Energy Trends

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Introduction

Energy Trends and Quarterly Energy Prices are produced by the Department of Trade and Industry on a quarterly basis. Both periodicals are published concurrently in June, September, December and March. The June editions cover the first quarter of the year.

Energy Trends includes information on energy as a whole and by individual fuels. The text and charts provide an analysis of the data in the tables. The tables are mainly in commodity balance format, as used in the DTI's annual Digest of UK Energy Statistics. (The 2002 edition of the Digest was published on 25 July 2002 and the 2003 edition will be available from 31 July 2003. Hard copies of the Digest can be obtained from The Stationery Office and electronic versions are available on our web site at www.dti.gov.uk/energy/.) The balance format shows the flow of a commodity from its sources of supply, through to its final use. The articles provide in-depth information on current issues within the energy sector.

The text and tables included in this publication represent a snapshot of the information available at the time of publication. However, the data collection systems operated by the DTI, which produce this information, are in constant operation. New data are continually received and revisions to historic data made. To ensure that those who use the statistics have access to the most up-to-date information, revised data will be made available as soon as possible, via the electronic versions of these tables. The electronic versions are available free of charge from the DTI web site. In addition to quarterly tables, the main monthly tables published in the previous version of monthly Energy Trends (last edition May 2001) continue to be updated and are also available on our web site. Both sets of tables can be obtained from www.dti.gov.uk/energy/.

The quarterly Energy Trends does not contain information on Foreign Trade, Temperatures and Prices. The Foreign Trade and Temperatures tables are however available on our web site and information on Prices can be found in the Quarterly Energy Prices publication. This information is also available on our web site at the above address.

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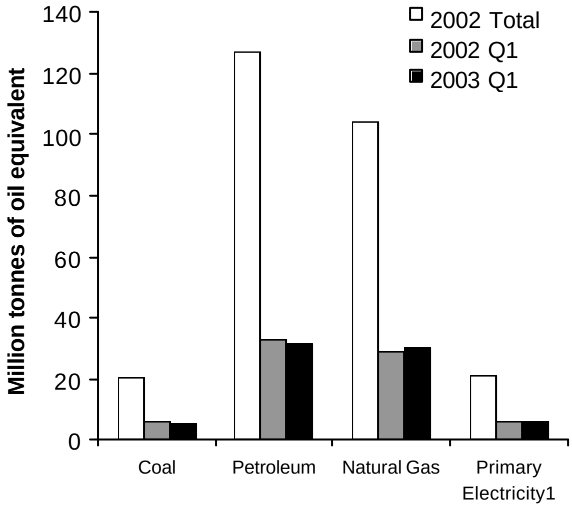
The main points for the first quarter of 2003:

- Energy production was 0.2 per cent lower than the first quarter of 2002.
- Oil production fell by 3 per cent compared to 2002 as production from older established fields continued to decline.
- Gas production rose by 4½ per cent to meet increased demand for space heating and exports (up 64.8 per cent).
- Total primary energy consumption for energy uses increased by 2 per cent, but this is equivalent to a fall of 1½ per cent when cooler weather is taken into account.
- Final energy consumption rose by 2 per cent, with increases in each of the industrial, service, and domestic sectors of 4½ per cent, 4 per cent, and 5½ per cent respectively; however final energy consumption in the transport sector fell by 6½ per cent.
- Coal production in the first quarter of 2003 was 8 per cent down on the first quarter of 2002 while coal imports were ½ per cent lower. However, demand for coal was 9 per cent higher.
- Coal supplied 9 per cent more electricity during the first quarter of 2003 than during the first quarter of 2002 while gas supplied 3½ per cent less. Electricity supplied from nuclear sources was 1 per cent higher. Net imports of electricity were down by 56 per cent.
- Total deliveries of transport fuels were 6½ per cent lower than in 2002 with demand for motor spirit 7½ per cent lower. Demand for aviation turbine fuel increased by 3 per cent.

Section 1 - Total Energy

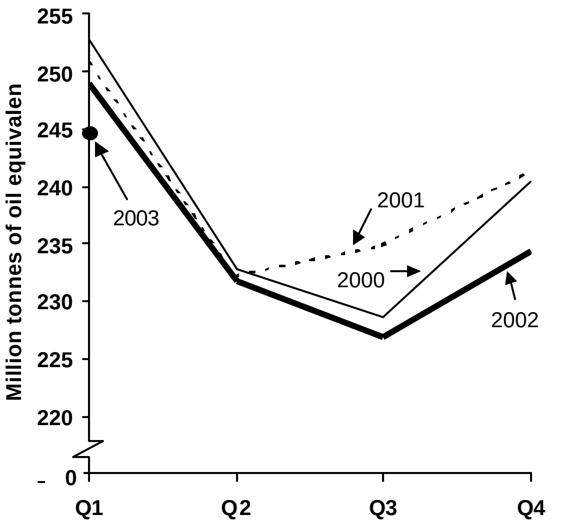
Chart 1.1 Production of indigenous primary fuels



1 Nuclear and natural flow hydro electricity.

- Total production in the first quarter of 2003 was 0.2 per cent lower than in the first quarter of 2002.
- Production of natural gas rose by 4.6 per cent, between the first quarter of 2002 and the first quarter of 2003 resulting from an increase in demand for space heating and higher exports.
- Production of petroleum fell by 3.1 per cent over the same time period, due to a decline in production from older established fields.
- Primary electricity output was 0.6 per cent lower.
- Production of coal and other solid fuel was 7.2 per cent lower mainly due to two colliery closures.

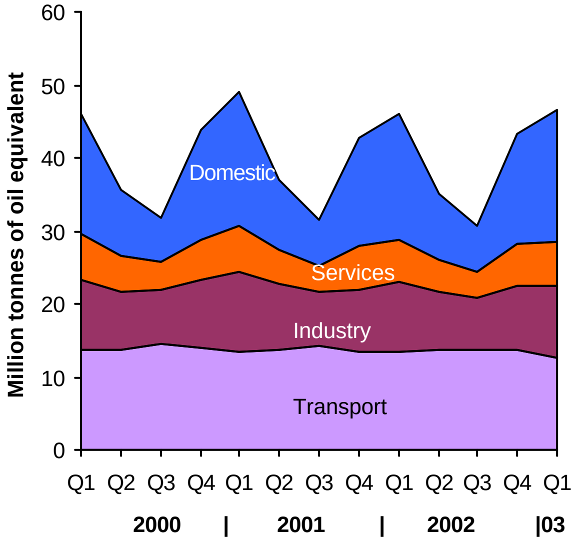
Chart 1.2 Total inland consumption (primary fuel input basis)[1]



1 Seasonally adjusted and temperature corrected annual rates.

- Total inland consumption on a primary fuel input basis was 244.9 million tonnes of oil equivalent in the first quarter of 2003 (temperature corrected, seasonally adjusted annualised rate).
- The 2003 quarter one level was 1.6 per cent lower than the same period a year ago and 2.3 per cent lower than the same period in 2001.
- Between the first quarter of 2003 and the first quarter of 2002 (on a seasonally adjusted and temperature corrected basis) coal and other solid fuel consumption increased by 5.4 per cent, as a result of greater coal use for electricity generation.
- Oil consumption fell by 6.5 per cent, mainly due to lower use for transport.
- Gas consumption fell by 0.8 per cent due to less gas being used for electricity generation as a result of increased gas prices.

Chart 1.3 Final energy consumption by user



- Total final energy consumption rose by 2.1 per cent between the first quarter of 2003 and the same quarter in 2002.
- Service sector energy consumption increased by 2.4 per cent.
- Domestic sector energy consumption increased by 5.3 per cent, as more energy was required for space heating due to colder weather.
- Transport energy consumption fell by 6.3 per cent.
- Industrial energy consumption rose by 4.6 per cent.

Background

Relevant tables
1.1: Indigenous production of primary fuels
1.2: Inland energy consumption: primary fuel input basis
1.3: Supply and use of fuels

Production
Indigenous production of primary fuels in the first quarter of 2003 at 72.9 million tonnes of oil equivalent was 0.2 per cent lower than in the corresponding period a year ago.

Production of petroleum was 3.1 per cent lower in the first quarter of 2003 than the first quarter of 2002; this results from a decline in production from older established fields. Indigenous production of coal and other solid fuel was 7.2 per cent lower mainly as a result of two collieries closing. Petroleum accounted for 43.2 per cent of total indigenous production in the first quarter of 2003; during the same period coal and other sold fuels accounted for 7.3 per cent of the total.

Nuclear electricity output was 0.8 per cent higher in the first quarter of 2003 compared with levels a year earlier, while output from natural flow hydro had decreased by 42.0 per cent because of dry autumn and winter weather.

Total inland consumption
Total inland energy consumption, on a primary fuel input basis (not temperature corrected or seasonally adjusted), in the first quarter of 2003 was 67.3 million tonnes of oil equivalent. This was 1.9 per cent higher than in the corresponding period a year ago and 4.4 per cent lower than in the corresponding period two years ago. The average temperature during the first quarter of 2003 was 1.3 degrees Celsius colder than the particularly mild first quarter of 2002; this resulted in increased consumption for space heating, particularly in the domestic sector.

On a temperature corrected and seasonally adjusted basis, total inland consumption was 1.6 per cent lower in the first quarter of 2003 than that recorded a year earlier. Over the same period and on the same basis:

- consumption of coal and other solid fuels rose by 5.4 per cent;
- petroleum consumption decreased by 6.5 per cent;
- consumption of natural gas fell by 0.8 per cent; and
- consumption of primary electricity decreased by 0.5 per cent.

There was greater use of coal and less use of gas for electricity generation, as a result of increased gas prices.

Consumption by final users

Final energy consumption shows a strong seasonal pattern with more energy being consumed in the winter months and less in the summer, particularly in the domestic and service sectors.

In the first quarter of 2003 the domestic sector was responsible for the largest share of final consumption at 36 per cent of all energy consumed by final users. The transport sector was responsible for a further 25 per cent, the industrial sector for another 20 per cent and the service industries, including agriculture, consumed 13 per cent. The remaining 6 per cent was made up by fuel use for non-energy purposes.

Final energy consumption rose by 2.1 per cent between the first quarter of 2002 and the first quarter of 2003, mainly due to changes in each of the sectors as follows:

- industrial energy consumption was 4.6 per cent higher; within this change, gas consumption increased by 13.5 per cent.
- service sector (including agriculture) energy consumption was 4.2 per cent higher;
- domestic energy consumption was 5.3 per cent higher; and
- transport energy consumption was 6.3 per cent lower.

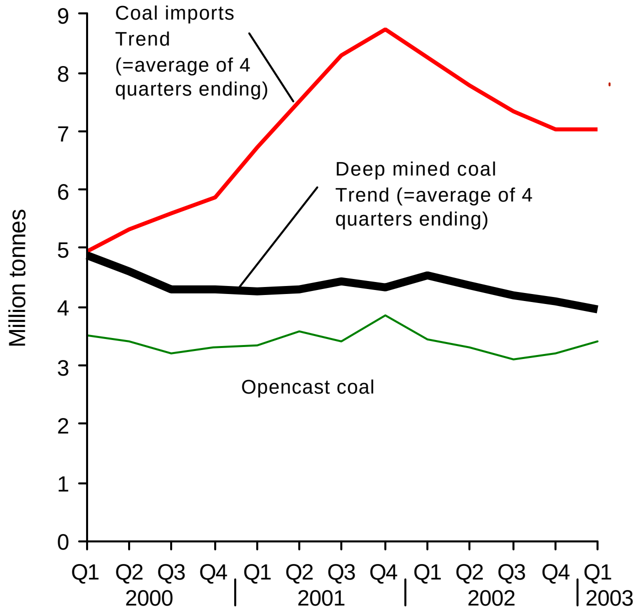
Changes to monthly internet tables

In December 2002's "Energy Trends" DTI announced its intention to cease the twice monthly updating of four of the energy statistics tables on its web site. Instead all tables would be updated, once a month, on the last Thursday of each month. As no comments were received about this proposal the final "start of the month" update of the following monthly tables will be on Tuesday 5th August 2003:

Table 1.1 Indigenous production of primary fuels
Table 1.2 Inland energy consumption, primary fuel input basis
Table 3.10 Oil production, refinery receipts, imports and exports
Table 3.13 Deliveries of oil and petroleum products for inland consumption.

