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The 2012 Oil & Gas UK Activity Survey

1. Foreword

The Oil & Gas UK 2012 Activity Survey, incorporating exploration, investment, production and decommissioning data, provides a unique insight into both the achievements of the UK’s offshore oil and gas industry in 2011 and the plans and challenges it faces in the coming years.

Whilst increased capital investment largely driven by five major projects is welcome news, the other headlines for 2011 do not make easy reading. Despite an average oil price which was directly in line with Government forecasts at Budget 2011, there was an 18 per cent fall in production, 50 per cent collapse in exploration activity and an acute decline in capital efficiency. However, this still remains an industry which, if the Government now takes the right actions, can contribute significantly more in investment, jobs and exports for the UK economy, all at no additional cost to the Exchequer.

Over recent years, production has been falling on average by six per cent per annum and it had been anticipated that 2011 would see the rate of decline slow down. However, last year’s 18 per cent decline was the biggest on record. This was caused by a significant number of unplanned production stoppages and made worse because only a few small fields were brought on-stream, together replacing less than five per cent of annual production. This reflects the slowdown in new field developments experienced in the aftermath of the tax increase of 2006.

The fall in production had significant consequences, driving the cost of producing each barrel up by 25 per cent last year. Companies also spent £500 million on action to ensure long term asset integrity and yet more expenditure of that nature will be required in the years to come. That additional unplanned capital spend, combined with existing commitments, drove total investment in 2011 to the top end of expectations, at around £8.5 billion.

It is apparent that this trend will continue in 2012 and activity will be dominated by the few large projects which were commercially committed before Budget 2011. This wave of investment is critical. However, these large projects are not typical of those in most companies’ portfolios, many of which are much smaller and challenged in the current fiscal environment. Indeed, of the 16 new projects that gained development approval in 2011, the five largest account for more than 85 per cent of the associated investment and production.

The combination of rising costs and the need to spend more capital to sustain the existing production base is having a major impact on capital efficiency. Although headline investment has tripled over the last decade, the amount of oil and gas recovered per pound invested has fallen by more than two thirds over the same period, leaving the industry fighting hard to stand still. The UK must compete globally for resources and capital. At present the UK is only able to attract less than 4 per cent of global investment and our uncertain fiscal environment just makes this more difficult.

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1 Ernst & Young Global E&P Benchmark Study, November 2011
The UK continental shelf (UKCS) still has the potential to deliver up to 24 billion more barrels of oil and gas, yet current plans will recover only 10 billion boe\(^2\) assuming a mid-case outcome. Worryingly, only fifteen exploration wells were drilled in 2011 (50 per cent of the 2010 activity) making it the lowest year for exploration since the mid-1960s. When exploration fell almost as low in 2002, HM Treasury led an initiative to stimulate activity.

The UK economy has been affected. First, the production collapse and the unforeseen capital spend on asset integrity mean the Treasury will receive £2.3 billion less in tax receipts this fiscal year than it had expected. Second, had production stayed on track, UK GDP would have been 0.2 per cent higher, demonstrating the scale of our industry’s contribution to the UK economy.

The UK’s oil and gas industry has more to offer, but needs the right fiscal regime to build on. Over the past year, Oil & Gas UK and its members have worked closely with Government officials to arrive at constructive proposals relating to decommissioning tax relief and fiscally stranded investment. If implemented, these should deliver three billion additional barrels over time, at no additional cost to the Exchequer. The proposals will increase field development activity and delay decommissioning, generating additional tax revenues for the Exchequer measured in tens of billions of pounds.

The first proposal is that the Government should enter into a contract to provide certainty on the continued availability of decommissioning tax relief. This would increase asset trades and free up capital, extending the productive life of many fields. Independent analysis shows this should allow recovery of an additional 1.7 billion boe or more over time. It will also send an important positive signal of fiscal certainty, providing a foundation for sustained activity on the UKCS.

The second area for action is to unlock £20 billion of investment held back by the current tax regime. Amendments to the existing field allowance regime should lead to the recovery of an additional 1.3 billion boe, with associated tax revenues exceeding £10 billion. Without intervention, these resources will remain fiscally stranded.

The UK competes in a global oil and gas industry – even for the largest companies, the UK represents 10 per cent or less of global production. Appropriate measures on decommissioning and field allowances will reduce fiscal uncertainty and help to ensure that UK investment is globally competitive over this decade and beyond. They will allow the UK’s oil and gas industry to play an even greater role in rebalancing the British economy towards growth and help suppress oil and gas imports. Following the shock announcement in Budget 2011, the industry has been strongly encouraged by the positive engagement with the Treasury and DECC in recent months. We now look forward to helpful fiscal change in Budget 2012.

