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Digital Transformation In Motion For Oil, Gas Sector

Technological advances have allowed the oil and gas industry to lower breakevens and improve efficiencies for a range of E&P projects, even costly deepwater ones.

But further gains could be made when digital technologies are part of the mix.

Oil and gas processes can leverage technologies such as artificial intelligence, the ability of machines to imitate human behaviors; deep learning, an algorithm-driven form of machine learning in which each layer of a deep neural network learns from the one before; and the industrial Internet of Things (IoT), which taps Big Data technology and machine learning with sensor data for automation and other manufacturing.

A crucial component of this so-called digital transformation has brought together Halliburton and software giant Microsoft Azure. Speaking during the recently held Landmark Innovation Forum & Expo in Houston, the two companies announced they will collaborate in areas such as applying deep learning to reservoir characterization, modeling and simulation, building domain-specific visualization for mixed reality, creating interactive applications and digitizing E&P assets.

(Source: Shutterstock.com)

"We believe that the cloud is going to be one of those key enablers for digital transformation," Jason Zander, corporate vice president for Microsoft Azure, said during the conference. The cloud is essentially software and related services that run on the internet instead of a computer hard drive. He added the cloud was a disruptive technology that changed Microsoft's business model and how the company engages with customers.

The same fate could be in store for the oil and gas sector.

Zander sees digital transformation trends and strategies emerging around customer engagement, transforming products, optimizing operations and empowering employees. Some of these have landed in silos, he said, with individual excellence in certain areas. However, he believes a combined effort could lead to growth.

As explained by the company, Microsoft Azure is a collection of integrated cloud services that can be used to build, deploy and manage applications through the company's data centers in more than 42 regions across the world. It's used in development of business apps, data and intelligence and security management among other uses.

WHAT'S INSIDE

The company also wants to make sure it's pulling together information technology and operational technology, "so the folks in the field have great data and information there and also pull back on the enterprise systems that are used" from upstream to downstream with a goal of optimizing the entire pipeline, Zander added.

Now, the E&P industry can access Halliburton's DecisionSpace 365 on Azure, a move that enables "real-time data streaming from IoT edge devices in oil fields and the ability to apply deep-learning models to optimize drilling and production to lower costs for customers," according to a news release. "With the power of DecisionSpace on Azure, big compute and predictive deep-learning algorithms will help optimize field assets and enable next-generation exploration and deep-earth models by using software to fill gaps in sensor data, while reducing the number of steps and time required to render models."

The partnership enables Halliburton and Microsoft Azure to work together to apply voice and image recognition, video processing and augmented reality/virtual reality to create a digital representation of a physical asset using Microsoft's HoloLens and Surface devices, the release said. The two also plan to use digital representation for oil wells and pumps at the IoT edge using the Landmark Field Appliance and Azure Stack.

The oilfield service provider's services cover the gamut, including subsea safety systems, pipeline and process services, and reservoir testing and analysis to name a few.

During the conference, Pom Sabharwal, senior global industry solutions adviser for Halliburton Landmark, explained how DecisionSpace 365 running on Azure was used for automatic fault interpretation to help with a complex problem offshore West Africa. In the past, there was a fault that was either misinterpreted or not highly defined, which led to stability problems when targeting a nearby hydrocarbon sweet spot, Sabharwal explained.

The technology drastically reduced the amount of time needed to sort through large quantities of seismic data to interpret and analyze faults, which enables better sweet-spot targeting and hazard avoidance.

"I can get the scale up from Azure on GPUs [graphics processing units] … in a matter of minutes," he said. "This is a very compute-intensive activity. Automated fault interpretation, even with the biggest workstation under my desktop, would probably take about 15 hours for this problem to be solved." The accuracy, however, comes from the extraction of faults from the interpretation. "I can look at very high-definition areas and faults and choose the ones that I want to use."

The technology also allows the user to tap into communities of experts, both within and outside Halliburton Landmark, with instant chat, Sabharwal added.

Features of Halliburton's DecisionSpace automated fault interpretation technology includes automated fault tracking volume, fault data analysis, grow faults that allow users to make modifications, a fault editing toolbox and fault snap, a picking tool that snap segments to the fault, Halliburton said on its website.

—Velda Addison

DEVELOPMENT

Statoil, Partners See Further Gains At Johan Sverdrup

The multibillion dollar development of Norway's Johan Sverdrup oil field, the largest North Sea discovery in decades, is progressing ahead of plan and below budget, operator Statoil said Sept. 4.

The construction of platforms and other equipment needed to start crude production from the field, which holds between an estimated 2 Bboe and 3 Bboe, is nearly 60% complete, the company added.

Development of the first of two independent phases is now estimated to cost about $11.8 billion, down from a previous estimate of about $12.5 billion and more than $3.9 billion less than the company had initially anticipated.

"We are seeing high quality in project planning and execution across the entire project," CEO Eldar Saetre said in a statement.

"The project continues to benefit from good drilling and well efficiency, which together has enabled us to further reduce our forecast for the first phase," he added.

Partner Lundin Petroleum said the breakeven price for the full field development is estimated at less than $25/bbl.

The assembly operation of the Johan Sverdrup drilling platform takes place in Klosterfjorden near Stord in Norway. (Source: Arne Reidar Mortensen/Statoil)

Phase 1 of the development, which remains on track for first oil in late 2019, includes four platforms connected by bridges along with three subsea water injection templates. Production capacity is expected to be an estimated 440,000 bbl/d.

Plans are for Phase 2 to start up in 2022. Full field production is estimated at 660,000 bbl/d.

"It has been my long held view that costs will continue to come down and today we can announce that the Johan Sverdrup partnership has managed to lower development costs even further," Lundin Petroleum CEO Alex Schneiter said in a statement.

Statoil reiterated the first phase was expected to start production in late 2019. Partners in the field are Lundin Petroleum, Aker BP, A.P. Moller-Maersk and Petoro.

In related news concerning the field, Lloyd's Register (LR) said it has been tapped by Statoil to conduct total risk analysis for the riser platform (RP) modification project at the field. In a news release, LR said most of this FEED work phase is being carried out by its risk management consulting team based in Bergen.

"The second phase of the Johan Sverdrup, which LR's team is contracted to work on, includes production capacity increase, tieback of satellites, increased oil recovery and an area solution for power from shore," LR said. "It comprises an extension of the field center with an additional process platform, P2, placed on the east side of the RP and interconnected to the RP via a new bridge.

"An additional HVDC [high-voltage, direct current] system with power supply from shore will be installed as part of this phase," LR added. "The HVDC system will also supply power to third-party fields in the Utsira High area, namely Edvard Grieg, Ivar Aasen and Gina Krog."

—Staff &Reuters Reports

Asia Sees Action, Cambodia FID Imminent

PetroVietnam Drilling & Well Service Corp. won a $6 million contract from KrisEnergy to provide the PV Drilling I jackup rig. (Source: PV Drilling)

Promising upstream activity in the Cambodian and Thailand sectors of the Gulf of Thailand (GoT) as well as offshore Vietnam has made Southeast Asia a happy hunting ground for some companies over the last week.

KrisEnergy has signed agreements with the government of Cambodia for Block A in the GoT as a pre-cursor to starting work on the country's first oil field development project.

KrisEnergy has operated Block A since 2014 and plans to develop the Apsara Area in the northeastern section of the concession, which is one of seven geological trends in the license where there is potential for oil and gas to be trapped.

Under the terms of the agreements, KrisEnergy has 60 days to make a final investment decision (FID). This will signal the launch of the Apsara project, which is expected to take up to two years to produce first oil.

Also under the deals, a 5% stake in Block A will be transferred to the Cambodian government, leaving KrisEnergy with 95% interest via two entities: operator KrisEnergy Aspara (71.25%) and KrisEnergy Cambodia (23.75%).

Block A covers 3,083 sq km (1,190 sq miles) in the Khmer Basin in the GoT. Water depths range from 50 m (164 ft) to 80 m (262 ft).