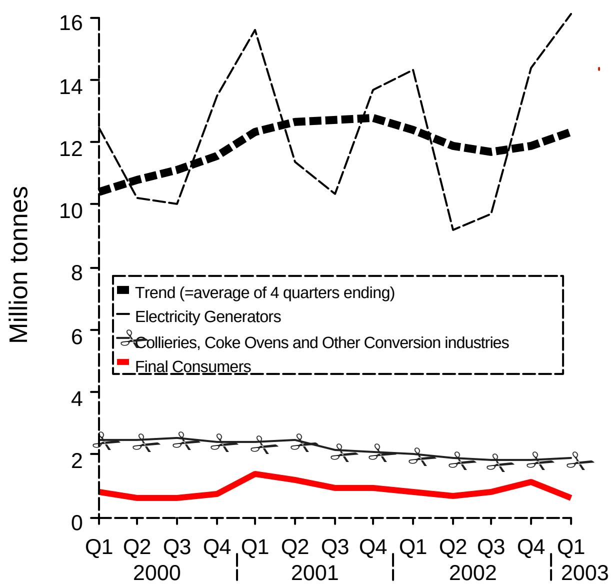
Section 2 - Solid Fuels and Derived Gases

Chart 2.1 Coal production and imports



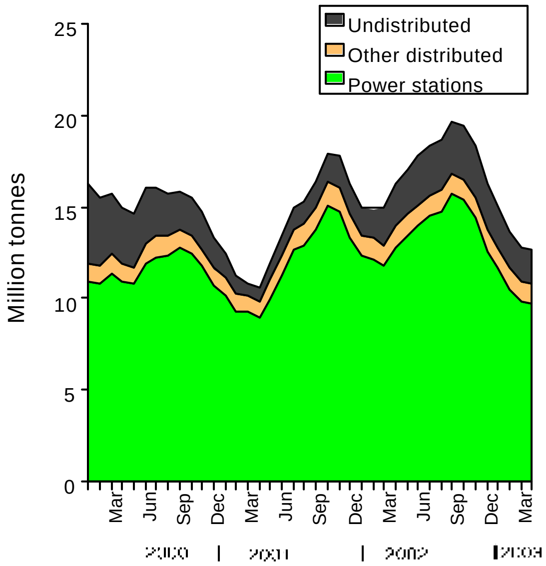
- Provisional figures for the first quarter of 2003 show that coal production (including an estimate for slurry) was 7.8 per cent down on the first quarter of 2002 at 7.8 million tonnes, with deep mined production down 12.3 per cent and opencast production down 1.5 per cent.
- Imports of coal in the first quarter of 2003 were 0.6 per cent lower than in the first quarter of 2002 at 6.9 million tonnes. Compared with very high import levels of two years earlier, imports were down by 22.3 per cent.
- 78 per cent of the imported coal in the first quarter of 2003 (5.4 million tonnes) was steam coal, largely for the power stations market.

Chart 2.2 Coal consumption



- Demand for coal in the first quarter of 2003, at 18.6 million tonnes was 8.6 per cent up on consumption in the first quarter of 2002; consumption by electricity generators was up by 12.7 per cent.
- Electricity generators accounted for 87 per cent of total coal use in the first quarter of 2003, compared with 83 per cent a year earlier and 81 per cent two years earlier.
- Final consumption fell by 27 per cent, within which domestic sector consumption was 34 per cent lower. Given that the first quarter of 2003 was mild and the data are disposals to the domestic market, consumers may not have needed to replace high domestic stocks.

Chart 2.3 Coal stocks



- Coal stocks showed a seasonal fall of 3.5 million tonnes during the first quarter of 2003 and at the end of the quarter stood at 12.8 million tonnes, 2.2 million tonnes lower than at the end of the first quarter of 2002. Despite this sharp fall, stocks were still 1.9 million tonnes higher than the record low level of 10.9 million tonnes at the end of March 2001. By the end of April 2003 there had been a further small decline to 12.7 million tonnes.

- The level of coal stocks at power stations fell by 2.7 million tonnes in the first quarter of 2003 to 9.8 million tonnes. This is 2.0 million tonnes lower than the corresponding level a year earlier.

- The level of stocks held by producers fell by 0.6 million tonnes in the first quarter of 2003 to stand at 1.8 million tonnes. This is 0.3 million tonnes lower than the corresponding level a year earlier.

Background

Relevant tables

2.1: Supply and consumption of coal
2.2: Supply and consumption of coke oven coke, coke breeze and other manufactured solid fuels
2.3: Supply and consumption of coke oven gas, blast furnace gas, benzole and tars

Coal production and imports

In 2002 indigenous production of coal fell by 1.9 million tonnes to a new record low level for deep mined coal and the lowest level since 1979 for opencast coal. At first the upward trend in coal production seen during 2001 continued into the first quarter of 2002 when production was 845 thousand tonnes higher than in the first quarter of 2001 but in the following quarters this was reversed with production down by around 900 thousand tonnes on a year earlier in each quarter. Longannet colliery closed in March 2002 and Prince of Wales in August 2002. A number of mines faced geological problems or had gaps in production while they moved to new faces. Geological problems eased in the first quarter of 2003 and production was down by only 660 thousand tonnes. Imports of coal in 2002 were 6.9 million tonnes lower than the record level in 2001, but still recorded the second highest ever annual volume. Exports in 2002 were 3 per cent lower at 533 thousand tonnes.

Coal consumption

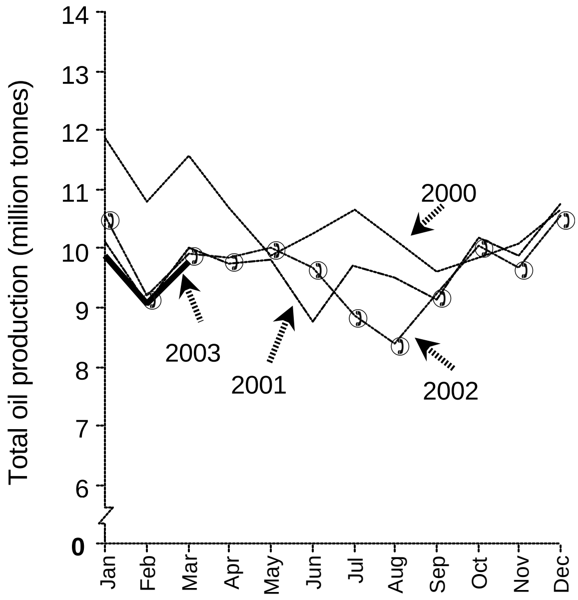
Coal use by electricity generators was 3.5 million tonnes lower in 2002 as a whole than it was in 2001. In the winter quarters of 2001 and 2002 and in the first quarter of 2003 when gas prices were particularly high, coal fired generation was used in preference to gas fired generation, but when gas prices eased in the second and third quarters of 2002 coal use for generation fell back. In the fourth quarter of 2002 reduced output from nuclear stations prompted increased use of coal fired generation. Reductions in UK steel making capacity led to a reduction of 1.5 million tonnes in the use of coal for coke making and at blast furnaces in 2002. Final consumption of coal and the use of coal for heat generation and patent fuel manufacture were together 1.1 million tonnes lower than in 2001.

Stocks

Following the seasonal rise during the summer of 2002, which added 4 million tonnes to coal, stocks, the seasonal fall over the winter 2002/03 period reduced stocks by 6 million tonnes as power station demand for coal rose. As a result total coal stocks at the end of March 2003 were 2 million tonnes lower than a year earlier.

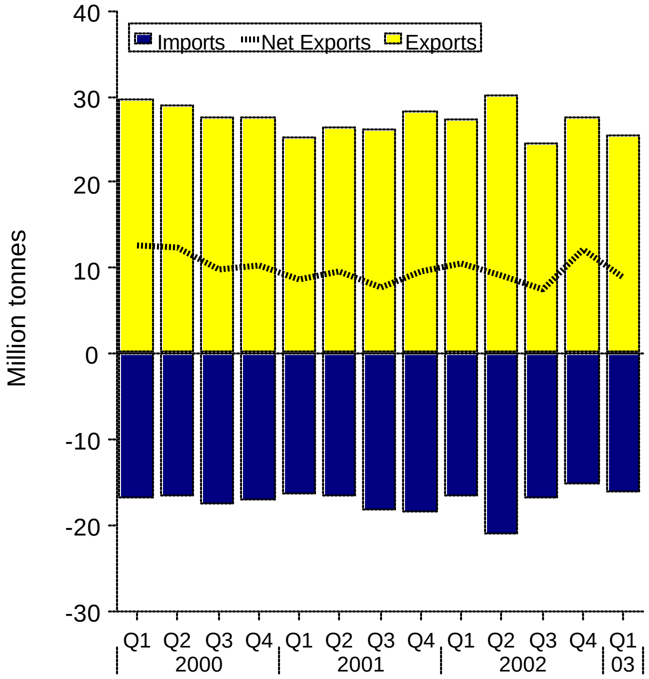
Section 3 - Oil and Oil Products

Chart 3.1 Production of crude oil and NGLs



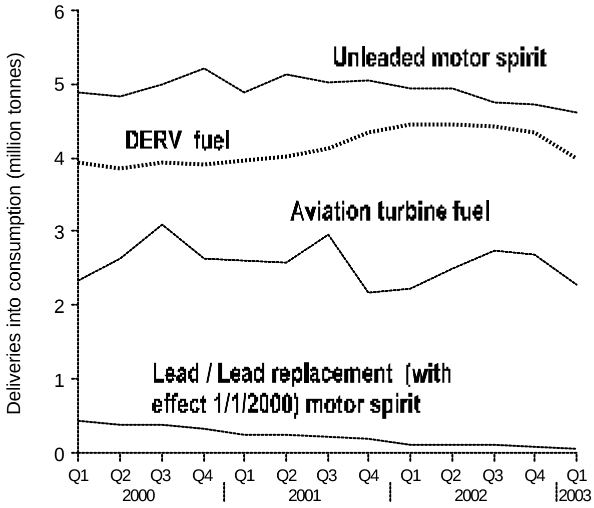
- Total indigenous UK production of crude oil and NGLs in the first quarter of 2003 fell by 3.1 per cent to 28.7 million tonnes when compared with the first quarter of 2002.
- There is a general decline in production from older established fields. Twelve new fields started production after March 2002. Without these new fields production would have been 7.0 per cent lower.

Chart 3.2 UK trade in crude oils, NGLs and petroleum products



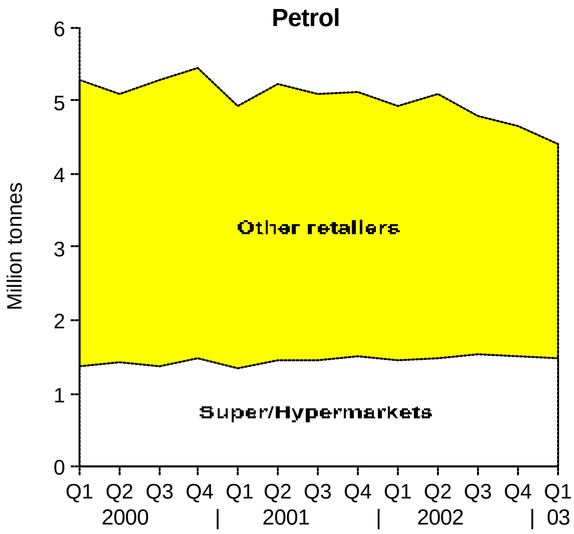
- Net exports fell by 13 per cent, to 9.0 million tonnes, when compared with first quarter of last year. Nevertheless the UK retained its position as a net exporter of oil and oil products.
- Net exports of crude oil and NGLs decreased by 24.5 per cent to 7.3 million tonnes.
- Exports of crude oil and NGLs decreased by 13.3 per cent while imports decreased by 4.6 per cent.
- Net exports of petroleum products were nearly double the level in the same period last year at 2.5 million tonnes.
- Exports of petroleum products rose by 20.8 per cent whilst imports fell by 6.1 per cent.

Chart 3.3 Demand for transport fuels

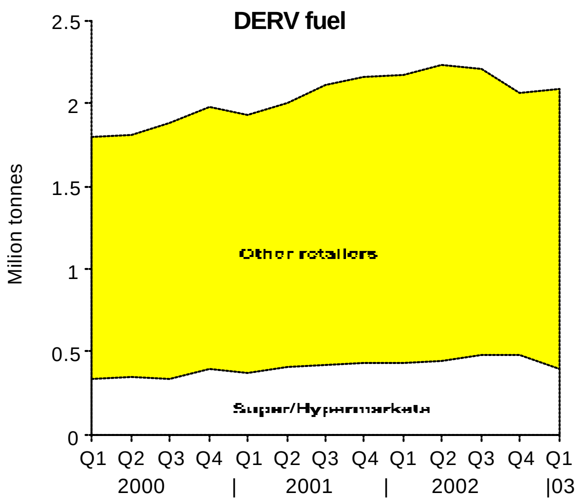


- Total deliveries of transport fuels were 6.4 per cent lower in the first quarter of 2003 than in the first quarter of 2002.
- Motor spirit deliveries fell by 7.4 per cent.
- Deliveries of unleaded motor spirit fell by 6.5 per cent. Unleaded petrol represented 98.7 per cent of total motor spirit deliveries during the first quarter of 2003, compared with 97.8 per cent in the first quarter of 2002.
- Deliveries of DERV fuel were 10.2 per cent lower than in the first quarter of 2002. Deliveries of aviation turbine fuel were 2.8 per cent higher.
- DERV fuel's share of road transport fuels was 46.1 per cent compared to 46.8 per cent in the same period a year earlier.