Malcolm Webb
Chief Executive

\(^2\) boe – barrels of oil and gas equivalent
2. Introduction

Each year, Oil & Gas UK surveys exploration and development activity on the UK continental shelf (UKCS) jointly with DECC. This provides a forecast of potential exploration and appraisal drilling activity over the next two to three years, as well as investment and new developments likely to occur over the next three to five years.

The surveys encompass the plans of the association’s member companies who operate oil and gas fields on the UKCS and also include the activities of non-operators, promote licensees and other explorers. They also consider the wider supply chain, very many of whom are also members of Oil & Gas UK.

Oil & Gas UK is provided with exploration plans, production profiles, capital expenditure, operating costs, tariffs and decommissioning costs by field. Projects are categorised by probability of development on the following basis:

- “Probable” activities which have a probability of greater than 50 per cent of proceeding;
- “Possible” activities which have a probability of 50 per cent or less of proceeding.

The survey reflects production from:

- “Sanctioned investments”: fields which are already in production or have already received investment approval;
- “Incremental developments”: which cover further development of existing producing fields, more usually referred to as “brownfield” developments;
- “New field developments”: which are new fields typically tied back to existing infrastructure.

It should be noted that, as in previous years, Oil & Gas UK has slipped the data for new projects, reflecting the probability of investment proceeding. This approach effectively smooths short term peaks in activity yet retains a coherent projection of overall reserves and investment activity.
3. Summary of Findings

The Oil & Gas UK 2012 Activity Survey is based on the latest data supplied by all the leading exploration and production companies operating in the UK. This provides a uniquely well informed insight into the opportunities and potential of this vital sector of the UK economy. The key results can be summarised as follows:

In 2011 the industry:
- Produced 1.8 million boe/d, (18 per cent less than in 2010);
- Invested £8.5 billion of capital, similar to that experienced in the late 90’s (£6 billion in 2010);
- Spent £7.0 billion on operating costs (2 per cent higher than 2010);
- Drilled 121 development wells (130 wells in 2010);
- Spent £1.4 billion drilling 15 exploration and 28 appraisal wells (50 per cent fall in exploration and 20 per cent fall in appraisal compared with 2010);
- Discovered a further 150-250 million boe;
- Initiated the development of 16 new fields and major field redevelopments (9 in 2010) which together with on-going brownfield investment will deliver 1.5 billion boe over time;
- Expects to pay more than £11.1 billion in production taxes in the 2011-12 fiscal year (£9.3 billion in 2010/11);
- Supported employment of 440,000 people across the UK (approx. 45 per cent of these are in Scotland).

Looking forward to 2012 and beyond...

3.1. Oil and Gas Reserves and Resources
- Total oil and gas resources in this year’s survey have risen to 11.9 billion boe. This compares with 11.6 billion boe in last year’s survey;
- Current expectations are that 10 billion boe (>P50) of these will be recovered. This is only about 0.1 billion boe higher than expected a year ago, on a like-for-like basis;
- Economically recoverable resources could be further increased if action were taken to address the 1.3 billion boe of resources which are fiscally stranded because of the impact of the tax increase in 2011;
- Proven reserves in existing fields or in projects currently under development have increased significantly to 7.1 billion boe.

Potential New Field Developments
- 64 new field developments, ranging in probability of being developed, have been reported by respondents; down from 67 the previous year. Nine of these are west of Shetland, 29 in the central North Sea, 15 in the northern North Sea and 11 in the southern North Sea/ Irish Sea;
- These potential new field developments include 3.8 billion barrels of recoverable reserves;
- Half of the current set of new fields seeking to be developed have reserves of less than 20 million boe. However, in contrast there are 13 potential field developments with expected recoverable reserves in excess of 100 million boe.
Incremental Development in and around Existing Fields

- There is the potential to develop 1 billion boe from 137 projects in existing fields, compared with 2.6 billion boe and 160 projects in 2011’s survey;
- These projects are typically small in size with 85 per cent being less than ten million barrels;
- Industry evidence suggests that 400 million boe of brownfield investments are uncommercial at current tax rates, so are unlikely to secure investment without changes to the regime;
- Initiating new brownfield investment provides rapid payback to the Exchequer.

3.2. Production

- Production fell 18 per cent in 2011 compared with an average annual reduction of 6 per cent per annum over the previous half decade. The fall was dominated by a combination of scheduled and unscheduled outages, health & safety and fiscal factors, plus greatly reduced gas demand;
- Had production not collapsed in 2011, UK GDP would have been at least 0.2 per cent higher, and North Sea tax receipts would have been £2.3 billion higher, demonstrating the wider impact on the economy;
- Production in 2012 is expected to improve modestly to around 1.85 million boe/d compared with 1.82 million boe/d in 2011. However, the overall production profile for the next five years remains depressed.

