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Noble Looks To Future With Leviathan Offshore Israel

Noble Energy and partners are barreling toward first gas by year-end 2019 for the gigantic Leviathan development in the Eastern Mediterranean offshore Israel, having doled out more than 150 major contracts after the $3.75 billion project was sanctioned in 2017.

The Houston-based company is working to move from sanction to first gas within 34 months, which is challenging but manageable thanks to the company's project execution experience, according to Brian Hogan, the Leviathan project manager for Noble Energy. Key enablers include having a development plan with a minimal onshore footprint, a proven execution model and highly reliable conventional technology—all contributing toward achieving first gas by the end of 2019.


The Leviathan development aims to reach first gas by year-end 2019. (Source: Shutterstock.com)

There were vendor-related challenges, driven by the 2014 market downturn that led to high staff turnover and reduced staff levels for not only contractors but also subcontractors, Hogan said while speaking during a gathering of the Society of Petroleum Engineers Gulf Coast Section in Houston.

Everything appears to be coming together for Leviathan, which is operated by Noble Energy with partners Delek Drilling and Ratio Oil. Noble has overcome challenges by relying on proven technology and execution models, pulling plays from its nearby Tamar Field, where Hogan said uptime is nearly 100%, and Mari-B.

If Noble is going to move at a fast pace, the company wants to implement what it has a proven track record doing, according to Hogan, who added that led Noble to develop the field as a tieback to a fixed structure platform. "The reality is we've done it twice" before in Israel, he said.

Also key in meeting challenges was early engagement with stakeholders and jumping in to assist contractors and subcontractors in resolving issues, increasing execution efficiency, identifying opportunities and driving safety programs. "At the end of the day if we're going to be successful, they have to be successful," Hogan said.

Noble Energy is considered a mainstay for Israel, considering the company is known for firsts there and in other parts of the Eastern Mediterranean. The company's portfolio also includes assets in prolific U.S. shale basins, the U.S. Gulf of Mexico and West Africa.

Work Progresses

"What really separates Leviathan from any other project around the world? It's an opportunity to change a region," Hogan said. "You're bringing an affordable, reliable and

WHAT'S INSIDE

clean source of energy to a region that doesn't always have access to it or it's intermittent or it's not reliable."

Hogan explained how 2017 was all about awarding contracts, finishing engineering work and moving through the permitting process.

Tasks ahead for this year include installing pipelines for the project in the Levant Basin.

"Big activity on the host side will be floating all the decks by the middle of the year. At the end of the year a big milestone for the host is the jacket actually sailing," Hogan said. "We're going to split the installation of the jacket and the topsides."

Plans are for 2019 work to include subsea umbilicals, risers and flowlines installation as well as manifolds and jumpers, precommissioning work, topside hookup and wrapping up any incomplete onshore commissioning work to hit first gas as scheduled.

So far, two of the four wells have been drilled for Phase 1 of the project. The remaining two, along with completion of all four wells, will be finished this year, Hogan said. Once complete, plans are for the wells to be flow tested.

(Source: Shutterstock.com)

The company said that each subsea well is capable of flowing more than 300 MMscf/d of gas. It will be delivered via two 117-km (73-mile) flowlines to a fixed platform. From there, Noble said processed gas will travel via pipeline to tie in to the national gas grid to be distributed throughout the Israeli domestic market for electricity generation and industrial uses. Natural gas from Leviathan will also be exported to regional markets.

Meeting Needs

Leviathan is believed to hold 623 Bcm (22 Tcf) of gross recoverable resources. The gas produced will help meet the growing energy needs of Israel and the region.

Israel's natural gas use is forecast to climb to 12.5 Bcm (441 Bcf) in 2020 and to 18 Bcm (636 Bcf) by 2030, compared to the 5.3 Bcm (187 Bcf) consumed in 2010, according to the Israeli Energy Ministry. Most of the gas will be used for electricity generation and industry. This comes as the state works to transition toward cleaner energy sources like natural gas as well as reducing imports of coal and oil among other goals.

Currently, the Noble Energy-operated Tamar Field—which has 11 Tcfe of gross recoverable resources—is supplying 60% of Israel's energy needs. During a November 2017 presentation, the company said high natural gas demand is leading to record sales volumes. With an existing capacity of 31 MMcm/d (1.1 Bcf/d) for Tamar, Noble is assessing expansion opportunities for not only Tamar but also Leviathan.

Hogan explained that when Tamar went online in 2013 there were swings in energy demands with peaks in the summer and winter and declines in the spring and fall during the so-called shoulder months.

"Over time not only have those peaks grown to essentially max out our capacity, but those shoulder months have almost grown up to those peaks," Hogan said, noting Tamar is essentially producing at max rates for most of the year now. "What we're seeing is not only the growth from the past, we are forecasting that growth for the future. That's where Leviathan comes into the picture."

Noble is not alone in the Eastern Mediterranean. Energean Oil & Gas, which in 2016 bought stake in the Noble-discovered Tanin and Karish fields offshore Israel, is working to develop these fields via tiebacks to an FPSO unit. In other parts of the Mediterranean, such as offshore Egypt, Eni's colossal Zohr Field—which has more than 850 Bcm (30 Tcf) of potential gas in place—started up in December 2017 less than 2.5 years after it was discovered.

Export Potential

Gas export possibilities or plans are in the forecast, especially considering other countries in the region and nearby Europe are experiencing demand growth.

Leviathan has been designed with growth in mind, according to Hogan. The development has the ability to expand beyond 57 MMcm/d (2 Bcf/d), which Hogan said would require resources from four additional wells. "We'd have another line tied back to the platform from the manifold and our regional export module [a gas processing and export compression module] installed on the topsides. That's effectively what is envisioned at this point."

The module would export gas to neighboring countries and even outside the region, he added, noting this was worked into the design so that "when we pull the trigger on this we minimize impact to ongoing Leviathan production."

It's a delicate balancing act, aiming not to overbuild from the start, when developing to execute the Phase 1 scope. But Noble has done a lot of work to determine what makes sense and what doesn't, including on the subsea side, to minimize future downtime when working around manifolds to install more flowlines and tiebacks to the platform, for example, he added. Export destinations include Jordan.

"There are a number of other options on the table," Hogan said, including Europe and Egypt. Even with Zohr up and running, "there's still a pretty big market over there. They are all on the table right now."

—Velda Addison

DEVELOPMENT

Karoon Pushes Forward With Echidna, Sees More Santos Basin Potential

Tim Hosking

With assets in Peru and Brazil, Australia's Karoon has been progressing developments within South America's oil and gas segment. Yet, Brazil is seen as a very strategic country for the company.

In 2017 Karoon expanded its presence in Latin America's largest oil-producing country, acquiring its sixth block—S-M-1537—in the Santos Basin for about $6.3 million during Brazil's 14th bidding round. The company has a decade of technical and operational experience in the southern Santos Basin with five blocks—S-M-1037, S-M-1101, S-M-1102, S-M-1165 and S-M-1166—acquired in the 9th bidding round.

"We always believed that Karoon's first oil would be produced in Brazil," Karoon South America General Manager Tim Hosking said.

The company's activities in Brazil have been hot. Since 2013 Karoon has operated two drilling campaigns and a total of six wells, and it has made three oil discoveries: Echidna, Kangaroo and Bilby fields.

However, the company is making a big bet on the Echidna oil field.

"Echidna is a project that represents our future in the country with constant investment in research, analysis and professional training. This field is a milestone for us to constantly evaluate our progress in terms of strict environmental guidelines and prospects for productive development in the medium term," Hosking said.

According to the manager, Karoon has been talking to different suppliers to contract the FPSO unit to be deployed in Echidna. "We believe [that] by the second half of 2018 we will have a final decision on this hiring," he said. The field is expected to start producing oil by 2020. The amount of investment estimated for the field development plan is $300 million.

The development concept comprises two extended horizontal production wells and one gas injection well and a leased FPSO unit. Peak production is forecast to reach about 28,000 bbl/d.

Currently, the project is in the pre-development, engineering and basic design phase. The phase includes reservoir modeling, production scenario analysis, wellbore feasibility studies and development optimization.

In April 2017 Wood Group was awarded a multiyear contract from Karoon Petróleo & Gás to provide engineering services to support the full field development for the Echidna field offshore. According to the engineering services company, the partnership represents the first project between the two companies. The contract focuses on the technical requirements of a floating production unit (FPU) and subsea structures, and all bid package evaluations and execution phase. The equipped FPU will be located in the Echidna Field in the Santos Basin and moored in a maximum water depth of 400 m (1,312 ft).

Hosking also hailed Brazil's current moment for investment opportunities in the country's oil and gas industry. "Karoon has always believed in the potential of the offshore oil and gas market in Brazil. The company has observed the resumption of investments in the sector and significant advances in the decentralization of the segment, structuring new ANP [bidding] rounds with valuable assets and the growth of the national production," he said. "Karoon wishes to be present in this historic scenario focused on generating value for the entire Brazilian oil and gas production chain."

Brazil is a positive for the oil and gas industry, according to Hosking. He said the Brazilian government is making assertive moves to provide legal certainty and business stability for foreign investors.

