Coal: The future

A Research Report

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YORKSHIRE AND HUMBER ASSEMBLY
Voice of the region

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Introduction and Objectives

This study was conducted for the Yorkshire and Humber Assembly .The purpose of this study was to investigate the current state, profitability and future viability of the coal-fired power stations and coal mining industry in Yorkshire and the Humber, with the following specific objectives.

Objectives

To obtain the following information within Yorkshire and the Humber

Coal-fired Power Stations

Ownership and number of direct employees
Profitability and how profits are distributed
Capacity and technology used and feasibility of employing new/more environmental/more cost effective technologies
Type, value and location of jobs dependent on the power stations (e.g. through service supplied and the supply chain)
Life expectancy of stations
Where coal (or other fuels) are sourced and how they are transported
Current and possible future impact of competition from other energy sources
Types and quantity of waste produced and how it is disposed of
Implications of new or forthcoming legislation, regulations or national policy and programmes (e.g. carbon emissions trading and the new UK White Paper on Energy)
Potential for contributing to reducing emissions of carbon dioxide through gasification technology and sequestration of carbon dioxide

Coal Mining Industry

Location, ownership and number of direct employees of remaining coal mines (including opencast mines)
Profitability and how profits are distributed
Type, value and location of jobs dependent on the coal mines
Size and potential life expectancy of coal reserves
Type, location and stability of markets for coal produced
Current and possible future impact of competition from other coal and energy sources
Implications of new or forthcoming legislation, regulation or national policy and programmes (e.g. carbon emissions trading and the new UK White Paper on Energy)

Methodology

The study was conducted in three stages, as follows.

1. Literature review
2. Primary research
3. Analysis and interpretation

The sources reviewed in stage 1 of this study were obtained mainly from the Internet and amounted to a large number of reports and publications by a wide range of publishers and relevant bodies. The main sources are listed in the Appendix to this report.

The primary research consisted of extensive consultation with individuals and organisations involved in the coal and power industries in Yorkshire and Humber, community miners' associations and with local government officers concerned with employment issues in their districts. Without exception, everyone consulted gave generously of their time and the information at their disposal and we wish to offer our thanks and to acknowledge their contribution to this study.

In the course of this consultation we held discussions with over 35 representatives of the following organisations and companies.

The Coal Authority
UK Coal PLC
Confederation of UK Coal Producers
Yorkshire Coal Task Force
Coalfield Communities Campaign
Drax Power Limited
British Energy PLC, Eggborough
UK Quality Ash Association
Five companies involved in purchasing, marketing and selling power station by-products (PFA and FBA)
Each of the local councils in Yorkshire and Humber

Executive Summary

The Yorkshire and Humber Region is an important producer of electricity for the United Kingdom. The region produces 16.3% of the nation's electricity but in comparison has only 8.3% of the national workforce and accounts for only 7.4% of the Gross Value Added in the national economy.

In 2003 Yorkshire and Humber produced 33% of the coal mined in the UK. In 2004, after pit closures at Selby, this will go down to 22%.

Almost all of the electricity generated in the region is produced with coal or gas. In 2002 Yorkshire and Humber produced 26.2% of the country's coal-fired power and 19.0% of the gas-fired power.

Electricity generation is an important contributor to the regional economy. 57% of the power generated in the region is exported and 43% is consumed locally.

There are three large coal-fired power stations (Drax, Eggborough and Ferrybridge) and 7 smaller gas-fired stations in the region. Drax, is the largest coal-fired power station in Europe and one of the largest in the world.

Drax is an independent non-portfolio generator owned by Drax Power Ltd. The company was owned by AES but following the collapse of TXU Europe in 2001, with which Drax had a long term supply contract, the company was placed in administration and in July 2003 AES withdrew support. In the past Drax has purchased 98% of its coal from British Coal, supplied primarily by Selby.

In 2001-2002 British Energy, owner of Eggborough power station, suffered a financial crisis due to high operating costs in its nuclear stations, the unprecedented falling price of electricity and two unplanned outages. The company reported a loss of £4,292 million for the year ending March 2002. Eggborough has bought 25% of its coal requirement from British producers and 75% is imported.

Ferrybridge, together with the Fiddler's Ferry 2 MW coal-fired station in Warrington is owned by American Electric Power (AEP). The two stations were purchased in December 2001 from Edison Mission Energy for £650 million. The company has suffered loses due to the falling price of electricity and the chairman of AEP has announced the intention to sell the two stations before the end of 2004 if a buyer can be found.

No formal life expectancy for the three stations has been stated but we have been advised by an expert in the regional industry that the stations have been well maintained and over the years much equipment has been replaced. The three power stations should have a life of 16-20 years.

The EU has three directives that will have a crucial impact on the future of the coal industry and the coal-fired power stations.

LCPD - Large Combustion Plant Directive, with targets for reduction of emissions of sulphur dioxide - SO_2, nitrogen oxides - NOx and particulates or dust. A total emissions "bubble" for the country has been established separately for each pollutant, with the annual permissible emissions and reductions in stages. For SO_2 the reductions are phased over two stages, from 2008 to 2015 and for 2016 onwards. For NOx a third stage is added from 2018 onwards. Two methods of measuring the reduction have been proposed; ELVs (Emission Limit Values) are limits to levels of concentrations of emissions not to be exceeded at any time; NERP (National Emission Reduction Plan) is based on an annual allocation of emissions not to be exceeded by the end of the year. There is much disagreement in the industry between these two options and a final decision is awaited from the government.

Sulphur emissions can be reduced either by burning low sulphur coal or by installing flue gas desulphurisation (FGD) equipment. In Yorkshire and Humber 5 GW already has FGD equipment under construction out of 8 GW total generating capacity. This amounts to one half of the already committed installation of FGD generating capacity in the entire country. Drax has 100% GFD retrofitted, Eggborough 50% and Ferrybridge none.

If a national plan is implemented, another option for coal-fired power stations to meet LCPD targets is to run at very low load factors, thereby burning less coal.

The important factor for the UK coal industry is that British coal has a high sulphur content, with the exception of coal from the Selby mining Complex which is closing in 2004 and some Scottish opencast mines. To remain within the LCPD SO_2 emissions limits, however measured, power stations without FGD equipment installed will have to use imported low sulphur coal. Stations with FGD equipment will be able to use British coal.

NOx emissions can be controlled with a variety of separate technologies to achieve the first set of limits from 2008 to 2015. To achieve the demanding target set for 2016 and the even more demanding target applicable from 2018, expensive SCR equipment will have to be installed.

Particulates or dust are already controlled with electrostatic precipitators.

Power generators have the option of meeting these standards or choosing to opt-out after 20,000 hours of operation. The later decision is not final, they can opt back in, but with even higher emissions limits.

The ETS - Emissions Trading Directive covers emissions of carbon dioxide. However there is scope within the Directive for the scheme to be expanded in the future to other activities and gases. A carbon allowance will be assigned to each operator, with a penalty of €40 per tonne of carbon for each tonne exceeded from 2005 to 2008, going up to €100 per tonne of carbon after 2008. The ETS Directive only covers generators over 20 MW capacity. To reduce the carbon output generators have to improve their generating efficiency, thus burning less coal for the same output of electricity. This can be achieved by switching to gas which emits less carbon and has more efficient generating technology, or by changing to expensive supercritical technology which burns coal at higher temperatures and higher steam pressures.

In the short term, the main tool in keeping within the carbon allowance is commercial, the buying and selling of carbon credits. At this stage no one knows how effective or liquid the market will be. Four other European countries have higher reliance on coal than the UK and three have nearly as much dependence. Many of these countries have an increasing demand for power. There may be limited liquidity of carbon credits. If this is the case, they will be expensive, if available, and power generators will have to balance the cost of buying them against operating costs and the price of electricity in the power market.

Co-firing coal with biomass is an option already being adopted and tested in the coal-fired plants to reduce CO_2 emissions.

A long term technical solution is carbon sequestration, whereby CO_2 is captured and piped to the North Sea, and injected into the oil reservoirs to lengthen the life of the UK oil fields. This is unlikely to be viable for another ten years and may raise environmental disagreements with North Sea neighbouring countries.

Under the IPPC, Integrated Pollution Prevention & Control Directive, operators have to apply best available techniques (BAT) to minimise environmental impacts.

The net result will be high imports of low sulphur coal and an increasing switch towards gas. The contribution of coal to power generation is predicted to fall from 71% in 1980 to 34% by 2000 and 21% by 2008. The share of gas will increase from its present level of 39% to 50% in 2011. Since British gas is running out, the UK will become a large scale importer of both coal and gas, both piped natural gas and LNG (liquefied natural gas).

This presents risks of interrupted supply because of inadequate infrastructure, political actions and more recently, terrorism. The UK is seriously deficient in gas storage capacity because when we had plentiful supplies from the North Sea we could use the gas fields themselves as gas storage facilities, by simply turning the tap on when needed. The UK only has storage for 4% of annual consumption compared with 20% in Germany. Substantial investment is currently going into import and transportation facilities both for piped gas and LNG.

In comparison, coal transport is better catered for and in 2004 will operate below the high level of 2002.

Some of the coal produced in Yorkshire and Humber is exported outside the region and the power stations in Yorkshire and Humber import some coal from other parts of the country and from abroad.

Using conservative estimate, the reserves of coal in deep mines in the UK including Reserve and Resource will last for 12 years at the rate of extraction estimated for 2004, which is 13.1 million tonnes.

Four deep mines remain in operation in the Yorkshire and Humber Region; Kellingley, Maltby, Rossington and the much smaller Hayroyds. The life expectancy of Kellingley Colliery is 22 years, Maltby Colliery 8 years, Rossington Colliery 12 years and Hayroyds Colliery 7 years. Annual deep mine production will be around 14 million tons in 2004.

We do not have a figure for reserves of opencast mines but estimate production at 11.6 million tonnes in 2004, and declining at an average of 3.7% a year thereafter.

Production of coal in the UK has declined from 53 million tonnes in 1995 to less than half that level, an estimated 25.5 million tonnes in 2004.

84% of coal consumed in the UK is burned in the power stations, amounting to 53 million tonnes in 2003 out of a total demand of 63 million tonnes.

The coal burn is forecast at 47 million tonnes in 2004, equal to 2002 but some 11% lower than the peak in 2003.

The UK coal-fired power stations will have a minimum of 10 GW of FGD installed capacity, a probable 12-13 GW and a possible 15.6 GW, requiring a coal burn between 18 million and 28 million tonnes at a load factor of 50%. This is the generating market for UK coal and would be higher if the load factor is increased. In 2003 10 million tonnes of coal was consumed in the non-generating sector. With a good level of FGD installations and sustained demand outside the power sector, total demand for British coal could be well above forecast UK production. The final outcome will depend on a number of other factors such as the price of carbon in the ETS.

In December 2003 the Coal Authority recorded a workforce of 3,344 in the deep and opencast mines in the Yorkshire and Humber region. With the closure of the Prince of Wales Colliery, Hatfield, Selby Complex and five opencast mines, employment will be reduced to 1,531 by the end of 2004.

It is worth pointing out that Hatfield Colliery in Doncaster, where the workforce was made redundant at the end of January 2004, has been left in a condition in which it could be re-entered if the remaining reserves became commercially attractive.

Closures started at Selby Complex in 2003 and at the start of the closures, the direct work force employed at Selby, including all office and other non-miner staff totalled 2,071. An additional 1,929 jobs are dependent on Selby in the surrounding communities. These include those working in supply chain businesses for the mines and in businesses providing goods and services to the employees of Selby.

The Prince of Wales Colliery did not support such a large indirect dependent employee workforce, perhaps because it was smaller and less dominant in the community. The indirect workforce of the supply chain and workers in businesses supplying goods and services to the employees of Prince of Wales amounts to 390. In total just under 5,000 direct and indirect jobs depend on these two mines.

A feature of the mining workforce in Yorkshire and Humber is its dispersion and the quite long commuter journeys that miners make to work. A substantial proportion of miners working at Selby opted to remain in their communities and not to move nearer to the mine. This will have the effect of reducing the local impact of the closures around Selby somewhat, although it will still be serious.

870 of the Selby workforce live in Wakefield, which is already suffering from the closure of the Prince of Wales Colliery in August 2002. Wakefield and Barnsley also have pockets with small communities which are suffering deprivation and are still recovering from the closures of the 1980s and 1990s. There will be losses in Barnsley, Doncaster and Leeds resulting from the Selby closure.

660 companies based in Yorkshire and Humber have been identified as direct suppliers to the Selby Complex. Between 10% and 25% of their total order value consists of purchases of products and services from UK Coal PLC.

Employment across the Yorkshire and Humber region is variable, in some cases well under the national average and in other LADs higher. Although overall employment in Selby is buoyant, unemployment is high in the central wards, with 9.4% in Selby Central and the district has not been gaining new jobs. Of particular concern are the levels of unemployment among men in Wakefield at 4.9% and in Barnsley at 6.6%.

The economic loss to regional output from the closure of Selby is calculated at an initial amount of £94 million rising to £150 million and possibly £165 million by 2011. This includes the effects on the supply chain as well as direct effects. If the initial impact recycles in the economy with no regeneration and no alternative employment is generated, supply chain industries could lose £100 million a year by 2011.

Losses of jobs, direct and indirect resulting from closures of any of the three remaining deep mines will range from 770 to 1,200 (rounded figures) and losses on output ranging from £34 million to £52 million. If there are any more closures, it is unlikely that more than one mine would close at a time, so we should not be looking at a cumulative figure.

Employment losses at the three coal-fired power stations would range from 380 at Ferrybridge to 910 (rounded) at Drax, including direct and indirect employment. The loss to output would range from £17 million to £40 million.

The Selby workforce is predominantly male, with an average age of 43 years, and 24 years experience in the mines. This analysis is important because it shows the extent to which redundant miners are dependent on the mines in terms of work experience and their community lives. The bulk of them have no experience of life outside the mining environment. They simply do not know what to do. They have no idea what jobs are available or what they can do.

They have been quite highly paid, with an average income of £26-28,000. They are flexible about jobs and training but less so about income levels required. There will be an increase in two earner families with many wives and partners taking jobs, where before the family had been wholly reliant on one main earner. The lower levels of unemployment among women will be a distinct advantage in this respect.

Two factors were picked out as improvements on past experience of closures. The 18 months notice of the Selby closures has helped considerably and improved retraining facilities.

A quarter of the redundant miners will seek redeployment within the industry and 70% will seek jobs elsewhere. 4% will retire or will have to retire for health reasons. They perceive two broad areas to be attractive to them, driving related occupations such as; HGV and fork-lift driving, work on railways and maintenance and construction; and construction trades, such as plumbing, gas fitting, or electrical work.

Experience shows that the full impact of redundancy can be delayed and that the worst time can be after 18 months to 2 years.

