ACTIVITY SURVEY 2014

Oil & Gas UK
the voice of the offshore industry

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Contents

1. Foreword

The UK offshore oil and gas industry remains the country's largest industrial investor, paying more tax into the Exchequer than any other corporate sector and with the potential to deliver huge economic benefit for the UK over the coming decades. The energy we extract from the UK Continental Shelf (UKCS), the thousands of companies in the supply chain that support us, the technology, skills and services developed domestically and exported to more than 100 countries are testament to what we have achieved.

However, our industry can only continue to compete globally if we have a strong home market for oilfield goods and services, serving a healthy offshore business here in the UK. This future is now at risk. Without greatly improved exploration success, a significant improvement in productivity, and the urgent implementation of a new and more dynamic approach to regulation and taxation, this potential will not be properly realised. The Oil & Gas UK *Activity Survey 2014* shows the challenges we face.

Whilst there are over ten billion barrels of oil equivalent (boe) currently in company plans, four billion boe of these have yet to secure investment. Improving recovery from existing fields and an active exploration programme to find new resources has the potential to add at least another ten billion boe, but none of this will be easy. The UKCS still holds significant potential – but only if the business conditions for investment in exploration, appraisal and development are right.

Exploration is facing its biggest challenge in 50 years. Exploration slumped in 2011 and has yet to recover. In 2013, only 15 exploration wells were drilled discovering just 80 million barrels. Unfortunately, 2012 was equally poor with 2011 very disappointing. Taken together, the last three years have seen the lowest rate of exploration activity in the history of the UKCS. This year, 25 exploration wells are planned, which still falls far below the 44 drilled just six years ago, and even if all the wells proceed, the rate of drilling is too low to recover even a fraction of the potential resources. There is still an abundance of resources yet to be found and it is imperative we find the means to turn exploration around.

There are other challenges too. Many of our existing assets are working hard to improve productivity. Despite an eight per cent fall in production, operating expenditure in 2013 rose by 15.5 per cent to an all-time record of £8.9 billion. Average unit operating costs have risen sharply to £17/boe and the number of fields with an operating cost greater than £30/boe has doubled in the last year.

In 2013, capital investment reached an impressive £14.4 billion and, thanks to a number of large projects now underway, investment is likely to remain above £10 billion until 2015. However, on current projection, overall investment by 2016 to 2017 will fall to half that of 2013. Whilst there are still good projects out there, more are needed.

The stream of new field allowances introduced over the last few years have been helpful in enabling investment on various types of development that would otherwise be stranded by current high UKCS tax rates. However, the overall fiscal regime for the UKCS is increasingly seen to be overly complex, burdensome and uncompetitive – and hence in need of a major overhaul.

Given this troubling picture, Sir Ian Wood's Review is, to say the least, a timely intervention. Sir Ian proposes the creation of a new, appropriately resourced, arm's length regulator and recommends that industry, the Department of Energy & Climate Change and HM Treasury adopt a tripartite approach to Maximising Economic Recovery on a new collaborative basis across the UKCS. He also sets out his ideas on the strategies which we should now adopt.

There is very strong support across industry for this new paradigm. Given this, and trusting that government is also minded to embrace this fundamental change in approach, there can be real grounds to believe the decline of recent years will be arrested and we will again enjoy sustainable growth in investment, jobs and production.

But let us not fool ourselves, this will not be achieved without much hard work and dedication to radical change and sustained improvement, which will be required of us all, in both the industry and government – and there is no time to lose. We need to implement these changes without delay. The clock is ticking.

Malcolm Webb
Chief Executive, Oil & Gas UK

2. Summary of Findings

The Oil & Gas UK *Activity Survey 2014* is based on the latest data supplied by all 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 economy. The key results can be summarised as follows:

2.1 Industry Performance in 2013

- Invested a record £14.4 billion of capital, 25 per cent of which was invested in just four fields.
- Spent £1.6 billion drilling 15 exploration and 29 appraisal wells (including sidetracks and encompassing seismic data acquisition and interpretation) and discovered 80 million boe.
- Drilled 120 development wells (including sidetracks), similar to 2012.
- Initiated development of 26 brownfield opportunities, 23 of which were enabled by the Brown Field Allowance.
- Spent £8.9 billion operating on the UK Continental Shelf (UKCS), 15.5 per cent higher than in 2012.
- Produced 1.43 million barrels of oil equivalent per day (boepd), eight per cent less than in 2012.
- Saw unit operating costs rise to £17/barrel of oil equivalent (boe), up from £13.50/boe in 2012.
- Expects to pay £5 billion in production taxes in the fiscal year 2013/14 (down from £6.5 billion in 2012/13).

2.2 Reserves Maturation

- A total of 10.7 billion boe are reported in the survey as being either in production, under development or potentially being considered for investment, compared with 11.4 billion boe in last year's survey.
- Around 0.4 billion boe have been removed from company investment plans due to increases in costs, poorer reservoir prognosis and the re-appraisal of a number of key developments.
- Proven reserves have decreased significantly from 7.1 billion boe a year ago to 6.6 billion boe in 2014.
- Around 9.4 billion boe of oil and gas reserves are forecast to have a 50 per cent or greater chance of being recovered.

2.3 Drilling Activity

- Whilst appraisal activity was slightly better than expected at 29 wells in 2013, exploration continued on its downward trend since 2008, with only 15 wells drilled last year compared with 44 in 2008. This represents a 66 per cent fall over the last five years.
- Of the p5 to c0 exploration and appraisal (E&A) wells forecast to be drilled last year, 20 were postponed and four were cancelled, primarily because of difficulties in securing rigs or an inability to access finance.
- The latest figures indicate that exploration activity discovered just 80 million boe of recoverable reserves in 2013.
- Around £1.6 billion was spent on E&A activity last year, including seismic data acquisition and interpretation.
- Based on operators' forecasts, it is anticipated that 25 exploration wells and 11 appraisal wells will be drilled in 2014. These plans, however, remain under severe market pressure, not least from any further increase in drilling costs.
- 120 development wells (including sidetracks) were drilled in 2013, a similar number to the last two years.

2.4 Investment

- In 2013, the UKCS experienced the highest rate of investment for more than three decades at £14.4 billion. This is expected to fall to around £13 billion in 2014 and decline further to around £7 billion by 2016 to 2017, unless the rate of maturing new developments increases.
- In 2013, ten new fields requiring £8 billion of investment and delivering 0.46 billion boe over time were sanctioned and an additional 26 brownfield developments of varying sizes were also approved.
- Currently, a total of £39 billion of investment is approved on the UKCS; £27 billion is on new fields whilst £12 billion will be spent on existing assets.
- There is the potential for another £35 billion (2.7 billion boe) to be invested in projects with a 50 per cent or greater chance of development. However, all of these projects are sensitive to any cost increases, not least from drilling; vessel; and floating, production, storage and offloading (FPSO) costs.
- A further £20 billion (1.3 billion boe) of investment is being considered in projects that currently have a less than 50 per cent chance of proceeding.
- 43 new field developments (2.7 billion boe), ranging in probability of proceeding, are currently being evaluated.
- Just under half (21) of these potential new field developments are less than 20 million boe in size, whilst ten have recoverable reserves in excess of 100 million boe.
- 109 potential incremental projects (1.38 billion boe) are also being evaluated by companies.
- More than half of all investment in 2014 is in receipt of a field allowance, demonstrating the effectiveness of these allowances.
- Further new opportunities, including a number of high pressure high temperature (HPHT) discoveries, need to be rapidly matured to avoid a major decline in activity.
- Whilst the Brown Field Allowance has had a significant positive impact on investment, there is a need to consider how it can be expanded to encourage deployment of enhanced oil recovery (EOR) techniques.

2.5 Operating Expenditure

- Operating expenditure rose to £8.9 billion in 2013, £0.5 billion higher than anticipated. This is the highest annual expenditure in real terms in the life of the UKCS.
- Operating costs are anticipated to rise further to around £9.6 billion in 2014, with asset integrity and maintenance, production efficiency[1], general productivity and cost pressures being contributory factors.
- Average unit operating costs (UOCs) have now risen to £17/boe and the number of fields with a UOC greater than £30/boe has doubled over the last 12 months. This trend is unsustainable.
- To stem the rise in UOCs, industry must do more to boost production and control the growth in costs.
- Based on current metrics, an increasing number of assets will be unviable in the event of any prolonged fall in oil and gas prices.

[1] Production efficiency is a measure of a field's actual performance against its maximum capability when measured from reservoir through well, platform and processing facilities and then to final point of export.

2.6 Production

- Production averaged at 1.43 million boepd in 2013 (eight per cent lower than 2012, with oil and gas down nine per cent and six per cent, respectively). This was better than anticipated at the end of the first half of the year, and may reflect some early results from work to improve production efficiency as part of the government-industry task force PILOT.
- Over the last three years, production has declined 38 per cent, but with the combination of new field start-ups and fields coming back on-stream, it is expected to begin to pick up in 2014.
- Whilst production efficiency has fallen from an average of around 80 per cent to 60 per cent over the last decade, it is expected to improve in 2014.
- As a result, operators are more positive about their asset performance, with more than 80 per cent predicting production will improve in 2014, compared with less than 50 per cent anticipating such a trend in 2013.
- Looking ahead, 25 fields are expected to start production in the next two years bringing combined reserves of 1.3 billion boe on-stream. By 2018, 40 per cent of production will come from new field developments; this emphasises the need to continually mature opportunities following exploration.

2.7 Decommissioning

- Total decommissioning expenditure is expected to be at £40.6 billion (2013 money) by 2040, of which £37 billion is for currently sanctioned installations and the additional £3.6 billion to decommission developments that are yet to be approved.

2.8 Oil and Gas Prices

- The oil price averaged at $109/barrel in 2013, similar to 2012.
- The gas price averaged at 68 pence/therm in 2013 (day ahead price), which is 13 per cent higher than in 2012.

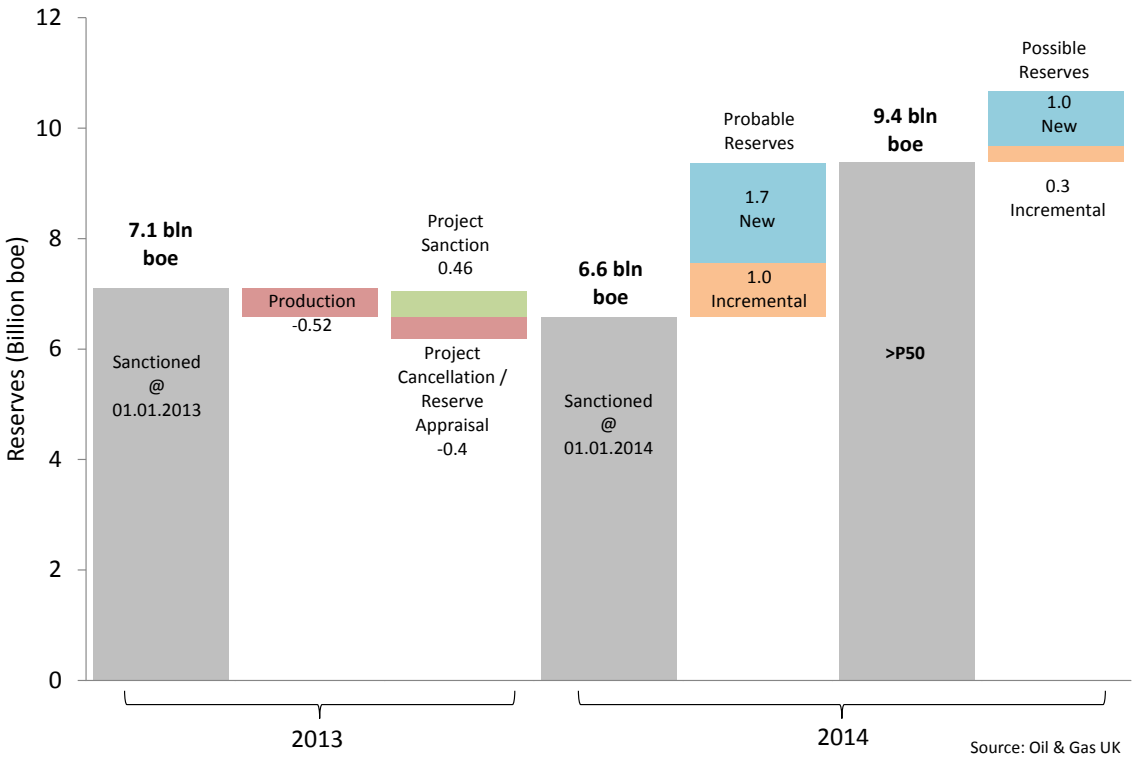
3. Reserves Maturation

A total of 10.7 billion boe are reported in this year's survey as either in production, under development or being considered for investment, compared with 11.4 billion boe a year ago. Of these reserves, 9.4 billion boe are reported to have a greater than 50 per cent chance of being recovered (>P50 confidence level) compared with 9.9 billion boe a year ago. This fall of five per cent in sanctioned and probable reserves recovery reflects the struggle to increase recovery from existing fields, the difficulty in commercialising new discoveries and poor exploration success in recent years, which continued through 2013.

The sanctioned reserves base fell to 6.6 billion boe at the start of 2014, seven per cent down on last year. This is the first decline in four years and marks a major change in trend for the UK Continental Shelf (UKCS). The fall is due to 0.52 billion boe having been produced and a further 0.4 billion boe being removed from plans, either due to cost increases (making a number of projects unviable), poorer reservoir prognosis or the re-appraisal of a number of key developments. Offsetting this near one billion boe decline, however, is 0.46 billion boe added from ten newly sanctioned projects in 2013, of which the Mariner field, announced at the beginning of last year, is by far the biggest contributor. Overall, though, this is the smallest addition to sanctioned reserves from new field approvals for four years.

Looking forward, the 'probable' reserves base awaiting development has remained at 2.7 billion boe while the 'possible' reserves have fallen by 0.2 billion boe compared with last year's survey, emphasising the challenges involved in maturing new opportunities on the UKCS.

Figure 1: Build-Up of the Reserves Base



Brownfields

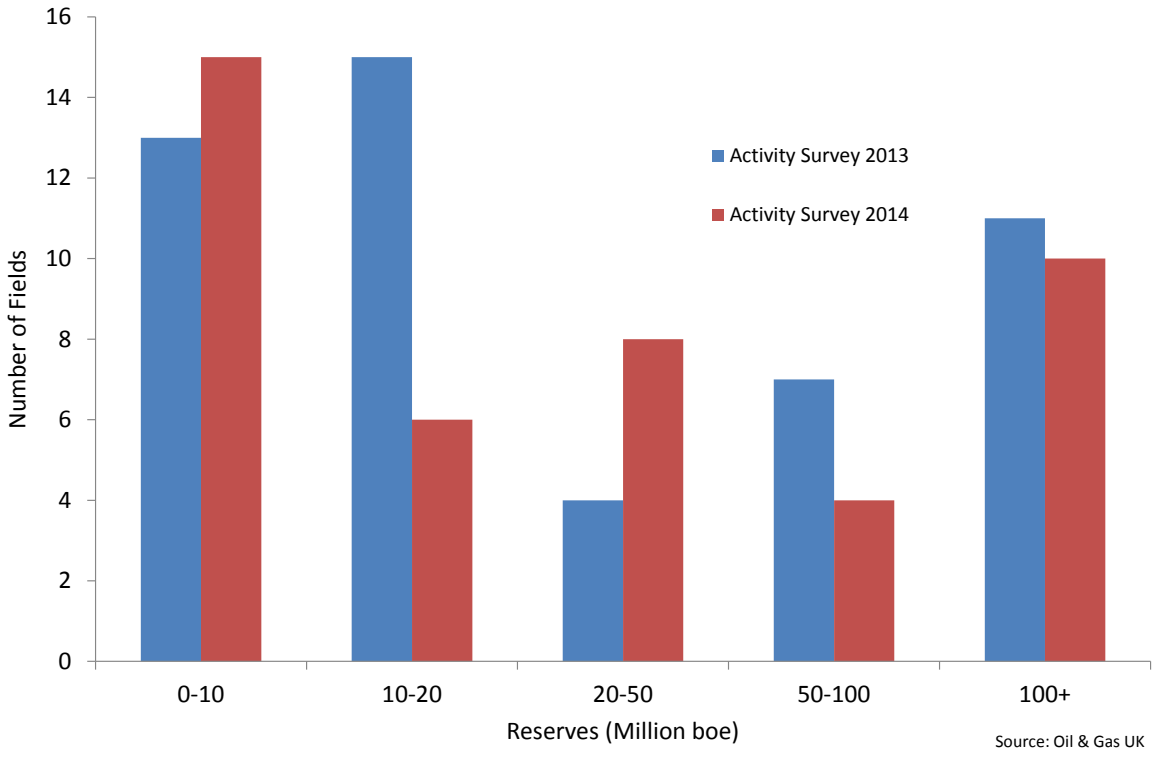
In this survey, 109 brownfield projects are reported containing 1.38 billion boe. This is up by just two projects from last year, but the total related reserves have risen by 25 per cent. Strengthening brownfield investment is therefore crucial to the future of the UKCS as it will improve the viability of many mature fields and extend the life of infrastructure. This will be critical to sustain exploration activity. The introduction of the Brown Field Allowance has been a significant contributory factor and may yet have a bigger role to play to promote increased and enhanced oil recovery (IOR and EOR) projects.

