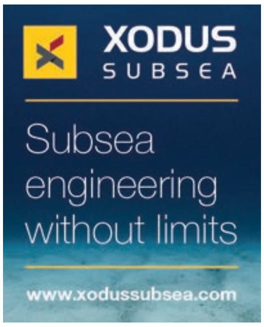

SEN
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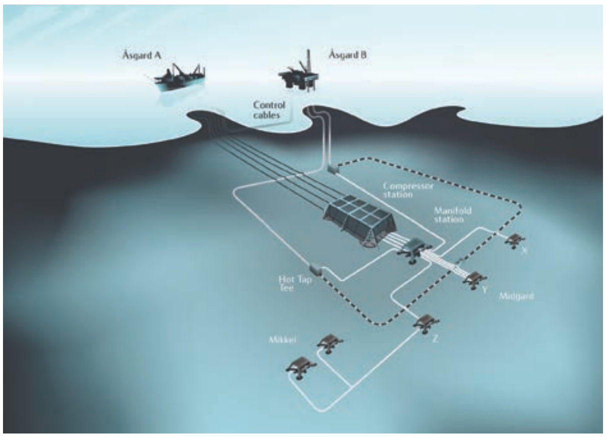
Subsea Milestone Hit; More Needed



The Åsgard compressor has been turned on.

The dream became reality this week as the first subsea gas compression plant in the world came online at Statoil's **Åsgard** (*SEN, 32/11*) Field in the Norwegian Sea.

This subsea technology milestone has been heralded as opening up new opportunities in deeper waters and in areas far from shore.

But the industry needs to kick on from here and push forward with full-scale subsea production including power on the seabed, according to speakers at the 2015 SPE Offshore Europe Conference last week in Aberdeen.

Subsea power is one of the keys to opening up deepwater plays, Kristin Moe Elgsaas, GE Oil & Gas' senior product manager told delegates in the Deepwater Zone at the conference.

"We are going into deeper water and deeper reservoirs. We are going into ever more remote locations and hostile environments. These drivers are putting subsea production under pressure and they will put subsea power and processing under pressure."

She said the industry needs to develop systems that produce power where it makes the most sense.

"We need to fully commercialise subsea distribution systems and place switchgears and variable speed drives subsea so we can supply multiple loads through one transmission cable rather than multiple cables. Cables are a significant cost driver in long step-out systems."

She said these types of system have been shown to be possible and that the next step is to show long-term reliability through real-life operation.

"What we need to be doing tomorrow is what we did not do today and what we could not do yesterday. We need to focus on what we should be doing and bring real value to the field. That means pushing the envelope."

She said the oil and gas business is fundamentally conservative and that subsea solutions need to be looked at earlier in development planning.

Tine Bauck Irmann-Jacobsen, field development specialist with FMC Technologies, echoed this view.

"If we are going to undertake projects in 2,000 m to 3,000 m, the subsea processing needs to be put in place first."

She said the adoption of such technology brings the benefits of increasing production while at the same time reducing downtime and lowering intervention costs.

"If you are going to use subsea processing, you need to be aware that the optimal installation time is when production is starting to drop off plateau," she said.

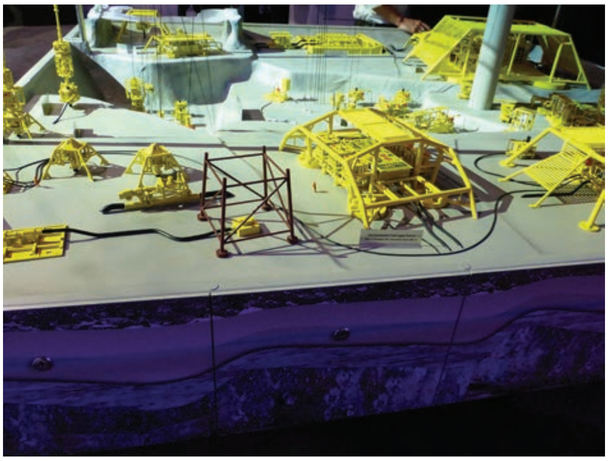
If that window of opportunity is missed, profitable projects could be lost, she added.

Moving gas compression from the platform to the wellhead substantially increases the recovery rate and life of fields, but the industry needs to grasp the nettle and move to the next step.

WHAT'S INSIDE

OFFSHORE EUROPE

Inspiring the Next Generation?



Subsea models on display at OE 2015.

Two years on from a bumper Offshore Europe Conference in 2013 and with the oil price crash still in sharp focus, there were fears that this edition of the industry showcase would be a bit of a damp squib.

But there was still a buzz about the place with plenty of punters in the aisles and a lot of interesting technology on the show floor.

Organisers said more than 56,000 attended this year's show compared to more than 60,000 in 2013, although Aberdeen's taxi drivers, normally a good barometer of economic conditions, reckoned business overall was down 35%.

Perhaps slightly mistimed, the question of how to inspire the next generation of oil industry professionals was the main topic of discussion at the show.

At the opening plenary session, a packed auditorium heard Expro Group's CEO Charles Woodburn urge the oil industry to be more vocal in highlighting the opportunities that await new recruits and what it has to offer.

Acknowledging the tough times the upstream industry is currently going through, he urged it to make more effort to make itself better understood and set its own agenda, rather than have others set the agenda for it. "We are just not vocal enough," he said.

Dr. Brian Cox, TV presenter and physicist, highlighted the need for the offshore business to better tell the story of what it does and achieves. "The story you tell is the important thing for inspiring young people," he said. "The more people understand something, the more interesting it gets."

Dr. Cox took the audience on a slightly longer-distance virtual tour than just the global offshore sector, pointing out that there may well be vast energy reserves lying within our own solar system. On Saturn's largest moon, Titan, for example, he pointed out that it appears there are "vast lakes of liquefied petroleum gas," with reserves estimated in the many hundreds of billions of barrels. However, he did not volunteer any proposed solutions for bringing the LPG back.

BP's Looney Outlines North Sea Necessities

From OE 2015 (MT): BP remains a believer in the future of the U.K. North Sea, with the sector on the right track but needing to do more.

According to Bernard Looney, COO, production at BP, times are undeniably tough with thousands (65,000 according to industry lobby group Oil & Gas UK, he pointed out) having lost their jobs.

But the long-term outlook is brighter, he said during a presentation. "First and foremost, we are in a growth industry and that is not going to change anytime soon. All the forecasts suggest demand for energy will continue to rise. At BP, we believe demand will be a full one third higher by 2035 than it is today. Much of this is driven by population growth—1.6 billion extra people will need energy in this time period—as well as increasing prosperity, especially in emerging economies.

"Secondly, despite the environment, the industry here in the North Sea continues to invest billions of dollars to bring new oil to the market place. Third, here we have a highly skilled, highly experienced and highly engaged workforce right on our doorstep—the envy of many an oil capital throughout the world. And fourth, the North Sea has an extensive infrastructure in place, not to mention resources. Some 15 to 20 Bbbl of oil potentially yet to be produced."

Admitting that the industry needs to drill more exploration wells and push reservoir recovery factors above the mid-40s, he highlighted the region still offers rewards. "Last autumn, we announced the **Vorlich** discovery, and earlier this year GDF Suez announced the **Dalziel** discovery," he said.

"But at the same time we also have to be realistic. There are some real challenges. This is a mature basin with declining production. There are reliability and production efficiency challenges, not to mention high costs. And of course, we have the backdrop of a 50% drop in the oil price. So given all that, is the North Sea worth fighting for? The answer is unequivocal—absolutely it is."

