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EnQuest plans new Thistle pipeline

From Aberdeen: EnQuest has revealed plans to build a new pipeline from its northern North Sea **Thistle** (SEN, 32/03) Field to **Cormorant Alpha**, because of the decommissioning of the **Dunlin** (31/03) Field infrastructure.

The current 16-in. Thistle oil export pipeline route runs 30 km to Dunlin before heading on to Cormorant Alpha and the Sullom Voe terminal, but Fairfield Energy's decision to shut-down Dunlin has left EnQuest with a bit of a headache.

John Cowie, in charge of the northern North Sea area for EnQuest told delegates at the Share Fair in Aberdeen this week, "One unforeseen blow has been that Dunlin is going to be decommissioned. "We are looking at a pipeline project to bypass Dunlin. We're in the select phase at the moment and will take that through to sanction next year."

Cowie told *SEN* that a number of options are still being considered. "At some point in the decommissioning programme that export route will become unavailable to us and we will have to do something to find an alternative.

"The most likely thing is we will bypass Dunlin with a subsea pipeline. One option might be to build a new drag pipeline all the way down to Cormorant Alpha from Thistle. We could go direct all the way with a new pipeline or we could build a bypass around Dunlin which would be shorter.

"We have got an option to tanker offload as well but I think that is fairly unlikely."

He said the existing export route should still be in place for the next couple of years, however.

The planned pipeline highlights EnQuest's desire to continue to invest in its North Sea assets.

The company, which is the largest independent oil producer in the North Sea and has just started up production on the **Alma/Galia** field (*see separate story*), bills itself as one of the new breed of operators in the region who have come in and made the most of ageing assets.

It initially took over the three producing hubs at Thistle, **Don** and the **Heather** and **Broom** fields before taking on operatorship of the **Greater Kittiwake** area.

EnQuest will pump around 35 Mboe/d this year and has production efficiency running at 90%, according to Cowie.

"From a place where those field were becoming unsustainable we have come in to invest. It's about getting the assets in the right hands.

"We have doubled production on Heather from 4 Mb/d but with well-placed wells you can make massive changes. Kittiwake production is also up to 8 Mb/d.

"In the northern North Sea we're the only people drilling. People are decommissioning and abandoning but we're the only ones making investments in the northern North Sea and we're doing that very successfully.

"We're a lot more streamlined and agile than a supermajor. Everybody wants to know how we do it."

EnQuest will spend US$600 million in Capex this year, reflecting its ongoing investment at Alma and Kraken.

Plans are also being finalised for the next step in the Kittiwake project with tiebacks planned from the nearby **Scolty** and **Crathes** fields.

The company's Quad 9 **Kraken** FPSO project is also on track, on budget and on-schedule for first oil in 2017, Cowie said.

Cowie added, "We have got the Transocean Leader drilling up on Kraken. An appraisal well has been drilled and now we are batch drilling. We are six months into the programme and already a month ahead of schedule."

He stressed that EnQuest is a producer and not an explorer. He said, "We're not an explorer we're a production company and we're trying to brick by brick build a low risk production portfolio in the North Sea and in other low risk basins across the world."

WHAT'S INSIDE

SHARE FAIR

Cost Reduction is Key, Share Fair told

The Glen Lyon FPSO has begun sea trials off Korea.

From Aberdeen: Cost reduction is still at the top of everyone's agenda as the oil price downturn continues to bite, but there are opportunities out there, delegates at the Share Fair here heard.

Kevin Ferrol, head of contracts for Total E&P, said that its operating costs have been increasing 14% year on year, while production has been declining from its mature assets.

"We can't continue like that," he said. "The key message is we need to focus on cost control."

But he did hold out a ray of hope for contractors. "We're really interested in hearing from suppliers who can help us improve our asset integrity and help manage that. We are also interested in suppliers who can help us with the cost of well construction.

"Also small pool development. With our hub strategy we have a number of small fields that can be potentially tied back to our hubs and we're looking at how we can do that cost effectively and how we can release the value from stranded assets."

Ferrol said that Total's current emphasis is on the delayed deepwater Laggan-Tormore subsea-to-shore project and getting that production onstream. "The real opportunity there is the long term support of the offshore assets and the onshore gas plant. In parallel we have the Edradour and Glenlivet project ongoing which is a subsea tieback to the Laggan-Tormore hub. All contracts been placed but there could be opportunities with our key supply chain partners."

Total is also mulling development for its **Tobermory** discovery, a potential 175 km long distance subsea tieback to Laggan-Tormore.

"It is a challenging project and in particular how do we make it economical? It is currently in the conceptual stage but there is still a lot of work to be done on that front."

He said that in the Central Graben area of the UKCS Total has undertaken a substantial campaign of redevelopment which should significantly extend field life.

The company will be operating four jack-ups in the area in 2016 which should produce opportunities in terms of well services.

BP, meanwhile, was keen to stress that it was in the North Sea for the long haul. It expects to produce 160 to 170 Mb/d this year and output will increase with some major projects coming onstream.

Andy Leadbetter, North Sea regional director for BP, said the increase in production is being driven largely by two major projects, Clair Ridge Phase 2 and Quad 204.

Leadbetter said Quad 204 was progressing well and the *Glen Lyon* FPSO vessel, which will be replacing the *Schiehallion* FPSO, is in Korea at the moment and will undergo sea trials in the next couple of weeks. In March or April next year it will go across to Norway for commissioning prior to start up towards the end of 2016.

Phil Webb, BP's well integrity team leader, said that out of the 299 wells BP operates in the UK sector 180 are subsea. "They all need routine maintenance and intervention. I have been working in the industry and I'm looking at the same thing I saw 33 years ago. We really have gone nowhere," he said.

He said he was "desperate" for someone to come up with a paint for 117 trees which could be treated without shot blasting and a loss of production.

He also questioned why all operators had their own well kill packages. Webb said if the industry was "wise, money could be saved with a single industry-wide shared capping stack."

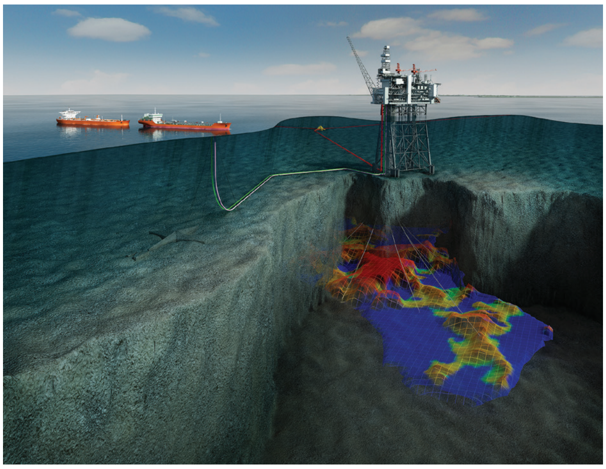
Over-engineering is another problem and Webb wanted to know why it was necessary to have a 13,500 psi rated wellhead for a 400 psi well.

