SEN
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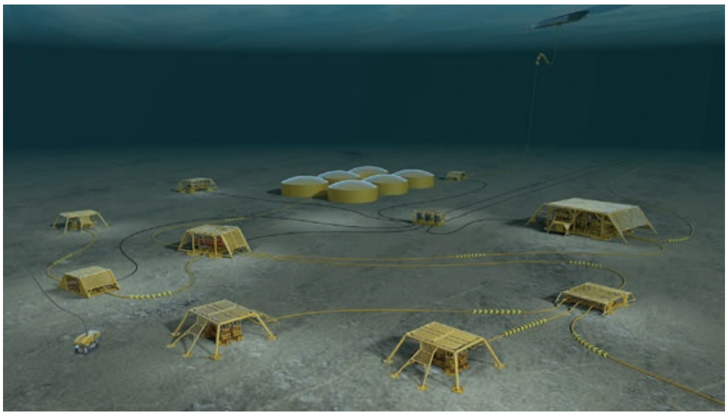
Statoil Searches For Presalt Solution

When Statoil acquired the Carcara Field in 2016 it was called a world-class discovery, and the company expected to recover up to 2 MMboe from this project. The field is in the development phase with a decision on the way forward expected later this year. The field is located in Brazil's prolific Santos Basin within the presalt area. It is about 200 km (124 miles) from shore in a water depth of 2,100 m (6,890 ft).

"The reservoir is currently placed under a fairly thick layer of salt with the top of the reservoir approximately 5,800 m [19,029 ft]," said Oystein Aa Myklebust, Statoil's subsea production systems manager for the Carcara project. "It contains light oil with a substantial amount of associated gas. It's overpressurized, meaning that the pressure in the reservoir is higher than what follows from the depth, giving us a maximum wellhead shut-in pressure of 650 to 800 bars, depending on the drainage strategy we select. This higher pressure distinguishes Carcara from some of the other fields in the area, and therefore, we may need different solutions than what has been used for these other fields."


An illustration of the subsea installation for the Peregrino Field in the Campos Basin is shown. (Source: Statoil)

Partners ExxonMobil, Barra Energia and Galp have agreed to develop the Carcara Field in two phases. The objective of Phase 1 is to obtain first oil in a timely manner. The objective of Phase 2 will be to maximize the full field value.

Phase 1 is based on resources driven by pre-exploration and appraisal by Petrobras inside the BM-S-8 area. The target for Phase 1 is to have first oil in 2023 or 2024.

The concept is based on 12 production wells and six water injection wells, with the water injection wells drilled and started up a few years after first oil. All the wells are vertical or near vertical.

"There are several challenges with drilling horizontal wells in the presalt area," Myklebust said. "No wells have been completed in this area with horizontal reservoir sections. Not even with high deviations in the reservoir. We have, however, assumed that we can have up to 500 m [1,640 ft] horizontal stepout from the wellhead to the well target. We will use this in designing this layout."

The production lines are made of carbon steel with a wet insulation that can be installed in one go. The riser sections will be configured as lazy waves with a flex-joint on the top. Myklebust explained that the manifolds are fairly simple, but they allow routing of the well flow in any

WHAT'S INSIDE

direction and methanol and glycol (MEG) injection. The manifolds are intended to be welded into the pipelines on the pipeline vessel. The plan is to utilize rigid well jumpers between the wells and manifolds. There is also a gas-lift riser to inject lift gas on the manifold nearest the riser.

"We have assumed, in this concept, two dynamic umbilicals and a separate MEG riser, as we have a fairly high need for MEG injection," Myklebust added. "We may be able to integrate those, the MEG and the dynamic risers, but for now they are separate. Then we integrate MEG and transport MEG to the wells and manifolds in the centrifugal static umbilicals."

Searching For New Solutions

When it comes to flow assurance, Statoil has several options.

"Petrobras has used a concept for several of its pre-salt fields where they have two flowlines to each well," Myklebust said. "One production line and one service line with a possibility for ground pigging or for displacing the volume. It is a solution that we have not excluded, but it is a solution we don't know very well. We are interested in solutions for commingled flow, and we see different solutions. We are also looking into the cluster manifold solution. These different solutions require different mediations in terms of flow assurance. So we need to find out what is the best solution for each of the layouts and then compare them."

Myklebust explained that another challenge is the distance between wells. "For now, we have assumed that we can only have a 500-m horizontal stepout from wellhead to well target," he said. "We will work to expand that step-out, but we haven't concluded that work yet. It's quite likely that we need to have quite a big distance between the wellheads, so it will be important for us to find solutions that allow us to connect each well to the flowline and umbilical in the cheapest way possible."

The distance between the well also will impact the cost of installation, a problem that Myklebust and his team are working on to reduce scope, simplify installation methods and make installation methods more effective.

Myklebust admited that they need more effective products, concepts and methods to succeed with Carcara. "It has a huge value potential, but we cannot just assume that we'll take that value potential out with using existing solutions," he said. "We already see that Carcara is definitely on top in our portfolio in terms of reserves, but we're certainly not on top in terms of project economics. We need to work on that and we're hoping for industry support on that."

Campos Basin Development

Farther north, Statoil already has producing operations in the Campos Basin with Peregrino Phases 1 and 2, along with 25% interest in the Roncador Field operated by Petrobras. They were awarded four additional blocks in the basin during the 15th licensing round in late March—C-M-657 and C-M-709, which will be operated by Petrobras, and C-M-755 and C-M-793, which will be operated by BP.

But there is another field, BMC-33, that has been in development since 2016 and comprises the Pão de Açúcar, Gavea and Seat discoveries, which together hold reserves of 1 Bboe.

"We are still working our way toward Decision Gate 1 (DG1), so still looking for physical solutions," said Patrice Aguilera, Statoil's subsea production manager for the field.

The water depth ranges from 2,600 m to 2,980 m (8,530 ft to 9,777 ft), which will be the deepest to date in the basin and is 240 km (149 miles) from shore.

"We have been investigating several solutions to solve the challenges," Aguilera said. "The most sensible will feature a floating production unit. We have three reservoirs in this project, 11 wells and a possible gas injector. Our current solution features a floating production system with PLEM, pipeline and manifold, and from there, we go 240 km to a plant that we are going to build in Brazil for gas export as these reservoirs contain both gas and oil."

The wells will feature slightly different solutions. The two wells in Seat will include a 40-km (25-mile) direct electric heating (DEH) pipeline. The two wells in Gavea feature a 12-km (7-mile) floor line, while Pão de Açúcar features an alternative solution.

"We don't use DEH here, but we use loops, we call them production loops," Aguilera added. "These production loops are designed in this way because of the wax and hydrates that mean we need to pig almost once a month.