1. Electricity generation in Yorkshire and Humber

Background

The Yorkshire and Humber Region is an important producer of electricity for the United Kingdom. The region produces 16.3% of the nation's electricity but in comparison has only 8.3% of the workforce and accounts for only 7.4% of the Gross Value Added in the national economy. Almost all of the electricity generated in the region is produced with coal or gas. In 2002 Yorkshire and Humber produced 26.2% of the country's coal-fired power and 19.0% of the gas-fired power.

Table 1: Gross electricity generation and the Yorkshire and Humber Region, 2002

GWh	UK	Yorkshire and Humber	Yorkshire and Humber as a percentage of UK
Coal-fired power stations	128,334	33,593	26.2%
Gas-fired power stations	142,661	27,124	19.0%
Other	116,147	2,411	2.1%
Total electricity generated	387,142	63,128	16.3%

Source: DTI and Energy Forum Foundation Study Up-date

Electricity generation is an important contributor to the regional economy. 57% of the power generated in the region is exported and 43% is consumed locally.[1] There are three large coal-fired power stations (Drax, Eggborough and Ferrybridge) and 7 smaller gas-fired stations in the region. Drax, is the largest coal-fired power station in Europe and one of the largest in the world.

Table 2: Power stations net output in Yorkshire and Humber, 2002

Power stations	Fuel	Capacity	Electricity output
		MW	GWh
Drax	Coal	3,795	19,570
Eggborough	Coal	2,001	6,393
Ferrybridge	Coal	2,000	7,630
South Humber	Gas	1,275	6,890
Killingholme	Gas	620	2,620
Killingholme A	Gas	848	4,010
Keadby	Gas	690	4,230
Brigg	Gas	240	1,325
Salt End (BP)	Gas	1,200	8,046
Conoco Refinery *	Gas	730	
Total		13,399	60,714

Source: Energy Forum Foundation Study Up-date

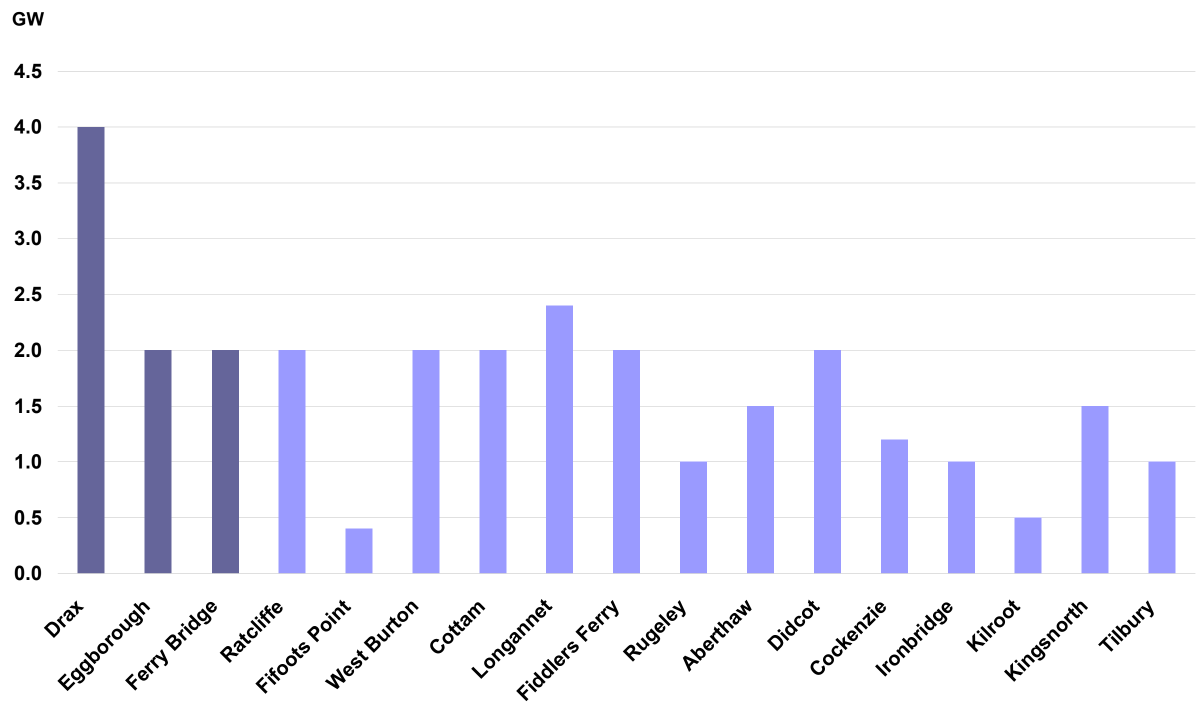
(* Due for completion in 2004)

The coal mines in Yorkshire and Humber currently produce enough coal for 87% of the requirements of the three coal-fired power stations in the region but for reasons which will be explained later some of the locally produced coal is exported outside the region and the regional power stations import some coal from other parts of the country and abroad.[2]

The coal-fired power stations in Yorkshire and Humber

Drax, Eggborough and Ferrybridge account for 10.2% of the total installed generating capacity in Britain and in 2002 they produced 8.7% of the electricity generated by all power stations and industry. There are 17 major coal-fired power stations in Britain with a total of 28.5 GW of generating capacity, out of which the three Yorkshire and Humber stations have 8 GW.[3]

Fig 1: Coal-fired power stations in Britain



Source: DTI

Industry structure and ownership of the power stations

In the last few years the electricity industry in Britain has been privatised and totally restructured. The industry consists of four sectors, all with different combinations of ownership and operating independently. Some of the world's major energy companies own companies in several of these sectors.

- Generators - the power stations are owned by investors or energy companies and compete with each other in a fully competitive market. An important category is "portfolio" generators, companies which own a portfolio of power stations using different fuels, enabling the company to switch from one fuel to another as fuel prices and supply fluctuate. Drax, Eggborough and Ferrybridge operate in this competitive sector of the industry.

- Transmission - one company, National Grid Transco, physically transmits the power via high voltage transmission lines from the power stations to the "load centres", the areas where the customers are located. Because the transmission company has a natural monopoly the regulator, Ofgem fixes the prices for transmission.

- Distribution - 9 authorised companies operate within 12 geographical areas, physically distributing the electricity to the customers. As with the transmission company they have natural monopolies within their areas and the prices are fixed by the regulator.

- Supply - licensed suppliers buy the electricity from the generators and sell it to the customers in a fully competitive market. These companies act as merchants, trading electricity and are not involved in the physical supply of electricity.[4]

There have been over 50 mergers and acquisitions of companies in the British electricity industry since privatisation. Following privatisation and market liberalisation, Britain was seen as an attractive country to invest in because of the free market and the absence of restrictions. A number of overseas investors came into the market, among them several major American energy groups. In 2001 there was a change in the method of trading electricity and NETA (New Electricity Trading Arrangements) was introduced. This resulted in a large fall in the wholesale price of electricity and a number of electricity generators, principally coal-fired, were unable to cover their costs. Some mothballed plant and others went into administration. Many power stations were offered for sale. The current state of ownership of coal-fired stations in Britain is as follows.

Table 3: Ownership of coal-fired power stations in Britain, 2004

	Capacity GW	Owner
Yorkshire and Humber		
Drax	4.0	DraxPower
Eggborough	2.0	British Energy
Ferry Bridge	2.0	AEP
Extra-regional		
Ratcliffe	2.0	Powergen
Fifoots Point	0.4	AES
West Burton	2.0	EdF
Cottam	2.0	EdF
Longannet	2.4	Scottish Power
Fiddlers Ferry	2.0	AEP
Rugeley	1.0	International Power
Aberthaw	1.5	Innogy
Didcot	2.0	Innogy
Cockenzie	1.2	Scottish Power
Ironbridge	1.0	Powergen
Kilroot	0.5	AES
Kingsnorth	1.5	Powergen
Tilbury	1.0	Innogy

Source: DTI

Power stations in Yorkshire and Humber

Drax

Drax is an independent non-portfolio generator owned by Drax Power Ltd. The company was owned by AES but following the collapse of TXU Europe in 2001, with which Drax had a long term supply contract, the company was placed in administration. In July 2003 AES withdrew support. There have been several offers of acquisition to the creditors in the last year, from BHP Billiton, International Power and most recently from CGE Ltd.

The draft balance sheet at December 2003 shows tangible assets of £1,060 million and current assets of £183 million. After deducting £62 million owed to creditors due in less than one year and long term debts of £1,935 million the company had a deficit of £775 million. The company plan anticipated a profit of £53 million in 2004 compared with a loss of £124.3 million in 2003, giving £70.2 million available for debt service. Although carrying a large amount of long term debt the company is solvent as a trading enterprise.[5]

Drax was commissioned in 1974 and currently has 480-500 employees.

Eggborough

In 2001-2002 British Energy suffered a financial crisis due to high operating costs in its nuclear stations, the unprecedented falling price of electricity and two unplanned outages. The company reported a loss of £4,292 million for the year ending March 2002, which included an exceptional item of £4,162 million, consisting of £3,738 million of write-down of nuclear assets. The company is implementing a restructuring plan and the government has provided a credit facility of £650 million. Trading results are positive.[6]

Eggborough was commissioned in 1967 and has 250 employees.

Ferrybridge

Ferrybridge, together with the Fiddler's Ferry 2 MW coal-fired station in Warrington is owned by American Electric Power (AEP). The two stations were purchased in December 2001 from Edison Mission Energy for £650 million. The company has suffered loses due to the falling price of electricity and the chairman of AEP has announced the intention to sell the two stations before the end of 2004 if a buyer can be found.[7]

Ferrybridge was commissioned in 1966 and has 200 employees.

Life expectancy for the three coal-fired power stations

No formal life expectancy for the three stations has been stated but we have been advised by an expert in the regional industry that the stations have been well maintained and over the years much equipment has been replaced. Theoretically coal-fired stations can be kept going indefinitely with good maintenance although this becomes increasingly expensive. The fact that Drax and Eggborough have had flue gas desulphurisation equipment installed at considerable cost confirms this view. One of the power station managers gave an informal opinion of 16-20 years.[8]

Coal mine methane (CMM)

Coal Mine Methane is a waste gas consisting of 70% methane, 15% nitrogen and 15% CO_2, which escapes from operating and abandoned mines. The DTI lets Petroleum Exploration and Development Licences (PEDLs) to developers who wish to extract and use the CMM.[9] The potential CMM generating capacity for the region is estimated at 100-150 MW [10] and seven PEDLs had been issued by February 2004 in the Yorkshire and Humber region.

Alkane Energy currently has two sites using CMM in the region, Whaledale (a dual fuel joint-venture with Scottish and Southern Energy) which runs on CMM and natural gas and Rexam Glassworks, which uses methane to produce process heat only.

A 5 MW CMM site at Hickleton near South Kirkby, operated by Octagon Energy, is in receivership and the status of the scheme is not known.

The two plants at Whaledale and Rexam captured CMM equivalent to 200,000 tonnes of CO_2 in 2003.

2. The environmental legislation of the EU

Over the last thirty years, the EU has enacted a wide series of environmental directives. These cover water and waste, land contamination, solid and dangerous waste and air pollution. The air pollution directives affect the future of coal burning industries, especially coal-fire power generation. Three directives affect coal-fired generators.

1. **LCPD - Large Combustion Plant Directive**
   The LCPD places limits on the emissions of sulphur dioxide - SO_2, nitrogen oxides - NOx and particulates or dust.

2. **ETS - Emissions Trading Directive**
   For the first phase of the scheme (2005-2007) it will cover emissions of carbon dioxide only. However there is scope within the Directive for the scheme to be expanded in the future to other activities and gases.

3. **IPPC - Integrated Pollution Prevention & Control Directive**
   Under the IPPC Directive, operators have to apply best available techniques (BAT) to minimise environmental impacts.

LCPD - Large Combustion Plant Directive

The LCPD places limits on the emissions of three pollutants from the combustion of coal, oil and natural gas.

- Sulphur dioxide- SO_2
- Nitrogen oxides - NOx
- Particulates or dust

A national emissions reduction plan has been drawn up, applying only to existing plants rated 50 MW or higher. Plants can opt out by electing to close after 20,000 operational hours. This option must be declared by 30 June 2004 and no plant in the UK has yet done so. They can elect to come back in after opting out, but will have more stringent emissions targets applied. The LCPD will be effective in several stages, the first running from 2008 to 2016 and at different intervals for the three emissions thereafter.

The national plan has established a total emissions “bubble” separately for each pollutant. When the relevant legislation comes into force the sum of the emissions of each pollutant from all combustion plants must be less than or equal to the size of the relevant bubble for each year of operation of the plan.

Table 4: The size of the emissions bubbles and reductions for the UK as determined in the National Plan

Parameter	Compliance period	SO2		NOX		Dust	
		Annual	Cumulative		Cumulative		Cumulative
		Tonnes	%	Tonnes	%	Tonnes	%
Annual emissions in 2001		805,680		356,059		21,749	
Annual emissions bubble	1 Jan 2008 - 31 Dec 2015	263,437		267,204		24,856	
	1 Jan 2016 - 31 Dec 2017	263,438		150,643		24,857	
	1 Jan 2018 onwards	263,439		133,712		24,858	
Minimum annual emissions reduction compared with 2001	1 Jan 2008 - 31 Dec 2015	541,474	67%	88,856	25%	-3,063	-14%
	1 Jan 2016 - 31 Dec 2017	541,474	67%	205,417	58%	-3,063	-14%
	1 Jan 2018 onwards	541,474	67%	222,348	62%	-3,063	-14%

Source: National Plan

Two methods have been proposed to achieve these reductions. They are in the consultation process now and are the subject of vigorous lobbying by the interested parties. The government has provisionally decided on the second method but a final decision is awaited.

Emission Limit Values (ELV) - A limit on the concentration of a pollutant is set and must not be exceeded at any time. Provided a generator has installed the appropriate measures to keep emissions below these limits at all times there is no restriction on the coal burn. In this case the government would have to ensure that the national sulphur ceiling is met because simply meeting ELVs cannot guarantee this if the coal burn were to rise substantially.

National Emission Reduction Plan (NERP) - Member states may implement a national plan based on average emissions over the five years from 1996-2000 from plants operating in 2000, providing that annual emissions fall to the level they would have done had ELVs been applied during the 5 year period. The annual caps for emissions are set for each generator and must not be exceeded by the end of the year. The concern within the coal industry and among generators is that, in the early half of the year generators will be reticent to use up their allowance.[11]

The technology and other abatement measures for each pollutant specified in the LCPD

Sulphur dioxide - SO_2

All coal contains sulphur, which turns into sulphur dioxide (SO_2) when the coal is burnt. SO_2 is a noxious gas which can cause breathing difficulties and turns into “acid rain”. The sulphur issue is a particularly important issue for British coal because much of it has a higher sulphur content than most imported coals. UK Coal advised that the average sulphur content of most British coal is 1.7%. The Selby deep mines and some open-cast mines in Scotland produce coal with lower sulphur content, averaging about 1.2%. Imports from Russia, Columbia, South Africa and Indonesia average a sulphur content under 1%, and in some cases well under this level.

