWR/AGR	BNFL	Thorp/Sellafield	1200 tHM/year
Magnox		B205/Sellafield	1500 tHM/year
Low-level waste disposal	BNFL UKAEA	Drigg Dounreay	~1.65 106 m^3

tU: tonne of uranium.
tSW: tonne of separative work.
tHM: tonne of heavy metal.
Source: NEA, 2002.

The United Kingdom Atomic Energy Authority (UKAEA) manages the facilities and sites used to develop the industry and which are now at different stages of decommissioning and restoration. The government has announced its intention to create a Liabilities Management Authority (LMA), a body that is to be responsible for civil nuclear liabilities in the public sector, i.e., for UKAEA and BNFL. Both the assets (funds set aside for decommissioning and waste disposal) and liabilities of UKEA and BNFL are to be transferred to the LMA. This body is intended to provide a sound framework for implementing the most effective and safe means of discharging liabilities covering decommissioning and dismantling of facilities, clean-up of sites and management of radioactive waste. A White Paper confirming the creation of the LMA was published in July 2002.

There are two repositories for low-level radioactive waste disposal in operation, one in Drigg, operated by BNFL, and one in Dounreay, operated by UKAEA. In the mid-1990s, a review of the radioactive waste management policy recommended the development of a programme leading to the implementation of deep geological repository for intermediate and low-level wastes (ILW and LLW) actinide-contaminated. However, Nirex's proposal for an underground laboratory was declined in 1997 and a step-by-step approach was adopted, aiming at a decision on final disposal by 2005 and including extensive consultations with stakeholders. For high level wastes (HLW), the policy is to secure their safe storage for the foreseeable future.

The UK's nuclear power plants are ageing and their technical characteristics (except for the Sizewell B PWR) make further lifetime extension uneconomic. The planned closure dates for all the magnox and AGR units range between 2002 and 2023. Therefore, if no new nuclear unit is built, nuclear energy will be nearly phased out by 2025 when the remaining nuclear capacity will be down to 1.2 GW, as compared with 12.5 GW today. In the context of privatisation and deregulation, the building of new nuclear units would have to be pursued by the industry on purely commercial grounds. Such a decision is unlikely since it is estimated that new nuclear units would provide electricity at a cost of around 2.5 p/kWh while gas-fired units generate electricity at less than 2 p/kWh.

Government-supported nuclear fission R&D programmes focus on safety, radiation protection and waste management issues. DTI, through the Health and Safety Executive (HSE), contributes around £1.25 million per annum to nuclear safety research programmes. DEFRA contributes some £850,000 to programmes covering safe handling and storage of nuclear waste. The Research Councils provide an additional support of some £350,000 by year to nuclear fission research programmes. The UK government contributes £4.5 million by year to the Euratom budget (under the 4-year Framework Programme V) for research focusing on radiation protection, waste management, plant life management and safety. Nuclear fusion research receives larger support from the government, around £14.3 million, including expenses associated with hosting the JET (Joint European Torus) in Culham.

CRITIQUE

Nuclear energy is providing more than 20% of UK electricity supply (23% in 2001). The existing nuclear power plants have demonstrated a good safety and technical record and have improved their economic performance in the deregulated electricity market. However, under present electricity market prices, new nuclear units would not be economic.

The nuclear power plants are ageing and their technical characteristics (except for the Sizewell B PWR) make further lifetime extension uneconomic. Therefore, if no new nuclear unit is built, nuclear energy will be nearly phased out by 2020 when the remaining nuclear capacity will be down to 1.2 GW, as compared with 12.5 GW today. Since nuclear electricity is practically carbon-free, the retirement of nuclear units will raise issues not only regarding security and diversity but also regarding the country's greenhouse gas emissions reduction policy.

In the short and medium term, it is necessary to ensure continued safe operation of the existing nuclear power plants and to prepare for their decommissioning, as well as for the management and disposal of all radioactive waste. A national policy on decommissioning and waste management/disposal of nuclear facilities is needed. The creation of the Liabilities Management Authority is a first step in the right direction.

Both the reports of the PIU and the House of Lords on energy policy published recently seem to advocate keeping the nuclear energy option open given its potential role in sustainable, secure, carbon-free energy supply. But the reports fail to indicate specific measures to be considered by the government in this regard.

While the government wants to keep the nuclear option open, it is not clear how that should happen in practice, given the retirement of the magnox reactors in the next few years and the subsequent retirement of the AGRs. This may result in the loss of human and other capacity to handle nuclear technology. The concept to buy nuclear technology from abroad as a back-up option seems to be feasible, provided that UK safety regulation can be adapted to these technologies and sites can be found.

RECOMMENDATIONS

The Government of the United Kingdom should:

- Take a more proactive attitude in the design and implementation of a comprehensive national policy for the decommissioning of nuclear power plants and fuel cycle facilities, and for the disposal of radioactive waste.

- In order to ensure the safe operation of existing nuclear facilities, continue to monitor the availability of adequate infrastructure, equipment and manpower.

- Clarify how it intends to keep the nuclear option open.