Lauren McGregor, Talisman Sinopec's functional excellence coordinator, echoed this sentiment.

"In 2013 we might have been asking for the gold plated standard, whereas in 2017 and beyond we might be asking for the bronze plated standard. We are changing our model."

DEVELOPMENT

Statoil Sees Delays, Cost Overruns



Production from Mariner has been delayed until 2018.

Statoil has flagged up delays in production startup at its **Aasta Hansteen** (*SEN, 31/18*) Field off Norway and the U.K. North Sea **Mariner** (*32/12*) Field from 2017 to second-half 2018.

Announcing the company's third-quarter results, Statoil's President and CEO Eldar Sætre said that while cost estimates for the development of the **Johan Sverdrup** (*32/15*) project had come down by 7%, costs for Mariner and Aasta Hansteen had spiked.

"However, Statoil and its partners have decided to accept a delayed timetable for the commencement of production from the Aasta Hansteen and Mariner fields from 2017 to the second half of 2018. The updated cost estimate for Aasta Hansteen has been increased by around 9% since the plan for development and operation (PDO)," he added.

"In addition, a currency effect of NOK 2.4 billion [US$280 million] brings the total cost estimate to around NOK 37 billion [US$4.3 billion]. For Mariner, the cost increase is slightly above 10% as compared to the original plan."

Meanwhile, Statoil said adjusted earnings were US$1.9 billion in the third quarter compared to US$3.6 billion in the same period in 2014 on the back of lower oil prices.

Adjusted earnings after tax were US$432 million, compared to US$1 billion in the same period last year.

Statoil's net operating income according to International Financial Reporting Standards for the quarter was US$852 million, compared to US$1.9 billion in the same period in 2014.

Statoil delivered production of 1,909 MMboe/d in the third quarter, up 4% compared to the same period in 2014. The underlying production growth, after adjusting for divestments, was 7% compared to third-quarter 2014.

The production from the Norwegian Continental Shelf grew 10% in third-quarter 2015 compared to 2014.

Equity production outside of Norway was 735 MMboe/d, up 4% compared to the same period last year, adjusted for divestments.

Chevron's Lianzi Sets New DEH Record

Chevron's recently started **Lianzi** (*SEN, 31/23*) oil and gas field off the west coast of Africa has employed a direct electrically heated (DEH) flowline system at a new record water depth.

Lianzi, in 900 m water depth, is located in a unitised offshore zone between the Republic of Congo and the Republic of Angola.

It is Chevron's first operated asset in the Republic of Congo and the first cross-border oil development project offshore Central Africa. The project is expected to produce an average of 40,000 bbl/d of oil.

The field, discovered in 2004, includes a subsea production system and a 43-km DEH flowline system, the first of its kind at this water depth.

The system transports the oil from the field to the Benguela Belize-Lobito Tomboco (BBLT) platform in Angola's Block 14 and utilises the DEH system to ensure fluid flow under a wide range of conditions.

Nexans supplied the DEH system under a $25 million subcontract with Subsea 7.

The design of the system was developed and qualified for Chevron over a three-year period before inauguration of the project.

The complete DEH system includes a DEH riser cable, an armoured feeder cable, a 43-km long piggyback cable and all associated accessories for connection to the flowline that will connect the Lianzi subsea facilities with the BBLT platform.

The DEH system is designed for both wax and hydrate management.

Nexans has delivered the DEH system at nine out of 10 fields using this technology.

The longest flowline with DEH technology currently in operation is at Statoil's **Tyrihans** Field.

"As the first offshore energy development spanning national boundaries in the Central Africa region, Lianzi represents a unique cooperative approach to share offshore resources and may serve as a model for the development of similar cross-border fields between two countries," said Ali Moshiri, president of Chevron Africa and Latin America Exploration and Production Co.

Chevron is operator of the Lianzi Field and has a 15.75% interest, along with its affiliate Cabinda Gulf Oil Co. Ltd. (15.5%), Total E&P Congo (26.75%), Angola Block 14 BV (10%), Eni (10%), Sonangol (10%), SNPC (7.5%) and GALP (4.5%).

DEVELOPMENT BRIEFS

Big Bend is tied back to Thunder Hawk.

The **Big Bend** (*32/14*) oil development in the deepwater Gulf of Mexico (GoM) began production on Oct. 26, Noble Energy said.

The single-well field is ramping up as expected and will likely produce about 20 Mboe/d max over the next few weeks, the company said. About 90% of the volumes being produced are oil.

The Dantzler development is being accelerated, and first production from it is now expected by early November, the company added.

Big Bend and Dantzler, located in Mississippi Canyon 698 and 782, respectively, are subsea tiebacks to the third-party **Thunder Hawk** production facility. Combined, the fields are thought to contribute 20 Mboe/d max net, to Noble's production rate.

Inpex has completed the offshore pipelay for its 890-km, 42-in. diameter gas export pipeline for the **Ichthys** (*32/15*) LNG project. Work began in June 2014.

The company said the export pipeline is the longest subsea pipeline in the southern hemisphere and the third longest subsea pipeline in the world. The gas export pipeline will deliver gas from the Ichthys gas-condensate field to the onshore facilities at Bladin Point near Darwin for processing.

"Completion of the offshore pipelay marks a significant milestone for the project," Managing Director of the Ichthys Project Louis Bon said. "It means we are one step closer to physically connecting our onshore plant near Darwin to the Ichthys Field where our offshore facilities will be permanently moored for the 40-year life of the project."

The pipeline was installed by Saipem's *Semac* and *Castorone* barges from Darwin to the Ichthys Field.

Inpex will conduct other necessary work on the pipeline in preparation for operational startup.

From Houston (BN): Shell development around its **Perdido** (*32/14*) hub continues. Shell has won approval of its plan to drill two 150-day to 200-day subsea wells and install trees, jumpers and umbilicals at **Silvertip** (*32/15*).

The project is in Alaminos Canyon blocks 815 and 859, in 2,850 m water depth about 240 km east of Brownsville, Texas.

Statoil isn't letting Shell keep **Power Nap** to itself. Regulators have approved a project that one Statoil filing dubs Power Nap 2.

The Norwegian company plans two sidetracks from a well in Mississippi Canyon 942 to bottomholes just southwest of Shell's late 2014 Power Nap discovery in MC 943.

Statoil's 53-day sidetracks, in 1,280 m water depth about 240 km south-southeast of New Orleans, will curve into MC 986 and MC 987.

Statoil's filing said it is targeting 27°API oil, similar in gravity to the 28°API oil Shell's Power Nap listed in its filing.