There are three ways of reducing sulphur emissions; reducing the coal burn, burning low sulphur coal and/or installing flue gas desulphurisation (FGD) equipment, also called "wet scrubbing". FGD can remove approximately 90% of sulphur emissions. FGD is expensive but, like all technology, it is coming down in price and we were given estimates in the range of £80-£100 million per GW to install at a typical coal-fired power station.[12] FGD is also expensive to operate, the main cost being the need for limestone, water and electricity. However, this is partly off-set by selling the gypsum, a by-product of the process, which is used in the manufacture of plasterboard.

10 GW of FGD is installed or under construction in the 17 coal-fired power stations in the UK. Consent has been granted or applied for in a further 5.6 GW of FGD capacity. The probable outcome will be between 12-13 GW of FGD by 2008.[13]

The power stations in Yorkshire and Humber will have an above average incidence of FGD installation with 5 GW (4GW Drax and 1 GW Eggborough (50% of the country's certain FGD capacity compared with 21% of total coal-fired generating capacity), coming online in September 2004) out of 8GW total capacity and a possible further 1-3 GW in Eggborough and Ferrybridge.

Table 5: Status of FGD installations in the UK coal-fired power stations, March 2004

	Capacity GW	Potential FGD capacity GW		FGD status
Drax	4.0	4.0	DraxPower	Operational
Eggborough	2.0	1.0	British Energy	Under construction
Ferry Bridge	2.0	1.0	AEP	S36 consent granted
Ratcliffe	2.0	2.0	Powergen	Operational
Fifoots Point	0.4	0.4	AES	Has FGD but in administration
West Burton	2.0	2.0	EdF	Commissioning
Cottam	2.0	1.0	EdF	Under construction, consent for further 1 GW
Longannet	2.4	1.2	Scottish Power	Call for tender published
Fiddlers Ferry	2.0	0.5	AEP	Applied for consent
Rugeley	1.0	1.0	International Power	Applied for consent, unlikely
Aberthaw	1.5	1.5	Innogy	Applied for consent, favoured position on grid
Didcot	2.0		Innogy	ni
Cockenzie	1.2		Scottish Power	Unlikely, too old
Ironbridge	1.0		Powergen	No
Kilroot	0.5		AES	Applied for consent
Kingsnorth	1.5		Powergen	Applied for consent
Tilbury	1.0		Innogy	Doubtful
	28.5	15.6		

Source: Confederation of UK Coal Producers

Nitrogen oxides - NOx

Nitrogen oxide emissions contribute to the formation of ozone and photo chemical smog. Limits on emissions affect British and imported coal equally. For example, South African and Indonesian coal are higher volatile than indigenous coal, potentially causing greater NOx problems. Volatile matter is a major contributor to production of nitrous oxide.

Whichever method of allocation is chosen, under the terms of the LCPD, each of the Yorkshire and Humber coal-fired power stations will have to reduce its current level of NOx emissions from its current level, around 650 mg/m_3 to 500 mg/m_3 between 2008-2015 and 200 mg/m_3 from 2008 to in 2016, a reduction of 25% in 2008 rising to 58% in 2016. In our discussions with power station managers the first level of reduction was regarded as “manageable” and the second as “very demanding”.

A number of measures can be instituted to reduce NOx emissions partially. Most of these, such as low-NOx burners achieve reductions of 20% to 50%. Some of these are relatively inexpensive and can be considered as the starting point in a NOx reduction programme. However, they will not meet the reduction targets set for the final stage of the LCPD to be met in 2016, which is less that 30% of current emissions. Only one technology, with two variants, will achieve NOx reductions adequate to meet this target and these are selective non-catalytic reduction (SCNR) and selective catalytic reduction (SCR). SCNR can achieve reductions of 50-70% and SCR 80-90%. The capital cost of SNCR is £7 to £15 million per GW and SCR £15 to £30 million per GW. In Germany and Austria SCR technology has been fitted to all their coal-fired plant achieving 80% NOx reductions.[14]

It is not possible to address the reduction of emissions by buying the right coal, the only solution is to fit the technology.

Drax, Eggborough and Ferrybridge have low NOx burners and where necessary are up-grading to a level sufficient for the fist reduction level in 2008.

Particulate matter/dust

Particulates or dust are produced when coal is burned. These can be removed by using electrostatic precipitators or baghouses which are used to remove fly ash. In electrostatic precipitators, the particulate matter is given an electrical charge. The charge attracts it to a collector plate, where the particles are collected, preventing their discharge into the atmosphere. In a baghouse, the particulate matter is filtered out as it passes through a series of filters, similar to a household vacuum cleaner. UK coal-fired power stations are fitted with these technologies.

All three coal-fired power stations in Yorkshire and Humber have precipitators in place.

ETS Emissions Trading Directive

Trading in carbon emissions has been taking place for several years in Europe on an informal basis but has recently been almost at a standstill because of uncertainty about the future. The UK was the first country to establish an emissions trading scheme. Denmark also operates a scheme.

The ETS was adopted in October 2003 and each country is responsible for formulating a National Allocation Plan, which outlines how it will allocate emission allowances to participating installations.

The EU has decided not to allow caps above business as usual levels, which can increase or decline, and has set a target of reducing carbon emissions by 12.5% on their 1990 level in the period 2008-2012.

The UK government has opted to exceed this level and has set targets of a 16.3% reduction by January 1, 2010 and 20% from 2012. Other European countries are understood to be setting caps at business as usual levels.

The EU Directive will be effective on 1 January, 2005 with the first stage running for three years to the end of 2007, followed by a 2008-2012 second period. A mandatory CO_2 cap and trade system will apply, in which sources are allocated a certain number of emission "allowances", based on historic performance and other parameters. Participants reducing emissions below their cap can sell the resulting excess allowances. The EU programme covers 12,000 – 15,000 sources such as; utilities, refineries, cement, glass and ceramics production facilities, the pulp and paper industries, combustion installations with a rated thermal input exceeding 20 MW (excepting hazardous or municipal waste installations), mineral oil refineries and coke ovens.

The new EU carbon trade market could reach 90 million tonnes and be worth as much as €1.8 billion a year by 2012.[15] In April 2003 the price was €5 per EUA (EU Allowance) rising to €12.40 in late December and declining to €7.40 by April 2004.

In its first year of operation the UK's own voluntary emissions trading scheme was relatively quiet, although some of those companies that did get involved made profits. The scheme was kick started with £215 million. Prices had risen steadily from £5 per tonne of carbon dioxide equivalent to a high of £12.50 in the first six months, before slumping as a result of oversupply in the second six months, to around £3. In some cases much larger gains were made by companies trading their carbon allowances via an auction process.

Emissions trading allocation plans were scheduled to be submitted on March 31 2004, with approval by the Commission later in the year. In the plans, each country in the EU submits an allocation of emission allowances to different industries. Only five countries met the March 31 deadline. These are the National Allocation Plans, a key part of the EU's emission trading scheme, ETS. The allocations will determine which companies have carbon credits, the financial incentives for meeting or exceeding emissions targets. These will be a potential revenue stream. Companies not meeting the targets will have to buy credits, adding to their costs. The allocations will run from January 1, 2005 for three years. New allocations will be set with effect from January 1, 2008 for a further three years.

Carbon emission prices have remained at about €13 a tonne of CO_2 in 2004, which is double the price of last year.[16] This price is comfortably below the EU penalty charge for exceeding the allocation, at €40 per tonne for the first three year period. The penalty rises to €100 a tonne in the second three year period. If the carbon price were to rise above the penalty charge this would distort the market because it would be cheaper to pay the penalty than to buy emissions credits.

The major brokers have already set up emissions trading arms and believe that emissions trading will become an important business.

The British coal generation industry has been provisionally allocated an allowance for a coal burn of 38 million tonnes. The actual coal burn in 2003 reached 53 million tonnes and 47 million tonnes in 2004.

The technology and other abatement measures for carbon dioxide - CO_2

Unlike SO_2 and NOx there is no cleaning technology to reduce carbon emissions but there are other measures which can be taken to deal with carbon production, both financial and operational, each making a contribution to the reduction of carbon emissions.

The carbon produced depends on the amount of coal burned, the first and most obvious solution is to reduce the coal burn. This can be achieved in three ways; either by reducing electricity supply contracts, by increasing the efficiency of the production of electricity from coal, or by switching to another less carbon intensive fuel, the most likely alternative being natural gas.

Reducing the supply contracts defeats one of the important purposes of having coal-fired power stations, which is to preserve security of supply with diverse energy sources.

Nuclear generation is a long term option but it takes a long time to build more nuclear plants and the government has not yet taken a policy decision on the future of nuclear supply.

A critical feature of most renewables is that they are energy sources and not fuels. The difference lies in availability. Fuels are always available for use when required, albeit at a price determined by the market. Energy sources are usually intermittent, but are free. Renewables will contribute to low carbon electricity production but most forms of renewable energy do not produce base load power. Base load is the amount of electricity required to meet normal minimum demands and it has to be available when required, as coal-fired power is. Some renewable energy, such as wind power is erratic and cannot be relied upon to be available all the time. The three Yorkshire and Humber coal-fired power stations are already co-firing biomass, a fuel which does not produce carbon. From 1% to 5% of the fuel mix is biomass, such as palm kernels from Malaysia, olive residue, willow, grasses etc. The power stations are currently conducting co-firing trials with these energy sources. Although the percentages of biomass used are small, Drax burns 1,500 tonnes of coal an hour, so 3% to 5% of that burn constitutes quite a large amount of carbon free energy. Ferrybridge is licensed to burn biomass equivalent to 12% by weight.

In the short term renewables, primarily wind power and biomass in Yorkshire and Humber, offer a valuable additional source of clean power in the mix but they do not offer a viable contribution to baseload generation.

Burning gas is an option in carbon reduction for two reasons. Firstly it contains less carbon than coal so it emits less CO_2. Secondly it can produce electricity more efficiently than coal. A conventional coal-fired station typically has a thermal efficiency of about 35%. In other words, the output of energy (electricity) is equal to 35% of the input of energy (coal), the remaining 65% being consumed or lost in the process of converting the energy from coal to electricity. Drax is one of the most efficient coal-fired stations in the country with thermal efficiency of 39%.[17] In comparison, the most modern type of gas plant, a combined cycle gas turbine (CCGT) fitted with an HSRG (a hot steam recovery generator, which uses the steam otherwise wasted from the first gas turbine generation) can reach thermal efficiencies of 55% and higher. With both of these two advantages, a CCGT plant can produce electricity with 40% less carbon than a conventional coal-fired station, for the same energy input.

Another long-term option is to increase the efficiency of coal-fired generation using super-critical technology, which burns coal at very high temperatures. This can raise thermal efficiency from 35-39% to 44-46%. Sub-critical steam cycle has been used in Europe since the 1950s with steam pressures and temperatures of 180 bar and 570^{o} C. Plants built in the 1970s and 1980s use higher steam pressures and temperatures, 240 bar and 590^o C, with thermal efficiency up to 41-42%. Even higher pressures and temperatures are now being tested and achieve efficiencies of 44-46%. This technology is expensive and there are still technical problems to be overcome.

An increase in efficiency can also be achieved in the delivery of electricity to customers. After leaving the generating plant, the electricity is transported via high voltage transmission lines to the point of distribution, where the voltage is stepped down and delivered through a distribution system to the consumer. It is similar to other commercial commodities, which are transported in large containers from the factory, and repackaged into smaller containers for sale to the consumer. During the journey from the power station to the consumer losses occur, which in the UK system amount to 9%. A trend which is rapidly gaining ground is for “distributed generation” or “embedded generation”. Instead of having all the electricity generated in large plants at a distance from the consumer, it is generated in small plants located near to the consumer. It then goes straight into the distribution system, without going through the long distance transmission grid. A switch to distributed generation cuts out the losses incurred in transmission, thereby reducing the amount of input energy required to deliver a given amount of electricity to the end-consumer. The inputs to a distributed generation system can come from any source, such as small stand-alone gas turbines and renewables. Such networks could be established close to the large coal-fired power stations.

Carbon sequestration

Carbon sequestration, or carbon capture and storage (CCS), is a method of capturing carbon from fossil energy systems and the provision of long-term storage of carbon in the terrestrial biosphere, underground, or in the oceans so that the build-up of carbon dioxide concentration in the atmosphere will reduce or be slowed down. In some cases, this is accomplished by maintaining or enhancing natural processes; in other cases, novel techniques are developed to dispose of carbon in underground geologic repositories or at sea.[18]

Carbon “sinks” offer one method of sequestering carbon. An example of this is a scheme in which Australia is planting 8,250 hectares of genetically improved forests, modified to absorb more carbon dioxide from the atmosphere, in Vietnam. The forests will be planted over a period of five years and are expected to absorb an extra 21,500 tonnes of carbon dioxide annually owing to a 15% increase in the volume of wood. Vietnam will sell carbon credits to Australia.

There are three generic process routes for capturing CO_2 from fossil fuel combustion plant:

- post-combustion capture
- pre-combustion capture
- oxyfuel combustion.

Each of these processes involves the separation of CO_2 from a gas stream. There are five main technologies available for doing this, with the choice depending on the state (i.e. concentration, pressure, volume) of the CO_2 to be captured:

- chemical solvent scrubbing
- physical solvent scrubbing
- adsorption/desorption
- membrane separation
- cryogenic separation.

Post-combustion capture involves the separation of CO_2 from flue gas. The preferred technique at present is to scrub the flue gas with a chemical solvent (usually an amine), which reacts to form a compound with the CO_2. The solvent is then heated to break down the compound and release the solvent and high purity CO_2. With current processes a large amount of energy is needed to regenerate the solvent and to compress the CO_2 for transport, which significantly reduces the net electricity output of the plant.

Pre-combustion capture involves reacting fuel with oxygen or air, and in some cases steam, to produce a gas consisting mainly of carbon monoxide and hydrogen. The carbon monoxide is then reacted with steam in a catalytic shift converter to produce more hydrogen and CO_2. The CO_2 is then separated and the hydrogen is used as fuel in a gas turbine combined cycle plant. The process can be applied to natural gas, oil or coal.

Oxyfuel combustion involves burning fuel in an oxygen/CO_2 mixture rather than air to produce a CO_2-rich flue gas.

All three of the above approaches could be applied to new plant or retrofitted to existing facilities.

While there are a number of examples of industrial applications involving separation and capture of CO_2, including some at utility-scale, there are no commercial installations using this technology in the electricity generation sector. The USA and Canada have plans to build a demonstration plant in the next few years. This suggests that this technology needs to be demonstrated satisfactorily before it can be considered to be commercially viable.

Options for carbon dioxide transport

CO_2 is stored and transported in gaseous, liquid or solid forms. Because the CO_2 captured from flue gases is in gaseous form and large capital investments would be needed to construct the cryogenic plant needed for liquefaction or solidification, transportation is also likely to be undertaken in the gas phase.

