E&P

Brighter prospects on the horizon

After a very challenging period, signs of optimism are returning to the North Sea basins. Companies are seeking to consolidate and build on the significant cost savings made in the last couple of years, and new players are bringing investment to the arena, reports *Brian Davis*.

First oil was produced from the redeveloped Shiehallion Area, West of Shetland, following completion of the Quad 204 project being developed by BP, Shell and Siccar Point Energy (see *Petroleum Review*, July 2017; **bit.ly/2uEFs8c**)
Source: BP

There is a mood of cautious optimism according to leading North Sea analysts, regulatory authorities and companies considering future exploration and production (E&P) prospects on the UK Continental Shelf (UKCS), Norwegian Continental Shelf (NCS) and nearby basins.

Oil & Gas UK sees 2017 as a 'critical year' in its latest *Business Outlook*. 'The upturn in oil price has coincided with signs of confidence slowly returning to the basin,' says Chief Executive Deirdre Michie. 'This is led by the E&P companies, who for the first time since 2013, may see a return to positive cash flow, provided costs are kept under tight control and commodity prices hold.'

With Brent crude hovering around $47/b, capital efficiency continues to improve. Oil & Gas UK mentions the Culzean field development, where robust design and planning and improved drilling efficiency helped reduce development costs by $500mn. Typically, the development costs of new projects being sanctioned are on average nearly half that of those approved in 2013. Unit costs in the North Sea have been driven down from $29/b in 2014 to $16/b in 2016. The task now is to maintain a lean approach.

Consolidation continues

Acquisition and divestment activity during the first six months of 2017 in the UKCS and NCS basins reached nearly $10bn (see **Table 1**). This is a major signal of confidence. At the start of the year, Chrysaor acquired Shell's UK North Sea assets for £3bn. Phil Kirk, Chief Executive of Chrysaor, said at the time: 'Chrysaor intends to grow the assets being acquired, and has identified a number of early incremental opportunities to maximise economic recovery and extend field life.'

Indeed, the new Oil and Gas Authority's (OGA) express aim is to maximise economic recovery in line with the Wood Report recommendations for the UKCS (see Perspective, p2 of this issue).

In May, Ineos bought DONG Energy's oil and gas business for $1.05bn, with around 570mn boe of potential oil and gas reserves across the Danish, Norwegian and UK continental shelves. This deal followed the purchase of BP's Forties pipeline system. According to Ineos Chairman Jim Ratcliffe: 'DONG Energy's oil and gas business is a natural fit for Ineos as we continue to expand our upstream interests... following the success of our petrochemical business.' The DONG portfolio is built around the Ormen Lange gas field, the second largest in Norwegian waters; an interest in Laggan-Tormore, a new gas field West of Shetland (see pp32–33); and Syd Arne, a large oil field in Denmark.

UKCS in focus

'This is a critical and challenging time for E&P in the North Sea, but we are optimistic. However, there are different challenges in various basins,' remarks Philip Whittaker, Director, Boston Consulting Group (BCG). 'The southern sector of the UKCS is very mature and the prospect of sunset is approaching, but this is a long way off for the northern sector.'

He adds: 'For much of the last decade, companies have been pushing efficiency measures in the face of assets that are well beyond their design lives. Moreover, majors' worldwide asset retirement obligations (AROs) rose by an average 14% a year during this period.'

In fact, the OGA estimates the cost of decommissioning oil and gas infrastructure in the UKCS has risen to £59.7bn in 2016 prices, although there is a shared industry objective to reduce costs by at least 35%.