Statoil is 100% owner of its blocks. Shell and Freeport McMoRan are 50:50 partners in MC 943, with Shell operating.

The area is crowded with activity. Power Nap is bracketed by the Shell-operated **Vito** (*32/01*) discovery, just to the southwest in MC 984, and Shell's producing **Crosby** Field, just to the northeast in MC 899. Statoil is not alone even in MC 942. Bennu Oil & Gas has operating rights in the block down to 5,486 m to run its **Morgus** Field.

Bennu's **Titan** hub is in MC 941 and serves Morgus, **Mirage** in MC 940 and **Telemark** in nearby Atwater Valley 63. It's no wonder elbows are flying.

BP has agreed to speed up development of the recent **Atoll** (*32/01*) gas discovery in the North Damietta Offshore Concession in the East Nile Delta, offshore Egypt.

The agreement is expected to enable first production to be expedited from an estimated 42 Bcm of gas resources and 31 MMbbl of condensate in the Atoll Field to the domestic market, with production anticipated to begin in 2018.

Full field development of Atoll is expected to consist of two phases. Phase 1 will consist of two development wells tied back to existing infrastructure, with production expected to start up in 2018. Success of Phase 1 is expected to trigger additional investment and further wells to increase production.

Development of Atoll will be executed and operated by Pharaonic Petroleum Co., BP's joint venture with EGAS and Eni.

BP Group CEO Bob Dudley said, "We are pleased to be making rapid progress towards the development of Atoll less than eight months after the announcement of its discovery. This is further demonstration of our continued confidence in Egypt—a key growth area for BP—and our commitment to continue to invest to unlock its energy potential."

From Houston (BN): The government of Newfoundland and Labrador has announced plans for a generic oil royalty regime for offshore projects.

Assuming final approval in early 2016, it will replace the old system of negotiating royalties project by project.

The new system comes as Statoil considers development of its deepwater Bay du Nord discovery, and reports indicate the system was influenced by Norway's royalty regime.

Under the new Newfoundland-Labrador system, developed after a study of systems worldwide with the help of Wood Mackenzie, the basic royalty at the start of a project's production will be 1% rising to 7.5% of gross revenue as project costs are recovered.

Once project costs are recovered, rates will climb from 10% to 50% of net revenue as profitability improves. The highest rates will apply to projects that have returned $3 for every $1 spent on development.

Pemex recorded its 12th quarterly loss in a row, almost $10 billion for the third quarter, nearly triple last year's third-quarter loss. Most of the blame went to declining world oil prices. The average price of Mexican crude exports was $41.75 per barrel during the quarter, half the $92 recorded in third-quarter 2014.

From Houston (BN): Just weeks after Petrobras touted record daily presalt production, the company faces a strike that is cutting output.

It reported a record 1.12 MMboe/d of presalt production on Sept. 15, as presalt accounts for a growing share of 2.5 MMboe/d in total output.

But on the first day of the strike, Petrobras said total output fell sharply—273 Mbbl/d for oil (13% of output) and 7.2 MMcm/d for gas (14% of output).

Petrobras said it is taking measures to maintain operations, preserve installations and protect workers, but it expects declines in production to persist pending a settlement and return to normal operations. The oil workers union, FUP, said Petrobras is understating the strike's impact. Workers are striking to protest against sales of assets, and the company is planning to reduce its huge debt load.

The workers complain the asset sales will lead to job cuts.

Meanwhile, adding to the turmoil that has plagued Petrobras as a result of the Carwash bribery-kickback scandal and falling oil prices, Petrobras' acting chairman, Clovis Torres Jr., resigned for what were described as personal reasons.

The unmanned Cavendish platform in the UK North Sea.

The Norwegian Petroleum Directorate (NPD) is pressing for unmanned wellhead platforms to be considered more often as an alternative to subsea tiebacks in connection with development decisions.

The NPD said a new study will look into the benefits and disadvantages of wellhead platforms, which have been dubbed "subsea on a stick."

The study into the different types of unmanned wellhead platforms will be carried out by Rambøll Oil & Gas and will be submitted to the authorities towards the end of December.

"The main argument in favour of unmanned wellhead platforms as a concept is that this could be an efficient development solution in terms of both cost and production. In fact, it is just as functional and robust as a subsea development, and it is also more accessible for inspection and maintenance," said Niels Erik Hald, principal engineer in the NPD.

Poland's Lotos has snapped up a 15% stake in the **Sleipner East** (*31/16*), **Sleipner West** and **Gungne oraz Loke** oil and gas fields on the Norwegian Continental Shelf.

Lotos also has taken a 28% stake in the **Alfa Central** deposit, currently under development and expected to begin production in 2020.

The deal is worth an estimated $160 million, with an additional payment of $25 million for Alfa Central pending the Norwegian regulator's approval of the field's development plan.

Alfa Central is a 60-MMboe gas and condensate field, which is planned to be developed as a tieback to the existing infrastructure for **Sleipner**.

From Australia (LB): Malaysian firm Sona Petroleum has struck a deal to buy the **Stag** oil field off Western Australia from Santos and Quadrant Energy for $50 million.

Under the proposed acquisition, Sona will acquire a 100% stake in production licence WA-15-L and pipeline licence WA-6-PL in the Stag oil field.

Sona Petroleum said it intended to undertake further development of the oil field to enhance production, which will involve drilling of infill production wells.

"The Stag oil field has potential development and exploration opportunities and therefore, in a single transaction, Sona Petroleum will be able to enter the production, development and exploration stages of the upstream value chain," Sona Petroleum said.

The Quadrant-operated Stag oil field, which has been in production since 1998, is located in the Dampier sub-basin of the Carnarvon Basin in water depth of about 50 m.

FLOATERS

Alpha Firms up Cheviot Plans

Alpha Petroleum Resources has firmed up plans to tap the U.K. North Sea **Cheviot** Field with an FPSO vessel tied into 21 development wells.

A field development plan has been submitted to the Oil and Gas Authority.

Alpha, which acquired the licences for blocks 2/10b, 3/11b and 2/15a through a transfer from ATP Oil & Gas in 2014, said it had looked at more than 50 development scenarios for the field.

The blocks are located in the northern North Sea and contain the Cheviot oil and gas reservoir (previously developed as the **Emerald** Field between 1989 and 1993), along with two satellite reservoirs, the Peel oil reservoir and Padon gas reservoir.

The development will require the drilling of 26 wells; 20 oil production wells targeting the Cheviot reservoir, one production well targeting the Peel reservoir, three wells into which produced water will be reinjected and two wells into which gas will be reinjected.

The wells will be drilled from three clusters or drill centres from an anchored semisubmersible mobile offshore drilling unit and will be tied back via manifolds at the drill centres to the Cheviot FPSO vessel through production pipelines.