New Fields

A total of 43 new developments have been reported on the UKCS in the latest survey, compared with 50 in last year's survey. Of these 43, eight are located in the west of Shetland (W of S), 22 in the central North Sea (CNS), seven in the northern North Sea (NNS) and six in the southern North Sea (SNS) and Irish Sea (IS).

As can be seen in Figure 2, the smaller fields still dominate the undeveloped reserves portfolio, with only a third of these fields being greater than 50 million boe. Whilst small fields (less than 50 million boe) are able to access a field allowance, many of the larger potential field developments are not able to do so and may struggle to gain sanction given current cost pressures and increased capital rationing by many oil companies.

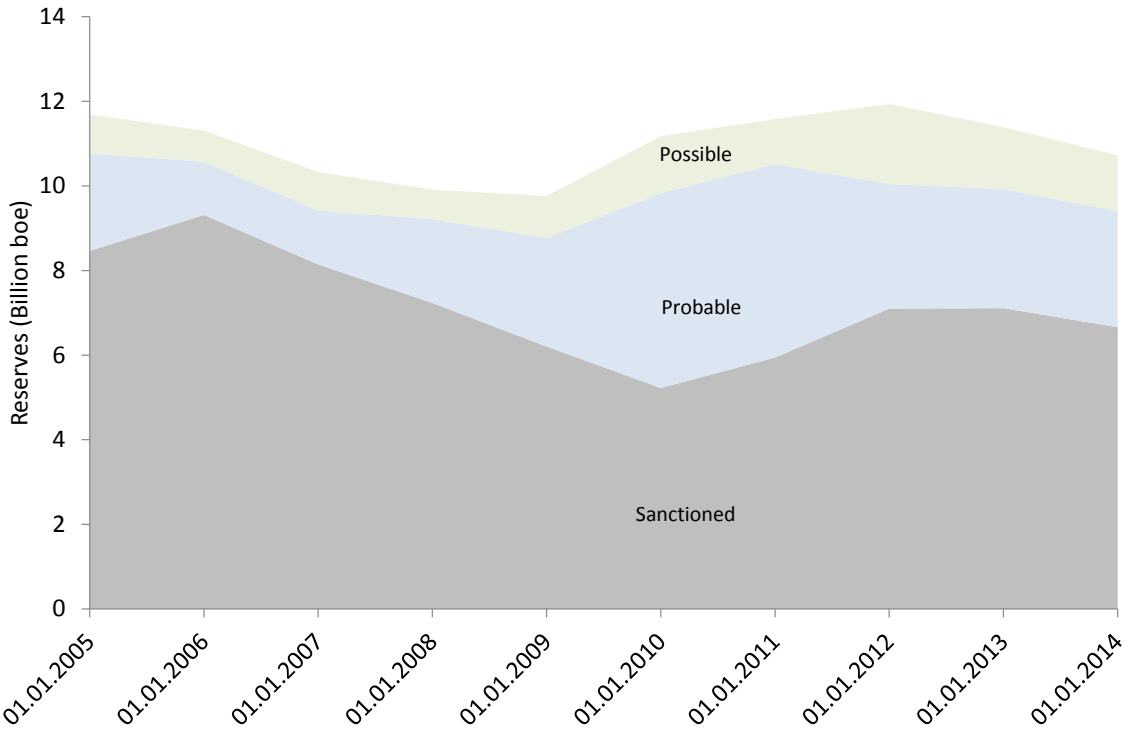
Figure 2: Distribution of Undeveloped Reserves



Maximising Recovery

Over the last decade, the total reported recoverable reserves, considering the full range of probabilities, has consistently remained at around 11 billion boe, with 2014 being no exception at 10.7 billion boe. However, only 60 per cent of these reserves in 2014 are sanctioned, compared with 80 per cent in 2006. This trend, with a much smaller sanctioned base, means that investment in UKCS developments is increasingly exposed to cost, production and price risks.

Figure 3: The Evolving Reserve Base of the UK Continental Shelf



Source: Oil & Gas UK

Maximising recovery from the UKCS requires the industry to take a three-pronged approach, as follows:

i. Continue to increase recovery from existing fields, using increased and enhanced oil and gas recovery techniques
ii. Find new means to commercialise existing discoveries which are as yet undeveloped typically for technical or cost reasons
iii. Increase exploration to replace the barrels that have been produced

With the difficulties in maturing new discoveries, it is all the more important to increase the recovery rate of existing fields, which is typically running at around 46 per cent on oil fields across the UKCS. Current estimates are that EOR technologies have the potential to add up to six billion barrels, taking a best case scenario. However, even with more conservative assumptions, effective implementation of EOR could readily add an additional 0.5 to 1 billion boe to recoverable reserves in the near term.

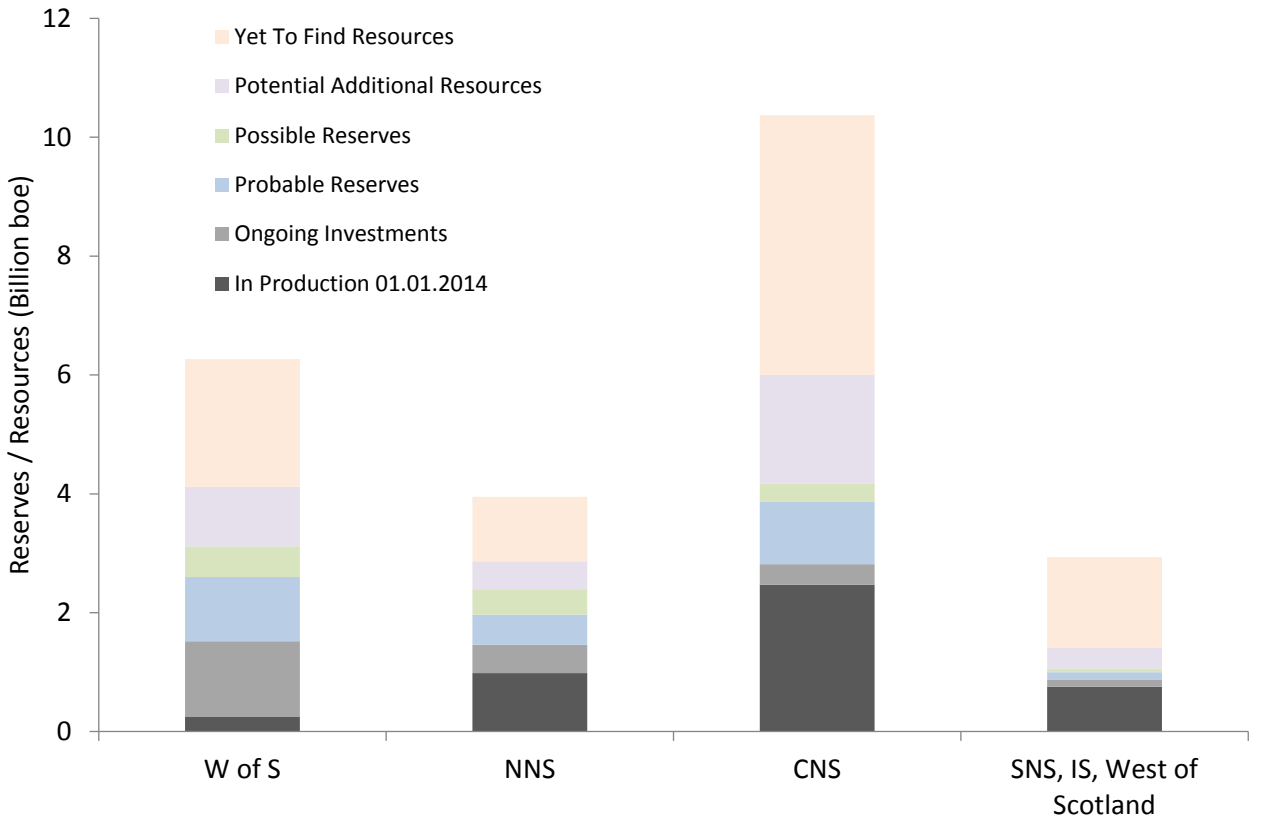
The 'yet-to-find' (YTF) opportunity remaining on the UKCS is inherently difficult to assess. Currently, the Department of Energy & Climate Change (DECC) carries a range of estimates of YTF varying from just below six billion boe of oil and gas resources in the low case to just over nine billion boe in the central case. Clearly not all of these potential barrels will be discovered, developed and produced unless exploration activity steps up from the current low rate (see Section 4), but the figures provide an indication of the scale of the opportunity.

Comparison by Region

To provide an indication of the distribution of the overall opportunity by region across the UKCS, central numbers provided by DECC for 'potential additional resources' (PARS) and YTF, together totalling 13 billion boe, have been overlaid on top of the existing reserves profiles (see Figure 4). Whilst the overall figures should be taken with caution due to their inherent uncertainty, they do illustrate the potential of each region.

With nearly four billion boe, the central North Sea has the largest base of sanctioned and probable reserves, 65 per cent of which are currently in production. However, the west of Shetland is shown to be a much less mature region. Only a tenth of the 2.6 billion boe of sanctioned and probable reserves are currently in production, emphasising the need to increase the pace of development in that region.

Figure 4: Reserves and Resource Growth by Region

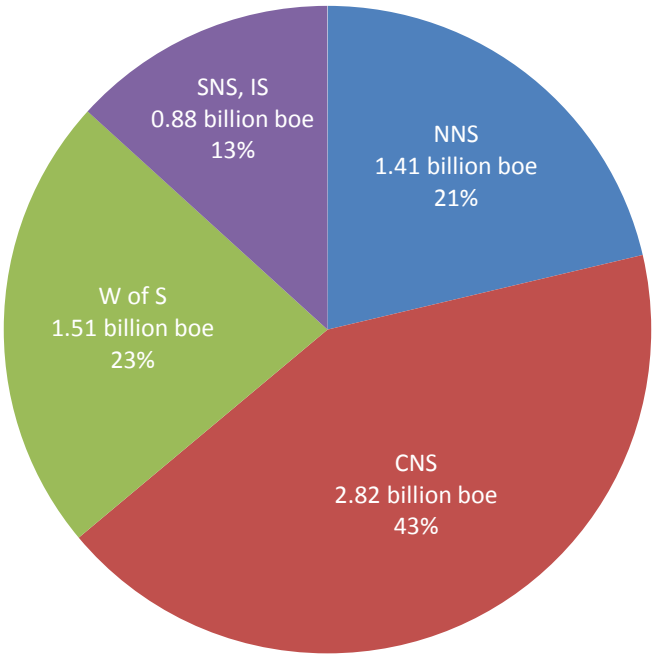


Source: Oil & Gas UK, DECC

Figure 5 shows that the central North Sea is still the leading region for sanctioned reserves, with over 40 per cent of the total reserves either in production or currently under development on the UKCS. This is despite a key project of over 100 million boe being withdrawn from development for the time being.

All regions failed to add significantly to their sanctioned reserves during the last year with the southern North Sea /Irish Sea seeing the largest decline in sanctioned reserves of 20 per cent.

Figure 5: Sanctioned Reserves by Region

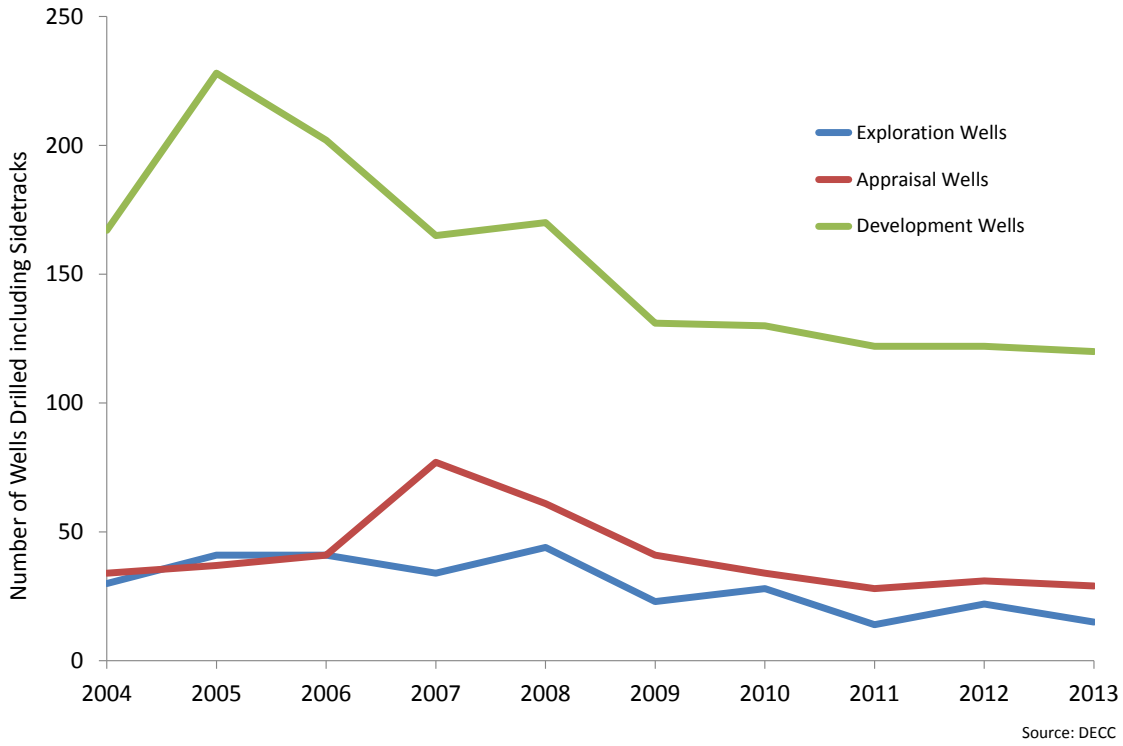


Source: Oil & Gas UK

4. Drilling Activity

Drilling Performance[2]

Figure 6: Drilling Activity on the UK Continental Shelf including Sidetracks



Source: DECC

Development Drilling

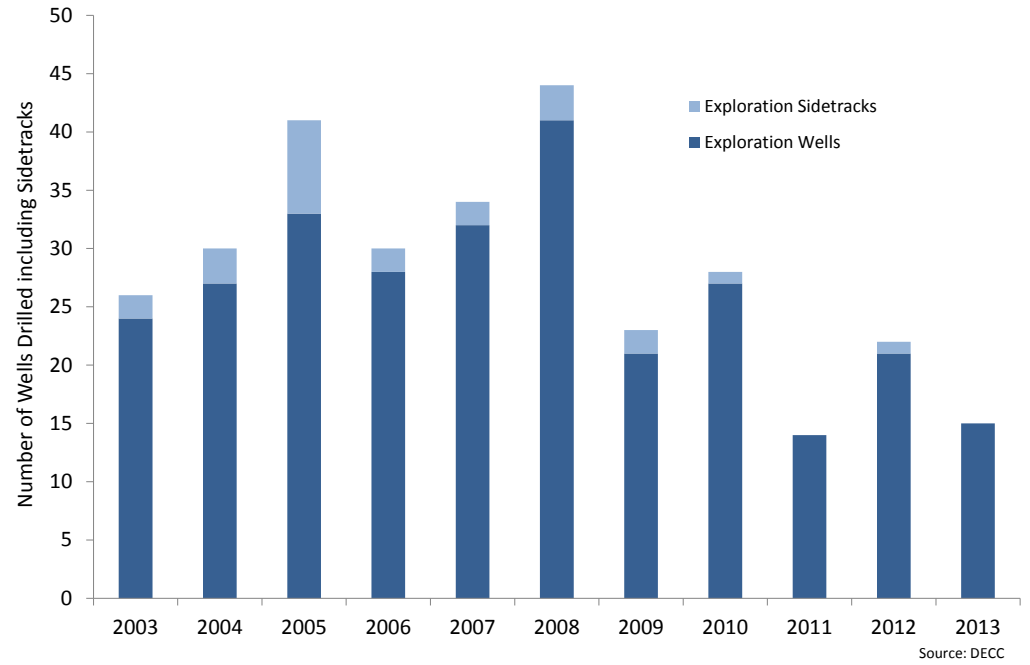
In 2013, a total of 120 development wells (including sidetracks) were drilled. Although the number of development wells has remained stable over the last three years (from 2011 to 2013) at an average of 121 wells per year, drilling has decreased by half over the last decade, contributing to the fall in production seen over this period.