Phase 1A of the Apsara development consists of a single unmanned minimum facility 24-slot wellhead platform producing to a moored production barge capable of processing up to 30,000 bbl/d of fluid with gas, oil and water separation facilities on the vessel. Oil will be transported via a 1.5-km (0.9-mile) pipeline for storage to a permanently moored floating, storage and offloading (FSO) vessel.

"The individual oil accumulations in Block A are small in size and spread over a large geographic area, requiring significant funds and time to fully develop. Additionally, reservoir production performance in the Khmer Basin has yet to be proven," KrisEnergy said.

"For these reasons, among others, there is some uncertainty regarding long-term production rates, reserves and commercial viability and therefore a phased development approach has been prudently adopted.

"Once the initial Phase 1A platform is onstream, there will be a period to monitor reservoir performance before commencing Phase 1B, which envisages up to three additional platforms producing to the Phase 1A facilities. A Phase 1C will potentially add up to six additional platforms for the full 10-platform Apsara development," the company added.

H.E. Meng Saktheara, secretary of state for the Ministry of Mines and Energy and chairman of the Inter-Ministerial Committee for Block A, said, "Producing Cambodia's first oil in its offshore waters will be a major step along our steady road to economic development and national prosperity and is aligned to the government's key development goals."

KrisEnergy COO Kelvin Tang added, "Our technical and project teams have a successful track record of bringing greenfield oil developments in the GoT into production on time and to budget. Apsara marks only the first phase of the development of Cambodia Block A, there remains further potential in other geological trends within the contract area for future investigation."

PV Bags GoT Contract

PetroVietnam Drilling & Well Service Corp. (PV Drilling) has sealed a $6 million contract from KrisEnergy to provide the jackup rig *PV Drilling I* for drilling in the GoT.

The work will be undertaken on Block G10/48 in the GoT, and the rig will remain on site until it has completed six firm wells and two optional wells. *PV Drilling I* is due to start operations in early October.

KrisEnergy (Gulf of Thailand) has an 89% operating stake in Block G10/48, while Palang Sophon Offshore holds the remaining 11%.

The *PV Drilling I* completed a contract offshore Myanmar for Total in April, and this new contract offshore Thailand is "in line with PV Drilling's business strategy to expand its drilling rig services into international markets," PV Drilling said.

Vietnam Blue Whale Output

ExxonMobil's Blue Whale gas field development project offshore Vietnam could achieve first production in November, according to Vietnam Television (VTV).

The Blue Whale Field has an estimated 150 Bcm (5.30 Tcf) of gas reserves.

Prime Minister Nguyen Xuan Phuc told ExxonMobil that he hoped to have the project starting officially at an Asia-Pacific Economic Cooperation summit in November when U.S. President Donald Trump and U.S. government officials are expected to attend, state-run VTV reported.

State-owned PetroVietnam, ExxonMobil's partner in Blue Whale, has said the project would contribute nearly $20 billion to the state budget.

—Steve Hamlen

DEVELOPMENT BRIEFS

Wood Group Snags Subsea Contract For Ichthys

A worker helps unload pipes for the Ichthys LNG project. (Source: Inpex)

Wood Group has won a contract to provide subsea engineering services for the integrity of the Inpex-operated Ichthys LNG project offshore Western Australia, a news release said.

The five-year contract, awarded by Ichthys Operations Australia, covers support for operations of all of the project's subsea assets and the gas export pipeline, Wood Group said.

The contract, which has two one-year extension options, builds upon Wood Group's 12-year support of the project, the company said. Other work has included providing subsea engineering and project management services during the concept and FEED phases of the project along with a subsea integrity and maintenance services contract completed in 2016.

Bibby Bolsters North Sea Presence With Contract Wins

Bibby Offshore Ltd. continues to strengthen its North Sea presence through its completion of two more contracts with Perenco and Endeavour Energy U.K.

Perenco appointed Bibby Offshore to perform subsea integrity inspections and maintenance works on the Inde

Joint pipeline, which runs to the Bacton Gas Terminal in the Southern North Sea.

A 15-day work scope, completed in early July, saw Bibby Offshore install a total of 94 concrete mattresses over the pipeline to assist in preserving the remaining rock dump mounds.

The second work scope, completed in late July, saw Endeavour Energy U.K. contract Bibby Offshore to carry out subsea tree inspections in the Renee and Rubie fields located in blocks 15/27 and 15/28 of the Central North Sea.

Both contracts utilized Bibby Offshore's inspection, repair and maintenance vessel *Olympic Bibby* and were the latest in a series to be awarded by these clients.

Total Sees North Sea Growth With Edradour, Glenlivet Startup

Oil major Total said it has started production at its Edradour and Glenlivet gas and condensate fields in the U.K., which is expected to boost its North Sea output with an additional 56,000 boe/d.

"We have completed this project ahead of schedule and 30 percent under the initial budget," Arnaud Breuillac, Total's president for E&P, said in a statement.

The Edradour and Glenlivet development is near the French oil and gas giant's existing Laggan-Tormore fields, which started production in February 2016.

Total's U.K. unit operates Edradour and Glenlivet with a 60% interest alongside partners DONG E&P and SSE E&P, which each have 20% stakes.

In other news, Total has shed its remaining 15% interest in the Gina Krog Field, which started production in June offshore Norway, to the Kuwait Foreign Petroleum Exploration Co. (KUFPEC). The divestment is part of a 2016 transaction between the two companies involving Norwegian North Sea assets.

When the sale is completed, KUFPEC will have a 30% stake in Gina Krog, which is operated by Statoil (58.7%). Other partners are PGNiG Upstream International (8%) and Aker BP (3.3%).

Ensco Lines Up Work For Drillship At Leviathan Field

Noble Energy has awarded Ensco a contract for use of its ultradeepwater drillship *ENSCO DS-7*.

The drillship will be used to drill two wells and complete four production wells at the Leviathan Field in the Mediterranean Sea, Ensco said in a news release. The contract is slated to begin March 2018 and run through December 2018. The contract could be extended into 2020 if four one-well priced customer options are fully exercised.

ENSCO said it will upgrade the drillship with a second BOP, already in inventory, at a price of less than $10 million.

The contract win marks the fourth for a drillship for Ensco during third-quarter 2017.

"This award and our other recent contract wins validate our strategy, increase contracted revenue backlog and advance our efforts to drive growth and value creation for all Ensco shareholders," Ensco CEO Carl Trowell said.

He added, "Our recent contract awards underscore that there is strong customer demand for the type of high-specification assets that will be added to Ensco's fleet through our pending acquisition of Atwood, which will create a leading global offshore drilling company and better position us as the market recovery cycle unfolds."

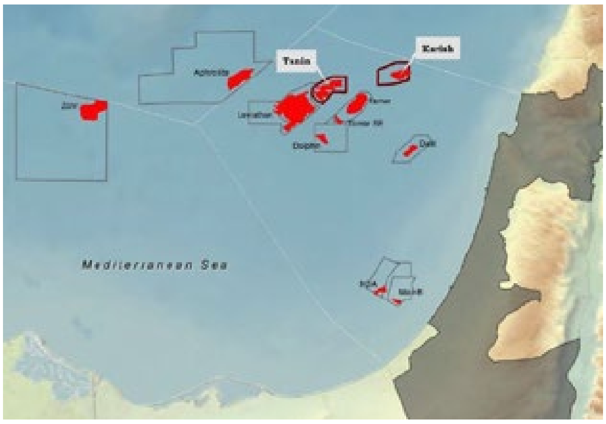
Aker Wins Brownfield Modifications, Maintenance Support Contract

Aker Solutions has secured a framework agreement from Shell to provide brownfield modifications services and maintenance support for the Nyhamna and Draugen facilities in Norway, according to a news release.

The four-year agreement, which may be extended by up to seven years, covers the offshore Draugen oil platform and the onshore Nyhamna natural gas processing plant in Aukra that is connected to the Ormen Lange Field in the Norwegian Sea, Aker Solutions said.

The value of the contract was not disclosed.

Israel Approves Energean's Plans For Karish, Tanin Gas Fields



(Source: Energean)

The Israeli petroleum commissioner has approved the field development plan for the Karish and Tanin gas fields being developed by Energean Oil & Gas subsidiary Energean Israel, a 50:50 joint venture between Energean and Kerogen Capital, according to a news release.

