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Opening New Horizons With Next-generation Composite Risers

Composite materials have existed in many forms throughout history, from the brick-making depicted in ancient Egyptian paintings to the use of fiberglass on military aircraft in the 1940s.

Today they are providing a new opportunity for global oil and gas operators as commercial pressures and technologically challenging environments have combined to create something of a perfect storm. The desire to go into deeper waters equates to higher pressures and larger diameter pipes, and traditionally this would mean adding more expensive steel. Yet with composite technology, stronger does not have to mean heavier and more expensive.

A section of composite pipe section is shown at the Newcastle facility in the U.K. (Source: BHGE)

Baker Hughes, a GE company, (BHGE) has moved a step closer on its composites journey, with the delivery of a new manufacturing module for its Newcastle facility in the U.K. that will allow it to deliver its first composite risers in early 2019.

Commissioning of the composite manufacturing line was completed at the Newcastle plant in November and the company is in the process of manufacturing production-grade pipe for qualification testing, according to Ray Burke, product management executive at the BHGE Flexible Pipe Systems division. Talks concerning qualification for presalt deployment, offshore Latin America, are also underway with several customers.

"While various companies have attempted to qualify a range of partly or fully composite flexible pipes as deepwater risers, we believe that BHGE will be the first to successfully complete qualification and deployment of a dynamic riser in a floating production system with composite structural components," Burke said.

The company aims to have a prototype riser in service next year, Burke added, noting this is the subject of current negotiations with operators.

Conventional flexible pipe contains multiple layers that perform separate load-bearing functions, and conventional designs may be heavier than rigid steel pipe, which is homogeneous and can be more efficient in carrying load. The additional weight of conventional flexibles impacts not only the raw material usage but also the transportation, installation and the infrastructure needed to hold them in place. Composite flexible pipe solves this problem by replacing the metallic pressure armor layer with an innovative composite bonded liner.

The technology enables use of a "high-performing composite alternative" to the metallic component of the flexible pipe's pressure armor layer.

While admitting that fabrication of the composite structures is complex, he was confident in the module's

WHAT'S INSIDE

ability—with its automated laser tape placement system—to ensure greater speed, consistency, repeatability and reliability of the production process. The technology also aims to lower costs, while improving productivity and quality.

"Our customers are shooting for deeper waters in a bid to sustain production, which equates to higher operating pressures and larger diameter pipe. That is the beauty of composites," Burke said. "They will help to reset the equation, providing the required structural capacity without the weight gain, thereby enabling us to side-step some physical limitations."

This is a dynamic test run where they produce a length of 30 m (98 ft) of pipe and bend it through full life-cycle motions and durations that it will experience during service, and then dissect it. The step is part of the final qualification with customers and for qualification with Lloyd's Register.

The company uses what Burke called an "unusual" combination—something other than the thermoset bottoms for carbon fiber applications typically used.

"In this application, because we've got so much dynamic motion that strains the pipe repeatedly to the structure, the thermoplastic is a much better matrix," he said before explaining how it is made. "We mostly amalgamate the tapes, so applying layer by layer of tape circumferentially on the pipe, and use a laser to melt and amalgamate the matrix."

The end result is a solid layer with polymer on the inside and then carbon fiber and reinforced polymer on the outside, he said, adding it's the "same material with no join, no bonding, so polymer to polymer."

Part of the so-called "secret sauce" involves the patented quality control module.

"What this does is inspects the composite structure online, so as we've made the layer, it comes through an ultrasonic unit," Burke said. "If we see any voids we have a means to immediately re-amalgamate [and] reheat the polymer to solidify it. That inspection technology came from GE Aerospace, so it's one of those crossover technologies we've been able to harness."

Burke said the real challenges are the two areas at end of the riser—the seabed and topsides. "At the topside's hangoff, there is variable tension but also variable bending. Because the fibers are wound all around the pipe circumferentially, we have quite complicated mathematical equations to characterize these forces.

"It is the same with the touchdown. At the point the pipe touches the ground you have compression. Can you imagine if you had orientated fibers and you're compressing them and they got a kink?" Burke asked. "There were some other attempts at designing risers in the past where people have used the axial components and tried to replace those with composite. It's not a very appropriate solution for that application just because of the forces."

The first area of competitive advantage is deepwater and/or high-pressure riser duties. As the composite armor has superior strength to weight characteristics, BHGE is exploring additional applications across a range of depths where the structural reinforcement allows them to adapt traditional flexible pipe geometries to enhance the cost benefit or capability of the product.

—Mark Venables

DEVELOPMENT

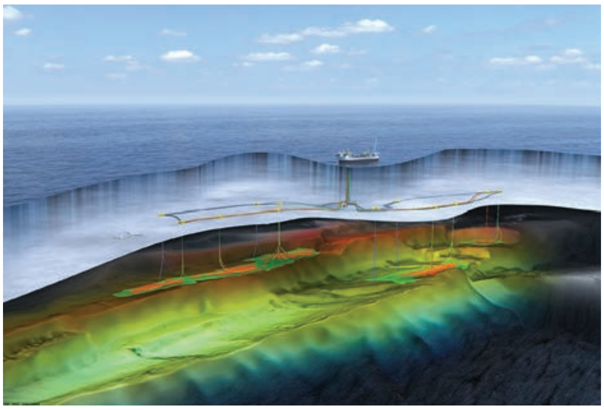
Statoil Delivers $5.9 Billion Plan For Arctic Johan Castberg Project

Statoil and partners have delivered to Norwegian authorities a $5.9 billion development plan for their massive Arctic Johan Castberg oil discovery, having halved costs for the project that now has a $35/bbl breakeven price.

The development, which Statoil called the biggest subsea project underway today, targets an estimated 450 MMboe to 650 MMboe of recoverable resources from Skrugard, Havis and Drivis discoveries in the Barents Sea. The concept includes an FPSO vessel along with 30 wells, 10 subsea templates and two satellite structures. First oil is planned for 2022.

The plan for development and operation (PDO) comes after operator Statoil (50%) and partners Eni (30%) and Petoro (20%) cut capex for the project by more than 50%.

"We have been working hard together with our suppliers and partners, changing the concept and finding new solutions in order to realize the development," Margareth Øvrum, Statoil's executive vice president for technology, projects and drilling, said in a news release. "Today we are delivering a solid PDO for a field with halved capital expenditures and which will be profitable at oil prices of less than US$35 per barrel."



The Johan Castberg development plan includes an FPSO vessel along with 30 wells, 10 subsea templates and two satellite structures. (Source: Statoil)

Statoil, like many others in the industry, have focused on capital discipline and finding ways to become more efficient. The company has given credit to an optimized field layout, fewer wells and reduced seabed intervention costs for the falling capex—feats reached by working with suppliers and challenging the team to embrace collaboration and think differently.

For example, Statoil said it shaved about $48 million by opting to manage production without water injection for a while, without compromising oil production, if one power generator failed.

Production ships require power from two generators for oil production and water injection, and a backup generator is required, Statoil explained. However, Statoil's reservoir engineers determined it is not necessary to have water injection all the time. So if one generator failed, there is no need for a backup generator while repairs are made to downed generator. Each generator costs about $48 million.

"The saving here was approximately NOK 400 million," the cost of a generator, Aker Solutions' Nils Olav Solheim said a Statoil report on how it cut costs.

Aker Solutions, which has carried out concept studies and FEED work for the project, won the contract to supply the subsea production system and design the topside for the FPSO unit. The work is valued at about $482 million, Aker said Dec. 5.