Each of the development wells will have a separate subsea production christmas tree installed on top of its wellhead. Additional pipelines and umbilicals from the FPSO vessel to the drill centres will provide gas, water and chemical injection in addition to well control.

Oil will be processed on the FPSO vessel and stored in the hull prior to being offloaded to an export tanker.

The Cheviot reservoir is considered to have a moderate to high potential for producing sour gas during field life. This will be sweetened and compressed for injection and use as gas lift.

High levels of produced water are anticipated. This will be treated and then reinjected into the reservoir and will aid in the recovery of hydrocarbons.

Maximum oil production is predicted to peak at about 35 Mbbl/d during the first year of field life. Once oil production becomes uneconomic, consideration will be given to depletion of the gas caps and export of the gas.

Alpha said in an environmental statement for the project that the potential for the development of the second satellite reservoir, the **Padon** gas reservoir, will be considered at this time.

Alpha said it intends to begin drilling activities in first-quarter 2019. The wells will be drilled in a continuous programme with drilling operations expected to be completed by second-quarter 2023.

Installation and commissioning of the infield pipelines and subsea infrastructure will be carried out from 2020 to 2023.

The heavy Cheviot oil is not suitable for export through existing offshore pipeline systems. It will be stored in the hull of the Cheviot FPSO vessel and offloaded to an export tanker.

During the year of peak production, it is estimated that there will be up to 32 round tanker trips per year to the FPSO vessel.

For the remainder of the field life, the expected number of tanker visits will decrease significantly to only two to four tankers per year in the last years of production.

Previous owner ATP had been planning to develop the field with an Octabuoy floating production system being built at the Cosco shipyard in China. The plan collapsed when ATP's U.S. parent filed for bankruptcy.

Technip Breaks New Ground with Libra

Technip is moving into uncharted territory with its deal to supply 8-in. flexible oil production pipes to Petrobras for the **Libra** presalt field off Brazil.

These will be the first 8-in. oil production pipes to be installed in the presalt area.

The project includes the supply of flexible pipes for the Libra extended well test field, located in the Santos Basin, one of the first steps of the Libra giant field development.

The contract covers the supply of high-end flexible pipes including 8-in. oil production, 6-in. service and 6-in. gas-injection flexible pipes.

Technip said the deal reinforces flexible pipes' suitability for the ultradeepwater and fluid harsh conditions of Brazilian presalt fields.

The company's operating centre in Rio de Janeiro will perform the project management and engineering.

The highly technological flexible pipes will be produced at Technip's manufacturing sites in Vitória and Açu, Brazil. Delivery is scheduled to start in second-half 2016.

Adriano Novitsky, president of Technip in Brazil, said, "Technip is very proud to have been selected to supply the first pipes for the Libra development. It is the result of strong R&D and engineering efforts to overcome the presalt technical challenges using a flexible pipes solution."

Meanwhile, Technip also has picked up more work under a frame agreement signed with Petronas last year.

It has been awarded a subsea contract by Petronas' partner JX Nippon Oil and Gas for work in the **Layang** Field in Block SK10 offshore Sarawak, Malaysia, at a water depth of 85 m.

The contract covers the engineering, procurement, fabrication, installation and commissioning of three flexible pipes totalling 9.9 km.

The flexible pipes consist of two production risers and flowlines and one gas export riser and flowline, connecting shallow-water platforms to a new FPSO vessel.

The flexible flowlines will be produced in Asiaflex Products, Technip's manufacturing facility in Tanjung Langsat, Johor, Malaysia. Installation will be done with the *Deep Orient,* and the project is scheduled to be completed in second-half 2016.

FLOATER BRIEFS

Brazil will lead global growth in the FPSO vessel industry out to 2019, despite national oil company Petrobras facing allegations of corruption, according to research and consulting firm GlobalData.

The country has spearheaded recent growth in the global FPSO industry, deploying 17 FPSOs between 2009 and 2014.

Adrian Lara, GlobalData's senior upstream analyst, said, "Petrobras' strategic plans in 2013 and 2014 had almost 40 FPSOs deployed in Brazil through 2020. Based on the company's latest plan, there are currently seven FPSOs still on time for delivery, whereas 11 have had their delivery date moved back a couple years and about 12 FPSOs are now expected after 2020."

While Petrobras is planning to spend $108.6 billion, or 83% of its total capex, on the E&P sector as part of its 2015 to 2019 business and management plan, corruption allegations have hampered its ability to execute the planned projects, including those involving FPSO units.

Lara added, "Planned projects have been affected in large part by the ongoing investigation into corruption. In particular, domestic shipyards have been hit hard.

"Sete Brasil was set to build 29 offshore rigs for Petrobras but has scaled back to 15. The uncertainty around when and how many rigs will be available will have a knock-on effect on FPSO delivery dates."

Shell has been hit with an improvement notice by the Health & Safety Executive (HSE) following a gas leak at its U.K. North Sea **Curlew** (*30/23*) Field in January 2015.

The leak occurred near Maersk Oil's *Curlew* FPSO vessel. Shell owns and operates the wells and subsea infrastructure that tie back to the *Curlew*.

HSE investigators found that in late 2014 Shell decided to use the *Pacific Dolphin s*tation keeping assist vessel, to ensure the *Curlew* FPSO would stay on location during rough weather because of concerns over the integrity of the FPSO's own mooring lines.

On Jan. 19, the line between the *Pacific Dolphin* and *Curlew* FPSO became snagged around a subsea isolation valve on the FPSO's gas export pipeline.

The gas export line ruptured and gas was released to the surface.

EnQuest has pumped first oil from the U.K. North Sea **Alma/Galia** (*32/11*) development following final commissioning of all the required systems.

The Alma/Galia fields are located in blocks 30/24c and 30/25c respectively, 310 km southeast of Aberdeen, in the Central North Sea. Production is via the *EnQuest Producer* FPSO vessel.

Alma, formerly the **Argyll** Field, was the first commercially produced oil field in the U.K. Continental Shelf and produced oil in the early 1990s at a relatively low water cut using the technology available at the time.

With current technology, field life can be extended significantly, with the *EnQuest Producer* having liquid-handling capacity of 120,000 bbl/d.

Only 30% has so far been recovered from Alma/Galia's STOIIP (stock tank oil initially in place) of 307 MMbbl.

EXPLORATION

Anchor Away for Chevron

Chevron said appraisal of its **Anchor** discovery in the Gulf of Mexico (GoM) suggests that the find is huge, "potentially hub class scale," in the words of Jay Johnson, executive vice president upstream.

The appraisal found 211 m of net oil pay in a hydrocarbon column of at least 549 m in Lower Tertiary reservoirs.