8

ENERGY RESEARCH AND DEVELOPMENT

PRIORITIES, INSTITUTIONS AND FUNDING

The main objective of the UK's R&D policy is to promote enterprise, innovation and increased productivity. As noted in Chapter 3, the government's energy policy objectives are "to ensure secure, diverse, sustainable supplies of energy at competitive prices". Taken together, these two sets of objectives provide the framework for UK energy R&D policy. There are no separate general energy R&D goals. In energy R&D, objectives are generally developed for more confined areas, e.g. for individual industries such as the clean coal industry (see below). However, these sub-goals always remain closely connected to the DTI's overall R&D objectives to:

- Promote enterprise, innovation and increased productivity.
- Make the most of the UK's science, engineering and technology.
- Create strong and competitive markets.
- Create a fair and effective legal and regulatory framework.

The government believes that energy research is primarily a matter for the energy industries themselves. Direct government expenditure in recent years has been relatively small, focusing on technologies that have some promise but are not near the market.

Oil and Gas

The UK supports a small programme (about £1.2 million) of aid to companies supplying goods and services to the offshore oil and gas exploration and production industry. Within this programme, DTI provides financial assistance towards the development of innovative products in small to medium-sized companies and also funds technology transfer projects between universities and companies (LINK programmes) in collaboration with two UK research councils.

Cleaner Coal Technology

The government's policy is to encourage the development of cleaner coal technologies for application both at home and overseas. The policy is being implemented in a six-year programme that started in April 1999, linking R&D with technology transfer and export promotion. The broad aim of this programme is to provide a catalyst for UK industry to develop cleaner coal technologies and obtain an appropriate share of the growing world market for the technologies. DTI spending on cleaner coal technology over the first three years of the programme that commenced in 1999 was £12 million.

Most of the future R&D effort in this area is expected to focus on contributing to the recommendations of an industry-led Foresight Task Force covering advanced power generation technologies since these offer the most potential to enhance UK industry's future export activities. A limited amount of work is also expected on identifying innovative ways of exploiting UK coal reserves by non-mining methods. This includes underground coal gasification in collaboration with the UK Coal Authority.

The DTI-supported Cleaner Coal Technology Programme encourages collaboration between UK industry and universities in the development of the technologies and expertise. It is expected that research and development projects worth about £60 million in R&D will be generated as a result of initiatives under the programme. This programme is expected to contribute to the government's global strategy to contain the growth of carbon dioxide (CO_2).

The programme attempts to help develop advanced power generation technologies as recommended by the industry-led Foresight Task Force and to help industry meet the targets set by this body. Other aims are to encourage fundamental coal science research in support of the Foresight technology targets and to examine the potential for developing the UK coal-bed methane resource and underground coal gasification technology.

The DTI's Cleaner Coal Programme aims to facilitate the export drive of UK companies, focusing trade missions to India and China, together with seminars and workshops to encourage technology transfer. The DTI attaches considerable importance to industry being actively involved in advising on both the direction of the programme, and on which projects offer best value for money to meet the technical objectives and targets of the programme. It has established the Advisory Committee for Cleaner Coal Technologies (ACCCT) which has a membership drawn from equipment manufacturers, generating companies and universities. Representation is also included from the coal industry and mining equipment manufacturer trade associations, since an important role of the committee will be to advise on technology transfer and export promotion issues associated with the whole of the coal cycle. This is particularly relevant in developing countries, where coal preparation is a key issue to address in considering clean coal technology for power applications. This committee oversees the whole programme. A number of international collaborative activities take place, notably with China. The UK is involved in several clean coal-related IEA Implementing Agreements: Coal research, Multiphase Flow Sciences and Coal Combustion Science.

Renewable Energy

The government's policy is to stimulate the development of renewable and sustainable energy technologies where they have the prospect of being economically beneficial and environmentally attractive. The Sustainable Energy

Programme, which supports the policies to promote the appropriate technologies, was funded at £14 million for 2000/2001. The principal role of the programme is to support and encourage innovation by industry of those technologies that have the prospect of becoming competitive.

The process for defining objectives and priorities in relation to overall energy and environmental policies is overseen by an advisory group. The DTI, which is responsible for this programme, is preparing a series of route maps covering the time frame to 2020 to help determine R&D priorities for DTI funding under the Sustainable Energy Programme. A series of workshops in consultation with industry, academia, government departments and other interested parties, including the EU, was held in 2001. Draft technological route maps summarising current understanding of the technical and commercial status of the various technologies have been prepared on the basis of these consultations. They present the targets that will need to be achieved for commercial competitiveness in the UK and consider the UK strengths in the industrial and university sectors. The government is now seeking input of industry and academia to help ensure that the programme focuses on the key priorities.

The effect of the Non-Fossil Fuel Obligation and the supporting programme on the take-up of renewable energy technologies is the subject of a current independent evaluation. Results from this evaluation were expected in September 2002.

Activities funded under the programme include R&D studies to help guide the programme and inform the development of policy. It also aims to tackle the non-technical issues that may affect the deployment of these technologies. In addition, the programme undertakes technology transfer and promotional activities to disseminate the results of the research and to raise awareness of renewable energy. It also has an export promotion element that seeks to gain the UK additional business overseas in the expanding global market. International collaboration is at present mainly through the IEA Implementing Agreements. The UK supports all the Renewable Energy Implementing Agreements except hydro-power, although it does not play an active role in the hydrogen agreement at present. The UK is about to join the new Ocean Energy Systems Agreement.