Looney said BP has been going back to basics, making its equipment more reliable, eliminating defects and improving production efficiency. It is apparently paying off. In 2011, Looney said BP's plant reliability worldwide was 85%, whereas now it is 94%. "And with that improvement we are finally beginning to see a major turnaround in our North Sea operating efficiency," he said.

Contractors also "hold a mirror up to us as operators," Looney said.

This year the company sat down with many of its contractors, and he highlighted two: Wood Group and Cape. "At our request they provided us with lists of where we could save money if we changed the way we work. These ideas range from decommissioning plans to scaffolding management, from streamlining contracting norms to reviewing man-marking ratios. These are suggestions that will generate and sustain millions and millions of dollars in savings."

BP has been slimming down its portfolio for some time, even prior to the price drop. In the U.K., it has divested less strategic assets, allowing it to concentrate capital and effort in the Central North Sea and West of Shetland.

Statoil Mulls Options for Sverdrup Phase Two

Statoil is keeping its options open for Johan Sverdrup Phase 2.

Statoil is still to decide on a development concept for Phase Two of its giant **Johan Sverdrup** (*SEN, 32/11*) oil field off Norway, with both subsea and small unmanned platform options on the cards.

The company is due to select the preferred option by November, but with just weeks to go this deadline looks certain to pass without a definitive solution being put forward.

Updating progress on the scheme at Offshore Europe in Aberdeen, Johan Sverdrup Senior Vice President Øivind Reinertsen said, "For phase two, we are looking at how to produce the areas that are outside the reach of the field centre.

"We are looking at subsea tiebacks, but we also are looking at jackup drilling from small unmanned satellite platforms. Between eight and 12 platforms could be put in and then tied back into the field centre. Those are the main two concepts we are looking at."

Reinertsen said startup of phase two is slated for 2022 but added, "I would not be at all surprised if we took both alternatives into the next phase, which is the conceptual phase." That would mean a decision will be put off until July 2016.

The plan for development and operation for Johan Sverdrup, phase one, was approved by the Ministry of Petroleum and Energy in August. It will be developed in several phases.

Phase one consists of four bridge-linked platforms, in addition to three subsea water-injection templates.

Plans call for a recovery rate of 70%, allowing for advanced technology for IOR in future phases.

The Phase one development has a production capacity in the range of 315 Mbbl/d to 380 Mbbl/d. First oil is planned for late 2019.

The development already has started to take shape and the predrilling template has been installed.

The pre-drilling template contains eight well slots that allow production wells to be predrilled before the drilling platform is installed in 2018 and production starts at Johan Sverdrup in late 2019.

Contract bonanza

Statoil has been busy handing out the awards for the Johan Sverdrup development, with FMC Kongsberg scooping a $160m EPC contract for subsea equipment.

FMC will deliver 13 subsea trees and wellheads, in addition to three subsea templates and control systems.

Statoil said the award is based on a new standard vertical subsea tree, which has been developed in cooperation with the supplier market and DNV.

In the first phase of the Johan Sverdrup development, three standard templates will be installed north and south of the field centre. The subsea templates will be controlled and supplied with produced water or seawater through pipelines from the field centre.

Meanwhile, ABB has landed a $90 million contract from Statoil for the fabrication and installation of two high-voltage cables supplying power from shore to the field.

The engineering, procurement, construction and installation contract also covers fabrication and testing of two high-voltage power cables and a fibre-optic communication cable to the field centre from shore.

The high-voltage cables are 200 km long and designed for a supply capacity of 100 MW/80 kV.

This will cover the power need for the first phase of the Johan Sverdrup Field development, which is scheduled for startup late in 2019.

The contract also covers options for delivering high-voltage cables from shore to the Johan Sverdrup Field to meet the power requirement of a full development of the Johan Sverdrup Field as well as the **Edvard Grieg** (*32/11*), **Ivar Aasen** (*32/7*) and **Gina Krog** (*32/3*) fields on the Utsira High.

Statoil also has awarded an engineering, procurement and construction contract for the Johan Sverdrup gooseneck spool and retrofit hot-tap tee to IKM Ocean Design on behalf of operator Gassco.

Part of the gas export solution from the Johan Sverdrup Field, the assignment will take about two years to complete. Work starts immediately.

Sverdrup gas will be exported to Kårstø via a new 18-in. pipeline, tied into the Statpipe rich-gas leg from Statfjord with the aid of hot tapping and connection to a 30-in. retrofit tee.

Installation will be diverless, using hot tapping equipment from the pipeline repair system base in Haugesund.

Gassco will serve as the operator and technical manager of the 156-km pipeline from the riser platform on Johan Sverdrup to the Statpipe rich gas leg once the field comes onstream.

Kværner Verdal has secured a deal covering delivery of the steel jacket for the field's drilling platform. Weighing 22,500 tonnes, the drilling platform jacket will be the second largest of the jackets to be constructed during the first phase of the project. This jacket will be delivered and installed on the Johan Sverdrup Field in the spring of 2018.

The Johan Sverdrup partnership consists of Statoil, Lundin Norway, Petoro, Det norske oljeselskap and Maersk Oil.

GE Improves Wellhead Fatigue Life

GE Oil & Gas is in the process of getting some interesting technology into the market, including an increased life wellhead.

Nick Dunn GE Oil & Gas' senior vice president for services and offshore in subsea systems, told *SEN* at the 2015 SPE Offshore Europe Conference, "It is a very capex- and opex-focussed world right now, and we have continued to look at what the right products and solutions are for that."

One product the company is introducing is the SFX wellhead, which expands the fatigue life of a wellhead by 16 times. SFX meets or exceeds global fatigue requirements under multiple load conditions across the major operators worldwide.

Dunn said, "Sixteen times is a huge factor and it has come about through reviewing the design and moving some of the stress points. We have managed to incorporate that into our existing wellhead standards so we're able to use the existing tool fleet we have across the world to go and install them."

The optimised geometries of the wellhead are designed to reduce stress concentrations, and extended length forgings improve heat transfer and inspection capabilities. The design benefits from welding, advanced inspection and resonance testing.

Dunn added, "As we standardise that wellhead system, we can virtually halve the lead time. There is a lot of focus on getting one spec and common manufacturing and welding specs so we can then produce these wellheads wherever we want in the world."

Four SFX wellheads are in the process of being manufactured, which will go onto the shelf ready for deployment around the world.

GE Oil & Gas also signed a three-plus-three year subsea operations service frame agreement with Statoil for services on the Norwegian Continental Shelf.

The scope of work covers services and maintenance of subsea production systems during installation and operation phases and will be run from Dusavik.

Dunn said, "It covers about 85 trees and pods on **Tordis**, **Vigdis, Snorre** and **Troll**. A lot of the focus is working with Statoil on STEP [Statoil Technical Efficiency Programme] for technical efficiency where they are looking to take costs out of opex and make their investments more efficient. We're working with them and looking at how to maintain their existing production equipment, tool pools and give them some value.

"We're discussing condition-based monitoring of their existing trees where rather than bring it back and completely strip, inspect and rebuild, we can take the data we currently have and use it to perform a more cost-effective repair."

GE recently has expanded its service facility in Montrose. "We have expanded what we can do around subsea repair and upgrade and invested in the machine shop to the tune of $12.4 million

"We have done some projects recently where we have taken a full subsea tree, stripped it down to its constituent parts , inspected, done some repair and upgrade, rebuilt it and had it back out offshore within five weeks."