The discovery well in Green Canyon Block 807, drilled in late 2014, encountered 210 m of net oil pay en-route to 10,287 m total depth. Anchor is in about 1,400 m water depth and about 327 km south-southwest of New Orleans. Partners are Chevron (55%), Cobalt (20%), Samson (12.5%) and Venari (12.5%).

Chevron said complete appraisal of the opportunity awaits additional wells and technical studies. Executives of Cobalt said in their third-quarter earnings call that they are "very excited" because the early appraisal data suggest the Anchor structure extends southward into two blocks under Cobalt control, GC 850 (100% Cobalt) and GC 851 (70% Cobalt, 30% ConocoPhillips).

Elsewhere in the GoM, Cobalt executives in the company's earnings call focused on a solid appraisal result at **North Platte** in Garden Banks Block 959. The well found 168 m net oil pay, similar to the 2012 discovery in the inboard Lower Tertiary and had what executives described as "better developed" reservoirs.

Less than 5 km to the south, Cobalt acquired a permit to drill a prospect dubbed **South Platte** but said nothing about proceeding with the well anytime soon.

South Platte is in Garden Banks 1003 in 1,370 m water depth about 392 km south-southwest of New Orleans.

Although it is in a very promising neighbourhood, Chairman and CEO Joe Bryant said Cobalt's next exploratory well likely will be Goodfellow in Walker Ridge Block 89.

Bryant said the company is awaiting approval of its exploration plan by regulators, although there is no record in regulators' online data system of a plan even being filed yet.

Cobalt also is studying stepping outside its focus on the inboard Lower Tertiary and drilling Rocky Mountain in the Norphlet Play in Mississippi Canyon Block 693—but probably not until 2017.

Cobalt sees opportunity in other companies' pullback from the GoM.

James Farnsworth, executive vice president and chief exploration officer, didn't mention company names but told analysts, "Clearly some companies are choosing to make a decision not to compete there in the future. And I think that plays directly to our strengths. And we're taking a hard look at the opportunities there, and I think there will be some options for us."

Speaking of cutbacks, Stone has sold down its non-operating interest in LLOG-led **Crown & Anchor** in Viosca Knoll 959-60. Once 40%, Stone's holding is now 10% after sales of 15% each to ILX and Ridgewood in October.

LLOG continues to own 60% in the discovery, announced last June, of 15 m net oil in high-quality Miocene sands. The discovery well is in 1,330 m about 230 km southeast of New Orleans.

Meanwhile, Anadarko had good appraisal news about its big **Shenandoah** discovery in Walker Ridge Block 52, reporting the Shenandoah-4 sidetrack hit more than 189 m of net oil pay. The well tested the updip extent of the 2009 discovery and, in the process, extended the lowest known oil column downdip.

Anadarko said in its third-quarter update that drilling was continuing to try to find the bottom of the reservoir and obtain a full core sample.

Shenandoah is in 1,789 m about 367 km south-southwest of New Orleans. Partners are Anadarko (30%), ConocoPhillips (30%), Cobalt (20%), Marathon (10%) and Venari (10%).

Anadarko's news out of Colombia was less favourable. At Kronos-1, where drillers in July discovered up to 70 m of natural gas pay, tests of a deeper objective found non-commercial hydrocarbons. Kronos-1 is 53 km offshore in 1,584 m in the Fuerte Sur Block.

Apache Finds Life in the North Sea

Seagull is 50 miles from the Forties Field.

Apache Corp. has shown that there is life in the U.K. North Sea yet, after making significant discoveries on two exploration wells in the **Beryl** (*SEN 32/13*) area.

The **K** and **Corona** wells are the first exploratory prospects drilled by Apache in the Beryl area and each discovery proves a separate geologic concept that helps to de-risk additional drilling locations, Apache said.

Additionally, Apache said it made a large discovery at its **Seagull** prospect, which lies about 50 miles south of the company's **Forties** (*32/13*) Field.

The company said the size of the Seagull find meant that it might require standalone facilities to develop it.

"The success of our first two exploration wells at Beryl, combined with the Seagull discovery, could increase our total North Sea proved reserve base by more than 50%," said Thomas E. Voytovich, Apache's executive vice president of international, offshore and E&P technology.

Apache estimates likely net recoverable reserves could be from 50 MMboe to more than 70 MMboe.

Future appraisal drilling will enable the company to further define the upside potential beyond 70 MMboe. Apache's proved reserves in the North Sea at year-end 2014 were about 140 MMboe.

"These discoveries further reinforce our confidence that our North Sea business has the ability to sustain production volumes, extend the Forties and Beryl productive lives out beyond 2030 and consistently provide significant free cash flow back to the corporation," said John J. Christmann IV, Apache's CEO and president, in a statement.

The company also drilled two significant development wells, in the Beryl area, from which no reserves have been previously booked.

Mixed Messages on Deep Water from ConocoPhillips

From Houston (BN): ConocoPhillips (COP) plans to exit deepwater exploration by 2017.

But during COP's third-quarter earnings call, executives said the commitment to exit is, for now, confined to exploration and won't necessarily include development and production.

Meanwhile, COP remains busy in the deepwater Gulf of Mexico. It plans to spud an exploration well at Melmar (formerly Red Knot) in Alaminos Canyon Block 475 before year-end.

Plans filed with regulators called for five 168-day wells at the rate of one a year through 2020. The prospect is wholly owned by COP. The target is 40°API oil. The site is in about 1,560 m of water in the Lower Tertiary fairway about 560 km southwest of New Orleans.

COP also has received conditional approval of plans to explore its 100%-owned Taylor prospect in Keathley Canyon blocks 481, 525 and 569.

Taylor is north of Anadarko's Lucius and near pipelines carrying Lucius oil and gas towards shore. Plans filed with regulators called for seven 150-day wells in six years between January 2016 and November 2021. The target is 29°API oil. The well sites are in 1,800 m to 1,890 m of water about 430 km south-southwest of New Orleans.

Conoco also is a nonoperating partner in several projects, notably Anadarko-led **Shenandoah** (COP 30%, Anadarko 30%, Cobalt 20%, Venari 10% and Marathon 10%).

COP also is a partner in Eni's **Vernaccia** in Mississippi Canyon 34, 35 (COP 33.3%, Stone 16.7%, Eni 50%) and in Chevron's Gibson in Keathley Canyon 96 (COP 30%, BP 34%, Chevron 36%).

It will be interesting to see what effect, if any, COP's decision to exit exploration will have on its recently announced teaming up with Chevron and BP in promising northwest Keathley Canyon, a joint venture in which Chevron is operator.

In answer to analysts' questions, Matt Fox, COP's executive vice president of E&P, said, "We're willing to stay in our discoveries if that's what maximizes the value. We haven't made a commitment to exit deep water per se… but if we saw full value for those assets, then we'd certainly consider that."