A number of initiatives address concerns that technical, commercial and regulatory issues in the UK electricity networks could compromise the achievement of the government's targets for generation from renewable energy sources and CHP. Among these initiatives are the creation of an Embedded Generation Programme as part of the Sustainable Energy Programme and the establishment of the industry-wide "Embedded Generation Working Group". The Embedded Generation Programme, which was established in April 2002, reported in June and recommended a range of actions designed to facilitate the development of small, distributed generation. It is developing a portfolio of quality projects designed to address network-related barriers to the connection of small-scale generation. Examples of projects currently being supported include the application of storable technology (Regenesys) to facilitate the access of intermittent energy sources to the electricity market, and the development of integrated generator-network control strategies to overcome voltage and thermal network constraints.

Nuclear Fission and Fusion

A common theme of the government's approach to R&D in nuclear fission and fusion is that it seeks to maximise the benefits available through collaboration, both nationally and internationally. For fission, the work divides into parts looking back to improve management of past legacies, maintaining the safe efficient operation of current plants, and looking towards the future. The present broad division of roles between public and private sectors, and between national and EU/international effort remains appropriate. Current objectives of policy are to:

- Direct and influence the focus of international bodies, such as the International Atomic Energy Agency (IAEA) and the Nuclear Energy Agency (NEA), towards the harmonisation of international standards, in specific areas such as plant management and safety and reactor design, and of the wider regulatory framework for nuclear operators. This recognises that it is important now and in the longer term that nuclear technologies achieve the highest safety and environmental standards internationally, if they are to contribute alongside other technologies to the demand for carbon-free electricity generation.

- Direct and influence the focus of EU and other international research programmes towards research areas of UK interest, agreed in consultation with DETR, DoH, HSE and industry players, and at budgets consistent with UK policy.

In conjunction with HSE and industry players, review the ministerial guidelines for the Nuclear Safety Research Programme, taking account of the structural changes that have occurred within the nuclear industry since they were last issued (1994).

Nuclear fission is a well-developed technology; here the focus of private and publicly funded R&D is on improving fuel, plant and operational efficiency while meeting the high standards of safety, environmental protection (including waste management) and proliferation resistance. R&D related primarily to efficiency improvement is funded by the industry, while R&D related to "risk management" benefits from a combination of private and public funding. Many research activities in practice include both efficiency and risk management aspects. Both the scale of the required expenditures and the significance of international regulatory requirements for this sector mean that EU and international collaboration and funding is of major importance.

The UK is a Member of OECD's Nuclear Energy Agency (NEA) whose research programmes include those on nuclear safety, waste management, radiation protection and decommissioning. The International Atomic Energy Agency (IAEA) assists its broader membership to develop nuclear power programmes and to exchange nuclear technology; it is also responsible for drawing up non-mandatory safety standards and for helping its members to maintain and improve safety standards.

The UK is a major contributor to the EU Framework Programme, of which the Euratom fission research programme (current value 191 million euros) is part.

Nuclear research in the 5th Framework Programme is focused on addressing current issues such as radiation protection, radioactive waste management, plant life management and safety. Recent research of particular benefit to the UK relates to reactor ageing, graphite, medical uses of radiation – diagnostic and therapeutic – early work on partitioning minor actinides, and environmental aspects of storing radioactive waste in deep geological formations.

Research in the 6th Framework Programme (2003-2006), which will probably be called “Nuclear Fission Energy and Radiation Protection”, is likely to cover the following areas: radioactive waste management; radiation protection; plant management and safety; nuclear/radiation protection education and training research infrastructures; and public engagement with nuclear technology.

International collaboration into new reactor design has recently gained in importance in the global context of climate change and increasing energy demand. Both the US Department of Energy and the IAEA are pursuing initiatives to bring together private and public sector interests to focus R&D activities on the development of technologies and systems for the longer term that could meet stringent public and regulatory demands in the areas of cost, environment, safety and proliferation. Both initiatives are still at a formative stage but offer the UK government the opportunity of constructive participation without commitment either financially or in respect of UK energy policy.

Within the UK, on behalf of the Health and Safety Commission (HSC) the Health and Safety Executive (HSE) administers a co-ordinated Nuclear Safety Research Programme under guidelines issued by the secretary of state for trade and industry and funded mainly by the nuclear generators (HSE directly funds support for its regulatory activities). The programme aims to ensure that adequate and balanced nuclear safety research continues to be carried out. It also aims to ensure that, as far as reasonably practicable, the potential contribution which such research can make to securing higher standards of nuclear safety is maximised, and that research findings relevant to nuclear safety are disseminated appropriately. Some £7.9 million was spent on this programme in 2000/2001 of which 84% was directly funded by the nuclear generating companies. HSE also provides direct support to various NEA co-ordinated research activities in the nuclear safety area, including the CABRI project (£1 million over 8-10 years).