"All wells feature small manifolds [and] have a lot of functionality to allow pigging, injecting MEG and the gas lift. We have riser bases with injection of MEG and gas lift to lift up the oil, which is trapped in the riser," Aguilera said. "These risers are also long. It is, as I said, almost 3,000 m [9,846 ft] water depth, so those are almost 6 km long [3.72 miles]. It's a completely different story, compared to the North Sea."

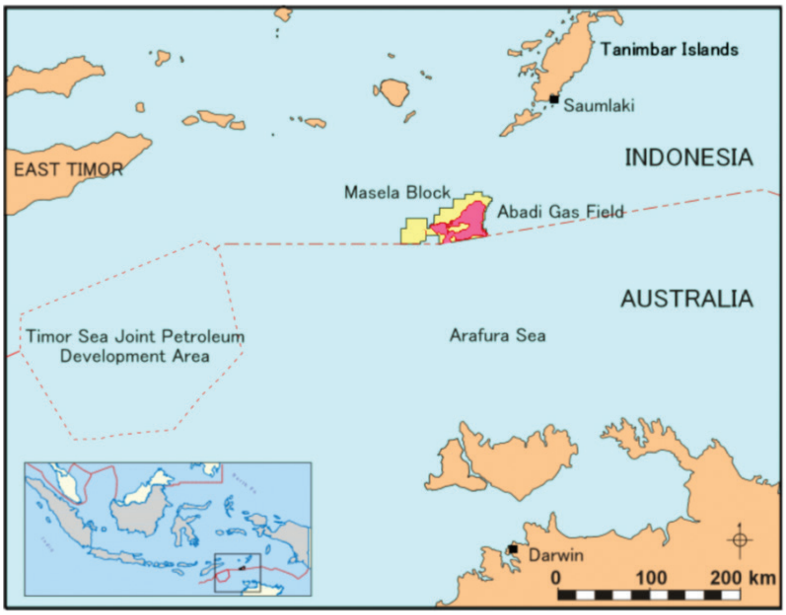
—Mark Venables

DEVELOPMENT

INPEX launches Pre-FEED For Abadi Projects

An INPEX Corp.-led consortium is firming up a plan to develop the Abadi gas field, located in the Arafura Sea offshore Indonesia, with an onshore gas liquefaction plant instead of the planned floating one.

In April the Japanese company picked up PT Technip Indonesia and PT KBR Indonesia to prepare pre-FEED work for the FPSO and onshore LNG plant at a nearby landfall point, respectively.



An INPEX Corp.-led consortium plans to develop the Abadi gas field offshore Indonesia. (Source: INPEX Corp.)

"INPEX will formulate a detailed revised plan of development contingent on the results of the pre-FEED work and ongoing discussions with the Indonesian authorities to achieve a cost-efficient and economically competitive project," the Japanese company said.

The pre-FEED works will focus on preparing designs to build a FPSO with a minimum capacity to produce 150 MMscf/d near the producing wells, 18-in. to 24-in. diameter and 100-km (62.13-mile) subsea pipeline to transport and an onshore LNG plant with a capacity of 9.5 million tons per annum (mtpa) at Pulau Yamdena or a nearby site.

These offshore units are to be designed to process the extracted condensate from the 18 development wells to be drilled in the northern part of Abadi in Phase 1.

The proposed wells are to be drilled from five subsea manifolds in the northern part of the field, where most of the reserves are concentrated. The drilling will target the reservoirs in Middle Jurassic Plover Formation at depths ranging between 3,700 m and 3,900 m (12,139 ft and 12,795 ft). The reservoir contains shallow-marine, highly mature, quartzose sandstones.

INPEC initially proposed to develop the Abadi Field with a 330-m-by-65-m (1,082.6-ft-by-213.2 ft) FPSO and a floating LNG plant of 7.5 mtpa but changed that to onshore after a "directive" from the Indonesian government.

Indonesia president Joko Widodo rejected the Abadi gas field development with a floating LNG facility plan and asked the operator to submit a new plan based on an onshore LNG plant to be located either on Tanimbar or Aru islands.

He said the onshore plant would help the development of the less-developed economy of southern Maluku province, particularly petrochemicals and fertilizers.

The mineral resources ministry said the onshore LNG plant will help the economic development of south Maluku region, similar to the Badak LNG's in Bontang and its neighboring areas in east Kalimantan. The construction of a 22.5-million-ton Badak LNG plant has helped the development of industries based on oil and gas (more than 80% share in region's GDP) as well as the supporting sectors such as electricity, transportation, construction and agriculture. PT Pupuk Kalimantan Timur, for instance, produces fertilizers of about 4.8 mtpa from CO_2 impurities stripped from the liquefaction of gas at the Badak plant.

The Indonesian government has offered INPEX an extension of the existing contract to operate Masela Block by an additional seven years over the agreed 20 years as the compensation for making changes to the onshore LNG project. The current production-sharing contract for Masela is valid until 2028.

However, the Japanese company said it is not against the development of the Abadi gas field with the onshore LNG project and selects the cost-effective model in consultation with the Indonesian government.

"We will maintain our policy of aiming for the early startup of development and implementing the [Abadi] project in the most economically and technically rational way, and will proceed with the project," INPEX CEO said in the company's latest annual report.

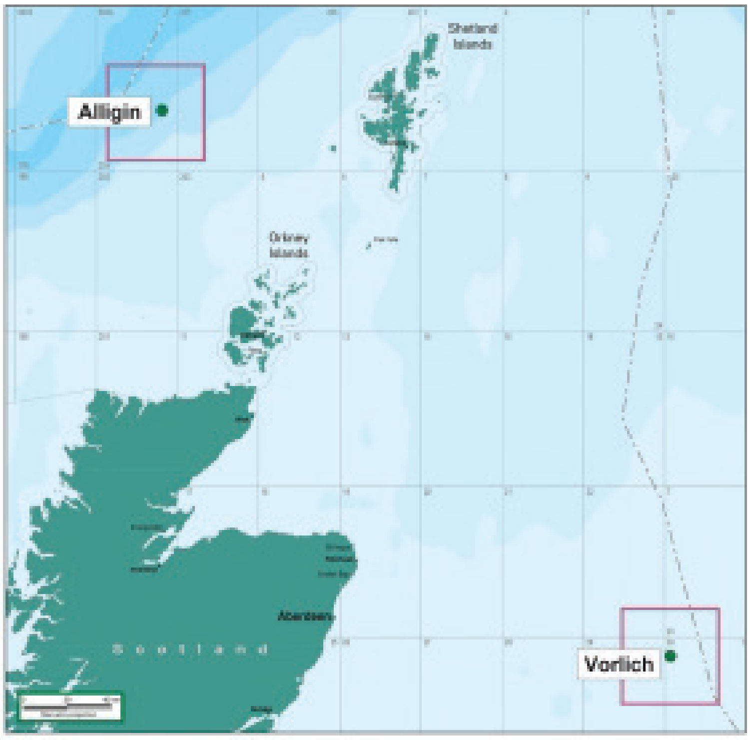
The operator is expected to submit the revised plan of development for the Abadi gas field and associated onshore LNG plant, based on the pre-FEED report, by November.