Chart 3.4 Super/hypermarket shares of retail deliveries

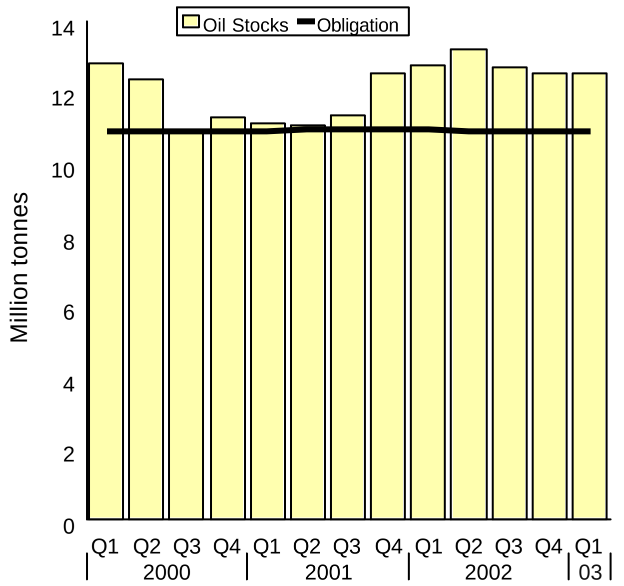


- Sales of motor spirit by super/hypermarket companies accounted for 33.5 per cent of retail sales of petrol in the first quarter 2003, up from 29.3 per cent a year earlier.



- Sales of DERV by super/hypermarket companies accounted for 23.7 per cent of retail sales of DERV in the first quarter 2003, up from 19.8 per cent a year earlier.

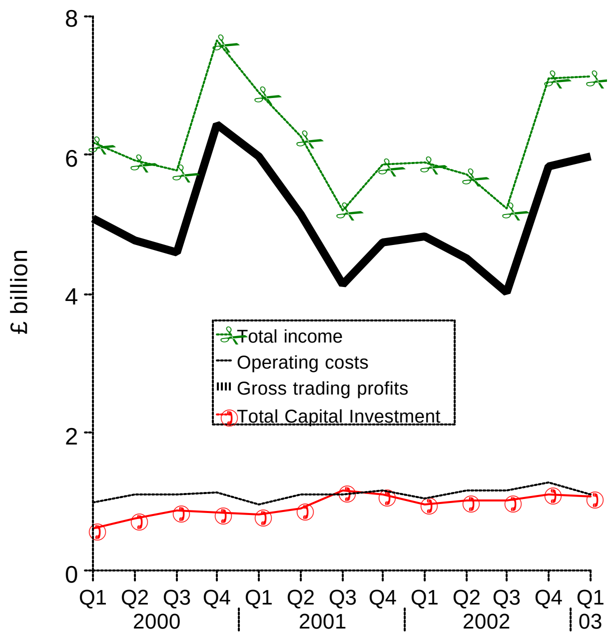
Chart 3.5 Stocks of key oil products[1]



(1) This includes motor spirit, DERV fuel, other gas diesel oils, aviation turbine fuel, kerosene and fuel oils.

- Overall, stocks of crude oil and petroleum products were 1.1 per cent lower at the end of the first quarter of 2003 than at the end of the first quarter of 2002.
- Compared with a year earlier crude oil and refinery process oil stocks were 7.3 per cent higher while stocks of products were 8.6 per cent lower.
- Stocks at UKCS pipeline terminals rose by 24.3 per cent (451 thousand tonnes).
- Chart 3.5 combines stocks of products with the product equivalent of stocks of crude oil to give an overall level of UK stocks of key products.
- At the end of the first quarter of 2003, the UK held stocks equal to 78 days of consumption of these key products, compared with an obligation of 67½ days (see Background for more details).

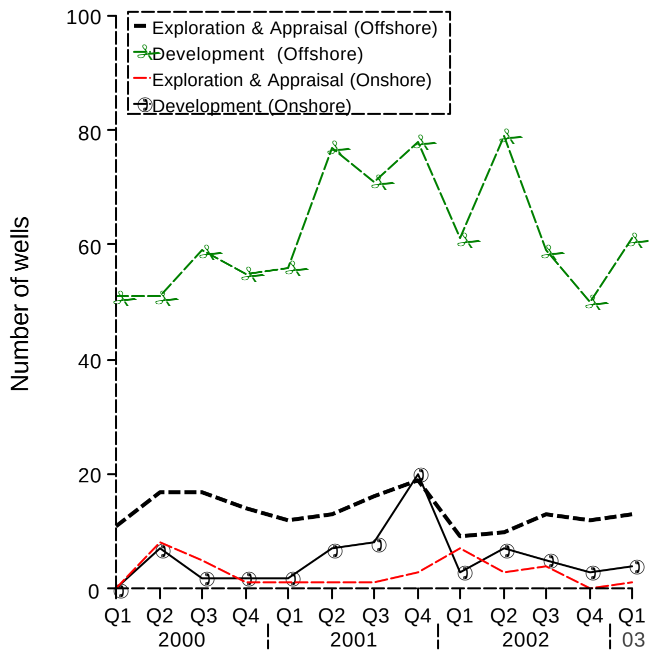
Chart 3.6 Value of UKCS production & investment by operators and licensees



Provisional figures for the first quarter of 2003 compared with the same period of 2002 showed that:

- Gross trading profits rose by 24.0 per cent.
- Total income rose by 21.2 per cent.
- Operating costs rose by 6.3 per cent.
- Total capital investment rose by 11.3 per cent.
- Exploration expenditure rose by 36.9 per cent.
- Other capital investment rose by 9.7 per cent.

Chart 3.7 Drilling activity on the UKCS



- Provisional drilling figures for the first quarter of 2003 showed an increase in the number of exploration and appraisal wells started offshore to 13 against 9 in the same quarter of 2002.
- The number of development wells drilled offshore, 61, was the same as in the first quarter of 2002.
- Four development wells were drilled onshore in the first quarter of 2003, compared to 3 in the first quarter of 2002.
- One exploration and appraisal well was started onshore in the first quarter of 2003, compared to 7 in the first quarter of 2002.

Background

Relevant tables

3.1: Supply and use of crude oil, natural gas liquids and feedstocks
3.2: Supply and use of petroleum products
3.3: Supply and use of petroleum products - Annual data
3.4: Supply and use of petroleum products - Latest quarter
3.5: Demand for key petroleum products
3.6: Stocks of petroleum at end of period
3.7: Drilling activity on the UK Continental Shelf
3.8: Value of UKCS production & investment by operators and licensees
3.9: Indicative tariff rates offered in the UKCS for the handling of oil and gas

Crude oil production and trade

Total UK production of crude oil and NGLs decreased in the first quarter of 2003 by 3.1 per cent compared to the same period last year. Twelve new fields started production after March 2002; without these production would be 7.0 per cent lower than the first quarter of 2002. The UK is still a net exporter of oil and oil products. The majority of UK production of crude oil and NGLs goes for export (69.0 per cent in the first quarter in 2003 compared with 76.0 per cent in the first quarter of 2002), as the UK generally produces a lighter, more valuable crude oil than other areas of the world such as the Middle East or West Africa. UK refineries are relatively modern and as such can cope with having these lower grade crude oils as an input. As such the economics of crude oil markets results in significant volumes of crude oil being imported into the UK.

Refinery production of petroleum products and trade

The net refinery output in the first quarter of 2003 was 19.9 million tonnes, about the same amount as in 2002. Refinery operations have evolved over the last two years to allow for the production of Ultra Low Sulphur Petrol. The switch to Ultra Low Sulphur Petrol is a contributory reason for the reduction of exports of UK produced crude oil as a higher-grade (i.e. lower sulphur content) input is needed, and so crude oil from the North Sea is used instead of cheaper, lower-grade imports from other areas of the world.

Demand for petroleum products

Overall deliveries of petroleum products for final consumption in the first quarter of 2003 were 3.4 per cent lower than in 2002. Deliveries of motor spirit and DERV were lower by 7.4 and 10.2 per cent respectively.

Aviation turbine fuel kerosene

The terrorist attacks on the United States on 11th September 2001 had a serious impact on the global aviation industry. This is evident from the clear downturn in consumption of ATF Kerosene in the UK following September 2001. Data for the first quarter of 2002 showed deliveries to be 14.2 per cent lower than in the same period of 2001 (prior to the attacks). The first quarter of 2003, which occurred during the build up to the Iraqi conflict, shows a 2.8 per cent increase over 2002 but is still down by 11.8 per cent when compared with 2001.

Stocks of crude oil and petroleum products

The UK has an obligation under EU law to maintain stocks of key oil products at or above a certain level to ensure adequate supplies would exist for any international oil supply emergency. These obligations are based on the UK's annual consumption of the key products motor spirit, DERV fuel and other gas diesel oils, aviation fuel and other kerosenes and fuel oils. These obligations are usually updated every 1st July as consumption data for the previous year are finalised. Chart 3.5 above combines data on stocks of key oil products with the product equivalent of stocks of crude oil to give an overall level of UK stocks of key oil products to show how the UK is complying with these obligations at an overall level. The UK's current overall obligation based on 2001 consumption data are to hold a total of 11 million tonnes of these products, equal to 67½ days of consumption.

Financial aspects of operations on the United Kingdom Continental Shelf

The data given in Table 3.8 are compiled from the Quarterly Inquiry into Oil and Natural Gas carried out by the DTI. This inquiry collects information from operators and other production licence holders. The information collected covers all income and expenditure directly related to the production of oil and natural gas, including exploration, development and other capital expenditures together with operating costs and the value of sales.

Biofuels- Recent Developments in the UK Road Fuels Industry

Introduction

Biofuels are becoming more important in the vehicle fuel industry because they are more beneficial environmentally than conventional fuels, and are derived from renewable sources. This article provides an overview of some of the recent biofuel developments including the impact the 2003 Budget has had in encouraging their use.

Biofuels can cut emissions of carbon dioxide by up to 60 per cent compared to fossil fuels and so can contribute to meeting UK targets for alleviating climate change. They can also reduce emissions of some tailpipe pollutants. Biofuels are safely and easily biodegradable and are therefore well suited to environmentally sensitive areas like inland waterways.

Background

There are two main-types of biofuel: biodiesel and bioethanol. These can be mixed with conventional road fuels to create bioblends. As its name implies, biodiesel (or methyl esters) is a diesel alternative and can be made from biomass (or vegetation), vegetable oils or recycled cooking oils. Bioblend DERV most often appears in the form B5 (5 per cent biodiesel and 95 per cent DERV fuel) and is often marketed as having environmental benefits over mineral diesel.

Currently combustion engines, without suitable modifications, running on bioblends higher than five per cent can fail to work in colder weather. This is the reason why most car manufacturers only warranty their engines to run on biodiesel in a five per cent blend with mineral diesel.

Biofuels are available for petrol vehicles, with alcohol (Bioethanol) used in some countries (notably Brazil and California). These blends are generally called E85 consisting of 85 per cent ethanol and 15 per cent petrol. This type of blend requires a modified fuel system to ensure reliable performance. These fuels are now being promoted in Europe, particularly Spain and Sweden, where it is mostly used in bioblend petrol denoted as E10 for example (10 per cent bioethanol and 90 per cent gasoline).

Use in the United Kingdom

HM Customs and Excise reported the total quantity of biodiesel retailed in the UK as around two million litres in 2002. Current estimates are that over a million litres of biodiesel are being sold every month representing a considerable increase from 2002. There were no sales of bioethanol or biopetrol.

The slow up take in biofuels is due to greater production costs in comparison to conventional fuels. The EU estimates that biofuels costs between 12 and 21 pence per litre extra to produce than conventional road fuels, dependant on the price of crude oil.

The Effects of the Budget 2003

The Budget has a significant effect on the use of road fuels in the United Kingdom. Taxes established in the Budget can provide incentives for behaviour that is beneficial to the environment. In July 2002 the Government introduced a duty differential of 20 pence per litre for biodiesel over ultra-low sulphur diesel. Production is from recycled vegetable oil and fats from the food chain with a small amount of finished product imported from elsewhere in Europe.

Budget 2003 also announced that a similar duty differential for bioethanol would be introduced. The differential will become effective on 1 January 2005 and will give bioethanol the same duty incentive as biodiesel, namely a 20 pence per litre differential over ultra-low sulphur petrol (ULSP).

By introducing these duty rates the Chancellor has made a commitment to encouraging the use of biofuels. The lower duty rates make the cost of biofuels comparable to conventional road fuels and are expected to provide some incentive to help meet the EU target of biofuels accounting for 2 per cent of the market in 2005.

Manufacture of Biofuels

The main process of manufacturing biodiesel is called transesterification and is similar to the making of soap. When sodium methoxide is mixed with oils or fats it causes them to split into ester chains (a chemical description of biodiesel) and glycerine, the soap residue. This soap residue must then be removed from the biodiesel. In Europe the most common type of biodiesel is Rape Methyl Ester (RME) manufactured from rapeseed oil by this simple transesterification process. Methanol is added to the oil, produced by crushing rapeseed, and heated in the presence of a catalyst to produce RME.

Bioethanol is produced by fermentation. Recent advances have been made by using enzymes to break straw into starch that is then fermented into ethanol although this is not yet at the stage of full commercial development.

There are problems involved with a continued increase in the biofuels industry. For example, the most common process of biodiesel production creates a large quantity of glycerine as a by-product.