And at the company's facility in Onne, Nigeria, 10 trees from the **Bonga** Field are in the process of being fully stripped, refurbished, rebuilt, tested and installed.

Subsea Technologies Key to 4,000 m 'Deepwater Frontier'

Total is operator of the CLOV project off Angola.

From OE 2015 (MT): The offshore industry is moving inexorably towards achieving field development activities in water depths of up to 4,000 m by 2025, according to one of the world's leading deepwater operators, with subsea advances key to the long-term exploitation of the new frontier.

Total has pioneered some of the deepest projects in the world so far including several major flagship developments offshore Angola including **Girassol, Dalia, Pazflor** and **CLOV.** (*SEN, 32/5*), Jeremy Cutler , the operator's head of technology innovation at Total E&P UK, told delegates at the 2015 SPE Offshore Europe Conference in Aberdeen, "By the year 2020, a water depth of 3,000 m—from an oil development perspective—seems to be achievable. We see that by 2025 the expectation is that 4,000 m will be achieved."

Discussing the technology challenges the company is facing, Cutler described water depths of 500 m and deeper as deepwater, with depths of 1,500 m beyond deemed to be ultradeepwater. "But the new frontier is beyond the current limit of about 3,000 m, which we term 'frontier deepwater.' More than 50% of Total's exploration portfolio is in deep and ultradeepwater, so it will be very much a big part of our future and where much of our production revenue is going to come from."

High development costs for this type of technology-intensive project make it hard to launch new developments in the current low oil price climate, he admitted, but as a result Total and the industry as a whole are being driven to study further ways to reduce development costs.

"The challenge for us now, going forward, is how do we go deeper, longer and cheaper?" Cutler said.

He flagged up Total and also Royal Dutch Shell as leading the other majors in the push to develop frontier deepwater areas, with the majors generally holding by far the largest average areas in terms of frontier deepwater acreage.

Frontier deepwater technology gaps to be addressed include pipelay and risers, flow assurance, subsea processing, and the mooring of FPSO units, he said, as well as increasing the length of step-outs and tiebacks (especially for oil). For gas, he added, "it's a little bit different, with the step-outs already longer."

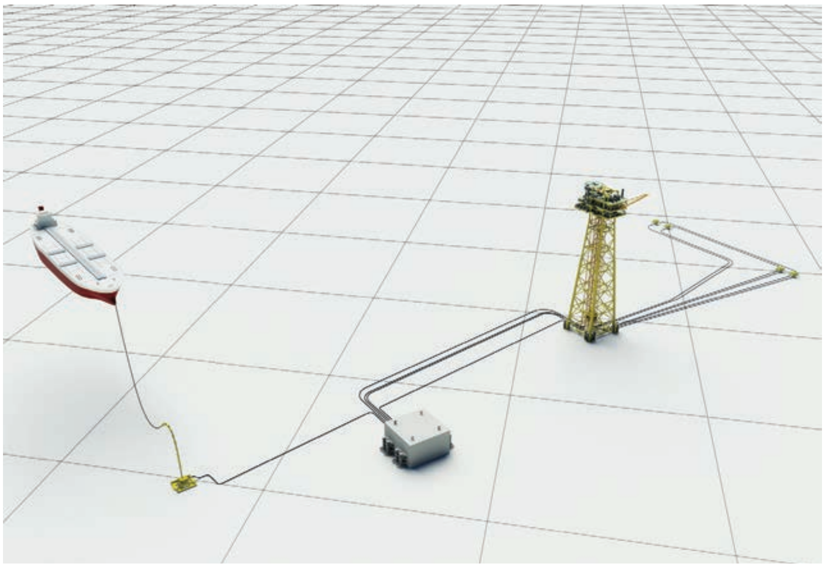
He went further to state clearly that Total has the long-term ambition to "eventually remove the floater from the equation and go subsea-to-beach"—a pretty bold statement at this current time. "We have in our R&D programme a number of different projects related to the so-called subsea factory concept," Cutler said.

Total, of course, is currently developing its deepwater **Laggan-Tormore** (*32/10*) gas field West of Shetland offshore the U.K. in this manner, with the field planned to be operational by year-end. The field's development is enabling a 19 MMcm/d gas export route from the area, and Cutler described Laggan-Tormore as "a challenging project for us" but one that has been "a good test of subsea-to-beach."

Asked by the audience how the industry can prove the business case for subsea processing, he said the industry had to "simply work harder" to get around the problems, which means it is taking it longer to get to the final solution. "But these deepwater fields are bigger, which really helps the economics. But the oil price is making us work that much harder to get a solution that works."

One challenge he further highlighted was related specifically to subsea control modules, which he said had been "one of the big problems we had in Angola." Cutler said the company "did not want to keep doing workovers or changing the modules," adding that the industry "needs to address the integrity of subsea control modules so that they do not fail."

UKCS 'Not Economically Viable'



Premier is working on the Solan Field.

Costs of operating in the U.K. North Sea are still too high to make the region economically viable, Premier Oil's Director North Sea and Exploration Robin Allan has warned.

He told delegates at Offshore Europe 2015 in Aberdeen that it is easier to do business in Vietnam than in the U.K. where costs have got to come down further.

He said, "I'm not that optimistic. I think most of the cost savings we have seen have come from cutting out work that was not absolutely necessary, from reduced fuel costs and from renegotiating such contracts as we were able to renew.

"I don't think the cost of this basin has reduced to the point where it is economically viable going forward."

He said costs in the company's businesses in Asia are "incredibly much lower on every aspect compared to here."

He added, "It is not just about the weather or the sea state in the North Sea. It is a way too high cost base. Unless the collaborative work goes to a whole new level, I don't see a particularly optimistic future for the U.K. North Sea."

He said Premier is in the middle of two large developments in the region, **Solan** (*SEN, 32/11*) and **Catcher** (*SEN, 32/11*), and that the company is committed to continuing with them and will be looking for others.

"But it is not a competitive basin for most of the companies, which have a desire to work internationally as we do. There are plenty of other places where the cost of doing things is incredibly much less."

He compared the furore caused when offshore workers on the U.K. Continental Shelf were asked to move to a three-weeks-on and three-weeks-off shift pattern from two weeks on and three weeks off, to those in Vietnam.

"In Vietnam we had a quick talk with our key suppliers and with the government one day, sent out an email the next and the entire workforce moved to a three-[weeks]-on and three-[weeks]-off pattern for the next rota.

"We did not get a single complaint from anyone anywhere—and yes they are unionised. It is an attitude issue. They saw the need and the government was fully behind Petrovietnam, and it happened.

"It is just so completely different here and I think we have a long journey ahead. I'm sorry if that sounds a bit bleak, but I don't think it's a surprise to anyone here."

Allan also called on the majors to improve the way they deal with the smaller players in the U.K.

"The view from a smaller company is the way that the majors approach for commercial problems and difficulties in tackling all these undeveloped discoveries [is inappropriate]. If you are a BP or a Shell or an Exxon [employee], you don't get promoted by being nice to an EnQuest or a Premier; you get promoted for sticking one over on them. That's what they want to see.

"The majors want to see aggressive commercial behaviour where they win and someone else loses. That works very well for them as companies globally but that is not a model that can help sustain the basin."

Brownfield Subsea Projects Flagged Up

From OE 2015 (MT): The North Sea industry must urgently stop overengineering its projects if it is to bring down its costs, with brownfield subsea developments flagged up as a clear example by the boss of offshore contractor Proserv.