The UK R&D programme for nuclear fusion is part of significant international collaborative efforts, all of which are focused on the far future. Fusion research has recently been subject to a policy review, which considered the consistency of the current effort with wider energy policy and the contribution that it makes to the wider science base. The review concluded that the economic and science and technology arguments, when combined, supported the continued involvement of the UK in international fusion research at around the current level. DTI ministers supported this view and agreed that the UK should continue its support for the Euratom fusion programme, but continue to press a review to determine the direction of future research.

As with fission, R&D on nuclear fusion addresses both economic and risk management concerns, with international collaboration a major feature. A basic contrast with fission is that fusion has yet to reach the applied technology state, and there is therefore limited non-government funding around the world. DTI funding of nuclear-related R&D is confined to the nuclear fusion programme, undertaken by the UKAEA at its Culham site under the Atomic Energy Authority Act 1954. The DTI provides funding of £38 million per annum which includes the following activities:

- A UK national programme, which is divided into eight areas of activity. The annual cost to DTI of the UK programme for 2000/2001 was £14.3 million, including the UKAEA's contribution as host to the Joint European Torus (JET), currently Europe's flagship fusion experiment. The UKAEA's JET contribution was £6.8 million in 2000/2001.

- The fusion part of the UK's gross contribution to the European Union R&D Framework Programme. Calculated as 15% of the EU Fusion Programme, this amounts to around £23.5 million per year.

Fusion research internationally is reaching a key stage. In June 2001, EU research ministers were asked to decide whether to use funds from the 6th Framework Programme to begin construction of an experimental reactor (called "ITER" – the International Thermonuclear Experimental Reactor) whose construction would take almost a decade. Preliminary estimates suggest the total cost could amount to 3.4 billion euros over the decade, which would be shared between several international partners, including the EU. Provisional conclusions, following an internal DTI review of fusion research policy, are that before making such a substantial and long-term commitment of funds, there should be an urgent EU-wide assessment of alternative strategies, including a possible fast-track route which might obviate the need to construct an ITER machine. Other issues requiring further consideration include future UK arrangements for managing and funding any continuing fusion programme.

CRITIQUE

In contrast to most IEA countries and after a decade of liberalisation and a tendency towards declining R&D budgets, in government as well as in industry, the UK government has recently increased its energy R&D budget. This reflects recognition that whereas it was necessary to streamline R&D efforts as carried out ten years ago, the time has come now for the UK to use its R&D funding and priorities to keep its energy policy options open. The government's approach to this subject is mature and circumspect and is to be commended.

The UK has also made progress in several detailed R&D areas, compared with the situation at the time of the last IEA in-depth review (1998). The effectiveness of government R&D support in areas not adequately addressed by the market was monitored through external evaluations of the government's financial support schemes for companies developing new products and services, especially in the oil and gas industry. Overall, the scheme was shown to have provided adequate value for money and new technology for the sector.

The government also has supported collaboration between universities and companies on long-term solutions that offer the potential for achieving its energy policy objectives, especially in the oil and gas industry. The R&D in this area being supported was recommended by PILOT, a joint industry/government body that has set targets for future production levels, capital investment and employment levels in offshore developments. The research and development in this area aims at reducing the costs of offshore developments through the introduction of new and innovative technology solutions. The government is also considering extensions to its collaborative programmes with the research councils in this area.

Still, the priority and focus among the government's various R&D objectives and programmes could benefit from further clarification of the respective roles of the government and industry to efficiently facilitate the deployment of new technologies. The PIU report and the follow-up debate in the country are expected to give further guidance to identify priority areas and the role of government in R&D.

RECOMMENDATIONS

The Government of the United Kingdom should:

- Clarify the priority among technology areas and revise the R&D programmes accordingly.

- Clarify the roles of the government and industry in specific technology areas to facilitate the deployment of technologies.

