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1. Foreword

Welcome to Oil & Gas UK’s 2016 Activity Survey, the leading account of the UK oil and gas industry’s past performance and future prospects.

The UK Continental Shelf (UKCS) is entering a phase of ‘super maturity’ and while this provides great depths of knowledge and expertise, along with significant opportunities still remaining, the report highlights the challenges posed here relative to other basins.

Thirty years ago, the province was producing more than double the current rate from around a quarter of the number of fields and, on average, discoveries were five times their current size. The report also illustrates that in this next phase, the basin must compete fiercely in the current price environment to attract the limited remaining global investment.

Despite production having risen by ten per cent in 2015, the halving in oil price and the 20 per cent fall in the average daily gas price over the last year have dramatically depressed revenues. If current prices prevail, nearly half of UKCS oil fields will not cover their operating costs in 2016.

This is leaving the sector with very little to reinvest in new UKCS projects. Less than £1 billion of fresh investment is expected to be sanctioned in 2016, a mere one eighth of the average over the last five years, and exploration has fallen to an all-time low.

Over the last year, the number of fields expected to cease production between 2015 and 2020 has risen by one fifth to over 100. The interconnectivity of fields on the UKCS makes a ‘domino effect’ on other production a very real risk.

Above all, the report demonstrates the vital need for a coherent approach by industry, the regulator, and the UK and Scottish Governments to boost competitiveness and confidence. Together, we need to transform the basin into a highly competitive, low tax, high activity province, which is attractive to a variety of operators and sustains and supports the supply chain.

We have a huge task ahead of us but the prize is worth fighting for. The UKCS still holds up to 20 billion barrels of oil equivalent (boe), which can continue to provide a secure supply of energy for the country, support hundreds of thousands of jobs, generate several billion pounds in corporate and payroll taxes from the supply chain, and stimulate countless technological innovations.

Moreover, the cost to individuals and families at a personal level due to the ongoing job losses makes it a moral as well as a business imperative that we effectively manage our way through this serious downturn.

The industry is striving to restore its competitiveness and has made very substantial progress in reducing costs and improving efficiency: average unit operating costs have fallen from almost $30/boe in 2014 to an expected $17/boe this year. However, to cope with an oil price that has continued to decline in the early part of this year, the industry needs to intensify its efforts even more and set its sights on a target of $15/boe by way of focussed company efforts as well as cross-industry initiatives through Oil & Gas UK’s Efficiency Task Force.

Government announcements of support for innovation and infrastructure in the north east of Scotland including investment in the Oil & Gas Technology Centre; the Oil and Gas Authority’s timely publication of its strategy to maximise economic recovery; and enterprise agencies’ measures to help mitigate the negative impact of job losses are encouraging reflections of the co-operative approach to assisting the sector.
However, it is absolutely crucial that in support of the basin in the immediate as well as the longer term, the tax regime be adjusted as follows: a significant permanent reduction in headline tax rates for old and new assets alike across the UKCS is required, a move which would be consistent with HM Treasury’s ‘Driving Investment’ plan for fiscal reform and would send the signal to investors that the government has confidence in the long-term future of this industry in the UK.

This should be combined with additional measures to help unlock the late-life asset market and encourage exploration by permanently removing the special taxes from all discoveries made over the next five years. Finally, improving the effectiveness of the Investment Allowance would stimulate activity in the short term and attract fresh investment.

We are an industry at the edge of a chasm. This report can provide the insights to help bridge to an enduring future.

I hope you find it informative and useful.

Deirdre Michie
Chief Executive, Oil & Gas UK
2. Summary of Findings

Industry Headlines in 2015

• Production on the UK Continental Shelf (UKCS) rose by 9.7 per cent in 2015 to 1.64 million barrels of oil equivalent per day (boepd). This is the result of improved production efficiency and asset upgrades, as well as the first signs of production from new field start-ups. It reflects significant expenditure of around £100 billion (~£60 billion capital, ~£40 billion operating) over the previous five years.

• Despite the improvement in production, revenues fell by 30 per cent between 2014 and 2015 to £18.1 billion. This is a consequence of the halving in oil price over the last year ($52.50/barrel (bbl) in 2015 versus $99/bbl in 2014) and the 20 per cent fall in the average daily gas price.

• The oil price has dropped even further since the third quarter of 2015 and averaged $30.65/bbl in January 2016. When adjusted for inflation, the prices reflect those last seen in the 1990s. The sustained downward trend combined with the latest outlook reinforces that the oil price is likely to be ‘lower for longer’.

• Industry has made substantial progress in reducing costs and improving efficiency. Unit operating costs fell from $29.30/bbl to $20.95/bbl in 2015 and are expected to fall by another 20 per cent to around $17/bbl this year, a total of 42 per cent within two years.

• Despite significant cost reductions, nearly half of the UKCS oil fields (43 per cent) are likely to be operating at a loss in 2016 at prevailing prices. While this represents about a sixth of total oil production, these fields collectively provide a significant proportion of the infrastructure used to transport oil and gas ashore. Were a number of these fields to cease production, their interconnectivity would mean many more could become sub-commercial, known as the ‘domino effect’.

• Oil and gas companies are cutting almost all their discretionary expenditure to survive in a $30 world. Intense global competition for capital and contraction in expenditure is leading to a major downturn in activity and consequent job losses across the whole sector.

• There are increasing signs that the UKCS is becoming ‘super mature’. Thirty years ago, the basin was producing more than double the current rate from around a quarter of the number of fields. Over the same period, the average discovery size has fallen five-fold and exploration has fallen to an all-time low.

• To transform the basin, the UKCS needs to become the most attractive, mature, oil and gas province in the world with which to do business. Achieving this requires a coherent approach from industry, the regulator, and the UK and Scottish Governments, including HM Treasury, to boost competitiveness and confidence. Industry must continue to reduce costs and improve efficiency but this alone will not be enough. The fiscal and regulatory regimes must transform the UKCS into a highly competitive, low tax, high activity basin, which is attractive to a variety of operators and supports the supply chain.

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1 All monies in 2015 money unless stated otherwise.
2 Production efficiency – the total annual production divided by the maximum production potential of all fields on the UKCS.
Oil and Gas Prices

- The Brent oil price almost halved in 2015, falling from $99/bbl to $52.50/bbl, and has since dropped below $30/bbl in January 2016.
- The average futures price for January 2018 delivery of Brent oil has fallen from $74/bbl at the end of 2014 to $44/bbl by February 2016, illustrating how price expectations have dampened over the last 18 months.
- The NBP month ahead gas price averaged 42.6 p/therm in 2015, down from 51 p/therm in 2014.

Reserves

- A total of 8.8 billion boe are reported in the survey as potentially recoverable reserves, down from ten billion boe a year ago. These 8.8 billion boe include sanctioned reserves, either in production or under development, plus a portfolio of opportunities that are still to be fully evaluated or sanctioned.
- Sanctioned reserves, either in production or under development, were maintained at around 6.3 billion boe following the development approval of five new fields during 2015.
- The portfolio of unsanctioned development opportunities has fallen from 3.7 billion boe to 2.6 billion boe. Despite 0.45 billion boe of reserve additions, 1.55 billion boe reported in last year’s survey are no longer deemed commercially viable under current market conditions.
- The number of unsanctioned brownfield developments in company plans has fallen from 120 to 49, while the number of unsanctioned new fields has decreased from 37 to 29.

Drilling Activity

- Last year, exploration and appraisal activity was at its lowest in 45 years as just 13 exploration wells and 13 appraisal wells were drilled, many of which were committed to prior to 2015.
- Around 150 million boe of recoverable reserves were discovered in total, representing the best success per exploration well in ten years.
- The inability to access funds at a time of global capital constraint was cited as the main reason preventing companies from drilling new prospects.
- As few as seven to ten exploration wells are forecast to be drilled in 2016 as market conditions look set to worsen and companies restrict capital further.
- Just six to nine appraisal wells are currently forecast for 2016, a fall that is again driven by budget constraints and a consequence of the low rate of exploration in recent years.
- Despite fears to the contrary, development drilling continues to hold up with 129 wells (including sidetracks) drilled in 2015, compared with 126 in 2014.
Investment

• In 2015, £11.6 billion was invested in the UKCS, down from £14.8 billion in 2014 as the wave of recent development capital began to tail off.

• The investment outlook remains dominated by projects that have already been sanctioned. £38 billion of capital was sanctioned in new development projects between 2010 and 2014. Around one fifth of this money is yet to be spent.

• Five new fields were sanctioned in 2015, which will require development capital of around £4.4 billion over time.

• The investment outlook is a major concern for the whole of the UK industry. Less than £1 billion of fresh capital is expected to be sanctioned over the course of 2016, compared with an average of around £8 billion per annum over the preceding five years. As a consequence, investment is expected to fall to less than £10 billion this year.

Operating Expenditure

• Operating expenditure fell from £9.7 billion to £8.2 billion in 2015 as companies adapted to a lower price environment.