Hosking said that the company eyes other opportunities in Brazil's oil and gas industry. "The development of the Brazilian market will be significant in the coming years. That's why Karoon is looking for valuable assets across the country. As I said, we believe in the resumption of the national oil and gas segment. That is why we want to strengthen our presence in Brazil more and more," he said.

—Brunno Braga

Shell OKs First UK North Sea Project In Six Years

Royal Dutch Shell gave the green light on Jan. 15 for an expansion of the Penguins oil and gas field in the U.K. North Sea, its first major new project in the aging basin in six years.

Shell said the development, which includes the construction of an FPSO vessel, reaffirmed the Anglo-Dutch company's commitment to the region after it sold around half of its assets there last year.

"Penguins demonstrates the importance of Shell's North Sea assets to the company's upstream portfolio," said Andy Brown, director of Shell's oil and gas production.

The FPSO vessel is expected to produce up to 45 Mboe/d.

Shell shares were 0.3% lower at 11:45 GMT.

The Shell-operated Penguins redevelopment is the first major project Shell has announced since 2012 when it made a final investment decision for the Fram Field in the central North Sea.

The project will generate a profit even with oil prices below $40 per barrel, Shell said in a statement, making it competitive against other offshore basins and most of North America's shale production

"We struggled to make it economic until the last couple of years when we closely worked with supply to redefine and redesign the development to reduce costs," Steve Phimister, head of Shell Upstream in the U.K. and Ireland, told Reuters.

After Penguins, Shell is expected to decide on a number of new projects in the central North Sea in the next year or two, Phimister said.

Shell gave no details on the cost of the project, which analysts at Bernstein in September 2017 estimated would be up to $2.5 billion.

Production in the U.K. North Sea has steadily declined since the late 1990s but has seen a modest recovery in recent years thanks to a number of new projects, including the BP-operated Quad 204 Field in the western Shetlands in 2017, in which Shell holds a 55% stake.

Operators have drastically reduced operating costs as a sharp drop in oil prices since 2014 forced companies to become more efficient and service providers to slash costs.

Shell's production is currently around 135,000 boe/d in the U.K. North Sea after completing the sale of a $3 billion package of assets to private-equity-backed Chrysaor in November 2017, Phimister said.

The company intends to maintain its production at this level into 2030, he added.

The Penguins Field was discovered in 1974 and first developed in 2002. It is a 50-50 joint venture with ExxonMobil.

—Reuters

DEVELOPMENT BRIEFS

Statoil Awards Aker Solutions Subsea Contracts For Troll, Askeladd

The Troll A platform is shown in the North Sea. (Source: Harald Pettersen/Statoil)

Aker Solutions said on Jan. 23 it was awarded contracts from Statoil to provide subsea production systems and services for the Troll Phase 3 and Askeladd natural gas developments offshore Norway.

The company will deliver a subsea production system consisting of two manifolds and nine trees for the Troll development in the North Sea. The system for Askeladd, in the Barents Sea, will comprise two manifolds and four trees. Both orders include installation and commissioning support services.

The contracts have a total estimated value of between $146 million and $194 million and will be booked in the first quarter. Work starts this month, with final deliveries scheduled for 2020.

Work on the two systems will involve facilities in Norway, Brazil, the U.K. and Malaysia. Initial deliveries are scheduled for second-quarter 2019. Aker Solutions' facilities in Ågotnes on the west coast of Norway and Hammerfest will provide the subsea services for Troll and Askeladd.

Troll, which contains about 40% of Norway's offshore gas reserves, is expected to continue producing for decades to come. Askeladd is slated to come onstream after 2020. It is located about 180 km (111 miles) from the Melkøya onshore plant, where the gas will be processed.

LLOG Kicks Off Drilling At Buckskin In US GoM

Louisiana-based LLOG Exploration has started development drilling at its Buckskin project in the U.S. Gulf of Mexico's Keathley Canyon area with a goal of starting production by mid-2019, the company said.

The initial phase of the deepwater project, where the water depth is about 2,073 m (6,800 ft), includes two development wells and a 1-km (0.6-mile) subsea tieback to the Lucius platform, which is also located in Keathley Canyon. The initial two wells will be drilled to about 8,839 m (29,000 ft), LLOG said. Following drilling and completion, subsea facilities will be installed.

LLOG said the field in the Lower Tertiary trend is estimated to hold nearly 5 Bbbl of oil and place. More wells and subsea facilities will be needed to fully develop the field, the company said.

LLOG affiliates Buckstone Development Co. and LLOG Deepwater Development Co. I hold a own a combined 33.8% working interest in the Buckskin development, with LLOG Exploration Offshore serving as operator. Partners are Repsol E&P USA Inc. (22.5%), Beacon Offshore Energy Buckskin LLC (18.7%), Navitas Buckskin US LLC (7.5%) and two entities managed by Ridgewood Energy Corp., Ridgewood Buckskin LLC and ILX Prospect Buckskin LLC, each of which owns 8.75%.

Aker BP Inks Frame Agreement With Aqualis Offshore

Marine and offshore engineering consultancy Aqualis Offshore has signed a frame agreement to provide marine services to Aker BP.

Under the frame agreement, Aqualis Offshore will provide marine warranty surveyor and marine services to Aker BP's fixed platforms, mobile units and subsea fields on the Norwegian Continental Shelf. Aqualis Offshore's scope of work covers loadouts, transports, installation, towages, moorings, rig moves and vessel inspections.

The agreement is valid for five years.

Aqualis Offshore, part of Oslo-listed Aqualis ASA, will support Aker BP with marine services from the company's offices in Norway.

Statoil Awards Sverdrup Reservoir Contract To Alcatel

Statoil has selected Alcatel Submarine Networks for permanent reservoir monitoring (PRM) on the Johan Sverdrup Field, according to a news release.

The seismic technology, a potential digital enabler for the field, will be a key contributor to delivering on Johan Sverdrup's 70% recovery ambition.

With 380 km (236 miles) of fiber-optic seismic cables installed on the seabed and more than 6,500 acoustic sensors covering an area of more than 120 sq km (46 sq miles), Johan Sverdrup will have one of the largest fiber-optic seismic systems of its kind.

For the first time on any field on the Norwegian Continental Shelf the seismic technology will be in place ready to optimize production in time for startup. The seismic cables will be installed on the seabed of Johan Sverdrup during 2019.

With PRM, seismic sensors are permanently embedded into the seabed, which enables more frequent and much improved seismic images of changes in the reservoir. The system on Johan Sverdrup will use optical fiber technology, which allows for continuous recording of changes in the subsurface, the release said. Data generated by this system are considered a key input to enable Statoil to deliver on its digital roadmap for the field.

The frame agreement with Alcatel Submarine Networks also includes opportunities for future collaboration around technology development and solutions to further maximize the potential from the PRM system. An option to extend seismic coverage to include the southernmost part of the Johan Sverdrup Field is also part of the agreement.

Aker Solutions Installs Manifold At Iracema Sul

A manifold is installed at the Santos Basin's Iracema Sul Field. (Source: Aker Solutions)

Aker Solutions has installed its first subsea manifold for Petrobras' deepwater presalt fields, the company said via Facebook.

The manifold was installed at the Iracema Sul Field in the Santos Basin offshore Brazil.

At a water depth of 2,200 m, the company called the equipment installation one of its deepest.

"Three more manifolds will be installed by May," the company said.

Production from Iracema Sul Field started in October 2014 via the *Cidade de Mangaratiba* FPSO unit.

Statoil May Build Onshore Terminal For Castberg Oil

Statoil has begun work on a proposal to build an onshore terminal in northern Norway for handling oil from the Arctic offshore Johan Castberg oil field and other yet-to-be-developed resources, the country's energy minister and Statoil's CEO said Jan. 16.

A report on the proposal is expected in 2019, Minister of Petroleum and Energy Terje Soeviknes told Reuters on the sidelines of a conference.

"We are working together with several other license holders and operators to see if there is a basis for building a terminal," said Statoil's CEO Eldar Saetre, also speaking to Reuters. "We want to make it work, but we need more resources than Castberg for it to be realistic."

An onshore terminal could help to cut oil shipping costs as it would allow larger tankers to ship the oil. The decision to build such a terminal would depend on whether it could also receive oil from other developments, including Lundin's Alta/Gohta and OMV's Wisting discoveries.

Lundin and OMV have yet to decide whether to develop those discoveries.

Eni and Norway's state-owned Petoro are Statoil's partners in the Johan Castberg license.

Talos Releases IP Results From GoM's Tornado II Well

Talos Energy is growing production at the Phoenix Field in the U.S. Gulf of Mexico's Green Canyon area, with the Tornado II deepwater well flowing more than 12,350 boe/d during a two-week test in December 2017.

The Houston-based company, which is set to merge with Stone Energy Corp., released IP results from the well on Jan. 16. The well is located in about 823 m (2,700 ft) of water.

Talos said the Tornado II drilling program consisted of an exploratory test penetration in a fault block adjacent to the company's initial Tornado discovery in 2016, followed by the Tornado II producer to delineate and further develop the initial reservoir. More than 80% of the gross production from the Tornado II deepwater well during the test was oil.