CEO David Lamont was obviously in the mood for some straight-talking at the 2015 SPE Offshore Europe Conference in Aberdeen.

Addressing brownfield subsea developments in particular, Lamont challenged the industry to change its "remove the old and replace with the new" culture.

"The challenges and opportunities that the industry faces with brownfield subsea developments are varied but all too often, the industry's initial response to them is not. The typical reaction to a problem is to undertake a complete system change when sometimes a more flexible and simpler approach might be appropriate, especially in a low commodity price environment. After all, you wouldn't replace your car if the windshield wiper wasn't working.

"For example, when the electronics in a subsea control module require replacement, either because of reliability issues or changes required elsewhere in the system, we [Proserv] apply subsea system "brain surgery." We focus on solving the electronics issue rather than changing out the entire control module—a costly process that brings significant risks because of the changes made to all the external interfaces. Replacing only the electronics allows for the external interfaces to remain intact. In addition, it gives operators a truly maintenance-free subsea production control system and uninterrupted production, with state-of-the-art system capability to allow the use of advanced system monitoring and data gathering."

Lamont also described the maintenance and optimisation of aging brownfield subsea fields as critical. "On mature brownfield assets with dwindling production, the longer it takes to make the right and cost-effective decision to maximise output, the more expensive that decision becomes. By not changing its operating model, the industry will risk the future of that asset. A subsea asset, which is losing production revenue, against a backdrop of increased operating costs is only going to become less viable to the point of shutdown and decommissioning—denying the world recovery of a limited and valuable resource.

On a wider level, Lamont stressed that the North Sea still has many years of profitable life ahead of it—if the industry quickly adopts more collaborative and efficient business practices. But it still has some way to go yet, he said bluntly. "Despite talk in recent years of the urgent need to act and collaborate, even before the oil price crash, the industry as a whole still has a long way to go. Everyone knows what needs to be done but the inertia in the industry is of great concern. The time is now to put a stop to this and make dynamic changes to the way we act and behave. Changing our approach to how we think and do business will see the industry thrive, rather than simply survive."

Lamont, speaking in a press briefing, said the industry needs to "embrace and rekindle the pioneering spirit that made the North Sea great in the past to ensure the North Sea industry doesn't fade out prematurely but really flourishes in its latter years."

A fundamental change in the way it works is required, he continued. "As a start, we must stop overengineering if we are to reset the cost base. Realising the value of the huge number of marginal fields in the UKCS [U.K. Continental Shelf] will only be possible if we as an industry collaborate and cooperate to make the most of the existing infrastructure, enhanced only by the most appropriate and efficient technology and engineering know-how. Applying the same old engineering practice and business model is simply not an option.

"While we are seeing real efforts and actions to collaborate, it is still the exception rather than the rule. Too many people in the industry are still holding their breath for a return to the 'good old days of $100 oil' which simply won't happen, and even if it does, the practices of the recent past are too wasteful in any case."

He concluded, "No matter what the commodity price is now or in the future, we have it within our power as an industry to control costs, improve efficiencies and prosper. We owe it to ourselves and to the next generation."

DEVELOPMENT

Gulf of Mexico Planning Slows

From Houston (BN): Few new exploration and development plans are being filed for projects in the Gulf of Mexico (GoM) and those that are being filed tend to have a long-time horizon.

Freeport McMoRan won regulator approval for its plan to drill, complete, test and install subsea trees on eight wells at its **Orange** prospect in Mississippi Canyon Block 216.

The site is in 1,825 m to 1,890 m of water and about 239 km southeast of New Orleans.

Each well is expected to take 65 days to drill. Spudding of the first well is targeted for August 2016 with the rest to be drilled at time intervals stretching to April 2022. Targeted trend is thought to contain 33 °API oil.

Regulators also have OK'd Statoil's plan to drill five wells at its **Monument** prospect in Walker Ridge 271 and 272. The site is in 2,050 m and about 290 km southwest of New Orleans.

Each well is expected to take 175 days to drill. The first well is to spud in December of this year and the rest to be drilled at the rate of one a year, with the last finishing in early 2020. Targeted oil is 35 °API.

BHP has received the green light for its plan to drill five wells at its **Caicos** prospect in Green Canyon 564. The location is in 1,290 m of water and about 280 km south of New Orleans. Each well is expected to take 200 days to drill and mudline suspend, with the first to spud next month and the rest to be drilled at the rate of one a year through 2020. Targeted oil is 31 °API.

In development activity, Energy Resource Technology won approval for its plan to drill a Phoenix Field expansion well at its Lindsey prospect in Green Canyon 237. The well is in 650 m of water and about 226 km south-southwest of New Orleans. The well is expected to take 70 days to drill and installation of lease term pipelines an additional 15 days to tie back to a planned expansion manifold. Oil targeted is expected to be 22 degrees.

Activity has slowed in the deep GoM but not stopped. Regulators counted 55 rigs on the job this week, including wireline, coiled tubing and platform rigs as well as floaters.

Subsea Solution Confirmed for Maria

Maria will be tied back to the Kristin platform.

Wintershall and its partners Petoro and Centrica have been given the green light by Norway's Ministry of Petroleum and Energy for their plan for development and operation for the **Maria** (*SEN, 32/8*) Field, offshore Norway.

Maria will be developed with two subsea templates tied back to several host installations in the area.

The Maria reservoir will be linked via a subsea tieback to the *Kristin*, *Heidrun* and *Åsgard B* production platforms. The Maria wellstream will go to the Kristin platform for processing while supply of water for injection into the reservoir will come from the Heidrun platform and lift gas will be provided from Åsgard B via the *Tyrihans D* Field subsea template.

Processed oil will be shipped to the Åsgard Field for storage and offloading to shuttle tankers. Gas will be exported via the Åsgard Transport System to Kårstø.

A significant number of contracts already have been awarded for the Maria project, notably the subsea production system to FMC Kongsberg and the contract for pipeline and subsea construction to Subsea 7.

Odfjell will carry out drilling on the project with the *Deepsea Stavanger* semisubmersible, which will drill six wells starting in April 2017.

"This is another important landmark for Wintershall in Norway. In a challenging oil price environment, we are moving ahead with the execution of this key development project. Through Maria, we are investing in one of our core international regions, which demonstrates our commitment on the Norwegian Continental Shelf," said Hugo Dijkgraaf, Wintershall Maria project director.

"By developing this innovative solution that utilises existing infrastructure in the Norwegian Sea, we are strengthening our position as a subsea operator and generating substantial value for the partnership and the whole supply chain," Dijkgraaf said.

Investments in the Maria development are estimated at about $1.86 billion, including development drilling.

Recoverable reserves on the field are estimated at about 180 MMboe, of which the majority is oil. The planned production startup for Maria is in 2018.

The Maria Field is located about 20 km east of the **Kristin** (*32/11*) Field and about 45 km south of the **Heidrun** (*32/4*) Field in the Halten Terrace in the Norwegian Sea.

DEVELOPMENT BRIEFS

Total has picked Norway's Ocean Installer to install umbilicals, flowlines and risers on its **Moho Nord** (*SEN, 32/11*) Field off the coast of the Republic of Congo.

Ocean Installer will install and precommission an umbilical, multiphase pump, flying leads and spools in water depths of about 1,000 m. The scope includes project management, engineering and logistics, in addition to offshore work.

The contract is Ocean Installer's first major operation in West Africa following the creation of the Africa, Mediterranean and Middle East regional office in second-half 2014.