The key there may be an offer for "full value"—not likely in the current oil-price environment.

Statoil Eyes Southern Africa Riches

Statoil is training its sights on eastern and southern Africa as it looks to develop its global exploration portfolio and has taken stakes in blocks off Mozambique and South Africa.

The company has together with partners submitted a winning bid on the **A5-A** Block offshore Mozambique in the fifth competitive bidding round.

The A5-A Block is located in the Northern Zambesi Basin in the Angoche area about 1,500 km north of the capital Maputo.

The block covers an area of 5,145 sq km in water depths ranging from 200 m to 1,800 m.

Eni is the operator of the joint venture with 34% participating interest. Partners are Statoil and Sasol with 25.5% each and ENH with 15%.

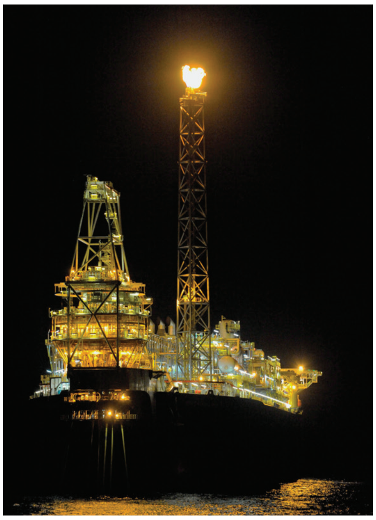
The minimum work programme includes seismic and three commitment wells.

"The Angoche area is a very promising frontier basin with significant oil potential and builds on Statoil's exploration strategy of access at scale," said Nick Maden, senior vice president for Statoil's exploration activities in the Western Hemisphere.

Statoil also has completed a farm-in deal with Exxon Mobil to acquire a 35% interest in the **ER 12/3/154 Tugela South** Exploration Right.

The remaining interests are held by the operator Exxon Mobil (40%) and co-venturer Impact Africa Ltd. (25%).

Maden said, "This opportunity is in line with Statoil's exploration strategy of access at scale. It represents access into a frontier basin where we believe we see indications of an active petroleum system and which has impact potential."


A drillship flares gas off Mozambique

The Tugela South Exploration Right covers an area of about 9,054 sq km. It is located offshore eastern South Africa in water depths up to 1,800 m.

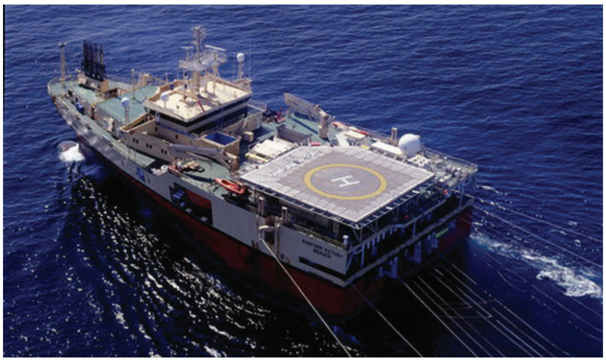
The farm-in deal represents a country entry for Statoil into South Africa. Statoil enters in an early exploration phase with a step-wise exploration programme.

Work commitments between 2015 and 2017 include the acquisition of 1,000 sq km of 3-D seismic data and geology and geophysics studies. There are no commitment wells during this exploration period.

EXPLORATION NOTES

Equatorial Guinea will kick off a new bidding round for all of its remaining deep and ultradeepwater blocks in 2016. Meanwhile, two operators have confirmed they will further explore prospects in Equatorial Guinea in 2016. RoyalGate Energy will drill **Block Z** and Brazil's G3 Oleo e Gas will drill **Block EG-01**. "In a sustained environment of low oil prices, Equatorial Guinea continues to be attractive for deepwater exploration," said Minister of Mines, Industry and Energy H.E. Gabriel Mbaga Obiang Lima. "The start of two more exploration drilling campaigns in 2016 reinforces the fact that our contract terms are competitive and appealing to international explorers."

WesternGeco has completed acquisition of almost 20,000 km of new 2-D seismic lines over an area of 200,000 sq km in underexplored areas of the U.K. Continental Shelf. The Oil and Gas Authority (OGA) said the $30.4 million programme will significantly improve the previously sparse seismic coverage in the Rockall Trough and Mid-North Sea High regions. The OGA is currently preparing for the 29th Round, which subject to the necessary regulatory approvals, will be announced in 2016 focusing on frontier areas using the data from the seismic campaign.



Western Geco has completed seismic in the UK North Sea.

Providence Resources hopes to take advantage of significantly reduced rig rates to carry out more drilling on the **Spanish Point** gas condensate discovery in 2017. The Irish explorer said that recent material reductions in both offshore rig-rates and associated services costs indicate that the net costs associated with the high-impact appraisal programme are likely to be significantly reduced compared to previous estimates. Providence has just commenced a farm-out process for a 32% interest in FEL 2/04 and FEL 4/08.

From Houston (BN): Chevron (Union) has won approval of its supplemental exploration plan for **Sicily** (*32/10*), a Lower Tertiary discovery announced last summer in Keathley Canyon Block 814.

The plan calls for nine 200-day wells to be drilled between now and 2020 targeting 37.1 °API oil. Six of the wells are planned for KC 770, with one each to be drilled in KC 769, 813 and 814.

The discovery well was drilled to 10,287 m in 1,950 m of water about 410 km southwest of New Orleans. Chevron was entangled in the **Big Foot** (32/15) fiasco at the time and did not put out a Sicily discovery news release, but partner Hess in its second-quarter earnings call described the discovery as a "four-way Lower Tertiary structure."

Reports have put oil in place at up to 400 MMbbl. Partners are Chevron (50%), Nexen (25%) and Hess (25%).

Eni has discovered gas and condensate in the Nkala Marine prospect offshore Congo.

The prospect is located in the Marine XII Block, about 3 km from the **Nene Marine** Field, already in production.

The find is expected to have a potential of 250 MMboe to 350 MMboe in place, Eni said.

During the production test, the well provided more than 300 Mcm/d of gas and associated condensates.

The well, drilled in a water depth of 38 m, encountered a major gas and condensate buildup in the presalt clastic geological sequence of lower Cretaceous age, crossing a hydrocarbon column of 240 m.

Eni said it will start the evaluation of Nkala Marine through new delineation wells. Meanwhile, with the joint-venture partners, the company will begin studies for its commercial development.

The exploration of the presalt sequences continues to deliver new discoveries all along West Africa's margin and confirms Eni's exploration technologies effectiveness, given the technical complexity of these plays.

Lundin Petroleum has successfully drilled a section of exploration well 7220/6-2 on the **Neiden** prospect in PL609 in the Barents Sea off Norway.