Coupled with the first Tornado well, Talos said it plans to flow the wells at a combined gross rate of between 24,000 boe/d and 27,000 boe/d. The wells flow through the existing Phoenix Field subsea infrastructure into the Helix Producer I floating production unit on the adjacent Green Canyon Block 237, the company said in a news release.

Talos serves as operator with 65% interest. Its partner is Deep Gulf Energy III with a 35% working interest.

KBR JV Wins Two FEED Contracts For Azeri Central East Project

KBR Inc. said on Jan. 16 that its joint venture (JV) with SOCAR has been awarded two separate FEED contracts for a new production, drilling and quarters platform.

The Azeri Central East platform will be located in the Azeri-Chirag-Gunashli (ACG) Field in the Azerbaijan sector of the Caspian Sea.

The contracts cover the provision of FEED services for the new platform, along with associated brownfield tie-ins to other existing platforms in the ACG Field, and a separate contract for the subsea services FEED.

Following previous awards to other regional and international clients, these contracts mark the fourth and fifth awards to the JV, SOCAR-KBR Ltd. Liability Co. (SOCAR-KBR), since its inception in mid-2015. SOCAR-KBR was formed to help further Azerbaijan's ambition for creating a world-class Azerbaijan based engineering company.

The value of the contract was booked into the backlog of unfilled orders for KBR's Engineering & Construction business segment in fourth-quarter of 2017.

Canada Orders Husky To Halt SeaRose Operation After Iceberg Close Call

Canadian regulators on Jan. 17 ordered Husky Energy to suspend operations on its 27,000-bbl/d *SeaRose* floating production vessel off the coast of eastern Canada after an iceberg came too close to the facility in March 2017.

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) made its decision after an investigation found Husky did not follow its own Ice Management Plan when an iceberg came within 0.25 nautical mile of the FPSO vessel.

Husky did not disconnect the *SeaRose* FPSO vessel and sail away from the iceberg as it should have done, and at one point people onboard were ordered to "brace for impact," the C-NLOPB said in a statement. "The C-NLOPB has determined there are serious issues respecting Husky's ice management, management systems and organizational decision-making," the regulator said.

At the time, there were 84 people and 340,000 barrels of crude onboard the vessel, which is located in the North Atlantic's White Rose oil field, about 350 km (217 miles) east off the coast of New Brunswick province.

The iceberg did not ultimately make contact with the *SeaRose* or underwater infrastructure and there were no injuries, environmental damage or damage to Husky facilities.

"We could have and should have responded differently according to the pre-existing plan, and we will learn from this incident. We will work with the C-NLOPB and take the actions necessary to satisfy the regulator," Husky's CEO Rob Peabody said in a statement.

Husky spokesman Mel Duvall said the company does not know for how long the *SeaRose* FPSO vessel will be shut down.

The C-NLOPB said SeaRose operations will remain suspended until it is confident Husky has addressed the findings in the investigation.

The *SeaRose* FPSO vessel began operations in 2005 and serves the White Rose Field as well as the North Amethyst, West White Rose and South White Rose extensions.

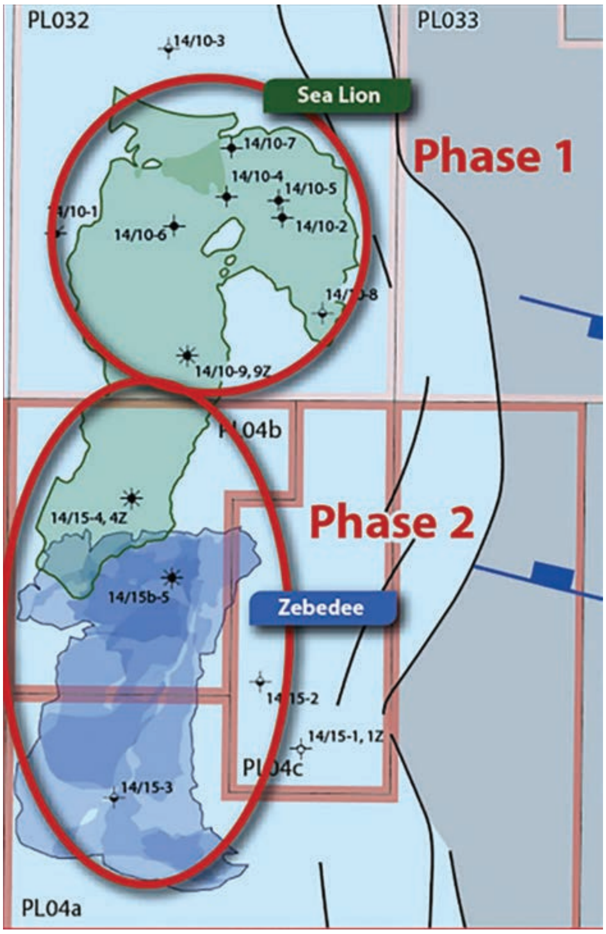
Rockhopper Eyes 2018 FID For Sea Lion Development

Rockhopper Exploration aims to make a final investment decision (FID) for the $1.5 billion Sea Lion Phase 1 development in the North Falkland Basin by year-end 2018.

Sea Lion is operated by Premier Oil, holding 60% interest.

The company, which delivered an update in January, said a new draft field development plan for the project was submitted to the Falkland Islands government in November 2017, and the governmental authorities "recently confirmed it does not anticipate that the planned discussions will uncover any major issues, and that the minor issues under discussion should be satisfactorily resolved in due course."

Recoverable resources for Phase 1 to be commercialized are about 220 MMbbl with peak production planned for about 80,000 bbl/d. The expected life of the field is 20 years, according to Rockhopper.



The Sea Lion Field in the North Falkland Basin will be developed in phases. (Source: Rockhopper Exploration)

FEED work for the project has been completed, and focus turned to the project's commercial, fiscal and financing elements during second-half 2017, the company said. "The joint venture continues to progress financing for the Sea Lion project including through senior debt and subordinated contractor funding streams," Rockhopper said.

Based on the latest update, letters of intent have been entered with contractors for well and certain logistical services as well as vendor financing. Rockhopper and its joint venture partners anticipate entering further agreements associated with drilling and the subsea system during first-quarter 2018.

On the financial side, the company continues potential export credit talks and "expects to commence a bank engagement process with the aim of establishing bank market appetite for the project" during first-quarter 2018.

Rockhopper holds a 40% working interest in the development.

—Staff & Reuters Reports

EXPLORATION

Schlumberger To Exit Land, Marine Seismic Acquisition Business

Schlumberger Ltd. has decided to exit the land and marine seismic acquisition business, which has been battered by the downturn and faces an uncertain future.

The business segment is the Houston-based company's only product line that fails to meet future return expectations, according to Schlumberger CEO Paal Kibsgaard.

"This has not been an easy decision to make. But following a careful evaluation of the current market trend, our customers' buying habits and our current and projected financial return, it is an unfortunate and inevitable outcome," Kibsgaard said during the company's earnings call on Jan. 19.

The exploration business was especially hit hard when global oversupply and unmatched demand combined to send oil prices down, causing oil and gas companies to cut back spending and halt projects. Exploration, for the most part, took a backseat to drilling and producing resources with fast turnaround times—U.S. shale plays—as operators looked to quickly reap gains in commodity prices.

Exploration investment is expected to remain suppressed and exploration budgets tight in 2018 despite a brighter price outlook, Wood Mackenzie said earlier this month. "Exploration's share of upstream investment has slipped to below 10% since 2016 and is not about to recover," the analyst firm said.

Schlumberger's marine and land seismic acquisition services are offered through WesternGeco, which is part of the company's reservoir characterization group. The group reported revenue of $1.6 billion for fourth-quarter 2017, down 8% sequentially and down 2% from a year ago.

The oilfield service company highlighted the strength of the group's Integrated Services Management operations, contract awards and new technology deployments for the quarter. However, that was not enough to help solidify the land and marine seismic acquisition business' place within the company.

Schlumberger reported about $3 billion of pretax charges for fourth-quarter 2017. This included more than $1.1 billion in seismic restructuring expenses related to WesternGeco and a $938 million write-down of holdings in Venezuela, which has been experienced economic and political turmoil.

The charges played a role in Schlumberger's fourth-quarter net loss of $2.26 billion, up from $204 million a year ago. Revenue jumped by 15% to more than $8.18 billion thanks in part to strong land activity in North America, where revenue increased 59% year-over-year to $2.8 billion.

"Geophysical measurement, survey design and seismic operations have been an essential part of Schlumberger and our R&E [research and engineering] efforts for more than 30 years," Kibsgaard said, pointing out the company's unique position in terms of intellectual property and its engineering and manufacturing capabilities. But as the downturn enters a sixth year for the seismic data acquisition business, "the present outlook provides no line of sight for the market recovery."

