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Analysts: Cost Inflation Could Threaten Improved Economics For Deepwater Oil Projects

Breakeven costs have fallen for deepwater projects, but analysts question whether the oil industry is ready for anticipated cost inflation. (Source: *Shutterstock.com*)

Oil and gas companies with the stamina needed to dive into deepwater projects and stay afloat have managed to slash breakeven costs in recent years. But analysts warn impending cyclical cost inflation could trigger a rise in such costs.

The average prefinal investment decision breakeven dropped to $49/boe Nov. 27 compared to $78/boe in 2014, according to a report released by Wood Mackenzie. Carrying out lessons learned during the most recent market downturn, some operators have opted for fewer wells, more phases and tiebacks to existing infrastructure while seeking lower rig rates and supply chain costs, drilling better wells, and utilizing technology to control expenses.

BP, for example, cut costs for the Mad Dog Phase 2 project in the deepwater U.S. Gulf of Mexico (GoM) by more than half. Focusing on value, industry solutions and collaboration with its partners, BHP and Chevron USA Inc. affiliate Union Oil Co. of California, the operator chopped the massive 33-well $20 billion development down to $9 billion with up to 14 wells.

The project, which is set to begin oil production in late 2021, remains on budget and on schedule, Starlee Sykes, BP's regional president for the Gulf of Mexico and Canada, said in a news release.

"This project is key to delivering high-margin production from one of the largest fields in the Gulf of Mexico, and it will strengthen our position in the basin for years to come," Sykes said.

Similar stories have unfolded across the deepwater GoM, where the number of subsea tiebacks has grown, and other parts of the world. Unit costs have fallen by more than 50% since 2013, Wood Mackenzie said. The firm added that improved project execution has resulted in the average deepwater project sanctioned between 2014 and 2016 starting up about 5% under budget, compared to the 10% to 15% overrun typically seen with projects between 2006 and 2013.

Improved project economics means more deepwater investments could be on the horizon, following the market downturn that halted or slowed many offshore projects. Wood Mackenzie forecasts developments offshore Guyana, Brazil and Mozambique will drive higher

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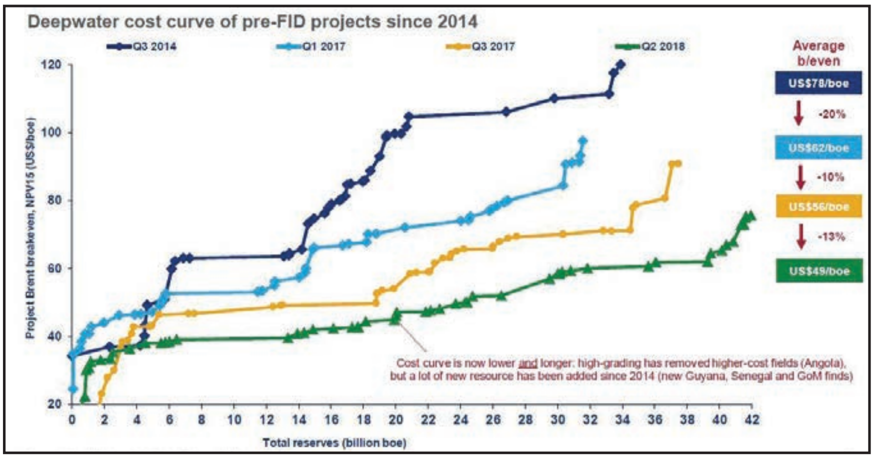
deepwater capex, expected to hit nearly $60 billion by 2022 from about $50 billion currently.

But the costs gains could be short-lived if companies fail to make the savings permanent.

"The return of cyclical inflation could see this epic period of deepwater cost reduction come to a close," said Angus Rodger, research director for Wood Mackenzie.



Source: Wood Mackenzie's Global Economic Model (GEM)

Cyclical inflation could impact deepwater costs in the areas of rig day rates, subsea equipment and services and other service sector costs, according to Wood Mackenzie. The speed of cyclical cost reinflation will depend on how quickly operators drive a recovery and the supply chain's ability to meet their demand, the firm said in the report.

"The question now is how much of the 'structural' cost savings we have seen through the downturn will prove sustainable through the investment cycle and which are just short-term company adaptions," Rodger added.

Structural costs savings, considered more "resilient/sticky" by Wood Mackenzie, include drilling faster and better wells, having quicker project lead times and phasing projects. The firm said that it was skeptical that some of these so-called "structural cost savings will stand the test of time in a sustained cyclical uptick." Such savings were viewed by the analysts as external environment-driven corporate behavior and project design changes.

"Those that 'stick' become cultural changes within the sector that can stand the test of time and price cycles, but historically the big players in deepwater have been slow to change, based on their size, culture and limited risk tolerance in a challenging operating environment," the report said.

