Energy Now and for the Future

UKOOA Economic Report 2006
“UKOOA is committed to deliver the best from the North Sea and create an industry which has an increasingly global reach.”
UK Offshore Operators Association Economic Report 2006

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Index

1. Foreword ................................................................................................................... ......4
2. Contribution to UK Economy .............................................................................................6
3. Providing for the UK’s Energy Needs ...............................................................................12
4. Outlook for the UKCS in 2006 ........................................................................................20
5. Global Competitiveness ..................................................................................................30
6. UKCS Contribution to Delivering Environmental Targets ..................................................36

Appendices ............................................................................................................................40

1. Fiscal Regime .............................................................................................................. ...40
2. 2005 Pre-Budget Report and 2006 Budget ......................................................................42
3. Glossary of Terms and Abbreviations ..............................................................................44
4. Contributors ...................................................................................................................45
The UK remains a very significant oil and gas producer and 2005 saw another strong year for the UK offshore oil and gas industry which produced 645 million barrels of oil and 85 billion cubic metres of gas. We continue to be an oil exporter and provided 93% of the nation’s gas. UK oil and gas met three quarters of the nation’s total energy demand in 2005, demonstrating the immense contribution our industry makes to the UK economy. Activity rose again last year as UKOOA’s member companies sought to explore and develop new opportunities and increase recovery from existing fields. Investment rose to £5 billion, again making them the largest industrial investor in the UK economy. Total expenditure including capital investment and operations reached nearly £10 billion, £1.5 billion higher than in 2004. Even before the latest tax increase, tax revenues to government in 2005/6 rose to nearly £10 billion in response to the rise in oil price.

The mix of gas supplying the UK is gradually changing as we move to import more of the nation’s needs over the next few years. New pipeline and LNG import projects, expansion of the existing interconnector to Belgium and completion of a new interconnector to the Netherlands will bring new supplies to the UK. In the meantime, supply next winter is anticipated to be in a similar position to the last one where the UKCS provided a reliable, dependable supply of gas to the UK market and it should continue to do the same this winter and for many more yet to come.

Employment is expected to rise in 2006, with the industry providing jobs for 380,000 people throughout the UK. This comprises 290,000 people directly employed by the industry, with another 90,000 jobs supported by economic activity induced by the direct employees. In Scotland alone, the industry provides more than a 100,000 skilled jobs and provided an export industry which was worth £4 billion even in 2004 (the latest year for which data is available).

UK production of oil and gas reached a peak in 2000 and has begun to decline. As production declines it becomes increasingly challenging to sustain the competitiveness of a basin. If the UK is to make the most of its indigenous hydrocarbon resources it will be necessary for UKOOA member companies to invest £100s of billions in technically and commercially risky opportunities in a mature, high cost oil and gas province.

The “Tale of Two Futures” diagram below provides a perspective on the long-term potential of the UKCS and also a view on how bleak that picture could be if we fail to make the necessary investment. Discoveries now average at 20–30 million barrels of oil equivalent. This is fifty to hundred times smaller than the fields on which the North Sea was built. Life will be different in the second half of the North Sea. A new field will have to be brought on stream every three or four weeks if we are to deliver the better future. Achieving that outcome is by no means assured; the right investment and regulatory climate has to be in place.

As a consequence of the latest tax increase, which was imposed on the industry in December 2005, new fields are now taxed at a rate of 50% and older fields (pre 1993) which pay PRT, are taxed at 75%. Even before this increase the UK oil and gas industry was the most highly taxed sector of the UK economy. This tax rise has made the UKCS less internationally competitive and dangerously exposed in the event of a downward correction in the price of oil. With production beginning to decline, it might be expected that the tax burden should be reduced, rather than increased, to encourage investment and extend the life of the basin.
Over the last year the government has recognised the need to take a fresh look at UK energy policy, culminating in the launch of the Energy Review in January, 2006. The Review seeks to identify the measures that are needed by 2020 and beyond to tackle climate change, and ensure secure and affordable energy supplies in the UK. DTI’s own figures, contained in the Review, demonstrate that the UK economy will become more reliant on oil and gas in the period through to 2020 with demand rising from three quarters to 83% of total energy requirement, even with sustained growth in renewable energy sources. However, the UK is fortunate enough still to have substantial petroleum reserves remaining (possibly as much as 27 billion barrels) and it is of the utmost importance that UK energy policy focuses on making the most of this opportunity.

We hope that the Energy Review will recognise that energy policy needs to be better aligned and represented within government. Currently, it is being determined by a number of separate teams, including DTI, Treasury, DEFRA, Foreign Office and the Prime Minister’s office. UKOOA believes that this is not sustainable and that a more efficient and coherent approach is required, preferably managed by a dedicated department and headed by a Secretary of State for Energy.

“UK oil and gas met three quarters of the nation’s total energy demand in 2005, demonstrating the immense contribution our industry makes to the UK economy.”

There are too many different and un-necessarily burdensome regulatory influences (UK and EU) which fail to recognise the objective of maximising economic recovery of our reserves. The unsatisfactory rules regarding decommissioning provide an example of conflicting policies which hinder the trading of assets and may well result in the premature removal of existing pipelines to the detriment of future production. The UK fiscal regime has failed to provide long term stability to encourage investment. More specifically, it discourages the pursuit of high risk exploration and development opportunities and does not recognise that new fields are predominantly small, costly to develop and of marginal value after tax.

In 2006 the industry will continue to address the challenges posed by the rapidly changing business environment. If recent years have been dominated by rising oil and gas prices, 2006 may well be dominated by rising costs and global competition for rigs and human resources. The rapidly rising costs of operating in the UKCS, the global shortage of rigs and resources and the current UK tax and regulatory regimes all have the potential to frustrate companies’ plans and may lead to a failure to maximise the production of oil and gas. Government should not presume that the UK will remain a preferred location for investment even at current high oil and gas prices. UKOOA is committed to deliver the best from the North Sea and create an industry which has an increasingly global reach. We hope that other stakeholders will join us in that essential task.

Malcolm Webb
Chief Executive
UK Offshore Operators Association
UK Oil and Gas Production

The UK remains a significant oil and gas producer. In 2005, the UK produced 1.2 billion boe (barrels of oil and gas equivalent) from the continental shelf, adding to the total of 35 billion boe produced since 1970. In 2005 the UK satisfied domestic oil demand for the year, producing 645 million barrels of oil which compared with UK domestic consumption of 610 million barrels of oil. The UK met 93% of gas demand, producing 85 billion cubic metres of gas; the remaining 7% being met by withdrawals from storage and imports.

Figure 2: UK Oil and Gas Production 1970-2005

The UK remains in the top ten global producers of oil and gas overall. In 2004, it ranked as the ninth largest producer above Venezuela, the UAE, Indonesia and Kuwait. In particular, the UK was the fourth largest gas producer and thirteenth largest oil producer in the world.

Figure 3: Major Oil & Gas Producing Countries 2004

The UK economy retains a competitive advantage as one of a limited number of nations producing oil and gas. Sustaining production from the UKCS will only become more imperative over time as demand for oil and gas continues to rise. In 2005, 73% of the UK’s primary energy demand was met by oil and gas and DTI projections show this is set to rise to as much as 83% over the next fifteen years, depending on the scenario considered within the DTI Energy Review.
In 2005, primary energy consumption exceeded indigenous production for the second year running. Total UK consumption was 235 Mtoe (million tonnes of oil equivalent) compared to indigenous energy production of 216 Mtoe. The shortfall of 20 Mtoe exceeded that in 2004 due to the 10% fall in UK oil and gas production but, despite this, UK oil and gas together met three quarters of total UK energy demand. Whilst oil and gas consumption together were flat in 2005, coal demand increased by 2.3% as it became more attractive for electricity generation as oil and gas prices rose.

**Capital Investment, Gross Value Added and Expenditure**

Oil and gas companies play a key role in UK investment activity. In 2004 the UK oil and gas industry contributed a fifth of the capital expenditure invested by all production and manufacturing industries.

The UK’s offshore oil and gas industry also continues to create more wealth than any other production or manufacturing industry. In 2004, the latest year available, the oil and gas industry contributed 13% of the gross value added (GVA) of all UK production and manufacturing industries. At £27 billion, the GVA of the oil and gas industry accounted for 2.6% of the total GVA for the UK in 2005.

While oil and gas production itself makes a very important contribution to the UK’s wealth generation, investment and expenditure through the supply chain also made valuable impact, adding a further £12 billion in GVA to the UK economy. The supply chain also provides goods and services for export, supporting the global oil and gas economy as well as a much wider range of related industries which further boosts UK GVA and exports.

**Figure 5: UK Oil and Gas Industry Investment & GVA 2004**

- 19% Oil & Gas
- 28% Electricity, Gas & Water Supply
- 10% Other Manufacturing
- 9% Transport (Road/Rail/Air/Sea)
- 7% Chemicals & Products
- 6% Pulp & Paper
- 5% Basic Metals
- 4% Food, Beverages & Tobacco
- 3% Mining & Quarrying
- 2% Machinery & Equipment
- 1% Mining & Quarrying

Source: National Statistics
Since 1970, the upstream oil and gas industry has spent nearly £350 billion exploring for and recovering reserves from the UKCS, comprising £50 billion on exploration, £177 billion on development of oil and gas fields, including offshore and onshore infrastructure, and a further £120 billion to operate these assets.