WesternGeco's offshore seismic ship *Amazon Conqueror* is shown off Malaysia's Labuan Island. (Source: Shutterstock.com)

Kibsgaard added that the company's customers are not willing to "pay a premium for differentiated seismic measurement and surveys" and "clearly believe that generic technology and performance is sufficient." This creates a low technical barrier for smaller players to enter the segment, which keeps demand in a chronic state of overcapacity, he said, adding the company's seismic acquisition business cannot provide the desired full-cycle returns for Schlumberger or compete internally for funding.

Schlumberger isn't the only one being challenged in today's seismic environment as evidenced by the financials of others in the business.

CGG, for example, filed for bankruptcy in France and the U.S. in 2017 in a move to eliminate $1.95 billion in debt from its balance sheet. Global Geophysical Services filed for bankruptcy in 2016 (its second time in two years). Seismic surveyor Dolphin Group filed for bankruptcy in 2015.

"This challenging commercial environment is clearly reflected in the financial statements of standalone acquisition players who are either at or close to bankruptcy, heavily burdened by weak cash flow and high debt," Kibsgaard said. "While these standalone acquisition players have no other choice than to stay in and fight on to avoid bankruptcy while hoping for a better future, we at Schlumberger do have a choice and we chose to exit the commoditized land and marine acquisition business."

The exit comes as the industry continues to make technological strides such as advances in high-performance computing, data analytics and machine learning. Such technologies enable the company to "extract significantly higher value from our previously acquired data," Kibsgaard said.

Schlumberger's WesternGeco will adopt an asset-light model going forward based on its multiclient data processing and interpretation businesses, he said. The company plans to honor its existing contracts and customer commitments and cold-stack equipment as it evaluates divestment options.

"Given the financial state of the other seismic acquisition players and the absence of a clear line of sight for a recovery in the seismic market, we are prepared for the divestiture process to take some time, and we may end up selling our acquisition business to a new market entrant," Kibsgaard said.

—Velda Addison

EXPLORATION BRIEFS

ExxonMobil Signs Deal For Deepwater Oil Exploration Offshore Ghana

ExxonMobil Corp. signed a deal with Ghana on Jan. 18 to explore for oil in the Deepwater Cape Three Point offshore (DWCTP) oil field.

The signing followed direct negotiations between Ghana and ExxonMobil without an open competitive tender due to the nature of the field, where the depth ranges from 2,000 m to 4,000 m (6,562 ft to 13,123 ft), Ghanaian officials said.

Ghana, which exports cocoa and gold, began commercial production of oil from its flagship Jubilee reserves in late 2010. Other firms drilling in the West African country include the U.K.'s Tullow Oil and Kosmos Energy.

The ExxonMobil deal is the first to be signed after the International Tribunal for the Law of the Sea in September 2017 drew an ocean boundary favoring Ghana in a dispute with its neighbor Ivory Coast. ExxonMobil, lead operator, holds an 80% interest in the DWCTP, while state-run Ghana National Petroleum Corp. holds 15%. ExxonMobil is yet to select a local partner to own the remaining 5% as Ghana's laws required, Energy Minister Boakye Agyarko told Reuters.

The agreement is subject to approval by parliament, and ExxonMobil is expected to start exploration this year, Agyarko said.

Total, Eni Award Seismic Survey To Shearwater GeoServices

Shearwater GeoServices said on Jan. 18 it has been awarded a 10,000-sq-km (3,861-sq-mile) marine seismic acquisition services contract by Total and Eni.

The contract is for Total and Eni's 2018 exploration program, which is located approximately 300 km (186 miles) offshore Myanmar. Shearwater will deploy the vessel *Polar Empress* for the survey, which is expected to take about six months, commencing in January 2018.

Total and Eni are the operators of the two blocks to be surveyed, YWB and MD-04, off the coast of Myanmar.

The *Polar Empress* vessel was built in 2015, has a capacity of up to 22 streamers and is one of the most powerful and efficient seismic vessels in the world.

This contract is the second significant recent award to Shearwater, following the November 2017 award by a national oil company for a five- to six-month contract for which it started mobilizing the vessels *Polar Duchess* and *Polar Marquis* in December.

"The seismic market remains challenging, but on the back of a solid operational performance in 2017 in combination with recently awarded contracts, Shearwater is well-positioned through the winter season and for 2018 as a whole," CEO Irene Waage Basili said.

Norway Awards Record 75 Oil Exploration Licenses

Norway has awarded a record 75 offshore oil exploration licenses to Statoil, Aker BP, Shell, Total and ConocoPhillips, among others, the energy ministry said Jan. 16.

The licenses comprised 45 in the North Sea, 22 in the Norwegian Sea and eight in the Barents Sea and were awarded in a so-called annual predefined areas licensing round, introduced by Norway in 2003 to encourage exploration and development of discoveries near existing infrastructure.

"The number of licenses is the highest ever awarded in a licensing round on the Norwegian Continental Shelf. Access to new prospective exploration acreage is a central pillar in the government's petroleum policy," Energy Minister Terje Soeviknes said in a statement.

The 75 licenses were awarded to 34 firms, of which 19 won the right to lead projects.

Environmentalists have criticized the expansion of exploration acreage via annual predefined areas rounds in the Barents Sea, saying that such moves into a largely unexplored area with only two producing fields exceed the original purpose of the rounds.

In total, 39 firms had applied for the offered acreage, up from 33 companies that applied in the previous round a year ago, when the ministry awarded 56 exploration licenses.

Statoil was the biggest winner in the latest round with 31 licenses, including 17 lead operators, while Aker BP came in second with 23 licenses, of which 14 were lead operators.

Shell, Total, ConocoPhillips, Lundin Petroleum and ExxonMobil were among those awarded acreage.

Energean Picks Up Exploration Licenses Offshore Israel

Israel's energy ministry has awarded Energean five offshore licenses to explore for oil and gas in the Mediterranean Sea, according to a news release.

The three-year licenses are for blocks 12, 21, 22, 23 and 31, which are all located near the Karish and Tanin gas fields Energean is working to develop.

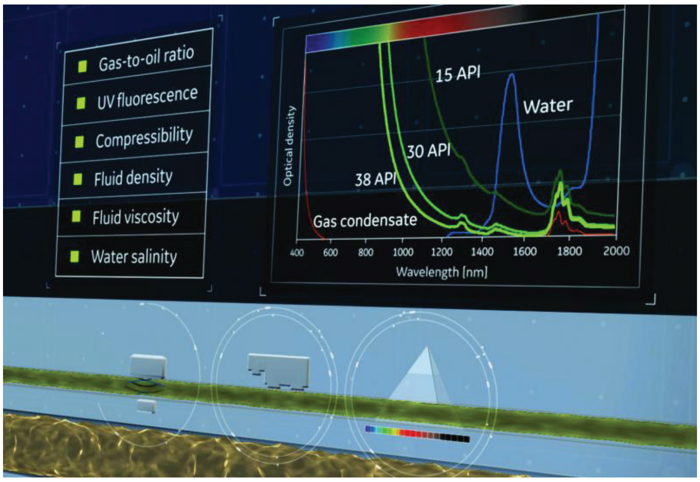
Energean said it believes licenses awarded are "highly prospective and would benefit, in the event of any economic hydrocarbon discoveries, from being developed via tiebacks to the FPSO [unit] that Energean will construct for the development of the Karish and Tanin fields."

The three-year licenses carry a possibility for an extension for another three years as long as the company carries out work and promises to drill. Reuters reported Energean was required to prove it had assets of at least $400 million and $100 million in shareholders' equity as a condition for the licenses, to ensure it would search for oil and gas.

—Staff & Reuters Reports

TECHNOLOGY

Meeting Wellbore Complexity With Real-time Fluid Analysis Advances



The FASTrak Prism service employs advanced sensors—including the newly introduced VIS-NIR and fluorescence spectrometers—to fully characterize reservoir fluids in real time. (Source: BHGE)

Though relatively new to the industry, fluid analysis and sampling-while-drilling techniques have quickly helped operators make more informed well construction decisions, eliminating risk and improving efficiency.

But as operators continue drilling geometrically complex wells into deeper and more remote reservoirs, fluid sampling services have to keep pace by developing more precise sensing capabilities. This was the motivation for Baker Hughes, a GE company (BHGE), to develop its FASTrak Prism fluid analysis and sampling-while-drilling service.

Real-time Characterization Of Multiphase Flows

This new service is built on the robust framework of the FASTrak, the industry's first commercial fluid sampling-while-drilling service introduced in 2014. The original technology afforded real-time analysis of bulk fluid properties and acquired clean fluid samples for more detailed testing at the surface, both of which helped optimize completion designs and production plans.

The next-generation technology incorporates new sensors, including visible-to-near-infrared (VIS-NIR) spectrometry, to fully characterize reservoir fluids in real time. The tool's multichannel optical density and fluorescence measurements accurately quantify fluid compositions in multiphase flows containing oil, gas and water. Additional sensors measure pressure-volume-temperature (PVT) properties such as fluid density, solution gas-oil ratio and fluid compressibility while providing measurement redundancy to give the operator greater confidence in the analysis results.

As with other LWD technologies, the sensors in this service relay information to surface in real time. The petrophysical team then uses proprietary software to evaluate the collected data in real time, which provides greater quality control, improved certainty of the measurements and faster decision-making.