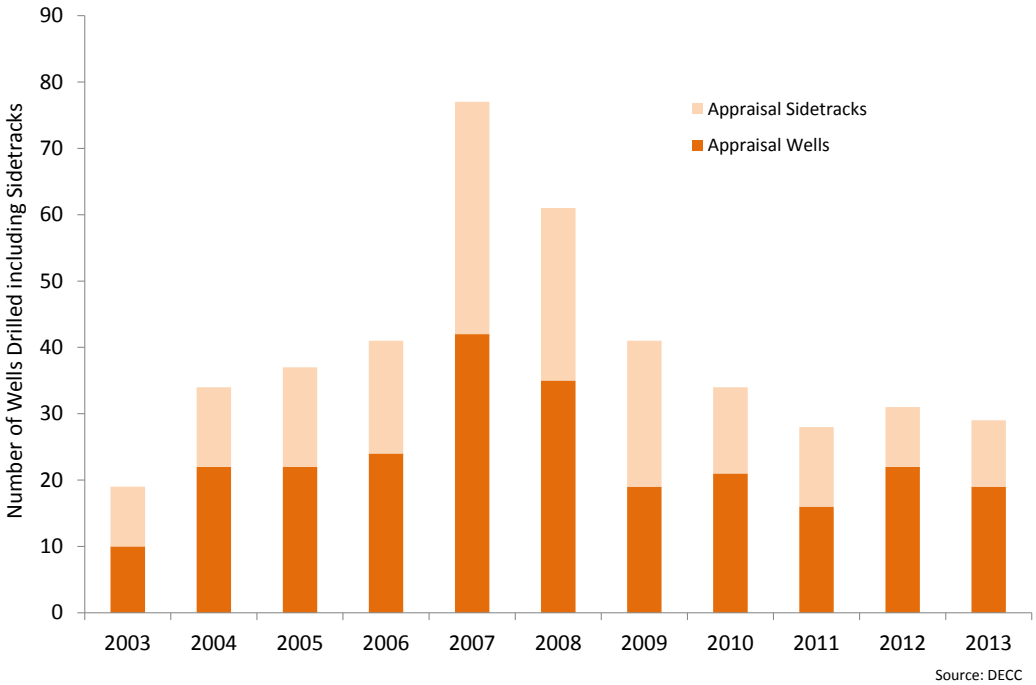
[2] Throughout this section the drilling numbers are quoted including sidetracks, unless otherwise indicated.

Exploration and Appraisal Drilling

Exploration and appraisal (E&A) drilling (including sidetracks) decreased from 53 wells in 2012 to 44 in 2013. This decline is due mainly to the drop in exploration drilling from 22 wells in 2012 to only 15 in 2013. Appraisal drilling numbers were similar, at 31 wells in 2012 and 29 in 2013. Expenditure on E&A activity, including seismic data acquisition and interpretation, was £1.6 billion in 2013, compared to £1.7 billion in 2012.

Figure 7: Exploration and Appraisal Wells, including Sidetracks

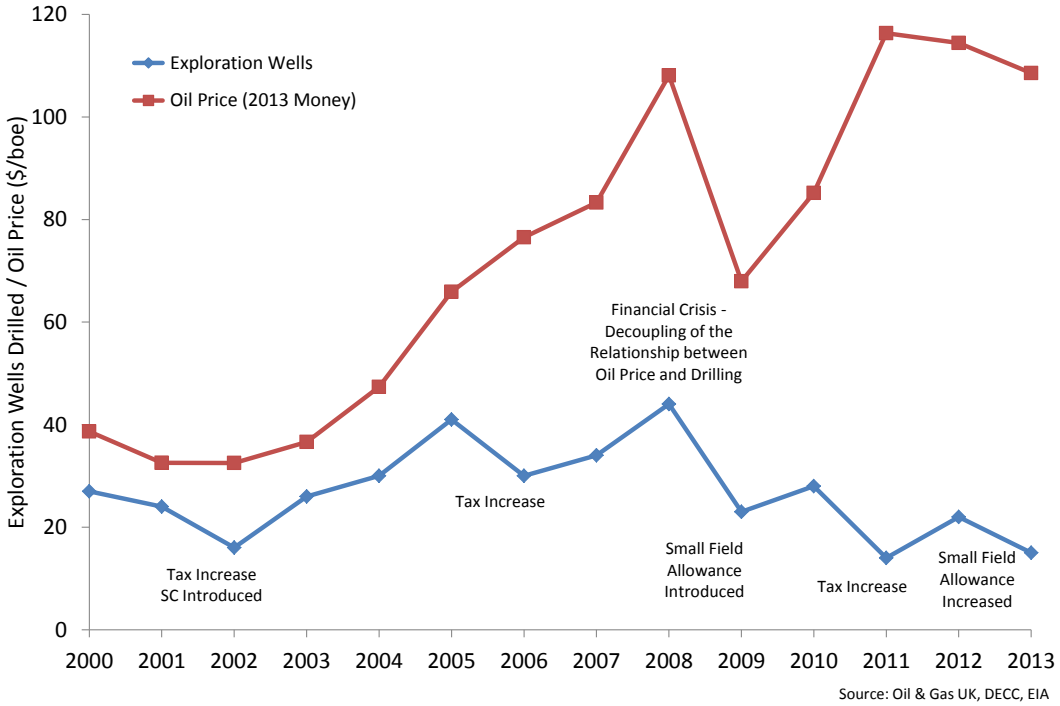




Exploration drilling has been on a downward trend since it first fell sharply in 2009 due to the collapse in oil price and the financial crisis which impacted the exploration and production sector. There was a further sharp fall in 2011 coinciding with the increase in the Supplementary Charge (SC) rate. Drilling activity is yet to recover.

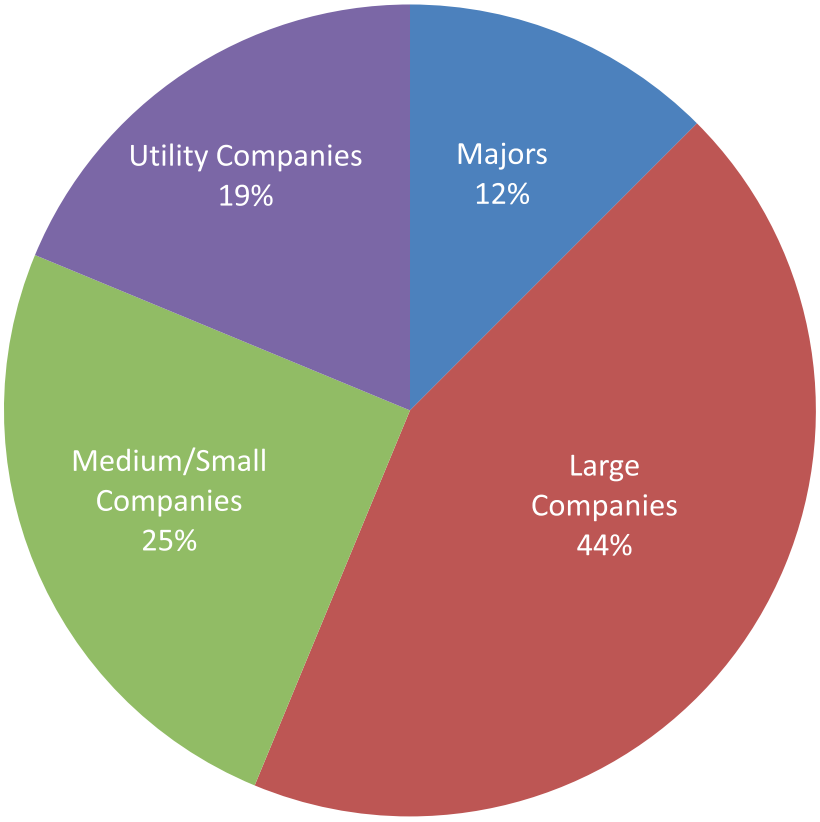
Over the last five years from 2009 to 2013, an average of 20 exploration wells have been drilled per year; this contrasts with the period from 2005 to 2008 when an average of 37 exploration wells per year were drilled. Furthermore, 2011 and 2013 saw the lowest and second lowest numbers of exploration wells drilled, respectively, since drilling began on the UKCS in the 1960s. If this low rate of exploration drilling continues, the UK will recover only a fraction of the YTF resources on the UKCS and many assets will be prematurely decommissioned for want of new production.

Figure 8: Exploration Drilling versus Oil Price



The distribution of E&A drilling by company type in 2013 has changed over the last 12 months. The share of drilling by the majors has remained similar at around 12 per cent in 2013. Energy utilities have become more active during the period, drilling 19 per cent of wells in 2013, compared to 12 per cent in 2012. Large companies were responsible for 44 per cent of E&A activity in 2013, whereas small to medium companies, which are probably most constrained by access to finance, contributed just 25 per cent of wells.

Figure 9: Exploration and Appraisal Drilling by Company Type in 2013



Source: Oil & Gas UK

Discoveries

Survey results from operators to date indicate that only 80 million boe of technically recoverable reserves were discovered in 2013, of which around half is currently considered commercially recoverable (these numbers are subject to further appraisal). Given only 20 million boe were discovered in 2012, recent poor exploration performance will put further downward pressure on production in the longer term.

Although ten wells drilled in 2013 found hydrocarbons, only three are currently considered commercial. Given the obvious immaturity of the discoveries, this number could change as further appraisal activity is carried out. This is broadly similar to 2012 when seven exploration wells found hydrocarbons and three of these were considered commercially developable.

Sixty per cent of discoveries in 2013 were from wildcat wells, which drill into a play that has not previously been tested and was not connected with a known hydrocarbon accumulation. This compares with 50 per cent of discoveries coming from wildcat wells in 2012, whereas in 2011, the majority of discoveries came from near-field targets[3]. Given the current low rate of drilling, there should be some caution in taking this as an indicative trend towards targeting wildcat opportunities; however, such an approach will be increasingly required to realise the full potential of the UKCS.

Over the four-year period from 2010 to 2013, around 0.5 billion boe was discovered on the UKCS. This compares with discovered volumes of around 1.5 billion boe from 2005 to 2008[4], which was a period of much more intense exploration activity. In 2013, the median unrisked reserve size targeted by exploration wells was 35 million boe. Whilst this is the same as in 2011 and 2012, the number of wells targeting volumes greater than 100 million boe decreased from seven in 2012 to just three in 2013.

Constraints

Clearly intervention is needed if the current trend is to be turned around. An Exploration Task Force, as part of the industry-government task force PILOT, is currently concentrating on key areas, including new and neglected plays; seismic imaging, technology, and data access and dissemination; collaboration particularly around mature hubs; comparative work considering similar markets and jurisdictions; and access to finance. The task force continues to pursue these issues actively and will report in due course.

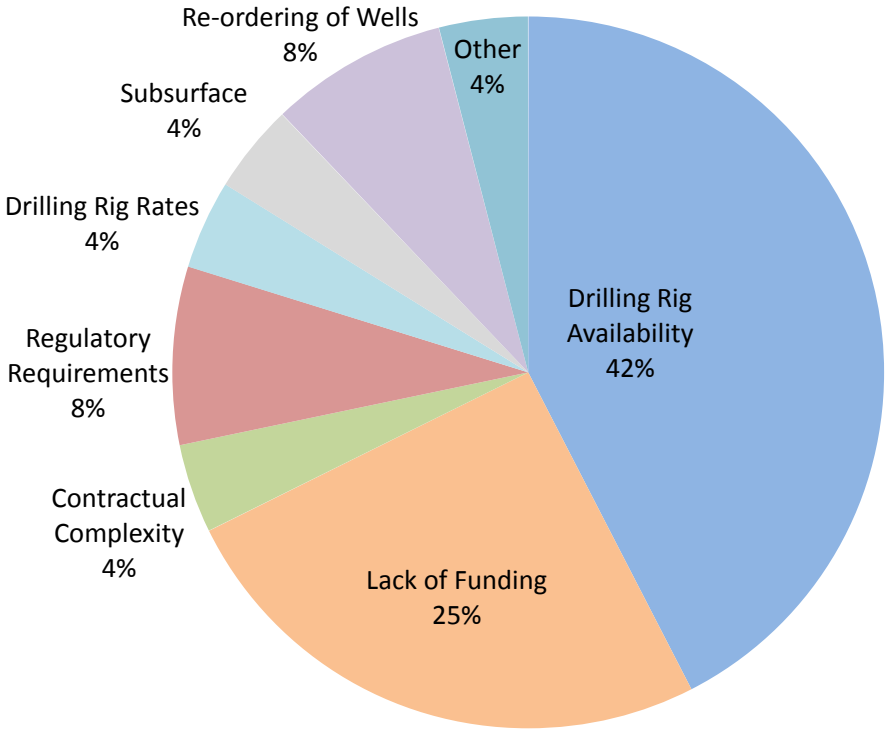
Of the 55 to 60 E&A wells which were forecast to be drilled last year, 20 were postponed and four were cancelled, which in turn adds pressure on the E&A programme in 2014. Eighteen of the 20 postponed wells are now intended to be drilled in 2014 and two wells have been further postponed until 2015. Similarly, many of the wells that were forecast last year for drilling in 2014 now appear to be in operators' forecasts for 2015, pointing to a growing backlog of wells.

Survey results show that a number of factors significantly constrained exploration drilling in 2013, with rig unavailability being the primary cause, accounting for 42 per cent of postponed or cancelled wells (ten wells). Several operators affected by rig delays revealed that they had in fact secured a firm rig slot to drill, but weather conditions and delays on other drilling sites had a knock-on effect. The lack of access to funding was also seen as a significant constraint on exploration, accounting for a quarter (six) of the wells that were postponed or cancelled.

[3] Near-field exploration wells typically target previously undrilled traps or fault blocks to test for the presence of new hydrocarbon accumulations.
[4] Source: Wood Mackenzie

Taking a regional perspective, nine wells were postponed in the central North Sea, six of which were due to rig unavailability. In the southern North Sea, three of the four postponed wells were adversely affected by the lack of rig availability, and in the northern North Sea, regulatory requirements, contractual complexity and the lack of external funding were reported as the main reasons for postponement.