**Figure 6: UK North Sea Expenditure 1970-2005**

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**Tax Revenues**

The UK economy has benefited from over £215 billion (2005 prices) in North Sea taxes since 1968. This is over and above the investment and expenditure in the UK economy, which has itself created further economic activity and additional fiscal revenues to HM Treasury.

Tax receipts have more than doubled, from £4.5 billion in fiscal year 2003-04 to £9.6 billion in 2005-06, as a result of high oil prices and acceleration of the payment of Corporation Tax announced in the Budget in March, 2005. This will rise further to around £10.3 billion in 2006-07 as a result of the December 2005 tax increase, which increases SCT (the Supplementary Charge to Corporation Tax first introduced in 2002) from 10% to 20%. The Treasury tax forecast is based on a $57 oil price in 2006, however it is anticipated that fiscal revenues will exceed this forecast given that oil prices averaged $64 over the first 4 months of 2006.

**Figure 7: UK North Sea Taxes 1991-2007**
Balance of Trade

Although UKCS production has declined since 2000, it still makes a very significant contribution to the UK’s balance of trade. With a current trade deficit of £47 billion and high global oil and gas prices, the UK is reaping the benefits of its status as an oil and gas producer. To demonstrate the scale of this industry, if the UK had imported rather than produced the oil and gas consumed in 2005, it would have added an extra £28 billion to its import bill and would have increased the total trade deficit to £75 billion.

The UK balance of trade in oil and gas has been in decline since 2000 but became negative to the tune of £1.6 billion in 2005. Unlike in 2004, net imports of natural gas (£1.2 billion) were not offset by net exports of crude and oil products; instead, the UK was also net importer of crude and oil products, but by a much smaller margin (£400 million).

Figure 8: Balance of Trade Crude Oil, Oil Products and Natural Gas 1995-2005

The UK balance of trade not only benefits from the export of hydrocarbons but also from the substantial international activity of the supply chain to the oil and gas industry. Providers of oilfield goods and services that once focused on UK oil and gas production are now exporting their considerable technology and expertise globally. Recent SCDI surveys show that oil and gas export activity from Scotland alone, derived for the UK oil and gas supply chain, is estimated to have grown from £2 billion in 1998 to £4 billion in 2004.

Office for National Statistics (ONS) data collection methods mean the export statistics provided do not lend themselves to the ready calculation of international activity of the supply chain. This shortcoming means that the total contribution of oil and gas supply chain and service companies to the UK economy is understated; however, UKOOA is now to commission a new study to assess more fully the impact on the UK’s balance of trade.

Without the presence of the UKCS, most oil and gas supply chain companies would not have emerged in the first place within the UK economy. Many of these same companies have now begun to reach a global market from the UK, building on the technologies and expertise developed in the North Sea. If the supply chain can continue to develop as it has done, the continued increase in their international economic activity will help offset the declining contribution of oil and gas production to the UK’s balance of trade.

Contribution to UK Economy Employment

In 2004 the total employment provided by the oil and gas sector in the UK was estimated at 340,000 based on a recent study commissioned by UKOOA. These comprised 31,500 people employed in oil and gas companies and major contractors, a further 223,000 employed within the wider supply chain and 85,000 jobs supported by economic activity induced by oil and gas employees spending throughout the wider economy.
In 2005, employment in the oil and gas sector is estimated to have risen to 365,000. This is a 25,000 increase in employment over a year and is derived from the £1 billion increase in oil and gas companies/major contractors’ capital investment and expenditure during 2005. In 2006, it is projected that total employment will rise further to 380,000, with 290,000 directly employed by oil and gas companies and within the supply chain, as a result of the continued increase in investment and operating expenditure in the basin.

The increase in employment witnessed over the last two years has not risen as quickly as total spend, in part because of recent rapid cost inflation which has been demonstrated in the sharp rise in development and lifting costs. However, higher activity levels are evident throughout the industry which will continue to encourage and sustain job creation.

It should be noted that current employment estimates are higher than those suggested by previous research. In past studies, the knock-on impact on employment as expenditure trickled down from the initiators of the activity was less well recognised. In this latest study the operating expenditure and capital investment from major contractors are for the first time treated in a similar fashion to that of the oil and gas operators. Given the bigger initial cash injection considered, it then follows that the number of jobs derived from spending within the supply chain is larger than previously estimated.

There are distinct regional clusters of oil and gas employment within the UK. Over 100,000 high skilled oil and gas jobs are provided in Scotland alone because of the presence of the UK oil and gas industry. When total economic activity is included the industry provides employment for around 150,000 people in Scotland. Four parliamentary constituencies in the Aberdeenshire area account for 38% of all UK jobs supported by the upstream oil and gas industry. Outside the Aberdeenshire area, regions that are home to ports and terminals where oil and gas come ashore (Eastern England 5%) as well as the major construction and fabrication yards (North West England 6%) have high levels of employment, as does the region where many oil and gas companies locate their headquarters (South East England including London 21%).
Examining the distribution of supply chain jobs indicates that the range of suppliers is diverse. However, a few key industries are particularly important. Metal products, construction and engineering industries account for 16%, 15% and 8% of total jobs respectively. There are also substantial purchases from the business and professional service sector (12%), the legal sector (8%) and banking, finance and insurance (5%).

Figure 12: UK Oil & Gas Industry Employment by Parliamentary Constituency

The numbers on this map refer to parliamentary constituencies. A full list of these constituencies can be found on the UKOOA website at http://www.oilandgas.org.uk/issues/economic/index.htm

Footnotes
1 "Barrel of oil equivalent" (boe) equates gas volumes with oil, so that a single measure can be made of the two in combination.
3. PROVIDING FOR THE UK’S ENERGY NEEDS

Primary Energy Demand

Oil and gas together met three quarters of primary energy demand in 2005\(^1\) and demand is forecast to increase significantly by 2020. Under the DTI ‘favourable to coal’ scenario described within the Energy Review, oil and gas together will contribute 78% of primary energy demand, under the ‘favourable to gas’ scenario demand will rise to 83%. Both scenarios are based on February 2006 investment plans for nuclear and coal and the same assumption about the shutdown rates of power stations fired by these fuels. The difference between the two scenarios is the extent of fuel-switching between gas and coal from 2006 onwards as a result of price differentials.

In the ‘favourable to gas’ scenario, lower general prices mean the gas price is cheaper relative to coal, which triggers more gas use in generation relative to coal (i.e. it is the difference between coal and gas prices that is important rather than the absolute levels). The environmental impact of lower general prices triggering higher total energy demand is slightly higher emissions than in the ‘favourable to coal’ scenario.

Figure 13: UK Primary Energy Demand 1970-2020

In contrast to oil and gas, the contribution of coal to primary energy demand falls from 17% in 2005 to 10-14% in 2020 dependent on the scenario considered. Given current investment plans in nuclear plants, the contribution of nuclear to primary energy demand falls from 8% in 2005 to only 3% in 2020. While the share of renewables doubles between 2005 and 2020, it grows from such a small base that its ability to satisfy primary energy demand still only stands at 4% in 15 years’ time.

Electricity Generation

While oil is of central importance in the transport sector, in the power generation sector DTI’s own figures show its use is insignificant and falling. However, the use of gas for electricity generation is projected to increase dramatically, from 37% in 2005 to 60% in 2020 in the ‘favourable to gas’ case and to 54% in the ‘favourable to coal’ case.

Meanwhile the share of coal falls in both scenarios from 34% in 2005 to 21% in the 2020 favourable to coal case and only 15% in the favourable to gas. Given that the contribution of nuclear is assumed to be immune to relative coal and gas prices, its share falls from 21% to 7% in both scenarios.
Security of Energy Supply

Oil and gas from the UK Continental Shelf have provided security of energy supply for nearly three decades.

The UK has been self-sufficient in oil for the last 25 years and is expected to remain so for the next 4 or 5 years, if current new developments proceed as planned. If the UKCS remains competitive in global terms and attractive for new, international investment, these new reserves should continue to be developed and, as a result, the UK would be able to meet around 65% of forecast oil demand in 2020 from indigenous production. However, if this investment does not materialise, only about 20% of such demand will be satisfied by domestic production.
With rising demand for gas expected over the next 15 years and having become a net gas importer in 2004 after a decade of self-sufficiency, future UKCS gas production will be a major factor for security of energy supplies. Current production plans are only expected to deliver ~10% of UK gas demand in 2020, but, with sustained investment, UKCS production could still meet around 25% of such demand.

**Oil Prices**

High oil and gas prices both contributed to and constrained activity in the oil and gas sector in 2005. While they had the effect of making a greater volume of reserves economically attractive to recover, they also put pressure on resources and increased capital development and E&A costs, reflecting a global trend.

![Figure 17: Daily Brent Crude Price 2003-2006](source: EIA)

Linkage to European, oil indexed markets and a tight gas supply-demand balance have contributed to the average NBP day-ahead gas price rising nearly 60% in 2005 to 41p/therm, compared to 24 p/therm in 2004.