—Velda Addison

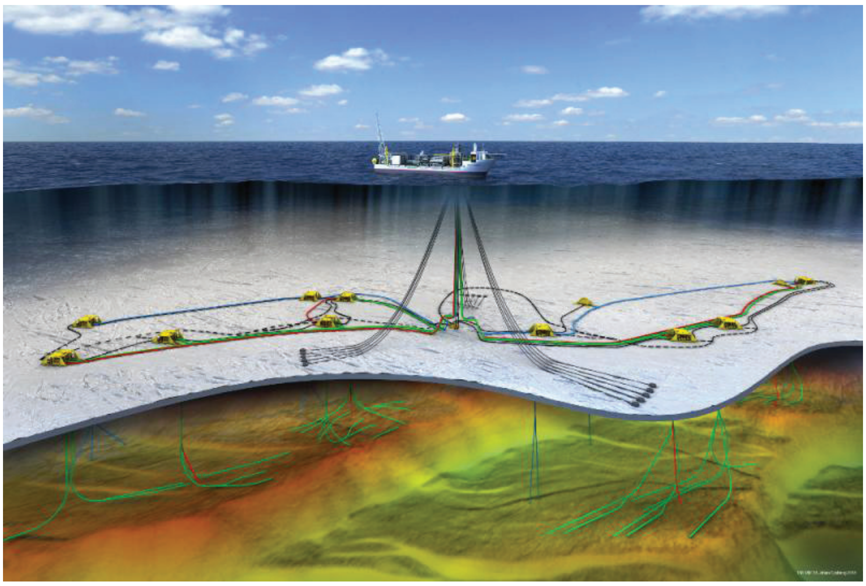
DEVELOPMENT

Norway, Newfoundland & Labrador Keep Arctic Exploration Alive

Some energy companies chasing potential hydrocarbon bounties in a region commonly known for its harsh environment, high price tags, infrastructure needs and environmental sensitivity are finding success and progressing multibillion-dollar projects.

Projects like the Equinor-operated Johan Castberg development in the less harsh Barents Sea and Bay du Nord discovery in the Flemish Pass Basin offshore Newfoundland in the Atlantic Ocean highlight the Arctic region's potential. The region, which continues to compete with onshore areas for investment dollars, still has its challenges but has managed to attract players, according to panelists speaking Nov. 5 at the Arctic Technology Conference.

"The change for us has been increased investments and knowl-



Plans for the Equinor-operated Johan Castberg Field in the Barents Sea include use of an FPSO. (Source: Equinor) edge of our prospectivity," said Doug Trask, assistant deputy secretary of royalty and benefits for Newfoundland and Labrador's Department of Natural Resources. "Prior to the last five or six years we were not investing, and the awareness was not there of how many basins we had and what the size of some of those potential discoveries were."

Newfoundland and Labrador has more than 20 basins with lots of exploration potential, he said, noting its regularly scheduled license rounds have played a role in gaining new entrants to its offshore region. The government has also made strategic investments in geoscience, including 3-D seismic data, in advance of license rounds to help attract investors.

"Newfoundland is well positioned to play a role in supporting Arctic development. We have 50 years of exploration behind us and 20 years of production in some of the most challenging offshore environments there is characterized by icebergs, sea ice and difficult metocean conditions," Trask said. "Today we produce about 1.8 billion barrels of oil from a number of facilities."

The province has undertaken a 12-year plan to speed up oil and gas development offshore, aiming to drill more than 100 exploration wells in multiple basins and increase production to more than 650,000 boe/d from the current level of about 250,000 bbl by 2030.

Production from the Exxon Mobil Corp.-operated Hebron project, which started production in late 2017, is expected to help in reaching the goal. The platform, which consists of a standalone gravity-based structure about 350 km (200 miles) offshore Newfoundland and Labrador, will produce up to 150,000 bbl/d at its peak.

In addition, first oil is expected from the Bay du Nord project, the first deepwater project offshore Newfoundland and Labrador, in 2025.

"We're certainly looking to continue to develop our offshore [projects]," Trask said. But its competitiveness hinges on the success of R&D initiatives and innovation, he added. These include remote sensing, offshore training, subsea technology and other emerging areas such as digital technology, AUVs and DNA environmental monitoring.

Another challenge when it comes to Arctic developments, including in Norway's "High North" Arctic region, is not having enough existing infrastructure.

"If you [make] a discovery in the Norwegian Sea or in the North Sea these days, you might have a host facility that you can tie back to and that will reduce the needed size of the discovery to be commercially attractive," said Lars Erik Aamot, director general and head of oil and gas department for Norway's energy ministry. "So that is the key for the future in the north. We need to do more big discoveries that have standalone potential and then, of course, exploration success is needed."

It helps that Norway's Barents Sea is ice-free, a benefit of the warm Gulf Stream, during the summer.

The region has two main producing fields in the Arctic: Equinor's Snøhvit, which provides gas for Hammerfest LNG and the Eni-operated Goliat Field, Aamot said. But more are in the works as Equinor moves forward with the giant Johan Castberg Field. The company recently said it found more oil with its nearby Skrius exploration well, further confirming the potential of the Barents Sea. Castberg is estimated to hold between 400 MMbbl and 650 MMbbl of oil with startup planned for 2022.

The development also illustrates that some Arctic projects can be economic. Equinor and partners cut the costs of the Castberg subsea development, which will utilize an FPSO, from NOK 100 billion to 50 billion (US$11.6 billion to US$5.8 billion) by changing the design concept.

Aamot added that Castberg is economically viable with an oil price of about $30/bbl.