Figure 10: Constraints on Exploration and Appraisal Drilling in 2013

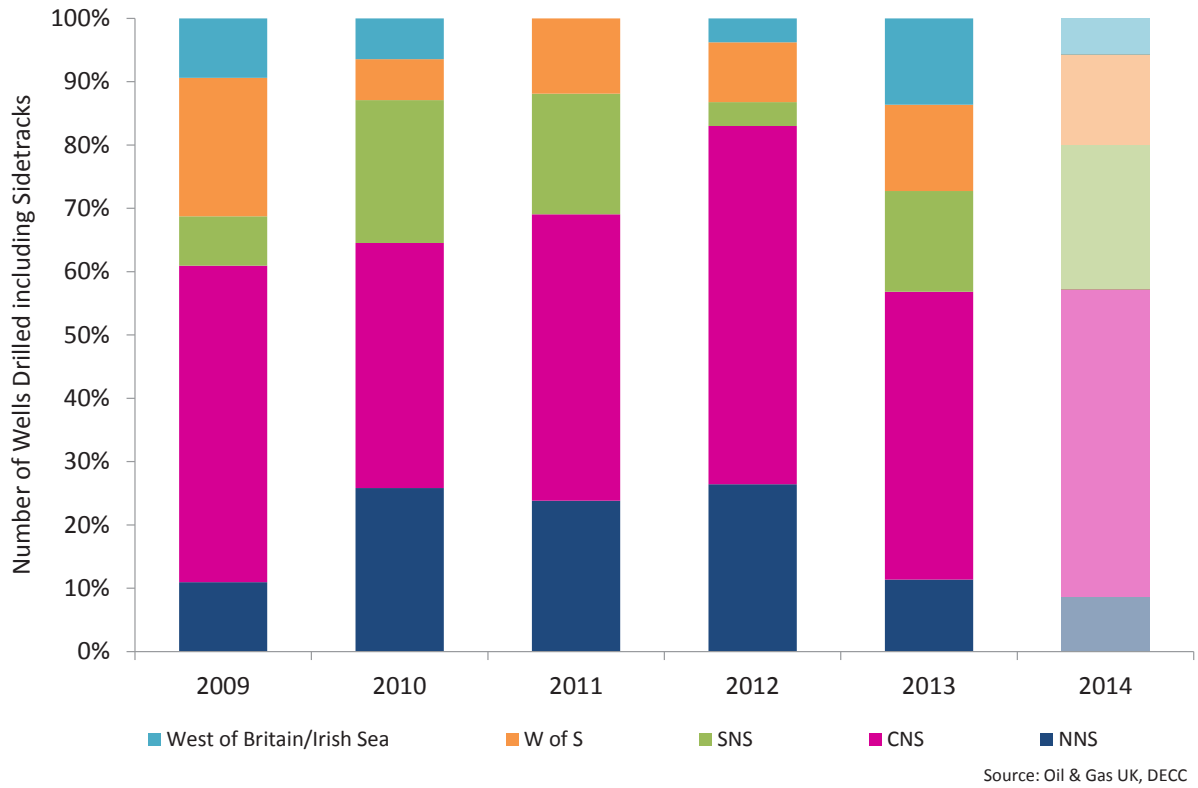


Source: Oil & Gas UK

Looking at the distribution of the 44 E&A wells drilled in 2013, 45 per cent (20 wells) were in the central North Sea, making it the most active region for E&A activity on the UKCS. The southern North Sea overtook the northern North Sea as the second most active drilling region with 16 per cent of wells drilled (seven wells), while the west of Shetland and west of Britain/Irish Sea had 14 per cent each (six wells each). The northern North Sea went from being the second most active region in 2012, with 26 per cent of wells drilled, to the least active region last year with 11 per cent of wells (14 wells in 2012, five wells in 2013).

Considering exploration drilling in isolation, the central North Sea dominated drilling with ten wells, compared with two in the southern North Sea and only one in each of the other three regions (northern North Sea, west of Shetland and west of Britain/Irish Sea).

Figure 11: Exploration and Appraisal Drilling by Region



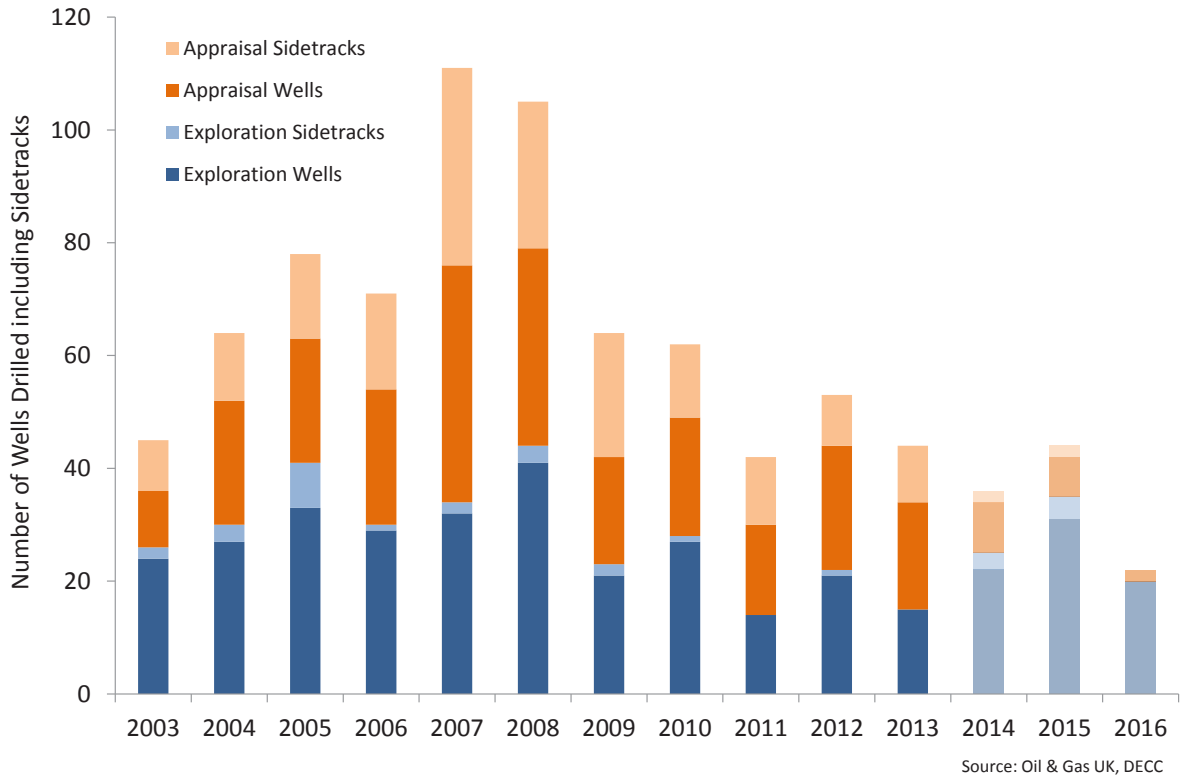
Source: Oil & Gas UK, DECC

Exploration Outlook

Operators currently indicate that they could drill around 25 exploration wells and 11 appraisal wells in 2014, of which 18 were postponed from 2013. This forecast considers only those wells with a probability of greater than 50 per cent of being drilled. A further total of 66 E&A wells are anticipated to be drilled from 2015 to 2016, again on a similar risked basis. The likelihood of these wells being drilled, especially those forecast this year, will depend on companies' abilities to overcome the constraints which have impaired activity in recent years.

Operators forecast that the central North Sea will remain the most active region for E&A drilling in 2014, accounting for half of the total forecast (18 wells). The southern North Sea is forecast to deliver almost a quarter of the wells (eight) in 2013, making it the second most active region. The remainder of E&A wells come from the west of Shetland (five), the northern North Sea (three), and the west of Britain/Irish Sea (two).

Figure 12: Exploration and Appraisal Forecast

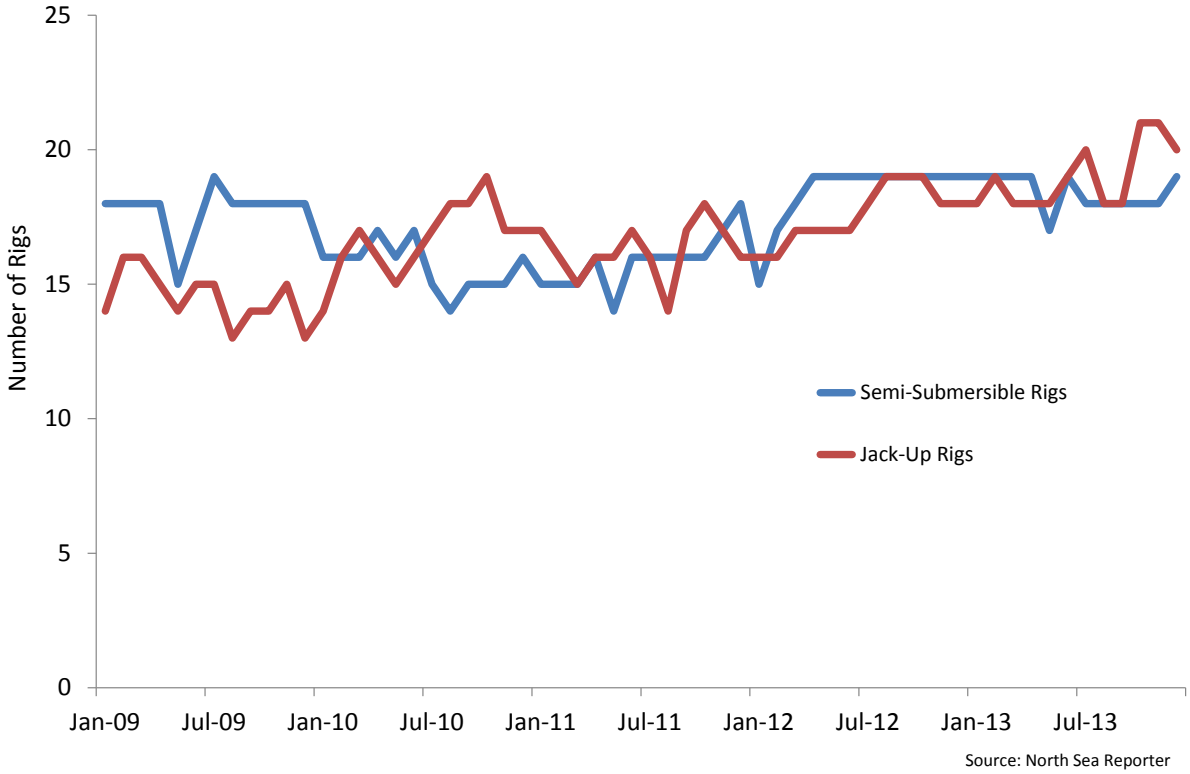


Source: Oil & Gas UK, DECC

Mobile Drilling Rig Market

The number of mobile drilling rigs deployed in the UK at the end of 2013 was at its highest since 2008 (20 jack-ups and 19 semi-submersible rigs). Despite this, it is very apparent that there remains a shortage of rigs on the UKCS, as demonstrated by the constraints on E&A drilling. Current daily rig rates are also a deterrent to further exploration, more so, given that the time taken to drill a typical well on the UKCS has increased by 17 days over the last five years.

Figure 13: Number of Rigs on the UK Continental Shelf

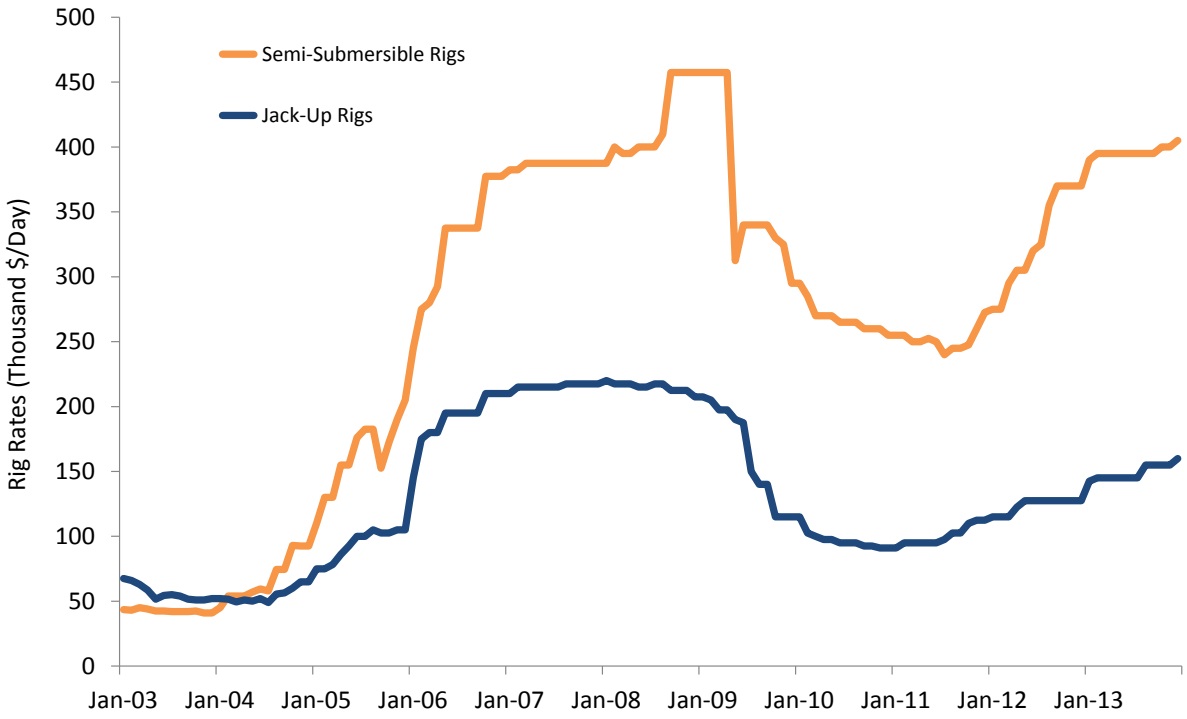


Source: North Sea Reporter

Figure 14 illustrates that semi-submersible rig day-rates have almost doubled over the last three years and jack-up rig day-rates have increased by 60 per cent. Such cost increases have been a major deterrent to exploration activity, as many exploration wells are simply unaffordable at current prices.

It is also observed that rig contracts on the Norwegian Continental Shelf are typically two or three years longer in duration than those on the UKCS.

Figure 14: Daily Rig Rates Based on Reported Contract Awards for Mobile Units



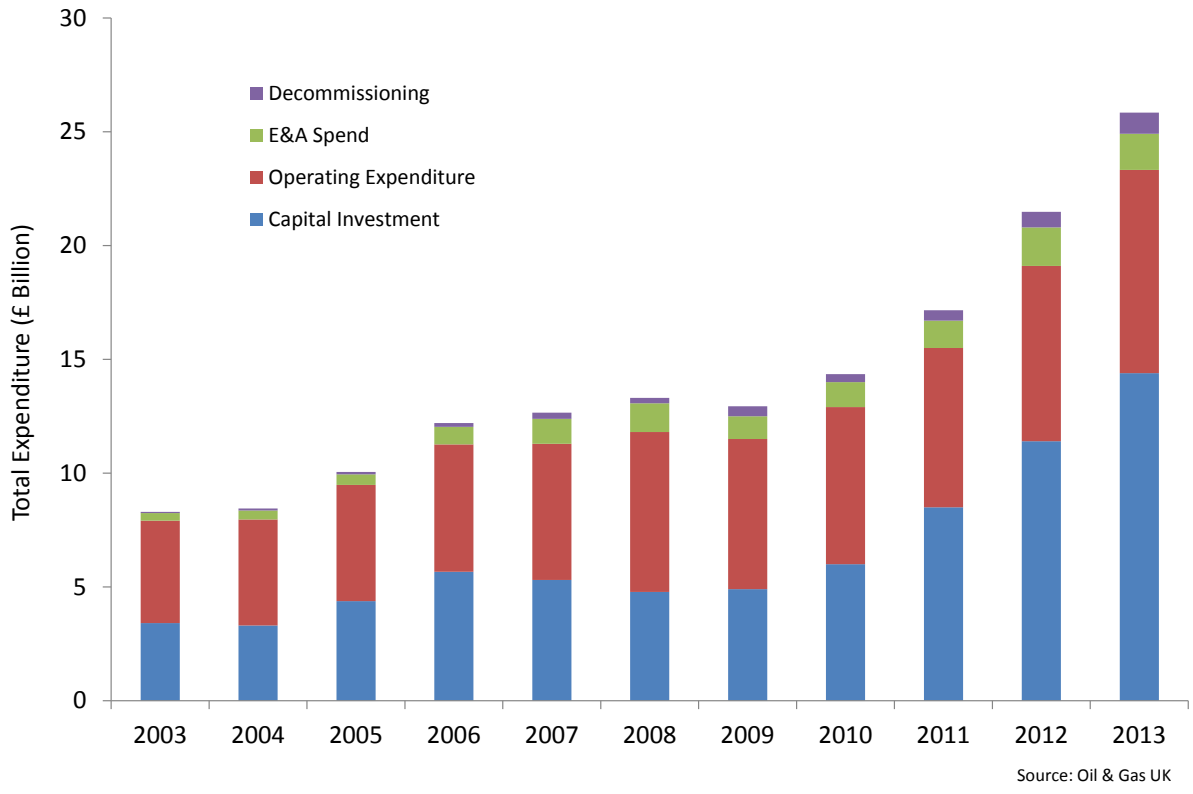
Source: North Sea Reporter

5. Total Expenditure

Total expenditure peaked at almost £26 billion during 2013, largely driven by strong capital investment and the rising costs associated with operating the basin. Despite the decline in E&A activity in 2013 (see Section 4), the drilling campaigns that took place were often expensive and subject to time and cost over-runs. As a result, total E&A expenditure, including seismic data acquisition and interpretation, reached £1.6 billion last year despite the fall in the number of E&A wells drilled. Decommissioning is becoming a more significant activity and exceeded £0.9 billion (3.5 per cent of total expenditure) for the first time in 2013.