Discovered in 2000, the Abadi gas field is estimated to contain recoverable reserves of 303.8 Bcm (10.73 Tcf) of gas and 209 MMbbl of condensate. The gas field is situated in the Masela concession, spread over an area of 3,221 sq km (1,243.6 sq miles) in the Arafura Sea in a water depth ranging from 300 m (984.2 ft) to 1,000 m (3,280.8 ft).

INPEX holds a 65% participating interest in the Masela concession with Shell (35%).

—Ravi Prasad

BP Green Lights Two North Sea Projects



Alligin and Vorlich are satellite fields located near existing infrastructure and can be quickly developed. (Source: BP)

BP has committed to two new North Sea developments that are expected to produce 30,000 boe/d at peak production.

Alligin and Vorlich are satellite fields located near existing infrastructure, meaning they can be quickly developed through established offshore hubs.

Alligin, a two-well development West of Shetland, will be tied back to BP's *Glen Lyon* FPSO.

Vorlich, also a two-well development in the central North Sea, will be tied back to the Ithaca Energy-operated *FPF-1* floating production facility, which lies at the center of Ithaca's Greater Stella Area production hub.

Both fields are expected to go onstream in 2020.

BP also confirmed that it has awarded a major contract for the Alligin development to Subsea 7, which will provide project management, engineering, procurement and construction services for the subsea pipelines. Subsea 7 will deliver the contract from its Aberdeen base with offshore activities expected to get underway in 2019.

Meanwhile, BP has submitted its environmental statement for the Vorlich development to the Department for Business, Energy and Industrial Strategy and is finalizing its contracting strategy for the development.

"Through our Alligin and Vorlich developments we are simplifying and accelerating the stages of delivery to improve project cycle time, reduce costs and, importantly, add new production to our North Sea portfolio," said Ariel Flores, BP North Sea's incoming regional president.

Alligin is a 20-MMbbl recoverable oil field in the Greater Schiehallion Area, located about 140 km (86 miles) West of Shetland. BP is the operator (50%) with Shell (50%).

Vorlich will recover more than 30 MMboe and is located approximately 241 km (149 miles) east of Aberdeen. BP is the operator (66%) with Ithaca Energy (34%).

—Reuters

DEVELOPMENT BRIEFS

Lankhorst Delivers Mooring Ropes For Shell's Deepwater Appomattox

More than 63,000 m (206,693 ft) of deepwater mooring rope has been delivered for the Shell-operated Appomattox project in the U.S. Gulf of Mexico.

Lankhorst Euronete Portugal said it has finished the engineering, design, fabrication and delivery of the deepwater mooring rope for the project, marking a number of firsts for the industry and company during the process. These, according to a news release, included the first time two mooring ropes have been packed on a single reel, the largest reels ever handled (6 m [19.6 ft] diameter by 6.8 m [22.3 ft] traverse), and the heaviest reels ever handled (approximately 120 tonnes).

Sixteen mooring lines, arranged in 4-by-4 clusters, will be used for the Appomattox semisubmersible production platform in a water depth of about 130 km (80 miles).

The Gama 98 polyester ropes for the project were manufactured at the Lankhorst's Viana do Castelo, Portugal, facility. (Source: Lankhorst Euronete Portugal)

The Gama 98 polyester ropes for the project were manufactured at the Lankhorst's Viana do Castelo, Portugal, facility. In all, 78 ropes were manufactured at the facility for the project.

Serica Selects Shearwater Platform For Columbus Field

Serica Energy has decided to tie its Columbus gas condensate field in the U.K. North Sea to the Shell-operated Shearwater platform.

The option was selected over a tieback option to the Lomond platform, the offtake route for production from Serica's Erskine producing interest. This option included drilling an extended-reach development well into Columbus from the Lomond platform.

Plans are for the Columbus Field to be developed with one production well, which will be drilled and connected to a proposed pipeline between the neighboring Arran Field and the Shearwater platform, Serica said.

"Under this option, Arran and Columbus fluids will combine in the new pipeline and be produced together over the Shearwater processing facilities via an existing riser onto the Shearwater platform," Serica said. "Although the expected first gas date would be around a year later than the Lomond alternative, the overall capital costs under this option are lower."

The selection, however, is dependent on the Arran Field developing as planned. So discussion with the Lomond field operator continues in case Serica and partners need to pursue this route instead.

The Columbus Field was appraised with four wells. Serica said it expects to submit a full field development plan to the U.K. Oil and Gas Authority by mid-2018 with development work starting before year-end 2018. The company is targeting first gas in 2021.

Kenya's National Oil, Schlumberger Sign Field Development Deal

Kenya's National Oil Corp. and Schlumberger have agreed to finalize a field development plan on behalf of the government for oil blocks in the northwest of the country.

The East African nation discovered commercial oil reserves in its Lokichar Basin in 2012.

National Oil said in a statement that the agreement with Schlumberger would create a development blueprint for the field in the next year, according to Reuters.

"This FDP [field development plan] will provide the government with an independent view of the development of the Lokichar oil discoveries, which will be useful in supporting the government in evaluating work already being done by investors Tullow, Africa Oil and Maersk," National Oil said.

Britain's Tullow Oil and Canada's Africa Oil were first to discover oil in Kenya, holding an equal share in the 10 BB and 13T blocks where Tullow is the operator. Total later acquired a stake in the blocks from AP Moeller-Maersk, and the Kenyan government is expected to take a stake through National Oil.

National Oil did not disclose the value of the deal. Tullow expects to reach a final investment decision on the project in 2019 and first oil production by 2021-2022. Recoverable reserves are estimated at 750 MMbbl and considered feasible for production with oil prices at $55/bbl, which is below current levels.

Sapura Energy, Partners Agree To Develop Fields Offshore Malaysia

Development of the SK408 gas fields offshore Sarawak, Malaysia, is moving forward as Sapura Energy and partners have taken a final investment decision (FID) on the project.

The Gorek, Larak and Bakong fields will be developed as three separate wellhead platforms tied back to the existing processing facility and to the MLNG complex, Sapura said in a news release. Sapura's partners are PETRONAS Carigali Sdn Bhd and Sarawak Shell Berhad.

The fields are part of the discoveries made by Sapura E&P during its 2014 drilling campaign. The FID follows Petronas' approval of the field development plan and the signing of the key terms to the gas sales agreement for Phase 1 of the development, the release said.