The "Barents Sea has grown in the last decade from low exploration activity and no producing fields to become a fully fledged petroleum province," Aamot said. "As long as discoveries are made, they should be profitable there as well as elsewhere on the shelf."

A consistent and reasonable regulatory environment is also needed to draw investment, according to a statement by Alaska Sen. Lisa Murkowski. In the statement, read in the senator's absence by Sara Longan, executive director of the North Slope Science Initiative, Murkowski wrote about Alaska's Arctic potential, the North Slope's recent designation by IHS Markit as a super basin "ready for oil resurgence" and technology advances such as extended-reach drilling.

"We can now access more resources from less land than ever before, and we can do that more safely than ever before," she said.

The U.S. Geological Survey estimates that the Arctic holds more than 30% of the world's undiscovered gas resources as well as 13% of the world's undiscovered oil resources.

—Velda Addison

DEVELOPMENT BRIEFS

Shell Taps McDermott For Subsea Work At GoM's Great White Frio Development

Royal Dutch Shell subsidiary Shell Exploration and Production Co. has selected McDermott International Inc. for new subsea umbilical and flowline installation at the Great White Frio development in Alaminos Canyon Block 857 in the U.S. Gulf of Mexico (GoM), according to a news release.

The contract is valued at between $1 million and $50 million.

McDermott said its scope of work includes project management and engineering; installation of a flexible flowline from the well to a pipeline end termination; installation of one 610-m-long (2,000-ft-long) steel flying lead; and installation of two electrical flying leads in a water depth of 2,438 m (8,000 ft). Project management and engineering are scheduled to be performed in Houston, with offshore installation by McDermott targeted for completion in mid-2019.

The Shell Offshore-operated Great White development was described in the release by McDermott as a "pioneer deepwater oil and gas project that has unlocked a new frontier of energy development in the Gulf of Mexico's Lower Tertiary Paleogene." The Perdido regional host production hub processes oil and gas from Great White along with the Silvertip and Tobago fields.

McDermott said the contract award will be reflected in its fourth-quarter 2018 backlog.

The *Argos* platform will be the first for BP in the GoM since 2008. (Source: BP)

BP Gives Mad Dog 2 Floating Production Unit New Name

BP has selected *Argos* as the name of the new floating production unit for the $9 billion Mad Dog 2 project in the deepwater U.S. Gulf of Mexico (GoM).

The name is a reference to Odysseus' loyal dog from "The Odyssey" and a nod to the Mad Dog spar, an existing production facility operated by BP about six nautical miles away from the Argos site, BP said Nov. 27 in a news release.

The platform is capable of producing up to 140,000 bbl/d of crude oil (gross) through a subsea production system from up to 14 production wells and eight water injection wells, BP said in the release.

The hull and topsides of the *Argos* platform are under construction in South Korea.

"Selecting *Argos* as the name of our newest platform is an important milestone for the Mad Dog 2 project, which remains on track and on budget," said Starlee Sykes, BP's regional president for the GoM and Canada. "This project is key to delivering high-margin production from one of the largest fields in the Gulf of Mexico, and it will strengthen our position in the basin for years to come."

Oil production from the facility is scheduled to start in late 2021.

Black Sea Oil & Gas Awards EPCIC Contract For Offshore Romania Devolopment Project

Grup Servicii Petroliere (GSP Offshore) has landed an engineering, procurement, construction, installation and commissioning (EPCIC) contract for the Midia gas development project offshore Romania, Black Sea Oil & Gas (BSOG) said Nov. 23.

The contract was jointly awarded by BSOG and its co-venture partners Petro Ventures Resources and Gas Plus International B.V.

If a final investment decision is reached on the project, GSP will handle the procurement, construction, installation and commissioning of the complete subsea gas production system over the Doina Field. GSP will also carry out the construction, installation and commissioning of a new unmanned production platform over the Ana Field along with the subsea pipeline system, which will link production platform to the shore, the onshore pipeline and the new gas treatment plant, the release said.

BSOG said building the project's entire infrastructure is estimated to take two years.

Chevron Announces First Oil From GoM Big Foot Project

Chevron Corp. said Nov. 21 the Big Foot deepwater project, located in the U.S. Gulf of Mexico (GoM), has started crude oil and natural gas production. The field is located about 360 km (225 miles) south of New Orleans, La., in a water depth of about 1,584 m (5,200 ft).

Discovered in 2006, the Big Foot Field is estimated to contain total recoverable resources of more than 200 MMboe and has a projected production life of 35 years. The project uses a 15-slot drilling and production tension-leg platform, the deepest of its kind in the world, and is designed for a capacity of 75,000 bbl/d of oil and 707,921 cu. m/d (25 MMcf/d) of natural gas.

Chevron's subsidiary Chevron USA. Inc. is the operator of Big Foot with a 60% working interest. Co-owners are Equinor Gulf of Mexico LLC (27.5%) and Marubeni Oil & Gas (USA) LLC (12.5%).

The Chevron-operated Big Foot project uses a 15-slot drilling and production tension-leg platform, the deepest of its kind in the world. (Source: Business Wire)

BP Starts Production At Clair Ridge Field In North Sea

BP has started production at the Clair Ridge oil field in the West of Shetlands region of the North Sea, targeting a peak output of 120,000 bbl/d, the company said Nov. 23.