Over the last two years, as investment and operating expenditure have risen and production has fallen, the UKCS is generating less free cash. This reached the point in 2013 where once tax had been paid, the total revenue generated on the UKCS was equivalent to the sum being spent or reinvested. In such circumstances, capital efficiency will dominate investors' thinking as they will otherwise have to increase borrowing by going externally to shareholders or the market for further investment funds. This situation should ease over the next few years as the current wave of investments come into production.

Figure 15: Total Expenditure on the UK Continental Shelf

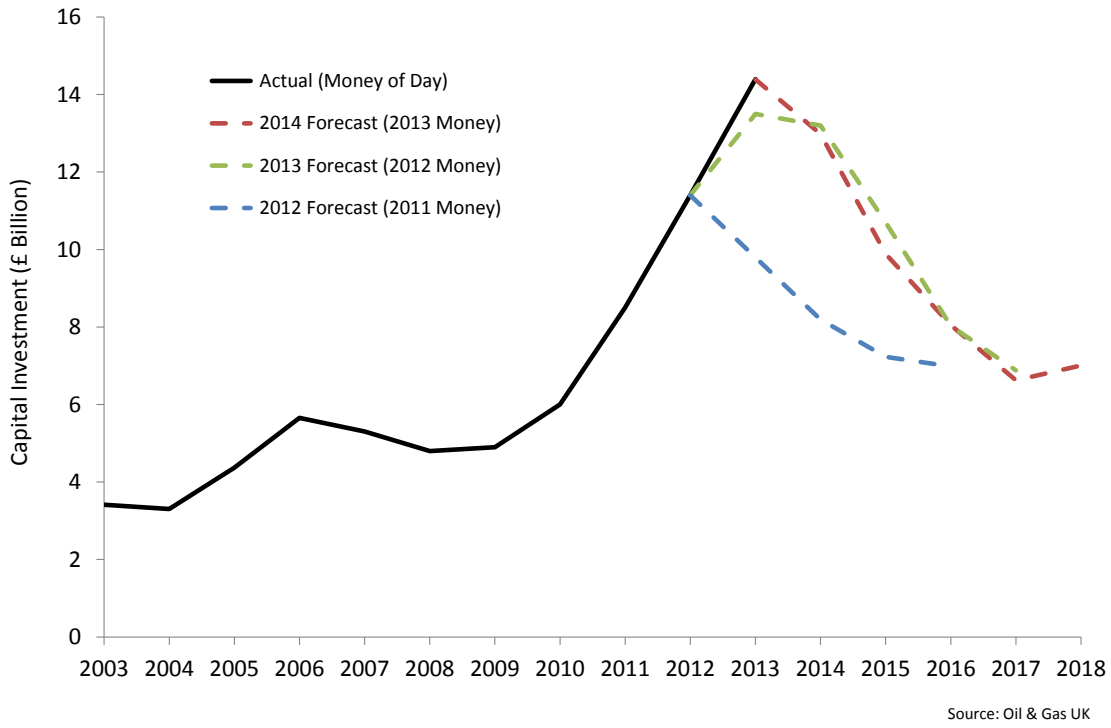


Source: Oil & Gas UK

6. Investment

Capital expenditure on the UKCS reached £14.4 billion last year, around £1 billion higher than was forecast 12 months ago, with growth in activity and general cost escalation both being contributory factors. Investment on the UKCS has more than doubled since 2010 and is expected to remain above £10 billion per annum until 2015, before falling back to around £7-8 billion per year by 2016 to 2017.

Figure 16: Capital Investment Forecast with Projections from Previous Surveys



Source: Oil & Gas UK

It is important to understand the factors that have driven this recent surge of investment to avoid a serious decline in activity later this decade. The need to sustain investment is vital to ensure the long-term future of the UKCS. Four key factors have contributed to the increase in investment in recent years:

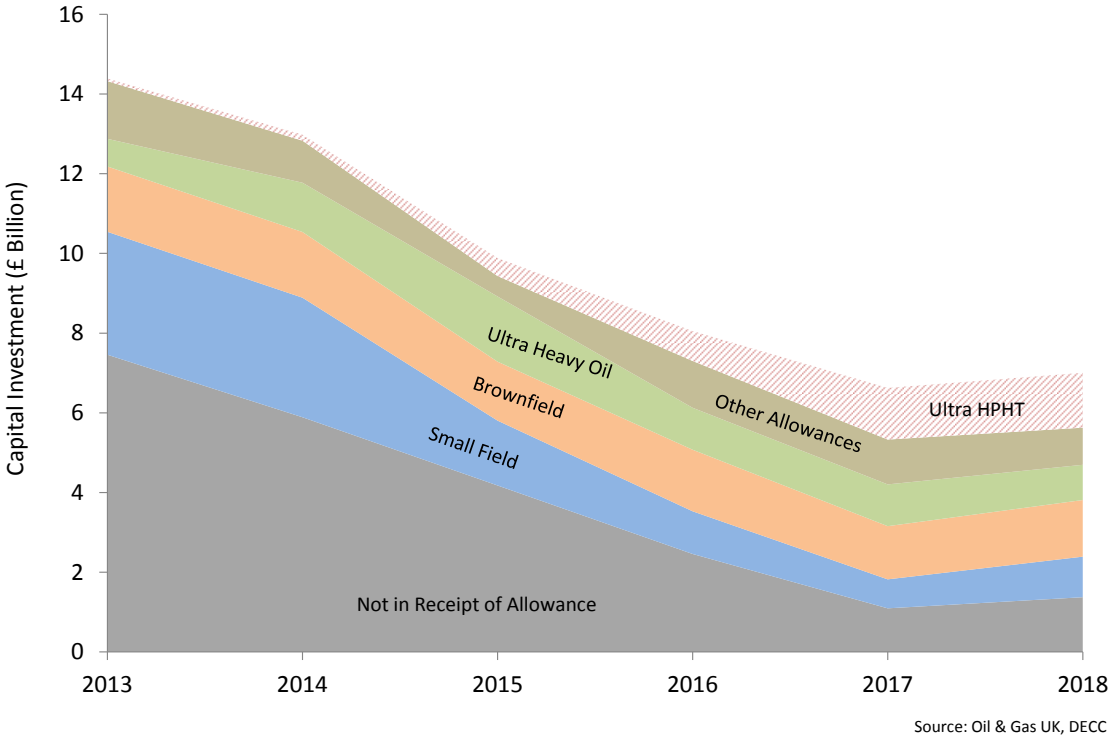
- **A number of large projects have been sanctioned** – since the start of 2010, five multi-billion pound investments, totalling £17 billion and 1.6 billion boe, have been approved and are now under development or nearing completion.

- **New field allowances have encouraged investment in opportunities that would otherwise have been unattractive at prevailing fiscal and market conditions** – in 2013, around half of the £14.4 billion of investment was in some way incentivised by an allowance and this proportion will almost certainly increase in 2014 (see Figure 17). Despite the apparent success of field allowances as part of the ring fenced tax regime, they are often seen to be niche solutions specifically tailored to particular investment opportunities. Additionally, the fiscal regime has a vital role to play to encourage greater recovery from existing fields through better deployment of EOR techniques and by increasing the scope of the Brown Field Allowance.

- **A new focus on asset integrity requiring significant capital investment** – offshore facilities require upgrades as they outlive their design life and there has been at least £1 billion per year spent on asset integrity since 2010.

- **A stable and high oil price over the last three years that has rarely moved outside of the $100 to $120 bracket** – the oil price has averaged $111, $112 and $109 in 2011, 2012 and 2013, respectively.

Figure 17: Capital Investment by Allowance Type



Source: Oil & Gas UK, DECC

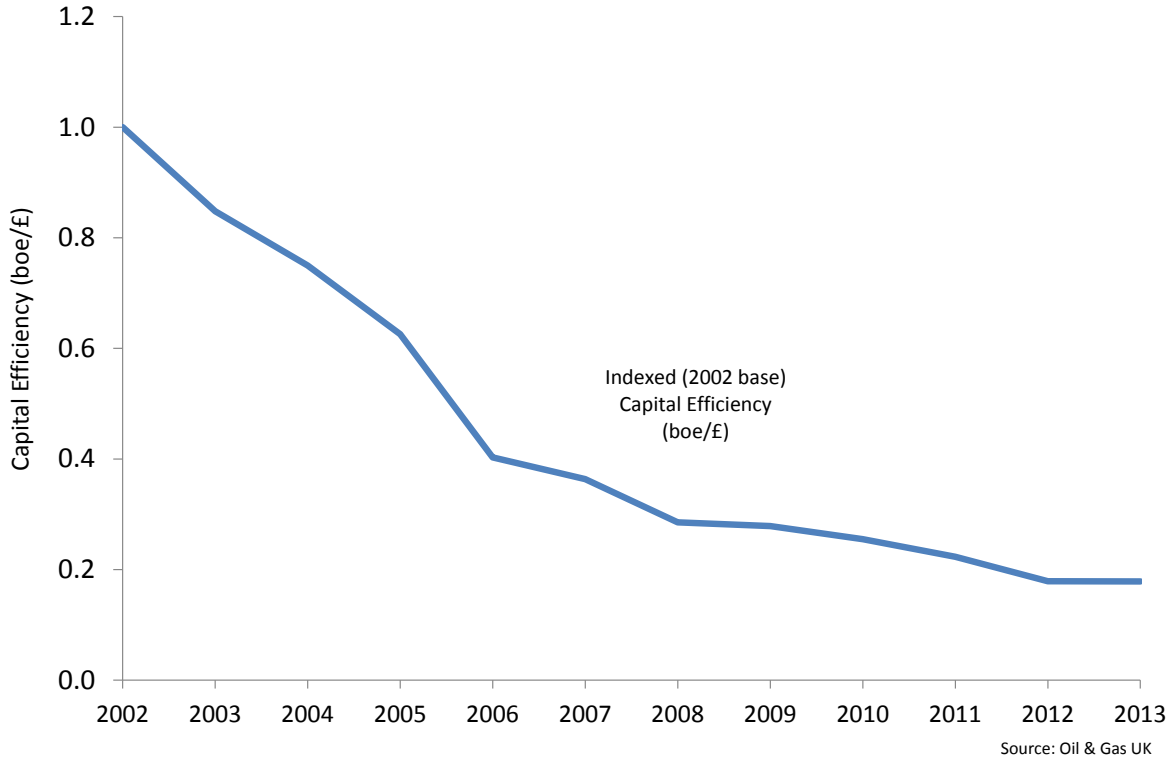
At the start of 2014, £39 billion worth of capital was planned to be spent on already sanctioned investments, both in new projects and existing fields. This will sustain capital investment over the next couple of years.

Current plans include £35 billion worth of investment in projects with a greater than 50 per cent chance of development, and a further £20 billion worth of investment is being considered for projects that currently have a smaller than 50 per cent chance of development. However, some of these projects appear uncommercial even at current oil prices when subject to marginal tax rates of between 62 to 81 per cent. For example, the investment in ultra high pressure high temperature (HPHT) fields shown in Figure 17 is only commercial subject to a change in the Ultra HPHT allowance, on which discussions are ongoing between industry and government. Whilst field allowances are helping and will continue to do so, there is an increasing need to consider a more fundamental review of the fiscal regime.

Furthermore, beyond the next couple of years, investment will tail off unless additional new developments are matured. There is typically a lag of four or five years between a discovery being made and it being brought forward for development; the significant decline in exploration activity over recent years will increasingly have an impact on the investment outlook over the remainder of this decade.

With continued high demand for supply chain services, cost pressures are clearly taking their toll on the UKCS. That said, capital efficiency has barely changed over the last 12 months and appears to have reached a ceiling, in part, reflecting investors' reluctance to sanction investments above last year's cost limits. This indicates that further cost increases may result in rapidly diminishing returns unless productivity improves.

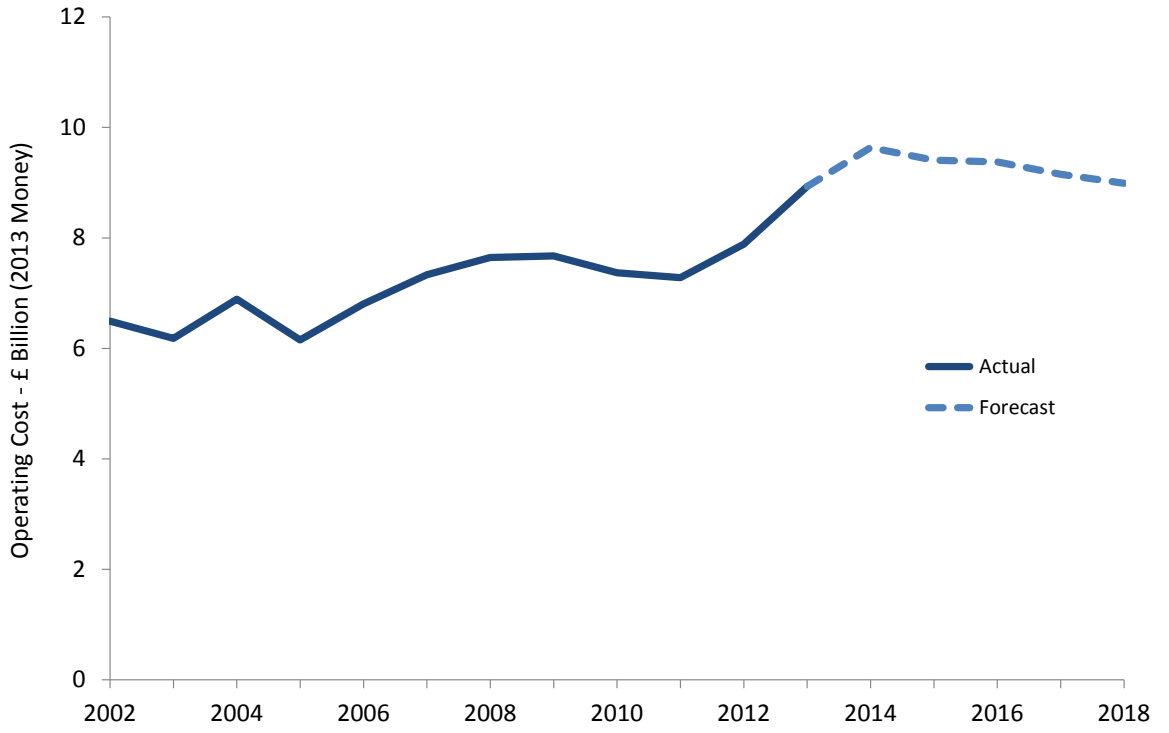
Figure 18: Capital Efficiency on the UK Continental Shelf



7. Operating Expenditure

The cost of operations on the UKCS rose by 15.5 per cent to £8.9 billion in 2013. This comes on top of a ten per cent increase in 2012. Operating expenditure, even when inflation is taken into account, is the highest since production began on the UKCS more than four decades ago. Current indications are that costs are likely to rise further in 2014 to around £9.6 billion, putting further pressure on the cost base and then stabilising thereafter. Given past performance, there must be some doubts that operating costs can be contained without intervention.