The average crude oil price increased by 40% to $54.5/bbl in 2005 compared to $38.3/bbl in 2004. These were 2 of only 5 years in history where the crude oil price in nominal terms has exceeded $30/bbl. However when the oil price is considered in real terms, taking inflation into account, the current high prices are put into context. It is then seen that over the last six years, average prices expressed in today’s terms have exceeded those of the previous twelve years, but are still not touching those experienced in the late 1970s and early 1980s.

![Figure 18: Annual Brent Crude Price 1965-2005](source: EIA / Bank of England)

When general inflation is taken into account, the volatility and cyclical nature of oil prices are much more apparent. Whilst the forward curve has an impact on investment, it continues to be seen that investments are driven by long term experience of oil price rather than recently seen prices.
UK Gas Market and Prices

The gas markets are currently undergoing some significant changes. The UK is becoming more dependent on imports, having for 10 years been a net exporter, and the price has been driven up by a combination of high oil prices, tight supplies in relation to demand allied to market sentiment and certain rigidities in the European market, all of which have led to volatility in wholesale prices at the National Balancing Point (NBP – the main trading point), where liquidity is good for short term, but poor for longer term trading.

High prices have led to a flattening of demand in recent years. During the winter of 2005-6 there was a reduction in demand for gas, as major users – especially power generators – switched to alternative fuels or curtailed production. It is likely that this will happen again during the winter of 2006-7. Looking further ahead, however, it is expected that growth in demand for gas will resume, as the retirement programme for nuclear power stations continues and large scale decommissioning of coal fired power plant occurs, on account of both age and increasing limits on environmental emissions. Within this timeframe (the next 10 – 15 years), only gas fired generation is capable of providing the bulk volumes of electricity required, while simultaneously keeping environmental emissions low, using proven technology and at an affordable cost.

Figure 19: Gas Demand by Sector 1985-2004

Imports: The market is responding to these trends and, although the UK remains and will remain a significant producer of gas for years to come, extremely large investment (c. £10 billion) in new supplies of gas from a variety of international sources is now well underway (see Figure 20):

- pipeline gas from Norway and Netherlands (both large exporters of gas) and mainland Europe via the Belgium – Barton Interconnector;
- Liquid Natural Gas (LNG) from Qatar, Egypt, Algeria, Nigeria and Trinidad.

Importantly, through such diversity of supply comes security of supply.

This list of projects is also a demonstration of the value to be derived from the technology and expertise which has been developed during 40 years of oil and gas activity on north-west Europe’s continental shelf.
Figure 20: New UK Gas Import Projects

<table>
<thead>
<tr>
<th>Name of Project</th>
<th>Target Date(s)</th>
<th>Capacity (bcm/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Langeled Pipeline (Ormen Lange)</td>
<td>2006 &amp; 7 (note a)</td>
<td>23</td>
</tr>
<tr>
<td>Bacton Interconnector</td>
<td>Phase 1 complete</td>
<td>8</td>
</tr>
<tr>
<td></td>
<td>Phase 2 2006</td>
<td>7</td>
</tr>
<tr>
<td>BBL Pipeline</td>
<td>2006 &amp; 7</td>
<td>14</td>
</tr>
<tr>
<td>Isle of Grain LNG</td>
<td>Phase 1 complete</td>
<td>4</td>
</tr>
<tr>
<td></td>
<td>Phase 2 2008</td>
<td>9</td>
</tr>
<tr>
<td></td>
<td>Phase 3 2010</td>
<td>7</td>
</tr>
<tr>
<td>Tamper Pipeline (Statford - FLAGS)</td>
<td>2007</td>
<td>10</td>
</tr>
<tr>
<td>South Hook LNG</td>
<td>Phase 1 2007-8</td>
<td>11</td>
</tr>
<tr>
<td>Dragon LNG (Milford Haven)</td>
<td>Phase 2 2008-9</td>
<td>10</td>
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<tr>
<td></td>
<td>Phase 1 2007</td>
<td>6</td>
</tr>
<tr>
<td></td>
<td>Phase 2 2010-12</td>
<td>6</td>
</tr>
<tr>
<td>Canvey Island LNG (planning submission)</td>
<td>2010-11?</td>
<td>5</td>
</tr>
<tr>
<td>TOTALS</td>
<td></td>
<td>83-210 (note c)</td>
</tr>
</tbody>
</table>

Notes:
(a) Southern leg of pipeline (from Sleipner) on-stream in 2006, Ormen Lange field and remainder of pipeline in 2007
(b) Original import capacity of Interconnector = 8.5 bcm/year
(c) Figure of 83 applies without Canvey Island and Phases 2 and 3 of other LNG projects

Current demand in the UK is $\sim$100 bcm/year, bcm = billion cubic metres.

Therefore, it is possible that over the next few years the UK will again have a surplus of gas although, with the Bacton Interconnector’s ability to flow gas in both directions (and perhaps the BBL pipeline similarly at some future date), the market will no doubt balance supply in accordance with demand throughout an increasingly interconnected north-west Europe.

It should also be noted that none of this list of import projects directly involves Russian gas supplies, although indirectly some such gas is probably being delivered via the Bacton Interconnector today and, if the proposed North European Gas Line through the Baltic Sea comes to fruition, Russian gas is likely to gain access to the UK via the BBL.

The rise in the LNG market in recent years has introduced a new and flexible dimension to international gas trading. It is expected that LNG will see a four-fold growth in shipments worldwide between 2000 and 2020 (and five-fold by 2030), albeit from a low starting point. While the UK will have to compete for LNG with other countries in Europe and North America, it has different supply characteristics from pipeline gas which will add to security of gas supplies.

Prices: The price volatility at the NBP mentioned above is demonstrated in figure 21 for both the prompt (day ahead) and forward markets (first quarter of each of the four years, 2005-8, shown for illustrative purposes). However, the prompt price also shows periods of significant stability, interspersed by volatility, while the forward prices generally show a rising trend as a result of the rising oil price and concerns about supply versus demand in winter. It should be noted, though, that the price for gas in the first quarter of 2008 is below that for the first quarter of 2007, reflecting the effects of the new imports. It is expected that greater stability should be restored as increasing imports of gas find their way to the UK’s market.

It should be noted, however, that gas traded through the markets accounts for about one third of the total volume sold. The remaining two thirds are sold under medium and long term wholesale contracts where prices are much more stable, although they have risen with energy prices generally. The gas sold under these medium and long term wholesale contracts is mainly used to supply domestic and smaller commercial customers.
Winter Supplies: During the winter of 2005-6, the UKCS delivered very much as predicted (which also happened in winter 2004-5) and, although there were inevitable short term variations, overall gas production was consistent (ref “beach” gas in figure 22 below). UKCS production of gas responds mainly to changes in demand, rather than changes in the prompt price. The winter of 2005-6 was colder in Britain than for 10 years, although no colder than average (other recent winters have been warmer than average). However, mainland Europe had a much colder than normal winter, with Eastern Europe experiencing an extremely cold winter. As a result, demand for gas was very high and so there was considerable pressure on supplies throughout Europe.

The prospects for the forthcoming winter, 2006-7, are similar to winter 2005-6 for Great Britain and Ireland (with the extent of inter-connection, the Irish market operates very much in tandem with GB’s). The natural decline in UKCS supplies should be matched by increasing imports from various sources.

Bacton-Zeebrugge Interconnector: As expected, flows of gas through the Interconnector from Zeebrugge to Bacton have increased in recent winters to compensate for declining UKCS production (in this direction, it is known as “reverse” flow – gas flowing from Britain to Belgium is known as “forward” flow). The first stage of the Interconnector’s expansion of reverse flow capacity was completed one month ahead of schedule in early November 2005. It took some time for the market to respond to the availability of this extra capacity, but later in the winter in February and March 2006 much of the additional capacity was being used during colder than normal weather. However, it is clear that there are physical restraints in the pipelines on the continent feeding gas to Zeebrugge which will not be fully resolved before 2010 and it would appear that public service obligations in various European countries keep gas in store early in a winter in case of need later in the winter. These two factors, together with the early completion of the Interconnector’s expansion, probably explain the seemingly slow response to the increased capacity.
**Gas Demand:** Because of its widespread use in space heating, demand for gas is driven largely by ambient temperatures, although business activity also has its influences. (For example, weekday demand is higher than at weekends; hence the saw-tooth nature of the demand curves shown in figure 24 below). Significantly, it can be seen that actual demand was below seasonal normal during the winter of 2005-6, even though it was an average winter overall. As mentioned above, high prices in the traded markets caused reductions in demand for gas mainly among power generators and, to a lesser extent, heavy industry (the day ahead price at the NBP is shown in blue shading at the bottom of figure 24).

Except in mild conditions, it is likely that the same will happen during the winter of 2006-7. Thereafter, the increasing availability of new imports of gas should make substantial improvements to the UK’s supplies, thus steadying the markets. It is worth noting that, at the time of writing (in late May 2006), with demand comfortably satisfied by available supply, the day ahead price at the NBP has fallen to the low to mid 30s of pence per therm which compares with an oil indexed price, typical in mainland Europe, of 45-50 p/th.