The Clair Ridge project is Phase 2 of the Clair Field, located 75 km (47 miles) west of Shetlands. Royal Dutch Shell, Chevron and ConocoPhillips also hold stakes in the field.

In addition to two bridge-linked platforms, the Clair Ridge project included a new oil and gas pipeline tying it to the Clair export pipeline, which delivers oil to the onshore Sullom Voe Terminal, BP said in a statement.

The Clair Ridge Field is the site of the first offshore deployment of BP's LoSal EOR technology. (Source: BP)

Clair was discovered in 1977 and is one of a number of big developments in the west of Shetland area, where other oil companies are investing. The new project is designed to recover 640 MMbbl of oil.

Clair Ridge is BP's sixth major project startup in 2018 after starting up seven in 2017. All these projects will boost the London-based company's output by 900,000 boe/d by 2021.

British Energy Minister Claire Perry said in a statement that Clair Ridge was vital for the country's energy security. "Aided by the innovative use of technology developed in the U.K. and a strong U.K.-based supply chain worth £1.5 billion (US$1.7 billion), this will allow the North Sea to continue to be a hub for the high-skilled, well-paid jobs at the center of our modern Industrial Strategy."

BW Offshore Makes FID For Tortue Phase 2

BW Offshore has agreed to move forward with Tortue Phase 2, having made a final investment decision (FID) for the development offshore Gabon.

The decision comes after the successful appraisal program on the western flank of the Tortue Field, the company said Nov. 20.

"We have demonstrated the attractiveness of our model of combining proven resources, a resourceful organization and access to production assets by bringing the Tortue Field to first oil within budget and on schedule in less than 18 months," said BW Offshore CEO Carl K. Arnet. "We look forward to commencing Phase 2 of development."

Phase 2 of the development entails drilling four more horizontal development wells. BW said orders for long lead equipment, including subsea trees, wellheads, drilling casing and completion equipment, already have been placed. In addition, a letter of intent has been signed for the drilling rig.

BW Offshore puts 2P gross reserves for the Tortue Field's two-well (Phase 1) and the four-well (Phase 2) at an estimated 30 MMboe to 40 MMboe, excluding contingent reserves.

First oil from Phase 1 was achieved in September by the FPSO *BW Adolo*.

McDermott Secures EPCI Contract For Rigid Pipeline Project

Petrobras has tapped McDermott International Inc. for a natural gas pipeline project in support of the Brazilian major's Santos Basin presalt field program.

The contract, valued between $50 million and $250 million, covers implementation of the ultrashallow segment of the new 355-km (220-mile) Rota 3 gas export pipeline, according to a news release.

The scope of work includes design and detailed engineering, procurement, construction and installation (EPCI) of 10 km (6 miles) of a 24-in. rigid concrete coated pipeline from the already installed shallow-water segment of this new pipeline system to the shore. This includes a horizontal directional drill, tie-in spools and precommissioning of the pipeline.

The pipeline project is part of Petrobras' Santos Basin presalt gas offloading and transportation system. The project is comprised of one onshore segment and three subsea segments, according to the release. McDermott scooped up the contract for the third subsea segment: an ultrashallow pipelay connecting the shallow segment to the onshore segment at Maricá City, north of Rio de Janeiro.

—Staff & Reuters Reports

EXPLORATION BRIEFS

Equinor Strikes Gas Discovery In Barents Sea Near Atlantis

A wildcat well drilled by Equinor Energy AS hit gas northwest of the Atlantis discovery in the Barents Sea.

The Norwegian Petroleum Directorate (NPD) reported Nov. 22 that the well, which was drilled to a vertical depth of 1,678 m (5,505 ft) at a water depth of 452 m (1,483 ft), encountered gas at its primary and secondary targets.

In the primary exploration target, the NPD said a gas column of about 30 m (98 ft) was encountered in the upper part of the Snadd Formation. About 20 m (66 ft) of the column was in an effective reservoir of primarily moderate to poor reservoir quality, according to the NPD.

In the secondary exploration target in the lower part of the Snadd Formation, gas was also hit in sandstone of poor to moderate reservoir quality. But efforts to define a gas gradient were unsuccessful due to the tight formation, the NPD said. In addition, 15 m (49 ft) of aquiferous reservoir sandstone was encountered in the Stø Formation, with moderate to good reservoir quality, for the other secondary exploration target.

"Preliminary calculations of the size of the discovery in the upper part of the Snadd Formation are between 10 billion and 20 billion standard cubic meters of recoverable gas," the NPD said. "In the lower part of the Snadd Formation, the gas volume is estimated at between 1 billion and 4 billion standard cubic meters of recoverable gas. The discovery's profitability is currently unclear."

The well was drilled by the West Hercules drilling facility.

Faroe Makes Small Gas, Condensate Discovery In North Sea

Faroe Petroleum Norge made what the Norwegian Petroleum Directorate (NPD) called a "minor" gas discovery in the North Sea north of the Oseberg Field center.