The gas fields are located offshore Israel.

The Karish main development includes drilling three wells and using an FPSO unit that will be located about 90 km (56 miles) offshore with a production capacity of 400 million standard cubic feet per day, Energean said in the release. The next step is to reach a final investment decision, which is expected before year-end 2017.

Energean said it has appointed Morgan Stanley as the project finance advisor for the $1.3 billion to $1.5 billion investment required for the Karish development.

Energean Israel owns 100% of the Karish and Tanin fields, which combined have 76 Bcm (2.7 Tcf) of natural gas and 41 MMboe of light hydrocarbon liquids, totaling 531 MMboe of 2C resources, Energean said.

ExxonMobil Brings Hadrian South, Galveston 209 Online After Hurricane

ExxonMobil Corp. said on Sept. 3 that its Hadrian South subsea production system and Galveston 209 platform in the U.S. Gulf of Mexico were back online after shutting due to storm Harvey, a spokeswoman said in an email on Sept. 3.

The company added that it was continuing post-storm assessment on the Hoover platform.

Hurricane Harvey, which first made landfall in Port Arthur, Texas, on Aug. 25, dumped more than 40 inches of rain in parts of Texas and resulted in more than 65 deaths. At one point, the storm caused the shut-in of about 323,760 bbl/d of oil production, or 18.5%, and about 17 MMcm/d (611 MMcf/d), or nearly 19%, of gas production in the U.S. Gulf of Mexico.

Gazprom Plans To Launch Yuzhno-Kirinskoye Gas Field In 2023

Russian energy giant Gazprom plans to launch the Yuzhno-Kirinskoye gas field offshore Russia's Sakhalin Island in the Pacific Ocean in 2023, Vadim Petrenko, the head of Gazprom's offshore department, said on Aug. 24.

Gazprom originally planned to launch the field in 2021.

Discovered in 2010, Gazprom has said the Yuzhno-Kirinskoye Field holds about 706 Bcm (25 Tcf) of gas reserves and 110.6 million tons of gas condensate. The field is expected to produce about 21 Bcm (742 Bcf) of gas annually.

Kosmos Reports Positive Tortue Drillstem Test Results

Oil and gas producer Kosmos Energy, which along with oil major BP Plc plans to produce gas off Mauritania coast, said a test drill showed that a key field would produce about 1.7 MMcm/d (60 MMcf/d) of gas.

Kosmos claimed the well is capable of producing about 5.7 MMcm/d (200 MMcf/d) once fully operational.

The company had in 2015 discovered a gas pool in the Tortue 1 exploration well, part of the Greater Tortue Complex spanning Senegal and Mauritania, contained more than 425 Bcm (15 Tcf) of gas.

In 2016, BP acquired working interest in Kosmos' exploration blocks in Mauritania and Senegal, including the Tortue Field.

Oil majors including BP and Total are investing in the waters of Senegal and Mauritania, boosted by recent drilling successes and relatively low costs.

Kosmos holds a 28% interest in Tortue with BP (62%) and Mauritania's state-run oil company Societe Mauritanienne des Hydrocarbures et de Patrimoine Minier (10%).

KBR Lands More Work For Hail & Ghasha Sour Gas Project

OMV Offshore Abu Dhabi GmbH on behalf of Abu Dhabi National Oil Co. has awarded KBR Inc. a project management services contract for management of the FEED phase of the Hail & Ghasha development project offshore the United Arab Emirates.

Under the terms of the contract, KBR said it will provide project management consultancy services over a 24-month period. One of the world's biggest sour gas fields, the Hail & Ghasha project is forecast to produce about 28 MMcm/d (1 Bcf/d) of sour gas. Development of the fields includes at least 11 offshore artificial islands to be designed and constructed.

—Staff & Reuters Reports

EXPLORATION

ONGC Moves To Develop Kutch Offshore

(Source: ONGC)

India's state-run ONGC Ltd. has launched pre-construction works to develop two gas fields—GK-28 and GK-42—in the shallow-water Block-1 Extension in the Kutch Basin in the Arabian Sea.

The operator intends to develop the two offshore gas fields, located about 65 km (45 miles) from shore, by using a mobile offshore production unit (MOPU) in the first phase.

"ONGC is hopeful of starting gas production from GK-28 and GK-42 within the next two to three years," said D.K. Sarraf, chairman and managing director for ONGC.

The field development plan envisages construction of three well platforms, named GK- 28-1, GK-28-3 and GK- 42-1, and a bridge-connected MOPU.

The three platforms are to be located in water depths between 22.6 m (74 ft) and 33.8 m (110.9 ft).

"Well fluid [mainly gas] from GK-28-1 [7 km from GK-28-3] and GK-42-1 [28 km from GK-28-3] shall be received at a gathering facility at platform GK-28-3. Platform GK-28-3 shall be bridge connected to the proposed processing facility at MOPU," ONGC said in a proposal. "Processed gas after compression from MOPU will be brought back to Platform GK-28-3 via another flexible pipeline for further evacuation to landfall point through rigid pipeline."

Gas compression is expected from 10 Kg/cm2 to 90Kg/cm2 at the MOPU.

Plans are to bring gas to landfall point after compression and dehydration at the offshore process facility. From the onshore terminal at landfall point, the gas will be piped to the nearest gas grid about 120 km (75 miles) away.

A nitrogen separation facility is also expected to be installed at the landfall point.

ONGC will initially charter the MOPU for up to 10 years for development of the two fields and construct its own facilities at the latter stage.

The operator is preparing feasibility studies for the design, fabrication, transportation and installation of suction piles for the wellhead platforms required for the project.

Tenders for hiring the MOPU and feasibility studies were floated in August. The contracts are expected to be awarded by the end of December.

Well Tests

Appraisal of the gas discoveries made in the two fields has indicated the presence of in-place oil and gas resources of about 100 million tonnes, of which more than 30 million tonnes could be recoverable.

The gas discovery in exploratory well GK-28#10 (GK-28-L), drilled to a depth of 1,520 m (4,987 ft), flowed gas at 134,846 cm/d (4.8 MMcf/d) through a ½-in. choke at an interval between 1,452 m (4,764 ft) and 1,520 m in the Deccan Trap on barefoot testing. The well was drilled to explore Paleocene-, Early Eocene- and Mid Miocene-age formations and the Deccan basalt.

ONCG claims that this discovery is the first gas pool discovered in Deccan basalts offshore Western India.

The GK-28#9 well, drilled to test the prospectively of Middle Miocene, Early Eocene and Paleocene traps, produced gas from two objects on conventional testing. Object-I (Paleocene age) flowed gas at 221,950 cm /d (7.8 MMcf/d) through a ½-in. choke and Object-II (Early Eocene age) flowed gas with surges of water. This well is considered to have three more prospective zones.

GK-42#3 well, drilled to assess the potential of the Jakhau Reservoir (Early Eocene) established by GK-42-1, flowed gas at 224,544 cm/d (7.9 MMcf/d) through a ½-in. choke.

"New pool discoveries GK-28#9 and GK-42#3 in [the] GK-28 PML Block in Kutch shallow water has a good potential to add value to GK-28/GK-42 areas which ONGC plans to put on production. Besides, this discovery has potential to add a new basin to the list of producing basins in the country," ONGC said in its annual report.

The Kutch offshore project will open India's eight sedimentary basin for development.

—Ravi Prasad

Statoil's Norwegian Double Act

Statoil has enjoyed a boost by revealing two discoveries offshore Norway in the last week—one with development potential and the other non-commercial at this time.

On the exploration front, Eni is keen to drill a prospect near the Goliat Field and Lundin Petroleum has completed appraisal wells on the Alta discovery.

Statoil is wrapping up exploration well 6507/8-9 in production license 124 (PL 124) offshore Norway as a small gas discovery with a tieback to the Heidrun Field on the cards as a development solution.

Well 6507/8-9 was drilled by the Deepsea Bergen. (Source: Norway's Petroleum Safety Authority)

The well was drilled 9 km (6 miles) northeast of the Heidrun Field in the Norwegian Sea about 270 km (168 miles) southwest of Sandnessjøen.