**European Gas Prices:** As may be seen in figure 25, gas prices for commercial and industrial customers throughout Europe have increased substantially in the past year, on the back of a higher oil price and increasing worldwide demand. Prices in Great Britain are among those which have risen the most, reflecting the influences described in the paragraphs above and the open nature of the UK’s market. As the large, new import projects come to fruition and more gas is delivered, it is a plausible prospect that prices in Britain will fall relative to those in mainland Europe which are indexed to the prices of oil products and, once more, prices here will become lower than elsewhere.
In this context, it is worth noting that, for the large majority of the years since our markets were liberalised in the mid-1990s, prices in the UK have been significantly lower than those in Europe. It is also worth commenting that there has been clear evidence of intervention by the authorities in France and Spain artificially restricting price rises and that, in Germany, small and medium users pay the highest prices among the countries surveyed, while large users are much lower down the scale. The consequences of oil indexation which take effect with a 6-9 month delay are likely to drive continental European gas prices even higher in the coming months.

Figure 25: European Gas Prices 2005-06

Footnotes

1 DTI ‘UK Energy and CO2 Emissions Projections’ published Feb. 2006
2 These are subject to an investigation by the European Commission’s Competition Directorate.
3 During last winter, 2005-6, demand for electricity in Great Britain peaked at about 60,000 Mega Watts (or the same as one thousand million 60 watt light bulbs burning).
4. OUTLOOK FOR THE UKCS IN 2006

Production

Total production of oil and gas was 3.2 million barrels of oil equivalent per day (boepd) in 2005 which represented a similar decline rate to 2004. This decline was more apparent in oil rather than gas production and can be attributed to some unplanned outages as well as prolonged maintenance shutdowns. UKOOA anticipates a more positive outlook for production from 2006 with several new small projects coming on stream as well the start up of the sizeable Buzzard field (200,000 boepd) towards the end of the year. Total production of oil and gas in 2006 is currently forecast to be in the range of 3.0 million boepd.

Figure 26: UKCS Oil & Gas Production Forecasts 2004-10

Continued investment in the UKCS has the potential to almost halve the production decline rate to the end of the decade from 7% per annum to 4% per annum. The reserves that are on plan to be recovered between 2006 and 2010 have increased by 2% since the 2004 Activity Survey.

Figure 27: UKCS Progress in Production Forecasts 2004-10

It is becoming increasingly likely that the industry will fulfil the PILOT vision of producing 3.0 million boepd in 2010. The Activity Surveys in 2003, 2004 and 2005 have projected 2.4, 2.6 and 2.7 million boepd respectively. In part this is a result of continued exploration and development activity, in part the slippage of production into subsequent years.
Oil and NGL production in 2005 continued to satisfy UK demand for over the year with recovery of 645 million barrels. Although this represented an 11% decrease compared to 2004, the outlook going forward continues to improve, with a slight increase in production projected over 2007/8. While this is predominantly due to Buzzard coming on stream, recent increases in drilling and new development activity are also contributing.

Taking this potential increase over the next couple of years into account, the oil production decline rate to 2010 could now stand at only 2% per annum in comparison to 6% per annum in the previous survey. This is a direct result of the increased investment in development activity that is so apparent and indicates that the UK could still be as self-sufficient in oil out to 2009/10.

85 billion cubic metres of gas were produced in 2005. While this represents a 9% decline on 2004 production, the outlook to 2010 has improved with the decline rate per annum now slightly lower than was estimated last year. Again, continued investment has the potential to almost halve the decline rate from 10% to 6% and UKCS production is still predicted to satisfy the vast majority of UK gas demand at least until 2010.
It should be noted that only 80% of the oil and gas production forecast in 2010 is from currently sanctioned investments. This is particularly relevant for gas when at a time of concern over security of gas supply investment decisions are still to be made on 20% of gas production through to the end of this decade. Investment decisions will be impacted by the commercial, regulatory and fiscal environment as well as the competitiveness of the province.

**Expenditure: Exploration and Appraisal, Development and Operations**

**Rising Cost trends:** The survey was taken at a time when development and operating costs are continuing to rise rapidly both in the UK and around the North Sea. The survey is based on the costs and availability of resource assumed at the time companies compiled their plans. However all the signs are that costs are continuing to rise despite the flattening in oil prices. This makes investments more costly and operating costs higher than anticipated when plans were compiled and has the potential to undermine the delivery of companies’ investment plans.

This is reflected in the unit technical costs of new developments where average costs are circa $17 per boe when capital and operating costs are included, discounted at 10%. When exploration and appraisal costs are included, total costs for new oil and gas are now in excess of $20 / boe which emphasises the poor competitive position of the basin if oil prices fall back below $40.

**Total Spend:** £350 billion has already been spent in the UKCS and, based on existing plans, it is projected that a further £42 billion will be spent before the start of the next decade. The survey shows that investment tails off with time; however capital investment plans tend to concentrate on the next 2-3 three years as companies address current developments.

The oil and gas upstream industry spent nearly 15% more in 2005 than 2004 with a total expenditure of £9.7 billion. This comprised £0.64 billion on exploring for and appraising new discoveries, £4.4 billion capital investment to bring new production on stream and £4.7 billion to enable recovery from existing fields.

**Figure 31: UKCS Expenditure Forecasts 2003-10**

![Figure 31: UKCS Expenditure Forecasts 2003-10](source)

£ Billion 2005 prices
The main driver of the increase in total spending was Capital Investment (Capex) of £4.4 billion. This represented a 30% increase in spending on wells (excluding E&A) and other field development activities, and due to the near term outlook in oil prices, Capex is expected to be maintained at this level in 2006. Current projections of capital investment fall off rapidly over the decade demonstrating the challenge if investment is to be sustained at current levels.

![Figure 32: UKCS Capital Expenditure Forecasts 2003-08](image)

Oil price hurdles used by many companies as a basis for investment decisions have risen over the last year, in part in response to current oil prices. This has increased the volume of reserves that are economically viable to develop; in response, the number of development wells drilled rose by 37% from 166 to 227 between 2004 and 2005. It is anticipated that a similar number of wells should be drilled in 2006, although this may be constrained by competition for the limited number of drilling rigs available in the North Sea.

![Figure 33: UKCS Drilling: Development Wells 1999-2006](image)

Also reflected in the increase in capital expenditure is the higher cost of development drilling; it is in direct competition with E&A activity to secure rig slots for which daily rates have soared – this will be explored further below. To alleviate the tightness of the UKCS rig market, there is evidence that platform rigs are being re-commissioned, a very expensive process in itself. Increasingly, companies are pursuing more marginal projects, in part responding to the forward oil curve. The recently increased tax rate could reverse this effect though as economically marginal projects become less viable, especially if the oil price falls from the level seen in 2005/6.

Exploration and appraisal activity has continued to increase over recent years with 78 E&A wells drilled in 2005, a 25% increase on the 63 drilled in 2004. Projections suggest that this upward trend will continue into 2006 and beyond, encouraged both by the PILOT initiatives as well as the current high oil price. In particular, the trend is that exploration wells will comprise a larger proportion of the total, implying that in future more appraising will take place which should yield greater reserves.
Despite these encouraging projections, several factors are liable to constrain E&A activity in the coming years. Note should be taken that a fifth of exploration activity aspirations are accounted for by Promote licensees, many of whom have made commitments to drill but have yet to secure rig slots.

Despite the increase in drilling activity in 2005/6 it should be remembered that previous experience has shown that higher levels of drilling have usually produced poorer success rates overall:
- Rising oil price has increased the proportion of finds which are commercially attractive to develop
- Only 4 wells have discovered over 100 million boe pools over the last decade
- Overall exploration has been showing a success rate of between 25% and 33%
- Against the better success rate this means exploration wells are recently delivering on average ~ 10 million boe per well or ~ 30 million boe/discovery
- It is clear that there is no “right” drilling rate. Even if the UK is to deliver 6+ billion boe from exploration, it could take 20 years or more.

The 23rd licensing round in 2005 saw a record 152 licenses awarded (76 Promote licenses, 6 Frontier and 70 Traditional). It attracted 24 new entrants to the UKCS and included 69 blocks previously released from earlier licenses under the DTI’s ‘fallow blocks and discoveries’ initiative.

The licensing activity was stimulated by recent high oil prices which have increased the potential rewards of successful exploration. Of particular note is licensing activity in areas previously less explored such as the Mid North Sea High, Moray Firth, East Shetland Platform and the Atlantic Margin as well as renewed focus on the extraction of heavy oil. Even with the potential rewards that exploration success might yield, these blocks are still regarded as high risk domains where there is heightened sensitivity to the cost, resource and investment environment.
E&A activity is competing for rig slots with development and production drilling; any projections of an upward trend of E&A wells in 2006/7 must reflect a measure of aspiration. Market capacity will only allow operators to drill a similar level of wells going forward as in 2004 and 2005, with rig utilisation already at 100% for jack-ups and 90% for semi-submersibles. There is potential for the rig market to become even tighter and act as a bigger constraint on activity if rigs are attracted away from the UKCS to other basins which offer a more attractive proposition.