• Operating costs of existing assets declined by around £1.7 billion in 2015, with the impact of new start-ups offsetting that by £0.2 billion to give a total fall of £1.5 billion.

• A further reduction of at least £1 billion in the cost of operating existing assets is expected in 2016, although again this will be offset in part by additional expenditure in new field start-ups.

• Unit operating costs fell by 28 per cent last year from $29.30/bbl to $20.95/bbl (23 per cent in sterling from £17.80/bbl to £13.70/bbl) and could fall by a further 20 per cent over the course of 2016 to around $17/bbl.

• Most of the cost reductions achieved to date were driven by the $50-60/bbl oil price world experienced last year. Further reductions are inevitable as companies continue to adapt to the ‘lower for longer’ $30/bbl environment.

Production

• Latest data show production averaged 1.64 million boepd in 2015, an increase of around 9.7 per cent on the previous year.

• The decline rate in production from existing assets slowed markedly in 2015, falling from 12 to four per cent, while production efficiency is expected to have increased to over 70 per cent from a low of 60 per cent in 2012.

• Liquids production increased by around 11.2 per cent and net gas production (less producers own use offshore) rose by around 7.7 per cent.

• A further increase of 2.3 per cent is forecast this year, which would take production to around 1.68 million boepd.
• Production is expected to rise to around 1.74 million boepd by 2018, provided new fields come on-stream as planned and currently approved brownfield investment is sustained.

• The impact of new start-ups is so great that over 40 per cent of total production in 2018 is expected to come from fields that have started production or seen significant redevelopment since the start of 2013.

• In spite of this wave of new start-ups, production is likely to halve between 2015 and 2025 if fresh investment opportunities are not realised.

**Decommissioning**

• In 2015, 21 fields ceased production in part due to the worsening market outlook.

• A further 80 fields are expected to cease production by the end of the decade.

• Just over £1 billion was spent on decommissioning activity in 2015, similar to 2014.

• Decommissioning expenditure is expected to be around £1.5 billion in 2016, rising to over £2 billion by 2017 and could match capital expenditure by the end of the decade.

• Through to 2055, total decommissioning spend on sanctioned assets is forecast to be in the region of £50 billion.
3. Oil and Gas Markets

Oil Markets

Oil markets have firmly re-established their reputation for volatility since the middle of 2014. In January 2016, Brent briefly touched $27/barrel (bbl), the lowest for 12 years, having traded at $110/bbl just 18 months before. Over the entire year of 2015, the dated Brent price averaged $52.50/bbl, down from $99/bbl in 2014 and the lowest nominal annual figure since 2004.

The decline in prices was most rapid in late 2014, as the cumulative impact of rising non-OPEC supply, especially in the US, was exacerbated by OPEC’s decision in November 2014 not to cut output to rebalance the market. For most of 2015, Brent prices traded in a range of $45-65/bbl and oil markets showed some signs of moving awkwardly and gradually towards a precarious balance as demand growth picked up and non-OPEC supply growth abated. However, in December 2015 and January 2016, the selling pressure suddenly resumed, as OPEC’s continued inaction was reinforced by a slowdown in the Chinese economy and anticipation of a rise in 2016 of Iranian crude oil exports as it emerges from sanctions.

One of the most striking aspects of energy commodity price behaviour in 2015 was the re-convergence of spot oil and hub gas prices, represented in Figure 1 by dated Brent and month ahead NBP. Together, these two market benchmarks determine the value of UK Continental Shelf (UKCS) hydrocarbon production. In the latest cycle, gas prices began to weaken in early 2014, before oil prices, but in 2015 NBP prices took their lead from the steady erosion of oil prices, reinforced by the re-emergence of LNG over-supply.

*Figure 1: Crude Oil and Natural Gas Prices Re-converged in 2015*
Oil prices are driven principally by market fundamentals of supply, demand and stocks but there remains a powerful interconnection with financial markets. The collapse in dollar oil prices since mid-2014 was accompanied by a rapid 20 per cent appreciation of the trade-weighted value of the US dollar and 15 per cent against sterling. For 2015 as a whole, the US dollar strengthened by 7.2 per cent against sterling to an average $/£ exchange rate of 1.53, compared to 1.65 in 2014. Any halt in the appreciation of the US dollar in 2016 can be expected to provide some support to dollar oil prices.

**Figure 2: US Dollar to UK Sterling Spot Exchange Rate**

In recent months, oil prices have been seen as a barometer of the state of the world economy and a source of additional deflationary risks. At the same time, the correlation between Brent prices and world equity markets increased sharply. As markets recognised the beneficial impact of lower prices to oil consumers and investors readjusted their expectations of central bank tightening, oil prices recovered slightly. At the time of writing, dated Brent is trading at around $30/bbl. Few commentators would be able to confidently predict its evolution over the rest of the year but the UK industry continues to recalibrate its price and revenue expectations to reflect the decline in forward Brent future prices (see Figure 3).
The impact of the abrupt correction in oil and gas prices in 2014-16 on the UK upstream sector is difficult to over-state. It may in future come to match that seen in the years immediately after the price collapse in 1986, although the market circumstances are quite different today. The recent sharp contraction in operators’ cash flow has prompted accelerated reduction of controllable costs, contract renegotiation, cuts in discretionary operating and capital expenditure and, in some cases, a strategic review of operations. Brent (or more accurately Brent, Forties, Oseberg and Ekofisk – BFOE) may be the benchmark used to price half the world’s internationally traded oil but all North Sea producers are price-takers in a competitive global market; their only possible response is to seek to cut their controllable costs in an effort to maintain their cash flow, profitability and competitive position.

Natural Gas

While oil prices are set in a global market, gas markets are still essentially regional in nature. Prices in the UK NBP hub market, like those on the adjacent Dutch TTF hub market, declined in 2015, but much less dramatically than those of oil. The annual average month ahead NBP price was 42.6 p/therm ($6.50/million British Thermal Units (m BTU)), down only 17 per cent from 51.0 p/therm ($8.40/m BTU). Annual Brent prices, by contrast, fell 47 per cent in 2015. The revenue impact of lower prices in 2015 was therefore highly differentiated between oil and gas producers on the UKCS. Even as oil prices dropped to 12-year lows in early 2016, prompt gas prices of 30 p/therm were still well above the range of 20-25 p/therm witnessed as recently as 2009-10.
The indirect influence of oil prices on NBP prices is visible in the behaviour of forward winter prices because of the continuing oil-indexation of some long-term supply contracts on the continent and the assumption that the UK will need to attract gas from the continent to meet peak winter demand. Despite the progressive reduction in expected peak-day demand, a series of warm winters, and growing hub price-indexation on the continent, the link to oil prices is still discernible in forward TTF and NBP prices. As Brent weakened in 2014-16 from $100/bbl to $30/bbl, front winter NBP slid gradually from 60 p/therm to 35 p/therm. This, in turn, undermined NBP prices in the ‘day ahead’ and ‘month ahead’ market in which most UK producers sell their gas.

Figure 4: NBP Day Ahead and Front Winter Prices

NBP price volatility was subdued through most of 2015, reflecting a 6.9 per cent rise in UK net gas production to 37.2 billion cubic metres (bcm), which almost matched the estimated 4.3 per cent increase in total UK demand. The very warm 2013-14 winter was followed by a warmer-than-normal winter in 2014-15. The current winter (2015-16), affected by the strong El Nino in 2015, is also proving to be warmer than normal and, in consequence, prompt day ahead NBP slid in early 2016 to the lowest level since 2010 (see Figure 4).

The consequence of the price weakness in 2015 was that gas became more competitive in the UK generation mix and gas-fired CCGT plants saw a modest improvement in their operating rates despite the connection of new wind capacity to the grid. According to provisional data from the Department of Energy & Climate Change (DECC), gas use in UK power generation rose by 6.1 per cent to 20.5 bcm in 2015. There is likely to be further upside in the coming decade if unabated coal is gradually removed from the UK market, as set out in the UK Government’s recent statement of energy policy.

European gas markets remained very well-supplied in 2015 despite the restriction to Groningen output in the Netherlands and a recovery in regional gas demand of about 5.5 per cent to an estimated 470 bcm. LNG imports into the UK and into Europe as a whole increased in 2015 as Asian demand waned and new sources of supply were commissioned in Australia.
The first cargo of LNG to be exported from the US Gulf coast is due to be loaded in March 2016. Although investment in US Gulf coast liquefaction capacity was contractually underpinned by demand for LNG in Asia, much of the LNG will be capable of being delivered to Europe when Henry Hub-NBP price spreads are favourable. If US Henry Hub prices remain in the range of $2-3/m BTU, US LNG may find itself competing in Europe with low-cost Russian pipeline gas and Qatari LNG in Europe. Talk of a new ‘gas price war’ in Europe may be premature but there is little doubt that any recovery in NBP and TTF gas prices may be capped by the growing supply-side competition in European markets.