"The preliminary estimation of the size of the discovery is between 700 MMcm (24.71 Bcf) and 1.2 Bcm (42.36 Bcf) of recoverable gas. The licensees in PL 124 will consider a tie-in of the discovery to existing infrastructure on the Heidrun Field," the Norwegian Petroleum Directorate (NPD) said.

The well encountered a gas column of about 80 m (262 ft) in the Åre Formation in the Båt Group, of which 35 m (115 ft) were in sandstone with good reservoir quality. The gas/water contact was proven 2,185 m (7,169 ft) below the sea surface.

Well 6507/8-9 was drilled by the *Deepsea Bergen* drilling facility, which will now move to drill exploration well 33/9-22 S in PL 881 in the North Sea, which is operated by Wellesley Petroleum.

Minor Barents Sea Find

Statoil also had success—albeit limited—with exploration well 7435/12-1 in PL 859, making a minor gas discovery. The well was drilled about 365 km (227 miles) northeast of the 7324/8-1 discovery (Wisting), about 420 km (261 miles) from the Norwegian coast and about 35 km (22 miles) from the border between Norway and Russia.

"This is the first well to be drilled in the southeastern Barents Sea, which was opened for exploration activity in 2013. It is also the northernmost wildcat well drilled on the Norwegian shelf," the NPD said.

Well 7435/12-1 encountered a 34 m (112 ft) gas column in the Stø Formation, of which 28 m (92 ft) were in sandstone with good to very good reservoir quality. The gas/water contact was proven 580 m (1,903 ft) below the sea surface. In the secondary exploration target in the Snadd Formation, aquiferous sandstone layers with moderate reservoir quality were encountered.

Sandstones with poor reservoir quality were encountered in the Kobbe Formation, of which some sandstone layers contained gas. Preliminary estimates place the size of the discovery in the Stø Formation at between 6 Bcm and 12 Bcm (211.8 Bcf and 423.6 Bcf) of recoverable gas.

"As of today, the discovery is not profitable to develop," the NPD noted.

This is the first exploration well in PL 859, which was awarded in the 23rd licensing round in 2016. The water depth is 253 m (830 ft). The well will be permanently plugged and abandoned.

Well 7435/12-1 was drilled by *Songa Enabler*, which will now move to spud exploration well 7317/9-1 in PL 718 in the Barents Sea, where Statoil is the operator.

Eni Eyes Goliat Prospect

The NPD has granted Eni Norge a drilling permit for exploration well 7122/10-1 S offshore Norway.

The probe will be drilled on the Goliat Eye prospect using the *Scarabeo 8* semisubmersible rig in production license 697 (PL 697).

"The area in this license consists of the northwestern half of Block 7122/10. The well will be drilled about 10 km [6 miles] southwest of the Goliat Field," said the NPD. "PL 697 was awarded Feb. 8, 2013, in APA 2012. This is the first well to be drilled in the license."

Drilling is scheduled to begin in the first half of September and will last at least 37 days. The water depth at the site is 342 m (1,122 ft).

The *Scarabeo 8* was built in Russia and Italy and commissioned in 2012. The facility is classified by DNV GL and registered in the Bahamas.

Eni Norge operates PL 697 with a 70% stake, while Edison Norge holds 20% and Concedo has 10%.

Alta Appraisals Wraps Up

Lundin Petroleum has completed the drilling of appraisal wells 7220/11-4 and 7220/11-4 A on the 7220/11-1 (Alta) oil and gas discovery in production license 609 (PL 609) offshore Norway.

The wells were drilled about 2 km (1 mile) south of the discovery well 7220/11-1, 3 km (2 miles) north-northeast of the appraisal wells 7220/11-3 and 7220/11-3 A and 190 km (118 miles) northwest of Hammerfest.

The discovery was proven in carbonate rocks in the Gipsdalen Group in October 2014.

Appraisal wells 7220/11-4 and 7220/11-4 A were drilled to a vertical depth of 2,255 m (7,399 ft) and 2,027 m (6,651 ft) below the sea surface, respectively, and were terminated in Carboniferous rocks in the Ugle and Falk formations, respectively. The water depth at the site is 402 m (1,319 ft).

The wells were drilled by the *Leiv Eiriksson* drilling facility, which will now proceed to drill exploration well 7220/6-3 in the northern part of PL 609.

Well 7220/11-4 encountered a 48 m (157 ft) hydrocarbon column in Late Permian to Early Triassic conglomerates, of which 44 m (144 ft) was an oil column.

Well 7220/11-4 A encountered a 54 m (177 ft) hydrocarbon column in Late Permian to Early Triassic conglomerates and carbonate rocks in the Ørn Formation, of which 44 m (144 ft) was an oil column.

—Steve Hamlen

EXPLORATION BRIEFS

Deep Gulf, Stone Energy Strike Wet Gas In GoM

Deep Gulf Energy III and partner Stone Energy have hit liquids-rich natural gas pay in the U.S. Gulf of Mexico's Mississippi Canyon Block 116.

The Rampart Deep well, operated by Deep Gulf, hit about 40 m (130 ft) of net pay in three primary zones, Stone Energy said in a news release Sept. 5.

The partners are deferring completion of Rampart Deep as they analyze well data. In addition to the reserve potential of Rampart Deep, Stone said the well provides critical information that reduces the exploration risk of Stone's Derbio prospect. Derbio is located up-dip and northwest of Rampart Deep in Mississippi Canyon Block 72, said Stone, which holds a 40% working interest in the well.

Drilling plans for Derbio will be reviewed with the Rampart Deep partners over the next 90 days.

If Derbio is successful, first production from the Rampart Deep/Derbio project is expected by late 2019 and could be a multi-well tie back to the Pompano platform, which is owned 100% by Stone.

Working interest partners in the Rampart Deep well are Deep Gulf Energy III, with 30% and entities managed by Ridgewood Energy Corp., including Riverstone Holdings and its portfolio company ILX Holdings III, with 30%.

Stone holds a 100% working interest in the Derbio prospect, but the Rampart Deep partners may elect into the Derbio well for a 60% total working interest, proportionate to their respective Rampart Deep working interests, with the remaining 40% owned by Stone.

CNOOC, SK Innovation Will Explore New South China Sea Block

China National Offshore Oil Corp. (CNOOC) signed a production-sharing contract with South Korea's SK Innovation Co. to explore a block in the South China Sea, its listed unit CNOOC Ltd. said in a statement on Sept. 5.

Block 17/08 is located in the Pearl River Mouth Basin and covers an area of 466 sq km (180 sq miles), with water depths ranging between 100 m and 130 m (328 ft and 427 ft).

SK, South Korea's largest refiner, will carry out exploration in the block and bear all the expense during the exploration phase. If a discovery is made and development starts, CNOOC will have the right to take up to a 51% participating interest in any commercial production.

The companies signed similar contracts in 2015 to develop blocks 04/20 and 17/03 in same basin of the South China Sea.

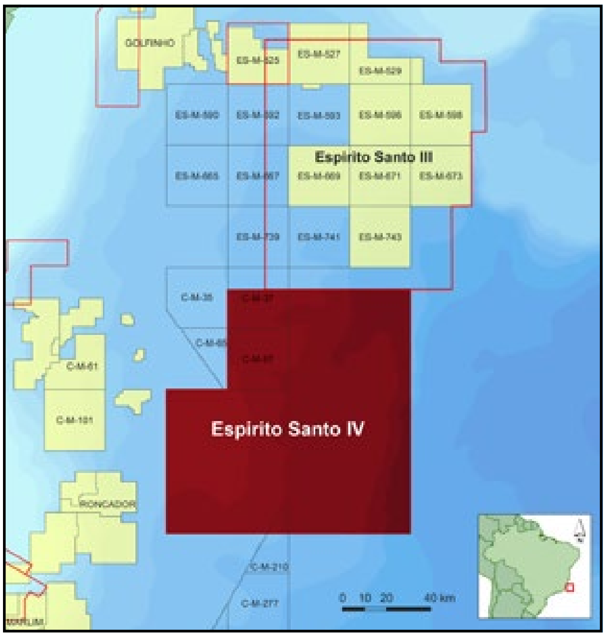
CNOOC, according to its website, is looking for foreign partners to explore and develop 22 blocks this year.