Figure 19: The Cost of Operating on the UK Continental Shelf

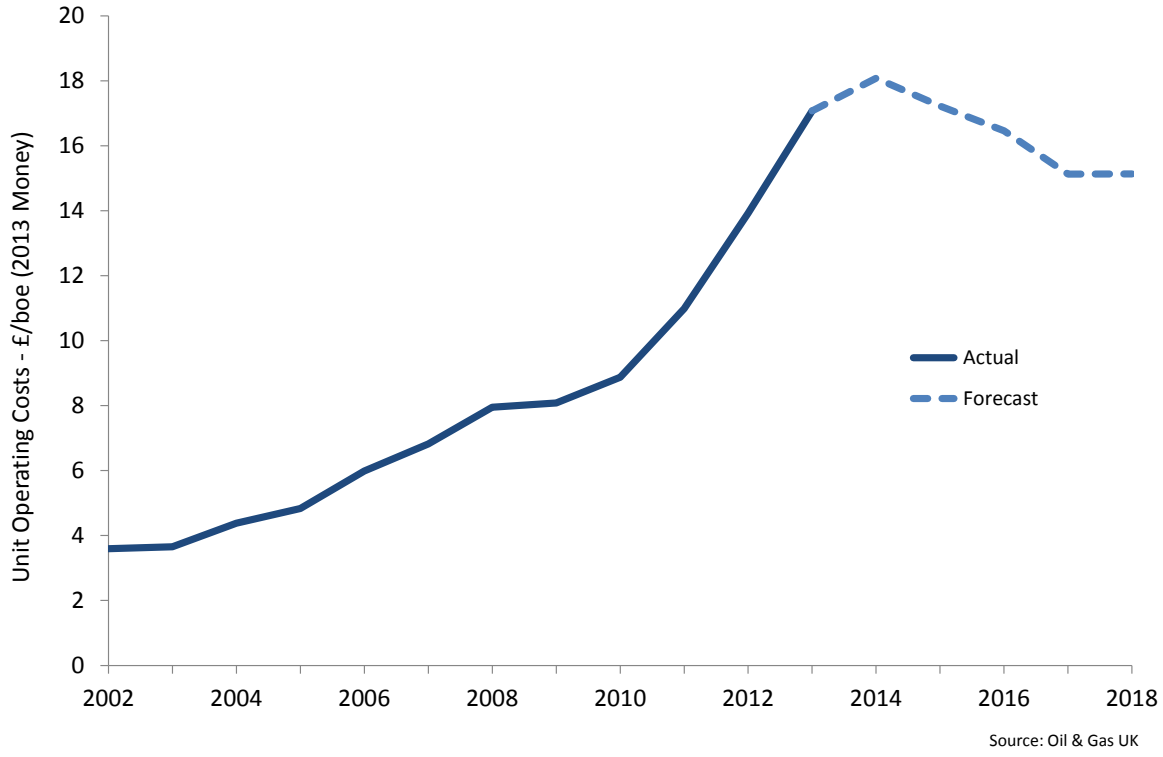


Source: Oil & Gas UK

The rising cost of operating on the UKCS becomes all the more concerning when put in context with the continued decline in production. The average unit operating cost (UOC) per boe rose to over £17/boe in 2013 and is expected to exceed £18/boe in 2014. The survey shows that in the space of 12 months, around 300 million boe of reserves are no longer considered recoverable as a result of operating cost increases that are shortening the economic life of fields. This relentless rise in costs is unsustainable and will result in yet more fields being shut-in and prematurely decommissioned if it is not addressed; in such an environment, any significant fall in oil and gas prices could have serious consequences for the industry.

Current projections would suggest UOCs are expected to fall towards the end of the decade, but this will only become a reality if production efficiency improvements are achieved, new field start-ups come on time and overall operating costs are controlled.

Figure 20: Average Unit Operating Costs

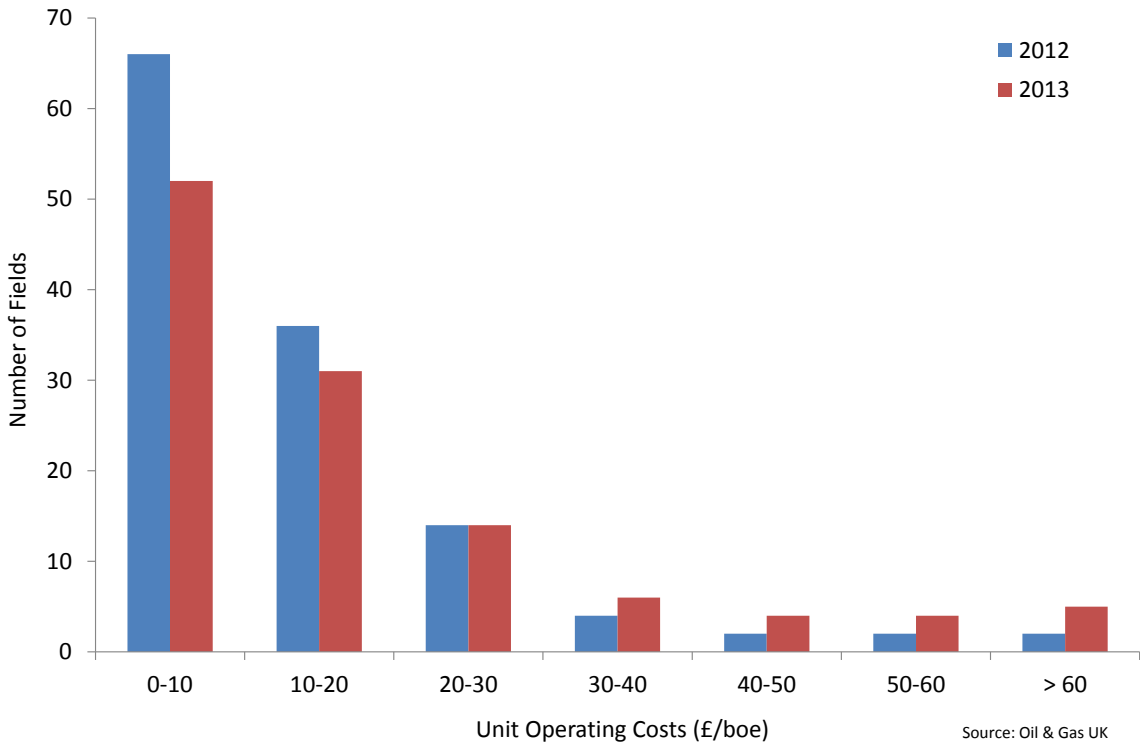


Source: Oil & Gas UK

Figure 21 shows how UOCs vary across all fields that currently produce at least one million boe per year. The impact of the continued growth in costs is noticable with 19 fields now having a UOC of greater than £30 per boe compared to just ten 12 months ago.

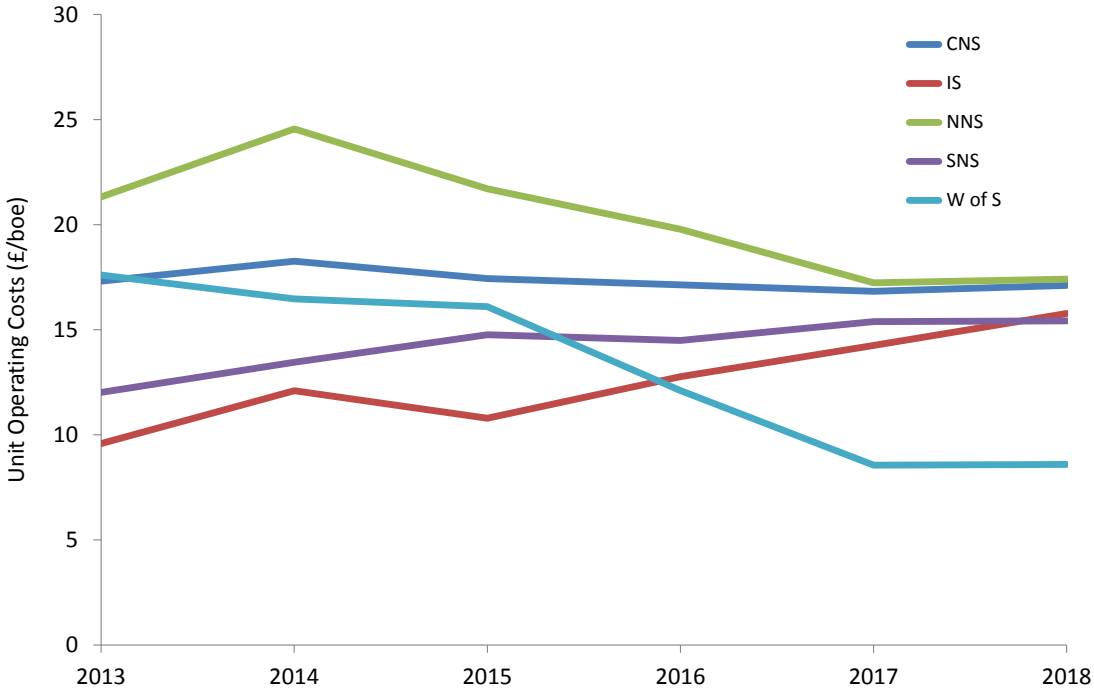
Despite this trend, there are still more than 50 fields in production with a UOC of less than £10 per boe, and the median UOC for the basin is around £11.50 per boe; significantly lower than the mean which is pushed higher by the growing, but still relatively small, number of very expensive fields.

Figure 21: Distribution of Unit Operating Costs



Of the 19 fields with a UOC of greater than £30 per boe, 18 are located in the central or northern North Sea whereas only one is located in the southern North Sea. This is reflected in Figure 22 which shows that the northern North Sea is expected to continue to be the most expensive place to operate until the end of the decade. Unit costs in the west of Shetland area are expected to fall the most over the next five years as production from the region picks up as new developments come on-stream.

Figure 22: Forecast of Unit Operating Costs by Region



Source: Oil & Gas UK

8. Production

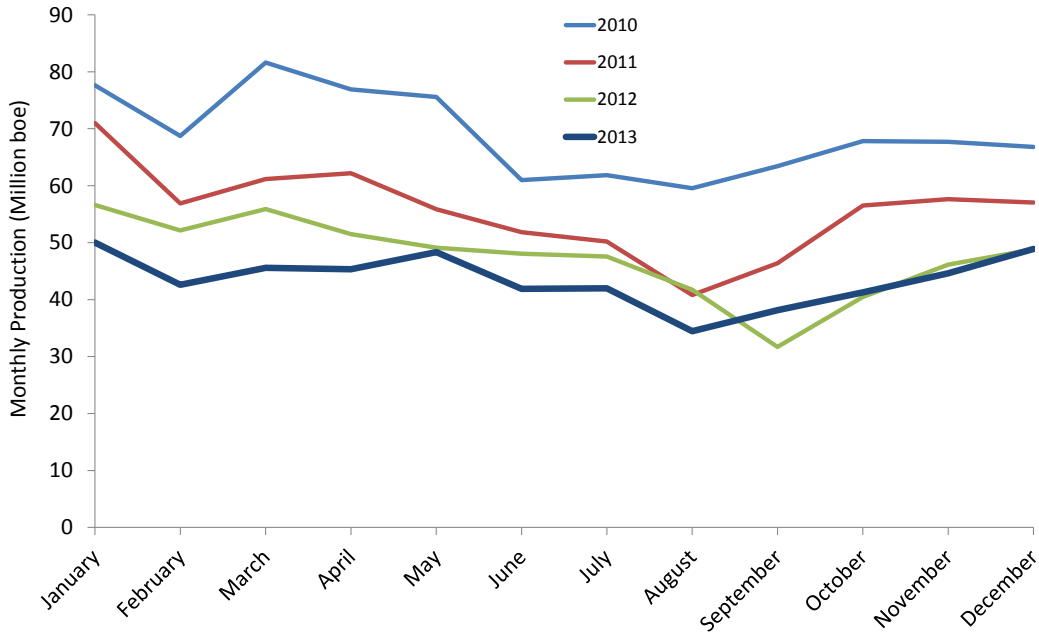
The decline in the annual rate of production slowed to just eight per cent last year. This is a significant improvement compared with the average decline of 15 per cent per year (31 per cent total) experienced from 2010 to 2012. As a result, the UKCS produced an average of 1.43 million barrels of oil equivalent per day (boepd) over 2013. This outcome was better than anticipated at mid-year 2013 and may reflect some early results from the PILOT work to improve production efficiency[5] and increased expenditure on assets over recent years.

Usually, production varies over the year, being higher over the winter months and lower in the summer as a result of maintenance shutdowns, which peak in August and September, typically a period of calmer weather conditions. On top of this annual swing, there is a general decline from existing fields. Over the last decade this has resulted in production in the second half of the year averaging 13 per cent lower than in the first half of the year.

The summers of 2010, 2011 and 2012, for example, were dominated by extended shutdowns, both planned and unplanned, as operators focused on a range of integrity issues in addition to scheduled inspection and maintenance interventions. 2013 bucked this trend with production in the second half of the year being only nine per cent lower than the first half. In part, this was because the period of summer shutdowns was shorter than in recent years, suggesting that operators are improving operational performance.

Furthermore, UKCS production in fact rose steadily on a monthly basis from August 2013, with December production only marginally lower than that at the start of the year. This reflects the increased attention on production efficiency and the benefit of a series of new start-ups in quarter four of 2013, including Jasmine and Breagh, plus Huntingdon in April last year. The expected restart of Rhum in 2014 will also provide a timely boost to UK production.

Figure 23: In Year Production Trends



Source: Oil & Gas UK, DECC

[5] Production efficiency is a measure of a field's actual performance against its maximum capability when measured from reservoir through well, platform and processing facilities and then to final point of export.

Production Efficiency

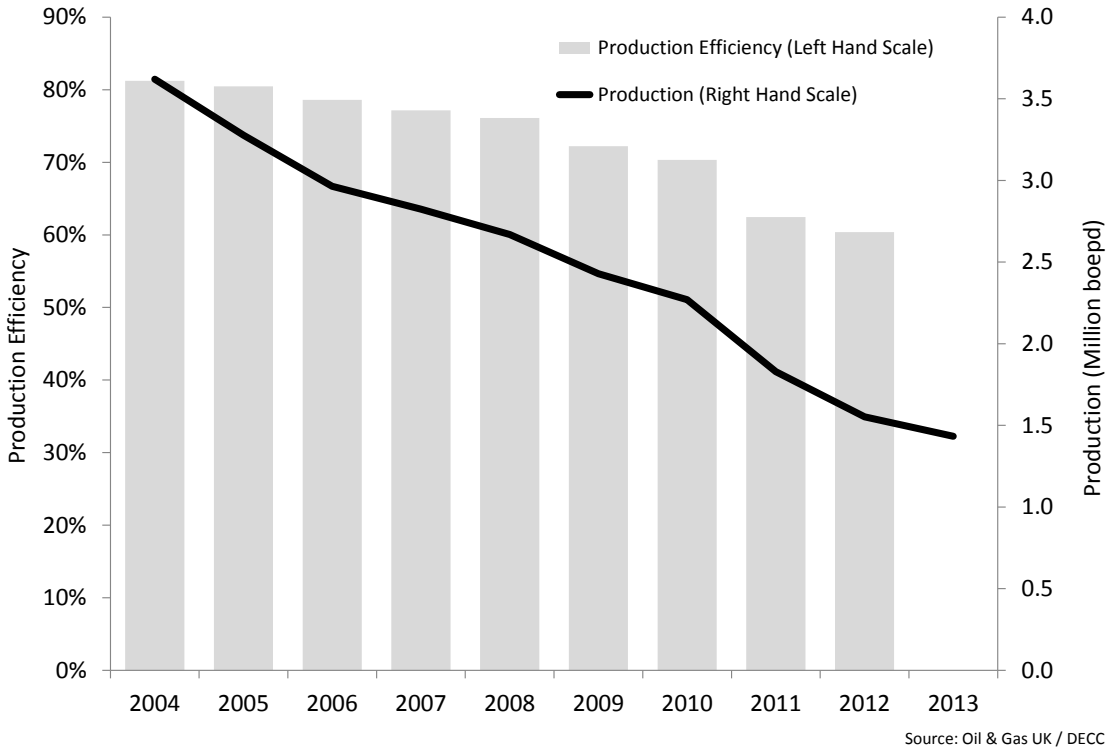
It has become apparent that declining production efficiency is a significant contributor to the recent decrease in production. A decade ago, production efficiency was averaging at around 80 per cent across the UKCS, however, it had fallen to 70 per cent by 2010 and then to 60 per cent by 2012. As a consequence, industry and government through PILOT set up a Production Efficiency Task Force to address production efficiency on a systematic basis.