3.3. Investment

- Capital expenditure is expected to reach £11.5 billion in 2012;
- Sixteen new fields and major field redevelopments gained approval in 2011, together requiring £13 billion capital investment and adding 1.5 billion boe over the next three or four years;
- When taken together, the last two years have seen 25 new fields and major field extensions requiring total investment of £19 billion. Of these, the top seven new developments dominate the outlook, accounting for £15.5 billion (85 per cent) of new investment initiated over this period;
- As a consequence, £31 billion of capital investment is committed and in progress at the start of 2012, compared with £24 billion in 2011;
- Whilst capital investment is at a recent high, capital efficiency has fallen by more than two thirds over the last decade.

3.4. Operating Expenditure

- Whilst operating costs have only risen marginally in 2011, operating costs per barrel rose by 25 per cent and are expected to rise by a further 4 per cent in 2012.

3.5. Exploration and Appraisal (E&A) Activity

- Total E&A activity is expected to rise to 35-40 wells in 2012;
- Exploration is expected to increase to around 25 wells, driven by the need to meet “drill or drop” commitments and as companies try to recover drilling plans which slipped in 2011;
- Global competition for drilling resources is strong. Exploration in the UK remains constrained by difficulties securing rig slots and access to finance, and was made more difficult by the tax increase in 2011. These pressures are felt most by smaller companies.
3.6. Fiscal Regime

- The introduction of targeted field allowances to promote investment in specific new field developments has had a notable impact on activity;
- In 2010 and 2011, 7 and 8 new fields respectively gained a field allowance and 9 new fields are expected to be developed as a result of field allowances in 2012;
- Further extensions to these allowances could encourage an additional £20 billion of investment to be initiated over time, adding 1.3 billion boe to production.

3.7. Decommissioning

- Total cost of decommissioning existing facilities has grown by about 4 per cent (in line with inflation);
- Decommissioning expenditure is expected to remain similar to last year’s survey through to 2040, though new developments sanctioned in the last year may ultimately add to costs;
- Decommissioning expenditure over this decade is expected to be about 10 per cent below previous forecasts, in part as a response to higher oil prices and new investment prolonging the life expectancy of some mature assets.
4. Oil and Gas Prices

From a trough in early 2009, the price of crude oil rose steadily through 2009 and 2010, driven by strong global economic recovery and, therefore, increasing demand in Asia and the middle East. While growth in demand eased in 2011, there was the complication of political turmoil in various parts of North Africa and the Middle East which restricted supplies from Libya and created nervousness in the market, leading to higher prices. Since August, worries about the economies of OECD countries, particularly in the Euro zone, have caused the market to drift slowly downwards, but with considerable variability in prices.

During 2011, the average price of Brent crude oil was $111 a barrel ($80 in 2010), with a minimum of $93 in January and a maximum of $127 in May. Clearly this has reflected the various circumstances affecting the market outlined above. Also worth noting is the comparison of oil priced in dollars and pounds sterling which obviously reflects movements in exchange rates (Fig. 1). In particular, for the past 10-11 months the price in sterling has been at or very close to the peak reached in mid-2008.

Figure 1: Comparison of Price of Brent Crude Oil in Dollars and Pounds, 2008 – 2012

In Great Britain, the largest and only truly open gas market in Europe, prices for traded gas are set at the NBP (National Balancing Point), a fictitious location where the system is nominally in balance. In addition, longer term contract prices are usually set by reference to the NBP, although the proportion of these contracts in terms of overall supply in Great Britain is much smaller than it used to be. It can be seen clearly in Figure 2 how prompt prices fell sharply in early 2009, more slowly in mid-2009 and then rose steadily through 2010 and into 2011, before levelling off and, towards the end of last year, beginning to drift downwards.

Most gas for Europe is delivered by pipeline, whether from Russia, Algeria or Norway, but in the Far East LNG dominates, with long term contracts and pricing generally oil indexed, resulting in the highest prices for gas in the world. There is an interesting tug of war going on, as LNG links Europe to Asia and vice versa. On the one hand, the EU is pressing on with opening its markets and looking
to replicate the freedom of the NBP at other hubs within mainland Europe while, on the other, long term LNG contracts indexed to oil prices continue to dominate Far Eastern supplies. It is the trade in uncontracted cargoes of LNG that joins the two.