Work will begin in December with initial deliveries set for second-quarter 2019. Final delivery is expected in first-half 2023.

"Our early involvement and strong collaboration with Statoil have helped halve the development costs, enabling this strategically important project to move forward," Aker Solutions CEO Luis Araujo said. "The field is critical in further developing northern Norway as an oil and gas region."

The Norwegian Petroleum Directorate (NPD) called the accomplishment a "milestone for the Barents Sea."

"Johan Castberg will become the first infrastructure in this petroleum province and will thus become an important building block for future activity in the Barents Sea southwest and farther north," the NPD said. "The authorities have been concerned with ensuring that a solution is chosen that facilitates further development of the province, instead of a solution that is tailored just for Johan Castberg's needs."

Statoil said it is studying the possibility of a standalone oil terminal at Veidnes. An investment decision could be made in 2019.

Danske Bank analyst Anders Holte told Reuters the field is important for Statoil's long-term liquids production.

"The field is essential for continuous production growth on the Norwegian continental shelf for Statoil from 2022 onward," Holte said. "The field is one of the few remaining large developments offshore Norway."

Statoil also shared on Dec. 5 steps made on another project—Snorre in the Norwegian Sea. The company and Snorre license partners have signed a letter of intent with FMC Kongsberg Subsea for the subsea system for the Snorre Expansion project, which includes six subsea templates and equipment for 24 wells. The letter of intent is valued at less than about $241 million, Statoil said.

—Velda Addison

Premier Oil Natuna Moves Ahead With BIGP Project

Premier Oil is developing the Bison, Iguana and Gajah Puteri (BIGP) oil and gas fields in the Natuna Sea offshore Indonesia to increase gas supplies to consumers in Indonesia and Singapore.

"The Indonesian government formally approved the project in October, and all major contracts have now been awarded. Premier is targeting first gas in 2019 to backfill our existing Singapore and domestic market contracts," Premier Oil said in an operational update.

Operator Premier Oil Natuna Sea BV has launched preconstruction works to develop the three oil and gas fields located in Block A as subsea tiebacks to the producing Gajah Baru and Anoa fields.

First gas is projected to be achieved in third-quarter 2019.

The offshore block is located in the Natuna Basin in the northwest part of Indonesia, near its maritime border with Malaysia and Vietnam.

(Source: Premier Oil)

Development Plan

The plan involves development of three subsea wells each at the BIGP fields in a water depth of about 80 m (262 ft), with subsea pipelines tied back to the existing Pelikon and AGX central processing platforms (CPPs).

Oil and gas produced from Bison and Iguana will be flowed respectively through 8-km (5-mile) and 6-km (4-mile) pipelines to the Pelikan platform before being channeled to the Gajah Baru CPP facility for processing. Output from Gajah Puteri will be transported via a 42-km (26-mile) pipeline to the AGX platform with a control system from Naga platform.

The existing Pelikan, Naga and AGX wellhead platforms and the Gajah Baru CPP will be restructured to receive supplies from the three fields.

The project's engineering and related equipment contracts have been awarded. The operator signed engineering, procurement, construction and installation (EPCI) contracts with PT Timas Suplindo for development of the production facilities for the three fields, while Proserv was contracted to deliver a subsea control system and related equipment.

S2V Consulting carried out the FEED for the subsea controls and umbilicals required for the development. GE Oil & Gas won the contract for the project's subsea trees and wellheads.

The BIGP project is expected produce up to 60 million standard cubic feet per day of gas and about 1,100 bbl/d of condensate.

Gajah Puteri is estimated to contain about 4.2 Bcm (150 Bcf) of gas, while Bison and Iguana are believed to hold about 1.6 Bcm (57 Bcf) and about 82 MMcm (29 Bcf), respectively, according to a certified gas reserves estimate.

The Gajah Puteri discovery is considered to be an elongated, westward-plunging, moderately faulted anticline with a three-way dip closure located south-southeast of the producing Anoa Field. Pay is found in channel sands of the Lower Arang and Gabus formations.

Supplies To Singapore

Premier Oil is developing the three gas fields to support gas supplies committed to consumers in Singapore and Indonesia as part existing and future gas supply contracts.

Development of the fields will allow the operator increased operational flexibility, the ability to supply additional volumes to meet growing market share within existing contracts and provide an opportunity to respond to increased Singapore or domestic gas demand.

The company is supplying about 200 billion Btu per day (BBtu/d) from its four fields—Anoa, Pelikan, Gajah Baru and Naga—to consumers in Singapore through a 540-km (336-mile), 28-in. diameter West Natuna Transportation System under two long-term gas sales agreements.

The operator also is committed to supply an additional 40 BBtu/d to power generation plants on Indonesia's Batam island.

Block A has more undeveloped discoveries, including Lama, Macan Tutul, Lembu Peteng and Lukah. They are to be commercialized after development of the BIGP project.

The offshore concession is estimated to have more than 56.6 Bcm (2 Tcf) of gas reserves.

Premier Oil is the operator of the field with a 28.67% participating interest in Block A. The other partners are Petronas (15%), PTT Exploration and Production and Pertamina (23%) and Kuwait Foreign Petroleum Exploration Co. (33.33%).

—Ravi Prasad

Maersk Oil, Partners Sanction $3.4 Billion North Sea Project

The redevelopment plan includes a new processing platform and a new accommodation platform for Tyra East (shown here) and Tyra West. (Source: Maersk Oil)

Maersk Oil and partners will recharge the North Sea's Tyra Field, where production was once set to cease next year, with plans to pump about $3.4 billion into its redevelopment.

The company announced Dec. 1 that Danish authorities approved the redevelopment plan for Denmark's largest gas field. The investment, which marks the largest ever for the Danish North Sea, is expected to allow operations to continue at the field for at least 25 years and enable the production of more than 200 MMboe.

Discovered in 1968, production started at the more than 616-sq-km (237-sq-mile) Tyra Field in 1984. However, since then, subsidence of the chalk reservoir has taken a toll on the field, causing its platforms to sink by about 5 m (16 ft) over the last 30 years, according to Maersk, which said this has reduced the gap between the sea and platform decks at the field.

The field, which comprises the Tyra East and Tyra West centers tied into the Tyra Southeast, Harald, Valdemar, Svend and Roar unmanned satellites, will see infrastructure improvements that include:

- A new processing platform and a new accommodation platform on Tyra East and Tyra West;
- A 10-m (33-ft) extension of jackets on the four wellhead platforms and two riser platforms; and
- New topsides, according to a news release.

The investment decision by Maersk and partners and Danish approval comes as market conditions continue to improve and demand increases.

Expectations are for the redeveloped field to deliver about 60,000 boe/d—mostly gas—at its peak, Maersk said.

"Tyra has been a key asset in the history of Maersk Oil, and an important source of energy security for Denmark," Maersk Oil CEO Gretchen Watkins said in a company statement. "The redevelopment of Tyra is the largest investment carried out in the Danish North Sea, and when completed in 2022, production from the Tyra Field itself has the potential to cover Danish gas consumption for a decade."

Danish Energy Minister Lars Christian Lilleholt praised Maersk and the Danish Underground Consortium—the partnership between field operator A.P. Moller-Maersk (31.2%), Shell (36.8%), Nordsøfonden (20%) and Chevron (12%)—for making the final investment decision (FID).

"The full reconstruction of Tyra is vital to the development of the Danish North Sea oil and gas sector," Lilleholt said, "not just to Maersk Oil, but to many companies relying on Tyra as a central gas hub."