A

ANNEX

ENERGY BALANCES AND KEY STATISTICAL DATA

Unit: Mtoe

SUPPLY		1973	1990	1999	2000	2005	2010	2020
TOTAL PRODUCTION		**108.5**	**208.0**	**281.5**	**272.7**	**..**	**..**	**..**
Coal		75.9	53.6	22.1	18.6	9.0	2.6	–
Oil		0.5	95.2	143.0	131.7	..	..	..
Gas		24.4	40.9	89.1	97.6	..	..	..
Comb. Renewables & Wastes[1]		–	0.6	1.9	2.1	5.0	10.4	10.5
Nuclear		7.3	17.1	24.8	22.2	24.7	18.9	7.7
Hydro		0.3	0.4	0.5	0.4	0.4	0.4	0.4
Geothermal		–	0.0	0.0	0.0	–	–	–
Solar/Wind/Other		–	0.0	0.1	0.1	–	–	–
TOTAL NET IMPORTS[2]		**110.4**	**2.1**	**–50.7**	**–42.8**	**..**	**..**	**..**
Coal	Exports	2.0	1.8	0.7	0.7	0.2	–	–
	Imports	1.1	10.3	13.3	15.3	16.5	18.8	15.6
	Net Imports	–0.9	8.5	12.7	14.6	16.4	18.8	15.6
Oil	Exports	20.9	76.5	117.5	118.2	..	..	..
	Imports	136.9	65.4	60.8	71.0	..	..	..
	Bunkers	5.4	2.5	2.3	2.1	..	..	..
	Net Imports	110.6	–13.6	–59.1	–49.3	..	..	..
Gas	Exports	–	–	6.5	11.3	..	..	..
	Imports	0.7	6.2	1.0	2.0	..	..	..
	Net Imports	0.7	6.2	–5.5	–9.3	..	..	..
Electricity	Exports	0.0	0.0	0.0	0.0	–	–	–
	Imports	0.0	1.0	1.2	1.2	0.9	0.4	0.3
	Net Imports	0.0	1.0	1.2	1.2	0.9	0.4	0.3
TOTAL STOCK CHANGES		**1.8**	**2.3**	**0.5**	**2.8**	**..**	**..**	**..**
TOTAL SUPPLY (TPES)		**220.7**	**212.4**	**231.2**	**232.6**	**238.3**	**244.1**	**251.5**
Coal		76.4	63.3	34.3	36.0	25.3	21.3	15.6
Oil		111.6	82.6	84.3	83.2	86.9	92.6	103.0
Gas		25.1	47.2	84.1	87.5	95.1	100.1	114.1
Comb. Renewables & Wastes[1]		–	0.6	1.9	2.1	5.0	10.4	10.5
Nuclear		7.3	17.1	24.8	22.2	24.7	18.9	7.7
Hydro		0.3	0.4	0.5	0.4	0.4	0.4	0.4
Geothermal		–	0.0	0.0	0.0	–	–	–
Solar/Wind/Other		–	0.0	0.1	0.1	–	–	–
Electricity Trade[3]		0.0	1.0	1.2	1.2	0.9	0.4	0.3
Shares (%)								
Coal		*34.6*	*29.8*	*14.8*	*15.5*	*10.6*	*8.7*	*6.2*
Oil		*50.5*	*38.9*	*36.4*	*35.7*	*36.4*	*37.9*	*40.9*
Gas		*11.4*	*22.2*	*36.4*	*37.6*	*39.9*	*41.0*	*45.3*
Comb. Renewables & Wastes		–	*0.3*	*0.8*	*0.9*	*2.1*	*4.3*	*4.2*
Nuclear		*3.3*	*8.1*	*10.7*	*9.5*	*10.4*	*7.8*	*3.1*
Hydro		*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*	*0.2*
Geothermal		–	–	–	–	–	–	–
Solar/Wind/Other		–	–	–	–	–	–	–
Electricity Trade		–	*0.5*	*0.5*	*0.5*	*0.4*	*0.2*	*0.1*

0 is negligible, - is nil, .. is not available

Please note: Forecast data are based on the 2000 submission. Forecasts for production, imports and exports of coal are IEA Secretariat estimates.

Unit: Mtoe

DEMAND

FINAL CONSUMPTION BY SECTOR

	1973	1990	1999	2000	2005	2010	2020
TFC	**147.1**	**145.4**	**161.9**	**161.5**	**172.4**	**180.0**	**195.6**
Coal	26.5	10.8	5.3	3.9	4.1	3.6	3.3
Oil	77.0	68.8	75.2	73.6	79.5	84.9	95.2
Gas	23.6	42.0	52.9	55.0	56.8	57.9	61.3
Comb. Renewables & Wastes[1]	–	0.2	0.8	0.7	0.8	0.7	0.8
Geothermal	–	0.0	0.0	0.0	–	–	–
Solar / Wind / Other	–	0.0	0.0	0.0	–	–	–
Electricity	20.0	23.6	27.8	28.3	31.2	32.9	35.1
Heat	–	0.0	–	–	–	–	–
Shares (%)							
Coal	*18.0*	*7.4*	*3.3*	*2.4*	*2.3*	*2.0*	*1.7*
Oil	*52.3*	*47.3*	*46.5*	*45.6*	*46.1*	*47.2*	*48.7*
Gas	*16.1*	*28.9*	*32.6*	*34.0*	*33.0*	*32.2*	*31.3*
Comb. Renewables & Wastes	–	*0.1*	*0.5*	*0.4*	*0.5*	*0.4*	*0.4*
Geothermal	–	–	–	–	–	–	–
Solar / Wind / Other	–	–	–	–	–	–	–
Electricity	*13.6*	*16.2*	*17.1*	*17.5*	*18.1*	*18.3*	*17.9*
Heat	–	–	–	–	–	–	–
TOTAL INDUSTRY[4]	**65.0**	**42.8**	**46.2**	**45.2**	**47.5**	**48.1**	**50.0**
Coal	13.3	6.4	3.1	2.2	3.1	2.9	2.9
Oil	33.7	15.7	17.2	16.3	16.7	17.0	17.1
Gas	10.1	12.0	15.9	16.5	16.8	17.0	17.8
Comb. Renewables & Wastes[1]	–	0.0	0.4	0.4	0.7	0.6	0.6
Geothermal	–	–	–	–	–	–	–
Solar / Wind / Other	–	–	–	–	–	–	–
Electricity	7.8	8.7	9.5	9.8	10.2	10.6	11.6
Heat	–	0.0	–	–	–	–	–
Shares (%)							
Coal	*20.5*	*14.9*	*6.8*	*4.9*	*6.4*	*6.0*	*5.7*
Oil	*51.8*	*36.8*	*37.3*	*36.2*	*35.2*	*35.3*	*34.2*
Gas	*15.6*	*28.0*	*34.4*	*36.6*	*35.4*	*35.3*	*35.6*
Comb. Renewables & Wastes	–	–	*0.9*	*0.8*	*1.5*	*1.2*	*1.2*
Geothermal	–	–	–	–	–	–	–
Solar / Wind / Other	–	–	–	–	–	–	–
Electricity	*12.1*	*20.2*	*20.7*	*21.6*	*21.5*	*22.0*	*23.2*
Heat	–	–	–	–	–	–	–
TRANSPORT[5]	**31.0**	**46.5**	**53.0**	**52.7**	**57.7**	**62.8**	**73.0**
TOTAL OTHER SECTORS[6]	**51.2**	**56.2**	**62.7**	**63.7**	**67.2**	**69.1**	**72.7**
Coal	13.1	4.4	2.1	1.7	1.0	0.7	0.4
Oil	12.6	7.0	5.7	5.4	5.8	5.8	5.9
Gas	13.5	30.0	37.0	38.4	40.0	40.9	43.5
Comb. Renewables & Wastes[1]	–	0.2	0.4	0.4	0.1	0.1	0.2
Geothermal	–	0.0	0.0	0.0	–	–	–
Solar / Wind / Other	–	0.0	0.0	0.0	–	–	–
Electricity	12.0	14.5	17.5	17.8	20.3	21.6	22.7
Heat	–	–	–	–	–	–	–
Shares (%)							
Coal	*25.5*	*7.8*	*3.4*	*2.7*	*1.5*	*1.0*	*0.6*
Oil	*24.7*	*12.5*	*9.1*	*8.4*	*8.6*	*8.4*	*8.1*
Gas	*26.4*	*53.5*	*59.0*	*60.4*	*59.5*	*59.2*	*59.9*
Comb. Renewables & Wastes	–	*0.4*	*0.6*	*0.6*	*0.1*	*0.2*	*0.2*
Geothermal	–	–	–	–	–	–	–
Solar / Wind / Other	–	–	–	–	–	–	–
Electricity	*23.4*	*25.8*	*27.9*	*27.9*	*30.2*	*31.3*	*31.2*
Heat	–	–	–	–	–	–	–