**Figure 2: NBP Day-Ahead and Forward Gas Prices, January 2009 – January 2012**

The average price of day-ahead gas at the NBP was 56 pence/therm during 2011 (42.5 p/th in 2010), but notably with much less “swing” between winter and summer prices which makes the economics of storage difficult. Also notable is the size of the discount at which gas trades compared with oil – currently about 50 per cent, in energy equivalent terms, whereas this has normally been nearer 25 - 35 per cent. This discount makes the development of gas projects on the UKCS considerably less attractive than oil, and all the more so given they face similar development costs.

**Figure 3: Comparison of Brent Oil and NBP Gas Prices, 2007 – 2011**
5. Oil and Gas Reserves and Resources

This year’s survey shows that total discovered commercial and recoverable reserves remaining in the UKCS have reached 11.9 billion boe, 300 million boe higher than last year. Work over the last nine months has established that around 1.3 billion boe are unlikely to attract investment, even given the current price of oil, because of the impact of the tax increase in 2011. When these opportunities made commercially unattractive by the UKCS tax regime are included, the total figure of potentially recoverable reserves and resources rises to 12.7 billion boe. It is emphasised that these figures cover a range of probabilities of recovery (from less than 10 per cent to more than 90 per cent), reflecting the underlying economics as well as technological and commercial challenges.

On a P50$^3$ basis, sanctioned and probable reserves and resources in companies’ plans amount to around 10 billion boe at 1 January 2012, compared with 10.5 billion boe at 1 January 2011 in the previous survey. Given production of 0.66 billion boe in 2011, P50 reserves/resources have grown by just 0.1 billion boe in a year, a relatively small increase given the strengthening oil price since 2009.

Figure 4: Build-up of Reserves / Resource base

The sanctioned reserves base in fields that are on-stream or have received investment approval has increased substantially to 7.1 billion boe over the last year. This reflects the large scale of the projects which received final investment decisions during 2011 and their reserves moving from the ‘probable’ into the ‘sanctioned’ categories. Of the 16 projects which received approval in 2011, the top five projects contributed the 1.3 billion boe of the 1.8 billion boe added to proven reserves over the past year.

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$^3$ Considering outcomes with a 50 per cent or greater chance of proceeding
The survey shows that nearly half of all sanctioned reserves (in production or under development) are located in the central North Sea (CNS). The west of Shetlands (WoS) contains nearly a quarter of sanctioned reserves and the remainder is split between the northern North Sea (NNS) and southern North Sea / Irish Sea (SNS / IS). It is seen that major developments initiated in 2011 added new reserves to all areas of the UKCS and that there is the potential for further new field and brownfield investment across the basin.
Within the latest survey, respondents indicate that 64 new field developments feature in their business plans, down from 67 in the previous year. These potential new field developments include 4.7 billion boe of recoverable reserves.

Nine of these projects are west of Shetland, 29 in the central North Sea, and 15 in the northern North Sea, with the remaining 11 split between the southern North Sea and Irish Sea.

Again a small number of potential new field developments dominate the agenda with the six largest fields accounting for almost half of the resources being considered for investment. It is also seen that 13 fields have reserves greater than 100 million boe located across the central North Sea, northern North Sea, and west of Shetland. In contrast, half of all new fields seeking development have reserves of less than 20 million boe.

In addition to the new developments, there are plans to develop a further 1 billion boe from 137 projects in existing fields, of which 85 per cent are less than 10 million boe in size. Detailed research indicates that 15 existing opportunities that hold over 400 million boe in reserves have been rendered commercially unattractive since the tax increase in Budget 2011. These projects are now unlikely to secure investment without further beneficial changes to the fiscal regime.

Figure 7: Distribution of Undeveloped Reserves
6. Oil and Gas Production

2011 Production Performance
Over the past half decade, production from the UKCS has declined at an average of around 6 per cent per annum, whereas expectations a year ago were that 2011 would, if anything, see a smaller production decline. However, the opposite was the case and production unexpectedly fell by 18 per cent, declining from 0.81 billion boe in 2010 to 0.66 billion boe in 2011. Oil/NGL production together fell by 17 per cent - the largest drop since 1988, and gas production fell by 20 per cent – the largest year on year fall ever recorded.

Figure 8: Analysis of Production Loss in 2011

The major factors seen to impact production were:

i. **The rapid rise in unscheduled maintenance and plant outages** – reflecting the maturity of the basin. Whilst just under a quarter of the 380 fields in production delivered better than expected, more than half underdelivered, with ten fields in particular responsible for half of the net fall in production. Unplanned outages in key fields also constrained infrastructure capacity, limiting the ability to export production from other fields;

ii. **Infrastructure and asset maturity** – demonstrating the challenge many companies face when operating in this mature basin. Much of UKCS infrastructure is now more than 30 years old and operators have to devote increasing resources to extend its life beyond that originally anticipated. As a consequence, capital expenditure was £500 million higher than expected last year as operators invested to address these issues. It is apparent now that this increased rate of expenditure will be required for a number of years to come;

iii. **Lower gas demand** - UK gas demand fell last year by at least 12 per cent compared with 2010, impacted by the broader state of the UK economy and higher energy costs as well as an improvement in winter weather conditions;
iv. **Declining investment since 2006** – only five small new fields were brought on-stream last year, adding around 30 million barrels and replacing less than five per cent of annual production. This reflects the slowdown in new field developments experienced after the tax increase in 2006, something which could yet be repeated in the coming years after the latest tax increase in 2011;

v. **General operational issues** - including unforeseen health and safety incidents, reservoir performances, fiscal changes and geopolitics constraining field production.