Of the investment, about $2.7 billion will be spent on the renovations and new infrastructure with the rest going toward decommissioning of existing infrastructure.

In preparations for the work, Maersk said the field will be shut in November 2019. Production is set to resume in July 2022.

The FID comes about three months after Total agreed to buy Maersk Oil as parent company A.P. Moller-Maersk continued its mission to separate its oil and gas business as it focuses on integrated transport and logistics. The deal, valued at $7.45 billion, is expected to close in first-quarter 2018.

—Velda Addison

DEVELOPMENT BRIEFS

Saipem Scoops Up EPC Contract Offshore Saudi Arabia

Saudi Aramco has tapped Saipem to engineer, procure and construct (EPC) a new 42-in. offshore pipeline for the Manifa water injection system offshore Saudi Arabia.

The work is part of the scope for an EPC activities contract the company landed under a long-term agreement renewed until 2021, Saipem said in a news release. The pipeline work involves replacing an existing line and other activities to update the water injection system.

Saipem said the company also was assigned additional engineering and construction work regarding previously awarded projects offshore West Africa.

Combined, the awards were valued at about $400 million.

EnQuest Keeps Kraken Production Ramp-up On Track

Production at EnQuest's flagship Kraken oil field in the North Sea is ramping up as planned, hitting production rates of more than 40,000 bbl/d gross, the company said in its latest operational update.

"We are on track to deliver a Kraken production rate of 50,000 bbl/d gross during [first-half] 2018," EnQuest CEO Amjad Bseisu said in a company statement.

The milestone follows the final drill center two production wells going online and beginning the process of bringing the drill center three wells onstream early. EnQuest said it is developing plans to drill DC4 wells in 2018.

Production at the Kraken oil field is on course to reach 50,000 bbl/d in 2018. (Source: EnQuest)

This comes as project costs fall. EnQuest puts the full-cycle gross capex for Kraken at about an estimated $2.4 billion, down 25% from the $3.2 billion original sanctioned cost. Savings were realized from the "excellent delivery of the DC3 drilling program and also the lower market rates for the remaining subsea campaign," the company said.

McDermott Lands EPCI Contract For Safaniya Field

Saudi Aramco has turned to McDermott for engineering, procurement, construction and installation (EPCI) services for the Safaniya onshore and offshore field.

The contract, which is valued at between $750 million and $1.5 billion, entails the EPCI specialist providing such services for nine slipcover jackets, 10 production deck modules, an electrical distribution platform and associated cables and pipeline, a news release said. The EPCI services include the design, fabrication, installation and precommissioning of the jackets.

The project is massive, considering its combined structures will weigh more than 22,000 short tons with more than 26 km (16 miles) of pipelines and about 22 km (13 miles) of cables, according to McDermott.

The Safaniya oil field, the largest oil field in the world by production, is located in the Arabian Gulf.

Work on the contract was set to start immediately.

CNOOC Commences Production At Weizhou Oil Field

CNOOC Ltd. has commenced production at its Weizhou 12-2 oilfield Phase 2 project, the company said.

The project is located in the Beibu Gulf in the South China Sea with an average water depth of about 35.7 m (117 ft). In addition to fully use the existing facilities of Weizhou 12-2 oil field, the project has also built one wellhead platform.

There are seven wells producing about 6,400 bbl/d of crude oil. The project is expected to reach its ODP designed peak production of about 11,800 bbl/d in 2018.

The Weizhou 12-2 oil field Phase 2 project is an independent oil field in which the company holds 100% interest and acts as the operator.

ExxonMobil Turns On Tap At Hebron Field Offshore Canada

ExxonMobil Corp. has started production at the Hebron Field offshore Newfoundland and Labrador, the company said in a news release.

The company said it will produce up to 150,000 bbl/d of oil from the project. The field is estimated to hold more than 700 MMbbl of recoverable resources, according to the news release.

Located in water depths of about 92 m (300 ft), the Hebron platform consists of a standalone gravity-based structure that supports an integrated topsides deck, which includes living quarters and drilling and production facilities, the release said. The platform has storage capacity of 1.2 MMbbl of oil.

The field was discovered in 1980, according to the release.

With 35.5% equity in the project, ExxonMobil affiliate ExxonMobil Canada Properties serves as operator. Partners are Chevron Canada Ltd. (29.6%), Suncor Energy Inc. (21%), Statoil Canada Ltd. (9%) and Nalcor Energy—Oil and Gas Inc. (4.9%).

Total Sells Two Norwegian Oil Fields To Statoil For $1.45 Billion

Total has agreed to sell its stakes in two Norwegian oil fields to Statoil for $1.45 billion as it reviews its North Sea portfolio after acquiring Denmark's Maersk Oil in August.

The company said Statoil will take over its 51% stake in the Martin Linge Field and its 40% holding in the Garantiana discovery on the Norwegian Continental Shelf.

The company said that although Norway remains strategically important as one of the largest contributors to its output, it plans to focus on its non-operated assets such as Ekofisk, Snohvit and Johan Sverdrup fields.

Total's decision to scale back its presence in Norway, focusing on non-operated assets, follows a recent trend among foreign oil majors, including BP and ExxonMobil, to become junior partners in Norwegian fields and concentrate their exploration and field management in less mature regions.

The Martin Linge development has been plagued by delays and cost overruns, with the latest investment estimate seen at $5.1 billion, about 42% more than originally anticipated.

The field is expected to start production in 2019 after a one-year delay following a fatal accident in May at a South Korean yard building the platform for the field, raising the cost for the project.

Total is also the largest investor in the Garantiana discovery, which is being developed.

DEA Doles Out Dvalin Drilling Contract To Transocean

DEA Deutsche Erdoel AG has selected Transocean Norway Operations AS, with drilling rig Transocean Arctic, to drill four production wells at the Dvalin Field in the Norwegian Sea.

The contract is valued at $68 million.

Plans are to begin drilling in mid-2019 and wrap up operations within 340 days.

The Dvalin Field development plan calls for tying the four subsea wells back to the existing Heidrum platform, where a new module for processing and compressing gas will be installed. Gas will be transported via pipeline from Heidrun to the Polared trunk line for processing to dry gas. From there, it will move to the Nyhamna onshore gas terminal and ultimately to the market via Gassled, according to DEA.

Production is slated to begin in fall 2020. The field is located in production license 435 northwest of the Heidrun Field and south of the Skarv Field.

—Staff & Reuters Reports

EXPLORATION BRIEFS

ExxonMobil Acquires Deepwater Acreage Offshore Mauritania

ExxonMobil affiliate ExxonMobil Exploration and Production Mauritania Deepwater Ltd. has signed production-sharing contracts with the government of Mauritania for three deepwater offshore blocks.

Blocks C22, C17 and C14 are located an average of 200 km (124 miles) offshore Mauritania. Together they measure nearly 8.4 million acres in water depths ranging from 1,000 m (3,300 ft) to more than 3,500 m (11,500 ft).

(Source: Shutterstock.com)

Following government approval of the contracts, ExxonMobil will begin exploration activities, including acquisition of seismic data and analysis.

ExxonMobil will carry out the work program as operator with 90% interest. Societe Mauritanienne des Hydrocarbures et de Patrimoine Minier holds a 10% interest.

Interest has surged in oil and gas fields offshore of Mauritania and neighboring Senegal since big discoveries by Cairn Energy and Kosmos Energy, the latter now partnered with BP, in separate projects over the last three years. Both are expected to start production early next decade.

London-based BP is developing a major gas project and France's Total has bought into several exploration licenses in both countries.