Bulk gaseous transport of CO_2 may be undertaken by tanker (road, rail or water) or by pipeline, but with the large volumes involved in a CCS scheme (10-30Mte CO_2 per year), pipeline transport is the only practicable option. Tanker transport may have a role in smaller demonstration projects of the order of 100-200kt of CO_2 per year.

Most experience of pipeline transport of CO_2 has been gained in the USA where the gas is used extensively for Enhanced Oil Recovery (EOR). This practical experience shows that CO_2 transport by pipeline is an established commercial technology and it has potential to increase the life of the UK oil reserves in the North Sea.

Options for carbon dioxide storage

Various methods have been proposed for storage or management of captured CO_2 including injection into geological formations, deposition into the water column on the deep ocean floor and conversion into solid minerals.

Geological storage requires permeable rock strata that provide space for the gas to be stored. These strata must be sealed by rock which is impermeable to CO_2. There are three main options for geological storage.

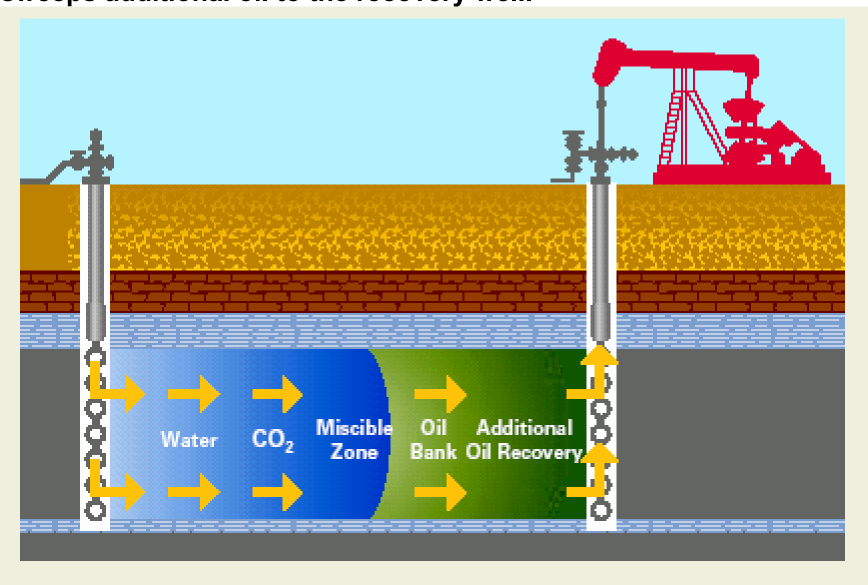
- Depleted or near depleted oil and gas reservoirs. This option may offer some financial return if the CO_2 can be injected as part of an EOR operation.
- Deep saline aquifers.
- Unmineable coal seams.

Enhanced Oil Recovery (EOR)

Enhanced Oil Recovery merits particular attention in the UK context because it represents an appreciable storage option for CO_2 while offering a financial return from the additional oil extracted from UK Continental Shelf reserves.

EOR may use CO_2 to mobilise some of the oil remaining in a reservoir after primary and secondary production is complete. It does this by dissolving in the oil thereby reducing the oil's effective viscosity and making it more mobile. The movement of the CO_2 from within the reservoir can then sweep the oil to the production wells. CO_2-based EOR is an established onshore procedure in North America but has not yet been undertaken offshore.

Fig 2: Carbon dioxide-Enhanced Oil Recovery with Water/Alternating Gas (WAG) injection sweeps additional oil to the recovery well.



Source: DTI/Courtesy of Kinder Morgan CO_2 Company L.P.

Environmental risks of carbon sequestration

CO_2 is in common use in a range of applications including fire extinguishers, refrigeration and carbonated drinks. However, it is an acidic gas with asphyxiant properties, and consequently its capture and storage does present finite risks to human health and safety and to the natural and built environments. These risks are mainly linked to the possibility of CO_2 release from either the engineered system (i.e. capture and transportation plant) or from the geological storage site.

In the longer term any risk from carbon sequestration will arise from releases of CO_2 from the geological storage site, which will be under pressure. This could take the form of a direct leak to the sea, possibly through the failure of a well closure, or slow migration either laterally or through the cap rock.

An example of EOR is the Norwegian Sleipner West gas field project, where 1million tonnes of CO_2 per year are separated from the well stream and re-injected under the seabed. This is therefore excluded from the Norwegian inventory of green house gases.

Carbon sequestration is not a fully economic proposition at present, even with the off-setting revenue from EOR. This position is not unique to the UK. Both the USA and Canada have put fiscal measures in place to support and encourage CO_2-based EOR including reduced production taxes and enhanced capital allowances. Moreover, the Sleipner CO_2 sequestration project currently underway in the Norwegian North Sea was encouraged by a carbon emissions tax.

Coal-fired power stations in Yorkshire and Humber - Overall assessment of the coal-fired power stations and LCPD

The opinions expressed by management in the coal-fired power station with whom we discussed the issue were that attainment of the allocated carbon targets will depend principally on whether the ETS market works. We formed the view that management of coal-fired power stations is faced with an extraordinarily complex task to achieve the optimum result when they have to operate within the constraints of the LCPD, the ETS and the IPPC. They acknowledged the difficulties and uncertainties they face but we were impressed with their measured optimism. It is clear that a number of decisions have yet to be made by participants in the industry. Of the three large coal-fired stations in the region, we were told that one has made a positive decision to carry on and the other two have not yet decided whether to continue and sign up to the LCPD to choose the option to opt-out after 20,000 operational hours. Eggborough has yet to decide whether to add another 1 GW of GFD capacity and Ferrybridge whether to add any at all.

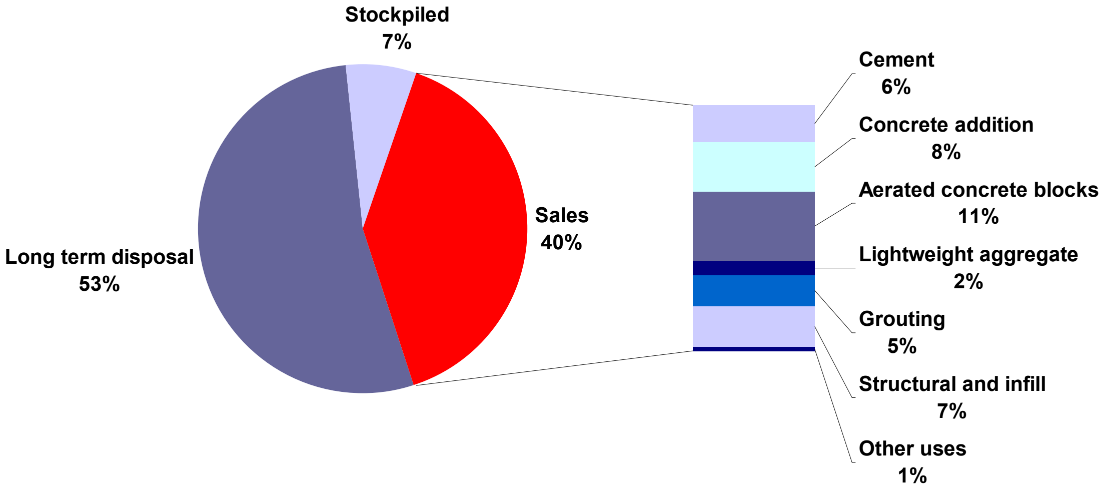
One consultee in the coal industry expressed the dilemma in terms of a “sulphur-carbon loop”. A generator may take a decision to make the investments necessary to meet the SO_2 and NO_X targets. However, if it becomes apparent that the carbon EUAs are not going to be available in the market to operate within his carbon allowance at a price low enough to ensure profitable operation, he may decide to reverse the decision on SO_2 and NO_X abatement equipment and cease operation.

3. Waste products from coal-fired power stations

When pulverised coal is burned in a coal fired power station the ash is carried out with the flue gases. These pass through electrostatic precipitators that remove the fine ash or PFA (pulverised fuel ash) from the flue gases. The PFA is collected in silos where it is either sold dry for use as an aggregate, in concrete, for concrete blocks, or moistened (called conditioning) in applications such as for fill, grouts, etc. Some stations may mix the ash with large quantities of water and pump the resulting slurry to lagoons. Eventually lagoon ash is allowed to drain and it is also sold for fill and grouting applications. FBA (furnace bottom ash) is molten ash that clings to the boiler tubes and falls into the bottom of the furnace.

The latest consolidated data for production of PFA by UK power stations was published in 2001 and is for the year 1997. This records production of 6,235,000 tonnes of PFA in 1997. The coal burn was 47.3 million tonnes in 1997, 47.3 million tonnes in 2002 and 53.3 million tonnes in 2003, so we may reasonably assume that production of PFA would have been about the same in 2002 as in 1997 and about 13% more in 2003.[19]

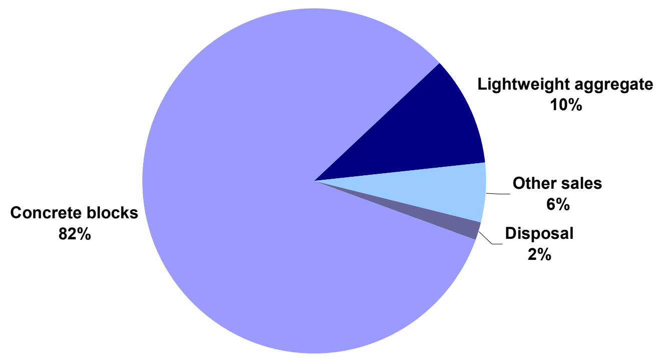
Fig 3: Disposal and sales of PFA in the UK, 1997 utilisation data



Source: UKQAA/European Coal Combustion Products Association

FBA is extracted wet in UK power stations. It is graded and sold to make lightweight concrete blocks. 1,160,000 tonnes of FBA was produced by the power stations in the UK in 1997 and by the same reasoning as for PFA we assume about the same production in 2002 and 13 % more in 2003. Almost all of the FBA produced in the UK is sold.[20]

Fig 4: Production and sales of FBA in the UK, 1997 utilisation data



Source: UKQAA/European Coal Combustion Products Association

We interviewed five of the major marketers of PFA, between them responsible for sales in 2003 of approximately 2.2 million tonnes of PFA, or 78% of the total 2.8 million tonnes estimated sold in 2003 in the UK. They bought all their PFA from the major coal-fired power stations, with the bulk coming from stations located as near as possible. All of the PFA marketers except one smaller one in the south named Drax and most named Eggborough and Ferrybridge as sources of supply. They were unanimous in reporting that if the power stations closed their business would cease. The nearest competitive products are sand or aggregate but there is no substitute for PFA.

4. Competition from other energy sources

The last twenty years have seen a dramatic change in the composition of energy sources for electricity generation in the UK.

In 1980 no less than 71% of the nation's electricity was generated from coal. By 2000 this had decreased to 31% but has increased to around 33% in 2003. The coal burn has enjoyed a resurgence in the last four years, from 41 million tonnes in 1999 to 53 million tonnes in 2008. UK Coal forecast a coal burn of 47 millions tonnes in 2004 and a steady decline to 39 million tonnes in 2008(including imported coal), when the new LCPD target date comes into force.[21]

Oil has followed suite with a decline from 13% to 2%.

Gas now has the largest share of the generation market with 39% in 2002. Hydro power and other renewables have grown from an aggregate of 3% to 5%.

The rapid rate of increase in nuclear generation in the 1980s tailed off in the 1990s but nuclear power still accounts for 21% of generation. Nuclear power is a proven technology which continuously generates electricity on a large scale with zero greenhouse gas emissions. The supply of uranium required for nuclear generation is reasonably plentiful and secure. Nuclear power stations in the UK were designed for base-load operation and, as a consequence, lack the flexibility of output that the UK's new electricity trading arrangements are designed to encourage. Alternative reactor types, as adopted in countries such as France, are more flexible and can respond, to a limited extent, to fluctuations in demand. British Energy has experience of operating the other types of reactors in countries such as Canada.

Since 1995, the Government's position on nuclear energy has been that the building of new nuclear power stations should be a commercial decision. Market conditions and other considerations, such as the potential environmental impact and public acceptability of nuclear power generation, have deterred companies from investing in new plant for more than 10 years and much existing nuclear plant has reached, or is approaching, the end of its useful life. Current events have increased concern over the vulnerability of nuclear installations to terrorist attack. In the absence of new capacity, nuclear power's share of electricity generating capacity is likely to decline from the current level of about 21% to possibly less than 17-18% by 2010 and to 7-8% by 2020.

The UK has not been at the forefront in developing renewables. The leading countries developing the so-called "new" renewables (i.e. excluding hydro power) are the USA, Japan, Germany, Denmark and Spain. The main renewables are biomass, geothermal, wind power, solar photovoltaic, and ocean energy. Renewables have made rapid growth in the last two to three years, principally wind, but as a non-baseload generator they still remain a small component in the secondary energy mix. The installed capacity of renewables in the Yorkshire and Humber region is only 21 MW compared with a total capacity of 13,369 MW of power generating capacity and 386 MW of CHP (combined heat and power), totalling 13,776 MW including all facilities.[22]

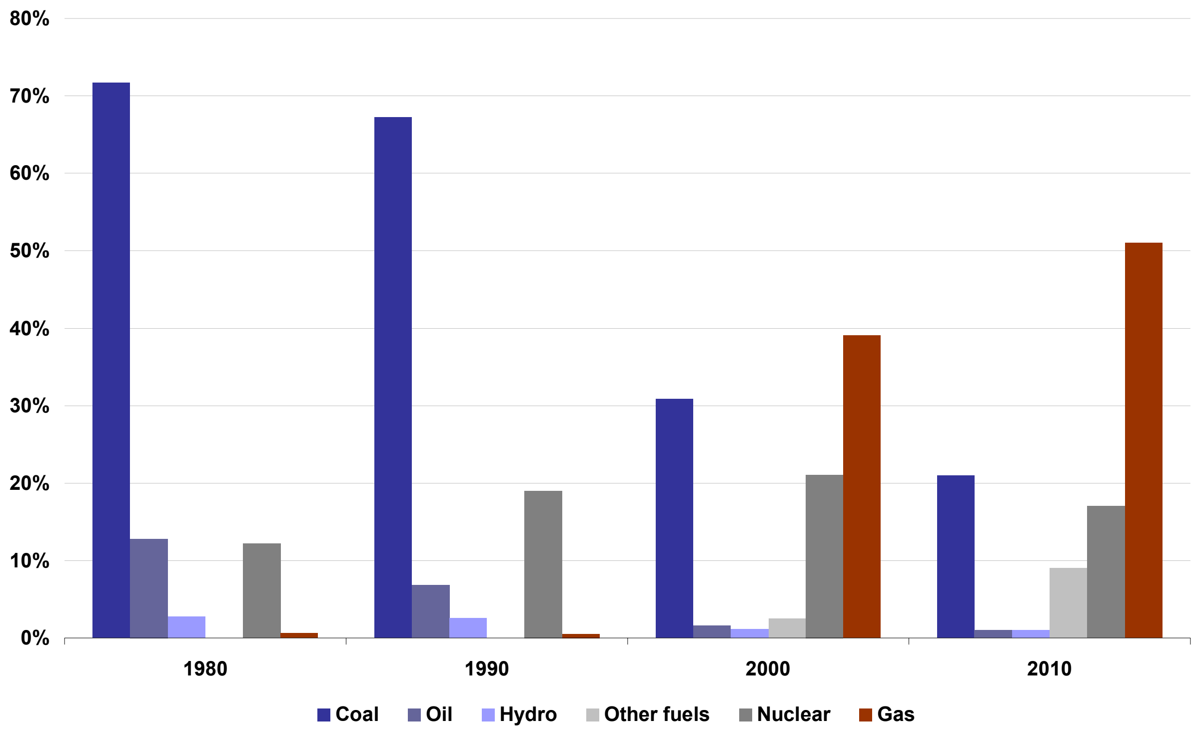
Energy demand growth

There is disagreement between forecasts of the rate of growth of primary energy demand and there are considerable uncertainties attached to any prediction. Factors contributing to uncertainty include the decoupling of demand for electricity from economic growth, changes in types of demand (such as the loss of energy-intensive industries, but growth in demand for transport), the increase in the uptake of information technology both in the business and domestic sectors, even changing trends in consumers' use of domestic appliances. Changes in patterns of use will also affect energy supplies; for example, in the UK energy demand traditionally exhibited winter peaks. Nationally, peak demand occurs in winter but in the commercial and financial areas of many UK cities, because of the increased usage of air conditioning in offices and IT installations, the peak demand now occurs in the summer.[23]