The drop in production had wide reaching consequences across the economy. North Sea tax receipts were around £1.75 billion lower because of the production loss and this taken together with higher spending on infrastructure last year meant that Treasury tax receipts overall were £2.3 billion lower than expected. Likewise, it is estimated that UK economic output (Gross Domestic Product) would have been around 0.2 per cent higher had production continued on past trends.

**Figure 9: UKCS Production Outlook** (showing actual decline since 2007 and projection; also showing last year’s survey - P50 slipped forecasts)

**Production Outlook 2012 – 2017**

Production in 2012 is expected to be similar to 2011, rising modestly from 1.8 million boe/d to 1.85 million boe/d. Over 1.2 billion boe net have been added to future production during 2011 (when netting off new investment against annual production). Whilst this is a positive trend, it is primarily the result of investment in a limited number of large field developments initiated over the last year.

Based on this year’s survey data, production is forecast to recover gradually until 2019, as several of these large projects come on-stream. However, there is still downside risk if further unscheduled outages occur. Despite the investment in new production initiated in 2011, production (on a P50 basis) through to 2020 remains some 188 million boe lower than forecast a year ago. These barrels
are only recovered in the five years after 2020, emphasising the economic impact of last year’s fall in production.

**Figure 10: Production Forecast (boe) 2010 – 2017 (P50 slipped forecasts)**

The balance of oil to gas produced from the UKCS has ranged from 55 - 60 per cent over the past decade. The ratio looks set to be increasingly weighted towards oil and away from gas as companies respond to the relative price signals. By 2017 production is expected to rise to 66 per cent oil / NGL, with new gas production coming increasingly from new developments West of Shetland. It is apparent there is still space for further intervention to improve the production outlook, even within the next five years. If the currently proposed initiatives on decommissioning and extension to field allowances are implemented, the pace of investment in brownfield production will be the first to benefit, providing an immediate impact.

**Figure 11: Production Forecast (Oil and Gas) 2010 – 2017 (P50 slipped forecasts)**
7. Investment

In 2011, capital investment rose to £8.5 billion, compared with the £8 billion forecast a year ago. This increase has been prompted by two main factors: (i) rapidly increasing capital investment to sustain the integrity and improve the reliability of existing assets and (ii) acceleration of investment in new opportunities initiated in 2010.

**Figure 12: Investment Forecast (P50 slipped) 2010 - 2017**

The UKCS is currently benefiting from a wave of new investment arising from a limited number of very large opportunities. These had either been approved or were about to be approved in advance of Budget 2011 and are atypical of investment opportunities routinely found on the UKCS. A number of these big projects have also benefited from the introduction of new field allowances, especially in the heavy oil, west of Shetlands gas and HPHT (high pressure, high temperature) areas.

It can be seen that 16 new fields and major field extensions gained development approval in 2011. Together these require £13 billion capital investment over the next three or four years to add 1.5 billion boe. When general brownfield and asset integrity investment is included, capital investment initiated in 2011 amounted to £14 billion in total and will deliver 1.8 billion boe over time.

As a consequence, during 2010 and 2011, 25 new fields and major field extensions requiring total investment of £19 billion gained investment approval, with a number of large investments such as that in Laggan/Tormore, Jasmine, Claire Ridge, Schiehallion and Golden Eagle dominating the agenda. Seen together, the top seven new developments initiated over the last two years account for £15.5 billion, effectively 85 per cent of new investment initiated over this period, with the remaining 18 fields accounting for just 15 per cent of investment.

Taken together, the investment approved in 2011 resulted in around £31 billion of sanctioned capital investment being committed and in progress of being spent at the start of 2012, compared with £24 billion being sanctioned at the start of 2011.
Capital investment is expected to rise to around £11.5 billion in 2012, including projects that have already, or are expected shortly to receive final investment sanction. On an annualised basis, the wave of large investments contributed half the capital invested in 2011 and this trend looks set to continue into 2012.