CGG Pursues Surveys Offshore Mozambique, Brazil

(Source: CGG)

CGG said it will begin acquisition of a new multiclient survey of up to 40,000 sq km (15,444 sq miles) of 3-D data offshore Mozambique after the company signed an agreement Mozambique's Instituto Nacional de Petroleo (INP).

The survey will cover the Beira High in the Zambezi Delta, including blocks Z5-C and Z5-D and surrounding acreage, CGG said in the release. Deliverables will include fast-track PreSTM, final PreSTM and PreSDM. The seismic data will be imaged with the latest 3D broadband deghosting and advanced demultiple, velocity modeling



(Source: CGG)

and imaging techniques, including full-waveform Inversion, the company said.

This survey is part of a JumpStart geoscience program that aims to improve the understanding of the prospectivity of the region, CGG said. Marine gravity and magnetic data will be acquired simultaneously with the seismic to accelerate regional interpretation.

On Aug. 29, CGG said it has begun work on the BroadSeis 3-D multiclient survey in the Espirito Santo Basin offshore Brazil. Called Espirito Santo IV, the survey spanning 10,300 sq km (3,977 sq miles) is expected to take seven months to acquire. It will be acquired by the *Oceanic Champion*.

"The high-end broadband sequence will include the latest 3D deghosting, full-waveform inversion velocity modeling and tilted transverse isotropy imaging," CGG said in the release. "Fast-Track PSDM products will be delivered six months after completion of the acquisition."

Schlumberger Completes Survey Offshore Malaysia

WesternGeco has completed a hybrid seismic acquisition survey for Roc Oil using its newly deployed multipurpose vessel (MPV)—a first in the industry, Schlumberger said on Aug. 25.

The 340-sq-km (131-sq-mile), 3-D seismic survey was acquired offshore Sarawak, Malaysia, using a triple source array with simultaneous recording by ocean-bottom nodes and a towed-streamer spread, all from a single seismic vessel.

The WG Vespucci MPV acquired the high-quality ocean-bottom seismic (OBS) data required around existing platform obstructions supplemented by streamer seismic data. Simultaneously acquiring the OBS and streamer data without having to employ multiple acquisition vessels and crews resulted in cost reduction and greater efficiency while achieving the survey objectives.

"Providing a hybrid OBS and streamer acquisition option with our multipurpose vessel versus a traditional OBS or towed streamer survey gave the customer a versatile and cost-effective solution to better fit their specific challenges and budget," said Maurice Nessim, president at WesternGeco. "This industry-first acquisition underscores our commitment to offering our customers innovative approaches to offshore seismic acquisition challenges."

The WG Vespucci is one of three newly configured MPVs in the WesternGeco fleet. The WG Tasman and WG Cook are equipped with Q-Seabed multicomponent seabed seismic systems.

Oil Firms Preregister For Brazil's Upcoming Presalt Auctions

Nearly a dozen oil companies have filled out initial forms for two upcoming oil exploration rights auctions in Brazil's presalt area, underscoring growing interest in one of the world's most promising oil discoveries in decades, a government official said Aug.24.

Presalt's second and third auction are scheduled to take place on Oct. 27, allowing oil companies to bid on eight blocks in the Santos and Campos basins.

"Today we have nine that have expressed interest in the second (auction) and ten that have expressed interest in the third," said Waldyr Barroso, ANP director.

Barroso said the companies had filled out an initial form expressing interest in the bidding process, but would not officially be considered registered until they had completed further requirements and been approved by a committee. Interested companies have until Sept. 8 to register.

—Reuters & Staff Reports

TECHNOLOGY

Converging Futures In The North Sea

Obvious differences aside, what has set the business models for oil and gas and renewables apart is the attitude toward cost. When the oil price is up, the long-established oil and gas sector has traditionally adopted a high-spend approach to exploration, development and extraction.

As more of a challenger industry, this is a luxury that the renewable sector has not been able to enjoy. Striving to enhance its competitiveness and in anticipation of the end of subsidy regimes in the long term, the focus on driving down costs has been embedded in offshore wind from its very inception.

There are ample opportunities for collaboration and technology development between the offshore oil and gas industry and the renewable energy industry in areas like the design, construction and installation of wind farms. (Source: V. Schlichting, Shutterstock.com)

So it is perhaps not surprising that with a prolonged slump in the price per barrel, oil and gas operators are looking at the renewables sector as a potential source of cost savings. Equally, in its constant search for cost-effective innovation, the renewables sector has been eyeing possible solutions from its oil and gas counterparts.

The idea that there could be some technology-driven convergence between oil and gas on one hand and renewables on the other is not as outlandish as it might have seemed only a few years ago, so much so that certain oil and gas operators that had previously exited the renewables sector are now considering a reentry, with some already taking the plunge.

Nowhere is this convergence more obvious than in the area of offshore energy generation, where technologies used by the North Sea oil and gas community are being considered by offshore wind operators and innovations developed for wind and tidal generation are being considered by oil and gas operators.

Higher Voltage, Lower Costs

The first area of interest is that of high-voltage cabling developed for offshore wind generation that also can be used in the oil and gas sector as a cost-competitive solution for driving large amounts of power across the seabed.

For example, new so-called "wet design" 66-kV cabling significantly steps up the voltage from the 33-kV inter-array standard cable voltage capacity and is being adopted by a number of new wind development projects this year. The advantage of this type of cabling is that it enables power to be transmitted to and from larger turbines that are installed farther offshore, essential as the industry starts to look beyond shallower waters to build its wind farms.

The wet-design cable ensures long-term operations without the need for a metallic barrier layer such as an extruded circular lead sheath that, until now, has typically been a large cost component of high-voltage power cables at 66 kV. With the removal of the lead sheath barrier layer the cable is also much lighter, allowing the capital costs associated with installation to be reduced and further enabling operators to deliver more power for the same amount of copper. Although the cable itself requires a small increase in outside diameter over standard 33-kV alternatives, it can deliver double the amount of power through the same conductor size with much less than double the overall cable capital cost.

The cable was initially developed to support expansion of offshore wind turbine capacity to higher power generation, enabling developers to exploit more offshore wind resources including locations farther away from shore. But those high-power deeper water characteristics also make it a suitable technology for offshore oil and gas applications. What's more, the 66-kV technology allows a cable to run from the shore to field, where a distribution hub and subsea transformer can be configured to distribute power on the seabed at typically 11 kV to suit subsea consumers such as pumps, compressors and other subsea processing equipment.

Some examples already being seen are of a hub-style power distribution system off the coast of Cornwall in the U.K., this time for wave energy. An export power cable runs underneath the beach in the village of St. Ives and travels 25 km (15.5 miles) out into the Bristol Channel to a hub, where a number of smaller cables split off to connect different wave-energy devices, test them and enable them to transmit power back into the grid.

This kind of subsea power distribution system and the technologies that support it also present great opportunities to oil and gas operators for subsea power consumption rather than generation. Interestingly, it may be possible to combine energy generation with energy consumption on the seabed, enabling oil and gas infrastructure to be powered by future tidal energy devices.

Dynamic Opportunities

In return, the possibilities offered by deepwater operations give the offshore wind industry plenty of opportunity to consider the technologies and expertise residing in the oil and gas sector. There is a growing drive toward floating structures for offshore wind as a means of reducing the construction costs associated with building an offshore wind farm in harsh environments and difficult weather conditions and to create more efficient and effective maintenance operations.

With the Norwegian Continental Shelf dropping away, floating systems are going to be a very interesting development in the North Sea, offering significant growth potential. When Statoil presented its view of offshore wind up to 2030, it claimed that about 105 GWh of installed capacity, about 20% to 25% of the total, would be floating offshore wind.