The project will be managed from Stavanger and the high-capacity DP3 construction support vessel *Normand Vision* will be used for the offshore work.

The vessel is equipped with a 150-mt vertical lay spread, a 400-mt active heave compensated crane and two work class ROVs from Oceaneering.

The Moho Nord Field is located 75 km off the coast of the Republic of Congo in water depths ranging from 450 m to 1,200 m.

Ezra Holdings will carry out work for BHP Billiton for the **Angostura** Phase 3 development offshore Trinidad and Tobago in the eastern Trinidadian sector of the Venezuela Basin.

The total scope of work includes the project management, fabrication, construction and installation of a 12-in. flowline along with a complete subsea package comprised of control umbilicals and detailed engineering, construction and installation of the pipeline end manifold and inline sled.

Engineering and procurement are underway from EMAS AMC's Houston office with fabrication of the subsea structures and stalking and spooling of flowlines to be carried out at EMAS Marine Base facility in Ingleside, Texas.

Offshore execution is scheduled for mid-2016, utilising the *Lewek Express* subsea construction and reel lay vessel.

From Australia (LB): Origin Energy has tied in the *Yolla-5* development well to export facilities on the *Yolla* (*32/9*) platform in Victoria's Bass Strait offshore Australia.

AWE, a 35% joint-venture (JV) partner in the **BassGas** (*32/9*) project, said production from the well had started, marking a significant milestone for the project.

Origin, as operator of the JV, is monitoring well performance to achieve optimal comingling with production from the existing *Yolla-4* well and the *Yolla-6* well, which was brought online in July.

"The addition of the Yolla-5 and Yolla-6 development wells will now provide increased stable longer term production capability and a greater level of well redundancy," AWE Managing Director Bruce Clemet said.

"The joint venture is now turning its attention to the tie-in and commissioning of the gas compression and condensate pumping modules on the Yolla platform, work that is expected to take approximately 18 months to complete."

The BassGas project consists of the Yolla offshore wellhead platform connected by pipeline to the gas processing facility at Lang Lang in Victoria.


The *Deep Orient* will carry out work on the D18 project.

Technip has been awarded an engineering, procurement, installation and commissioning contract by Petronas for the **D18** project.

The project covers the procurement and installation of two 8-in. water-injection flexible pipes totalling 9.5 km.

The flexible pipes will connect three fixed jacket platforms which form the existing D18 infrastructure offshore Sarawak, Malaysia, in 36 m of water.

This contract is part of the five-year framework agreement signed with Petronas in late 2014 and is in line with Technip's strategy to strengthen its partnerships with its clients to drive cost optimisation.

Asiaflex Products, Technip's flexible pipe manufacturing plant located in Johor, Malaysia, will execute the contract with support from Technip's operating centre in Kuala Lumpur, Malaysia. The project is scheduled for completion in late 2015.

The flexible pipes will be manufactured at Asiaflex Products and the *Deep Orient*, one of Technip's subsea construction vessels, will be mobilised for installation during the second semester of 2015.

Hurricane Energy's **Lancaster** (*31/20*) discovery has been granted oil field status by the U.K. Oil and Gas Authority. This represents the first step in progressing the submission of the Lancaster early production system field development plan.

CEO Dr. Robert Trice said, "I'm delighted that the Oil and Gas Authority has granted Lancaster oil field status, which is an important step in progressing to first oil from Lancaster. Furthermore, the granting of oil field status for Lancaster helps the partitioning of Hurricane's other discoveries and prospects that sit within Licence P1368."

N-Sea Offshore said it has completed work on Maersk Oil UK's 2015 subsea inspection programme.

The workscope involved four field locations in the North Sea and utilised N-Sea's inspection, maintenance and repair and subsea capabilities over 135 days.

The *Siem N-Sea* was used for the work and to combine ROV inspection services with IMR diving works. The vessel is part of N-Sea's fleet of dive, multisupport and construction vessels designed to deliver a range of subsea services for offshore assets, platforms, FPSOs and renewables operations.

Apache has exercised the first of two options to extend its existing contract with Archer for the provision of platform drilling services for a further year.

Archer currently operates 33 platforms in the North Sea, Greece and Brazil, including platform drilling services on the *Forties Alpha*, *Bravo*, *Charlie* and *Delta* platforms along with the *Beryl Alpha* and *Bravo* installations.

Bibby Offshore is taking advantage of the growing market for decommissioning and has delivered two multi-million-pound contracts in the U.K. North Sea this year.

Endeavour Energy appointed Bibby Offshore to carry out work in the **Renee** and **Rubie** (*32/6*) fields located in blocks 15/27 and 15/28 of the Central North Sea.

The 60-day agreement, which was completed in third-quarter 2015, involved Bibby Offshore's dive support vessel (DSV) *Bibby Sapphire* and construction support vessel *Olympic Ares*, completing the recovery of subsea equipment including cross-over structures, umbilicals and protection mattresses.

Bibby Offshore also successfully completed work for Tullow throughout April and May, utilising DSV *Bibby Topaz* to perform decommissioning operations at the **Orwell** and **Wissey** (31/19) subsea installations, including the tie-ins at the *Thames, Horne* and *Wren* platforms, in Block 49/28 of the Southern North Sea.

Nexans has been awarded the contract to deliver 48 km of static umbilicals to BP and partner DEA for the **West Nile Delta Taurus Libra** (*32/10*) project in Egypt.

The Taurus Libra development is a subsea project tied in to existing BG Group operated Burullus facilities.

The umbilicals consist of electrical and fibre-optic cables as well as hydraulic and chemical lines. They will be designed, engineered and manufactured at Nexans' specialised subsea cable and umbilical facilities in Halden and Rognan, Norway. Nexans also will deliver accessories for this project. The delivery will take place in May 2016.

Houston-based subsea services outfit Deep Down has won a large order from an undisclosed client for patented flying leads and an umbilical termination assembly (UTA).

The flying leads and UTA will be delivered and deployed in the Gulf of Mexico in the first quarter of 2016.

Ron Smith, CEO of Deep Down, said, "Despite the current environment of lower oil prices, this order from a new customer reinforces our strategy and ability to work directly for operators."

FLOATERS

Inpex Delays Ichthys Startup

From Australia (LB): Inpex has delayed the startup timetable for first gas from the **Ichthys** (*SEN, 32/8*) LNG development off the coast of northern Australia, pushing the project's budget up by about 10%.

Production, which was initially expected to start towards year-end 2016, is now expected to start in third-quarter 2017, resulting in a nine-month delay.

It's understood the main reason for the delay is due to bottlenecks in the South Korean shipyards, at Geoje, where Ichthys' central processing facility and FPSO vessel are being built. However, it is unclear whether onshore construction work at the Bladin Point LNG plant in Darwin is on schedule.

Japan's Inpex attempted to put a positive spin to the news, advising that it had raised the annual LNG production capacity for the two-train project from 8.4 Mtpa to 8.9 Mtpa.

Capital costs for Ichthys, which represents Japan's largest investment in Australia, were originally budgeted to be $34 billion, estimated in 2012 when a positive investment decision was made. The 10% cost overrun pushes the project's estimated cost to $37.4 billion.

The project's overall development was about 74% complete as of June and had, up until now, flown in the face of some of the other mega LNG developments in Australia, which have suffered from cost blowouts and project delays.

Inpex plans to cover the increased costs of the project through its own funds as well as external loans as originally scheduled.

Inpex President and CEO Toshiaki Kitamura failed to provide reasons for the delay, instead highlighting the positive outcomes that Ichthys would create.