Figure 14: Investment by Approval Year (including investment qualifying for/seeking field allowances)
Targeted field allowances have had a notable impact on activity – 7 fields in 2010, and 8 fields in 2011 were developed with the benefit of an allowance, and 10 fields are expected to be developed in 2012 as a result of the existing field allowances. Without these allowances 2012 would have been a poor year for investment as 40 per cent of anticipated investment is expected to come from fields that have already qualified for an allowance.

The current rise in investment must also be set against the context of rising development costs and the increasing challenges faced when investing in a basin with ageing infrastructure and diminishing investment targets. Capital efficiency (the amount of oil delivered per £ invested) is used as a simple measure of this trend of diminishing returns and has been calculated over the last ten years. Whilst capital investment is seen to be at a recent high, capital efficiency has fallen by more than two thirds over the last decade. The UKCS effectively has to work hard to stand still.

This industry must compete globally for capital yet the UK attracts less than four per cent of global oil investment⁴ and in an uncertain fiscal environment is struggling to match the competition from more prolific oil provinces.

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⁴ Ernst & Young Global E&P Benchmark Study, November 2011
Over the last decade the UK has seen a number of major tax increases. Such tax increases have typically taken eighteen months to three years to have an impact, but as evidence shows, they gradually suppress investment.

**Figure 16: Impact of Tax Increases on Investment**

![Graph showing impact of tax increases on investment](image)

After each tax increase, it has been apparent that additional measures need to be introduced to restore the UK’s competitiveness and the same is now apparent after the tax increase last year. Oil & Gas UK has identified an additional £20 billion of investment, delivering 1.3 billion boe that are fiscally stranded by the tax regime, which could be unlocked as a result of targeted extensions to the field allowance regime.

Crucially, it is proposed that a new brownfield allowance is introduced to encourage investment in mature fields, which account for a significant proportion of our remaining reserves. This would be a focused allowance which prolongs infrastructure life and actively promotes investment with a fast payback to the Exchequer. Additionally, it is proposed that the field allowance regime is extended to all new developments west of Shetlands. This would open up one of the most challenging oil regions in the world and one which holds about a quarter of the UK’s remaining known resources. It is also proposed that the existing HPHT field allowance is extended and increased to enable investors to overcome the commercial and technical challenges encountered when exploring, appraising and developing such opportunities. Taken together these measures will have a powerful impact on investment, materially sustaining the development of the UKCS over this decade.
8. Drilling / Exploration and Appraisal (E&A) Activity

Mobile Drilling Unit Rig Rates
Rig rates for new drilling contracts rose steadily during 2011, particularly in the second half of the year. Semi-submersible drilling rates for standard rig configurations average $273,000 per day at the start of 2012, a 7 per cent increase on rates compared with January 2010; standard jack-up drilling rates range from $100,000 per day to $125,000 per day, a 24 per cent increase compared with January 2010. The growth in rig rates shows the increased global demand and impact of rising commodity prices over the last year. In the UKCS, the number of active drilling days (well spud to well completion) in 2011 was just over 6,000, a 6 per cent fall compared with 2010. The figures reported refer to standard, rather than high spec, mobile units and exclude platform based drilling.

Figure 17: North Sea Rig Rates 2005-2012 reported for ‘Standard’ rigs

Looking ahead into 2012, all the signs are that the pressure on day rates is likely to accelerate, driven by growing global demand. The drilling rig utilisation rates for the year are currently 83 per cent and 82 per cent for semi subs and jack-ups respectively, with further growth anticipated in the short term. Competition for drilling rigs is such that three rigs will enter the UK from other North Sea regions during the early part of 2012. All these factors indicate that there will be much demand for the remaining rig space in 2012.

Development Drilling in 2011
In 2011 a total of 121 development wells (including side-tracks) were drilled, which is a 7 per cent fall from the 130 development wells drilled in 2010. Despite this, the number of drilling days spent on development wells in 2011 was 30 per cent higher than 2010, suggesting more challenging targets were being drilled. There was also a noticeable shift towards developing fields through subsea tie backs. Development drilling has fallen by half over the last decade compounding the fall in production seen over this period. Over the last two to three years a number of new operators have re-commissioned platform based drilling modules which had previously been mothballed. It is envisaged that further asset trades could lead to an increase in new platform based brownfield drilling activity.
2011 E&A overview

2011 saw a fall in exploration and appraisal drilling activity, with only 15 exploration wells and 28 appraisal wells drilled in the year, together costing £1.4 billion. It was particularly noted that exploration drilling was down 50 per cent compared with 2010 and the lowest seen since the mid-1960s, although activity in 1999 and 2002 fell nearly as low.