The task force has made good progress. Over the last six months it has carried out root cause analysis of the main factors impacting production efficiency and is now targeting the 50 field clusters which contribute 80 per cent of production.

One workstream is addressing planned shutdowns to promote more efficient management and execution. Industry will share best practice in this area. Another group is investigating how to improve 'wrench time'[6] across the industry, by reducing unplanned compressor outages and coordinating planned maintenance schedules across assets with shared infrastructure. Another workstream is reviewing other oil and gas basins and industries for areas of transferable best practice.

Early indications are that the decline in production efficiency has been arrested and is starting to improve. The task force continues to work towards its goal of restoring production efficiency to 80 per cent over the coming years.

Figure 24: Production Efficiency on the UK Continental Shelf



Source: Oil & Gas UK / DECC

[6] 'wrench time' is a measure of offshore employee efficiency

Liquids Production

Liquids (oil/natural gas liquids) production was nine per cent lower in 2013 compared with the previous year. Liquids production in September and October 2013, however, was much higher than in the corresponding period in 2012. This was primarily due to Buzzard, which was experiencing its first five-yearly shutdown for inspections and modifications during those months in 2012. Liquids production from Buzzard has been over 12 per cent higher in 2013 compared with the previous year. This is important as Buzzard was responsible for over 11 per cent of UK production in 2013.

Production of natural gas liquids (NGLs), such as ethane, propane, butane and condensate, account for about eight per cent of total liquids output. NGLs are derived from the processing of wet natural gas, mainly at onshore terminals, and are used as feedstock for the petrochemical industry or as heating fuels in the UK and the rest of Europe.

In recent years, NGLs output has been in more rapid decline than crude oil output as a consequence of the fall in associated gas production offshore. In 2008, the UK produced 6.2 million tonnes or 0.19 million boepd of NGLs from upstream operations; by 2013, provisional data indicate a fall in NGLs output to less than 2.2 million tonnes or 0.07 million boepd. This accelerated erosion of local petrochemical feedstock availability is leading gradually to an increase in feedstock imports and lower exports of NGLs.

Gas Production

Gas production fell by just six per cent in 2013, a significant improvement on the previous two years. Production from some existing gas fields has increased, notably Sean, which came off its production contract in 2011, allowing it to produce all year round.

Gas production also now shows much less seasonal swing in the summer months than in earlier years. This is because demand for gas in the UK is now consistently higher than what can be supplied domestically and so more is provided from associated gas tied to oil production in the central and northern North Sea. As a result, the seasonal swing for gas is now driven by the summer oil field shutdown period.

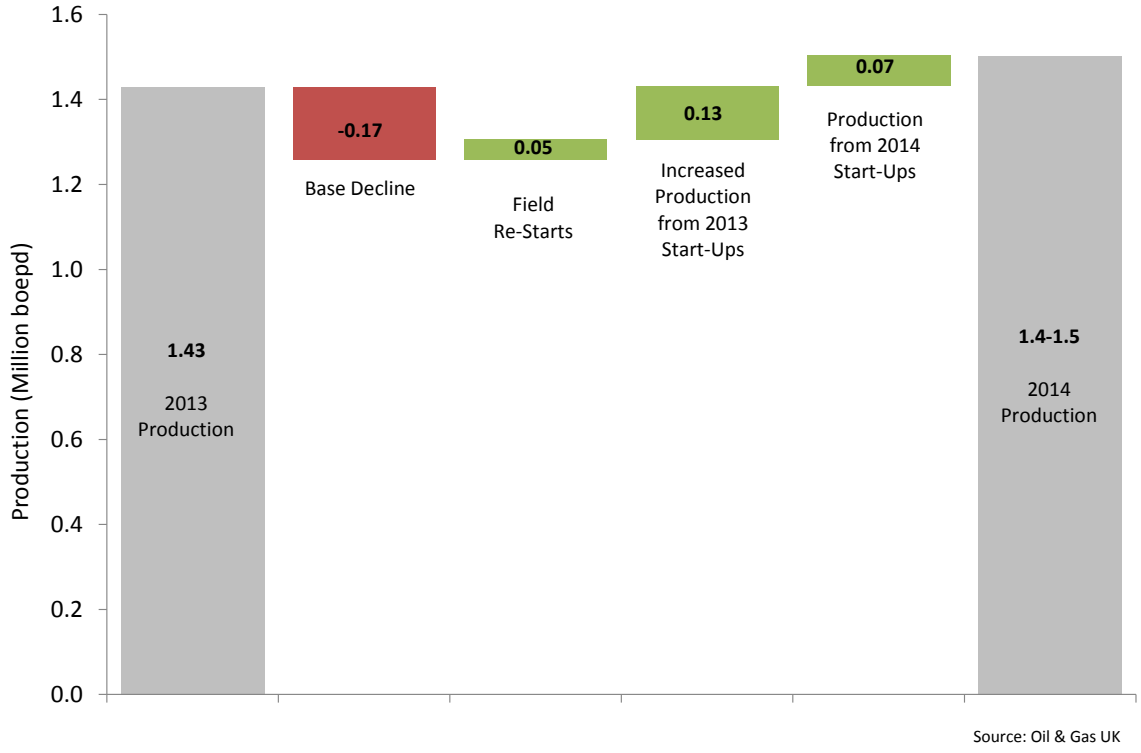
Jasmine, a new large HPHT field, also came on-stream in late November, with production ramping up in December and contributing to a 14 per cent increase in gas production compared to the previous month.

Elgin and Franklin also returned to production in 2013, albeit at a reduced rate compared to before the well control incident in March 2012. As already noted, Rhum is also expected to come back on-stream in 2014.

Production Outlook

The upshot of improved performance from the existing asset base in quarter four 2013 coupled with new large field start-ups has put the UKCS in a much better position than it has been for six years. Production is expected to begin to pick up in 2014. Operators are also more positive about their asset performance. More than 80 per cent of operators predict production will improve in 2014, whereas last year, more than 50 per cent predicted production would fall.

Figure 25: Production from 2013 to 2014

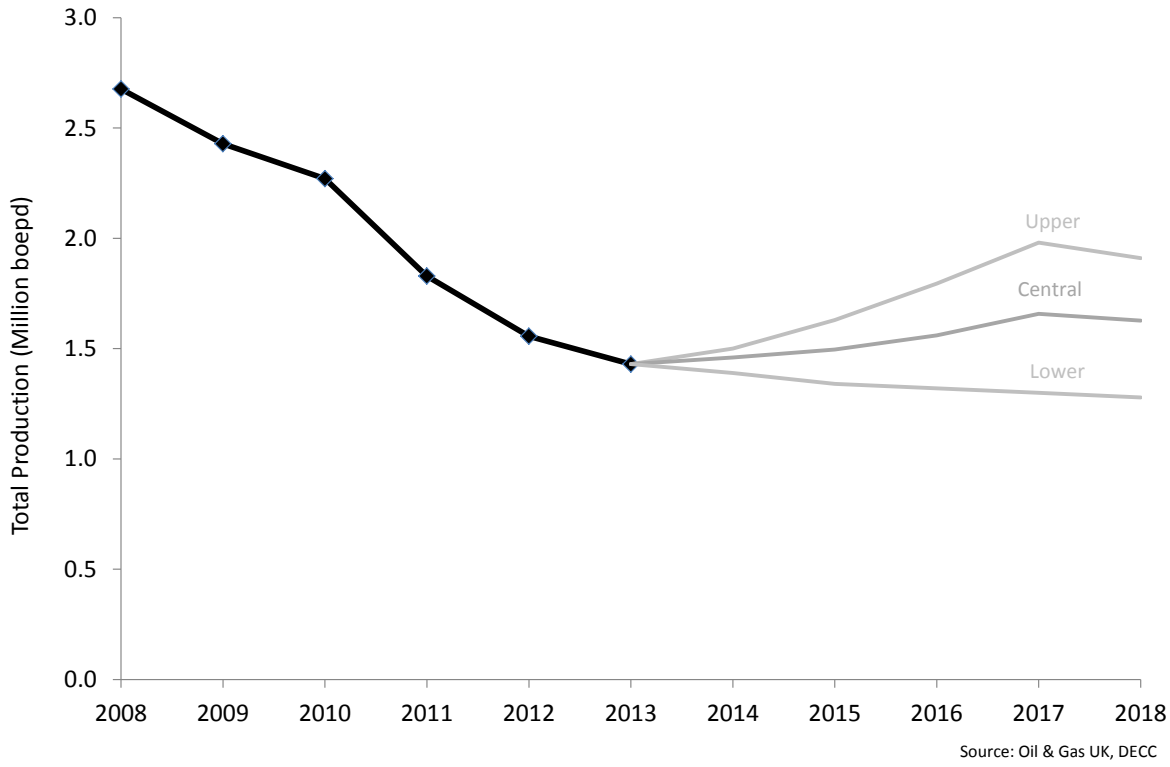


Source: Oil & Gas UK

Looking ahead, 25 fields are expected to start production in the next two years, bringing combined reserves of 1.3 billion boe on-stream. By 2018, 40 per cent of production will come from new field developments; this emphasises the need to continually develop opportunities from exploration finds.

In 2014, production is forecast to be in a range of 1.4-1.5 million boepd benefitting from the effect of the new fields coming on-stream and higher production efficiency from existing assets. Considerable uncertainty remains on the production outlook over the remainder of the decade. However, Oil & Gas UK's central case assumes production will rise gradually to around 1.7 million boepd in 2018 with an uncertainty of +/- 0.3 million boepd, after which it may begin to decline again unless the pace of new developments is sustained.

Figure 26: Production Forecast for the UK Continental Shelf

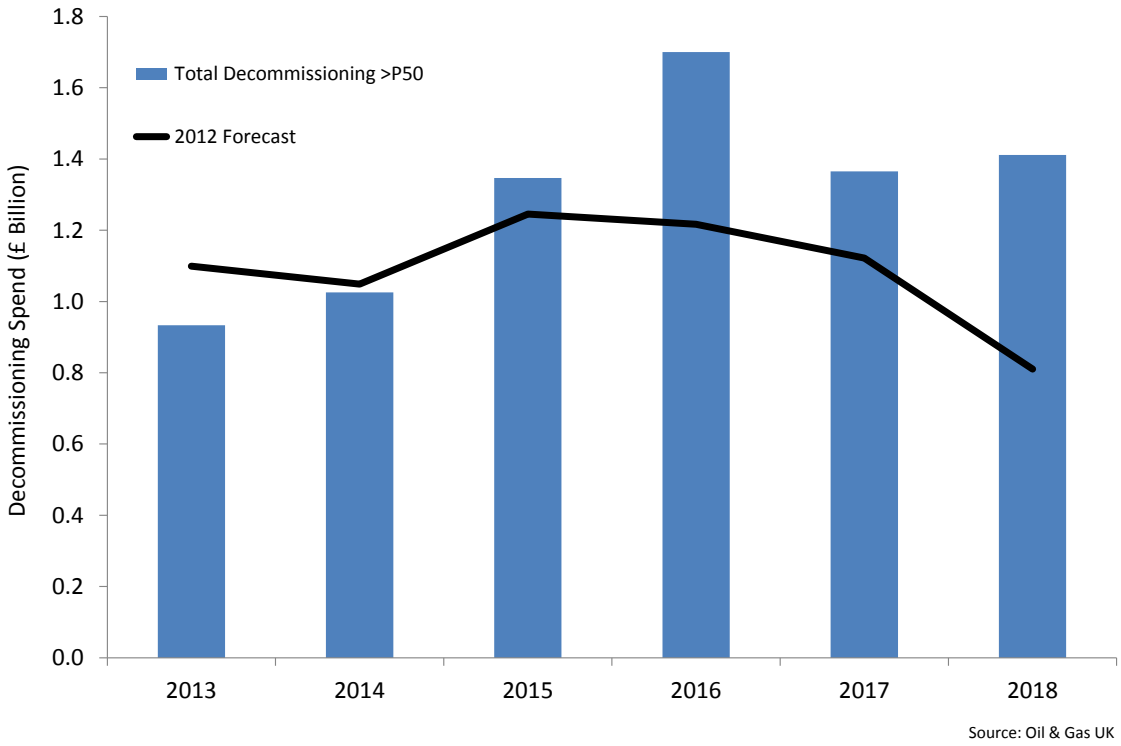


Source: Oil & Gas UK, DECC

9. Decommissioning

Decommissioning is now becoming a significant part of UKCS expenditure, accounting for 3.5 per cent (£0.9 billion) of the total spend in 2013. Decommissioning expenditure is expected to average £1.3 billion per year over the remainder of the decade, peaking at £1.7 billion in 2016.

Figure 27: Forecast for Decommissioning Expenditure

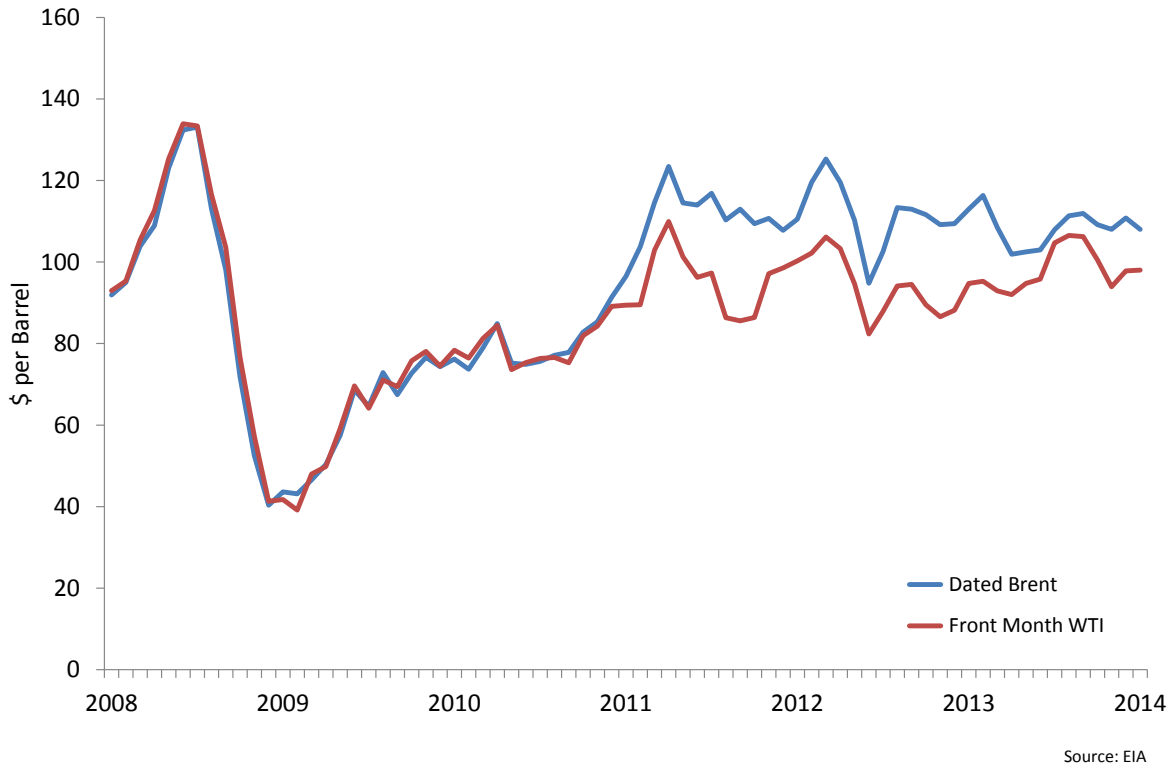


When looking out to 2040, it is anticipated that decommissioning expenditure will total about £40.6 billion, of which £37 billion will be to decommission existing installations and those that have already been approved and a further £3.6 billion to decommission new fields yet to be installed. Overall predicted decommissioning costs to 2040 have remained fairly static compared with last year's survey, suggesting that decommissioning has been postponed on a number of facilities. The reassurances provided by the Decommissioning Relief Deeds (DRDs), contracts between government and industry guaranteeing tax relief on decommissioning costs, are likely to be a contributory factor.