Whittaker maintains that companies need to demonstrate that potential field investments are robust well below $50/b. 'Today companies want projects that are robust at lower prices, and want to

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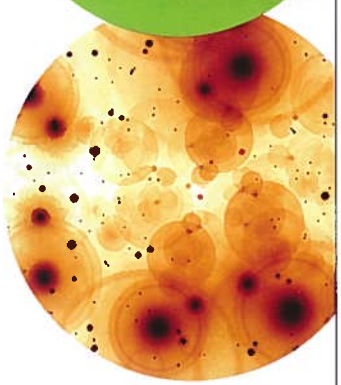

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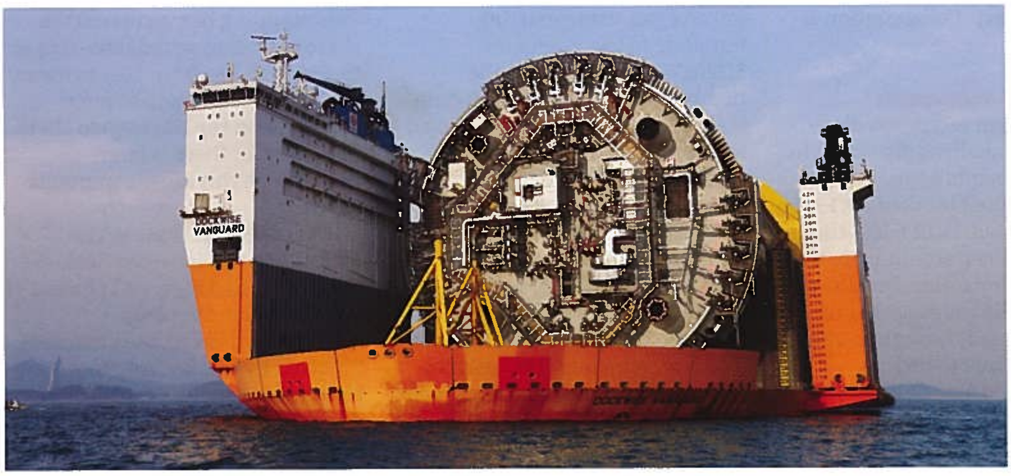

Float out of Statoil's Aaste Hansteen Spar floating platform, which is due onstream late 2017
Source: Statoil

ensure that the quantum of investment is not too huge in an uncertain world. Therefore, smaller developments or those that can be chunked up into phases are preferred.'

He suggests the keys to success are robust, reliable developments at a competitive cost; modular developments; and speed to output so uncertainty and lingering is reduced. He recommends a BCG paper entitled *Killing the complexity monster*, which defines a framework to drive costs out of offshore operations.

Standardisation required

Alan McCrae, PwC Oil and Gas Leader, also considers North Sea operations are on a more stable footing since costs have been reduced. However, he emphasises the lack of standardisation and elements of 'gold plating' in many previous projects, 'as operators felt they could make more money chasing the next barrel rather than sorting out basic housekeeping – which created inefficiencies.'

The need for standardisation in new developments is coming across loud and clear. Katy Heidenreich, Operations Optimisation Manager for Upstream at Oil & Gas UK mentions the work of the Efficiency Task Force on certification and standardisation of design. Subsea standardisation guidelines have been published for simplifying existing and proposed North Sea developments, with potential cost savings of between 15–30%.

Currently there are over 3bn barrels of oil stranded in about 350 small reserves (under 50mn barrels) that are too costly to develop. Oil & Gas UK suggests that by taking a more innovative approach in areas such as design optimisation, field layouts and manufacturing, marginal prospects could be brought onstream. As an example, the Centrica Group determined that the potential application of a three-well gas tie-back on the West Pegasus field could offer overall savings of 24% by applying standardisation themes.

Heidenreich claims a lot of projects are still awaiting final investment decision (FID). 'Fresh investment is desperately needed if the UKCS basin is going to manage the decline,' she says. A detailed table of current and potential North Sea developments can be found online on the EI website (visit **bit.ly/2v9JCBG**) based on the comprehensive BIES/DECC/OGA Pathfinder table.

The OGA, Oil & Gas UK and analysts all stress the impact of new alliances and joint ventures. BCG points to the multiple types of alliances in the oilfield service sector 'which each have a slightly different flavour', like the GE acquisition of Baker Hughes. These new combinations all aim to eliminate interface costs.

'We are also entering a world of smaller companies which need packaged solutions they can trust. The big question is: Can we change the business models and make a step change from the traditional approach? Modularity makes good sense and subsea tie-backs fit the bill because they are relatively quick and can take advantage of existing infrastructure, so they eliminate risk,' says Whittaker.