Chevron Pursues Study On Deepwater Block Offshore Mexico

U.S. oil major Chevron Corp. will focus on studying the geology of its block in Mexico's deepwater Gulf during the first four-year phase of its contract, rather than drilling new wells, a senior executive said.

The company, which leads a consortium that includes Mexican state oil firm Pemex and Japan's Inpex, won the rights to deepwater Block 3 at auction late last year. The exploration plan calls for the consortium to invest $37 million over four years, according to the National Hydrocarbons Commission, which expects to approve the plan in January. The block is located in the productive Perdido Fold Belt, which straddles the U.S.-Mexico maritime border.

"Block 3 is very complicated, and we want to use these first few years to better understand the geology," Evelyn Vilchez, Chevron's top executive for E&P projects in Mexico said during a briefing with reporters in Mexico City.

Commercial production will likely take between 10 and 16 years to begin, with the time frame depending on successful exploration efforts plus other factors, she added.

Mubadala, Partners Find More Oil At Manora

LWD data from the Mubadala Petroleum-operated Manora-6 exploration well indicate the presence of oil, according to partner Tap Oil Ltd., which holds 30% interest in the G1/48 concession where the Manora oil field is located.

Targeting the L fault block prospect in the northern Gulf of Thailand, the well reached a total depth of 2,412 m (7,913 ft). Interpretation of LWD data indicates a 5.8-m (19-ft) oil column in the primary reservoir section.

"This result was encouraging enough for the joint venture to proceed with a sidetrack to the well, Manora-6ST, to test the M prospect," Tap Oil said in a news release.

Interpretation of LWD data from the sidetrack shows about 5.8 m of oil in three separate reservoir sandstones.

Results are being evaluated by Tap Oil and Mubadala to further understand the field and its upside potential.

Tap is working with the operator who continues to evaluate the results, and these will be incorporated into Tap's understanding of the Manora Field production contract area and its upside potential.

Statoil Plans To Drill Five To Six Wells In Arctic Barents Sea In 2018

Statoil will continue to drill for oil in the Arctic Barents Sea next year even though its 2017 campaign was mostly disappointing, the company's head of exploration told Reuters on Nov. 28.

Statoil plans to drill between 25 and 30 wells in Norwegian waters in 2018. Of these wells, five or six are expected in the Barents, and the rest will be split between the North Sea and the Norwegian Sea, which are both located farther south.

"We have tested a lot of potential there [in 2017], and that potential is gone. But we still believe in the overall potential of the Barents Sea," Exploration Chief Tim Dodson told Reuters on the sidelines of a Statoil conference.

Even though the company failed to make any large Barents Sea discoveries from the five wells drilled in the current year, it did make a small oil find, known as Kayak, and the exploration campaign had a positive overall value for the company, he added.

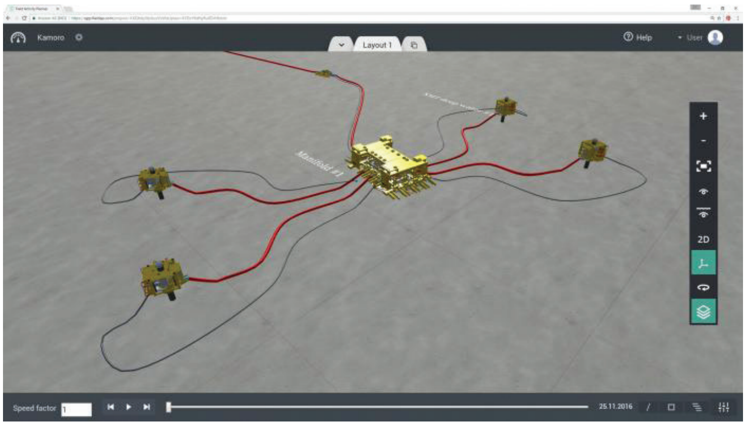
Statoil's plans for 2018 also include at least three wells off Brazil, one off Tanzania, one or two onshore wells in Argentina and one onshore in Russia, Dodson said. He declined to give a number for the overall number of wells to be drilled globally by Statoil next year, but he said the company's exploration budget would not change much from 2017.

Separately, Statoil's CFO said the company would continue to cut the operating costs of its Norwegian offshore oil and gas business. "We see potential for more efficiency gains next year," CFO Hans Jakob Hegge told Reuters.

—Staff & Reuters Reports

TECHNOLOGY

Digitalization: A New Era Of Offshore Operations



The current volatile market provides an opportunity to gain competitive advantage by embracing new IoE technologies. (Source: Xvision Software)

Digitalization is emerging as a technological driver of change around the world and provides businesses with abundant opportunities for growth and monetary gain. While industries like manufacturing and healthcare have taken the digitalization world by storm, the oil and gas industry has been remarkably slow to adopt this new way of thinking.

It is true that oil and gas has been "digitalized" for some time. True digital transformation, however, now requires adoption of the Internet of Everything (IoE)—the networked connection of people, process, data and things—throughout the value chain.

Most of today's digital initiatives in oil and gas are incremental rather than disruptive. Some offshore operators are taking a step forward to make improvements in technical or operational capabilities, but many are not fully embracing the power digitalization can provide. Numerous benefits such as increased cost savings and significant improvements in collaboration, productivity, maintenance and revenue can be realized through digitalization if more offshore operators would take the technological plunge.

According to a January report by Accenture on digitalization in the oil and gas industry, the primary barriers to change or adoption include:

- Regulatory frameworks that are struggling to adapt to a new era of data sharing along value chains;
- A lack of standardization in data coming from sensors;
- An inability to share information across the ecosystem; and
- The challenge of recruiting millennials to replace an aging workforce.

Digital collaboration technologies provide oil and gas companies, and specifically offshore engineers, a multitude of benefits. These include the ability to digitalize workflow and planning processes; optimize decisions between experts, disciplines and companies involved in the life of field perspective; and visually identify operational activities and maintenance events once projects are online.

Through digitalization, all offshore field projects can be easily understandable through online 2-D/3-D visualizations rapidly created or replicated using existing field layouts with a 3-D asset library and immediately monitored and reported to real-time operating levels. It also can offer an instant view of the cost consequences due to a required action or change to a field.

For offshore operators subsea and topside assets are their most valuable players. The foundation of these structures comprises years of knowledge, engineering talent and commitment. The technology-savvy world is moving to a digital environment. For the oil and gas industry to respond to this trend, offshore assets must reside there too. Offshore operations will dramatically change when oil and gas companies embrace and upgrade their digital capabilities, thus improving the way they collaborate with and connect new data insights to their operating models.

Digital collaboration technologies offer several benefits. (Source: Xvision Software)

Real-world Results

An independent European oil and gas operator was looking to exploit the Norwegian Shelf in the North Sea. It aimed to reduce costs by using already existing infrastructure in a neighboring oil field and had appointed an engineering firm to install a cable along the seafl oor.

Collaboration meant having to work across multiple disciplines and languages. This increased the complexity of communications, decision-making and project management, all of which could lengthen the delivery timescale. For example, each company used a different type of planning software, with Gantt charts provided as the basis for project discussions. But it was almost impossible to get diverse teams of operations personnel, managers and budget holders on the same page.

The operator turned to a specialist in 3-D visualizations and software development for major subsea and offshore engineering companies to find a solution. The digital collaboration platform created by the third-party expert brought all project data—assets and activities, both subsea and topside—online and into plain sight through an easy-to-understand visualization.