10. Oil and Gas Prices

The prices of benchmark North Sea crude oil in 2013 were characterised by relatively low volatility, reflecting the disruption to low sulphur crude oil supply elsewhere in the Atlantic Basin and a narrowing of the backwardation in the Brent market. Dated Brent, based on the four grades Brent, Forties, Oseberg and Ekofisk (BFOE), averaged $108.60/barrel (bbl) in 2013, down slightly from the average of more than $111/bbl in the previous two years. The modest strengthening in the US dollar in 2013 to an average of $/£ 1.56 left the average Brent price almost unchanged in sterling terms at £69.50/bbl.

Figure 28: Brent Price versus West Texas Intermediate Price



Source: EIA

Even compared to recent years, the volatility of Brent prices was low in 2013. Dated Brent traded in a relatively narrow range centred on $105-110/bbl. Support for Brent was provided by the renewed disruption of crude exports from Libya and the recovery in worldwide oil demand in 2013, although the demand for North Sea grades from refiners in Europe and Korea was more subdued.

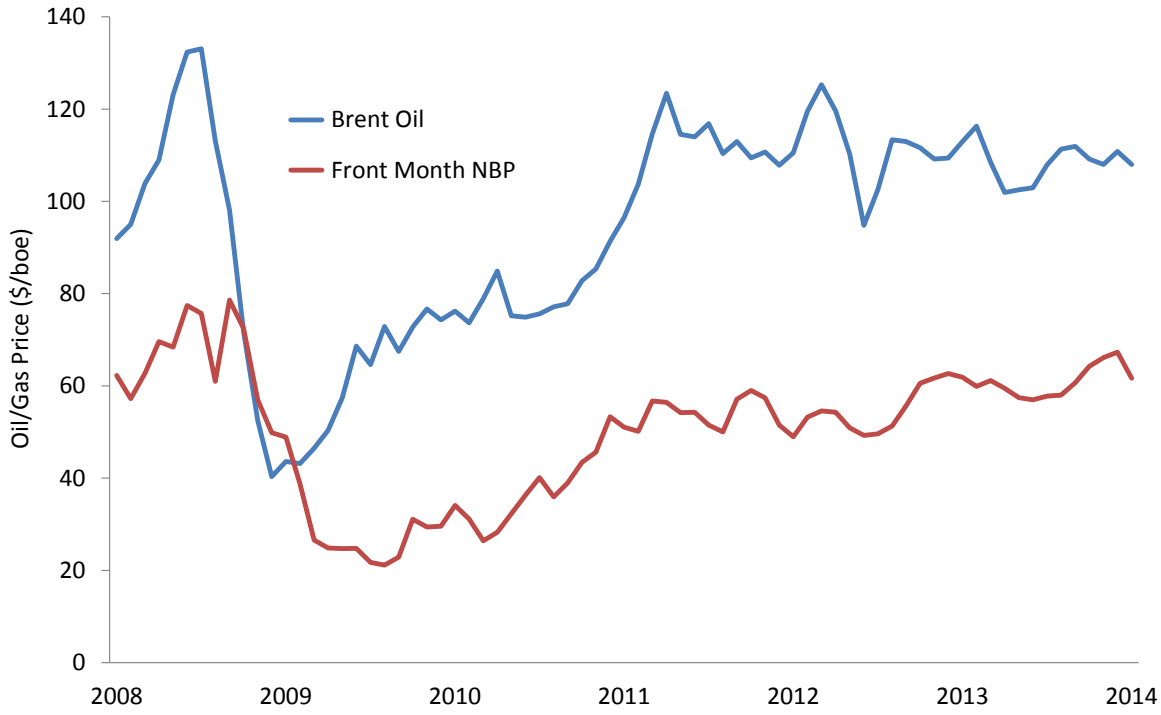
The spread between Brent and West Texas Intermediate was highly volatile, narrowing from $20/bbl to just $3/bbl in July before widening unexpectedly to $12-15/bbl by year-end as the domestic US supply of light tight oil from shale weighed again on mid-continent prices.

The US domestic crude market is still searching for a sustainable equilibrium as light tight oil supply continues to grow strongly. The prices of European NGLs suffered a larger fall than crude oil prices in 2013, declining by five to ten per cent in dollar terms, partly in response to rising US output and weak demand from European petrochemicals.

UK natural gas prices continued their steady recovery in 2013 from the recession-hit low in 2009. Reform and renegotiation of continental term contracts and the post-Fukushima tightness of world liquefied natural gas (LNG) markets both served to tighten the north-west European market again in 2013 amid near-stagnant UK gas demand.

The month ahead National Balancing Point (NBP) price averaged 67.1 pence/therm ($10.50/million British Thermal Units (m BTU)) in 2013, the highest since liberalisation of the UK market in the mid-1990s. However, in dollar terms, this was still below the previous peak of $11.40/m BTU in 2008. Relative to Brent, in 2013, NBP recovered to the highest level since 2008, reaching $61/boe or 56 per cent of Brent in energy equivalent terms.

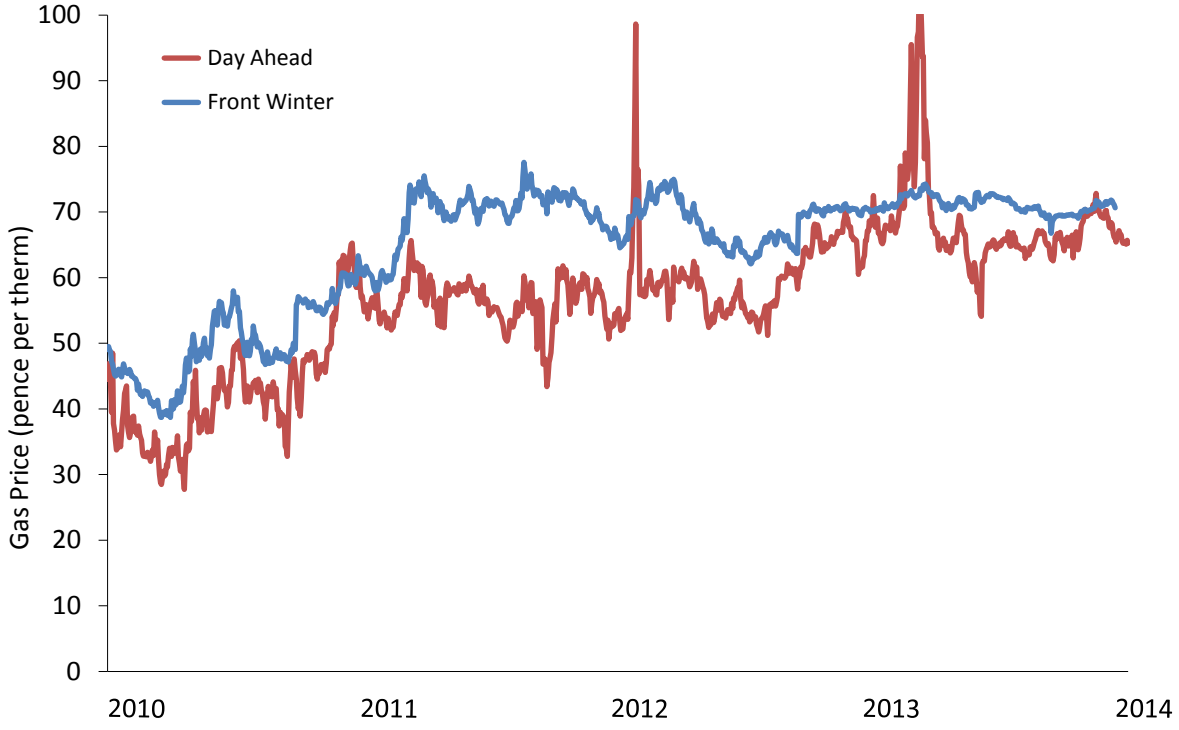
Figure 29: Dated Brent versus Month Ahead NBP Gas Prices



Source: EIA

The NBP market was characterised in 2013 by low daily volatility, narrow summer-winter spreads and the almost complete erosion of the former 'risk premium' in forward winter prices. However, we still saw a sharp spike in day ahead prices in late March 2013 at a time of cold weather, low stocks and a brief interruption in interconnector imports. This has not been repeated in the winter of 2013 to 2014, which has so far proved to be milder than normal.

Figure 30: Day Ahead and Front Winter NBP Prices



Source: ICIS Heren

11. Summary Table of Key Statistics

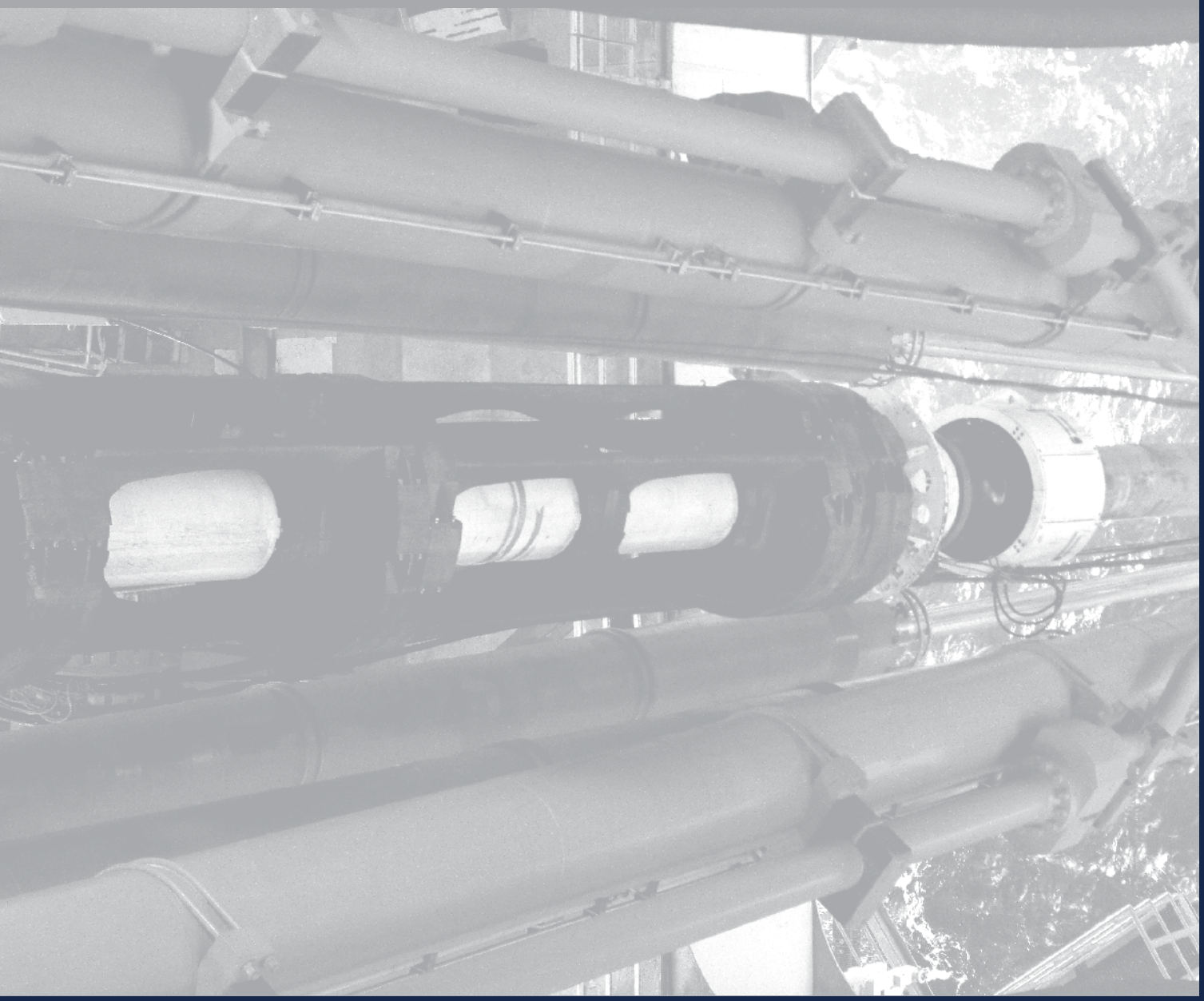
	2011		2012		*2013*		*2014*	
Total Production	1.83 mln boepd		1.56 mln boepd		1.43 mln boepd		*1.4-1.5 mln boepd*	
Oil / Liquids	1.11 mln boepd		0.95 mln boepd		0.86 mln boepd		*~0.88 mln boepd*	
Gas	0.72 mln boepd 109 mln cm/d		0.61 mln boepd 92 mln cm/d		0.57 mln boepd 84 mln cm/d		~0.56 mln boepd ~84 mln cm/d	
Total (£billion)	~16.7 billion		~£21.3 billion		~£25.8 billion		*~25 billion*	
Capex	£8.5 billion		£11.4 billion		£14.4 billion		*~£13 billion*	
Opex	£7.0 billion		£7.7 billion		£8.9 billion		*~£9.6 billion*	
Exploration & Appraisal	£1.2 billion		£1.7 billion		£1.6 billion		*~£1.4 billion*	
Decommissioning	~		£0.5 billion		£0.9 billion		*~£1.0 billion*	
Unit Technical Cost ($/boe)	34		43		47.5		*~50.5*	
Unit Dev't Cost ($/boe)	18		21.5		21		*~21.5*	
Unit Operating Cost ($/boe)	17		21.5		26.5		*~29*	
Unit Technical Cost (£/boe)	21.5		27		30.5		*~31.5*	
Unit Dev't Cost (£/boe)	11		13.5		13.5		*~13.5*	
Unit Operating Cost (£/boe)	10.5		13.5		17		*~£18*	
Oil price (avge)	$111 per bbl		$112 per bbl		$109 per bbl		~	
Gas price (avge – day-ahead)	56 p/th		60 p/th		68 p/th		~	
Combined Oil & Gas Price	$88 per boe		$89 per boe		$90 per boe		~	
Direct N. Sea tax revenues (Fiscal year)	£11.3 billion		£6.5 billion		*£5.0 billion*		*~ £4.6 billion**	
Wells Drilled	incl. sidetracks	excl. sidetracks	incl. sidetracks	excl. sidetracks	*incl. sidetracks*	*excl. sidetracks*	*incl. sidetrack*	*excl. sidetra*
Exploration	14	14	22	21	*15*	*15*	*~ 25*	~
Appraisal	28	16	31	22	*29*	*19*	*~ 11*	~
Development	122	67	122	75	*120*	*67*	~	~
Total	**164**	**97**	**175**	**118**	***164***	***101***		
New Field Approvals	12		*21*		*10*		~	
Incremental Projects	6		*8*		*26*		~	
New Field Start-ups (Excludes incrementals)	5 (30 million boe)		9 (146 million boe)		*13 (392 million boe)*		~	
Exploration Volumes Discovered	209 million boe		20 million boe		*80 million boe*		~	

N.B - All expenditures and costs are quoted in money of the day

List of new fields given DECC field approval:

2011	2012		2013
Blackbird	Alma	Solan	Balloch
Breagh	Barra	Soitaire	Cladhan
Causeway	Cayley	Stella	Enochdhu
Clipper South	Conwy		Kraken
Conrie	Cormorant East		Kraken North
Ensign	Cygnus		Mariner
Falcon	Fionn		Morrone
Golden Eagle	Fram		Orca
Kinnoull	Gala		Orlando
Peregrine	Godwin		Tonto
Rochelle	Harrier		
York	Harris		
	Juliet		
	Katy		
	Kew		
	Leman South		
	Rhyl		
	Shaw		

* Based on HM Treasury's Autumn Statement 2013 forecast



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