Moreover, 'For many years technology allowed us to go further, deeper and colder. Now the mindset is to go lighter, simpler and cheaper using an operational model which can strip costs from the system,' he says.

Innovation is key

Considering areas of innovation, PwC's McCrae is enthused by the work Hurricane Energy is doing with fractured basement development of the Lancaster field, west of Shetland. He is also eager to see how the 30th Licence Round goes, which is expected to be announced during 3Q2017. 'There is a lot of new frontier stuff West of Shetland and around the Norwegian Continental Shelf area, which will require the latest enhanced oil recovery techniques for production,' he notes.

'What's changed this time round is the availability of 3D seismic imaging from the OGA which is giving people a lot more confidence in taking new opportunities forward,' says Craig Stevens, PwC Oil and Gas Strategy Analyst. He considers the OGA's small pools project is also an opportunity for small independents. 'If significant accumulations occur close enough, then it will make sense to put in infrastructure to extract value from these fields.'

FPSO float out

FPSOs (floating production, storage and offloading vessels) look set to play an increasing role along with subsea tie-backs. Stevens notes that the Western Isles FPSO was recently floated out of Rotterdam for Dana Petroleum's Western Isles development, to support tie-back from five subsea wells in 4Q2017 for oil production.

Enquest's Kraken development also recently came onstream, one of the largest subsea heavy oilfield projects to be developed in the UKCS, East of Shetland (see p3). The Kraken field is estimated to have reserves of 137mn barrels of heavy oil and is scheduled for three phases of development in block 9/2b using an FPSO. Premier Oil's Catcher oil field is also due onstream and combines development of the Catcher, Varadero and Burgman fields located in the Central North Sea, with all three fields tied-back to an FPSO. Stevens remarks that the risk with using an FPSO is cost over-run. 'Examples where that hasn't been an issue are few and far between,' he says. It should be noted that Kraken is an example of one such project coming onstream on time and actually under budget.

PwC recently issued a report urging oilfield services to 'reset their business to deal with the operational, financial and strategic challenges in the new operating environment'. The report claims the diverse and fragmented nature of oilfield services has contributed to the sector's slow recovery. According to Stevens: 'To enhance the opportunities for companies operating in oilfield services, they must focus on key deliverables and capabilities to provide more integrated solutions upstream, like a one-stop shop. Collaboration is vital.'

Norwegian developments

The Norwegian sector has also experienced challenging times. In 2016, investments across the Norwegian Shelf totalled NK135bn ($15.8bn), about $5.8bn less than the peak in 2014, according to the Norwegian Petroleum Directorate (NPD). Spending is expected to remain subdued through to 2018, but is then likely to pick up.

In 1H2017, three fields – Flounder, Sindre and Gina Krog – were put in production. There are currently 12 field development projects on the NCS and two decommissioning plans were received to close Trym and Gyda (see the online North Sea development table at **bit.ly/2v9JCBG**).

So far this year there are approved plans for development and operation (PDO) for the Utgard field (gas and condensate, production start 4Q2019), Byrding (oil and gas, using existing template in the Fram area, 3Q2017), Oda (oil field to be tied-back to Ula, 3Q2019), Dvalin (gas, 4Q2020), Trestakk (oil linked to FPSO, 2Q2019) and Bauge (oil, 4Q2019). The NPD also approved an amended PDO for Njord (oil and gas, 4Q2020). The Goliat Snadd, Troll Brent B and Sindre fields received PDO exemption.

Some 15 exploration wells were drilled in the NCS in the first half of this year, nine monitoring wells and six appraisal wells. There were six discoveries, two in the NCS and two in the Barents Sea. In 2H2017, 20 to 25 explorations wells are planned.

Statoil plans to start a drilling campaign in the Korpfjell formation this year, which will be one of the northernmost drill campaigns. Today, the southern sector of the Barents Sea is open for petroleum activity. In April the NPD presented mapping of resource potential in the eastern part of the northern Barents Sea. This mapping has increased the share of undiscovered resources in the Barents Sea from 50% to nearly 60% of the total undiscovered resources on the Norwegian shelf. 'We consider there is large potential in this area,' comments Solvberg.