![UKCS Rig Utilisation 2003-06](source)

While rig availability could prove to be a material constraint on E&A activity, the soaring rig rates may yet prove to have a bigger impact. Rig rates continue to rise. Semi-submersibles have shown the most dramatic increase, rising six-fold since the start of 2004, with jack-ups rig rates rising by three-to-four-fold over the same period.

![UKCS Rig Day Rates 2003-06](source)

Operating expenditure to enable recovery from existing fields remained flat at £4.7 billion but given the 8% production decline, unit operating costs (UOC) increased. In 2004 it cost £3.7 per barrel to produce a barrel of oil or gas equivalent (disregarding initial finding and development costs) but this rose to £4 per barrel in 2005, an increase of 8%.

Typically, the lowest unit operating costs have been in the Southern Gas Basin (together with lower revenue) but this advantage is being gradually eroded. This is worrying because a third of UKCS gas is still produced from the Southern Gas Basin and projects that are already marginal in economic and technical terms appear to be getting more expensive.
Despite the more positive production outlook for 2006 and 2007, UOCs are projected to be higher than was thought in the 2004 Activity Survey, reflecting the increasing cost of maintaining ageing assets and recent decline in production.

To ensure the industry can take advantage of investment opportunities that continue to present themselves in the UKCS, there is continued investment in long-term asset integrity and maintenance. This is a significant cost in such a mature basin.

### Figure 39: Projected UKCS Field Developments 2006-07

<table>
<thead>
<tr>
<th>Field</th>
<th>Location</th>
<th>Field Type</th>
<th>Operator</th>
<th>Development Status</th>
<th>Development Type</th>
<th>Expected Startup</th>
<th>Recoverable Oil million bbl</th>
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<tr>
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Energy Now and for the Future | UKOOA Economic Report 2006
Outlook for the UKCS in 2006  New Developments

22 projects were given development approval in 2005, comprising 13 new field developments (7 liquids and 6 gas) and 9 incremental projects on existing fields (7 liquids and 2 gas).

13 new fields were brought into production in 2005, comprising 9 subsea developments and 4 new platforms. Figure 39 summarises the new field developments that operators are expected to bring on-stream in 2006 and 2007. As has been the case in recent years, they are predominantly subsea developments and located in the Southern and Central North Sea.

Outlook for the UKCS in 2006  Asset Trading and New Entrants

The UKCS has seen a healthy level of asset trading in the last decade with 1 billion boe being traded on average each year. There has, however, been a slow down in the asset transfer market since the peak in 2000 with only 700 million boe a year being traded, seemingly because the current era of global mergers has come to an end.

Figure 40: UKCS Asset Transfer 1993-2005

Over the last decade about 50 deals a year have taken place, the buyers comprising existing large and small players as well as new entrants. Over the period, commercial activity was equally split between existing large and small buyers. However, the number of deals where the buyer is an existing large player has fallen with time.

Figure 41: Buyers of UKCS Assets 1995-2005
The contribution of small participants (production of less than 20 thousand boepd in 2005) has increased since 1999, in terms of both production and expenditure. The share of production accounted for by the majors (production of more than 200 thousand boepd in 2005) has fallen over recent years; however expenditure by majors appears to be increasing as a proportion of the total over the next two years. It is estimated that large and medium sized companies will account for over half of production in 2008.

**Stewardship of the UK’s Oil and Gas Resources**

Based on the latest DTI figures UKOOA estimates that there are still somewhere between 16 and 27 billion boe to be recovered from the UKCS over time with a mid case estimate of around 21 billion boe. However little of this will appear without companies’ continued willingness to invest in technically and commercially risky opportunities.

New production will come from:

i) Increased recovery of reserves in currently producing fields (“brownfields”)

ii) Development of known discoveries which are mostly small in size and marginal in economic terms

iii) Continued new exploration

The latest activity survey shows that the current industry plans may recover up to 11 billion boe from existing fields and new developments over the period from January 2006 to 2030. Of this figure, circa 9.3 billion boe are to be produced from currently sanctioned investments and a further potential 1.7 billion boe from new fields and incremental developments.
The survey shows a more positive picture than anticipated in the previous 2004 survey. Sanctioned investments will now deliver 2 billion boe more than expected a year ago, although the remainder of incremental and new reserves currently being worked has dropped from 3.2 to 1.7 billion boe. The challenge for the industry now is to identify new opportunities from exploration, enhanced recovery and new developments to replace the reserves currently being developed.

Figure 44: Evolution of UKCS Reserves
5. GLOBAL COMPETITIVENESS

UK Fiscal Environment

The tax increase for the UKCS announced in the Pre-budget Report in December 2005 saw the supplementary charge to corporation tax (SCT) doubled to 20% from 1 January 2006. As a consequence, new fields are now taxed at a rate of 50% and older fields (pre 1993) which pay PRT, are taxed at 75%. Overall, the effective tax rate on the UK oil and gas industry has risen from 49% to 56%.

When the measures were announced in December, HM Treasury stated that the increase in SCT would raise an additional £2.0 billion in 2006/7; however by the time of the 2006 budget, the estimate was lowered to £0.9 billion. It appears that costs in the North Sea have risen faster and production was lower than anticipated by HM Treasury. The impact of carrying capital allowances from 2005/6 forward into 2006/7 may also have been a factor. In subsequent years, HM Treasury now forecast the increase in SCT will raise around an extra £2.4 billion in 2007/8 and 2008/9.

This was the third substantial change to the tax regime in as many years and reinforced perceptions of fiscal instability in the UK. At the same time fundamental questions remain on the global competitiveness of the UKCS which will not have been helped by the tax increase. It is essential that all parties properly recognise the impact on investment behaviours, without a regime that recognises the global nature of the business long term recovery from the UKCS will be impaired. HM Treasury stated that the increase in SCT was prompted by the increased rate of return by companies operating on the UK Continental Shelf. HM Treasury also promised that there would be no further tax changes for the life of this parliament, to provide some stability for investors, and announced a consultation on structural issues regarding the North Sea fiscal regime. The following sections address each of these issues in more detail and also consider current initiatives to promote the UKCS.

Impact of the Increase in SCT on the UKCS

The increase in SCT may have an unintended long-term impact on the UKCS:

- Oil and gas activity in the UK is now ~ 16% less attractive. The increase in SCT reduced the value of new exploration and development, which in turn will reduce the global competitiveness of the UK, damage investment and, ultimately, security of supply.

- The UKCS is now increasingly exposed to lower oil and gas prices. Investment and drilling activity were declining rapidly on the UKCS prior to the increases in oil price seen in 2004. It should be anticipated that activity would again decline sharply if oil and gas prices revert to more usual levels.

- Marginal / riskier developments are less attractive. In 2002 when SCT was introduced, capital allowances were increased to encourage investment. This time there was no increase to capital allowances, which will impair the attractiveness of investments.

- Investors now add a risk premium to UK investments because of fiscal instability. This makes investment in the UKCS less attractive, particularly when compared against global competition.

- The short term impact of the tax increase in isolation may be limited but gives cause for concern when combined with rapidly rising costs. The surge in oil price has increased activity which will only be tempered in part by the increase in tax. At this time availability and costs of rigs and other resources are the primary constraints on activity. Indeed, rapidly escalating rig-rates may begin to deter investment.

- The offer of stability for the life of this Parliament may provide only limited comfort for investors. Given that investments typically take between 2 -5 years to come on stream, investors may still consider that they are significantly exposed during the productive life of new developments.

- Post-tax rate of return of the UKCS has declined over the last five years. The 2002 tax increase had already increased the economic rent transferred to HM Treasury. The latest increase will further depress post tax rates of return. It also raises concerns about the long term competitiveness of the basin, the more so when oil and gas prices have been rising.
Global Competitiveness

The competitiveness of the UK has been monitored by Wood Mackenzie, the oil and gas industry consultants for many years. Their latest published analysis covers new developments based on exploration activity over the period 1994-2003. The study looks at a wide range of measures of economic competitiveness; however, it is best to focus on the ability of the UK to attract exploration investment when considering the impact of the tax increase.

Expected Monetary Value (EMV) measures the success of exploration taking into account the impact of the tax regime, costs of development and risks of exploration failure. The following chart compares the UK against other countries of similar maturity or with similar types of fiscal regime. It is clear that even before the latest tax increase, the UKCS only just remains competitive for future investment.

Figure 45: Full Cycle EMV Comparison UK and Competitor Provinces

On a comparison of tax rates, the UK is seen to have become less competitive against all of the countries cited above as a result of the tax increase. This becomes more pronounced when the average size of discoveries is considered.

Figure 46: Comparison Tax Rate and Average Discovery Size 2005

Note: Average discovery size includes commercial and technical discoveries and is unrisked

Source: Wood Mackenzie
Oil and Gas Investment Drivers

Industry is concerned that changes to the fiscal and regulatory regime will have an adverse impact on investment. The following list highlights many of the key criteria which are routinely considered as part of an investment decision:

- Economic measures, (addressed below)
- Portfolio fit (e.g. global or regional)
- Strategic fit (e.g. niche / independent / major)
- Materiality (size, value and impact of opportunity addressed below)
- Timing and Longevity (addressed below)
- Risk exposure (addressed below)

The relative importance of the different metrics, risks and opportunities will vary depending on the company, global competition and the local fiscal, regulatory and business environment. However, all the following measures have been impaired by the recent tax increases.