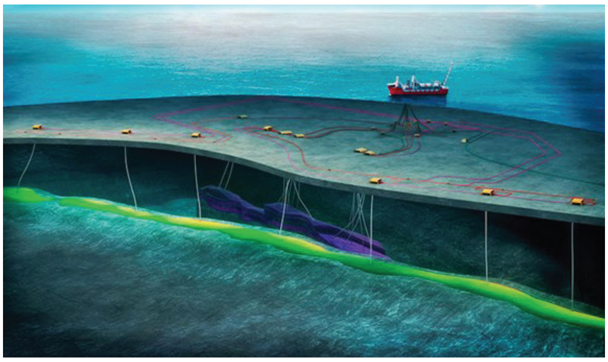
"The development of the SK408 gas fields further strengthens Sapura Energy's position in Malaysia as a significant partner and supplier of natural gas to one of the world's largest LNG production facilities, the PETRONAS MLNG complex in Bintulu," Sapura Energy Berhad CEO Tan Sri Dato' Seri Shahril Shamsuddin said in the release.

Sapura E&P is the development and production operator of the Larak and Bakong fields, while Sarawak Shell Berhad is the development and production operator of the Gorek Field.

Norway Green Lights Aker BP, Partners' Ærfugl Plans

The Norwegian Ministry of Petroleum and Energy has approved Aker BP and its joint venture development plan for the Ærfugl Field in the North Sea.

Plans for Ærfugl, including the Snadd Outer, includes six new subsea production wells that will be tied into the *Skarv* FPSO. The field will be developed in two phases—three wells for each phase.



The Ærfugl Field in the Norwegian North Sea will be developed in two phases. (Source: Aker BP)

Condensate will be exported to the market on tankers while gas will be exported via existing gas export pipelines to European markets, according to the energy ministry.

"The development involves an investment of approximately NOK 8.5 billion [US$1 billion] and helps to maintain the level of activity in the industry," Minister of Petroleum and Energy Terje Søviknes said in a news release. Recoverable resources are an estimated 44 million standard cubic meters of oil equivalent, mostly gas.

Startup is expected in fourth-quarter 2020.

Aker BP is the operator with 23.835% interest, with partners Statoil (36.165%), DEA Norge (28.0825%) and PGNiG Upstream Norway (11.9175%).

Proserv Secures $5.5 Million Repsol Contract

Proserv has secured a contract worth more than $5.5 million with Repsol to upgrade and build new subsea production control equipment for the Yme Field redevelopment in the Norwegian North Sea.

The award scope initially covers the refurbishment and upgrade of the existing subsea control system. The entire subsea control system will be upgraded to provide functionality including high-speed data management and transmission capability with sufficient capacity for future field expansion or increased data capture.

As part of the work scope, Proserv will engineer, manufacture and supply all associated topside and subsea equipment. The refurbishment and servicing of the subsea control modules and the manufacturing of the subsea electronics modules and master control station will be delivered by the company's subsea controls experts in Trondheim and Stavanger, Norway. Each control module will include Proserv's Artemis 2G subsea electronics modules.

Recoverable oil reserves for the field are estimated at about 65 MMbbl at 10-year's total production with first oil planned for the first half of 2020. The project will be delivered over a two-year period in line with key project milestones.

TechnipFMC Wins Contract For Tortue-Ahmeyim Development FPSO

TechnipFMC has been awarded a FEED contract by for the FPSO unit for the Tortue/Ahmeyim Field development, the company said.

The LNG project is located offshore on the maritime border of Mauritania and Senegal.

The agreement between the two companies provides a mechanism to allow a transition of the contract to an engineering, procurement, construction and installation contract at a later stage.

TechnipFMC will work on defining the technology and equipment scope, leveraging extensive experience with Chinese fabrication.

"We look forward to collaborating with BP to unlock the full potential of this important project," said Nello Uccelletti, TechnipFMC's onshore, offshore business president.

The initial subsea infrastructure connects the first four wells consolidated through production pipelines leading to a FPSO vessel. From here, liquids are removed and the export gas is transported via a pipeline to the floating LNG hub terminal where the gas is liquefied.

The Tortue/Ahmeyim field development is located in the C-8 Block offshore Mauritania and the Saint-Louis Profond Block offshore Senegal. The Tortue discovery was made by Kosmos Energy, which farmed down its investment to BP in December 2016. Operator BP now has the largest interest (about 60%) among the four partners in the project.

Fenja Development Pushes Forward With Norway's Approval

Faroe Petroleum and partners VNG Norge and Point Resources' plan for the development and operation (PDO) of the Fenja Field has been approved by the Norwegian Ministry of Petroleum and Energy, the company said.

Located southwest of the Njord production facility, the VNG Norge-operated oil field will be developed with three oil producers, two water injectors and one gas injector, which will be converted to a gas producer during the gas blow-down phase toward the end of field life, Faroe said.

The field is believed to hold gross recoverable resources of about 97 MMboe, mostly oil.

Fenja is slated to go onstream in 2021 with a planned field life of 16 years.

The approval comes about two months after Faroe announced that it executed a transaction with Suncor Energy Norge AS to sell a 17.5% working interest in the Fenja development for $54.5 million. The Fenja PDO approval is the principal condition precedent to completion of this transaction, according to Faroe, which retains a 7.5% working interest in the development.

BW Offshore Completes First Production Well Offshore Gabon

BW Offshore has successfully drilled and completed its first development well, DTM-2H, in the Tortue Field within the Dussafu license offshore Gabon.

Drilling of the oil production well commenced in late January and was completed with no safety-related incidents, on schedule and within budget. Interpretation of the logging results indicated that the well was entirely consistent with pre-drill prognosis and objectives. DTM-2H was drilled and completed as a horizontal production well in the Dentale D6 reservoir and encountered a long horizontal section of oil-saturated Dentale D6 sandstone.

Following demobilization at the DTM-2H well, the Borr Norve drilling rig will commence operations on the DTM-3 appraisal well to the northwest on the Tortue Field. After completion, the rig is scheduled to drill and complete the horizontal oil production well, DTM-3H, in the Gamba sandstone. Drilling operations are expected to continue until the end of June.

—Staff Reports

EXPLORATION BRIEFS

Shell To Resume Deepwater Exploration Offshore Egypt

Royal Dutch Shell said it will resume deepwater exploration for oil and gas off Egypt's Mediterranean coast, executive vice president Sami Iskander said during an April 17 news conference.

Egypt is looking to production from recently discovered fields to halt energy imports by 2019.

A petroleum ministry official said in March that new production at Shell's West Nile Delta Field 9B is expected to reach about 9.9 MMcm/d to 11.3 MMcm/d (350 MMcf/d to 400 MMcf/d) by 2019.

Separately, production from the first three wells in the field is set to begin in the 2018-2019 fiscal year.

The field is owned by Egypt's General Petroleum Corp., Malaysia's Petronas and Shell.

New Zealand Halts Future Oil, Gas Offshore Exploration Permits

New Zealand will not grant any new permits for offshore oil and gas exploration, Prime Minister Jacinda Ahern said, taking the industry by surprise with a decision that it said will push investment overseas.