Emissions

Research suggests that conventional engines using both biofuels at 5 per cent blends (B5 and E5) produce reductions in particulate emissions, with a small increase in the quantity of nitrous oxide, a toxic low-level pollutant. This results from both biofuels having a higher oxygen content than conventional diesel, which causes the fuels to ignite more readily.

The Future

The European Union believes that biofuels will increase the security of supply of energy and may also provide a sustainable alternative to conventional oil as resources decline. The potential environmental benefits could also be considerable.

Currently, Germany is by far the most substantial European producer of biodiesel with 52 per cent of the total European production capacity in 2002.

In June 2002 the EC published indicative targets for the introduction of biofuels in the EU. The EU targets are for biofuel to represent 2 per cent of total petrol and diesel sold in 2005, rising to 5¾ per cent in 2010. The Department for Transport estimates this could result in a reduction of 0.7 to 1.5 million tonnes of carbon dioxide emissions from UK road transport.

The UK Government has responded to this commitment by introducing tax incentives designed to encourage and expand the growth of the biofuels industry as viable alternatives to conventional road fuels in the UK.

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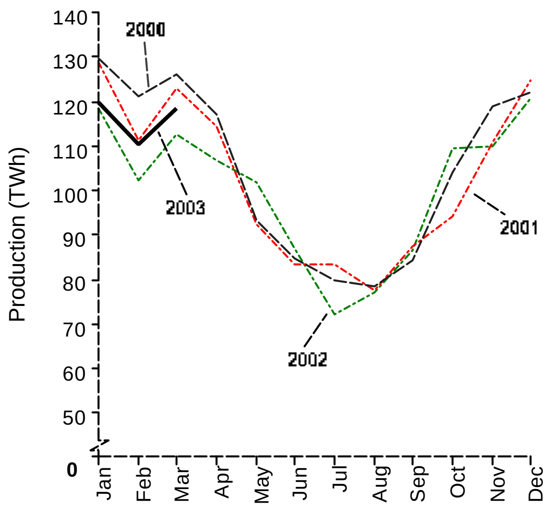
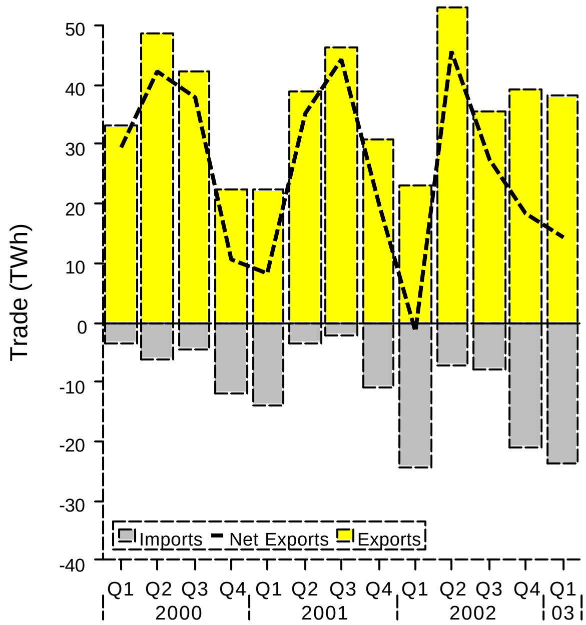
Section 4 - Gas

Chart 4.1 Production of natural gas



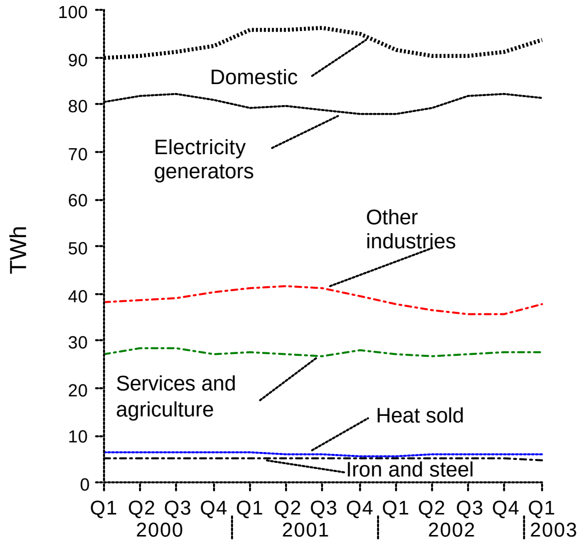
- Total indigenous UK production of natural gas in the first quarter of 2003 was 4.6 per cent higher than in the same period a year earlier.
- Production was higher because of increased demand for gas in the UK, partly due to colder weather in 2003 increasing demand for space-heating. There were also increased exports of gas.

Chart 4.2 UK trade in natural gas



- Compared with the same period in 2002, exports of natural gas in the first quarter of 2003 increased by 64.8 per cent while imports were 2.3 per cent lower.
- Whilst overall imports were a little lower than last year, imports from Norway via the Vesterled pipeline nearly doubled. This increase in supplies from Norway to Scotland freed the Bacton-Zeebrugge interconnector in the south east of England to increase exports to the continent, hence the significant increase in exports.

Chart 4.3 Natural gas consumption - average of four quarters ending



- Demand for gas in the first quarter of 2003 was 4.6 per cent higher than the level in the first quarter of 2002.
- Gas use for electricity generation was 4.2 per cent lower than in the first quarter of 2002. High gas prices meant that some generators found it more profitable to sell gas than use it for generation.
- Provisionally, consumption in the domestic sector rose by 7.3 per cent, mainly because temperatures were less mild than during the first quarter of 2002.
- In public administration, commerce and agriculture consumption rose by 3.8 per cent compared with a year earlier. In the industrial sector gas sales were provisionally 13.6 per cent higher than in the first quarter of 2002.

Background

Relevant table

4.1: Natural gas supply and consumption

Gas production and trade

Chart 4.1 shows an increase in production throughout the first quarter of 2003 compared to 2002. The UK currently exports gas to the Netherlands via Markham and Windermere fields, the Irish Republic and, since 1998, to Belgium through the Bacton-Zeebrugge interconnector. During the first quarter of 2003 imports to the UK were mainly from the Norway via the Frigg and Vesterled pipelines. Indigenous UK production accounted for 92.3 per cent of gas available for consumption in the UK in the first quarter 2003.

Gas consumption

Until the middle of 2000 the growth in consumption of natural gas was dominated by growth in consumption for electricity generation, mainly in Combined Cycle Gas Turbine stations. However, high gas prices led to the use of gas for generation following a downward trend until the end of 2001, but in summer 2002 gas prices fell back and gas use for generation rose again. In 2003 high prices again deterred use for generation. Gas use in the domestic sector is particularly dependent on temperatures during the heating season. With very mild temperatures in the first three months of 2002, domestic gas consumption declined. Mild temperatures also affected services sector consumption. With temperatures in the first quarter of 2003 being less mild, consumption has increased again. The closure of an integrated steel plant accounts for the reduced gas use in the iron and steel sector.

Regional and local gas consumption statistics for 2001

Introduction
DTI obtain aggregate data on gas sales from gas suppliers in order to obtain the UK figures published in the Digest of UK Energy Statistics (DUKES), Energy Trends and on the DTI web site. Until now, the only sub-national gas statistics available have been the data obtained by DTI from National Grid Transco and published in Table 4B of DUKES. These data show domestic and total gas consumption in the 13 Local Distribution Zones (LDZs) of the gas distribution system in Great Britain. These LDZs are not comparable with Government Office Regions or Eurostat's NUTS1 areas[1]. In order to produce estimates at a more disaggregated geographical level, Transco have provided to DTI consumption data for 2001 at postcode district level (ie the full postcode less the last 4 digits or letters). As a pilot exercise DTI have converted these data into estimates of gas consumption at a local level. This article sets out the methodology that has been used and invites comments on the final estimates.

Methodology
Using algorithms obtained from the Office for National Statistics, postcoded consumption data were allocated to one or more NUTS4 areas. These areas correspond to Counties or Unitary Authorities in Great Britain. The data set contained some postcodes that were not recognised as being valid postcodes and these were omitted from further analysis[2]. Where one postcode district covered more than one NUTS4 area, the consumption data was divided between each NUTS4 region. The totals for all NUTS4 areas in Scotland and Wales were individually scaled to match the totals for those countries shown in Table 4B of DUKES. The NUTS4 areas in England were similarly scaled to match the total of the English LDZs. NUTS4 areas were then aggregated to NUTS1 (Region) level and the summary table below produced. The data represent gas transported through the Transco distribution system alone and exclude any gas passing through other transmission and distribution systems such as those owned by North Sea producers. However, gas that passes through the Transco system and then into another independently owned local distribution system before reaching consumers is included. The Transco data relate only to distribution and exclude large loads fed directly from the national transmission system (such as certain power stations). As such, the total consumption of the NUTS4 areas given in this article represents about 70 per cent of the total UK gas consumption for 2001, as recorded in the Digest of UK Energy Statistics 2002. Of the remaining 30 per cent, 18 per cent is gas supplied directly from the National Transmission System and 12 per cent is gas supplied through the transmission systems of others, or used in oil and gas extraction.

Regional and local estimates
Table 1 shows gas sales via the Transco network for Scotland, Wales and the regions of England. Domestic sector sales are distinguished from commercial and industrial sales and the numbers of consumers are also given. From this information sales per consumer have been calculated.

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[1] NUTS (Nomenclature of Units for Territorial Statistics) is a hierarchical classification of spatial units that provides a breakdown of the European Union's territory for producing regional statistics which are comparable across the EU. NUTS1 refers to the 9 Government Office Regions in England, and separately Wales, Scotland, (and Northern Ireland), totalling 12 UK NUTS1 regions. NUTS4 refers to the 354 individual London boroughs/metropolitan districts in England, the 22 individual unitary authorities in Wales, the 41 individual or groups of whole/part unitary authorities and/or local enterprise company areas in Scotland, (and the 26 individual district unitary authorities in Northern Ireland), totalling 443 UK NUTS4 regions. There were 3 NUTS4 areas in Great Britain where Transco transmitted no gas.

[2] In the revised data for 2001 and 2002 referred to later in this article such rogue postcodes do not occur. The new data sets are at Postcode Sector level rather than the Postcode District level of the original pilot data set provided to DTI.

In addition, Table 1 shows information for a selected number of NUTS4 areas. The full table showing all 408 NUTS4 areas[3] is available on the DTI Energy statistics web site at www.dti.gov.uk/energy/inform/energy_trends/2003/gas2001nuts4.xls . Maps showing NUTS4 areas are available from the National Statistics web site at www.statistics.gov.uk/geography/maps.asp

The NUTS4 areas selected for Table 1 have been chosen to show some of the variation within the wider region. NUTS4s with the highest per consumer sales are shown (i.e. Chiltern for the domestic sector and North East Lincolnshire for commercial and industrial) as well as the area with the lowest per consumer sales (i.e. Penwith for both categories).

Users with a requirement for data at a level lower than NUTS4 (e.g. at Postcode Sector level) can obtain such data from the Transco web site at www.transco.uk.com/publish/gdd/postcode2002.xls. The data used in this article match the information provided to DTI by Transco for the Digest of UK Energy Statistics 2002. The data on the Transco web site have since been updated and 2002 annual data added.

It is our intention to publish 2002 regional and local gas consumption data using the methodology described above in the September edition of Energy Trends. We are also looking to publish the remaining 30 per cent of gas consumption, not covered by these Transco data, at a similar regional and local level. However, due to confidentiality constraints, these data may not be available for all NUTS4 areas.

Uses for regional and local data

When DTI consulted on the potential uses for data such as those presented in this article, replies were received from DEFRA, the Devolved Administrations, Local Authorities, The Audit Commission, Regional Development Agencies and the Environment Agency. They said that these data are useful to inform policies concerning the environment, energy efficiency or sustainable development at a sub-national level. Further details are available at the DTI's dedicated web site http://www.dti.gov.uk/energy/inform/regional_energy/index.shtml

Consultation

If you have any comments on these estimates please send them to David Nolan at the email address below. Alternatively mail can be addressed to David Nolan, Bay 226, 1 Victoria Street, London, SW1H 0ET.

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[3] The NUTS4 areas in Scotland do not exactly match the Scottish Local Authority Areas. There are more NUTS4 areas in Scotland than Local Authorities. In the analysis in the full table Scottish Local Authorities are used in place of NUTS4 giving a total of 408 local areas in Great Britain.