**Economic Measures** include Net Present Value (NPV) and Expected Monetary Value (EMV) which are both post tax measures and sensitive to changes in tax rate.

**Materiality** considers the size, value (post-tax) and impact of the opportunity. The size of new discoveries in the UKCS is typically small and may demand disproportionate company resource to develop.

**Timing and Longevity** of investments are both considerations. The oil and gas industry is a long term industry, seeking to make long term investments which will deliver long term value for all stakeholders. Investments typically take 2-5 years to come on stream and may be producing for 15 years. In such cases, investments are tested against long term perceptions of price combined with an assessment of regulatory and fiscal risk.

**Risk Exposure** In all cases an assessment of risks is a fundamental part of making an investment decision. Oil and gas investments typically face a number of risks in which different parties are involved:

<table>
<thead>
<tr>
<th>Risk</th>
<th>Party</th>
</tr>
</thead>
<tbody>
<tr>
<td>Technical</td>
<td>Industry</td>
</tr>
<tr>
<td>Costs</td>
<td>Industry, Market</td>
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<td>Government</td>
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<td>Political / Regulatory</td>
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</tbody>
</table>

All these risks are borne by the investing companies; the only risks that the Government can influence are within the fiscal, regulatory and political environment. Companies will assess these risks when deciding on the proportion of their capital funding that is likely to be invested in different oil and gas basins. Perceptions of future risks are based on historic experience and assessments of likely future decisions and policies. These may be reflected in different discount rates being applied to different basins according to the perceived risk.
UKCS Rates of Return

The Office of National Statistics (ONS) regularly publishes details of the Rates of Return for the oil and gas sector. This profitability measure is more usually referred to as “Return on Capital Employed” (ROCE). It is an accountancy measure calculated as the ratio of EBIT (Earnings before Tax and Interest) to capital employed.

ONS follows the convention in reporting Rates of Return (ROCE) on a pre-tax basis. However, in doing so it fails to highlight that the UKCS is taxed at a much higher rate than other industries, with marginal tax rates ranging from 40% - 70% in 2005 rising to 50% - 75% from 1 January, 2006.

Figure 47: UKCS Rate of Return (Pre- and Post Tax) 1995 - 2005

The above chart compares ONS Rate of Return (ROCE) on both a pre-tax and post-tax basis for the UKCS over the last decade. Despite the increase in oil price since 2003, the post tax rate of return has declined over the last five years. In large part, this reflects the tax increase imposed on the UKCS in 2002; it demonstrates that even before the latest tax increase in 2005, the fiscal regime was already very effective in transferring economic rent to HM Treasury. The continued decline of the post-tax Rate of Return also raises concerns about the long term competitiveness of the basin, all the more so when oil and gas prices have been rising.

Moreover, UKOOA has fundamental reservations on the use of Rate of Return (ROCE) as a measure of profitability. Economic measures are used to drive investment rather than accountancy measures such as Rate of Return (ROCE). UKOOA consider that ONS figures understate the massive capital investment in the UKCS, leading to an over estimation of the Rate of Return. In recognition of this, ONS, on their website, express concern about the use of this measure for the UKCS.

Current Initiatives to Promote the UKCS

DTI and UKOOA are working closely together through PILOT, the joint Oil and Gas Industry / Government body chaired by the Energy Minister, to encourage a positive business environment which can maximise recovery of oil and gas. These measures combined with the rise in oil price have undoubtedly benefited the UKCS:

- **Access to Data**  the DEAL website (www.ukdeal.co.uk), is now an indispensable tool for any company working or wanting to work in the offshore UK. DEAL is a free publicly available web-based service managed for UKOOA by its subsidiary CDA. This includes access to the National Hydrocarbon Data Archive, the repository for relinquished licence data;
- **Access to licences**  new promote and frontier licences enhance the fallow discoveries and blocks process;
- **Access to infrastructure**  through the revised Infrastructure Code of Practice;
- **Good stewardship of UKCS assets**  through the new “stewardship process” launched in 2005;
- **Positive commercial behaviours**  through the Commercial Code of Practice;
- **Strong supply chain**  through the Supply Chain Code of Practice.
The industry is committed to self regulation and performance improvement. Delivery against codes of practice is reviewed annually and reported through PILOT. The Infrastructure Code of Practice was re-written in 2004 and a full review will be carried out by UKOOA with DTI during 2006.

### Meeting the Decommissioning Challenge

Over the next two decades the industry will begin to decommission many of the installations that have been producing oil and gas in the North Sea. It is a complex process which will represent a challenge to the industry on many fronts encompassing technological, economic, environmental and health and safety issues. Approximately 470 installations are planned to be decommissioned, which include small and large steel platforms, subsea and floating equipment. Some 10,000 kilometres of pipelines, 15 onshore terminals and around 5,000 wells are also part of the infrastructure planned to be gradually phased-out.

**Figure 48: UKCS Decommissioning Profile 2005-30+**

An indicative profile of the asset base to be decommissioned is shown in figure 48; however the precise timing of decommissioning is highly uncertain and has in many cases already been pushed back from what is shown. Decommissioning timing will be influenced by a range of factors including:

- **Long-term trends in oil and gas prices** which will determine whether it remains economic to keep a field in operation;
- **Long-term certainty on both fiscal and regulatory regimes** which will influence the future investment environment;
- **Increased recovery** from existing fields, new exploration and tie-back of new fields, which will extend the productive life of these assets and infrastructure;
- **Reduction of decommissioning cost** through greater co-ordination with the supply chain and a more systematic approach across the industry;
- **Technological innovation** - which will increase oil and recovery, extend the life of many existing ageing facilities and ultimately reduce the costs of decommissioning.

The costs involved in decommissioning UKCS infrastructure are estimated at £10 - £20 billion - the wide range reflects the uncertainties regarding those liabilities. UKOOA's own activity survey places decommissioning costs at just under £12 billion in real terms, some £2 billion higher than expected only three years ago. It should also be noted that over the same period decommissioning has slipped by around two years as a result of the increase in oil prices and improved projections of recovery.
Whilst for most fields decommissioning is not an imminent activity, it already has an impact on the economic life of the UKCS. There are concerns whether current requirements regarding the financial securitisation of decommissioning liabilities and their fiscal treatment are creating an unnecessarily costly and rigid framework in which to operate in the UKCS. It is increasingly recognised that changes may well be required to the regulatory framework and fiscal treatment of decommissioning if the UK is to continue to attract new entrants and extend the economic life of the basin. PILOT is now addressing these issues and hopes to report on its findings in 2006.
As the UK economy has shifted from reliance on manufacturing to services and energy efficiency has improved, less energy has been required per unit of output. Overall, the energy intensity of UK output has halved since 1970, with reductions in coal (82%) and oil (63%) intensity leading the way. However, the use of natural gas has increased dramatically with the volume of gas consumed in the creation of every £1 of output having tripled since 1970. Although the use of renewables and hydro-electricity in output creation has more than quadrupled since 1970, the starting point was so small that even in 2004 only 2% of energy used per £1 output was attributable to this type of energy.

Given that gas is less polluting than oil or coal, this switch between energy sources has made a positive contribution to efforts to reduce emissions of greenhouse gases as shown in figure 51. This is reflected in the emissions intensity of energy consumption which fell by 20% between 1990 and 2004.

The UK is committed under the Kyoto Protocol to reduce greenhouse gas emissions by 12.5% by 2008-12 compared with emissions in 1990. Furthermore it has set its own target of reducing CO₂ emissions by 20% between 1990 and 2010. As figure 51 below shows, the UK is already meeting the Kyoto target of greenhouse emissions.

Despite an increase in energy demand of 10% over the last 15 years and a slight increase in CO₂ emissions since 2002, overall the UK has recorded a reduction in CO₂ emissions since 1990. This trend has been assisted by the switch from coal and oil to gas, for which power generation is much more thermally efficient and lower carbon-emitting. The extent to which the proliferation of gas’ contribution to electricity generation is forecast to rise from 37% in 2005 to as much as 57% in 2020 can continue to contribute to the UK’s CO₂ emissions reduction will depend on the mix of gas and nuclear generation capacity that is built to replace coal-powered generation.
Carbon Capture and Storage and Enhanced Oil Recovery

Recent increased focus on carbon abatement technologies is driven both by a growing awareness of climate change, and the provisions of the Kyoto protocol. Carbon capture and storage (CCS) is one such abatement technology, which has the capability to reduce substantially emissions from the use of fossil fuels. It involves three separate stages: capture, transport and storage. The CO₂ from large industrial or power generation sources is first captured using a combination of physical and chemical processes, then transported to a storage location and finally stored in a geological structure such as a suitable mature oil or gas reservoir or an aquifer.

Europe is believed to have extensive CO₂ storage capacity, predominantly located beneath and around the North Sea. The British Geological Survey has estimated the potential storage capacity under the whole of the North Sea at around 20 billion tonnes of CO₂ in oil and gas fields, with an additional 2070 billion tonnes of CO₂ in confined aquifers. This compares favourably with the UK’s current emissions of around 560 million tonnes CO₂ per year.