The goal was to prove gas and condensate in Middle Jurassic reservoir rocks with its primary and secondary exploration targets in the Oseberg Formation and Etive/Ness formations, respectively, the NPD said Nov. 23.

In the primary exploration target, the well encountered about 85 m (279 ft) of aquiferous sandstone, mainly with moderate to good reservoir quality. In the secondary exploration target, a total gas-condensate column of about 55 m (180 ft) was encountered in the Ness Formation, while 25 m (82 ft) of aquiferous sandstone was encountered in the Etive Formation, according to the NPD.

"Preliminary estimates place the size of the discovery between 0.4 and 2.7 million standard cubic meters of recoverable oil equivalents," the NPD said. "Preliminary assessments indicate that the discovery is not currently profitable, but the licensees will assess the discovery together with other nearby discoveries/prospects with regard to further follow-up."

The well was drilled by the Transocean Arctic drilling facility.

Oil Firms Seen Drilling Up To 50 Exploration Wells Off Norway In 2019

Oil and gas companies plan to drill 40 to 50 exploration wells on the Norwegian Continental Shelf in 2019, similar to levels seen in 2018, the head of exploration activities at the Norwegian Petroleum Directorate said.

Norway also plans to conduct further seismic studies near its maritime border with Russia so that it can better prepare for any potential discovery of oil or gas on the Russian side, Torgeir Stordal said.

"If the [Russians] find something there, we have to be ready to act," he said, adding that it could potentially lead to pressure on Norway to open areas near the maritime border for exploration.

Cairn Energy Makes New North Sea Oil Discovery

Cairn Energy has made an oil discovery at the 9/14a-17B well and associated sidetrack on the Agar-Plantain prospect in the U.K. North Sea, the company said Nov. 15.

Based on preliminary analysis, the operator estimates the Agar-Plantain discovery holds recoverable resources of between 15 MMboe and 50 MMboe.

The discovery is near existing infrastructure, located 12 km (7 miles) from the Beryl Bravo facility to the southwest and 14 km (8 miles) from the *Alvheim* FPSO to the southeast.

Further evaluation of development options to establish commerciality will be undertaken by the joint venture partners in the coming months.

The initial 9/14a-17B well on the Agar-Plantain prospect was drilled safely to the target depth and encountered excellent quality oil- and water-bearing sands. The wellbore delineated the eastern extent of the hydrocarbon discovery and the partners agreed to drill the contingent sidetrack to further appraise the discovery. The Agar sidetrack encountered a 20-m (65-ft) gross interval of very high-quality oil-bearing sands.

Cairn has an option to take over operatorship with respect to future activity on the Agar-Plantain project. The Agar-Plantain well is being plugged and abandoned by operator Azinor Catalyst. Working interests in the well are Azinor Catalyst (operator 25%), Cairn (50%) and Faroe Petroleum (25%).

The commitment exploration well on license P2184 in the U.K. North Sea targeting the Ekland prospect (Cairn operator, 45% working interest) failed to encounter commercial hydrocarbons and has been plugged and abandoned.

—Staff & Reuters Reports

TECHNOLOGY

What An Intelligent E&P Enterprise Should Look Like

Maverick NextGen Energies leans heavily on tools like machine learning, artificial intelligence (AI) and predictive analytics to leverage the huge amounts of data it culls from connected assets across a vast and diverse portfolio of energy businesses. To reinforce the use of best practices across the enterprise and optimize its assets, the company houses most of its software-based systems and processes in the cloud.

Bold strategic maneuvers would make Maverick a role model to even the most forward-thinking of energy companies—if Maverick were a real company, that is.

In fact, Maverick is a digital figment of the imagination, a model of what an intelligent E&P enterprise could and perhaps should look like, developed over the past couple years by Shell, with the help of PwC and SAP, to provide the company with a guiding vision for staying competitive using the latest generation of digital solutions.

"It's really going to be an effective change tool to help change the mindset of what the art of the possible is," said Shell CIO Jay Crotts of Maverick.

Using learnings from the Maverick exercise, Shell is discovering what's possible as an intelligent enterprise. And it is not alone. E&P companies around the globe are exploring ways to deliver more value to customers, enabled in large part by data and digital tools that are widely available to E&P companies today. But successfully evolving into an intelligent enterprise entails not only investments in the right tools but a commitment to follow several key fundamentals.

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Embrace end-to-end processes

To find new ways to be agile and innovative, even when commodity prices are low for extended periods, energy companies are shedding complex, siloed custom IT solutions and processes in favor of simplified, end-to-end business processes and connected ecosystems where data, learning and best practices flow freely but securely across the enterprise. They're doing so by implementing comprehensive, real-time planning, forecasting and modeling, and by creating scalable processes and systems through automation, AI and machine learning.

On one level, digitalization serves as a lever for automating day-to-day business process to improved productivity and efficiency in the field and back office. By connecting assets across plants and fields to a central digital core using Internet of Things sensors, companies have the means to collect and analyze data in real time to see the big picture.

The condition and performance of assets can be monitored, managed and maintained centrally to maximize equipment uptime (with a pump in the field, for example, sensors monitor pressure, temperature, vibration, etc.). Machine learning tools in the cloud define what's normal and what's anomalous behavior for that asset, so a predictive maintenance program can be tailored to that asset. From there, the system can issue a maintenance work order, source a replacement part and even identify the most appropriate contractor from the company's contingent workforce to perform the maintenance.