Table 1: Regional and local gas consumption statistics

Government Office Regions and selected NUTS4 Regions	Domestic consumers (1)		Commercial and industrial consumers		All consumers		Sales per consumer - kWh	
	Sales 2001 GWh	Number of consumers (thousands)	Sales 2001 GWh	Number of consumers (thousands)	Sales 2001 GWh	Number of consumers (thousands)	Domestic	Commercial and industrial
Wrexham	457	25.68	1,888	0.42	2,345	26.10	17,806	4,476,837
Newport	1,032	55.83	1,945	0.63	2,977	56.46	18,493	3,076,238
Cardiff	2,016	107.93	2,704	1.55	4,719	109.48	18,676	1,741,092
TOTAL WALES	**18,556**	**977.00**	**27,105**	**15.00**	**45,661**	**992.00**	**18,993**	**1,807,000**
Aberdeenshire	1,219	51.88	1,578	1.12	2,797	53.00	23,495	1,409,182
Falkirk	978	44.47	2,237	0.67	3,214	45.14	21,985	3,334,875
Glasgow City	3,546	192.06	3,243	4.89	6,789	196.95	18,462	663,410
TOTAL SCOTLAND	**34,242**	**1,625.00**	**30,989**	**32.00**	**65,231**	**1,657.00**	**21,072**	**968,406**
Newcastle upon Tyne	1,949	94.74	1,269	2.53	3,218	97.27	20,573	500,836
Sunderland	2,253	103.54	1,235	1.76	3,488	105.30	21,757	700,450
Hartlepool	606	31.35	770	0.52	1,376	31.88	19,328	1,466,795
TOTAL NORTH EAST	**19,849**	**962.94**	**13,515**	**18.82**	**33,364**	**981.77**	**20,613**	**718,085**
Vale Royal	1,093	53.63	2,113	0.97	3,206	54.60	20,382	2,169,968
Manchester	3,686	178.20	2,280	4.57	5,966	182.77	20,688	498,425
Liverpool	2,792	160.76	1,797	3.57	4,590	164.33	17,370	503,230
TOTAL NORTH WEST	**51,542**	**2,591.19**	**44,862**	**59.54**	**96,404**	**2,650.73**	**19,891**	**753,536**
Leeds	5,028	272.54	5,331	6.65	10,360	279.19	18,450	801,640
Sheffield	3,277	165.74	3,243	2.46	6,520	168.20	19,773	1,319,246
North East Lincolnshire	1,008	56.07	3,472	0.62	4,481	56.68	17,986	5,626,968
TOTAL YORKSHIRE AND THE HUMBER	**36,454**	**1,911.54**	**38,138**	**38.66**	**74,592**	**1,950.20**	**19,070**	**986,509**
Corby	305	15.20	787	0.20	1,092	15.41	20,076	3,886,437
Lincoln	430	23.84	265	0.26	695	24.10	18,045	1,035,587
Nottingham	1,589	82.69	1,558	1.21	3,148	83.90	19,219	1,292,570
TOTAL EAST MIDLANDS	**30,521**	**1,555.28**	**23,692**	**20.65**	**54,213**	**1,575.92**	**19,624**	**1,147,528**

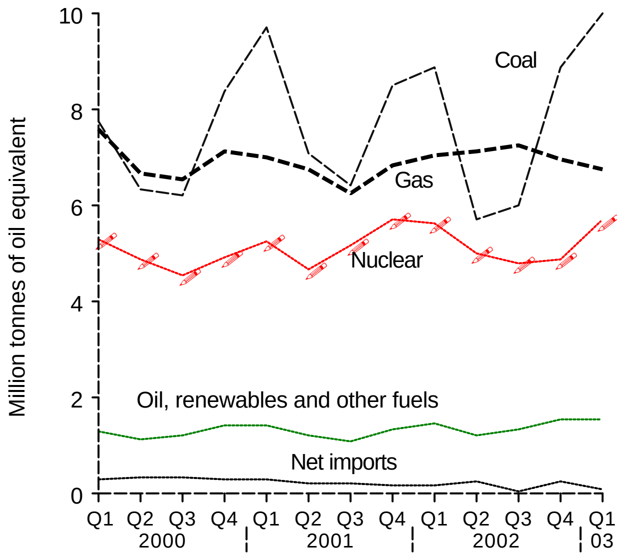
Domestic consumers (1) Commercial and industrial consumers All consumers Sales per consumer - kWh

Government Office Regions and selected NUTS4 Regions	Sales 2001 GWh	Number of consumers (thousands)	Sales 2001 GWh	Number of consumers (thousands)	Sales 2001 GWh	Number of consumers (thousands)	Domestic	Commercial and industrial
East Staffordshire	467	24.44	609	0.35	1,077	24.79	19,126	1,746,352
Worcester	389	21.88	337	0.61	725	22.49	17,759	549,658
Birmingham	6,269	324.63	5,246	7.63	11,515	332.26	19,312	687,650
TOTAL WEST MIDLANDS	**37,224**	**1,910.39**	**30,125**	**38.65**	**67,349**	**1,949.03**	**19,485**	**779,521**
Norwich	716	38.77	469	0.71	1,185	39.49	18,477	657,349
Basildon	1,429	71.59	1,105	1.03	2,534	72.62	19,958	1,077,735
Thurrock	992	53.02	2,374	0.71	3,366	53.73	18,715	3,339,524
TOTAL EAST OF ENGLAND	**35,329**	**1,766.20**	**22,650**	**32.64**	**57,979**	**1,798.84**	**20,003**	**694,025**
Bexley	1,453	75.95	1,321	0.79	2,773	76.74	19,128	1,668,718
Hammersmith and Fulham	1,346	72.51	2,365	1.65	3,711	74.15	18,561	1,436,712
Tower Hamlets	1,044	62.79	1,281	1.31	2,324	64.10	16,622	980,793
TOTAL GREATER LONDON	**54,484**	**2,758.90**	**31,255**	**49.33**	**85,739**	**2,808.23**	**19,748**	**633,622**
Maidstone	1,317	67.34	598	0.78	1,916	68.12	19,559	766,793
Chiltern	983	36.73	219	0.66	1,201	37.38	26,753	332,921
Slough	616	28.56	648	0.56	1,264	29.12	21,570	1,155,717
TOTAL SOUTH EAST	**59,030**	**2,909.03**	**31,359**	**57.05**	**90,389**	**2,966.08**	**20,292**	**549,647**
Bristol, City of	2,114	113.14	1,230	2.35	3,344	115.49	18,683	522,597
Penwith	182	11.95	61	0.30	243	12.25	15,262	199,715
Salisbury	472	25.31	335	0.84	807	26.14	18,640	400,850
TOTAL SOUTH WEST	**27,607**	**1,522.53**	**18,642**	**34.68**	**46,249**	**1,557.20**	**18,132**	**537,624**
GREAT BRITAIN	**404,837**	**20,490.00**	**312,333**	**397.00**	**717,170**	**20,887.00**	**19,758**	**786,733**

(1) Customers with an annual consumption of 73,200 kWh or lower which will include some small industrial and commercial consumers

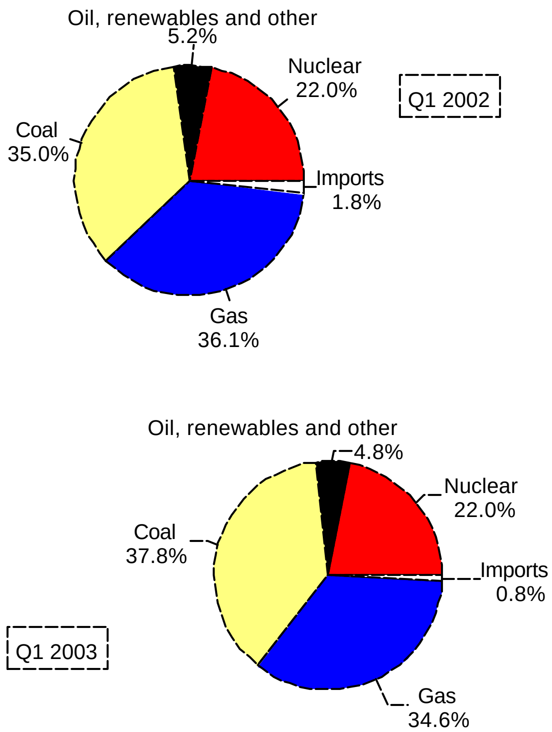
Section 5 - Electricity

Chart 5.1 Fuel used for electricity generation



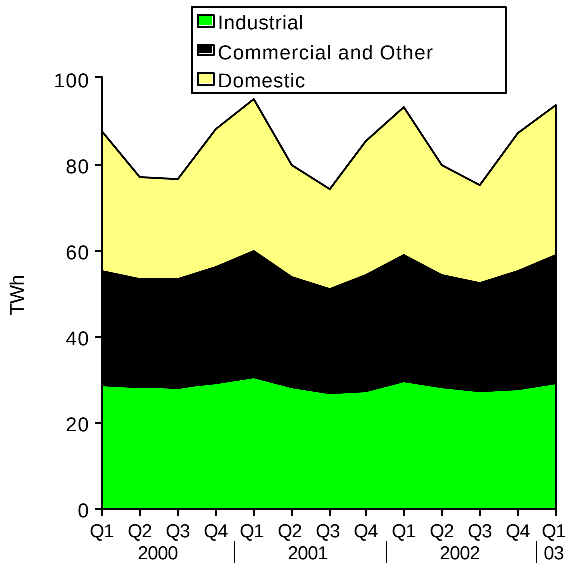
- Fuel used by generators in the first quarter of 2003 was, in total, 3.8 per cent higher than in the first quarter of 2002.
- Coal use during the quarter was significantly higher than a year earlier with 12.7 per cent more coal being consumed.
- Gas use was 4.2 per cent down on the first quarter of 2002 with high gas prices discouraging generation.
- Nuclear sources were up 0.8 per cent on the first quarter of 2002.
- Hydro sources were only half the level of the first quarter of 2002 because of low precipitation in the catchment areas.

Chart 5.2 Electricity supplied



- Total electricity supplied by all generators in the first quarter of 2003 was 0.7 per cent higher (+¾ TWh) than a year earlier.
- Indigenous supply was 1.8 per cent higher while net imports were down by 56.2 per cent (-1 TWh). Imports from France have been on a downward trend since NETA was introduced in March 2001, while a record 535 GWh of electricity were exported during the quarter.
- The supply from coal rose by 8.8 per cent (+3¼ TWh), while from gas fired stations supply fell by 3.3 per cent (-1¼ TWh).
- The supply from nuclear stations rose by 0.8 per cent (+¼ TWh).
- Between the first quarter of 2002 and the first quarter of 2003 coal's share of the electricity supplied rose by 3 percentage points to 38 per cent. Gas' share fell by 1½ percentage points to 34½ per cent, and nuclear's share was unchanged at 22 per cent. Imports' share fell by 1 percentage point to ¾ per cent.

Chart 5.3 Electricity consumption



- Final consumption of electricity rose by 1.0 per cent in the first quarter of 2003 compared with the first quarter of 2002. Domestic use was up by 2.3 per cent while consumption by commercial, public administration, transport and agricultural customers was up by 1.7 per cent. Industrial use of electricity was down by 1.0 per cent.
- In this period temperatures were 1¼ degrees Celsius cooler than in the very mild first quarter of 2002, but 1¼ degrees warmer than the long term mean.

Background

Relevant tables

5.1: Fuel used in electricity generation and electricity supplied
5.2: Supply and consumption of electricity

Fuel use

In 2001 higher gas prices brought a temporary halt to the rising trend in gas use at power stations, but during summer 2002 lower gas prices led to a resumption of growth in gas use. At the end of 2002 and in the first quarter of 2003 high gas prices have again restricted gas use for generation. The downward trend in generation from nuclear sources since 1998 was reversed during 2001 and nuclear's recovery continued during the first half of 2002, but in the third and fourth quarters outages at British Energy stations produced a further downturn.

Supply

Supply from the coal fired power stations of major power producers rose by 15 per cent in 2000 having fallen at an average rate of 9½ per cent a year over the previous four years. Supply from coal rose by a further 8½ per cent in 2001 but slipped back by 5½ per cent during 2002. This was mainly due to resumed competition from gas-fired stations which recorded a 7 per cent increase in electricity supplied during 2002, although the 2½ per cent fall in supply from nuclear stations also helped in gas' moderate resurgence. In the first quarter of 2003 coal was again the preferred fuel. Supplies from hydro sources were 24 per cent higher in 2002 than in the previous year which was affected by low rainfall levels, although the winter of 2002/3 was also a low rainfall period. Since the introduction of the New Electricity Trading Arrangements (NETA) imports and exports of electricity from and to continental Europe have been more volatile with suppliers taking advantage of price differentials, especially during periods of cold weather.

Consumption

Electricity demand has been rising at a trend rate of 1½ to 2 per cent a year over the five years to 2001 so the absence of any significant growth in 2002 is unusual. Provisionally, electricity demand in 2002 was divided 29 per cent to the domestic sector, 28½ per cent to industry and 18 per cent to the commercial sector leaving a further 17 per cent of demand shared by public administration, transport, agriculture and the fuel industries. The remaining 7½ per cent is accounted for by transmission and distribution losses. In recent years these proportions have changed very little with fuel industries' share falling and services sector share rising. Because electricity is used for heating and lighting in the domestic sector, and heating and lighting uses are also prominent in the commercial sector, domestic and commercial sector shares of consumption rise in the winter and fall in the summer.

Savings in carbon emissions resulting from the use of Combined Heat and Power

Introduction

This article discusses the assumptions that have to be made to calculate the carbon savings from Combined Heat and Power (CHP) and updates the analysis presented in Energy Trends in October 2000[1].