"The Ichthys LNG project is a world-class project with an expected operational life of at least 40 years," he said.

"The project also is expected to make a significant contribution to the social and economic development of Australia, one of the world's foremost producers of energy."

The Ichthys project is a joint venture between Inpex, Total and the Australian subsidiaries of Tokyo Gas, Osaka Gas, Chubu Electric Power and Toho Gas.

Other mega LNG projects that have suffered production delays and subsequently increased cost estimates include Chevron's Gorgon project and the three coal seam gas and LNG developments on Queensland's Curtis Island.

FLOATER BRIEFS

Exxon Mobil has turned the taps on at its **Erha North** Phase 2 (*SEN, 31/14*) deepwater subsea development offshore Nigeria.

Phase 2 includes seven wells from three drill centres tied back to the existing *Erha North* FPSO vessel.

The project is expected to develop an additional 165 MMbbl from the currently producing Erha North Field. Peak production from the expansion is currently estimated at 65,000 bbl/d of oil and will increase total Erha North Field production to about 90,000 bbl/d.

"Executing successful projects such as Erha North Phase 2 ahead of schedule and under budget results from Exxon Mobil's disciplined project management approach and expertise," said Neil W. Duffin, president of Exxon Mobil.

Duffin said the ahead-of-schedule startup was supported by strong performance from Nigerian contractors, which accounted for more than $2 billion of project investment for goods and services, including subsea equipment, facilities and offshore installation.

The Erha North Field was discovered in 2004 and IP commenced in 2006.

Woodside has tapped Aibel to carry out the FEED work for a subsea tieback to the *Ngujima-Yin* FPSO as part of the **Greater Enfield** (*32/5*) development offshore Australia.

The FPSO will undergo modifications to the topsides, hull and turret. Aibel's scope of work includes management, engineering and provision of procurement services for FEED. The contract also holds an option for the project's execution phase.

The *Ngujima-Yin* FPSO is operating on Woodside's producing **Vincent** (*32/5*) oil field.

Heavy transportation and lifting contractor ALE has mated the topsides for the deepwater **Malikai** (*31/12*) tension-leg platform with the hull at Malaysia Marine & Heavy Engineering's yard in Malaysia.

ALE was given the scope of weighing and transporting four unit hull blocks, living quarters and mega beams for what it called the "superlift" activities.

Modec has signed a contract with Maersk Oil UK to supply a floating storage and offloading (FSO) vessel for the **Culzean** (*32/12*) development project in the North Sea.

Modec is responsible for the engineering, procurement and construction of the FSO.

Sofec, a subsidiary of Modec, will design and supply the internal turret mooring system.

The FSO will have receiving capacity of 25,000 bbl/d of condensate and storage capacity of 350,000 Mbbl/d. The complete unit will be delivered to Maersk Oil UK in first-half 2018.

EXPLORATION NOTES

From Houston (BN): The U.S. Bureau of Ocean Energy Management has announced plans for central and eastern Gulf of Mexico (GoM) lease sales in New Orleans on March 23, 2016. Central GoM Sale 241 will include more than 7,900 blocks covering more than 42 million acres from 5 km to 400 km offshore in water depths of 3 m to 3,400 m. Eastern GoM Sale 226 will offer about 175 blocks covering more than 595,000 acres at least 200 km offshore in water depths of 810 m to 3,113 m. The agency estimates Sale 241 could lead to output of 460 MMbbl to 894 MMbbl of oil and 54 Bcm to 110 Bcm of gas, and Sale 226 could result in production of 71 MMbbl and 4.8 Bcm.

Electromagnetic Geoservices (EMGS) is due to kick off a 3-D electromagnetic (EM) survey for Pemex offshore Mexico with the *BOA Galatea* vessel. The survey is expected to take a month to complete. EMGS said it is prioritising the acquisition of EM data for the future bid rounds in Mexico and is actively seeking funding of its projects.

Erin Energy said it has successfully completed an acquisition of a new 3-D seismic survey off the coast of The Gambia.

Polarcus was contracted by the company to carry out the survey using the *Polarcus Alima*, an ultramodern 12-streamer 3-D/4-D seismic vessel. The survey covered about 1,613 sq km on Erin Energy's A2 and A5 blocks. Results of the survey are expected to be available during second-quarter 2016.

VESSEL BRIEFS

Seadrill is exploring new options to fulfil a five-year drilling contract with Husky Oil for operations in Canada and Greenland, after it cancelled a contract with Hyundai Heavy Industries (HHI) for the building of the *West Mira*, a sixth-generation ultradeepwater harsh environment semisubmersible rig.

Seadrill has told HHI that it has exercised its right to cancel the contract for the construction of the semisubmersible, which was due for delivery by year-end 2014.

Seadrill said, "Due to the shipyard's inability to deliver the unit within the time frame required under the contract, the company has exercised its cancellation rights.

"Under the contract terms, Seadrill has the ability to recoup the $168 million in predelivery instalments to the shipyard, plus accrued interest."

Aberdeen Harbour has welcomed its largest vessel to date with the arrival of the *Lewek Express* pipelay construction vessel. At 162 m long, it has two reels capable of holding up to 3,000 mt of pipe up to 14-in. in diameter. The *Lewek Express* is carrying out work for Apache on the **Aviat** (*32/7*) Field development.

TECHNOLOGY

Composite Pipe Battle Heats Up

The race to prove the worth of thermoplastic composite pipe for subsea operations is heating up.

Magma Global has just signed a joint development agreement with BP and Subsea 7 in a project to qualify its carbon fibre m-pipe as part of the next generation of subsea pipelines.

Rival Airborne Oil & Gas's thermoplastic composite pipe flowline has been undergoing qualification offshore Malaysia for the past three years and is due to be used in a pilot project there next year.

The 550-m, 6-in. flowline is to be installed in 30 m of water and will connect two platforms located on the **West Lutong** (*SEN 32/11*) Field.

The oil and gas industry has widely adopted the use of composites in a variety of applications over the past 20 years, including onshore production piping, fire water pipe and repair, and protection of structures.

The increasing demands on materials to meet future technical requirements for risers, intervention lines, spools and components such as stress joints has led the industry to take a closer look at composites for these more demanding subsea applications.

The Magma qualification programme, which runs for 30 months, targets 6-in. to 12-in. pipes for risers and jumper systems for deepwater environments and includes laminate testing, single load tests (tensile, burst, collapse, bending, torsion, compression, impact) and combined load tests (axial bending, collapse bending, pressure bending and axial pressure bending).

The programme also is supported by the National Composites Centre and Innovate U.K, the government initiative established to support pioneering technologies in the energy sector.

Magma's m-pipe is a high strength, lightweight, corrosion-resistant, fully bonded, composite thermoplastic pipe, which is stronger than steel and traditional flexibles, and is typically one-tenth the weight.

Magma said, "The high specific strength and corrosion resistant nature of composite technology makes it ideal for the oil and gas industry where deepwater environments and corrosive fluids challenge the integrity of steel structures.

"Manufactured from highest quality carbon fibre and PEEK polymer materials, m-pipe is immune to corrosion and is suitable for a wide spectrum of fluids and gases."

The hope is that the results will lead to lighter and more cost-efficient riser systems than currently exist to help reduce the costs of deepwater field developments, and in particular those with corrosive fluids.

Similarly, jumpers or spool pipes which are subject to exceptional cyclical loads will be easier and less expensive to design and install, and will be more reliable to service.