Naturally, managing floating structures is something the oil and gas sector has been doing for decades. And with savings in capex and opex on offer, the offshore wind industry is looking for ways of replicating its success—in particular, by deploying more dynamic power cables that can be hooked onto floating structures and FPSO vessels. These cables have to be capable of installation and dynamic operation underneath a floating structure and withstand all the fatigue loads and various environmental conditions throughout the cable life.

With static applications the cable design often has a single layer of armoring, with a roved protective outer layer comprising a series of polypropylene strings to protect the cable. For the design of dynamic systems, cable design is more complex, ensuring that the cable remains torque-neutral under high tensile loads and that the outer protective layers can withstand the arduous external environment. The cable design has to minimize twist and to ensure the dynamic cable stays in place and responds appropriately to the motion of the vessel and the platform to safeguard its longevity and long-term performance.

Collaboration, Convergence

Many of the underlying differences come down to cost. Static cables for current offshore wind farms tend to be a highly cost-efficient design optimized for a range of subsea locations and often either buried or protected by additional cable protection conduits.

Cables for dynamic systems are a highly engineered product that is more bespoke and can sometimes be fine-tuned to suit the specific dynamic conditions prevalent at the offshore location and precise water depth.

There are plenty of opportunities for renewables and oil and gas to learn from each other. The gap between the two industries seems likely to become narrower as those lessons are embedded in technology development. The collaborative future goes beyond the essential support technologies like cabling. Engineers are looking at the possibility of reusing oil and gas infrastructure itself for some offshore wind projects as well as combining new infrastructure.

The future will increasingly be about knowledge-sharing and integration. Driving down the costs of offshore operations will mean that the distinction between offshore renewable and offshore oil will diminish. Soon the conversation and the innovation will simply be about offshore energy and reducing the offshore costs for the benefit of developers and operators alike.

—James Young, JDR Cables

TECHNOLOGY BRIEFS

Consortium Puts NDT Technologies In Radar

A consortium is studying non-destructive testing of corroded pipes. (Source: CENSIS)

TRAC Oil & Gas, the University of Strathclyde and the Scottish Innovation Centre for Sensor and Imaging Systems (CENSIS) have teamed up to tackle the non-destructive testing (NDT) of corroded pipes under insulation and engineered temporary pipe wraps, according to a news release.

The consortium will audit tools, capabilities and techniques used by the oil and gas industry to look at the steel surfaces of assets. Viewing these assets can be challenging, considering layers of material can obstruct views, the group said in a news release. Many existing NDT technologies are ineffective when used on pipes that protected by insulation.

"By taking regular readings on an asset's condition, we can determine whether they are fit for purpose and operations can keep oil flowing, all within as safe an environment as possible. To do this effectively, we need to take stock of all the technology available, verifying its capabilities and limitations," Bill Brown, technical manager at TRAC Oil & Gas, said in the release. "From there, we'll be able to look at potential new methods for inspecting the integrity of assets, using non-destructive techniques."

The group is examining how companies currently measure wall thickness, "repeating it in the lab on specimens, and trying to develop a standardized approach to getting more accurate information from NDT," added Gordon Dobie of the University of Strathclyde's Department of Electronic and Electrical Engineering. "We're validating what the instrumentation is saying about the thickness of walls with a view to filling a real and significant gap in the technology already available."

3D at Depth Partners With Schlumberger's OneSubsea

Subsea LiDAR systems provider 3D at Depth has reached a strategic collaboration agreement with OneSubsea, a

Schlumberger company, to jointly accelerate deployment of 3D's technologies.

The agreement aims to advance 3D's subsea LiDAR solutions for use in offshore survey data collection, visualization, and measurement applications, according to a news release.

"The decision to work with Schlumberger was based on our mutual desire to significantly improve subsea field economics," Neil Manning, chief business office for 3D, said in the release. "OneSubsea's strong portfolio across life-of-field applications will allow us to leverage our subsea LiDAR platform to increase customer efficiencies and provide value across the board."

Probe Releases Intelligent Quantitative Well Casing Properties Tool

Probe Technologies Holdings Inc. has release the iQ, an inspection tool that provides quantitative measurements of well casing thickness and inner diameter and casing material properties analysis, a press release stated.

The tool is designed to operate in HP/HT wellbores up to 20,000 psi in temperatures as high as 175 degrees C. The Probe iQ provides casing measurements such as ID, thickness, and material properties, including magnetic permeability and electrical conductivity with quadrant circumferential sensitivity.

The iQ, which has undergone testing at Probe's Technology Center in Fort Worth, Texas, is being qualified for use by a major wireline service company and other independents in North America, Probe said.

Drilling Jar Clamp Designed For Increased Safety, Well Integrity

Emerson Automation Solutions has released its PolyOil jar handling clamp for increased safety and well integrity, a press release stated.

One key threat to well integrity and safety in drilling and completions operations is the danger of jars firing prematurely at the surface prior to being deployed into the well. Jars are mechanical devices used downhole to deliver an impact load to another downhole component (especially when that component is stuck) and include a firing mechanism that activates when the necessary compression or tension has been applied to the running string.

The inadvertent firing of such jams prematurely, however, can pose a hazard and lead to possible injuries and the dropping of the bottomhole assembly if pins are sheared.

The new PolyOil jar handling clamp acts a safety device to prevent the jar from cocking and firing, with the jar unable to fire unless the fishing neck—designed to enable running and retrieval tools to reliably engage and release—is closed. Therefore, when the clamp is fitted to the jar, the rod is kept in the open position, thereby preventing premature firing during the handling of the jar at the surface.

The clamp also prevents the jar rod from being damaged during transportation and keeps it debris-free during storage. Applications for the new jar handling clamp include drilling, drillstem testing jars, coiled tubing and wireline applications.

—Staff Reports

FLOATERS

Baker Hughes Lands Contracts For Coral South Floating LNG Project

The TechnipFMC and JGC Corp. joint venture has selected Baker Hughes, a GE company, to provide rotating equipment for the power and gas refrigeration process of the Coral South floating LNG (FLNG) facility offshore Mozambique.

(Source: Shutterstock.com)

The contract was awarded in second-quarter 2017 through the former GE Oil & Gas business, BHGE said in a news release. TechnipFMC and JGC are providing engineering, procurement, construction, installation, commissioning and startup services for Eni East Africa's (EEA) Coral South FLNG facility.

The order consists of four turbo-compression trains for mix refrigeration services, using the BHGE's aeroderivative gas turbine (model PGT25+G4) technology and driving its centrifugal compressors, the release said. The company will also provide four Turbo-generation units, also driven by aeroderivative gas turbines (model PGT25+G4).

The components of the turbo compressor trains and turbo-generation units will be manufactured at BHGE Nuovo Pignone facility in Florence, Italy, where the train will be assembled and tested in the Massa facility, according to the release.

After the GE Oil & Gas and Baker Hughes merger was completed, BHGE also won a contract to supply boil-off gas (BOG) and booster compressors capable of operating at -180 degrees C to re-liquefy excessive BOG evaporating out of the LNG storage tanks.

The two contracts bring the number of contracts awarded to BHGE for the Coral South project to three. In June, BHGE won an award to supply seven christmas trees, three two-slot manifolds with integrated distribution units, MB rigid jumpers, seven subsea wellheads with spare components, a complete topside control system to be installed on the Coral South FLNG facility, and associated services equipment and support including IWOCS and landing strings, tools, spares and technical assistance for installation, commissioning and start-up, the release said.

The Coral South FLNG project, the first phase of a plan to develop discoveries made in the Rovuma Basin Area 4, will see the installation of an FLNG facility with a capacity of about 3.4 mtpa, fed by six subsea wells. Production is expected to be about 5 Tcf of gas during its 25 years of production. Startup is anticipated in mid-2022.

EEA is the operator of Area 4, holding a 70% participation interest in the Area 4 Concession. Eni (71.43%) and CNPC (28.57%) are shareholders of EEA.

—Reuters

VESSEL BRIEFS

Subsea 7 Awards Letter Of Intent For New Vessel

Subsea 7 has signed a letter of intent with Royal IHC in the Netherlands for the construction of a new reel-lay vessel and associated pipe lay equipment, the company said Sept. 6.