A CHP scheme generates power (usually electricity) and heat in a single process. These energy outputs displace power and heat that would otherwise have been generated separately and results in energy and carbon savings. CHP is an important technology contributing to measures aimed at reducing carbon emissions to tackle climate change. As such, there is a need to account for the carbon reductions:

- to help assess the overall progress made in the UK to meeting the Kyoto target;
- to assess the contribution made by individual schemes to reducing carbon emissions, in particular where this needs to be quantified to obtain benefits, for example in Emissions Trading Schemes; and
- to help plan policies and measures to achieve carbon emissions reductions.

In the recently published White Paper on Energy (Our energy future – creating a low carbon economy) the Government reaffirmed the importance of CHP and its commitment to a CHP target of 10 GWe of Good Quality Capacity installed by 2010.

The degree of carbon savings will depend on the technology and fuel used in the CHP scheme and on the alternatives displaced. The characteristics of a CHP scheme are well defined, so the main uncertainty in assessing carbon savings is in the fuel and efficiency assumed for alternative sources of the heat and power displaced. For practical purposes, certain conventions must be adopted to calculate carbon savings, particularly for portfolios of schemes. The choice of convention, and the assumption to be made regarding fuel and efficiency for alternative sources, will be determined by the purpose and scope of the calculation and whether the savings are to be assessed now or into the future.

A CHP scheme is installed to meet a heat demand, either existing or new, that would otherwise be provided by boilers, along with an economic electricity demand. Existing boilers have well-known characteristics and it is relatively straightforward to calculate avoided emissions. Where the heat demand is new or the existing boiler has reached the end of its lifetime, it may be more appropriate to calculate the avoided emissions based on the characteristics of a new boiler. To assess savings into the future, assumptions have to be made on the future performance of boilers i.e. any fuel switching or improvements in efficiency.

For displaced power, the situation is more complex as the actual carbon emissions will depend on the dynamics of the electricity generation system. When new generation capacity is needed to match demand, CHP may be built in place of other generation technologies, for example new gas turbines, and could thus be argued to displace that technology. Where there is over-capacity in the generation system CHP could result in mothballing of existing capacity, which may be coal-fired generation. The generation avoided for existing CHP will depend on a number of factors including site location, time of day and season of production and the number of hours run and will vary over the lifetime of the scheme. Detailed modelling of the electricity system would be required to estimate the avoided carbon emissions for individual CHP schemes, so a simplifying convention has to be adopted. The most commonly used conventions are that CHP displaces electricity:

[1] "Savings in carbon emissions from Combined Heat and Power", Energy Trends, October 2000 http://www.dti.gov.uk/energy/inform/energy_trends/articles/bpoct2000.pdf.

- at the carbon intensity[2] of the most cost effective new generating technology in the absence of CHP. This reflects the fact that CHP schemes are installed in preference to whatever is otherwise most economic at the time of building;
- at the average carbon intensity of the whole electricity system;
- from the basket of fossil fuel generating technologies. This reflects the fact that, in practice, fossil fuel fired generation is reduced more quickly in response to falls in electricity demand. Renewable and especially nuclear generation tends to operate at maximum capacity as much as possible.

In general it would be expected that over the next few years new CHP build would displace new gas generating technologies, because these are the technologies used where companies invest in power stations that are not CHP. In the short term, it could however be that, with few new power stations being built, new CHP schemes would displace existing plant, which would be something closer to the fossil fuel basket.

When looking at CHP already built, rather than new CHP, emissions savings could, in theory be calculated by looking historically at what were the competing technologies at the time. However, this would be quite complex given the range of ages and types of existing CHP. More often, therefore one of the averaging conventions is used.

Given the inherent uncertainties in the electricity market it is difficult to project the transition between displacement of fossil fuel basket and displacement of new gas generating technologies. In this paper, we therefore present an assessment of

- future savings from new CHP;
- a best estimate range for savings in 2010, and
- savings from existing CHP.

CHP in the UK

The basic element of a CHP scheme is one or more prime movers (e.g. a reciprocating engine, gas turbine or steam turbine) driving electrical generators. The heat generated in the process is recovered for use either in industrial processes, typically as steam, or in community heating and space heating, typically in the form of hot water. Useful outputs can be varied: heat can be used to drive absorption chilling, and in some cases, the power output can be mechanical power, e.g. to drive a compressor.

Most conventional electricity supply is from large power stations connected at high voltage to the grid transmission system. CHP is typically much smaller, sized to make use of the available heat and connected to the lower voltage distribution network (i.e. embedded). Compared to electricity-only plant, CHP is not only more efficient because of the use of cogenerated heat but it also avoids significant transmission and distribution losses.

In 2001, there were 1,573 sites with CHP in the UK, with a total installed capacity of 4,801 MWe. By far the majority of schemes had a capacity less than 1 MWe, however larger schemes (>10 MWe) represent 80 per cent of the installed capacity. Over the last five years, heat output has remained broadly stable, whilst electricity generated has increased by 30 per cent. The largest proportion of fuel used is natural gas, but other fuels such as oils and coal are used. New build of CHP is expected to be largely gas or renewable fuel fired.

Savings from the portfolio of CHP schemes in the future

Emissions savings for future years must take into account not only developments in electricity-only and heat-only plant, but also improvements in CHP. Actual changes in emissions savings will depend on the relative improvements in each of the technologies.

[2] Carbon intensity – the quantity of carbon emitted per unit of electricity delivered (kgC/kWh)

Special feature - CHP

The share of gas in electricity generation and in boilers is projected to further increase over the medium to long term. At the same time, efficiencies will improve in both separate heat and power generation and in CHP. To illustrate these effects, potential savings in the future have been calculated based on the following assumptions:

1. the electricity displaced will be from gas generation with 48 per cent delivered efficiency[3], giving a carbon intensity of 104 gC/kWh[4]. This assumes that there will be an improvement in the efficiency of CCGT compared to the average now;
2. the heat displaced will be from new 90 per cent efficient gas boilers (56 gC/kWh);
3. the average electrical efficiency of CHP will be 35 per cent and the overall efficiency 78 per cent These figures assume that there will be an increase in efficiency, particularly electrical efficiency, driven by improvements in technology and policies to encourage carbon savings. Technologies exist now that are designed to deliver these efficiencies. The fuel for CHP will be gas and the average load factor (the proportion of the year for which the CHP is operating) will be 60 per cent[5].

Table 1 shows calculated savings from CHP in the future based on 1,000 MWe of installed capacity.

Table 1 Savings from future CHP schemes

	Output (GWh)	Emissions factor (gC/kWh)	Carbon emissions (MtC)
Equivalent emissions from electricity	5,256	104	0.55
Equivalent emissions from heat	6,457	56	0.36
Emissions from CHP[6]		50	0.75
Savings per 1,000 MWe			**0.16**

Under these assumptions, the savings from CHP may be calculated as 0.2 MtC per 1,000 MWe. These savings omit the contribution from renewable fired CHP, which would increase these savings.

Savings from individual new schemes

CHP project developers will have to calculate the expected emissions savings from individual CHP schemes for a variety of reasons. It will often be appropriate to do this by comparison with the competing technology, usually gas.

In this case the assumption might be that the electricity displaced is from a gas generator with efficiency of 48 per cent for delivered electricity (carbon intensity: 104 gC/kWh). The heat displaced is from a 90 per cent efficient gas boiler with a carbon intensity of 56 gC/kWh. For illustrative purposes, the effect of load factor has been removed from the calculation by assuming 100 per cent load. In practice, CHP schemes operate at lower load factors and the savings are reduced. This scenario gives a range of annual savings of 0.04 to 0.29 MtC per 1,000 MWe (Table 2).

[3] The efficiencies in this paper are presented for Gross Calorific Value (GCV) of fuel, which are typically 6-10 percentage points lower than for Net Calorific Value (NCV). National energy statistics in the UK are based on GCV. Figures from the power generation industry are often based on NCV. For example, electricity-only combined cycle gas turbine generation (CCGT) currently achieves up to 55 per cent NCV, and around 50 per cent GCV. The values used for electricity are based on delivered efficiencies and include transmission and distribution losses.

[4] The average carbon intensity of the electricity generation system is also projected to approach this value in 2015 (Central High projections from Energy Paper 68).

[5] If a load factor of 75 per cent is assumed instead the savings shown in Table 1 would increase to 0.19 MtC per 1,000 MWe.

[6] 50 gC/kWh is the emissions factor for the fuel input to CHP.

Table 2 Example CHP schemes and associated savings (if a 100 per cent load factor is assumed).

	Fuel cell micro-CHP	Small[7]	Medium[8]	Large[9]
Electrical efficiency (per cent)	35	31	29	35
Thermal efficiency (per cent)	45	34	45	40
Heat to power ratio	1.3:1	1.1:1	1.6:1	1.1:1
MtC per 1,000 MWe	**0.29**	**0.04**	**0.16**	**0.22**

Carbon savings from the new CHP schemes to 2010

An estimate of the potential savings from new CHP installed to meet the Government target of 10 GWe installed capacity by 2010 needs assumptions on the performance of that new CHP and of the carbon intensity of the displaced heat and electricity. In the latter part of the period, new-CHP will probably be displacing new gas generation and gas boilers as discussed above. Currently, it is displacing something closer to the fossil fuel basket and current boiler mix.

Based on the performance of new schemes being commissioned now, an electrical efficiency of 30 per cent and overall efficiency of 73 per cent is assumed. New schemes are assumed to be gas fired with a load factor of 60 per cent. This omits any contribution from renewable fired CHP and the improvement in efficiency and load expected from new CHP.

The range of savings from new CHP to 2010 is given by considering the two scenarios.

Scenario 1 – in the short term

The carbon intensity of the fossil fuel basket in the electricity generation system in the short term is around 190 gC/kWh based on the proportions and average efficiency of electricity generating plant in 2001[10] (Table). The carbon intensity of the fossil fuel basket is projected to decrease steadily over the next few years, reaching 142 gC/kWh[11] by 2010.

Table 3 Fossil fuel power station efficiency and emissions

	Efficiency				
	Range per cent	Average primary per cent	Delivered per cent[12]	Carbon (gC/kWh of electricity output)	Percentage of total mix
Coal	32-37	34	32	278	46
Oil	25-37	28	26	276	2
Gas	32-52	45	42	119	52
Weighted average			**37**	**196**	**100**

The heat displaced is at a carbon intensity of around 80 gC/kWh based on the current mix of boiler plant (Table). This carbon intensity is expected to decrease as the proportion of gas boilers increases and efficiency improves.

[7] Electrical capacity >500 kWe and <5 MWe
[8] Electrical capacity >5 MWe and <50 MWe
[9] Electrical capacity >50 MWe
[10] Digest of United Kingdom Statistics, 2002. http://www.dti.gov.uk/energy/inform/dukes/index.shtml
[11] Figure for 2010 taken from the Central High projection in Energy Paper 68.
[12] This includes an estimated 2 per cent for transmission losses and takes into account that not all CHP electricity supplied is embedded.

Table 4 Boiler plant efficiency and emissions

	Efficiency range per cent	Average per cent	Carbon emission factor (gC/kWh of heat output)	Percentage of total mix
Coal	51-82	70	127	8
Oil	58-87	74	98	31
Gas	61-82	76	66	61
Weighted average		**75**	**81**	**100**

In the short term, the projected savings are 0.7 MtC per 1,000 MWe.

Table 5 Annual emissions savings from new CHP installed to meet the Government target of 10 GWe installed capacity

Scenario 1 – in the short term			
	Output (GWh)	Emissions factor (gC/kWh)	Carbon emissions (MtC)
Equivalent emissions from electricity	27,331	190	5.2
Equivalent emissions from heat	39,175	80	3.1
Emissions from CHP			4.6
Savings			3.8
Savings per 1,000MWe			**0.7**

Scenario 2 – towards 2010

CHP displaces new gas generating technologies with a delivered efficiency of 45 per cent (based on average thermal efficiency in 2001, with 2 per cent transmission losses) giving a carbon intensity of 111 gC/kWh. The heat displaced is from a 90 per cent efficient gas boiler with a carbon intensity of 56 gC/kWh. The projected savings are 0.1 MtC per 1,000 MWe.

Table 6 Annual emissions savings from new CHP installed to meet the Government target of 10 GWe installed capacity

Scenario 2 – towards 2010			
	Output (GWh)	Emissions factor (gC/kWh)	Carbon emissions (MtC)
Equivalent emissions from electricity	27,331	111	3.0
Equivalent emissions from heat	39,175	56	2.2
Emissions from CHP			4.6
Savings			0.7
Savings per 1,000MWe			**0.1**

The projected savings range for new CHP to meet the Government target of 10 GWe is from 0.1 MtC per 1,000 MWe towards 2010 to 0.7 MtC per 1,000 MWe in the shorter term. Improvements in the efficiency of CHP and the contribution from renewable fired CHP would increase these savings. Table 1 sets out the savings assuming CHP becomes more efficient.

Current CO_2 savings from CHP schemes

Emissions from CHP schemes in 2001

The fuel used in CHP schemes in 2001 and the resultant emissions are shown in Table 7. Total emissions were **4.7 MtC**. This compares to 4.75 MtC reported for 1999. The slight decrease in emissions comes despite an increase in overall capacity from 4,239 MWe in 1999 to 4,801 MWe in 2001, and reflects a decrease in the use of coal and fuel oil.