Unit: Mtoe

DEMAND

ENERGY TRANSFORMATION AND LOSSES

	1973	1990	1999	2000	2005	2010	2020
ELECTRICITY GENERATION[7]							
INPUT (Mtoe)	**72.5**	**74.4**	**76.7**	**77.6**	**78.0**	**79.4**	**74.9**
OUTPUT (Mtoe)	**24.2**	**27.3**	**31.4**	**32.0**	**33.9**	**36.2**	**38.2**
(TWh gross)	281.4	317.0	365.5	372.2	394.7	420.9	443.7
Output Shares (%)							
Coal	*62.1*	*65.3*	*30.5*	*33.4*	*20.7*	*15.8*	*9.4*
Oil	*25.6*	*10.8*	*1.6*	*1.5*	*0.5*	*0.4*	*0.3*
Gas	*1.0*	*1.1*	*39.1*	*39.4*	*49.0*	*56.0*	*73.6*
Comb. Renewables & Wastes	–	*0.4*	*1.1*	*1.2*	*4.5*	*9.3*	*8.9*
Nuclear	*10.0*	*20.7*	*26.0*	*22.9*	*24.0*	*17.3*	*6.7*
Hydro	*1.4*	*1.6*	*1.5*	*1.4*	*1.3*	*1.2*	*1.1*
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	*0.0*	*0.2*	*0.3*	–	–	–
TOTAL LOSSES	**72.7**	**67.5**	**68.8**	**69.0**	**66.0**	**64.1**	**55.9**
of which:							
Electricity and Heat Generation[8]	48.3	47.1	45.3	45.6	44.1	43.2	36.7
Other Transformation	7.1	4.1	4.9	4.6	2.7	2.6	2.5
Own Use and Losses[9]	17.3	16.3	18.7	18.8	19.2	18.3	16.7
Statistical Differences	**0.9**	**–0.5**	**0.5**	**2.1**	**–**	**–**	**–**

INDICATORS

	1973	1990	1999	2000	2005	2010	2020
GDP (billion 1995 US$)	748.36	1040.25	1267.26	1303.75	1467.89	1640.63	2049.48
Population (millions)	56.22	57.56	59.50	59.76	60.35	61.00	61.65
TPES/GDP[10]	0.29	0.20	0.18	0.18	0.16	0.15	0.12
Energy Production/TPES	0.49	0.98	1.22	1.17	–	–	–
Per Capita TPES[11]	3.93	3.69	3.89	3.89	3.95	4.00	4.08
Oil Supply/GDP[10]	0.15	0.08	0.07	0.06	0.06	0.06	0.05
TFC/GDP[10]	0.20	0.14	0.13	0.12	0.12	0.11	0.10
Per Capita TFC[11]	2.62	2.53	2.72	2.70	2.86	2.95	3.17
Energy–related CO_2 Emissions (Mt CO_2)[12]	640.0	559.9	526.0	531.5	530.3	542.5	581.8
CO2 Emissions from Bunkers (Mt CO_2)	25.4	20.9	25.7	26.4	19.9	19.9	19.9