**Figure 5: Regional Hub Gas and Spot LNG Prices**

Carbon Prices

The EU Emissions Trading Scheme (EU ETS) remains the principal instrument of EU climate change policy and all electricity generators and large industrial users of energy are required to participate in the cap-and-trade scheme. Operators of most UKCS offshore installations and onshore terminals are included in the ETS and are consequently obliged to buy allowances if they do not hold sufficient free allowances to cover their annual verified emissions (14.8 million tonnes CO₂ in 2014).

Since the 2008-09 recession, which severely reduced EU energy demand, there has been a persistent over-supply of allowances and prices have remained depressed. In 2015, prices of ETS allowances staged a gradual recovery, reaching a three-year high of €8.50/te in November. However, they gave up most of these gains in December 2015 and January 2016 as energy commodity prices collapsed, falling back below €6/te (see Figure 6 overleaf).
The weakness of carbon prices has provoked sustained efforts at EU level to reform the ETS in its current Phase III (2013-20) and to reduce the over-supply of allowances. In September 2015, the EU finally approved the Market Stability Reserve (MSR) designed to reduce the over-supply, which will take effect from 1 January 2019. Legislative scrutiny also began in 2015 on the draft proposal to revise the existing ETS Directive, which will govern Phase IV from 2021 to 2030, to tighten the overall cap and to reduce the degree of carbon leakage support to energy-intensive industries within the ETS.
4. 2015 Performance

An Overview of the Year

2015 will be remembered as the year the oil price halved leading to a major contraction in the UK offshore oil and gas industry, driving the whole sector into a serious downturn. How the industry, regulator and government, including HM Treasury, respond will determine the future of the UKCS and the indigenous supply chain.

This report predominantly focusses on the UKCS’ headline performance, presenting the latest data to reflect the business cycle from exploration through to decommissioning. It provides some context on the activity under way to deliver an enduring future for this industry.

The industry’s efforts to deliver cost reduction and efficiency improvements began in 2014 and were significantly accelerated in 2015. Along with a realignment of costs, this resulted in an estimated 15 per cent contraction in jobs supported by the sector to 375,000, with further cuts already made and more to come in 2016.

Over the course of the year, through the work of the Production Efficiency Task Force\(^3\), the sector has demonstrated that gaining a more detailed understanding of how production losses have occurred in the past helps to tackle current operational challenges to boost output.

To achieve real transformation in the way the industry works, there is now widespread recognition across the sector that co-operation is needed and must be at the heart of a new way of doing business. The industry-led Efficiency Task Force was established last September as a catalyst to improve efficiency and achieve this cultural change. In December 2015, the group released the *Industry Behaviours Charter*\(^4\) to provide a strong framework for how companies must work together. In addition, the Rapid Efficiency Exchange was launched, an online portal for sharing successful efforts in improving efficiency and the problems that industry can tackle together (see the Appendix for more details on the Efficiency Task Force).

In the March 2015 Budget, the UK Government announced a ten percentage point reduction in the rate of Supplementary Charge, reducing the headline tax rate to 50 per cent, and introduced a simplified Investment Allowance to help the UK compete for investment internationally. It also announced a 15 percentage point reduction in Petroleum Revenue Tax from January 2016, bringing the rate down to 35 per cent. While this was a welcome move at the time, it has since become clear that in light of the further sustained drop in oil price, additional action is now urgently required to ensure that the fiscal regime continues to facilitate investment.

To further aid recovery of domestic oil and gas reserves, the UK Government funded £20 million of 2D seismic data acquisition in the under-explored Rockall Trough and Mid North Sea High areas of the UKCS. The resulting 20,000 kilometres of new data, in addition to 20,000 kilometres of legacy data, will be released free of charge to industry and academia from April 2016.

With the establishment of the new regulator – the Oil and Gas Authority (OGA) – the tripartite approach called for in the Wood Review took shape, bringing together industry, government/HM Treasury and the OGA in the new regulatory framework. The shared mandate to maximise economic recovery from the UKCS (MER UK) faces severe

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\(^3\) The Production Efficiency Task Force was established by Oil & Gas UK in 2013 to address the 80 per cent production efficiency target set by government-industry forum PILOT.

\(^4\) The *Industry Behaviours Charter* is available to view at [www.oilandgasuk.co.uk/industry-behaviours-charter.cfm](http://www.oilandgasuk.co.uk/industry-behaviours-charter.cfm)
challenge in the current business environment. The newly established MER UK Forum replaces PILOT and the Oil and Gas Industry Council, bringing together all key stakeholders. It has drawn up a focussed agenda to help respond to the downturn. The MER UK Forum’s meetings coincide with those of the Fiscal Forum with HM Treasury and are attended by relevant government ministers.

Industry took the lead in responding to the challenges it faced during 2015. A combination of cost reduction and efficiency improvements have already delivered an effective response to the $50-60 world anticipated a year ago, leading to unit cost reductions of 28 per cent and a production increase of 9.7 per cent. Figure 7 provides a summary of the industry’s performance in 2015, including a comparison of outturn against the forecast given 12 months ago.

*Figure 7: Industry Key Metrics Scorecard for 2015*

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Source: Oil & Gas UK
Production in 2015

Recent investment in both new and existing assets on the UKCS had a positive impact on production in 2015. After successive years of slowing decline, production increased in 2015 for the first time in 15 years by an impressive 9.7 per cent. Latest published national statistics data suggest that 598 million barrels of oil equivalent (boe) were produced on the UKCS last year, equivalent to 1.64 million boe per day (boepd). Liquids production grew by 11.2 per cent while net gas production (less producers’ own use offshore) increased by 7.7 per cent. The regional distribution remained largely unchanged with the central North Sea (CNS) still the UKCS’ most productive area, contributing around 60 per cent of total production.

Figure 8: Production Change from 2014 to 2015

An improvement in production in 2015 had been anticipated as new fields were expected to come on-stream over the year to supplement the hundreds of producing assets, many of which are now being carefully managed through late-life. However, delivery from existing assets far exceeded expectations with production decline rates from these fields slowing from 12 to four per cent.

Record capital investment and operational expenditure in recent years, as well as the work of the Production Efficiency Task Force, appear to be the catalyst for the remarkable improvement in existing assets’ reliability and integrity. There were fewer prolonged unplanned production outages recorded in 2015, while more detailed planning and efficient execution of maintenance resulted in shorter planned shutdowns. Production efficiency on the UKCS is consequently rising, and is anticipated to be over 70 per cent in 2015 from 60 per cent in 2012. As company cash flows were exposed to falling prices, this increased production revenue was crucial for many companies in 2015.

5 2015 production numbers are still provisional and may be subject to revisions later in the year.
6 Production efficiency – the total annual production divided by the maximum production potential of all fields on the UKCS.
To complement the exceptional performance from existing assets, field restarts played an unusually significant role in the production improvement last year, contributing an additional 43 million boe. Elgin Franklin, Rhum, Shearwater, Banff, Gannet, Pierce and Andrew are examples of fields that were previously shut-in for various reasons but have now come back on-stream and are increasing in output.

New field start-ups also boosted production, although project delays meant that their impact was not as significant as expected. Although eight new fields began production last year, around the same number again slipped into 2016, adding to the growing concerns over the timeliness of project execution on the UKCS. Helping to offset these delays were Kinnoull and the Golden Eagle Area, both of which came on-stream during the final quarter of 2014 and increased output throughout the course of 2015 as they ramped up towards plateau production.

**Operating Expenditure in 2015**

After a four-year period where the average annual increase in operating expenditure was ten per cent, operators were under severe pressure to cut their costs last year, particularly against the backdrop of a falling oil price. The pace of cost reduction has been far quicker than anticipated, with £1.7 billion removed from existing assets on the UKCS over the last 12 months. This has been partially offset by £0.2 billion in new field start-up costs, resulting in a net decrease of £1.5 billion and bringing total operating expenditure for the basin down from £9.7 billion to £8.2 billion.

Operators' concentrated focus on achieving cost reductions and efficiency improvements, in conjunction with the collective efforts of the pan-industry Efficiency Task Force, have delivered much needed results, helping many assets maintain a positive cash flow position despite falling prices.
Combined with strong production performance, the cost reductions have led to a sharp fall in unit operating costs (UOCs) from $29.30 to $20.95 (£17.80 to £13.70). However, it should be noted that even though production is becoming cheaper on a unit basis right across the basin, some of the more mature fields on the UKCS with little room for production growth and a higher proportion of fixed costs are heavily exposed to falling oil and gas prices. This is a major concern in 2016.

The significant reduction in UOCs seen during 2015 must be commended, but companies are aware that the work has only just begun. After a small rebound, the oil price continued to fall during the final quarter of the year and, by the end of the year, almost one third of UKCS operators had a UOC higher than the prevailing Brent spot price. Even those companies operating below the UOC average last year were generating such small margins that, combined with dampened price expectations for the future, there will be very little free cash available for reinvestment in 2016 and beyond.