For example, real-time PVT analysis informs the operator's decision on which zones to complete and which ones to bypass. And the ability to analyze fluids while drilling provides additional information to fine-tune the reservoir navigation workflow, thus enabling timely confirmation of whether the well is still in the optimal pay zone or if a course correction is required.

The service's probe is typically positioned 15 m to 30 m (50 ft to 100 ft) away from the drillbit and behind other formation evaluation-while-drilling tools. This positioning provides sufficient time to drill through the interval; evaluate the formation evaluation data such as nuclear magnetic resonance, resistivity and porosity; and pinpoint the optimal locations within each of the target reservoirs. This efficient approach of evaluating and then sampling the reservoir while drilling offers the added cost-saving benefit of limiting the reservoir's exposure to the drilling mud, which means lower contamination samples can be acquired within two hours of setting the probe.

High-quality, High-volume Sampling

Most field development decisions require more information than real-time fluid characterization alone provides. Operators routinely require 10 liters (2.6 gal) or more of fluid from different reservoir compartments to run analyses that help evaluate reserves, improve completion and surface facility designs and optimize the flow assurance program.

The original LWD fluid sampling service has successfully acquired high-quality fluid samples during drilling operations in many wells since its inception. The new service is similarly designed to acquire formation fluids of the same quality and volume for the range of laboratory analysis required.

During a sampling operation the service's sensor array continually measures the properties of the pumped fluids and monitors for contaminants. Once the fluid's quality has been confirmed, the service collects up to 12 liters (3.2 gal) of single-phase reservoir fluid per run and preserves them in 16 750-ml (566.3 oz) sample chambers prior to bringing them to surface for evaluation. This sizable fluid sample, which represents the largest total volume and most sampling chambers collected in a single run from any sampling- while-drilling service, helps operators make strategic development decisions more quickly and cost-effectively.

Reducing Risk, Time

The new LWD fluid sampling service is ideally suited for offshore, high-angle and extended-reach onshore wells—all applications that introduce considerable time and risk for conventional fluid sampling services. Wireline-conveyed testing and sampling techniques, for example, are commonly deployed to measure formation pressures and fluid properties but only after the drillstring has been pulled out of hole. In deeper wells with long lateral sections wireline tools require lengthy, risky and expensive pipe-conveyed logging operations. And in deepwater environments well integrity risks arise when the hole is left open for many days between drilling and the wireline run.

The new sampling service, by contrast, allows the operator to quickly identify the productive zones of interest, continue circulating to maintain well control and acquire fluid samples shortly after drilling the interval. And because this is accomplished with the same drillstring in the hole, the risk and time associated with performing an additional wireline run are eliminated.

After a wireline deployment the operator would typically need to go back in and recondition the drilling mud in the well prior to moving to the casing and/or completion phase. But by acquiring fluid samples while drilling, the new service ensures that the mud in the well is already conditioned. Once the drillstring is pulled out of hole, the operator immediately moves to the casing and/or completion stage, saving time and lowering construction costs in the process.

Optimizing Production Output

Since its introduction earlier this year the service has been deployed offshore, where rig rates are higher and the need for high-efficiency, low-risk operations is more acute.

An operator off the coast of Africa recently selected the technology to help drill a deepwater extended-reach well intersecting two reservoir compartments. Accurate fluid characterization was necessary to design the optimal completion for commingled production and to estimate each reservoir's contribution to total production.

The operator needed high-quality single-phase samples and formation pressure tests from each reservoir while avoiding the extended rig time and deployment risks associated with pipe-conveyed wireline sampling. Any solution also would have to fit seamlessly with the reservoir navigation geosteering tools and an on-command downhole digital rat hole-reaming tool on the bottom-hole assembly (BHA).

BHGE personnel worked closely with the operator's field crews to develop a comprehensive formation evaluation plan while drilling. The new sampling-while-drilling service was deployed to collect samples in each reservoir per operator requirements for fluid volume and number of samples while also performing 33 formation pressure tests.

The section was drilled to its targeted measured depth with a final inclination of 90 degrees. All tests were performed in the 8½-in. hole prior to opening up to 9½-in. hole size with the reamer. The LWD sampling service also acquired fluid samples to calibrate downhole flowmeters and quantify each reservoir's production contribution.

The new fluid sampling service did not interfere with the operation of the geosteering service, which accurately directed the well to maximize contact through the two target reservoirs. There was also no interference with the operation of the on-command digital reamer, which reamed the rat hole in the same drilling run.

This combination of technologies saved 48 hours of rig time while achieving well production output that exceeded initial targets by more than 30%.

Setting Sampling Records

An operator developing a new field offshore Australia required large volumes of high-quality fluid samples for detailed geochemical analysis to inform its completion, surface facilities and pipeline designs. Selecting the wrong metallurgy raised the possibility of reservoir fluids degrading or corroding completion and surface equipment, leading to significant costs and HSE risks.

The operator estimated that 20 liters (5.3 gal) of fluid were required for proper PVT analysis from the first wells, which were highly deviated with an inclination of up to 80 degrees. After discussing the specifics of the reservoir, the production goals and the completion challenges, the BHGE team recommended the fluid analysis and sampling-while-drilling service for this operation. The service would not only capture up to 400% more fluid volume than other sampling-while-drilling systems, but it also would avoid the differential sticking risks common to wireline sampling systems in deviated wells.

To save time in the analysis, the operator and service provider developed a sampling strategy that maximized fluid volume capture from two drilling runs on two different wells. The plan called for spending two hours on the wall at each sampling location followed by retracting the probe and adjusting the BHA to mitigate sticking risks.

The service captured 26 samples—12 from the first well and 14 from the second—with a total sample volume of more than 20 liters. This represented a global record for fluid sampling-while-drilling and an improvement over similar services that required at least four runs to reach the same volume goal.

This large sample volume allowed the operator to test and select all materials that would safeguard the integrity of the completion and surface equipment. And despite the extended on-wall sampling times and challenging hole inclination, the sampling service exhibited no differential sticking issues.

These early field successes are prompting other operators to take a closer look at FASTrak Prism's potential for their high-risk wells.

—Femi Adegbola, Baker Hughes, a GE company

TECHNOLOGY BRIEFS

Delta, Optime Combine To Offer Subsea System

Delta Subsea LLC and Optime Subsea AS have joined to provide a small and light deepwater Intervention Workover Control (IWOC) system for depths of up to 3,000 m (9,843 ft).

The system moves hydraulics from topside to subsea, which eliminates the need for top-heavy hydraulic umbilical, reel or designated containers. That reduces the expense of mobilization and demobilization, cuts operational time and enhances safety by avoiding handling and clamping topside.

"This IWOC system will potentially free up the drilling rig and allow installation to be carried out by one of our fleet's IMR [inspection, maintenance and repair] vessels," said Delta CEO Scott Dingman. "This system can be utilized for installation and testing of subsea trees as well as operating and overriding of the same subsea assets. The IWOC system is supported subsea via the Delta SubSea ROV system(s) and associated intervention tooling as required. By using this system, we estimate that customers can achieve a 60% cost savings directly on installation cost in many of their projects."

Among the solutions provided by IWOC are christmas tree control for installation, interventions, testing, SCM diagnostics or other subsea XT tests and applications.

ExxonMobil, MagnaBond Partner On Well Integrity Evaluation Technology

ExxonMobil Corp. said Jan. 16 it has formed a new partnership to develop technologies addressing well decommissioning activities.

ExxonMobil Upstream Research Co. signed a three-year joint development agreement with MagnaBond LLC to develop new technologies that could enhance cost-effective evaluation of well cementing, casing and tubing. The agreement was facilitated by the Industry Technology Facilitator as part of its initiative to address challenges associated with well-decommissioning activities such as plugging and abandonment.

ExxonMobil and MagnaBond will work toward developing technology that allows for through-tubing cement evaluation prior to the arrival of a costly rig or workover unit.

Current evaluation technology cannot adequately characterize cement quality through multiple strings of casing, according to the company press release. A well's production tubing must be pulled to inspect the cement, resulting in additional time and expense for decommissioning activities.

"Developing a technology that enables us to see the quality of well casing and cement with a single tool is a major step in determining overall well integrity and could result in significant cost savings," Jayme Meier, vice president of engineering for ExxonMobil Upstream Research, said in a statement.

Meier added that the agreement will bring together the strengths of each company to jointly develop solutions. The new collaboration combines ExxonMobil's expertise in developing a wide range of inspection technologies and tools with MagnaBond's strengths in technology transfer and supply chain design from other industries.

Bourbon, Bureau Veritas Form Vessel Digitalization Partnership

Bourbon and Bureau Veritas have signed a strategic partnership agreement to develop and deploy automation and real-time monitoring fleet applications, developing digital technologies, while mitigating cyber risks, the companies said.

First application of the partnership will be real-time verification of the dynamic positioning (DP) operations of the Bourbon fleet.

The partnership aims to deliver advanced automation of dynamic positioning systems to enable improvement of DP operational safety through real-time advisory tools for bridge operators and remote support for onshore teams; streamlining of onboard organization leading to potential reduction of manning; and a reduction in fuel and DP maintenance costs.