The collaboration platform complemented the use of Gantt charts, which are still maintained to plan activities. The intuitive interface presented all of the project data as an animated time line, with a customizable set of information layers. Users could navigate to a snapshot of the project for any date using a simple slider and toggle information layers as required.

The platform has matured to support the entire process of offshore and subsea installations, from planning and feasibility to preparation and actual operations. It gave users a simplified view of activities being carried out offshore along with the status of vessels, rigs and installations.

According to the operator, the digital collaboration platform simplified the business of understanding with what was already there and what had yet to be installed at any point. It presented the field layout graphically, with vessels, trenching, production, rock tumblers and pipe information layers that could be switched on and off, depending on the remit. Further, by using the digital platform, the operator successfully collaborated with all parties as one team, accelerated its project time line by 30% and incurred only minor errors and low periods of downtime.

The benefits are undeniable when digital technologies are implemented across the oil and gas industry, regardless of current oil prices. These include:

• *Return on investment*: Digital collaboration tools are easy to integrate and train employees on and are capable of accelerating project time lines by up to 80%, especially during the early concept and FEED phases. Once the project data are centralized and visualized, they can then be leveraged across the organization for collaboration in fluid analysis, operational data gathering, maintenance and decommissioning planning. These time savings can drive cost savings as high as 70% across a project's life cycle;

- *Simplified collaboration*: By providing a unified view of the project, digital collaboration tools simplify multilanguage cross-disciplinary communications. This reduces the opportunity for misunderstandings and scheduling conflicts and supports knowledge transfer, collaboration and creative problem-solving;
- *Better decision-making*: The solution enables activities to be tracked against the project plan and any deviation easily measured. The ability to perform "what-if" analysis allows the outcome of decisions to be modeled in a risk-free environment before taking action in the field; and
- *Reduced risk*: Increased visibility allows a safety zone to be established around the installation to enable compliance with health and safety requirements. Vessels are prohibited from entering or remaining in the zone at specified points of the project.

Digitalization has the potential to create tremendous value for both the industry and society as a whole. However, for oil and gas such a transformation will require organizations to implement a focused digital strategy championed by the C-suite, executive teams and IT leaders to create a culture of innovation and technology adoption. It also will need investment and commitment to revisit, renew and upgrade current processes, infrastructure and systems and a willingness to share and collaborate across the ecosystem. All the aforementioned needs will be required for a successful digital transformation for the oil and gas industry to truly realize the power and potential digitalization provides.

— Olav Sylthe, Xvision Software

TECHNOLOGY BRIEFS

New HT/HP Subsea Valve Coating Developed, Deployed

An international collaboration between Hardide Coatings and Master FloValve Inc. (MFV) has developed a new coating to protect HP/HT subsea choke valves, a press release stated.

MFV's P4-20K choke valve is rated from -29 C to 204 C and 20,000 psi. (Source: Hardide Coatings)

The valves are the first of their kind to feature the Hardide-T coating, which can be applied to choke valve stems so they can withstand temperatures up to 204 C (400 F) and pressures of 20,000 psi.

MFV found that alternative hard coatings previously applied to the stem assembly were not rated to sufficiently high temperatures. The challenge was to have a durable coating with a completely smooth finish to form a tight metal-to-metal seal. The new coating has been applied to MFV's P4-15K choke valve, which is rated from -29 C (-20 F) to 204 C and 15,000 psi, and the P4-20K choke valve, which is rated to the same temperatures but to 20,000 psi. They are typically installed on subsea production trees and are used for single/multiphase production or water/chemical/gas injection.

There is also an application for use on a capping stack, designed to be deployed in the event of a blowout situation.

Companies Partner To Advance Subsea Robotic Inspection

Avitas Systems, a GE Venture, announced a partnership with Kraken Robotics Inc. to integrate AUVs, acoustic and laser sensor technology, and artificial intelligence-based navigation software into unique subsea inspection solutions for the oil and gas, offshore renewable energy and shipping industries, a press release stated.

Routine subsea inspections can be slow and costly and often include manual visual inspection with a large margin of error. Utilizing enhanced imaging technology and inspection solutions will improve the jobs of inspectors and increase safety, accuracy, speed, cost efficiency and asset longevity. Avitas Systems will be able to complete subsea inspection with reduced cost, time and operational footprint. Kraken Robotics brings a broad range of cost-efficient AUV technologies such as sensors, pressure-tolerant batteries, thrusters and control electronics. Avitas Systems will integrate these technologies into an autonomous subsea inspection system.

The data from this inspection will be uploaded into a platform that includes robust data ingestion, automatic defect recognition, predictive analytics and a cloud-based visualization portal for oil and gas and offshore energy customers.

Avitas Systems provides autonomous inspection with robots that can target specific points on industrial assets and follow precise paths from digitized 3-D models. The paths' repeatability enables artificial intelligence-based change detection and automated defect recognition for smarter inspection scheduling based on anticipated risk. Early detection and resolution of potential industrial issues means safer, more reliable operations and enhanced asset integrity.

Working with Kraken Robotics, Avitas Systems will now be able to apply this process to underwater inspections. The partnership expands capabilities for inspections of ship and FPSO hulls, underwater production fields, subsea pipelines and cables, and offshore wind farm assets.

Subsea UK, Scottish Enterprise Launch R&D Funding Call

In a quest to uncover new technology and methods to help solve complex challenges faced by the industry, Subsea UK and Scottish Enterprise have put out a $20 million funding call.

David Rennie (left) is head of oil and gas at Scottish Enterprise and Neil Gordon (right) is chief executive of Subsea UK. (Source: Subsea UK)

The funding call was recently announced after a memorandum of understanding was signed between Scottish Enterprise and The Nippon Foundation, a Japanese philanthropic group. The pact aims to help both countries seize opportunities in the subsea sector, according to a news release. The two will provide equal funding in support of joint projects, aiming to maximize use and development of digital technologies and challenge the status quo.

Applications are being sought under two categories:

- Subsea digital oilfield technologies (real-time underwater communication, inspection, monitoring and control, subsea sensors, robotics and artificial intelligence); and
- Subsea oil and gas innovation (well productivity and intervention, well design, low-cost drilling, decommissioning, subsea factory, remote monetization and challenging field development), the release said.

Interested companies may visit the Subsea UK website for proposal applications until March and for more information. Applications are due by June.

—Staff Reports

FLOATERS & VESSELS

Golar: LNG Boom Fuels Recovery In Shipping Market

Bermuda-based Golar LNG has declared that the shipping market recovery has begun.

Noting that demand has exceeded supply growth for the first time since 2013, Golar said natural gas liquefaction trains that started operations in 2016 continue to ramp up with more on the way, the comapny said in its third-quarter report released at the end of November.

Six trains with a collective capacity of 28 million tons commenced operations in the U.S., Australia and Russia in 2017 alone, with the 5-million-ton capacity Cove Point, Md., facility expected to start by year-end. From January through September, U.S. LNG volumes in ton-miles were up 10% compared to the same period in 2016, Golar said.

Strong demand from China and South Korea has pushed LNG prices up in the region, with spot rates that reached two-year highs in October rising to three-year highs by the end of November. China's imports through the end of October were up 48% compared to the same period in 2016.

Golar noted that about 45 vessels are scheduled for delivery in 2018, or an increase in the current fleet of about 10%. Production growth is expected to hit 12% in the coming year, and an expected growth in ton-miles is anticipated to create a significant increase in term charters.