*Figure 10: Unit Operating Cost by Company in 2015*

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1 UOCs only consider the cash costs of operating assets. They do not encompass non-discretionary capital investment, corporate overhead costs, general administrative costs, or the future cost of decommissioning liabilities.
Capital Investment in 2015

Capital investment fell by 22 per cent last year as some big capital projects reached completion and fewer greenfield or brownfield developments were undertaken in difficult market conditions. Oil & Gas UK predicted this fall last year, although, at £11.6 billion, capital investment for 2015 came in just above the forecast range. The main factors that drove the higher than anticipated figure were:

- The sanction of greenfield projects (Culzean, the Glenlivet–Edradour development, the Scolty–Crathes development) and significant brownfield investment in the Eastern Trough Area Project (ETAP). Fresh capital sanctioned in greenfield developments last year totalled £4.4 billion with a further £670 million in the ETAP area\(^a\). However, it is worth noting that only £0.5 billion of this investment was actually spent last year, the remainder will be spent over the next five years as the projects are developed.

- Further slippage and cost overruns of major projects that were expected to start production in 2015.

- A longer than anticipated time-lag between global capital cost deflation and the impact of this on capital projects on the UKCS.

- More capital than anticipated invested in UKCS infrastructure.

The majority of capital invested last year was spent developing new projects that were approved prior to the start of 2015. Investment in existing assets accounted for over one third of the total spent last year, most of which was essential to maintain production.

\(^a\) http://bit.ly/8P-ETAP
Exploration and Appraisal Drilling in 2015

The continued low rate of exploration and appraisal (E&A) drilling remains an area of serious concern. The number of exploration wells drilled fell to 13 in 2015, a record low on the UKCS. However, those wells that were drilled were relatively more successful than in recent years. Initial indications suggest that around 150 million boe were discovered, the highest in four years despite fewer wells being drilled. As in previous years, most of the exploration drilling was concentrated in the CNS region, although there was a notable pick-up in activity in the northern North Sea (NNS) with four wells drilled, the most since 2012.

With such little recent exploration success, it was expected to be a slow year for appraisal drilling. While a total of 13 appraisals wells were drilled, ten of these were geological sidetracks.

In total, just 26 E&A wells were drilled, the lowest in 45 years. This emphasises the need for further action to stimulate activity before critical infrastructure required to transport and process oil and gas is decommissioned. Given the global collapse in exploration expenditure, the UK will need to transform its competitiveness if it is to attract the funds it needs to sustain an appropriate rate of exploration. To replenish production, the annual number of E&A wells spudded will need to increase three to four fold. This will take concerted action by industry, government and the regulator to:

- Apply the latest technological advances in seismic data acquisition and interpretation
- Make better use of existing data by facilitating access across industry where possible
- Improve access to finance
- Continue to push for cost reductions, driven by falling rig rates and an initiative to halve well design costs
- Evolve the fiscal regime to rapidly address the balance of risk and reward when exploring on the UKCS
Figure 12: Exploration Wells Spudded in 2015

There were a total of 13 exploration wells spudded in 2015. One well is not visible on this map due to its close proximity to another well.
5. Business Outlook

This section focusses on the challenges the industry faces in 2016 and beyond. Given the recent fall in oil price and the consequent need for companies to reassess their near-term business plans more regularly, it should be noted that most of the data underpinning this section of the report were received from operators during the last quarter of 2015 when the Brent price was in the $40-50/bbl range and there were greater expectations of price growth during 2016. As such, the results in this survey should be taken as high watermarks. Where possible, given prevailing prices of around $30/bbl, the results have been modified to reflect operators’ latest best estimates through a high-level data reconciliation process undertaken in January 2016.

5.1 Reserves

Company business plans provided to Oil & Gas UK during the fourth quarter of 2015 reflect the difficult market conditions. According to these plans, up to 8.8 billion boe of known recoverable reserves could be extracted from the UKCS over the next 40 years, down from ten billion boe forecast at the same time last year.

Of the 8.8 billion boe, almost 6.3 billion boe are sanctioned reserves from fields that are already in production or under development. Reserves of nearly two billion boe sit within 29 potential greenfield developments that are yet to secure investment, while a further 0.63 billion boe are reported in 49 brownfield (incremental) opportunities, which companies are considering but again are yet to secure investment.

*Figure 13: Build-Up of the Reserves Base*
Changes in the Reserves Base

Despite the loss of 1.2 billion boe from the total reserve base this year, the sanctioned production remains largely the same as at the start of 2015. This is because five new projects and some further brownfield opportunities were approved over the course of last year, offsetting the 598 million boe produced. There are concerns, however, over whether the UKCS can continue to replenish its sanctioned base when market conditions mean that few new projects are likely to be approved in the coming year.

A year ago, it was estimated that a total of 8.3 billion boe of discovered reserves had a greater than 50 per cent chance of being recovered (>P50 confidence level), 6.33 billion of which were already sanctioned. However, the P50 outlook has now fallen by almost 0.7 billion boe to 7.61 billion boe, 6.28 billion of which are sanctioned. This decline within the P50 reserve base is largely because unsanctioned reserves have been downgraded from ‘probable’ future developments to just ‘possible’ future developments, as many projects are now deemed less likely to proceed. Within the ‘possible’ category, there is also a net fall in reserves by almost 0.5 billion boe.

Figure 14 opposite breaks down further the change in unsanctioned ‘probable’ and ‘possible’ reserves, which have fallen by 1.1 billion boe. It reveals that around 0.07 of this decrease is due to changes in the size of projects present in last year’s survey. The majority of the decline is associated with the removal of 79 projects (containing 1.48 billion boe) from company plans this year because they are now deemed unviable for development. A small number of new projects entering the survey for the first time have softened the fall slightly on a net basis, contributing 0.45 billion boe to the overall unsanctioned reserves base.

In the 2015 Activity Survey, 120 potential unsanctioned brownfield projects were reported and now 12 months later there are only 49 such projects being considered by operators on the UKCS. Moreover, the total volumes associated with these projects has fallen by almost half to only 0.63 billion boe.

The change in the outlook for potential greenfield developments is similarly stark, dropping by over a fifth from 37 reported 12 months ago to 29. Eleven of these 29 new field opportunities hold estimated recoverable reserves of greater than 50 million boe each, while the ‘lost’ opportunities are typically smaller in size.

Figure 15 opposite demonstrates that the significant fall in the Brent Crude Oil price has been a key factor behind the decline in unsanctioned reserves. In mid-2014, the Brent Oil price was over $100/bbl. At that price, just under half of the reserves now lost from company plans would have been potentially commercially viable. Almost all of the remaining 50 per cent appear to have been economically viable at $100/bbl yet they did not meet typical industry investment thresholds.

However, at $40/bbl, much closer to the expected average 2016 outturn price, only 20 per cent of the reserves now removed from company plans appear to be potentially commercially viable given their current expected unit costs. These projects represent a population of relatively small infill opportunities that may have been dropped due to capital rationing or lack of materiality. Figure 15 shows how changes in the price might result in some of the lost opportunities being recovered, although the impact of price alone is not going to be sufficient in most cases. Without significant reductions in unit cost, most of these opportunities are unlikely to return to company plans for the foreseeable future. For every one dollar per barrel increase in the oil price, if companies can remove one dollar per boe from their UOC, a typical UKCS project would see a net present value (NPV) gain of around an additional 50 per cent.

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9 While it is acknowledged that investment hurdle rates differ between companies, to be deemed potentially commercially viable for the purposes of this figure, each project has to have a profitability index (NPV/Capital Investment) ratio of at least 1.5 with no fiscal synergies.
Figure 14: Changes in Unsanctioned Reserves

Possible and Probable at 01.01.2015
Net Change in Reserves from Existing Projects
Loss of Projects
New Projects
Possible and Probable at 01.01.2016

Source: Oil & Gas UK

Figure 15: Price Sensitivity of Reserves Removed From Company Plans Over the Last 12 Months

Source: Oil & Gas UK
Figure 16 shows a broader picture of how the UKCS’ reserve base has changed over time. It reveals that the reserves base consistently grew between 2009 and 2012 before falling in each of the last four years as a lack of exploration activity curtailed the rate of new volumes being discovered.

Sanctioned reserves have tracked a similar trend as maturation through to sanction also slowed following the wave of big field approvals at the start of the decade. However, in 2015, the volume of sanctioned reserves was upheld by the approval of new projects, particularly large developments such as Culzean and Glenlivet/Edradour.

The total volume in the ‘probable’ and ‘possible’ categories, meanwhile, has not been this small since 2007. As outlined, prevailing economic conditions have led companies to reassess their portfolio of future developments and, at this time, only the best and most material projects are deemed to be potentially viable opportunities.

Figure 16: Reserves by Probability of Proceeding

Resource Comparison by Region

While resource projections should be treated with even greater caution at a time of price uncertainty, Figure 17 opposite estimates the potential of each geographic region of the UKCS.