CCS has the potential to enable low carbon electricity production and provide an environmentally attractive method of disposing of CO₂. The DTI Energy Review identified a role for carbon abatement technologies such as CCS within the nation’s energy strategy. In parallel, HM Treasury has launched a consultation on barriers to commercial deployment of CCS. However, this correctly identifies that the lack of economic incentive is the single biggest issue to be addressed, if CCS is to be pursued in and around the North Sea.

Figure 52: Carbon Capture and Storage

CCS may in some circumstances provide tertiary oil recovery, as enhanced oil recovery techniques such as water and gas injection have already been employed on the majority of the UK’s oil fields. In many cases, even if the CO₂ is used for EOR, the benefits are anticipated to be insufficient to render a project commercially viable. It should be noted that CCS will not enhance the recovery of hydrocarbons from gas fields, particularly in the southern North Sea. However, such fields in the southern North Sea are closer to shore and possibly cheaper to redevelop for CCS than fields in the central and northern sectors of the North Sea.
Existing offshore oil and gas fields, pipelines and infrastructure have not been designed for CCS. Indeed, the costs and complexity of retrofitting CCS capability on ageing facilities may prove excessive and instead require substantial rebuild which may prove to be similarly costly.

CO₂ storage is only currently used in the North Sea in one application, at the Sleipner field in Norway. Here CO₂ is removed from the produced natural gas, to improve its quality, and then reinjected in the “utsira” formation - a 200m thick sandstone aquifer located 800m below the sea bed. In the case of Sleipner, reinjection of the CO₂ was an integral part of the field’s overall development planning and economics, and the offshore production facilities were specifically designed for that purpose. Sleipner does not involve the import of CO₂ from other fields or onshore industrial processes, nor is the CO₂ used to enhance oil recovery.

The recently announced project to take natural gas from North Sea fields, convert it to hydrogen as fuel in Peterhead and utilise the CO₂ produced from the process for enhanced oil recovery and long-term geological storage in the Miller Field is a first for the UK. Other projects are also being considered elsewhere in the North Sea. However all these projects demonstrate the current lack of commercial viability of CCS.

Aspects of the legality of CCS offshore are currently in question. CO₂ is officially designated a waste product and injection offshore is only allowed under international law (the London and OSPAR Conventions) if it is associated with EOR. It is understood these Conventions are being reviewed with the intent of permitting CCS offshore, independent of EOR. Until the Conventions can be amended, it will only be possible to store carbon offshore as a means of providing EOR, which limits the candidate reservoirs and may constrain the development of this business.

In the longer term, if CCS is to emerge as a commercially viable form of carbon abatement, one of the drivers underpinning investment will be the traded price of carbon. Current indications are that the traded price of carbon in the EU Emission Trading Scheme (EU ETS) must be several times higher than the recently seen prices of €20 - €30 before projects using current technology for carbon capture start to become commercially viable. Investors will have to begin to gain confidence in the carbon price and the liquidity and depth of the carbon market before investing in CCS.

The current volatility of the traded carbon market demonstrates that the market is insufficiently mature at this time to drive investment in CCS and it may take many years before sufficient experience is available. The recent drop in the traded price of carbon, which saw prices halve, only serves to emphasise the volatility of the market. Until this market attaches a sufficiently high value to carbon, the UK will need to consider its own means of incentivisation if this potentially significant industry is to develop.

**Emissions Trading Scheme**

The EU ETS came into effect at the beginning of 2005, as part of Europe’s response to the challenge of climate change. The first phase is from 2005 to 2007 and the second from 2008 to 2012, the Kyoto period. Already, consideration is being given to a third phase; it will be important that clear decisions are taken by governments for the post Kyoto period to ensure that the evolving market is given the necessary signals to plan and develop in a manner which will deliver reductions in emissions in the most competitive way.

The results for the first year of phase one have now been published and, although too much should not be read into one year’s outcome, it would appear that the UK is shouldering its full share of the burden among EU Member States, significantly because of the government’s domestic target for CO₂ emissions which is far more demanding than achievable the country’s Kyoto target. Over all industrial sectors within the EU ETS, the UK’s emissions were 12.5% in excess of plan. However, this excess occurred entirely within the power generation sector, with other sectors including offshore oil and gas being within their plans.

When the first year’s results across the EU were published, the price of a tonne of CO₂ fell dramatically from €25-30 to around €10, although it has since partly recovered to €15-20. Such volatility suggests a “thin” market and lays down a challenge to those countries who have probably not implemented the EU ETS with the rigour which the UK has applied. Indeed, it is concerning that our government is potentially jeopardising industrial competitiveness through its more stringent implementation of the scheme than is occurring in other Member States.

Preparations for phase two are well advanced with a draft National Allocation Plan due to be published for comment in summer 2006, for final submission to the European Commission by the end of the year. DEFRA is the leading department for the ETS,
with major support from DTI with whom UKOOA is working closely on all aspects of the scheme as it applies to offshore oil and gas. As part of an expansion of the emissions covered by the scheme, it is likely that offshore flaring will be included in the second phase.

Nonetheless, it is essential that those sectors of the economy within the EU ETS do not shoulder more than their fair share of the burden of reducing harmful emissions and that, in a competitive economy such as ours, all parts make their contribution. It is far from clear that this is the case currently, just as it is far from clear that all other Member States are contributing to the extent which the UK is.

Produced Water Trading Scheme

Water is produced in combination with the associated hydrocarbons from oil and gas reservoirs; this produced water is first cleaned to remove hydrocarbons then discharged to sea. Currently the maximum allowable discharge of oil in produced water is 40mg/l; however the industry averaged around 20mg/l in 2005. Independent research indicates that produced water’s contribution to the total volume of oil entering the North Sea is around 6%. In 2005 approximately 240 million tonnes of produced water were discharged to sea and the rate of water production continues to rise as reservoirs age.

Following recommendations by OSPAR in 2001, the DTI is introducing new regulations to:

1. Limit dispersed oil in discharges to sea to a monthly average of 30mg/l by the end of 2006.
2. Reduce total dispersed oil in produced water discharges by 15% below the quantities produced in 2000 by 2006.

The reduction in the discharge of produced water effectively requires a 28% reduction in total water discharged to sea, given the continuing trend of increasing water production since the 2001 recommendation was made. It is also proposed that all new installations achieve zero discharges of oil in produced water to sea. This may be problematic to implement and will act as an impediment on new developments given most are subsea tiebacks and rely on the use of existing processing facilities. It is also questionable whether a zero discharge has an environmental benefit.

The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (OPPC) came into effect on 20 August 2005 replacing POPA. Under OPPC, installations are granted a permit for activities discharging oil to sea. From 1 January 2006 the oil in produced water must not exceed 30 milligrams per litre as a monthly / yearly flow weighted average. Additionally, in 2006, each installation has a total tonnes of oil discharged to sea contained within their permit which operators should make every effort to comply with. The regulations include a trading mechanism through which installations should be able to work together to meet the UK wide target. The regulations also contain a substantial civil penalty, currently set at £108 for every kilo of oil discharged in excess of that permitted.

Recent improvements in produced water management have been maintained. The improvements in this area are an achievement for the offshore oil industry as the amount of water produced with oil increases as fields mature. This highlights the considerable efforts being made by both Government and industry in minimising the oil in produced water discharges. Each installation’s produced water discharge is different and as such there is no single solution to reducing the oil discharges.

Current indications are that the industry will invest over £250 million in additional abatement measures to meet the new regulations. A large variety of techniques are already employed to remove oil from produced water and it has to be recognised that further abatement measures come with an environmental as well as a financial cost. These costs should be compared with the incremental environmental benefit. The Policy Studies Institute has examined the overall environmental impact from further abatement of produced water and made an overall impact assessment. The study concludes that current levels of emissions suggest only a hypothetical or low risk; it must be questioned, therefore, whether the substantial new investments will deliver environmental value for money and provide the most appropriate environmental effects.

Footnotes

The offshore oil and gas industry is the highest taxed industry in the UK. Fields developed since March 1993 are taxed at 50%, liable for both Corporation Tax at 30% plus a Supplementary Charge at 20%. The marginal tax rate rising to 75% on fields developed prior to 1993, which are also liable for Petroleum Revenue Tax (PRT) at 50%.

Figure 53: Marginal Government Take from Fields Ranges from 50% to 75%

**Corporation Tax (CT) and Supplementary Charge (SCT):**

The combination of SCT and CT mean that all new field developments are taxed at a rate of 50%.

Corporation Tax (CT) is applied to all company profits in the UK at a rate of 30%. However the CT regime applying to the oil and gas exploration and production industry is modified and extended. Production has been subject to two additional imposts: Royalty and Petroleum Revenue Tax (PRT), although Royalty was abolished from 1 January 2003.

The Supplementary Charge to Corporation Tax (SCT) was raised to 20% from 1 January 2006. It was originally introduced at a rate of 10% in the April 2002 budget, which also saw the introduction of 100% First Year Allowances for UKCS capital expenditure. Since the introduction of 100% First Year Allowances, all costs are effectively tax deductible as incurred, with the exception of long life assets which secure a 24% First Year Allowance, and 6% of the remaining balance on a reducing balance basis.