The center-left Labour-led government said the move would not affect the country's 22 existing exploration permits and any oil and gas discoveries from firms holding those licenses could still lead to mining permits of up to 40 years.

Ardern, who campaigned heavily on preventing climate change in the run-up to last year's tight election, said the decision was a responsible step and provided certainty for businesses and communities.

"We have been a world leader on critical issues to humanity by being nuclear free...and now we could be world leading in becoming carbon neutral," she told university students in the country's capital, Wellington.

Interest in oil exploration in New Zealand has waned in recent years due to lower global oil prices, with only one permit issued in 2017, compared with 10 in 2014. However, business and regional leaders said they had been blindsided by the move and feared the government was risking jobs in the $1.8 billion oil and gas industry.

Ghana To Launch First Exploration Licensing Round In First-quarter 2018

Ghana will launch its first exploration licensing round in the last quarter of this year offering about six offshore blocks, deputy energy minister Mohamed Amin Adam said.

Ghana produces 200,000 bbl/d, led by its flagship Jubilee Field, which produces about 100,000 bbl/d, he said.

The West African nation, which became a significant oil producer in 2010 when it began pumping from the offshore Jubilee Field, is keen to unlock its vast oil and gas resources.

Adam said global oil majors like BP, Shell and some independent producers have shown interest in acquiring a stake in oil assets in Ghana.

Drawn to Ghana's hydrocarbon potential, ExxonMobil Corp. recently signed a deal with Ghana to explore for oil in the Deepwater Cape Three Point offshore oil field. ExxonMobil is doing due diligence to find a local partner to explore the block, a condition required to operate a field in Ghana, he said.

Shearwater GeoServices Returns To Atlantic Margin For TGS

Shearwater GeoServices AS has been awarded a contract by TGS for the expansion of its Atlantic Margin multi-client program in the Norwegian Sea, the company said.

The project is expected to take approximately three months and is scheduled to be completed by the end of September.

For the second consecutive year, Shearwater has been awarded a contract for a seismic survey on the Atlantic Margin in the Norwegian Sea. The 2018 survey will cover 5,135 sq km (1,982 sq miles) and will be performed by one of Shearwater's high-end 3-D vessels. The vessel will utilize FlexiSource and a wide tow spread, for which all Shearwater vessels are designed.

"We are very happy to return to the Atlantic Margin to work with TGS once more, extending the largest 3-D seismic survey in Northern Europe," said Shearwater GeoServices CEO Irene Waage Basili.

In 2017 Shearwater acquired 29,500 sq km (11,390 sq miles) of FlexiSource data for TGS, including 17,700 sq km (6,834 sq miles) for the TGS Atlantic Margin project. The 2018 season will bring the total area shot by Shearwater for the Atlantic Margin project to 22,835 sq km (8,816 sq miles).

—Staff & Reuters Reports

TECHNOLOGY

Direct Heating Helps Overcome Deepwater Flow Challenges

The advance of E&P into ever deeper waters, the increasing length of step-outs and the growing number of satellite developments from mature fields indicate that in coming years umbilicals will play an even more important role in offshore oil and gas production.

They provide the link from the host facility through which control is exercised, power transmitted and utilities such as injection chemicals supplied to the subsea wells.

Typically they range in length from a few kilometers to well over 100 km (62 miles), but future projects are expected to see umbilicals reaching lengths of more than 200 km (124 miles) and possibly even longer. The multiple functions it performs, the extreme reliability required and the demanding environment in which it is installed and operates, make an umbilical an extremely high-tech product.

The burgeoning electrification on the seabed is heralding a new era for umbilicals with less hydraulics required countered by a growing need for medium and high voltage. "This trend has been in the industry for some time, but now everybody is talking about all-electric as being the near future," said Jon Arne Hall, Nexans' technical project engineering director. "This will reduce the number of super duplex tubes in an umbilical."

Flow Assurance

The move to deeper water with longer subsea tiebacks is causing new potential flow assurance challenges for operators, particularly in deepwater where low temperature and high pressure at the ocean floor increases chances of hydrate and wax formation, blocking the flow of oil and gas.

"It is common to prevent hydrate and wax formation by injecting chemicals into the well stream, but this is not always the most beneficial method seen from a technical, cost and environmental perspective," Hall said.

With the push to improve operational efficiency, topside space is valuable while feeding the chemical processing equipment is very costly. To develop an alternative, a joint industry project (JIP) was formed by Nexans, Statoil and the research organization Sintef, to evaluate alterna-

Nexans will deliver an innovative 32-km-long umbilical, combining power, signal and steel tubes as well as other services to OneSubsea and Woodside in Western Australia. (Source: Nexans) tive methods of flow assurance. The outcome of the JIP was direct electrical heating (DEH), a technology which was qualified in 1998.

Hall explained that the DEH system heats the flowline above the temperature at which hydrate formation takes place by applying AC to the pipeline. This is supplied via the riser cable from the topside power system. Down on the seabed, the cable is connected to the subsea junction box. Another advantage is that the DEH riser cable can be used to bring down other service lines, such as signal and power cables, or additional fiber optics to the subsea junction box. A coaxial feeder cable is used between the subsea junction box and the pipeline.

At the pipeline the outer conductor in the cable is connected to the flowline, while the inner conductor is joined to a single core piggyback cable, which is attached to the flowline along the entire length to be heated and connected at the far end. The flowline then becomes the primary return conductor in the system, which is heated by its own electrical resistance.

At each end of the flowline, where the current is transferred between the pipe and cable, additional sacrificial anodes are mounted to form a well-defined, low-impedance path for the current to the sea, known as the current transfer zone. This makes it an open system, which improves safety and reliability. The anodes are rated for both corrosion protection and sufficient grounding of the system during the designed lifetime of the flowline and the heating system. The AC does not influence the internal corrosion of the flowline.

Future For DEH

Nexans has delivered nine out of 10 DEH systems that are in operation. The first DEH system was installed on the Åsgard Field, operated by Statoil, in 2000. The longest pipeline with DEH technology in operation is Tyrihans, also operated by Statoil. The production line is an 18-in. diameter, 42-km (26-mile) pipeline. The system installed at Tyrihans was the first installation with fiber used for break detection, another Nexans patent.

Hall believes the current developments in the deepwater oil field will make the DEH product more attractive. "DEH systems react instantly if an unplanned shutdown occurs and are simple to use," he said. "The systems have the additional advantage of being environmentally friendly. Each DEH system is tailored to the needs of the individual project. While the longest individual piggyback cable to date has been 42 km long, Nexans has the technology and know-how to significantly increase the length in future projects.

"The piggyback cable has been developed and qualified down to a water depth of 1,070 m [3,511 ft], but this depth is set to be increased in the future."