The distribution among these regions has changed little over the last 12 months, with the CNS area remaining the largest resource base. Of the ten billion boe in the CNS, just over 3.5 billion boe are currently within company plans, over three billion boe of which are already sanctioned. The materiality of developments typically found in this area means it is the only region of the UKCS that has not suffered a fall in its resource base over the last 12 months. On the other hand, the resource base in the NNS region has declined the most. Reserves within company plans in the area fell by almost 15 per cent to just under two billion boe. This is because the region has the highest cost base on the UKCS and faces severe operational challenges.
Figure 17: Reserves and Resource Potential by Region

Technical Reserves

Wood Mackenzie estimates that there are around four billion boe of discovered technical reserves\(^{10}\), most of which are additional to the volumes reported in this survey that companies do not consider viable investment opportunities in current market conditions. However, it is important that companies continue to work these opportunities by applying new technologies and securing greater efficiencies so that ultimately they may become commercial in times of higher oil price. The OGA’s MER UK Boards are also turning their attention to those 370 discoveries reported as technical reserves, over 80 per cent of which are found in small pools with volumes of less than 20 million boe.

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\(^{10}\) Technical reserves are discovered volumes that are not yet considered to be commercial.
5.2 Drilling Activity

Exploration

Despite efforts to stimulate exploration through the initiatives of the Exploration Task Force, activity continued to decline in 2015 with only 13 exploration wells drilled.

Exploration budgets are particularly impaired by global capital constraints. The outlook is expected to worsen this year with only seven to ten wells anticipated. With economic conditions making investment in exploration drilling tougher than ever, there is much need for urgent government stimulus if anywhere close to the estimated 2-6 billion boe of yet-to-find potential is to be recovered.

*Figure 18: Exploration Well Count and Forecast*
Appraisal

Appraisal activity also continued to decline with 13 wells (including ten geological sidetracks) drilled in 2015. Activity has fallen sharply over the last decade from an average of 51 wells per year from 2006 to 2010 to an average of only 24 wells per year from the period 2011 to 2015.

This fall is in part driven by the need to keep pre-development costs down for smaller prospects by cutting back on the number of appraisal wells drilled. The lack of exploration success in recent years means there are also fewer new opportunities to appraise, while the low oil price means companies are less likely to appraise more marginal discoveries that may turn out to be sub-economic in the current climate.

Oil & Gas UK expects appraisal activity to fall again in 2016, forecasting only six to nine wells across the year.

*Figure 19: Appraisal Well Count and Forecast*
Constraints on Exploration and Appraisal Activity

The lack of available funding and the difficult market environment are cited as the main drivers for the decline in E&A activity. In 2015, 12 wells were affected by difficulties in obtaining capital. The reallocation of budget outside the UK, the difficulty in finding farm-in partners and the current fiscal environment are all factors contributing to the challenges in accessing capital. Smaller organisations and energy utility companies, which have typically accounted for around half of the exploration wells drilled over the last five years, are particularly constrained by capital markets and are therefore not expected to carry out the same level of activity this year. Some of these companies have also been involved in mergers and acquisitions recently and so have been unable to commit to drilling new wells.

Access to capital will continue to pose a significant challenge for the UKCS. Information collected by Oil & Gas UK shows that at least 34 potential wells have been affected, in part, by availability of funding and have not been included in companies’ drilling programmes for the next two years. With exploration budgets under continuous pressure, this figure could rise yet further.

Exploration and Appraisal Activity by Region

As in previous years, the most active area for E&A drilling in 2015 was the CNS region, where half of the wells (13) were drilled and where the most undiscovered resource potential remains (see section 5.1). It is expected that the CNS region will continue to be the most active for E&A activity in the coming years.

Activity in the west of Shetlands (W of S) meanwhile decreased with only two E&A wells drilled, compared with four in 2014, although these wells were successful as Chrysaor announced its Mustard discovery\(^\text{11}\) in September.

Reversing the decline in recent years, activity in the NNS region increased to nine wells in 2015 (from three in 2014). Importantly, Apache announced in October news of two discoveries in the NNS – K Prospect and Corona – from exploration wells drilled in the Beryl Area\(^\text{12}\).

The decline in drilling in the southern North Sea (SNS), the most mature region of the UKCS, was anticipated. Two wells were drilled in this area in 2015, down from six the previous year.

\(^{11}\) \url{http://bit.ly/ChrysaorMustard}  
\(^{12}\) \url{http://bit.ly/ApacheBeryl}
Discoveries from Exploration Activity

Despite only 13 wells being drilled in 2015, seven of them were successful, discovering just over 150 million boe of technically recoverable reserves. While these discoveries are yet to be fully appraised, it is likely that they will produce a number of commercially viable development opportunities, although some prospects will require an improvement in market conditions before reaching that stage.
Figures 21 and 22 show that, in comparison to the last three years, exploration was significantly more successful in 2015. In addition to discovering larger volumes than in each of the last three years, the success per exploration well was also greater, with each well discovering on average 12 million boe compared with an average over the decade of just seven million boe. Looking forward to 2016, while drilling activity may reduce further, at least two wildcat wells\(^\text{13}\) targeting more than 100 million boe are expected to be drilled, signalling the shift towards higher risk but potentially higher value opportunities.

\[\text{Figure 21: Recoverable Reserves Discovered}\]

\[\text{Figure 22: Volumes Discovered per Exploration Well}\]

\(\text{Wildcat wells – drilling for oil or gas in an unproven area that has no historic production and has not been explored in the past.}\)
Exploration and Appraisal Drilling Expenditure

Just over £780 million was spent on E&A activity in 2015, compared with just over £1.1 billion in 2014. Within this total, expenditure on exploration drilling decreased by over a third from £610 million in 2014 to £390 million in 2015, while expenditure on appraisal drilling fell by a similar proportion from £440 million to £285 million. Operators’ expenditure on acquiring and processing seismic data decreased slightly from £95 million in 2014 to £85 million in 2015. Around half of this was spent on seismic purchase and reprocessing, while the remainder funded new seismic acquisitions.

A further £20 million came through UK Government funding for two 2D seismic surveys in the Rockall Trough and Mid North Sea High regions. The government-funded surveys will be made freely available to the industry in April 2016, providing some 40,000 kilometres of new and legacy data to both industry and academia. This will be followed by a frontier\(^{14}\) licensing round later in 2016.

In 2015, the average cost per exploration well decreased to £30 million from just under £44 million in the previous year, the second consecutive annual decline. The fall in 2015 was largely due to the deflation in drilling costs as they adjust to the price cycle, but also because fewer high-pressure high-temperature (HPHT) or very deep wells were drilled last year. These are more technically challenging and therefore tend to be more expensive. Individual well costs last year ranged from under £13 million to over £85 million, reflecting the breadth of complexity involved in drilling the different types of prospects on the UKCS.

However, over a longer period, exploration costs have risen sharply from an average of just under £23 million per well from 2006 to 2010 to nearly £42 million from 2011 to 2015. The Oil & Gas UK 50 per cent Challenge Group, working for the association’s Wells Forum and comprising operators and the broader supply chain, has been created to help the industry establish a new, lower, sustainable, cost of drilling that will help to secure the further cost reductions anticipated over the course of this year. This new group is focussed on reducing drilling costs in the CNS and west of Shetland areas where over two-thirds of remaining known reserves are located.

Figure 23: Average Cost per Exploration Well Drilled

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\(^{14}\) The 29th licensing round will be centred on frontier acreage in the Mid North Sea High and Rockall Trough areas but will also include acreage nominated by industry. A 30th licensing round will follow in 2017 focussed on more mature areas.
Development Drilling

129 development wells were drilled in 2015, rising from 126 in 2014. This is mainly due to more activity in the west of Shetland region, which saw the number of development wells increase from two to 13. This rise more than offsets the decline in development drilling in regions such as the SNS and CNS. Taking a broader picture, development drilling has been on a downward trend since its peak of 289 wells in 1998, despite small increases over the past two years.

Development drilling in 2016 will depend on programmes that have already been sanctioned as part of new field or infill drilling campaigns. It is envisaged that the number of development wells drilled will drop significantly in future years especially if E&A activity is light in 2016. There is considerable concern about the pipeline of activity.

Mobile Drilling Rig Market

In January 2016, there were 22 semi-submersible and 18 jack-up drilling rigs deployed in the UK. The rig count began to fall over the second half of 2015, but not as aggressively as might have been expected due to the long-term contracts in place prior to the change in market conditions. However, the number of idle and stacked rigs rose sharply in 2015 from an average of four in 2014 to an average of 11. Already in 2016, at least three more mobile rigs have been stacked. There are concerns that more rigs may be decommissioned or leave the UKCS, leading to a shortage when activity recovers.
The market daily rig rate continued to decline in 2015 in response to falling demand. While daily rates for jack-ups held up at the beginning of 2015, the average day-rate fell by over $50,000 during the second half of the year. This lag occurred because a number of rigs were leased on long-term contracts and it is only when those contracts expire that the rates adjust to reflect market conditions. Semi-submersible rigs, used for drilling in the deeper waters of the CNS, NNS and west of Shetland areas, saw a much sharper decline from an average day-rate of $400,000 in mid-2014 to almost half that by the end of 2015.
5.3 Production

In 2015, the UKCS produced 1.64 million boepd (598 million boe total), 9.7 per cent more than the 2014 production figure of 1.49 million boepd (545 million boe total). This represents the first annual production increase on the UKCS since the year 2000 and comprises an 11.2 per cent year-on-year rise in liquids production and a 7.7 per cent upturn in net gas production.