The cost, excluding capitalized interest, is expected to be less than $300 million with an early 2020 delivery. The firm contract with Royal IHC is expected to be awarded before year-end 2017, subject to certain conditions and final board approval.

When delivered, the vessel will be Subsea 7's highest specification reel-lay vessel, capable of installing complex rigid flowlines, including pipe-in-pipe systems and electrical trace heating. This capability will address the market trend towards longer tieback developments. The new vessel will replace *Seven Navica*, which is expected to be retired from reel-lay operations in due course.

DOF Subsea Secures Vessel Utilization With Several Contract Awards

DOF Subsea has been awarded several contracts securing utilization for several vessels in the Subsea IMR Projects segment.

In the Asia-Pacific area and the Atlantic, DOF Subsea has been awarded several contracts and work under existing frame agreements, securing utilization of the vessels *Skandi Singapore*, *Skandi Hercules* and *Skandi Neptune* in third-quarter and into fourth-quarter 2017.

In Brazil, Petrobras has extended the contract for *Skandi Salvador* by six months from August.

In North America, DOF Subsea has been awarded several contracts for the diving support vessel, *Skandi Achiever*, in the Gulf of Mexico and Trinidad and Tobago. The contracts secure utilization of the vessel until October 2017.

"I am pleased with the contract awards and our global organization's ability to secure utilization for the group's vessels in a challenging market," DOF Subsea CEO Mons S. Aase said.

—Staff Reports

BUSINESS

BP, Shell Tie Future To North Sea Despite Broad Retreat

Production in the North Sea peaked in the 1990s, but it has staged a modest recovery since 2015.
(Source: Shutterstock.com)

Two of the most veteran oil and gas producers in the U.K. North Sea—Royal Dutch Shell and BP—still tie their future to the ageing offshore basin despite a broad retreat in recent years.

Both companies plan to explore this year for new resources in the North Sea, one of the oldest deepwater hubs faced with harsh weather conditions, executives told Reuters.

The two oil giants have sold billions worth of North Sea fields, many of them nearing the end of their life, in recent years. But still they see golden opportunities there as new technologies open up resources that can be profitable with oil trading at about $50/bbl and in some cases lower.

"We like the North Sea. It has been an important hub for us for a long time and it will remain one," BP Chief

Executive Bob Dudley said on the sidelines of the Offshore Europe conference in Aberdeen, Scotland, from where many companies hold their North Sea operations. "This year we will be drilling six exploration wells in the U.K. North Sea. That's more than we drilled in decades."

In another sign of confidence, France's Total last month acquired Maersk Oil, which will see it leapfrog Shell and BP to become the second-largest North Sea producer after Norway's Statoil.

The parallel investments and retreat in the North Sea come as the basin prepares to dismantle dozens of platforms and plug hundreds of depleted wells that will cost operators including BP and Shell more than $60 billion by 2050.

The North Sea became a major offshore hub in the 1970s. Although its production peaked in the late 1990s, it has staged a modest recovery since 2015.

It is believed to hold an additional 20 Bbbl, according to the British government.

Despite harsh weather and often high costs, the North Sea offers a stable tax regime and guaranteed payments as its oil is sold in industrialized countries with high investment ratings and no military conflicts.

BP, together with Shell and Siccar Point, started production in 2017 at one of the largest projects launched in the region in years, the Quad 204 Field in the west Shetlands.

BP plans to launch another field, Clair Ridge, in 2018 with the aim of doubling production by 2020 to 200,000 boe/d.

At the same time, BP has sold a number of ageing fields, pipelines and terminals in recent years.

Good Margins

Shell's oil and gas production in the North Sea is set to fall by about 40% to 150,000 boe/d after the planned completion this year of the $3.8 billion sale of a large number of fields and assets to private-equity-backed Chrysaor.

But Shell vowed to remain a key player in the North Sea and invest hundreds of millions of dollars there.

"Shell very much plans to be part of that future," Shell Chief Executive Ben van Beurden said of the North Sea.

The Anglo-Dutch company plans to drill three to five exploration wells in the North Sea this year, according to Shell's U.K. Chair Sinead Lynch and Steve Phimister, director of its U.K. oil and gas production, known as upstream.

Shell also aims to maintain stable production of 150,000 boe/d into 2030, which will require an annual investment of between $600 million and $1 billion, the company said.

The North Sea was severely hit by a three-year drop in oil prices, with drilling activity falling to levels not seen since the 1970s, according to Catherine MacGregor, drilling group president at services provider Schlumberger.

But operators rose to the challenge, sharply reducing operating costs and introducing efficiencies that were lost throughout the rally in oil prices to above $100 a barrel in the first half of the decade.

Operating costs in the North Sea have halved since 2014 to an average of about $15/bbl, Dudley said.

"The margin on the barrel in the North Sea is so strong it asks for you to come to invest in the basin to maintain production levels," Phimister said.

—Reuters

Offshore Startup Borr Drilling Aims To Expand Fleet, Keep Costs Low

Borr Drilling, the Norwegian drilling start-up, which listed on the Oslo exchange on Aug. 30, said it aimed to expand its fleet, taking advantage of its low cost base.

The start-up, launched last year and backed by the world's biggest oil service firm Schlumberger (NYSE: SLB), said it aimed to have the lowest cash break-even costs in the industry and would take advantage of current low prices for rigs.

"We have no debt," Borr's CEO Simon Johnson told Reuters after its shares started trading on Oslo's main market. They were previously listed on the over-the-counter market.

"That might change in the future, depending on the financing needs, but we can control what we pay for assets," Johnson said.

Offshore drilling companies have come under pressure as oil companies have cut back on spending to cope with lower oil prices. Seadrill, part of Norwegian billionaire John Fredriksen's business empire, is trying to restructure its debts.

Borr Drilling, which is led by former Seadrill executives, has acquired 17 jackup rigs since last December and in March won a one-year contract for drilling off Nigeria from Total.

Johnson, who joined Borr in August, said he expected more rig contracts to be announced soon and the fleet expansion would continue, but acquisitions would depend on the price.

Asked if he was looking into possibility of buying rigs from his former employer Seadrill, Johnson said, "I'm not sure that Mr. Fredriksen is interested in selling Seadrill's assets to us."

Borr is also seeking closer cooperation with Schlumberger, which owns 20% of the startup.

"We are looking to become an exclusive provider of rigs (for Schlumberger), we are looking to become a captive drilling contractor," Johnson told Reuters.

This could help to shorten offshore oilfield development times, increasing their competitiveness relative to onshore shale oil, Johnson said.

—Reuters

BUSINESS BRIEFS

DEA Scoops Up Engie CEO To Lead Company

Maria Moraeus Hanssen

DEA Deutsche Erdoel AG has appointed Maria Moraeus Hanssen as its new CEO and chairman of the management board effective January 2018, the company said.

Hanssen, who currently serves as CEO of Engie's E&P business, will succeed Thomas Rappuhn, who has served 30 years at DEA, including eight years as CEO.

Hanssen is credited for leading a strategic transformation at Engie's E&P business, including a portfolio restructuring the portfolio, improving profitability and applying new technology among other accomplishments, according to DEA.

Having trained as a reservoir engineer and petroleum economist, Hanssen's extensive oil and gas industry experience includes positions served at Hydro (later acquired by Statoil), Statoil, Aker Group (now Aker BP) and GDF Suez (now Engie).

Expro Secures Repsol Well Services Contract

(Source: Expro)

U.K.-headquartered Expro has won an $8 million master services agreement with Repsol Sinopec Resources UK Ltd. for well services across its U.K. North Sea assets, according to a news release.

The five-year contract, which includes extension options, covers well intervention services for production assurance and enhancement, well integrity, subsea, reservoir and decommissioning and abandonment applications.

Expro said the wireline and cased hole logging services also include personnel to supervise offshore intervention activity, including slickline and electric line conveyance, memory and real-time cased-hole logging, explosive and perforating services, downhole cameras, gauges and sampling.

McDermott Adds SBM Offshore Executive To Board

Philippe Barril, who has served as COO of SBM Offshore since March 2015, has been appointed to McDermott International's board of directors effective Sept. 1, the company said.