If an issue is encountered with a field asset, digital tools can use sensor data to reproduce that asset's behavior in the laboratory to diagnose a cause. The system then can arm field workers with all the information they need (work order, up-to-the-moment reports on conditions around the failure site, manufacturer disassembly and repair specs, etc.) to address the issue.

This simplified, end-to-end approach helps to optimize an E&P operation, freeing a company and its employees to focus on higher value pursuits and innovation. It becomes a strategic enabler for companies to pursue new business models that leverage suppliers and customers and focus on value-creation for the customer (via new outcome-based offerings).

Embrace market-standard IT approaches

As they worked to become leaner in the low-commodity-price environment that prevailed a couple years ago, energy companies realized they could run more efficiently and innovate more effectively by replacing complex, siloed IT solutions and processes with simplified market-standard digital approaches.

Shell, for example, has committed to follow an 85/15 rule with its digital strategy, whereby 85% of the IT solutions on which it relies are market-standard and the remaining 15% are proprietary solutions, Frank Westerhof, the company's enterprise platform manager, explained at the Best Practices for Oil and Gas Conference in September. That 15% is the "special sauce"—custom digital processes and solutions the company can leverage to distinguish its brand and to explore and build out new products, services and business models.

Such an approach could start with an intelligent, cloud-based digital solution for collecting, analyzing and acting upon the data that fuel the intelligent enterprise. "Data, I think, is the new oil," said Shell's Crotts.

Embrace the public cloud

Energy companies are fast realizing that moving key business processes to the public cloud and embracing software as a service solutions give them the means to optimize and innovate on the fly. To that end, a consortium of E&P companies, including BP, Devon Energy, Apache, ConocoPhillips, Chevron, Equinor and Shell have joined forces to develop parameters for market-standard upstream digital solutions housed in the cloud.

"For us, it's important that as an industry we define the right sort of processes and standards for oil and gas," said BP's Dan Smith. "We want to collaborate with other operators and other industry players to do that definition…At end of the day, this is about removing complexity…from our landscape."

When new U.K. E&P company Assala Energy launched its African operations using assets purchased from Shell Gabon, it relied on digital tools in the cloud, as well as industry templates, to become operational in a mere six months.

Besides rapid implementation, digital systems and processes housed in the public cloud bring a new level of standardization to IT, along with lower total cost of ownership and ease of scalability. Unlike Maverick, these benefits are real, not just hypothetical.

—Brent Potts, Contributing Editor

TECHNOLOGY BRIEFS

MacArtney To Provide Source Control Solution To ION Geophysical For Seismic Survey

New technology developed by MacArtney and ION, in the form of a SailWing actuator and control system designed to ensure the correct positioning and stability of seismic survey source arrays, has been launched to gather data for enhanced oil and gas E&P.

MacArtney's SailWing actuator is designed for correct positioning and stability of seismic survey arrays. (Source: MacArtney)

Earlier this year, MacArtney provided six customized SailWing actuators in a control system for ION Geophysical. The SailWing actuator and its control panel are designed to control sources towed from a seismic vessel gathering data intended for 3-D interpretation of the subsurface in search of oil and gas.

Traditionally, source arrays are stabilized by a complicated connection of ropes and deflectors. The SailWing actuator is installed in each source head float and controls the SailWing angle of attack, which stabilizes the array with software controlled adjustable lift.

The 3-D surveys repeated over time (4-D) provide critical information to allow the optimization of fields over their lifetime. Improved source stability means the signature from the source is more repeatable, survey after survey, which in turn delivers better 4-D information.

Additionally, with the SailWing, costly downtime is avoided during source maintenance and repair since neighboring sources can be navigated to a safe distance for trouble-free maintenance and quick redeployment, according to a news release.

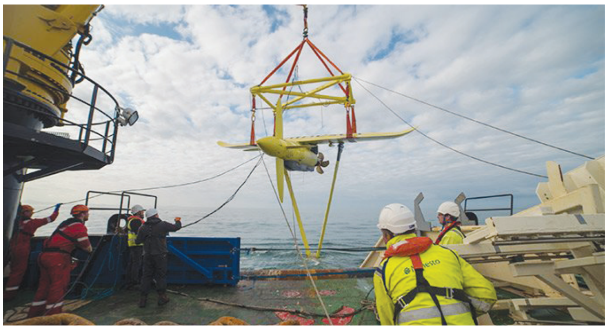
Control of SailWing happens via ION's Orca or Gator navigation system interfacing with the electronic control rack that then communicates with the actuator, signaling the mechanism to adjust the lift provided by SailWing.

MacArtney has designed and manufactured the SailWing actuators, control system topside rack, power supplies and a remote control box allowing manual control of each SailWing actuator.

Minesto Concludes Subsea Kite Technology Trials

Marine energy developer Minesto has completed the offshore commissioning and test program of its EU-funded tidal energy project 6 km (4 miles) offshore Holyhead, North Wales, which aims to demonstrate the company's first utility-scale system of its pioneering subsea kite technology.