This rise was driven by a combination of improved performance from existing assets, increased output from fields that came on-stream in late 2014, field restarts, and a small contribution from new field start-ups during 2015 (see section 4 under production in 2015).

**Figure 27: Liquids and Gas Production**

Production Outlook

Oil & Gas UK expects the increase seen last year to continue into 2016, with a further production rise forecast of 2.3 per cent to 1.68 million boepd (611 million boe). This increase will only be delivered if reservoir decline rates within existing fields continue to be carefully managed and the anticipated new field start-ups this year materialise with minimal slippage.
Looking beyond 2016, production is forecast to rise above 1.7 million boepd by 2018. Over 40 per cent of total production in that year is anticipated to come from fields that have started production or seen significant redevelopment since 2013.

Very few new start-ups are currently scheduled post-2018, a consequence of the anticipated lack of new developments sanctioned over 2016 and 2017. As a result, there are increasing concerns that the UKCS will be exposed to another collapse in production at the start of the next decade. There is a clear lack of fresh investment opportunities. On a net basis, around 1.1 billion boe of potential reserves across 79 projects have been removed from company development plans over the last 12 months (see section 5.1 on reserves). Potential development projects that do remain in company portfolios seem unlikely to be commercially viable in current market conditions and would require significant cost reductions or price support to proceed. Without a material improvement in the economics of these prospects, production is likely to decline by up to 50 per cent over the next ten years.

Continued investment in both the current asset base and new field developments throughout the downturn will be critical to sustain indigenous production in the long term and underpin security of primary energy supply. Key to achieving this is ensuring that the industry continues to bear down on its costs with support from an internationally competitive fiscal regime and an effective economic regulator.
Figure 29 shows the breakdown of Oil & Gas UK’s central production forecast to 2020. However, it should be noted that the unsanctioned new and brownfield production opportunities illustrated could well be at risk in the current business environment.

![Figure 29: Breakdown of the Central Production Forecast](chart)

Figure 30 shows how the average production per field has declined from almost 80,000 boepd in 1985 to little over 5,000 boepd in 2015. This is the result of the inevitable long-term decline of some of the biggest and oldest fields on the UKCS that have long since come off plateau. However, the start-up of a small number of very large fields between now and the end of the decade will offset this impact over the next few years. There are currently just three fields on the UKCS producing in excess of 50,000 boepd but this number is likely to double by 2018.

The reliance on volumes from sanctioned new fields in the near term reaffirms the importance of ensuring timely capital project delivery of new UKCS developments over the next few years. While Oil & Gas UK’s central production forecast does account for the prospect of some delay, if the recent record of poor project delivery continues, it will have an increasingly significant negative impact on the UKCS’ near-term production profile.
Production by Region

In 2015, the CNS accounted for 60 per cent of the total UKCS production. It is expected to remain the most productive area over the next five years, but is forecast to reduce its share of UKCS output to around 45 per cent by 2020.

Meanwhile, the west of Shetland region will become increasingly important, with its proportion of UKCS production rising from just 2.8 per cent in 2015 to around 20 per cent by 2020. This is the result of significant field start-ups, such as Claire Ridge, Schiehallion, the Laggan-Tormore area and Solan.

The NNS region is forecast to hold up well through to 2020, with the decline in base production offset by significant new field start-ups, including Mariner, Kraken and Western Isles. Production from the SNS will continue to decline over time and it is estimated that over half of the fields in this region are due to cease production by 2020. As in other areas of the UKCS, there is potential for output to be boosted by new field start-ups. Securing development of the Tolmount field\(^\text{15}\) and the performance of the Cygnus field\(^\text{16}\) will be crucial beyond 2020. These two fields alone could be producing over one-third of SNS volumes by the early part of the next decade.

Production from the UKCS is highly reliant on a network of ageing, complex and interdependent infrastructure. Careful management of this infrastructure is crucial as removal, which for some fields is now a real threat, would have a severe impact on production, causing volumes to be permanently lost. Innovative solutions must be found to overcome access to infrastructure issues to ensure fields are not prematurely decommissioned.

\(^{15}\) [http://bit.ly/EONTolmountdiscovery]

\(^{16}\) [www.engie-ep.co.uk/our-operations/cygnus.aspx]
Figure 31: Production Outlook by Region

Production (Million boe per year)

Source: Oil & Gas UK
5.4 Total Expenditure

The industry recognises it needs to improve efficiency and reduce costs for sustainable operations in a world of lower oil prices, while upholding the imperative to maintain safe production. Over the last 18 months, individual companies have looked to readjust their businesses to secure their future by rationalising capital budgets, reducing operational costs and increasing efficiencies, particularly as medium-term price expectations have dampened. Pan-industry, co-operative efforts to increase efficiency across the sector have also been important. This work initially began in the first half of 2014, but was stepped up through the formal launch of Oil & Gas UK’s Efficiency Task Force in September 2015 (see Appendix for more details on the Task Force’s initiatives).

Over the course of 2015, industry efforts have seen total expenditure fall by almost £5 billion, from £26.6 billion to £21.7 billion. However, the oil price has continued to fall and measures to reduce costs that may have been sufficient at $50-60/bbl will now need to be revisited as companies are forced to make their businesses robust at current prices.

The immediate desire for cash flow and ongoing transformational change mean that further efficiency gains and expenditure reductions are likely during the course of 2016. Without such cost reductions many companies working on the UKCS will simply cease to exist. The restructuring of the industry so far has been painful for many, especially for the tens of thousands who are estimated to have lost their jobs in the UK. The sobering human cost makes it all the more important that the industry redoubles its efforts so that the sector can emerge from the downturn with the competitive and efficient cost base it will need to ensure an enduring future. Changing the way business is done on the UKCS will help to maintain the cost improvements through future price movements.

Figure 32: Total Expenditure on the UK Continental Shelf
**Capital Investment**

Capital investment in the UKCS is forecast to fall rapidly following years of record expenditure. After peaking at £14.8 billion in 2014, capital investment declined to £11.6 billion in 2015 and is likely fall to less than £10 billion this year.

*Figure 33: Capital Investment Outlook*

The near-term outlook is dominated by capital committed to ongoing developments that have already been sanctioned (£38 billion of new capital was approved from 2010 to 2014 and over one fifth of this is still to be spent), as well as non-discretionary investment required to keep existing assets operational.

However, very little new investment is available in current market conditions. As shown in Figure 34 opposite, Oil & Gas UK forecasts that less than £1 billion of new capital will be sanctioned in 2016. This reflects a scarcity of capital globally across the oil and gas industry, primarily due to the price fall, but also the lack of attractive investment opportunities on the UKCS, which is of serious concern. The basin risks another production collapse at the start of the next decade if new development opportunities do not begin to be delivered now.

Industry, government and the regulator must look at how they can improve the competitiveness of UKCS opportunities relative to those in other basins worldwide. Industry must continue to reduce costs and improve efficiency but this alone will not be enough. The fiscal and regulatory regimes must transform the UKCS into a highly competitive, low tax, high activity basin, which is attractive to a variety of operators and supports the supply chain.
Operating Expenditure

Industry made substantial progress in reducing UKCS operating costs in 2015, with total operating expenditure falling by around 15 per cent to £8.2 billion. It should be noted that this only covers the aggregate cost of operating assets on the UKCS. Cost reductions achieved on existing assets are partially offset by the operating costs of new field start-ups. On a like-for-like basis, operating costs on existing assets actually fell from £9.7 billion in 2014 to £8 billion in 2015. A further reduction of more than £1 billion is expected over the course of 2016.
There are a number of factors driving this decline:

- The urgent need for companies to reduce operating expenditure in an attempt to maintain a positive cash flow position amidst falling revenues – simply, the existing industry cost base was not sustainable.

- The industry’s cyclical nature whereby cost trends often track the lagged oil price – there has been some cost deflation so some activities are now cheaper to carry out.

- The high volume of ‘one-off’ maintenance work that was carried out from 2011 to 2014.

- The cross-industry efforts to work together to improve efficiency that are now seeing a quantifiable impact (see Appendix).

Despite the strong progress made, the need for further cost reduction measures is pressing. As such, total operating costs are forecast to fall below £7 billion by the end of 2017, back to 2007 levels, despite the addition of almost 70 new assets over the ten-year period.

*Figure 36: Total Operating Expenditure Outlook*
Unit Operating Costs

The operating cost reductions seen over the last 12 months look particularly impressive when assessed on a cost per unit of production basis. A 15 per cent operating cost reduction alongside a 9.7 per cent production increase has led to a 28 per cent fall in unit operating costs, from $29.30/bbl to $20.95/bbl (from £17.80/bbl to £13.70/bbl).