Electricity demand increased at annual rates of 1.55% in the 1980s and 1.86% in the 1990s. Assuming a continuation of this rate of growth in the next decade, the share of coal in electricity generation would decline to 21% in 2008, with gas growing to 47%. The DTI forecast that this will rise to 50% by 2011. The country will then be approaching the reverse of the energy mix in 1980, when 71% was provided by indigenous coal. In 2008 almost half the country’s power will be generated from imported natural gas and liquid natural gas (LNG). LNG import storage facilities are one of a number of options to bridge the gap in natural gas supply. Providing LNG import facilities with storage allows the UK to import more gas, while having the option to hold gas in storage to meet demand for longer periods, which is particularly important in the event of any disruption to supplies coming into the UK.

The DTI expects demand for gas, both for electricity generation and for direct use, to rise gradually, from about 90 Mtoe (million tonnes of oil equivalent) in 1999 to more than 120 Mtoe by 2020.[24]

Fig 5: Electricity generation by fuel, 1980, 1990, 2000



Source: DTI, ABS Generating Capacity Database

Source of energy supply

For many years the UK has been self sufficient in energy, with ample reserves of coal, oil and natural gas as well as a small amount of hydro resources, mainly in Scotland. The country was once described as “an island of coal in a bubble of gas floating in a sea of oil”. Soon, this will no longer be the case.

The issue of energy security is attracting new attention in the EU and is one of the drivers of subsidisation of indigenous energy production. The EU countries all have different mixes in fuel generation. Greece, Germany, Denmark and Ireland all have higher proportions of coal generation than the UK, while Spain, Portugal and the Netherlands approach the level of the UK. All of these countries must be considered keen competitors for EUAs when the emission trading scheme comes into operation.

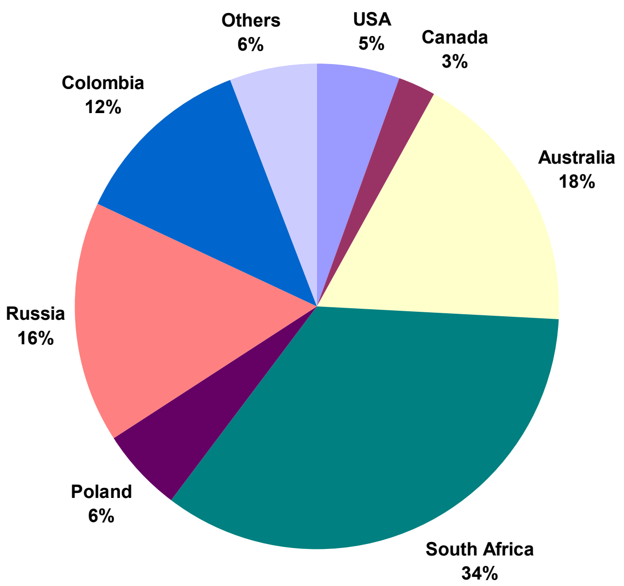
Table 6: Generation fuel mix of EU countries, 2002

	Nuclear	**Coal & lignite**	**Petroleum products**	**Natural & derived gases**	**Hydro & wind**	**Biomass & geothermal**	**Other fuels**	**All fuels**	
	%								**TWh**
Germany	29	50	1	11	6	1	1	100%	582
France	77	..	..	..	14	1	8	100%	549
United Kingdom	23	34	2	37	2	1	-	100%	386
Italy	0	11	27	36	20	3	3	100%	279
Spain	27	30	10	10	21	1	1	100%	238
Sweden	45	1	2	1	49	2	-	100%	162
Netherlands	4	25	3	62	1	4	-	100%	94
Belgium	58	12	2	23	2	1	1	100%	80
Finland	31	23	1	16	18	11	-	100%	74
Austria	0	11	3	15	68	3	-	100%	64
Greece	0	66	16	11	6	0	-	100%	54
Portugal	0	29	20	16	31	4	-	100%	47
Denmark	0	47	11	25	11	6	0	100%	38
Ireland	0	37	21	37	5	-	0	100%	25
Luxembourg	0	0	0	22	73	5	-	100%	1
EU total	33	25	6	17	15	2	2	100%	2,671

Source: Eurostats

The sources of imported energy have implications for security of supply. The main sources of imported coal in 2002 into the UK were South Africa, Australia, Russia and Colombia.

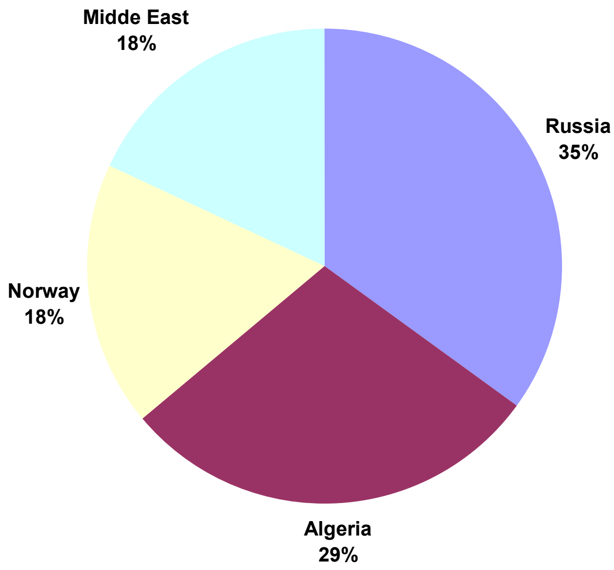
Fig 6: Coal imports into the UK by country of origin, 2002



Source: Eurostats

When the UK starts to import piped natural gas, the main sources will be Russia, Algeria, the Netherlands and Norway. The UK does not yet import gas but it soon will and these countries are already the main providers for the EU gas importing countries.

Fig 7: The source of imports of natural gas, projected EU gas imports by country of origin



Source: EU Analysis of Security Threat

5. Security of supply - coal and natural gas

Security of supply is subject to three types of risk:

1. Interruption of transport or storage through breakdown or inadequacy of capacity
2. Political interruption and price manipulation
3. Terrorist action

Both coal and gas are subject to each of these risks to a greater or lesser degree.

The International Energy Association (EIA) forecasts that EU gas imports will increase from 44% today to 80% in 2030 and has stated "from an energy security supply point of view, to rely so much on imports for its gas would be very risky business". [25] The US Department of Energy has painted a bleak picture for US dependence on imported energy in the coming decades and the US Federal Reserve Chairman Alan Greenspan has drawn attention to the coming natural gas supply crisis threatening the USA, advocating a rapid build-up of LNG import and storage capacity.

1. Transportation and storage risk

Piped natural gas

The UK is supplied via interconnecting gas transmission pipelines from Zeebrugge and from the North Sea. Another major pipeline is currently under construction to the Norwegian gas fields.

The UK gas transmission system is a network extending from Aberdeenshire to the South West of England. The network is fed through seven beach terminals at which gas from more than 100 gas fields on the UK Continental Shelf is landed. The main terminals, in terms of throughput, are sited at St Fergus, in the North East of Scotland, and Bacton, Norfolk. Smaller terminals are sited at Theddlethorp, Lincolnshire; Easington, East Yorkshire; Barrow, Cumbria; Burton Point in North Wales; and Teesside. In addition, gas could be supplied to the UK through an interconnector to the European gas networks. At present, the Bacton-Zeebrugge Interconnector is capable of transporting 20 billion cubic metres (bcm) per year from the UK to Europe, or 8.5 bcm in the other direction. This capacity will increase to 20 bcm in the near future. The technical feasibility of a second interconnector between the Netherlands and the UK is under consideration by a number of potential investors and if developed would provide a valuable alternative route. The UK is currently a net exporter of gas but in 2000 imported about 2% of its gas demand of about 97 bcm per year. Some predictions indicate that by 2006 this may rise to 15%. An Irish Interconnector running from Moffat in South West Scotland to Loughshinney near Dublin delivers about 4.7 bcm gas to the Republic of Ireland to meet 50% of Irish needs.

A number of inter-connector pipelines are under review to strengthen the UK's links with the European gas market. These include an upgrade of the Bacton-Zeebrugge Interconnector to 16 bcm by 2005, the Gastransport Services Interconnector from the Netherlands with over 10 bcm capacity by 2006, and the Ormen Large pipeline linking the Norwegian Ormen gas fields directly to Britain, with capacity of 20 bcm by 2006.

The physical infrastructure has been identified as the most serious security-of-supply issue to be addressed in the gas sector. At present, gas throughput is concentrated at St Fergus and Bacton and the capacity there might not be adequate to meet demand and guarantee security and reliability of supply. It also leaves the system open to the risk of major disruption in the event of serious accidents (such as the explosion at the Esso Longford gas plant in 1998 in Victoria, Australia, which disrupted supplies across the State for nearly two weeks), or terrorist attack. [26]

The gas grid is a high-pressure (up to 75 bar) transmission system which moves gas at 25 kph through the network, progressively reducing the gas pressure according to the needs of the end consumer, to the point where domestic appliances receive gas at about 25 millibar. The network is not comprehensive. Homes in large tracts of Great Britain are without a domestic gas supply, on the grounds that it would not be commercially viable for gas suppliers to provide the infrastructure necessary to extend the domestic distribution system.

Natural gas storage

In the UK, BG Storage provides gas storage services to a wide range of customers operating in a competitive market. The company utilises man-made salt cavities at Hornsea, Yorkshire, to store gas 1,800 metres below ground. The Rough field is a partially depleted gas field in the southern North Sea which has been developed to store natural gas 3,000 metres underground. More limited storage facilities for LNG are situated at locations close to Bristol, Strathclyde, Rochester, Manchester and in Mid Glamorgan. In addition, Transco owns more than 450 overground gas holders, with a total storage capacity of 24 million cubic metres of gas at low pressure for delivery to domestic and industrial consumers. These are scheduled to be phased out over the next ten years or so. In practice, the North Sea gas fields have themselves been regarded as storage reserves in the past, in that they could be tapped to a greater or lesser extent, within transmission and compression limits, depending on demand. As a result, compared with countries elsewhere in Europe, the UK has very limited purpose-built storage facilities, providing for less than 4% of annual consumption. In comparison, France, Germany and Italy each have storage capacity in excess of 20% of annual consumption.

There is currently no statutory requirement for the provision of strategic gas reserves, unlike in the coal and oil sectors. Storage capacity has increased by 10% since deregulation of the gas sector.[27]

Proposals have been put forward to increase the amount of gas storage available, with the following facilities planned.

- Statoil and Scottish and Southern Energy - a storage facility at Garton, capacity 17 bcm by 2006/2007
- Star Energy - a storage facility at Barton Stacey in Hampshire, capacity 9 bcm from 2005
- Scottish Power - a storage facility at Byley, Cheshire, capacity 5 bcm from 2008
- Star Energy - a facility at Welton, Lincolnshire, capacity 9 bcm from 2005

Fig 8: European natural gas transmission systems, 2002

Source: UNECE Gas Centre, Geneva

LNG transport and storage

Natural gas can be cooled and treated in order to form a liquid, and so natural gas can be stored and transported as Liquefied Natural Gas (LNG). Hence gas can be transported in bulk by ship and this enables imports from relatively distant natural gas sources without the need for pipeline transport. Such transport by ship would typically require an LNG import facility to handle offloads and regasification of LNG from ships. Gas can also be stored relatively easily in LNG form, thereby enabling both gas transporters and suppliers greater flexibility to accommodate fluctuating demands for gas. Although there are some LNG storage facilities currently owned and operated by NGT in the UK, there are at present no LNG import facilities operating in the UK. The first of three import facilities under development will be commissioned in 2005.

LNG offers the UK the potential for diversity of supplies and LNG storage could increase reliability of gas supply for the winter peak demands. It can be shipped in from as far afield as Australia, Qatar, Malaysia and Indonesia but it is most likely that supplies to the UK will be sourced from North Africa and the Caribbean.[28]

Certain other European nations, such as Germany, France and Italy, have such storage facilities and could meet demand for longer periods than the UK in the event of any disruption to supplies. The LNG import storage facilities also reduce the reliance on a single source for imports.

The growth in LNG facilities in the UK is being spearheaded by three major import storage facilities.

Isle of Grain - NGT is building a facility at the Isle of Grain with capacity of 4 bcm by 2005 increasing to 13 bcm.

- Petroplus Milford Haven - Capacity of 6-9 bcm by 2006/7

- Exxon Milford Haven - ExxonMobil is building the world's biggest gas import terminal near Milford Haven in Wales, at an estimated cost of £1 billion. The estimated cost of the overall project including the terminal and dedicated shipping fleet is $9 billion. Exxon's plans are to import LNG from Qatar in purpose built tankers.