A pilot has been implemented on the *Bourbon Explorer 508* operating in Trinidad waters. Developed with Kongsberg Maritime, it is certified by Bureau Veritas. It collects data from the DP system and drives the development of novel decision-making and verification applications for both offshore crew and onshore support teams.

According to Bourbon, another vital element of the project is addressing cybersecurity threats. APSYS, an Airbus company specialized in product security, is helping identify and mitigate risks linked to data collection and communication between Bourbon's vessels and onshore infrastructure.

Based on this risk assessment relying on best practices from APSYS's aerospace experience, Bureau Veritas is able to issue cybersecurity certification on products and class notations for ships meeting global industry security standards.

Pendant Detects Trips Or Falls From Equipment On Offshore Rigs

The MD-S provides global GPS services and is able to withstand extreme conditions and uses. (Source: SecuraTrac)

SecuraTrac has released the Mobile Defender-Model S, an mPERS pendant equipped with location technologies and a built-in fall advisory capability.

The Mobile Defender-Model S can detect horizontal and vertical movement and can be used to detect trips or falls from equipment on offshore rigs with cellular signal. Injured employees do not need to place a call for help, the Mobile Defender-Model S will trigger one automatically, or the SOS button on the device can also be used to trigger a call. Wake-on SOS gives this small, mobile PERS device the ability to last over 30 days on a single charge.

SecuraTrac mPERS solutions work in more than 120 countries across North and South America, Europe, Asia, Africa, the Middle East and Australia, and are compatible with every major cellular service provider including Verizon, AT&T and T-Mobile in addition to foreign carriers.

Web-based tool Enables Live Ship Management, Data Tracking

ChartCo, a global supplier of maritime digital data and compliance services, has released its new FleetManager software, a press release stated. As a web-based tool, FleetManager enables shore-based customers to access live ship management and tracking data in one place at any time and on any popular browser (Chrome, Firefox, Safari, IE or Edge) as well as via smartphones and tablets.

FleetManager offers a range of highly effective environmental, piracy and regulatory overlays that can highlight potential sources of delay or hazard. It also provides the ability to link with ChartCo's e-navigation platform

ChartCo's FleetManager enables shore-based customers to access live ship management and tracking data. (Source: ChartCo)

PassageManager. This enables shore-based staff to view an active passage plan so that any deviations from the expected track can be interrogated in real time.

FleetManager also helps managers to ensure fleet compliance with the ability to inspect any vessel remotely and to view and instantly audit its navigation and compliance status. Managers also can check software versions installed, connection history and data download volumes. They also can authorize, approve or reject electronic and paper chart and publication orders placed through PassageManager.

McDermott's First Digital Innovation Center Unveiled in India

McDermott International Inc. has launched its First Digital Innovation Center in Pune, India.

The 5,400-sq-ft center will focus on digital innovation delivery, digital product management and the digital experience, McDermott said in a news release.

"This facility has been developed as an expansion to McDermott's operations in India," Akash Khurana, McDermott's vice president, chief information and digital officer, said in the statement. "The aim of the center is to cater to our current and prospective clients with the best possible digital technology in the EPCI [engineering, procurement, construction and installation] space of offshore facilities and subsea fields."

The center will serve as a technology epicenter to support India plans for growth and the company's global digital initiatives, McDermott said.

—*Staff Reports*

FLOATERS

Shell's Penguins Field Means New FPSO Unit

Royal Dutch Shell's final investment decision (FID) on the redevelopment of the Penguins Field in the U.K. North Sea authorizes the construction of an FPSO unit, the company's first in the northern North Sea in almost 30 years.

Redevelopment of the field, which became necessary because the Brent Charlie platform will cease production, will involve the eight additional wells drilled to be tied back to the new FPSO vessel. Additional pipeline infrastructure, along with existing subsea facilities, will be needed to move natural gas.

Penguins, which was discovered in 1974, is a 50:50 joint venture (JV) between Shell and ExxonMobil. It was first developed in 2002.

"Shell and Exxon taking FID on the Penguins redevelopment in early 2018 is very positive for the North Sea, marking the end of a cautious era during the downturn," said Fiona Legate, Wood Mackenzie senior research analyst. "The Penguins redevelopment is expected to produce around 80 MMboe via a newbuild FPSO development. This is the largest FID since Culzean [gas field] in August 2015 and shows market confidence has returned. We are expecting up to 14 U.K. FIDs in 2018. Penguins is the second largest by reserves."

The FPSO unit, which will be a JV-owned and Shell-operated Sevan 400, is expected to have peak production of about 45,000 boe/d. Tankers will transport the oil to refineries, and the FLAGS pipeline will move gas to the St. Fergus terminal in northeast Scotland.

The Penguins cylindrical FPSO unit will be Sevan Marine's sixth. Fluor has been awarded the engineering, procurement and construction contract.

"Penguins demonstrates the importance of Shell's North Sea assets to the company's upstream portfolio," said Andy Brown, upstream director at Shell. "It is another example of how we are unlocking development opportunities, with lower costs, in support of Shell's transformation into a world-class investment case."

Deirdre Michie, CEO of Oil & Gas UK, called the news "an exciting start to the new year. A global leader like Shell making a commitment on this scale demonstrates the investment potential the U.K. Continental Shelf still holds. It also shows the importance of the efficiency improvements our industry has delivered, which have helped make redevelopment projects like this commercially attractive. We are hopefully entering a more positive phase for our industry in the U.K. with new projects on the horizon that I hope will bring a much needed boost for companies in the supply chain."

The Penguins Field is in 165 m (541 ft) of water, about 241 km (150 miles) northeast of the Shetland Islands.

—Joseph Markman

FLOATER BRIEFS

Topsides Construction Begins For Liza FPSO Unit

Construction for the Liza FPSO unit, which is destined for the ExxonMobil-operated Liza Field offshore Guyana, has begun at the Dyn-Mac yard, according to SBM Offshore, the company that landed the contract.

"With the topsides fabrication now running in parallel with the tanker conversion, the construction phase is proceeding as planned," SBM Offshore FPSO Managing Director Bernard van Leggelo said in a statement. "SBM ran a two-day safety-engagement event with the experienced teams at the two yards in Singapore to ensure that all aspects of HSSE [health, safety, security and environment] and quality remain focused objectives for the Liza FPSO delivery."

SBM selected the Tina very large crude carrier for the conversion. Designed to produced up to 120,000 bbl/d with an associated gas treatment capacity of about 4.8 MMcm/d (170 MMcf/d) and crude storage capacity of 1.6 MMbbl, the FPSO unit will be spread moored in a water depth of 1,525 m (5,003 ft).

Golar Lands 15-Year Contract For FSRU

A 15-year charter for a floating storage and regasification unit (FSRU) and related services in the Atlantic Basin will give Golar LNG Partners LP the flexibility to use either the *Golar Spirit* or *Golar Freeze.*

The project of an energy and logistics company, announced Jan. 19, is expected to start in fourth-quarter 2018 and require the vessel to be in service for up to 15 years without drydock.

Golar expects the charter to generate an annual operating income of $18 million to $22 million. The rate will vary according to demand for regasification throughput but includes a cap and floor.

"Securing this contract demonstrates the underlying value of the partnership's existing assets, adds significant term and revenue backlog whilst simultaneously reducing recontracting risk," Golar Partners CEO Graham Robjohns said in a statement. "It also reflects the growing interest in smaller, cost-competitive FSRUs that can facilitate the opening of niche markets previously considered uneconomic for LNG."

Either side in the contract can terminate after three years if certain targets are not met. The charter also includes an option for a five-year extension.

SBM Offshore Completes Turritella Handover, Transaction

SBM Offshore and Shell E&P Offshore Services have completed the transaction related to the sale of *FPSO Turritella* following an operational transition period, according to a news release.

The Jan. 16 news followed word in July 2017 that Shell would purchase the unit, which is being used at its Stones development in the U.S. Gulf of Mexico. The purchase allows a Shell affiliate to assume operatorship of the development in its entirety in an effort to improve efficiency via integration of subsea to surface operations.

The unit was sold by a joint-venture company owned by SBM Offshore (55% interest), Mitsubishi Corp. (30%) and Nippon Yusen Kabushiki Kaisha (15%). The transaction was valued at about $1 billion.

SBM has called FPSO Turritella the world's deepest FPSO development, located at a water depth of 2,896 m (9,500 ft). The unit features a turret with a disconnectable buoy that allows it to weathervane in normal conditions and disconnect from the FPSO unit if a hurricane approaches.

"Both companies have worked successfully together to ensure a safe and controlled handover of operation," SBM said in the release. "The financial impact of this transaction on the SBM Offshore accounts remains in-line with earlier disclosures."

—Staff Reports

VESSEL BRIEFS

Kreuz Subsea To Deliver Vessels For Subsea Works Off India

Kreuz Subsea Pte. Ltd. has landed a contract for five vessels to assist in installation of equipment for the Daman Field offshore Mumbai, India.