First Oil And Contract Startup For Libra FPSO Unit

FPSO Pioneiro de Libra (Libra) has achieved first oil in the Santos Basin, the first FPSO unit to do so on the giant Libra block, Teekay Offshore Partners LP announced in late November.

Libra has commenced a 12-year charter contract with a group of oil companies that include Petrobras, Total, Shell, CNPC and CNOOC Ltd. It is performing early well tests in the field, which covers more than 1,500 sq km (579 sq miles).

Teekay owns *Libra* as part of a 50:50 joint venture (JV) with Odebrecht Oil and Gas. The FPSO unit was converted from one of the JV's shuttle tankers at Sembcorp Marine's Jurong shipyard in Singapore and can operate in depths of up to 2,400 m (7,874 ft). Its capacity is 50,000 bbl/d of oil and 4 MMcm (141 MMcf) of natural gas.

"Today marks another significant milestone for Teekay Offshore and its growing presence in the Brazilian market," Ingvild Sæther, president and CEO of Teekay Offshore Group Ltd., said in a statement. "This successful Libra FPSO conversion project demonstrates that we can confidently deliver highly complex FPSO solutions for Brazil's massive presalt play and is expected to provide significant future cash flow growth to the partnership."

Work On Pace With FPSO Unit For Catcher Field

BW Offshore continues to make progress with the *BW Catcher* FPSO unit at the Catcher Field in the U.K. North Sea, where first oil remains on schedule for December, the company said.

With commissioning activities underway, BW Offshore have already checked off hook up of the submerged turret production mooring system, completing a rotation test and final pull-in of risers and umbilicals from its list of tasks to complete.

The project is expected to add about $200 million in annual EBITA to the FPSO firm's results when it comes onstream in December, according to BW Offshore CEO Carl Arnet.

Boskalis Adds Two Ex-Harkand DSVs

Netherlands-based Royal Boskalis Westminster said in early December that it had added two large diving support vessels (DSVs) to its fleet.

In a statement, Boskalis said the purchase of *DSV Atlantis* for $60 million and three-year charter of *Da Vinci* from Harkand moves forward with its 2017-2019 corporate business plan that focuses on expanding its subsea services. This move, the company said, strengthens its inspection, repair and maintenance of subsea offshore installation, pipelines and cables offerings.

The two DSVs create the opportunity for the company to expand its subsea contracting, installation and SURF activities and grow this segment in northwest Europe, Africa and the Middle East.

The sister ships were built by Hanjin Heavy Industries in Pusan, South Korea and went into service in 2011. They feature eight-man, Twinbell saturation diving systems and displace about 12,600 tons. Bells can operate to 300 m (984 ft) and the ships can accommodate crews of 120.

Maersk Takes Delivery Of *Involver*

The second in a quartet of Stingray-class subsea support vessels, *Maersk Involver*, has been delivered to Maersk Supply Service.

The versatile Stingray-class vessels are built by COSCO Dalian Shipyard in China. They can accommodate crews of 120 and are designed for a range of operations in deep and shallow waters and boast energy-efficient propulsion, class 3 dynamic positioning, a 400-tonne active heave-compensated crane and two work-class ROVs that can operate in depths of up to 3,000 m (9,843 ft).

—Joseph Markman

POLICY & REGULATIONS

BP North Sea Field To Test US Policy On Iran

A small gas field on the edge of the British North Sea could become a litmus test for U.S. policy toward Iran.

BP agreed to sell to North Sea producer Serica Energy three fields in the aging offshore basin, including the Rhum Field which is co-owned by a subsidiary of Iran's national oil company.

For Serica, the $400 million deal will increase its production sevenfold. It nevertheless hinges on the British company receiving a license from U.S. sanctions enforcement authorities at a time when President Donald Trump is flexing his muscles against Tehran.

For BP and its American Chief Executive Bob Dudley, selling Rhum, which BP discovered in the 1970s, removes a potential source of friction as it mends its ties with the U.S. government following the deadly 2010 Deepwater Horizon spill in the Gulf of Mexico.

Rhum was shut down for most of the first half of the decade due to western sanctions on Tehran before resuming normal operations in 2016 following a landmark nuclear deal between Iran and the world's top powers.

Because of the Iranian involvement, BP needs a license from the U.S. Treasury's sanctions enforcement arm—the Office of Foreign Asset Control (OFAC)—allowing U.S. nationals and companies to take part in the field's operations.

The license was renewed in September, a month before Trump sought to reverse the U.S. position on the nuclear deal with Iran. Serica will apply for its own license in the coming months, Tony Craven Walker, Serica's Executive Chairman, told Reuters.

"Getting an OFAC license for Serica to assume operatorship of Rhum is part of the conditions of the transaction with BP," Walker said.

OFAC did not immediately respond to a request for comment.

BP, founded more than a century ago as the Anglo-Persian oil company, will lobby the British government to lend its support in requesting the U.S. administration to grant the license to Serica, according to a source at BP.

Though not a prerequisite to operate the field, the license is needed as a back-up in case of an emergency that requires U.S. equipment and companies, Walker said.

"Given the nature of the operations and our intentions to meet the same obligations as BP we don't foresee any reason for the license not to be granted," Walker said.

France's Total, which recently opened an office in Washington, is also closely monitoring the U.S. position on Iran which could decide the fate of its plans to develop a huge offshore gas field in Iran.

Britain Offers North Sea Tax Relief To Spur Investment

Britain plans to introduce tax changes to oil and gas companies operating in the North Sea, finance minister Philip Hammond said, in a bid to spur investment in the aging basin.

Presenting Britain's budget for next year, Hammond said that starting November 2018, tax history for oil and gas fields in the North Sea would be transferable from seller to buyer.

That will allow buyers to benefit from larger tax relief when fields reach the end of their life and require dismantling, known as decommissioning.

Britain's Oil and Gas Authority forecasts that North Sea oil and gas operators will spend almost $78 billion on decommissioning wells, platforms, pipelines and other infrastructure between now and the 2050s.

Government relief covers about 40% of the total costs.

Legislation on the tax relief will be published in spring 2018 with the aim of making transferrable tax histories available from Nov. 1, 2018, according to the proposed budget.

The North Sea has seen a flurry of deals in recent months, including Royal Dutch Shell's $3.8 billion sale of assets to private-equity backed Chrysaor, as longstanding operators make way for a new generation of smaller firms focused on squeezing more profit from old assets.

A row of decommissioned oil rigs from the North Sea in the Cromarty Firth, Scotland, is shown. (Source: Shutterstock.com)

Decommissioning remains a sticking point in many of the negotiations as the original operator of a North Sea field retains ultimate responsibility for its dismantling.

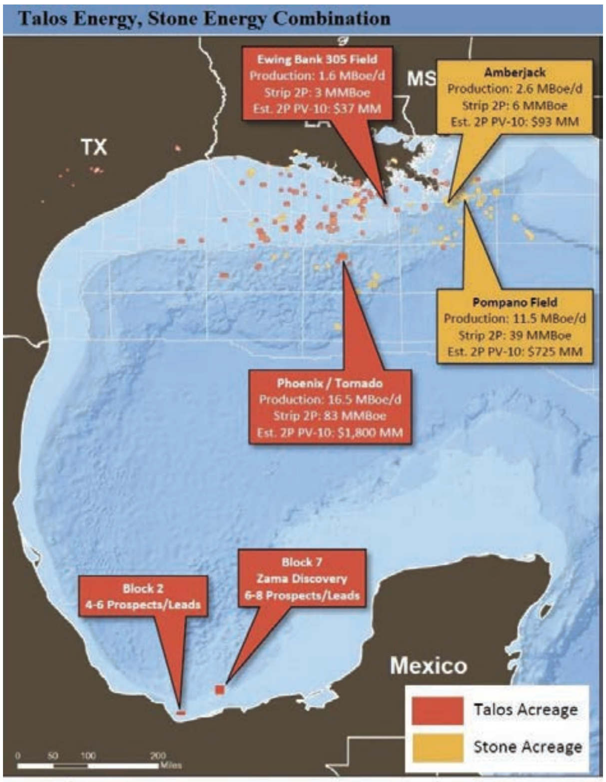
As a result, companies such as Shell or BP agreed in some cases to share part of future decommissioning liabilities in deals in recent years.