So far companies have been able to improve or maintain production levels while simultaneously reducing operating costs. If further cost reductions and efficiency improvements are achieved, unit operating costs could fall to as low as $17/bbl (£11/bbl) by the end of this year.

Figure 37: Unit Operating Cost Outlook
Impact on the Supply Chain

The UK’s oil and gas supply chain has grown significantly over the last decade in response to the increase in activity on the UKCS as well as demand growth for exports to the global sector.

In its latest review of the UK oilfield services sector, EY estimates that turnover rose by more than eight per cent per year from 2008 through to 2014\(^7\). This fuelled a boom in employment across the whole of the supply chain over that period.

However, the sharp decline in investment and expenditure over the last 18 months has led to a severe contraction across the supply chain, the consequences of which will continue to be felt in 2016 and beyond. The supply chain has had to adjust quickly to falling demand for goods and services, as well as contending with a significant downward pressure on costs that is greatly affecting their margins. Figure 38 shows that turnover has fallen by around one quarter in 2015 with a further decline anticipated in 2016. The lack of new development projects on the UKCS has hit the engineering, procurement, construction and installation section of the supply chain the hardest, where a contraction of almost 50 per cent is anticipated by the end of this year.

The future of the industry, and therefore the thousands of businesses and hundreds of thousands of jobs it supports, will depend on the sector’s ability to sustain investment through the downturn. The value of the supply chain’s contribution to the UK economy and the world-class expertise currently anchored in the UK are at stake. Many businesses will not be able to sustain falling revenues for much longer and, without a lift in activity, will inevitably have to focus resources in other sectors or look to migrate overseas. Actions the industry takes now will determine the future of the UK offshore oil and gas supply chain for many years to come.

Industry Profitability

Figure 39 focusses on the cost of operating an asset safely without accounting for capital, corporate overhead, general administrative, or abandonment costs. Even on this simplified basis, over 40 per cent of fields (or more than 15 per cent of total production) on the UKCS are operating at a unit cost higher than the prevailing oil price around $30/bbl at the time of writing. Even those fields that are able to stay in a positive cash flow position are not generating sufficient margins for reinvestment after other costs and returns to shareholders. In an industry where returns on existing assets are often the source of new project funding, it is no surprise that fresh investment in the UKCS is set to plummet over the next few years (see section above on capital investment).

Figure 39: Proportion of Oil Fields Operating at a Loss

This position is further evidenced by Figure 40 overleaf. As the average oil price fell from $99/bbl in 2014 to $52.50/bbl in 2015, there was a £4.2 billion free cash flow deficit across the sector despite the £5 billion reduction in total expenditure.

Even if expenditure falls by another £3-4 billion this year, revenues will fall by a greater amount if the average output price falls below $35/bbl\(^{18}\). In summary, despite industry demonstrating substantial progress on cost reduction and production performance, the cash flow position is still likely to worsen during 2016 unless there is a sharp recovery in price.

\(^{18}\) The average output price is derived by weighting production over an estimated average oil price of $40/bbl and an estimated average gas price of 32 p/therm.
Figure 40: Revenues, Costs and Cash Flow on the UK Continental Shelf

Figure 41 shows this picture on a company by company working interest basis. Only five companies generated free cash flow in excess of $200 million in 2015. Lower prices mean that this number is likely to fall in 2016. This strongly illustrates the scarcity of internally generated funds for much needed reinvestment into the UKCS.

Figure 41: Free Cash Flow Generation by Company in 2015
The Office for National Statistics (ONS) publishes a quarterly rate of return metric for the UKCS on a pre-tax basis. Latest available data for the third quarter of 2015 show a rate of return of just 3.2 per cent for the industry, even lower than in 1999 when the oil price dipped below $10/bbl. Given the typical high risk-reward balance sought by investors in the oil and gas industry, rates of return as low as 3.2 per cent are simply not sufficient to encourage investment within the sector. The falling oil price and increasing capital employed\textsuperscript{19} are the primary reasons for the collapse in profitability.

\textit{Figure 42: Pre-Tax Rate of Return}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure42}
\caption{Pre-Tax Rate of Return}
\end{figure}

\textsuperscript{19} Capital employed – the value of fixed assets employed by the industry.
5.5 Decommissioning

Although decommissioning on the UKCS is still in its infancy, it is becoming an increasingly significant area of the business as many fields are now approaching maturity to the point of cessation of production. Through to 2055, total expected decommissioning spend on sanctioned assets is in the region of £50 billion. This demonstrates the scale of the opportunity for the UK supply chain to further diversify into this expanding market.

In 2015, 21 fields ceased production on the UKCS compared with 14 anticipated at the start of the year. A further 80 fields are expected to cease production over the next five years, reflecting the worsening expectations around market conditions over the remainder of the decade. In total, this is equal to almost 30 per cent of the total number of fields currently in production and is a 20 per cent increase on the number forecast 12 months ago. It is possible that this number could rise as companies continue to review their business plans in light of the current market environment.

The production capacity of these fields is relatively low, with most having long since fallen off peak production (three quarters produced less than one million boe in 2015). However, a number are considered to be infrastructure ‘hubs’, and fields upstream depend on these hubs to export the hydrocarbons they produce. The interdependence of certain high value pieces of infrastructure is a consistent theme throughout every region of the UKCS and their decommissioning risks triggering a ‘domino effect’, where one field’s closure could have a knock-on effect on fields in the same area that rely on its infrastructure as an export route.

Although the number of fields that ceased production last year was greater than anticipated, there were also a number of fields where cessation of production was originally planned for 2015 but has been deferred into 2016 and 2017. Again, this reflects the capital constraints on the UKCS where some companies would prefer to operate assets at a loss in the short term rather than bear the major capital expense of decommissioning. This situation potentially increases the opportunity to open up a new market for enhanced late-life field management to maximise economic recovery in the years leading up to cessation of production.
Comparison by Region

The regions with the greatest exposure to near-term decommissioning are the SNS and Irish Sea. Sixteen of the 21 fields that ceased production in 2015 are located in these areas. A further 35 fields are expected to cease between 2016 and 2020, by which time more than half of the fields in these regions will have reached end of field life. This reflects the maturity of these areas in comparison to other regions of the UKCS.

Three fields ceased production in the CNS region in 2015, with a further 35 expected by 2020. In total, this represents around one third of the producing fields in the CNS today. Meanwhile, in the NNS area, just two fields ceased production in 2015. The number of fields beginning decommissioning in this region is expected to be relatively low compared to other areas on the UKCS, with ten more fields ending production by 2020, accounting for almost a quarter of the fields in the area.
Decommissioning Expenditure

In 2015, decommissioning spend on the UKCS was £1.05 billion. This is significantly lower than the £1.5 billion forecast in the Activity Survey 2015, partly because decommissioning activity on some fields was deferred, but mainly because a number of projects significantly reduced levels of decommissioning expenditure and very few of the fields that ceased production during 2015 incurred material decommissioning costs within the year. As these fields move from the cessation of production stage to the decommissioning stage, we expect expenditure to rise to over £2 billion by 2017. The outlook towards the end of the decade will be determined by the industry’s ability to manage its assets in a way that enables it to remain cash-flow generative even if low prices persist.
6. Appendices

6.1 Oil & Gas UK’s Efficiency Task Force

The Case for Change

Sharply rising costs and decreasing efficiency in recent years have left the UK sector particularly exposed to the drop in oil price. Even before prices slumped, the industry was developing a response to the challenges it faced while upholding safe production.

Work to increase efficiency initially began in 2014 but gathered greater momentum with the rapidly changing business environment prompted by the plummeting oil price. In September 2015, Oil & Gas UK stepped up this activity with the formal launch of the Efficiency Task Force (ETF).

Introducing the Task Force

The ETF comprises a group of experts tasked with driving forward pan-industry high impact initiatives to help improve the international competitiveness of the UKCS and support government policy to maximise economic recovery from the basin. The Task Force provides a catalyst for the rapid change in behaviours and practices that will encourage companies to look for efficiencies in their operations and put the industry as a whole on a more sustainable footing for the future.

It is led by Oil & Gas UK co-chairman John Pearson, group president Northern Europe and CIS at Amec Foster Wheeler, and supported by a dedicated team from Oil & Gas UK working alongside industry members. The ETF takes a three-pronged approach under the themes of Co-operation, Culture and Behaviours; Business Process; and Standardisation – focussing on two or three projects in each.

Co-operation, Culture and Behaviours

Long-term transformational change will only come about through real collaboration between operators, major contractors and SMEs, embedding new ways of working and creating new business models. Under the Co-operation, Culture and Behaviours theme, the ETF aims to deliver the tools for that transformational change.
Oil & Gas UK’s Share Fair event in November 2015 was recast with a stronger focus on tackling efficiency improvements through greater co-operation between operators and the supply chain. The event provided the platform for operators and Tier 1 contractors to clearly articulate to the supply chain where expertise and knowledge is needed to develop projects and services – and for suppliers to share insight and their thoughts on how activity could be carried out in a more efficient and less costly manner.