—Mark Venables

Petrobras To Interconnect Platforms Via Fiber-optic Communication System

The Brazilian state-owned oil company Petrobras plans to start building an ambitious telecommunication infrastructure project by the end of the year. This project consists of interconnecting 36 oil platforms in the presalt Campos, Santos and Espirito Santo basins, covering an area of 1,700 m (5,577 ft).

The plan intends to establish an integrated work between technicians who work in those units and specialists in the company's control centers. The goal is to optimize E&P activities and avoid problems before they happen with efficiency and lower costs.

The project, for which tender was launched in February, is the largest of its kind in recent years for Brazil. According to some sources of the segment, the whole plan, which establishes a complex installation process of fiber-optic cables, could generate investments of roughly $400 million.

Most important telecommunication engineering companies, equipment manufacturer factories and investors from other segments were allowed to bid alone or in a consortium. Petrobras did not want to reveal the name of the bidders, although some sources reveal that companies from U.S., Germany, Japan and China are among them. The awarded company will be announced in June, according to Petrobras.

According to Eberaldo de Almeida Neto, goods and services supply manager for Petrobras, the company designed a new contracting model that aims to reduce costs for the company. Renting the data connection instead of owning systems is one of the new points to put in the contract.

"The idea is to comprehend what is the best model for the market. This model is different from the previous one, when Petrobras was designed to have the ownership of the fiber-optic system in the Campos Basin," said Almeida Neto. "From now on, the bid winner company itself will be responsible for building the fiber-optic system, launching it in the sea and establishing the network communication system."

The company that wins the contract will be allowed to rent the fiber-optic system to other offshore companies that may also need data processing to operate in the Brazilian coast, Almeida Neto said.

For Statoil Brazil Vice President Supply Chain Mauro Andrade, the new Petrobras fiber-optic plan represents an important step toward the improvement of the infrastructure of Brazil's oil and gas industry.

"Brazil's oil and gas industry is passing through a very positive moment, and this project is going to help in this process," Andrade said during an event held in Rio de Janeiro.

Petrobras' fiber-optical network is larger than many similar projects operated by telecommunication companies in the South American country. The company uses its system to interconnect refineries, offices, processing centers, terminals, fertilizer units and FPSOs. Established in 1998, it is the world's first offshore optical communications network.

According to Petrobras, its fiber-optic communication system also plays an important role in the automation of the company's pipelines. "Most optical cables have 36 fibers. We have 7,979 km [4,958 miles] of terrestrial fiber-optic cables installed near the pipelines and 544 km [338 miles] of submarine optical cables, connecting the platforms of the Campos Basin. Our cable extension is slightly larger than the size of the Brazilian coast, which is 7,000 km [4,350 miles]."

Real-Time Drilling Problems Diagnosis Program

Petrobras will try to replicate a successful cost cut plan using real-time data analytics achieved in the Real-Time Drilling Problems Diagnosis Program (PWDa), the technology deployed in the drilling activities that led Petrobras to save roughly $100 million between 2014 and 2017. Through automated interpretation of data from different sensors installed in drilling systems, PWDa recognizes unwanted situations that can be avoided, working to detect signals that allowed corrective or preventive actions.

The program has an integrated 24-hour drilling monitoring service at Petrobras Decision Support Centers and at the Petrobras Research Center in Rio de Janeiro.

PWDa was developed by Petrobras, with the support of the State University of Campinas, the Federal Rural University of Rio de Janeiro and the Federal Technological University of Paraná.

—Brunno Braga

TECHNOLOGY BRIEFS

Acteon, Arundo Deliver Advanced Machine Learning Applications

Acteon Group, an integrated global provider of subsea services, and Arundo Analytics, a software company enabling advanced analytics in heavy industry, have partnered to deliver machine learning models for subsea applications on the Arundo Enterprise platform.

Acteon will work with Arundo as one of its preferred partners to develop high-value advanced analytics for its operating companies. Arundo will use tools, including machine learning and artificial intelligence, to help Acteon reach its goal of reducing the cost of asset ownership by 30%.

"We have a range of service lines focused on data capture and interpretation across all stages of the field life cycle," Paul Alcock, executive vice president of Acteon Group, said in a statement. "The aim of this partnership with Arundo Analytics is to align our digital solutions with advanced analytics to deliver operational efficiency increases to our clients through improved data insight."

BMT Releases Interactive Asset Data Platform

BMT has released BMT Deep, an advanced interactive asset data platform that delivers deeper insights for enhanced asset performance management and is the product of over 20 years' practical infield experience in offshore oil, gas and renewables, a press release stated.

BMT Deep harnesses Big Data to deliver a clear picture, and it is designed to quickly store, manage, integrate, post-process and visualize vast datasets. The platform is interactive, intuitive and facilitates the exploration of data from multiple sensor time series to post-processed and statistical data from a single asset or a fleet. All data are stored, managed and processed in the secure environment provided by BMT.

The platform also is fully customizable. The processing and analytics can be scaled and configured to match specific needs so that users can gain the most important insights within their time frame.

— Staff Reports

VESSELS

Norway's DOF Sees Offshore Supply Vessel Market Improving

The cost of renting offshore supply vessels (OSVs) servicing oil and gas firms will continue to rise as many ships that were mothballed up during the downturn will not return to the market, Norway's DOF CEO Mons S. Aase said.

A number of offshore vessel companies went bankrupt after oil prices plunged between 2014 and 2016 or were forced to merge with competitors to survive as oil companies cut spending for exploration and new developments.

But the rates for hiring specialized vessels, which include platform supply vessels (PSVs), diving support vessels (DSVs) and anchor-handling vessels, have increased in the last year.

While the North Sea has been leading the increase in demand for OSVs, with rates for some vessel segments improving by 30% from a year ago, activity also is starting to pick up elsewhere in the world, Aase told Reuters.

"The rate levels for PSVs have increased quite a bit from low levels [last year]... Now, at least, you can pay interest rates," he said.

The company, which operates more than 60 OSVs, said in a separated statement on April 11 that it had won a three-year contract from Petrobras for a DSV in Brazil.

As of April 11, DOF shares were trading up by 3.8% on the Oslo exchange by 09:55 GMT and were up 37% since the beginning of the year.

The company didn't disclose the contract's value or price, but Aase said it expected "better earnings" from the new contract than before.

"There are reasons to be a bit more optimistic than we have been...Overall [globally], we see a modest increase in activity," he told Reuters.

His optimism was based on the expectation that a majority of OSVs laid up in Europe will not return to the market.

"Many of those vessels parked in Europe came from Africa and Brazil, and they don't meet the [European] specifications... We clearly see that a significant portion, about two-thirds, will not be back," Aase said.

In April the Norwegian Shipowners' Association said oil companies had to be prepared to pay higher rates for OSVs to ensure the survival of their suppliers.