The project includes the construction, installation and demonstration of Minesto's Deep Green technology.



Minesto has completed the offshore commissioning and test program of its EU-funded tidal energy project offshore Holyhead, North Wales. (Source: Minestro)

In spring 2018, Minesto installed and commissioned the DG500 site infrastructure, which includes the seabed foundation, tether, umbilical and a buoy containing a micro grid system. In the summer, the power plant itself was installed and commenced sea trials. The sea trials culminated in Minesto verifying the functionality of the Deep Green technology at a utility scale and successfully flying full subsea operational trajectories. In early October, Minesto generated electricity for the first time with the DG500 device.

As the test program of Minesto's EU-funded project has been completed, Minesto has decided to resume offshore operations of its DG500 system in the second quarter of 2019.

—Staff Reports

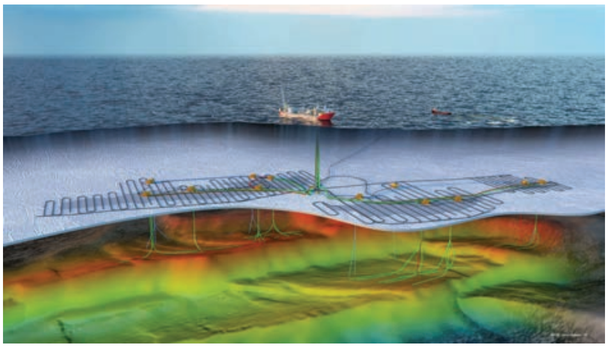
VESSEL BRIEFS

Kvaerner Begins Work On *Johan Castberg* FPSO Topside Modules

Kvaerner said it cut first steel on Nov. 21 for the *Johan Castberg* FPSO, the first vessel in Equinor's ambitious $5.7 billion Barents Sea project.

The contract, signed in February, entails construction of topside modules, plus hookup and integration of the modules with the hull and carries a value of about $440 million.

"*Johan Castberg* is an important project for Kvaerner and the Norwegian supplier industry because it enables us to further develop our expertise in constructing floating production vessels, which is expected to be the preferred platform type for future developments in the Barents Sea," said Karl-Petter Loken, CEO of Kvaerner, in a statement.



The *Johan Castberg* FPSO will operate in the continental shelf of the Barents Sea for Equinor. (Source: Kvaerner)

"As such, you could say that Equinor's *Johan Castberg* is a valuable springboard for future development requirements in the Barents Sea, which will be a very important region for Kvaerner with regard to future activity at our Norwegian facilities," he added.

Johan Castberg "is the next major development on the Norwegian Continental Shelf and will open a new area in the Barents Sea for Equinor," said Anders Opedal, Equinor's executive vice president for technology, projects and drilling.

SBM Offshore Confirms Second FPSO Hull Contract For Accelerated Program

SBM Offshore has locked in the second hull contract for its Fast4Ward FPSO program, just as the market is picking up.

Shanghai Waigaoqiao Shipbuilding (SWS) will begin construction of the FPSO hull in January 2019. The program is designed to provide a completed vessel six to 12 months faster than the typical three years required for a third-generation FPSO.

"The timing of our Fast4Ward strategy fits in perfectly with the market upturn," said SBM Offshore CEO Bruno

Chabas in a statement. "We have been preparing for this exact scenario since 2014, and today we see tangible evidence of how Fast4Ward matches the industry's need for cost-conscious, standardized solutions, which de-risk and accelerate projects. Major players are starting to invest in projects and are seriously considering our game-changing solution."

SBM, the world's largest FPSO provider, announced in August that it intended to speed delivery of its overall lineup of products and services. Fast4Ward relies on standardized construction and delivery processes, which result in lower costs.

Rystad: Lower Oil Prices Could Push Approvals For Over 30 FPSO Projects

Consulting firm Rystad Energy projects that more than 30 FPSO projects will receive final investment decision (FID) approval in 2019 through 2021.

The projects are benefiting from a wave of efficiencies since the price downturn that began in 2014 that have made them economically viable. Rystad said 14 projects have breakeven prices below $50/bbl and 15 have breakevens in between $50/bbl and $70/bbl. Only three require oil prices to be above $70/bbl to be viable.

Rystad expects projects to mostly be based in South America, Europe and West Africa. Among them:

- Fluor's newbuild circular FPSO for Shell's Penguins project;
- Teekay Offshore's deal to re-deploy the FPSO *Petrojarl Varg* (formerly at the Varg Field offshore Norway) for Alpha Petroleum's Cheviot project;
- Siccar Point Energy's Cambo oilfield west of Shetland, where Crondall Energy is working on plans that would include a newbuild, redeployment or conversion; and
- Bridge Petroleum's Galapagos project, which involves an ice-class Aframax-size tanker set for a hull conversion.

In addition, offshore Africa projects include:

- Cairn Energy and partners are looking for a large FPSO and infrastructure for the deepwater SNE project;
- The Aker Energy-operated DWT/CTP block offshore Ghana may include a purpose-built FPSO for the Pecan Field development;
- Shell and partners' deepwater Bonga South-West project offshore Nigeria could involve a newbuild; and
- ZabaZaba offshore Nigeria could be sanctioned in 2019.