In December, at Oil & Gas UK’s Annual General Meeting, the Task Force launched the *Industry Behaviours Charter*\(^{20}\). Having gained Oil & Gas UK Board approval, it has since been signed by over 30 organisations and the principles the Charter contains will be measured on an ongoing basis by Deloitte in reports into co-operation, collaboration and efficiency in the industry.

Also unveiled was the *Rapid Efficiency Exchange (REE)*, an online portal for sharing successful stories in improving efficiency and for exchanging knowledge. It is hoped that the REE, a sector first, will become a catalyst for knowledge sharing across the industry. Companies are invited to use the REE to promote what they are doing well and to share problems that industry can tackle together. All Oil & Gas UK Board member companies have already contributed since the launch of the pilot website, with almost 30 good practice case studies and industry challenges shared to date\(^{21}\).

### Business Process

The Business Process work stream is taking a fresh look at day-to-day operations, exploring how companies can work together to share resources and good practice. For example, the Inventory Rationalisation Project involves operators looking to see how they can rationalise their inventory holdings to reduce the costs associated with the storage and maintenance of materials. The outcome of this project – a means for companies to share details of their inventories and a trial trading platform – will launch in spring this year. The group is working with a small number of companies who will be early adopters of the solution. The Inventory Rationalisation Project will also focus on valves used offshore, with an additional investigation into the simplification and standardisation of valves covered under the Standardisation work stream discussed below.

Another example is the Compression Systems project, where a group of operators who are accountable for the bulk of UKCS compression system outages – the biggest cause of unplanned maintenance – are working together to reduce the number and duration of these outages. Work is currently under way to expedite this activity, in the hope of further improving production efficiency across the basin.

### Standardisation

The tendency for all parts of the industry to over-specify products and services has been one of the biggest drivers behind rising costs. The Standardisation work stream is looking to simplify business approaches and drive standard solutions to reduce costs, accelerate delivery and minimise operational complexity.

Projects in this area include using data from extensive thru-tubing plugging and abandonment (P&A) projects in the Gulf of Mexico to provide a business case for promoting greater use of thru-tubing P&A on the UKCS.

\(^{20}\) The *Industry Behaviours Charter* is available to view at www.oilandgasuk.co.uk/industry-behaviours-charter.cfm

\(^{21}\) The Rapid Efficiency Exchange portal is available at http://portal.oilandgasuk.co.uk
Another project focusses on the standardisation of subsea technology, where potential savings are estimated to be substantial. The results from this work will be used to identify a fit-for-purpose approach that industry will be encouraged to adopt.

Next Steps

Efficiency Roadshows across the UK will begin in the first half of 2016. A number of preliminary town hall style meetings, tailored to the audience to ensure appropriate messaging, will take place at Oil & Gas UK’s members’ offices. The aim is to encourage engagement in the Task Force’s ongoing projects, take general advice on its future direction, and crucially ensure that the group’s key messages reach the workforce.

The Task Force is also now looking into new efficiency target areas that have the potential still further to reduce unit operating costs. These include establishing how the tendering process can become more efficient; identifying best practice for maintenance regimes; and understanding how collaboration around logistics can reduce excess costs.

6.2 Driving Efficiencies outside the ETF

Publication of Guidance

Member companies have supported Oil & Gas UK in publishing guidelines on the following topics to encourage standard practices and operational streamlining22:

- Execution of planned maintenance shutdowns – to improve efficiency and reliability offshore
- Well operations – to provide industry with a common framework in which to generate more consistent and complete cost estimates
- Late-life/decommissioning inspection and maintenance – to aid efficient planning and execution of decommissioning
- Adoption of novel solutions – identifying, qualifying and adopting new technologies used in the decommissioning of offshore assets

Learning from Other Sectors

The industry has actively sought to learn from the experience of other sectors. As part of the then Oil and Gas Industry Council, PwC was commissioned to study the measures taken by other industries to improve efficiency. The Cross-Sector Efficiency Study23 identified characteristics – from leadership to treating operations as a strategic asset and innovation – that drive efficiency in high performing sectors such as aerospace, automotive, chemicals and rail, and proposed tangible practices that can be transferred to oil and gas industry operations.

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22 The guidelines are available to download at www.oilandgasuk.co.uk/publicationssearch.cfm
23 http://pwc.to/1ih4gZ1
## 6.3 Summary of Key Statistics

<table>
<thead>
<tr>
<th></th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Production</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Oil/Liquids</td>
<td>1.50 mln boep</td>
<td>1.49 mln boep</td>
<td>1.64 mln boep</td>
<td>1.68 mln boep</td>
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<tr>
<td>Gas</td>
<td>0.86 mln boep</td>
<td>0.85 mln boep</td>
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<td></td>
<td>0.63 mln boep</td>
<td>0.64 mln boep</td>
<td>0.69 mln boep</td>
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<tr>
<td></td>
<td>34.5 bcm</td>
<td>35 bcm</td>
<td>37.2 bcm</td>
<td>~38 bcm</td>
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<td><strong>Total Expenditure</strong></td>
<td>£25.8 billion</td>
<td>£26.3 billion</td>
<td>£21.7 billion</td>
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<td><strong>Capital Expenditure</strong></td>
<td>£14.4 billion</td>
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<td>~£8.6-9.2 billion</td>
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<td><strong>Operating Expenditure</strong></td>
<td>£8.9 billion</td>
<td>£9.7 billion</td>
<td>£8.2 billion</td>
<td>~£7.0-7.6 billion</td>
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<td><strong>Exploration and Appraisal</strong></td>
<td>£1.6 billion</td>
<td>£1.1 billion</td>
<td>£0.8 billion</td>
<td>~£0.7 billion</td>
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<tr>
<td><strong>Decommissioning</strong></td>
<td>£0.9 billion</td>
<td>£1 billion</td>
<td>£1.1 billion</td>
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<td><strong>Unit Technical Cost</strong></td>
<td>51.50 $/boe</td>
<td>49.70 $/boe</td>
<td>38.25 $/boe</td>
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<td><strong>Unit Development Cost</strong></td>
<td>26.10 $/boe</td>
<td>20.40 $/boe</td>
<td>17.30 $/boe</td>
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<td><strong>Unit Operating Cost</strong></td>
<td>25.40 $/boe</td>
<td>29.30 $/boe</td>
<td>20.95 $/boe</td>
<td>~17.00 $/boe</td>
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<tr>
<td><strong>Unit Technical Cost</strong></td>
<td>33.70 £/boe</td>
<td>31.40 £/boe</td>
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<tr>
<td><strong>Unit Development Cost</strong></td>
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<td>13.60 £/boe</td>
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<tr>
<td><strong>Unit Operating Cost</strong></td>
<td>16.30 £/boe</td>
<td>17.80 £/boe</td>
<td>13.70 £/boe</td>
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<td><strong>Oil Price (avge)</strong></td>
<td>$109/bbl</td>
<td>$99/bbl</td>
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<td><strong>Gas Price (avge – day-ahead)</strong></td>
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<td>51 p/therm</td>
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<td><strong>Combined Oil and Gas Price</strong></td>
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<tr>
<td><strong>Direct N. Sea Tax Revenues</strong></td>
<td>£4.7 billion</td>
<td>£2.2 billion</td>
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<td>~£0.1 billion</td>
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<td><em>(Fiscal Year)</em></td>
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<td><strong>Wells Drilled</strong></td>
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<td>Exploration</td>
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<td>Appraisal</td>
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<tr>
<td>Development</td>
<td>120</td>
<td>69</td>
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<tr>
<td>Total</td>
<td>164</td>
<td>102</td>
<td>158</td>
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<tr>
<td><strong>New Field Approvals</strong></td>
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<tr>
<td>Incremental Projects</td>
<td>10</td>
<td>8</td>
<td>5</td>
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<tr>
<td>New Field Start-ups</td>
<td>26</td>
<td>28</td>
<td>10</td>
<td>~</td>
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<tr>
<td><em>(Excludes Incrementals)</em></td>
<td>13 (392 million boe)</td>
<td>5 (195 million boe)</td>
<td>8 (100 million boe)</td>
<td>~</td>
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<tr>
<td>Exploration Volumes Discovered</td>
<td>80 million boe</td>
<td>50 million boe</td>
<td>~150 million boe</td>
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</tbody>
</table>

1 This reflects the Unit Development Costs of new fields approved within each year
2 Based on HM Treasury’s Autumn Statement 2015 Forecast

NB - All expenditures and costs are quoted in money of the day

List of new field development plan approvals by year

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<thead>
<tr>
<th>2013</th>
<th>2014</th>
<th>2015</th>
</tr>
</thead>
<tbody>
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<td>Kraken</td>
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<td>Kraken North</td>
<td>Cawdor</td>
<td>Culzean</td>
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<tr>
<td>Mariner</td>
<td>Flyndre (UK)</td>
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<td>Morrone</td>
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