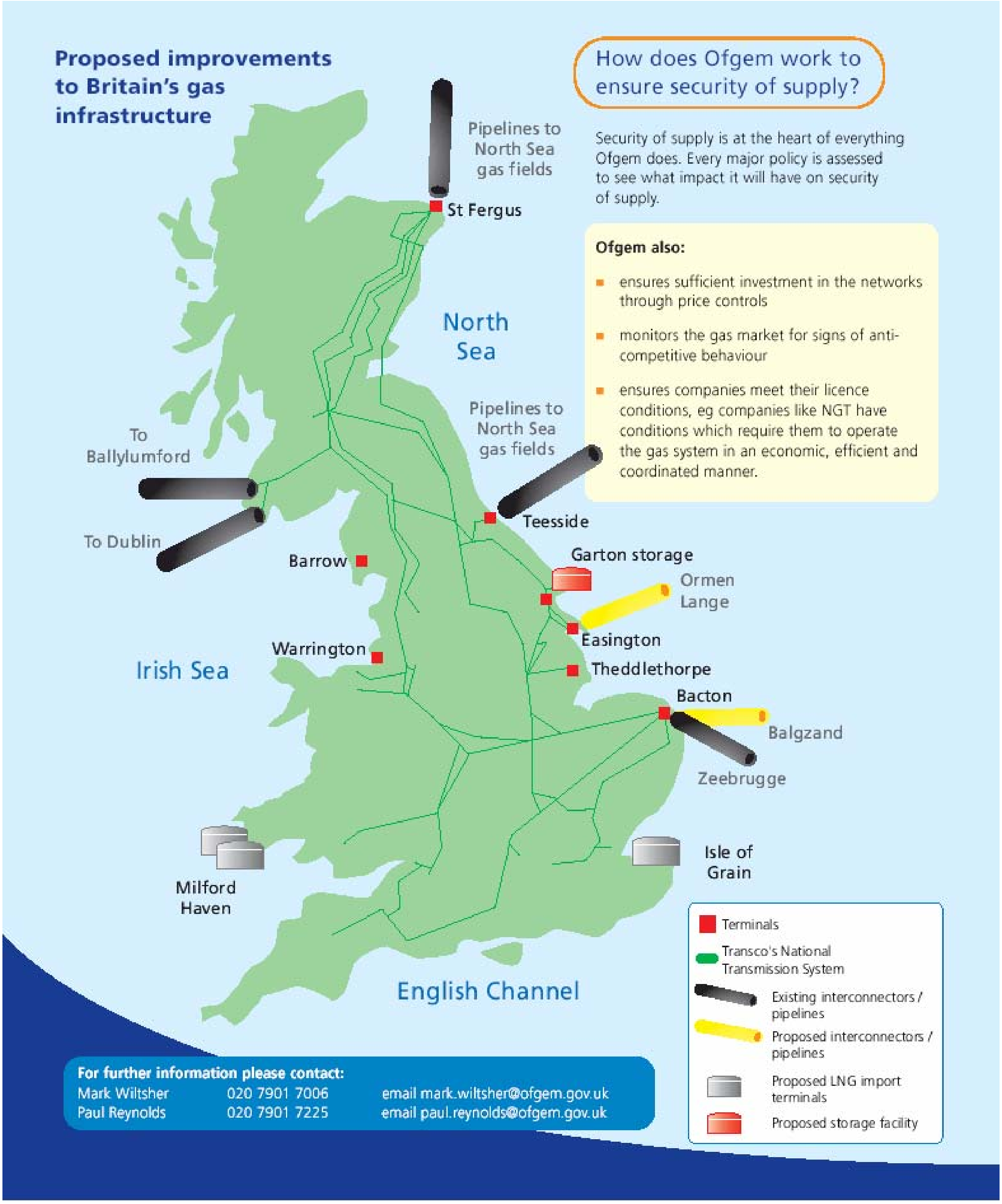
Advantica operates five LNG storage facilities in the UK plus four satellite sites together with associated road tankers. The five operating LNG storage facilities are as follows:

- Isle of Grain, near London
- Partington, near Manchester
- Avonmouth, near Bristol
- Glenmavis, near Glasgow
- Dynevor Arms in South Wales

The road tanker supplied LNG satellite facilities are:

- Wick
- Thurso
- Oban
- Campbeltown

Fig 9: Britain's gas infrastructure



Source: Ofgem

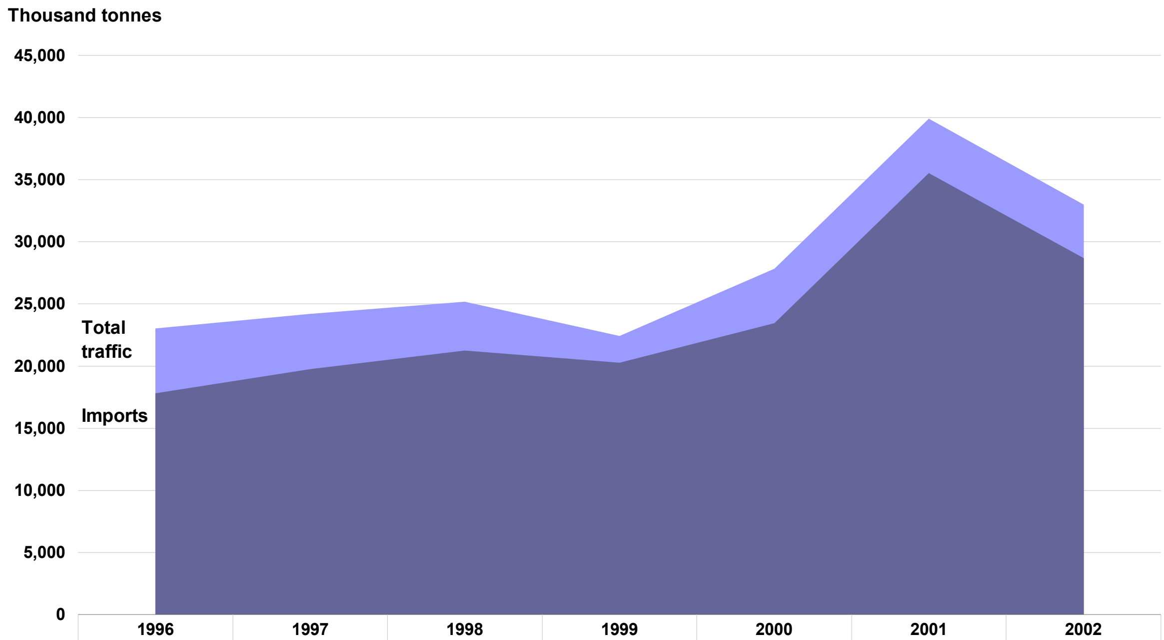
Coal transport

32,998,000 tonnes of coal was shipped through British ports, mostly inbound, consisting of 29,433,000 tonnes imported and 1,136,000 tonnes shipped domestically in 2002. The highest volume has been in 2001, when total traffic was just below 40 million tonnes. The ports therefore have 21% more capacity to handle coal than was used in 2002, without taking account of any further expansion of handling capacity.[29]

A new rail terminal became operational in August 2002 capable of handling over 100 train-loads of power-generator coal each week from Humber International Terminal. Civil works have commenced on a second phase of the Humber International Terminal (HIT2) in order to ensure that planning permission is not lost but a go-ahead has not yet been given for the full scheme. If approved, HIT2 is likely to be a dedicated dry-bulk handling facility. The second phase will add 220 metres to the berthing face.[30]

It seems likely that the port system will have the capability to handle an increase in imported coal should this occur.

Fig 10: Total shipments of coal through British ports, domestic and foreign traffic



	1996	1997	1998	1999	2000	2001	2002
Total traffic	23,045	24,193	25,175	22,419	27,830	39,920	32,998
Imports	17,799	19,757	21,244	20,293	23,446	35,542	28,686

Source: Office of National Statistics

27.2% of all coal traffic was shipped through Grimsby and Immingham. The predominant cargo handled by Grimsby and Immingham is coal, destined for power generators. Immingham is capable of handling Capesize vessels carrying in excess of 100,000 tonnes of cargo.[31]

Table 7: Port traffic, coal 2002

	Thousand tonnes	%
Grimsby & Immingham	8,971	27.2%
Clyde	4,913	14.9%
Bristol	3,638	11.0%
Tees & Hartlepool	3,251	9.9%

Liverpool	2,892	8.8%
Medway	2,643	8.0%
London	1,876	5.7%
Port Talbot	1,828	5.5%
Londonderry	402	1.2%
Hull	374	1.1%
Other ports	2,210	6.7%
All ports	32,998	100.0%

Source: Office of National Statistics

The bulk of land shipment is by rail, with a small amount transported by canal. We have been informed that the link between Immingham-Scunthorpe-Doncaster is the busiest freight line in the country, accounting for about 25% of national freight traffic and that it is currently full.[32] With the current establishment of dedicated rail capacity, including the "merry-go-round" trains to the Aire Valley power stations carrying either indigenous or imported coal, present capacity is just adequate. If HIT2 proceeds, transport will present a problem for coal, without major capital expenditure to upgrade this route.

2. Political and price risk

Security of supply is an issue which will always be with us. The UK government has argued that security of supply will best be guaranteed by market forces, which will adjust to changing circumstances. Questioning this, the Parliamentary Committee has suggested that market forces may not by themselves be sufficient to guarantee that the transmission and distribution networks will be sufficiently robust to provide security, and have made recommendations about the strategic roles of the government and the regulator in ensuring security. However, such security has a cost to it. If the operators have to invest more in infrastructure these extra costs are likely to be passed on in some form to consumers. In addition, ensuring diversity of supply does not come free. Greater reliance on home-produced energy, whether in the form of promotion of renewables or of more systematic exploitation of the UK's fossil fuel reserves, could be more expensive than leaving everything to the market. On the other hand, complete reliance on the market could leave consumers exposed to the risk of sudden price shocks, as overseas supplies are disrupted or diverted to other customers willing to pay a higher price.

Europe is already vulnerable because it has a limited number of suppliers and lacks the means of pressure. Russia has withheld supply because of non-payment by other CIS countries, which could interrupt the transit of gas supply through those countries. There have been cases when supply was interrupted briefly but line pack (the gas in the pipeline) kept the pressure up in Western Europe. However, this is a thin margin which will last for hours rather than days. We should also consider the possibility of secession by any of the 81 republics within the Russian Federation. This has already been attempted, especially by the Siberian energy producers and only staved off by remission of taxes to Moscow.

Algeria presents a different political threat. The country is only now stabilising after a fundamentalist Islamic war which cost 100,000 lives in brutal circumstances. It is not impossible that in the future the United States could find itself imposing sanctions against Algeria and its closest ally would find itself having to make difficult choices.

Supplies of coal to the UK could be insecure but less so than gas. South Africa and Colombia are both countries with political risks and Colombia has a high degree of terrorist risk. In Colombia the national electricity grid has been disconnected due to bombings and the main oil pipeline, Cano Limon was bombed no less than 170 times in 2001.

On the other side of the coin, it should be pointed out that when the UK relied on indigenous coal for 71% of its power generation, national electricity supply was vulnerable and supplies to industry were interrupted on a large scale.

Price risk could be a potentially greater threat than political risk with imported gas. Russia is in a dominant position as gas supplier and has recently suggested the creation of a gas cartel similar to the oil cartel OPEC. Saudi Arabia has used its dominance of oil markets three times as a threat tactic, twice against the western industrialised world and once against the former Soviet Union.[33] Coal could also be subject to this sort of manipulation. Four or five mining companies control about half the global coal trade (BHP Billiton, Rio Tinto Zinc, Anglo-American Peabody) and fears have been expressed that they could form a coal cartel.

We do not wish to paint an alarmist picture. Nevertheless, it would be sensible to bear these potential threats in mind, when embarking on a course of change from self sufficiency of indigenous supply to reliance on imported sources. We are entering a new energy world with different parameters.

3.Terrorist action

Before September 11, analysts rated mechanical failures of transport and storage as the major threat to imported energy but new threat analysis has raised the profile of terrorist attacks. It is not a new threat but has achieved higher salience. Thirty years ago the Breton separatists were sabotaging electricity assets in France. Colombian and Nigerian regional guerrilla movements have been active in the last five years against oil infrastructure. Nuclear plants, gas pipelines and LNG storage facilities are seen as vulnerable targets.

6. Coal Mining Industry

Background - The UK's Coal Resources

The UK has proved reserves of 1.5 billion tonnes of coal, 1 billion tonnes of anthracite and bituminous coal and 500 million tonnes of lignite. This is enough to last for 60 years at current rates of extraction.[34] However, reserves of coal and any other forms of energy are expressed at several different levels, depending on the economic viability of extracting the coal. The coal may be there but it cannot be exploited if it is so deep or in conditions which make it dangerous or too expensive to mine. We know the coal is there but it is only counted as a useful reserve if it can be extracted economically and safely.

Three different definitions of reserves are commonly used.

Reserve - Proved Reserve - A reserve zone in which sufficient data is available to predict with a high degree of confidence and the proposed method of extraction is known and tested.

Probable Reserve - A reserve zone in which insufficient data is available to predict with a high degree of confidence or where the method of extraction has not been fully tested.

Resource- An area of mineral in which there is an economic interest but major access is required and has not yet been fully investigated.

Mineral Potential- An area which could fall into a Reserve or Resource when planning permission and licence has been obtained.

The reserves are under constant re-evaluation and change with time. The DTI conducted a review of the UK's coal reserves in 1998 and again in 2002 using an independent consultant. Coal prices today are high at about £50 per tonne, but in 2002 they were low, at about £25 per tonne.[35] The assessors took the view that it was not economic to extract it because the selling price was low and the costs of extraction high and they moved a substantial proportion of the "Resource" into "Mineral Potential". Today, two years later when the coal price has almost doubled they might assess some of the Mineral Potential as a resource which could be extracted economically and increase the reserves and the life of the mine accordingly. In today's economic conditions the figures given below can be regarded as minimum values but they are based on the latest data available. We consulted with the Confederation of UK Coal Producers and UK Coal plc and they agreed that a life expectancy for each mine based on Reserve plus Resource is a reasonable assessment and probably conservative in view of the price increase.[36]

The reserves of coal in deep mines in the UK including Reserve and Resource will last for 12 years at the rate of extraction estimated for 2004, which is 13.1 million tonnes. If Mineral Potential is added in the life expectancy would increase to 27 years.[37]

Table 8: Reserves and life of deep coal mines in the UK, thousand tonnes

	Reserve	Life in years	Resource	Life in years	Mineral Potential	Life in years
		Reserve		Reserve + Resource		Reserve + Resource + Mineral Potential
UK	66,610	5	84,412	**12**	262,562	27

Source: DTI

Reserves of the deep mines in Yorkshire and Humber

Four deep mines remain in operation in the Yorkshire and Humber Region; Kellingley, Maltby, Rossington and the much smaller Hayroyds.

The life expectancy of Kellingley Colliery is therefore 22 years, Maltby Colliery 8 years, Rossington Colliery 12 years and Hayroyds Colliery 7 years.[38]

Table 9: Reserves and life of deep coal mines in Yorkshire and Humber, thousand tonnes

	Reserve	Life in years	Resource	Life in years	Mineral Potential	Life in years
		Reserve		Reserve + Resource		Reserve + Resource + Mineral Potential
Kellingley	8,644	5	26,148	**22**	22,693	36
Maltby	5,000	4	6,300	**8**	12,200	17
Rossington	3,169	4	7,982	**12**	6,542	20
Hayroyds	180	6	50	**7**	0	7

Source: DTI

Factors changing forecasts at deep mines

Three unforeseeable factors can affect future life expectancy and output:

- Changes up or down in the price of coal can alter the classification of economically extractable reserves.
- Geological problems can interrupt production and even close a mine.
- Industrial action is unpredictable. At the time of writing this report there are several disputes in progress.