PaxOcean Delivers Largest FSRU To Be Built In China

PaxOcean's Zhoushan Shipyard set a milestone for China Nov. 16 when it delivered the largest floating storage regasification unit (FSRU) ever built in that country.

Karunia Dewata, the largest FSRU ever built in China, was delivered to an Indonesian customer in mid-November. (Source: PaxOcean)

Karunia Dewata, a 26,000-cm (918,181-cf) vessel, is also the first Chinese-built FSRU equipped with Type C cargo tanks and is the first FSRU built by PaxOcean. It was delivered to Indonesia-based Jaya Samudra Karunia.

"This is an important milestone for PaxOcean," said the company's engineering director, Lixin Bian, in a statement. "The design is focused on simple and reliable operation for Indonesian water. By working closely with Lloyd's Register on classification requirements, and international maritime legislations for vessels carrying liquefied gases in bulk, PaxOcean has successfully designed, built and delivered the largest FSRU with Type C cargo tanks in China in our Zhoushan Shipyard."

With its ability to regasify about 1.4 MMcm/d (50 MMcf/d), the vessel is expected to play a major role in the development of Indonesia's gas supply.

Brazil Offshore Invests: Belov To Build RAL-Designed DSV

Salvador, Brazil-based Belov Engenharia Ltda is moving into the construction and operation of dive support vessels (DSVs), with its first two to be designed by Robert Allan Ltd.

The vessels, *Belov Humaitá* and *Belov Amarlina*, will be designated as RAlly 4000 and be fitted with dynamic positioning systems, and diesel electric propulsion. The vessels will be certified as a special DSV suitable for unrestricted Navigation, as classified by RINA, the global classification group.

The RAlly 4000 is being designed to be fitted with an ROV LARS (Launch and Recovery System), an aft mounted A-Frame to operate the diving bell, a decompression chamber to support the divers and more spacious crew quarters. All of this will be incorporated within a gross tonnage under 500 GRT. Waterjets are used to ensure diver safety. Because waterjets are typically used on higher speed vessels, extensive self-propelled CFD analysis was performed in-house by Robert Allan Ltd. to verify resistance and thrust at the slower speeds that this design will operate at.

—Staff Reports

BUSINESS BRIEFS

Iran Said China's CNPC Replacing France's Total In Gas Project

China's state-owned CNPC has replaced France's Total in Iran's multibillion-dollar South Pars gas project, Iranian Oil Minister Bijan Zanganeh said, according to the semi-official news agency ICANA on Nov. 25.

"China's CNPC has officially replaced Total in Phase 11 of South Pars, but it has not started work practically. Talks need to be held with CNPC ... about when it will start operations," Zanganeh told ICANA, without giving further details.

Total, which had a 50.1% stake in the project, and CNPC could not immediately be reached for comment.

The French company said in August it had told Iranian authorities it would withdraw from the South Pars gas project after it failed to obtain a waiver from U.S. sanctions against Iran.

In May industry sources said CNPC was ready to take over Total's stake in the project.

The offshore field, which Iran calls South Pars and Qatar calls North Field, holds the world's largest natural gas reserves ever found in one place.

CNPC already holds a 30% stake in the giant field, while National Iranian Oil Co. subsidiary PetroPars holds the remaining 19%.

Hess Donates Subsea Tree to UH Engineering Program

Forty-one tons of bright yellow equipment might seem hard to miss, but most people—even many of those working in the offshore industry—never get an opportunity to see a subsea tree.

A donation from Hess Corp. is changing that for subsea engineering students at the University of Houston (UH), along with their fellow students in petroleum and mechanical engineering.

"One of the challenges we have as educators is enhancing the knowledge of our subsea, petroleum and mechanical engineering students beyond the classroom," said Phaneendra Kondapi, director of the UH subsea engineering program and founding director of engineering programs at UH Katy. "I teach it, but they don't get a chance to actually see the equipment."

The tree donated by Hess was manufactured by Aker Solution, and Kondapi said it is valued at more than $3 million.

He singled out several people for their work in making the donation happen, including Jason Harry, subsea engineering adviser, and Chris Starcke, senior manager, supply chain, both from Hess, and Moacir Farias, Venu Kopparthi and Guiton Ragsdale from Aker Solutions.

Starcke said the donation is a reflection of Hess' values.

"The donation aligns with our values and our commitment to creating a long-lasting, positive impact on the communities where we do business," he said.

Ultimately, Kondapi said he would like to use the tree as the centerpiece of a proposed subsea engineering museum at the Katy campus, which would be first of its kind in the world. The Katy campus is under construction and is expected to open in fall 2019. UH Katy students currently attend classes at a building owned by Houston Community College.

For now, the subsea tree is installed in an open area on the edge of the University's Technology Bridge research park, about 3 km (2 miles) from the UH campus. The Cullen College of Engineering's petroleum engineering department is based at the research park.

The subsea tree, designed for deepwater production and weighing more than 91,000 lb will allow students to explore its design and function in a way that photographs and digital representations can't, Kondapi said.

—Staff & Reuters Reports

UPCOMING

The next issue of *Subsea Engineering News* will be distributed Dec. 13. Until then, visit *EPmag.com*.

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