GROWTH RATES (% per year)

	73–79	79–90	90–99	99–00	00–05	05–10	10–20
TPES	–0.1	–0.3	0.9	0.6	0.5	0.5	0.3
Coal	–0.5	–1.4	–6.6	4.8	–6.8	–3.4	–3.1
Oil	–2.6	–1.3	0.2	–1.3	0.9	1.3	1.1
Gas	8.3	1.4	6.6	4.0	1.7	1.0	1.3
Comb. Renewables & Wastes	–	–	13.3	9.9	18.6	15.8	0.0
Nuclear	5.4	5.0	4.2	–10.6	2.2	–5.2	–8.6
Hydro	1.6	1.8	0.4	–4.8	–0.4	–	–
Geothermal	–	–	–	–	–	–	–
Solar/Wind/Other	–	–	25.2	10.8	–	–	–
TFC	0.1	–0.2	1.2	–0.2	1.3	0.9	0.8
Electricity Consumption	0.9	1.0	1.8	1.9	2.0	1.1	0.6
Energy Production	10.1	0.7	3.4	–3.1	..	..	..
Net Oil Imports	–27.1	–	17.7	–16.6	..	..	..
GDP	1.5	2.2	2.2	2.9	2.4	2.2	2.2
Growth in the TPES/GDP Ratio	–1.5	–2.5	–1.2	–2.2	–1.9	–1.7	–1.9
Growth in the TFC/GDP Ratio	–1.3	–2.3	–1.0	–3.0	–1.1	–1.3	–1.4

Please note: Rounding may cause totals to differ from the sum of the elements.

Footnotes to Energy Balances and Key Statistical Data

1. Comprises solid biomass, biogas, industrial waste and municipal waste. Data are often based on partial surveys and may not be comparable between countries.
2. Total net imports include combustible renewables and waste.
3. Total supply of electricity represents net trade. A negative number indicates that exports are greater than imports.
4. Includes non-energy use.
5. Includes less than 1% non-oil fuels.
6. Includes residential, commercial, public service and agricultural sectors.
7. Inputs to electricity generation include inputs to electricity, CHP and heat plants. Output refers only to electricity generation.
8. Losses arising in the production of electricity and heat at public utilities and autoproducers. For non-fossil-fuel electricity generation, theoretical losses are shown based on plant efficiencies of 33% for nuclear and 100% for hydro.
9. Data on "losses" for forecast years often include large statistical differences covering differences between expected supply and demand and mostly do not reflect real expectations on transformation gains and losses.
10. Toe per thousand US dollars at 1995 prices and exchange rates.
11. Toe per person.
12. "Energy-related CO_2 emissions" have been estimated using the IPCC Tier I Sectoral Approach. In accordance with the IPCC methodology, emissions from international marine and aviation bunkers are not included in national totals. Projected emissions for oil and gas are derived by calculating the ratio of emissions to energy use for 2000 and applying this factor to forecast energy supply. Future coal emissions are based on product-specific supply projections and are calculated using the IPCC/OECD emission factors and methodology.

B

ANNEX

INTERNATIONAL ENERGY AGENCY "SHARED GOALS"

The Member countries* of the International Energy Agency (IEA) seek to create the conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and the well-being of their people and of the environment. In formulating energy policies, the establishment of free and open markets is a fundamental point of departure, though energy security and environmental protection need to be given particular emphasis by governments. IEA countries recognise the significance of increasing global interdependence in energy. They therefore seek to promote the effective operation of international energy markets and encourage dialogue with all participants.

In order to secure their objectives they therefore aim to create a policy framework consistent with the following goals:

1 **Diversity, efficiency and flexibility within the energy sector** are basic conditions for longer-term energy security: the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable. Non-fossil fuels, particularly nuclear and hydro power, make a substantial contribution to the energy supply diversity of IEA countries as a group.

2 Energy systems should have **the ability to respond promptly and flexibly to energy emergencies.** In some cases this requires collective mechanisms and action: IEA countries co-operate through the Agency in responding jointly to oil supply emergencies.

3 **The environmentally sustainable provision and use of energy** is central to the achievement of these shared goals. Decision-makers should seek to minimise the adverse environmental impacts of energy activities, just as environmental decisions should take account of the energy consequences. Government interventions should where practicable have regard to the Polluter Pays Principle.

4 **More environmentally acceptable energy sources** need to be encouraged and developed. Clean and efficient use of fossil fuels is essential. The development of economic non-fossil sources is also a priority. A number of

* Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.

IEA Members wish to retain and improve the nuclear option for the future, at the highest available safety standards, because nuclear energy does not emit carbon dioxide. Renewable sources will also have an increasingly important contribution to make.

5 **Improved energy efficiency** can promote both environmental protection and energy security in a cost-effective manner. There are significant opportunities for greater energy efficiency at all stages of the energy cycle from production to consumption. Strong efforts by governments and all energy users are needed to realise these opportunities.