In addition, the qualification programme will deliver the necessary inspection techniques to verify the long-term integrity of the systems.

Magma Global is based in Portsmouth, U.K., and is currently expanding its capacity to meet growing demand for risers, jumpers and intervention lines.

New JIPs launched

Meanwhile, DNV GL also is launching two joint-industry projects (JIP) to investigate affordable composite components for the subsea sector and qualify technology for more efficient linepipe production processes. It is estimated that the JIPs could deliver a combined saving of £6.75 million (US$ 10.4 million).

The DNV GL Affordable Composites for the oil and gas industry JIP aims to reduce the cost of qualifying composite components for subsea use by replacing large-scale tests with "certification by simulation."

Statoil, Petrobras, Petronas, Nexans, Airborne and the Norwegian University of Science and Technology in Trondheim, Norway, are participating in the project. The project is partly funded by the Research Council of Norway.

The project, which could potentially deliver a 40% to 50% cost saving for certification and qualification of subsea composite components, will seek to validate new advanced material models by experimentation, with the main focus on predicting chemical ageing.

"Composite components require full-scale testing to document long-term properties to achieve certification," said Jan Weitzenböck, principal engineer, DNV GL—Oil & Gas. "A typical qualification campaign for a subsea composite component can cost in the region of 10 million NOK to 100 million NOK (US$ 1 to 12 million). The results of this JIP could potentially save up to 16 million NOK (US$ 1.9 million) for recertificaiton of existing components."

Smørbukk South Delivers with 'Fishbones'

Statoil has begun production from its **Smørbukk South Extension** (*SEN, 32/11*) off Norway using "fishbone" drilling technology on the Norwegian Continental Shelf for the first time.

The technology involves drilling 150 "fishbones," where each "bone" is 10 m to 12 m long, into the reservoir from the main well.

The multilateral well that has been drilled by *Deepsea Bergen* was delivered well below estimated time and cost. Pending production experience, a gas-injection well will be drilled to further increase the recovery from Smørbukk South Extention.

"This is an important step forward in testing and implementing a technology that enables increased oil recovery from reservoirs where the method of fracking is not feasible. The experience gained with long reservoir sections and "fishbones" opens up for several new projects both at the Åsgard (*32/11*) Field and elsewhere on the NCS," said Åsgard Petech Manager Mari Skaug.

The fast-track development of the Smørbukk South Extension project includes, in addition to the wells, a new subsea template connected to existing infrastructure at the Åsgard Field and a new umbilical to Åsgard A.

Larger parts of the subsea structures were installed at the field during summer 2014, with the remaining scope and hookup to Åsgard carried out this summer.

Smørbukk South Extension holds estimated reserves of 16.5 MMboe and will contribute significantly to the production from the Åsgard A FPSO unit in the times ahead.

"This has been a world-class challenge. Very few offshore fields have been developed with such low permeability under normal pressure conditions," said Asset Owner Representative Ove Andre Pettersen. "The main solution for cracking the code with such tight reservoirs is to drill long horizontal reservoir sections. At Smørbukk South Extention, a multilateral production well with approximately 5,200-meter reservoir exposure has been drilled."

TECHNOLOGY BRIEFS

Red Marine is further expanding its subsea testing capabilities with the development of a new high-capacity test rig.

The 200-mt capacity cable and umbilical test rig, the CTR 200, is currently under construction and will enable testing of subsea power cables and umbilicals prior to installation offshore.

The CTR 200 can be configured in a number of ways to allow the accurate assessment of cable strength, torque balance, stiffness and fatigue properties.

These features combined with an internal bed length of 11 m will allow testing of samples up to 7 m in length (including pull heads) with a maximum axial load of 200 mt.

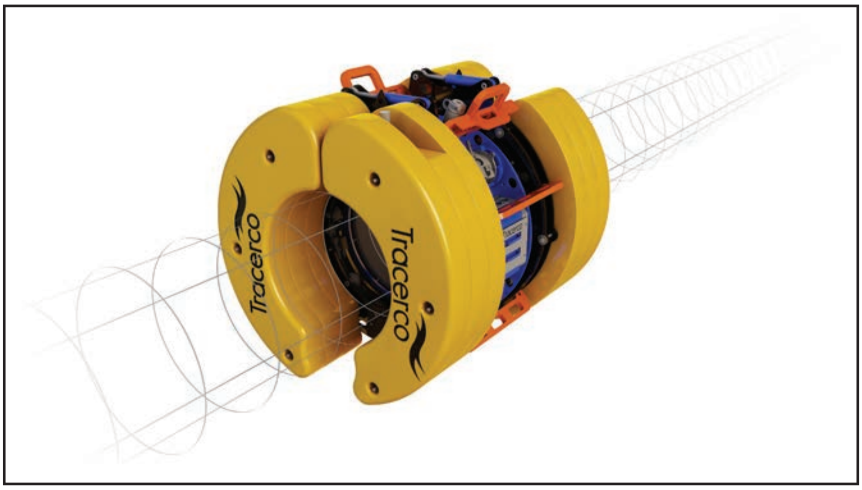
Longer samples also can be tested as the rig design allows the pull heads to be held outside the test frame if required.

Together with Red Marine's existing thermal chamber and friction test rigs, the new rig will allow the provision of a full range of cable qualification tests against industry standards or client specific requirements, the company said.

Dr. Simon Bittlestone, vice president of research at Schlumberger, focused on a number of technology innovations at the 2015 SPE Offshore Europe Conference, including advances in steerable marine seismic acquisition streamers. The so-called "steerable birds" are used by Schlumberger on streamers of up to 10 km in length, with a "bird" positioned every few hundred metres. With adjustable wings, the inline "birds" enable both vertical and horizontal steerability by rotating the streamer cable and enabling accurate placement.

Tracerco will have five of its deepwater computed tomography pipeline scanners available for use by the end of September.

The technology can be used to scan through coated pipelines without removing the coating. It has been used in the U.S. Gulf of Mexico and in the North Sea.



Tracerco's scanners were on show at OE 2015.

Tracerco Managing Director Andy Hurst said, "Undoubtedly, there are strong headwinds in subsea inspection as there are in any part of the industry, but we are seeing very strong interest for life-extension verification and flow assurance is strong too.

POLICY

Nigeria to Revisit Offshore PSCs

In a move that will set the alarm bells ringing for international oil companies working offshore Nigeria, the country's National Petroleum Corp. (NNPC) said it is to review deep offshore oil production agreements.

The NNPC said it is set to revisit the fiscal terms of the existing production sharing contracts (PSC) entered into by the corporation with some international oil and gas companies "with a view to seek favourable benefits to Nigeria based on prevailing realities in the industry."

Speaking at the France-Nigeria Business Forum organised to mark the state visit of President Muhammadu Buhari to Paris, Dr. Ibe Kachikwu, group managing director of the NNPC, disclosed that in the weeks and months ahead, the corporation will be renegotiating the contracts to extract as much benefit as possible for Nigeria.

Dr. Kachikwu noted that though the PSC agreements are firm contracts that should be adhered to, the NNPC is allowed to renegotiate in some circumstances.

"We intend to begin the process of the renegotiation of the PSCs to see what value chain and improvements we can have from these contracts. Some of the contracts were negotiated over 20 years ago, and they have since been overtaken by new realities in the industry," he said.

He noted, however, that in carrying out a review of the existing PSCs, care must be taken not to create an anti-investment atmosphere as that might be counter-productive to the industry.