The announcement was welcomed by industry players.

—Reuters

BUSINESS

Talos, Stone Energy Merger Builds GoM Dreadnought



Source: Talos, Stone

Readying an E&P broadside at the Gulf of Mexico (GoM), Talos Energy LLC and Stone Energy Corp. said Nov. 21 they will merge in an all-stock transaction that the companies say represents an equity value of $1.9 billion.

The combined company will be named Talos Energy Inc. and stocked with pro forma proved reserves of about 136 MMbboe, of which 70% is oil. The reserves have a strip-priced PV-10 value of $2.28 billion, the companies said.

A Talos-Stone leviathan would give the company reign over 1.2 million combined gross acres, including 160,000 acres offshore Mexico. Estimated 2017 average daily production for the new company is anticipated to be 47,000 boe/d. Talos, based in Houston, reported that its third-quarter production averaged 28,700 boe/d.

The boards for both companies unanimously approved the combination. The deal value is partly based on Lafayette, La.-based Stone's stock price of $35.49 as of Nov. 20, or about $700 million in equity value.

Talos CEO Timothy S. Duncan said the combination represents an important step toward a goal of becoming a premier offshore E&P. The company's core areas will be deepwater GoM and the Zama discovery located offshore Mexico.

"The combined talent, technical resources and balance sheet of the resulting company will allow us to accelerate development of our own robust project inventory while also giving us the horsepower to pursue compelling transactional and exploration opportunities," Duncan said.

Duncan said operating synergies and capital efficiency give Talos and Stone an opportunity to create a GoM "front-runner." The combined companies said they expect to achieve up to $25 million in annual pre-tax synergies from supply chain management and other operational efficiencies by the end of 2018.

The Zama discovery, operated by Talos, is estimated by the company to have gross crude oil reserves between 1.4 Bbbl and 2 Bbbl. Talos drilled the first private sector offshore exploration well in the history of Mexico, which led to Zama—one of the 15 largest shallow-water discoveries of the past 20 years, the company said. Talos has two lease blocks offshore Mexico with an additional 10 prospects.

The combined company's other prospects include the deepwater GoM's Phoenix and Pompano fields.

In October Talos completed the Tornado II deepwater drilling campaign in the Phoenix Field in about 823 m (2,700 ft) of water. The Tornado II drilling campaign consisted of an exploratory test penetration in a fault block adjacent to the company's initial Tornado discovery in 2016, followed by a sidetrack well to delineate the initial reservoir.

Talos-Stone Combination, Pro Forma

Strip proved reserves (MMboe)	135
Strip 2P reserves (MMboe)	172
Strip proved PV-10 value ($MM)	$2,277
Strip 2P PV-10 value ($MM)	$2,976
2017E production (boe/d)	47,000
Pro forma 2017E EBITDA ($MM)	$440
Net debt / EBITDA (estimate)	1.4x
Operational Estimates 2018E	
Production (boe/d)	Up to 50,000
Capex ($MM)	$430 to $450

Source: Talos Energy, Stone Energy

Financially, the new company is expected to have a $1 billion credit facility with $600 million in initial borrowing capacity and no material long-term note maturities until 2022, the companies said.

"Upon closing, the combined company's pro forma unrestricted cash, undrawn credit facility and ability to access public capital markets will provide flexibility to pursue additional attractive growth opportunities," the company said.

Pro forma, the company's estimated 2017 net debt-to-2017 EBITDA ratio will be 1.4x and the new Talos will have liquidity of between $325 million and $375 million.

Neal P. Goldman, chairman of Stone, said the transaction represents the culmination of Stone's announced strategic review process and offers a compelling opportunity for shareholders to benefit from a combined company.

"Talos Energy Inc. will have substantial scale, important asset diversification and a talented management team, along with the strong financial position to continue to grow value for our combined shareholder base," he said. "I am very proud of Stone's success in growing shareholder value since its financial restructuring in February 2017 and I am confident Tim [Duncan] will lead the combined company to even greater success."

At closing, Talos stakeholders will own 63% of the combined company and Stone shareholders will own the remaining 37%. Stone's second lien notes will be exchanged into Talos' second lien notes and the company will carry a net debt of $611 million.

Duncan will lead the combined company with a board comprised of six directors named by Talos and four named by Stone.

The transaction is subject to the approval of Stone shareholders, consent of a majority of the unaffiliated holders of Stone's 7.5% senior secured notes due 2022 and successful completion of an exchange of the Stone notes for Talos notes. The deal must also pass regulatory approvals.

Franklin Advisers Inc. and MacKay Shields LLC, investment managers for about 53% of Stone's outstanding shares, have entered into voting agreements to vote in favor of the transaction, subject to certain conditions.

The transaction is expected to close in the first or second quarter of 2018, the companies said.

Citigroup acted as lead financial adviser and UBS Investment Bank as financial adviser to Talos in the transaction. Vinson & Elkins LLP and Paul, Weiss, Rifkind, Wharton & Garrison LLP were the company's legal counsel.

Petrie Partners Securities LLC acted as financial adviser to Stone, and Akin Gump Strauss Hauer & Feld LLP was the company's legal counsel in the transaction.

—Darren Barbee

BUSINESS BRIEFS

Subsea 7 Joins Shareholder Base Of Airborne Oil & Gas

Thermoplastics composite pipe manufacturer Airborne Oil & Gas said Subsea 7 has joined its shareholder base.

"The investment by Subsea 7 entails a partnership of strategic importance to both parties providing the oil and gas industry with cost-effective pipe technology solutions that are non-corrosive, lightweight, simpler and faster to install," Airborne said in a news release.

Subsea 7 contributes to Airborne's value proposition, and its presence in Brazil supports Airborne's deepwater business opportunities, Airborne CEO Marnix Boorsma said in a news release.

Chevron, Saudi Aramco, Shell and Evonik are also part of Airborne's shareholder base.

3D at Depth, iQ3 Collaborate To Deliver Subsea LiDAR Virtual Reality Data Platform

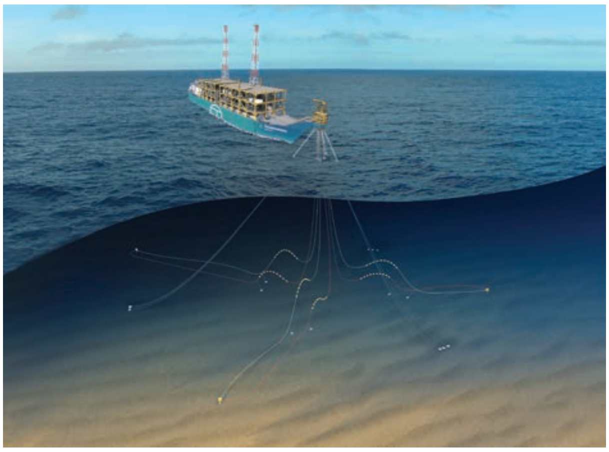
3D at Depth Inc. and iQ3Connect Inc. have teamed up to deliver a new data visualization tool aimed at helping clients build, maintain, map and monitor subsea assets, environments and resources, according to a news release,

The partnership will feature use of 3D at Depth's subsea LiDAR data and iQ3's augmented reality and virtual reality (VR) platform.