The limited exploration activity in 2011 was however reasonably successful as operators typically targeted lower risk but lower reward opportunities. As a consequence, 60 per cent of these 15 wells were deemed commercially successful: i.e. a discovery was made which could be developed in the future. It is currently estimated that these discoveries will translate into a total discovered volume of 150-250 million boe, though this may change over time as they are subject to further appraisal. Most of these discoveries were made as a result of near field exploration and are small, with six under 10 million boe and three larger discoveries of around 30 million boe.

Global competition for drilling resources is strong. As a consequence, exploration in the UK remains constrained by difficulties in securing rig slots and by access to finance, with these pressures felt most by smaller companies. The tax increase in 2011 only added to these difficulties, making exploration even less attractive. It is now seen that 16 wells which were planned for 2011 have been delayed by a year or more; some have re-entered the plans for 2012.

Wells planned by smaller companies have been more affected by capital constraints and fiscal change. The proportion of exploration and appraisal wells drilled by small companies fell from 30 per cent in 2010 to 21 per cent in 2011, while the proportion drilled by majors increased by 10 per cent.
The move towards near field exploration in 2011 is part of a wider trend for companies to prioritise lower risk opportunities in appraisal and development wells and whilst such behaviour is wholly rational from a commercial perspective, it will do little to realise the full exploration potential of the UKCS.

**E&A Outlook for 2012**

The survey results indicate a more positive outlook for 2012, with operators forecasting a potential 64 E&A wells for the year. However, only 40 of these have a firm rig slot at the present time and because of the tight rig market Oil & Gas UK anticipates that only 35 - 40 wells will actually be drilled in 2012.

![Figure 19: UKCS E&A Activity](image)

The number of exploration wells is anticipated to rise to around 25 in 2012 and is largely driven by the pressure to meet ‘drill or drop’ licence commitments from the 25th and 26th Licensing Rounds. The survey shows that 12 wells delayed from 2011 have been put back to 2012. However some wells delayed from 2011 are not in the forecasts for the next three years, suggesting that the opportunity to drill these may have been lost.

The survey shows that there was a reduction in drilling activity in the west of Shetland frontier area last year with only two wells drilled. In contrast, exploration West of Shetland is expected to increase over the next three years with a total of up to 31 exploration and appraisal wells forecast in this region over the period. The central North Sea remains an active area for exploration, not least with material HPHT prospects. The mature southern North Sea also remains attractive for explorers. Both regions benefit from extensive infrastructure, enabling any near-field discoveries to be rapidly developed via tie-backs to existing facilities. Activity in the northern North Sea is anticipated to fall over the next few years and it remains to be seen whether this will increase again beyond 2014.
The survey shows that exploration activity has the potential to increase in 2012. However, the outlook remains cautious. Much of the activity in 2012 and beyond is driven by licence commitments, and in some cases these commitments were made to DECC in licence applications just before the financial crash in 2008 and so do not reflect the changed risk profile of UK based drilling.

Difficulties in accessing finance for drilling are also expected to continue, and this problem has been exacerbated by the impact of the increase in the supplementary corporation tax paid by the industry, making the risk taken in carrying out exploration projects less attractive. The shift in exploration activity away from smaller companies towards larger companies, who have more capacity to manage these risks, is forecast to continue in 2012. Only 20 per cent of the wells forecast in the survey are expected to be drilled by small companies.
9. Operating Expenditure

Operating costs have only risen marginally in 2011 to £7.0 billion for the year. This demonstrates the efforts the industry is making to control expenditure and must be viewed positively.

Fig 21: Growth in Operating Costs (P50)

However, the rise in unit operating costs was much more pronounced due to the poor production performance last year. In 2011, operating costs per barrel increased by 25 per cent when compared with 2010, and they are expected to rise further by an additional 4 per cent in 2012. Any further such increase in costs per barrel, or sudden fall in commodity prices, could rapidly render UKCS production uncommercial for many operators.

Fig 22: Growth in Unit Operating Costs (P50): All regions
On a regional basis, the impact of the current programme of large field investments should provide some relief on unit operating costs. The full benefit, however, will only arise if investment is sustained in both new and brownfield activity.

**Fig 23: Unit Operating Costs (P50), By Region**
10. Decommissioning

Decommissioning expenditure for existing fields is expected to remain similar to last year’s survey through to 2040, although new developments sanctioned in the last year may ultimately add to costs. Total spend on existing and sanctioned fields and infrastructure, from 2012 onwards, is now projected at £28.7 billion (2011 money). New investment on probable developments could add £4.3 billion to the total cost of decommissioning. Over the very long term, this latest survey shows that the total cost of decommissioning existing facilities through to end of field life has risen by about 4 per cent, in line with general inflation.