Table 7 Fuel use and emissions from CHP schemes in 2001

	Fuel used (GWh)	Emissions factor (3) (gC/kWh)	Emissions (MtC)
Natural gas	68,804	50	3.4
Fuel oil	8,066	73	0.6
Gas oil	419	68	0.0
Coal	7,256	89	0.7
Blast furnace gas	1,537		
Coke oven gas	526		
Refinery gas	6,737		
Renewable fuels (1)	2,224		
Other fuels (2)	17,485		
Total fuel	**113,053**		**4.7**

(1) Renewable fuels include: sewage gas; other biogases; clinical waste; municipal waste.
(2) Other fuels include: process by-products and uranium.
(3) 'Alternative' fuels such as blast furnace gas contribute 25 per cent of the fuel use in CHP. Because these fuels would otherwise have been flared, vented or dumped, they are treated as having no additional carbon implication.

Avoided emissions from separate heat generation

Boiler replacement does not happen quickly, many remain in the stock for 40 years or more. For this reason the assumption for current savings is that the heat sources displaced by CHP are best represented as the mix of boiler plant currently installed.

Table 4 gave boiler plant efficiency and emissions. Based on the efficiencies, the weighted average for the emission factor for heat is 81 gC/kWh of heat output. CHP schemes in 2001 generated 60,753 GWh of heat, which, if generated by boilers, would have resulted in the emission of **4.9 MtC**.

Avoided emissions from separate electricity generation

Convention 1: Electricity displaced is generated at average carbon intensity

In 2000 (the latest year for which data are available), the average carbon intensity of the whole electricity generation system was 134 gC/kWh[13]. In 2001, 22,227 GWh of electricity was generated by CHP. If this had been generated at the average carbon intensity, it would have resulted in emissions of **2.9 MtC**

Convention 2: CHP displaces fossil fired generation of electricity

The weighted average carbon intensity of current fossil fuel fired power stations is 196 gC/kWh supplied to site. This is higher than the figure in 1999 as the proportion of coal in the mix was higher in 2001 and the average efficiency was lower. At this intensity, separate conventional generation of the 22,227 GWh of electricity from CHP would have resulted in emissions of **4.3 MtC**.

Savings from CHP

Annual savings based on the first convention (average carbon intensity for electricity) may be calculated as (4.9 + 2.9) – 4.7 = 3.1 MtC. Using the second convention the figure comes to 4.5 MtC.

Given 4,801 MWe of installed CHP capacity, the savings are equivalent to between 0.7 and 0.9 MtC per 1,000 MWe of installed capacity. The upper limit is higher than the figure of 0.78 MtC per 1,000 MWe calculated in the previous article[1]. There are three main reasons for this apparent improvement:

1. the statistics for CHP schemes are now obtained from the CHPQA programme, which gives access to more accurate data on the performance of CHP;

[13] Data from the National Atmospherics Emissions Inventory, 2002

2. there has been an increase in the use of gas in CHP, thus lowering average emissions from CHP;
3. there was an increase in the proportion of coal in the electricity generating mix, thus increasing average emissions from electricity generated in fossil fuel plants.

If the heat sources displaced by CHP are considered to be 80 per cent efficient gas fired boilers (emission factor 63 gC/kWh), rather than the current average boiler stock (81 gC/kWh), then the calculated savings reduce to 0.4 - 0.7 MtC per 1,000 MW.

Savings from individual CHP schemes in operation in 2010

As discussed previously. CHP project developers will have to calculate the expected emissions savings from individual CHP schemes. For example, it will be necessary to do so when project based emission trading is developed. If the calculation is to be done for a specific purpose, the convention to be used in the calculation will be defined externally, for example in regulations. To illustrate the range of savings that might be achieved by individual schemes, representative scheme performance for CHP units of different sizes is used in the following example.

The electricity displaced has the average carbon intensity of the UK electricity generation system in 2010 (117 gC/kWh). To date, this is the most commonly used convention for official reporting purposes in the UK. It is assumed that the alternative source of heat is a 90 per cent efficient gas boiler with a carbon intensity of 56 gC/kWh. All CHP units are assumed to be gas fired. This scenario gives a range of annual savings of 0.15 – 0.40 MtC per 1,000 MWe.

Table 8 Examples of CHP schemes and associated savings in 2010 (assuming 100 per cent load factor)

	Fuel cell micro-CHP	Small[14]	Medium[15]	Large[16]
Electrical efficiency (per cent)	35	31	29	35
Thermal efficiency (per cent)	45	34	45	40
Heat to power ratio	1.3:1	1.1:1	1.6:1	1.1:1
Emission factor of separate heat (gC/kWh) (baseline)	56	56	56	56
Electricity emission factor 117 gC/kWh				
MtC per 1,000 MWe	**0.40**	**0.15**	**0.28**	**0.33**

Conclusions

The actual savings from an individual CHP scheme will depend on the fuel used in that scheme and the fuel used for separate generation of heat and power. For most schemes, the alternative source of the heat will be easy to identify and the main uncertainty is the fuel and technology used to generate the displaced electricity.

In the future it may be assumed that newly built CHP displaces the next most cost effective generating technology. In the medium to long term this is projected to be gas generation. Using this convention future savings of 0.2 MtC per 1,000 MWe of installed capacity can be calculated.

For individual CHP schemes yet to be built, a more rigorous calculation of the carbon savings can be made. The examples for new schemes in this paper give a range for annual savings in the future of 0.04 – 0.3 MtC per 1,000 MWe.

Estimated savings for new CHP schemes to reach the Government target of 10 GWe of installed capacity are estimated to be between 0.1 and 0.7 MtC per 1,000 MWe depending on the fuel displaced, with higher savings for renewable fired CHP.

[14] Electrical capacity >500 kWe and <5 MWe
[15] Electrical capacity >5 MWe and <50 MWe
[16] Electrical capacity >50 MWe

Two conventions are commonly used for the displaced electricity in the shorter term, namely that it is at the average carbon intensity of the electricity generation mix or that it is at the carbon intensity of the fossil fuel part of the generation mix. The latter convention reflects the fact that, in practice, fossil fuel fired generation is reduced more quickly in response to falls in electricity demand. For currently installed CHP, these assumptions give a range of savings from 0.7 - 0.9 MtC per 1,000 MWe of installed capacity.

For individual schemes in operation in 2010, use of the average carbon intensity of the electricity generation mix, which is the most commonly used convention for official purposes, gives a range 0.2 – 0.4 MtC per 1,000 MWe of installed capacity.

The draft Cogeneration Directive includes provisions on how carbon savings should be calculated. When these provisions are finalised, a revised paper will be published discussing these provisions and the consequent effects on calculations of carbon savings from CHP in the UK.

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Renewable energy in 2002

Introduction
This article updates that published in the June 2002 edition of Energy Trends. It looks at the latest position on the new Renewables Obligation and lists statistics on renewable energy production and use in the UK in 2002. It also re-examines progress with other policies designed to help mitigate greenhouse gas emissions through supporting the uptake of renewables.

The collection of renewable energy statistics began in 1989, when all relevant renewable energy sources were identified and, where possible, information was collected on the amounts of energy derived from each source. The renewable energy sources currently covered are as follows: active solar heating; photovoltaics; onshore and offshore wind power; wave power; large and small scale hydro; biofuels; geothermal aquifers. The database now contains 14 years of data from 1989 to 2002. Detailed figures on renewable sources of energy will be available in the new Digest of UK Energy Statistics for 2003 to be published at the end of July.

UK's renewables policy
Until 2000, the main instruments for pursuing the development of renewables capacity have been the Non Fossil Fuel Obligation (NFFO) Orders for England and Wales and for Northern Ireland (NI-NFFO), and Scottish Renewable Obligation (SRO) Orders; the term "NFFO Orders" is used to refer to these instruments collectively. These aimed to assist the renewables industry by allowing premium prices to be paid for electricity for a fixed period. Since February 2000, however, the United Kingdom's renewables policy has consisted of four key strands:

- a **new Renewables Obligation** on all electricity suppliers in Great Britain to supply a specific proportion of electricity from eligible renewables;
- exemption of electricity from renewables[1] from the **Climate Change Levy**;
- an **expanded support programme** for new and renewable energy **including capital grants** and an expanded **research and development** programme;
- development of a **regional strategic approach** to planning and targets for renewables.

In parallel with this, the European Union's Renewables Directive (RD), which came into force in October 2001, proposes that Member States adopt national targets for renewables that are consistent with reaching the overall EU target of 12 per cent of energy (22.1 per cent of electricity) from renewables by 2010. The proposed UK "share" of this target is that renewables source eligible under the RD should account for **10 per cent of UK electricity consumption by 2010**.

Renewables obligation
The obligation is part of the UK's proposed programme to tackle climate change and to encourage a more sustainable approach to energy consumption. Previous policy has been successful in introducing renewables to the UK marketplace and in reducing costs. The focus of current policy is to build on these achievements through the Obligation and a system of capital grants designed to bring forward offshore wind and energy crops, thereby maximising the chances of meeting the Government's targets.

In April 2002 the new Renewables Obligation (RO) and the analogous Renewables (Scotland) Obligation came into effect[2]. It is an obligation on all electricity suppliers to supply a specific proportion of electricity from eligible renewable sources so that by 2010 **10 per cent of licensed UK electricity sales** will be from renewable sources eligible for the RO. Examples of eligible sources are listed in Table 1.

[1] Electricity generated by hydro stations with a declared net capacity of more than 10 MW is not exempt from the Climate Change Levy.
[2] Parliamentary approval of the Renewables Obligation Orders under The Utilities Act 2000 was given in March 2002.

Table 1: Examples of eligible sources of renewable energy
Wind energy
Hydro power, but some exclusions
Tidal and tidal stream
Wave energy
Photovoltaics
Geothermal
All biodegradable material
Landfill gas and sewage gas
Energy crops

There are, however, specific exclusions. These are generating stations using peat; existing hydro plant of over 20 MW built before 1990 (unless re-furbished); and energy from mixed waste combustion. Mixed waste that is converted to fuel using advanced conversion technology is eligible, but only the biodegradable fraction of any waste is eligible (in line with the EU Directive). All stations outside the UK (which includes its territorial waters and the continental shelf) are also excluded.

Monitoring compliance is the responsibility of the Office for Gas and Electricity Markets (OFGEM), who administer a system of certification. **Renewables Obligation Certificates** (ROCs) are issued to qualifying renewables generators as evidence that a licensed electricity supplier has supplied qualifying electricity to their customers in Great Britain. These certificates may be traded separately from the electricity to which they relate through a system of limited banking and borrowing in order to give individual suppliers more flexibility as to how they meet the demands of the Obligation.

Renewables - statistics update

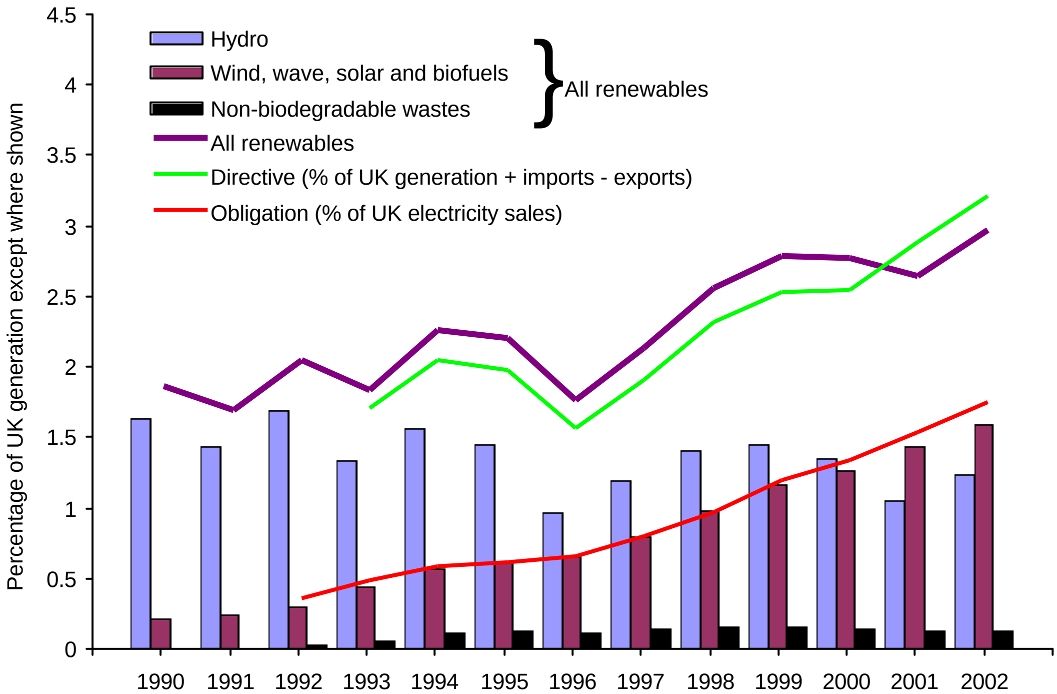
Renewables provided 2.96 per cent of the electricity generated in the United Kingdom in 2002, 0.34 percentage points higher than in 2001, which was affected by low large scale hydro output, and 0.20 percentage points higher than the previous highest figure in 1999. Chart 1 shows the growth in the proportion of electricity produced from renewable sources. It includes the progress towards the renewables targets set under the Renewables Obligation and Renewables Directive. As the chart shows, the variability in hydro output makes the path towards two of these targets a far from smooth one. Large-scale hydro generation in 2002 was 19 per cent higher than in 2001.