On the ongoing reforms of the Nigerian oil and gas industry Dr Kachikwu said, "There is a lot of interest in our quest to seek joint ventures across the value chain; there are huge potentials across board and all we need to do is to galvanize the efforts to get the best out of it."

Decommissioning to Take Centre Stage on UKCS

The Brent Delta platform is due to be decommissioned.

Decommissioning activity and spend are forecast to ramp up over the next five years in the U.K. North Sea as mature fields are no longer economically viable in a low oil price environment.

A report prepared by analyst Wood Mackenzie for Offshore Europe 2015 suggests 140 fields could cease operations over the next five years.

A high oil price has enabled operators to extend field life and delay decommissioning time and time again on the U.K. Continental Shelf (UKCS). However, the current low oil price has brought into stark relief that this cannot continue indefinitely, the report said.

Wood Mackenzie forecasts that about 140 UKCS fields will cease over the next five years even if oil prices return to $85/bbl.

Fiona Legate, U.K. upstream research analyst for Wood Mackenzie, said, "We may see around 50 fields ceasing even earlier than expected if the oil price returns to a level around $70/bbl. This is compared with 38 new fields that are expected to be brought onstream in the same time.

"Seventeen fields are expected to be sanctioned over the next five years. In the current price environment there is a risk projects may be cancelled or delayed. We could start to see a shift away from work in new developments to decommissioning projects."

And with a shift in activity, so too would be a corresponding shift in spend. "We expect around £54 billion [US$ 84 billion] (in nominal terms) will be spent on decommissioning on the UKCS and anticipate it to be completed in the early 2060s. Decommissioning spend is expected to increase by over 50% by 2019 and will overtake development spend in the same year," the analyst said.

There have been announcements of five fields to be retired early this year, none of which have come as a surprise.

The fields most likely to be decommissioned are uneconomic without high oil prices to justify escalating maintenance costs and declining production, which are unable to support the high operating costs. Some 30 fields have been abandoned in the UKCS to date.

Legate added, "The costs assumptions for decommissioning projects are higher than estimates from 10 years ago as there is more knowledge of what is involved, through regular decommissioning reviews, benchmarking against previous projects and more accurate estimates as the industry seeks costs savings across the board. Stricter plugging-and-abandonment rules also have driven up well abandonment costs."

Wood Mackenzie concludes its analysis by offering one possible solution to managing costs.

"Batch decommissioning involves a group of fields being abandoned together. These are selected by geographical proximity, operator or play. Our analysis takes a group of geographically close fields in three sectors (the central North Sea, northern North Sea and southern gas basin) and applies reductions to get an indicative view of the benefits of batch decommissioning.

"By our estimations, this could yield an average cost reduction of around 20% for small batches in the three sectors," Legate added.

BUSINESS

Proserv Dives in for Nautronix

Takeover mania continues with Proserv Group acquiring subsea digital acoustic communication and positioning specialist **Nautronix**.

The company is internationally recognised for its through-water digital acoustic wireless communications and positioning systems, diver communications and vessel systems whilst also providing survey services.

Proserv said the deal, which includes Nautronix COO Mark Patterson joining Proserv, heightens Proserv's position as a leading player in the controls and communications market.

Mark Patterson, CEO of Nautronix, said, "It was important for us to find the right company to partner with and we are delighted that it's Proserv. Strategically, this is a fantastic opportunity for Nautronix as we can leverage from the increased exposure globally.

"That, combined with our considerable experience in the drilling, subsea and survey market, presents us with considerable opportunities going forward. We relish joining David and the Proserv team in building what we feel will be a compelling service offering, particularly with the significant cost savings and life-of-field benefits our products and services can bring within an increasingly challenging market."

Employing 120 people, Nautronix is headquartered in Aberdeen where the main R&D and manufacturing facilities are located.

Proserv is a portfolio company of Riverstone Holdings, an energy-focused private-equity firm based in New York.

David Lamont, Proserv's CEO, said, "I am thrilled to welcome the Nautronix team to Proserv. We have been working together on bringing the two companies together for over a year, and while times in our industry are challenging, the rationale and benefits to all stakeholders including employees, shareholders and our clients remain as strong, if not stronger than ever."

Ceona Slides into Administration

The Ceona Amazon has been put up for sale.

Heavy subsea engineering contractor **Ceona** has gone into administration and ceased trading with the loss of more than 100 jobs.

The company provides engineering and project management services for complex subsea construction and pipelaying projects, utilising a fleet of ships.

Administrators EY said 35 jobs have gone in Hammersmith, 15 in Houston, 15 in Aberdeen and 37 offshore. Some 18 employees have been retained to assist the joint administrators whilst they seek to realise value in the assets of the group.

The joint administrators now intend to take steps to market for sale of the assets of the group, including the *Ceona Amazon*.

Alan Bloom, joint administrator of the U.K. group companies, commented, "In the period leading up to the administration, the group's cash flows came under significant strain due to falling demand for the group's services as a result of the depressed market conditions and ongoing investment in the group's fleet.

"Despite attempts to restructure the group, it was unable to achieve a turnaround on a solvent basis and the group was therefore placed into administration by the directors."

Neil Gordon, CEO of Subsea UK said, "With its fresh approach to subsea vessels and construction, Ceona is a good example of a young, dynamic company aiming to do things differently. Today's announcement highlights the tragic consequence of major project cancellations and postponements and lack of new projects coming onstream.

"Despite our rapid growth over the last few years and our world-leading position, the subsea sector is not immune to the impact of the low oil price, particularly those with costly assets such as vessels. As an industry, we must be doing more and doing it faster to adjust to current conditions. Subsea UK, along with other industry bodies, is focused on driving real changes in behaviour that will result in the necessary actions that deliver true collaboration, genuine efficiencies and a resetting of the cost base that is not simply about cutting margins."

BUSINESS BRIEFS

DeepOcean has been awarded a three-year plus options call-off contract for provision of ROV-based survey services by Shell in the U.K. North Sea.

"By pushing survey speeds far beyond today's standards for acoustic and visual data capture and processing, we expect Shell and our other clients to see a direct effect on their overall survey cost in years to come" said Ottar Maeland, DeepOcean's executive vice president for the Greater North Sea.

The **National Subsea Research Initiative** is hosting an event in Aberdeen on Sept. 23 to help connect U.K. subsea technology developers with end users and funding sources in a bid to get new subsea technology off the ground.

Aimed at supporting and encouraging investment in emerging technologies that will make a significant contribution to the continued prosperity of the U.K. Continental Shelf and the country's subsea industry, the event will bring developers and the wider industry together to help break down the barriers in commercialising new technology.

Aker Solutions has appointed **José Formigli** to its innovation board and to serve as an adviser for overall strategic decisions.

Formigli, a Rio de Janeiro native and engineer by training, has more than 30 years' experience in the oil and gas business, starting at Petrobras in 1983. In 2012, he assumed the position as director of exploration and production before stepping down earlier this year during the ongoing "Car Wash" scandal.

He has broad experience in well construction, subsea and topsides engineering as well as planning, designing, implementing and operating production systems in shallow, deep and ultra-deep waters.

Norway's **North Energy** is making further cost cuts as it bids to ride out the current oil price crisis.

North will close down its Tromsø and Stavanger offices and concentrate all activities in Oslo.

Acting CEO Knut Sæberg said, "That means further redundancies. The approved cost cuts will have consequences for a number of employees."

In parallel with the programme of cost savings, North Energy is continuing its process of assessing different strategic directions for the company.

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