The multimillion-dollar deal from Larsen & Toubro (L&T), which Singapore-based Kreuz said is the most significant in its history, was announced in mid-January. It involves assistance in installation of riser clamps, risers and tie-ins as well as crossing works, subsea trenching and hydrotesting of pipelines.

The project is part of the Oil & Natural Gas Corp.'s (ONGC) Daman Field development and Pipeline Replacement Project (PRP4).

"Securing a contract of this size and with a major company like L&T is a fantastic achievement for the whole team at Kreuz and sets a record in the company's history," Kreuz Subsea CEO AJ Jain said.

The ships include *Kreuz Installer*, a SURF vessel built for DP2 purpose, and *Kreuz Supporter*, a diving support and construction work vessel.

"The waters of Daman Field are known for experiencing very high tidal currents and near zero visibility," Jain said. "Being awarded this work to ultimately support ONGC in the region reaffirms our reputation for providing flexible, safe operations, dedicated and experienced personnel, as well as the ability to pass on great value to our clients."

ELA Container Offshore Delivers Offshore Living Quarters

Jumbo Offshore's transportation and installation contract for a wind farm will be accomplished with two new living quarters units.

ELA Container Offshore GmbH delivered and installed the Allrounders on Jumbo's construction support vessel MV Fairplayer in time for its voyage to deliver 60 transition pieces for the farm.

"Jumbo was looking for extra sleeping accommodation on short notice for their client and available deck space was limited," said Frank ter Haak, business development Netherlands and Belgium at ELA. "As we always keep containers in stock, we were able to deliver instantly."

ELA Container Offshore GmbH delivered two Allrounder living quarters units for Jumbo's Fairplayer heavy-lift vessel for its wind farm contract. (Source: ELA Container Offshore GmbH)

Jumbo, a Netherlands-based heavy-lift shipping and offshore transportation and installation contractor, has been engaged in the offshore subsea installation market since 2003. The company operates in-house designed heavy-lift vessels with a capacity from 650 tons up to 3,000 tons.

Maersk Supply Service Wins Contract For Starfish Newbuilds

Maersk Supply Service's two first Starfish-class anchor-handling vessels built in 2017, *Maersk Master* and *Maersk Mariner*, will be on contract with Quadrant Energy in Western Australia starting March 2018.

Both vessels will support Quadrant's Phoenix South and Van Gogh drilling campaign, which will initially cover three wells for 150 to 200 days. The vessels will support Transocean's semisubmersible rig DD1 with supply and anchor-handling duties throughout the campaign.

"This is a unique opportunity to demonstrate their state-of-the-art capabilities such as minimized environmental footprint, high standard for safety and onboard comfort for customers," said David Lofthouse, head of commercial Asia-Pacific.

Before coming to Australia, *Maersk Master* worked in the North Sea region on a decommissioning project, while *Maersk Mariner* came to Australia in August 2017 to work for another customer.

—Staff Reports

POLICY

Nigeria Passes Major Oil Reform Bill After 17 Years

Nigeria has moved closer to turning an oil industry bill into law after a 17-year struggle to complete the legislation that aims to increase transparency and stimulate growth in the country's oil industry.

Nigeria's lower house of parliament has passed a version of the bill that is the same as one approved by the Senate last year. This is the first time both houses have approved the same version of the bill. It still needs the president's signature to become law.

The legislation, known as the Petroleum Industry Bill (PIB), was broken up into sections to help to get it through. The House of Representatives passed the first part called the Petroleum Industry Governance Bill (PIGB) on Jan. 17.

"The PIGB, as passed [Jan. 17], is the same as passed by the Senate. We have harmonized everything and formed the National Assembly Joint Committee on PIB," Alhassan Ado Doguwa, a key PIB lawmaker in the House of Representatives, told reporters in the capital Abuja. "Every consideration of the bills is now under the joint committee. We have broken the jinx after 17 years. We are working on the other accompanying bills."

The passage of the first bill means that the government can move forward with new taxation legislation, which could make it more attractive for companies to invest, particularly offshore.

"It's an unprecedented step forward. The PIB is something that has defied the last two governments," Antony Goldman of PM Consulting said. "The detail of what is agreed will determine the extreme to which the bill takes politics out of the sector and tackles systemic corruption."

Uncertainty over terms affecting taxation of upstream oil development has been the main sticking point holding back billions of dollars of investment for the oil industry. This will be addressed later in an accompanying bill.

Shell, Chevron, Total, ExxonMobil and Eni are major producers in Nigeria through joint ventures with the state oil firm NNPC.

The speaker for the House of Representatives Yakubu Dogara said later on Jan. 18 that "the new legislation will be transmitted to the president within the next few days."

The governance section deals with management of the Nigerian National Petroleum Corp. (NNPC). The National Assembly Joint Committee is working on two more bills as part of the PIB.

Dogara added that NNPC would be unbundled as a result of the legislation going through.

The PIGB would create four new entities whose powers would include the ability to conduct bid rounds, award exploration licenses and make recommendations to the oil minister on upstream licenses.

Nigerian lawmakers ordered an investigation on Jan. 18 into whether the government could recover $21 billion in revenues from international oil companies.

—Reuters

BUSINESS

Pertamina Signals Total, INPEX Role In Mahakam

Indonesia's state-run upstream company PT Pertamina is looking to re-engage Total and INPEX Corp. in reviving oil and gas production from the aging fields and developing new fields in the hydrocarbons-rich Mahakam Block offshore Makassar Strait.

Arcandra Tahar, the country's junior energy and mineral resources minister, said ministry officials are in talks with Total and INPEX to divest up to 39% participating interest (PI) in the Mahakam concession as part of a new production-sharing contract (PSC).

The ministry is in favor of the duo's re-participation in Mahakam considering its familiarity with the block's complicated geology and long experience in reviving production from the aging seven oil and gas fields in the concession.

United Arab Emirates-based Mubadala Petroleum and PetroChina have also evinced interest in acquiring a minority interest in Mahakam.

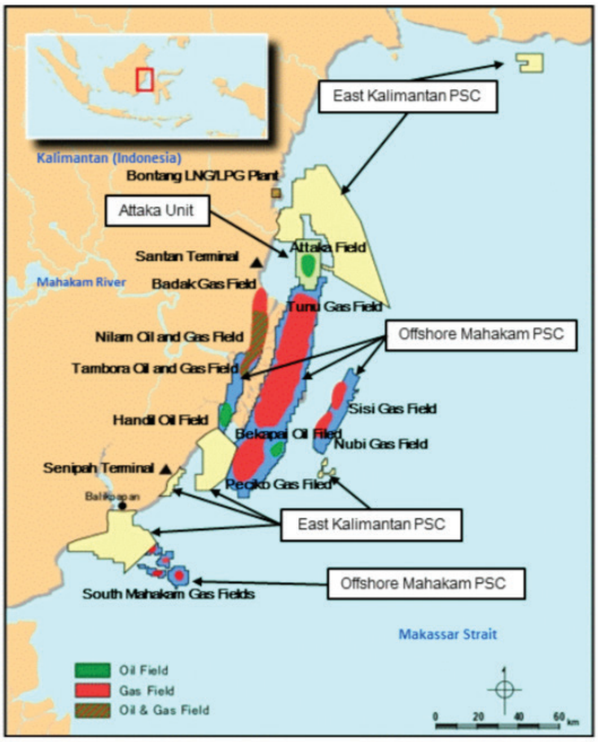
Both Total and INPEX have confirmed the talks with the Indonesian ministry. The two companies are seeking no less than 39% PI in the gas-rich Mahakam Block they jointly developed till the 50-year PSC expired Dec. 31, 2017.

"INPEX will continue pursuing discussions, in close partnership with Total, with Pertamina and the Indonesian government authorities with the aim of participating in the block under the new PSC," the Japanese company said.

The companies held 50% PI each in the Mahakam concession.

PT Pertamina acquired the entire PI from Total and INPEX and named its subsidiary PT Pertamina Hulu Indonesia (PHI) as the operator of the concession before divesting 10% PI to the local government in East Kalimantan.

Mahakam is still the country's biggest gas-producing block despite a fall in production from the peak level of 197,000 bbl/d of oil and 1,700 million standard cubic feet per day



Source: Inpex Corp.

(MMscf/d) of gas a few years ago. It currently pumps an average more than 50,000 bbl/d and 1,300 MMscf/d of gas.

Need Partners

Pertamina is equally interested in a partnership with the former operator due to its limitations in reviving the production from the seven oil and gas fields—Handil, Bekapai, Tambora, Nubi, Tunu, Sisi, Peciko—in the Mahakam concession. It is said that 30% of the total drilled wells in the concession are 20 years old.

The Indonesian company said the association with the former operator for the revival of production in Mahakam Block is vital considering its understanding of the geophysical complexities of the concession and the expertise developed in producing hydrocarbons from the aging fields for the last 10 years.

The French major drilled more than 2,000 wells in Mahakam Block with various types of wells based on function, architecture, completion type, lifting-mechanism and wellhead-tree technology to maintain production levels since the discovery of oil and gas in Bekapai Field in 1974.