In Chart 1 the bars show the growth in the three constituent parts of renewables generation since 1990. The lines show the growth in the three percentage measures used for renewables growth. In 2002 all three percentages continued to grow. The percentage of UK electricity sales that were of electricity generated from sources eligible for the RO grew by 0.22 percentage points to 1.74 per cent, and, on the basis favoured by the Renewables Directive, the percentage of UK electricity consumption accounted for by RD eligible renewable sources increased by 0.32 percentage points to 3.19 per cent in 2002. Table 2 sets out the percentages for each of the last three years for each of the three percentage measures.

Table 2: Percentages of electricity derived from renewable sources

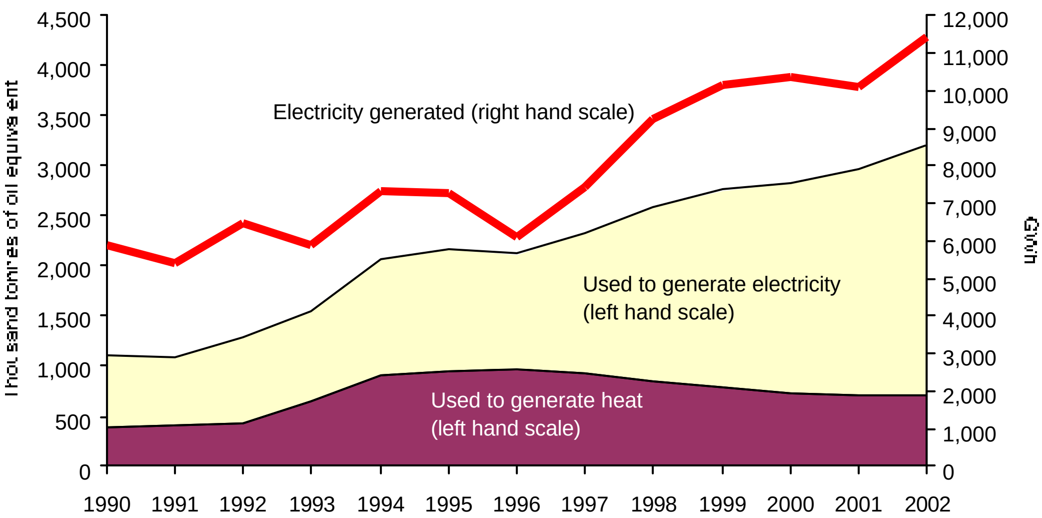
	2000	2001	2002
Overall renewables percentage (Electricity generated from all renewables and wastes as a percentage of all electricity generated in the UK)	2.75	2.62	2.96
Percentage on a Renewables Obligation basis (Electricity generated from renewables eligible for the Renewables Obligation - see Table 1 - as a percentage of electricity sales by licensed suppliers in the UK)	1.32	1.52	1.74
Percentage on a Renewables Directive basis (Electricity generated from renewable sources eligible under the EU Directive - ie all renewables except non-biodegradable wastes – including any net imports of eligible electricity, as a percentage of UK electricity consumption)	2.52	2.87	3.19

Chart 1: Growth in electricity generation from renewable sources since 1990



Total electricity generation from all renewable sources in 2002 amounted to 11,444 GWh, 40 per cent of which was from large-scale hydro generation. Generation from renewable sources other than large-scale hydro was 10 per cent higher than in 2001 and 59 per cent higher than 5 years earlier in 1997. Chart 2 shows the growth in generation from renewables.

Chart 2: Trends in the use of renewable energy for both heat and electricity



Heat production

Renewable sources are also used to generate heat. The three sources of heat production in the United Kingdom are: the direct combustion of biofuels (98 per cent of the total), active solar heating, and geothermal aquifers. Together they produced energy equivalent to 717 thousand tonnes of oil equivalent, slightly above the figure for 2001. When this figure is combined with the use of renewable sources for electricity generation, renewable sources accounted for 1.4 per cent of the United Kingdom's total primary energy requirements in 2002, up from 1.25 per cent in 2001 and 1.2 per cent in 1999. The trends in the use of renewable energy for both heat and electricity are shown in Chart 2.

These data are compiled for the Renewable Energy STATisticS (RESTATS) project and are published in further detail in the Digest of UK Energy Statistics (DUKES)[1]. Government's encouragement of a regional strategic approach to planning and targets for renewables has now resulted in the production of regional statistics in support of both these regional initiatives. Regional renewables statistics for 2000 and 2001 were given in articles in the December 2001 and September 2002 issues of Energy Trends, respectively. An article updating the figures to 2002 is planned for September 2003.

NFFO

As at 31 December 2002, 417 projects contracted under the NFFO, the SRO and the NI-NFFO had been commissioned and were generating electricity, with a capacity totalling 1,053.4 MW DNC. These figures include those projects formerly contracted under NFFO 1 and 2, whose contracts expired on 31 December 1998. The breakdown is shown in Tables 3 and 4.

Table 3: NFFO Orders status summary as at 31 December 2002

Technology	Contracted projects		Commissioned projects	
	Number	Capacity (MW DNC)	Number	Capacity (MW DNC)
Biomass	32	256.0	9	106.5
Hydro (small-scale)	146	95.4	69	46.8
Landfill gas	329	699.7	209	436.3
Municipal and industrial waste	90	1,398.2	19	223.8
Sewage gas	31	33.9	24	25.0
Wave	3	2.0	1	0.2
Wind	302	1,153.7	86	214.7
Total	**933**	**3,638.9**	**417**	**1,053.4**

Sources: NFPA, Scottish Executive, Northern Ireland Electricity
Includes those projects formerly contracted under NFFO 1 and 2

Of the 32 schemes totalling 76.0 MW DNC that came on-line during the calendar year 2002:

- 25 (44.0 MW DNC) were projects with NFFO contracts under NFFO 4 (1 Hydro, 4 Landfill Gas, 2 MSW, 1 Agricultural waste and 4 Wind) and 5 (13 Landfill Gas)
- 7 (20.3 MW DNC) were schemes commissioned under SRO 1 (2 Hydro), SRO 2 (1 Wind, 1 Waste), SRO 2 (2 Waste) and NI-NFFO 1 (1 Hydro).

Table 4 summarises the current status of renewable energy projects contracted by means of the NFFO Orders and shown in order of their historical development. In 1990, the first year of NFFO, projects contracted within NFFO accounted for about 34 per cent of the total capacity (excluding large-scale hydro) ie 51 MW out of 151; by 1998, this figure had risen to 86 per cent, but dropped to 50 per cent in 1999 due to the expiry of NFFO I and 2 contracts. In 2002 the NFFO capacity rose slightly faster than non NFFO (including formerly NFFO 1 and 2) capacity therefore the proportion is 62.6 per cent, up from 61.5 per cent in 2001.

Renewables outside of NFFO

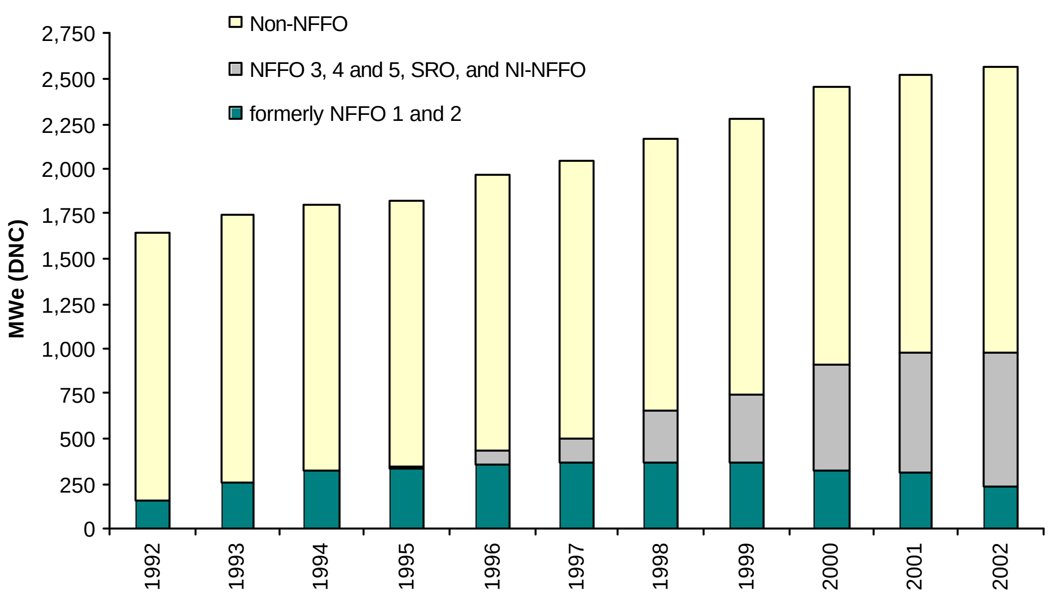
Since the expiry of the NFFO 1 and 2 contracts on 31 December 1998, these projects are no longer included in the monitoring of NFFO Orders and DTI no longer receive any status/output data on them from the NFPA. For some of these projects operational data have been obtained from other sources, while for the remainder estimates have been made based on output in 1998. For 2002 another source of information became available in the form of the Renewable Obligation data that are published on the OFGEM web site. This enabled FES to identify, which former NFFO 1 and 2 schemes were applying for ROCs and therefore were still running. Twenty-six such operational projects were contracted under the first Order and 56 under the second Order.

Table 4: NFFO Orders and operational capacity as at 31 December 2002

	Contracted Projects		Live Projects	
	Number	Capacity MW	Number	Capacity MW
England and Wales				
NFFO - 1 (1990)	75	152.1	59	141.0
NFFO - 2 (late 1991)	122	472.2	80	172.4
NFFO - 3 (1995)	141	626.9	79	292.6
NFFO - 4 (1997)	195	842.7	77	195.2
NFFO - 5 (1998)	261	1,177.2	65	118.8
NFFO Total	**794**	**3,271.1**	**360**	**919.9**
Scotland				
SRO - 1 (1994)	30	76.4	18	46.5
SRO - 2 (1997)	26	114.1	11	47.7
SRO - 3 (1999)	53	145.4	9	21.3
SRO Total	**109**	**335.9**	**38**	**115.5**
Northern Ireland				
NI NFFO - 1 (1994)	20	15.6	14	15.0
NI NFFO - 2 (1996)	10	16.3	5	2.9
NI NFFO Total	**30**	**31.9**	**19**	**17.9**
Total	**933**	**3,638.9**	**417**	**1,053.4**

While live projects under NFFO accounted for 1,053.3 MW DNC of renewables capacity at the end of 2002, this was only about 41 per cent of the total renewables generating capacity in the United Kingdom at that date. The majority of the additional 1,511.9 MW is accounted for by large-scale hydro capacity operated by major power producers. Progressively offshore windfarms will increase this non-NFFO capacity. Trends in capacity since 1992 (in DNC terms) are shown in Chart 3.

Chart 3: Renewable generating capacity from NFFO, former NFFO contracts (including equivalents in Scotland and Northern Ireland) and capacity outside of NFFO



Treatment of renewables in the Climate Change Agreements and for emissions trading purposes

The **Climate Change Levy** (CCL) was launched in April 2001. This is a tax on *energy supplied to businesses* – energy from qualifying renewable sources is exempt. Eligible renewables (Table 1) are treated as having a CO_2 emission factor of zero, and can therefore contribute to emissions targets under the UK Emissions Trading Scheme. For Climate Change Agreements that are expressed in terms of energy use rather than CO_2, energy derived from eligible renewable sources can be excluded from the reported energy consumption for that site.

The **UK Emissions Trading Scheme** (UKETS) was launched in April 2002. Companies signed up to the UKETS will be paid £53 for every tonne CO_2 reduced relative to their baseline. This incentive is designed to kick-start emissions trading, and places the UK at the lead of the emerging global emissions trading markets. The rules of the schemes currently allow ROCs to be used against emissions targets under the UKETS, but allowances from the UKETS cannot be used against the RO because of the expected price differential.

Further details, including the impact of the CCL on the Government backed **'Future Energy'** Scheme, were discussed in the corresponding article to this in the June 2002 edition of Energy Trends.

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[1] The Digest of United Kingdom Energy Statistics 2003 is due to be published by The Stationery Office on behalf of the Department of Trade and Industry on 31 July 2003. The Complete digest will be available as a series of PDF files that may be downloaded from the DTI's web site (http://www.dti.gov.uk/energy/inform/dukes/index.shtml); renewable energy elements are also available via the RESTATS web site (http://www.etsu.com/RESTATS).