Ownership of the deep mines in Yorkshire and Humber

Kellingley, Maltby and Rossington Collieries are owned by UK Coal plc. Hayroyds Colliery is owned by J Flack & Sons Ltd.

Production of open-cast mines in the UK

We do not have a figure for reserves of opencast mines but estimate production at 11.6 million tonnes in 2004, and declining at an average of 3.7% a year thereafter.[39]

Production of open-cast mines in Yorkshire and Humber

Production in Yorkshire and Humber open-cast mines averaged 1.3 to 1.5 million tonnes a year for the past five years.[40] However, five out of six larger current sites are due to close in 2004 and the sixth, producing 185,000 tons is due to close in 2005. Planning permissions for opencast mines granted by local authorities in Yorkshire and Humber have averaged about 500,000 tons per year in recent years. Permission for 3 sites is currently being sought, holding 713,000 tons, equivalent to about half current annual production. This would leave a regional shortfall for the Aire Valley power stations, necessitating purchases from other UK sources, unless these and additional open-cast reserves are approved for working.

Factors affecting production at opencast mines

Whereas deep mines require long term planning and investment, opencast mines are smaller and much shorter term operations and can be brought on-stream relatively quickly, sometimes to meet contracted supply when problems cause shortages at the deep mines. We were told that opencast mines can have lives from 1 to 5 years. They are often brownfield sites which the coal operator takes over with agreement to clean up the site.

Ownership of the opencast mines in Yorkshire and Humber

Because the opencast mines open and close with such frequency the published returns are nearly always out of date. Currently UK Coal PLC is operating three opencast mines in Yorkshire and Humber; Ferry Moor, Orgreave and Moorhouse. HJ Banks & Co Ltd was reported by the Coal Authority in December 2003 to be operating three opencast mines in the region; Lewden and Woodhouse in Barnsley and Moss Carr in Leeds.[41]

Government investment aid

The government will offer up to 30% of required investment to companies wiling to make the 70% investment. This may be taken as an indicator of intention by companies accepting aid.

Profitability of mines

UK Coal plc

The results for 2003 announced by UK Coal PLC on March 4, 2004 disclosed a pre-tax operating loss of £7.6 million on turnover of £563.9 million, compared with an operating profit of £8.4 million on turnover of £596.6 million in 2002. The post-tax profit in 2003 was £3.9 million on turnover of £563.9 million compared with an operating loss of £81.8 million in 2002 on turnover of £596.6 million.[42]

A loss of £8.6 million before tax and exceptionals was made on the deep mines in 2003 compared with £5.9 million in the previous year. The open cast mines were profitable in each year but the profit declined from £16.5 million in 2002 to £0.7 million in 2003.

UK Coal PLC was offered £36.5 million of investment aid and accepted £35.4 million during the year. £3.5 million was included in the 2003 results.

J Flack & Sons Ltd

We have been unable to obtain financial details of this company but the company has accepted £140,000 of government investment aid.

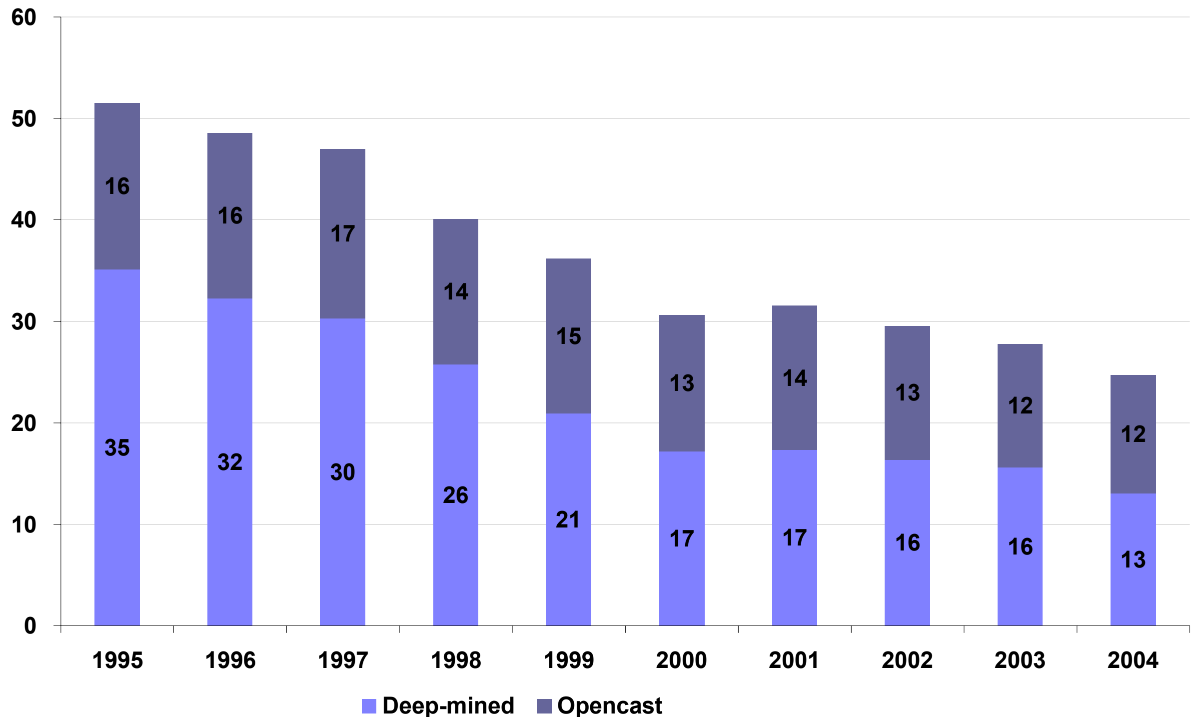
HJ Banks & Company Ltd

No information is available.

Coal production

Production of coal in the UK has declined from 53 million tonnes in 1995 to less than half that level, estimated in 2004 at 25 million tonnes.[43]

Fig 11: Production of coal in the UK 1995 to 2004

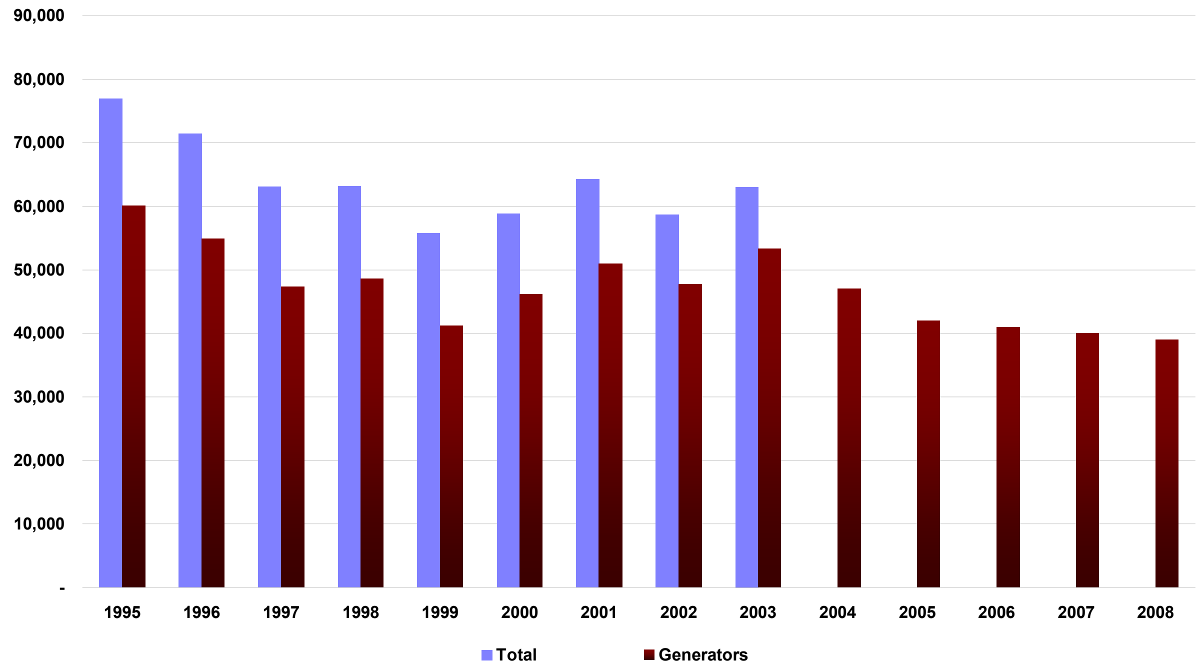


Source: DTI and ABS estimate for 2004

Markets for coal

84% of coal consumed in the UK is burned in the power stations, amounting to 53 million tonnes in 2003 out of a total demand of 63 million tonnes. Coke ovens used 6.6 million tonnes and domestic use accounted for 1.3 million tonnes.

Fig 12: Total and generators' consumption of indigenous coal, with UK Coal PLC forecasts 2004-2008



Source: DTI and UK Coal

UK Coal has forecast the coal burn at 47 million tonnes in 2004, equal to 2002 but some 11% lower than the peak in 2003.

With current high prices for imported coal, demand for UK coal is determined by one overriding factor, its high sulphur content. With an average of 1.7% sulphur, British coal can only be burned in power stations fitted with FGD equipment or the power station will exceed its sulphur allocation. Imported coal, with its sulphur content below 1% and in some cases considerably below that level, can be used in power stations without FGD equipment without producing excessive sulphur emissions.

The UK coal-fired power stations will have a minimum of 10 GW of FGD installed capacity, a probable 12-13 GW and a possible 15.6 GW [44], requiring a coal burn between 18 million and 28 million tonnes [45] at an average of 1.8 million tonnes per GW. In the past ten years the average coal burn has ranged between 1.44 and 2.11million tonnes per GW.

Table 10: The market for UK coal in power stations

Installed FGD capacity	Coal burn
Minimum 10 GW	18 million tonnes
Probably 12-13GW	22-23 million tonnes
Maximum 15.6 GW	28 million tonnes

Source: DTI and Confederation of UK Coal Producers Data

Depending on prices, some imported coal will be burned in FGD plant, reducing the total market available to indigenous coal. However, to off-set this, 16% of demand for coal is outside the power generation sector, amounting to 10 million tonnes in 2003, with less stringent emissions limits.

Our best estimate of the production of coal in the UK in 2004 is 24.6 million tonnes. With the exception of 2001, total production has declined every year in the past ten years at an average rate of decline of 8.1% per year and the annual total may continue to go down, depending on a variety of unforeseen factors.

Provided that off-take of British coal continues outside the power generation sector, even at a reduced level, the estimated market and production for British coal are in rough balance. With a good level of FGD installations and sustained demand outside the power sector, total demand for British coal could be well above forecast UK production. The final outcome will depend on a number of other factors such as the price of carbon in the ETS.

With 5 GW of installed FGD generating capacity in the Aire Valley, demand for high sulphur British coal could theoretically reach 9 million tonnes in the region but it will to be lower because some imported coal will be used in FGD installations. Production in Yorkshire and Humber in 2004 is estimated at 5.4 million tonnes.[46] With continued exports of coal from the region, together with consumption outside the power generating sector, there should be adequate and continued demand in the market for Yorkshire and Humber coal production at predicted levels.

7. Employment and jobs in the mines in Yorkshire and Humber

The Coal Authority returns show a workforce of 4,030 in the deep and opencast mines in Yorkshire and Humber at the end of December 2002. According to the DTI, with known closures during 2004, deep mine employment will be reduced from 3,139 in March 2004 to 1,531 by the end of the year. According to the DTI, planning permissions are being sought for three new opencast sites in the region and if these are successful employment will increase accordingly. It should be noted that Hatfield has been left in such a condition that it could be re-entered.

Table 11: Employment in the collieries

		Dec 2002		Dec 2003		March 2004	
		Mines	**Manpower**	**Mines**	**Manpower**	**Mines**	**Manpower**
Barnsley	O/C	3	98	2	59	2	47
Doncaster	Rossington	1	618	1	624	1	577
	Hatfield	1		1		1	
North Yorkshire	Selby 4	4	2,453	4	1,952	4	1,813
	Kellingley	1		1		1	
Leeds	(2) 1 O/C	2	119	1	30	1	30
Rotherham	Maltby	1	538	1	514	1	519
	O/C	1	120	1	108	1	109
Wakefield	3 O/C	2	40	3	57	2	44
	PoW	1	44	0	0		0
			4,030	15	3,344	14	3,139

Source: Coal Authority, UK Coal

Closures started at Selby Complex in 2003 and at the start of the closures, the direct work force employed at Selby, including all office and other non-miner staff totalled 2,071.[47] An additional 1,929 jobs are dependent on Selby in the surrounding communities. These include those working in supply chain businesses for the mines and in businesses providing goods and services to the employees of Selby. The Prince of Wales Colliery did not support such a large indirect dependent employee workforce, perhaps because it was smaller and less dominant in the community. The indirect workforce of the supply chain and workers in businesses supplying goods and services to the employees of Prince of Wales amounts to 390. In total just under 5,000 direct and indirect jobs depend on these two mines.[48]

A feature of the mining workforce in Yorkshire and Humber is its dispersion and the quite long commuter journeys that miners make to work. A substantial proportion of miners working at Selby opted to remain in their communities and not to move nearer to the mine. This will have the effect of reducing the local impact of the closures around Selby somewhat, although it will still be serious. In another case it may create further distress. 870 of the Selby workforce live in Wakefield, which is already suffering from the closure of the Prince of Wales Colliery in August 2002. Wakefield and Barnsley also have pockets with small communities which are suffering deprivation and are still recovering from the closures of the 1980s and 1990s. There will be losses in Barnsley, Doncaster and Leeds resulting from the Selby closure but we do not have exact numbers.

Table 12: Aggregate direct and indirect job losses including supply industries to Selby Complex and Prince of Wales Colliery

Job losses	Selby	Prince of Wales
Direct	2,071	600
Indirect	1,929	390
	4,000	990
Combined losses		
Selby LAD	850	
Wakefield LAD	850	870
Regional *	2,300	120
	4,000	990

Source: Selby Impact Study Econometric Models

660 companies based in Yorkshire and Humber have been identified as direct suppliers to the Selby Mines complex. 50% are in South Yorkshire, with the highest concentration in Doncaster. Most are traditional manufacturers (prefabrication/tracking/light engineering), service suppliers and stockists (electrical/engineering/lubricants/clothing/timber/tools/safety equipment). They have an average of 25-125 employees. The purchase value of orders placed by UK Coal PLC is estimated at 10%-25% of their total order value.[49]

The outcome of closures on these companies is still unclear. An important observation made in the Selby Coalfield Task Force Report is that for many of the businesses this is a completely new situation.