"Powered by iQ3's cloud-based software platform, customers can access 3D at Depth's subsea LiDAR data through a secure, optimized web-based portal," the release said. "The technology creates an immersive VR environment with true 1-to-1 3D scale models generated using repeatable, millimetric subsea LiDAR data inputs."

Companies Form Partnership To Unlock Smaller Offshore Gas Assets

Add Energy has partnered with Transborders Energy and joined forces with TechnipFMC and MODEC to create a fast deployment business model for the floating LNG (FLNG) industry that will free up small-scale stranded resources around the world and establish a new concept in global gas field development, a press release stated.



A partnership aims to free up small-scale stranded resources around the world and establish a new concept in global gas field development. (Source: Add Energy)

The new business model targets discovered gas resources of about 0.5 Tcf to 2 Tcf (56.6 Bcm) of gas that have little value to their current owners because they are either in remote locations where tieback is capital intensive or lack an economically viable development concept. Key to the model is the deployment of a small-scale FLNG vessel. Rather than investing up to five years in identifying a gas resource, understanding its size and potential and creating a bespoke development concept, the new model establishes a predefined concept incorporating the use of a about 1-million-ton-per-annum FLNG vessel and applies it to fields that fit the concept. This low-cost concept is designed to unlock hundreds of the world's previously uneconomic smaller natural gas plays.

Acteon Group Completes Viking Seatech Acquisition

Subsea services group Acteon has completed its purchase of the Viking Seatech Group.

As part of the move Mirage Machines will be sold to U.S.-based Actuant.

The deal is expected to extend Acteon's global reach with Viking Seatech's services complimenting those of mooring services specialist InterMoor, an Acteon company.

"The synergies between Viking Seatech and InterMoor, in terms of our complimentary assets and aligned values, mean we can enhance our offering to clients with locations in key hubs around the world, combining global strength with local expertise," Mark Jones, global CEO of InterMoor, said in a company statement.

Tamar Petroleum In Talks To Buy Noble Energy's Stake In Gas Field

Israel's Tamar Petroleum said it is in talks to buy a 7.5% stake in the Tamar natural gas reserve and the Dalit Field from Noble Energy for cash and equity.

The cash portion would be financed by a public bond offering without harming the company's credit rating, Tamar Petroleum said in a statement to the Tel Aviv Stock Exchange. The deal, which *The Marker* financial newspaper said could be worth as much as $900 million, would be subject to regulatory approvals.

Texas-based Noble owns 32.5% of the Tamar Field, Israel's primary supply of natural gas, and must reduce its holding to 25% by 2021 under government plans to open the market to competition.

Tamar Petroleum was created in July when Israel's Delek Drilling spun off a 9.25% stake in the Tamar reserve into a new company.

Delek Drilling still holds 22% of the Tamar reserve, which it must also sell by 2021.

Ashtead Appoints Regional VP For Americas To Drive GoM Growth

Steven Trasher has been appointed regional vice president for the Americas for subsea equipment specialist Ashtead Technology.

Bringing almost 20 years' experience in the subsea industry, Thrasher will lead Ashtead's U.S. operation as it gears up for further growth in the Gulf of Mexico (GoM) and neighboring markets. He will be based in Houston.

Prior to joining Ashtead, Thrasher held a number of senior and technical positions at FTO Services, C-Innovation and Schilling Robotics.

Steven Thrasher has joined Ashtead as regional vice president for the Americas.

The company also announced Chris Echols will take on the new role of vice president of sales for the Americas. With more than 20 years' experience with Ashtead, Echols will focus on delivering growth in existing and new markets across the region.

Global Marine Seals Fugro Trenching, Cable Lay Business Acquisition

Global Marine Group (GMG), an offshore engineering services provider, has completed its previously announced acquisition of Fugro's trenching and cable lay services business.

The acquisition bolsters GMG's offerings to the market with a range of integrated services, a news release stated.

The transaction also adds 23 Aberdeen-based employees with subsea engineering experiences to GMG along with the *M/V Symphony* multipurpose vessel, two Q1400 trenchers and two work class ROVs.

Diamond Offshore CFO Heads To BJ Services

Kelly Youngblood will join Texas-based BJ Services Inc., a pressure pumping services provider, as the company's executive vice president and CFO, according to a news release.

With 29 years of experience, Youngblood recently served as senior vice president and CFO of Diamond Offshore Drilling Inc. In November Youngblood notified Diamond Offshore of his intention to resign to accept a job at another company, according to filings with the Securities and Exchange Commission. He had joined the company in May 2016 following the retirement of its CFO Gary T. Krenek, who was retiring after 33 years of service to Diamond Offshore and its predecessors.

Diamond Offshore is conducting a search for Youngblood's replacement. In the interim, the company appointed Scott L. Kornblau, vice president and treasurer, to serve as Diamond Offshore's acting CFO until said replacement is found, the filings said.

Prior to his time at Diamond Offshore, Youngblood held a variety of executive and leadership positions with Halliburton Co.

Tom Leeson, interim CEO, Decom North Sea

Decom North Sea Appoints Well P&A Expert As Interim CEO

Decom North Sea has appointed Tom Leeson as interim CEO, the membership organization for the oil and gas decommissioning sector said in a news release.

Leeson, who immediately took on the role, brings nearly 30 years' industry experience—including 15 in the decommissioning sector, to the role.

Most recently, Leeson served as well abandonment global business manager for Halliburton and as principal consultant of well abandonment for Aberdeen-based Reverse Engineering Services. He is also a former vice chair of Decom North Sea's board.

M2 Subsea Names Business Development Manager For European Business

M2 Subsea has appointed David Sinclair as business development manager – renewables and decommissioning.

Based in Aberdeen, Sinclair will be responsible for leading the company's business acquisition strategy for both these sectors in the U.K. Continental Shelf and Europe.

Sinclair last served as the engineering and innovation manager for Bibby Offshore.

He brings to M2 Subsea more than 10 years of industry experience, having also worked as a project engineer at Global Pipelay Operations Group and holding several senior engineering roles at Subsea 7 and Technip Offshore Wind.

Aker BP Forms Separate Alliances With Maersk, Odfjell, Halliburton

Aker BP ASA has entered agreements to form two separate drilling and well alliances with Maersk Drilling and Halliburton for jackup drilling rigs, and with Odfjell Drilling and Halliburton for semisubmersible drilling rigs.

The framework agreements are five-years firm with the option to extend for another five years. Aker BP said the intent is that the alliances will plan and execute sanctioned production and exploration drilling activities by using an integrated well delivery model.

From left to right: Jørn Madson, CEO of Maersk Drilling; Joe D. Rainey, president–Eastern Hemispere at Halliburton; Karl Johnny Herswik, CEO at Aker BP; and Simen Lieungh, CEO at Odfjell Drilling. (Source: Aker BP ASA)

As part of the agreements, Halliburton will provide Aker BP's well construction activities performed from either a jackup (Maersk) or semisubmersible (Odfjell) drilling unit, provided the model is approved in the respective licenses.

The Norwegian oil firm said that both alliances were formed under "one for all, all for one" collaboration model where the partners align around common goals to drive continuous improvement and create greater value for all.

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