Some 183 OSVs and drilling rigs, corresponding to almost one-third of the Norwegian offshore supply fleet, were idle last year, the association's data showed. That number had fallen to 162 units by February, the association added.

—Reuters

VESSEL AND FLOATER BRIEFS

SMD To Supply ROV System To China Southern Power Grid

U.K.-based subsea equipment design and manufacturer Soil Machine Dynamics Ltd. (SMD) has landed a contract to supply ROVs to China Southern Power Extra High Voltage Power Transmission Co., a subsidiary of the state-owned power grid operator.

The system will be equipped with SMD's Curve-tech components, DVECSII control system and 6-m (20-ft) control cabin. (Source: Soil Machine Dynamics Ltd.)

SMD's light work class Atom Mk1 1000m 100hp Work Class ROV system will be used to inspect power cable connections in the Qiongzhou Strait between Hainan Island and mainland China, an area where it will often be exposed to high currents. Delivery is scheduled for the end of this year.

The system will be equipped with SMD's Curvetech components, DVECSII control system and 6-m (20-ft) control cabin that will be mobilized onboard China Southern Power Grid's (CSG) new cable installation vessel. SMD services also will train CSG's operational team. SMD will integrate a TSS350 cable tracking system and other survey tools to perform cable inspection.

CRRC SMD Shanghai's facilities will provide mobilization of the ROV onboard CSG's new vessel.

Siemens To Deliver Gas Turbine Packages For Sépia FPSO

MODEC has ordered four gas turbine power generation packages and two compressor packages for its Sépia Field vessel, *FPSO Carioca MV30*, in the presalt region of the Santos Basin offshore Brazil.

Siemens Power and Gas will deliver the SGT-A35 gas turbine packages and SGT-A35-driven DATUM CO_2 compressor packages for the FPSO, which is scheduled to be deployed about 249 km (155 miles) off the coast of Rio de Janeiro beginning in 2021. The contract provides for long-term service and maintenance.

The Siemens equipment is scheduled for delivery late this year. When it begins operations, *FPSO Carioca MV30* is expected to process 180,000 bbl/d of crude oil and have a storage capacity of 1.4 MMbbl oil.

This project is MODEC's 13th FPSO/FSO vessel in Brazil and sixth FPSO in the presalt region.

Longitude Concludes Predecommissioning Plan Contract For PTTEP

Longitude Engineer's new decommissioning barge concept offers operators of small oil and gas platforms an alternative to the conventional "reverse installation" method that relies on heavy-lift crane barges.

The London-based company said on April 17 that it had sought to develop a cost-effective way for Thailand's state-owned oil company, PTT Exploration and Production (PTTEP), to remove its minimum facilities platform assets in the Gulf of Thailand. The cost-effective removal concept focuses on moving topside weights up to 800 tons and jacket dry weights of up to 1,000 tons.

The solution that Longitude Engineer produced uses reverse float-over and onboard lifting methods to enable a single vessel to remove both topside and substructure. The company worked with Bosch Rexroth to develop a heave-compensated hydraulic lifting and skidding system.

As a result, the single vessel can handle different types of topsides and jackets without modifications to the barge. It can accommodate a crew of 60 for up to 40 days.

—Joseph Markman

BUSINESS

Cobalt's US GoM Bankruptcy Auction Pulls In $578 Million

The largest winning bid was a $339 million joint offer by Statoil and Total for Cobalt's 60% operated interest in the North Platte discovery.

Cobalt International Energy Inc. accepted bids totaling $577.9 million for its U.S. Gulf of Mexico (GoM) assets as part of the Houston E&P's bankruptcy auction, court documents revealed.

Cobalt filed for Chapter 11 bankruptcy in December following initial trouble selling the assets in addition to a lingering arbitration dispute with Angola's state-owned Sonangol.

The largest winning bid at the auction held in early March was a $339 million joint offer by Statoil and Total for Cobalt's 60% operated interest in the North Platte discovery.

Total and Statoil said April 11 that the companies completed the acquisition from Cobalt and as a result Total will now take over as operator and increase its holdings to 60% from 40%. Meanwhile, Statoil will own a 40% nonoperated interest in the project.

Discovered in 2012 by Total and Cobalt in the Wilcox play, North Platte covers four blocks of the Garden Banks area, 275 km (171 miles) off the coast of Louisiana in roughly 1,300 m (4,265 ft) of water. The field is fully appraised with three wells and three sidetracks.

"This is a high-quality asset with a low CO_2 footprint and so [it] strongly supports our strategy," Torgrim Reitan, Statoil's executive vice president for development and production USA, said in a statement. "It is also an excellent fit with our existing U.S. offshore portfolio, competence in technology development and knowledge of the Paleogene play in which we are the second largest producer."

Statoil plans to start production in North Platte in the mid-2020s, company spokesperson Erik Haaland said in a Reuters report.

Total also grew its U.S. GoM footprint further through Cobalt's bankruptcy auction by picking up an additional 20% stake in the Anchor discovery for $181 million and 13 offshore exploration blocks for $25 million, according to court documents.

Anchor, which is operated by Chevron Corp., was discovered in 2014 in the Wilcox play, 225 km (140 miles) off the coast of Louisiana in about 1,500 m (4,921 ft) of water. Total now holds 32.5% in Anchor, which the French oil major said is "one of the most significant recent discoveries in the GoM."

In addition to North Platte and Anchor, Total holds working interests in three producing fields in the U.S. GoM: Jack with 25% and Tahiti with 17%, both operated by Chevron, and Chinook with 33.33%, operated by Petrobras. The company also holds 40% in the Chevron-operated Ballymore discovery and participation in more than 160 exploration leases.

Statoil already has interests in eight producing fields in the U.S. GoM and two in development. The company's production is expected to reach 110,000 boe/d, making Statoil a top-five producer from the deepwater GoM, according to its press release.

In addition, Statoil said it expects its U.S. GoM portfolio will achieve an average cash margin of at least $45/bbl after tax at an oil price of $70 by 2020.

New York-based law firm Orrick advised Statoil on its acquisition with Total. The effective date of the North Platte transaction is Jan. 1.

During the bankruptcy auction, W&T Offshore Inc. also presented the winning bid for Cobalt's Heidelberg assets in the Green Canyon area for $31.1 million, and Navitas Petroleum US LLC's $1.8 million bid was selected for the company's Shenandoah properties in the Walker Ridge area, court documents said.

Kirkland & Ellis LLP was Cobalt's legal adviser, and Houlihan Lokey Inc. served as financial adviser for the company's restructuring.

—Emily Patsy

BUSINESS BRIEFS

Tullow Oil Names New Director, Board Chairman

Dorothy Thompson, who served as CEO of the Drax Group international power and energy trading company, has been appointed independent nonexecutive director and chair designate for Tullow Oil, according to a news release.

The director appointment takes effect at the end of Tullow's annual general meeting April 25.