Over the next three years Statoil's Aasta Hansteen field, Total's Martin Linge, and phase 1 of Statoil's Johan Sverdrup development will come onstream, followed by Maria, Troll Brent B, Hanz etc (see online table). The Aaste Hansteen gas field will use a unique Spar floating platform and two subsea tie-backs.

Start-up of the Goliat oil field in the Barents Sea in 2016 marked a significant stage in Norwegian developments far north, as more than half of Norway's undiscovered resources are in the Barents Sea. The $4bn Snorre expansion project will involve installation of six subsea templates, to increase recovery by 300mn boe. FID is anticipated by year-end.

Date	North Sea deals	Buyers
7/6/2017	Total acquires 35% WI* in FEL 2/14 from Providence and Sosina	Total
24/5/2017	DONG divests E&P business to Ineos	Ineos
23/5/2017	Total divests remaining 15% WI in Gina Krog field to OKEA	OKEA
11/5/2017	Neptune to acquire ENGIE E&P	Neptune Oil & Gas
10/4/2017	Hague acquires Netherlands gas assets from Tullow	Hague and London Oil
8/3/2017	Cairn Energy to acquire 30% WI in FEL 2/14	Cairn Energy
8/3/2017	Cairn Energy to acquire 70% WI in LO 16/19 from Europa	Cairn Energy
3/3/2017	Sterling divests UK and Netherlands ops to Oranje-Nassau	Oranje Nassau Energy
22/2/2017	Decipher acquires Iona Energy	Decipher Energy
6/2/2017	Israel's Delek acquires remaining 80.3% stake in Ithaca	Delek Group
31/1/2017	Shell sells UKCS assets to Chrysaor	Chrysaor Holdings
24/1/2017	BP sells 25% WI in Magnus oil field to EnQuest	EnQuest
25/12/2016	Israel's Delek acquires 13.18% stake in Faroe	Delek Group
21/12/2016	Total sells offshore Norway assets to Kufpec	Kufpec
16/11/2016	Antrim divests FEL 1/13 to AzEire	AzEire Petroleum
8/11/2016	OMV divests UK operations to Siccar Point	Siccar Point Energy
23/8/2016	Statoil acquires 70% stake in P2170, UK North Sea	Statoil
9/8/2016	Suncor acquires 30% WI in Rosebank project from OMV	Suncor Energy
2/8/2016	Ithaca acquires interests in Greater Stella area licences	Ithaca Energy
14/7/2016	Faroe acquires interests in 5 N Sea fields from DONG	Faroe Petroleum
10/6/2016	BP divests Norwegian subsidiary to Aker and Det Norske	Aker; Det Norske Oljeselskap
10/6/2016	Independent acquires Vulcan satellites from Verus	Independent Oil and Gas
3/5/2016	Statoil divests 15% WI in Edvard Grieg field to Lundin	Lundin Petroleum
3/5/2017	Statoil acquires additional 1.2% stake in Lundin	Statoil
18/4/2016	Kerogen acquires 30% stake in Hurricane	Kerogen Capital
18/4/2016	Independent acquires remain 50% WI in N Sea licence from Alpha	Independent Oil and Gas
22/2/2016	First Oil divests 15% WI in Kraken field to EnQuest and Cairn	EnQuest PLC; Cairn Energy
22/2/2016	Zennor Petroleum acquires UK N Sea assets from First Oil	Zennor Petroleum
10/2/2016	Shell divests 7.59% WI in Maclure field	Nobel Upstream
14/1/2016	Statoil acquires 11.93% stake in Lundin	Statoil
13/1/2016	E.ON divests UK North Sea assets to Premier	Premier Oil

Table 1: North Sea deals, Jan 2016 to date *WI - working interest

Unlike the UKCS which is considered to be a mature basin in the southern and central sectors, decommissioning is not such a steadily growing issue in the NCS. According to Ingrid Solvberg, Director of Development and Production at the Norwegian Petroleum Directorate (NPD): 'We expect 10–20 fields to cease production in the next five years. But the production from these fields is so small that it will hardly impact overall NCS production.'

On the horizon

By the end of 2016, 77 discoveries on the NCS were being considered for development. 'Many of these discoveries are quite small and most are likely to be developed with subsea tie-backs to existing infrastructure,' says Solvberg.