With more than 25 years of experience in the offshore oil and gas construction industry, Barril has also served in various roles at Technip. These have included president and COO, senior vice president of the offshore segment and senior vice president of the offshore and onshore product lines and technologies.

NPD Gets New Exploration Director

Torgeir Stordal

The Norwegian Petroleum Directorate (NPD) has a new exploration director: Torgeir Stordal, who has worked for Shell since 1989.

Stordal took on the new role Sept. 1 and replaced Sissel Eriksen, who left the NPD's management team after completing her rotation. She served as exploration director since September 2007, the NPD said.

At Shell, Stordal has worked as a geophysicist and geologist as well as exploration manager in Norske Shell.

Well-Safe Adds To Management Team

Jim Christie has joined Well-Safe Solutions as the company's director of programs. The company also announced Alan Cormack as its finance director.

Christie is a former decommissioning head for OGA where he developed the U.K. decommissioning strategy working with industry and the government. His experience also has included time spent as global decommissioning projects manager for Houston-based Marathon Oil.

Cormack joins Well-Safe from Raeburn Recruitment, where he was head of finance, following nearly a decade at finance director for Nautronix, Well-Safe said.

The recently launched specialist well abandonment company also said it is moving into an office at Hill of Rubislaw in Aberdeen.

Energy XXI Gulf Coast Appoints T.J. Thom As CFO

Energy XXI Gulf Coast Inc. appointed Tiffany J. ("T.J.") Thom as its CFO, the Houston-based company said Aug. 24.

As a result of Thom's appointment, which became effective Aug. 28, Hugh Menown has resigned as executive vice president, chief accounting officer and interim CFO to pursue other interests, the release said. Menown has agreed to serve as an advisor to Energy XXI during a transition period.

Thom has more than 20 years of financial and operational experience in the energy industry, primarily offshore Gulf of Mexico operations, according to the company press release. Most recently, she served as the CFO of KLR Energy Acquisition Corp. from January 2015 until April when it combined with Tema Oil and Gas Co. to form Rosehill Resources Inc.

In addition, Thom served in positions at EPL Oil & Gas Inc., Energy XXI Ltd., Exxon Production Co. and ExxonMobil Corp as well as a director for Patterson-UTI Energy Inc. and Yates Petroleum Corp.

James Swent Named CEO At Paragon Offshore

Paragon Offshore Ltd. said Aug 25 that James ("Jay") Swent III, Paragon's current chairman of the board of directors, has been named president and CEO following a comprehensive executive search process.

Swent's career includes more than a decade of experience in the offshore drilling industry including his most recent role as executive vice president at ENSCO Plc. He will continue to serve as a member of the board of directors; however, in keeping with best practices for corporate governance, Paragon will maintain separation between the roles of CEO and chairman of the board. Effective immediately, current board member George Sandison will become chairman. Paragon's board size will remain at six members.

Swent assumes the role from Dean E. Taylor, who has served as Paragon's Interim president and CEO since November.

KrisEnergy Appoints Tang As New CEO

KrisEnergy Ltd. has named Kelvin Tang, who currently serves as COO and president of the company's Cambodian operations, as the new CEO. The change takes effect Sept. 1, according to a news release.

Tang will replace interim CEO Jeffrey S. MacDonald, who is resigning from the CEO and board executive director roles effective Aug. 31.

"Kelvin has been an instrumental member of senior management since KrisEnergy was established in 2009 and led our negotiations with the Cambodian government regarding the Block A petroleum agreement, which was signed on Aug. 23, 2017," Tan Ek Kia, KrisEnergy's nonexecutive chairman, said in the release. "The Block A agreement is significant for Cambodia and for KrisEnergy."

Tang has been working in the upstream oil and gas industry since 2005 when he joined Pearl Energy Ltd. as general counsel and company secretary, the release said.

BHP Billiton Replaces Two Directors In Board Shake-up

Global miner BHP Billiton unveiled a board shake-up where controversial director Grant King will step down just six months after his appointment with the company amid oil investments concerns, BHP said on Aug. 23.

King, former CEO of Origin Energy, was once tipped to succeed Jac Nasser as chairman of the world's biggest mining company, but was passed over earlier this year for fellow board member Ken MacKenzie.

"Owing to concerns expressed by some investors, Grant King has decided that he will not stand for election at the 2017 annual general meetings of BHP and will retire from the board on August 31," Nasser said.

BHP is under pressure from investors led by hedge funds, Elliott Management and Tribeca Investment Partners, to rethink its investment in oil and boost shareholder returns. The company said on Aug. 22 it would exit its underperforming U.S. shale oil and gas assets.

In addition, another director, Malcolm Brinded will not to stand for re-election as a non-executive director, BHP said.

The company named Terry Bowen, a finance director for Australian retail and mining conglomerate Wesfarmers Ltd., and John Mogford, a former BP executive, as the two new independent non-executive directors. The pair will take up their roles on Oct. 1.

Global Marine Group Extends Into Port Of Blyth

(Source: Global Marine Group)

Offshore engineering service provider Global Marine Group (GMG) has added the Port of Blyth, Northumberland, to its U.K. operations base, the company said.

Calling the port a "major support base for UK offshore energy projects," GMG said its CWind offshore wind business unit and Global Marine, which provides fiber-optic cable solutions, will operate from the port.

Adding the port to its U.K. footprint means the company aims to "offer regionally focused support, resulting in faster mobilization, greater flexibility and enhanced response times for customers."

Bourbon Sees Brighter Outlook After 1H Profit Slump

Bourbon said on Sept. 7 that oil companies are restarting projects, which should help its business pick up after profits fell sharply in the first half.

Weak oil prices, which are more than 50% lower than 2014 highs, have prompted oil companies to cut back on spending and oil services companies have seen sharply declining profits. However, Bourbon said new projects were going ahead, citing Qatar's plan to raise LNG output by 30% and French oil major Total's return to Iran.

"The fact that clients earn money, are finding room for maneuver, can invest with oil at $50 means that this situation will generate business for us," CEO Jacques de Chateauvieux said during a Sept. 7 call with journalists.

Adjusted core profit (EBITDA) for the first half fell 55.7% year-on-year to about $71.4 million due to a continuing freeze in investment by oil companies. The average utilization rate for the company's vessels fell 13 percentage points in the first half to 53.8%.

The company said that it expects utilization rates to stabilize in the subsea and crew boats segments.

EnQuest Profits Slide On Slower Kraken Oil Field Ramp-up

EnQuest on Sept. 7 reported a sharp drop in first-half profits on lower production and delays in ramping up its flagship Kraken oil field.

EnQuest kept its previous full-year production guidance, which calls for a fall of as much as 18% to 10% above or below its output in the first half of the year of 37,015 boe/d.

The company reduced its expected capex this year to the lower end of previous guidance at $375 million to $400 million. Spending on Kraken was expected to be lower by $100 million, bringing the project's cost to $2.4 billion, about 25% below its original budget in 2013.

The London-listed company's shares have dropped sharply since it forecast last month the fall in output due to delays in bringing Kraken's floating production, storage and offloading vessel into operation. Other operational issues and the lack of recent drilling in other fields will also affect production, the company said.

EnQuest is confident it will resolve issues related to Kraken, which started production in June, by the end of the year and reach a production plateau of 50,000 boe/d in first-half 2018, CEO Amjad Bseisu said in an interview. "Kraken is a complex system ... so we are not getting the efficiencies that we had hoped for but I think things are improving now," Bseisu said, adding that Kraken's reservoir and subsea equipment was performing according to expectations.

The first cargo of crude from the heavy-oil field is expected to load next week.

Kraken is one of a string of new North Sea fields that have started producing in recent months, heralding a small revival in the mature basin despite persistently weak oil prices.

EnQuest's earnings before interest, tax, depreciation and amortization (EBITDA) for first-half 2017 fell to $151 million from $243 million a year earlier.

—Staff & Reuters Reports

UPCOMING

The next issue of *Subsea Engineering News* will be distributed Sept. 21. Until then, visit *epmag.com*.

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