During the operatorship, Total adopted different methods to tackle the mature field challenges in Mahakam on a field basis due to the uniqueness of every field. The revival of the Tunu Field, according to the operator, succeeded to maintain its production through lowering network pressure, lighter well architecture and lowering well spacing to re-access disconnected reservoirs.

Production from the Handil and Bekapai fields were revived through pressure maintenance, new EOR screening, 3-D seismic and intensive drilling.

PHI president director Bambang Manumayoso said the oil and gas fields in the Mahakam Block have entered Phase Four or production decline.

In the absence of any revival efforts, he said oil and gas production could drop drastically to 25,717 bbl/d and 934 MMscf/d in 2018, down from the average production of 52,000 bbl/d and 1,360 MMscf/d in 2017.

Concerned over this, PHI has prepared a $1.8 billion revival plan, which includes drilling 55 development wells, re-work in 132 wells and maintenance for 5,601 wells over three to five years.

The revival plan is targeted to produce 1,100 MMscf/d of gas and oil of 48,000 bbl/d from Mahakam by 2018, he said.

The Mahakam concession is estimated to contain proven reserves of 139 Bcm (4.9 Tcf) of gas and 57 MMbbl of oil as of 2016.

—Ravi Prasad

BUSINESS BRIEFS

EnQuest Reportedly Seeking Buyers For Stake In Kraken Field

North Sea-focused oil and gas producer EnQuest Plc has hired investment bank Jefferies to advise on a sale of a 20% stake in its recently started Kraken Field, according to a document seen by Reuters.

The sale could fetch as much as $400 million for EnQuest, based on recent analyst valuations of the field. EnQuest holds a 70.5% stake in Kraken where production is expected to ramp up to 50,000 bbl/d by mid-year following its startup last June.

EnQuest declined to comment.

EnQuest has previously sought buyers for a stake in its flagship $2.5 billion development to help with its costs, but talks with Israeli conglomerate Delek Group failed in 2016. The heavily indebted company, headed by CEO Amjad Bseisu, is hoping to attract more interest now that the field is up and running.

The recent sharp rise in oil prices to about $70/bbl, levels not seen since 2014, is anticipated to spur further interest, banking sources said.

EnQuest's lenders in November agreed to ease the terms of its loans as it struggled with a debt of about $2 billion compared with a market value of about $680 million. In the sale document, EnQuest, which specializes in extending the life of aging fields, said it intended to open a data room in January and set a deadline for bids in March or April.

Analysts at Barclays in December valued EnQuest's 70.5% stake at about $1.4 billion while Jefferies analysts valued it at about $1.3 billion. Cairn Energy owns the remaining 29.5% in the Kraken Field.

API President, CEO Jack Gerard To Step Down In August

Jack Gerard (Source: American Petroleum Institute)

The American Petroleum Institute (API) said Jan. 17 that President and CEO Jack Gerard will not make another long-term commitment to API and will step down when his current contract ends in August 2018.

Since Gerard joined the oil and natural gas trade association in 2008, API membership grew by almost 50% and added members from every sector of the industry, according to API's press release. The organization also tripled its growth in global markets where it promotes safety through standard setting and best practices, including expansions to Singapore, Dubai and Rio de Janeiro.

Additionally, Gerard helped build a grassroots network comprised of 45 million voters with representation in congressional districts who communicate with their elected officials on energy issues, the release said.

Gerard will assist in the search for a new CEO and continue to direct API's work until a replacement is found.

Petrobras, Total Close Deal Involving Presalt Fields

Petrobras and Total said they have completed the previously announced transaction involving Lapa and Lara area fields, finalizing a milestone in their strategic alliance signed in March 2017.

The transactions, which total $1.95 billion, involve Petrobras transferring to Total 35% of the rights and operatorship of the Lapa Field in Block BM-S-9A in the Santos Basin presalt. Partners in the field are Shell (30%), Repsol-Sinopec (25%) and Petrobras (10%).

Petrobras also transferred to Total 22.5% of the rights of the Lara area, which comprises the Sururu, Berbigão and Oeste de Atapu fields in Block BM-S-11A in the Santos Basin presalt, operated by Petrobras (42.5%) with Shell (25%) and Petrogal (10%).

Production in Lara is expected to start in 2018 through the 150,000 bbl/d-capacity *P-68* FPSO unit in the Berbigão-Sururu fields, which will be followed by a second FPSO unit in 2019 in the Atapu Field, Total said in the release.

Production at the Lapa Field started in December 2016 via the 100,000 bbl/d-capacity *Cidade de Caraguatatuba* FPSO vessel.

Noble Corp. Names Julie Robertson As New CEO

Julie J. Robertson (Source: Noble Corp.)

Noble Corp. Plc said Jan. 11 David W. Williams, the company's chairman, president and CEO, will retire from the London-based offshore drilling company.

Julie J. Robertson, the company's executive vice president, has been elected by the Noble board of directors to succeed Williams, according to the company press release. As part of the leadership succession plan, Williams will remain with Noble through February, serving in an advisory capacity.

In her current role that she has held since 2006, Robertson has had direct oversight for human resources, procurement and supply chain, learning and development, HSE functions functions and information technology. She has been with Noble since 1979, according to the company website.

UTEC Appoints Business Unit Director, Lands Survey Contracts

UTEC has appointed Bill Hickie as business unit director of its Middle East and Caspian operations.

Previously, with UTEC in the role of global director of business development for the Eastern Hemisphere, Hickie has developed strong relationships in the region and provides continuity for UTEC's clients as he moves into this new role, the company said in a news release. Hickie has over 12 years' experience in the oil and gas industry, working internationally with companies including Ceona and Subsea 7.

In addition, the company said it won geophysical survey contracts in Saudi Arabia with its partner *Zamil* Offshore. The contracts, which include multiple worksites, are for geophysical surveys in the Safiniyah, Marjan and Zuluf fields offshore Saudi Arabia. UTEC will utilize the Zamil 51 offshore support vessel using a combination of multibeam and side scan sonar survey techniques. The projects will be executed in January and February 2018.

—Staff & Reuters Reports

SUBSEA PERSPECTIVE

Offshore Oil Industry: Engineering A Bright Future

The offshore oil and gas industry, even in times of low prices and abundant supply, is driven by the almost relentless search for new fields to replace those coming toward the end of their natural productive lives. Often this forces

Joe Orrell (Source: RED Engineering)

exploration in ever more challenging environments and places huge demands on the boundaries of technology.

And these challenges are no better exemplified than in the design and construction of subsea flowline infrastructure in very deep waters, where operators strive for ways to shorten project lead times to reduce both development costs and the time to 'first oil,' which is critical in terms of project cash flows. This has demanded innovation in both technology and working methodology—necessitating close working partnerships with clients and the supply chain alike.

Deepwater flowline infrastructure takes many different forms and configurations but a universal demand is for methods to retain position relative to vessels, wellheads and other subsea structures. Such methods must allow for tidal range, subsea currents, inherent buoyancy and variable weight. Critical in securing a solution is the method of holding or clamping equipment in place.

The demands this places on existing technology and design solutions is illustrated in the development of a tool-assisted piggyback blocking clamp system, designed to allow the development of the Laggan Tormore project off the Shetland Islands by Subsea 7.

During the installation and operation of pipelines, a secondary line is sometimes introduced attached to the main pipeline using a piggyback system to provide adequate support. The Laggan Tormore project required the simultaneous installation and long-term subsea deployment of 140 km (87 miles) of a primary 8-in. diameter pipe with a secondary 2-in. pipe attached or 'piggybacked' on top of it. This involved RED Engineering developing a new, semi-automated clamp and installation system in less than 12 months. As a result installation rates increased from 200 m/hr to 1,200 m/hr (656 ft/hr to 3,937 ft/hr) while generating savings of several million dollars due to tumbling installation times.

Another area to benefit from the latest in fast-track design and engineering innovation is around the economic, safe and efficient servicing and maintenance of subsea oil wells in deep water.

When FMC Technologies was developing its new vessel-based well intervention system, a requirement was identified for a subsea umbilical clamp as part of the equipment spread to securely 'hold back' a compressible control umbilical cable deployed to operate subsea hardware. This threw up a particularly challenging requirement as the umbilical cable was compressible and because it comprised of a series of cables and hoses (electrical, fiber-optic and hydraulic) couldn't be squeezed excessively when clamping to avoid internal damage. A clamp solution, featuring an innovative arrangement of spring-applied pads to give a consistent squeeze pressure over a 3 m (10 ft) length without resorting to a more complex electrohydraulic system, was designed and commissioned in less than seven months. Key to the success here was prior knowledge of the friction properties of subsea cables and the ability to quickly test and validate a potential solution.

There's no doubt that as oil and gas reserves become more difficult and costly to recover, the demands for innovative technology will continue to grow, providing opportunities for engineering companies who have grown up on the back of innovation and engineering excellence, to show their capabilities. Investment in new technologies and engineering talent alongside experience gained working around the world will continue to secure a strong position for oil and gas service expertise in the times ahead.

— Joe Orrell, RED Engineering

UPCOMING

The next issue of *Subsea Engineering News* will be distributed Feb. 8. Until then, visit *epmag.com*.

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