The survey shows that decommissioning expenditure over this decade is expected to be about 10 per cent below previous forecasts. This is in response to higher oil prices and sustained investment prolonging the life expectancy of some mature assets. As a result, over the next five years, whilst decommissioning expenditure remains very similar to that forecast a year ago, beyond 2016 decommissioning expenditure is forecast to fall and will only reach previously expected rates beyond 2025.

Figure 24 – Cumulative Cost of Decommissioning
## Summary Table of Key Statistics

<table>
<thead>
<tr>
<th>Money of the day</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012 Forecast</th>
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<tbody>
<tr>
<td>Total production</td>
<td>2.4 mln boe/d</td>
<td>2.3 mln boe/d</td>
<td>1.8 mln boe/d</td>
<td>1.85 mln boe/d</td>
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<tr>
<td>Oil / liquids</td>
<td>1.4 mln boe/d</td>
<td>1.35 mln boe/d</td>
<td>1.10 mln boe/d</td>
<td>1.12 mln boe/d</td>
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<tr>
<td>Gas</td>
<td>1.0 mln boe/d</td>
<td>0.94 mln boe/d</td>
<td>0.71 mln boe/d</td>
<td>0.73 mln boe/d</td>
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<tr>
<td>Total (£bln)</td>
<td>165 mln m3/d</td>
<td>155 mln m3/d</td>
<td>107 mln m3/d</td>
<td>109 mln m3/d</td>
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<tr>
<td>Capex</td>
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<td>~16.9 bln</td>
<td>~20.8 bln</td>
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<tr>
<td>Opex</td>
<td>£4.9 bln</td>
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<td>£8.5 bln</td>
<td>~£11.5 bln</td>
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<tr>
<td>Exploration &amp; Appraisal</td>
<td>£6.6 bln</td>
<td>£6.9 bln</td>
<td>£7.0 bln</td>
<td>~£7.5 bln</td>
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<tr>
<td>Unit Technical Cost ($/boe)</td>
<td>30</td>
<td>28</td>
<td>34</td>
<td>~36</td>
</tr>
<tr>
<td>Unit Dev't Cost ($/boe)</td>
<td>15</td>
<td>15.5</td>
<td>18</td>
<td>~18</td>
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<tr>
<td>Unit Operating Cost (£/boe)</td>
<td>12</td>
<td>12.5</td>
<td>17</td>
<td>~18</td>
</tr>
<tr>
<td>Unit Technical Cost (£/boe)</td>
<td>16</td>
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<td>21.5</td>
<td>~22</td>
</tr>
<tr>
<td>Unit Dev't Cost (£/boe)</td>
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<td>10</td>
<td>11</td>
<td>~11</td>
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<tr>
<td>Unit Operating Cost (£/boe)</td>
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<td>~11</td>
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<tr>
<td>Oil price (avge)</td>
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<td>$80 per bbl</td>
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<td>Gas price (avge – day-ahead)</td>
<td>30 p/th</td>
<td>42.5 p/th</td>
<td>56 p/th</td>
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<tr>
<td>Combined Oil and Gas Price</td>
<td>£ 48 per boe</td>
<td>£63 per boe</td>
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<tr>
<td>Direct N. Sea tax revenues</td>
<td>£ 6.5 billion</td>
<td>£8.8 billion</td>
<td>£11.1billion</td>
<td>£10.5 blln</td>
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<td>(Fiscal year)</td>
<td></td>
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<td>Development</td>
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<td>Total</td>
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<td>New field approvals</td>
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<td>Major Incremental projects</td>
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<td>New field start-ups</td>
<td>8 (150 mln boe)</td>
<td>8 (84 mln boe)</td>
<td>5 (30 mln boe)</td>
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</tr>
<tr>
<td>Exploration Volumes Discovered</td>
<td>~ 300 - 400 mln boe</td>
<td>~ 300 - 400 mln boe</td>
<td>~ 150 - 250 mln boe</td>
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</tbody>
</table>

### New Fields Approvals / Major Redevlopments

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<thead>
<tr>
<th>2009</th>
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<tr>
<td>Auk North</td>
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<td>Blackbird</td>
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<tr>
<td>Babbage</td>
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<td>Breagh</td>
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<tr>
<td>Bardolino</td>
<td>Devonick</td>
<td>Causeway</td>
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<tr>
<td>Burghley</td>
<td>Huntington</td>
<td>Clair Ridge</td>
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<td>Seven Seas</td>
<td>Islay</td>
<td>Clipper South</td>
</tr>
<tr>
<td>Topaz</td>
<td>Jasmine</td>
<td>Connie</td>
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<tr>
<td></td>
<td>Laggan Tormore</td>
<td>Ensign</td>
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<td></td>
<td>Maule</td>
<td>Everest Phase IV</td>
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