Taxable profits derived from the extraction of oil and gas from the UKCS are also “ring fenced” so that losses from other activities cannot be offset against ring fenced profits. Stringent rules are also applied to ensure that only interest relating to UKCS projects is deductible within the ring fence. The taxable profit for SCT differs from CT in that finance costs are not deductible.

**Petroleum Revenue Tax (PRT):**

PRT of 50% raises the marginal rate of tax to 75% for many oil and gas fields.

It is applied on all fields which received development consent before 16 March 1993, and to tariff arrangements existing prior to 9 April 2003 relating to pipeline systems and other facilities which in some part service a PRT paying field. Tariff contracts arranged on or after this date are exempt from PRT, as addressed in the Finance Act 2004. PRT is applied to profits on a field-by-field basis in six-month chargeable periods. If losses arise, the ability to surrender losses to other fields is extremely limited.

PRT is deductible for CT and SCT. Capital and operating costs are also deductible. No deduction is allowed for interest, but most capital incurred pre-payback (see below) qualifies for an additional deduction of 35% (uplift). As most fields subject to PRT are past payback, the significance of this relief is now very limited.

Payback is the period in which total cumulative income exceeds total cumulative expenditure. This period not only determines the cut off for uplift but also dictates the number of six-month periods for which safeguard applies.
Safeguard was introduced as a safety net for the benefit of the less profitable fields, essentially to ensure that in the early years of field life the PRT cannot exceed a level that would reduce the participants after tax profit below a minimum return on investment in the field. It limits PRT in each six-month chargeable period to 80% of the excess profits over 15% of cumulative capital which has qualified for uplift. It applies to the period from the start of production to the period of payback plus half as long again. It will not apply if it calculates PRT in excess of the “normal” calculation.

An “Oil Allowance” can be applied for fields with development consent on or before 31 March 1982, which makes the first 250,000 tonnes per six-month period, up to a cumulative total of 5 million tonnes, PRT free. For southern fields the amounts are 125,000 and 2.5 million tonnes, and for all other taxable fields 500,000 and 10 million tonnes respectively.

A “Tariff Receipts Allowance” is available for some income streams. This makes the first 250,000 tonnes of throughput for each user field per six-month period, PRT free.

Gas sold under contracts entered into before 30 June 1975 is exempt from PRT.

As mentioned above, new tariff business for transportation, processing, and other services provided through the use of UK and UKCS infrastructure, which is transacted under contracts entered into on or after 9 April 2003 will be exempt from PRT. The use of UK and UKCS infrastructure will need to be in relation to:

a) A field receiving development consent on or after 9 April 2003; or
b) An existing field using a new evacuation route, but only if that field has not to date made use of non-field assets, which have qualified for PRT relief.

While the exemption covers new tariff business contracted on or after 9 April 2003, it will only apply to income and expenditure received and incurred under such contracts since 1 January 2004.

Royalty

Royalty was abolished from 1st January 2003. Prior to this date, fields which had received development consent before 1st April 1982 received a charge at 12.5 per cent on the gross value of oil and gas produced, less an allowance for the costs of conveying, treatment and initial storage.
APPENDIX 2: 2005 PRE-BUDGET REPORT AND 2006 BUDGET

The Pre-Budget Report in December 2005 announced with effect from 1 January 2006:--

- an increase in the rate of SCT from 10% to 20%;
- the option to defer 100% First Year Allowance claims for expenditure incurred in the year ended 31 December 2005, to the first accounting period commencing on or after 1 January 2006. By doing so, companies will offset capital expenditure against profits charged at a higher rate of SCT;
- the introduction of the Ring Fence Exploration Supplement (RFES), which extends and replaces the Exploration Expenditure Supplement (EES), is intended to act as an investment incentive;

The 2006 Budget introduced new rules to crude oil pricing for taxation purposes, which will apply from 1 July 2006. The RFES and the new rules for oil valuation are explained below.

Ring Fence Exploration Supplement (RFES)

The Exploration Expenditure Supplement (EES) which was introduced on 1 January 2004 was replaced by the Ring Fence Expenditure Supplement (RFES) on 1 January 2006. The RFES is aimed at companies exploring for oil or gas or in the development phase which do not yet have any taxable income against which to offset their exploration and appraisal capital allowances. The main difference with the EES is that RFES applies not only to exploration and appraisal but to all expenditure which has not already been offset against taxable income. The RFES increases the value of unused allowances forward from one period to the next by a compound 6% per year. Six years is the time limit but it does not need to be consecutive.

Crude Oil Valuation

The changes introduced by HM Revenue & Customs on North Sea crude oil pricing are intended to reduce tax-motivated commercial behaviours. The new measures relate to the following operations:

- Oil traded in non-arm’s length operations (i.e. internal trading of crude oil between businesses within a single company). For these operations and where a published price from price reporting agencies is readily available, crude oil will be valued by taking the daily average of the quoted prices on the day of delivery or appropriation, and two days either side of that day (known as the 2-1-2 method). For crude oils with no published prices, the valuation will be agreed with HM Revenue & Customs based on actual arm’s length sales (i.e. sales to non-associated companies). In the previous regime, values for crude oil in non-arm’s length operations were obtained monthly by taking the average of daily prices in actual arm’s length sales over a six week period.

- Oil traded in forward contracts at arm’s length (which does not relate to a specific cargo of oil and where the contract may be booked out, as in the case of the current Brent forward market). For this type of operation, the Government decided to tighten up the scheme used to nominate oil sales (the Nomination Scheme) by changing the previous limit of 5.00 pm on the day after the transaction to within 2 hours from the time the transaction is agreed. The new scheme allows for nominations outside office hours.

- Sales of blended equity and non-equity oil cargoes of blended oil will be allocated to source fields, pro-rata to the company’s monthly production from those fields. Such change will override, for tax purposes, the field or fields the cargo is actually lifted from, as determined within the complex web of commercial agreements between different field, pipeline and terminal owning companies. In the previous regime, companies had the option to choose the onshore terminal or offshore loading point from which field blended oil was deemed to be lifted.
Costs to Industry of the 2005 Pre-Budget Report and 2006 Budget

According to HM Treasury, the measures announced since December 2005 will cost the upstream oil and gas industry an additional £0.9 billion in taxes in 2006/07, climbing to around £2.4 billion per year additional tax in 2007/08 and 2008/09. The benefit to industry from the RFES is estimated at £5 million, which will be noticeable in 2008/09.
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
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<tbody>
<tr>
<td>bbl</td>
<td>barrel (1 barrel = 6.3 m³)</td>
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<tr>
<td>bcm</td>
<td>billion cubic metres (1 metre³ = 35.3 cubic feet)</td>
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<tr>
<td>billion</td>
<td>One thousand million</td>
</tr>
<tr>
<td>boe</td>
<td>barrel of oil equivalent - including oil, gas and gas / hydrocarbon liquids. (1 boe = 164 m³ gas = 5.8 thousand cubic feet)</td>
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<tr>
<td>bpd</td>
<td>barrels per day</td>
</tr>
<tr>
<td>boepd</td>
<td>barrel of oil equivalent per day</td>
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<td>Capex</td>
<td>Capital Expenditure</td>
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<td>CCS</td>
<td>Carbon Capture and Storage</td>
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<td>Central North Sea</td>
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<td>European Union</td>
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<td>EU ETS</td>
<td>European Union Emissions Trading Scheme</td>
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<td>FYA</td>
<td>First Year Allowances</td>
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<tr>
<td>kboepd</td>
<td>thousand barrels of oil equivalent per day</td>
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<tr>
<td>kbps</td>
<td>thousand barrels per day</td>
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<tr>
<td>m³/d</td>
<td>cubic metres per day (gas)</td>
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<tr>
<td>Mtoe</td>
<td>Million tonnes of oil equivalent</td>
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<td>MW</td>
<td>Mega Watts</td>
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<td>NG</td>
<td>National Grid</td>
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<td>NNS</td>
<td>Northern North Sea</td>
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<td>NTS</td>
<td>National Transmission System</td>
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<td>Opex</td>
<td>Operating Expenditure</td>
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<td>OSPAR</td>
<td>Oslo and Paris Convention for the Protection of the Marine Environment of the North East Atlantic</td>
</tr>
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<td>PILOT</td>
<td>Joint Oil and Gas Industry/Government Task Force chaired by the Energy Minister</td>
</tr>
<tr>
<td>PRT</td>
<td>Petroleum Revenue Tax</td>
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<tr>
<td>p/therm</td>
<td>Pence per therm</td>
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<tr>
<td>SCT</td>
<td>Supplementary Charge to Corporation Tax</td>
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<td>SNS</td>
<td>Southern North Sea</td>
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<td>United Kingdom Continental Shelf</td>
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<td>UK Offshore Operators Association</td>
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<tr>
<td>WoS</td>
<td>West of Shetlands</td>
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APPENDIX 4: CONTRIBUTORS

Many thanks to the following who have co-authored and compiled the 2006 economic report with grateful appreciation for the contributions from many, across both Industry and Government.

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