Phase 1 of Johan Sverdrup is the largest discovery being developed, with estimated oil and gas resources of 1.9–3boe. Phase 2 is expected to be sanctioned in 2018. Phase 1 comprises four fixed platforms. Phase 2 comprises a fifth fixed platform and additional subsea or platform wellhead structures. Statoil's Johan Castberg discovery in the Barents Sea is estimated to have 400–650mn boe, and is planned for development using an FPSO with subsea well tie-backs to start production in 2022. There are also plans for a new oil terminal, north in Finnmark, to serve discoveries in the Barents Sea, as a joint project between Statoil, Eni, OMV and Lundin.

Repsol plans to submit a revised PDO for the Yme field in 3Q2017, using a jack-up with drilling and processing facilities to produce remaining resources. A PDO is expected to be submitted in 4Q2017 for Aker-BP's Snadd gas discovery. It is proposed to develop the field in two phases using the gas processing facility of FPSO Skarv. PDOs are expected by 4Q2017 for the VNG operated Arrow and Bow oil and gas discoveries, for production start in 2020.

There has been significant cost reduction in the Norwegian sector since 2014. The NPD looked at seven development projects and determined that total costs in 2014 of NK220bn were cut to NK110bn by 2016, with no major changes to development plans.

Significant consolidation has also been underway. Aker and Det Norske Oljeselskap purchased BP Norway's portfolio in October 2016. Total sold its offshore Norway assets to KUFPEC and recently divested its 15% interest in the Gina Krog field to OKEA. ExxonMobil divested its field operatorships to Norwegian company Point Resources, but retained some partnerships on the NCS, while DONG divested part of its NCS portfolio to Faroe.

Solvberg concludes: 'There is great remaining value potential on the NCS, with big opportunities for those companies with a positive attitude and the ability and willingness to act.' ●

Sellers	Deal ($mn)	Transaction	Hydrocarbon	Location
Providence Resources ; Sosina	27	Exploration blocks	oil	Irish Sea
DONG	1,050	Corporate M&A	gas	NCS
Total	350	Fields under development	oil, gas	NCS
Engie	3,900	Corporate M&A	oil, gas	UKCS
Tullow	10.33	Producing fields	gas	Netherlands CS
Providence Resources; Sosina	9.12	Exploration blocks	oil	Irish Sea
Europa	1.8	Exploration blocks	oil, gas	Irish Sea
Sterling Resources	163	Producing fields	gas	UKCS
Iona Energy	7.01	Corporate M&A	oil	UKCS
Ithaca Energy	1,004	Corporate M&A	oil	UKCS
Shell	3,024	Producing fields	oil	UKCS
BP	85	Producing fields	oil	UKCS
Korea National Oil Corp	52.88	Corporate M&A	oil, gas	UKCS
Total	300	Producing fields	oil. gas	NCS
Antrim Energy	0.25	Exploration blocks	tbc	Irish Sea
OMV	875	Fields under development	oil, gas	UKCS
Jersey Oil and Gas; Itochu	9.5	Exploration blocks	oil	UKCS
OMV	50	Discoveries	oil	UKCS
ENGIE (GDF Suez), Ineos, Maersk	6	Discoveries	oil	UKCS
DONG	70.2	Producing fields	oil, gas	NCS
BP	1,146	Producing fields	oil, gas	NCS
Verus Petroleum UK	7.24	Discoveries	gas	UKCS
Statoil	470.01	Producing fields	oil	NCS
Lundin Petroleum	68	Corporate M&A	oil	NCS + onshore
Hurricane Energy	62.66	Corporate M&A	oil	UKCS
Alpha Petroleum	2.13	Fields under development	gas	UKCS
First Oil	10	Fields under development	oil	UKCS
First Oil	46.82	Producing fields	oil	UKCS
Shell	24	Producing fields	oil	UKCS
Lundin Petroleum	538.89	Corporate M&A	oil	NCS + onshore
E.ON	120	Producing fields	gas	UKCS

Source: PwC

GAS

Subsea-to-shore innovation

Installation of import pipeline at Orka Voe, Shetland Islands
Source: Total

The Laggan-Tormore project west of the Shetland Islands is the first subsea-to-shore development in UK waters. *Nic Newman* reports.