6 **Continued research, development and market deployment of new and improved energy technologies** make a critical contribution to achieving the objectives outlined above. Energy technology policies should complement broader energy policies. International co-operation in the development and dissemination of energy technologies, including industry participation and co-operation with non-member countries, should be encouraged.

7 **Undistorted energy prices** enable markets to work efficiently. Energy prices should not be held artificially below the costs of supply to promote social or industrial goals. To the extent necessary and practicable, the environmental costs of energy production and use should be reflected in prices.

8 **Free and open trade** and a secure framework for investment contribute to efficient energy markets and energy security. Distortions to energy trade and investment should be avoided.

9 **Co-operation among all energy market participants** helps to improve information and understanding, and encourage the development of efficient, environmentally acceptable and flexible energy systems and markets worldwide. These are needed to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives.

(The Shared Goals were adopted by IEA Ministers at their 4 June 1993 meeting in Paris.)

C

ANNEX

GLOSSARY AND LIST OF ABBREVIATIONS

In this report, abbreviations are substituted for a number of terms used within the International Energy Agency. While these terms generally have been written out on first mention and abbreviated subsequently, this glossary provides a quick and central reference for many of the abbreviations used.

AC	alternating current.
AGR	advanced gas-cooled nuclear reactor.
bbl	barrel.
bbl/d	barrel per day.
bcf	billion cubic feet.
bcm	billion cubic metres.
BP	British Petroleum.
cal	calorie.
CCGT	combined-cycle gas turbine.
CERT	Committee on Energy Research and Technology of the IEA.
CFCs	chlorofluorocarbons.
CHP	combined production of heat and power; sometimes, when referring to industrial CHP, the term "co-generation" is used.
CNG	compressed natural gas.
CO	carbon monoxide.
CO_2	carbon dioxide.
cm	cubic metre.
DC	direct current.
DH	district heating.
DSO	distribution system operator.
EFTA	European Free Trade Association: Iceland, Norway, Switzerland and Liechtenstein.
EIA	environmental impact assessment.
ETSO	European Transmission System Operators Group.

EU	The European Union, whose members are Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, the Netherlands, Portugal, Spain, Sweden and the United Kingdom.
Euro	European currency (€).
FCCC	Framework Convention on Climate Change.
GDP	gross domestic product.
GNP	gross national product.
GEF	Global Environmental Facility.
GJ	gigajoule, or one joule $\times 10^9$.
GW	gigawatt, or one watt $\times 10^9$.
GWh	gigawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^9$.
IAEA	International Atomic Energy Agency.
IEA	International Energy Agency whose Members are Australia, Austria, Belgium, Canada, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Japan, the Republic of Korea, Luxembourg, the Netherlands, New Zealand, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, the United Kingdom, the United States.
IEP	International Energy Program, one of the founding documents of the IEA.
IGCC	integrated coal gasification combined cycle plant.
IPCC	International Panel on Climate Change.
ISO	independent system operator.
J	joule; a joule is the work done when the point of application of a force of one newton is displaced through a distance of one metre in the direction of the force (a newton is defined as the force needed to accelerate a kilogram by one metre per second). In electrical units, it is the energy dissipated by one watt in a second.
kV	kilovolt, or one volt $\times 10^3$.
kWh	kilowatt-hour, or one kilowatt $\times$ one hour, or one watt $\times$ one hour $\times 10^3$.
LDC	local distribution company.
LNG	liquefied natural gas.
LPG	liquefied petroleum gas; refers to propane, butane and their isomers, which are gases at atmospheric pressure and normal temperature.
LWR	light water reactor.

mcm	million cubic metres.
Mt	million tonnes.
Mtoe	million tonnes of oil equivalent; see toe.
MW	megawatt of electricity, or one watt $\times 10^6$.
MWh	megawatt-hour, or one megawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^6$.
NEA	Nuclear Energy Agency of the OECD.
negTPA	negotiated third party access.
NO_x	nitrogen oxides.
OECD	Organisation for Economic Co-operation and Development.
PJ	Petajoule, or one joule $\times 10^{15}$.
ppm	parts per million.
PPP	purchasing power parity: the rate of currency conversion that equalises the purchasing power of different currencies, i.e. estimates the differences in price levels between different countries.
PWR	pressurised-water reactor.
regTPA	regulated third party access.
R&D	research and development, especially in energy technology; may include the demonstration and dissemination phases as well.
SB	single buyer.
SLT	Standing Group on Long-Term Co-operation of the IEA.
SO_2	sulphur dioxide.
TFC	total final consumption of energy; the difference between TPES and TFC consists of net energy losses in the production of electricity and synthetic gas, refinery use and other energy sector uses and losses.
toe	tonne of oil equivalent, defined as 107 kcal.
TOP	take-or-pay contract.
TPA	third party access.
TPES	total primary energy supply.
TSO	transmission system operator.
TW	terawatt, or one watt $\times 10^{12}$.
TWh	terawatt $\times$ one hour, or one watt $\times$ one hour $\times 10^{12}$.

UGS	underground storage (of natural gas).
VAT	Value-Added Tax.
VOCs	volatile organic compounds.
WANO	World Association of Nuclear Operators.

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