Drilling operations on Neiden have now been temporarily suspended due to winter restrictions on the use of the *Island Innovator* drilling rig in the Barents Sea South. Operations to complete the well are expected to resume next year.

VESSEL BRIEFS

The Songa Trym will be stacked after completing the Tavros well

In more bad news for rig operators, Statoil has decided to cancel the contract for the *Songa Trym* unit four months before it expires on March 4, 2016. Statoil had previously notified Songa Offshore that the rig would be suspended for a period. Statoil tried to find other assignments for the rig after the suspension period and up to the expiration of contract but had no success. Songa said that following completion of work on the **Tavros** exploration well, *Songa Trym* will be stacked while being marketed for new employment.

Due to the soft market conditions Siem Offshore has decided to take another two anchor-handling tug supply (AHTS) vessels out of the market and place them in cold lay-up. The company is now only trading three out of 10 AHTS in the North Sea spot market.

From Houston (BN): Helix announced its *Q5000* purpose-built well-intervention semisubmersible unit has entered service in the Gulf of Mexico. It is the company's second purpose-built well-intervention vessel, *Q4000* launched in 2002 being the first. Helix said it has a long-term contract with BP for *Q5000* starting next year. Meanwhile, the vessel was doing short-term work for Bennu Oil & Gas at **Telemark** in 1,350 m of water in Atwater Valley Block 63. Telemark, originally an ATP project, first produced in 2010 and flows via subsea links to Bennu's **Titan** hub.

Jacktel has been awarded a contract for the *Haven* jack-up accommodation rig for the installation and commissioning period for the **Johan Sverdrup** project phase 1.

Included in the accommodation services is bed capacity and catering services for project personnel. The accommodation rig will provide up to 400 beds on the Johan Sverdrup field.

TECHNOLOGY

Blue Ocean Glides in for Ashtead

Gliders can be equipped with over 40 sensors.

Ashtead Technology has landed a global asset management agreement with Blue Ocean Monitoring to store, maintain and supply underwater gliders for ocean data monitoring.

Blue Ocean Monitoring is a world-leader in the provision of ocean data solutions using autonomous subsea and surface glider technology.

The deal will see Blue Ocean Monitoring expand its service offering globally with Ashtead providing asset management services and project support from its offices in Aberdeen, Houston and Singapore.

Unlike AUVs that are driven by conventional propellers, the gliders operate using either buoyancy or wave motion propulsion mechanisms, which allows longer deployment periods and the collection of large datasets continuously over extended time scales.

The gliders are capable of transmitting data in real time and can be deployed and recovered easily, at a fraction of the cost of traditional vessel-based or fixed-mooring monitoring approaches, lowering both project costs, and HSE risks.

Tim Sheehan, commercial director at Ashtead Technology, said, "The gliders can be equipped with a choice of over 40 different sensors and can be deployed in the water for up to a year at a time. With two-way satellite communications, the gliders can be deployed and controlled anywhere in the world, they are highly weather resilient and have no environmental impact."

Simon Illingworth, managing director of Blue Ocean Monitoring, added, "Initially used extensively for academic and military applications, these gliders are now increasingly being embraced by the oil and gas community for a wide range of purposes.

"Oil and gas applications include pipeline leak detection, oil spill response, decommissioning studies, dredge/construction plume monitoring, environmental monitoring and metocean studies."

BUSINESS

Technip Highlights Diversity

From London (SS): In the past, it was integrated oil companies with large upstream and downstream divisions that led the industry.

With a number of companies having hived off their downstream activities—often in the name of providing "shareholder" value—into separate companies and others simply selling off individual plants, that era seems to have gone.

But now we can speak of integrated supply sector companies, those that provide services for both upstream and downstream operations, along with those working onshore and offshore.

If there is one company that epitomises such diversity, it is Technip.

According to head man Thierry Pilenko, speaking at a press gathering, the group's current revenue stream is half from subsea activities and half from what it calls onshore/offshore.

Pilenko proudly said there was no other company in the industry with as diverse a portfolio of activities including manufacturing of flexibles and umbilicals, installation of all types of shallow and deepwater pipelines, the design and fabrication of platforms and FPSOs and the engineering and construction of various downstream plant.

And yet the current industry funk—a state of affairs that began more than 18 months ago with the realisation that prices for goods and services in the subsea, offshore, deepwater sector were out of control and deepened with the oil price crash of late 2014—sent a market leader like Technip off looking for new, more secure opportunities, which it has found with its new relationship with FMC.

The result is an exclusive alliance for engineering, procurement, construction and installation contracts and a joint venture in the form of new front-end player Forsys Subsea, led by industry veteran Rasmus Sunde.

Sunde seems unconcerned that the focus for Forsys, i.e., to promote the technology and services of its parents, might put off some clients. There will be others, he told *SEN*.

While Forsys has begun life doing concept and FEED work, notably targeting potential developments often described as "stranded assets," it has an expanded goal in the area of life-of-field services to maximise the upside value for customers. In addition, while both parents spend copiously on R&D, Forsys will do its own, particularly in asset integrity and product enhancement.

"Some of the best technology development work has been done when prices are low," Sunde said.

Technip Tidbits: Technip's own front-end specialist Genesis is moving into the subsurface arena with a new alliance. The partner's name will be announced before year-end….R&D head Laurent Decoret said that current development work is being done on extending the scope for the use of electric trace heating and in-service riser inspection systems….Technip UK head Bill Morrice, back for his second stint with the group, said there are currently more decommissioning applications (24) before the Department of Energy and Climate Change than new field developments and expressed concern that any acceleration in abandonment work will hamper future small developments.

Shell Flags More Savings from BG Deal

Royal Dutch Shell's management have reminded investors of the advantages that will emerge from its planned $69.6 billion takeover of BG Group, believing the deal still remains attractive for both sets of shareholders despite a backdrop of weak oil prices.

Speaking at a management day event in London, Shell chief executive Ben van Beurden said the company had updated the expected cost savings set to arise from the deal to $2 billion, representing an increase of $1 billion on previous estimates.

It brings the total externally verified synergies to $3.5 billion in 2018, an increase of 40%.

"The $1 billion increase is in operating cost synergies and has arisen from both de-risking our original assumptions and identifying further opportunities," van Beurden said.

"Although oil prices have fallen in 2015, the valuation case for the BG acquisition still looks compelling today for both sets of shareholders."

Shell lobbed its takeover bid for BG Group in April this year. If the deal is successful, it would combine Europe's largest oil explorer and producer by market value with the third largest ranked U.K.-based energy producer.

Shell chief financial officer Simon Henry told investors overnight that BG was a great fit for the company, with the tie-up expected to add around 73% to Shell's 2014 equity LNG capacity.