Employment across the Yorkshire and Humber region is variable, in some cases well under the national average and in other LADs higher. Although overall employment in Selby is buoyant, unemployment is high in the central wards, with 9.4% in Selby Central and the district has not been gaining new jobs. Of particular concern are the levels of unemployment among men in Wakefield at 4.9% and in Barnsley at 6.6%. Job losses will be concentrated in the east and south of Wakefield. Barnsley is still recovering from past closures and has high unemployment. High deprivation exists in many ex-mining areas.

With the addition of well over 2,000 men coming onto the labour force in these two areas which are economically affected by the closures, the effects are likely to be more serious than elsewhere in the region.[50] Unemployment among women is lower in all cases. In Doncaster and Leeds the prospects for job generation are poor but the economies are improving.

Table 13: Impact of job losses at Selby Complex and Prince of Wales Colliery

	Total employment		Employment in Selby & PoW	% of total workforce	Unemployment March 2002	
LAD	**1991**	**2001**	**closure job losses**		**Men**	**Women**
Selby	26,551	25,927	850	3.3%	2.9%	1.6%
Wakefield	111,962	119,124	1,720	1.4%	4.9%	2.0%
Barnsley	63,105	72,533	2,420	ni	6.6%	2.4%
Doncaster		107,490		ni	ni	ni
Leeds		431,560		ni	ni	ni
Surrounding LADs	ni	ni		ni	ni	Ni
Total	201,618	756,634	4,990			

Source: Selby Coalfield Impact Study

The economic loss to regional output from the closure of Selby is calculated at an initial amount of £94 million rising to £150 million and possibly £165 million by 2011. This includes the effects on the supply chain as well as direct effects.[51] Supply chain industries to Selby Complex are likely to lose about £75 million initially. The sectors particularly affected are electrical equipment supply, wholesaling, retailing, hotel and catering, construction. The electrical and machinery equipment supply industries stand to lose £9 million and construction £5 million. These suppliers to Selby Complex are located mainly in Selby and Wakefield LADs. The banking and business services sector will lose about £10 to £15 million initially.

If the initial impact recycles in the economy with no regeneration and no alternative employment being generated, supply chain industries could lose £100 million a year by 2011.

The effect of the closure of the Prince of Wales Colliery will be an initial loss of output of £35 million in the Wakefield LAD, rising to £46 million in the local economy by 2008 and a further £12 million to the regional economy, totalling a loss of £58 million in output.

These figures primarily reflect the impact on local economies. There was however, agreement from more than one consultee in the region, including interviews with representatives of every council in Yorkshire and Humber that the dispersion of miners away from the work site will be a major factor ameliorating the impact.[52]

Table 14: Economic loss through closures at Selby Complex and Prince of Wales Colliery

	Selby	Prince of Wales	Total
Loss £ million	165	58	223
£ per direct job loss	79,672	96,667	83,489
£ per total job	41,250	58,586	44,689
Direct loss £ million	94	33.5	128
Indirect loss £ million	71	13	95

Source: Selby Mines Econometric Impact Assessment, Prince of Wales Colliery Econometric Impact Assessment

Losses of jobs, direct and indirect resulting from closures of any of the three remaining deep mines will range from 770 to 1,200 (rounded figures) and losses on output ranging from £34 million to £52 million. If closures happen, the losses are very unlikely to occur at the same time.[53]

Table 15: The job losses from further pit closures in other deep mines

	Job losses			Cost
	Direct	Indirect	Total	£ million
Kellingley	624	562	1,186	52
Maltby	514	463	977	43
Rossington	404	364	768	34

Source: ABS calculation based on Selby Impact Study Model

There is no data available regarding the size of the supply chain dependent on the coal-fired power stations but using the Selby and Prince of Wales Colliers models the employment losses would range from 380 at Ferrybridge to 910 (rounded) at Drax, including direct and indirect employment. The loss to output would range from £17 million to £40 million. As in the case of the surviving collieries, losses are unlikely to happen all at one time.

Table 16: Job losses with power station closures

	Job losses			Cost
	Direct	**Indirect**	**Total**	**£ million**
Drax	480	432	912	40
Eggborough	250	225	475	21
Ferrybridge	200	180	380	17

Source: ABS calculation based on Selby Impact Study Model

Effects of unemployment on the workforce and communities

The Selby workforce is predominantly male, with an average age of 43 years and 24 years experience in the mines.[54] This analysis is important because it shows the extent to which redundant miners are dependent on the mines in terms of work experience and their community lives. The bulk of them have no experience of life outside the mining environment. They simply do not know what to do. They have no idea what jobs are available or what they can do. There is an urgent need for information and advice. We quote the Selby Coal Field Task Force Report, “An overriding impression is that the respondents need on-to-one support with more information on both job needs and training opportunities.”

Qualifications are mainly limited to City & Guilds. A small minority need basic literacy and numeracy teaching although this may understate the real demand.

They have been quite highly paid, with an average income of £26-28,000. They are flexible about jobs and training but less so about income levels required. There will be an increase in two earner families with many wives and partners taking jobs, where before the family had been wholly reliant on one main earner. The lower levels of unemployment among women will be a distinct advantage in this respect. (Table 13)

Two factors were picked out as improvements on past experience of closures. The 18 months notice of the Selby closures has helped considerably, compared with closures in the past which have often taken place with a minimum of notice.

Secondly, the retraining facilities and a more proactive approach to solving the problems are contributing significantly.[55]

Work expectations

A quarter of the redundant miners will seek redeployment within the industry and 70% will seek jobs elsewhere. 4% will retire or will have to retire for health reasons. They perceive two broad areas to be attractive to them, driving related occupations such as; HGV and fork-lift driving, work on railways and maintenance and construction; and construction trades, such as plumbing, gas fitting, or electrical work.

15% of redundant miners want to have computer training.

Many will be seeking a wholly different environment from work in the mines; often outdoors, non-shift and where skills and training are less industry specific, providing them with more employment flexibility.

There is an urgent need for training.

Table 17: Work expectations

Job intentions	
Redeploy in the mining industry	26%
Seek other jobs	70%
Retire or disabled	4%

Source: UK Coal survey, Leeds University survey

Social outcomes

There is much past experience which can be used to predict the difficulties which will arise in the communities and to provide aid in combating these problems. They are not all obvious at first glance, which is why study of past experience is so productive.

The experience of redundancy has been so threatening, after a life time spent in one occupation, with an average of 24 years in the mines and no experience outside that environment, many redundant miners will take the first opportunity that crops up. This in turn can compound the whole problem of redundancy. They may find themselves working in a job that is totally unsuitable and that they dislike and furthermore, it may lead to a second unemployment, destroying confidence and bringing serious psychological effects.

There will be significant and protracted incapacity benefit claims, much of which will be dependent on the level of economic regeneration and jobs available.

There will be greater susceptibility to mental health problems requiring early supportive action.

Environmental impacts

Pit closures require careful environmental management. There are threats such as contaminated land to clean up, subsidence to manage and the serious threat of pollution from mine waters.

Impact on families

Experience shows that the full impact of redundancy can be delayed and that the worst time can be after 18 months to 2 years.

Data Sources

The following reports and papers were identified and used, some extensively in the report.

1. DTI Energy White Paper, “Our energy future, creating a new carbon economy”
2. DTI Energy Trends and Quarterly Energy Prices
3. Review of the remaining reserves at deep mines for the DTI
   IMC Consulting Ltd
4. The Selby Impact Coalfield Study
5. Selby Coalfield Task Force Report
6. Government Response to Selby Coalfield Task Force Report
7. The Selby Complex, by Miners Advice
8. ABP Associated British Ports Handbook 2004
9. Coal Authority Production and Manpower Returns
10. UKQAA, UK Quality Ash Association, production and sales statistics for PFA and FBA
11. UK Coal PLC
12. Energy Forum Foundation Study
13. Regional Gross Value Added
14. Energy Forum Foundation Study Update, February 2004
15. Drax Power Limited Investors Presentation
16. MPR Engineering Services, Overview of Technologies for Reduction of Nitrous Oxides Emissions, by R. Bell, PE & F Buckingham Ph.D.
17. Corporate Carbon Strategies Outlook to 2012, by Reuters Business Insight, September 2003.
18. DTI Review of the feasibility of carbon dioxide capture and storage in the UK, cleaner fossil fuels programme
19. DTI Energy Statistics
20. House of Commons Select Committee on Trade and Industry, 28 January 2002
21. Department of Transport, Maritime Statistics 2002
22. Confederation of UK Coal Producers, Position Paper
23. Financial Times, 2004 Review of Russian Federation
24. BP Statistical Review of World Energy, June 2003
25. 2002 CERES Report
    Fiddlers Ferry and Ferrybridge Power Stations
    American Electric Power - United Kingdom

26. United Kingdom National Emission Reduction Plan for implementation of the revised Large Combustion Plants Directive (2001/80/EC)
November 2003

27. DTI Transport Statistics Report
Maritime Statistics 2002

28. Green Paper, Towards a European Strategy for Energy Security

29. UNITED NATIONS
UNECE GAS CENTRE - Geneva
UNECE gas centre report on security of natural gas supply in the European part of the UNECE area

30. EU Climate Policy and Integrated Pollution Prevention and Control
Article for the NSCA's Clean Air, July 2000
Ian Skinner, IEEP

31. Electricity Association
The production and applications for Pulverised Fuel Ash (PFA)

32. IEA
Policies and funding for coal utilisation R&D in the EU
20th Annual International Pittsburgh Coal Conference
Coal – Energy and the Environment

33. Air Pollution and Climate Series No. 3
Sulphur Emission from Large Point Sources in Europe
Swedish NGO Secretariat on Acid Rain

34. Global and regional coal demand perspectives to 2030 and beyond
WEC study
19th WEC World Energy Congress, Sydney, 5 – 9 September 2004

35. Applications for aid received by the DTI

36. IEA, Energy security and LNG

37. EU Supercritical Report

38. Powerplants -Coal-fired generation draws new interest (3/15/2004)
By Housley Carr

This list is not an exhaustive record of the information obtained via the internet during the course of researching this study.

Notes

[1] Regional Energy Forum Foundation Study Update, February 2004.
[2] Regional Energy Forum Foundation Study Update, February 2004.
[3] DTI.
[4] ABS British Electrical Utility Market Report Edition 2, 2004.
[5] Drax Power Limited, Annual Presentation, 12 March, 2004.
[6] British Energy website.
[7] American Electric Power website.
[8] These observations were made in personal discussions at the plants and in other interviews in the industry in the region.
[9] Energy Forum Foundation Study Update, February 2004.
[10] Alkane Energy estimate, CMM developer.
[11] Industry interviews.
[12] Industry interviews.
[13] These views were reported during industry interviews with a number of different sources.
[14] MPR Engineering Services, Overview of Technologies for Reduction of Nitrous Oxides Emissions, by R. Bell, PE & F Buckingham Ph.D.
[15] Corporate Carbon Strategies Outlook to 2012, by Reuters Business Insight, September 2003.
[16] Financial Times report.
[17] Drax Power Ltd.
[18] DTI Review of the Feasibility of Carbon Dioxide Capture and Storage in the UK, Cleaner Fossil Fuels Programme.
[19] UKQAA/ECOBA European Coal Combustion Products Association, 2001.
[20] UKQAA, United Kingdom Quality Ash Association August 2003.
[21] DTI Energy Statistics.
[22] Energy Forum Foundation Study Update, March 2004.
[23] House of Commons Select Committee on Trade and Industry, 28 January 2002.
[24] House of Commons Select Committee on Trade and Industry, 28 January 2002.
[25] IEA, International Energy Agency Energy Security Assessment, Chief Economist Dr Fatih Birol.
[26] House of Commons Select Committee on Trade and Industry, 28 January 2002.
[27] House of Commons Select Committee on Trade and Industry, 28 January 2002.
[28] House of Commons Select Committee on Trade and Industry, 28 January 2002.
[29] Department of Transport, Maritime Statistics 2002.
[30] ABP, Associated British Ports website, March 2004.
[31] ABP, Ports Handbook 2004.
[32] Confederation of UK Coal Producers.
[33] Financial Times, 2004 Review of Russian Federation.
[34] BP Statistical Review of World Energy, June 2003.
[35] Note: Coal prices vary substantially according to quality, calorific value etc. For the purpose of this evaluation we are more concerned with change over time than absolute values and we have taken the broad prices quoted by the DTI.
[36] DTI, Review of the Remaining Reserves at Deep Mines by IMC Consulting Limited, 2002.
[37] Production in Yorkshire and Humber in 2004 has been estimated by subtracting all of the production of Clipstone and two thirds of the production of Ricall Combine, Stillingfleet and Wistow Collieries from the total for 2003. This was discussed with UK Coal and we were given a best estimate of the production at those three collieries before they close during the year.
[38] Life expectancy is based on the reserves as estimated in the Review of the Remaining Reserves at Deep Mines by IMC Consulting Limited, 2002, divided by production in the same report. In the case of

Rossington actual production in 2003 was 900,000 tonnes as reported by UK Coal versus a forecast in 2002 by IMC of 1.2 million tonnes. We have reduced the figure to 900,000 tonnes for forward production.

[39] Production at opencast mines in the UK in 2003 was 12,126,000 tonnes, and has declined at a CAGR of 3.7% since 1995. We reviewed this with UK Coal who agreed it is a reasonable assessment.

[40] Coal Authority.

[41] UK Coal PLC confirmed that these sites are in operation but we were unable to confirm that the three sites reported as operated by HJ Banks are still in operation.

[42] UK Coal PLC Preliminary Results for 2003, 4 March 2004.

[43] Our estimated were checked with UK Coal plc and found to be in agreement with their forecasts.

[44] See Table 5.

[45] The coal burn per GW averaged 1.75 million tonnes from 1995 to 2003 and 1.78 million tonnes during the last three years.

[46] Kellingley 1.6 million tonnes, Maltby 1.4 million tonnes, Rossington 900,000 tonnes, opencast mines 1.5 million tonnes.

[47] The principal sources used in this report for employment data are the Coal Authority manpower returns. There are discrepancies between the figures in these returns and those shown on the UK Coal website and also in the Selby Coalfield Impact Study. This is partly because the figures in different sources may refer to different months and may have been estimated in advance or collated retrospectively, depending on the source. A fourth figure, which does not agree with either the existing Coal Authority or UK Coal figures is the DTI estimate of 1,531 for the end of 2004. We accept that the DTI figure for December 2004 is a prediction based on better information than is available to us.

[48] Selby Mines Econometric Model and Prince of Wales Colliers Econometric Impact Assessment, Coalfield Impact Study.

[49] Selby Coalfield Task Force Report.

[50] Selby Coalfield Impact Study, Selby Coalfield Task Force Report.

[51] Selby Mines Econometric Model.

[52] Interviews with the Coalfields Communities Campaign, LADs.

[53] These estimates are made using the combined rations of the Selby Mines Econometric Model and Prince of Wales Colliers Econometric Impact Assessment. UK Coal PLC informed us that they have used the same model.

[54] Jobcentre Plus Survey, July 2002.

[55] Coalfield Communities Campaign, Yorkshire Coal Fields Task Force, Councils' observations.