Thompson will succeed Aidan Heavey, Tullow's current chairman and founder, as chair at the end of the company's July 20 board meeting. Heavey is retiring from the board.

Thompson served 12 years as CEO of Drax Group until year-end 2017. Before joining Drax, she managed InterGen's European power business, was head of project finance at PowerGen and worked at CDC Capital Partners.

US Interior Secretary Opts Against Lowering Offshore Royalty Rates

U.S. Interior Secretary Ryan Zinke said he will not lower royalty rates for offshore oil and gas lease sales "at this time" despite a recommendation from an advisory panel to do so.

Zinke cited the success of President Donald Trump's energy strategy as a reason for not adhering to the recommendation of his appointed Royalty Policy Committee, which in late February advised him to slash the royalty rate for offshore drilling by nearly one-third to 12.5%.

"Right now, we can maintain higher royalties from our offshore waters without compromising the record production and record exports our nation is experiencing," Zinke said.

Balmoral Offshore Engineering Acquires Seaproof Solutions

Balmoral Offshore Engineering is expanding into the offshore renewables market with its acquisition of Norwegian manufacturer Seaproof Solutions, which designs and manufactures advanced cable protection systems, bend stiffeners and flexible J-tubes.

Seaproof is forecast to have about $18 million in sales this financial year, Balmoral said in a news release.

The value of the acquisition was not disclosed, but Balmoral said it plans to retain Seaproof's current management team and workforce. The Seaproof plant employs more than 35 people.

Seaproof will continue trading and manufacturing under that name as a division of Balmoral, the company said.

The acquisition is the latest sign of growth for Balmoral, which recently opened a subsea test center in Aberdeen, made a $14.2 million investment in ACE Winches and completed an industrial tank manufacturing facility in South Yorkshire in 2017, Balmoral said.

Odfjell Drilling Wins $160 Million Sverdrup Contract From Statoil

Statoil has awarded a conditional letter of intent for a drilling contract for the Deepsea Atlantic rig for six firm wells, with an estimated total duration of 18 months, for the Johan Sverdrup development.

The contract, scheduled to commence in early first-quarter 2019, has an estimated value of $160 million. It includes some third-party services such as casing running services by Odfjell well services. The contract also contains an option to continue operations for Statoil after firm period with such options based on market pricing.

"We have enjoyed great operational success in our partnership with Statoil on Johan Sverdrup, and we are setting our sights even higher to improve on previous performance going forward by implementing new digital solutions to increase efficiency in operations," Odfjell Drilling CEO Simen Lieungh said.

Statoil, which develops the Arctic Johan Sverdrup oil field northwest of Hammerfest, has ditched previous plans for an onshore terminal to reduce the development's costs.

The company plans to export oil from the field by using shuttle tankers, the development plan presented to the Norwegian parliament showed. The onshore terminal, however, could be revived if it could receive oil from other developments in the Barents Sea, making it more profitable.

Sumitomo Invests In Airborne Oil & Gas

Japan-based Sumitomo Corp. has acquired a significant shareholding in Airborne Oil & Gas, which manufactures thermoplastic composite pipe (TCP), according to a news release.

Airborne, which is headquartered in The Netherlands, said the investment "strengthens a strategic partnership, which both companies entered into in 2016, in which the companies collaborate to provide the oil and gas industry with cost-effective TCP technology solutions that are noncorrosive, lightweight and result in significantly lower total installed cost."

Sumitomo is a Fortune 500 global trading and business investment company. Energy, mineral resources, chemical and electronics are among its core business areas, according to the news release.

SSEN Awards Subsea Cable Contract To Global Marine Group

Global Marine Group has landed a contract from Scottish and Southern Electricity Networks (SSEN) to install and commission a 10.8-km (6.7-mile) electricity cable between Rousay and Westray in the Orkney Isles, U.K.

As part of SSEN's ongoing electricity distribution subsea cable replacement program, the new cable will replace the existing 35-year-old cable that is nearing the end of its operational life, according to a news release.

"The Rousay -Westray submarine cable replacement is one of a number of projects that are being progressed to maintain the electricity distribution infrastructure serving the Scottish islands, ensuring continued security of supply for Scotland's island communities," the release stated.

"From now until 2023, around 90 km [56 miles] of submarine cables are due to be replaced—a fifth of the total number currently in operation."

Subsea 7 Lands Contract Offshore Nigeria

Subsea 7 said it has been awarded a contract by Mobil Producing Nigeria Unlimited for the Production Uplift Pipeline Projects in shallow water offshore Nigeria.

The contract scope includes engineering, construction, transportation, installation and precommissioning of 20 km (12 miles) of 24-in. corrosion-resistant alloy (CRA) pipeline between the Idoho Platform and the terminal onshore and of 2 km (1 mile) of 24-in. CRA pipeline between the Edop and Idoho platforms as well as associated topside modifications and tie-ins at both ends.

Engineering and procurement will start immediately at NigerStar 7's offices in Lagos, while offshore operations will take place from third-quarter 2018 to first-quarter 2019 using the Subsea 7 vessel, *Seven Antares.*

ONGC Taps Cosasco For Corrosion Monitoring System

Cosasco has been awarded a $380,000 contract with Afcons Infrastructure Ltd. to deliver corrosion monitoring systems for Oil and Natural Gas Corp. Ltd. (ONGC), a press release stated.

The scope of work includes the installation of 132 intrusive electrical resistant probes, 22 corrosion coupons and 11 bio probes across 11 unmanned offshore platforms at the LEWPP-II project. In addition, Cosasco will deliver services that include technical consultancy, manufacturing, post-sales support and a long-term warranty.

Deep Down Secures Over $4 Million In Equipment Installation Orders

Deepwater equipment and services specialist Deep Down Inc. has secured more than $4 million in orders to install subsea equipment from two new customers, the company said April 18.

The orders are for the planning, installation and commissioning of an umbilical and a flexible flowline, equipment that enables the transmission of controls, fiber-optic communications, electricity and hydraulic and other fluids between surface installations and the clients' subsea equipment, Deep Down said in a news release.

Engineering, procurement and construction of associated tie-in equipment and the rental of Deep Down installation equipment are part of the contracts. Deployment is planned for second- and third-quarter 2018 in the Caribbean and South Pacific Ocean.

—Staff & Reuters Reports

UPCOMING

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CONTACT INFORMATION

LEN VERMILLION Group Managing Editor
Digital News Group
lvermillion@hartenergy.com

VELDA ADDISON Senior Editor
Digital News Group
vaddison@hartenergy.com
(713) 260-6400

CONTRIBUTORS:

Ariana Benavidez (Houston)
Brunno Braga (Rio de Janeiro)
Mary Holcomb (Houston)
Joseph Markman (Houston)
Emily Patsy (Houston)
Ravi Prasad (India)
Mark Venables (UK)

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