"We see strong growth potential in Australia, from Shell's share in Gorgon and Prelude and BG's Queensland LNG, totalling 44 mtpa of equity liquefaction capacity by 2018, based on projects that are under construction today, an increase of around 70% in equity liquefaction capacity compared to Shell alone at 25.6 mtpa at the end of 2014," he added.

In addition, Henry said BG's undeveloped resources positions, particularly in Brazil, combined with Shell's recent uptick in exploration performance meant the company could dial back on exploration activity in the next several years.

More Pain at Maersk Oil

Maersk Oil is slashing its global workforce by 10% to 12% as it looks to drive down operating costs by 20% by year-end 2016 in the face of continued low oil prices.

There will be a reduction in the number of employee and contractor roles in a range of Maersk Oil business locations as well as the company's headquarters.

It brings the total number of positions cut during 2015 to about 1,250.

Business units in Qatar and Norway will face cuts in the 10% to 12% range, with slightly lower levels in the Danish operations, in Kazakhstan and in the company's Copenhagen headquarters.

In the U.K., the business already has outlined plans to reduce headcount by about 220.

Maersk Oil said this is linked to the retirement of the Janice asset and changes to the offshore rotation.

Meanwhile, 60 roles in Angola and the U.S. associated with delays in the **Chissonga** (*SEN, 31/23*) project were announced in October.

Maersk Oil CEO Jakob Thomasen said, "We are operating in a materially changed oil price environment and have taken necessary decisions to reduce activity levels through 2015, and ensure we focus where we can see adequate returns from our most robust projects.

"This approach has seen us sanction mega-projects like **Johan Sverdrup** (*32/15*) and **Culzean** (*32/12*) during the year. We remain focused on longer-term growth opportunities, which play to our technical strengths, and the continued safety of all our people and assets.

"We expect the pressure to continue into 2016 and we must remain cost-focused to grow in this market. I commend our people for the improvements in our operating performance whilst we have been managing down costs across the organisation."

WoodMac Looks Ahead to 2016

From Australia (LB): Increasing production levels and deep cost cutting will be some of the key themes dominating the oil and gas industry in 2016, Wood Mackenzie predicts.

The firm's corporate upstream research team has assessed the third quarter results from the major oil and gas companies and has identified a few key themes to look out for in 2016.

According to Wood Mackenzie, the latest round of earnings results offered the industry an early glimpse at what lies ahead in 2016 in terms of companies' budgets and strategies.

Among the stand out themes include slashing costs and tighter allocation of limited capital.

"The crash in oil prices this year is having a transformative impact on the industry," Wood Mackenzie head of corporate upstream analysis Tom Ellacott said.

"The majors are now making real progress in reshaping their investment strategies for a sustained period of low prices."

According to the firm, the majors had a strong quarter when it came to production as the impact of low prices on production sharing contract (PSC) volumes and reduced maintenance downtime flowed through.

"Total was the top performer, delivering double digit production growth," the firm said.

"Eni, Statoil and Shell also had strong quarters. But longer-term growth prospects are starting to suffer from lower investment. Chevron and Total have now downgraded their 2017 production targets and longer-term growth trajectories will be flatter as companies focus on value not volume."

Meanwhile, Wood Mackenzie believes a new phase of cost cutting is underway as the majors adapt to a scenario of lower oil prices for longer.

"The aim is to fund dividends through organically generated cash flow," Wood Mackenzie said.

The company predicts Chevron's revised capex projection for 2016 – 2017 alone could be up to $17 billion lower than the guidance provided in its 2015 analyst day earlier this year.

"Spending levels in 2017 could be down by around 30 per cent versus guidance prior to the oil price crash as more projects are deferred and underlying costs continue to fall," Wood Mackenzie said.

Wood Mackenzie has previously forecast a global LNG supply gut arising in the medium to long term if the projected additional 100 million tonnes per annum of supply is added to the market.

BUSINESS BRIEFS

BP has announced a third round of spending cuts and more asset sales over the coming years to tackle an extended period of low oil prices and help pay for its $54 billion U.S. oil spill settlement.

BP, which has already sold nearly $50 billion in assets since the deadly 2010 Gulf of Mexico spill, said it expected an additional $3 to $5 billion of divestments in 2016.

The company BP also said that capex for this year would now come in at close to $19 billion, down from a previous estimate of under $20 billion, and capex would fall to $17 to $19 billion a year through to 2017. This is the third time the company has reduced its 2015 capex target from an original goal of $24 to $26 billion.

The oil producer reported better-than-expected third quarter underlying replacement cost profit, the company's definition of net income, of $1.8 billion, compared with analysts' consensus of $1.2 billion.

Despite the steep drop in oil prices, BP ramped up oil and gas production in the third quarter by 4.4% from a year earlier, producing 2.242 million barrels of oil equivalent a day. It said it expected production to rise again in the fourth quarter after seasonal maintenance ends.

CGG has announced a new restructuring to begin next year that could see the French seismic survey group reduce its workforce by 25%, the CGT union said.

CGG is already cutting 2,000 jobs over two years in order to reduce the workforce to 7,700 people by the end of this year after suffering as oil exploration companies have slashed their budgets in response to a sharp drop in the price of crude.

GE Oil & Gas has beefed up its mature fields offerings with the acquisition of subsea intervention equipment and services supplier **Advantec**. GE is currently one of Advantec's largest customers for electro-hydraulic subsea controls equipment, system integration as well as engineering and fabrication. Advantec is a leading supplier of installation workover control systems (IWOCS), including a fleet of IWOCS rental units. Advantec will operate under the existing name and management team as part of GE's Subsea Services & Offshore division. Since Advantec was established in 2005, the company has grown from 20 to 370 employees with facilities in Norway, the U.K., Lithuania, and the U.S.

Ashtead Technology has invested more than $300,000 in the latest generation of visual inspection tools for deep-sea exploration. The investment will see Ashtead offering a range of SubC Imaging products to meet increasing industry demand for enhanced, cost-effective inspection solutions. SubC Imaging provides cameras with high-definition video capabilities that can capture and transmit high-quality data from extreme water depths.

McDermott International said it has received regulatory approval for its McDermott Marine Construction Ghana Ltd. (MMCGL) joint venture to pursue key offshore opportunities in Ghana. The Petroleum Commission Ghana told MMCGL that it has been granted regulatory approval to develop contracting abilities to support the country's burgeoning subsea and offshore engineering, procurement, construction and installation industry.

McDermott has teamed up with local partner Hydra Group of Accra.

Flexlife has appointed **Richard Gibson** as business development manager for engineering, delivery and integrity services in the U.K./Europe region. He will work part time out of the Aberdeen office. Gibson is a seasoned business development manager and has previously worked for the likes of Acergy (now Subsea 7), Technip and Petrofac.

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