Developed by Total E&P UK (operator, 60%) in partnership with SSE E&P UK (20%) and DONG E&P UK (20%*), the innovative Laggan-Tormore project is located in blocks 206/1a and 206/5a, in water depths of 600 metres. Total field reserves are put at 1tn cf of gas and condensates – a substantial addition to the UK's known reserves.

The £3.5bn project comprises the development of two deep offshore gas fields – Laggan and Tomore – the first to be developed in the Atlantic Margin, a region that until now was known primarily for its oil output. First gas was produced on 8 February 2016, via a semi-autonomous system lying on the seabed connected by a 143-km subsea export pipeline, known as the Laggan Tormore export pipeline (LTEP). The LTEP links the gas fields with a new gas plant located in Shetland, next to the Sullom Voe oil and gas terminal. The facility is able to process 500mn cf/d – enough gas to supply two million households or about 8% of the UK's energy needs. After processing, the gas is piped through a second 243-km newly constructed Shetland Islands Regional Gas Export (SIRGE) pipeline which connects with the Frigg-UK pipeline and then into the UK's gas pipeline network in Scotland.

A combination of the extreme weather experienced in the Atlantic Margin, including hurricane force winds in winter; water depths of some 600 metres, where temperatures are commonly –1°C; typical current speeds as high as 0.64 m/s; and the large volumes of gas to be developed made it unrealistic to employ a traditional platform or a FLNG (floating LNG) vessel to collect, process and store gas ready to be offloaded onto LNG tankers. Instead, a subsea-to-shore development concept was chosen – a UK first.

Essentially, the Laggan and Tormore fields are each serviced by a semi-autonomous subsea production system consisting of a set of six-slot manifold templates lying beneath 600 metres of water on the seabed. Each manifold template measures approximately 30 metres wide, 40 metres long and 21 metres tall, weighing in at 900 tonnes. At present, five subsea wells are in operation out of a 12-well capacity.

These subsea installations represent two major engineering achievements for the UK. The first is the installation of a subsea production system with remote controlled wells, and the second is the longest tie-back between offshore wells and an onshore terminal.

Installation challenges

The depth of water at Laggan-Tormore precluded the use of divers so Heerema Marine Contractors' *Thialf* heavy-lift vessel was used to transport and install the production systems on the seabed. Subsea work was sub-contracted to Aberdeen-based Specialist Subsea Services (S³), who provided and operated remotely controlled underwater vehicles (ROVs) for the subsea installation work.

The project has a field life expectancy of 20 years. As with any production facility, wellhead pressures naturally decline over time and the pipeline export flow will fall below a critical value. At this juncture compression boosters will most likely be installed at each wellhead and one for each export pipeline in order to boost production and recovery from the reservoir by reducing backpressure on the wells by increasing the flow rate in the export pipelines, thus extending field production.

In the pipeline

Two sets of new pipelines were constructed for the project, the first being the LTEP network linking the fields with the newly constructed Shetland gas processing plant. A second pipeline system exports the processed gas from the gas plant to the UK mainland. The entire pipeline network required 200,000 tonnes of high-grade steel. Internally the pipes are protected by a three-layer polypropylene anti-corrosion coating, internal flow-efficiency coating and concrete-weight coating. The pipeline network is regularly inspected and can be cleaned by a remotely controlled pig.

The LTEP comprises three pipelines and a communication or control umbilical. On the seabed this network consists of two 18-inch diameter flow-lines that carry gas from the fields to the Shetland gas plant for processing and an 8-inch diameter pipeline carrying MEG (mono ethylene glycol) from the gas plant to the Laggan-Tormore field's production sites. MEG is used to prevent the condensate from freezing at the start of its journey, much like antifreeze is used in a car. When the gas arrives at the processing plant, the MEG is removed and pumped back to the wellheads, to start its journey again. Gravity causes the contents in the gas pipelines to separate into gas in the top half of the pipe, whilst the heavier gas liquids settle along the